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4 March 2009

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Review of Energy Market Frameworks in light of Climate Change Policies – First Interim Report

The Energy Supply Association of Australia (esaa) welcomes the opportunity to comment on the Australian Energy Market Commission's (AEMC) Review of Energy Market Frameworks in light of Climate Change Policies, First Interim Report (the Interim Report).

esaa's response to the issues raised by the AEMC is divided into two sections, the first focusing on Part A of the Interim Report: National Electricity Market (NEM) and Eastern States Gas Markets and the second on Part B: Western Australian Energy Markets.

The energy supply industry faces a period of ongoing market and investment uncertainty until the detail of climate change policies such as the Carbon Pollution Reduction Scheme (CPRS) and expanded Renewable Energy Target (RET) are finalised and implemented. It is difficult to predict how the energy market frameworks in both the NEM and Western Australia will cope with such a fundamental shift in operating costs and investment incentives. Added to this, is the impact of the recent sharp downturn in global and domestic economic conditions, the tightening of capital markets and asset write downs by many major equity providers.

The AEMC needs to be mindful that any fundamental changes to the energy markets framework would take a number of years to implement and could add to the regulatory risk faced by the energy supply sector. The AEMC should consider the impact proposed changes will have on existing asset holders and potential new investors. Any recommendations for fundamental and immediate reforms to the energy sector should be made cautiously and on the basis of careful analysis as much of the major policy uncertainty may be driven by schemes and programs that are outside the control and influence of energy market institutions and participants.

The number of reviews affecting both energy market frameworks and climate change policy is continually escalating. There are more than ten review processes currently in place that could have a bearing on the AEMC's Review. These include the Federal

Government's Energy White Paper process, proposed parliamentary inquiries into various aspects of the Carbon Pollution Reduction Scheme, Ministerial Council on Energy (MCE) and MCE Standing Committee of Officials' processes to implement the Australian Energy Market Operator, AEMC reviews and Rule change proposals including those relating to the gas supply industry and demand side management, and State and Territory reviews of existing climate policy mechanisms and proposed new programs. The AEMC will need to take account of the possible findings and outcomes from each of these review processes when preparing its 2nd interim and final reports.

If you have any questions or require any further information please contact Nicholas Wilson, Acting Policy Development Manager on nicholas.wilson@esaa.com.au or 0396700188.

Yours Sincerely

Clare Savage
Chief Executive Officer

Comments on Part A: NEM and Eastern States Gas Markets

esaa broadly agrees with the AEMC's assessment of the materiality of the energy market framework issues in the Interim Report. The proposed approach of identifying those energy market design areas that may require more substantial regulatory change and those issues that could be addressed through the existing Rule change process is supported.

The interim report focuses on the implications of climate change policies for the generation and transmission sectors, with a separate section considering the impact of retail price caps. esaa has outlined some specific issues facing distribution network service providers if there is a major increase in the number of small renewable projects that connect through the local network. esaa would welcome greater consideration to the challenges facing electricity distribution networks in the second interim report.

A1. Convergence of gas and electricity markets

Modelling work commissioned by esaa and other industry bodies indicates that gas will play an important role as a transitional fuel for electricity generation as emission targets increase. Unless the market settings for electricity and gas are broadly consistent, the risk of skewing commercial decision making in favour of a single market increases. For example, if the NEM market price limit is set inconsistently with any limits in the respective gas markets, it could create incentives to arbitrage to the market with highest returns, with implications for system security in either the electricity or gas markets. Similarly, emergency supply situations in one market need to have regard to the consequences for the other market.

esaa considers that consistency between the gas and electricity markets is an important policy objective for governments and regulatory bodies when major regulatory changes are contemplated in either market. However, at this point in time, esaa agrees with the AEMC's finding that that there are sufficient processes underway that will consider the interplay of both markets in the development of the detailed market rules for each sector. In particular, the implementation of a common AEMC Rule change process for electricity and gas and the establishment of the Australian Energy Market Operator should result in greater consistency between settings in each market over time.

A2. Generation capacity in the short term

The AEMC is concerned by NEMMCO's forecasts of low reserve levels in Victoria and South Australia in 2010-11 and invites comment on the scope to consider additional mechanisms to manage supply shortfalls in the short-term. esaa considers that this is a material issue for the review to evaluate but considers that issues of generation adequacy should also address the factors that drive investor decision making over the longer-term to ensure persistent supply shortfalls do not occur.

Little ability to respond to supply shortfalls in the short-term

In the short-term there is little that the system operator, the AEMC or governments can do to avoid possible supply shortfalls. Investors have commissioned new generation projects over recent years, predominately gas-fired projects in Queensland and New South Wales, but system load has also risen steadily during this time. There are some generation projects likely to come on line in 2009-2010 that are currently at or near the committed stage. However, apart from some smaller renewable generation projects, there are few major generation projects that are well advanced in the planning, development and environmental approvals processes.

If supply reliability problems do emerge, the system operator has the power to direct plant to operate during low reserve conditions. However, the power to direct does not deliver system reliability if there is not sufficient plant capacity able to generate during peak demand periods. The possibility of early plant retirements, caused by the imposition of a carbon price on higher emission baseload plant, could exacerbate supply reliability problems in the short-term.

