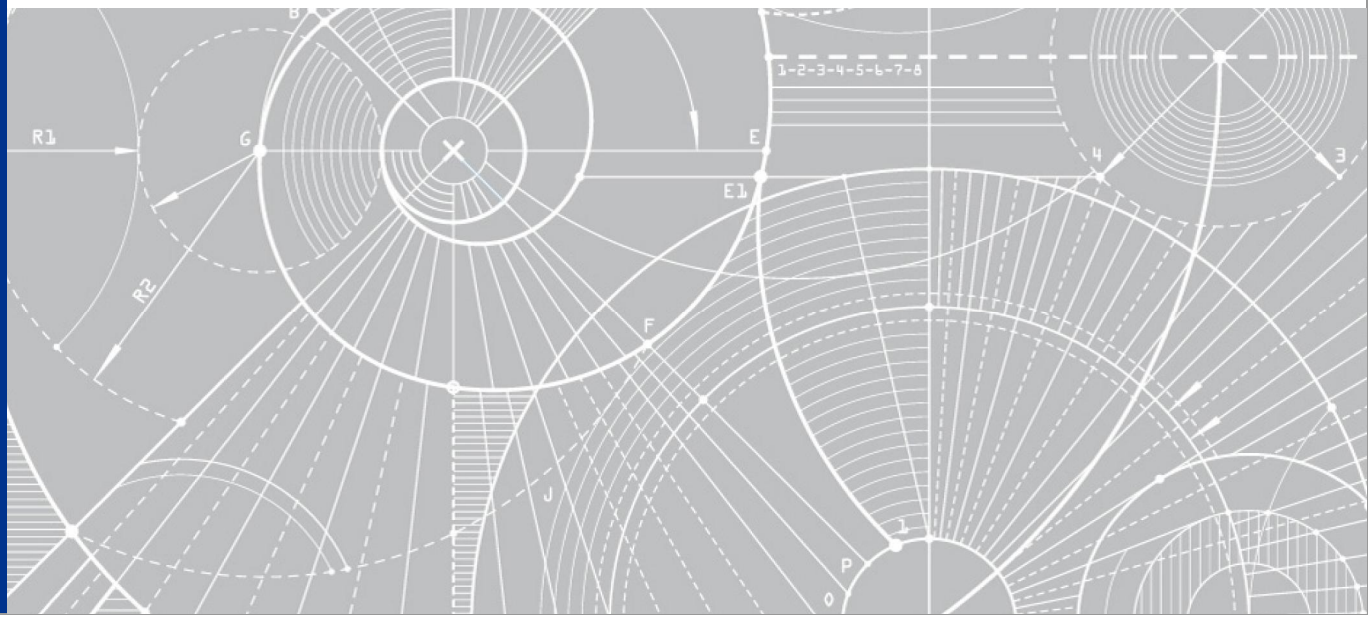
Impacts of Changes to the RET on Electricity Market Participants

THE CLIMATE INSTITUTE, AUSTRALIAN CONSERVATION FOUNDATION, WWF-AUSTRALIA

Final Report

August 2014



JACOBS

Impacts of RET on market participants

Project no:	SH43721
Document title:	Impact of Changes to the LRET on Market Participants
Document no:	Final report
Revision:	3
Date:	August 2014
Client name:	The Climate Institute
Project manager:	Walter Gerardi
Author:	Walter Gerardi
File name:	

Jacobs Group (Australia) Pty Limited
ABN 37 001 024 095
Floor 11, 452 Flinders Street
Melbourne VIC 3000
PO Box 312, Flinders Lane
T +61 3 8668 3000
F +61 3 8668 3001
www.jacobs.com

COPYRIGHT: The concepts and information contained in this document are the property of Jacobs Group (Australia) Pty Limited. Use or copying of this document in whole or in part without the written permission of Jacobs constitutes an infringement of copyright.

Contents

1. Introduction 4

2. Approach 5

2.1 Electricity market models 5

2.2 DOGMMA 7

2.3 REMMA 7

3. Assumptions 9

3.1 Structural assumptions 9

3.2 Price and revenue factors 9

3.3 Demand projections 10

3.4 Interregional trade 11

3.5 Fuel costs 13

3.5.1 Gas market and prices 13

3.5.2 Coal prices 16

3.6 Carbon Pricing and Emissions Reduction Fund 17

3.7 New generation entry 17

3.7.1 Reserve requirements 17

3.7.2 Thermal new entry 17

3.7.3 Renewable energy generation new entrants 19

3.8 Market Structure 21

4. Modelling Scenarios 22

5. Results 23

5.1 Wholesale prices 23

5.2 Retail Prices 25

5.3 Generator profits 27

5.4 Investment 29

5.5 Other benefits 30

5.5.1 Resource costs 30

5.5.2 Emissions 32

5.6 Employment 34

5.7 Sensitivity to lower demand 34

Important note about your report

The sole purpose of this report and the associated services performed by Jacobs is to provide an assessment of the impact of changes to, the LRET scheme on market participants in accordance with the scope of services set out in the contract between Jacobs and The Climate Institute (the Client). That scope of services, as described in this report, was developed with The Climate Institute, the Australian Conservation Foundation and WWF-Australia.

In preparing this report, Jacobs has relied upon, and presumed accurate, any information (or confirmation of the absence thereof) provided by the Client and/or from other sources. Except as otherwise stated in the report, Jacobs has not attempted to verify the accuracy or completeness of any such information. If the information is subsequently determined to be false, inaccurate or incomplete then it is possible that our observations and conclusions as expressed in this report may change.

Jacobs derived the data in this report from information sourced from the Client (if any) and/or available in the public domain at the time or times outlined in this report. The passage of time, manifestation of latent conditions or impacts of future events may require further examination of the project and subsequent data analysis, and re-evaluation of the data, findings, observations and conclusions expressed in this report.
Jacobs has prepared this report in accordance with the usual care and thoroughness of the consulting profession, for the sole purpose described above and by reference to applicable standards, guidelines, procedures and practices at the date of issue of this report. For the reasons outlined above, however, no other warranty or guarantee, whether expressed or implied, is made as to the data, observations and findings expressed in this report, to the extent permitted by law.

This report should be read in full and no excerpts are to be taken as representative of the findings. No responsibility is accepted by Jacobs for use of any part of this report in any other context.

This report has been prepared on behalf of, and for the exclusive use of the Client and is subject to, and issued in accordance with, the provisions of the contract between Jacobs and The Climate Institute.

Jacobs accepts no liability or responsibility whatsoever for, or in respect of, any use of, or reliance upon, this report by any third party

1. Introduction

The Climate Institute, Australian Conservation Foundation and WWF-Australia are seeking an assessment of the impacts on electricity market participants (generators and retailers) of potential changes to the structure of the LRET scheme. They have engaged Jacobs to undertake this assessment.

This report outlines the key assumptions and the approach used in the modelling, and discusses the results of the analysis.

2. Approach

Jacobs' market models are designed to create predictions of wholesale electricity price and generation driven by the supply and demand balance, with long-term prices capped near the cost of the cheapest new market entrant (based on the premise that prices above this level provide economic signals for new generation to enter the market). Price drivers include fuel costs, unit efficiencies and capital costs of new plant.

The primary tool used for modelling the wholesale electricity market benefits is Strategist model. Strategist simulates the most economically efficient unit dispatch in each market while accounting for physical constraints that apply to the running of each generating unit, the interconnection system and fuel sources. Strategist incorporates chronological hourly loads (including demand side programs such as interruptible loads and energy efficiency programs) and market reflective dispatch of electricity from thermal, renewable, hydro and pumped storage resources.

Strategist also accounts for inter-regional trading, and scheduled and forced outage characteristics of thermal plant (using a probabilistic mechanism).

Timing of new generation is determined by a generation expansion plan that defines the additional generation capacity that is needed to meet future load or plant retirements. The expansion plan has a sustainable wholesale market price path, applying market power where it is evident, and meets reserve constraints in each region.

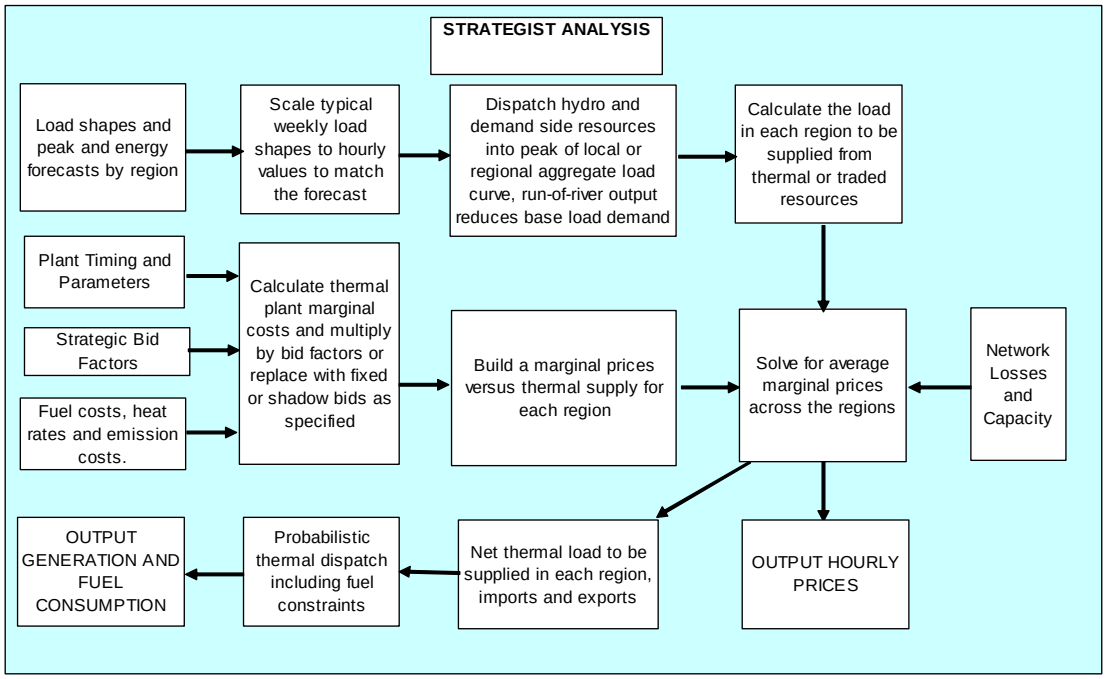
General assumptions are provided below:

- Capacity is installed to meet the target reserve margin for the NEM in each region.
- Utilises medium demand growth projections with annual demand shapes consistent with the relative growth in summer and winter peak demand.
- Generators behave rationally, with uneconomic capacity withdrawn from the market and bidding strategies limited by the cost of new entry.

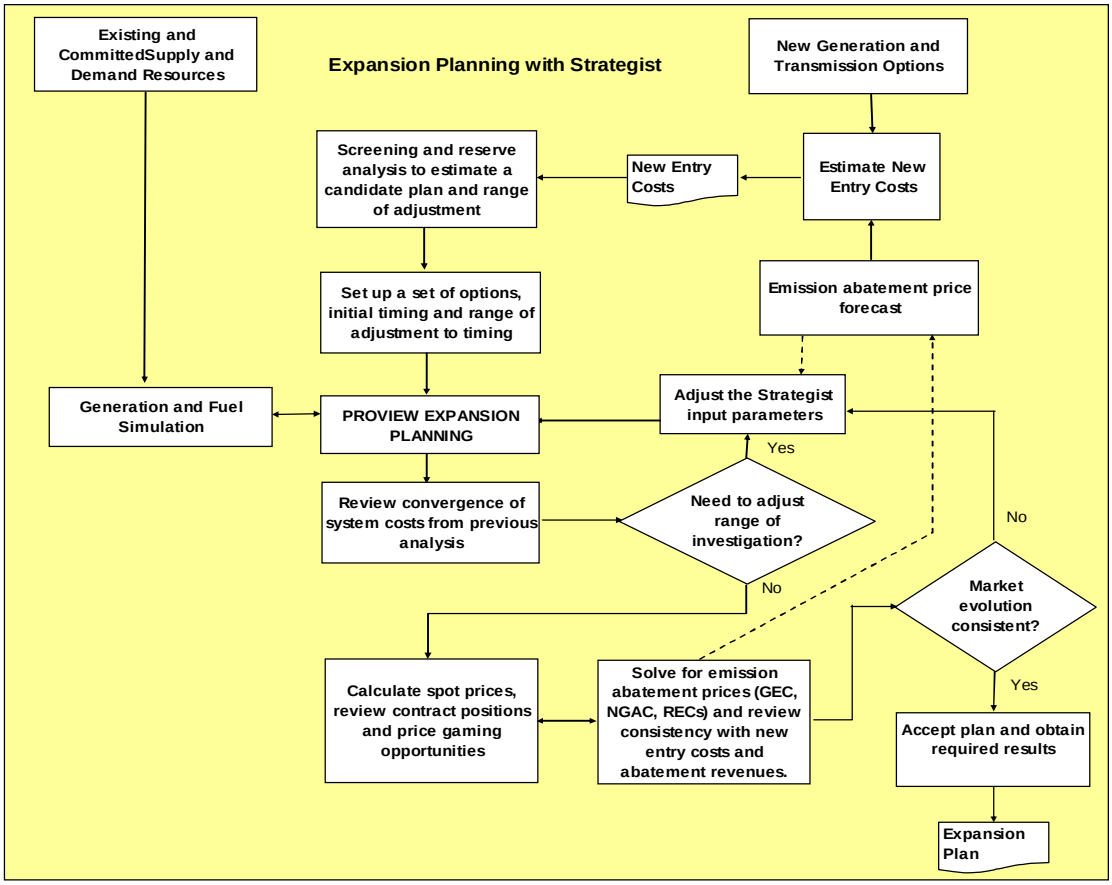
2.1 Electricity market models

Average hourly pool prices are determined within Strategist based on thermal plant bids derived from marginal costs or entered directly. The internal Strategist methodology is represented in Figure 1 and the modelling procedures for determining the timing of new generation and transmission resources are presented in Figure 2.

Figure 1: Strategist analysis flowchart



- Figure 2: Modelling procedures



Strategist generates average hourly marginal prices for each hour of a typical week for each month of the year at each of the regional reference nodes, having regard to thermal plant failure states and their probabilities. The prices are solved across the regions of the NEM having regard to inter-regional loss functions and capacity

constraints. Transmission failures are not represented although capacity reductions are included based on historical chronological patterns.

