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A few words.

Australian Energy Market Commission
PO Box A2449
Sydney South NSW 1235

3 August 2009

Reference EMO 0001: 2nd Interim Report

Dear Sir/Madam,

AGL welcomes the opportunity to comment on the Australian Energy Market Commission's 2nd Interim Report on the Review of Energy Market Frameworks in light of Climate Change Policies.

Please find attached AGL's response to the recommendations outlined in the 2nd Interim Report. AGL is very supportive of the AEMC's findings in respect of the risks presented to retailers by the continuation of retail price regulation regimes in the context of a CPRS. AGL continues to advocate de-regulation, but in the absence of de-regulation endorses the AEMC's suggestions as to the required level of flexibility in the regulatory arrangements.

AGL believes that some of the other proposed recommendations fail to overcome a net public benefit test and should be reconsidered. AGL is concerned that if implemented, some of the recommendations in relation to transmission would transfer material economic risks from electricity generation proponents to electricity and gas customers.

Should you have any questions or comments on this submission, please contact Tim Nelson, Head of Carbon and Sustainability on (02) 9921 2516 or at tanelson@agl.com.au.

Yours sincerely

Paul Simshauser
Chief Economist and Group Head of Corporate Affairs

AGL SUBMISSION ON THE PROPOSED EXPANDED RENEWABLE ENERGY TARGET

1. Introduction

AGL Energy (AGL) is Australia's leading energy company and Australia's largest privately owned renewable energy generator. AGL is well placed to comment on emissions trading and renewable energy targets because of the diversity of our operations. We operate across the supply chain and have investments in energy retailing, coal-fired electricity generation, gas-fired electricity generation, renewables and upstream gas extraction. The diversity of this portfolio has allowed AGL to develop a detailed understanding of the risks and opportunities presented by climate change policy, renewable energy targets and emissions trading.

AGL is Australia's largest retailer of gas and electricity with over 3 million customers in New South Wales, Victoria, South Australia and Queensland. AGL has significant investments in upstream energy markets. We own and operate 645 MW of hydroelectric power generation assets, the 95 MW Hallett and 71 MW Hallett 2 wind farms, the Torrens Island gas-fired power station (1280 MW), the Somerton gas-fired peaking power station (150 MW) and a number of landfill gas, biogas and biomass generation facilities. AGL also has a 32.5% equity investment in the Loy Yang A power station. We are currently constructing new hydro and wind assets and developing one of Australia's largest pipelines of renewable projects.

2. Connecting Remote Generation (Chapter 2)

Recommendation	AGL Position
That a new framework be introduced to the National Electricity Rules (NER) for the efficient connection of remote generation to distribution and transmission networks where clusters of generators in the same locations are expected to seek connection over a period of time. This new type of network service, and adjustments to the regime for planning, charging and revenue recovery would allow for Network Extensions for Remote Generation (NERG).	Not supported
That under the new framework customers would underwrite the cost of any additional capacity in excess of the requirements of the first connecting generators that is forecast to be efficient.	Not supported
That if there is a significant risk that Network Service Providers (NSPs) will not develop NERGs, their provision should be made contestable.	Not supported

AGL has significant concerns about the broad direction of the recommendations outlined in Chapter 2. There are a number of basic policy principles that AGL believes should be applied in considering these recommendations:

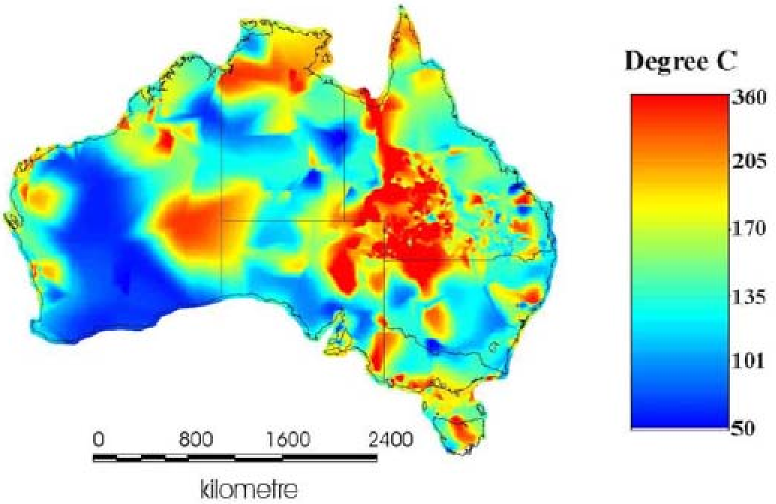
Is there a current market failure?

