EUAA
ENERGY USERS ASSOCIATION
OF AUSTRALIA

Submission to AEMC Scoping Paper for the Review of Energy Market Frameworks in light of Climate Change Policies

November 2008

EXECUTIVE SUMMARY

The introduction of a price on greenhouse gas emissions, combined with the expansion of the renewable energy target will provide strong incentives for the development of combined cycle gas turbine and renewable generators. This will in turn lead to significant development in gas processing and pipeline capacity, and also in electricity transmission networks.

These are step changes. They will result in significantly higher energy prices and possibly a reduction in the reliability of supply during the transition to a lower emission electricity industry.

The Ministerial Council on Energy (MCE) has requested that the Australian Energy Markets Commission (AEMC) review Australia's existing energy market frameworks to assess whether they should be amended to accommodate these structural changes.

This document is the Energy Users Association of Australia's response to the AEMC's request for comments on its Scoping Paper.

We think the key issue for this review is to assess whether the existing frameworks will ensure that properly co-ordinated decisions will be made. The areas where co-ordination will be important include:

- The investment and operating decisions by transmission network service providers that affect generators and vice versa;
- The competition between centrally dispatched generation versus distributed generation and demand response;
- The choice between investment in gas pipelines or electricity wires;
- NEM-wide co-ordination of investment by regional transmission network service providers.

If the investment response by generators and transmission service providers are unco-ordinated the outcome will be lower efficiency and higher costs overall.

These co-ordination challenges are not new. They arise, mainly, from the decision to split transmission from generation in order to facilitate competition in electricity production and sales. Many of these co-ordination challenges have been actively debated since the creation of the national electricity market. But, the introduction of emission prices and the expansion of the renewable energy target are step changes, that remain poorly understood.

In the rest of this submission, we describe the co-ordination challenges in greater detail, and provide our response to the eight issues described in the Scoping Paper.

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1 Introduction

The Ministerial Council on Energy (MCE) has requested the Australian Energy Markets Commission (AEMC) to review Australia's existing energy market frameworks to assess whether they should be amended to accommodate the changes likely to follow the introduction of a Carbon Pollution Reduction Scheme (CPRS), which will put a price on greenhouse gas emissions, and the expanded mandatory renewable energy target (MRET).

The outcome of the review will be advice to the MCE on changes to the energy market frameworks covering gas and electricity markets, gas pipelines and electricity transmission. The final report is due in September 2009, with various interim reports and other consultation between now and then.

This document is the Energy Users Association of Australia (EUAA) submission to the AEMC's Scoping Paper for this review. The EUAA is a non-profit organisation funded by membership fees, internally generated revenue and external funds. It is focused entirely on energy issues and was formed in 1996. The Association members are business users of energy with activities across all states and many sectors of the economy. The EUAA has over 100 members and this includes most of the nation's largest users.

Pricing emissions and the expanded MRET will have a significant impact on energey price and reliability. These will impact our members' commercial operations in Australia, and in some cases could also have an impact on their continued viability. If energy markets do not function well and are not well placed to respond to the challenges of Australia's climate change response, the resultant higher prices and inefficiencies will impose even higher costs on energy users. Our members are heavily involved in energy markets in Australia – both electricity and gas – as major energy users and major purchasers of energy. The impact of the CPRS and expanded MRET on energy markets is therefore important to EUAA members including aspects such as the efficient operation of these markets, access to competitively priced energy and also continued surety of reliable supply.

Sections 2 summarises our thoughts on the main issues for this review. Section 3 sets out our response to the questions in the Scoping Paper. The appendix provides analysis and information to support our views.

2 The main issues for energy users

The objective of the national electricity market is to promote efficient investment in and use of electricity services for the long-term interests of consumers of electricity with respect to price, quality, reliability, safety and security.

A number of exogenous factors are likely to result in significantly higher energy prices in future. These exogenous factors include the:

- prospect of higher gas prices if significant liquefied natural gas capacity is developed;
- introduction of a price on emissions;
- expanded renewable energy target; and
- the recent global financial crisis that has devalued Australia's currency and raised the cost of capital.

These exogenous factors can be expected to drive rapid structural change and a massive capital investment program in both generation and transmission. Effective co-ordination will be critical in delivering the NEM objective. We think that the main issue for this review is to assess the extent to which the existing market and regulatory arrangements will result in efficiently co-ordinated decisions. The main dimensions of this co-ordination are:

- The decisions by transmission network service providers that affect generators and vice versa;
- The competition between centrally dispatched generation versus distributed generation and demand response;
- The choice between investment in gas pipelines versus electricity wires;
- National co-ordination of regional transmission network service providers.