2.2 DOGMMA

DOGMMA (Distributed On-site Generation Market Model Australia) determines the uptake of small scale renewable energy technologies based on net cost of generation (after FIT revenue and other subsidies are deducted from costs) versus net cost of grid delivered power. Because the cost of renewable generation will vary by location and load factors, the model estimates uptake based on renewable resources and load levels within distribution regions. Other factors that may impact on the decision are modelled as a premium prepared to be paid for small scale renewable generation. The premium is calculated based on market survey data and other published market data. The premium is assumed to decrease as the rate of uptake increases (reflecting the fact that the willingness to pay will vary among customers).

The cost of small scale renewable energy technologies is treated as an annualised cost where the capital and installation cost of each component of a small scale generation system is annualised over the assumed lifespan of each component, discounted using an appropriate weighted average cost of capital. Revenues include sales of electricity using time weighted electricity prices on the wholesale and retail market, avoidance of network costs including upgrade costs if these can be captured, and revenues from other Government programs such as feed-in tariffs and the Small-scale Renewable Energy Scheme (SRES).

The model is:

- Disaggregated by the major transmission nodes for each state. The number of eligible residential and/or commercial entities in each region will be the basic unit for modelling. That is, costs of delivered electricity is modelled for each customer group where these groups will be defined by insolation levels, renewable energy resource cost and load profiles. The degree of disaggregation within customer classes will depend on the amount of data available on insolation levels, renewable energy resource cost and load profiles.
- The degree to which each customer group adopts renewable energy technologies will also depend on tariff arrangements, with assumptions made on the uptake of interval meters and the time of use tariffs.

The model has a built in function to reduce the cost of generation from small scale technologies as a function of adoption of these technologies. International studies have indicated that the level of utilisation is likely to be the best predictor of future cost reductions through learning by doing. Economies of scale in production are likely to be achieved through increasing capacity installed.

2.3 REMMA

The Australian renewable energy market may be modelled in REMMA. REMMA is a tool that estimates a least cost renewable energy expansion plan, and solves the supply and demand for LGCs having regard to the underlying energy value of the production for each type of resource (base load, wind, solar, biomass with seasonality). REMMA is an Excel application based on a database of nearly 900 existing, committed, proposed and generic projects across Australia.

REMMA also allows modelling of the impact of policies affecting the expanded RET scheme. Policies affecting the RET scheme often affect change to LGC prices and technology uptake over the period of the scheme.

Projecting LGC prices with the REMMA model is based on the assumption that the price of the LGC will be the difference between the cost of the marginal renewable generator and the price of electricity achieved for that generation. The basic premise behind the method is that the LGC provides the subsidy, in addition to the electricity price, that is required to make the last installed (marginal) renewable energy generator to meet the LGC target economic without further subsidisation. The REMMA uses a linear programming algorithm to determine least cost uptake of renewable technologies to meet the target, subject to constraints in resource availability and regulatory limits on uptake. The optimisation requires that the interim targets are met in each year (by current generation and banked certificates) and generation covers the total number of certificates required over the period to 2030 when the program is scheduled to terminate. The certificate price path is set by the net cost of the marginal generators, which enable the above conditions to be met and result in positive

returns to the investments in each of the projects. Jacobs has a detailed database of renewable energy projects (existing, committed and proposed) that supports our modelling of the LGC price path. The database includes estimation of capital costs, likely reductions in capital costs over time, operating and fuel costs, connection costs, and other variable costs for over 900 individual projects.

3. Assumptions

3.1 Structural assumptions

All major electricity systems will be modelled which include the National Electricity Market (NEM), South West Interconnected System (SWIS), North West Interconnected System (NWIS), Northern Territory systems (Darwin/Katherine) and Mt Isa. The NEM system is the largest and contributes over 85% of the electricity demand in Australia.

Key assumptions used in the modelling include:

- The medium demand growth projections, with annual demand shapes consistent with the relative growth in summer and winter peak demand. For the NEM this is based on the 2013 National Electricity Forecasting Report, with adjustments for known closures for industrial plant[1]. For the remaining systems the latest demand forecasts available will be used (i.e. 2012/13 demand forecast). Due to the relative size of the NEM this mismatch in demand forecasts is unlikely to change the results. Figure 3 and Figure 4 represents the demand forecast used in the analysis for the NEM and the other regions respectively.
- Capacity is installed to meet the target reserve margin for the all systems and each region in the NEM at least cost. Some of this peaking capacity may represent demand side response rather than physical generation assets.
- Generators behave rationally, with uneconomic capacity withdrawn from the market and bidding strategies limited by the cost of new entry. This is a conservative assumption as there have been periods when prices have exceeded new entry costs when averaged over 12 months.

The modelling output will be in December 2013 dollars.

3.2 Price and revenue factors

The electricity price path and related market outcomes is essentially driven by the supply and demand balance and long-term pool prices being effectively capped near the cost of new entry on the assumption that prices above this level provide economic signals for new generation to enter the market. Consequently, assumptions on the fuel costs, unit efficiencies, and capital costs of new plant and carbon prices will have a noticeable impact on the long-term average price forecasts. Year to year prices will deviate from the new entry cost level based on the timing of new entry. In periods when new entry is not required, the market prices reflect the cost of generation to meet regional loads, and the bidding behaviour of the market participants as affected by market power.

The critical factors for renewable energy projects during the immediate period to 2020 are:

- The magnitude of the renewable energy target
- The new renewable energy supply curve which will determine the new entry cost for renewable energy
- The extent to which renewable resources are developed in areas of higher energy costs relative to other locations. Returns to wind farms in other locations would be reduced if LGC prices are lower due to high energy prices elsewhere, such as in Western Australia.

The combination of these factors will be the primary driver of revenue to renewable energy projects. The renewable energy revenue would be influenced by the intersection of the demand for renewable energy and the long-run marginal cost of new renewable energy.

The market forecasts take into account the following parameters:

[1] AEMO have released new forecasts since the modelling was completed. AEMO's 2014 forecast of demand is lower than in the 2013 forecast. However, we have adjusted for the closure of known loads such as Point Henry and actual uptake of PV systems. Projecting forward we also adjusted AEMO's previous forecast using our own forecasts of PV uptake and have adjusted for the impact on demand of the removal of the carbon price (assuming an own price elasticity of demand of -0.3 applied to the retail price change after the carbon price is removed). Hence, our demand projections are slightly higher than AEMO's current forecast but still plausibly reflect different assumptions affecting electricity demand.

- Regional and temporal demand forecasts;
- Generating plant performance;
- Timing of new generation including embedded generation;
- Existing interconnection limits; and
- Potential for interconnection development

3.3 Demand projections

Figure 3 2013 Medium demand forecast for the NEM regions

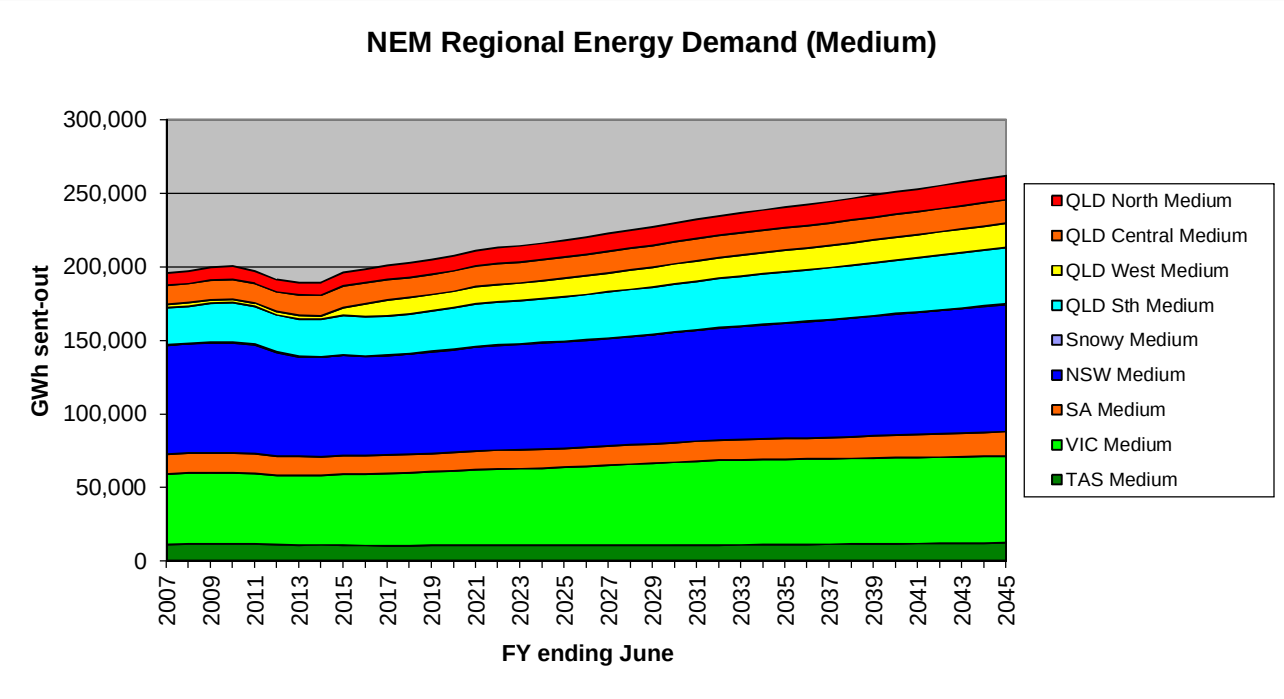


Figure 4 Non NEM energy demand forecast – medium scenario

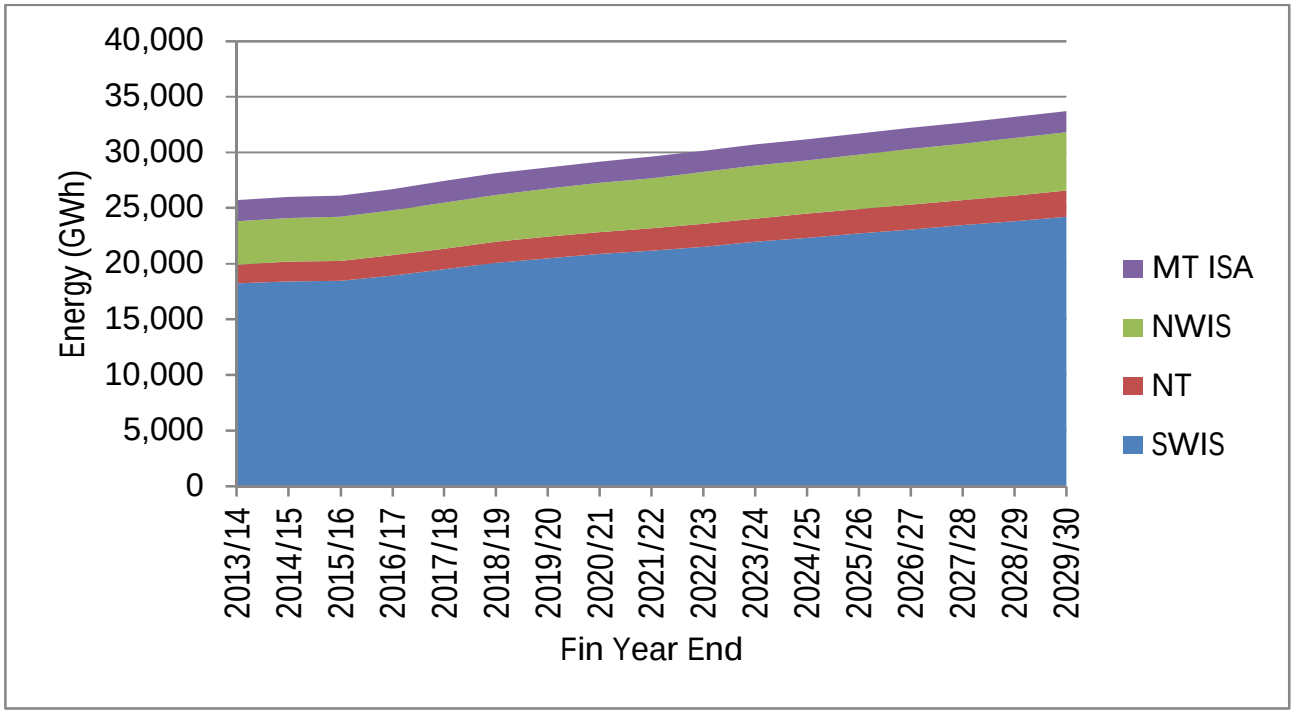
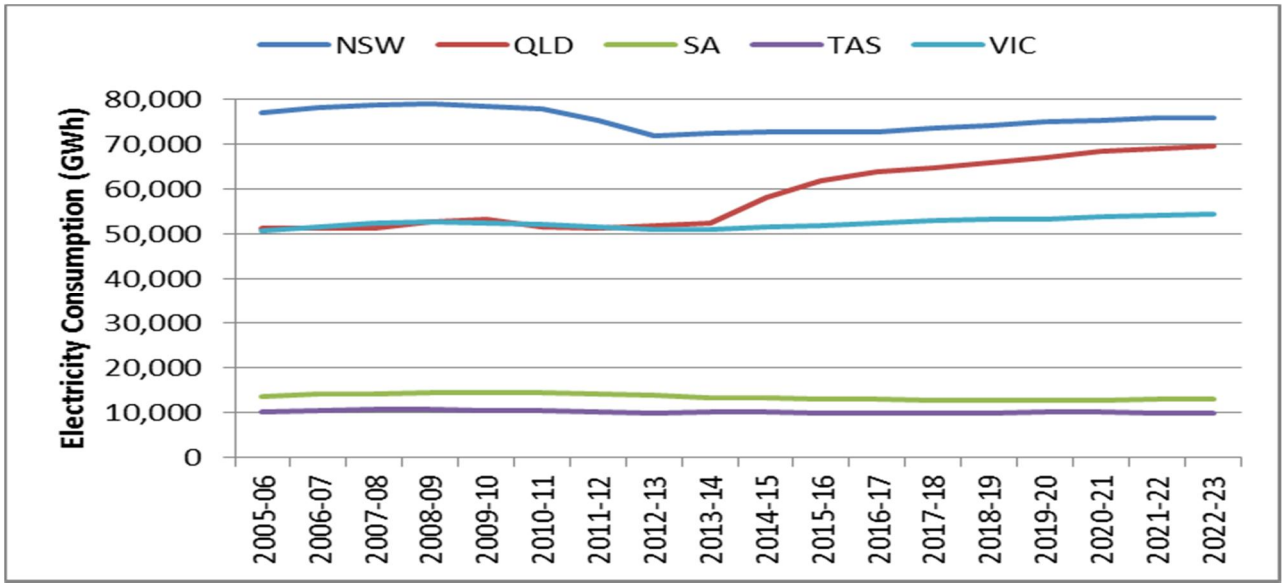


Figure 5 AEMO updated electricity consumption forecast – March 2014.



