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14 November 2008

Dr John Tamblyn
Chairman
Australian Energy Market Commission
AMEC Submissions
PO Box A2449
Sydney South
NSW 1235

Your reference: EMO 0001

Dear Dr Tamblyn,

**Review of energy market frameworks in light of climate change policies – scoping paper**

TRUenergy is pleased to have the opportunity to comment on this scoping paper for the current AEMC review into the impacts of climate change policies on energy market frameworks.

*Background on TRUenergy*

TRUenergy operates assets that span the gas, electricity and renewable markets across eastern Australia. Our asset mix includes a large brown coal power station, gas fired peaking stations, the new generation combined cycle Tallawarra gas plant, an electricity and gas retail business with 1.3 Million customers, gas exploration acreage, a merchant underground gas storage, investments in renewable generation assets (including large scale solar, wind and geothermal) and a significant gas and electricity trading business to optimise the operations of these assets.

Our business is deeply entrenched in the gas, electricity, and renewable markets and is increasingly being influenced by the emerging carbon markets. In many ways our asset mix mirrors the overall Australian energy mix, with a high exposure to high emissions coal plant, and a growing position in low emissions and renewable technologies.

*In this context we believe we are well placed to comment on the likely impacts of* climate change policy on energy market frameworks.

*Importance of the investment environment*

Key amongst the impacts of the Carbon Pollution Reduction Scheme (CPRS) will be the need to ensure that the energy market frameworks provide an investment environment that is able to deliver the significant investment that will be required to retool the Australian energy sector for a low emissions future. In this regard TRUenergy has made a significant start with over $1 Billion of emissions reducing projects under development.

In addition to investment, climate change related policies will create serious operational challenges for energy markets through the transition as:

- Existing power generators face the need to adopt operating regimes for which they were not designed; and
- Generator retirement timings are brought forward, and concentrated into a shorter period than would have otherwise been the case.

The AEMC faces the responsibility of ensuring that market frameworks will provide adequate incentives for this transition to be dealt with smoothly and efficiently.

*Need for a smooth transition to the new policy regime*

While the AEMC can ensure market incentives are appropriate, a smooth transition will only be possible if the introduction of the new policy regime itself avoids the risk creating systematic financial failure amongst energy market participants. Critical to this will be government policy settings associated with the proposed Electricity Sector Adjustment Scheme.

Without appropriate transitional assistance, high emission generators will face immediate financial impairments which will undermine their balance sheets, and severely limit their ability to fund investment and continued operational expenditure.

Such a serious financial deterioration of a large group of the energy market participants would produce negative flow on impacts across the sector, by:

- Potentially creating incentives for distressed generators with bleak futures to seek short term earnings;
- Reducing the ability of effected business to adequately invest in operations and maintenance;
- Impacting on the finances of other participants exposed to effected generators; and
- Undermining investor confidence in the NEM as an investment destination.

These impacts have the potential to adversely impact on reliability and market stability.

*Ongoing market changes*

Even if the initial scheme introduction avoids immediate financial problems in the sector (via an appropriate transitional assistance scheme), the need for generators to transition to new market roles over time will create a number of operational challenges.

Increasing gas generator penetration is expected under a CPRS and is likely to stress gas markets – particularly with respect to intraday risk allocation. In addition the introduction of the expanded RET scheme will drive significant development of intermittent generation. This will create its own operational challenges associated with ancillary services, technical connection standards, transmission grid topology, and incentives to maintain and operate capacity plant. Intermittent power generation may also reflect into increased gas demand volatility, which will amplify intra-day impacts on gas markets.

*Key areas for focus*

In this context this review is timely, and we believe that the AEMC has broadly captured most areas of concern in its scoping paper.

Our attached submission sets out our more detailed comments on the nature and materiality of issues raised in the scoping paper, as well as the few matters not covered in the scoping document which we consider require attention.

In summary, key areas of focus that we believe should be addressed by the review include:

*Gas related matters*

- Sufficient flexibility in regulated gas transmission regimes is needed to deal with the uncertainties of climate change policy and ensure that investment will be delivered in a timely manner, to underpin required generation and storage investments;
- Improved intra-day gas market cost allocation and more market based approaches to gas emergency management are required;
- Historic gas marketing anomalies should be removed to increase upstream competition in the gas sector;

*Operational matters*

- Ensuring market frameworks deliver sufficient incentives for reliable operation and investment to meet the market objective without recourse to distortionary market operator or government interventions;
- Ancillary service arrangements need to be reviewed including reserve requirement quantum in the face on increased intermittent generation, hedging and investment incentives;

*Electricity investment related matters*

- Increases in VoII/MPL are likely to be needed to ensure incentives for maintaining/investing in capacity plant remain sufficient;
- Facilitation of the investment environment through creating an ability of generation investors to achieve certainty in access to the local reference node for the life of an investment (ie. ability to protect against congestion);
- Examination of options to provide increased certainty on loss factors for the life of a project at the time of investment;

*Network matters*

- Consideration of greater alignment of electricity and gas connection regimes to deliver dynamic efficiency benefits;
- Improvements to the connection process including implementation of a one-window nationally consistent connection agent for generators via AEMO;
- Further consideration should be given to the benefits and risks of regulatory approaches to provide transmission backbones to open up promising long term renewable resource areas;

*Retail and financial investment matters*

- Removal of retail price caps to allow continued investment in retail markets, and implementation of an improved ROLR scheme; and
- Maintaining financially robust and stable market operators to underpin the energy sector as an attractive investment environment.