2.1 Generation and transmission decisions must be co-ordinated

As described in the Appendix, emission prices and the renewable energy target will induce investment in generation sources – both gas and renewables – distant from existing networks. This is likely to lead to significant demand for additional transmission investment to cater for changed power flows. Generation and transmission are in many circumstances substitutes and complements. The separation of the ownership and control of generation and transmission – a condition for generation competition - creates co-ordination problems. The AEMC needs to examine whether the current arrangements are likely to lead to decisions that result in efficient supply to users. The issues that the AEMC should examine here include:

- Connection charging policy (shallow versus deep connection charges) and the obligation for connecting generators to finance any reduction in the capacity of shared networks[1];
- Whether generators should share in the transmission use of system charges in order to provide stronger locational signals;
- Whether the system of marginal loss factors combining regional and inter-regional elements provides the correct locational signals from a NEM-wide perspective;
- Whether the restriction on TNSP's ability to own or contract with generators should continue to apply, or whether it should be relaxed in some way;
- Whether the pass-through arrangements for network support by generators result in co-ordinated decisions not just in deferring network investment, but also in permanently avoiding such investment;
- Whether it would be appropriate for NEMMCO/AEMO to take on an obligation to minimize network congestion including through contracting with generators, as does National Grid Transco in England and Wales.

[1] This is our understanding of the "causer pays" principle described in Rule No 22 (Pricing of Prescribed Transmission Services).

2.2 Central generation and distributed generation must compete fairly

Federal and state government policies to promote distributed generation technologies such as solar PV feed-in tariffs or solar water heaters have been uncoordinated and changeable. Australia has also made little progress in the development of co-generation and combined heat and power, despite the significantly greater efficiency that such opportunities offer.

Some state governments have created (generally inconsequential) incentives for network service providers to promote distributed generation and demand side management. A bias in favour of central generation and transmission remains, as a result mainly of the financial incentives provided to transmission network services providers to develop and own transmission assets.

The MRET and CPRS will provide financial incentives for solar water heaters, distributed biomass generation, photovoltaics, and co-generation. Technology and commercialization advances in these areas may strengthen the competitiveness of these technologies. The AEMC should consider whether:

- Investment incentives for network services provided under Chapter 6 of the Rules hinder the development of distributed generation technologies.
- The incentives for demand-side response need to be strengthened, including through changes to the regulation of network service providers.
- Federal and state government policies on distributed generation technologies including feed-in tariffs should be harmonized.

2.3 Access arrangements should support efficient choice between gas pipelines and electricity wires

The rapid development of base-load gas generation capacity will promote convergence of the electricity and gas markets. However, the access arrangements for gas pipelines and electricity transmission networks are quite different. Most major gas pipelines are unregulated. Electricity transmission revenues are regulated, with shallow connection charges, non-firm generation access, marginal loss factors and no charge for the use of the shared network[2]. In many generation applications, gas pipelines and electricity transmission wires are substitutes. The AEMC should examine the extent to which differing access arrangements are likely to lead to inefficient investment and operating decisions.

2.4 Transmission investment must be nationally co-ordinated

The progress towards national transmission planning has been slow. Both the Parer and ERIG reviews concluded unequivocally that centralized transmission planning across the NEM would be beneficial. Their recommendations have not been implemented. Jurisdictional planning bodies retain hegemony over investment within their areas of jurisdiction. Significant barriers to co-ordination between state-based entities exist, including from the misalignment of costs and benefits for those transmission augmentations that occur in one jurisdiction, but whose benefits accrue to market participants outside that jurisdiction.

There is reason to doubt that the creation of a national transmission planning advisory body within AEMO will have access to information, the organisational capacity or the executive authority to counter the incentives for parochialism under the existing arrangements. In view of the significant changes to power flows likely to result from investment in renewable capacity and gas, and the consequential network investment that may result, we suggest that the AEMC should examine again the balance of costs and benefits of continued state-based transmission planning arrangements.

[2] Unless a new connection causes a reduction in shared network capacity.

3 Answers to Scoping Paper questions

3.1 Issue 1. Convergence of gas and electricity markets

1. How capable are the existing gas markets of handling the consequences of a large increase in the number of gas-fired power stations and their changing fuel requirements?

We suggest the main issues here are as follows:

- The need for much deeper short term markets to trade over-runs and under-runs: Arguably there has not been much demand for such short term trading mechanisms given the multi-day line pack storage in most long distance pipelines. The AEMC should take a leading role in developing such market mechanisms.
- In response to rapid changes in demand, other security of supply infrastructure such as underground storage and LNG reinjection facilities - such as the Dandenong facility - may become valuable. The AEMC should investigate whether the market arrangements are likely to deliver such investments.
- The price and availability of gas, considering the potential large scale export of coal seam gas from Queensland and possibly New South Wales.
- The emergency rationing arrangements and specifically the relative priority of gas supply to electricity generators versus other customers.

2. What areas of difference between gas and electricity markets might be cause for concern and how material might the impacts of such differences be?

Besides the issue of poor price discovery and the absence of effective short term gas markets – discussed above - the EUAA's main concern on the difference between gas and electricity markets relates to the differences in the regulatory frameworks for electricity network and pipeline access. As the gas pipeline infrastructure develops, there may be a case to consider the benefits of the regulated access such as those in Victoria. However, this may not be a short-term priority.

3.2 Issue 2: generation capacity in the short term

3. What are the practical constraints limiting investment responses by the market?

The EUAA is not overly concerned that investment in CCGT capacity or renewables will not arise in response to incentives provided by emission prices and RECs. Rather the main issue for users is that the most efficient investment decisions are made. Our main concerns in this area is the vertical integration of generation and retail and the resulting barrier to entry to independent power producers.

