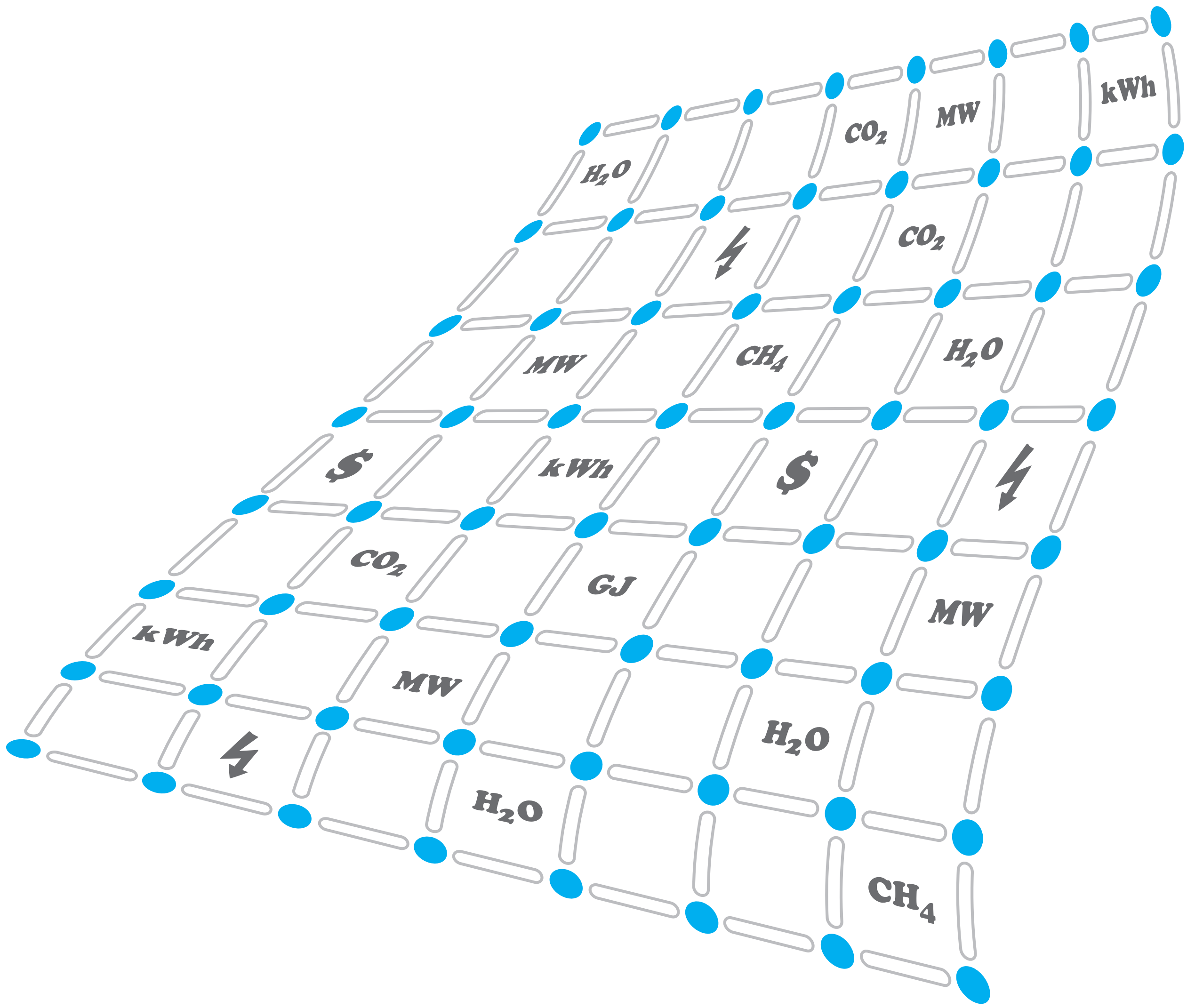
ENERGY MARKET DESIGN & AUSTRALIA'S LOW-CARBON TRANSITION

A case study of distributed gas power

Tom Foster
David Hetherington



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About Per Capita

Per Capita is an independent progressive think tank which generates and promotes transformational ideas for Australia. Our research is rigorous, evidence-based and long-term in its outlook, considering the national challenges of the next decade rather than the next election cycle. We seek to ask fresh questions and offer fresh answers, drawing on new thinking in science, economics and public policy. Our audience is the interested public, not just experts and practitioners.

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Executive Summary

There is much debate of the long-term potential of energy technologies in reducing greenhouse gas emissions – clean coal, concentrated solar power, geothermal and wave energy. Yet our transition to a low-carbon energy sector must begin now, using readily available technologies. Only two fit the bill: gas-fired power generation and large-scale wind. Since wind cannot provide baseload power, gas must underpin the lion's share of the effort.

This paper explores the role of distributed gas-fired power generation in Australia's transition to a low-carbon economy. It uses the framework of market design to consider why a technology which is cost-effective and readily available has not penetrated the Australian electricity market to the extent it has elsewhere in the world.

We compare the levelised costs of five existing generation technologies, and find that the cost of power from distributed gas generators is approximately 10% lower than power from black and brown coal. Once trigeneration technology is added, which recycles waste heat to provide heating and cooling, the full-cost economics of distributed gas power are around 25% better than coal. In addition, each megawatt hour of coal-power we can substitute with gas trigeneration allows us to reduce greenhouse gas emissions by two-thirds.