3.4 Interregional trade

Assumptions on interconnect limits are shown in Table 1. We have retained a Snowy zone in our Strategist model to better represent the impact of intra-regional constraints on each side of the Victoria/NSW border.

Table 1 Interconnection limits

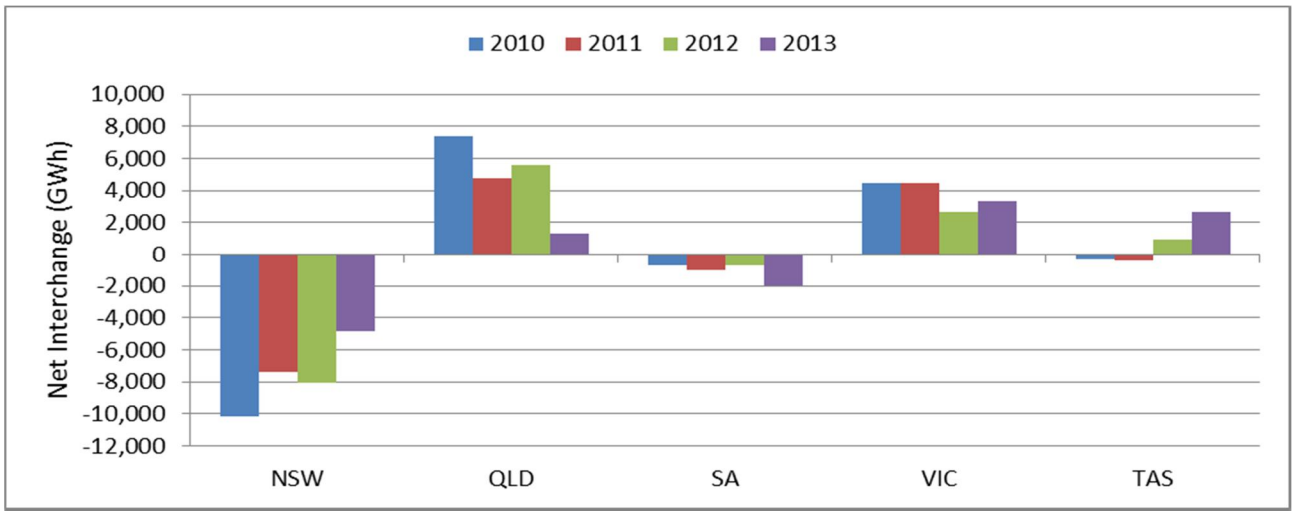
From	To	Capacity	Summer
Victoria	Tasmania	480 MW	
Tasmania	Victoria	600 MW	
Victoria	South Australia	460 MW	
South Australia	Victoria	460 MW *	
South Australia	Redcliffs	135 MW	
Redcliffs	South Australia	220 MW	
Victoria	Snowy	1,300 MW *	
Snowy	Victoria	1,900 MW	
Snowy	NSW	3, 559 MW	3,117 MW
NSW	Snowy	1,150 MW	
NSW	South Queensland	120 MW	
South Queensland	NSW	180 MW	120 MW
NSW	Tarong	589 MW	
Tarong	NSW	1,078 MW	

** From 2011 data*

The actual limit in a given period can be much less than these maximum limits, depending on the load in the relevant region and the operating state of generators at the time. For example, in the case of the transfer limit from NSW to Queensland via QNI and Terranora, the capability depends on the Liddell to Armidale network, the demand in Northern NSW, the output from Millmerran, Kogan Creek and Braemar, and the limit to flow into Tarong[2].

Interregional trade between states has been decreasing as proportion of energy demand within each state. However, energy transfers between regions represent a significant part of total NEM consumption. During 2013 South Australia imported 16% of its energy demand and NSW imported 7%, with Victoria and Queensland being significant exporters.

Figure 6 Net interchanges in the NEM, 2010-2013 calendar years



[2] There is currently expected to be a limit of about 900 MW for flow into Tarong. This is not a fixed limit and could be increased with additional load shedding in Queensland.

Inter-regional loss equations are modelled in Strategist by directly entering the Loss Factor equations published by AEMO except that Strategist does not allow for loss factors to vary with loads. Therefore we allow a typical area load level to set an appropriate average value for the adjusted constant term in the loss equation. The losses currently applied are those published in the AEMO 4 May 2012 Report "List of Regional Boundaries and Marginal Loss Factors for the 2013/14 Financial Year"[3].

Negative losses are avoided by shifting the quadratic loss equation so that the minimum passes through zero loss.

Intra-regional losses are applied as detailed in the AEMO 28 March 2013 Report V1.0 "List of Regional Boundaries and Marginal Loss Factors for the 2013-14 Financial Year",

The long-term trend of marginal loss factors is extrapolated for two more years and then held at that extrapolated value thereafter.

3.5 Fuel costs

3.5.1 Gas market and prices

Eastern Australia (New South Wales, Victoria, Queensland, South Australia, Tasmania and the ACT) has a domestic market estimated at 709 PJ in 2012, supported by substantial conventional and coal seam gas (CSG) reserves – 2P reserves at are currently estimated at 49,838 PJ. Regional breakdowns of these figures are shown in Table 2.

Table 2 Gas demand and reserves by state, 2012 (PJ)

	NSW	Victoria	SA	Tasmania	Queensland	Total
Demand	158	218	103	18	212	709
2P Reserves	2,663	5,779	2616	247	38,533	49,838

Source: Demand: AEMO Bulletin Board; Reserves: Oil and Gas Resources Australia; Queensland Department of Natural Resources and Mines; and Producer Estimates

Demand and supply patterns in this market have operated in isolation from other gas markets in Australia and overseas because to date there have been no gas exports from or imports to the region. Recent growth of CSG reserves, to levels in excess of foreseeable domestic demand, has led to construction of a number of LNG export projects which have already begun to change the domestic market, both in terms of the demand-supply dynamics and the nature of the participants.

The gas resources and delivery infrastructure in this region are illustrated in Figure 7. All Eastern States sub-markets except Northern Queensland are now served by multiple basins and/or pipelines.

The historical gas prices have steadily increased over time. This is depicted for the Victorian gas price shown in Figure 8. The variation of the spot price from underlying contract price has been driven by the following:

- 2007 spike was driven by high demand for generation due to Qld drought;
- 2009 to 2011 saw an excess capacity overreaction to 2007 as well as gas bid below cost due to take-or-pay arrangements.
- 2012 Reversal of Take or Pay leading to gas hoarding.

[3] Note that we have not updated the inter-regional loss functions to 2013-14 as yet. This is not a significant factor because the loss equations are stable with only minor variations from year to year.

Figure 7 Gas reserves at 31/12/2012 and pipeline flows in 2012, Eastern Australia

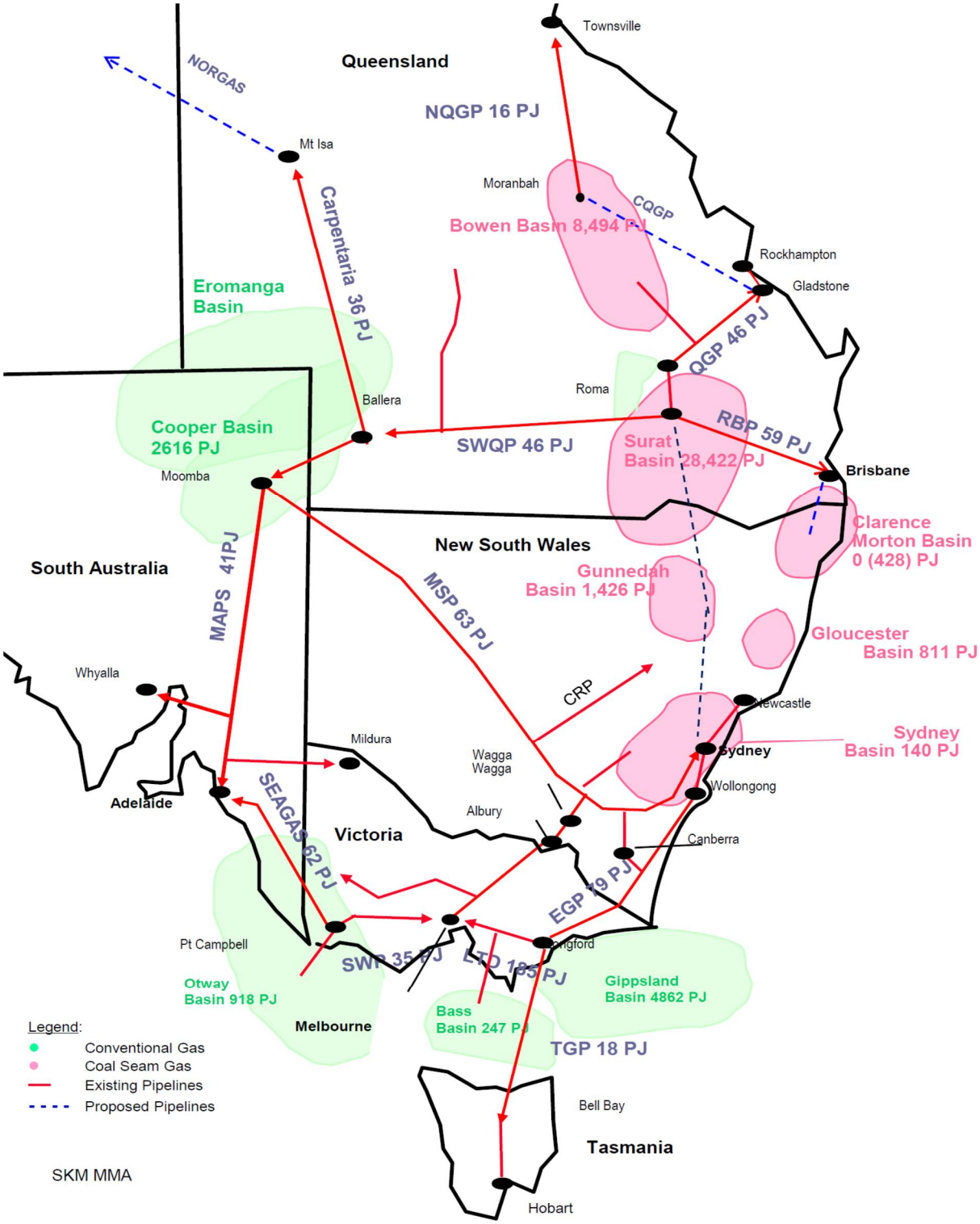
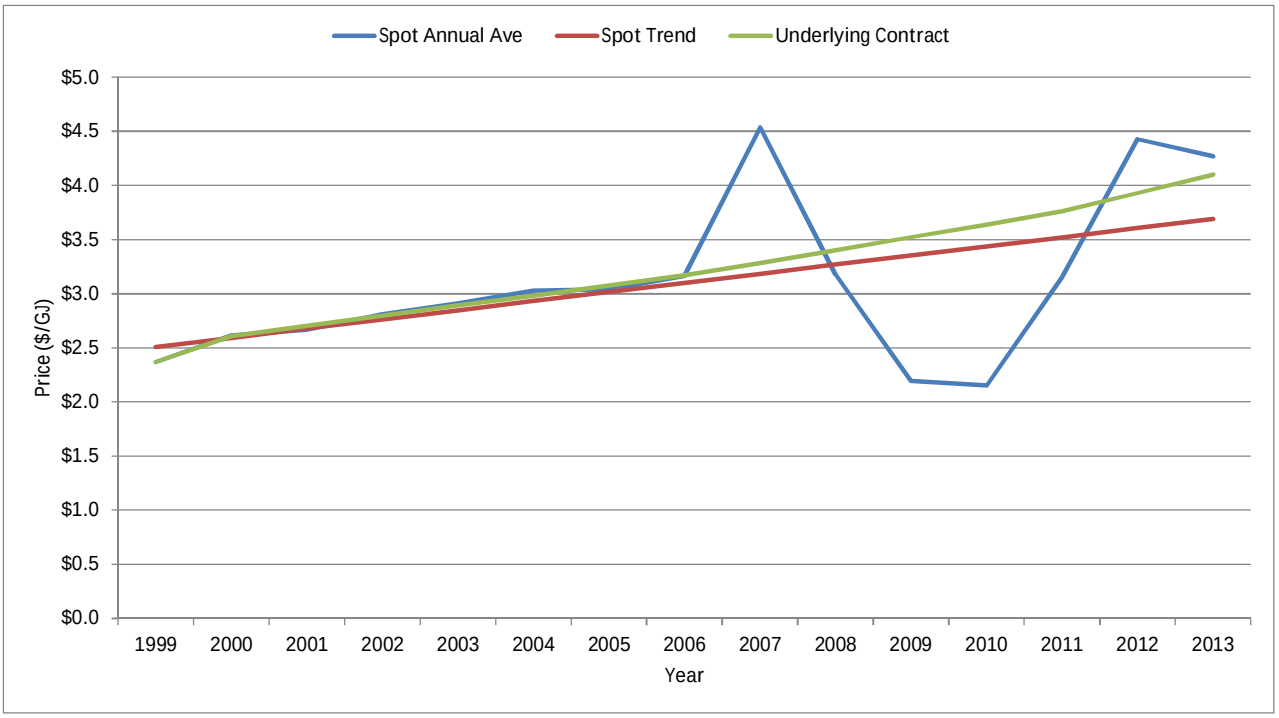
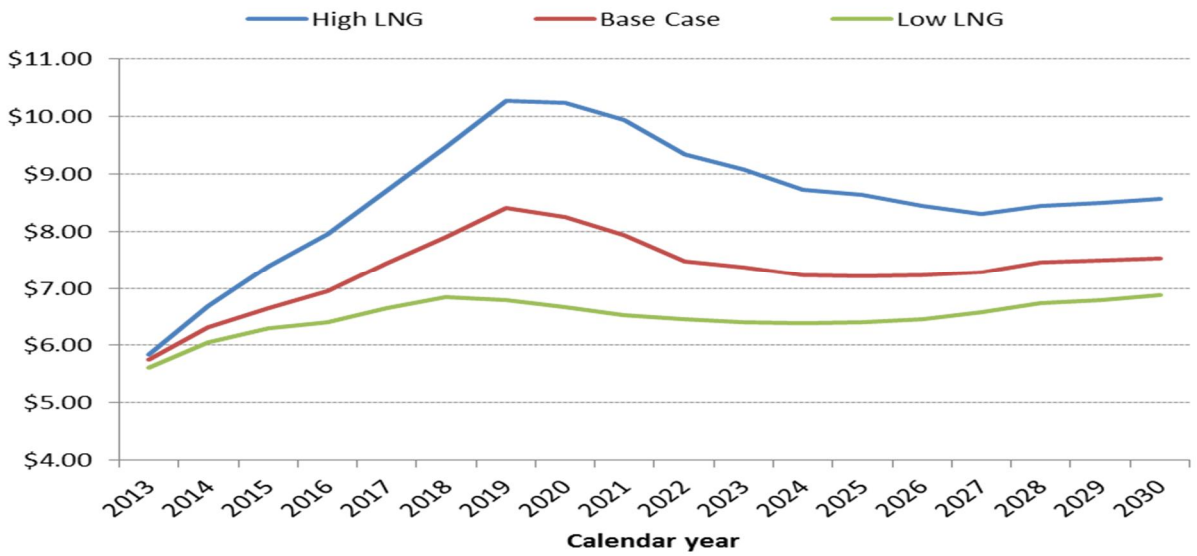


Figure 8 Annual spot and contract prices for Victorian gas market



Jacobs prepares gas price forecasts based on projected demand-supply balances in Eastern Australia, the physical characteristics of the market, and the underlying cost of supply to provide scenarios on future demand and price projections. Figure 9 provides a view on a number of scenarios for new upstream 15-year gas contract prices for Eastern Australia.