We look forward to further participation in this review, and would welcome the opportunity to clarify any areas of our submission required, or discuss our views on the impacts of climate change policy on energy market frameworks in general. To facilitate such discussions, please contact Mark Frewin, Manager Wholesale Market Regulation, in the first instance on 8628 1000.

Yours faithfully,

Carlo Botto
Director, Portfolio Management

## TRUenergy submission to the AEMC review of energy market frameworks in the light of climate change policy – Scoping paper

### 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?*

With high power generation demand increases following the introduction of the CPRS, as well as the development of an LNG export industry in Queensland, the east coast gas market may face significant price pressure over the medium term. Apart from pricing pressures, questions of reserve adequacy could also become relevant.

More specifically, the impacts on gas markets associated with climate change policy are likely to include:

- The need for infrastructure investment in the entire gas chain to supply large increases in base load power generation from gas (in response to the CPRS);
- Large chunks of gas reserves being locked up to underpin investments in power generation assets;
- RET induced increases in intermittent generation feeding into greater volatility in gas demand, as gas power stations respond to generation deficits when intermittent plant is not available;
- General increases in gas market demand volatility (both between days, and within days), as an increasing proportion of demand is met by power generation that will experience contingencies, and otherwise need to respond to 5 minute electricity price signals;
- Increased importance of reliability of gas supply to power generators as they take up an increasing role in providing electricity system reliability and security.

In general unregulated gas infrastructure providers have shown a track record of being able to deliver major projects when the market for them is available (eg. SEAgas, QSN, EGP, CSM development, Otway developments etc.). However there are a number of areas where regulatory changes could assist in creating a more competitive gas market, which will be needed to keep pricing pressures to justifiable levels. These include:

- The need for publication of sufficient information for potential investors to ascertain reserves and whether or not they are committed to projects (noting that the proposed gas SOO will go some way toward improving this area);
- Historic marketing arrangements (eg. Joint marketing) continue to artificially concentrate the upstream gas market in a way that is no longer justified given the well developed and diverse downstream gas market that faces significant demand pressures over the medium term.

In contrast regulated pipeline systems have proven more problematic from a development point of view.

One area that has created challenges for TRUenergy is aligning the development of regulated gas network assets with merchant asset development in Victoria. In particular TRUenergy is expanding its underground storage capacity in response to market interest, but faces network constraints in delivering the capacity to market due to a divergence in the market outlook between assumptions used in the regulatory test used by the network developer and the consensus market view that has underpinned the merchant development. Difficulties in factoring in CPRS based power generation expansions into the regulatory decision making process appear to be a key contributor to the gap between market and gas planner views on required future augmentations.

An alternate approach to developing network assets available under the regulated gas regime is to have proponents fund the augmentations. However the rights received for such funding are of questionable value to power generator developers given gas market curtailment practices – which means this option remains unattractive. If no change in the regulatory investment criteria is possible, then review into improving rights received for investment in this area may be warranted.

On the demand side, questions remain about the ability of power generation developers to connect to the Victorian Principal Transmission System (PTS) in a way that will provide adequate certainty over intraday flexibility rights (ie. MHQ) needed to manage demand volatility without undue impact on the system or exposure to imbalance charges.

Closely related to these questions are the way in which power generators are viewed in market operator and government curtailment processes. In the past power generators have often been seen as interruptible, and have been curtailed at the first sign of system problems. While in the past this has led to investment problems, such as creating a disincentive to develop liquid fuel backup on power stations, it will be unsustainable in the future as gas power stations take on a more important role in providing electricity system reliability. It is also important that realistic views about power generation interruptability are factored into regulatory investment decisions if adequate gas networks are to be built.

There will also need to be review of the ability of the various gas markets to efficiently deal with intra-period demand variations – but this discussed in more detail in the next section.

Overall there are a number of material issues that warrant exploration in relation to the investment environment around regulated pipelines in Victoria.

*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?*

The main area of discussion here is around the fact that the electricity market is a highly responsive 5 minute market, which combined with increased gas generation and intermittency is likely to drive significant intra-period demand volatility in gas markets.

*Victoria*

The Victorian gas market currently has the capability to price down to the 4 hourly intervals. This is quite dynamic by world gas market standards and better aligned with electricity requirements than other Australian arrangements. However intra four hourly variations can attract significant charges and in some circumstances these can be smeared over participants who have not caused the deviations. While there is some risk of inefficient cost allocation within this framework, the Victorian arrangement is probably best able to deal with the operational challenges of demand variations.

An area for improvement in Victoria however will be to ensure that curtailment practices and system development arrangements do not result in power generation being interrupted in a way that could impact on electricity system reliability. This issue is seen as material and worthy of review.

*Contract carriage states*

In other states, a range of gas network balancing arrangements are currently in place. These generally rely on network contracts dealing with excessive intra-period volatility, and have proved effective historically – as generators know in advance what level of flexibility they have available under their transport agreement. While effective, a higher level of power generation is likely to open up the option for more dynamic trading of flexibility rights embedded in these contracts.

The STTM is being proposed to help provide a daily price signal, which is likely to provide a useful reference price for secondary trading of capacity and energy. This market should also assist by providing a more relevant reference price against which any curtailments can be valued. For power generators, the key issue facing contract carriage markets is the need to better manage emergency situations and in particular power generation curtailments. Curtailment management is a material issue that should be reviewed – as it directly impacts on incentives to invest in gas system capacity and dual-fuel capability.