Given this, and the widespread availability of gas in south-eastern Australia, why has distributed gas not been adopted more quickly? We identify a range of barriers to entry for distributed gas producers which are the result of poor market design in our energy sector. These barriers include implicit subsidies to coal-fired generators through coal and water inputs which are priced below market value; reluctance from energy retailers to facilitate connections to the grid; the absence of a carbon price; distortionary feed-in tariff regimes; lack of temporal pricing; and poor information amongst consumers and producers. We propose a set of market design reforms which would level the playing field for distributed gas relative to coal.

The main findings of the paper are as follows:

- Coal-fired power stations in Australia receive implicit subsidies of $5.3 billion p.a. through fuel and water costs that are purchased below true market value
- On a fully costed basis, including a carbon price of $20 per ton, distributed gas-fired power costs 9.8 cents per kWh
- This compares to 10.7 cents for black and brown coal, and 11.5 cents for large-scale combined-cycle gas turbine
- Once the impact of tri-generation is included, the cost for distributed gas-fired power falls to 6.6 cents per kWh
- Australia could reduce its greenhouse gas emissions by 10%, or 54 million tons per year, if half the coal-fired power in the National Electricity Market were substituted with distributed gas-fired trigeneration
- This would involve 8,050 new 1.5MW units and would cost approximately $14.1 billion, which could be paid for through private investment

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The paper makes the following market design recommendations:

- Price fuel and water inputs to coal-fired power stations at their true market value
- Introduce a national carbon price covering the entire electricity sector
- Offer incentives to distributed network service providers (transmission and distribution companies) for rapid connections to the grid and impose penalties for tardy connections
- Place a cap on the maximum percentage of connection applications the distributed network service providers are entitled to refuse
- Roll out a national gross feed-in tariff scheme which does not discriminate between generation technologies
- Install distributed gas-fired power generation in the 19,000 new social housing units currently under construction by the Federal Government
- Establish a public/private energy aggregation company to pool savings from energy efficiency measures
- Introduce seasonal variation for retail electricity pricing alongside time-of-day pricing variation
- Roll out smart meters on a national basis building on the Victorian model

Section I: Introduction

In recent years, Australia has searched in vain for a coherent response to global warming. The national debate has focused on the market mechanisms that will stimulate investment in a low-carbon economy. The relative merits of an emissions trading scheme (ETS) and a carbon tax have been hotly contested.

Yet there has been less emphasis on the specific technical steps that will allow Australia to meet meaningful emissions reduction targets in a cost-effective manner. The chosen market mechanisms are intended to stimulate carbon reduction through the magic of the invisible hand.

But what are the realistic sources of this reduction? Clean coal, or carbon capture and storage (CCS), is unproven at commercial scale. Most renewable sources except wind are still too expensive to attract significant investment and wind's unpredictability means it cannot guarantee baseload supply. Nuclear energy is bedeviled by the issues of the removal and storage of radioactive waste. On the demand side, energy efficiency measures have an important role to play although there are important problems of collective action to overcome.

Most of these measures have a place on the roadmap to a lower carbon future. However, their effects will not be felt until the latter stages of the journey. This raises an important question: What are the right measures for the early stages of the journey? Are there options that are commercially viable, technologically proven and available now?

There are only two: large-scale wind farms and gas-fired power generation. Wind is carbon-free, proven and scalable, but it cannot provide base supply: there are periods throughout the year when the lack of wind means that it cannot provide a single kW in southeastern Australia.

Natural gas is not carbon-free – it is a fossil fuel after all. However, it is almost half as carbon intensive as the black coal Australia uses for the bulk of its electricity production. New natural gas-fired power generation emits around 0.5 kg of carbon per kWh, while black coal-fired generation produces 0.8-0.9 kg and brown coal emits 1.0-1.3 kg (CSIRO). The simple inference is that on every kWh of coal-fired capacity we replace with gas-fired capacity, we halve our carbon intensity.

For this reason, gas is a natural complement to wind. Gas can provide baseload and the technology is readily available. Taken together, gas and large-scale wind allow us to take the first steps on our journey to a low-carbon economy.

Yet this raises another important question. If this argument is so straightforward, if gas technology is really cost-competitive and freely available, why has this shift not already begun in earnest? This paper addresses these questions using distributed gas-fired power (DGP) as a case study. DGP involves the production of electricity using small generators at the point of consumption, and is likely to be a critical element of Austra-lian's transition to a low-carbon economy. DGP can be produced using a basic rotaryturbine (like a jet en-gine) or using a reciprocating engine (with pistons like those in a car). Turbines have less maintenance, lower vibration, less emissions and are more compact, whereas reciprocating engines have better efficiency,

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lower capital costs but higher recurring service costs. The decision to use one or the other is done on a case-by-case basis. In Victoria, gas turbines have been used for years in hospitals. In NSW, reciprocating engines have been installed in numerous city buildings. Either type can be made more efficient by adding co-generation/tri-generation technology in which waste heat is used to provide heating and/or cooling. The latter approaches are highly efficient in their use of energy and output of CO_2.

The paper examines the potential for DGP to reduce Australian emissions, and presents a comparative cost analysis of distributed gas and centralized coal-fired generation. It argues that the slow uptake of DGP as a carbon reduction measure is the result of ill-suited market design, and proposes a set of market design measures to stimulate rapid investment in DGP.

