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An analysis of Australia's large scale renewable energy target: Restoring market confidence☆

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HIGHLIGHTS

- We examine the history of Australian renewable energy policy.
- We examine whether capital market efficiency losses occur under certain policy scenarios.
- We find electricity prices increase by up to $119 million due to renewable policy uncertainty.
- We conclude that constant review of policy is not reform and should be avoided.

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ABSTRACT

In 2001, Australia introduced legislation requiring investment in new renewable electricity generating capacity. The legislation was significantly expanded in 2009 to give effect to a 20% Renewable Energy Target (RET). Importantly, the policy was introduced with bipartisan support and is consistent with global policy trends. In this article, we examine the history of the policy and establish that the 'stop/start' nature of renewable policy development has resulted in investors withholding new capital until greater certainty is provided. We utilise the methodology from Simshauser and Nelson (2012) to examine whether capital market efficiency losses would occur under certain policy scenarios. The results show that electricity costs would increase by between $51 million and $119 million if the large-scale RET is abandoned even after accounting for avoided renewable costs. Our conclusions are clear: we find that policymakers should be guided by a high level public policy principle in relation to large-scale renewable energy policy: constant review is not reform.

1. Introduction

Australia has significant reserves of low-cost black coal, brown coal and natural gas. This energy providence has sustained Australian economic growth for much of the last century. However, as Jarvinen et al. (2012, p.63) observed, Australian policy derivation is often 'policy taking' rather than 'policy making' due to the relatively small size of Australia in terms of population, technology origination and global influence. To that end, Australia has been one of 96 countries that have embraced government policies designed to facilitate greater investment in renewable energy technologies (BNEF, 2012) despite the advantage of abundant low-cost fossil fuel energy reserves. Globally, concerns about energy security have motivated policymakers to introduce mechanisms designed to deploy renewable energy. Within Australia, it would be reasonable to state that the public policy objectives being pursued in relation to renewable energy relate to reducing greenhouse gas emissions and diversifying Australia's electricity supplies. This is in addition to market failures associated with sub-optimal, inter-temporal, investment allocation given the long-lived nature of electricity infrastructure, and a bipartisan agreement to reduce greenhouse gas emissions over the long-term.

In 2011, approximately 90% of all electricity generated in Australia was fuelled by either coal or gas (ESAA, 2012). The remaining 10% was sourced from renewables with hydro-electric generation producing around 7% and wind contributing around 3% (ESAA, 2012). This result is different when compared to ten years ago. In 2000, coal and gas collectively powered 92% of all electricity generation in Australia with hydro-electricity comprising the remaining 8% (ESAA, 2000). Wind was almost non-existent as a deployed technology within the Australian electricity market. The critical difference between the years 2000 and 2011 was the operation of the Mandatory Renewable Energy Target (MRET).

The MRET was introduced in 2001 by the Commonwealth Government with a public policy objective of increasing Australia's

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renewable electricity generation by an 'additional 2%'. It became known as the '2% MRET' policy and was successful in achieving its public policy objective: the deployment of more renewable energy. However, there have been several policy development 'junctures' where investor confidence has been damaged due to ongoing reviews and amendment of this policy. Since the passage of the legislation underpinning the original MRET policy, there have been two major amendments and five points of 'review' by policy-makers. While one of these amendments could be thought of as being unambiguously material – the expansion of the policy from 2% to 20% – the remaining reviews contributed little towards providing a stable platform for investors to make long-term decisions regarding renewable energy infrastructure. For a more comprehensive outline of the history of Australia's renewable energy policy see Nelson et al. (2011).

In addition to consistent uncertainty in relation to Australian renewable energy policy, there has been the added uncertainty created by the intense debate around climate change policy within Australia. A thorough explanation of the history of Australian climate change policy is provided by Nelson et al. (2012). Most recently, on 1 July 2012, the Commonwealth Government introduced a fixed carbon price or carbon tax of $23 per tonne of carbon dioxide equivalent (CO_2e) which will apply to all industrial facilities with emissions greater than 25,000 tonnes of CO_2e. It is intended that the fixed price (which increases each year) will apply for three years with an emissions trading scheme to commence operation from 2015. This policy mechanism is designed to deliver on the Government's policy objective – reducing Australia's 2020 greenhouse gas emissions by 5% relative to 2000 levels. However, while the objective is shared by the opposition (Liberal/National Coalition), the mechanism by which to achieve the target is not. The opposition has committed to repealing the carbon price legislation if elected to form Government and will then implement a 'direct action' framework. Accordingly, policy uncertainty exists in relation to the longevity of carbon pricing in Australia.

The impact of carbon policy uncertainty has been quantified in two aspects by Australian economists (a) suboptimal investment decisions, and (b) suboptimal investment costs relative to a counterfactual scenario. Nelson et al. (2010) examined the costs associated with the sub-optimal capital investment caused by carbon policy uncertainty. They found that the costs could be as high as $2 billion per annum due to unnecessarily high electricity prices. This research was tested by other economic modeling firms and while the thesis was found to be correct, cost estimates varied. Nelson, Simshauser, Orton and Kelley (2011) provide a summary of these studies so we do not intend to replicate such analysis here. On suboptimal investment costs, Simshauser and Nelson (2012) estimated the capital market efficiency losses associated with carbon policy uncertainty. Their project finance market survey established that providers of debt finance would impose higher risk premiums as a result of ongoing policy uncertainty in relation to carbon pricing. The higher risk premiums would result in capital market efficiency losses of up to $4.5 billion over the period between 2015 and 2020.

It is in this context that this article considers approaches to renewable energy public policy development in Australia, applying the same methodology utilised by Simshauser and Nelson (2012) to assess the capital market efficiency losses associated with uncertainty in relation to the LRET. It is important to note that this article is not intended to discuss the merits or otherwise of renewable energy policy. This has been debated at length in the Australian and international context (for example, see SKM-MMA, 2012). Rather, our analysis takes as given a renewable energy policy in place for 11 years with legislated targets for the following 18 years.

This article is structured as follows: Section 2 reviews the evolution of large scale renewable energy policy in Australia and associated global market developments; the supply and demand for Large Scale Generation Certificates (LGCs) is presented in Section 3; the results of a survey of renewable electricity market participant views in relation to policy and pricing are documented in Section 4; Section 5 analyses the capital market efficiency losses associated with higher risk premiums being applied to new developments; partial equilibrium analysis of electricity price impacts related to ongoing policy uncertainty is presented in Section 6; our policy recommendations are presented in Section 7 with concluding remarks provided subsequently.

2. The evolution of large-scale renewable energy policy in Australia

The Mandatory Renewable Energy Target (MRET) was introduced in Australia in 2001. The legislation underpinning the policy was passed in 2000. The *Renewable Energy (Electricity) Act 2000* and *Renewable Energy (Electricity) Regulations 2001* required electricity retailers to purchase Renewable Energy Certificates (RECs) to avoid paying a shortfall penalty of $40 per megawatt hour (MWh) of renewable energy not acquired. Under MRET, new renewable electricity generators constructed after 1997, and incumbent renewable generators who generated power above their historical baseline, were eligible to create RECs with one REC equivalent to the generation of one MWh of renewable energy. The legislation required retailers to progressively increase their purchases of RECs so that by the year 2010, an additional 9500 MWh of new renewable generation would be produced. It was forecast that the policy would add renewable generation output equivalent to around two percent of electricity demand by 2010. It could be argued that the policy was effective in achieving its objectives over its first few years of existence as significant new investments in renewable energy capacity were made in biomass, landfill gas and wind farms. Fig. 1 shows the new installed renewable capacity (wind and non-wind) since 2001. This is in addition to the roughly 1.5 GW of small scale solar PV installed between 2001 and 2011.

In 2003, a review of the MRET legislation was initiated by the Howard Government and conducted by a panel chaired by former Senator Grant Tambling. The review came to be known as the 'Tambling Review' and heard from interested stakeholders about the operation of the MRET since its inception in 2001. Recommendations from the review included: the MRET measure to continue to operate; MRET targets to continue to be expressed in GWh and not as a percentage of overall electricity demand; MRET targets to increase beyond 2010 and to stabilise at 20,000 GWh in 2020; and the end date of the measure to be extended beyond 2020 so that renewable energy projects receive RECs for a full 15 year period presumably because such a tenor would align more closely to project financings (Australian Greenhouse Office, 2004).