From a retailer's perspective, a key concern will be that cost allocation mechanisms in markets related to intra-period demand volatility do not result in unmanageable costs being smeared onto retailers. This issue should also be reviewed.

## 2. Generation capacity in the short term

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

To comment on this section it is worth expanding on our view of how the CPRS may impact on generators over the short, medium and long terms.

In the short term, the severity of response will be driven by the transitional assistance policy adopted by government. Should inadequate assistance be provided, existing generators will face serious deterioration in their financial position (due to balance sheet asset impairments as the impacts of future permit costs on asset valuations are recognised). Financially challenged generators are likely to:

- Seek to cut costs in all areas, including maintenance – with the likely result of increased forced outage rates potentially impacting on system reliability; and

- Face Incentives to increase returns in the short term – on recognising that the station is not likely to survive into the longer term, generators may seek to maximise returns in the short term pool, which could be possible if continued policy uncertainty further delays investment in replacement generators leading to a short term increase in market power for incumbents.

These impacts clearly have the potential to impact on reliability and affordability of electricity in the short term. They are best avoided by provision of certainty over the CPRS regime, and an appropriate transitional regime to allow the graceful phase out of high emission plants. We see the risk of these outcomes as material and potentially lasting until replacement generation stock can be developed.

In the medium term, key challenges will include:

- The need for existing generators to change their mode of operation as entry from lower emission plants pushes historic base load plant into a more peaking role. Given the age and design features of a wide section of the existing coal fleet this will be a major operational challenge and is likely to require significant levels of investment to allow more flexible operations of this kind. This is a particularly material issue in Victoria which has over 6000MW of plant that will potentially need to retire or move into more flexible operating regimes in the medium term.
- Ensuring smooth retirement of high emissions stations as carbon pricing makes them uneconomic.
- Practical constraints on building the next generation of low emission plant will also play a role in determining when significant replacement plants will be available to reduce emissions. These constraints will include:
    - Permitting processes, which typically take over 18 months;
    - Time lags in procuring and constructing turbines, likely to be around 40 Months for combined cycle gas plants;
    - Ability to source skilled personal, experienced in constructing and operating gas / renewable technologies (noting that the majority of Australia's skill base is based around coal technologies, and this workforce is aging);
    - Pipeline, and upstream gas infrastructure delays. In particular concerns with regulated pipeline development outlined above are of relevance;
    - Inability of investors to manage congestion / MLF risks (discussed in more detail later) creating a material barrier to investment in the NEM;
    - The potential for ongoing constraints on funding availability – although this will be a function of returns on offer from the sector, and general the general economic growth outlook.

Finally in the longer term, climate change policies may create a major change in network topology as historic centrally planned transmission paths become less relevant and a more renewable rich dispersed generation fleet emerges. It is unclear how the network investment regime will deal with these changes. In particular it is likely network planning approaches may need to become more flexible to deal with the uncertainties of technology development that the CPRS may bring.

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

To summarise some of the key constraints discussed in the preceding discussion and their materiality:

- Reduced maintenance spending and its impacts – Material if transitional assistance inadequate and likely to persist for the medium term until replacement stock can be constructed.
- General infrastructure constraints – seen as material in effecting the period over which renewable and replacement base load fleet can be rolled out.
    - Some of these areas can't be managed by regulation, and will only be addressed by greater certainty over climate change policies.
- Regulation constraints on pipeline investment are material and will be long term if not addressed:
    - This is material and the review should ensure that regulated transmission can be delivered to ensure required power generation investment in a timely manner.
- The lack of MLF and congestion risk management options creates a barrier to entry which will become increasingly material given the level of new development required in response to climate policies.

*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?*

*Concerns over the nature of this question*

We are concerned with the direction of this question. The whole philosophy of the NEM is to create market incentives for the delivery of a power system geared to deliver the market objective. In contrast to this philosophy, this question appears to assume that it will be acceptable to have an increase in system operator interventions – which by their very nature indicate the market has failed.

We note that any increase in the level of intervention is likely to impact on the investment environment. This will occur by decreasing the certainty that market signals will be the key determinant of system operations and investment / retirement decisions. A move in this direction could be the first step in a process that leads to centrally planned investment – something that would clearly undermine the market philosophy, and that we strongly oppose.

Rather than contemplating the effectiveness and efficiency of system operator interventions, the AEMC should be focusing this review on ensuring that such measures are never likely to be required.

*Uncertainty over CPRS creating delays to investment*

One scenario that could lead to operational problems would be ongoing uncertainty over the CPRS and RET policies leading to ongoing delays in investment – and ultimately an inability to meet the reliability standard.

It is noted that neither of the existing intervention options, either the reserve trader or system operator direction would be able to deal with this scenario. In particular the reserve trader is only effective at bringing existing capacity back into the market that had voluntarily decided to forgo market opportunity (or bring demand side response in which is otherwise uneconomic). The reserve trader is not able to bring forward investments that have been delayed by uncertainty over future government policy.

Market operator direction would also be unable to deal with this situation for similar reasons. The only way of dealing with this risk, is for the government to provide increased policy certainty on the CPRS and RET. In this context we see no reason to pursue this area further in this review.

*Implementation of CPRS results in financial distress of major generators*

Under this scenario, the financial impacts of the CPRS (with inadequate transitional assistance), would cause major generators to face severe financial problems. It is not inconceivable that this could push some generators into the hands of their creditors.

Decisions to continue trading are assumed[1] to be based on incentives for the controlling entity to maximise its returns from a distressed asset. It is conceivable that under some conditions (ie. when forecast costs exceed expected revenues) the commercial decision may be to close the facility.

