more give, less take

Sector Insights: Energy & Utilities

April 2012

Welcome

Andrew Wright
Managing Director,
Head of Resources,
Energy & Utilities
Institutional Banking

Fiona McIntyre
Director
Head of Energy & Utilities
Institutional Banking

Welcome to our inaugural issue of *Sector Insights: Energy & Utilities.*

We are pleased to launch the inaugural issue of ‘Sector Insights: Energy & Utilities’ – a publication that seeks to offer some unique insights into the energy sector and credit markets. As well as commentary from a number of our key senior executives, we are extremely fortunate to have two industry leaders, Richard McIndoe, Managing Director, TRUenergy, and Rob Grant, Chief Executive Officer, Pacific Hydro, share their views around the opportunities and challenges impacting their business.

The European sovereign debt crisis continues to create increased uncertainty and risk, resulting in credit markets remaining expensive and volatile until a resolution is reached. There is heightened interest in the cost of funds in Australia, with the major banks moving to sever the link between the Reserve Bank of Australia’s cash rate decisions and their own lending rates.

At the same time we are at a very interesting juncture in the history of the Australian energy market.

The introduction of a price for carbon has been extensively debated for many years and has proven to be very politically sensitive. The Clean Energy Future legislative package passed in November 2011 will result in the introduction of a fixed carbon price from 1 July 2012 transitioning to an emissions trading scheme from July 2015.

Significant investment is required to meet the government’s legislated Large Renewable Energy Target (LRET) of renewable power generation by 2020. New wind farm developments have stalled over the last two years due to the overhang of Renewable Energy Certificates (RECs). The depressed REC price has in turn resulted in wind farm developers having difficulty securing long-term Power Purchase Agreements. There will need to be a rapid acceleration in investment to meet the government’s legislated target.

The Clean Energy Future package together with the LRET and other initiatives, such as the Solar Flagship program, are designed to reduce the emissions intensity of Australia’s electricity generation sector. This, however, is not a simple task as other factors such as increasing gas prices arising from the development of new LNG projects in Australia further impede the transition from a coal dominated electricity generation sector. The carbon price alone will not reduce Australia’s reliance on low-cost brown and black coal.

Substantial capital expenditure is also required to ensure our ageing transmission and distribution energy infrastructure remains safe and reliable. We explore how gradual privatisation of the energy sector remains a constant with the NSW government recently announcing a second round of electricity generation privatisation.

We are sure 2012 will be another interesting and eventful year in the energy sector and market more broadly.

Yours sincerely

Andrew Wright   Fiona McIntyre

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The state of funding
for renewable energy projects in Australia

Phillip Mak
Head of Origination
Energy, Asia Pacific
Global Specialised Finance

Phillip Mak analyses the key challenges ahead in securing the funding for Australian renewable energy projects

State of the funding market

While the financing market for Australian renewable energy projects is still open for business, three broad challenges have arisen recently which have softened the deal pipeline. Firstly, project developers have had difficulty securing Power Purchase Agreements (PPAs). Secondly, the European debt crisis has had a negative impact on bank funding. Finally, the introduction of Basel 3 will cause some longer term changes in the broader bank funding market, including the renewable energy sector.

The difficulty in securing PPAs has been driven partly by a sharp fall in renewable energy certificate (REC) prices in 2010 due to State Government policies promoting household-based solar installations. The fall in REC prices created uncertainty in the market and threatened to deter potential investment in large-scale renewable energy projects. Chart 1 illustrates the movement in REC spot prices over the past four years. In response, the Government split the Renewable Energy Target (RET) scheme into two, the Large-scale Renewable Energy Target (LRET) for large-scale projects, such as wind farms, and the Small-scale Renewable Energy Scheme (SRES), for small-scale installations, such as rooftop solar.

Since that time REC prices have recovered, although there is still an overhang of certificates which is causing some continued price uncertainty. This challenge has prompted the financing market to develop alternative approaches to funding renewable projects, such as bridging structures and financing structures dealing with projects with lower coverage from PPAs.

The ongoing turmoil in Europe has meant that bank funding in general has become more expensive. In addition, bank appetite for long-dated tenors has waned. As a result, margins for energy and utilities projects have not returned to their pre GFC lows, as shown in Chart 2. While this means that refinancing risk is present in the Australian renewables market, it is currently sufficiently liquid for this risk to only pose a marginal issue for developers. Historically, there has been strong interest from banks in the renewable energy market due to its favourable returns, as well as providing banks with an opportunity to demonstrate a commitment to taking action to reduce carbon emissions. Apart from the four domestic banks, which contributed approximately \$1.6 billion out of \$2.9 billion[1] in project debt in 2011, European and Asian banks have also provided liquidity to the bank debt market. Despite the number of the European banks that pulled back from lending towards the end of 2011, intense competition has continued

Chart 1: LREC Spot Price

Source: NAB Markets January 2012.

"Based on some estimates, the investment in renewable generation capacity needed over the next decade to achieve the target is between $25 billion and $30 billion."

for the limited number of renewable energy opportunities that reached financial close over the past year. Currently, we see eight to 10 banks still active and therefore believe sufficient liquidity exists to meet the required transaction sizes, which tend to be smaller than infrastructure or thermal energy deals. Relatively limited transaction flow and smaller ticket size, together with the growing interest in the renewable space, has also influenced pricing.

Debt margins on renewable deals have been tighter in some instances than those seen in other infrastructure sectors which would arguably have a relatively lower risk profile. This continues to make the bank debt funding market an attractive option for renewable energy developers.

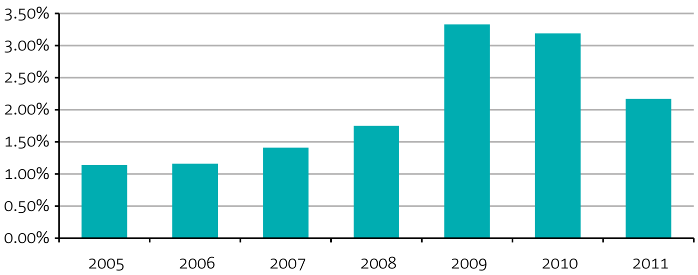
One of the longer term impacts from new regulation associated with Basel 3 will potentially be a shift in the composition of the funding market, driven by long-dated tenors becoming less attractive for banks. Non-bank financiers such as Export Credit Agencies (ECAs) and bond market investors may become more active in this market. We have seen examples of this recently, with ECA tranches being structured into a couple of recent wind farm transactions in Australia and New Zealand. While in the medium term the renewable funding market will continue to be dominated by bank debt, over time banks may provide financing initially, with a view to advising and connecting developers with the capital markets for their long-term financing requirements.

Future pipeline

As shown in Chart 3, total renewable generation in the year to June 2010 was just over 19,000 GWh.[2] Therefore, with the LRET being set at 41,000 GWh p.a. of renewable power generation by 2020,[3] it is clear that acceleration in investment is required in this sector in order to meet the legislated target. Based on some estimates, the investment in renewable generation capacity needed over the next decade to achieve the target is between $25 billion to $30 billion, mainly comprised of wind and solar projects.[4] The introduction of the Solar Flagships program also provides impetus to establish further development of large-scale, grid connected solar power stations in Australia. Other technologies, such as geothermal or bio-mass, may be developed on a smaller scale in the medium term, but their utility scale viability is more a long-run potential.

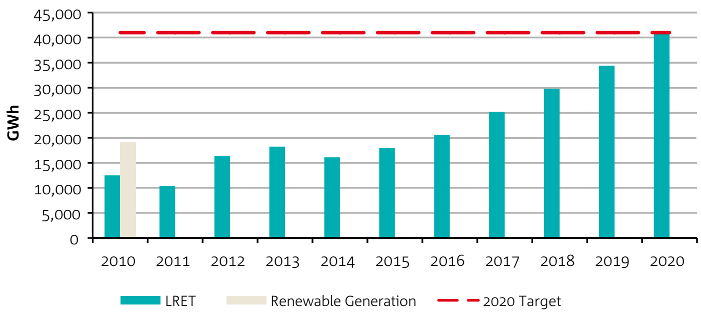
While the renewable energy financing task is sizable over the next decade, the Australian funding market has demonstrated that it has the liquidity and the size to be able to absorb this investment.

Chart 2: Average project finance Energy & Utilities margins



Source: NAB Estimates 2005 – 2011.

Chart 3: Large-scale Renewable Energy Target



Source: ORER, ESAA 2011.

1. NAB Estimate.
2. Electricity Supply Association of Australia, "Electricity Gas Australia 2011," 2011.
3. Office of the Renewable Energy Regulator, "Increasing Australia's renewable electricity generation," April 2011.
4. Bloomberg New Energy Finance, MMA, ROAM Consulting estimates.

NSW Power Privatisation No 2:
To privatise or not to privatise?

Matthew Sandham
Director
Resources, Energy & Utilities
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Associate Director
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Amy Lloyd and Matthew Sandham look at the challenges the NSW government faces in the second round of electricity privatisation.

