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Pondering on Change in the Australian Electricity and Gas Sectors

By Hugh Bannister

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As this article goes to press, Barack Obama has become President-Elect in the United States, accompanied by much euphoria and talk of this being a transformational moment. Be that as it may, this is a time when change does seem to be in the air, not least in the Australian energy industry and the electricity and gas sectors in particular.

Change implies uncertainty, and with it comes both opportunity and risk. Change implies the possibility of significant wealth shifts between different parties, quite apart from the direct economic impacts that are more commonly assessed. In this article I intend to walk around some of the change elements at work, and perhaps prod them gently to see whether anything is likely to jump up and bite.

Elements of Change

So what are the change elements that appear to be at work?

As seen on the front page of every newspaper, we have the current, or we all hope recent, global financial meltdown and the economic fallout from that. The immediate impact will pass in time, but the change in perceptions and attitude to the Australian national electricity market, which can be regarded as a construct of the financial engineering age, may be much longer lasting.

Next is the growing international pressure on energy resources. While slowed down in the current economic climate, there remains a huge, pent-up demand for internationally-sourced energy from half of the world's population that is rapidly urbanising and industrialising. What does that mean for Australia with its abundant export energy reserves, and, historically, relatively cheap and abundant energy used to fuel the domestic electricity sector?

Thirdly we have the increasing pressure to move to a more carbon-constrained world. The Australian government is clearly committed to introducing some form of a Carbon Pollution Reduction Scheme (CRPS) and a Renewable Energy Target (RET) to boot. The current economic uncertainties may or may not hold things back a little; on the other hand, the election of Obama suggests that something will surely happen.

For the last ten years of the national electricity market and as much as ten years before that, the bulk of Australia's east coast electricity system has been able to live off the fat of earlier over-expansion. While there has been some regional base load plant commissioned, and of late more renewables and peaking plant, at some

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Intelligent Energy Systems ABN 51 002 572 090

Head Office – Sydney Level 2 10-12 Clarke Street Crows Nest NSW 2065 Australia PO Box 931 Crows Nest NSW 1585
Telephone 61 2 9436 2555 Facsimile 61 2 9436 1218 Email ies@iesys.com.au Web www.iesys.com.au
Melbourne Level 8 45 William Street Melbourne VIC 3000 Australia PO Box 405 Collins St West Melbourne Vic 3000
Telephone 61 3 9614 6200 Facsimile 61 3 9614 6255 Email ies@iesys.com.au Web www.iesys.com.au

stage in the foreseeable future some major base load decisions will need to be made, perhaps driven by, or accelerated by, carbon pressures. The current economic slowdown may put off the day, but not for long. How will all these other developments affect what will go on, how will it affect individual businesses and how can they respond?

What does all this mean for how the electricity and gas supply sectors in eastern Australia might develop in the coming years? Let's focus on each issue in turn and then try to put everything together.

Impact of the Financial Crisis

At the recent Association of Power Exchanges (APEx) Conference in Sydney, the NEMMCO speaker pointed out that prudential management in the NEM was being re-visited as a result of the financial crisis. Perhaps the bank guarantees that prop up the system do not look so hot anymore; perhaps the NEM gross pool design looks a little fragile in the light of these experiences.

As I think back a little to the days when the NEM was being put together, in the mid 1990s, I recall that one of the original design features of the NEM was a short term forward market (STFM) that was eventually dropped. Why? One argument that I heard while working on the Victorian electricity sector reform in the mid 1990s was that trading in such instruments was not a job for electricity amateurs, but best left to the financial professionals. Within the electricity sector itself, many felt that an STFM was simply unnecessary.

The outcome? To my pleasant surprise, one concern was unfounded – namely, that generators had no trouble committing their plant satisfactorily without the aid of an STFM. But other problems remain, largely unseen, but still festering. One problem, starkly evident in New Zealand, has been that uncontractable network risk arising from implementing nodal pricing without financial transmission rights (FTRs) has driven the industry to vertically integrate. This reduces competition by narrowing the opportunities for stand-alone merchant generating plant. The situation is less stark in Australia because we have regional rather than nodal pricing, but we do have residual network risks and we have suffered a lack of contract liquidity in some places because of government policies intended to take over the management of risk in the industry – most notably in NSW.