Under this scenario the ability of intervention mechanisms to operate in a way to capture these events prior to closure will be important (as post closure staffing may not be present to respond to an operator direction even if one was issued).

In order to avoid this scenario, it is likely the reserve trader would need to facilitate the transfer of market risk and carbon risk onto the system operator, potentially for the medium term until replacement capacity was constructed. This would appear to move the retirement decision onto the market operator – an outcome which is at odds with the market philosophy. It also creates significant unhedgeable costs for retailers which have undesirable effects outlined below.

The other alternative intervention would be for the market operator to direct the participant to continue operating – presumably indefinitely. This approach has several problems:

- Firstly, this power of direction was originally conceived to deal with short term problems in the energy market and not to deal with longer term problems (eg. premature retirement). It would be inappropriate to seek to alter this mechanism to deal with longer term matters – the key priority should be on ensuring that CPRS policy is implemented properly, and that the market incentives drive retirement behaviour consistent with the market objective;
- Secondly, the current direction power has compensation provisions that require an independent expert to determine reasonable costs of providing the directed service. It is not clear that this ex-post process of determining costs would provide sufficient clarity over future revenues to allow those responsible under corporate law for the ongoing operation of the asset to responsibly let

[1] Note: TRUenergy has not considered legal constraints that may over-rule commercial drivers in situations of financial distress.

its operations continue. It is not clear that the power of direction under the NER would over-rule any duties of this kind under the corporations law.

As such system operator directions do not appear to be well suited to deal with premature retirements.

In either of the above examples, costs incurred by the market operator would be recovered from market customers. This outcome would create large unhedgeable costs for retailers, and them with no option but to seek to pass these imposts through to customers (clearly undesirable), or in cases where pass-through is not possible to seek to fund them from the retailers own resources. Needless to say, unhedgeable costs of the magnitude involved in these examples, would substantially increase the risk of the Retailer of Last Resort (ROLR) events being initiated.

Overall the option of relying on reserve trader or direction mechanisms is counter to the overall philosophy of the market design and creates undesirable impacts on retailers and customers. For these reasons we do not consider these options either efficient or effective, and suggest that the focus of the AEMC should be on ensuring that the standard market incentives are sufficient to avoid these interventions ever being needed.

## 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?*

In assessing whether increased intermittent generation is likely to impact on reliability, it will be important for system operators and planners to increase their analysis capabilities to allow assessment of the portfolio of intermittent projects across the NEM. This is important as it would be expected that a geographically diverse mix of intermittent resource may to a degree offset the intermittency effect. Given that siting for the RET inspired projects is not clear at this stage, and that we are not aware that the capability exists to estimate the portfolio effects that may emerge from any given siting, it is difficult to estimate this impact at this stage. In any event, creation of enhanced analysis facilities would appear to be a low-risk policy and should be pursued.

Apart from better understanding the portfolio effect described above, the other key factor in ensuring the system will remain reliable is to ensure that sufficient market incentive exists for ongoing investment in non-intermittent plants to provide reliable supply when intermittent resources do not permit.

In considering the incentives for maintaining and investing in further capacity providing plant, it is useful to consider the recent analysis by the Reliability panel in its comprehensive reliability review. In this review, the Panel found that even without the expanded RET and CPRS policies in place, an increase in VoII/MPL up to $12,500/MWh was required to ensure that the sufficient return would be available to capacity providers to ensure the reliability standard could continue to be met.

If we consider that the impact of large increases in intermittent generation are likely to further reduce the expected load factor of peak capacity providing plant, it is logical – based on the panels work – to conclude that further increases in Voll/MPL will be needed to allow the standard to be met under an enhanced RET world.

On this basis it is also logical to conclude the risk of the standard not being met is material and that this issue should be thoroughly considered by the AEMC during this review.

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

As outlined above, one simple option would be to increate Voll/MPL and maintain the current energy only market design. This would increase the potential returns from capacity investments, thereby maintaining sufficient incentives to allow the reliability standard to be met. An added benefit would be that this could increase incentives for demand side participation, with one of the key economic barriers to this in the past being insufficient capacity value in the market to provide a return from demand response.

Some commentators have indicated that increasing the Voll/MPL is not desirable on the basis that it increases participant risk. Other suggest that government intervention is likely to prevent high Voll/MPL prices ever being allowed to be reached for sufficient time to allow a return to be made, or that further policy interventions (eg. RET) will undermine potential returns from the market.

We are comfortable with the risk profile from a Voll/MPL increase as this can be managed through investment or via contract. The increased cost of meeting the standard imposed by policy interventions such as the RET, will be passed through to market customers via the contract market.

On the issue of future policy interventions impacting on the market, we agree this is an ongoing risk. However it is not clear that changing to an alternate market framework (as proposed by some) would create a model any less prone to heavy handed policy interventions of this type. On the contrary, we believe it would be better to ensure that policy makers where better informed about the impacts of their actions so that the incidence of distortionary policy is reduced. In addition, a clear statement from the reliability panel that it would ensure that the Voll/MPL was maintained at levels sufficient to deliver the reliability standard *in whatever external policy environment emerges*, may go some way to alleviating this risk.

Contrary to these views, proposals such as capacity payments, reliability options and other variants have been proposed from time to time. In our view, for these mechanisms to create the same incentives as Voll/MPL increase, the same additional risk premium would need to be recovered from customers for and equivalent reliability outcome.

