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06 August 2009

Dr John Tamblyn
Australian Energy Market Commission
AEMC Submissions
PO Box A2449
SYDNEY SOUTH 1235

Dear Dr Tamblyn,

AEMC 2nd Interim Report, June 2009 – Reference EMO001

Please find attached Babcock and Brown Power's (BBP) submission to the Australian Energy Market Commission's (AEMC) 2nd Interim Report into the Review of Energy Market Frameworks in light of Climate Change Policies. BBP considers that the work being undertaken by the AEMC will determine the work program faced by the market:

- in the immediate 6 to 12 month period as Rule changes are proposed to amend the current market design to support the functioning of energy markets during the "transition period" from 2010/11 out to 2015
- in the subsequent period undertaking further analysis of potential options to address those market design areas where the AEMC has assessed weaknesses as not posing any material risk to the energy market during the transition period.

Accordingly, given the considerable direct and indirect costs associated with the market addressing energy reform processes it is critical that the AEMC's work program incorporates the "best" risk weighted prioritisation of the challenges facing the energy market in light of climate change policies. BBP considers that the greatest regulatory risk carried by the AEMC would be a failure in the setting of the appropriate priorities, which would carry quite dramatic asymmetric consequences.

From a public policy perspective the Commission's over-arching threshold for determining the merits of changing the National Electricity Rules (NER) is to have regard to achieving the National Electricity Law's (NEL) objective of:

> *"...promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to—*
> *(a) price, quality, safety, reliability and security of supply of electricity; and*
> *(b) the reliability, safety and security of the national electricity system."*

When the NEL was introduced in the SA Parliament the first reading speech was careful to interpret the NEL objective noting:

"The market objective is an economic concept and should be interpreted as such.....investment in and use of electricity services will be efficient when services are supplied in the long run as least cost,...are used to deliver the greatest possible benefit and there is innovation and investment in response to changes in consumer needs...."

And,

"The long term interest of consumers of electricity requires....., to be maximised. If the National Electricity Market is efficient....the long term economic interests of consumers in respect of price, quality, reliability, safety and security of electricity services will be maximised."[1]

More importantly in introducing the NEL objective to replace the market objectives of the National Electricity Code (NEC) it was noted that *all* participating jurisdictions "remained committed to the goals expressed" in the original objectives. Namely, that in applying the objective of economic efficiency be recognised in a general sense that the national electricity market should be:

- competitive
- allow any person wishing to enter the market should not be treated more nor less favourably than persons already participating in the market
- that particular energy sources or technologies should not be treated more nor less favourably than other energy sources or technologies.

BBP has assessed the AEMC's second interim report from the analytical prism incorporating the following criteria:

- correct prioritisation of matters between being dealt with immediately as the risks to the energy market are material during the transitional period and the remaining risks are able to be dealt with at a later date or in an ongoing manner
- against the NEL objective, and the expanded market objectives.

A summary of BBP's assessment of the AEMC's proposed work program, using these criteria is outlined in Appendix A.

At this stage, BBP's considers that the AEMC's current approach to identifying the costs and benefits to accrue to consumers has been limited. Moreover, the AEMC has not presented any clear and robust basis on a cost and benefit basis as to it prioritisation between immediate transitional matters that need to be addressed in the next 6-12 months and those matters where reform can occur beyond this date. A clear example of this is the AEMC's prioritisation of the NERG as an immediate matter to be addressed to support new intermittent generation while delaying the G-TUOS – which in effect involve reforming the way transmission network assets are regulated.

The AEMC needs to provide more quantitative analysis to support these threshold policy decisions that are being made particularly in relation to:

- transmission regulation covering the AEMC's **NERG** for new remote intermittent generation, **G-TUOS** and **congestion pricing** for all generators as all proposed regimes:

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1 http://www.ret.gov.au/Documents/mce/_documents/NEL2ndreadingspeechhansard9feb0520050211091852.pdf

   - need to be based on the same economic principles given it is to be applied to the same transmission assets
   - require substantial information around risks, costs, elasticities of demand, and understanding incentive behaviours (particularly of transmission businesses)
   - require the development of an accountability framework that ensures that transmission business use the revenue recovered to actually build network
- **retail price regulation**
- meeting **short term generation needs** in a manner that is consistent with the NEL objective.

BBP have addressed these matters, and others, in more detail in the attached submission.

Should the AEMC wish to discuss the content of this submission or require any further information on matters addressed within the submission please contact me on 07 3011 7629 or James Reynolds on 07 3011 7646.

Yours sincerely,

Mark Williamson
General Manager Wholesale Energy
Wholesale Energy
Babcock and Brown Power

AEMC Review of Energy Market Frameworks in light of Climate Change Policies

Submission to 2nd Interim Report

06 August 2009

Babcock and Brown Power Pty Ltd
Level 23 Chifley Tower,
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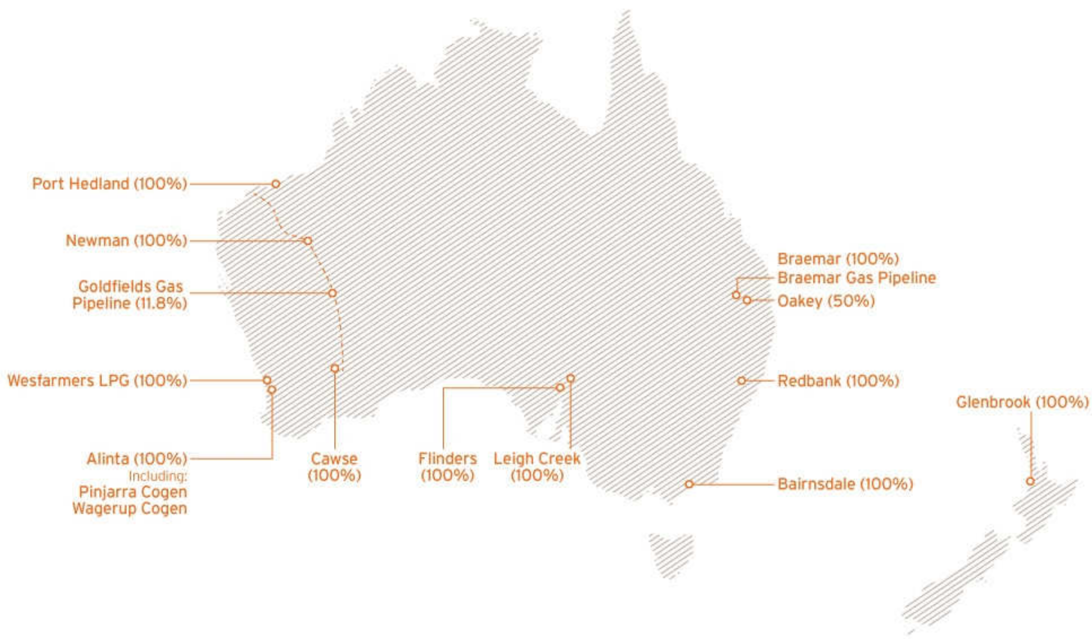
2nd Interim Report, June 2009 Reference EMO 0001
www.aemc.gov.au

Overview to Babcock and Brown Power

Babcock & Brown Power Limited (BBP) is an Australian listed power generation business with an extensive portfolio of assets diversified by geographic location, fuel source, customers, contract types and operating mode. The portfolio has interests in twelve operating power stations representing approximately 2,000MW[1] of base load, intermediate and peaking power generation. BBP's history includes over 10 years of experience in developing, operating and acquiring various forms of generation. BBP currently employs around 900 people across its portfolio of assets, and has corporate service centres in Sydney, Brisbane, Adelaide and Perth.

The location of the current energy assets in the company group is as follows:



1 Some assets may have minority interest.

Introduction

Babcock & Brown Power (BBP) welcomes the Australian Energy Market Commission's (AEMC) 2nd Interim Report (the Report) into the Review of Energy Market Frameworks in light of Climate Change Policies. The Report presents a broad suite of draft recommendations or preferred options for amending the existing energy market framework to ensure an efficient transition to a low carbon energy sector.

As per BBP's submission to the AEMC's 1st Interim Report, BBP continues to agree in principle with those areas of market design which may face material risks as a result of the Commonwealth Governments Carbon Pollution Reduction Scheme (CPRS) and expanded Renewable Energy Target (eRET).

BBP supports the AEMCs endeavour to identify draft recommendations or preferred options to those key challenges facing Australia's energy market. BBP understands the AEMCs recommendations seek to ensure that energy market frameworks support an efficient transition to a low carbon energy sector, consistent with safe, secure and reliable supplies for communities and business[2]. BBP however have identified a number of issues with the draft recommendations or preferred options outlined within the Report that they wish to bring to the Commissions attention.

Our submission is therefore structured as follows:

- The National Electricity Market (NEM) transition;
- Comprehensive review – a comprehensive review of the draft recommendations or preferred options and specific responses to the AEMC's request for information.

The National Electricity Market (NEM) transition

As a policy intervention, the intention of the CPRS and eRET is designed to make market participants internalise the costs of its consumption or use of resources on the environment. The CPRS and eRET are designed to change the make-up of the Australian economy's source of energy, particularly electricity generation. From a market design perspective the risk to the NEM occurs during the transition phase.