AGL is concerned that no existing policy failure has been identified. Prior to market deregulation, central planning led to the vast over-capitalisation of the Australian power system and in turn formed the basis for industry reform. The proposed recommendations would effectively re-introduce a central planner, and have them try and determine the optimal investment configuration. Yet this reintroduction of central planning would occur in the context of a deregulated downstream investment environment. Vertically integrated central planning led to the overcapitalisation of the power system when central planners controlled both the planning mandate and the generation plant investment mandate. In this particular instance, network central planning for generation developments is divorced from the (deregulated) generation plant investment mandate, and thus the risk of manifest failure and overcapitalisation of the network must by definition, be very materially higher.

The overarching objective of energy policy makers is security of supply. Since the creation of the National Electricity Market (NEM), 14,504 MW of new generating capacity has been added to the system (Source: ESAA Data 1998-2008). This capacity has included a range of technologies including gas-fired, coal-fired, wind, cogeneration and solar. Security of supply has at no time been compromised because of a lack of existing generation capacity. The current market rules are ensuring that capacity (across a range of technologies) is brought online to maintain security of supply. In this context, AGL believes that adjusting the rules to facilitate transmission investments specifically for new generation is unnecessary.

In addition to security of supply, it could be argued that energy policy makers have a role in facilitating new technologies. In this context, it would be necessary to demonstrate that new technologies require differential treatment from existing thermal technologies in relation to new transmission connections. AGL believes that emerging technologies do not have significantly different characteristics to existing technologies in relation to optimisation of location. For example, one of the most misunderstood characteristics of geothermal technology is that the only resources that exist are in very remote areas of central Australia. Figure 1 shows a map of Australia with the approximated heat resource related to geothermal energy. It is clear that while the hottest sites are in relatively remote areas, there are substantial sites (yellow and orange) close to the existing transmission system in NSW, QLD, SA and Victoria.

Figure 1



To demonstrate this point, there are a number of geothermal companies which are developing resources in areas which would require minimal transmission costs (e.g. Panax Geothermal Limited and Torrens Energy in South Australia). These projects seek to optimise the heat resource and energy capability with the cost of transmission augmentation. Through generation and transmission investment co-optimisation, economic efficiency is maintained and an optimal allocation of resources can be achieved. If transmission access is provided at no risk to competing projects (as would be the case if the proposed recommendations were implemented), it would penalise prudent co-optimising investors by providing an unfair advantage to remote projects.

Appropriate distribution of risk

One of the founding principles of energy market deregulation is to shift the allocation of the risk of suboptimal investments away from consumers, and onto investors which is where that risk can best be managed. This has been one of the clear successes of Australia's world-renowned energy market reform.

New generation proponents should bear all of the economic risk associated with their proposal or technology not being delivered. The recommendations as currently drafted would see Network Service Providers (NSP's) determining whether generation projects are 'likely' or 'unlikely', which technologies and regions are optimal for transmission connection and overall optimisation of the generation and transmission systems. In this context, we note that:

- There are significant costs to consumers if NSP's incorrectly determine where new transmission lines should be constructed. At the extreme, in South Australia, a 500km investment in new transmission would add approximately $4.50/MWh to electricity bills if constructed and was not utilised.

- These price increases would occur at a time when underlying energy costs are increasing due to a range of factors. The introduction of the Carbon Pollution Reduction Scheme and expanded Renewable Energy Target are likely to add between 10 to 15% to electricity prices in the first few years of the scheme. Network tariffs are known to be increasing very significantly over the next 5 years.

Information asymmetry and availability

To adequately perform their functions under the proposed recommendations, an NSP would require close to 'perfect information' about technology options, costs (both current and prospective), investment plans by existing and new market participants and the probability of projects proceeding. To put this in perspective, AGL has analysed the status of every major proposed generation project in the NEM since 1998. It is clear that anticipating which projects will proceed to financial close and subsequent commissioning is impossible. Of the projects proposed between 1998 and 2008:

- 197 power projects have been proposed, representing up to 43,500 MW of new generating capacity at a template capital cost[1] of up to $74.8 billion in 2009 dollars;

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[1] This analysis is based upon projects identified by the Energy Supply Association of Australia in Electricity and Gas Australia (Appendix 2). Capital values are calculated using $2200/kW for coal, $1500/kW for CCGT, $990/kW for OCGT and $2500/kW for renewables

- Only 34% of these projects (14,504 MW) have actually proceeded to the construction stage representing a template capital cost of $27.8 billion;

- More importantly, total generating capacity of projects proposed that have not moved to the construction stage is 28,820 MW at a template capital cost value of $47 billion; and

- Of the 69 successfully developed projects, a comparison between actual and original planned commissioning aggregates to 18.5 years worth of delays – the cost of which (under the current proposal) would be borne by consumers.