Notwithstanding this, we realize that the global financial crisis may have made it considerably more difficult to raise capital, and that financing the purchase of emission permits may provide additional strains.

Generation/retail integration particularly in South Australia and Tasmania gives AGL and Aurora respectively a monopsony in the acquisition of generation in these markets. The EUAA is concerned that this provides a barrier to entry by independent power producers in these markets. As discussed earlier, we have similar concerns in NSW where incumbent retailers (County Energy, Integral and Energy Australia) have retained almost complete dominance of the supply to customers within the area of their historic monopoly.

We are concerned that the failure of the NSW Government to reform the electricity industry in NSW may deter new generation entry in NSW. Important point

We suggest that the main practical constraint limiting renewable investment is transmission access arrangements. This issue is covered in greater detail in our answers to Questions 4 to 7.

4. How material are these constraints, and are they transitional or enduring?

The transmission access constraints are potentially enduring. These are discussed in greater detail below under Issue 4.

The policy uncertainty in NSW is of considerable concern, considering the significance of demand and supply in NSW, on outcomes throughout the NEM.

5. How material is the likelihood of a need for large scale intervention by system operators? How likely is it that this will be ineffective or inefficient?

In the short term (over the next five years) we do not necessarily see a significantly enhanced role for NEMMCO in managing the system to ensure security of supply to cope with supply shortfalls. Beyond this time however, there may be significant scope for system operator intervention in response to significant new investment in renewable capacity and base load gas generation, possibly accompanied by the closure of significant tranches of coal thermal capacity, or a reduction in the availability of that capacity. The AEMC should review whether NEMMCO's ability to procure reserves is likely to be an efficient and effective way to ensure supply security.

3.3 Issue 3: Investing to meet reliability standards with increased use of renewables

6. How material is the risk of a reduction in reliability if there is a major increase in the level and proportion of intermittent generation?

As discussed in Section 2, CME project wind generation entry (the main intermittent renewable resource) of between 6,700 MW and 8,900 MW by 2020 – on the assumption that the MRET target is met. Actual investment may be significantly lower than this in view of supply-chain bottlenecks in the wind industry (access to erection equipment, turbines etc.) and possibly also because of transmission connection bottlenecks.

On the basis of expected NEM-wide simultaneous maximum demand, by 2020 the aggregate diversified maximum production from wind resources is likely to be a small proportion (probably less than 10% - basis for this?) of the aggregate diversified maximum wind production. On the assumption of largely unconstrained NEM transmission networks, this would suggest limited risk of a reduction in reliability from the rapid entry of wind generation.

However, if much of this additional wind capacity is located in South Australia, and if there is no expansion of the interconnection to Victoria and if there is inadequate investment in spinning reserve in South Australia, then it may be that rapid entry of wind generation in South Australia could threaten the reliability of electricity supply in South Australia. This may not necessarily jeopardize supply reliability in other parts of the NEM, but could have an impact, possibly significant, on prices in other parts of the NEM.

It is difficult to be certain on whether or not, there will be very significant entry of wind generation in South Australia particularly. CME suggest that of the 12,700 MW of prospective future wind capacity, 4050 MW is located in Victoria and 3700 MW is in South Australia. If all of this capacity entered South Australia and Victoria then in the absence of major network investment and/or major investment in back-up and spinning reserve, there is likely to be a significant threat to the reliability of supply. However there are reasons to believe that future wind entry may not be disproportionately located in South Australia:

- Significant wind entry in South Australia accompanied by constrained interconnectors would result in a price collapse in South Australia. There is limited ability to hedge inter-regional price risk in the NEM. Wind developers may therefore invest elsewhere even if the wind resources are not as good as may be available in South Australia;
- Some wind developers – such as Epuron with its proposed 1000 MW Silverton wind farm in NSW - suggest that parts of Australia not commonly seen as having high quality wind resources, may actually have such resources. The Australian wind industry is at an early stage in its development. Better knowledge of wind resources combined with developments in turbine design to

cater for lower winds may alter the attractiveness of other parts of the NEM relative to South Australia.

These issues are complex and merit a deeper engineering-economic examination.

On the narrow issue of the reliability of electricity networks, we do not think there is a significant issue here. Transmission network service providers can be expected to invest to develop electricity networks to ensure the necessary levels of redundancy of the electrical systems within their area of jurisdiction. The existing "causer pays" provisions in the Rules will allocate the cost of investment needed to make good any loss in shared network capacity, to new entrants. While such provisions can be difficult to implement in practice, the provision exists for entry to be delayed if it is expected to detrimentally affect the reliability of the shared network.

7. What responses are likely to be most efficient in maintaining reliability?

We have no strong views on this. Instead we suggest possibilities for further analysis as follows:

- **Stronger interconnection:** The threat to reliability posed by concentrated amounts of intermittent generation in some NEM regions such as South Australia can be reduced through much stronger interconnection. However, considering the considerable distances between the generation/load centers in different NEM regions, this will be very expensive.
- **Stronger locational transmission cost signals:** At present generators do not pay for use of the transmission system, and location marginal charges for transmission losses are dominated by losses calculated with respect to supply to the regional reference node in the NEM region in which that generator is located. It would be possible to strengthen the locational signals for transmission costs by introducing zonally differentiated charges for use of the power system and also locational marginal loss factors calculated with reference to a single point in the NEM. However, such zonally-differentiated use of system and loss charges would be difficult to implement in view of largely autonomous network services providers in each NEM region.