The paper is organized as follows. Section II outlines the potential of DGP by outlining the fuel sources, reserves and distribution structures which underpin the Australian electricity market today. Section III presents a full-cost comparison of coal- and gas-fired power under alternative generation techniques. Section IV analyses the market design challenges in Australian electricity, highlighting the barriers that have impeded the development of DGP. Section V presents a set of policy recommendations and Section VI concludes with an examination of how these policies promote fairness as much as they advance prosperity. In particular, we consider the intergenerational equity issues surrounding carbon reduction policies and the question of whether feed-in tariffs are regressive.

Section II:
The potential of distributed gas-fired power

The use of natural gas to produce electricity generates about half the CO_2 emissions compared to coal-fired production. Yet this is only part of the story. The comparative economics of various fuel sources is obviously a critical factor which is examined in Section III. A prior question is whether Australia has sufficient gas reserves and pipeline infrastructure to sustain a transition from coal to gas.

The reserves picture is promising. At current levels of production, Australia has 63 years of conventional gas reserves and an additional 100 years of coal seam methane reserves (ABARE, 2010). This compares with 90 years of black coal reserves. The level of gas reserves has approximately tripled in the last 30 years. Approximately 90% of conventional gas reserves are located off north-western Australia while most coal seam methane is found in coal deposits in NSW and QLD.

Natural gas currently constitutes 16% of Australian electricity production by fuel type, whereas black coal makes up of 54% of production and brown coal 23%. On these figures, there are clearly sufficient reserves for natural gas to displace a share of black and brown coal production, and clearly ample production to displace.

Australia's pipeline infrastructure means that gas production is structured into three discrete hubs. The largest hub, Western Australia (1095 PJ p.a., or 64% of total production), primarily supplies export markets plus some domestic demand in WA. The southeastern Australian hub (582 PJ p.a., 34% of production) supplies domestic gas markets in NSW, VIC, QLD, SA and TAS. Finally, the Northern Territory hub (33 PJ p.a.) supplies export markets plus NT's domestic demand.

Given this, the primary opportunity for gas to displace coal is in the states comprising the National Electricity Market (NSW, QLD, SA, TAS and VIC) where: a) electricity demand is concentrated; b) coal currently provides 82% of electricity production; and c) export markets are not a viable alternative source of gas demand.

National electricity production in 2009 was 225 TWh, of which 206 TWh was generated in the NEM. Coal's share of this production was 169 TWh. Per Capita has examined the implications of a 50% substitution of this coal production with distributed gas trigeneration (see Chart 1 below). This requires 84.6 TWh p.a. to come from trigeneration units. If each unit comprises a 1MW generator with a 500 kW exhaust absorption chiller for trigeneration, we would require the installation of 8,050 units to produce 84.6 TWh p.a. (assuming an 80% capacity factor). This would involve a capital investment of around $14.1b, not cheap but no more than 7-8 new coal-fired power stations.

As we shall see below, with the right market design, this investment would be willingly provided by the private sector rather than acting as a drain on the public purse. Most significantly, this substitution would reduce Australia's greenhouse gas emissions by 50 million tons of CO2-equivalent per annum, almost 10% of Australia's annual emissions (548 mt CO2-e).

Chart 1:
Australian Electricity Production Suitable for Substitution with Distributed Gas (2009)

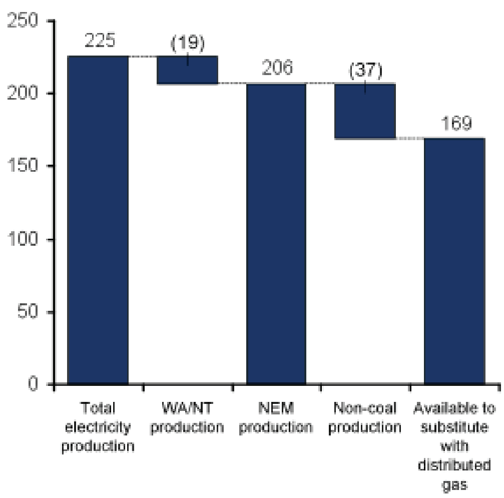
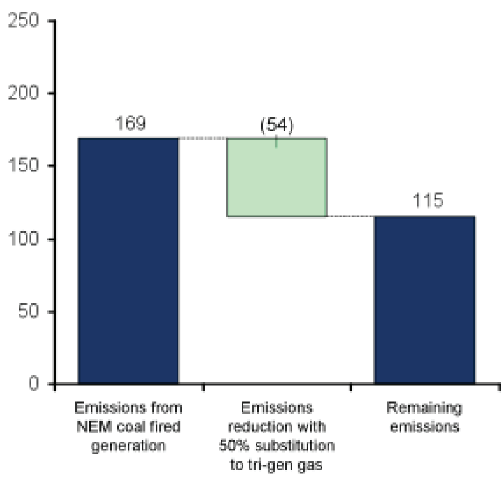


Chart 2:
GHG Emission Reductions from a 50% Substitution to Distributed Gas Trigeneration (2009)



Sources: ABARE, The Climate Group, Department of Climate Change, Per Capita analysis

The additional gas supply is likely to come from coal seam methane sources in NSW and QLD, as new reserves are discovered and commercialised. The CSM share of total gas production has grown from 2% in 2002-03 to 9% in 2008-09 and six new projects are currently planned across NSW and QLD.