Table 1 provides a breakdown of investments proposed that have not moved to the construction phase by technology and that would have occurred had construction commenced.

Table 1: Investment announced but not delivered (by technology)

Period	Investment	CCGT	Coal	Renewable	OCGT	Total
1998-2005	MW	2,716	3,211	681	4,424	11,032
	$ Value	$4.0 b	$7.1 b	$1.7 b	$4.3 b	$17.2 b
2006-2008	MW	2,140	3,240	4,763	7,645	17,788
	$ Value	$3.2 b	$7.1 b	$11.9 b	$7.5 b	$29.8 b

The importance of Table 1 is that it shows investment failures are not restricted to any particular technology, nor to any particular time period in the NEM. Again, if networks had been augmented because an NSP believed prior predictions, billions of dollars in investment would have been wasted as generation investments did not eventuate as originally envisaged.

The distribution of announced but not constructed projects is not consistent across NEM jurisdictions as illustrated in Table 2. However, even the State with the highest conversion rate of projects proposed through to construction (i.e. QLD) has still seen almost 1 in 2 projects fail.

Table 2: Investments constructed as a proportion of total proposed)

Jurisdiction	Project Conversion Rate
NSW	15%
QLD	58%
SA	43%
VIC	24%

It is unclear to AGL how an NSP would have been able to determine (years in advance of financial close) which projects at any point over the last 10 years would have actually proceeded to construction. Many projects are announced each year, and despite having large organisations as sponsors with material financial backing and planning approvals in place, a high proportion still end up being abandoned. It is entirely unreasonable to expect an NSP to determine which projects and technologies should be supported through customer underwritten transmission.

The current environment makes this task even more complex. At a recent NSP annual planning report seminar for stakeholders, that organisation noted that it expected more gas turbine developments in line with recent investment trends. Yet the Project Finance community has an entirely different view because long-dated fixed price gas contracts are unattainable in the current (LNG build-up) environment.

This analysis also applies to the proposed roles of Australian Energy Market Operator (AEMO) and the Australian Energy Regulator (AER) under the proposed recommendations. AGL does not believe a case had been made to demonstrate that AEMO and the AER have the requisite skill sets to determine the likelihood of project success. While the AEMO has highly competent power system planning skills and could be relied upon to assess the efficacy of a generation site or probable generation plant cluster, it is disingenuous to expect that the AEMO would possess skills necessary to make judgements about the reliability of all technologies being proposed, or the likely success of any given power project. In order to do so, the AEMO would need, at a minimum, to house all of the skill sets that currently reside in:

- investment banks - to assess the probability of success of equity capital raisings (which is important giving diminishing investments by Government Owned Generators);

- corporate institutional and project finance banks - to assess the probability of success of structured and project finance raisings;

- merchant utility energy trading desks - to assess whether the commodity hedge contracts are profitable, bankable and reflect an appropriate allocation of risk;

- engineering firms - to assess whether the technology, and the manufacturer selected represents a bankable proposition; and

- power development business units of the utility businesses sponsoring such projects - to assess whether the project is in fact likely to be committed to by a Board of Directors.

The obvious added difficulty here is that the above 5 skill sets are required in real time to determine whether a project can proceed. How such skills can be directed to non-committed project hubs remains unclear, and the NEM investment 'hit-rate' data merely serves to confirm this.

Furthermore, it is not the case that projects can be neatly 'warehoused'. Just because a project looks achievable at a certain point in time does not mean it is indicative of future success. Changes in all of the variables, especially Power Island and Balance of Plant contracts, equity market conditions, interest rates and spreads, debt sizing criteria and forward commodity prices are notoriously unstable.

The site location component represents a crucial 'hygiene factor' for a power project development and the AEMO could clearly advise on this.[2] But the five components outlined above will define whether a project is likely to proceed or become a casualty. AGL does not believe that NSPs, the AEMO or the AER are in a position to make judgements over these key drivers of deregulated power generation plant development and investment as it is not within their respective areas of expertise.