Figure 9 New upstream contract prices for Eastern Australia ($/GJ, $2013 real)



The base case prices were used in this analysis. The base case represents the most likely outcome for the Eastern Australian wholesale gas market. It assumes that 2 further LNG trains in Queensland are commissioned in addition to the 6 that are currently committed to enter production.

At all delivery points new contract prices are expected to rise to 2019, where it reaches over $8/GJ (city-gate, flat load prices). The prices fall after LNG growth either stops or slows and more of the gas reserve growth becomes available for domestic supply.

3.5.2 Coal prices

Jacobs' coal price assumptions are shown below in Figure 10. As part of the AEMO NEFR (2012, 2013 and 2014) and ESOO (2012, 2013) processes, ACIL Tasman also supplied coal prices. Their forecast prices by region are shown in Figure 11.

Figure 10 Jacobs' coal prices by power station

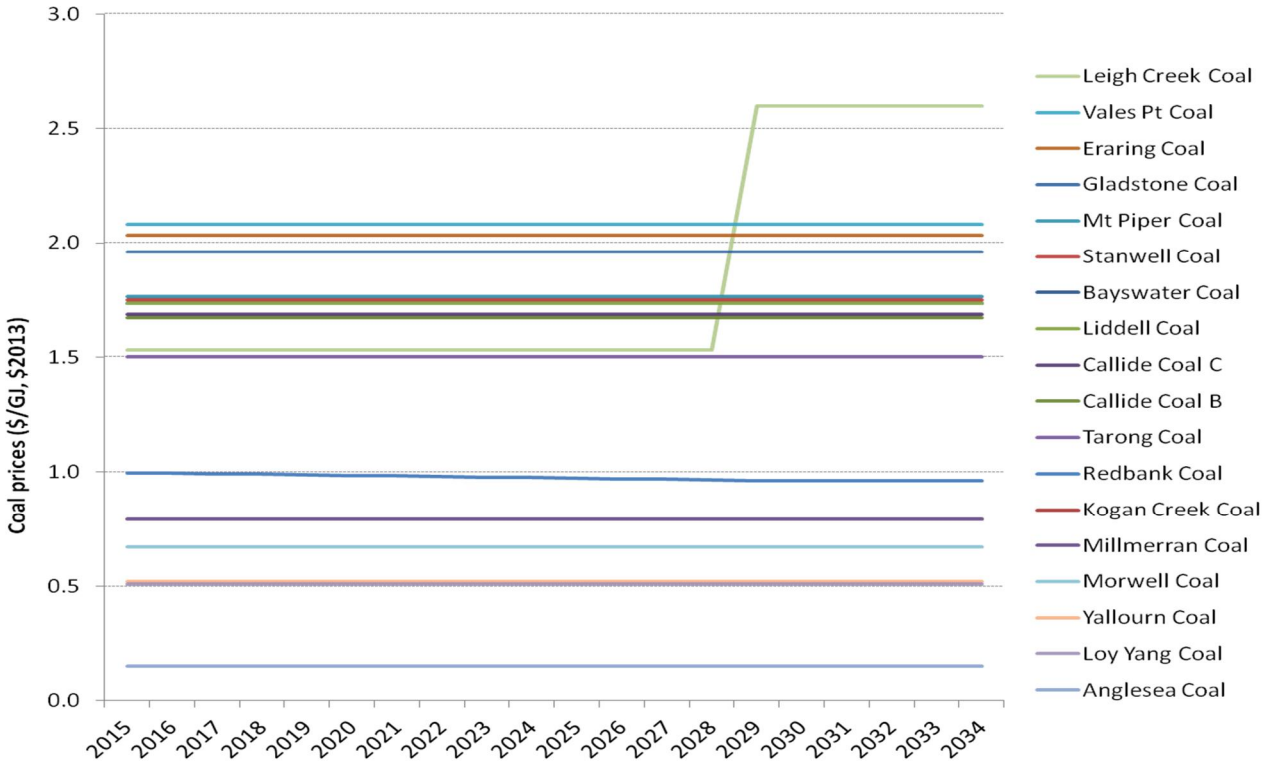
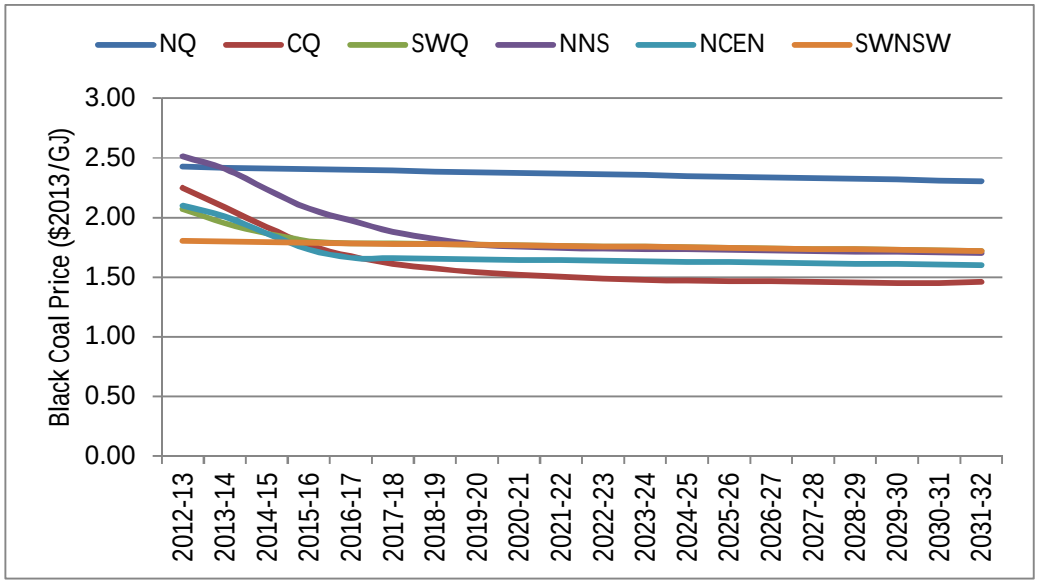


Figure 11 ACIL Tasman Black Coal prices by region



Both forecasts are reasonable similar with flat prices over the long term. Hence, Jacobs uses our internal forecast.

3.6 Carbon Pricing and Emissions Reduction Fund

For the purposes of this modelling we have assumed there is no carbon price enforced sometime in the future. However, we have assumed that the potential threat that carbon pricing may be enacted sometime in the future means that investors will be unwilling to invest in new coal plant.

The Emissions Reduction Fund (ERF) will work together with other incentives under the Direct Action Plan and the Renewable Energy Target to help Australia meet its target of reducing emissions by five per cent below 2000 levels by 2020. The Emissions Reduction Fund will extend from 1 July 2014 to 2020 and will include initial funding of $1.15 billion for the first 4 years of the scheme. The ERF will mainly be a reverse auction to buy back the lowest-cost abatement and hence will not impact on electricity market prices. We assume that electricity generation will receive minimal funding under the ERF, although we assume that 80 MW of coal mine gas plant or waste to energy plant do get funded.

3.7 New generation entry

Only generic new entrant technologies are included as possible new entrants in order to limit the size of the computational problem to make it manageable. These technologies include:

- Combined cycle gas turbines (CCGT) with and without carbon capture and storage (CCS)
- Generic open cycle gas turbines (OCGT)
- Integrated gasification combined cycle generators (IGCC), with and without CCS.

Supercritical and ultra-supercritical coal units are considered highly unlikely in the current market environment. Even with no carbon price we do not generally include these options on the basis that the continued threat of the introduction of a carbon price would be enough to discourage construction of this type of plant in the NEM. However, we allow carbon capture ready Integrated Gasification Combined Cycle (IGCC) plant to be selected if economic.

3.7.1 Reserve requirements

Timing of new plant entry is formulated to ensure that the reserve requirements are met in each region at least cost. The minimum reserve levels assumed for each state are taken from minimum reserve level requirements for long term planning and are generally based on covering the loss of the largest unit in the system.

Table 3 Minimum reserve levels assumed for each state

Region	Queensland	NSW	Victoria	SA	Tasmania
Reserve Level	666.1 MW	673.2 MW	498 MW	439 MW	194 MW

The minimum reserve level for VIC and SA combined is now adjusted for reserve sharing to minimise the local reserve requirement in SA. This means that Victoria must carry 530 MW when South Australia is partially relying on Victoria. The increase in reserve in Queensland reflects both the increase in the size of the largest unit by 300 MW (Kogan Creek) and the support provided to NSW through increased export power flows.

3.7.2 Thermal new entry

After selecting new entry to meet minimum reserve criteria, Jacobs pool market solution indicates whether prices would support additional new entry under typical market conditions and these are included in the market expansion if required. We assume that:

- Some 75% of base load plant capacity will be hedged in the market and bid at close to marginal cost to manage contract position.
- New entrants will require that their first year cash costs are met from the pool revenue before they will invest.

- Infrequently used peaking resources are bid near the maximum allowable price or removed from the simulation to represent strategic bidding of such resources.

Cost and financing assumptions used to develop the long-term new entry prices are provided in Table 4 applicable to the financial year 2014/15. The trend in annualised capital recovery costs is shown in Figure 12, assuming that the Australian dollar falls to US90c in 2013/14 and then to US80c by 2019/20. Thereafter the exchange rate is stable. The real pre-tax equity return applied was 17% and the CPI applied to the nominal interest rate of 8% was 2.5%. The capital costs are generally assumed to rise slowly in real terms to 2020, and then escalate at between 0.5% and 1% below CPI to 2040 until they reach long term stability. New technologies have higher initial costs and greater rates of real cost decline up to -1.0% p.a. for IGCC. The debt/equity proportion is assumed to be 60%/40%. This gives a real pre-tax vanilla WACC of 10.02 % pa.

The availability factors are applied as capacity factors in Table 4 to allow us to approximate a time-weighted new entry price in each state that can rapidly be compared to the time-weighted price forecasts to determine whether or not new entry would be encouraged to enter the market.

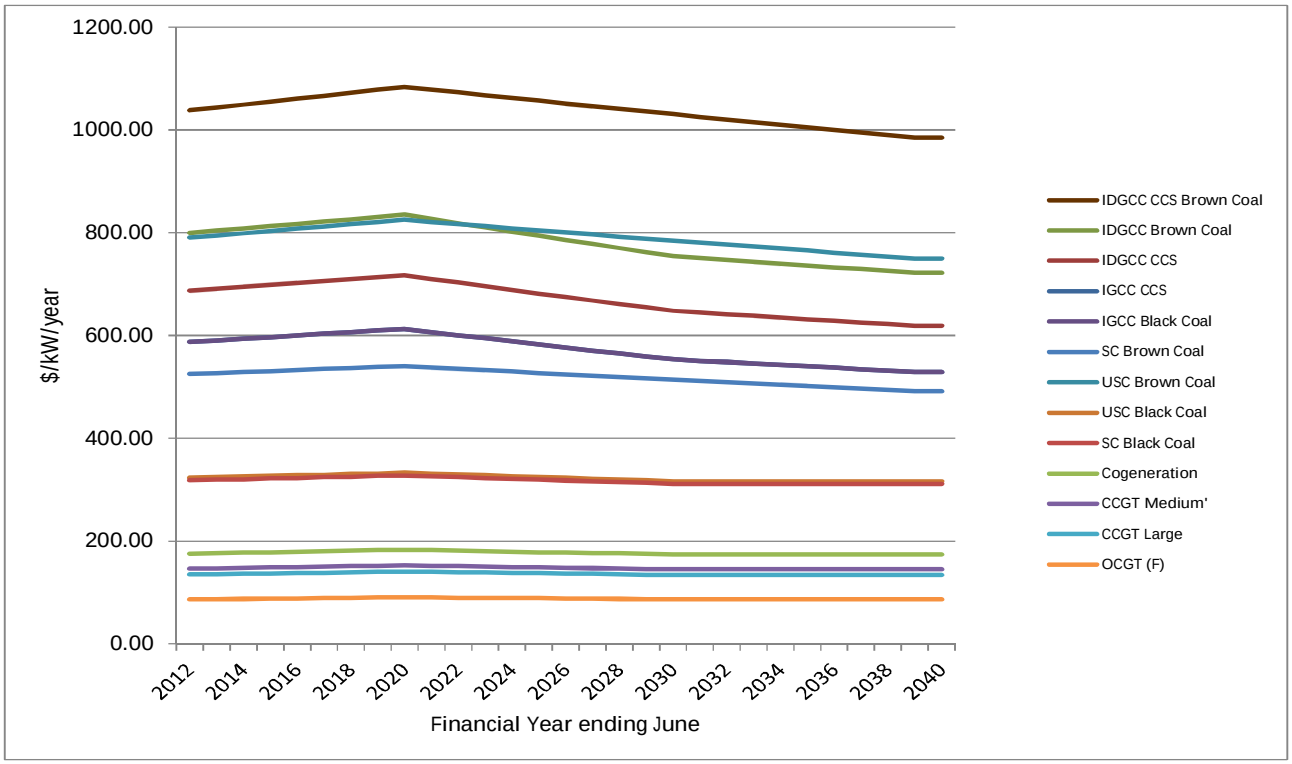
Retirements of old plant are co-optimised with new entry, taking account of the avoidable costs and the minimum reserve levels assumed in each state. Units with revenues not recovering annualised operating costs for greater than 2 years are retired or mothballed (if the period of negative operating profits is short). A portfolio optimisation may also occur in periods with sustained low wholesale prices, where generating units are mothballed/retired if they improve the overall revenue earnt by the portfolio (that is, the additional revenue on the remaining generating assets in the portfolio outweigh the loss in revenue of the retired plant).