In his quest to support the development of critical infrastructure in New South Wales (NSW), Premier Barry O'Farrell announced on 24 November 2011 his intention to privatise the State's remaining electricity assets through a second round of the auction process.

In alignment with the recent Tamberlin Inquiry, the cabinet has endorsed the sale of the State's electricity generators, development sites and the Cobbora coal mine. That support does not extend to the privatisation of the State's transmission and distribution assets (the 'poles and wires'), continued public ownership of which was a pre-election promise of the Premier.

Estimated sale proceeds of $3-5 billion would contribute to funding the government's infrastructure development program for NSW. This includes the former state government's transport blueprint, which while never formally published was estimated to include over $150 billion of proposals, including M4 East ($10bn+), Pacific Highway upgrades ($7.6bn), Northern Beaches Hospital ($600mn+), Hornsby Hospital upgrade, M5 East duplication ($5.2bn), North West Rail Link ($7-10bn) and the F3-M2 missing links ($4.5bn).

Up to $25 billion infrastructure funding needed

This commitment to retaining the transmission and distribution assets may leave a substantial source of funds untapped – reportedly as much as $25 billion. Infrastructure NSW chair, Nick Greiner, has publicly stated that without this additional capital, the Government will make little impact on the funding task in hand, and leave the State in continued search of the cash proceeds it desperately needs.

In addition to the 'poles and wires', O'Farrell's announcement made no inclusion of Snowy Hydro, which many in the industry believe is worth an estimated $6 billion, (58% NSW Government owned, 29% Victorian Government, 13% Federal Government). Snowy Hydro provides risk support for east coast energy retailers in a volatile wholesale electricity market – its water supply exhausts relatively quickly, but its two gas-fired peaking plants are critical to the security of the east coast supply. The business also includes an energy retail arm, Red Energy, making the Snowy Hydro business model very much like that of a private operator.

Who will emerge as interested buyers?

Following partial privatisation of NSW power assets in early 2011, a question remains over which potential buyers will come forward in this second round. The Labour Keneally government privatised electricity retailers Integral Energy, Country Energy, and Energy Australia, and also sold the electricity trading rights to the generation output of the Eraring and the Delta West power stations. The State's sale process, closed with Origin Energy ($3.26bn) and TRUenergy ($2.035bn), yielded gross proceeds of $5.3 billion, but prompted speculation as to whether the highest possible price had been achieved for the assets. Further, the prior sale of the gen-trader rights effectively diminishes the realisable value of the remaining assets.

While the State is facing the challenge of attracting prospective buyers to ensure competitive price tension and a strong valuation dynamic to the sale process, the offer may fail to capture the full attention of domestic industry players such as Origin, TRUenergy and AGL. Following the exertions of the first round of privatisation, these players are focused on delivering corporate strategy to customers and shareholders, and may offer conflicting priorities to a competitive auction.

"A number of questions remain unanswered following the partial privatisation of NSW power assets in early 2011, particularly over which potential buyers will come forward in this second round."

Financing and political uncertainty may impact value proposition

Strong asset valuation has recently come into question, with the introduction of the carbon tax labouring the profitability of the state-owned generators, forcing them to recently disclose their inability to make dividend payments in future years. In addition, the global capital markets do not currently provide the benign environment conducive to raising significant amounts of debt and equity, which similarly may dictate a reduced level of interest from private equity.

The barometer of public sentiment is notoriously difficult to forecast, particularly with regard to privitisation. Precedent has been established in Victoria (and South Australia), which successfully privatised its transmission and distribution assets in the mid-1990s to multiple counterparties, including Singapore Power and CLP. A final hurdle lies in obtaining legislative approval, with many political and Union opponents publicly criticising further privatisation, citing higher electricity bills, job losses and reduced governmental control over environmental impacts.

Fraught with challenges, but an essential step forward for Government and industry

Fundamentally, the challenge for the NSW government will be to navigate successfully these various pitfalls to ensure the launch of a robust tender process. Criticism is inevitable, but if the NSW government is to secure a quantum of funding sufficient to address its infrastructure task, it will require a greater degree of support from the political and legislative arena, keener interest from prospective buyers with access to funding, and a clearly articulated rationale for the exclusion of potentially valuable assets from the auction.

Executive insights: Rob Grant, CEO, Pacific Hydro and Richard McIndoe, Managing Director, TRUenergy

Rob Grant
Chief Executive Officer
Pacific Hydro

Richard McIndoe
Managing Director
TRUenergy

Rob Grant and Richard McIndoe discuss how changing economic, political and regulatory dynamics are impacting the energy and utilities sector.

What are the biggest challenges facing the sector and your business specifically?

Rob Grant: Right now the global emphasis of the industry is around generating energy more cleanly. The biggest challenge for Australian producers is navigating the political uncertainty around the carbon scheme. Any talk from politicians about dismantling parts of the scheme plays on investors' minds; creating uncertainty won't produce the outcome we need to hit our targets. At worst, it leaves us in a situation where no new capacity is built because everyone is too scared to invest.

Australia has a comparative mineral advantage. Like our biggest competitor, Brazil, we export to China and India, but Brazil has a renewable energy market that represents 70 to 80 per cent of the grid. Australia's biggest customer is China, which spends more per year in renewables than we will through to 2020. The world is moving – our biggest competitors are moving but there are some in Australia that don't necessarily understand that. Policy in Australia – regardless of whether it's a carbon tax or a renewable scheme – is only just keeping us up to speed with major customers and competitors. More needs to be done.

Richard McIndoe: There are a number of challenges ahead. A key issue is the impact of political and regulatory change. Along with banking, the Energy sector is the sector most regularly on the front pages with regard to consumer and price issues. As such, it continues to be a political football and an area politicians dip into to express populist views and opinions. With the changing political scene at state and federal levels, we see a lot of different political approaches to energy issues, especially around carbon and the environment – this makes long term planning and investment decisions very difficult.

How we manage our business and move ahead in a carbon-constrained world is a huge challenge, especially in Australia, where the economy is particularly carbon-intensive.

Fuel and energy costs are high and continue to be high due to demand out of Asia. Network costs are increasing because of the huge geographical footprint of Australia, population growth and the need to update the network. On top of this, the impact of carbon pricing and the various Federal and State government renewable energy targets and schemes will all lead to a greater focus on energy and electricity prices, which will continue to go up.

How are you positioned for the implementation of the carbon scheme? Does the opposition's threat to repeal the scheme cause further uncertainty to your investment plans?

Grant: We have a structure in place in Australia to transition the energy market from being very carbon intensive to something more sustainable. The mechanisms being employed are based on a carbon trading scheme – a long-term measure that will transform the electricity industry for the next 10 to 20 years. In the short term, the industry is looking to ensure that any new capacity to meet demand does not contribute to the CO_2 footprint.

Ultimately the carbon trading scheme will drive the demand-side of the electricity equation in Australia. Whether the targets are strong enough is a matter for debate, which also depends on the obligations Australia chooses to assume. Having said that, it is a good starting point for future stronger action.

We support the trading scheme and carbon tax and long-term emissions targets – the biggest challenge is any risk associated with the regulatory framework. It is a policy framework that relies on a government mandate to make it work. Therefore any changes to it bring uncertainty, which drives up the cost of capital.

Australia has had a problem with this transition both philosophically and politically. We have not made huge progress compared to other countries with which we compete and sell products to. We are not leading the world; we are behind and at risk of losing our competitive advantage. Brazil has 70-80 per cent in renewable energy, but that does not affect its economy or make it uncompetitive.

The mechanisms to deploy the transition are in the long-run value enhancing. It is hard to argue the scheme should be repealed.

McIndoe: We have spent a lot of time preparing for the carbon challenge. We originally owned just one coal-fired power station; over the last six years we have diversified out of that single asset exposure and into a retail business, upstream gas, gas-fired generation and renewable generation. We've also grown our business significantly through acquisition. Last year, for example, we acquired Energy Australia and Delta West in New South Wales, which almost doubled the size of the business.

Diversifying our asset base and growing the business has meant the impact of the scheme is spread over a larger business. It has also have given us exposure to areas that will benefit from a carbon price, including wind, renewables, and low-emitting gas-fired generation.

We have advocated with the government to have a sensible transition period to the carbon scheme. The Greens position is that we need to close all coal generators now. This is obviously completely impractical and we have consistently explained the need for a long-term plan to move from being a high carbon to low carbon intensive economy while preserving a reliable energy supply. This will also involve compensatory payment to existing generators which will help maintain the integrity of balance sheets and therefore allow for the necessary ongoing investment in this critical sector of the economy.

We also have a pipeline of new assets – cleaner gas-fired generators, and renewables like wind and solar – which we will develop to replace the high-emitting coal-fired generators as they close to maintain security of supply.

The threat from the Opposition to repeal the scheme adds another layer of uncertainty which is not helpful in a capital intensive industry. We need a level of ongoing stability and certainty within the regulatory framework to be able to attract long term investment.