- **Attribution of frequency control ancillary services costs (FCAS):** Allocating FCAS costs to those generators out of balance - as measured against their offers – should provide incentives for actual production to follow the forecast. But FCAS costs arise for many reasons that are no fault of generators, such as demand forecast errors and transmission congestion. The calculation and allocation of FCAS costs inevitably requires numerous subjective assumptions.
- **Differential access rights:** Intermittent generators could be subject to a less firm access right than other generators. While this may improve the reliability of supply it will reduce the revenues and increase the trading risks that renewable generators are expected to bear. This could be a barrier to entry to renewable generators.
- **Linking REC eligibility to NEM regions:** The MRET is a national market, while the NEM is a series of inter-linked regional markets. Income from RECs may be up to half the total income (in present value terms) for wind farms developed in the early years of the expanded scheme. If the allocation of RECs was affected by the NEM region in which the development is situated, it would be possible to provide stronger signals to locate in parts of the NEM that would avoid significant investment needed to maintain reliability. For example 1.5 RECs could be issued for electricity produced by wind farms located in Queensland, while only 1 REC would be issued to wind farms located in South Australia.

3.4 Issue 4: Operating the system with increased intermittent generation

8. How material are the challenges to system operations following a major increase in intermittent generation?

This issue has been discussed in our answers to questions 6 and 7. An additional issue not dealt with in our answers to those questions, is the impact over the long term of a reduction in the inertia provided by the large rotating mass of steam turbines, the thermal intertia provided by coal thermal plant. Such plant is ideally suited to operation on automatic generation control to smooth frequency perturbations. The loss of a number of coal thermal generators may be an issue in time. Other solutions may be appropriate including a greater proportion of real-time load control including remote control of large loads such as air-conditioners, and the greater use of power electronic devices and synchronous condensors. Expert electrical engineering advice should be sought on these issues.

9. Are the existing tools available to system operators sufficient, and if not, why?

We do not know enough about the limitations of the existing tools to answer this question.

10. How material is the risk of large scale intervention by system operators and why might such actions be ineffective or inefficient?

Our answer to question six discussed this.

11. How material are the risks associated with the behaviour of existing generators, and why?

No comment.

3.5 Issue 5: Connecting new generators to energy networks

12. How material are the risks of decision-making being "skewed" because of differences in connection regimes between gas and electricity, and why?

Although we do consider that there may be substantial issues arising from differences in access regime (see section 2) we do not see a significant issue in the differences in connection regime between electricity and gas. The fact that it is a *negotiated* access regime does not seem *apriori* to result in skewed decisions – or at least this is not obvious to us.

13. How large is the coordination problem for new connections? How material are the inefficiencies from continuing with an approach base on bilateral negotiation?

We think there is possibly a significant co-ordination problem for new connection of renewable capacity, as a result of the bi-lateral negotiation approach.

This issue is prevalent in other countries that have been seeking to fast-track the entry of renewable generation onto power systems historically optimised around fossil-fuel based generation sources. In Denmark, Germany, Texas and California, there are examples of connection policies and regulatory decisions that have involved the development of major transmission network extensions in expectation of subsequent connection. [3] In Britain, we understand that Ofgem is considering an incentive for National Grid to take risk on network extensions that may subsequently be stranded, in return for higher returns on investment.

We do not have the information to determine whether or not this will be an issue in Australia. The AEMC should work with NEMMCO, renewable generators and TNSPs to develop a renewable generation expansion forecast. This would deliver the information needed to assess whether the bilateral negotiation approach will result in inefficient under-investment, or delayed progress in meeting the MRET target.

14. Are the rules for allocating costs and risks for new connections a barrier to entry, and why?

Please see our answer to question 13.

3.6 Issue 6: Augmenting networks and managing congestion

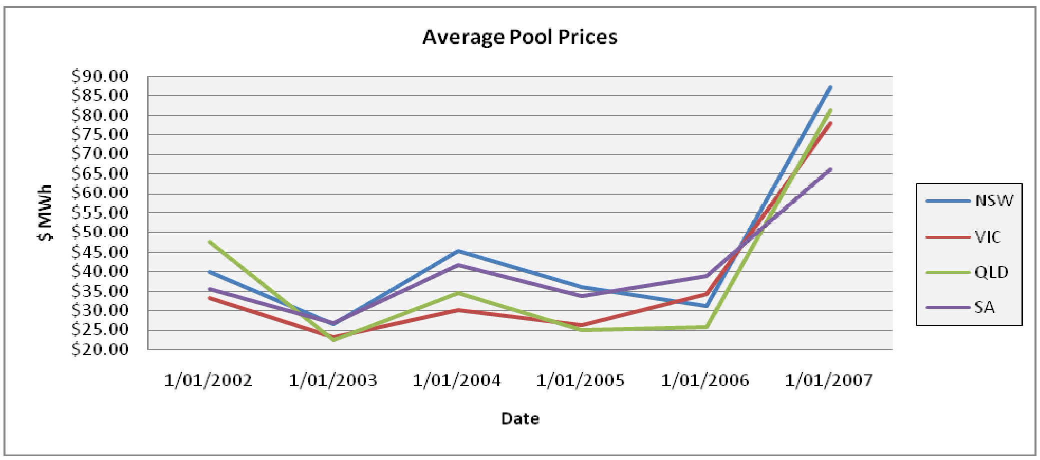
15. How material are the potential increases in the costs of managing congestion, and why?