Coordinating a demand-side response is one way of mitigating the risks associated with low reserve levels. The AEMC's current review of demand-side participation in the NEM may offer practical solutions to facilitate the recruitment of demand management at a scale that may delay the need for some new generation capacity. However, it may be difficult to deliver a large-scale demand response at short notice to offset peak demand events.

The AEMC discusses the possibility of amendments to the Reliability and Emergency Reserve Trader (RERT) mechanism to alleviate supply reliability problems. esaa observes that the RERT mechanism was only intended to play a minor role in the market to recruit relatively small quantities of contracted services either through demand side response or the fast tracking of committed generation projects. Any major change to this mechanism would represent a fundamental shift in NEM design, potentially distorting investment incentives, dispatch patterns and market outcomes.

Investor confidence over the long-term

The willingness of investors to build new plant in the NEM over the longer term will be driven by investor perceptions about the credibility and stability of climate change policies, the extent of any sovereign risk for the sector and the ability to secure an adequate return on their investment. Incremental changes to the current NEM design will not bring forward timely new investment or act to reduce the perceived 'riskiness' of the sector.

Uncertain greenhouse gas emission policy has deterred generation investment in recent years and contributed to the tightening supply-demand balance. Since 2006, esaa has supported the introduction of a well-designed emissions trading scheme as a least-cost mechanism for delivering greenhouse gas abatement. The introduction of the CPRS will provide a greenhouse gas emissions price signal and will guide future generation investment. However, the inadequate level of assistance offered to coal-fired generators does not recognise the significant asset value losses incurred due to the introduction of the Scheme. The Government's apparent willingness to strand substantial energy sector investments could jeopardise future investment in the sector or, at the very least, impose a higher risk premium on future investments.

The White Paper's proposed $3.5 billion of assistance is insufficient and considerably lower than the consensus of modelling results (including two sets of Government modelling results) which suggest around $10 billion of assistance is required over ten years. It should also be noted that for many coal-fired generators, the loss in asset value extends well beyond the first 10 years of the Scheme. In particular, for some coal-fired generators the most significant asset value loss will occur in the second decade of Scheme but these losses have been completely ignored by this assessment. Ultimately it will be the market that will determine whether the $3.5 billion is sufficient and, if it proves to be insufficient, the impact on the energy sector and the broader economy could be extremely costly.

Investor confidence in the energy sector is also dependent on the ability to confidently determine a clear view of future greenhouse gas emission prices. To date, this has not been possible, but the introduction of the CPRS is intended to rectify this.

The CPRS proposes arrangements that would result in 5 years of firm Scheme caps followed by a gateway of between 5-10 years. This arrangement provides an inadequate timeframe for planning long-lived, capital intensive investments. esaa considers that at a minimum, annual Scheme caps should be set for a 10-year period that is extended by one year, each year. The proposition of a 10-year gateway is supported as it then makes for an effective 20-year view of Scheme caps and gateways. However, rather than allowing the gateway to contract to five years before the next gateway announcement, the gateways should also be extended by one year, each year. Setting broad gateways would provide scope for responding to international developments, but it reduces investor confidence in the likely national targets.

The Government is the only entity that can commit Australia in international negotiations and, therefore, the Government should bear the risk of future Scheme caps and/or gateways being inappropriate. If the Government enters an international agreement that requires it to reduce emissions below the Scheme caps or gateways, it should purchase the required abatement on the international market.

A3. Investing to meet reliability standards with increased use of renewables

One of the key questions often raised in relation to the NEM is whether the energy-only design is capable of providing the price signals necessary to adequately reward generation capacity and to ensure sufficient new generation capacity is delivered in a timely manner.

Under an energy-only model the only payment generators receive for their plant is the price of the electricity they produce; no payment is made for being available to generate. As such, generators are reliant on periods of higher electricity spot prices (as a result of high demand, outages and/or transmission constraints) to make a return on capital and to generate sufficient revenues to fund new investment in generation capacity.

The energy-only market has worked effectively over the last ten years to deliver some new investment and to provide an incentive for plant to be available during periods of tight supply and demand conditions. The NEM framework is supported by an extensive regulatory structure and businesses have developed advanced trading systems to manage risk and monitor market conditions. The NEM is regarded internationally as a successful model that delivers high levels of reliability and transparent pricing signals for existing participants and potential new entrants.

However, the inherent volatility associated with high spot market prices is a potential source of concern for governments, In the past governments have introduced various "safety net" measures to the market, such as retail price caps and caps on the spot market price itself, in an attempt to smooth out and reduce such price fluctuations to the end consumer. Placing limits on the effective operation of the energy-only market acts to blunt the price signals that are required to reward generation and to indicate new investment is needed (and also to enable the demand-side to respond). This creates what some have called the 'missing money' problem – referring to the lost revenue which would have been earned by a generator in the absence of government-imposed constraints on the market. The effective operation of the energy-only market is also impacted by other factors such as interventions to deliver capacity through NEMMCO's reserve trader mechanism and government investment.

Given the above issues, some participants have questioned whether there is a need for some form of explicit capacity mechanism to provide generators with sufficient revenue to reward their existing investments and with which to fund new investment. There are a number of capacity mechanisms, both market based and regulatory, which have been used with varying degrees of success in electricity markets both overseas and in Western Australia.