The prospect of having carbon legislation completely repealed is problematic for the whole industry and has made people very cautious on large scale capital investment. This will inevitably compound issues on potential supply shortage.

How do you see the transition to a lower carbon emissions environment? What do you think it will look like in 2025?

Grant: Australia faces a real challenge. Our strong economic growth means energy demand will double over the next 30 years. Over the next 10 years alone we will see a 30 per cent increase in demand for electricity. To meet demand we have to install new capacity, but in a completely different way than in past. We also have to think about what to do when we retire the large coal fire generators in the Hunter and La Trobe Valleys and what fuel we use to replace them.

The carbon pricing and renewable energy schemes will drive new renewable capacity into the market. Most will be around wind energy and new gas generation. Over the long term we believe most new electricity will be generated from a combination of various renewable energy technologies and gas in combined cycle plants.

McIndoe: Over the next decade we will see more renewable generation through wind and solar as a result of legislation that obliges us to source 20% of our electricity from renewable sources by 2020. That will require major investment in the industry over the next 10 years.

The intent of a carbon price is to make existing coal-fired generation less profitable and encourage investment in other lower carbon generation sources. However, given the relative low cost of generation from coal and the expectation of rising gas costs when the Queensland LNG projects start to export our east coast gas, we will need to see a much higher carbon price to force the industry to switch on a large scale from coal to gas-fired generation.

So when I am asked whether we will see a short term boom in baseload gas fired generation I am sceptical. In a rising gas market it will be very expensive as we start to pay international prices for our domestic gas. We actually need a carbon price of A$60-A$70 to see the closure of coal-fired and the building of new baseload gas-fired generators. That won't happen, but we will still see the higher energy costs from the introduction of the carbon tax.

"Like our biggest competitor, Brazil, we export to China and India, but Brazil has a renewable energy market that represents 70 to 80 per cent of the grid. Australia's biggest customer is China, which spends more per year in renewables than we will through to 2020. The world is moving – our biggest competitors are moving but there are some in Australia that don't necessarily understand that." – Rob Grant

While a $23 carbon price won't cause significant change in the current mix of baseload generation, we will start to see more renewable generation as part of the Federal Renewable Energy Scheme. As a result, but by 2025 energy output will be largely similar to what it is now, with addition of more and higher cost renewables.

Ten years on from that, however, we will see considerable change as the existing fleet of generators comes to the end of their natural lives and owners choose not to invest in extending those lives. I also believe that by 2024 renewable energy costs, particularly solar, will have reduced significantly and will have become competitive with fossil fuel generation.

How significant a role do you see utility-scale solar playing in Australia over the short-to-medium term, particularly the combination of PV and thermal?

Grant: Pacific Hydro is technology agnostic. We are trying to promote best practice policy mechanisms to deliver the best outcome to reduce emissions in the cheapest way – it's up to the best technologies to deliver that outcome. Normally hydro would be in the frame, but Australia does not have enough water to use that as a source of significant new renewable energy capacity. Wind is the next priority and then utility-scale solar.

The cost of solar panels is coming down and it is becoming more efficient. If it continues to improve in scale and the manufacturing of large volumes of panels occurs, large-scale solar will get there. At the moment, the Solar Flagship program is key support mechanism provided by the Federal government, without which deployment of large scale solar would not progress.

With regard to PV and thermal, we don't really differentiate between that and solar PV. It's all about bringing the cost curve down – that's what will make options viable.

McIndoe: One of the attractions of solar is that in Australia we have a lot of wide open space and a strong solar resource. So with reducing construction costs we see a great future for commercial-scale solar generation.

There is a first-mover disadvantage right now because solar technology and installation costs are changing so quickly. For example, over the last two years costs of large-scale solar have halved. It is still expensive relative to fossil fuel consumption but if the cost of production continues to come down at the same rate it will become more competitive.

What role do you see for the Clean Energy Finance Corporation (CEFC)? What specific areas of concern do you have, if any?

Grant: Its mandate is beginning to clarify. Our main concern is that the CEFC doesn't cannibalise the Large-scale Renewable Energy Target (LRET) policy and over subsidise technologies that would be successful under that scheme. It should play a role in identifying areas of failure in the electricity market not specifically covered under LRET in relation to transmission.

The regulatory framework in Australia is quite outdated; it's built around large generators sitting in the Hunter and Latrobe Valleys. The CEFC could bring down the cost of delivering renewable energy to markets by supporting regulatory change or financially through the implementation of large connection points to areas that don't have them, allowing large renewable energy projects that are not currently economically viable to be joined to the market.

The Brazilian government does that very well – it auctions off 1,000 megawatts of wind capacity per year and the transmission connection after that. CEFC should look outside where current policy works and find failures in the market and address them specifically.

McIndoe: If we move towards more solar generation, it is likely to be in more remote areas. Solar plants will need to be interconnected to the grid, which can be expensive. This is an ideal space for the CEFC to facilitate efficient renewable technologies which, given the remoteness of the continent, may be disadvantaged even though they are viable, reliable and may offer lower cost forms of generation.

It is not the CEFC's role to pick a winner in terms of technology, but it could take proven technology disadvantaged by geographic distances and help facilitate interconnection and financing.

Secondly, at the moment bank markets cannot provide the liquidity or tenor we need for long-term assets. The CEFC could play a role in co-financing projects, like the Asian Development Bank or International Finance Corporation. They would offer extended tenors to projects and help facilitate the funding from other lenders which is desperately needed to make these projects stack up.

Do you believe Carbon Capture and Storage will ever be commercially viable in Australia, and if so by what year?

Grant: It has gone off the radar a bit as it rightly should. It will probably remain popular with government as they seek to maintain existing industries, but economic viability is likely to be 20 years away. As we can see there are cheaper options to reduce emissions from existing and near term renewable energy and I'd rather see money go into those proven technologies and energy efficient options rather than trying to dig holes for CO_2.

McIndoe: The problem with carbon capture and storage is cost – it is very expensive. There are viable carbon sinks, especially in the Bass Strait, but the cost of capturing carbon then piping it out underground will become prohibitively expensive. So we will need a very high carbon price or very significant government subsidies to achieve this.

The problem with subsidies is that after the long period of research and development a capture and storage system would require, the cost of alternative technologies, such as solar, may have come down, so capture and storage would be even less competitive. There is a danger that the government picks a prospective winner and overtly supports a particular technology, which it did with the global carbon capture and storage institute, which can be detrimental to other technologies.

What are potential game changers for your industry over the next 10 years?

Grant: Australia is on the start of a journey to transition its energy mix. The large generators and retailers are designing the new energy framework and are starting down a more sustainable path – they're not building new coal-fired power stations and banks aren't encouraging investors to build them or funding them.

The real game changers continue to be the carbon tax and LRET – it is nation-building in scale. The amount of capacity we need to achieve it is twice the size of the Snowy scheme and must be built in half the time.

Certainly, international efforts to move towards legally binding targets are important but in itself is not critical to success over the next 10 years. Why? Because what we are seeing is that nations are not waiting for an international treaty to begin meaningful action at a domestic level. We are also starting to see bilateral agreements emerging that when combined with strong domestic action are building a very strong 'bottom up' push that is likely to be more important over the coming years.

McIndoe: Solar is a potential game changer and as you can see I am excited about opportunities in that space as costs come down. I also think interval meters could be a game changer. They are the key to getting individuals and households to be more effective in energy management. They generate greater visibility of consumption and therefore cost savings over time. They represent an opportunity to work closely with customers – if I can keep customers loyal it helps my business because the cost of churn is the single biggest financial and opportunity cost for the business.

The interval meter scheme was very poorly managed by the previous Victorian Government. Government needs to understand that we in the industry are not in an adversarial relationship – we are happy to work with them in educating consumers and changing behaviour.

A third game changer is electric vehicles. The energy storage these vehicles could facilitate is potentially a huge game changer for the industry. At the moment we can't store electricity, but if we have thousands of electric vehicles with batteries the ability to store electricity on a large scale is much greater. This opens up a range of opportunities around energy management.

"Solar is a potential game changer and I am excited about opportunities in that space as costs come down. I also think interval meters could be a game changer. A third game changer is electric vehicles. The energy storage these vehicles could facilitate is potentially a huge game changer for the industry."
– Richard McIndoe

Network funding requirements accelerate

Jason Brown
Associate Director
Energy & Utilities
Institutional Banking

James Waddell
Director, Debt Markets
Origination
Wholesale Banking

Jason Brown and James Waddell discuss the increasing funding task and challenges for the regulated utilities sector.

What is the size of the funding task for the energy and utilities sector over the coming few years?

The Australian Energy Regulator has made significant allowances in recent regulatory decisions for both electricity and gas. This will see capital expenditure across the sector rise by more than 60% over the next regulatory period as all networks update aging infrastructure and invest for future demand growth.

We estimate new debt funding of this capex will be around $4.2 billion[1] over the next three years. In addition to new capex funding we expect $11 billion of refinancing to be completed over the same period. The additional piece to this will be the roll-off of credit wrapped bonds, which will essentially require new money given the demise of the monoline insurers. Therefore total debt funding required will be around $15.2 billion. Chart 1 outlines the forecast regulated utilities maturities.