The Tambling Review provided its report to the Minister for the Environment and Heritage in late 2003, which was tabled in Parliament in early 2004. The Commonwealth Government made a number of minor changes to the policy as a result of the Tambling Review but the significant recommendations outlined above were largely ignored (Australian Greenhouse Office, 2004). When considered in the context of global renewable energy policy, this is not surprising. Renewable energy investment at the time was relatively small by comparison to investment in thermal coal-fired and gas-fired power generation. This is shown in Fig. 2. Global renewable energy investment (LHS) and the ratio of global thermal to renewable investment (RHS) are plotted for the years 2004 through 2011. In 2004, when the Commonwealth

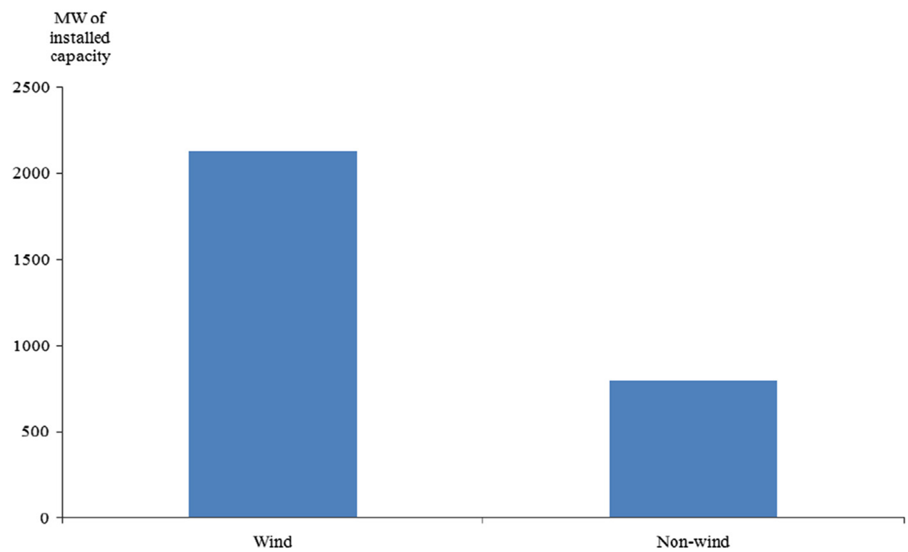

Fig. 1. Investment in large-scale renewable capacity 2001–2012.
Source: ESAA, 2012.

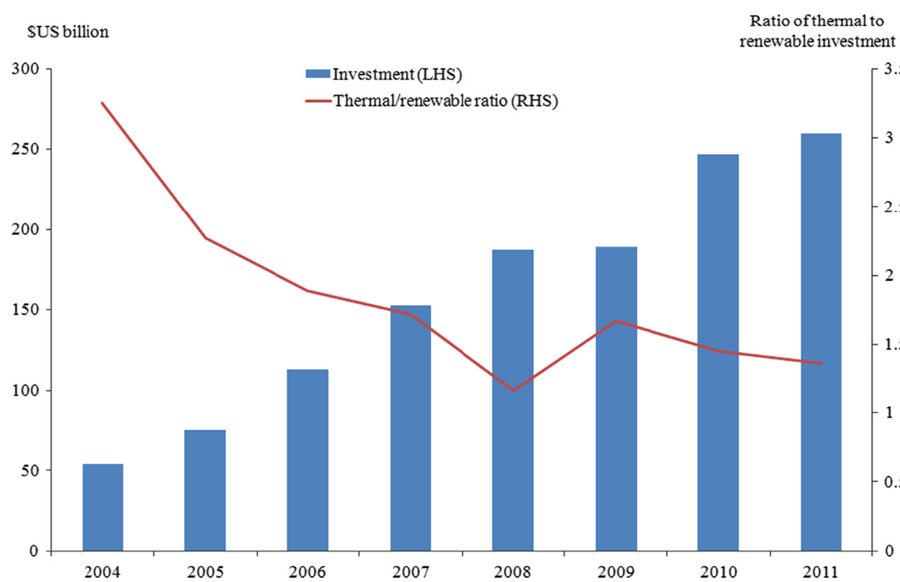

Fig. 2. Global investment in renewable energy.
Source: Adapted from Bloomberg New Energy Finance (2012).

Government largely rejected many of the recommendations of the Tambling Review, investment in new thermal electricity generation was around 3.5 times greater than investment in new renewable electricity capacity.

Fig. 2 shows that between 2004 and 2007 there was a rapid run-up in global renewable energy investment and a significant decline in the ratio of thermal to renewable investment. This coincides with a rising number of countries around the globe introducing renewable energy targets. While the Commonwealth Government had ruled out increasing the MRET, various state governments initiated their own policy frameworks designed to support the uptake of renewable energy. In 2006, the Victorian Government legislated the Victorian Renewable Energy Target (VRET) and the New South Wales Government developed (but did not legislate) the New South Wales Renewable Energy Target (NRET). Both policies were effectively duplicates of the MRET policy with higher targets, whereby a liability was placed on retailers incentivising the development of new renewable energy through tradable certification.

The 2007 Commonwealth election saw both major political parties put ambitious clean energy policies to the electorate. The incumbent Howard Government outlined an expansion of the MRET to achieve 15% 'clean' energy production by 2020. In addition to expanding the targets under the MRET, the eligibility criteria was to be amended to allow 'effectively zero emission' technologies such as coal and gas generation with carbon capture and storage. The Rudd Opposition proposed an expansion of the MRET targets to achieve 20% renewable energy production by 2020. Regardless, both the incumbent Government and the Opposition pledged to introduce emissions trading and expand renewable energy policies. However, a key point that was noted by all market participants was the broad-based bipartisan agreement related to anthropogenic climate change and renewable energy policies.

Policy certainty did not occur immediately. The Rudd Government took almost two years to legislate a relatively simple set of amendments required to give effect to the expanded 20% Renewable Energy Target, lifting the fixed energy target significantly

Table 1
Premium Feed-in Tariff policies in place during 2010.
Source: Nelson et al. (2012).

State	Max size (kW)	Rate ($/MWh)	Duration (years)	Approximate pay-back period (years)
Vic	5	$600 (net)	15	6.5
SA	30	$540 (net)	20	7.5
NSW	10	$600 (gross)	7	2
QLD	30	$440 (net)	20	9
ACT	30	$450 (gross)	20	2.5

from 9500 GWh to 41,000 GWh.[1] However, the legislation passed in August 2009 also contained a number of material changes to the design of the original MRET legislation. The most notable of these was the Solar Credits Multiplier. While small-scale solar PV generation (residential solar) had historically been able to create RECs for fifteen years of generation upfront (known as 'deeming'), the Solar Credits Multiplier allowed installers of small scale solar PV to create five times the number of these certificates. In effect, residential solar PV was receiving 75 years worth of certificates immediately while all other generation types (e.g. large-scale biomass, solar, landfill gas and wind) only created RECs as the actual energy was generated.

At the same time, premium feed-in tariffs for small-scale solar PV units were being introduced by most Australian state governments. Table 1 outlines the premium feed-in tariff policies that were in place in 2010 in each jurisdiction. With the introduction of the Solar Credits Multiplier and the various premium feed-in tariff policies, the payback for installing small-scale solar PV was between 2 and 9 years. With such attractive investment returns, installation of small-scale solar PV systems significantly increased. The result of these distortions was an effective 'crowding out' of other renewable energy technology options within the RET and an associated slump in prices due to the material oversupply of RECs.

Fig. 3 shows the annual creation of RECs by generation type since 2005 (LHS). Note in 2010 that the actual target under the MRET policy had a demand of 9.5 million certificates but about 40 million were actually created/supplied, primarily through the distortionary effects of the Solar Credits Multiplier, or 'phantom RECs' as they became known. The combination of the Solar Credits Multiplier and state-based premium feed-in tariff policies resulted in approximately 500 MW of new installed residential solar PV capacity over the same period (RHS). The RET policy framework was not incentivising new renewable energy development other than residential solar PV, but the annual production of renewable energy was only 1/75 of the certificates created because, as noted earlier, the 15-year output from such units is deemed up-front, and was then multiplied five times over. Unsurprisingly, REC prices plunged from around $50 in April 2009 to just $28 per REC in late-2009 as Fig. 4 later reveals. With wholesale electricity prices in the various National Electricity Market (NEM) regions in 2009 between $33/MWh and $55/MWh, combined revenue from wholesale and REC pricing was well short of the roughly $120/MWh required to bank a new wind farm project at that time.

In late-2009 and early-2010, there were a number of vocal critics of the newly designed RET. The significant disquiet from large-scale renewable energy producers about the unintended consequences of the Solar Credits Multiplier and complementary premium feed-in tariff policies resulted in the Government (with Opposition support) announcing fundamental changes to the operation of the policy. In February 2010, the Commonwealth Government announced that the RET would be split into two new policies: the Large-Scale Renewable Energy Target (LRET) and the Small-Scale Renewable Energy Scheme (SRES). The LRET would operate in the same way that the RET and its predecessor MRET had operated – fixed GWh targets applied to liable entities with Large-Scale Generation Certificates (LGCs) replacing RECs as the certificate eligible to be traded. However, only large-scale generation would be eligible to create LGCs for the 41,000 GWh target in 2020. The SRES would allow installers of small-scale renewable generation (i.e. solar PV units) to create fixed price $40/MWh certificates for their deemed abatement with liable entities (electricity retailers) required to purchase them at rates prescribed by the independent regulator.

These changes were legislated in June 2010. One of the amendments negotiated during the legislative review process related to ongoing 'statutory review' of the policy. Section 162 of the *Renewable Energy (Electricity) Act 2000* (the legislation underpinning the LRET and SRES) requires an independent statutory review to be conducted every two years and presented to Parliament. The first of these reviews was conducted by the newly established Climate Change Authority and completed on 19 December 2012. Perhaps unsurprisingly, and indeed ironically, 12 months prior to this current review, the market essentially closed down for business due to low certificate prices and heightened uncertainty that prevailed due to the review itself. The consequences for market pricing of renewable energy are highlighted in Fig. 4.

Fig. 4 shows the prices of LGCs (formerly RECs) from 2003 to 2012 (LHS). Also shown is the average revenue that would have been earned by a large scale renewable energy generator from LGCs and the average wholesale energy price in South Australia in that year. It should be noted that the long-run marginal cost (LRMC) of the most economic renewable technology (wind) is currently about $90–$100 per MWh. Two things are clear from this graph. First, the market for LGCs responds significantly to movements in government policy. Three examples are highlighted: (a) the rapid run up in LGC prices in 2007 as a result of an election in which political parties were effectively seeking to *'out-bid'* each other in relation to support for renewable energy policy; (b) the significant fall in prices in 2009 as the combination of the Solar Credits Multiplier and premium feed-in tariffs resulted in significant oversupply of certificates; and (c) the fall in prices in 2010 associated with emerging knowledge of the extent of the oversupply of RECs that would be carried into the LGC market. And second, relative policy certainty is required for the combined LGC and wholesale market revenue to equal or exceed the LRMC of developing renewable energy in Australia.