Interconnector capacity between different NEM regions is limited. The effect of this is often significant price separation between NEM regions. This is illustrated in Figure 1

[3] See "International approaches to transmission access for renewable energy, a report for Ofgem prepared by Dr Chris Decker, March 2008, Regulatory Policy Institute Oxford.

below. This shows traces of the average spot (pool) prices in various NEM regions from 2002 to 2007. If there were no transmission constraints between NEM regions, then the traces would be separated only by the difference in prices attributable to transmission losses. However, as the lines in Figure 1 show, there is often significant variation in the average prices in different NEM regions. This points to the existence of significant binding transmission constraints.

Figure 1. Average spot prices in different NEM regions



Other evidence of the impact of transmission limitations is data published by the Australian Energy Regulator that shows the market impact of transmission congestion rising to $107m in 2006/7, from $66m in 2004/5 and $36m in 2003/4. [4] It should be noted that the definition of "market impact of transmission congestion" by the AER reflects an attempt to measure the "economic" impact of transmission congestion. However, as Figure 5 shows, the existence of these binding constraints (and transmission losses) has had a big impact on price differences in different parts of the NEM. If these constraints were built-out, it is possible that there could be significantly lower prices throughout the NEM.

[4] AER Press Release, 20 November 2007.

Our expectation is that transmission constraints will rise, and that in the absence of investment in interconnector capacity, there will be increasing regional price separation. This effect may be marked if there is a different rate of renewable generation entry in different parts of the NEM. However, we find it difficult to be definitive on this. Again we point to the value of a well-constructed generation expansion study to inform this issue.

16. How material are the risks associated with continuing with an 'open access' regime in the NEM?

The reference to risks associated with an open access regime, we understand to be the risk:

- of the loss of profits if generators are constrained off the system (i.e. their offer price is below the clearing price in the spot market, but they are still not dispatched); and
- the inability to recover its full costs for generator that are constrained on (i.e. dispatched even if its offer price is above the regional reference price.)

Before answering this question, we think it is important to be clear on the nature of the access rights under the NEM. It is clear that generators are not compensated for their lost profits if they are constrained off. While in principle they are not compensated if constrained on, in practice if a generator is scheduled to dispatch even if its offer is above the regional reference price, such generators can and typically do, declare themselves unavailable. In such circumstances, generators can then be "directed" by NEMMCO to generate. Under the Rules, generators are entitled to fair compensation if so directed. The effect of this is that generators are compensated if they are constrained-on. The "risks" associated with the NEM's open access regime are therefore principally the risk of lost profit if transmission congestion results in generators that are in-merit from being constrained down or off the system.

In spite of the AER's $107m calculation of the market impact of constraints, we think the actual risks at present are small. Major generators have well-established relationships with network service providers, the ability to understand and negotiate the complexity of network economics and the ability to lobby TNSPs to ensure that constraints are minimized. Transmission congestion has historically not been a significant commercial risk for generators.

We do think that there is a risk that this will change. This is probably more likely to be a risk for fossil fuel generators than for new entrant renewable generators. Energy users will also bear the losses associated with the inability to dispatch the cheapest generation.

There are many possible solutions to this including:

- Changing the nature of the access right;
- Greater locational pricing - nodal or zonal;
- Incentives on TNSPs or NEMMCO to manage the costs of constraints;
- Refusal to connect generators that are likely to exacerbate constraints;
- Creating transmission property rights ("financial transmission rights").

There has been a long debate of these issues in Australia and internationally, but little progress has been made anywhere (that we are aware of) in tradeable transmission property rights, that would allow differentiated levels of transmission access to be priced in a market.

Our inclination on these issues is that the policy framework should focus on creating competitive energy markets and reducing barriers to entry. Transmission, while expensive, is a small share of the aggregate cost of supply in comparison to the cost of generation. Inefficient operation and development of the energy market is more important than inefficient operation and development of transmission networks.

Efficient energy markets and efficient transmission development are not necessarily mutually exclusive. But greater locational pricing accuracy can result in more complex and less efficient energy markets. Introducing ever greater locational price differentiation creates locational basis risk. This has a real management cost. It can also reinforce ever greater geographic vertical integration – as has occurred in New Zealand for example. This creates significant barriers to generation entry. This is not in the interests of energy users.We think the focus of the AEMC's attention should be on simple, understandable energy spot markets that support liquid forward hedge markets.

However, we recognise that the magnitude and rate of change to the power system that emission pricing and the renewable energy target is likely to induce, may merit greater locational price differentiation than under the current NEM regions. This issue should be informed by the expansion planning study referred to earlier.