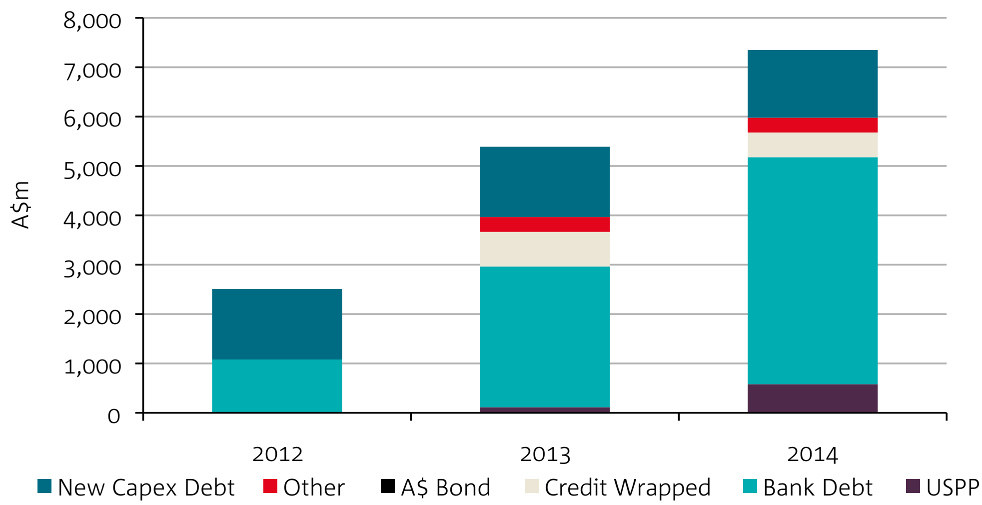
How is the sector currently funding itself?

Historically the funding mix was generally guided by the strength of the credit rating of the business, with a much higher proportion of bonds to bank debt at the A-level, with fewer bonds issued in the lower investment-grade range. However, in recent years there have been numerous domestic and offshore issues in the BBB/BBB– range as investors have gained comfort around the stable cashflows and regulatory environment. Chart 2 displays the funding mix of Australian network utilities.

Credit insured bonds were very big across the sector through the 1990s, with $5.9 billion (21% of total sector debt) remaining on issue[2]. As we see a roll-off of this paper we expect to see some pressure on coverage ratios, with margin increases likely from the low double digits to high 100 to high 300 basis points range[3]. While the regulator makes allowance for the debt margin (average allowed margin for the sector is currently in the high 300's) there is still likely to be a noticeable impact on interest costs for those that have a larger portion of the insured bonds rolling off.

Moving forward, we expect to see the sector continuing to access longer-dated funding across multiple debt markets with shorter term bank facilities used to fund capital expenditure and provide liquidity.

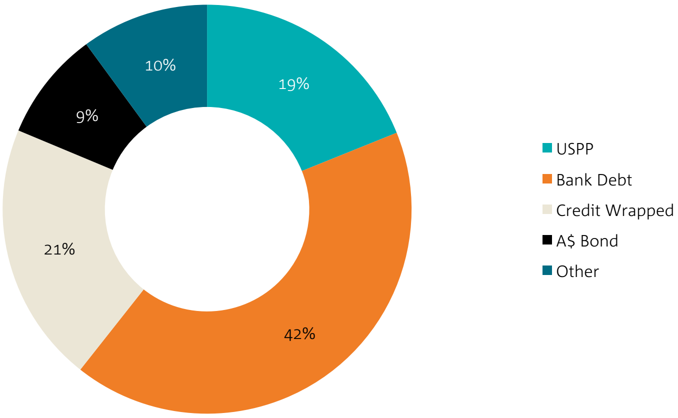
Chart 1: Forecast regulated utilities maturities 2012-2014



Source: Australian Energy Regulator, Annual Reports, Bloomberg, NAB research January 2012.

1. Based on 60% regulated debt funding.
2. As at January 2012. Source: Bloomberg, Annual reports, NAB research.
3. Based on 5 year debt. Subject to asset type and level of investment grade rating.

Chart 2: Funding mix of Australian network utilities



Source: Annual Reports, Bloomberg, NAB research January 2012.

With the demise of the wrapped bond market and the increasing pullback of funding from foreign banks how can the sector achieve optimal pricing and tenor?

The Australian market is the easy and obvious choice for many issuers. Typically issuers have the required credit rating while documentation is easy and cost effective. The main benefit to issuers in the domestic market is the speed and availability of Australian dollars. The only drawback for BBB issuers is that tenor can be short and volumes lower than their needs.

The traditional US private placement (USPP) market has been another preferred destination for Australian utility borrowers. This market offers the longer tenors not available locally at cost effective pricing. The US lenders are always open and this has driven many issuers to this market. Prior to 2007 many of the investors have been able to offer Australian companies Australian dollars and in the future we expect this will be a feature of the market again.

In 2012 issuers may also look to tap markets like Switzerland, Japan, the UK and Europe but cross-currency swap costs will give borrowers pause when they look at the landed cost of funds.

Over recent years there has been increased issuance of USPPs across the sector. Is there a threshold of investor appetite for the sector, or Australian issuers into the market?

If there is a threshold of investor appetite we have seen no sign of it. All our surveys and conversations with investors indicate strong appetite exists for the Australian utility sector. Investors like, understand and are comfortable with the industry.
We would anticipate volume available per issuer being up to $1.5 billion.

Will we see a return of credit- wrapped bonds issues?

No, not in the form borrowers were used to. For some borrowers export credit agencies (ECAs) are performing the function of monoline insurers, but this form of wrap is typically tied up with the procurement of equipment associated with the ECA's domicile.

In summary, investor and bank appetite remains strong for the sector, however given the quantum of funding required early engagement by borrowers in assessing market options and pricing will ensure financing requirements are met with the most appropriate market and timely execution.

"The Australian market is the easy and obvious choice for many issuers, whilst the USPP market continues to offer longer tenor not available locally."

Power security and the generation mix

Stuart Glen
Head of Institutional Banking Qld

"Within the existing network it is impossible to provide customers with a secure electricity supply from wind generation alone."

Stuart Glen discusses the feasibility of wind power generation in the context of reactive power requirements.

Industry change: what a year

I don't recall Australia experiencing a year in the Energy and Utility sector where the announcements made by the Federal Government would have such far-reaching and significant effects on the industry.

One initiative of significant interest in the Climate Change Plan announcement, was the concept and development of the Energy Security Council. In principle the purposes of the Council is to, "provide assurance that energy supply security will be maintained during the transition to a clean energy future and to help manage any residual energy security concerns."[1]

I have read articles in the general press expressing the view that, as Australia moves to a cleaner energy future, renewable energy will dominate generation supply.

While this is an admirable ambition it is difficult to envisage the possibility that wind and solar generation, for example, will replace thermal (coal, gas and nuclear) generation entirely. There are two main reasons why this proposition is unlikely to eventuate.

The first relates to the ability of wind generators to support system reactive power requirements; the second relates to the inconsistent nature of wind generation.

Wind generators' ability to support system reactive power requirements

In most instances the simple view of maintaining a secure energy supply means 'keeping the lights on' and is usually defined by ensuring real power or watts are delivered to households and industry. What is often missed in the general discussion of system stability is the important role reactive power plays in the operation of the electricity system.

Consider the following facts: "Power flows must be carefully controlled for a power system to operate within acceptable voltage limits. Reactive power flows can give rise to substantial voltage changes across the system, which means that it is necessary to maintain reactive power balances between generators and points of demand".[2] A network operator ensures system stability by adhering to "defined voltage and stability criteria."[3] Typically, reactive power is "provided or absorbed by conventional generators or by network operators using synchronous condensers or static VAR compensators. If new plant capacity has a bias toward wind generation rather than thermal plant then new sources of reactive power may need to be supplied."[4]

In other words, wind generation doesn't have the capacity of thermal plant to produce or absorb sufficient reactive power to ensure system stability.

Wind generation – inconsistent by nature

If you consider the national electricity market, 10 years ago electricity supplied from wind generators was negligible. It was too expensive. If not for the Government's emission reduction targets of 2010 and 2020 it still would be.

For comparative purposes black coal, brown coal and Combined Cycle Gas Turbine (CCGT) plant long-run marginal cost (LRMC) ranges from $53-57/MWh, with peaking Open Cycle Gas Turbines (OCGT) costing $78/MWh. The LRMC of large scale wind generation is $120/MWh."[5]

With the introduction of the Renewable Energy Target (RET) of 20% by 2020 (equivalent of 45,000 gigawatt-hours GWh) wind energy became the preferred source of renewable generation. While wind generation achieves its goal of reducing carbon emissions it fails to satisfy system stability criteria. This is simply because of the nature of the source. Excuse the pun.