The review of policy history in this section highlights the particularly volatile nature of large-scale renewable energy policy development since 2001 within Australia. Specifically, the original MRET legislation has been materially amended twice in ten years and reviewed publicly by policymakers on at least four occasions. The logical question that follows is whether investor and market participant perceptions of the market have been skewed towards expecting further legislative or regulatory change.

3. Supply and demand for large scale generation certificates

Economic theory dictates that the price of an LGC today should reflect the difference between the wholesale electricity price and the long-run marginal cost of the most economic renewable energy project at the point of time where new renewable generation is required due to LGC supply falling short of demand (discounted to current prices). Accordingly, we have constructed a simple model of LGC supply and demand to test whether the price today reflects the underlying fundamentals of the market.

[1] Following passage of the amendments giving effect to the expansion of the MRET, the policy became known as the Renewable Energy Target (RET).

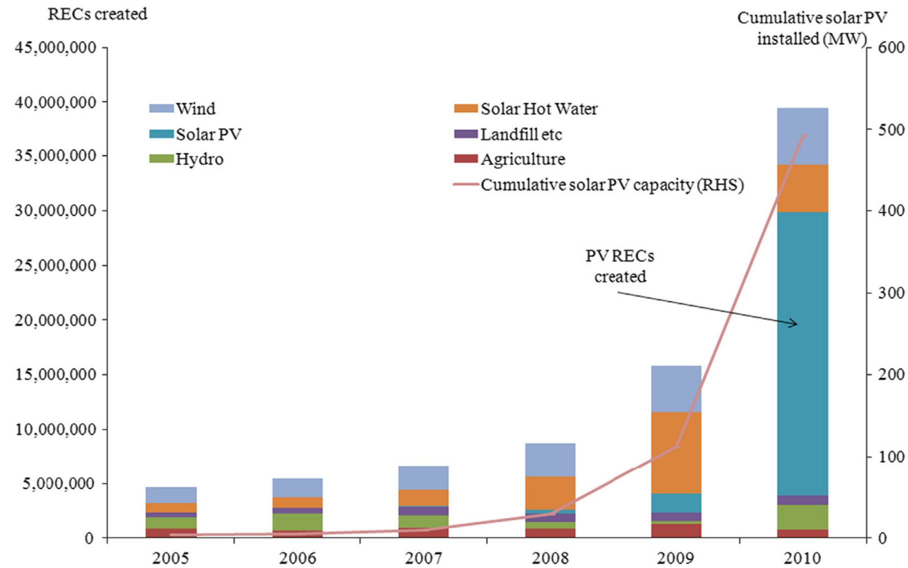

Fig. 3. Renewable Energy Certificates (RECs) created and cumulative solar PV installed.
Source: REC Registry; Nelson et al. (2012).

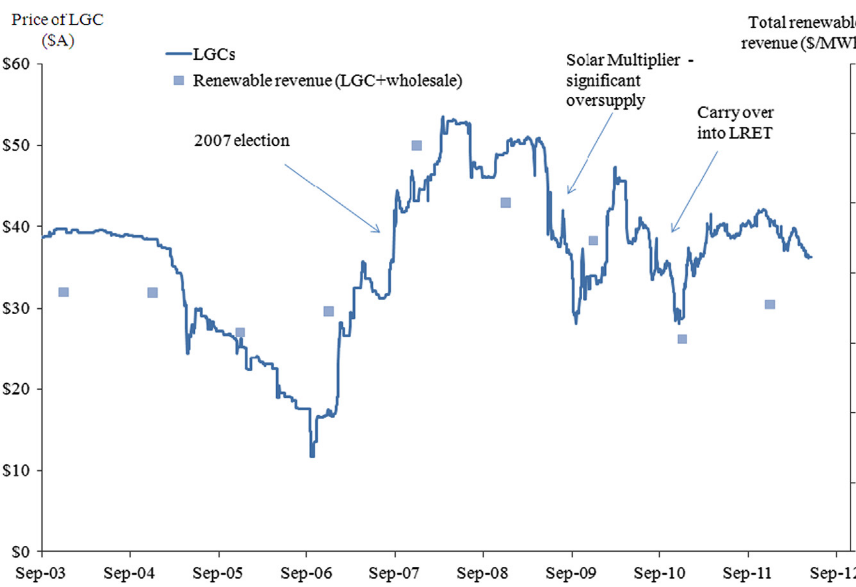

Fig. 4. LGC (formerly REC) price and total renewable revenue.
Source: ICAP, AEMO.

The demand and supply for LGCs in our model in any year (y) is calculated using Eq. (3.1) (demand) and Eq. (3.2) (supply)

$$D_{LGC} = D_{RET} + D_{GP} + D_V \tag{3.1}$$

where D_{RET} is equal to legislated targets under the *Renewable Energy (Electricity) Act* in year (y); D_{P} is equal to yearly demand for Green Power (projected forward unchanged)[2]; and D_{V} is equal to yearly demand for other renewable energy (e.g. known large contracts).[3]

$$S_{\mathrm{LGC}} = S_{\mathrm{CS}} + S_{\mathrm{W}} + S_{\mathrm{H}} + S_{\mathrm{O}} + S_{\mathrm{NW}} \tag{3.2}$$

where S_{CS} is equal to the cumulative surplus of LGCs carried forward from $y-1$[4]; S_{W} is equal to the annual supply produced by existing wind turbines; S_{H} is equal to the annual supply produced by existing hydro generators; S_{O} is equal to the annual supply produced by other existing renewable generators; and S_{NW} is equal to the annual supply produced by wind turbines under construction today.

Balancing Eqs. (3.1) and (3.2) in each year (y) produces either a surplus of LGCs carried forward to y+1 as cumulative surplus or a deficit carried forward as new supply required. At the beginning of the modeling period (2012), we have assumed a cumulative surplus of 32 million LGCs. This is based upon the surplus of certificates available at the end of the 2011 compliance period.

[2] Data sourced from reports available from: www.greenpower.gov.au.

[3] Data based upon knowledge of voluntary industry contract purchases of new renewable energy.

[4] Data for existing generators sourced from REC registry – www.rec-registry.gov.au. Data for new generation sourced from ESAA (2012).

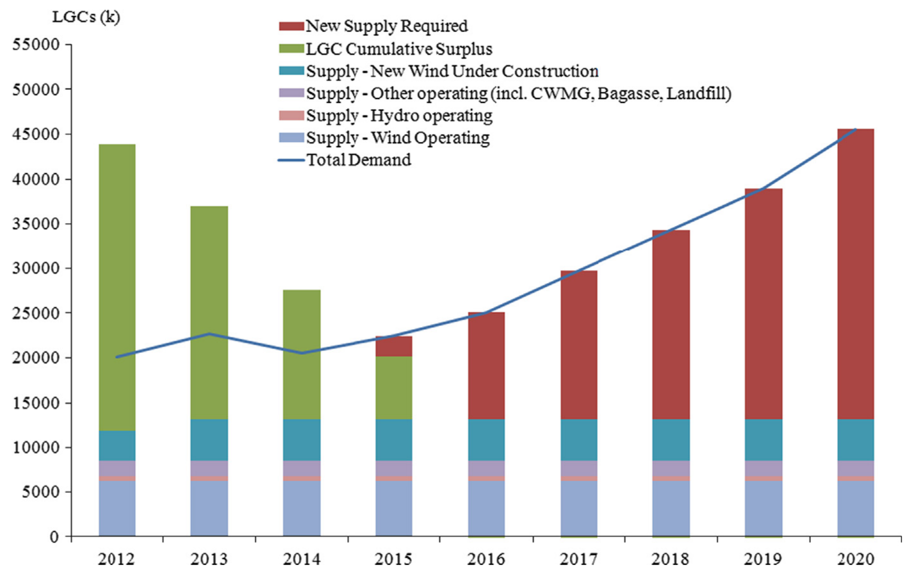

Fig. 5. Modeled supply and demand of LGCs from 2012 to 2020.

Fig. 5 shows the results of our modeling of the supply and demand of LGCs from 2012 to 2020. The significant existing surplus of LGCs in 2012 is gradually absorbed by increasing demand despite a small amount of new supply through commissioning of projects currently under construction. However, new supply (from new projects not yet under construction) is not required until 2015. Beyond 2015, the significant increase in legislated targets under LRET results in rapidly increasing new build requirements. By 2020, an additional 32 million certificates are required to be produced each year to ensure compliance with the scheme. This is the equivalent of approximately 9000 MW of new renewable energy capacity (assuming 35–40% capacity factors and median output from existing fleet of renewable plant). Over the 6 years between 2015 and 2020 (inclusive), implied annual new investment is therefore around 1500 MW or $3.3 billion assuming an 'all-in' overnight capital cost of $2200/kW for new wind (ANZ, 2011).