During the transition phase it is important to consider the key factors driving change, which in effect create risk and instability in the NEM. BBP consider these factors to be:

- price revelation and risk management of ETS trading products;
- substantial operational disruption as existing coal fired generators manage their way through:
  - asset impairment tests and debt re-sizing processes with financiers;
  - any flow-on impacts that this process may have on power station economics, operations and subsequent trading;
  - dealing with impacts of wind generation and intermittent generation;
- a significant increase in investment in wind generation, as the most provable and inexpensive technology to meet the eRET, and more importantly with sufficient time, from a financing perspective, to recover investment costs;

2 AEMC, (2009), Second Interim Report, page i

- increased system operation errors, and instances of system violation of operating constraints, as the Australian Energy Market Operator (AEMO), the AEMC and the Australian Energy Regulator (AER) gain experience with dealing with increased wind penetration in the NEM, changing energy flows as the electricity network evolves, and changing sources of power generation supply.

For the NEM the transition BBP's expectation is that this transition will continue beyond 2020 driven by the following reasons:

- existing coal fired generators determine they are able to economically survive beyond 2020, which either reflects a low cost of carbon or technology breakthrough in carbon capture storage or an adjustment to the energy derivative markets that results in more contracts for capacity or other energy services supporting continued economics of existing power stations;
- AEMO and TNSPs establish the power station and system control that makes wind generation more 'reliable' in a real capacity sense[3];
- for new generation a technology breakthrough for a base load renewable energy source arrives in commercial levels of supply for example geothermal installation as indicated by market modelling suggesting 2017 in South Australia or 2026 or solar thermal where market modelling suggesting early 2020s;
- the new generation to be supported sufficient investment in direct network connection assets, and common network assets; and
- electricity users both domestic, commercial and industrial are provided with sufficient price and 'quality' signals to pay more for less reliable energy – which in itself will require a change to consumer's consumption of electricity.

Unlike previous times of electricity market reform the Australian power industry has almost no spare capacity that increasing consumer demand can utilise while new power stations are planned, designed and built, a fact highlighted by NEMMCo's Statement of Opportunities (SOO) 2008. Similarly, the 2008 SOO prepared by the Independent Market Operator (IMO) in Western Australia indicated a shortfall in targeted spare capacity beyond that already in service or under construction would arise in that market in 20010/11[4].

Without this latent capacity, managing through the transition period becomes a complex risk management proposition whereby policy interventions intended to address these short term challenges do not distort long term incentives in the market. Despite this pressure it is also the responsibility of the AEMC and the MCE to consider real options that promote the NEL objective, which may result in short term policy interventions in market design actually representing the best option to meeting the NEL objective in the long term,.

The increased penetration of intermittent generation, predominately wind, and the technology risks making the arrival of new generation problematic to forecast may mean that the short term challenges around reliable capacity and ancillary services actually represents a long term risk to the NEL objective. It is BBP's position that the NEL objective is best achieved by adoption of the following proposals:

- making amendments to the semi-scheduling rules;
- an improved regulatory regime for TNSPs and DNSPs; and

3 From BBP's perspective, AEMO and TNSPs manage wind operations by adjusting the system and other power stations' operation to accommodate wind's operation. This reflects the underlying instability of the fuel source.

4 IMO, July 2008, Statement of Opportunities, page 4.

- adjustments to the reliability mechanisms in the NEM.

These proposals require further consideration by the AEMC on whether they meet the NEL objective in a superior manner, in terms of least cost to maximise benefits, than the options or recommendations presented by the AEMC to date. From BBP's perspective our proposed options are consistent with NEL objective as they:

- depend on competitive markets to promote efficiency seeking behaviour;
- do not look to favour a technology over another;
- present the same technical barriers of entry to all prospective entrants but with reference to NEM reliability, security and safety requirements; and
- require that we re-examine the effectiveness of the regulatory regime impacting on the provision of monopoly services by TNSPs and DNSPs.

The details of our proposals are outlined within our response to the relevant AEMC's topic areas.

Comprehensive review

This section provides BBPs response to those specific questions asked by the AEMC and BBP's opinion in regards to the AEMCs draft recommendations or preferred options.

Chapter 2: Connection remote generation

AEMC Draft Recommendation
The AEMC has identified a requirement for a new framework to be introduced into the NER for efficient connection of remote generation to transmission and distribution networks where clusters of generation are expected to seek connection over a period of time. The framework includes the following key elements:

- development of new framework introduced into the National Electricity Rules (NER) for the efficient connection of remote generation to distribution and transmission networks where clusters of generators in specific locations are expected to seek connection over a period of time, named as the Network Extensions for Remote Generation (NERGs);
- customers to underwrite the cost of any additional capacity in excess of requirements of the first connecting generators that is forecast to be efficient; and
- in light of significant risks, a Network Service Provider (NSP) will not develop NERGs and provision should be made contestable of service delivery.

The AEMC has considered the NERG proposal to be of immediate priority.

BBP Response
The AEMC concluded that existing bilaterally negotiated arrangements for new transmission connections are likely to:

- make it difficult for network businesses to coordinate (including issues regarding confidentiality and information requirements);
- provide insufficient incentives for networks to right size the investment;
- not resolve the free-rider problems from going forward;
- unable to provide a capacity right to first movers to on-sell.

In addition, the AEMC concluded that the existing transmission arrangements were unable to facilitate TNSPs to effectively address the commercial risks associated with remote network connections. The AEMC found that the issue was significant and represented a material risk that could not be facilitated through the existing market design framework.

Accordingly, the AEMC found that as a material, and immediate risk it would be making recommendations to change the existing market design to facilitate change. The AEMC's proposed Network Extensions for Remote Generation (NERG) model looks to overcome weaknesses by making adjustments to planning, charging and revenue recovery regime. A key element of the NERG is that customers would underwrite costs for additional capacity in excess to requirements for first connecting generator. As more generation enters the area, and takes up the excess capacity the revenue recovery moves from customers to the new generation. Importantly, where a TNSP is to identify 'significant risks' associated with a proposed NERG it will not proceed.

To achieve this model the AEMO and TNSP would undertake initial planning to identify NERG zones, and identify the necessary connection assets required to support the NERG. The sizing of connection assets to meet the NERG's forecast capacity requirements are to be based on anticipated future generator connections.

Generally, BBP supports the concept of the NERG to facilitate the connection of new generation in remote locations, however, BBP considers that the AEMC has further analysis to undertake to:

- articulate why it has decided to treat new power generators differently to existing generators when addressing the need for new transmission assets (NERG and the G-TUOS proposal), and more critically demonstrate how two disparate transmission investment frameworks can co-exist within the NER having regard to the NEL objective; and
- demonstrate the basis of addressing the noted weaknesses with the NERG.

At the policy level, BBP maintains that the AEMC has yet to demonstrate, prime facie, the manner in which the NERG would meet the NEL objective. For instance, the AEMC's proposed approach of time sculpting the NERG/TUOS revenue recovery between consumers and new entrants for excess capacity is conceptually sound, however, from BBP's perspective lacks credibility without there being at least the setting of a framework around how this approach meets the NEL objective.

For instance, taking the IES modelling completed for the AEMC[5] over the next 20 years the NEM will see around 48,111MW of grid connected renewable generation producing some 163,794GWh of energy. If we assume that much of this grid connected renewable investment is remote, and new transmission assets for NERG will be $250,000 per km[6] then Table 1 sets out some likely capital costs, capital charge recovery, and what a consumer would see in terms of an annual average price impact if the NERG TUOS recovery were to be levied on a postage stamp basis.

Table 1 – Cost recovery NERG Transmission Assets

Km Line	**Value of Asset Installed \$ million**	**Capital Charge 6% 40 Year return \$ million**	**Depreciation \$ million**	**Total Annual (Asset Only) Charge \$ million**	**Households**	**Average Cost per Household pa**
10,000	2,500	166	63	229	8.1 million	$ 28.06
15,000	3,750	249	94	343		$ 42.09
20,000	5,000	332	125	457		$ 56.12
25,000	6,250	415	156	572		$ 70.16
30,000	7,500	498	188	686		$ 84.19
35,000	8,750	582	219	800		$ 98.22
40,000	10,000	665	250	915		$ 112.25

The alternative of then levying on new generators may result in the imposition of costs, which if able to be passed through by the generator could represent a more costly option than the illustrative postage stamp costs outlined in table 1.

5 Intelligent Energy Systems (IES) Future Congestion Patterns & Network Augmentation – Report on Assignment A Transmission Development Framework Scenarios, page 28

6 GridAustralia, 40,000km of HV line with an asset value of $10 billion, as monopoly regulated business lets assume that the total cost base is 'efficient'.

In terms of the NEL objective, to balance the expected costs there needs to be quantification of the benefits from the NERG to consumers in the long run by imposing these costs (which are a maximum given the proposed risk sharing mechanism). The benefits of the NERG are quantifiable from the two broad concepts of value:

- avoidance of direct and indirect costs associated with any penalties that may accrue to Australia as a result of not being able to meet its international carbon emissions reduction targets; and / or
- the capturing of any incremental economic value from having a well functioning renewable energy sector attributable to having a supportive regulatory framework cover transmission network for renewable energy.

Translating these benefits into quantifiable measures within the RIT is a different albeit more complex issue.