The issue of capacity has been reviewed by the COAG Energy Reform Implementation Group process and the AEMC's Comprehensive Reliability Review. The Reliability Panel commissioned market modelling that shows the energy-only market is capable of achieving the NEM reliability standard in the future. The modelling considered a number of scenarios including various carbon prices, the timing and cost of new technologies, and the achievement of the RET. esaa also notes the AEMC Reliability Panel has responsibility for periodically reviewing the reliability mechanisms, including the level of the market price limit and floor, the unserved energy target and reserve trader arrangements. The Reliability Panel is required to report annually on the performance of the market in achieving reliability targets.

A major overhaul of the NEM energy-only design would introduce significant regulatory risk and should not be contemplated in the absence of significant evidence demonstrating the benefits of change. Such a major change of the market model would require substantial changes to existing trading and contractual arrangements. It would also require a detailed consideration of alternative models and would take many years to finalise and implement. The AEMC should further consider this issue and assure itself that the existing market settings and review processes will be capable of delivering least-cost generation in a timely manner.

A4. System operation and intermittent generation

The expanded RET will significantly increase the level of intermittent generation in the NEM, possibly resulting in technical challenges for the power operating system. Whether the system is capable of handling a high level of intermittent plant is dependent on the uptake of particular technologies, the location of the plant in the

NEM and the capability of the network infrastructure to transport electricity to load centres.

esaa agrees with the AEMC that the current dispatch systems provide a sound basis for meeting demand and maintaining system frequency. Other arrangements such as the “semi-dispatch rule”, the setting of technical standards, NEMMCO’s ability to procure additional ancillary services and reactive power are considered to be sufficient. Further, esaa understands that NEMMCO, the state planning bodies and the Transmission Network Service Providers (TNSPs) have undertaken detailed modelling of scenarios based on the deployment of various technologies within regions at different times. These bodies are best placed to provide expert technical advice on the practical implications of achieving the RET target under a range of market scenarios.

esaa also agrees with the AEMC that the current Rule making process should provide opportunities to address system security issues relating to intermittent generation if required. For example, it should be possible to change Frequency Control Ancillary Service (FCAS) arrangements to procure additional FCAS if required to maintain system security or meet reliability standards. The Rule change process would also consider which party bears the cost of procuring additional FCAS services.

The AEMC has also identified a number of AEMC Reliability Panel and NEMMCO review processes currently underway that are associated with frequency and voltage control that should help identify any necessary changes to access standards, FCAS levels or network support control services. Many of these review processes are well advanced and will assess the impact of the expanded RET and the likely uptake of intermittent generation. These processes provide an opportunity for all participants to state a case for increasing the number or expanding the level of voltage and frequency services that are recruited for the efficient operation of the market.

A5. Connecting new generators to energy networks

The AEMC considers the RET will drive investment in wind and other renewable generation clustered in locations remote from load and transmission. This may raise the following issues:

- The inability of TNSPs to negotiate over investment in connection assets jointly with multiple generation proponents due to confidentiality requirements in the Rules. At the same time, the AEMC noted that generators were often wary of co-ordinated connection processes due to concerns about their commercial interests.

- The scope for developing optimal extensions to accommodate future anticipated remote connections. This requires a party to take on the risk that the ‘right-sized’ asset may not be fully utilised if expected new generator connections do not eventuate. TNSPs may not be willing to take on this risk; nor may the initial connecting generator.

The AEMC considered a number of possible “mitigation” options to address these issues.

Option 1 entails incremental changes to the current arrangements. The TNSP and the connecting party maintain bilateral negotiations over new connections, but the TNSP declares an 'open season' for connections in certain geographic areas. Once the season closes, new applications would not be accepted. This would encourage all prospective investors to put forward their plans during the period of negotiation. Like all schemes that involve arbitrary deadlines, it would not capture those projects that are under serious consideration but are not sufficiently well advanced to make commitments before the open season is closed.

esaa considers that Option 1 would seem to have merit in overcoming the coordination and information problems inherent in the current Rules. Where clustering of new generation occurs, this option would facilitate joint negotiation between TNSPs and connection proponents regarding the scale and timing of the new transmission asset. This option would not require fundamental change to the current energy market framework and could be implemented through a Rule change process.

An alternative to the open-season proposal would be to amend the Rules to allow a connection party to give its consent for the TNSP to discuss its connection proposal with one or more other connection parties that have made similar inquires requiring an extension along a similar corridor. This would avoid the need for artificial timelines and may encourage a greater level of negotiation between committed and uncommitted participants.

The remaining three options attempt to address the potential problem of determining the "right sized" connection asset. The three options are variants on the same concept of establishing a "hub" for each cluster whereby the extension assets from the "hub" to the shared network would be funded, either in part or in total, by customers through transmission use of system charges.

The Association's preference is for market led development, where possible, achieved through bilateral and/or multilateral negotiations. Addressing confidentiality concerns either through an 'open season' or through voluntary opt-out of the standard confidentiality provisions would assist this. However, where a social benefit exists that may not be realised through negotiations, there is merit in further examining the "hub" proposal in the next stage of the AEMC's review. Given the economies of scale in the physical operation of network assets, customers could benefit in the longer term if assets were constructed at a scale that enabled new generators to pay for a share of an existing asset rather than having to duplicate a previous network investment.

However, the assessment of the "hub" proposal would need to consider a number of matters:

- The materiality of the issue – will there be major pockets of remote generation in the NEM and will those remote locations continue to attract new projects through time?

- How would the "economic test" be defined under the Rules and who should administer it – the National Transmission Planner or the Australian Energy Regulator?