Another perceived problem is the limited level of demand-side participation in the NEM. A close look at demand patterns around the time of price spikes in the NEM suggests that some load management is indeed going on, but outside the wholesale market rather than inside. Nevertheless, a flexible demand-side adds a great deal of robustness to the wholesale market and there is no doubt a lot more potential out there. An STFM would allow industrial plant to plan ahead and lock in a working schedule, which I believe is far more acceptable to a plant manager than effectively handing plant over to retailers to operate. Suitably designed (essentially, by turning the current PASA projections into a contract market), current network constraints could also be better accounted for. However, systems that have operated quite successfully for many years, as the NEM has, can unravel unexpectedly and extremely rapidly after some plant failure, if such matters of detail are not properly attended to.

With the imminent establishment of the Australian Energy Market Operator (AEMO) which will be responsible for both gas and electricity, there will be the opportunity and the need to operate the gas and electricity sectors in a more co-ordinated fashion. It will be interesting to see how the national system develops under AEMO. The Victorian system already operates on a daily bid market basis. Will the rest of the gas industry move in this direction also, and should the electricity sector follow suit with a day-ahead facility to aid coordination with the increasingly important gas supply sector? There are plenty of examples around the world where day ahead electricity markets have been implemented.

Another possible effect of the financial crisis is that the federal government is likely to have a greater inclination, not necessarily inhibited by limited financial means, to pursue large infrastructure projects. This could easily include transmission and gas pipeline projects, built for security reasons but also to soften the impact on the energy sector of some of its other policies. Such policies will not be neutral in their financial impact as I will discuss later.

Impact of International Demand for Fuels

Now let's look at the gas supply cost issue, going forward, beyond the current economic slowdown. I will assume that internationally traded LNG prices will be high reflecting buoyant and growing demand, as reflected in the value of recent transactions involving Queensland coal seam methane.

What will high LNG prices do to domestic gas prices? Perhaps not much initially. It will depend on the location and cost of available gas supplies, the configuration and capability of gas transmission infrastructure, the cost of LNG conversion and some technical and market factors. But we can be assured that east cost gas suppliers will be doing their sums on the export market.

Now we consider another possibility. In the moderately carbon-constrained world we seem to be entering, gas is likely to become a dominant fuel for new supply. But this presents a problem to the secure operation of the electricity system. The failure of gas supply infrastructure becomes a critical contingency for electricity. Gas infrastructure can and does fail and cause great disruption; witness Longford more than a decade ago and the more recent West Australian episode.

What to do? Electricity system security may not be at the top of the gas suppliers' agenda so they may not be willing to build redundant lines for the sake of electricity security. One answer is to sponsor a systematic strengthening of the gas grid, paid for by electricity users, perhaps by also dipping into the infrastructure fund. This will open up and diversify gas supply to coastal locations. But this freeing up of gas transmission may make export opportunities more attractive. Can export-linked domestic gas pricing be far behind?

There does seem to be an emerging view in Australia that gas prices will start to approach export levels, at a pace which is not entirely clear but which will be very important for specific businesses. But let's look at this a little more closely. Conventional analysis and modelling would argue that the domestic price of gas will trend to the internationally traded price of LNG ex Queensland, say, less the cost of conversion. Anything less and a supplier would prefer to export. But why not a higher price than this? What is the effective ceiling on domestic gas prices?

Let's look at this historically. When natural gas began penetrating into the east coast market around 40 years ago, there was no serious LNG export potential. Further, gas had to compete hard to displace established fuel sources – coal used in industry and power generation, coal-based town gas, and coal-based electricity in domestic, commercial and industrial applications. Gas had a real competitor in coal. Because of this, for years we used to assume gas priced at $3/GJ and we probably weren't far wrong at the time.

Under a CPRS, however, coal is effectively removed as an effective competitor for gas. So we don't need to refer to the export potential of gas to believe that, with a limited number of suppliers over a fairly skinny gas transmission system, gas prices are likely to follow the price of carbon upward, with the only effective limit being the competition from renewables or, ultimately, of gas from LNG imports! We can model and evaluate the ability of gas suppliers to exert market power under a CPRS. How policymakers will respond to this possible out-turn of events will affect the value of quite a few electricity businesses.