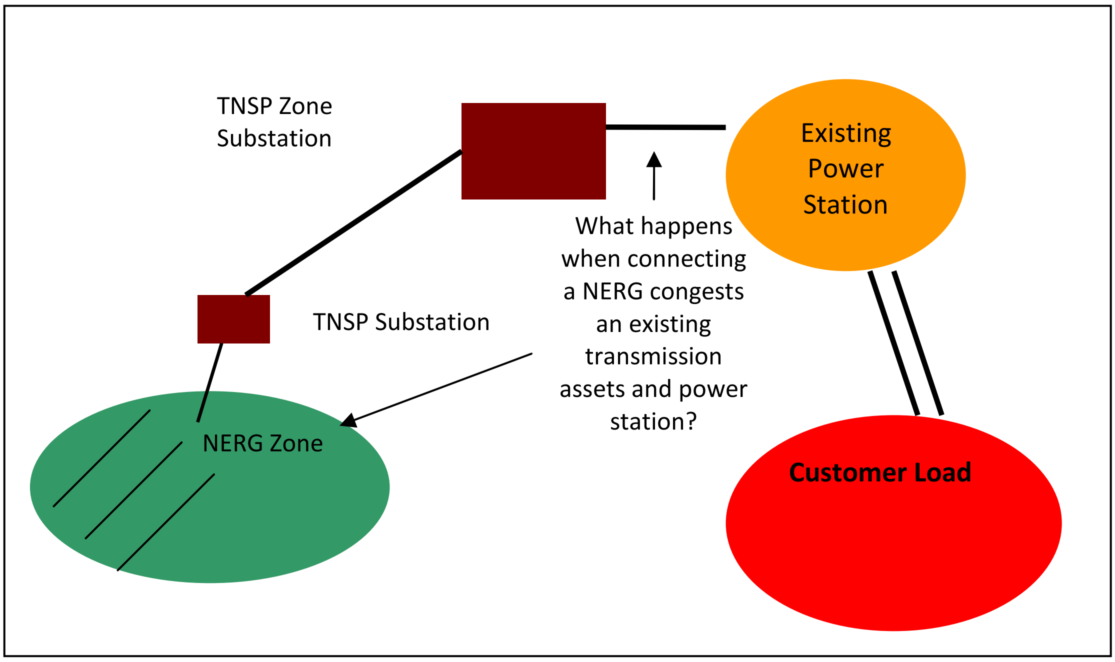
To present a more dynamic policy prescription the AEMC may then consider such costs and benefits associated with a range of options, not just the NERG. In recommending the NERG option, BBP maintains that the AEMC has not identified the costs and benefits as per the NEL objective, nor have they been able to set down a rigorous framework to quantify these items. It is BBP's position that prior to establishing a clear timetable for review, the AEMC must set down an appropriate policy framework to measure whether the NERG will enhance the long term interest of users.

Another policy concern that BBP has with the NERG recommendation is that as a new arrangement for transmission networks it has not been linked to the AEMC's other report recommendations which have a direct impact on the manner in which transmission networks are regulated – G-TUOS. Moreover, it is apparent that the AEMC's basis for the NERG is different to that being applied to the G-TUOS (discussed more in section G-TUOS). At principle were the AEMC to continue with the existing inconsistency between NERG and GTOUS recommendations the inconsistency may manifest when decisions need to be made as to when NERG transmission assets convert under the G-TUOS arrangement.[7]

From a practical basis consider the following worked example as illustrated in Figure 1. The NERG zone is identified and appropriately sized transmission assets built, including connection assets to the common existing network. But connection of the NERG causes congestion within the existing network. From a basic practical perspective the NERG as it stands does very little to address this issue, and combined with G-TUOS, as currently proposed exacerbates the financial impact of congestion impacts on the existing transmission network. If the AEMC's proposal for assessing and justifying a NERG zone does not address the congestion that it will ultimately cause in existing networks then it needs to be reconsidered.

7 If is the case that the NERG survives in perpetuity then the NERG represents a form of permanent access holiday which has not been subjected to the substantial regulatory rigour associated with Part 3A of the TPA processes.

Figure 1 – Illustration of the NERG impacts – practical challenges on implementation



In implementing the NERG, BBP considers that the AEMC needs to provide further details around Option 2, and why this model is preferred to Option 3. Specifically, the AEMC commissioned two independent consulting reports as part of its deliberations, Intelligent Energy Systems (IES) and ROAM Consulting (ROAM). Each group were asked to examine:

- "Future Congestion Patterns and Network Augmentation. Report on Assignment A: Transmission Development Framework Scenarios" 25 June, 2009;

- "Network Augmentation and Congestion Modelling", 25 June 2009.

It is important to note that both modelling groups utilised the concept that the 'socially optimal generation and network investment case that reflects co-optimised investment decisions by generation and transmission from a central-planning perspective', as best achieved by assuming a co-optimising central planner[8].

Option 2[9] includes no role for the National Transmission Planner (NTP) within AEMO, and leaves central planning outcomes to be determined by transmission businesses separately, but in coordination. Option 3 has the NTP within AEMO replacing individual transmission businesses, however the AEMC dismissed Option 3 on account that AEMO had indicated it did not have the resources[10].

From BBP's perspective it seems incongruous that a key assumption driving modelling outcomes would be so readily dismissed as a policy option to address one of the most significant issues facing the NEM as it evolves through CPRS and eRET. Moreover, if AEMO considers that it needs more resources, whether these be financial or technical, to

8 EGR Consulting Limited, (2009), IES/ROAM Modelling of Future Congestion Patterns: Due Diligence Review, page 6.
9 AEMO's already has the transmission planning responsibilities for South Australia (ESIPC absorbed by AEMO) and Victoria (VenCorp absorbed by AEMO). From BBP's perspective the AEMC's challenge is demonstrating that having fragmented roles between AEMO as NTP for South Australia and Victoria, and New South Wales and Queensland with PowerLinke and TransGrid, respectively, if the most efficient and effective outcome with regard to the NEL objective.
10 AEMC, (2009), Second Interim Report, page 22.

effectively implement the NTP then from BBP's perspective the AEMC represents the relevant regulatory institution within the NEL regulatory framework to make recommendations to ensure that AEMO is sufficiently resourced.

A lack of transmission networks is noted as being a barrier to connecting new power generation, and congestion within the current transmission network. All of the results provided by the various modelling groups point to the substantial risks to the NEM by a lack of transmission. From BBP's perspective the goal of having power generators responding to locational price signals is essential, in addition it is also crucial that transmission assets are built. The NERG provides for new transmission network to be built, but does not address more common transmission network to be built – which is the other key challenge.

The AEMC's NERG provides limited accountability on transmission businesses to:

- choose the least cost of supply or ensure that the TNSPs have sufficient incentives to 'right size the asset'[11];
- set an appropriate WACC that takes into account the extent to which the risk-sharing with customers alters the WACC (BBP considers that TNSP's WACCs on NERG should be time sculptured where initially the WACC applied to NERG should reflect an equivalent risk free rate of return, and then ratchet upwards as new renewable generators take up capacity);
- improve transparency through annual planning reports, BBP recognises this process needs to be improved by having AEMO, operating as NTP, identify appropriate criteria for transmission businesses to identify and report NERG areas, and if the second best policy option is taken then there should be a requirement that TNSPs address common criteria when publishing information on NERGs, and this needs to be outlined in the NER; and
- improve TNSP efficiencies through making the provision of the NERG contestable, where a better outcome would be to explore the process whereby existing regulatory regime applied to transmission businesses is improved (see Chapter 3: Efficient utilisation and provision of the network).

11 The AER and formerly the ACCC may have reduced TNSPs proposed capital expenditure programs as part of ex-ante revenue requirement setting processes, but there little evidence of 'optimising' of transmission investments once made.

Figure 2 – Choosing the right regulatory regimes for TNSPs

BBP considers that the NERG and G-TUOS represent the AEMC's options to address the same problem impacting existing and new generators – insufficient transmission assets. BBP is reminded that in terms of regulating monopoly infrastructure, like transmission networks, it is important to consider options with regard to the following criteria:

Objectives

- What is the problem that the regulation seeks to address?
- Is the problem significant enough to warrant a response, having regard to the costs of intervention? Ie are the benefits of intervention greater than the costs

General efficacy

- Does the intervention target the problem effectively?
- Are there unintended consequences and costs?
- Is it consistent with related regulations?
- Can improvements be made to the design and implementation of the intervention?
- Would alternative interventions be more effective?

Administrative efficiency and accountability

- Timely and transparent?
- Is there effective monitoring and review provisions?
- Are regulators accountable for their decisions?
- Is there appropriate separation of policy making and regulatory functions?

(*Productive Commission (2001), "Review of the National Access Regime – Inquiry Report", page 45)*

TNSPs are service providers, regulators, and participants. Their income is regulated, unregulated, and ultimately provided due to the distinctive capability defined by their legislated state franchise. As regulated businesses, TNSPs have undergone several rate of return/revenue (price) regulation over the past 15 years by independent economic regulators. Accordingly, the asset base should be efficient, and the cost streams should represent productive and allocative efficiency.

The real question for the AEMC, and the MCE, is whether the existing regulatory regime can provide incentives to TNSPs to deliver the dynamic efficiency that will be required to address eRET, and CPRS to a lesser extent, to build more transmission network? BBP considers the greatest challenge that the existing regulatory regime for TNSPs is dual role that TNSPs play as service providers (some of which are monopoly services) and providers of regulatory functions in the NEM.

Regulatory certainty and dynamic efficiency in transmission network provision would benefit by separating these functions.

Chapter 2 Questions

2a. Will the recommended model adequately address the deficiencies in the existing framework?