- What would be the basis for selecting a "pre-defined proportion of the estimated capacity"?

It should be noted that where new transmission investments are funded through transmission use of system charges an adequate return on capital will be required to ensure there is sufficient transmission investment.

Impact on distribution networks

In response to the AEMC's scoping paper, the Association indicated that there are a range of connection issues at the distribution network level that the AEMC should consider further in the Review. Both the RET and CPRS, as well as other policy measures such as solar feed-in-tariffs, will drive increases in the connection of embedded generators to distribution networks. The scale and intermittent nature of these embedded generation sources will give rise to increased challenges for Distribution Network Service Providers (DNSPs) from a reliability, operational, safety and power system quality perspective. DNSP's will increasingly have to manage reverse flows of electricity from point sources within the network and network stability issues arising from greater penetration of intermittent generation technologies.

DNSP's are receiving increased numbers of applications to connect generation assets directly to the distribution network. This is causing logistical problems for the DNSPs given the need to conduct network system planning studies and assess each connection application to ensure that they can meet their network reliability obligations and maintain system security.

Differences in the connection arrangements between transmission and distribution networks may also skew generation location decisions, further exacerbating the challenges for DNSPs outlined above. esaa is aware of jurisdiction-specific legislation that requires DNSPs "to offer fair and reasonable terms" to connect new generation projects that locate within a local network. This includes both the assets at the connection point and the cost of the line connecting the generation project and the local network. The same obligation does not apply to TNSPs. This problem is compounded in the short-term by the revenue caps that exist in particular jurisdictions that do not allow the DNSPs to recover the cost of the project until the next determination period.

esaa urges the AEMC to give greater weight to the impacts of climate change policies on distribution networks in its Review. esaa is concerned that these distribution network issues are being handled in a fragmented way across different work streams and the MCE is not receiving appropriate analysis of this issue. In particular, the AEMC should consider whether there is efficient investment signalling for generators to make appropriate decisions between distribution and transmission connections.

A6. Augmenting networks and managing congestion

The AEMC notes it is unclear whether the CPRS and RET will lead to increased congestion. The AEMC is continuing to investigate this issue including through the commissioning of modelling on the timing and incidence of network congestion. The

AEMC noted that the location of new wind plant and its effect on congestion and inter-regional flows is of concern.

The AEMC commented on the appropriateness of locational signals for new generation and highlighted the strong signals inherent in the connection charging regime and application of loss factors. However, at the same time the AEMC acknowledges that the current locational signals may be inadequate due to the regional pricing model and the lack of firm access arrangements.

esaa supports the AEMC proposal to further examine the materiality of congestion in the NEM. While the recent AEMC Congestion Management Review concluded that historically congestion in the NEM has not been sufficiently material to justify fundamental changes to the current market design, little consideration was given to the potential impact of climate change policies. The introduction of such policies could significantly alter the timing and location of new investment, result in the retirement of existing baseload plant and see a substantial shift in power flows around the NEM. Some areas may experience energy shortfalls or surpluses, resulting in an increase in the level of binding constraints that are both material and persistent.

esaa acknowledges that the assessment of the materiality of congestion is, by its nature, a difficult task but it is an important first step in determining whether other changes may be necessary. Such a modelling exercise would need to look at a range of scenarios at the sub-regional level using reasonable assumptions on the uptake of various technologies, network capabilities and current network investment plans, load growth, gas availability and other key inputs.

Due to the significant financial impact congestion can have on both existing and new generators, as a general principle, esaa considers that where congestion risk is demonstrated to be a material and ongoing problem there should be a way of pricing and allocating that risk among existing and new generators, at the point where the congestion is material, to encourage efficient investment and production decisions.

If the Review demonstrates that there is empirical evidence of an emerging congestion problem, the AEMC may wish to pre-empt such problems by investigating changes to the current incentives that are created through “regulatory obligations, market prices and network charges, and through the allocation and management of trading risk” as outlined in the Interim Report.

A number of market participants consider that the Rules relating to the connection process currently provide a workable regime for allocating access to the shared network. However, there is currently a lack of agreement among industry participants as to how Clause 5.4A of the Rules (which relates to the negotiation of new connection applications) should be applied.

The level of disagreement as to the effectiveness of this Clause indicates there is uncertainty about its original intent and ongoing interpretation. The AEMC has not considered the drafting of this Clause in previous work including the congestion management review. esaa would invite the AEMC to comment on the application of Clause 5.4A and its usefulness in managing congestion that may arise following the implementation of climate change policies.

AER Weighted Average Cost of Capital Review

The coming decade will see considerable pressure and stress within the energy industry as it transitions to a low emission energy supply system and dramatically increases the proportion of renewable energy. The current global financial crisis has further challenged the sector's ability to access sufficient capital at reasonable rates to make this transition. Efficient and timely investment in network infrastructure will be a critical component of making this as smooth a transition as possible and the need for investor confidence is paramount.

With this firmly in mind, the AER's draft proposal of December 2008 to significantly reduce the rate of return on network investments not only runs counter to the policy intent of regulatory stability and predictability but could seriously threaten future network investment and innovation, with flow on consequences for the wholesale energy market and the extent and location of network congestion.