Table 4 New entry cost and financial assumptions

State	Type of Plant	Capital Cost *$/kW*	Available Capacity Factor	Fuel Cost* *$/GJ*	Weighted Cost of Capital *% real*	Interest Rate *% nominal*	Debt Level	LRMC *$/MWh*
SA	CCGT	1,327	89.7%	$ 7.26	10.02%	8.00%	60%	$ 81.96
Vic	CCGT	1,191	89.7%	$ 6.69	10.02%	8.00%	60%	$ 71.53
NSW	CCGT	1,191	89.7%	$ 7.03	10.02%	8.00%	60%	$ 72.60
NSW	Black Coal	2,719	90.6%	$ 1.76	10.02%	8.00%	60%	$ 64.41
Qld	CCGT	1,191	89.7%	$ 8.39	10.02%	8.00%	60%	$ 81.00
Qld	Black Coal (Tarong)	2,719	90.6%	$ 1.50	10.02%	8.00%	60%	$ 59.90
Qld	Black Coal (Central)	2,719	90.6%	$ 1.45	10.02%	8.00%	60%	$ 59.75

** Fuel cost shown as indicative only.*

Figure 12 Trend in New Entry Capital Recovery Costs ($/kW/year)



3.7.3 Renewable energy generation new entrants

For the purposes of forecasting renewable energy development, a critical requirement is a database of potential renewable energy projects. Jacobs has developed a database which includes existing, committed, and prospective projects including some allowance for generic projects based on projections by industry organisations. With the continuing aftermath of the global financial crisis, we have maintained stringent financial parameters by keeping the debt level to 60%. The resulting pre-tax real WACC is 9.3% from 2014.

Figure 13 shows the cumulative renewable energy supply curve developed from the database for all proposed renewable plants. The supply curve includes all proposed resources expected to be available until 2040. The existing and committed resources provide approximately 16,000 GWh of LGCs and 31,000 GWh in total generation[4]. A reduced LRET target would see a significant drop in the LRMC on the marginal renewable generator to $110/MWh, from around $125/MWh with the existing LRET target.

Typical generic costs for new entrant renewables is also shown in Table 5 by state.

[4] The difference between 31,000 and 16,000 GWh represents the pre-existing renewable energy generation.

Figure 13 Renewable energy plant merit order, 2013/14

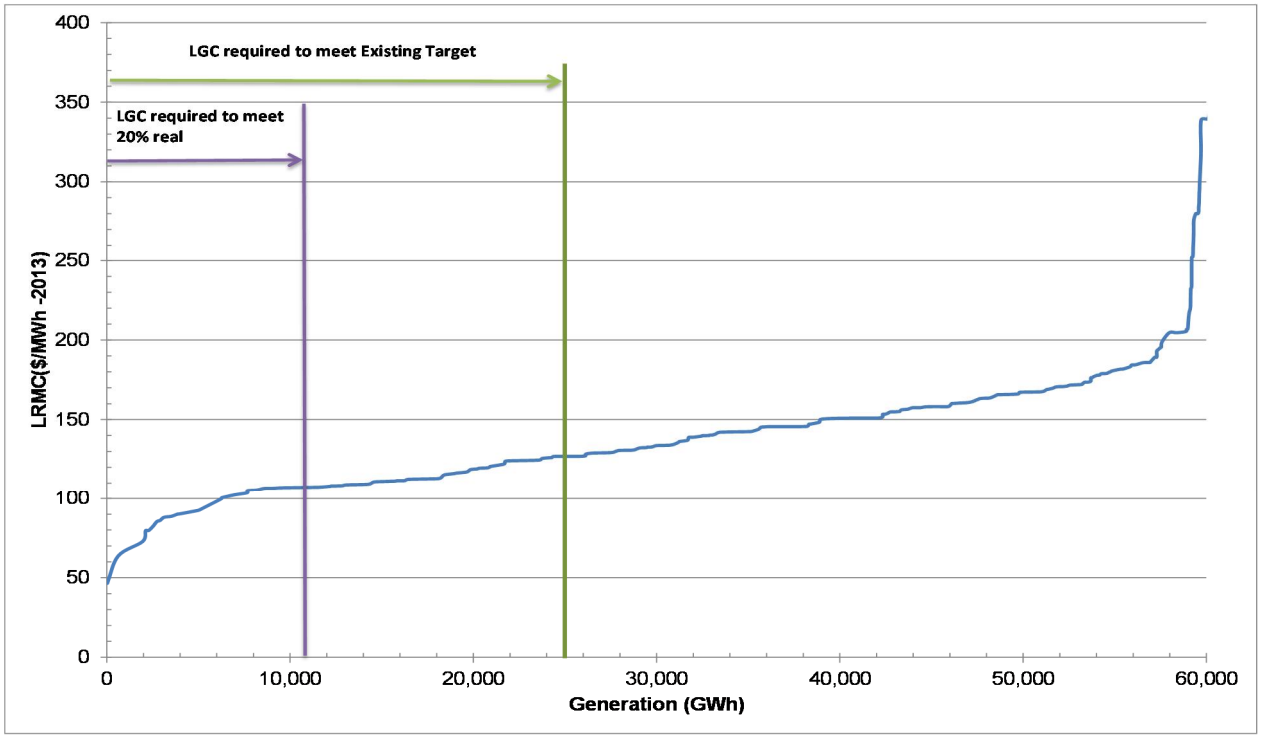


Table 5 New entry cost and financial assumptions for renewable generators for 2013/14

State	Type of Plant	Capital Cost (sent-out)	Available Capacity Factor	VO&M & Fuel cost	Weighted Cost of Capital	Interest Rate	Debt Level	LRMC	Capital cost reduction
		$ / kW sent out		$ / MWh	% real	% nominal	%	$ / MWh	% per annum
SA	Wind	$2689 - $4217	26% - 36%	$7.3 - $7.3	11.00%	9%	60%	$118 - $238	0.4%
	Biomass	$3159 - $6664	57% - 80%	$20.9 - $50.2	12.00%	9%	60%	$118 - $178	0.3%
	Hydro	N / A	N / A	N / A	N / A	N / A	N / A	N / A	N / A
	Geothermal	$4643 - $6598	85% - 85%	$23 - $23	11.00%	9%	60%	$105 - $138	0.7%
	Solar	$3578 - $16050	15% - 47%	$5.2 - $5.2	11.00%	9%	60%	$128 - $1533	2.0%
Vic	Wind	$2183 - $13421	18% - 41%	$7 - $7.3	11.00%	9%	60%	$105 - $544	0.4%
	Biomass	$2765 - $9693	57% - 80%	$20.9 - $62.7	12.00%	9%	60%	$92 - $298	0.3%
	Hydro	$3123 - $5619	35% - 58%	$3.1 - $3.1	11.00%	9%	60%	$126 - $136	0.2%
	Geothermal	$4677 - $5362	85% - 85%	$23 - $23	11.00%	9%	60%	$106 - $117	0.7%
	Solar	$5770 - $11183	15% - 50%	$5.2 - $5.2	11.00%	9%	60%	$204 - $1212	2.0%
NSW	Wind	$1976 - $4743	20% - 35%	$7.3 - $7.3	11.00%	9%	60%	$88 - $217	0.4%
	Biomass	$2363 - $4547	57% - 80%	$20.9 - $60.6	12.00%	9%	60%	$92 - $156	0.3%
	Hydro	$2382 - $2706	36% - 73%	$3.1 - $3.1	11.00%	9%	60%	$48 - $101	0.2%
	Geothermal	$4698 - $5810	85% - 85%	$23 - $23	11.00%	9%	60%	$106 - $125	0.7%
	Solar	$3578 - $11980	17% - 57%	$5.2 - $5.2	11.00%	9%	60%	$169 - $1146	2.0%
Qld	Wind	$2680 - $15285	28% - 35%	$7.3 - $7.3	11.00%	9%	60%	$116 - $618	0.4%
	Biomass	$3617 - $5144	35% - 80%	$20.9 - $62.7	12.00%	9%	60%	$105 - $275	0.3%
	Hydro	$2139 - $2348	27% - 38%	$3.1 - $3.4	11.00%	9%	60%	$80 - $122	0.2%
	Geothermal	$4894 - $5265	85% - 85%	$23 - $23	11.00%	9%	60%	$109 - $116	0.7%
	Solar	$3578 - $11183	20% - 57%	$5.2 - $5.2	11.00%	9%	60%	$169 - $910	2.0%
Tas	Wind	$2510 - $3508	33% - 42%	$7.3 - $7.3	11.00%	9%	60%	$112 - $149	0.4%
	Biomass	$1124 - $5708	57% - 80%	$7.7 - $41.8	12.00%	9%	60%	$31 - $195	0.3%
	Hydro	$2822 - $5403	10% - 46%	$3 - $3.1	11.00%	9%	60%	$141 - $400	0.2%
	Geothermal	N / A	N / A	N / A	N / A	N / A	N / A	N / A	N / A
	Solar	N / A	N / A	N / A	N / A	N / A	N / A	N / A	N / A

3.8 Market Structure

The market structure has changed significantly over the past 15 years. This has mainly resulted in less government ownership and more consolidation of generation and retail ownership across the NEM. This has resulted in three main gentailers (generators and retailers), AGL, Energy Australia and Origin Energy, servicing approximately 80% of the retail sector, with a number of smaller second tier retailers (i.e. ERM, Momentum Energy, Lumo Energy, Dodo Power, Simply Energy, among others).

This structure has implications for future renewable development as these three large retailers effectively have the majority of the RET liabilities and become the entities future developers need to write power purchase agreements (PPA)[5] with. Otherwise developers would have to take market price risk, obtain financing from other sources, or fund the project on balance sheet.

It is unlikely significant future market structure change will occur. The most relevant changes will be the continued sell off of the remaining government owned generation assets in NSW[6] and Queensland generation assets, although the time frame on the latter is uncertain. It is unlikely these sales will impact the wholesale market substantially and other factors will have a more significant effect (i.e. electricity demand and the overall RET target).

[5] Note to obtain financing of large scale renewable projects having a 10+ year PPA is generally required.
[6] AGL are in the process of acquiring Macquarie generation assets. Delta Central is in the process of being sold.

4. Modelling Scenarios

There are a number of factors that will influence future electricity market and LGC prices and therefore the impact on retail prices and generator profitability. The four key areas where the most change is expected and hence should be considered in the future scenarios to be modelled are:

- Demand forecast (and assumed uptake of PV);
- Carbon pricing
- RET scheme; and
- Gas prices.

The scenarios to be modelled are outlined below.

No LRET

The assumptions for this scenario are:

- No carbon price after July 2014 but also no investment in new coal plant
- LRET scheme is disbanded and there is no future expansion of the target. Current and committed generation (around 16,000 GWh) is compensated with a certificate price of $35/MWh for their production to 2030.
- Medium or expected demand growth forecasts (published by AEMO, WA IMO, NTUC)
- Jacobs base gas price scenario.
- Jacobs base assumptions on new generation capital cost.

Current LRET.

The assumptions for this scenario are:

- No carbon price after July 2014 but also no investment in new coal plant
- LRET scheme current target range (41,000 GWh from 2020 to 2030).
- Medium or expected demand growth forecasts (published by AEMO, WA IMO, NTUC).
- Jacobs base gas price scenario.
- Jacobs base assumptions on new generation capital cost.

Reduced LRET.

The assumptions for this scenario are:

- No carbon price after July 2014 but also no investment in new coal plant
- LRET scheme current target range reduced to true 20% of 27,000 GWh from 2020 to 2030. Linear increase in the interim target to this ultimate target from the current 2014 target.
- Medium or expected demand growth forecasts (published by AEMO, WA IMO, NTUC).
- Jacobs base gas price scenario.
- Jacobs base assumptions on new generation capital cost.

5. Results

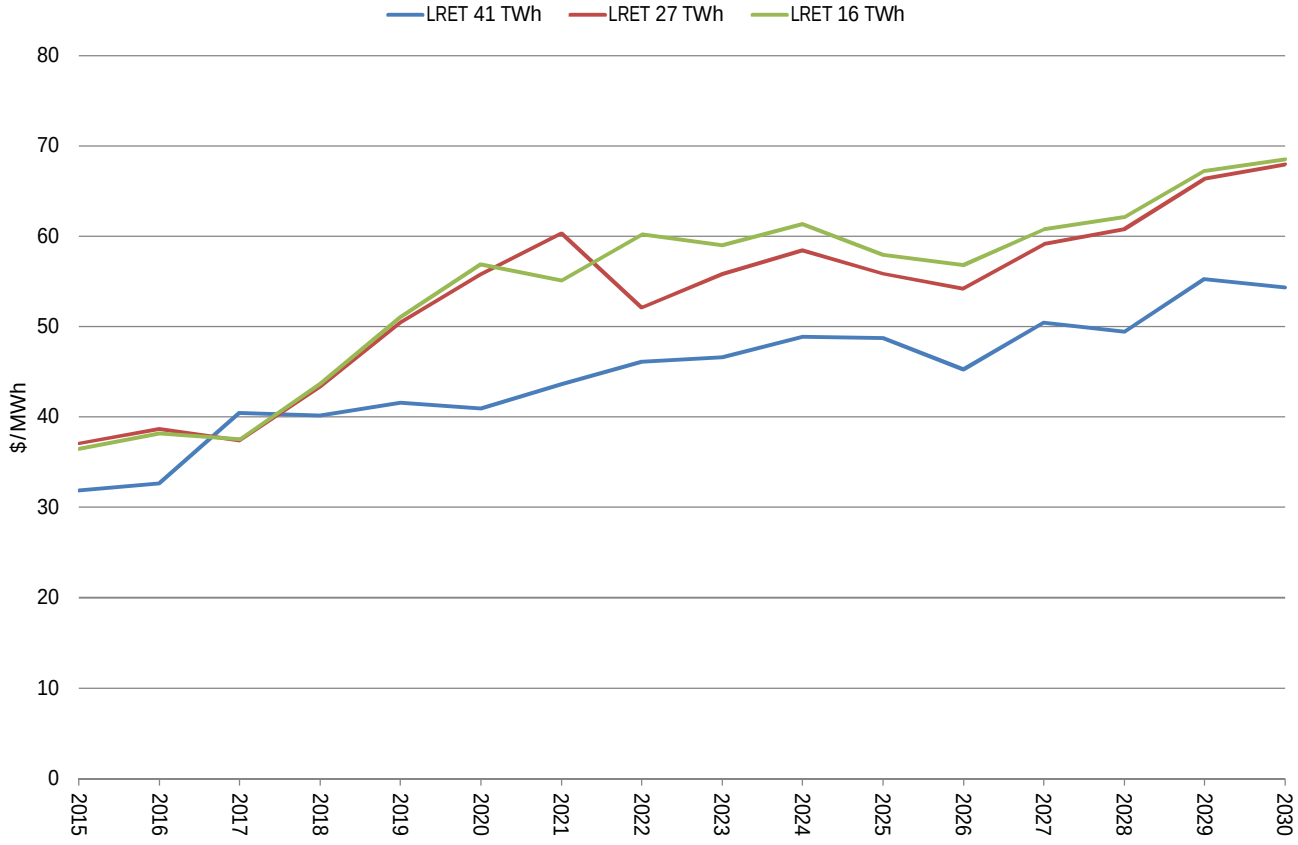
5.1 Wholesale prices

Reducing the level of renewable generation leads to an increase in the wholesale price (see Figure 14). The increase reflects two key considerations. First, the higher renewable energy target leads to greater levels of surplus capacity, leading to lower prices. Second, wind and solar energy accounts for most of the renewable capacity being adopted. These technologies have low short run marginal costs, so that the marginal bid that sets the price are reduced when these technologies are dispatched (and displace generating plant with high short run marginal costs). In the case of solar energy, this is accentuated as most of the generation from this technology is likely to occur in peak price periods.

