Liberalised Electricity Markets and Long-term Capacity Adequacy

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Presentation to the ATSE Conference: Nuclear Energy for Australia? Sydney, 25-26 July 2013

Introduction

Electricity markets in many countries have been undergoing substantial change over recent years, mainly associated with the (on-going) shift from vertically integrated state monopolies to liberalised, privately-owned, unbundled market participants operating in a carbon-constrained environment. As a result, traditional methods for determining the optimal portfolio of power generation assets have also radically changed, as the industry has moved from one of being largely driven by capacity to one relying predominantly on short-term wholesale market price signals, uncertain environmental regulations, and changeable renewables policies.

Current government policies in the electricity sector are primarily focused on programmes to support the development and deployment of low-carbon technologies in order to reduce their costs and thus reduce the long-term cost of decarbonising the sector. However, the design of liberalised electricity markets may actually make low-carbon investment riskier than continued investment in fossil fuel technologies. Thus, even with a carbon price, investment in low-carbon technologies may be discouraged.

Australia's National Electricity Market (NEM) is an energy-only obligatory market for trading electricity¹. Scheduled and semi-scheduled generators offer price and associated quantity bids for five-minute dispatch intervals, with prices average over a thirty minute trading interval. The marginal generator (i.e. the highest accepted bid) sets the wholesale price, which then applies to all successful bids. The marginal generator is generally a fossil fuel generator. Thus, marginal bid pricing will include the carbon price, since this will be part of a fossil fuel generator's short run costs. This should give a competitive benefit to low carbon technologies. However, the risks attached to recovery of fixed costs of new investment in low carbon generation assets will vary considerably depending on the capital intensity of the different technologies.

This paper discusses the prospects for investment in high capital cost, low-carbon, technologies in liberalised electricity markets.

Investment issues in liberalised electricity markets

Table 1 shows the capital cost (in \$/kW) of a range of current and potential power generation technologies in Australia. What is particularly noticeable is the marked cost difference between gas and the other technologies. The corresponding levelised costs of electricity (LCOE) are given in Table 2, where the differences between the technologies are far less pronounced. Table 3 provides estimates of the LCOE by technology and discount rate (either 5% or 10%) for a number of OECD countries,

¹ Energy-only markets rely solely on wholesale market prices to stimulate investment in generation capacity, although subsidies also exist to support renewable technologies and carbon prices to discourage investment in carbon-intensive technologies.

Table 1: Capital costs: power generation technologies for Australia: (A\$/kW)

IGCC (brown)	6306	
IGCC (black)	5346	6841 (with CCS)
Coal S/C (brown)	3788	7363 (with CCS)
Coal S/C (black)	3124	5855 (with CCS)
CCGT	1062	
OCGT	723	
Wind (on-shore)	2530	
Nuclear	3470	
Solar thermal	4920	
(parabolic trough)		

Source: BREE (2012) and ACIL Tasman/DRET (2011)

Table 2: Levelised costs of electricity technologies in Australia (A\$/MWh)

	*	<u> </u>
IGCC (black)	176-189	193-253 (with CCS)
Coal S/C (brown)	162	205 (with CCS)
Coal S/C (black)	135-145	162-205 (with CCS)
CCGT	96-108	
OCGT	203-259	
Wind (on-shore)	111-122	
Nuclear	94-99	
Solar Thermal	330-402	
(parabolic trough)		

Source: BREE (2012)

Table 3: Levelised cost of electricity by technology and discount rate (5% and 10%) (US (2015) cents/kWh)