BBP, as outlined above, does not consider that the proposed model addresses the weaknesses in the existing framework as per the following:

- the AEMC has not provided sufficient basis around the costs and benefits of the NERG in terms of long term interests of electricity consumers
- different reform approaches for NERG and G-TUOS without articulating a clear approach for addressing weaknesses in the regulatory framework being applied to transmission assets is a significant policy weakness in the AEMC's proposals
- the option chosen is contrary to the AEMC's own modelling assumption around the best policy alternative with regard to transmission planning

- if revenue recovery decisions to charge the next new renewable generator are in error then the free-rider problem may remain.

2b. Does the recommended assessment process appropriately balance customer risk with potential customer benefits?

BBP considers that the AEMC needs to undertake further analysis around the costs and benefits of the proposed NERG with regard to the NEL objective.

2c. Is there merit in allowing rival service providers to deliver network extensions for remote generation?

BBP considers that there is substantial merit in allowing transmission business on transmission business competition. It is suggested that this is best achieved not at the periphery (ie the AEMC's proposal that contestability on NERG assets) but through a more structural adjustment consisting of:

- at principle a decoupling of existing transmission businesses from their existing state based franchise areas;
- a staging arrangement to move transmission asset ownership and NER regulatory responsibilities away from the TNSP service provision (structural separation);
- the NTP to be revenue regulated by the AER and to set TUOS;
- a greater role for the NTP in planning and coordination; and
- service provision by existing TNSPs to compete for operating and maintenance and capital expenditure contracts.

Chapter 3: Efficient utilisation and provision of the network

AEMC Draft Recommendation

The AEMC's draft recommendations to address efficient utilisation and provision of the network include:

- Generator Transmission Use of System charge (G-TUOS) to be applied to all generators. The G-TUOS charge is proposed to be:
    - reflective of forward looking long run incremental network costs at a particular location;
    - calculated as a fixed charge per kilowatt of generating capacity;
    - set on an annual basis; and
    - designed to be revenue neutral in aggregate on the network
- if required, an additional Congestion Pricing Mechanism to manage short term congestion (location and time specific); and
- negotiated financial access rights to the shared network is not an appropriate means to address congestion in the future.

In terms of prioritisation, the AEMC determined that G-TUOS is a material risk but that as an issue there is sufficient time to address the risk beyond the immediate period (next 6 months). The AEMC did not explicitly consider any costs or benefits of G-TUOS in terms of the NEL objective.

BBP Position

Firstly, BBP does not support the AEMC's differential treatment of transmission issues between existing generators and new remotely located renewable generators. The G-TUOS and NERG look to address the same weakness and risks associated with the regulation of transmission businesses/networks where the only difference occurs as a function of time.

The NERG and G-TUOS are both designed to achieve the same objective – sufficient transmission network to ensure that the most cost effective generation is able to be dispatched. For new and existing generators, the only difference is time, which is a matter of perspective shaping a generators' demands and needs, but in the long run all generators share the same objective – certainty that knowing that when we generate in response to the expected gross energy pool price we can have reasonable level of certainty that we can transport our energy to market ie we will not be limited due to insufficient transmission investment.

To this end, the AEMC's G-TUOS and NERG are similar in that they:

- intend to signal investment need through the right sizing of transmission network investment to meet transmission capacity needs;
- signal asset use through the setting a revenue recovery price that reflects use of capacity; and
- aim to address market failures associated with first mover advantage and free-rider problems within transmission network investment.

Where the AEMC's NERG and G-TUOS depart include:

- the NERG allows transmission businesses to continue to make planning outcomes on an individual basis, whereas G-TUOS seeks the superiority of a NTP socially optimum central planning outcome for building new transmission to overcome existing congestion problems;
- the NERG requires the transmission business to build the network but under G-TUOS the transmission business is given an option not to build out the congestion;
- the NERG sets a requirement to allocate identified assets to revenue recovery and asset build out, under the G-TUOS there is not such requirement; and
- the NERG provides for a revenue and capacity risk sharing mechanism whereby transmission business' risks on revenue recovery are ameliorated by revenue associated with excess transmission capacity being levied on consumers through TUOS until new generation arrives, while in stark contrast G-TUOS looks to levy a two part tariff regime on existing and new generators but in a revenue neutral manner[12].

BBP suggests that by not explicitly seeking to demonstrate how G-TUOS and NERG meet the NEL objective the choice of policy interventions to resolve the electricity markets ongoing and increasing needs for greater transmission investment may result in a sub-optimal outcome. More critically, in the absence of the AEMC explicitly demonstrating the G-TUOS and NERG's contribution to the NEL objective, BBP considers that where the AEMC progresses any NER change process which looks to establish two separate transmission schemes within the NER there are substantive prime facie arguments that such action could be considered ultra vires.

12 From BBP's perspective this represents a policy intervention free-rider problem, for example, G-TUOS process is as follows: transmission congestion is an issue, lets identify it, lets determine what assets we need to remove it, lets charge generators to signal where to locate based on the physical costs to build it out, then lets give transmission businesses an option not to build the congestion out, and lets make the scheme revenue neutral. It's a puzzling outcome.

If we consider G-TUOS in isolation BBP notes the following key weaknesses.

The AEMC's G-TUOS proposal does not provide appropriate investor certainty as it:

- potentially may undermine financial viability of projects by introducing a new variable cost which at the moment would be un-hedgeable;
- it is not credible that an annual "arbitrary" and variable charge would facilitate long-term generation investment decisions; and
- the G-TUOS charge (negative prices for areas with free capacity and positive prices where no excess capacity) simply collapses into a basic transfer between generators – it contributes nothing to value in terms of long term interests of consumers.

At an implementation level the AEMC's G-TUOS proposal needs to take into consideration the following limitations.

The basis for setting the annual fees – as a relative annual charge the volatility of the charge, and the likely regulatory risk attached to the cost streams, does not contribute to investment certainty. The long term interests of users is best achieved through providing investors (participants) with a regulatory environment that provides for stability, predictability and transparency in pricing (cost streams)[13]. Moreover, where similar regimes have been attempted in other electricity markets the market consensus is not resoundingly positive that G-TUOS achieves these objectives.[14]

Figure 3 – Illustrative example of LRMC Pricing for Regulated Infrastructure

In order to achieve the desired market benefit the G-TUOS charge must provide a LRMC price signal consistent with a planning horizon that provides stability to the LRMC calculation. A practical 'regulatory approach' to network LRMC pricing for infrastructure going through expansions phases is provided by the Queensland Competition Authority (QCA), in their 2000 GAWB determination. The QCA adopted an LRMC estimate including both the marginal capacity cost and marginal operating costs.

The QCA's decision presents two methods for estimation of LRMC, the Present Worth of Incremental System Costs (the Turvey Method)[1] and the Average Incremental Costs Method (AIC Method)[1]. The QCA considered the Turvey Method a more appropriate measure for the determination of LRMC as it considers the opportunity cost of delaying or bringing forward infrastructure augmentation by one year. Although from a practical sense the AIC method would be more straight forward to determine.

The QCA noted that, "Turvey argues the cost saving from deferral of augmentation is relevant to the marginal cost measure, not the cost savings from abandoning it entirely"[1]. As a result the QCA argued the Turvey method presents a theoretically purer determination of marginal cost relative to the AIC method[1].

BBP considers the QCAs determination as an appropriate basis for considering LRMC pricing in the context of transmission investments.

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13 AEMC (2006), National Electricity Amendment (Pricing of Prescribed Transmission Services) Rule 2006 No.22, 21 December, p.2

14 National Grid (2009), Transmission Charging – a new approach, May, p.30

The establishment and management of G-TUOS zones is "problematic" – a recent change in transmission zones in south west Queensland resulted in some power stations remaining within an existing transmission zone, and others being included within a new transmission zone. The zones reflected PowerLink's own assessment of existing transmission assets, and expected assets to be constructed in the future. If G-TUOS were levied as per such an arrangement the cost impacts on generators would be highly volatile, and to a large extent unmeasurable. Such an outcome would further erode G-TUOS contributions to the AEMC's objectives of stability, predictability and transparency in pricing.

The AEMC's use of a 'retirement signal' argument in support G-TUOS is of great concern. A possible outcome of the G-TUOS, should the AEMC be able to demonstrate that it addresses the NEL objective, is that existing generators may pay more in TUOS, which may bring forward a retirement decision. BBP considers that for the AEMC to consider a retirement outcome as a reason in support of G-TUOS is contrary to the NEL objective in terms of favouring a technology over another, and treating existing and new entrants equitably.

Furthermore a G-TUOS charge needs to create the necessary incentive for TNSPs to invest in the network. This may be achieved through; behavioural regulation – placing more accountability on TNSPs to make publicly available information on existing and forecast network congestion issues. This could be achieved by providing greater scope to require that TNSP to adopt clause 5.4A of the NER for all new connections or augmentations of the network.

From BBP's perspective there is a greater need for more wholesale changes to the regulatory regime applied to TNSPs. At principle, a new regulatory regime for TNSPs should have the aim of ultimately de-coupling current TNPS from their state based franchise areas.

Such an option would ensure the separation of TNSPs from service provision, and the asset ownerships and regulatory functions, which currently is problematic. In the future this type of structural weakness may significantly increase challenges associated with building new transmission assets for remote generation and to build out congestion.

Promoting regulatory oversight and service provision separation would promote TNSP competition in service provision, as well as ensuring that regulatory approval processes around the transmission assets being based on what is best for the NEM, as per the NEL objective rather than being clouded by commercial incentives of the individual TNSPs. Broadly the approach would work as follows.