Networks will require significant expansion, reinvestment and reinforcement if they are to support and facilitate a new mix and pattern of generation in response to the CPRS and the RET. For example, the nature and levels of investment in energy infrastructure is likely to be affected by:

- Requirements to expand and reinforce networks to connect new renewable sources;
- Increased "peakiness" of the load profile;
- A need for upgraded interregional connections to maintain reliability while accommodating increased levels of intermittent renewable generation;
- An overall increase in demand for gas-fired generation and associated gas and electricity transmission infrastructure; and
- A need for innovation in network design, control and protection arrangements to support the increasing connection of distributed and renewable generation to distribution networks.

The set of required network infrastructure investments to respond to these policies and market signals will be significant. Elements of the regulatory regime do provide assurances relating to the recovery of actual capital expenditure. However, it does not follow, as assumed in the AER assessment of these issues, that sufficient investment will occur if the returns are not reasonable.

The AER's view that a reduced return on investment will be adequate is underpinned by two assumptions. First, that the current overall level of risk is comparable to the risk environment for past investments and consistent with the AER's assumptions. Second, that significant additional increments of network infrastructure can be financed by capital raising with no investor requirement for higher expected returns.

esaa has written to the AER questioning the basis for both of these assumptions and asked the AER to more fully consider the likely impact of climate change policies on the risks, and investment incentives required, in relation to energy transmission and distribution infrastructure.

A7. Retailing

esaa has long supported the removal of retail price regulation where competition is demonstrably effective. A study undertaken for esaa by CRA International into the effect of retail price regulation found that price regulation in contestable retail energy markets is likely to confer little or no public benefit but impose considerable direct and indirect costs, thus reducing overall welfare[1].

For the CPRS to operate efficiently and provide least-cost emission reductions, consumers should be exposed to the cost implications of greenhouse gas emissions. The retention of regulated price caps creates the real risk that retailers may be prevented from passing on higher wholesale energy and network related costs and increased prudential costs associated with the CPRS in a timely manner. This could force retailers to experience significant losses and be unable to contract forward with generators. Systemic failure or financial distress among major retailers would increase volatility and risks in the energy market, reduce competition and potentially undermine system reliability and security of supply.

The Federal Government has acknowledged in the CPRS White Paper that ideally there should be no regulatory impediments to the timely pass-through of reasonable costs, to ensure the objectives of the CPRS are not undermined. The White Paper goes on to recognise that competition and consumer choice are the best ways to achieve cost-effective demand-side participation in energy markets. However, it concludes that the best way to progress cost pass-through is to support the work of the Ministerial Council on Energy (MCE). The MCE agreed at its meeting on 12 December 2008 to propose to the Council of Australian Governments that the Australian Energy Market Agreement (AEMA) be amened to specify that, where retail prices are regulated, energy cost increases associated with the CPRS shall be passed through to end-use customers.

esaa has concerns as to the effectiveness of the proposed approach to facilitating appropriate and timely cost pass-through for retailers.

esaa considers that the introduction of the CPRS and the imposition of other climate change measures will make the already difficult task of setting cost-reflective retail prices for those customers eligible for 'standard' or 'default' tariff offers substantially more complex. esaa agrees with the AEMC's finding in the Interim Report that "we do not consider that the current retail price regulation arrangements are sufficiently flexible to be able to cope with the potentially large and rapid changes in retailer costs".

Designing a regulatory regime that can set retail prices in advance based on forecasts of likely forward wholesale prices, network charges and retail costs and margins is an inherently difficult task. esaa considers that retail prices set by open and competitive retail markets provides retailers with the greatest flexibility to pass through such costs and provide end use customers with appropriate signals to engage in cost effective energy efficiency and demand-side management activity.

[1] esaa (January 2007) The effects of retail price regulation in Australian energy markets, CRA International. Available from http://www.esaa.com.au/reports__studies.html

However, where governments are unwilling to commit to reform, there should be a consistent, national framework for the regulation of both electricity and gas retail prices that enables cost-reflective pricing and the full pass-through of emissions related costs to consumers. Our preferred option would be for the AEMC to determine a clear and workable methodology for determining fully cost-reflective tariffs that would be applied by the AER.

Despite the potential effectiveness of this approach, esaa recognises that State and Territory based retail price regulation may continue in some jurisdictions for some time, including through the initial commencement of the CPRS. The AEMC has indicated that it would like to work with jurisdictional regulators to workshop possible mechanisms for ensuring that retailers are able to recover all reasonable costs under regulated retail tariff arrangements. The industry strongly supports this initiative and esaa would be happy to facilitate an initial session between the AEMC and the industry to determine how the risks to retailers through retail price regulation can be reduced. Possible mechanisms the AEMC process might consider include the re-opening of existing price determinations based on pre-defined criteria, fast-track reviews, ex-post revenue recovery procedures, or some automatic retail price adjustment formula in line with wholesale price changes.

These mechanisms require detailed analysis and examination, particularly as to the financial risks and implications for existing businesses and the opportunity for new retail entrants. This is an area where the AEMC could potentially make recommendations on possible changes to the existing regulatory design to cater for the likely and intended price impacts of climate change measures.

<u>Retailer of Last Resort</u>

esaa agrees that the Retailer of Last Resort (RoLR) arrangements will need to be able to function effectively across a range of scenarios – for example, the exit of a major retailer operating in a number of jurisdictions, the exit of a host retailer, and the exit of retailer supplying both regulated and contestable customers. The AEMC observes that the MCE and the MCE Standing Committee of Officials are currently working on a national RoLR framework. There may be scope for the AEMC to provide comment on the likely effectiveness of any proposed changes to these arrangements through the course of the current AEMC review.