Our modeling has shown that new renewable generation is required in 2015. Based upon this observation, we are now able to calculate the implied LGC price today. As outlined earlier, the price of an LGC certificate today should reflect the difference between the wholesale electricity price and the LRMC of the most economic renewable energy project in 2015 (discounted). Based upon a wind LRMC of $99/MWh[5] (inflated by 2.5% to account for inflation and expressed in 2015 dollars)[6] and a 2015 forward electricity contract price (P_E) of $55/MWh,[7] we can use Eq. (3.3) to solve the efficient LGC price.

$$\mathrm{LRMC} = P_{\mathrm{LGC}} + P_{\mathrm{E}} \tag{3.3}$$

$107/MWh = P_{LGC}+$55/MWh, P_{LGC} = $52 per certificate (2015 dollars).

Discounting this price using a discount rate for the 'cost of carry' for the three years between 2015 and 2012 is inherently difficult given the number of diverse participants in the market with varying costs of finance.[8] Accordingly, we have used a 7–10% discount rate range to determine that the efficient price of LGC certificates in 2012 is in the range of $39 to $42. This can be contrasted with the price of LGC certificates being $36 at the time of this calculation. Based upon this analysis, it would appear that LGC market participants either: disagree with the fundamentals presented in this paper; or they believe the market structure is likely to be changed through further legislative or regulatory change, thereby diminishing LGC value. In our view prices are well below those implied by market fundamentals. The efficient price (based upon market fundamentals and assuming perfect information) is 8–17% higher than the actual market price depending upon the discount rate used. Given this disparity, it is necessary to consider why market participants are not acting on this clear arbitrage opportunity and increasing demand for LGCs to reflect the economic disparity between actual and our estimate of efficient pricing. Our hypothesis is that the continuing review and change to the large-scale renewable energy policy outlined in Section 2 has led to a belief among market participants that, in aggregate, ongoing policy changes will occur and thus any apparent arbitrage opportunity may well be nothing more than *'a mirage'*. Accordingly, prices have and will continue to trade at a discount to the 'efficient' price because investors must, based on historical experience, wait to see the government response to the legislative review by the Climate Change Authority before they commit scarce debt and equity capital to meet the underlying policy objective function.

4. Market participant views on the LGC market

To suggest that a genuine price arbitrage exists, is well known but is not being cleared by a market of buyers and sellers requires more than a casual observation to be credible. To that end, we conducted a survey of LGC market participants in mid-2012 to

[5] We have based our estimate of the LRMC of wind utilising project financing results from a subsequent section within this article. The estimate would be at the low conservative end of a spread of low, medium and high estimates.

[6] It is reasonable to utilise current capital costs for wind given that a two year construction timeframe would require financial close for new projects to be completed in 2013 (less than a year from the time of writing) to ensure that the shortfall of LGCs in 2015 is met. Wind is currently the most economic large-scale renewable energy opportunity in Australia.

[7] Obtained from d-cyphatrade on 18 June 2012–2015 base future for NSW.

[8] The carryover of Renewable Energy Certificates (RECs) into the Large-Scale Renewable Target when it was established in 2010 has resulted in a diverse group of investors holding LGCs. Banks, merchant generators, retailers, vertically integrated utilities and individual investors are all holders of LGCs. Accordingly, we have used a discount rate range (7–10%) to reflect the full range of finance costs that these participants may face.

Table 2
Survey response (large scale renewable energy developers/retailers).

Survey question	Response
When do you think the market will require new renewable generation?	μ=2015 (Var=0.98 years)
Does the current LGC price represent simple market oversupply or other factors	5 Participants stated simple oversupply, 6 participants stated other factors
Based upon market fundamentals, what do you believe the market price of LGCs should be in 2012?	μ=$45–$50 (Var=$1.19)
What do you believe is the reason for why the current LGC price is not in the range you provided in the previous question?[a]	4 Participants stated uncertainty about both LRET and carbon pricing, 2 participants stated uncertainty about LRET, remaining participants gave other reasons[b]
Do you believe the LRET should be amended through the Climate Change Authority review?	10 Participants stated no amendments should be made, 1 participant said amendments should be made (related to reducing the target)

[a] Four options were provided: uncertainty about carbon pricing; uncertainty about the LRET policy; uncertainty about both carbon pricing and LRET; and other.
[b] Other reasons provided were: lack of spot trading due to prevalence of non-market PPAs; market dynamics where short term over supply over rides risks of long term under supply; and monopolistic market.

Table 3
Survey response (project financing professionals).

Survey question	Response
When do you think the market will require new renewable generation?	μ=2015 (Var=0.54 years)
Does the current LGC price represent simple market oversupply or other factors	4 Participants stated simple oversupply, 6 participants stated other factors
Based upon market fundamentals, what do you believe the market price of LGCs should be in 2012?	μ=$45–$50 per certificate (Var=$11.14)
What do you believe is the reason for why the current LGC price is not in the range you provided in the previous question?[a]	6 Participants stated uncertainty about both LRET and carbon pricing, remaining participants gave other reasons[b]
Do you believe the LRET should be amended through the Climate Change Authority review?	7 Participants stated no amendments should be made, remaining participants stated amendments extending the scheme beyond 2030 should be made

[a] Four options were provided: uncertainty about carbon pricing; uncertainty about the LRET policy; uncertainty about both carbon pricing and LRET; and other.
[b] Other reasons provided were: combination of oversupply and policy uncertainty; and oversupply of RECs and retailers carrying large surplus purchased previously.

confirm whether the existence of an arbitrage exists, and if so, to test whether 'policy uncertainty' is the key issue preventing the arbitrage from being cleared by the market efficiently. Two sets of market participants were invited to participate in the survey: (1) large-scale renewable energy developers and the buyers of the certificates (i.e. energy retailers); and (2) project financing professionals. The survey responses for the first group of respondents were facilitated by the Energy Retailers Association of Australia (ERAA) and the Clean Energy Council (CEC) to remove any bias associated with knowledge of the authors. 11 firms responded and given the relatively small number of materially substantive participants in the sector, we believe this sample size is in fact quite robust because we understand that the most significant participants (by market share) have been included in the sample. That said, we acknowledge that such a small size requires further validation of results which we provide in the following analysis. The second group of respondents was contacted directly. The survey size for project financing professionals was 14 banks and 10 responses were received representing a response rate of 71%. The results of the survey of large-scale renewable energy developers and electricity retailers are presented in Table 2.

The results contained in Table 2 confirm that ongoing policy uncertainty is impeding the efficient clearing and indeed, functioning of the LGC market. The mean of responses indicates that market participants expect that new generation will be required to be operational by 2015 to ensure that demand is met. These views of market participants align with our modeling presented in Section 3, which is important given our earlier comments on the existence of market arbitrage. The mean of responses provided in relation to the 'efficient' market price was the price band $45–$50 per certificate, significantly above the current market price of $36 per certificate. Again, this aligns closely with our modeling in Section 3 which produced an 'efficient' market price of $39 to $42 per certificate (depending upon the discount rate applied). It is likely that our lower estimate of the 'efficient' market price relative to the views of those surveyed is a function of our estimate of the LRMC of wind being at the conservative (low) end of the full spectrum of estimates of wind LRMC within the industry (perhaps due to locational or intermittency discounts).

While we would not suggest such results could be relied upon as conclusive, they are, in our opinion, persuasive in relation to our hypothesis being robust. Importantly, the majority of market participants were of the view that the disparity of pricing between implied efficient prices based on market fundamentals and actual prices is the result of ongoing policy uncertainty – specifically carbon pricing and the LRET. When asked whether the LRET should be amended through the legislative review process undertaken by the Climate Change Authority, 10 out of the 11 participants surveyed stated that it should *not* be amended. Importantly, the results of our analysis of this relatively small sample (by number of participants) are supported by others including ROAM Consulting (2012) and environmental market brokers such as Nextgen (2012) who noted that, "*given the history of regulatory change that has occurred over the last five years in particular, having confidence in the long term appearance of the LRET is no easy thing.*" Importantly, our results are not specific to LRET market participants. Project financing professionals provided similar responses as Table 3 demonstrates.

Table 3 shows that electricity generation project financing professionals have similar views on the LGC market to LGC market participants – bearing in mind that project financiers have an especially acute understanding of market conditions given their debt facilities are illiquid and particularly long-dated. Project financiers must closely analyse wholesale electricity and environmental markets to assess the business case for providing funding to any new or existing piece of energy infrastructure. Project financing professionals expect that new generation will be required from 2015 and that the price of LGCs should be between $45 and $50 per certificate at the time of writing (albeit with a significantly greater variance of pricing expectations than LGC market participants). Based upon the mean, these results mirror those of the market participants. In relation to the reasoning behind the misalignment between market fundamentals and pricing, the majority of respondents stated that uncertainty about the legislative review of LRET and the longevity of carbon pricing policy are key factors. It is unsurprising given the similarity of views on these issues that the majority of project financiers do not support further changes to LRET through the Climate Change Authority legislative review.

5. Capital market efficiency losses and policy uncertainty

Policy uncertainty is evidently present within the large-scale renewable energy industry. There is a rich and detailed existing economic literature related to the costs of policy uncertainty in Australia's electricity markets (see for example Nelson et al, 2010; Frontier Economics, 2010; Sinclair Knight Merz, 2011a; Deloitte, 2011; Nelson et al, 2012a; and Simshauser and Nelson, 2012). Two basic implications of ongoing public policy uncertainty on the electricity industry have been explored. Firstly, the impact of sub-optimal investment in new generation capacity has been examined. As electricity generation is highly capital intensive, it is necessary to take a long-term view of market fundamentals and regulatory and legislative stability to ensure that capital is not stranded. Secondly, the impacts of capital market efficiency losses have been examined.