Country	Nuc	lear	Coal		Coa	with CC	ссст		Onsh wind	
Belgium	6.1	10.9	8.2	10.0			9.0	9.6	9.6	13.6
Czech Rep	7.0	11.5	9.0	12.4	9.1	13.9	9.2	10.4	14.6	21.9
France	5.6	9.2							9.0	12.2
Germany	5.0	8.3	7.5	9.1	7.7	9.8	8.5	9.3	10.6	14.3
Hungary	8.2	12.2								
Japan	5.0	7.6	8.8	10.7			10.5	12.0		
Korea	3.1	4.5	6.7	7.3			9.1	9.5		
Netherlands	6.3	10.5	8.2	10.0			7.8	8.2	8.6	12.2
Slovakia	6.3	9.8	12.0	14.2						
Switzerland	6.2	11.3					9.4	10.5	16.3	23.4
USA	4.9	7.7	7.4	9.0	6.8	9.4	7.7	8.3	4.8	7.0
China	3.3	5.0	5.5	5.8			4.9	5.2	7.0	9.9

Source: IEA/NEA (2011)

plus China. All LCOE estimates in both Tables 2 and 3 embody a carbon price, with the exception of China.

In general, nuclear and renewable technologies possess relatively low running costs of generation, but involve relatively high initial capital investments. Thus the appropriate discount rate (or the weighted average cost of capital) is critical in determining the lowest cost technology, as can be seen from Table 3. As discount rates increase, the high initial capital cost technologies become less attractive particularly if they have long construction time frames. Whilst the LCOE is an appealing concept, however, it ignores the practical realities of investment in energy-only liberalised electricity markets based upon a portfolio of generation technologies.

Figure 1 illustrates the merit order for a hypothetical energy-only market with no wind capacity, where it is assumed that all generators offer bids at their SRMC. Thus nuclear, having the lowest short run marginal cost (SRMC) is dispatched first, followed by coal, combined cycle gas turbine (CCGT), and finally open cycle gas turbine (OCGT). The wholesale price (WP) paid to all generators is determined by the marginal bid which, in this illustration, belongs to an OCGT unit. The surplus price received by each technology over its SRMC is known as its infra-marginal rent and, in the long-term, it is intended that this should reimburse generators for the fixed costs of each technology.²

Figure 2 assumes that a wind generator now enters our hypothetical market. Wind has a negligible SRMC and thus is first to be dispatched. This shifts the merit order for the other technologies to the right. Now, with the same level of demand, the wholesale price has dropped and, as a consequence, so has the infra-marginal rent for all technologies.

Wind power operates as base-load, ahead of nuclear, coal and CCGT, because of its lower SRMC, and can therefore offer very low (or even negative in the presence of subsidies) price bids to ensure dispatch. However, the large gap between the SRMC and the average cost of wind gives rise to a high level of risk that full cost recovery will not be achieved.

Note from Table 1, however, that the two gas technologies have much lower capital costs than the low-carbon technologies, and shorter construction periods that permit an earlier revenue stream to be achieved, a major asset in the context of high discount rates brought about by market uncertainties and associated risks. In addition, OCGT technology has the advantage of being modular and "off-the-shelf", and its use as back-up for wind serves to counteract any significant environmental opposition. Further, the cycle can be "closed" when commercial conditions deem it appropriate. Gas technologies are also partially hedged against fuel and carbon price volatility as they are generally the marginal-bid technology. Thus gas and carbon price volatility can be built into their bid price, although technologies earlier in the merit order will also receive these higher prices.

² It is assumed that the market is competitive and thus all generators bid at their SRMC. In practice this may often not be the case and opportunities to exert market power may arise. Market power is a feature of most electricity markets, offering generators the potential for bidding parcels of output at prices significantly higher than their SRMC when capacity is in short supply.