Proponents of these options have tended to argue that they are likely to be more robust against external policy interventions (such as the RET). As mentioned above, we are not clear why this would necessarily be the case, and suspect that a determined policy intervention could impact these alternate market designs just as dramatically as it would the energy only market. For this reason we are yet to be convinced that a major change to the market structure of this type is likely to be the most efficient way of maintaining reliability.

In summary we see the issue of maintaining reliability and returns to capacity suppliers in the face of the expanded RET policy as material and worthy of review by the AEMC. At this stage we believe the current market design with adjusted reliability settings is likely to be the most efficient way of delivering the desired outcome.

## 4. Operating the system with increased intermittent generation

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

The key challenges we perceive in regard to large increases in intermittent generation include:

- Barriers to investment related to increasing and unmanageable network congestion and instability of MLF's over the life of an investment. These matters are explored in more detail below.
- Ancillary service requirements and cost recovery mechanisms. It is not clear to us that system operators have the tools to adequately determine the required levels of reserve to deal with large increases in intermittent generation. In addition, the implementation of cost recovery for regulation services should be altered to ensure intermittent plants are treated in line with other generators. Appropriate cost recovery arrangements are necessary to ensure efficient investment outcomes.
- In the longer term the ability of the investment environment to deliver sufficient non-intermittent generation will be essential. As outlined above increases in Voll/MPL are required.

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

From a system operators point of view, we are unclear if the current backward looking approaches to determining contingency and regulation requirements will be sufficiently robust to deal with major increases in intermittent generation. Consideration of the adequacy of existing analysis tools is warranted in this review.

With regard to the other issues raised above, they relate more to participants than operators, but for completeness we note that tools to allow investors to manage congestion and MLF risks do not currently exist (discussed further below), and that the ability of the market to deliver adequate capacity investment over time is likely to have a direct bearing on market operators ability to meet its reliability and security obligations. This later issue will need to be managed by ensuring reliability settings are adequate.

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

Our views on the inappropriateness of intervention by market operators have been clearly laid out above (ie. we believe the market design should be designed to avoid any such interventions).

The introduction of semi-scheduled status may mitigate the need for manual operator intervention in cases of network congestion to some degree, however this will do nothing to assist investors overcome the barriers to investment created by an inability to mange exposure to congestion created by others.

It is not clear to what extent manual intervention may be needed to deal with ancillary service matters associated with large increases in intermittent plant. This area warrants further consideration.

Finally, failure to ensure the market delivers adequate investment drivers to deliver sufficient back-up capacity, is likely to result in intervention, for example if operators are forced to direct participants to maintain plant commitments in the face of unattractive market prices resulting from excessive intermittent generation in a region. A requirement for this type of intervention should be avoidable by ensuring sufficient incentives exist in both the energy and contingency FCAS markets to avoid this risk.

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

Increasing intermittent generation will increase the volatility of the residual demand faced by scheduled generators. More analysis is required to assess how great this volatility will be across the NEM fleet of intermittent plants, and over various time frames (eg. sub five minute, half-hourly, daily etc.). Given the large increase in intermittent generation forecast to be developed to meet the expanded RET targets, our intuitive view is that impacts in most of these timeframes are likely.

*Flexibility*

Many existing generators have been designed and optimised to provide base load power and face practical constraints in the level of flexibility they can provide. These could include:

- Minimum generation levels below which large thermal units are not able to operate;
- Limited ability to maintain ramping capability and increased maintenance costs if consistent ramping is experienced;
- Start up times ranging from around 15 minutes for so called "fast start" turbines, and over 12 hours for coal stations.

These limitations mean that large quantities of thermal generation will need to operate at minimum load to be available to provide ramping capability in the event of unexpected decreases in intermittent output. In order for this activity to remain economic (given that excess plant at minimum load, and high intermittent output are likely to lead to low energy prices), it is likely that FCAS requirements will need to be increased to allow FCAS prices to rise to levels that will provide a return to the thermal plants for remaining available in these conditions. To put this another way, it may be the case that prime revenue source for some generators switches from being energy provision, to the provision of contingency FCAS services.

It is noted that hedging has not developed in FCAS markets and low spot FCAS price have not delivered investment to date. In addition to reviewing FCAS requirements, the AEMC may wish to review the broader incentives to invest in the provision of FCAS services – including the ability of the current FCAS markets to support secondary hedging, which in turn could support investment in FCAS capability.

In the longer term, it may be that more flexible scheduled capacity becomes available to more efficiently meet this intermittency challenge. However it is unlikely that sufficient sources of flexibility will be available for at least a decade to replace the existing reliable generators, and so this issue will be material and should be reviewed.

*Retirement*

While flexibility will present serious challenges to scheduled generator operations, it is also likely that many may become uneconomic and seek to retire due to inadequate returns. If this effect is prevalent enough, then reliability could become threatened.

As outlined above, we have serious concerns with market interventions to deal with retirements. However unless significant incentives are maintained in the form of adequate market returns (Voll/ MPL – and the contracts that the threat of these prices drive, sufficient FCAS returns, etc.), some form of intervention may become necessary. For this reason it is critical that the AEMC ensures there will be adequate incentives in the market frameworks to ensure excessive retirement does not occur.

*Congestion*

It is likely that large increases in wind capacity in certain areas may congest out existing generators for much of the time, creating a local amplification of the increased volatility in scheduled demand problem outlined above for local capacity providers.

There is a risk that this situation will be faced by our Hallet power station in South Australia, which is located in a network area facing large increases in wind development. This risk weighed heavily on recent considerations we made into expanding our Hallet capacity. In fact this was the key commercial risk that the project faced – and it was apparent that there was no way to manage it. Ultimately the project did not proceed for technical reasons, but the threat of localised congestion was a key commercial issue that remained unresolved when it was decided not to proceed with the project.