Unintended Consequences

The recommendations as drafted only address connection assets. The impact on the shared network is not discussed. It is likely for three (Eyre Peninsula, Flinders Ranges and Broken Hill) of the potential 'Network for Remote Generation' zones, the connection of the remote generation would occur into parts of the network that are going to become congested as a result. By not examining the costs all the way to the node, the coordinated investment may be wasted in any event.

If new remote network assets are underwritten by electricity customers, NSP's would be incentivised to 'overbuild'. In the context of the information asymmetry outlined above, and the data presented in Tables 1 and 2, it seems clear that even with the role of the AER as envisaged, an overallocation of resources is probable.

Given this backdrop, the case for transmission optimisation does not appear to AGL to be compelling at all. Appendix E in the AEMC Report uses an elegant example of 4 x 100MW generators and 4 transmission investment optimisations. A comparison between option 4 and option 1 in Appendix E found the former to be 50% lower in cost as a result of the optimisation. As a static proposition, this clearly demonstrates a more cost efficient outcome. However, we would argue that even if a piecemeal approach leads to a doubling of the cost of a handful of remote transmission connections, the gains would be more than lost in the non-negligible variation in the entry cost of renewable power projects; which are known to be in the range of $80/MWh to $135/MWh in the current environment. And the attempt to optimise a comparatively small transmission cost could end up creating large stranded assets which will be borne by the consumer.

The 2nd Interim Report makes the comment that customers already face similar stranded asset risks, with footnote 32 noting that "…for example, forecast consumer demand may fail to materialise…". This does not provide a robust reason to add to whatever stranding risk already exists in the NEM. Besides which, the argument here seems to be referring to a general 'undershooting' of demand growth. Lower demand growth is a transient risk in that demand growth may slow but ultimately, the demand for electricity is unlikely to be saturated. This risk should be distinguished from a deliberate centrally planned investment decision to try and optimise the transmission investment to size for lumpy generation investments of a particular 'cluster' in an environment of known upstream investment risk which can incorporate very lengthy delays, and of course, multiple casualties as per the data presented in Tables 1 and 2. In short, while demand growth can generally be relied upon to increase over time, there can be no guarantee that a generation 'cluster' will emerge given the deregulated investment framework which characterises the NEM.

Alternative Solution

The trigger for identifying a 'Network for Remote Generation' zone is "connection enquiries by generators", indicating that a number of parties will have already expressed an interest. It would therefore be appropriate to size a network augmentation to the known

[2] Although this should be distinguished from the 'site permitting' task – for example, site approval for the Uranquinty gas turbine took 3 years to complete.

interested parties and charge them their share of the cost of that connection from the date the construction is completed – just as occurs with gas transmission network augmentations for generators. The 'Network for Remote Generation', like all connection assets, should be contestable.

3. Efficient utilisation and provision of the network (Chapter 3)

Recommendation	AGL Position
We are minded to recommend to the MCE that a transmission use of system charge be applied to all generators (G-TUOS).	Not supported. Existing generators cannot respond to the locational price signal as capital costs are sunk and generation equipment cannot be easily relocated. The CPRS and RET will provide sufficient price signals to retire high emitting plant over time and encourage the development of new lower emitting plant and technologies.
What additional value would a congestion pricing mechanism add? If such a mechanism is required, what design variations should be considered to improve signals to manage short-term intra-regional congestion in the most efficient way?	Partially supported. There is value in allowing some price signal during short term congestion events to prevent "disorderly bidding". The CSP/CSC approach is not appropriate if applied in an ad-hoc way. AGL, with others, has proposed a more efficient solution.

Risks in not fully testing an approach before finalising the report

The AEMC considers that the existing frameworks for developing networks to support generator investment are inadequate. The commission accepts that congestion:

- is likely to be more material in the future and particularly due to the new investments that will result from climate change policy; and
- reduces generator certainty around access to market, increasing dispatch risks.

The AEMC notes that these risks distort locational signals and delay new entry.[3] The commission does not, however, examine why this failure is occurring but rather seeks to change the framework.

AGL is concerned that this approach misunderstands how the current framework was intended to (and could) work and risks installing an untested framework that will not work.

In 2002, the National Electricity Code Administrator (NECA) determined that a better framework for TUOS would be to charge participants based on the benefits they gained from network investments. Like the AEMC, they assumed that the Regulatory Test would provide the necessary support for investments. And as with G-TUOS, the approach was only sketched out before NECA recommended it. In the event neither component worked:

- the regulatory test did not support investment to relieve generator congestion; and

[3] AEMC (2009), *Review of Energy Market Frameworks in light of Climate Change Policies, 2nd Interim Report*, 30 June, pp. 23 – 29.