17. How material are the risks of 'contractual congestion' in gas networks – and how might they be managed?

We do not understand this question.

18. How material is the risk of inefficient investment in the shared network and why?

We understand the reference to "inefficient investment" to be a reference to investment in transmission elements that are subsequently under-utilised. In principle we think there are significant risks of inefficient investment partly as a result of the co-ordination problems discussed in Section 2 and partly also because the likely generation technology changes that may occur in response to emissions prices, are difficult to foresee with certainty.

The AEMC should be concerned about this. However, in line with our answer above, we suggest that the AEMC should be at least as concerned about the liquidity of contract markets, and also of the cost of delayed investment in low emission plant, that may occur in more complex market arrangements. Such delays have a cost to energy users in the form of REC and electricity prices that are higher than otherwise they would be.

19. How material is the risk of changing loss factors year-on-year?

While it is understandable that generators should seek stable loss factors, this is arguably a second-order issue in comparison to spot market price volatility – which market participants are exposed to. Our expectation is that this should not be a significant risk, and at any rate is one that generators should be exposed to.

3.7 Issue 7: Retailing

20. How material is the risk of an efficient retailer not being able to recover its costs, and why?

Australia's state governments have generally been recalcitrant in relinquishing control of retail prices. We suggest that this is driven by a misguided belief that this protects customers.

The disastrous experience in California that followed clamped retail prices but variable wholesale prices is compelling evidence of what not to do.

Retail price caps force retailers to seek higher prices from larger users, in order to achieve their overall returns. If retail prices are capped below sustainable levels, the CPRS/MRET will increase pricing pressure on large users.

21. What factors will influence the availability and pricing of contracts in the short and medium term?

We suggest the following are the main factors:

- Degree of vertical integration;
- The existence of traders and arbitrageurs;
- Policy/regulatory uncertainty;
- Market design;
- Level of renewable and CCGT investment by independent power producers.

22. How material are the risks of unnecessarily disruptive market exit – and why?

We are not sure how the Scoping Paper distinguishes between "unnecessarily disruptive" and "disruptive". Existing high emission coal generation exit will be disruptive if the remaining supply can not meet the demand. In theory coal generators will exit once they are no longer able to cover their variable costs – in other words when they are displaced from the merit order by lower cost plant. We recognise that practice is likely to be more complicated:

- If an exiting generators will not be able to recover incremental fixed expenditure (such as major maintenance expenditure) and it could not operate without such expenditure, then it would exit even if it expects that future prices will be above its short run costs,;
- Portfolio generators may be able to extract benefit (high prices) by withdrawing capacity;
- Debt convenants and similar financing issues may force closure of otherwise solvent businesses.

3.8 Issue 8: Financing new energy investment

23. What factors will affect the level of private investment required in response to climate change policies?

There are obviously many such factors. Rather than single out specific factors, we refer instead to our response to the questions and our discussion in Sections 2 and 3.

The EUAA agrees that changes to the policy frameworks need to be made to ensure that private investment in renewable and low emission capacity occurs.

24. What adjustments to market frameworks, if any, would be desirable to ensure this investment is forthcoming at least cost?

Our answer to this question is encompassed in our response to the previous questions, and the information provided in the appendix.

4 Appendix A: What changes will the CPRS and MRET induce ?

The major source of greenhouse gas emissions in Australia is electricity generation. Competitively priced coal based electricity generation has been a key competitive advantage underlying significant industrial development. The introduction of emissions pricing will quickly turn this into a competitive disadvantage. This section describes our expectations of the impact of the CPRS and MRET on:

- The economics of electricity generation;
- The impact of the expanded RET on renewable generation supply;
- Foreseeable impacts of these changes for energy networks and energy markets.

4.1 Pricing GHG emissions creates a comparative advantage for low emission generating sources [5]

Following the introduction of emission prices, the analysis of generation economics must consider both fossil fuel costs and emission prices. To analyse the impact of a price on greenhouse gas (GHG) emissions we calculated the difference in annual operating costs[6] for the NEM's least efficient large thermal generator (Hazelwood) compared to a modern combined cycle gas turbine plant. We have performed the same analysis for the most efficient thermal generator (Kogan Creek). The analysis uses publicly available information on heat rates and coal prices. The results are shown in Figures 1 and 2 below.

[5] Some of the information in this section draws on a forthcoming report produced for the EUAA on the impact of climate change policies on the rise of gas powered generation.