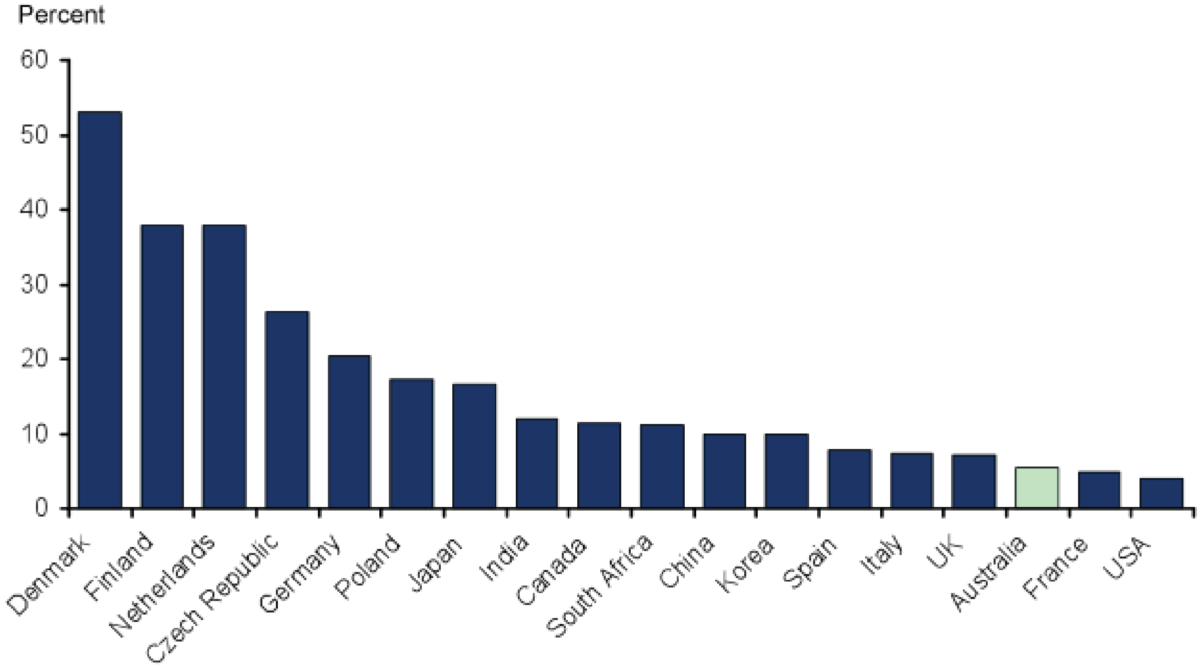
International experience of distributed generation

One common question raised by those unfamiliar with distributed generation is whether it's just another quirky idea that might work in theory but would be impossible to implement in practice.

International experience shows that distributed generation can provide a sizeable share of national electricity (and heat) supply. In Denmark, distributed generation accounts for 53% of electricity generated and 75% of all heat production. In Finland and the Netherlands, its share of electricity production is 38%.

In Australia, by contrast, the equivalent share is 5% (see Chart 3 below). The European Environment Agency observes that, "Poor infrastructure for natural gas, unhelpful electricity market structures and less demand for heat…has historically hindered CHP [cogeneration] development. Combined Heat/Cooling-Power Conversion may help utilise additional heat production in summertime and in warmer countries…" (EEA, 2010: 1) Australia has strong natural gas infrastructure and can apply tri-generation to produce cooling in summer. It is these "unhelpful electricity market structures" that hold back distributed generation in Australia.

Chart 3:
Distributed Energy Share of Total Power Generation
Selected Countries (2006)



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Section III:
The full-cost economics of gas versus coal

If the gas resources are available and the technology can be acquired off the shelf, why has this shift towards distributed gas-fired power not already happened? It is because the prevailing economic structure has dictated that gas is a 'peak' fuel only, and that coal is most suitable for base-load demand. This is a function of the relatively low capital costs and high operating costs of gas relative to coal.

These economics assume a centralized model of generation, with a small number of large generators producing electricity far from the source of demand. An extensive distribution network then transports this electricity to users. This structure is a legacy of market design from the early 20th century.

This legacy is the only reason why generation continues to be centralized. If we remove the assumption that decentralized generation can't deliver baseload power, the economics change completely. Gas-fired power, with centralized and distributed plants working in tandem, becomes far more cost-effective and the scope for significant emissions reduction increases dramatically.

Gas-fired generators can be built at extremely small scale, down to a size of about 2 kWh. A small car engine, by comparison, would deliver 25-40 kWh. For the purposes of this paper, we have modeled a 1MW generator which is about the size of a shipping container. If these units can be placed on-site in office buildings, schools and hospitals, these institutions will be able to meet their own demand and sell any surplus back into the grid. The fuel would be delivered through the existing gas network.

To test the economics of this proposal, Per Capita has compared the cost base of five methods of electricity production:

- Centralised black coal production
- Centralised brown coal production
- Centralised gas production (combined cycle gas turbine or CCGT)
- Distributed gas production
- Distributed gas production with trigeneration

For each method, there are four principal components of cost: capital cost of generation, operating cost of generation (fixed and variable), transport cost and an optional carbon cost. We have also included the impact of losses during transport through the transmission and distribution network. The assumptions underlying these costs are outlined in Table 1 below.