Consider that wind, as an energy source, is not constant. The consequence of this is that energy output from wind generation is variable. In an electricity system, supply equals demand on an instantaneous basis. This means that when wind is completely unavailable or varies alternative generation is needed to fill the short fall in wind generation. This alternative generation is provided by thermal generators.

Within the existing network it is impossible to provide customer with a secure electricity supply from wind generation alone. It must be supplied with a combination of renewable and thermal generation.

In this article I've tried to dispel some of the more imaginative views of the media on what is plausible when discussing renewable generation as it relates to system stability.

1. Hon Wayne Swan MP, Hon Greg Combet MP and Hon Martin Ferguson MP Joint Media Release of 12 October 2011 "Michael Vertigan To Chair Energy Security Council" page 2.
2. 3. An Introduction to Reactive, The National Grid Company plc, Market Development: October 2001, Page 1.
4. The Hidden Costs of Wind Generation in a Thermal Power System: What cost? Paul Simshauser, The Australian Economic Review, vol. 44, no. 3, pp 282, September 2011.
5. The Hidden Costs of Wind Generation in a Thermal Power System: What cost? Paul Simshauser, The Australian Economic Review, vol. 44, no. 3, pp 273-274, September 2011..

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Interest rates, capital markets and the cost of money

David de Garis
Director and Senior Economist
Fixed Interest, Currencies and Commodities

"Perceptions of an immutable link between the cash rate and banks' variable mortgage rates have side-stepped a more thorough analysis of the cost of money for financial institutions and the influence of the Greek and Euro debt crises."

David de Garis explains why the Reserve Bank of Australia's cash rate and bank lending rates are no longer moving in lock step.

The usual deluge of interest rate speculation has saturated the press recently, but this time the focus has not been on the Reserve Bank of Australia (RBA) and the cash rate, but on bank lending rates. Perceptions of an immutable link between the cash rate and banks' variable mortgage rates have side-stepped a more thorough analysis of the cost of money for financial institutions and the influence of the Greek and Euro debt crises.

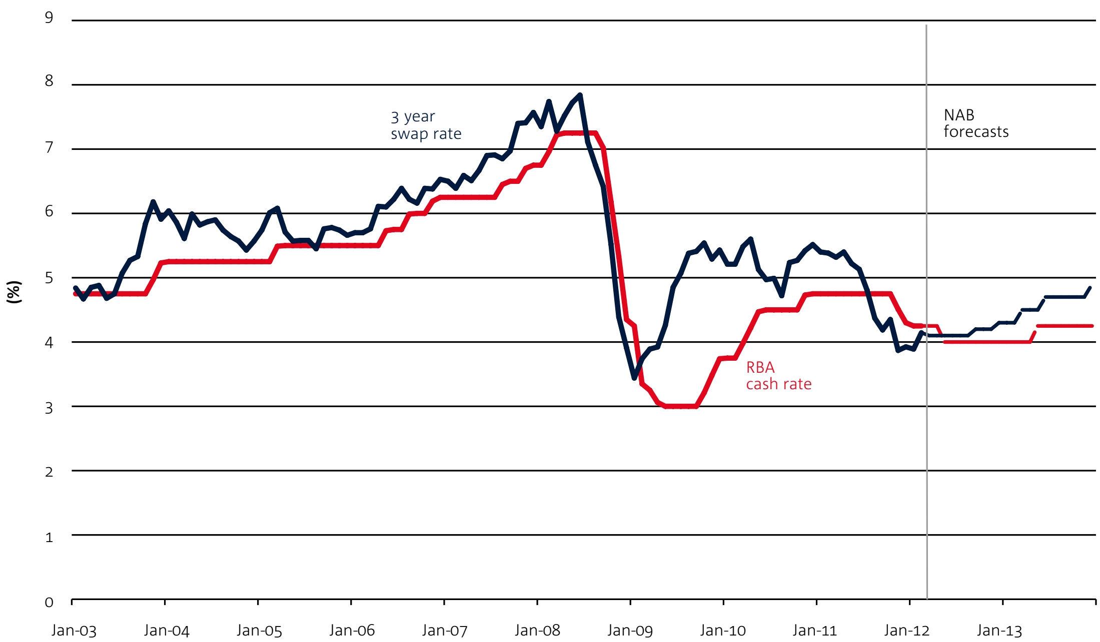
This article seeks to explain recent lending rate and funding cost developments, and provide an outlook for the RBA's official cash rate.

Cash rate likely near its low, if not already there

NAB's cash rate forecasts are based on our forecasts for the Australian economy. GDP growth, the outlook for inflation in the lead up to and after the carbon tax are key considerations.

Through the current episode of disjointed growth over 2011 and into 2012, Australia finds itself with a little more spare capacity than anticipated. The unemployment rate has risen from under 5% twelve months ago to a little over 5%, and NAB's measure of capacity utilisation has eased from 82.0% to around 81%; some modest net reduction in inflationary pressures, has provided a little room for the RBA to ease, which they did late last year. Early 2012 data points to the economy growing at around trend and not capitulating.

Chart 1: Outlook for key market interest rates



Sources: RBA, NAB Global Markets Research DX data February 2012.

NAB forecasts the economy to grow 3.7% this year, and a still-solid 3.5% in 2013, supported by skewed growth toward super-strong resource investment. Australia's underlying inflation rate is forecast to grow within the RBA's 2-3% target range, looking through the initial spike in inflation as a result of the carbon tax. Headline CPI is expected to decline from its current 3.1% (December 2011) to a low of 1.6% by June 2012, before the carbon tax boost kicks in through 2012-13.

The RBA has said it will 'look through' the first round impact, on the basis that second round effects do not lead to a further inflationary surge. The existence of some spare capacity overall suggests that is a reasonable starting assumption on which to base current monetary policy settings.

NAB's economic forecasts call for little to no further easing in the stance of monetary policy (Chart 1). If there is any change in the near term, the RBA is likely to ease a little further. Barring the unknown of exceptional market-threatening events from Europe, if there is no rate change by mid-year, we expect the RBA to leave rates on hold, before re-adopting a tightening bias in 2013.

At the time of writing, the market was still pricing in another 50-60 basis points of cash rate cuts for the year ahead, even after the February surprise 'no change' Board meeting outcome and somewhat better data of late. Against our forecast the cash rate will be cut just once more at the most; this points to term swap rates as likely to trend higher with the three-year swap rate forecast to reach 5% by late 2013.

Cost of money more broadly determined than the cash rate

But with all the recent focus on out-of-cycle mortgage rate rises after this month's 'no change' from the RBA, it's worth considering what has been driving the cost of funds for financial institutions in addition to the level of the cash rate.

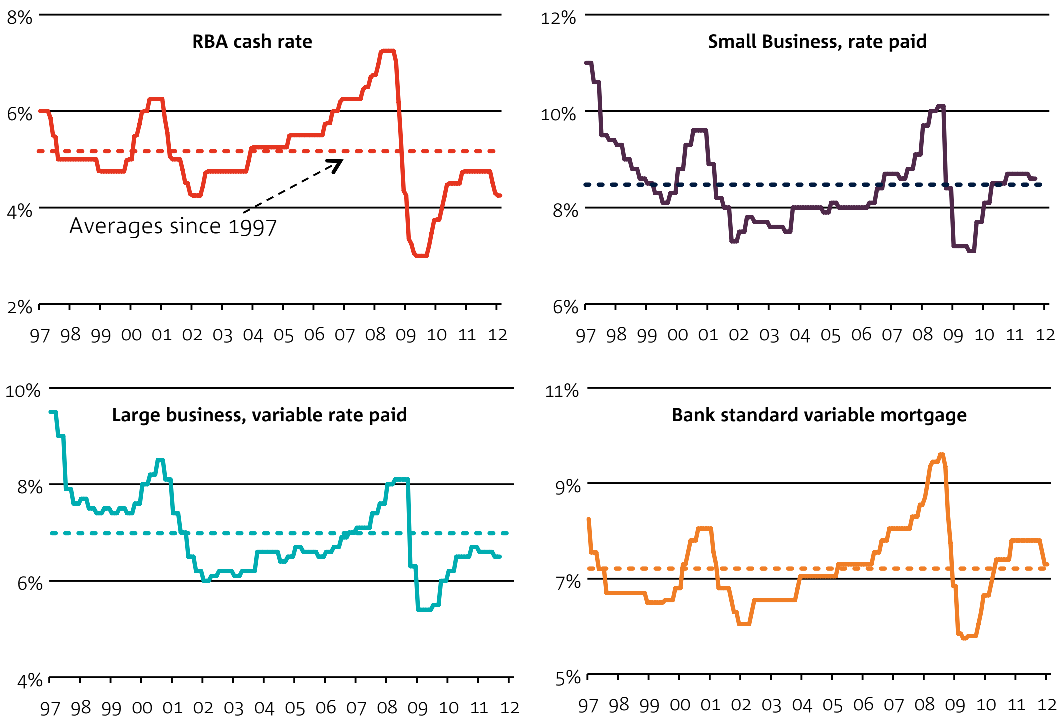
There's little doubt that the RBA cash rate remains an effective policy instrument through which the RBA sets monetary policy, the central bank's attention being on rates paid by households and businesses. In the end it is the lending and deposit rates that determine spending, borrowing, saving and economic decision-making. And those rates reflect not only the RBA cash rate but a plethora of other domestic and international factors – factors that have a bearing on the cost of money for financial institutions.