This is not all bad news for generators, some of whom can ride happily on higher electricity prices, although whether prices will actually be higher as a result of high gas prices depends on the interaction of the CPRS with the RET. The development of the gas sector along the east and south east seaboard is a key pricing and value-shifting factor for the electricity sector.

Related issues face the coal sector. If current coal export bottlenecks are removed, some coal supplies currently directed to power stations could become a lot more expensive for domestic use, even without a carbon penalty.

There are other areas where policy developments might significantly affect business. In the long run, for example, if energy policy drives remote renewable energy such as wind to be the marginal supply source (and therefore price setter), the cost of generation and connection together will be a key determinant of electricity prices. The cost of transmission may be a lesser cost and pricing factor than the price of natural gas, but there will be conflicting pressures from different sources arguing the case for these connection costs to be spread around, rather than focussed on the renewable suppliers, to shift value in a way favourable to one party or another.

I haven't much focussed on the demand-side so far. Needless to say, in the long run some profound shifts in lifestyle and the shape of our cities are possible and likely, much as these things have changed profoundly in the past 60 years. Some studies have drawn attention to specific cases where electricity demand might actually increase under a carbon constraint, as some demands switch away from oil to a newly decarbonised electricity sector (carbon capture and sequestration (CCS) is the key technology assumed here). Such a shift, driven by sustained high world oil prices and improved technology, could well occur even without CCS.

What I like about the hybrid and electricity vehicle technology is the scope to use smart technology to integrate such vehicles into the electricity system, in order to absorb some of the supply variability from the growth of renewable electricity supply. In essence, with suitable smarts, hybrid car batteries and fuel storage tanks can act as the storage that absorbs the ups and downs of variable supply. This would be a fun modelling exercise, but also an important one.

Carbon Emission Reduction

No discussion of current market change factors would be complete without considering the CPRS and any associated RET. In broad terms we understand what could happen as the carbon target is tightened up, focussing on the supply side. First, a switch to gas for new generating plant is likely (assuming the gas source itself is not a significant carbon emitter), a trend already evident but perhaps driven at present by the plant mix needs of the system. Press harder still and some existing fossil fuel plant may retire early. Press harder still and some renewable options start to become viable and gas plant less so. Energy conservation becomes increasingly viable and so on – a relatively straightforward modelling exercise in principle although data are always a challenge.

But what if there is also an ambitious renewable energy target? This will contribute to the reduction in carbon emissions. So you don't have to press quite so hard on the carbon price to get the desired emission result. There is an interesting interplay here. The renewable energy target will probably be expressed as a renewable portfolio standard (RPS) for electricity retailers, as under the current REC scheme. In theory, such a scheme is not the most efficient way to achieve a particular level of carbon emission reduction; it ignores the role of gas, for example.

I used to think the only merit of the RPS approach was to put a warm glow into our hearts that we are looking after mother earth. However, RPS schemes are popular (and they are indeed popular all over Asia, in various guises) because they have a pricing outcome that is satisfactory to policymakers. We can model this. Essentially, the market price to consumers of energy subject to an RPS is, in essence, the volume weighted average of the ordinary and renewable input energy prices. So you can hide quite a bit of renewable energy in an energy form (for example, in electricity but also petrol in the form of ethanol blends) and affect the market price to consumers only a small amount. But a CPRS alone would tend to price energy at the marginal cost of the most expensive carbon–efficient fuel - gas or perhaps renewable energy in the longer run. This will likely yield a much higher price to consumers than an RPS for the same degree of carbon emission reduction. What happens to the dollar difference? It would appear as value shifts between suppliers, customers and the government.

So what is the net outcome when both schemes are present? There is no simple answer; it depends. But it could affect the value of your business and how you respond.

So Where Does This Lead?