[6] Variable fuel and operating and maintenance costs

Figure 1. Annual operating cost savings if a CCGT replaces replaces Hazelwood power station

Gas Price ($/GJ)	CO2 price ($/tonne)										
	$ 15	$ 20	$ 25	$ 30	$ 35	$ 40	$ 45	$ 50	$ 55	$ 60	$ 65
$ 2.20	9%	24%	34%	41%	45%	49%	52%	54%	56%	57%	58%
$ 2.50	0%	18%	29%	36%	41%	45%	49%	51%	53%	55%	56%
$ 2.80	-8%	11%	24%	32%	38%	42%	46%	48%	51%	53%	54%
$ 3.10	-17%	5%	18%	27%	34%	39%	43%	46%	48%	50%	52%
$ 3.40	-25%	-2%	13%	23%	30%	35%	40%	43%	46%	48%	50%
$ 3.70	-34%	-8%	8%	18%	26%	32%	37%	40%	43%	46%	48%
$ 4.00	-43%	-15%	2%	14%	22%	29%	34%	38%	41%	44%	46%
$ 4.30	-51%	-21%	-3%	10%	19%	25%	31%	35%	38%	41%	44%
$ 4.60	-60%	-28%	-8%	5%	15%	22%	28%	32%	36%	39%	42%
$ 4.90	-68%	-34%	-13%	1%	11%	19%	25%	30%	34%	37%	40%
$ 5.20	-77%	-41%	-19%	-4%	7%	15%	22%	27%	31%	35%	38%

Figure 2. Annual operating cost savings if a CCGT replaces replaces Kogan Creek power station

Gas Price ($/GJ)	CO2 price ($/tonne)										
	$ 15	$ 20	$ 25	$ 30	$ 35	$ 40	$ 45	$ 50	$ 55	$ 60	$ 65
$ 2.20	-63%	-35%	-18%	-7%	2%	8%	13%	17%	20%	23%	25%
$ 2.50	-78%	-47%	-28%	-15%	-5%	2%	8%	12%	16%	19%	21%
$ 2.80	-93%	-59%	-37%	-22%	-12%	-4%	2%	7%	11%	15%	18%
$ 3.10	-109%	-70%	-46%	-30%	-19%	-10%	-3%	2%	7%	11%	14%
$ 3.40	-124%	-82%	-56%	-38%	-26%	-16%	-8%	-2%	3%	7%	10%
$ 3.70	-139%	-94%	-65%	-46%	-32%	-22%	-14%	-7%	-2%	3%	7%
$ 4.00	-154%	-105%	-75%	-54%	-39%	-28%	-19%	-12%	-6%	-1%	3%
$ 4.30	-170%	-117%	-84%	-62%	-46%	-34%	-24%	-17%	-11%	-5%	-1%
$ 4.60	-185%	-129%	-94%	-70%	-53%	-40%	-30%	-22%	-15%	-9%	-5%
$ 4.90	-200%	-140%	-103%	-78%	-60%	-46%	-35%	-26%	-19%	-13%	-8%
$ 5.20	-216%	-152%	-113%	-86%	-67%	-52%	-41%	-31%	-24%	-17%	-12%

Figures 1 shows that even with emission prices as low as $20/tonne CO2-e, Hazelwood will be substantially undercut by new entrant CCGTs assuming the existing gas prices for base load electricity generation ($2-$3/GJ). Hazelwood's competitiveness will be secured however, if gas prices rise significantly. For example, Figure 1 shows that with gas prices above $5/GJ, emission prices would need to rise above $30/tCO2-e before CCGT will undercut Hazelwood.

Figure 2 shows that Kogan Creek – one of the most efficient coal thermal generators in the NEM - will be significantly more secure against the threat of CCGT. This is to be expected in view of Kogan Creek's much higher heat rate and the lower emission intensity of higher quality Queensland coals. Figure 2 shows that CCGTs will only begin to undercut Kogan Creek when emission prices rise above $50/tCO2-e assuming gas prices around $3/GJ. If gas prices rise in Queensland in response to Liquified Natural Gas (LNG) development, Kogan Creek will be competitive until emission prices rise to very high levels.

While Figures 1 and 2 relate to operating cost competitiveness, new investment in CCGT capacity will occur once the expected electricity prices exceed the long run average cost of CCGT. On this, our estimate of the long run average cost of CCGT ranges between $55/MWh and $85/MWh depending on assumptions on capital costs, fuel costs, emission prices, non-fuel variable costs, capacity factors, cost of capital and plant life. Furthermore as discussed below, there is scope for significant CCGT entry by way of conversion of existing open cycle gas plant. Such conversion could be achieved with relatively little incremental capital expenditure. As such lower average electricity prices would still stimulated investment in CCGT capacity.

Therefore we expect that all of Victoria's brown coal generators, and older inefficient coal plant in NSW (Wallerawang, Red Bank, Munmorah) and Queensland (Collinsville, Swanbank and Gladstone) and South Australia (Thomas Playford B and North Power) will be threatened by CCGT in the shortly foreseeable future. These inefficient plant will no longer be able to recover their short run costs when new entrant CCGTs displace them from the merit order. Some plant may close soon, others will converted to more flexible operation (weekend shut downs, possible two-shift operation on a daily cycle) and increased use of biomass co-firing.

The rate of coal plant closure will be affected by the rate of entry of CCGT and renewable capacity. While it is possible that gas prices may rise significantly and defer entry of CCGT, our expectation is that with emission prices above $20/tCO2-e significant CCGT entry will occur quickly. Evidence of CCGT either under construction or at an advanced level of planning by Origin Energy, Santos, QGC/AGL, Truenergy and ERM amongst others supports this conclusion. In addition, we note that CCGT plant orders have more than doubled over each of the last four years.