Since the GFC and European debt crisis, there's now a changed relationship between lending rates and the cash rate, as demonstrated in Chart 2. The cash rate is below its long-term average, while the lending rates shown in Chart 2 are closer to, if not above, their long-term average.

This brings us to the liabilities side of bank balance sheets. It has been well-chronicled that bank liabilities have been re-configured to rely more on both retail deposits and term wholesale funding and reduce reliance on short-term wholesale funding.

On the retail side, aggressive competition 'on the street' among institutions for more attractive stable retail deposits has driven up the rates paid, for example on special 'blackboard' term deposit rates on offer. Since the GFC, such special term deposit rates have been, and continue to be, well in excess of the cash rate, which is unusual. That wedge has been driving up the cost of funds relative to the cash rate, as Chart 3 shows.

Chart 2: The RBA cash rate and key lending rates



Sources: RBA, NAB Global Markets Research DX data February 2012.

Wholesale funding costs up

As for wholesale funding markets, the GFC and the European debt crisis have resulted in very elevated rates for banks around the world. Notwithstanding the high credit ratings of Australian banks relative to the great majority of offshore banks in advanced economies, wholesale term funding markets have remained volatile and with elevated costs.

In a recent speech, RBA Assistant Governor Guy Debelle cited such higher-priced wholesale funding costs, noting: "The global repricing of bank debt has clearly affected the Australian banks' funding costs."[1] Chart 4 illustrates the shift in bank corporate lending rates and funding costs from June 2008 until now.

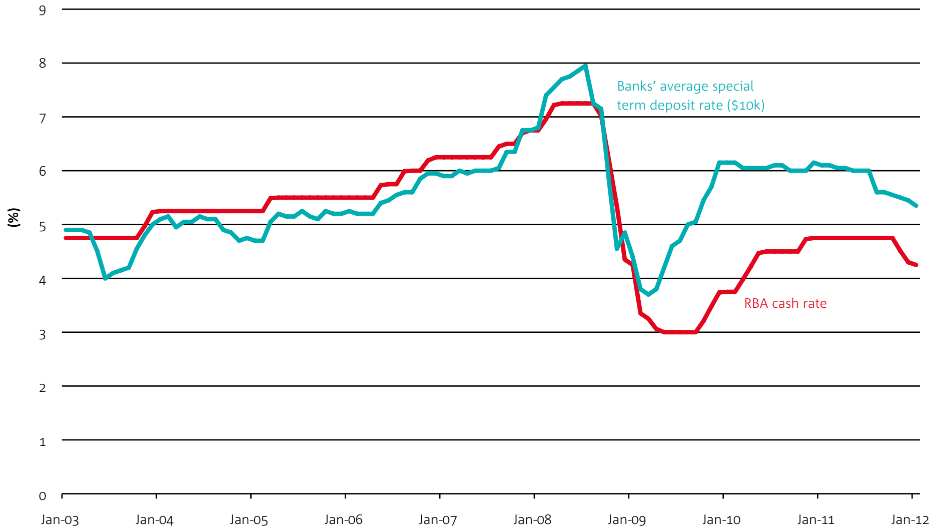
The lower line of Chart 4 (together with individual issue pricing depicted as the square dots) shows very high wholesale term funding costs with little relief at hand.

The bottom line is that upward pressure on loan pricing has been real, reflected most recently by the out-of-cycle variable mortgage rate rises. In the institutional lending space, recent NAB research shows that for syndicated lending facilities, banks' pricing over recent months has been under some not- unexpected pressure even though that upward pricing has followed upward pressure on funding costs that has been evident for some time.

The outlook for corporate loan pricing will hinge on the funding costs relative to the cash rate, as well as market and commercial conditions at the time of pricing. The cash rate continues to be a major determinant of pricing, with the RBA retaining ultimate effective control on lending rates through its major monetary policy instrument.

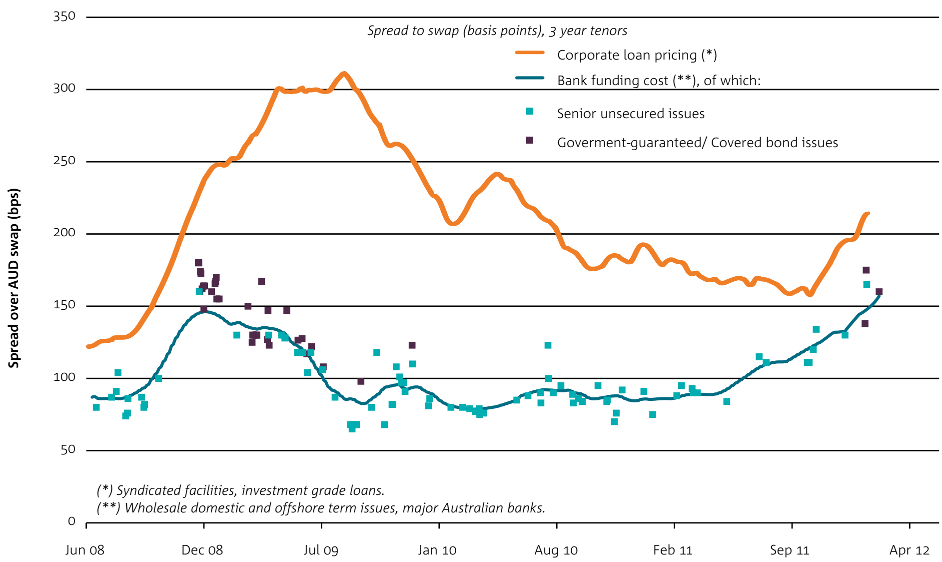
With its eyes on lending rates, the RBA can re-set the level of the cash rate to achieve its ultimate desired level of lending rates, adjusting its policy instrument along the way, and responding to any material changes in the spread between the cash rate and private sector lending and deposit rates interest rates.

Chart 3: RBA cash and term deposit rates (%)



Sources: RBA, NAB Global Markets research, DX data February 2012.

Chart 4: Bank corporate lending rates and funding costs



Source: NAB, February 2012.

1. See "On Europe's Effects on Australian Financial Markets", Guy Debelle, Assistant Governor, Reserve Bank of Australia, speech to Bloomberg Seminar, Sydney, 14 February 2012, available at http://www.rba.gov.au/speeches/2012/pdf/sp-ag-140212.pdf.

Will the carbon price change the energy mix?

Robert White
Associate Director
Environmental Finance Solutions
NAB Advisory

"The carbon price alone is unlikely to drive a transition to less carbon intensive power production in the short to medium term."

Robert White discusses if a carbon price will act as a catalyst for clean energy innovation and investment.

Australia's stationary energy sector is responsible for 53.9% of the country's greenhouse gas emissions, with electricity generation accounting for 70.3% of that total.[1]

This is the consequence of our reliance on low-cost brown and black coal for the production of power. In 2008-2009 76.6% of the country's electricity output was from coal-fired generation, leaving Australia with the world's eighth most carbon intensive electricity sector.[2] In addition, and unlike the rest of the OECD, Australia is currently increasing emissions per unit of energy output.[2]

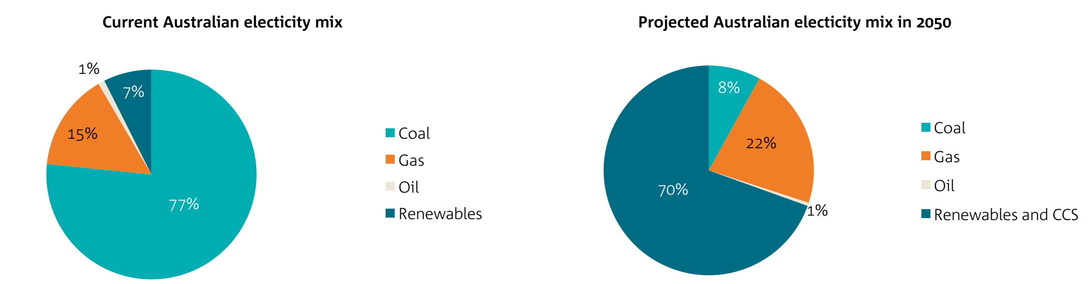
Looking forward, Australia has committed to reduce overall emissions by 5% on 2000 levels by 2020, and then 80% by 2050. Achieving these goals against the backdrop of a forecast 22% increase in emissions[3] is no mean feat; reducing the emissions intensity of the electricity sector is critical to achieving these goals. Chart 1 illustrates a projected shift in the Australian electricity mix by 2050. But will the carbon price be enough to facilitate this change?