Figure 1: Infra-marginal rent in the absence of wind

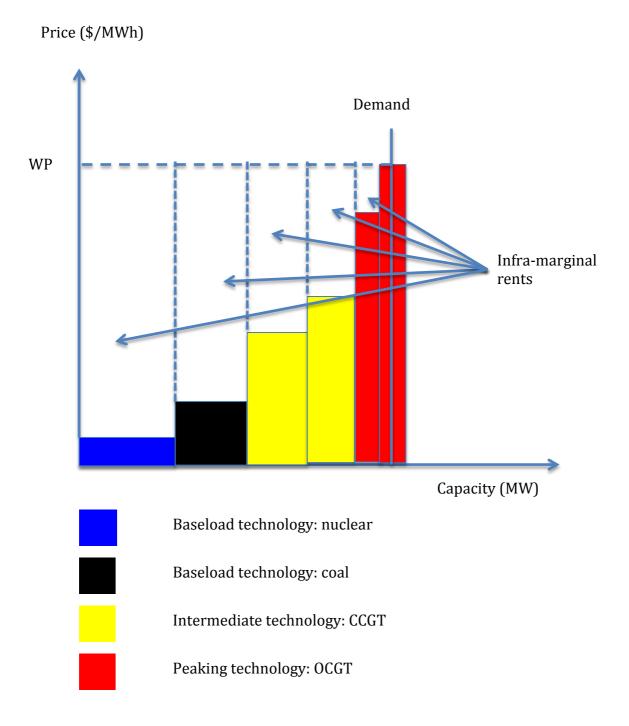


Figure 2: Infra-marginal rent with wind

Price (\$/MWh)

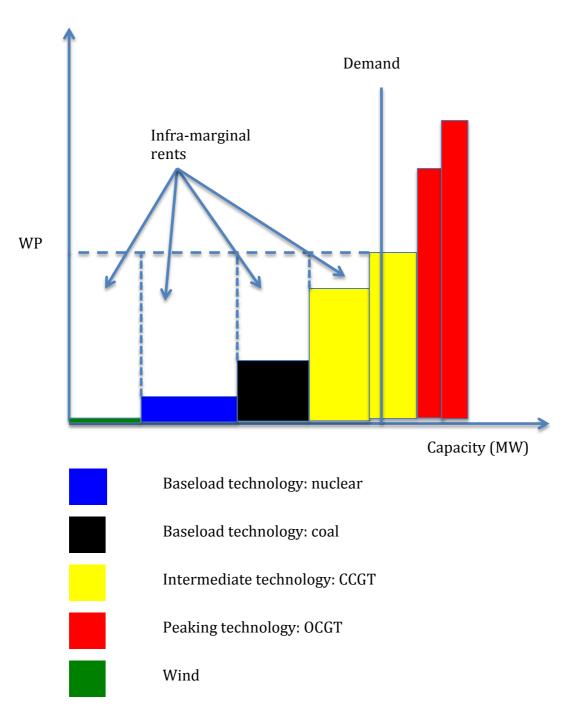
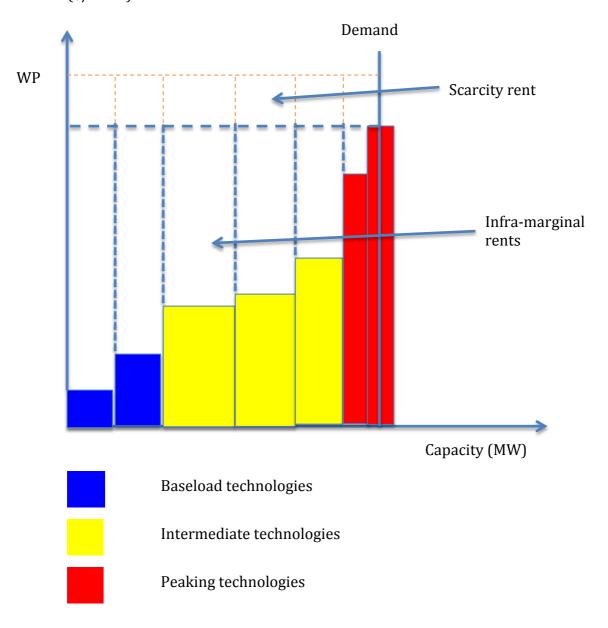


Figure 3: Scarcity rent

Price (\$/MWh)



The critical question when considering the long-term capacity adequacy in energyonly markets, therefore, is whether wholesale electricity prices and ancillary services can provide sufficient revenue to attract adequate investment in low carbon technologies, particularly in the presence of a market price cap.