It is the second form of uncertainty related to capital market efficiency losses that we address in this article. Given the results presented in Section 4 indicate that the market is concerned that further changes to the LRET policy may be made as a result of a government response to the Climate Change Authority's legislative review, it is appropriate to ask whether *actual* material amendment of the policy in 2013 would result in additional risk premiums being applied to large-scale renewable energy investments. The framework applied by Simshauser and Nelson (2012) is useful for answering such a question. We have adopted this framework in the current section to determine whether further amendment of the LRET will result in capital market efficiency losses.

Simshauser and Nelson (2012) surveyed project financing professionals to determine pricing, tenors and participation in the market for funding large scale generation in the NEM. Simshauser (2010) found that the NEM has more than 20,000 MW of privately owned (i.e. pre-existing and new entrant) generating plant and around 17,000 MW (85%) of this is project financed. With such a heavy reliance upon project financing, spreads on syndicated project debt provide a specific and relevant insight into market participant expectations about the risks associated with investment in electricity generation infrastructure. This is important for two reasons. First, historically much of the plant introduced since the creation of the NEM in the late 1990s has been project financed. Second, and looking forward, while it may well be true that the large retailer/developers (i.e. AGL Energy, Origin Energy, TRUenergy) may be theoretically able to raise on-balance sheet finance from debt capital markets to avoid the use of project finance, such an outcome may lead to a substantial concentration of renewable plant ownership. In a well functioning market for new plant, a material proportion of the large investment required under LRET should be project financed and undertaken by Independent Power Producers if for no other reason than the predictable balance sheet and investment concentration constraints of those large retailer/developers – hence our interest in broader bank debt spreads.

Table 4
Survey results on perceptions of PF facilities in 2006, 2008 and 2011.
Source: Simshauser and Nelson (2012).

	2006	2008	2011
PF Spreads	100–120 bps	400–450 bps	350–400 bps
Spread Movement	*Stable*	*Up 3.8 ×*	*Down 11%*
Max tenor	12 years	3 years	7 years
Max gearing	65%+	Approx 55%	Approx 60%
MLA Banks	3 or less	7–8 banks	7–8 banks
Syndication Banks	3 or less	Club deal	4–8 banks
Active Banks	29	11	14
Spread on BBB Bonds	85 bps	360 bps	240 bps
Spread Movement	*Stable*	*Up 4.2 ×*	*Down 33%*

The results of the Simshauser and Nelson (2012) survey are presented in Table 4. Note the significant increase in Project Finance (PF) spreads for electricity generation from 2008 to 2011 relative to those of BBB bonds (down only 11% compared to 33%).[9] BBB bonds were used as a comparator. While corporate bonds are not necessarily good substitutes for PF, the relative change in pricing of both debt instruments is of course entirely relevant. They found that the most logical explanation of the elevated spreads relative to local and global comparators was the ongoing policy uncertainty on greenhouse gas emissions. The conclusion of the study was that the higher spreads arising from carbon pricing uncertainty would result in increased electricity prices for consumers.

The 2012 study noted that volumes in syndicated debt markets retreated significantly during the 'great recession' of 2008 and 2009. While markets have rebounded, the most recent observations point to further potential retreats due to ongoing concerns about economic conditions in Europe and the fragility of some banking industries. Fig. 6 shows total syndicated debt transactions broken down by quarter and year since 2004. While 2011 saw a significant turnaround post the 'great recession', quarter on quarter trends for 2012 reveal a subsequent retreat in syndicated debt.

This has non-trivial implications for Australian energy markets given around half of Australian investment funding (debt and equity) is sourced internationally as Simshauser and Catt (2012) noted. Simshauser and Catt (2012) estimate that between 2010 and 2015, $85.9 billion in capital will be required within the electricity supply system. Capital investment on new network infrastructure and upgrades to existing equipment was forecast to hit $43 billion. Fully $33.6 billion was projected for refinancing of existing network infrastructure while $9.4 billion was forecast to be used to refinance existing power stations. In addition, incremental capital between 2012 and 2020 related to the LRET is likely to be between $20 billion and $30 billion.

This vast capital inflow requirement within Australia needs to be assessed within a domestic capital market which is increasingly skewed towards energy and resources. Fig. 7 shows private capital investment in mining, manufacturing and other industries since 2000. Fig. 7 illustrates that capital expenditure on mining has risen by around 100% since 2009. It is therefore critical that consideration be given to the importance of capital inflows for financing resource and energy projects – a thematic identified in Simshauser

[9] The Project Finance (PF) spreads for electricity generation effectively represent the specific cost of financing electricity generation infrastructure.

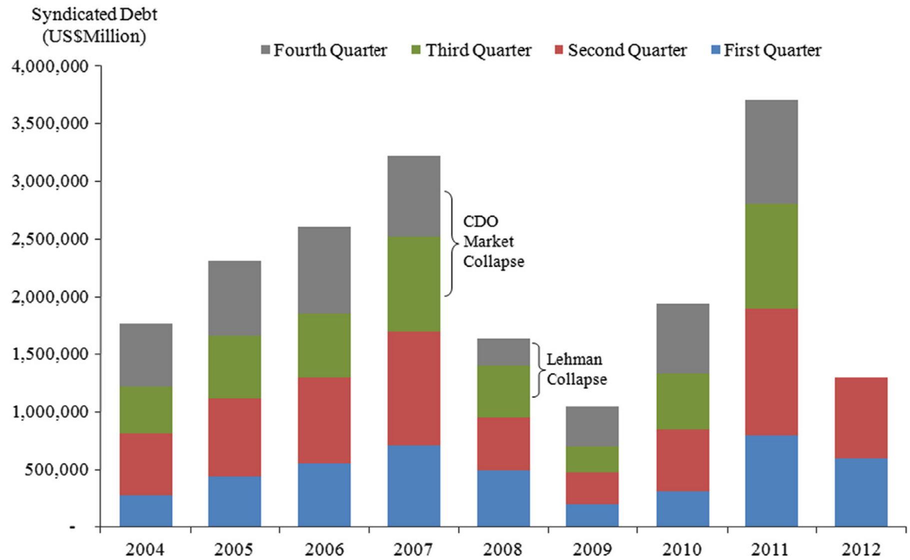

Fig. 6. Global syndicated bank debt by Calendar Year – 2004 to 2012.
Source: Bloomberg (2012).

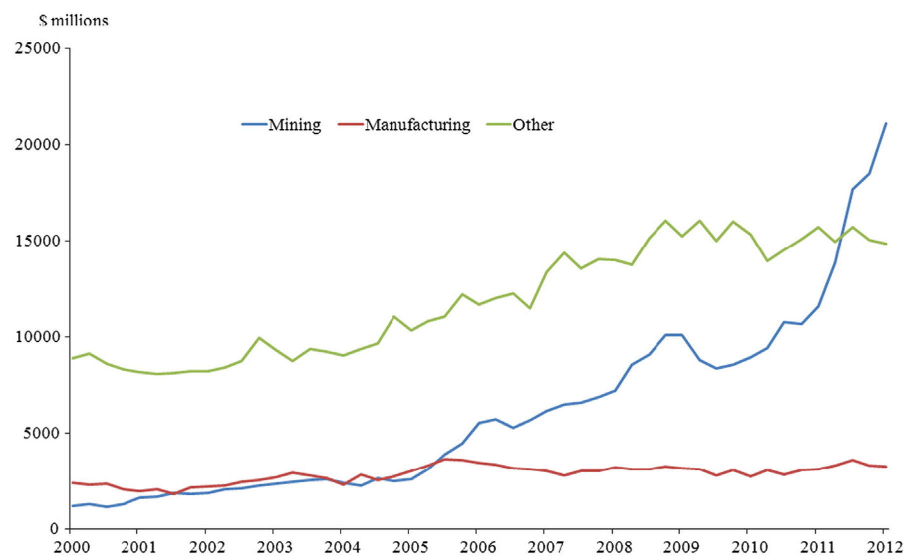

Fig. 7. Private new capital expenditure by industry.
Source: ABS (2012).

(2010b). As a consequence of credit concentration limits, domestic banks are simply incapable of funding all new capital expenditure in the sector. Given the vast capital financing requirements of the electricity sector between now and 2020 and potential constraints in global syndicated debt activity as a result of global economic conditions (and indeed Basel III reforms), it is paramount that energy policymakers consider the impacts of policy uncertainty on the attractiveness of Australia (and the Australian energy sector in particular) as a destination. Intense competition for capital both domestically (between sectors) and internationally (between countries) underscores the importance of maintaining policy stability for investors in electricity infrastructure with long-lived asset lives.

To test whether policy uncertainty in relation to large-scale renewable energy would result in distortions related to pricing of infrastructure by these capital markets, we conducted a survey of project financing professionals as noted in Section 4. The results of this survey are presented in Table 5.

The results of the survey presented in Table 5 are consistent with the thematic identified in Simshauser and Nelson (2012). Respondents indicated that policy uncertainty (measured by material amendment to the LRET) would result in financing 'premium penalties' being applied to both new renewable and new gas-fired generation projects, which is to be expected. The mean response was the band 51–100 bps providing an effective mean of 75 bps above the reasonable credit margin over BBSW in 2012 of 275 bps.

We have applied these survey results to the PF Model utilised in Simshauser and Nelson (2012) and documented in Nelson and Simshauser (2013) to examine how changes in financing parameters impact on the underlying cost structures of baseload/intermediate combined cycle gas turbine plant (CCGT), renewable projects (wind) and peaking open cycle gas turbines (OCGT). We have used the same range of assumptions published in Table 7 of Simshauser and Nelson (2012) and so we do not intend to reproduce them here. One key variation is a lower capital turbine

Table 5
Survey response (project financing professionals).