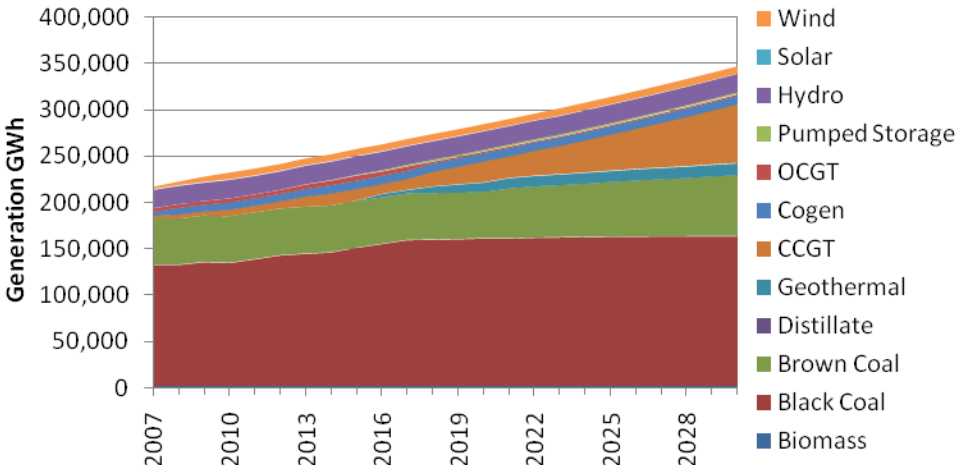
If we incorporate these three change elements together with various other possibilities and uncertainties relevant to the electricity market, we can see that the development of the electricity and gas sectors in east Australia is highly uncertain, yet critical to future business prospects and strategies. Here at IES, our work is concerned with considering all market factors and coming up with some possible future scenarios. A topical issue right now is how these change elements might impact on the breakdown of electricity generation by fuel type in the Australian electricity market.

Let us consider five scenarios:

1. Business as usual (BAU)
2. CPRS with 5% emissions reduction target by 2020
3. CPRS with 15% emissions reduction target by 2020
4. Expanded national renewable energy target (ENRET) scheme with 20% target by 2020 and CPRS 5% reduction target by 2020
5. ENRET scheme with 20% target by 2020 and CPRS 15% reduction target by 2020

The BAU case (shown in Figure 1 Breakdown of fuel type for Business as usual case) is very much a continuation of the status quo, with the addition of a few new players. Coal remains the dominant source of electrical energy for the next few decades while a small amount of geothermal enters around 2016 with the introduction of the Cooper Basin project. The new middleweight in the field is CCGT which expands to supply around 18% of the market by 2030, while OCGT gradually gives way to the newer generation technologies.

Figure 1 Breakdown of fuel type for Business as usual case



Once an emissions trading scheme is introduced (see Figure 2 and Figure 3), CCGT moves from the middleweight division to the super heavyweight division, replacing coal as the dominant energy source in less than twenty years. Wind also plays a more important role from 2020 onwards. Our models suggest that the existance of the emissions trading scheme is more important than the emissions reduction target chosen, with both the 5% and 15% targets leading to similar electricity generation landscapes. The reason is that the targets are referenced to the year 2000, so that from the the current 2008 the reductions are larger and relatively closer together. Notwithstanding this, the more strenuous emissions target of 15% does result in a smaller proportion of coal-based electricity as one would expect.