While in this example the impact of this congestion impacted on an investment decision, it is likely that similar impacts may bring forward retirement decisions for existing plants impacted by congestion in the future as well.

## 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?*

In the contract carriage gas regime, generators normally face the full costs of gas transmission (via a take or pay capacity charge) required to service their needs, and therefore factor these costs into their locational decisions. In contrast the electricity regime mandates that only shallow connection costs must be borne by the generator, with any deeper connection investment optional (and unattractive given that such investment provides no ongoing rights to access). It is noted that if generators perceive a growing demand for energy within the region they operate, it may be a reasonable risk to avoid deep connection charges and gamble that within a short period the regulatory test will build out any resulting congestion to meet customer reliability requirements. These incentives can be amplified in cases where very large fixed pipeline capacity obligations can be avoided.

Under this environment generators in many cases face incentives to minimise gas transmission and maximise electricity transmission (which is paid for by others) when they locate. While this may be optimal from the perspective of the generator, from a societal point of view, a more optimal outcome may have resulted in a location that primarily transported the energy as gas and produced electricity closer to the load centre. This latter scenario would be attractive if the cost per GJ of gas transport was lower that the cost per GJ of electricity transport, taking into account the energy losses involved in transporting energy in either medium.

For the long term dynamic efficiency of the market, it will be important to ensure that the incentives on generators drive selection of efficient locations. Once a generator has located any inefficiencies are locked in for the life of the asset. For this reasons we perceive the long term efficiency benefits of improving the neutrality of gas and electricity transmission incentives are material, and likely to grow if CPRS drives gas generation growth as expected.

It is noted that the regulated Victorian network faces similar issues to the electricity arrangements in this regard.

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

*Bi-lateral negotiation inefficiencies*

The scoping paper raises the issue of the negotiation framework related to connections. Once a generator has made a site decision, it has few realistic options to counter unfavourable proposals put by network businesses during the connection agreement finalisation process (ie. the Network business has a dominant negotiating position). In addition to this, it is also apparent that NSP's have differing levels of experience dealing with generator connections, and adopt differing interpretations of the Rules from each other.

Another inefficiency, is that many connection issues require involvement of NEMMCO, and this creates another layer of negotiation that must be managed.

In order to address these challenges and streamline the connection process as we move into a period of significant and sustained new connection, a new approach is warranted to ensure that a single national approach is adopted on connection issues, and that one body is responsible for dealing with its implementation.

These efficiencies could be achieved by adopting a one-window approach to connection negotiations, with an appropriately resourced AEMO being the single point of contact for generators. AEMO would then co-ordinate any issues required with NSP's and ensure that a consistent approach was taken nationally. AEMO managing the connection process would also ensure an independent view on points of contention and provide a level of discipline on NSP monopolists in negotiations.

Another inefficiency raised in the paper relates to NSP's being unable to co-ordinate between various connecting counterparties when a co-ordinated application process may lead to a more efficient solution for all parties concerned. It appears that Rule confidentiality provisions currently prevent NSP's from disclosing potential counterparties to each other in this regard.

It is unclear to us why this confidentiality regime has been put in place, but we assume it related to some concerns over protecting the legitimate commercial interests of connectors. Given that prior to connection negotiations, proponents generally have to publicly lodge more general planning approval permits which outline the features of their projects, it is unclear if there is much commercially confidential information being protected by this Rule. In any event it may be acceptable to provide proponents with the option of allowing the NSP to disclose their identity to other potential proponents if the potential for a more efficient connection presents itself. Further exploration in this area would be warranted in this review.

*Connection of remote renewables*

The scoping paper also discusses the potential for some greater form of co-ordination of connection for remote areas where a significant renewable resource exists and a number of projects are likely – but would be more efficiently connected if a shared transmission backbone was built to the area.

A number of variants to this model have been suggested including having such backbones built by NSP's with the costs recovered through regulated revenues, the potential proponents creating a consortium to build the shared backbone, or even government infrastructure funds building these shared elements.

While our general view is that dynamic efficiency will be supported by proponents facing the cost impacts of their locational decision at the time they choose locations, we see that there may be potential for some longer term benefits from a regulatory funded solution under some conditions.

Such a situation could be attractive if development of a backbone network to a particularly rich renewable resource area could be shown to deliver long term benefits by opening up access to resources not otherwise available. This is analogous to historic decisions to develop areas like the Latrobe valley – which at the time would have required a relatively long transmission network to be constructed to open up a resource area that had provided economic advantage to Victoria for over half a century.

While we see the potential for such benefits, the mechanism to allow them to be unlocked without loosing broader efficiency benefits remains unclear. In this context we maintain an open position on this matter, and support further consideration of it during this review.

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

As outlined above, connection charges are a key locational incentive in the NEM. This may have the effect of making some projects uncompetitive with other options due to large connection costs. Such cases are not an unnecessary barrier to entry, but are examples of efficient market outcomes.

A material barrier to entry related to connection that we have experienced relates to the inability to lock in a predictable access level for the life of a project. This is a barrier to renewable and traditional developments, and is explored in more detail below.

## 6. Augmenting networks and managing congestion

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

Large increases in new connections in response to the CPRS and the expanded RET will create increased congestion on the network if current arrangements continue. This will become an increasing barrier to entry for all forms of plant, but particularly for generators seeking to provide reliable capacity to the market.