Survey question	Response
What would you expect the 'reasonable' credit margins over BBSW[a] for a large-scale renewable project in 2012?	μ=250–300 bps
If the LRET is materially amended in 2012/13, what additional credit margin would be applied to reflect risks associated with ongoing regulatory change	Renewable: μ=51–100 bps Gas: μ=51–100 bps

[a] BBSW is the Bank Bill Swap Reference Rate. It is effectively the borrowing interest rate among Australian financial institutions. It is used as a benchmark interest rate for other financial instruments.

cost for wind at $2200/kW, compared to $2500/kW in the 2012 study.[10] Three scenarios have been modeled

1. *Certainty scenario*: In this scenario, we assume that the Climate Change Authority recommendation of no substantive changes to the operation of the LRET is supported by government, and critically, bi-partisan support for the policy in its current form continues.[11] Spreads on project financed power generation facilities reflect uncertainty in relation to carbon pricing but not uncertainty in relation to renewable policy. This results in credit margins of 275 bps over BBSW and enables firms to secure longer facility tenors. Gas input pricing for CCGT is assumed to be steady at $4.50/GJ.
2. *Uncertainty scenario*: Key assumptions in this scenario relate to government implementing "material changes" to the operation of the LRET. Bi-partisan support for the policy in its current form evaporates, resulting in genuine policy uncertainty for investors. Spreads on project facilities reflect both uncertainty in relation to carbon pricing, and uncertainty in relation to development of large-scale renewables. Credit margins increase by 75 bps to 350 bps over BBSW, and facility tenors are reduced, which heightens refinancing risks and reduces achievable debt levels within the capital structure of projects. Gas input pricing for CCGT remains unchanged and steady at $4.50/GJ.
3. *High gas scenario*: Primary assumptions in this scenario are that as in the certainty scenario, the Climate Change Authority recommendations of no material changes to the operation of the LRET are adopted and bi-partisan support for the policy in its current form continues. Spreads on project-financed power generation facilities reflect uncertainty in relation to carbon pricing but not uncertainty in relation to renewable policy. This results in credit margins of 275 bps over BBSW. However, gas input pricing for CCGT significantly increases from $4.50/GJ to $10.00/GJ reflecting high global demand for natural gas and the linkage of previously isolated Australian east-coast domestic gas markets with LNG pricing (see Simshauser et al., 2011 for further information on structural gas pricing shocks in Australia). Carbon pricing of $15/tonne of carbon dioxide equivalent is also included in fuel costs. This scenario has been included to reflect consideration of issues related to gas pricing raised by Riesz and Tourneboeuf (2012), which as our partial equilibrium analysis subsequently reveals, is critically important for policy-makers to consider.

[10] Most recent observations for wind capital costs indicate prices are even lower (see Trustpower (2012) which indicates pricing at $1630/kW). However, we are uncertain as to whether such pricing includes the full cost of construction, and specifically, items such as interest during construction, owners project development costs, grid connection and so on. Accordingly, we have opted to use estimates based on information provided in BREE (2012).

[11] For further information on the Climate Change Authority's recommendations to leave the policy largely unchanged, see Climate Change Authority (2012).

The PF Model results for these three scenarios are presented in Fig. 8. Gearing is applied relatively consistently at between 60% and 63%. This represents the main variation in application from Simshauser and Nelson (2012) and explains the higher returns to equity and lower interest payments in each of the results for the 200 MW wind project. Financing is provided using 5, 7, 10 and 12 year tenors depending upon the scenario and technology.

Fig. 8 shows that, unsurprisingly, the unit cost of a 200 MW wind project increases by $4.20/MWh (4.3%) from $98.57/MWh to $102.77/MWh with the introduction of policy uncertainty. Importantly, the unit cost of a 1 × 400 MW CCGT project also increases by $0.73/MWh (1.1%) from $64.32/MWh to $65.05/MWh under the same conditions. The most material change in unit cost occurs with the significant increase in gas pricing where CCGT costs increase to $103.22/MWh (i.e. above the cost of wind).

Due to the different operating duties of an OCGT (peaking) plant, the financing results are very different to those of a CCGT, as shown in Fig. 9, which presents the 'carrying cost' or 'total fixed costs' (including a normal return on funds invested) for a 525 MW plant comprising three units. This can be thought of as the fair value of a $300/MWh call option written by new entrant peaking plant. The incremental cost of an OCGT in moving from certainty to uncertainty (scenario 1 to scenario 2) is $0.44/MWh.

6. Partial equilibrium analysis – policy uncertainty and electricity prices

To assess the economic impact of our different scenarios on electricity prices, we assume financing costs calculated in previous sections begin to bind immediately from the date at which legislative change in response to the Climate Change Authority review is proposed (i.e. 2013). For simplicity, we have assumed that any legislative change would be announced in late 2013 and implemented in 2014. Higher LRMC costs associated with policy change would be revealed in the market from 2017 onwards as new plant is commissioned (and in practice, as existing plant is refinanced). CCGT forms the dominant base and intermediate load technology while OCGT undertakes peaking duties.

We utilise the Optimal Plant Mix Model (OPM Model) from Simshauser and Wild (2009) to undertake the analysis. This partial equilibrium electricity system model simulates half-hour resolution and assumes perfect competition and essentially free entry to install any combination of capacity that satisfies differentiable conditions. As this model has been documented in Simshauser and Wild (2009), we do not intend to reproduce the details here. A static graphical representation of the half-hourly modelling results is presented in Fig. 10.

Demand has been projected utilising the latest forecasts from the Australian Energy Market Operator (AEMO, 2012). These forecasts account for the recent declines in energy demand associated with adoption of embedded solar PV, energy efficiency schemes and responsiveness to higher retail prices driven by increased network costs. Average growth in annual energy for

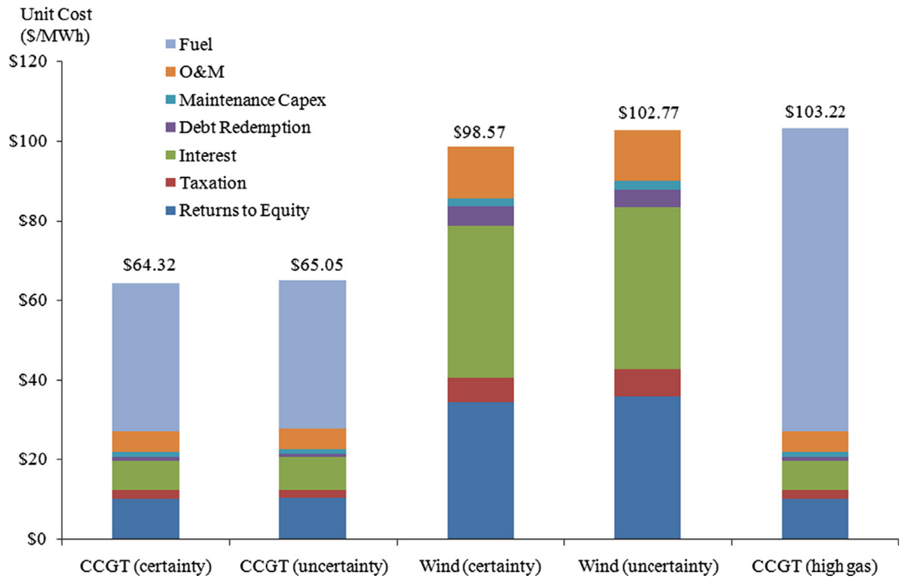

Fig. 8. Project financing model results for CCGT and wind.

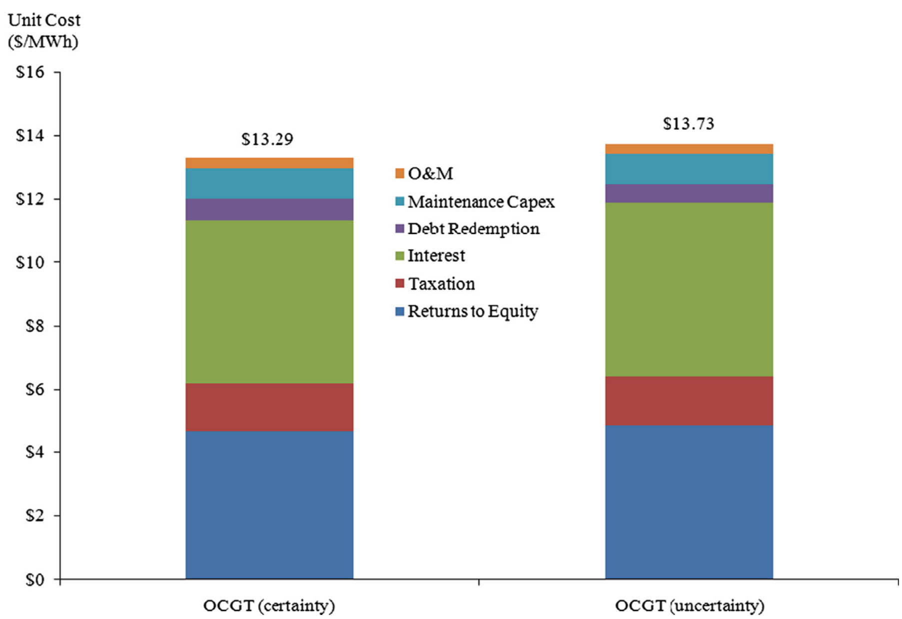

Fig. 9. Project financing results for OCGT.

the ten year period out to 2022 is now forecast to be 1.7%, down from the previous forecast of 2.3% in 2011. We utilise the methodology outlined in Nelson et al. (2010) to distribute the average annual growth of 1.7% across deciles of actual 2011 NEM demand ranked by time.