- the “Beneficiary Pays” approach proved impossible to implement in the form proposed.

Failure of the G-TUOS approach to address the real issue

The AEMC indicates that its G-TUOS proposal is driven by the need to create an efficient locational price signal for new and retiring generation investment in the NEM in addition to (and compounding) that signalled by marginal loss factors. Each NEM region would be divided in to G-TUOS zones, which would be charged a positive or negative fixed transmission charge, depending on the level of projected transmission congestion. As outlined below there are significant objections to the G-TUOS proposal; both from a theoretical and practical perspective. Below we have reproduced the key components of a industry presentation pack prepared by the Southern Generators on G-TUOS. The AEMC’s G-TUOS proposal does not provides appropriate investor certainty as it:

- undermines financial viability of projects by introducing a new variable cost that cannot be hedged;
- is not credible that an arbitrary and variable charge would facilitate long-term generation investment decisions; and
- the G-TUOS charge is simply a wealth transfer between generators and does nothing to address the underlying problem of lack of transmission.

It seems clear to AGL that G-TUOS would at best greatly increase the risk and task of banking new power projects in an environment in which there is known to be more than $30 billion in new generating plant investments required between now and 2020, along with the addition of $19 billion in existing asset refinancing between now and 2014 (Source: esaa survey data). The AEMC’s G-TUOS proposal does not support decentralised decision-making as:

- relative (not absolute) charges do not provide least cost delivered energy – charges need to reflect absolute costs;
- it provides no mechanism to support decentralised investment in generation and transmission and investment disincentives remain; and
- it promotes a centrally planned and regulated approach to all transmission decisions and undermines private investment in the NEM.

The AEMC’s G-TUOS proposal does not provide a credible long-run locational transmission cost signal:

- because it is a scaled charge, the G-TUOS charge would not be cost-reflective, and is not an efficient signal;
- because it is forward-looking, the G-TUOS charge would be highly dependent on the underlying assumptions that are adopted, and will not be stable as a result; and
- therefore such a charge is ineffective as a long-term signal.

The AEMC’s G-TUOS proposal does not ensure new transmission investment matches the preferences of new generation investment given:

- the charge does not provide TNSPs with recourse to any additional funds to build out congestion (i.e. does not fund augmentation of network to accommodate new entrants);
- congestion build out remains dependent on the existing RIT-T process; and

- the proposal fails to satisfy the real problem: lack of transmission investment to match the needs determined by a generation investor.

G-TUOS is not appropriate for the NEM

The AEMC's G-TUOS proposal is not appropriate as:

- it is not economically efficient, misinterprets the problem and creates a signal for signals sake;
- it ignores principles of dynamic efficiency and is only relevant from a static perspective; and
- existing generators cannot effectively respond to the locational price signal.

The AEMC's analysis does not support the introduction of the proposed G-TUOS mechanism and we strongly recommend the AEMC undertake a more appropriate level of analysis in conjunction with market participants.

Deep Connection Charging (like Clause 5.4A of the NER)

AGL suggests that the AEMC, rather than removing Rule 5.4A, examine the underlying principles embodied in it.[4] This approach was designed to support economically efficient development of the transmission network by:

- supporting decentralised decision making and locational signalling since a generator could examine all of the costs of their investment at one time;
- allowing cost effective development of the network since the generator would fund up to the full cost of their impact on the grid;
- providing for sharing of the network if construction was uneconomic or if a generator was unwilling to fund the network (ironically in exactly the same way proposed for the NERG extension when the initial investment fills); and
- ensuring that a generator would only pay up to the LRMC of their network impact.

AGL believes that the primary reason that Rule 5.4A has not delivered network investment is the failure of TNSPs to develop approaches to use deep connection charging approaches. At the time the Rule was developed, it was assumed that TNSPS would negotiate in good faith as the Rules require and not simply require generators to sign away their access rights. This failure on the part of TNSPs to implement 5.4A and not the rule itself is undermining the negotiated access framework

Use of a localised congestion management tool

The use of a localised congestion management tool is supported. The tool needs to be applied universally and in advance of the congestion occurring because the location of the congestion may be hard to predict. The impact of network outages, the main cause of transient congestion, is reflected in constraint equations developed by AEMO on the advice of TNSPS. The particular set of equations in use at any particular time will depend on the network configuration and, in some circumstances, new constraints are written on the fly. No ad-hoc scheme will be able to effectively manage this situation.