In theory the existing regime allows generators to make arrangements with NSP's to allow for compensation if constraints on their operations emerge. However to our knowledge no generator has ever been successful in implementing such rights, and we do not believe any NPS's have arrangements in place to deliver such a regime.

Disagreements also exist between generators and NSP's on interpretation of access rights previously granted to generators, which have subsequently not been implemented by NSP's; and on interpretations of the rights of generators as Network Users under the current Rules. There is a real threat that this situation could escalate into dispute as congestion mounts and existing generators investments are further undermined.

To summarise, a workable implementation of the existing Rule arrangements in this area has not proved possible, leaving generator investors facing unnecessary, inefficient and unmanageable risks.

As we discussed above, we have already faced this barrier in considering expansion at our Hallet power station.

While capacity providers will find the inability to be confident of ongoing unfettered access to the local reference node a barrier, even wind developments and other intermittent plants are likely to find the inability to be able to manage exposure to congestion from future entrants a barrier. We have faced this through our part ownership of Solar Systems, which is seeking to develop a 154MW solar facility in

Northern Victoria. Uncertainty over ongoing access to reference node pricing is a serious concern for this investment given the quantities of wind forecast to be developed in Western Victoria and South Australia.

As the impact of this growing congestion is felt by investors and financiers, funds for continued investment will dry up, or alternatively costs of capital will increase significantly. This will create very material impacts on the market and therefore urgent remedial action is required in this area.

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

We are concerned that the definition of "open access" stated by the AEMC in the scoping paper does not take into consideration the full range of issues encompassed by the concept of open access. The stated definition indicates that "open access" means that access seekers are not entitled to compensation if constrained off due to temporary network limits constraining generator behaviour.

The precise definition of how "open access" is defined is an academic question, which we will not attempt to address in this submission. However we are concerned with the definition that the AEMC describing this concept in its scoping paper, and would suggest a more complete (or at least referenced) definition be discussed in any future publications. We note for example that the Victorian gas market – which we would describe as a variant of an open access regime – does contemplate a degree of congestion rights and protection of users from congestion costs in the event of network constraints.

In our view the key objective of the regime, now that a regional model has been firmly endorsed, is to ensure that competition for supply is focused at the reference node, and that the costs of relieving congestion are faced by developers at the time of connection. Under this view of the world, developers can be certain of the level of access to the local reference node they will enjoy for the life of their project; and face incentives to locate in areas where their long term access can be delivered at lowest cost. They can then focus on competing in the contract market at the reference node to secure long term sales to underwrite their investments, and face a locational incentive that aligns with the interests of the broader market.

This model would contemplate temporary instances of congestion for example when network elements were out of service, and to this degree would be consistent with the AEMC definition. Despite this it would provide sufficient certainty over intra-regional access to allow investment in generation to proceed.

While this is one incremental solution to this problem, the key issue is that currently developers do not have a mechanism to manage the risk of intra-regional congestion over the life of a project. This creates a material barrier to investment which should be addressed in this review.

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

*Contract carriage*

It is not clear exactly what is meant by contractual congestion in this scoping paper.

Under the contract carriage pipeline regime, shippers contract for capacity with associated rights. In the event a shipper is unable to obtain a contract from a pipeline operator on an existing pipeline, this indicates it is fully used by other users. The options available are either to sub-contract existing capacity from an existing user – which is common practice; or to contract for additional capacity on the pipeline with its owner which would allow the pipeline to be augmented.

This system is workable for power generators or other users who seek long term certainty over transport rights, and fuel supplies.

The only area we are aware that this can create concerns is in relation to areas where FRC has been introduced downstream of a pipeline which has been fully contracted by a dominant retailer. For competing retailers seeking to win customers in such conditions, incentives for the incumbent retailer to sub-contract on competitive terms are minimal. In addition it would be risky for the retail entrant to contract for the development of additional capacity to access the downstream market because the contract would need to be long term, and the potential for fierce competition from the incumbent may limit the prospects for maintaining and adequate customer base over the term of the transport contract.

This is second point is not a climate change policy related matter, and has been previously identified by the AEMC in other reviews. It is not clear this warrants specific inclusion in this review, although a way forward on this would be welcome.

*Victoria*

The key gas transmission concern in Victoria relates to difficulties in understanding how the regulated network development process will operate in the face of uncertainty over future power generation load created by the uncertain CPRS and RET policies. An example of this relates to the TRUenergy underground storage asset, which we are currently upgrading in response to market demand. This market demand however, is not being reasonably factored into assumptions underpinning regulatory investment decisions, which has resulted in a situation where customers may not be able to obtain the benefits on the new capacity due to delays in upgrading transmission capacity on the South West pipeline.

As with the similar electricity network regime, it is likely that greater co-ordination of generator network connection could deliver benefits in the Victorian pipeline investment regime.

A review of the ability of the Victorian regulated investment regime is warranted in this review.

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

A lack of certainty of MLF at the time a project is developed creates a material investment risk.

In some cases wind farms have experienced MLF reductions of up around 25% from one year to the next. Across the life of a project, a reduction of this magnitude effectively removes 25% of expected revenue – which is almost certain to undermine the investment economics.

TRUenergy has been impacted on this via contracts with several wind farms, which passed MLF risk through to us as the buyer. A more recent impact, and one that shows the impacts on investment, relates to our involvement in the Solar Systems plant location in Northern Victoria. Attempts to assess attractive loss factor locations have proved unfruitful, due to the high probability of loss factors collapsing as generation in Western Victoria, NSW, and SA is developed in response to the RET. It was clear in this analysis that the loss factor uncertainty over the life of the project rendered any intended locational signals associated with loss factors meaningless.