The three scenarios outlined in the previous section have each been modeled using the partial equilibrium framework discussed above. One additional scenario has also been modeled based upon material adjustment of the LRET targets to reflect recent commentary related to electricity demand being softer than anticipated when the LRET was first legislated. Origin Energy (2012) made the salient point that with softening electricity demand, the RET would result in more than 20% of Australia's electricity being sourced from renewable sources, at least given most recent forecast information.

The power generation system cost results for each scenario are presented in Table 6. The certainty scenario results in a system average cost of \$69.17/MWh between 2017 and 2021. The introduction of policy uncertainty results in average system costs increasing by \$0.69/MWh (1.00%) to \$69.86/MWh. If the high gas scenario were to materialise, average system costs would increase by \$33.88/MWh (49%) to \$103.05/MWh. Additional costs of operating higher LRMC renewable plant are revealed in LGC costs which our subsequent analysis examines.

Table 6 notes that uncertainty results in higher costs associated with servicing projected future demand. However, this ignores any potential savings associated with reductions in LGC costs incurred by retailers, then passed through to customers as reductions in prices. These cost savings are significant. We have utilised an LRMC methodology represented graphically in Fig. 11.

Fig. 11 shows the revenues that a wind turbine would earn, on average. Note that these revenues come from two sources: (1) from the wholesale energy market and (2) from the sale of LGCs. These two income streams can be thought of as the components that

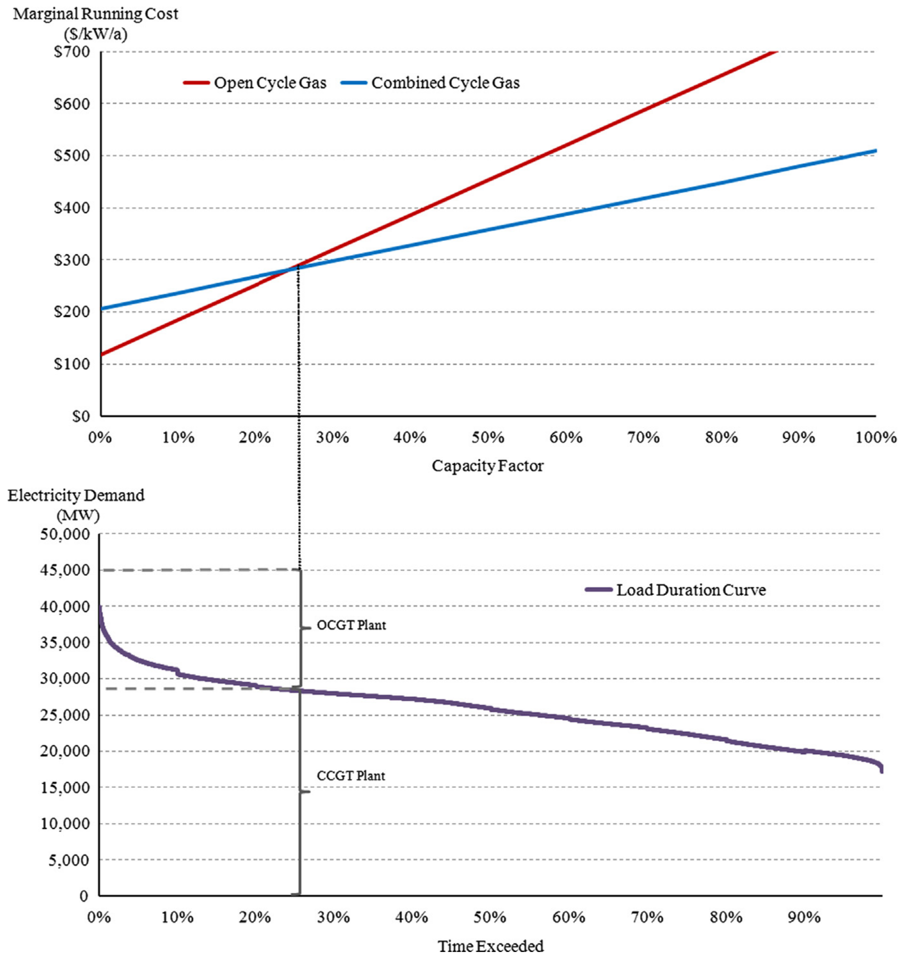

Fig. 10. Graphical representation of partial equilibrium analytical framework.

Table 6
NEM system average cost between 2017 and 2021 (2012$).

	Certainty ($/MWh)	Uncertainty ($/MWh)	High gas ($/MWh)
Underlying energy costs	69.17	69.86	103.05

comprise an appropriately priced Power Purchase Agreement (PPA). We have assumed away any penalty applied to wind in wholesale energy markets related to the intermittency of output. We consider this to be a reasonable assumption given the relatively modest penalties identified by Simshauser (2011) in relation to intermittent wind generation, and the fact that most other plants will face equivalent intermittency issues in any event. To calculate the net costs to society of uncertainty created by material amendment to the LRET, we have contrasted reduced LGC costs to 2021 with higher wholesale energy costs associated with the results of our partial equilibrium analysis. Effectively, we have created two scenarios

- *Uncertainty*: In the uncertainty scenario, we have assumed that LRET targets beyond 2016 are not increased at all. Effectively, this scenario simulates a situation where the LRET policy is repealed. However, it presumes that existing investments are grandfathered (including projects committed through to 2014). Higher wholesale energy costs (outlined in Table 6 previously) are incurred due to investor perceptions of regulatory risk as a result of the material amendment of the policy. However, these higher costs are somewhat offset by the reduced LGC liability between 2017 and 2021 as a result of repeal of the LRET legislation.[12]
- *Uncertainty* (*low demand*): For the uncertainty (low demand) scenario, we have assumed that LRET targets are reduced in 2014 to reflect softening projections of electricity demand in 2020 and a desire to achieve no more than 20% renewable electricity by 2020 given lower demand forecasts. Using the logic in Origin (2012), we have reduced the targets between 2016 and 2020 to ensure a linear approach to 27 TWh in 2020, down from 41 TWh. Higher wholesale energy costs (outlined in Table 6 previously) are incurred due to investor perceptions of regulatory risk as a result of the material amendment of the policy. However, these higher costs are somewhat offset by the reduced LGC liability between 2017 and 2021 as a result of lower LRET targets relative to current legislation.[13]

Our results for the two scenarios identified above are presented in Fig. 12.

Fig. 12 shows the costs and benefits associated with significantly amending the LRET. While lower LGC costs are incurred in

[12] As our analysis is for the NEM, we have reduced the LGC liability in our modeling by 10% to reflect that the Western Australian and Northern Territory LGC liabilities are not relevant (around 10% of national electricity demand).

[13] As per footnote 12.

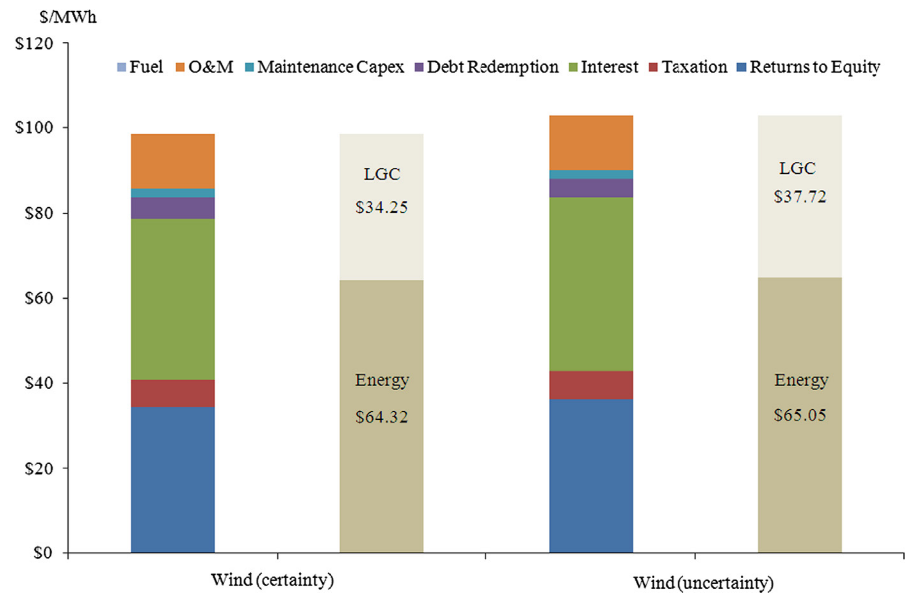

Fig. 11. Breakdown of revenues for wind under certainty and uncertainty scenarios. The lower implied LGC pricing (relative to Section 3) is a function of higher wholesale pricing in 2017 ($64.32/MWh compared to $55/MWh for 2015 energy futures contracts available at the time of writing). For our modeling, we have used the actual yearly estimates produced through our partial equilibrium analysis (rather than the cost of a CCGT or average wholesale prices).