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[4] AGL outlined an approach that was consistent with the NERG approach in its earlier submissions to this review.

AGL, with other Victorian generators has provided the AEMC with alternative approaches to this problem. We consider that the AEMC should examine these proposals.

4. Inter-regional TUOS (Chapter 4)

Recommendation	AGL Position
Is the proposed design for the load export charge appropriate as an effective mechanism to address the identified problems?	Supported. The charge should focus on the capacity issues in the network.
Is our suggested commencement date of 1 July 2011 achievable?	Yes. The major issues with this approach were resolved in 2000 by NECA

We support inter-regional TUOS but suggest the link between inter-regional TUOS and augmentation of the shared network requires ongoing observation to ensure the proposed charging mechanism is effective.

AGL is concerned that many issues with the load export charge, such as tidal flows and measurement days, are not fully described in this chapter. The proposed approach was fully developed and examined by NECA in 2000. AGL considers that the AEMC should review that work and provide a fully defined solution in the final report.

One key issue is the measurement days. Since the key problem with network is capacity, it is important that the load export charge only apply when the adjacent network is using a regions network during peak times. This allows the charge to support appropriate inter and intra-regional investment.

5. Regulated retail pricing (Chapter 5)

Recommendation	AGL Position
By the time the CPRS commences all jurisdictions retaining retail price regulation should have developed an adjustment mechanism for energy and carbon related costs which: can be invoked as frequently as six monthly subject to a cost change threshold; is symmetrical to allow adjustment for increasing or decreasing costs; and optimally can be initiated by retailers where costs are rising.	Supported

AGL is very supportive of the AEMC's findings in respect of the risks presented to retailers from continued price regulation. While AGL agrees with the AEMC's conclusions in relation to these risks, AGL believes that removal of retail price regulation is the only solution which will effectively mitigate the risk retailers face, and therefore the risks the market as a whole faces, against the risks identified. In the absence of de-regulation, there are a number of criteria which AGL believes are critical in ensuring sensible policy outcomes. Most importantly, there needs to be a degree of flexibility shown by regulators in approaching retail price determinations. The introduction of the Carbon Pollution Reduction Scheme is likely to present unforeseen risks and consequences. It is not possible to predict the manner in which the CPRS will impact the 'black' price, nor the price of the AEUs themselves. There will clearly be a need for flexibility in how retail prices are regulated, to ensure that retailers are at all times able to recover the market costs incurred with the introduction of the CPRS and the expansion of the RET.

6. Generation capacity in the short-term

Recommendation	AGL Position
The reserve shortfall risk be addressed through a combination of: • facilitating more accurate reporting of demand side capability; and • utilising the potential for distribution connection generation to help alleviate capacity shortfalls. Active load shedding management could mitigate the need for involuntary load shedding. Should we recommend this mechanism as part of our final advice to the MCE?	AGL supports the maximum use of demand side and distributed resources. To that end we have been involved with demand response suppliers. Our experience is that centrally contracted demand side response has never actually provide additional capacity but rather has raised the cost of existing capacity. AGL has always provided accurate information to AEMO. Further rules in this area are not supported, although the use of dispatch rules for large blocks of demand side response could be effective. The proposal for active load shedding management is not supported.

<u>Load Shedding Management is not efficient</u>

We are concerned with the AEMC's proposals to increase regulatory responses in this area. We do not support the AEMC's suggested approach to procuring reserve capacity and do not support load shedding management in the manner outlined by the AEMC. We believe further interventions in the market are likely to undermine investor confidence.

The AEMC proposal to pay some participants but not all their value of customer reliability combines the worst aspects of a standing reserve and a compensation scheme and should be discarded. By restricting the scheme to demand side response, the least cost option is not assured.

It is also not clear that those larger players that self select to be shed first are actually those with the lowest cost for customer response. Studies to establish the value of VoLL and the Value of Customer Reliability have shown that customers vary in their valuation of reliable supply. The payment to some participants, levied on others, is therefore unlikely to be efficient since it is not clear that those being levied would ascribe the same value to the reliability.

The idea that parties should be paid an amount greater than Voll to shed load reflects a problem with pricing rather than a real dispatch signal. If customers saw the true marginal price for their supply they would reduce their consumption as the price of that supply reached its marginal value. Involuntary load shedding would be unnecessary.

Since it is considered that customer are unable to respond efficiently to market signals, the Reliability Panel is required to set the marginal value of supply as a proxy for the market. To allow some parties to define a higher marginal value, and then charge others the resulting price, is incompatible with the market design and the National Electricity Objective.