Table 1: Assumptions on Generation Costs by Fuel Source

	Units	Black coal	Brown coal	CCGT	Distributed gas	Distributed gas tri-generation
Capital cost (Installed)	$/kW	1,850	2,050	1,200	1,500	1,167
Operating life	Yrs	50	50	25	30	30
Capacity factor	%	80	87	80	80	80
O&M cost	$/MWh	6.60	6.00	7.80	15.00	10.00
Fuel cost	$/MWh	$9.00/mWh	$5.80/mWh	$22.00/mWh	$6.00/GJ	$6.00/GJ
Heat rate	kJ/kWh	n/a	n/a	n/a	10,900	7,300
Emissions factor	Kg CO2e / kWh	0.80	1.00	0.40	0.54	0.36
Carbon price	$ / ton CO2e	20	20	20	20	20
Transmission cost	$/kWh	0.008	0.008	0.008	0.00	0.00
Distribution cost	$/kWh	0.051	0.051	0.051	0.00	0.00
Transmission & distribution losses	%	9.4	9.4	9.4	0.00	0.00

Sources: AER, EIA, CSIRO, Garnaut Report, NEMMCO, Per Capita analysis

The breakdown of the costs analysis is outlined below, beginning with capital costs. The large centralized generators have higher installed capital costs per unit of capacity than small gas-fired systems. The large generators' capital costs range between $1,200-2,050/kW while the small gas systems are around $1,200-1,500/kW.

Secondly, we examine the various elements of operating cost – fuel, operations and maintenance. Our fuel cost assumptions are $9.00/MWh for black coal, $5.80/MWh for brown coal and $22.00/MWh for gas. As expected, coal's non-fuel operating cost at $6.00-6.60/MWh is somewhat lower than CCGT at $7.80/MWh, and far lower than distributed gas with tri-generation ($10.00/MWh) and without ($15.00/MWh).

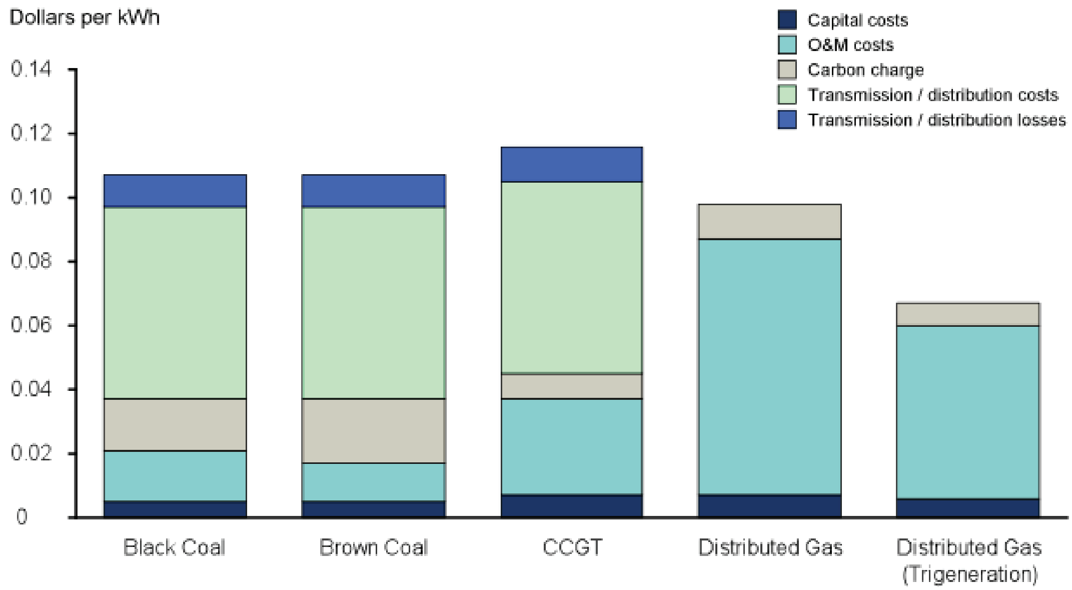
Energy transport costs are straightforward. The average transmission and distribution cost for power generated at large, centralized stations is $0.59/kWh. The transport cost for distributed power is zero as the power is produced at the point of demand.

However, the picture is more complex than that. On average, around 10% of generated power is lost in transmission and distribution which means that extra power must be produced under centralized generation in order to deliver the required power to the point of consumption. This effectively increases generation and transport costs by 10%, and significantly, produces additional carbon over and above the amount needed to deliver the required power. While new black coal centralized generators produce 800kg of CO_2 per MWh, new distributed gas generators with trigeneration produce only 360kg, a 60% reduction.

For the purposes of this analysis we have assumed a carbon price of $20/ton, resulting in carbon costs ranging from 2.0c/kWh for brown coal down to 0.8c/kWh for distributed gas.

Combining these costs gives us an overall picture of the delivered cost of alternative power generation methods (see Chart 4 below).

Chart 4:
Levelised Cost of Newbuild Electricity in Australia by Fuel and Technology



Sources: AER, EIA, CSIRO, Garnaut Report, NEMMCO, Per Capita analysis

The full levelised cost of coal generation is around 10.7 cents per kWh. Centralised gas generation is more expensive at 11.5 cents. The two least expensive generation sources are the distributed gas options. Without trigeneration, the cost for distributed gas at 9.8 cents per kWh. Once trigeneration is included, the cost falls to 6.6 cents per kWh, as the waste heat can be recycled to produce heating and cooling, displacing further electricity usage.

The attractiveness of the economics of distributed gas raises important questions, especially if the fuel and technology are readily available and it has the potential to dramatically reduce our greenhouse gas emissions as outlined in Section II above. If the economics are so good, then why hasn't distributed gas already penetrated our electricity mix to any meaningful extent?