Making the transition

The Clean Energy Future Package (CEFP), combined with the existing Renewable Energy Target (RET), is the Government's main incentives to drive the transition. The most prominent component of the CEFP is the carbon price; however this alone is unlikely to drive a transition to less carbon intensive power production in the short- to medium term. Chart 2 compares the impact of increasing carbon prices on the long-run marginal cost (LRMC) of generation for different sources of power generation.

Chart 2 demonstrates that the merit order shifts to Combined Cycle Gas Turbines (CCGT) at the carbon starting price of $23/t. At a price of $52.6/t (predicted price by Treasury for 2030).[4] CCGT is still the front runner, with wind (currently the lowest LRMC of the renewable technologies) still significantly higher, noting that technological and experience advances are not included in the analysis. Moreover, it is important to note that a number of factors influence generation investment, not just the LRMC of production, including the ability to meet volatility in demand, and reliability of supply. Clearly, though, the LRMC of renewable generation needs to decrease if Australia is to reach its long-term reduction commitments. This is where the RET and the complementary measures of the CEFP come into play as these will drive experience advances by bringing forward renewable investment, and ultimately reducing their LRMC.

Chart 1: Current and projected electricity supply sources



Source: ABARES: Energy in Australia, 2011.

Source: Commonwealth Treasury Department: Strong growth low pollution: modelling a carbon price, 2011 (average of SKM and ROAM models).

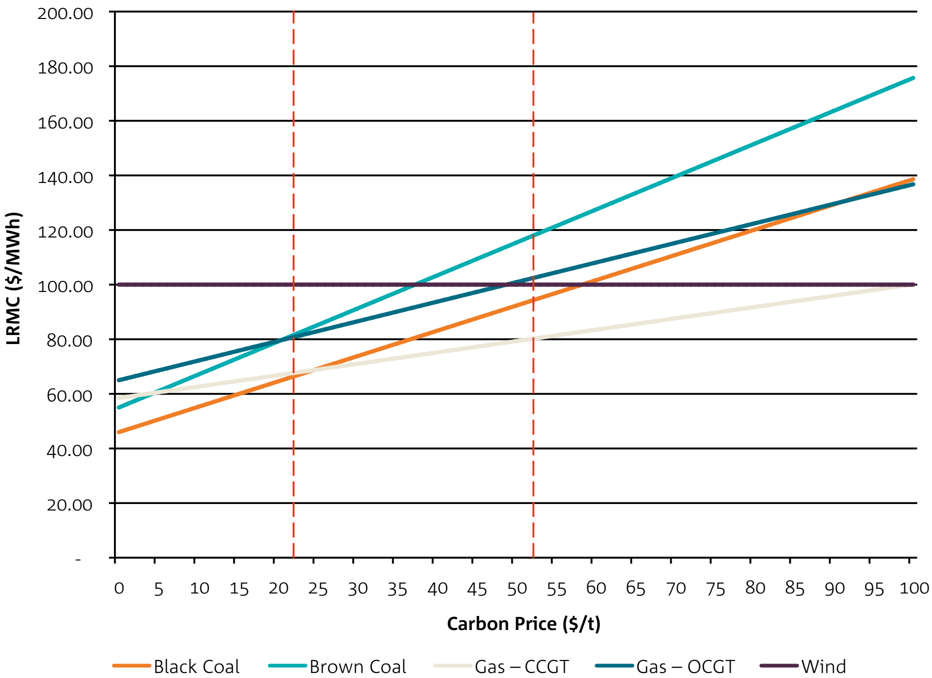
1. National Greenhouse Inventory 2009, Department of Climate Change and Energy Efficiency, April 2011.
2. World Resources Institute, Climate Analysis indicators Tool version 8.0, Washington, DC, 2011.
3. Commonwealth Treasury Department: Strong growth low pollution: modelling a carbon price, 2011 (medium global action scenario).
4. Commonwealth Treasury Department: Strong growth low pollution: modelling a carbon price, 2011.

In light of the above, the most dramatic impact of the CEFP on Australia's grid in the short term will be the declared closing of 2000MW of high intensity (>1.2tCO2e/MWh) generation. The stations that were eligible to apply are listed in Table 1, with the successful applicants expected to be announced shortly. If this 2000MW is replaced by CCGT generation, as Chart 2 suggests, then the national electricity market's intensity could drop from its current level of 0.89tCO2e/MWh, to ~0.84tCO2e/MWh. At current production levels this could reduce permit demand by as much as 22Mt p.a.

Important consideration needs to be given to how quickly and orderly the shutdown will be. While a linear phase-out will give certainty to permit demand it is likely that the majority of the work will occur at the back-end of the decade commencing in 2016-17.

The remaining generators whose intensity is greater than 1.00tCO_2e/MWh will be eligible for compensation in the form of cash ($1 billion for the 2011-2012 financial year) and free permits. The eligible power stations are expected to be those remaining from table 1, plus those in table 2.

Chart 2: Long-run marginal cost of electricity generation technologies at different carbon prices



Source: ACIL Tasman: Projected energy prices in selected world regions, May 2008.
CSIRO: Projections of the future costs of electricity generation technologies, February 2011. National Australia Bank.

Table 1: Power stations eligible to apply for early closure

Power Station	Size (MW)	Fuel	Location	Emissions intensity (tCO2e/MWh)	Output 2009-2010 (GWh)
Yallorn	1,480	Brown coal	VIC	1.30	10,821.9
Hazelwood	1,600	Brown coal	VIC	1.37	10,576.8
Energy Brix	195	Brown coal	VIC	1.27	1,254.7
Playford B	240	Brown coal	SA	1.39	950.3

Source: ACIL Tasman: Fuel resource, new entry and generation costs in the NEM, 2009, and National Australia Bank.

Table 2: NEM power stations expected to be eligible for compensation under the CEFP

Power Station	Size (MW)	Fuel	Location	Emissions intensity (tCO2e/MWh)
Liddell	2,000	Black coal	NSW	1.03
Munmorah	600	Black coal	NSW	1.07
Redbank	150	Black coal	NSW	1.12
Collinsville	195	Black coal	OLD	1.09
Anglesea	150	Black coal	VIC	1.09
Loy Yang A	2,120	Black coal	VIC	1.11
Loy Yang B	1,000	Black coal	VIC	1.15

Source: ACIL Tasman: Fuel resource, new entry and generation costs in the NEM, 2009, and National Australia Bank.

In order to be eligible for compensation, those stations that are not under a contract to close will need to submit a Clean Energy Investment Plan, outlining investments that will be taken to lower the intensity of the plant. Capital upgrades, investment in emission reducing technology, and enhanced maintenance programs can deliver quick efficiency improvements.
More groundbreaking options under consideration range from solar thermal primers, carbon capture and storage, and algae treatment. For example, MBD Energy is developing a process to capture and recycle emissions from coal fired power stations into animal feeds and bio-fuels.

Without the other complimentary measures, it is unlikely that the carbon price alone would have a short-term material impact on Australia's energy mix. However, the framework itself is expected to provide the catalyst for clean energy innovation and investment in a sector that needs to undergo significant change over the next few decades.

Carbon trading in Australia: what is the state of play?

David Krsevan
Director
Environmental Markets

David Krsevan considers the opportunities and challenges for greenhouse gas emitters as Australia moves towards an emissions trading scheme

Despite Australia's late entry as a Kyoto Signatory and Emissions Trading Scheme (ETS) implementer, Australia has been a leader in market-based policies to reduce greenhouse gas emissions and increase the use of renewable energy for a number of years. The introduction of the national Mandatory Renewable Energy Target (MRET) in 2001 was the first scheme of its kind globally. The New South Wales (NSW) Greenhouse Gas Abatement Scheme, introduced in 2003, was the world's first mandatory carbon trading scheme. Other state-based schemes followed and are still in existence today.

Given the simultaneous development of these schemes at the State and Federal government levels, overlaps resulted that necessitated policy consolidation. The passing of the Clean Energy Future Package (CEFP), combined with the existing Renewable Energy Target (RET), are the Government's main tools to achieve this outcome.

The carbon pricing mechanism will commence with a fixed price on carbon in July 2012 and will transition to an emissions trading scheme from July 2015. The Government has announced various assistance measures for households and small businesses which result in no direct obligations under the carbon pricing scheme. However, around 500 of the biggest greenhouse gas emitters in Australia will be required to pay for their emissions.

It would appear that with the scheme starting with a fixed price in 2012, there is no requirement or opportunity for liable entities to manage their forward carbon liabilities; however the market is developing much like other traditional commodity markets.

As companies assess their obligations and marginal abatement curves, opportunities will arise to assist their transition to a lower carbon economy. Entities engaged in traditional energy and commodity markets will be very familiar with the typical derivative products, such as forwards, options etc, which will be utilised within carbon markets, so the learning curve will be more focused on carbon fundamentals.

Renewable energy markets activities aside, the key carbon markets of relevance to scheme participants include the Carbon Farming Initiative (CFI), the international Kyoto and related markets and of course forward trading of Australian carbon permits pre-2015. CFI projects generate carbon permits from domestic land based abatement and sequestration projects e.g. tree planting and waste capture from piggeries.