AEMO's National Transmission Planner function could move towards setting 25, 10 and 5 year transmission planning requirements with specific focus on:

- amendment to the NER to set-up the relevant mechanisms to:
    - identify congestion;
    - demonstrate how it will be measured;
    - establish the threshold around 'triggers' to identify "inefficient" levels of congestion;
    - provide criteria to identify zones, and more importantly the process to amend zones;
- identifying congested areas of the network and determining the transmission assets to build out congestion or provide capacity;

- identifying capacity constraints on the common network and determining transmission assets to build out congestion or provide capacity;
- identifying areas for remote generation, including the right sizing of assets;
- setting of contingent capital expenditure profiles by region, which once built are subject to a post efficiency review, and then rolled into that state region's asset base for the purpose of TUOS recovery from all users; and
- provide the AER with the regulatory power to monitor and enforce rule compliance.

Existing regulatory and NER role within TNSP's would be funded through the TUOS recovery, while the service provision areas of TNSPs would compete to provide operating and maintenance of existing assets, and to compete to build new infrastructure. Eventually, the regulatory and NER roles carried by individual TNSPs would migrate to AEMO's NTP function, and be regulated by the AER through current revenue determination processes. Existing service delivery arms of TNSPs would compete to building new capacity in existing network assets, and provide operating and maintenance services to existing assets.

Other comparable regulatory regimes for monopoly infrastructure provide a guide that the AEMC could follow for TNSPs. For example, the review of price regulation of airport services conducted by the Productivity Commission in 2002[15] prompted the use of a light handed approach to the setting of prices for aeronautical and related services. The move to limit the direct involvement of the regulator in the setting of prices was intended to facilitate investment and innovation by airports whilst preserving the restriction of any misuse of market power in their dealings with customers[16].

This is one such example of an approach to the setting of network charges for transmission assets. Ensuring network assets are built only after undertaking required negotiation with generators and customers provides for greater incentive for and accountability in the efficient development of additional capacity investment. Applied to the NEM the accountability would help overcome existing issues with RIT-T optimisation (primarily concerned with markets benefits test).

Chapter 3 Questions

3a. Do you agree that we have accurately identified which elements of the existing framework are considered inadequate and therefore require change?

BBP considers that the AEMC has accurately identified 'part' of the elements in the existing framework that require change. The AEMC has not identified the limitations in the existing regulatory regime applying to TNSPs is restricting investment in transmission assets – to either remove congestion; or build new networks.

3b. Would the G-TUOS charging option design improve pricing signals to promote efficient location and retirement decision in the most efficient way? Are there any design variations that may improve signals?

BBP considers that in its current form G-TUOS would not improve pricing signals, and more critically, the AEMC needs to demonstrate with greater clarity how G-TUOS would meet the NEL objective. Moreover, the G-TUOS would not result in congested transmission networks being "built out". BBP maintains that the AEMC should re-examine G-TUOS, accordingly, it would be premature to even consider improved pricing designs.

15 Productivity Commission, (2002), Price Regulation of Airport Services,

16 Productivity Commission, (2006), Review of Price Regulation of Airport Services, page XIII

3c. *Given that G-TOUS is a preferred option, what additional value would a congestion pricing mechanism add? Of 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?*

Please refer to the above.

Chapter 4: Inter-regional transmission charging

AEMC Draft Recommendation
The AEMC's draft recommendation for inter-regional transmission charging consists of the following key elements:

- all TNSPs calculate a load export charge;
- charge follows electricity;
- charge reflects cost of new and current assets to support transfer;
- transmission passes the charge through to users based on proportionate use of network;
- no change in total permitted revenue – re-allocation of transmission revenues.

AEMC's recommends that the charging will commence 1 July 2011.

BBP Position
BBP supports the AEMC's prioritisation, and substantially supports the proposed recommendation.

Chapter 4 Questions
4a. *Is the proposed design for the load export charge appropriate as an effective mechanism to address the identified problems?*

BBP considers that the AEMC's proposed recommendation on intra-regional charging represents an effective approach to ensure that the support that intra-regional transmission investment provides to inter-regional flows is financially recognised. BBP considers that the AEMC's rejection of a single NEM-wide pricing methodology did not sufficiently articulate why its preferred option better met the NEL objective compared to the NEM-wide option.

That said, BBP does not consider this to be a material matter at this stage.

4b. *Is our suggested commencement date of 1 July 2011 achievable?*

BBP considers that the proposed commencement date is achievable, however, with the impact largely being borne by AEMO and TNSPs then it is likely that these participants are best placed to address timing.

Chapter 5: Regulated retail prices

AEMC Draft Recommendation
The AEMC has recommended that by the commencement of the CPRS 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.

The AEMC did not set a prioritisation to implement its recommendations.

BBP Response
CPRS and eRET are creating substantial uncertainty in the NEM as a consequence of:

- impacts on cost base and structure of costs of power stations; and
- the extent of pass through of CPRS costs.

For energy retailers the continuance of retail price regulation for all states (excluding Victoria) could potentially distort the NEM in a manner similar to the Californian electricity market[17]. BBP commends the AEMCs attempt to provide for greater flexibility in the market through an appropriate adjustment mechanism, however, the first best policy solution is to examine whether the retail energy markets are sufficiently robust to be regulated through more light handed approaches rather than by direct price regulation.

In order to mitigate wholesale energy price risk retailers are required to enter the OTC market. Uncertainty in wholesale energy prices and a retailer's ability to recover costs creates further risk in the timing of payments and distortion of the OTC market. Generators, facing already significant costs as a result of the CPRS and the impact of eRET, face a further threat of retailer failure as a function of not being able to timely recover retail costs, and with razor thin margins, increased risks of the retailers failing to make contract payments.

For the OTC market to clear there needs to be greater certainty around CPRS pass through to retail energy prices. A move from uncertainty to certainty provides the basis for market participants to 'price' the likely cost increase, and the risk associated with the forecast price increases driven by CPRS. This is a mechanical process that the energy market is able to 'digest'[18] but there needs to be some certainty on some variables for this volume and price revelation process to occur.

More importantly, from BBP's perspective the current retail price regulation could be seen as a barrier to more effective competition in the energy market. Vertical integration within the power industry is seen as being a competitive response to responding to the inherent, and substantial risks associated with dealing with an essential, highly valuable, and real time commodity. A direct retail price cap with razor thin profit margins discourages market entry, and provides vertically integrated power businesses with a substantial competitive advantage.

To achieve cetertainty, the AEMC should recommend to the MCE a 6 month process of reviewing existing retail energy price regulation. Victorian retail price regulation was removed after an AEMC review determined that competition had been effective. SA has had a similar review conducted, and the findings of the review are now with the SA Government.

BBP considers that a workable review process could consist of:

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17 The basis for the 2001/03 crisis in the Californian electricity market can be attributed to a number of causes. A significant cause was that retail price caps were kept well below full cost reflectivity, while wholesale energy prices were rising sharply in response to a capacity shortage. With retail price regulation in the NEM determined by state based processes there is the potential that these processes may not be able to respond quickly enough to effectively pass through any significant movement in wholesale energy costs.

18 Pricing of CFDs in response to the impact of the drought on energy prices is a case in point.

- reviewing current retail price regulation arrangements;
- determining the best form of future regulation having regard to the approach for considering benefits to consumers as per the Victorian approach;
- establish a clear timeframe for jurisdictions to consider the outcomes, ie within 3 months;
- if the jurisdiction decide to retain the current form of regulation of retail prices then the jurisdiction should be required to set out the basis for the retail price regulation:
  - identifying size and type of CPRS pass through;
  - the mechanism or method it intends on adopting to measure CPRS cost imposts;
  - how ex-ante mistakes on CPRS forecasts will be rectified; or
  - how the loss of value to retailers will be accommodated for any ex-post pass through arrangement;
  - timetable for reconsidering the regulation of retail prices;
- if the jurisdiction decides to remove regulation of retail prices then it should be required to set out the basis under which regulation of retail prices would be re-introduced ie some market monitoring, and threshold tests to identify anti-competitive and anti-consumer behaviour.

Chapter 5 Questions

5a. Do you agree that wholesale energy costs will be less certain, less able to be hedged and harder to forecast following the introduction of CPRS?

BBP agrees that wholesale energy costs will be less certain, less able to be hedged and harder to forecast after CPRS when compared to how the market currently operates. The increased uncertainty could be addressed by there being:

- greater clarity around CPRS and eRET timings
- the removal of retail price regulation – allowing CPRS pass through.

For further details see the above arguments.

5b. If jurisdictions and / or pricing regulators incorporate additional flexibility in pricing instruments, as set out in the recommended principles, does this sufficiently decrease the risks to retail competition and of retailer failure?

BBP considers this to be the second best regulatory option. A better alternative would be to examine existing regulatory regimes as outlined above. The approach being proposed by the AEMC:

- has not substantiated its meeting of the NEL objective;
- not made a comparison with other options, such as that proposed by BBP, in meeting the NEL objective;
- depends substantially on state based jurisdictions being able to have perfect foresight when setting of the retail prices with regard to:
  - the quantum of the CPRS cost pass through;
  - the timing of the CPRS pass through;
- requires the state based jurisdictional regulators having clear, transparent and robust processes able to approve any CPRS pass through in a timely manner.

5c. Are existing regulatory approaches adequate to assess the costs to retailers of the expanded RET?

BBP supports the AEMC's findings in relation to the pass through of eRET costs.