Section IV: Market Design Challenges

There are at least five weaknesses in the current design of energy markets that inhibit the growth of distributed gas-fired power:

- Barriers to entry for new producers
- Distorted electricity pricing structures
- Information gaps
- Subsidies to existing producers
- Failures to capture externalities

Barriers to entry

The most significant impediment to the growth of distributed gas-fired power is the reluctance of existing electricity retailers to facilitate a connection to the grid by new distributed generators. There are a range of legitimate technical assessments which are required by existing retailers to ensure the safety of their staff in installing and maintaining new connections. However, there is also a powerful incentive for retailers to limit the number of new connections as each one equates to a permanent loss in revenue for the retailer. Retailers and other upstream operators also express concerns about security of supply into the grid by micro-generators. (This argument is unconvincing since eventually the growth in micro-generators will ultimately improve, rather than diminish, overall security of supply.)

The upshot is that existing retailers have no incentive to assist new generators to connect to the grid. They are likely to make it as costly and time-consuming as possible to commission new micro-generation capacity. The solution to this predicament is to address the incentives faced by the retailer to ensure they have a shared interest in facilitating new connections.

The challenges of connecting to the grid

The enormous challenges faced by small distributed generators in connecting to the grid are widely recognised. These challenges arise because it is not in the interests of electricity distribution companies (known as distribution network service providers or DNSPs) to promote potential competitors by facilitating access to the grid. As the Australian Energy Market Commission (AEMC) observes in a study in understatement, "DNSPs have no incentive to minimise the costs of connecting embedded [distributed] generators." (2008: 45).

To overcome the barriers presented by reluctant DNSPs, the AEMC recommends that they be required to offer a single standardised connection service across all jurisdictions for small distributed generators. This is a welcome initiative, but it is not enough. Instead, DNSPs must be rewarded by governments for prompt connections (which create social value) and penalised for slow ones (which destroy it).

Distorted pricing structures

The current pricing structure of electricity discourages micro generation at several levels. The most serious is that micro generators do not receive a market price for their entire production. Instead, in all states and territories except the ACT, micro generators are only paid for the surplus electricity that they supply back into the grid. As they are not paid for the power they produce on site, they implicitly receive a below-market price for this share of their production. This undermines the economic return on their investment, reducing the incentive to install generators on-site.

A second distortion is that electricity pricing does not typically reflect cost variations based on changing demand during the day and across the seasonal cycle. Electricity demand is greatest on the hottest and coldest days of the year, and is higher in the evening than during the day. Production costs rise during these peaks as higher-cost generators are used, and transport networks are stretched to capacity (and beyond).

Under a full-cost economics approach, pricing would reflect these cost variations of seasonal demand. This would have a twofold effect. It would act to dampen demand by increasing price during peak periods. And it would stimulate supply, particularly from micro generators, by offering higher margins to those able to produce in those periods. Loads on the electricity grid would be lower in high-demand periods, reducing the need to expand capacity at great expense solely to meet these seasonal peaks.

Information gaps

One of the benefits of pricing that reflects full economic cost is that it informs both consumers and producers of the true value of their actions. Ignorance of the economic opportunity is yet another impediment to the adoption of distributed generation.

Currently, the most viable adopters of distributed generation are small-scale industrial sites, hospitals, schools, universities, multi-story commercial buildings and apartment blocks. But none of the facilities managers on these sites are likely to be aware of the opportunity presented by distributed generation, and if they are, they may feel the potential benefit is hardly worth the effort.

Information on the costs, demand and emissions profiles of their current electricity consumption is patchy at best; the same goes for feed-in tariff regimes (where governments pay localized generators for their electricity output). So it is particularly difficult to assess how one's own on-site production may compare with electricity purchased from the grid.

What is needed is better information on both the profile of their existing supply, and the costs and income likely to be involved with on-site generation.

Subsidies to existing producers

A further distortion to the full-cost economics of the sector occurs as a result of public subsidies provided to electricity providers throughout the supply chain. These subsidies are both explicit, in the form of direct payments, and implicit, in the form of discounts and guarantees.

It is widely understood that generators receive cooling water at sub-market prices. Transmission and distribution companies receive a guaranteed return on their installed capital base, providing an incentive to continue to expand the capital base over time. This approach fosters an inexorable growth of the energy transport network over time; it provide little incentives for transmission and distribution companies to explore alternatives which reduce the volume of electricity moving through the grid.

The hidden value of implicit subsidies

A principal reason that electricity has been relatively inexpensive in Australia is that generators have benefited from several implicit subsidies that have kept prices down. These subsidies create market distortions by tilting the playing field in favour of the incumbent generators.

The first implicit subsidy is in the foregone revenues of export coal sales. Most generators source coal from state-owned or company-owned mines at or near the power station. This coal is typically passed on at cost, which is generally at or below $20/ton. However, Australian export coal has traded above US$120/ton this year. Even allowing for transport costs, this represents a foregone margin of at least $80/ton. Given that around 63Mt of black coal is used by Australian electricity generators, this represents foregone revenues of $5.0 billion p.a. By requiring coal assets to be used domestically in power generation, governments are effectively giving up $5 billion. By artificially holding input costs down, they are distorting the economics of Australia's energy sector.

The second implicit subsidy is that coal-fired generators use vast quantities of fresh water at prices considerably below the market value of that water. Coal-fired generators use around 235,000 ML of water in their production processes at an average efficiency of 1.5ML/GWh (NWC, 2009). The marginal value of this water entitlement is estimated at between $14,000 and $18,000/ML, yet the generators can acquire it for around $1,500/ML (NWC, 2009). At a value of $16,000/ML, the perpetuity value of this subsidy is $3.4 billion. This means that with a capital charge of 8%, the annual value of water subsidies to the generators is over $270m.