Figure 2 Breakdown of fuel type for CPRS 5% reduction target

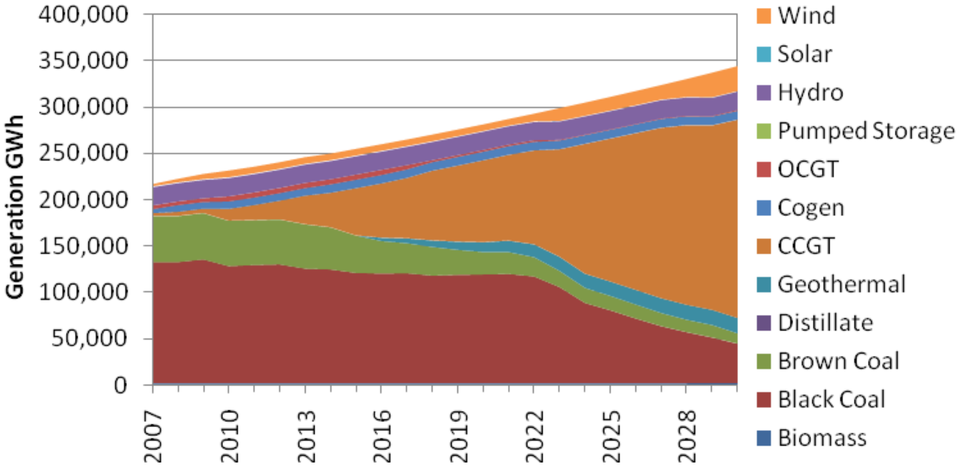


Figure 3 Breakdown of fuel type for CPRS 15% reduction target

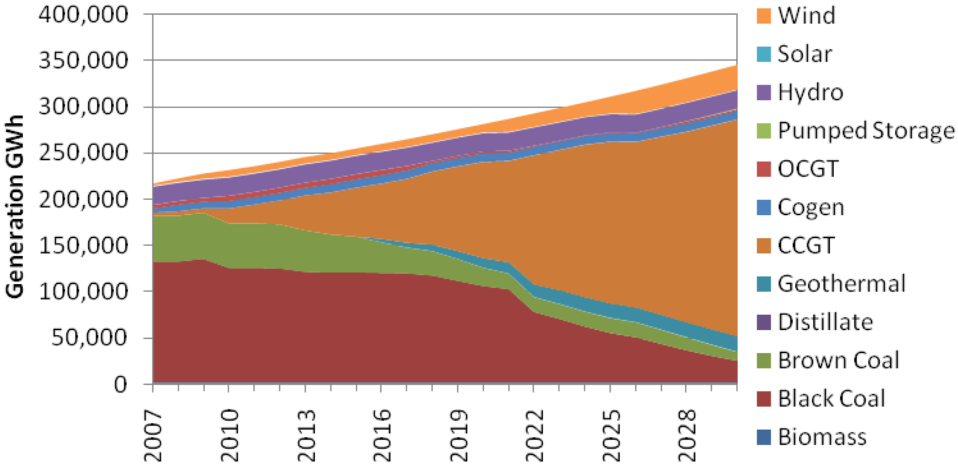


Figure 4 and Figure 5 show the two CPRS targets of 5% and 15% in combination with an expanded national renewable energy target (ENRET) of 20%.

The most obvious difference is the earlier and greater uptake of wind power, which supplies almost 8% of the market by 2030. This makes an interesting contrast with the situation of brown coal which dies off to 3% or less by the end of this period.

Figure 4 Breakdown for ENRET 20% target with CPRS 5% reduction target

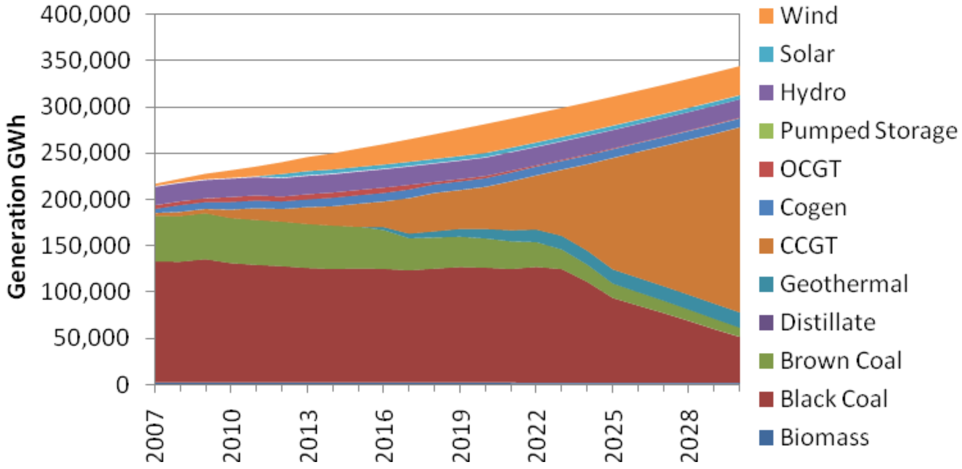
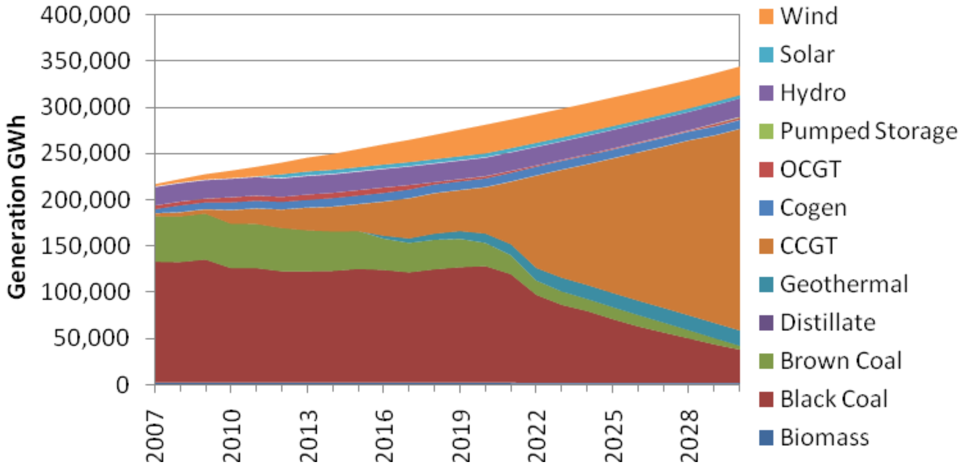