Chapter 6: Generation capacity in the short term

AEMC Draft Recommendation
AEMC considers that existing market frameworks may be inadequate to address short term generation capacity needs. The AEMC has recommended that this would be best addressed through:

- facilitating more accurate reporting of demand side capacity;
- utilising the potential for distribution connection generation to help alleviate capacity shortfalls.

AEMC is also seeking views on its recommendation to extend AEMO's short term reserve trader (RERT) options or procurement of capacity. The AEMC has placed an immediate priority on addressing short term capacity needs.

BBP Response
BBP considers that any AEMC recommended response to ensuring that generation capacity arrives in the short term needs to have regard to the NEL objective. The NEL objective requires that the long term interest of consumers is served by:

- the supply mix, including network solutions, represents the least cost of supply
- this must have regard to the price, quality, safety, reliability and security of supply,
- reliability, safety and security of the national electricity system.

For short term generation capacity needs the NEL objective is served by: mitigating the risks of USE and reliability being breached; and in a least cost manner. We consider AEMC's proposed options with regard to these elements.

Firstly, the general market consensus is that the NEM is not carrying the 30% to 40% spare capacity that it carried in the early 1990s when microeconomic reform of the power industry commenced. Moreover, the AEMO SOO process has identified potential USE breaches in:

- Victoria and South Australia summer of 2009/10[19];
- Tasmania summer 2010/11;
- South Australia summer 2010/11;
- Queensland summer 2013/14;
- New South Wales summer 2014/15.

The reserve plant margin for the NEM in 2008 was approximately 10% over PoE50 demand against typical world benchmarks of 15% and US standards of 15-20%. Similarly, the 2008 SOO prepared by the Independent Market Operator (IMO) in Western Australia indicated a shortfall in targeted spare capacity beyond that already in service or under construction would arise in that market in 20010/11[20].

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19 And for the next three to four summers based on Newport Economics "Managing Short Term Reliability – AEMC Review of Energy Market Frameworks in light of Climate Change Policies, page 10.

20 IMO, July 2008, Statement of Opportunities, page 4.

CPRS and eRET is designed to make the community value the environment, and in response to a price signal reduce the use of carbon emission intensive products. In the production of electricity CPRS adds a cost to carbon emitting plant, while the eRET uses the NEM to deliver a subsidy to renewable energy sources.

Commercial decisions by the owners (equity and debt) of power stations that are heavy carbon emitters post CPRS implementation will be driven by conservative accounting concepts not ambiguous results from the various modelling groups.[21] Unfortunately, their choices are stark and simple – post CPRS implementation, and eRET the earning profiles from affected assets are "uncertain". Uncertainty is different to risk – it represents an unknown, and unfortunately it can not be managed through the best practice risk methods developed and applied in the NEM.

Put simply the decision criteria is "should we spend a dollar today on the basis that the earnings in the future are unknown?". In a conservative business environment still reverberating from the shocks of the GFC, where cash reserves and debt pay down is critical to short term survival, there is a very simple and obvious course of action that equity and debt holders must take when confronted with such uncertainty. [22]

Moreover, the AEMC needs to also consider the individual asset decisions facing affected power station owners.

Table 2 highlights key characteristics of power generation, but is also illustrates:

- the capital intensity of the sector, for example to replace the brown and black coal assets is a staggering $71 billion;
- of the installed assets, black and brown coal fired power stations are only half way through their useful lives.

Table 2 – Key Characteristics of Australia's Power Generation Fleet 2008

Generation Technology	Installed Capacity* (MW)	Replacement Cost# ($/kW)	Replacement Value ($m)	Average Fleet Age* (Yrs)	Total Useful Life# (Yrs)	Remaining Useful Life (Yrs)	Depreciated Value ($m)
Hydro	7,609	2,500	19,023	37.2	100	62.8	11,953
Black Coal	22,601	2,250	50,852	23.5	50	26.5	26,957
Brown Coal	7,335	2,750	20,171	28.1	50	21.9	8,842
Natural Gas	6,688	1,100	7,357	15.2	30	14.8	3,629
CCGT	2,154	1,550	3,339	5.0	30	25.0	2,782
TOTAL	46,387	2,172	100,742	24.4	54	30.0	54,164

*Source (esaa, 2008). #B&B Est.

From an asset owners perspective the stranding of these assets is not occurring at the end of their useful lives, but right at the time where the assets' substantial economies of scale start to payback on the initial capital invested.

There is a "real risk" that existing heavy carbon emitting plants will:

21 BBP notes that the various energy market modelling groups are providing a range of forecasts to various energy market participants, whether existing, green, coal-fired, government, and regulators. More critically it is noted that the widely varying results still reflect the perspective, the assumptions, and predictive scenarios adopted. The AEMC takes on substantial regulatory error risk where it attempts to prescribe NER interventions driven by the modelling results. From a NEL objective, and regulatory best practice perspective, until the modelling results and forecasts begin to "cluster" or normalise around common outcomes, the AEMC may be better calibrate its interventions around principles rather than technical prescriptions as the basis to minimise its regulatory error risks.

22 For clarity, this discussion represents a hypothetical future designed to identify and articulate issues, and does not reflect current BBP practice.

- at a minimum, look to postpone, and/or minimise any expenditure on power stations within the immediate time horizon[23] reflecting:
    - o a post CPRS/eRET budget constraint;
    - o uncertainty around earnings;
    - o noted substantial shortening of asset life due to policy intention of CPRS and eRET;
- at a maximum, either mothball or retire existing heavily affected power stations[24].

The Commonwealth Government has offered the Electricity Sector Assistance Scheme (ESAS) to "help" the coal fired generation sector "transition" to a low emissions economy. The ESAS is designed to provide:

> "…[in the] absence of any assistance, this could negatively impact on the investment climate in the Australian energy industry…..assistance to ameliorate the risk of adversely affecting the investment environment is a necessary and important contribution that supports essential new investment in the electricity generation sector."[25]

But the ESAS comes with conditions. The assistance, while designed to keep the investment climate in the power industry as benign as possible, requires that power stations in receipt of ESAS keep their capacity in the market. Also, two years into ESAS (start date of ESAS is when CPRS commences) the carbon regulator will review recipient power stations earnings, and where a 'windfall gain' is identified, the offending power station will have its last three years of ESAS cancelled.

Finally, ESAS is capped at $3.5 billion (2008/09 dollars) with levels of individual assistance determined by heat rates, individual carbon intensity levels pegged to an industry wide benchmark, and the price of the ETS commodity. The $3.5 billion represents the minimum of the modelling forecasts made regarding the hypothetically required level of the ESAS. The medium is around $12 billion. [26]

For equity and debt holders in a power station the 'real risks' with ESAS are:

- only the first two years of "volume" in ETS free permits are 'bankable';
- in the first year their value is $10, and the second year value is determined by a forecast price coming off the $10 floor;
- the last three years volume, hence value, are unbankable as the windfall test parameters are unknown, but based on the present variability of results from the various modelling groups, utilising a conservative business frame would consider the outcomes as "uncertain";
- the condition to keep "capacity" in the NEM, if it is needed, creates further uncertainty associated with the process to review;
- the condition to keep "capacity" in the NEM will create measurable costs, these will be certain.

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23 As noted by the AEMC the power station could also experience increased operating costs by nature of the change to its operating profile (ie more stop, starts etc), which may accelerate this decision. In addition, given the substantial economies of scale in refurbishment capital expenditure on power stations there is the risk that there may be no minimum increment of capital expenditure.

24 Such action is likely to supported by legal action examining 'just compensation' for a material loss associated with a change in government policy.

25 http://www.climatechange.gov.au/whitepaper/factsheets/pubs/019-electricty-sector-adjutsment-scheme.doc

26 AEMO and the AEMC have advised that the existing ESAS is 'sufficient' to address any risks associated with reliability of supply from heavily affected power stations retiring early.

For the above reasons BBP disagrees with the AEMC's assessment and conclusion as to impact and effectiveness of ESAS in terms of addressing the NEL objective with regard to sufficient short term generation capacity.

In the immediate period the dominant intermittent generation source will be wind. Wind provides energy but it does not provide capacity. For instance, market modelling shows that between 2009/12 around 4,700MW of wind will be installed across the NEM in response to eRET.

Given that wind farms have a reliable capacity to meet peak energy demand of 8% to 15% AEMO, and the NEM, can only depend on between 370MW and 700MW of installed wind. In contrast the Commonwealth Treasury's CPRS Modelling also shows that from 2009/10 the investment need in Australian electricity markets is around 700MW of capacity per annum to meet customer load growth.[27]

BBP suggests that the increase penetration of wind creates two types of risks for AEMO:

- system operating risks as operating the power system requires further adjustments given the volatility of wind/intermittent generation; and
- risks to quality, reliability and security of supply.

The AEMC quite rightly conclude that short term generation capacity represents a real risk. To address the AEMC then recommends that the best approach, which we assume the AEMC considers to meet the NEL objective, involves:

- potentially expanding the RERT;
- examining the merits of moving to a short notice reserve contracting, and standing reserves;
- deployment of a more rigorous demand side program that AEMO can depend on, and use in conjunction with its existing functions;
- improving the incentives for distributed generation.

From BBP's perspective, these recommendations may not actually resolve the problem.