Finally, much of the additional CCGT capacity may not necessarily be new plant – much could be conversion of existing open cycle plant to CCGT. We have identified 4,700 MW in 13 existing and planned OCGT plant where this may be a possibility (Oakey, Kemerton, Laverton North, Braemer 1, Wagerup , Uranquinty, Munmorah, Quarantine, Braemar 2, Neerabup, Mt Stuart and Mortlake).

The main point that we would like to communicate with this analysis is that there is a significant likelihood that there will be an aggressive "dash for gas". This has implications for the urgency and seriousness with which the AEMC prepares for the changes to the energy market frameworks.

4.2 The expanded RET will create significant demand for additional renewable generation

Of all the possible renewable generation technologies, wind farms are likely to have the highest REC price supply elasticity. Carbon Market Economics (CME) has estimated low and high scenarios for the relative contribution of different renewable generation sources over the period 2008 to 2020, assuming the MRET target is met. This is shown in Figure 3 below. [7]

[7] Source: "Not tilting at windmills" , a presentation by Carbon Market Economics to the EUAA Annual Conference, October 2008.

Figure 3. Contribution of different renewable technologies to total REC creation 2008 to 2020

Renewable gen source	Low scenario: Total RECs ('000) 2008 to 2020	High scenario: Total RECs ('000) 2008 to 2020
Biomass	41,821	74,004
Geothermal	3,526	15,842
Hydro	15,831	44,505
Wave & tidal	14	15
Solar water heaters	18,000	36,000
Wind	170,000	221,000
Solar thermal + PV	3,995	5,095

Figure 3 shows that around 170 million to 221 million RECs can be expected to be created by wind farms in the period to 2020. This is consistent with aggregate investment in wind generation of between 6,700 and 8,900 MWs by 2020.

For the high scenario, CME expect that around 40% of the additional wind capacity to be added after 2009, will occur in Victoria with the balance mainly in South Australia and New South Wales.

Achieving such a significant increase in renewable capacity will require massive capital investment in generating technology and, as discussed below in greater detail, also in networks and possibly also back-up fossil-fuel generation.

4.3 Some impacts for networks and energy markets are foreseeable

We summarise below our thoughts on the foreseeable impacts for networks and energy markets, of emission pricing and the expanded MRET.

4.3.1 Linkage of electricity and gas markets

The high-capacity long distance gas pipelines on the southern and eastern seaboard of Australia are predominantly unregulated. Outside of Victoria, long term off-take contracts with daily withdrawal limits and annual take-or-pay terms are the dominant contractual model. Price discovery is poor and there is limited short term trading. This will almost certainly change as higher daily gas demands result in a significant reduction in line-pack (gas stored in the pipelines). This will create much higher demand for a short-term market to balance overruns and underruns. This will also lead to much stronger linkage of the electricity spot market and gas markets.

4.3.2 Electricity network congestion

It is possible that much of the new CCGT capacity will be built at or near existing base load coal thermal capacity and will use existing transmission connections. This may be likely in the Latrobe Valley where CCGT plant could directly replace existing brown coal plant. However, there is also significant possibility that base load gas could be located in new locations (particularly in south/central Queensland and south western Victoria. This will lead to changed power flows and, to the extent that transmission augmentations do not keep up, to network congestion. Renewable generation – particularly in South Australia and Victoria will also add significant additional capacity. Depending on the coincidence of wind in different geographies, this could result in many thousands of MW’s that will need to be moved around the power system. Again, our expectation is that this will result in higher network congestion.

4.3.3 Electricity network investment

Significant investment will be required in connection assets (transformers, switchgear, radial lines) to connect numerous wind farms, and also large CCGT generators. Another key area is likely to be investment in transmission capacity to move electricity between NEM regions. It is difficult to predict where additional investment may be required, but large amounts of wind capacity in south and eastern Australia is likely to require either much greater interconnection or back-up generation to maintain secure suppliers particularly within South Australia and Victoria.

4.3.4 Gas pipeline and related ancillary investment

Investment in base load gas generation will quickly raise gas demand from existing levels. Greater pipeline capacity is likely to be required to transport gas from the Otway and Gippsland basins, and also from Queensland coal seam methane (CSM) fields to generators located around or near the Surat and Bowen basins. Significant pipeline capacity may be needed to transport CSM from Queensland CSM fields to generators to be located in NSW, depending on the rate of progress in the development of NSW's CSM fields particularly in the Gunnedah basin. In addition to investment in pipeline capacity, there will also be a need for significant investment in ancillary equipment including gas processing capacity, compressor stations, and possibly also gas storage capacity.

4.3.5 Price volatility

The NEM is a final price market with spot market trades conducted at the highest price in half hourly auctions. With the entrance of large amounts of non-storable low variable cost, there is the possibility of significantly lower prices for extended periods in some NEM regions. The scope for such price collapse may be limited if there is significant additional interconnection therefore allowing the renewable capacity to absorbed into larger markets. The effect of price collapses may be to defer the entrry of reneewable and non-renewable fossil fuel capacity. At some point this will result in supply shortfalls and thus much higher spot prices. The EUAA is concerned that the contract markets may not always "see through" such spot market volatility and generation investment may therefore be volatile.