Trading will build progressively during the fixed price period as permits issued at the fixed price will be automatically surrendered on the emitter's behalf; however Kyoto-accredited Australian Carbon Credit Unit (ACCU) offsets, from the CFI, will be allowed for up to 5% of a liable entity's obligation, creating potential demand of approximately 18Mt p.a. During the flexible pricing period no limitations exist on the quantity of ACCU offsets surrendered, significantly increasing the demand for and importance of the CFI scheme – projected to be a $4 billion market by 2015. Supply, however, is likely to be limited given the dynamics of CFI projects and the time required to build scale.

In relation to Australian carbon units, forward auctions for the floating price period are anticipated to commence as early as 2014, although specific dates are yet to be announced. Significant work is already being undertaken by liable parties and service providers to assess their likely purchase requirements, permit allocation, financing and auction bidding strategies. The importance of access to robust emissions data, marginal abatement curves as well as knowledge of alternative markets is not to be underestimated as we move towards 2015.

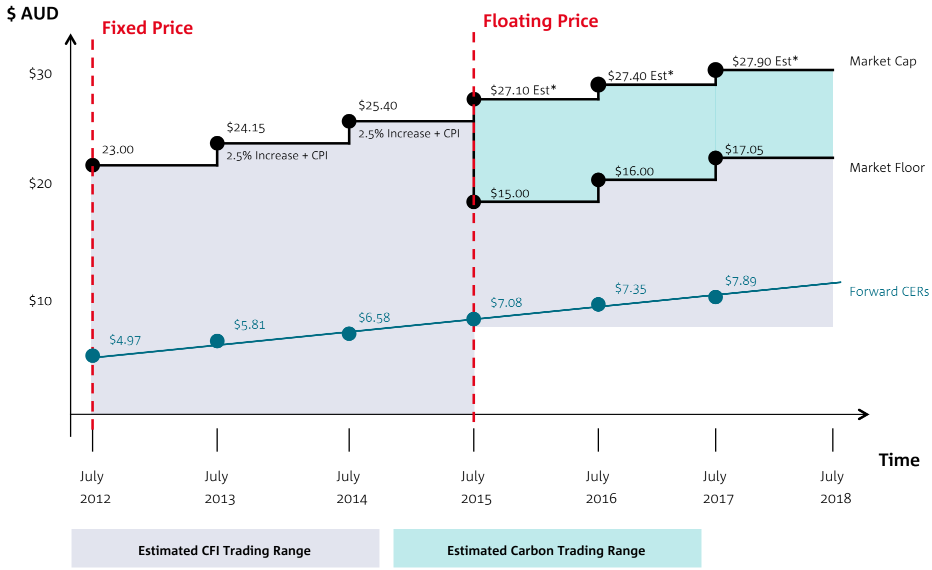
"Despite weak carbon market conditions, opportunities do exist now to gain experience in the market and manage future exposures using principles and concepts applied to mature markets."

Another key market is the United Nations-governed Certified Emission Reduction (CER) market given that liable entities are permitted to surrender these for up to 50% of their liability during the flexible pricing period and beyond. The economic woes in Europe, energy demand/supply dynamics and uncertainty regarding the future of the Kyoto scheme have certainly impacted the state of the CER market recently, with CERs trading at record lows. However, CERs remain a viable compliance tool for Australian entities and there are signs that market interest is building for CERs with suitable specifications and pricing structure.

The floor price proposed by the Government for 1 July 2015 – 30 June 2018 continues to create much discussion regarding its specific implementation and operating model. The Government has consulted with the market regarding alternative models for implementation and is currently deciding on its preferred solution. Obviously the specific model chosen will have significant implications for CER trading activity during the floor price period, so we watch with interest how this situation will develop, particularly given CERs are currently trading well below the proposed floor ($15) and are likely to do so for some time.

Chart 1 outlines the pricing structure of both the fixed and flexible price periods of the Carbon Pricing Scheme.

Chart 1: Australian Carbon Pricing Scheme – Price Paths



* Estimate is for $20 above expected international price for that financial year. These estimated figures were derived from the AUDEUR forward rate and CER curve as a proxy to international prices (as at 14th March 2012)

The collar arrangement will be in place for 3 years, following this the collar will be reviewed

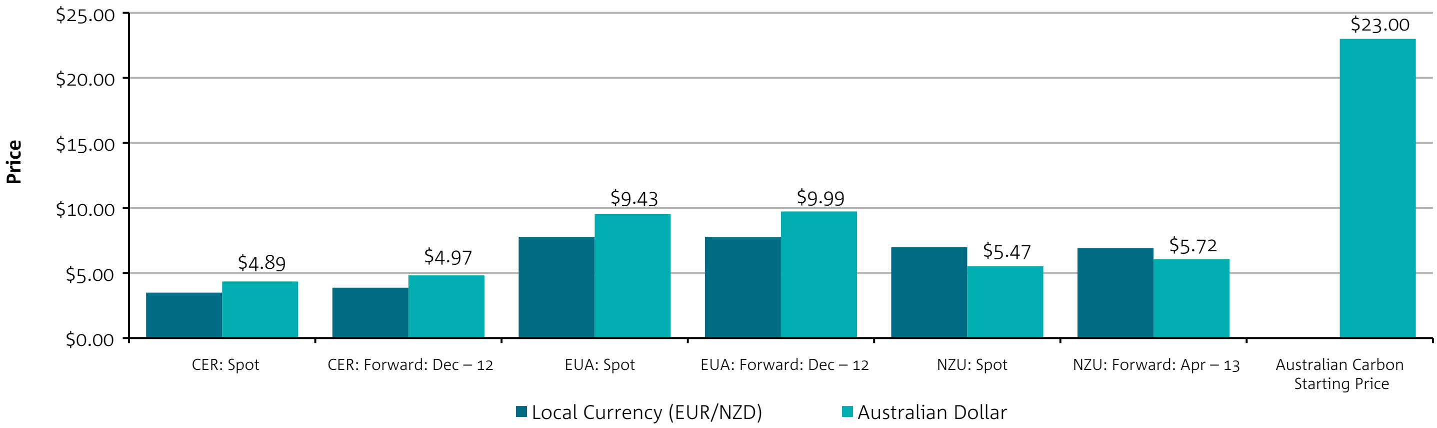
Source: NAB, Reuters, March 2012.

Pricing for carbon units in various markets (converted to AUD) is shown in Chart 2 for comparison purposes. Note the significant difference between Australian units and NZUs/CERs. The question is, will the $23 starting fixed price survive?

It is clear that interesting times are ahead for the Australian and broader international carbon market as a combination of policy and economic environments shape the long-term market dynamics. Despite weak carbon market conditions, opportunities do exist now to gain experience in the market and manage future exposures using principles and concepts applied to mature markets.

There is much to do as we prepare for the July 2012 start of the Australian Carbon Pricing Scheme and keep abreast of opportunities and developments that exist. We watch the existing CER, CFI and related International markets with interest in conjunction with policy tweaks that may eventuate as the government implements the second largest carbon compliance market in the world.

Chart 2: International Carbon Market Prices



Source: NAB, Reuters, March 2012.

NAB Contacts

Andrew Wright
Managing Director, Head of Resources, Energy & Utilities
Institutional Banking
+61 (0)3 8641 4193
andrew.w.wright@nab.com.au

Fiona McIntyre
Director, Head of Energy & Utilities
Institutional Banking
+61 (0)3 8641 2923
fiona.mcIntyre@nab.com.au

Jason Brown
Associate Director
Energy & Utilities
Institutional Banking
+61 (0)3 8641 2571
jason.c.brown@nab.com.au

David de Garis
Director and Senior Economist
Fixed Interest, Currencies and Commodities
+61 (0)3 8641 3045
david.degaris@nab.com.au

Stuart Glen
Head of Institutional Banking Qld
+61 (0)437 871 774
stuart.glen@nab.com.au

David Krsevan
Director
Environmental Markets
+61 (0)2 9237 1181
david.krsevan@nab.com.au

Amy Lloyd
Associate Director
Resources, Energy & Utilities
Institutional Banking
+61 (0)2 9966 3371
amy.lloyd@nab.com.au

Phillip Mak
Head of Origination, Energy, Asia Pacific
Global Specialised Finance
+61 (0)3 8641 0390
phillip.mak@nab.com.au

Matthew Sandham
Director
Resources, Energy & Utilities
Institutional Banking
+61 (0)2 9237 9419
matthew.sandham@nab.com.au

Rachel O'Neill
Director
Energy & Utilities
Institutional Banking
+61 (0)7 3234 6649
rachel.m.o'neill@nab.com.au

James Waddell
Director
Debt Markets Origination
Wholesale Banking
+61 (0)2 9237 1496
james.waddell@nab.com.au

Robert White
Associate Director
Environmental Finance Solutions
NAB Advisory
+61 (0)3 8641 5369
robert.j.white@nab.com.au