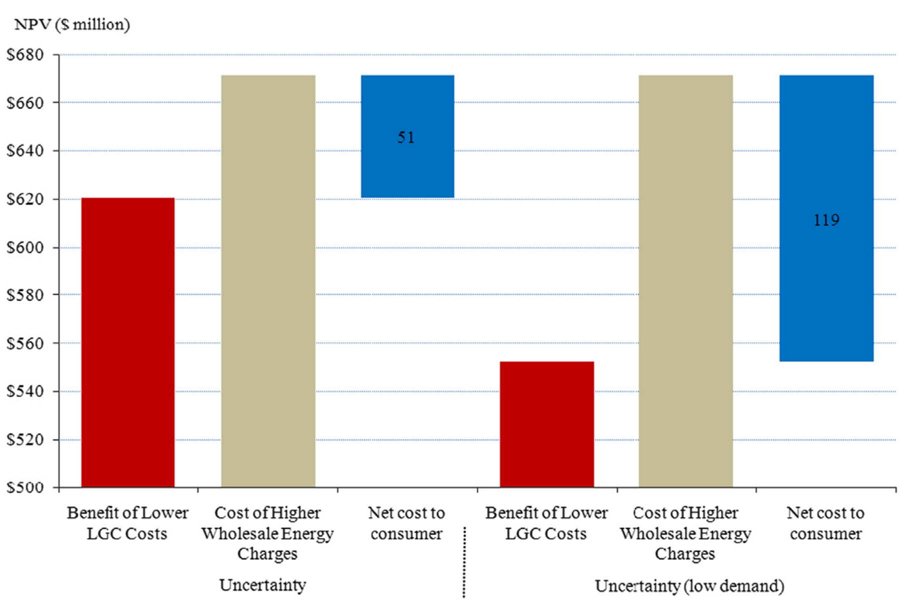

Fig. 12. NPV of net cost to consumer of uncertainty and uncertainty scenarios.

both scenarios, the higher wholesale energy costs, as identified in Table 6, are greater. The end result is a net cost to the consumer of $51 million (NPV 2012$) if the LRET is effectively repealed. Of course, the costs associated with this scenario would ultimately dissipate, while the benefits would more than likely be sustained. And so over the very long run, these results might reverse, although this is dependent upon Australia's policy of repealing the LRET being consistent with global trends (which based upon evidence presented in Section 2 appears somewhat unlikely). But over the period of our examination, that is, from 2012 to 2021, there would be a net cost to consumers from repealing the policy, even with a grandfathering of existing projects. If the LRET target was reduced to change with fluctuating demand, the net cost to consumers was found to be $119 million (NPV 2012$) over the period 2012–2021. While these results appear counter-intuitive, they are a simple function of the fact that there are real costs associated with policy uncertainty.

7. Policy recommendations

In its final report, the Climate Change Authority recommended no material changes be made to the LRET policy. A key finding of this article is that this finding is robust. Material amendments to the policy would result in heightened uncertainty in relation to energy policy with resultant costs being applied by financiers of power generation, and a further widening of the theoretical to actual prices. According to the modelling presented here, these costs would manifest themselves as higher costs to consumers – up to $119 million (NPV 2012$) between 2017 and 2021, and sharper run-up in LRET prices when shortages inevitably occur.[14]

[14] We acknowledge the somewhat arbitrary nature of modeling between 2017 and 2021. However, we expect that analysis beyond 2021 would not be relevant given that higher costs applied by project financiers would eventually abate.

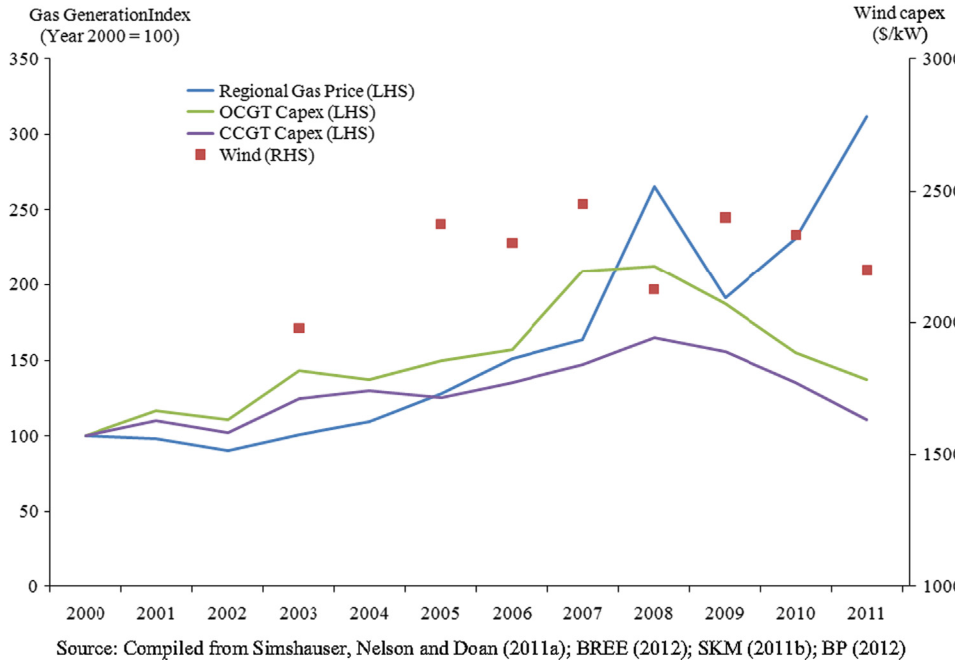

Fig. 13. Wind and gas capex and fuel prices.
Source: Compiled from Simshauser et al. (2011), BREE (2012), SKM (2011b) and BP (2012).

We have not considered the merits of first principle public policy objectives in relation to large-scale renewable energy policy. Instead, we have looked at the market as it exists today and found that amendment of the policy framework designed to alleviate pricing pressures would be a more expensive option for electricity consumers and society than leaving the current policy in place. Investors in power generation require stable policy frameworks and amendment to a policy which is designed to underpin infrastructure investment for the next 20 years will not be welcomed by most investors. International Power (reported in Maher, 2012) drew the obvious conclusion

> *"Over $6 billion of investment has to date been made in renewable generation and investors (both Australian and international) have relied on the RET legislation remaining in full force and effect. Stable legislation (and regulation) is required for large scale capital intensive infrastructure whether this is renewable generation and/or fossil-fired generation. If legislation is changed, then it sets a worrying precedent that the legislative/regulatory goalposts will be moved again and again over the next 20 to 30 years."*

In addition to our broad conclusions in relation to policy certainty, we believe the dynamic discussed by Riesz and Tourneboeuf (2012) in relation to uncertainties about gas pricing requires greater consideration. Policymakers should have regard to all of the factors which may result in wholesale energy price pressures when considering the merits of renewable energy. The nature of the NEM with its uniform, first-price, energy-only gross pool auction design means that plant with very low short-run marginal costs (such as wind farms) have little or even negative impacts on pool prices. Conversely, the cost structure of a gas-fired plant is a direct function of the gas price. Our research has shown that a significant increase in gas prices could result in gas-fired plant becoming more expensive than wind. We do not make conclusions about the likelihood of this occurring, only that renewable energy with no fuel cost should be contrasted with gas in this environment.

Fig. 13 shows indices for gas prices and capital expenditure for wind, OCGT and CCGT for the period 2000 to 2011. There are several conclusions that can be drawn by policy makers in relation to future pricing. Firstly, wind turbine prices are trending down while gas prices are trending up. Secondly, capital expenditure trends for OCGT, CCGT and wind are relatively similar. It is reasonable to state that the most recent pricing for turbines is likely to be temporary given the somewhat unusually high $A driven by international investor appetite for Australian denominated sovereign debt.[15] The trends in Fig. 13 appear consistent with those presented by US researchers (see Bolinger and Wiser, 2011). In this context, and given the net cost to society of amending the LRET policy, it would appear prudent to maintain existing policy commitments.

8. Conclusion

This article has found that ongoing uncertainty in relation to the future of large-scale renewable energy policy in Australia is preventing the LGC market from operating efficiently. Our survey of market participants confirms that buyers and sellers of LGCs are concerned about the potential for further legislative change and this concern is manifesting itself in poor pricing and capital allocation decision making. Arbitrage opportunities clearly exist but no party is willing to clear the arbitrage based on battle-hardened historical experience. Based upon the modelling presented in this article, our conclusion is clear – material amendments to the LRET would result in net costs to consumers of between $51 million and $119 million (2012$). Based upon this conclusion, our recommendation is that the LRET should remain in place and without amendment if confidence in the policy is to be restored. It is important to note that bipartisan support for the policy continues as indicated by recent statements by political

[15] The issue here is that, at the time of writing, Australia's terms of trade had been falling while the Australian dollar had concurrently remained unusually strong.

leaders such as, '*There's a review coming but we remain committed to the Renewable Energy Target*' (Hunt, 2012).[16]

Importantly, many of the conclusions made as a result of our survey of market participants appear consistent with previous and similar studies. In our view, ROAM Consulting expressed the requirement for consistency as well as any:

> *"a good outcome from the biennial review would be to leave the LRET to function in its current form. Uncertainty about the future of the scheme is a significant issue, and there was consensus that investor confidence will return only if the legislation goes through the review with no changes. Furthermore, the review should be done as quickly as possible and released as quickly as possible once complete."* (ROAM Consulting, 2012, p. 56).

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[16] Such a policy recommendation is consistent with community attitudes in relation to renewable energy. For example, community support for wind farms is high: 83% of people support wind farms; while only 14% oppose them; and 3% don't know. Over 7 in 10 people support wind farms being built nearby (to their residence) and over 8 in 10 agree that "wind farms are an important part of our clean energy future" (Pacific Hydro, 2012).