Figure 5 Breakdown for ENRET 20% target, CPRS 15% reduction target



Curiously enough, it appears that the amount of coal in use at the end of 2030 is greater for the 15% CPRS target with the 20% ENRET scheme rather than without. Let's investigate this further in Table 1. The business as usual case shows the predominance of coal in a market without environmental schemes. As seen graphically, the contribution of coal drops dramatically with the introduction of an CPRS. We can see also that the introduction of the ENRET scheme does indeed increase the total amount of coal at the end of the modelled period (or more accurately, decrease the reduction of coal). However, although the overall proportion of coal increases, the ENRET does lower the contribution by brown coal.

So what might be behind this phenomenon?

An explanation is that the ENRET scheme encourages significant early investment in wind which then displaces some of the investment in alternative baseload generators such as CCGT, thus leaving more market room for coal. Put another way, for a given CPRS carbon reduction target, if you force in more very low carbon options through ENRET, you leave more room low cost, high carbon options like black coal. The loser in the ENRET case relative to the no-ENRET case is CCGT; unable to qualify as renewable under ENRET and too costly to keep ahead of coal in the CPRS. The bigger loser in both cases is brown coal, unable to overcome its high carbon status (unless, of course, new technology comes along to fix it).

Table 1 Estimated contribution of coal to electricity market in 2030 (%)

	Black coal	Brown coal	Total coal
BAU	46.7	19.1	65.8
5% CPRS	12.4	3.2	15.6
15% CPRS	6.8	2.7	9.5
5% CPRS, 20% ENRET	14.4	3	17.4
15% CPRS, 20% ENRET	10.4	1.3	11.7

We digress here to remind everyone that that the results presented in this article are only rough projections and not gospel truth! The intention is to indicate what the overall impact of the CPRS and ENRET schemes might be on the Australian electricity market rather than to predict the exact proportion of energy contributed by each fuel type.

So what are the key lessons from this study? Most importantly, we learn that the impact of various green schemes and an CPRS on the Australian electricity market may not be as straightforward as one might think. It even seems possible that a more stringent renewable energy target could lead to a higher contribution of coal than would otherwise be (albeit black coal). However we can state that the main winner from the introduction of an CPRS would be CCGT, and that wind power benefits enormously from the ENRET scheme.

We also haven't discussed in these scenarios the very significant value shifts that might occur within the sector.

Business Challenge

So we come back to our first statement, which is that change does seem to be in the wind. International economic and policy developments and similar developments at home hold the key to the evolution of the Australian electricity and gas markets, and the wider energy markets as well. We have emphasised the uncertainty in all of this. There is policy uncertainty, technology uncertainty, domestic market uncertainty and uncertainty in international outcomes, not to mention the uncertainty introduced by current financial conditions. So the modelling we have described and illustrated cannot by themselves give you absolute answers, but you can get to a point where, first, you are not surprised at future out-turns and, second, that you are in a position to devise strategies that are as robust as possible against future uncertainties. We can model and optimise strategies where a sequence of decisions is contingent on the possibility of various out-turns as yet unknown. These techniques are well-established in the Operations Research business and now revived and rebadged to a wider audience as real options analysis.

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