Externalities

The most significant design flaw in Australia's energy markets is so widely discussed that it needs little further explanation here. Carbon dioxide emissions are a social cost – in the jargon, a negative externality – which electricity generators impose upon our community without any form of compensation in return. The environmental implications of these emissions are now well understood but, since the generators do not bear this cost directly, there is no economic incentive for them to reduce their emissions. The lack of response to this market failure has proven an ongoing weakness in the design of energy markets, one which demands immediate attention.

Section V: Policy Recommendations

Carbon price: A carbon price in the electricity generation market is critical for two reasons. It will help Australia reduce its overall carbon emissions and it will result in a more efficient allocation of capital within the generation sector which more accurately reflects the full costs of production.

The Federal Government is planning to introduce a carbon price during the current Parliament, although the passage of this legislation is dependent on negotiations with the Greens and the Independents.

A keenly contested issue in the debate over a carbon price has been whether a cap and trade system is preferable to a direct tax on emissions. While a tax has the advantage of being administratively simpler, its weakness is that it does not force a reduction in emissions across the whole economy in the way that a cap does. For this reason, we favour the cap and trade approach. Proponents of a tax point to the European experience of cap and trade, and argue that it is likely to be less volatile. However, there is no good reason why producers should expect low volatility in a carbon price. All commodity input prices are inherently volatile and carbon should be no different.

Cap and trade appears to be the approach Australia is likely to take under the Gillard government, but in either case, two elements are crucial to the policy design. Firstly, the price must cover all generation fuels with no exceptions. This is critical in order to provide a level playing field for all energy technologies. Secondly, and related to the previous point, excessive compensation to existing fossil fuel generators must be avoided. A payment of significant compensation to these producers has the effect of giving them an implicit discount (or even exemption) on the carbon price.

Water pricing: In the same way that a carbon price is necessary for a fully-costed energy market to evolve, a water price is equally important.

All inputs into the production process must be costed at their full market value. We need to explode the myth that Australia's economic development can or should be built upon cheap energy. In theory, it sounds wonderful but it only holds if the energy is truly cheap on a full-cost economics basis. If so, Australia possesses a genuine competitive advantage on energy; if not, we don't.

As an illustration, what if we charged Victorian brown-coal generators the same water price that Melbourne residents pay for fresh water, minus a reasonable discount for volume? Well, Victorian electricity would not be nearly so cheap. An analysis of the total value of the discounted water provided to coal-fired generators suggests they enjoy an implicit subsidy of almost $300m p.a. (see "Hidden Value of Implicit Subsidies" above).

The water pricing policy should require that if the producer is not using company-owned or closed-loop recycled water sources, then they should pay fully-costed market rates for their water inputs. These prices should be transparent, rather than commercial-in-confidence, and available to all producers.

Incentive structures for retailers: Regulators should institute a reward/penalty scheme for the processing of new grid connections by retailers. Those retailers who complete a new connection in under three months would be paid a bonus, perhaps $5,000, for rapid completion. For connections completed between three and six months, no bonus would apply. For each additional month beyond six months, retailers would be penalized $5,000.

Furthermore, retailers would be required to approve 80% of all applications over a 12 month period. This would give retailers room to deny certain applications on safety grounds, but would ensure that a reasonable minimum of all applications is approved.

Gross feed-in tariffs: Australian states and territories must legislate for gross feed-in tariffs which pay small-scale generators a predetermined rate for their entire electricity production. Some have already begun this process, with the ACT being the exemplary jurisdiction to date.

The tariff rate is usually fixed at a level intended to provide a payback on investment over a set period (usually 10-20 years). This rate is usually above the wholesale price received by centralized generators. In a pure market context, both centralized and distributed generators would receive a market price determined by the supply and demand balance. However, as centralized generators receive a contracted price supported by a range of (explicit and implicit) subsidies, it is reasonable that distributed generators which do not benefit from subsidies receive a higher price.

Like a carbon price, feed-in tariffs should be neutral to fuel sources (although they should include the carbon price where appropriate). It is not the intention of a feed-in tariff regime to favour particular technologies, but to stimulate alternative and competitive production. This has not been the case with most feed-in tariff schemes in Australia to date, which have supported specific technologies, notably solar PV.

It is important that a feed-in tariff scheme operates on a gross rather than a net basis. This means that operators of distributed generators receive payment for their gross exports of electricity to the distribution network, rather than simply on those exports above their own consumption levels. This means that the tariff (and investment payback) is applied to the totality of their production, and therefore their entire investment rather to a limited percentage of it.

Aggregating procurement: Government has an opportunity to facilitate the uptake of DGP through its procurement policies. Firstly, the construction of 19,000 new dwellings and refurbishment of 70,000 dwellings through the Social

Housing Initiative offers an excellent opportunity to introduce DGP into residential communities. The design of these communities will involve shared services facilities throughout and the incorporation of DGP is a straightforward step.

Secondly, the establishment of a public/private energy aggregation company to pool demand would further facilitate the spread of DGP. This organisation would offer developers of residential apartment complexes, commercial office towers and industrial facilities an integrated package whereby it installs and maintains an on-site gas-fired generator and shares the electricity savings with the developer and/or occupiers.

Interval pricing and smart meters: Across a range of public services, pricing is increasingly differentiated across peak and off-peak periods under an approach known as interval pricing. This is most clearly seen in transport, where rail and bus fares, road tolls and congestion charges are often determined on a time-of-day basis. In industries with fixed capacity, the private sector has long used these pricing structures – an air ticket is more expensive in June than in October, and more expensive at 7am than at 11am.