Figure 3 illustrates circumstances where prices incorporate a scarcity rent, which generally arises in the context of a supply constraint. It is the scarcity rent that provides an incentive for capacity to be made available on the very few occasions that the supply constraint may arise. Thus, units that provide power during such occasions must be compensated for the fact that they will lay idle for all but a few days a year. It is this price that is capped by the regulator at what is known as the value of loss load (VOLL). Note that all generators would receive this scarcity rent, so payments close to or at the VOLL generally receive close scrutiny from the regulator to ensure that no abuse of market power is taking place.

Investment issues

An overview of investment issues in liberalised electricity markets is given in Table 4. In the case of low carbon technologies, which are characterised by long-lived and high fixed cost capital assets, they are not only exposed to electricity market price risk arising from volatile coal, gas and carbon prices, but nuclear and coal with carbon capture and storage (CCS) are also exposed to load factor risk associated with high deployment of intermittent renewables. Whilst market participants are generally well equipped to handle fuel price volatility, they are generally less well equipped to handle carbon price and renewables policy risks.

Table 4: Overview of investment issues

	Financial crisis	Utilities' capacity to invest and credit		
General		rationing due to regulatory changes		
Context	Local acceptability issues	"Banana" syndrome (build absolutely		
		nothing anywhere near anyone)		
	Cash flows volatility and	Peak prices depend on weather conditions.		
Issues	variability	Fossil and carbon price risks		
pertaining	Load factor risk	Deploying renewables reduces load factors		
to energy	Price restrictions	Price caps reduce prices during peak		
		periods, leading to underinvestment		
	Incomplete markets	Flexibility not (or poorly) remunerated		
	Energy policy risk	Stop and go of renewables policies and		
		uncertain environmental regulations		

Source: Baritaud (2012)

Addressing the problem with policy intervention

The key to addressing the problem is to replace, or complement, long-term market arrangements with technology-specific policies. The challenge is to combine public and market co-ordinations in order to maintain financial incentives, while simultaneously reducing the risks inherent in the market regime sufficiently so as to ease investment.

There are two broad options for government intervention:

Financial measures that operate within the energy-only market structure

Feed-in tariffs are structured either as fixed payments, premium payments on top of the electricity price, or financial contracts for difference against the market price. They are designed with the intention of providing some degree of financial security and thus to encourage investment in long-term generation assets. Contracts for difference (CfDs) involve a government-determined "strike price" that generators would receive for their output. The intention is to set long-term assured prices for electricity generated using low-carbon technologies, thereby encouraging investment by removing the risks associated with carbon pricing and changeable renewables policies. If the market price exceeds the strike price, then generators must surrender the difference. If the market price is less than the strike price, then generators are paid the difference. In late June 2013 the UK Government announced strike prices to run for 15 years for a range of low-carbon technologies, a policy that is intended to replace the UK Renewables Obligation. Strike prices for new nuclear and CCS have still to be announced.

Policy interventions that modify the energy-only market structure

Alternatively, it may be preferable to adapt the structure of energy-only electricity markets to address the issue on a market-wide basis. Possible market reform may include the following (separately or in combination):

- Imposition of quantity obligations on suppliers (such as a renewables obligation), that forces the market to encompass technologies that would otherwise not be adopted for various reasons;
- Carbon price support: the guarantee of a minimum carbon price in the electricity market;
- Targeted capacity payments for flexible/peaking plants; and
- Emission performance standards.

Conclusion

Liberalised electricity markets such as the NEM have raised the risks faced by investors in high-capital-cost, low-operating-cost, generation. In addition, such market structures may not encourage low-carbon technologies due to uncertain environmental policies. A key question for governments, therefore, is whether to use targeted measures (such as capacity payments) to ensure capital cost recovery for low-carbon investments, or whether to impose market-based policies such as long-term contracts-for-difference payments that focus on selected low-carbon generation technologies.

The current structure of energy-only electricity markets is likely to lead to inadequate investment in capacity in the long-run without appropriate measures to reduce market risks associated with renewables and carbon policies, thus raising the cost of decarbonising the electricity sector.

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