In expanding the RERT it is important to note that when using the current RERT AEMO (NEMMCO):

- paid $4.3 million for 8 weeks for 375MW;
- paid $1.05 million 4 weeks for 195MW.[28]

Based on these market based prices AEMO values the ability to respond to the risk of USE through the RERT at between $192.31 and $207.14 per MW per day[29]. BBP suggests that at these prices any existing power station would find it difficult to see RERT revenues to counterbalance: (a) the uncertainty to earnings posed by CPRS and eRET; (b) to recover the costs incurred to continue operating. Moreover, as the AEMC has not considered the notion

27 MMA, October 2008, Report to Federal Treasury – Impacts of the Carbon Pollution Reduction Scheme on Australia's Electricity Markets, page 24.

28 Newport Economics, (June 2009), AEMC REVIEW OF ENERGY MARKET FRAMEWORKS IN LIGHT OF CLIMATE CHANGE POLICIES MANAGING SHORT TERM RELIABILITY, page 37.

29 Per MW per trading interval at $2.29 and $2.47.

of including capacity payments as part of the expanded RERT or standing reserve[30], then these recommendations have the same structural weakness – there is limited financial return to existing power stations.

From BBP's perspective the viability of the remaining AEMC recommendations depend largely on the flexibility of the existing regulatory frameworks for TNSPs, and Distribution Network Service Providers (DNSPs). BBP suggests that given that the AEMC's second interim report includes both a NERG and G-TUOS proposal, but no broader proposed reform of the regulation of TNSPs and DNSPs then there remains a substantial level of uncertainty that DSP and distributed generation will be able to make any meaningful contributions to this risk in the short or long term.

BBP suggests that the key decision points that the AEMC must examine when deciding whether the NEM design can effectively deal with the risk of there not being sufficient capacity in the short run are (in order of priority):

1. forecast energy demand needs to be matched by around 700MW per annum in installed capacity – inversely, without CPRS or eRET, the Australian economy needs the equivalent of a Northern and Playford Power Stations' capacity to be installed every year;
2. the dominate renewable energy supply does not contribute to capacity, despite forecasts of 4,700MW in the next four years – inversely taking into account average availability factors for wind, of the 4,700MW installed AEMO can depend on only 700MW from these power stations for capacity, which is the equivalent of Northern and Playford Power Stations;
3. it is more than likely that CPRS and eRET will push energy capacity from the NEM but at an uncertain rate and pace[31] making it essential that the AEMC consider the risk of exit and market failure (ie loss load) from a whole of energy supply chain basis;
4. the NEM has around 30,000MW of installed capacity that is coal fired, and with an approximate remaining useful life of around 25 years before CPRS and eRET, post these policies does the expected loss in value present ongoing concern problems, and does the ESAS ameliorate this risk;
5. depending on the arrival of unproven future renewable technologies (technically and commercial viability risks) to provide clean, reliable baseload energy represents a fundamental uncertainty to meeting the NEL objective.

From BBP's perspective despite ESAS and the AEMC's recommendations there still remains substantial residual risks in the transition period, and more critically BBP does not consider that these represent the best option to meet the NEL objective.

BBP considers that addressing short term capacity shortfalls can be resolved by taking a more fundamental view to defining the problem. The NEM is simply experiencing the rapid penetration of intermittent generation, but not capacity. Unfortunately, because electricity cannot be stored the market needs installed capacity to deliver the NEL objectives of "…*reliability, safety and security of the national electricity system*."

As a first step, BBP considers that an important incremental step is to move the pre-2005[32] wind farms with an installed nameplate rating of greater than 30MW from non-scheduled to

30 Newport Economics, (June 2009), AEMC REVIEW OF ENERGY MARKET FRAMEWORKS IN LIGHT OF CLIMATE CHANGE POLICIES MANAGING SHORT TERM RELIABILITY, page 36.

31 ROAM Consulting, (December 2008), Market Impacts of CRPS and RET, page 8, notes a 10% target could result in 6,700MW of base load plant retiring between 2011 and 2020, requiring 13,800MW of replacement generation to be built in the same period – something never achieved by the NEM.

semi-scheduled where technically capable. From a practical perspective, such a change would:

- ensure that these power stations are subject to AEMO's sole control rather than AEMO and the TNSP (see Chapter 9: System operation with intermittent generation);
- utilise the existing kit within these power stations (able to operate as semi-schedule); and
- provide some additional capacity in the NEM.

BBP considers that the AEMC needs to consider the impact of semi-scheduling, and whether there is merit in exploring a form of NEM registration that "requires" all new power stations to meet, through physical or financial means, or address the power stations contribution to:

- reducing risk of unserved energy (USE) – capacity;
- power system technical performance as measured across capabilities with regard to: quality, safety, reliability and security of supply; and the power system's contribution across these measures in relation to the NEM; where demonstration of the power generator's contribution to these technical requirements needs to be assessed to be registered[33].

Importantly, the AEMC must ensure that in examining this issue AEMO is not placed in the position of 'favouring' another technology over another. BBP suggests that this is a difficult exercise, however, given the expected level of intermittent generation installation it is an area that requires further examination.

BBP's considers that the best policy solution to incentivise entry in the short term is to change the current maximum price cap (MPC) (or Value of Lost Load – VOLL). Ideally, BBP considers that a more incentivised NEM encouraging power station investment would be to raise the maximum price cap and the administrative price cap mechanism, ie where prices accumulate to a level (current level of $150,000 and $187,500 needs to be examined), and then administered price cap of $300/MW.

It is noted that the AEMC's current review has recommended that the MPC change from $10,000/MWh to $12,500/MWh, however, BBP maintains that a more appropriate level for MPC lies between the $12,500/MWh and the $55,000/MWh set by VenCorp (the Value of Customer Reliability (VCR)).

A higher MPC would provide retailers with greater incentive to contract and seek demand side responses, and the occurrence of a higher MPC at say the $55,000/MWh or unlimited price would provide supply side incentives to new generation – particularly gas fired power stations.[34] Moreover, a higher MPC or APC allows the market to utilise its existing risk management practices to facilitate new investment in generation, which takes account of CPRS and eRET policy incentives.

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32 BBP's submission to ESCOSA's draft decision on licence conditions for wind farms is at Attachment A.

33 It is important to note that the Total Environment Centre, in a recent publication, noted that CPRS and eRET policy should not have regard to the NEL and NER's requirements for: quality of supply; reliability of supply; security of supply; and safety in production and delivery, which is a specific requirement to be within the NEM (Total Environment Centre, July 2009, Climate Change and the National Electricity Market).

34 The economic viability of gas fired power stations during the transition period will still be largely dependent on the occurrence of short term price spikes to offset the competition posed by increased wind penetration lowering average prices, and the likely market entry of base load geothermal.

Finally, such an arrangement can only be effective where the AEMC moves to either remove retail price regulation, where it is found to be warranted, or provides a transparent basis for CPRS pass through in regulated retail prices. Any distortion in the end-user market where consumers are not provided with a price that reflects the costs of supply could potentially result in a California type crisis.

Chapter 6 Questions

6a. Is it the case that there can be commercial advantages in market participants not disclosing information about Demand Side Participation (DSP)? If so, what factors should we take into account in drawing out accurate information about the levels and firmness of DSP that market participants have contracted?

BBP considers that DSP has a role to play, however, as identified by the AEMC, any process adopted by AEMO to take account of DSP needs to address the key issues of:

- identifying whether the market has already exhausted the immediate value from DSP;
- ensuring that the DSP is reliable;
- determining the value associated with DSP from non-commercial and industrial load, particularly given the roll out of smart metering; and
- understanding the likely impacts that BBP's proposals around increasing MPC and APC may have on the value, hence incentives for more effective DSP.

Chapter 7: Investment in capacity to meet reliability standards

AEMC Draft Recommendation

Existing frameworks provides effective signals to promote efficient levels of investment in transmission capacity, generation capacity and demand response. It can therefore be expected to continue to operate in the long term interests of consumers, if those signals are appropriately maintained. This is likely to involve significant increases in the spot market price cap over time, in particular to ensure that the necessary peaking plant to complement intermittent wind powered generation is economically viable.

BBP Response

Generally, BBP supports the AEMC's finding that the existing framework for long term reliability in the NEM is robust. BBP considers that the current framework provides effective signals from a generation capacity, and to a lesser extent from demand response, however, far greater work needs to be undertaken in relation to transmission capacity. In addition, the AEMC's found that the pricing in the gross energy pool continuing to provide sufficient guidance to the OTC market, which in turn, will continue to provide adequate capacity to reliably meet the capacity requirements of the NEM.

At face value the AEMC's finding is difficult to refute. However, currently the forward market for OTCs continues to remain illiquid as participants struggle with the challenge of pricing the cost of carbon into forward contract prices. Moreover, current pool prices are trending well below market expectations, given the deceleration in energy demand from the recession, and the return to normal weather conditions in Queensland and New South Wales (drought impacts on power stations water consumption in 2007-2008 period provided substantial price increases in the OTC).

Additionally, current experience of BBP in the South Australian region has observed the increased penetration of wind, both semi-scheduled and greater than 30MW non-scheduled wind farms, has depressed average prices (negative price events during low demand periods), less frequent but more spikier price events, and instances where as a result of disparate treatment the constraining off of scheduled power stations to 'make way' for non-scheduled wind. More pointedly, the setting of the MPC at $10,000/MWh (moving to $12,500/MWh), and the administrative price cap effectively caps the price event outcomes, while payments for RERT, even an expanded RERT will do nothing to provide ongoing viability of heavy emitting coal fired power stations.

To this end, BBP considers that the AEMC should examine the merits of moving the MPC to the value of Customer Reliability (VCR) used by VenCorp, and capped at $55,000/MWh. An increase to the MPC, along with a similar change to the APC would place renewed emphasise on the OTC market.