A8. Financing new energy investment

<u>Framework for merchant investment</u>

esaa engaged ACIL Tasman in 2008 to examine the impact of an emissions trading scheme and an expanded RET on the energy supply industry at 2020. ACIL Tasman found that an emission permit price of $42 (2005 dollars) in 2020 and a 20% renewable energy target resulted in several large power stations closing prior to their business-as-usual life. The report found that some 6,700 MW of mostly coal-fired generation capacity in the NEM would close, while the value of many other generation facilities would be substantially reduced. These closures would represent about 15% of current generating capacity on the eastern seaboard.

The study found that some 15,000 MW of gas-fired and renewable generation facilities would need to be constructed to replace these closed facilities and supply the expected growth in system load. This amounts to around a third of the NEM's existing installed capacity. The level of investment required in electricity generation over the period would therefore need to triple from around $10 billion to around $30 billion in real terms.

There are considerable lead times in the planning, permitting, construction and commissioning of large infrastructure projects. The NEM's minimum reserve methodology is designed to deliver low cost energy and to achieve the unserved energy target over the longer term. The NEM system reserve levels are low compared with other international benchmarks – around 10% reserves for the NEM, whereas most other electricity markets are set at around 15%. Based on median load forecast, planning reserves may fall to 8% by 2010.[2]

In the presence of a global financial crisis, sourcing sufficient capital to re-finance existing assets – many with shortened asset lives – and to invest in new capital may prove particularly difficult. The outlook for the global and domestic economies has deteriorated even further in the period since the AEMC considered the issue of financing new energy investment for the Interim Report. Feedback from esaa members is that the availability of credit from international and domestic sources for new projects and to refinance existing debt obligations has tightened significantly and risk premiums have increased. The number of equity providers able to invest large amounts of investment capital in sunk assets has also fallen.

As noted earlier, the level of assistance provided for electricity generators under the Electricity Sector Adjustment Scheme is substantially inadequate. This will create perceptions among debt and equity providers that the Australian Government is willing to strand assets even though investors committed significant capital in good faith under pre-existing market arrangements. This may make the investment task all the more difficult if investors are discouraged from making investments until there is a tight supply and demand balance in the market. Building higher rates of return into business cases to offset regulatory uncertainty would require higher electricity prices to justify new projects.

Framework for regulated investment

An altered generation mix and changed energy usage patterns will need to be accommodated by the transmission and distribution networks for both electricity and gas. These are the links between energy producers and final consumers and efficient and effective energy networks will be vital in the transition to a low emission energy supply system.

esaa anticipates that significant additional investment will be required in gas pipeline infrastructure along with considerable new investment in electricity transmission and distribution to meet the needs of a low emission energy supply system and ensure reliability of supply. The regulatory framework will need to accommodate these

[2] Simshauser, Nalder & Rolfe, "Survival of the 'pack' – on emissions trading permit allocation policy, reliability of supply and incumbent power generators in Australia", June 2008.

significant changes and enable the regulator to consider all costs incurred by network providers along with non-network options including embedded generation.

As noted earlier, the AER's recent draft decision on the weighted average cost of capital will discourage new investment in networks.

Comments on Part B: Western Australian Energy Markets

esaa broadly supports the AEMC's assessment and identification of the material energy market framework issues for Western Australia (WA) to be progressed under the Review. However, esaa recommends the AEMC give further consideration to the impact on short-term generation investment and reliability of the connection application and queuing policy process along with network planning approaches under issue B2/B3. In addition, while the AEMC did not consider the issue separately for WA, esaa considers aspects of the market frameworks may impede the financing of new energy investments. As such, issues raised under Section A8 of the Interim Report should also be considered in the WA context.

esaa notes that the AEMC's approach to this section of the review is that where an issue is well defined in WA, is specific to that jurisdiction and for which a clear mitigation course has already been identified, then the issue is noted but assumed to be resolvable by the relevant institutions or processes within the jurisdiction.

The AEMC should be aware that since the Interim Report was prepared, the Economic Regulation Authority's (ERA) report to the Energy Minister on the Efficiency of the Wholesale Electricity Market (WEM) was released with a recommendation to the Office of Energy to develop a "road map" to address longer-term fundamental market design issues. The full scope and timeframe for this process has not yet been announced.

In addition, the Minister for Energy has established a major review of the State's gas provisions to be undertaken by the Gas Supply and Emergency Management Committee, which is chaired by the Coordinator of Energy. The review will identify risks to the State's supply of gas, including the amount of gas reserves available to the domestic market as well as processing and gas delivery. It will also examine ways to improve the management of energy emergencies. The Committee is expected to begin work in March 2009, with a final report to be published at the same time as the AEMC's final report in September 2009.

esaa considers that, given the proposed start dates for the CPRS and expanded RET and the timing of the proposed WA-based reviews, there is a risk that critical issues with respect to market frameworks may not be addressed in a timely and adequate manner. As such, there may be scope for such issues and potential responses to be considered under the AEMC's Review. Nonetheless, some issues facing the WA market are largely related to more fundamental questions about market design and will not be materially exacerbated by the introduction of the CPRS and expanded RET. These may be more appropriately addressed through a specific WA review process.