Wholesale prices for all scenarios rise in the period to 2020. The rate of increase is faster with lower levels of renewable energy generation as there is less plant entering the market in that period. Prices continue to rise after 2020 due to rising fuel prices and a gradual reduction of the capacity surplus.

The jump in prices in 2017 in the 41 TWh LRET case occurs because in the 41 TWh case there is a lot of retirements/mothballing occurring in this year ahead of the big increase in renewable energy generation that occurs in the following years. In the other cases mothballing in 2017 is not as extensive as in the 41 TWh case.

Figure 14: Impact on wholesale prices

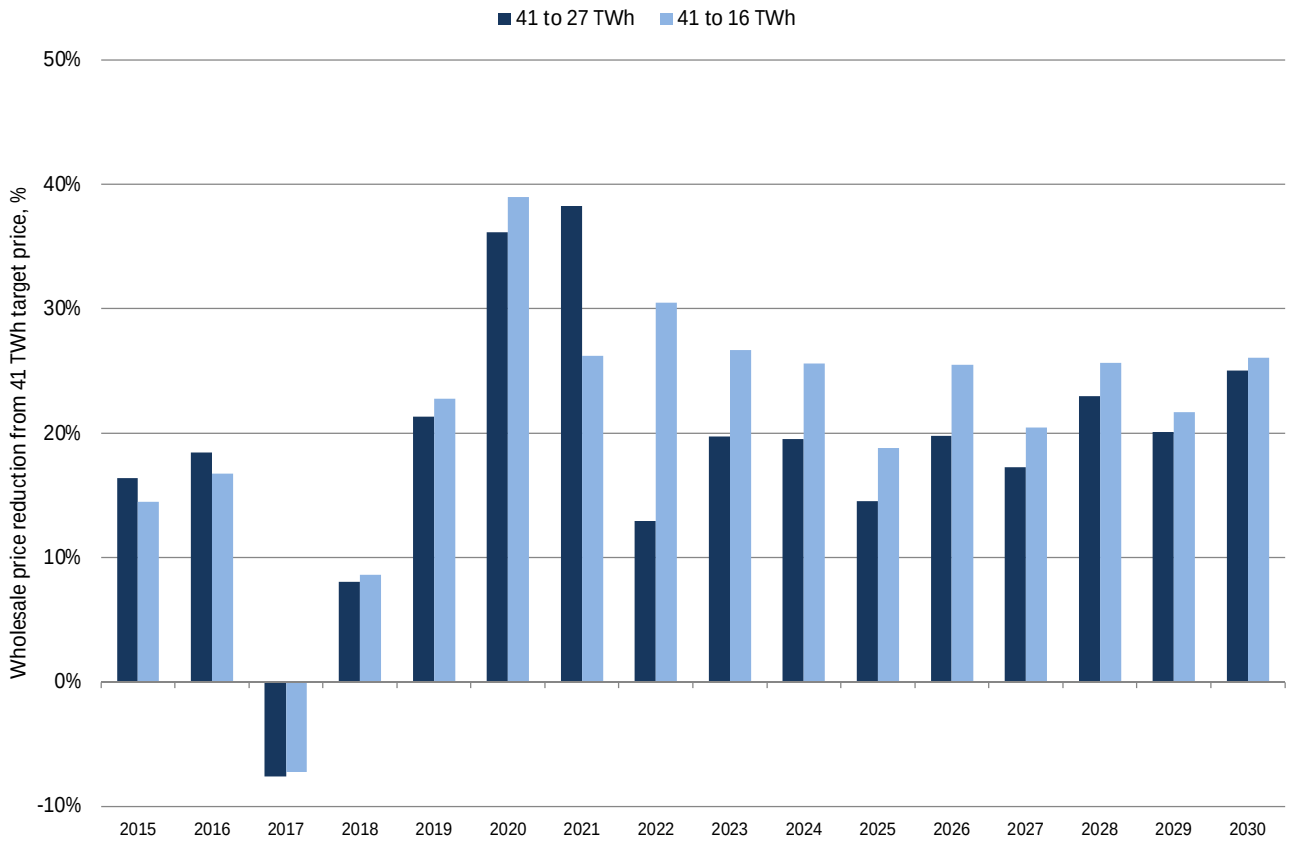


Source: Jacobs analysis.

The price rise is greatest when moving from a 41 TWh large-scale renewable energy target to a 27 TWh renewable energy target. The average annual price increase is around 15.5% (see Figure 15). The increase in price from moving to a lower target is greatest in the eastern seaboard States. Moving to a 16 TWh target (which basically means no new renewable energy capacity from 2015 onwards) leads to a further 2% increase in price. This occurs because the reduction to the 27 TWh leads to prices reverting to the long run marginal cost of new entrants by around 2025 (and sooner for Queensland) as opposed to past 2030 in the 41 TWh

target case. Reducing the target further to 16 TWh only brings this point of new entry forward to the early 2020s.

Figure 15: Change in wholesale prices



Source: Jacobs' analysis

Table 6: Average wholesale prices and change in prices

	2015 - 2020	2020 – 2025	2025 - 2030
Prices, $/MWh			
LRET 41 TWh	38.0	46.8	51.0
LRET 27 TWh	43.8	56.5	61.7
LRET 16 TWh	44.0	58.7	63.1
Change in price, $/MWh			
41 to 27 TWh	5.9	9.7	10.7
41 to 16 TWh	6.0	11.9	12.1
% change in price			
41 to 27 TWh	15%	21%	21%
41 to 16 TWh	16%	25%	24%

Source: Jacobs' analysis. Note prices are volume weighted averages for Australia (where State prices are averaged by the proportion of State generation to total Australian generation).

Table 7: Changes to wholesale prices in each State, $/MWh

	Wholesale Price			Difference		
	2015-2020	2021-2025	2026-2030	2015-2020	2021-2025	2026-2030
41 TWh						
Tasmania	31	34	36			
South Australia	32	33	35			
Victoria	32	35	37			
New South Wales	36	42	43			
Queensland	44	66	75			
SWIS	48	54	61			
27 TWh						
Tasmania	37	45	50	6	11	14
South Australia	40	48	51	7	15	16
Victoria	39	48	51	6	13	14
New South Wales	42	54	58	6	13	14
Queensland	51	72	81	7	6	5
SWIS	48	54	61	0	0	0
16 TWh						
Tasmania	38	51	54	6	17	18
South Australia	40	52	56	7	20	21
Victoria	38	52	55	6	17	18
New South Wales	42	58	60	6	17	17
Queensland	51	69	76	7	2	1
SWIS	50	58	64	2	3	3

Source: Jacobs analysis

5.2 Retail Prices

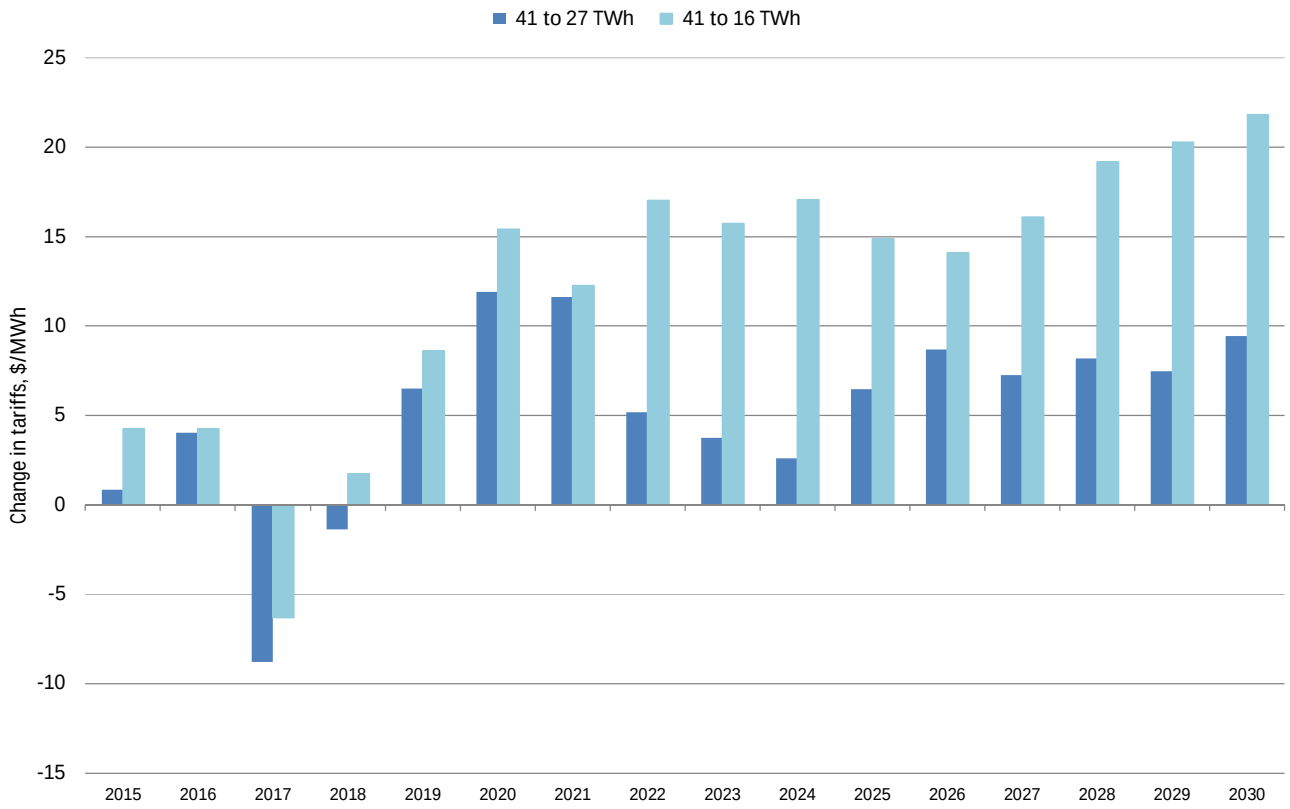
Retail price outcomes are a function of the change in wholesale price and the change in certificate price (with the change in certificate costs being smeared over liable customers). The change in retail tariffs are shown in Figure 17. Retail tariffs generally increase with the lower renewable target due to the impact of wholesale costs outweighing the impact of reduced certificate prices.

The average of certificate prices is some $3/certificate lower on average for the period to 2030 when the target is reduced from 41 TWh to 27 TWh. When the target is reduced to 16 TWh, the certificate price is on average $13/certificate lower[7].

[7] In the 16 TWh case we assumed a certificate price of $35/certificate paid to existing and committed plant.

Figure 16: Certificate prices

Figure 17: Impact on retail tariffs



Source: Jacobs analysis

Table 8: Average change in retail prices

	2015 - 2020	2021 - 2025	2026 - 2030
Change in price, $/MWh			
41 to 27 TWh	2.2	5.9	8.2
41 to 16 TWh	4.7	15.3	18.3
% Change			
41 to 27 TWh	1.0%	2.7%	3.7%
41 to 16 TWh	2.1%	7.0%	8.3%

Source: Jacobs analysis

5.3 Generator profits

Changes to profits to existing generators are shown in Figure 18. The results indicate that in the period to 2030, profits to incumbent generators increase by $11.1 billion when the renewable target is reduced from 41 TWh to 27 TWh. Profits to incumbent generators increase by $11.7 billion when the renewable target is reduced to 16 TWh. The increase in profits comes about due to both a rise in wholesale prices and increase in generation levels of incumbents (including a shorter period of mothballing or campaigning plants).

Only a small rise in profits for incumbents occurs between a reduction to 27 TWh and a reduction to 16 TWh. The small rise occurs because the reduction to 16 TWh leads to only modest further increase in wholesale prices and because there is more entry of new plant that usurps existing plant in the merit order (capping the increase in generation levels of incumbent fossil fuel plant).

Existing coal plant benefit most from the reduction in target (Figure 19) due to the reduced renewable generation, abolition of carbon prices and rising gas prices.