While we are clear that the current situation represents a material, and unmanageable investment risk, the solution is less clear. We understand that efficient short term dispatch will require an accurate loss factor, and that a factor locked in over a project life may create problems in this area.

One approach may be to set up an arrangement in which a new entrant that materially impacted on an incumbent's loss factor had to compensate back to pre-investment levels. Such a scheme could be co-ordinated through NSP's. Other options may also be available.

However more work would be needed to develop a robust scheme, and we believe this issue is material enough to warrant a place in this review.

## 7. Retailing

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

In states where regulated retail price caps remain in place, we consider the risk that costs will not be able to be passed through as material.

Experience has shown that some jurisdictions have sought to spread justified pricing increases over many years to reduce short term consumer impacts. The reality of this situation is revealed by the fact that several states maintain price caps below the cost of supplying customers in those states.

Regulated price caps are material and should be addressed.

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

Wholesale contracts have been primarily limited post 2010 by continuing uncertainty about the start date, design, trajectories, are resulting carbon price associated with the CPRS. In addition to a lack of clarity on carbon pricing, the threat to the financial integrity of high emissions generators has left some unwilling to make commitments past the scheme start date.

In this environment generators have been unwilling to take carbon risk and have sought carbon pass through clauses in contracts. This has left retailers unable to offer carbon inclusive prices to customers – even when contracts could be sourced.

This is a material issue, but not one that can be solved by the AEMC. The solution is for the government to provide greater clarity over its CPRS and RET schemes so that the markets can price their impact and resume trading.

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

Retailers will face increases in pool costs due to the cost of carbon being incorporated into the NEM spot price. This will result in increased NEM guarantee requirements as well as general increases in the working capital requirements of retailers.

In addition there is the real risk that some generators may not survive the introduction of the scheme due to large balance sheet impairments if sectoral adjustment assistance is inadequate. Under some scenarios this could leave retailers without adequate contract cover to hedge pool exposures.

All of these factors will increase pressure on retailer finances, and particularly if current tight credit conditions persist, could leave some retailers unable to continue operating.

An increased risk of ROLR is material, and it is not clear that existing schemes – will prevent cascading defaults in the market. This is particularly true in the gas industry where it remains unclear on what basis gas would continue to be supplied to customers transferred under ROLR schemes outside Victoria.

A more market focused ROLR scheme is required which will allow customers to be allocated to receiving retailers best able to absorb them. This should reduce the risk of cascading default – which we currently regard as material.

## 8. Financing new energy investments

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

A critical factor influencing the investment environment going forward will be the Government's treatment of existing investors in the implementation of the CPRS scheme. A fair transitional assistance package will allow ongoing investment and an orderly exit for existing high emission generators. This will be instrumental in avoiding cascading financial default through the industry, thereby maintaining a positive investment image of the industry for future investors.

Certainty over the CPRS and expanded RET policies will be key to ensuring risks can be understood and managed.

Continued financial stability of the NEM, including continued high pool credit quality, stable energy financial markets, and an orderly exit from retiring assets for both debt and equity providers will be important for the investment environment.

The ability to manage risks in the market, including congestion, MLF, energy price risk, carbon risk etc. will also be important.

Availability and cost of capital will be a challenge as well, particularly in the short to medium term as the world economic downturn and financial crisis continue.

From the perspective of this review, a robust and stable NEM environment that can clearly demonstrate that investors will be able to manage risks and have a reasonable prospect of returns going forward will be key.

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

The key areas that the AEMC should focus on in this review include:

- Sufficient flexibility in regulated gas transmission regimes is needed to deal with the uncertainties of climate change policy and ensure that investment will be delivered in a timely manner, to underpin required generation and storage investments;
- Improved intra-day gas market cost allocation and improved market based approaches to gas emergency management;
- Historic gas marketing anomalies should be removed to increase upstream competition in the gas sector;
- Ensuring market frameworks deliver sufficient incentives for reliable operation and investment to meet the market objective without recourse to distortionary market operator or government interventions;
- Increases in Voll/MPL are likely to be needed to ensure incentives for maintaining/investing in capacity plant remain sufficient;
- Facilitation of the investment environment through creating an ability of generation investors to achieve certainty in access to the local reference node for the life of an investment (ie. ability to protect against congestion);
- Examination of options to provide increased certainty on loss factors for the life of a project at the time of investment;
- Ancillary service arrangements including reserve requirement quantum in the face on increased intermittent generation, hedging and investment incentives;
- Consideration of alignment of electricity and gas connection regimes to deliver dynamic efficiency benefits;
- Improvements to the connection process including implementation of a one-window nationally consistent connection agent for generators via AEMO;
- Further consideration of the benefits and risks of regulatory approaches to provide transmission backbones to open up promising long term renewable areas;
- Removal of retail price caps to allow continued investment in retail markets, and implementation of an improved ROLR scheme; and
- Maintaining financially robust and stable market operators to underpin the energy sector as an attractive investment environment.

**Other matters – not mentioned in the scoping paper**

The other key matter that we believe warrants attention is the review of technical performance standards.

Standards should be reviewed and made generic to ensure they do not provide a barrier to future (as yet unknown) technologies that may seek to connect.

In addition we question if historic quality of supply, frequency standards etc. will remain economically sustainable given the technologies available for investment in the medium term. It would be worth the reliability panel considering this as part of its technical standards review.