For some issues, the AEMC has requested feedback on a range of mitigation options to be considered in the Review to determine a preferred approach. esaa does not yet have a detailed understanding of the implications of some of the suggested solutions and, as such, has not made specific recommendations. esaa is undertaking a strategic policy project to assess the optimal, long-run whole-of-industry energy policy framework and structure for the WA energy market, which will include a detailed assessment of potential solutions to market design stress points. This review will be well progressed in the next few months and esaa anticipates that it will be in a position to provide more detailed input into later stages of the Review.

B1. Convergence of Gas and Electricity Markets

Climate change policies will drive investment in new gas-fired generation and intermittent (largely wind) generation and, as a result, additional investment in low merit order gas-fired generation is also likely. Assuming that increased costs resulting from the climate change policies are allowed to be passed through to the end consumer, it is possible that the energy load profile may change to reflect a smaller ratio of average demand to peak demand (load factor) and therefore require increased investment in peaking plant. This is because annual peak demand may continue to grow, while the price increase will incentivise customers to reduce energy consumption on a day-to-day basis. Consequently, gas demand from the electricity sector may increasingly be in the form of “non-firm” demand for gas.

The current market structure for gas inhibits “non-firm” access required by peaking generators due to the lack of a comprehensive short-term gas trading market and the contract carriage nature of pipeline access. The inflexibility and unresponsiveness of the gas market mechanisms is further exacerbated by differences between gas and electricity market nomination timings, which impedes efficient coordinated decisions with respect to fuel usage and generation decisions. esaa notes that the current lack of consistency between, and transparency of gas and electricity markets in WA is already a material issue. While the impact of the CPRS and RET will serve to underline the current deficiencies of the market frameworks, esaa agrees the issues are largely related to more fundamental questions about market design that are more appropriately addressed via WA review processes.

Likewise, the lack of gas supply diversity (with respect to both upstream competition and pipeline transport) has significant implications for the competitiveness and security of both the electricity and gas markets, and should be progressed under the Minister for Energy’s Gas Supply Review.

B2. Generation capacity in the short-term

B3. Investing to meet reliability standards with increased use of renewables

The AEMC considers the Reserve Capacity Mechanism in the WEM will ensure that there is sufficient capacity in the system to meet reliability standards, because the Independent Market Operator is not permitted to allow capacity to fall below the amount that the Market Rules require to be installed. However, there is some debate as to whether the market is delivering the “right mix” of generation to deliver energy throughout the year and not just at times of peak demand. This could be exacerbated by the CPRS and RET due to the effect they may have on the merit order of generation. Additionally, the expanded RET will drive investment in renewable generation technologies, many of which are intermittent in nature, and will require additional back-up generation capacity.

The Market Rules require a potential generation investor to secure a firm network access offer from Western Power for its facilities in order to secure certification of its capacity. In assessing connection applications, network planning is undertaken on an "unconstrained" basis. That is, a new generation connection should not compromise the reliability and security of the network or the ability of other (existing) generators to deliver their certified capacity through the network.

Additionally, Western Power has implemented an application and queuing policy to assess connection applications in the order in which they are received. Given the requirements associated with the unconstrained network planning model, the assessment of network connections is, by necessity, a lengthy process.

Thus, the lengthy development and network access lead times brought about by the application and queuing policy and unconstrained network planning approach may impede the dynamic and allocative efficiency of the market. Significant delays could be experienced in delivering new renewable energy capacity and the required back-up support generation in order to meet the RET and deliver emissions reductions under the CPRS while maintaining system security.

The Renewable Energy Working Group (REWG) is considering how capacity credits are allocated to renewable energy generators to better reflect their contribution to peak demand. However, a complementary analysis should be undertaken of the compounding effects of the application and queuing policy and network planning approach on the market signals for the efficient and appropriate entry of new generation capacity in light of increased renewable penetration. The AEMC should consider and liaise further as to whether it or the REWG would be best placed to undertake such analysis.

B4. System operation and intermittent generation

esaa supports the AEMC's view that the current market framework in WA may not be sufficient to maintain a secure power system given the predicted increase in intermittent generation. The increased demand placed on the system by large volumes of intermittent generation is a material issue, particularly as intermittent generation does not currently face the full costs of the externalities it can create.

Variations in output from intermittent plant must be managed via balancing mechanisms and through network ancillary services. These services are essential in order to maintain system stability and security and to mitigate the risk of wide-spread system shutdown affecting both transmission and distribution systems. In the SWIS, this service is provided almost exclusively by Verve Energy.

Displacement of baseload generation as a result of climate change policy is likely to result in suboptimal operation of Verve's plant, which may limit its ability to efficiently contribute as a balancing generator and/or ancillary services provider. The current pricing mechanisms for these services may not provide sufficient signals for alternative plant to compensate and provide such services. The unconstrained network planning model and the application and queuing policy may compound this issue by impeding the allocative and dynamic efficiency of investment in generation and transmission.

esaa supports the investigation of options that would provide greater flexibility within the market to better manage fluctuations in supply and demand. For example, provided a detailed cost-benefit analysis indicates there is a net benefit, a move toward removal of the day-ahead Short Term Energy Market (STEM) to be replaced by a real-time competitive balancing market and economic dispatch could be considered. The option to investigate curtailment instructions for wind should also be considered, albeit in light of potential distortions on the REC and energy markets.