Figure 18: Change in generator profits

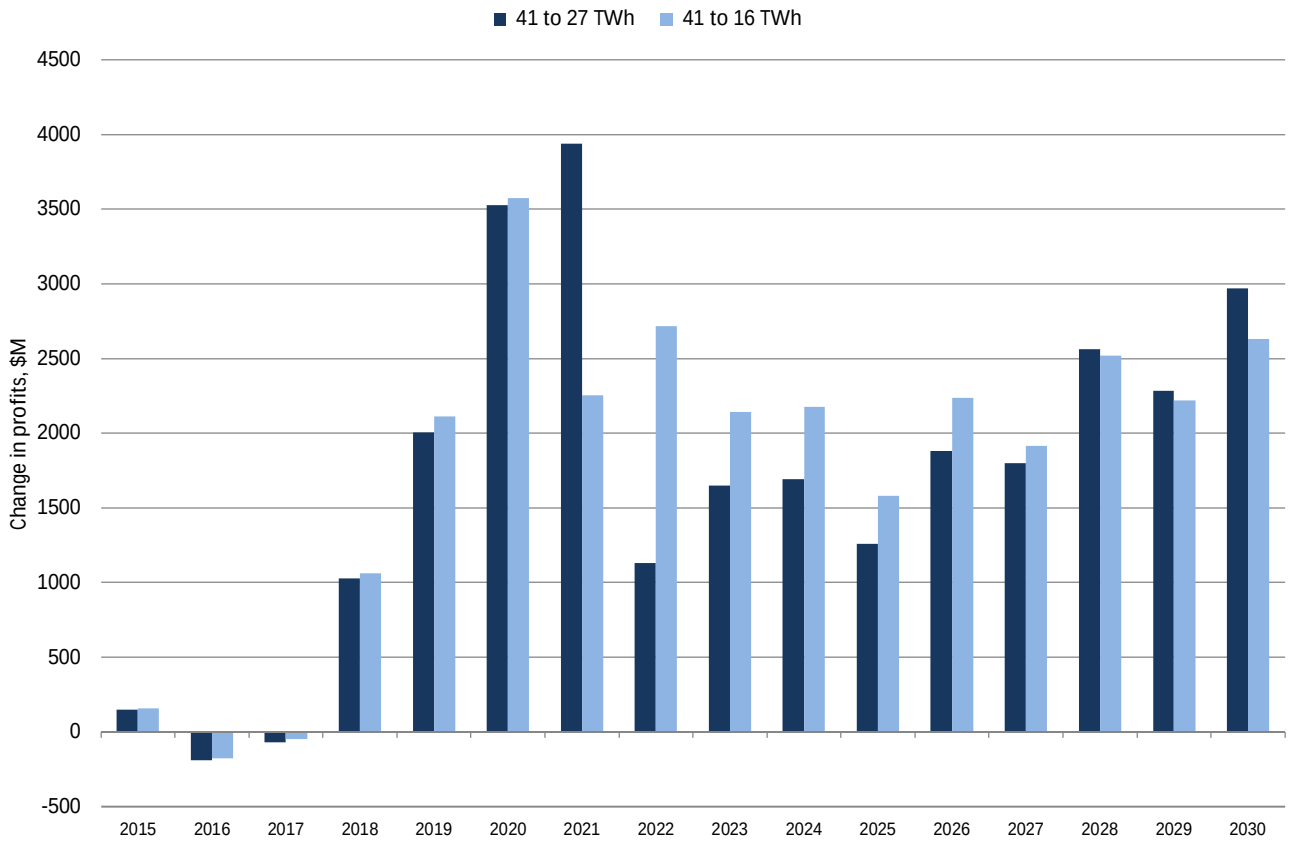


Figure 19: Change in profits by technology type

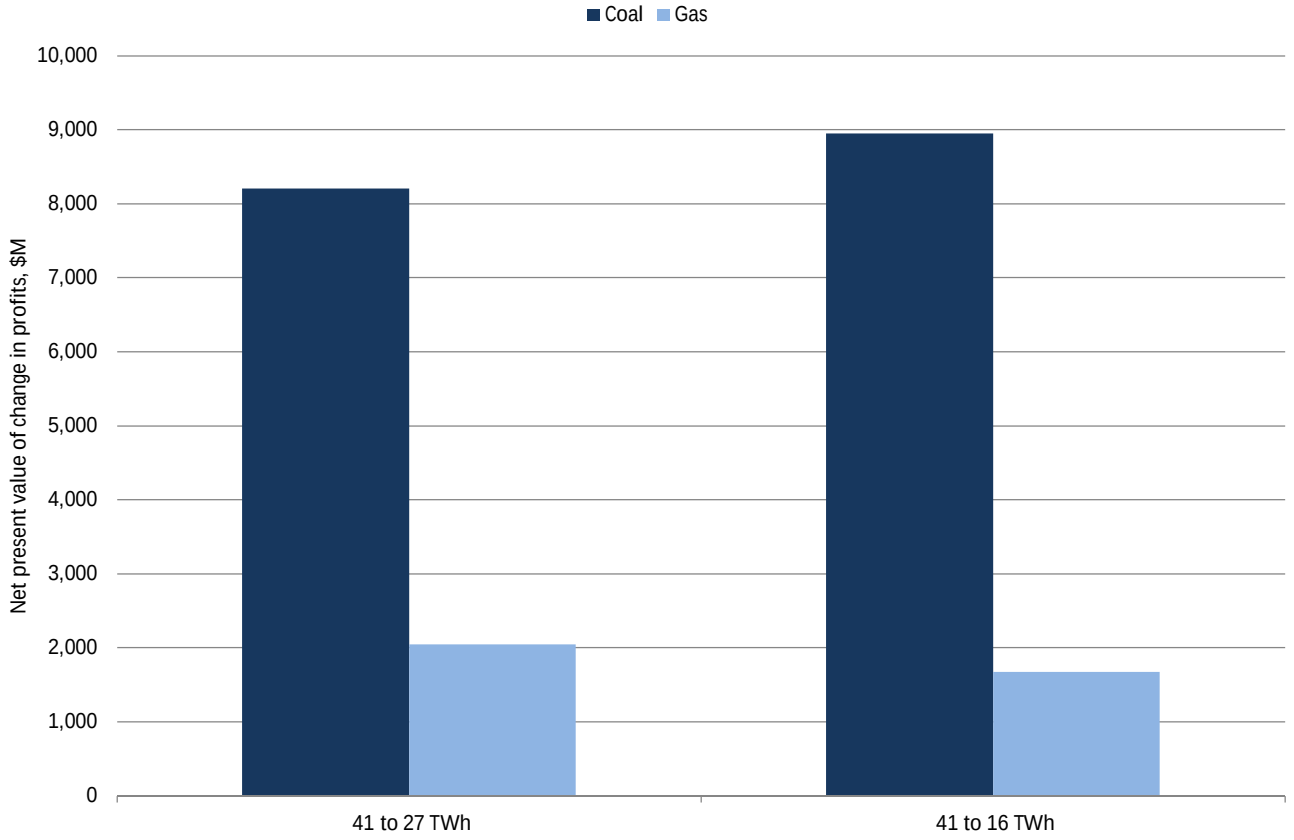


Table 9: Change in generator profit by region, $m

	2015-2020	2021-2025	2026-2030	NPV
41 to 27 TWh				
Tasmania	464	912	1104	967
South Australia	420	604	732	719
Victoria	1747	3671	4399	3788
New South Wales	1553	4704	6108	4422
Queensland	2258	-221	-852	1293
SWIS	11	2	1	9
41 to 16 TWh				
Tasmania	501	1182	1321	1161
South Australia	360	696	762	724
Victoria	1565	4216	4898	4028
New South Wales	1759	5870	6721	5209
Queensland	2370	-1279	-2296	457
SWIS	130	188	118	199

Source: Jacobs' analysis. Net present values are calculated for the period 2015 to 2030 using a real discount rate of 10%, being the assumed commercial weighted average cost of capital

5.4 Investment

Investment in new renewable generation is shown under the three target scenarios are shown in Table 10. In relation to renewable generation coming in under the LRET target[8], around $19 billion of investment occurs with a 41 TWh target to 2020, around $7 billion under a 27 TWh target and $6 billion under a 16 TWh target (mainly from completing plant currently under construction).

Table 10: Investment in renewable generation, $m

	2015 - 2020	2021 - 2025	2025 - 2030	NPV (to 2030)
41 TWh target	18,882	4,734	806	15,695
27 TWh target	6,934	3,618	806	7,570
16 TWh target	5,752	0	843	5,114

Source: Jacobs' analysis. Note: Net present values are calculated using a 10% discount rate (equivalent to a commercial WACC). Investments include investment in renewable generation to service the GreenPower markets

Table 11: Investment in renewable generation by State, $m

	2015 - 2020	2021 - 2025	2025 - 2030	NPV (to 2030)
NSW/ACT				
41 TWh target	6,223	0	0	4,070
27 TWh target	1,725	391	0	1,544
16 TWh target	1,644	0	0	1,314
Queensland				
41 TWh target	674	2,374	0	1,592
27 TWh target	36	796	0	376
16 TWh target	0	0	33	7
Victoria				
41 TWh target	3,412	2,095	0	3,640
27 TWh target	2,157	64	0	1,859
16 TWh target	2,157	0	0	1,828
South Australia				
41 TWh target	5,327	33	0	3,581
27 TWh target	816	1,149	0	1,255
16 TWh target	807	33	4	676
Tasmania				
41 TWh target	1,996	0	0	1,571
27 TWh target	978	980	0	1,335
16 TWh target	898	0	0	808
WA				
41 TWh target	1,251	232	806	1,240
27 TWh target	1,223	238	806	1,201
16 TWh target	246	214	806	481

[8] Renewable investment also occurs to service the GreenPower market. GreenPower demand is assumed to grow modestly at just around 1% per annum in line with long term trends.

5.5 Other benefits

5.5.1 Resource costs

Resource costs represent costs to the economy from electricity generation. It covers the capital (for new plant), fuel and operating (mainly labour) costs incurred by generating electricity. Differences in resource costs across scenarios are an indicator of differences in the economic efficiency with which resources are used in the sector.

Annual resource costs are shown in Figure 20. Resource costs are highest for the 41 TWh target. The capital costs of new renewable plant are not outweighed by the reduction in fuel and operating costs. This difference is exacerbated by their being little capital spend on new fossil fuel plant in in the 16 TWh and the 27 TWh cases (with most additional fossil fuel capacity needed in the 27 TWh case being met by reinstating mothballed plant).

The difference in costs to 2030 in net present value terms amounts to $4.7 billion when the target is reduced from 41 TWh to 27 TWh, and $6.2 billion when the target is reduced from 41 TWh to 16 TWh.

Figure 20: Resource costs

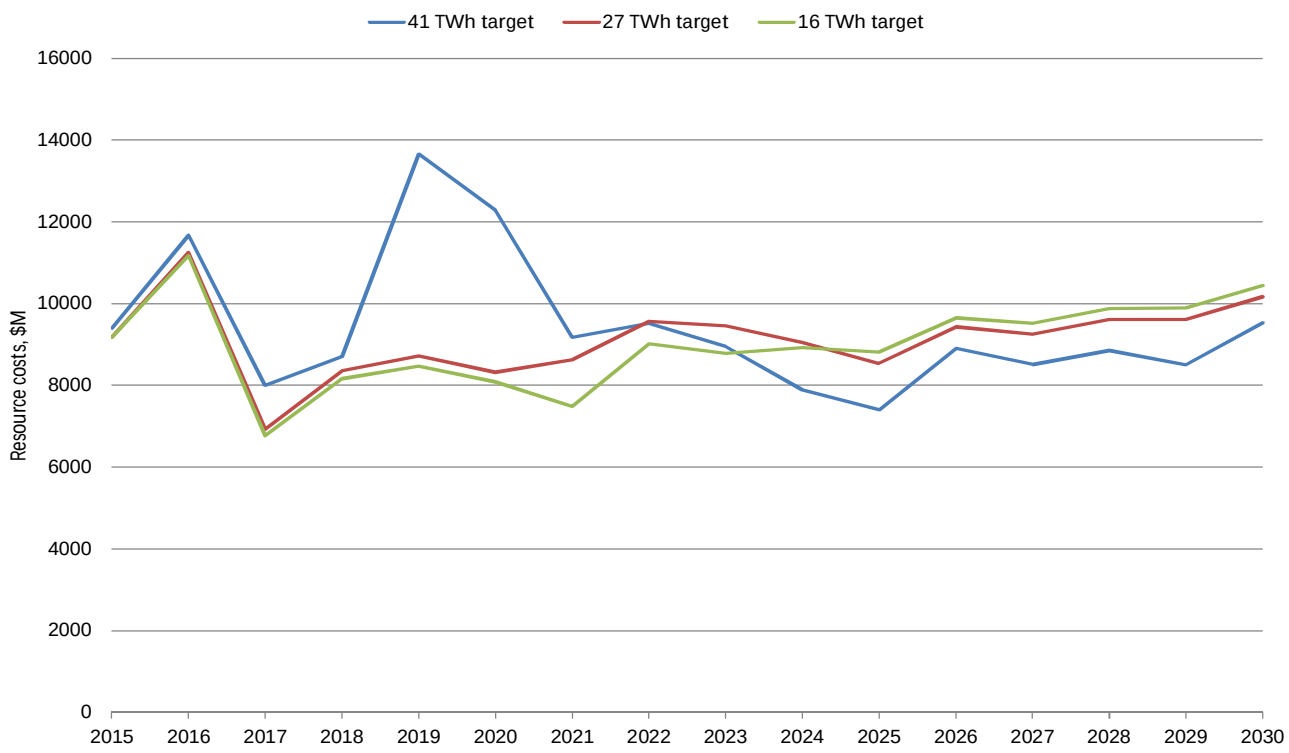


Table 12: Net present vales of resource costs, $m

	Total Costs	Difference
41 TWh target	92,062	
27 TWh target	87,319	4,742
16 TWh target	85,785	6,277

Source: Jacobs analysis. Net present value is calculated for the period from 2015 to 2030 using a social discount rate of 6%

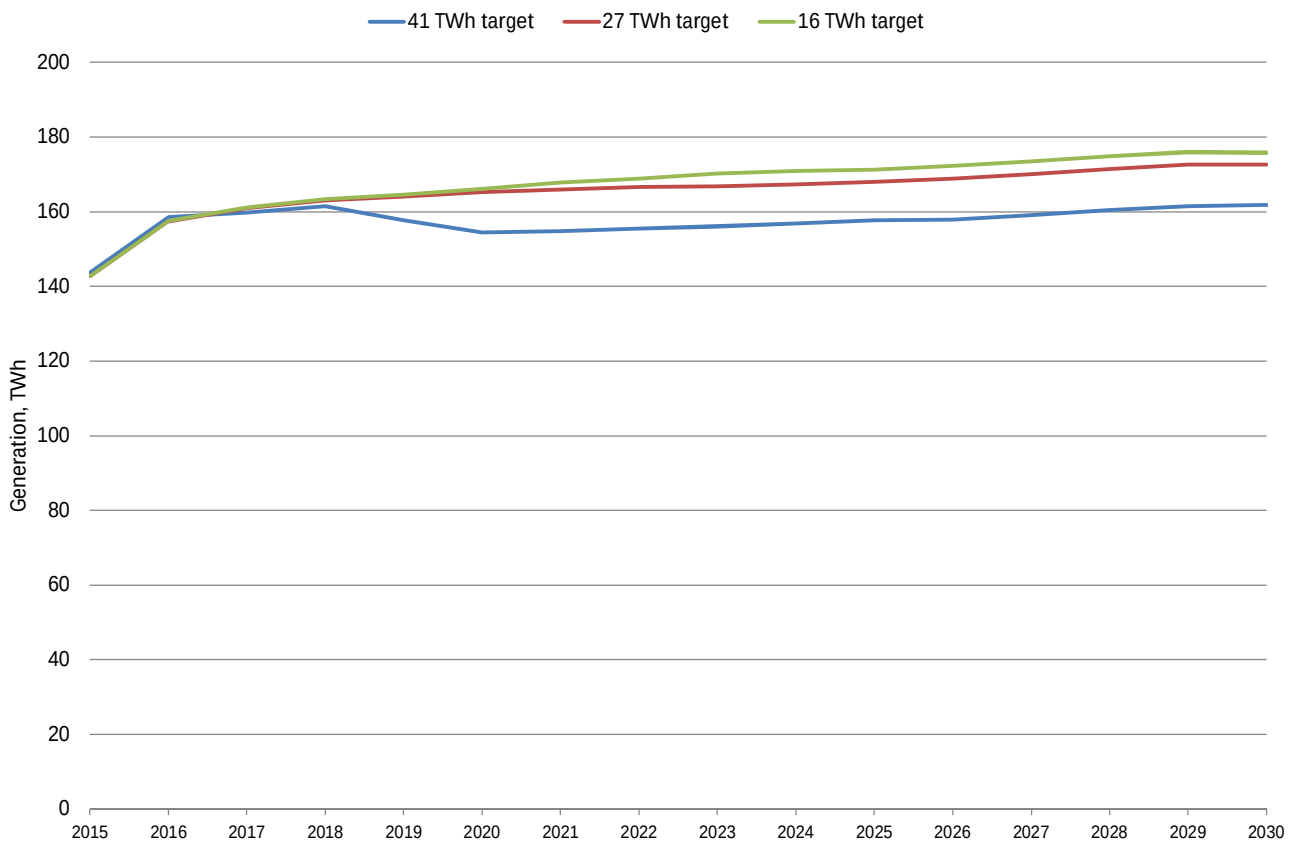
Table 13: Resource cost impacts by State, $M

	2015-2020	2021-2025	2026-2030	NPV
41 to 27 TWh				
Tasmania	1,000	272	1,248	167
South Australia	4,265	4,004	4,091	1,931
Victoria	978	5,070	3,461	1,611
New South Wales	3,831	6,046	5,182	1,163
Queensland	635	492	917	-152
SWIS	14	2,257	-48	22
41 to 16 TWh				
Tasmania	1,077	1,229	1,249	800
South Australia	4,259	5,027	3,960	2,523
Victoria	954	4,945	3,269	1,456
New South Wales	3,883	6,201	4,928	1,200
Queensland	654	669	352	-261
SWIS	883	2,099	-245	559

Source: Jacobs analysis. Net present value is calculated for the period from 2015 to 2030 using a social discount rate of 6%.