The economic basis for interval pricing is well understood. By offering capacity in peak periods at higher prices, producers ensure that peak access is used by those consumers who value it most highly. Demand is displaced from peak to non-peak periods, ensuring that usage is spread more effectively across the available capacity and lengthening the life of the asset. This pricing covers the full cost of production, including the externalities caused by congestion.

Electricity distribution networks experience peak and off-peak periods similar to transport systems. There are daily peaks in the late afternoon/early evening, and seasonal peaks in mid-winter and mid-summer. Recognising this, most electricity retailers in Australia already have some form of interval pricing in place. In NSW, for example, Energy Australia's PowerSmart Home package charges peak rates (36.6c/kWh) from 2-8pm on weekdays, off-peak rates (8.0c/kWh) from 10pm-7am everyday and shoulder rates (13.6c/kWh) at all other times (Energy Australia, 2010).

However, we can go much further with interval pricing, allowing us to better manage the existing capacity in our network and to foster the growth of low-carbon distributed power. We should introduce seasonal pricing variation alongside intra-day pricing variation. This would further smooth the demand profile by reducing demand on those days of temperature extremes in mid-summer and mid-winter.

As a complement to this pricing approach, our feed-in tariff should be graduated to pay distributed producers higher rates at peak times. This would stimulate additional supply from these producers during periods of high demand, and potentially draw additional distributed producers into the marketplace.

To ensure that both producers and consumers can respond to these price signals, we should roll out smart meters, which inform consumers (and producers) of how much electricity they are using (producing) at any point and the relevant price they are paying (receiving) for that electricity at that time of day. Victoria has commenced this process, announcing a four year roll-out of smart meters to 2.2 million homes and 300,000 businesses from September 2009. This initiative is expected to generate a net benefit of $700m over 20 years. (Oakley Greenwood, 2010).

Section VI:
Conclusion - Energy and a progressive Australia

Why do energy markets matter so much to Australia's future? How do energy markets help determine the kind of country we become? At first glance, they seem far removed from questions of fairness and prosperity.

Yet, if we want to build a more prosperous and fairer country, energy markets are an important, often unheralded, area for action. The arguments for addressing energy market design fall into two main categories: economic growth and social justice.

Energy production is inherently an inefficient business. Depending on technology, coal-fired power generation recovers 26-41% of the fuel's embedded energy, while gas-fired processes recover 46-72% (Treasury, 2009). Around 9-10% of the remaining energy is lost during transmission and distribution. As fossil fuels are both scarce and polluting, any increases in energy efficiency are highly desirable. This point is not novel – scientists have been working at it for years. It is worth reminding ourselves, however, that new approaches which move away from coal technologies and/or reduce electricity transport requirements are likely to lift system efficiency and in turn economic growth.

A further point is that job-creating growth is preferable to job-free growth, all other things being equal. In earlier work, Per Capita has shown that there is a psychological and social value to employment that makes job creation an important consideration in any economic policy development (see Hetherington, 2008). Modern electricity production is not a labour-intensive activity, employing less than 35,000 Australians (DEEWR, 2010: 5), so any reforms that increase efficiency and jobs are surely welcome. We will argue that a new market design in the energy sector can create jobs while delivering cheaper electricity and reducing carbon emissions. This will stimulate economic growth and help to rebalance the returns to labour relative to capital which have fallen considerably in recent years.

The second set of arguments concerns social justice - the underlying equity of energy market design. Under the present market structure, many incumbents are protected from open competition and some receive generous subsidies from taxpayers under 'guaranteed rate of return' arrangements. The monopolistic nature of electricity networks provides an historical justification protecting these producers at the expense of consumers and taxpayers. Decentralized networks will enable greater competition, allowing 'supernormal' profits to be returned to taxpayers and consumers, a far more equitable outcome.

The greatest inequity in our electricity market is surely carbon emissions. The sector accounts for 37% of Australia's total greenhouse gas emissions, producing 204Mt of CO_2-equivalent in 2008 (DCC, 2010: 7). By maintaining a high-carbon energy system, we continue to add to the stock of carbon in the atmosphere and the detrimental effects on our climate to be borne by our children and grandchildren.

In economic terms, this is a classic negative externality – but it comes with a twist. Most negative externalities temporarily inhibit a third party's welfare, but carbon emissions appear to permanently reduce the welfare of future generations. As many of those who bear this externality have not yet been born , they are unable to defend their interests by advocating its removal. So while our carbon production is forgivable since we did not understand its effects, the failure to reduce emissions now we comprehend the effects is grossly unfair to our kids and theirs.

A separate concern over equity relates to the proposal for feed-in tariffs raised in Section V. A common argument holds that feed-in tariffs are regressive because the taxpayer subsidy flows to those wealthier households who can afford the upfront investment in a domestic generation kit: it is an upward redistribution. This is likely to be true, but it ignores another dimension of equity – intergenerational equity. If we refuse to act to curb greenhouse gas emissions, we are likely to bequeath subsequent generations with dangerous climate change and unpredictable ecological damage. The scale of this intergenerational inequity outweighs the impact of inequity caused by the regressive nature of feed-in tariffs. Consequently, feed-in tariffs remain a good idea.

The design of energy markets is clearly important, on the grounds of both economics and fairness. If we are to set Australia on the transition path to a low-carbon economy, we must level the playing field to ensure that low-carbon energy sources like distributed gas and big wind are not crowded out by poor market design.

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