B5. Connecting new generators to energy networks

The AEMC considers that the expanded RET will predominantly stimulate investment in wind generation capacity given its maturity and cost competitiveness. This is likely to be concentrated in geographic areas remote from both the existing transmission network and load. The AEMC considers that the existing model of bilateral negotiation for new connections is unlikely to be sufficient in facilitating such investment. It also considers that the current unconstrained planning approach and queuing policy under the connection process could potentially exacerbate delays in new connections.

esaa agrees that the planning approach should be reviewed as a matter of priority, including an assessment of the unconstrained methodology and queuing policy. esaa recognises that the role of the application and queuing policy is not to pick "winners" or "losers" from prospective generation proponents. Nevertheless, an inadvertent consequence of the non-discriminatory queuing policy may be the impediment of efficient and appropriate generation investment and co-optimised transmission investment. Furthermore, there is anecdotal evidence that the connection queue is being constrained by the presence of speculative developments and the lack of a mechanism to identify and prioritise more robust projects. The continuation of the unconstrained network planning approach could result in over-investment in transmission network assets and exacerbate delays in the network connection process, further increasing economic inefficiencies.

B6. Augmenting networks and managing congestion

esaa agrees with the AEMC's consideration that the current planning frameworks for network augmentation are unlikely to be adequate in ensuring efficient use of, and investment in, electricity networks and provide for the ability to manage emerging congestion in a cost reflective manner.

As outlined in the response to issue B5, esaa agrees that the unconstrained network planning model may not be sufficiently flexible and robust to facilitate a large influx of generation connection applications, particularly from renewable energy plant as a consequence of the RET. It is considered that this is already a material issue, and should be addressed as a matter of priority. The AEMC is therefore supported in undertaking an investigation of mitigation options.

B7. Retailing

esaa agrees with the AEMC evaluation that the current framework for retail price regulation in WA is not sufficiently flexible to deliver efficient prices and services to retail customers following the introduction of the CPRS and RET. Given the lack of cost-reflective pricing and therefore effective retail competition in WA, esaa considers the scope to remove retail price regulation at this point in time is limited. It is important therefore that the Government introduces effective and efficient price regulation that delivers tariffs reflective of the underlying costs to supply.

It is well recognised that current electricity retail prices are well below the cost of supply in WA. Since the AEMC's Interim Report was released, the Minister for Energy has announced increases to the State's electricity retail tariffs. Prices for households will rise by 10 per cent on 1 April 2009 followed by a further 15 per cent rise on 1 July 2009. Prices for small business will increase by 5 and 10 per cent in April and July respectively, while most contestable tariffs will increase by 10 per cent in April and a further 10 per cent in July.

esaa notes with concern that these increases are significantly below the Office of Energy's final recommendations for increases of 52 per cent for residential customers, 29 per cent for small business customers, and 51 per cent for large contestable businesses. While esaa supports moving towards cost reflectivity as a priority, if such an outcome in unachievable in the short term, then the Government should explicitly fund the shortfall between the new tariffs and cost-reflective price levels through Community Service Obligation (CSO) payments so as not to further distort the wholesale and retail markets.

Depending on the final design features of the CPRS, there is a risk that counterparties, particularly existing emissions intensive generators, will be unable to meet their contractual obligations. This may expose retail counterparties to higher contracting costs or STEM exposure, and increase the risk of further Government intervention in the market. Flexibility in retail tariff price setting is required to ensure full cost pass through of costs arising from the CPRS and expanded RET.

The increase in wholesale electricity costs resulting from the CPRS may also create a significant step change to the quantum of capital or guarantees required to meet the WEM prudential requirements, thus the level of the prudential requirement should be reviewed to ensure participants are not exposed to undue financial distress.

Consistent with the position outlined in section A7, esaa also considers that retail price regulation in WA would be more effective if decisions were arrived at under a transparent, nationally consistent, framework for price setting. Furthermore, to assist this transparency and avoid inherent conflicts of interest, esaa supports the removal of price setting decisions from the Minister for Energy and transferring the decision making powers to an independent authority such as the Economic Regulatory Authority or AER.

Hardship Customers

Given the scale of the increase in electricity retail prices required to ensure cost-reflectivity, introducing cost reflective tariffs is likely to increase the proportion of customers experiencing hardship and the rate of payment default, particularly given the current global economic climate. Currently, approximately 300,000 customers from the total of 850,000 customers receive some form of energy concession or rebate. An overhaul of the rebates and concessions program will be required to ensure that targeted welfare packages are available to assist the most vulnerable customers experiencing hardship. Such welfare packages should be directly funded by Government through CSO payments, and remain explicitly separate to the market so as not to distort its operation or create cross-subsidies.

A8. Financing new energy investment

esaa contends that the cost, availability and form of finance will be sensitive to the recent developments in global and domestic financial markets, and the inadequate level of assistance provided under the ESAS will result in an increase in the risk premium associated with new investments.

Although the AEMC did not consider this issue separately for the WA market, esaa disagrees with the AEMC view that energy market frameworks do not impede the efficient financing of investment in WA on the basis that aspects of the market design intensify project risk from a financing perspective. This issue should therefore be considered under the Review.

For example, the long development and network connection lead times for generation are a significant issue, particularly in light of the two-year capacity cycle. The impact of the queuing policy and current network planning processes has undermined confidence in network connection timing. Similarly, the inflexibility of the STEM in allowing rebidding to adjust for real time scarcity or allowing generators to mitigate real time constraints through portfolio management creates additional trading risk, which may also result in a higher risk premium applied to new investments.