Coal-fired generation levels increase the most with a reduction in targets, accounting for over 90% in the reduction of renewable generation. The increase occurs in the incumbent coal-fired generators as there is no new coal plant predicted to enter under any of the scenarios modelled.

Figure 21: Coal-fired generation levels



5.5.2 Emissions

Emissions of greenhouse gas are predicted to rise with a lowering of the target (Figure 22). This reflects the fact that the reduction in renewable generation is mostly matched by an increase in coal-fired generation. Emissions are higher by around 10 Mt CO_2e per annum when the renewable target is reduced to 27 TWh and around 13 Mt CO_2e per annum when the target is reduced to 16 TWh.

Cumulative emissions from electricity generation to 2030 are around 2,909 Mt CO_2e when there is a renewable target of 41 TWh, increasing to 3,062 Mt with a 27 TWh target and 3,108 Mt CO_2e with a 16 TWh target. Thus, reducing the renewable target increases cumulative emission to 2030 by around 150 Mt CO_2e when the target is reduced to 27 TWh and by around 200 Mt CO_2e when the target is reduced to 16 TWh (see Figure 23). Cumulative emissions to 2020 is around 1,081 Mt CO_2e for the 41 TWh target, 1,116 Mt CO_2e for the 27 TWh target, and 1,120 Mt CO_2e for the 16 TWh target. Thus reducing the target increases emissions to 2020 by around 35 Mt CO_2e to 40 Mt CO_2e.

Figure 22: Emissions of greenhouse gases

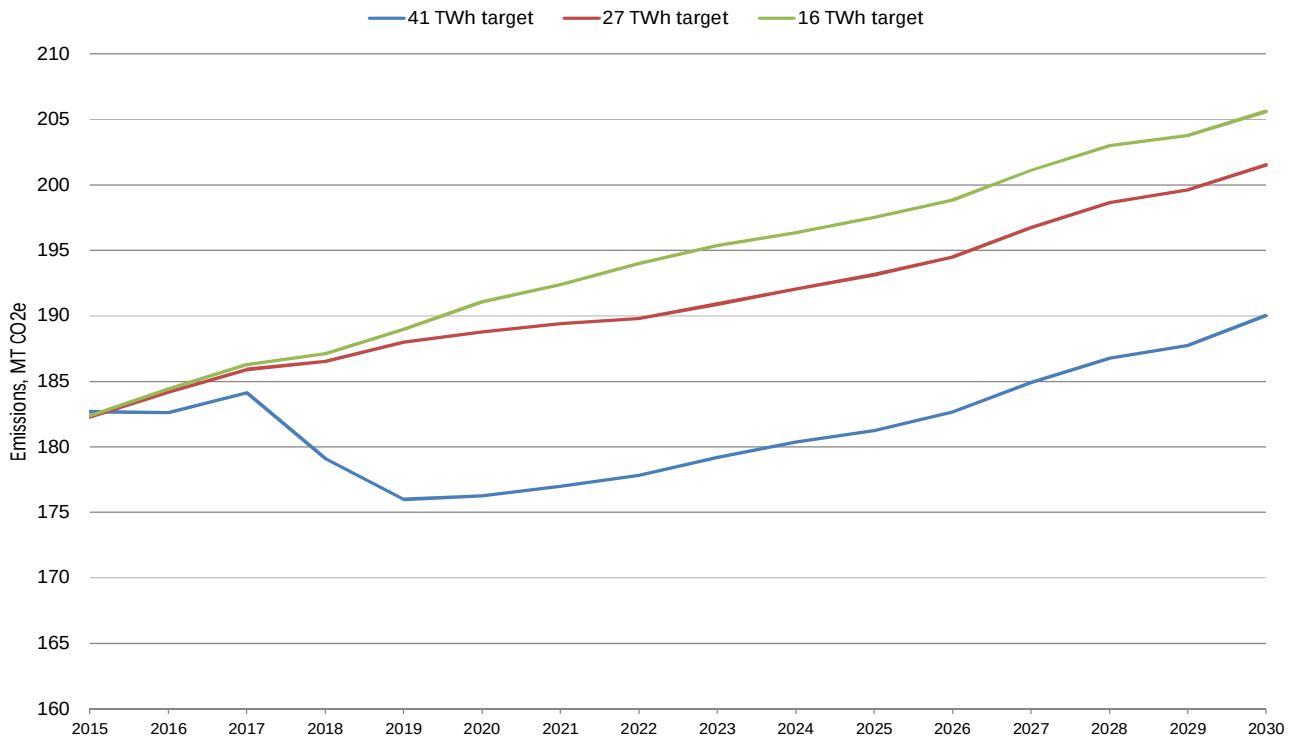
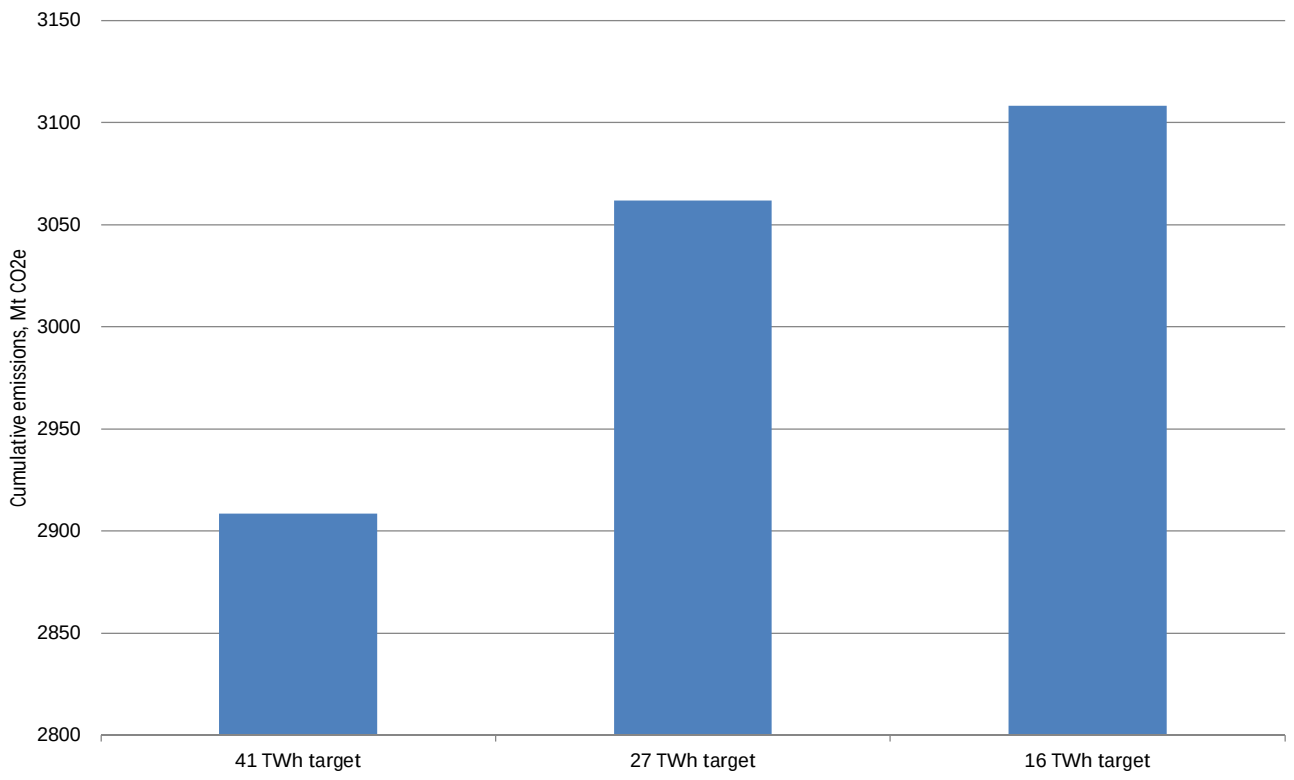


Figure 23: Cumulative emissions to 2030



The indicative cost of the additional emissions to 2030 from reducing the target is shown in Table 14. As estimates of the social cost of carbon vary widely, we have only provided indicative estimates of the social cost using the assumed carbon prices as being representative of the social cost for achieving a global concentration target of 550 ppm. The social cost ranges from $3.2 billion for the 27 TWh target and $4.1 billion for the 16 TWh target in net present value terms (for the period to 2030) using a social discount rate of 6% and between $4.2 and $5.6 billion assuming a 3% social discount rate. The social cost could be higher if other estimates of social value of reducing carbon emissions are used[9].

Table 14: Indicative cost of carbon emissions

	2015-2020	2021-2025	2026-2030	NPV		Diff in NPV	
				6% dr	3% dr	6% dr	3% dr
Emissions, Mt CO_2e							
41 TWh target	1,081	896	932				
27 TWh target	1,116	955	991				
16 TWh target	1,120	976	1,012				
Price, $/t CO_2e	22	35	44				
Social cost, $M							
41 TWh target	29,368	31,852	42,322	61,360	78,688		
27 TWh target	30,384	33,972	44,995	64,554	82,951	3,194	4,263
16 TWh target	30,518	34,700	45,959	65,506	84,257	4,147	5,570

Source: Jacobs analysis. Notes: Carbon prices are average for the period. Carbon prices start at $24/t CO_2e in 2015 escalating by 5% per annum to reach $30/t CO_2e in 2020 and $50/t CO_2e in 2030. NPV calculated using a social discount rate of either 6% or 3% (real).

[9] The estimates of carbon price are within the range of estimates of social carbon price used by the US EPA for evaluating carbon mitigation policies. See US EPA (2013), Fact Sheet: Social Cost of Carbon available on http://www.epa.gov/climatechange/Downloads/EPAactivities/scc-fact-sheet.pdf

5.6 Employment

Employment impacts are shown in Table 15. Essentially the employment impacts of a reduced LRET target is a reduction in employment associated with renewable energy generation, which is partly made up by increase in employment in fossil fuel generation.

Table 15: Employment impacts

	2015-2020	2021-2025	2026-2030
41 TWh			
Coal	2649	2598	2612
Gas	1076	1091	1249
Renewable - hydro	325	332	333
Renewable - wind	259	453	469
Renewable - biomass	52	53	53
Renewable - solar	13	13	13
Renewable - geothermal	0	2	2
Total	4373	4542	4730
27 TWh			
Coal	2649	2598	2611
Gas	1076	1118	1271
Renewable - hydro	320	330	331
Renewable - wind	208	263	280
Renewable - biomass	42	46	46
Renewable - solar	7	7	7
Renewable - geothermal	0	2	2
Total	4302	4364	4549
16 TWh			
Coal	2642	2590	2604
Gas	1076	1145	1303
Renewable - hydro	320	324	324
Renewable - wind	200	211	223
Renewable - biomass	41	41	41
Renewable - solar	7	7	7
Renewable - geothermal	0	2	2
Total	4286	4321	4504

Source: Jacobs' analysis. Only direct employment is considered. Head office and other company administrative staff are not considered.

5.7 Sensitivity to lower demand

Electricity demand growth could be significantly lower than projected for the base scenario. The analysis was tested for robustness by evaluating outcomes with native (that is, before embedded generation is deducted) growing at an average of 0.5% per annum. The results of this analysis are summarised in Table 16. The change in results from going to a lower RET are approximately similar for the electricity demand growth paths tested. This is essentially due to the fact that with lower demand growth, there is more mothballing of existing plant and there are fewer new fossil fuel plants entering the market in the period to 2030.

Table 16: Sensitivity of results to electricity demand growth

	Base	Low	Diff
41 to 27 TWh			
Change in wholesale price, $/MWh (average 2015 to 2030)	8.6	6.0	2.6
Change in wholesale price, % (average 2015 to 2030)	18.9%	17.8%	1.2%
Change in retail price, $/MWh (average 2015 to 2030)	5.2	1.2	4.1
Change in retail price, % (average 2015 to 2030)	2.4%	0.5%	1.8%
Change in industry profits, NPV (to 2030), $M	11,197	6,710	4,487
Change in emissions , Mt CO2e (cumulative over 2015 to 2030)	154	155	-1
41 to 16 TWh			
Change in wholesale price, $/MWh (average 2015 to 2030)	9.8	10.6	-0.8
Change in wholesale price, % (average 2015 to 2030)	21.3%	31.2%	-9.9%
Change in retail price, $/MWh (average 2015 to 2030)	12.2	13.4	-1.2
Change in retail price, % (average 2015 to 2030)	5.6%	6.1%	-0.5%
Change in industry profits, NPV (to 2030), $M	11,779	12,338	-599
Change in emissions , Mt CO2e (cumulative over 2015 to 2030)	200	202	-3