As identified by ROAM Consulting[35] transmission congestion represents a substantial barrier to the eRET and CPRS as both will change load flows over the network causing greater constraints between regions and within regions. As outlined by BBP, transmission congestion and building new transmission networks for new power stations (remotely located) is a problem that is best addressed through making the transmission regulatory regime more effective.

BBP appreciate the existing disciplines, requiring scrutiny of investment planning (APRs and RIT-T) and strategic planning documents to be published by the AEMO in its capacity as NTP, assist in safeguarding against the risk of inefficient transmission planning[36]. BBP also notes the MCE's progression towards a common framework for planning standards across all jurisdictions[37].

Despite these changes, BBP considers that more needs to be done to incentivise TNSPs to invest in the network beyond the minimum reliability standard requirements. This poses great risks for the market in meeting the necessary transmission investment required to match the additional generation investment under eRET and CPRS, in light of the potential for the early retirement of carbon intensive generation.

BBP is of the view that the introduction of a regulatory regime covering TNSPs that separated regulatory functions from service delivery, and implemented AEMO's NTP to determine NEM wide transmission asset needs subject to AER regulatory oversight would represent a more efficient market outcome.[38]

Finally, to support the provision of reliable generation in the long term requires the end user market (retail) to be as efficient and competitive. Accordingly, the AEMC needs to consider the proposal to review existing forms of retail regulation with a view to determining whether a more light handed form of regulation is justified. The current AEMC recommendation to continue with the current direct controls on retail energy tariffs, subject to better regulatory mechanisms for CPRS pass through, may represent a long term risk to reliable capacity supply in the NEM.

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35 ROAM Consulting, (December 2008), Market Impacts of CRPS and RET.

36 AEMC, (2009), Second Interim Report, page 76.

37 AEMC, (2009), Second Interim Report, page 76.

38 AEMO's already has the transmission planning responsibilities for South Australia (ESIPC absorbed by AEMO) and Victoria (VenCorp absorbed by AEMO). From BBP's perspective the AEMC's challenge is demonstrating that having fragmented roles between AEMO as NTP for South Australia and Victoria, and New South Wales and Queensland with PowerLinke and TransGrid, respectively, if the most efficient and effective outcome with regard to the NEL objective.

Chapter 7 Questions

7a. *Do you agree with our description and assessment of how the current framework operates, and our findings that the framework for the medium to long term is resilient to the stresses created by the CPRS and expanded RET?*

Please refer to the above discussion.

7b. *Do you agree with our characterisation of the risks under existing frameworks, and how could they be managed or mitigated?*

Please refer to the above discussion.

Chapter 8: Convergence of gas and electricity markets

AEMC Draft Recommendation
The AEMC found that the convergence of gas and electricity markets is not a material risk to the current market design. The AEMC considers that there is likely to be convergence between markets, and for CPRS and eRET to be effectively managed within existing gas market design there would need to be:

- sufficiently flexible and responsive;
- operating procedures to take into account interdependencies between gas and electricity markets; and
- establish incentives to deliver timely investment in gas production and transportation infrastructure.

BBP Response
As per BBP's submission to the AEMC's first report, BBP maintains that the AEMC's position and recommendation continues to downplay the significance of the barriers within the gas market that convergence between the markets will stress test.

Firstly, much of the gas market regulation is yet to be implemented, hence tested. Accordingly, until the new gas market rules are utilised then there remains residual risk that the arrangements may not work. Critically, the workings of such arrangements will only be tested by events requiring coordinated action between markets. Events can be broadly categorised as being either driven by:

- electricity market instability or violation; and
- gas market loss of supply or risks on the quality of supply.

In terms of meeting the NEL and NGL objectives, the Short Term Trading Market (STTM), and the Gas Bulletin Board (GBB) is expected to provide greater price and volume transparency around market information for gas. The effectiveness of the STTM and GBB will depend on there being:

- spare gas in existing contracts;
- ability to utilise any spare transportation capacity to physically transport traded gas;
- where there is limited spare transportation capacity – the ability of proponents to negotiate capacity expansion;

- where there is available capacity the ability to negotiate back to back transportation contracts to provide physical delivery.

Overcoming these barriers would represent a step forward, and ensure that the gas market is sufficiently flexible and robust to accommodate greater convergence with the electricity market.

Another important element to support a more robust gas market would be the development of a more liquid short term OTC market for gas. It is acknowledged that the bi-lateral contracts are an important feature supporting long term investment in new gas supply basins, and transmission pipelines, however, in the medium term this could represent a barrier to greater gas supply flexibility to support increased penetration of new gas fired generation.

BBP maintains that ownership concentration in upstream gas supply markets (single or joint marketing arrangements included) represents a further barrier to greater flexibility and robustness in the gas market. In the NEM and the WAEM the concentration of ownership, and the marketing arrangements pose a substantial barrier.

The AEMC concluded that convergence in the electricity and gas markets in the WAEM was not a material issue. Broadly, the AEMC reached its conclusion on the basis that:

- new generation, base load and high merit, is likely to be coal given high gas prices;
- low merit gas fired will have a role as load following generation – providing that short term challenges to gas supplies and pipeline capacity are addressed; and
- security of supply issues from a single gas transmission pipeline are mitigated by gas fired generation being able to operate on distillate.

BBP notes that there is a lack of competition in the upstream WA gas market, which manifests in a practical way in there being little flexibility or responsiveness to the demand for gas from the electricity industry. From BBP's perspective, the ability of the WAEM to effectively respond to CPRS and eRET is therefore at risk due to the linkages between the electricity and gas markets, particularly, electricity demand for greater gas supplies.

The BBP considers that the AEMC needs to reflect upon its current recommendation, and examine upstream gas markets.

Chapter 8 Questions

8a. How should reviews of market settings (such as market price caps) be best aligned across the gas and electricity markets?

Please refer to the above discussion.

8b. Do you agree that the current energy market frameworks would allow for AEMO to effectively review the existing rules provisions relating to market interventions?

Please refer to the above discussion.

Chapter 9: System operation with intermittent generation

AEMC Draft Recommendation

The AEMC's second interim report found that:

- existing market frameworks do not need to be changed to maintain secure system operation in the context of large increases of intermittent generation; and
- in light of the importance of effective management of reactive power, the network support and control services review commenced by NEMMCO be completed by AEMO as soon as practicable.

BBP Response

The operation of the NEM represents a complex system. As a complex system it is managed in real time with the principle objective to match demand and supply having regard to reliable, secure and safe delivery of energy at a least cost. The core elements in this real time management process includes:

- maintenance of power system voltage – too high or low voltage can cause increased power system losses and at the extreme voltage collapse and lost customer load
- management of power system inertia – high levels of inertia make the system more robust
- maintenance of power system frequency – strict tolerances need to be maintained to ensure power stations and customers loads do not trip-off.

AEMO (NEMMCO) manages the power system with regard to the above. This represents one of the most critical roles in the Australian economy.

Another important determinant in the NEM's robustness is the effective delivery of energy, and associated ancillary services is that as coal fired generators provide 80% of electricity they also provide substantial levels of ancillary services. With CPRS and eRET there are risks around the ongoing provision of these complimentary energy services.

BBP does not agree with the AEMC's findings relating to system operations and the increased penetration of intermittent generation, and consider that during the transition period, and potentially in the long term.

AEMO's central dispatch process is a solid foundation to manage the increasing impact of intermittent generation. However, there are material residual risks around the physical operation of the market and its impact on the operations of existing power stations as more intermittent generation enters the market.

From BBP's perspective the experience of the Flinders Power Stations in the South Australian region of the NEM represent a case in point.

Figure 4 – Impact of Non-scheduled Wind Farms greater than 30MW

> On 11 February 2009, between 6am and 6.45am, NEMMCO (AEMO) found that the combination of increasing wind generation and Playford B generation resulted in violation of the constraint equation S>NIL_DVPF_WYCL, and post contingency overloading of the Whyalla Terminal to Cultana line on the loss of the Davenport to Playford line in South Australian region.
>
> The Violation Report is of great interest, and represents a working example of the impact of increased wind penetration on the power system. Ignoring participant behaviour at the time, Playford B, Mt Millar and Cathedral Rocks, lets consider the network management issues that the incident highlights.
>
> As non-scheduled wind farms (pre-2005 wind farms grandfathered) the operating constraints around Mt Millar and Cathedral Rocks are determined, managed and controlled by the TNSP – ElectraNet. In AEMO's MMS (MDE) it has NO visibility on how TNSP constraints are operating in real time. Scheduled generators, like Playford B, have their operating constraints managed by AEMO through the MDE.
>
> From BBP's perspective the present arrangement erodes the most effective risk management tool to manage power system reliability – central dispatch and control. By fragmenting power system control between AEMO, and five TNSPs, it increases the systematic risks of real time errors.
>
> For the time being the semi-scheduling registration helps with this issue.

Figure 4 illustrates how AEMO and ElectraNet's physical management of the system in response to non-scheduled wind farms impact on system reliability and security, and how the physical operation of the constraints are effectively being carried by BBP's power stations.

BBP has submitted to ESCOSA (see Attachment B) that the exemption from semi-scheduling for pre-2005 wind farms should be removed, on account that the majority of these wind farms have the technology to meet AEMO's semi-scheduling requirements, and more importantly, system reliability and security is best managed by AEMO, not fragmented between AEMO and TNSPs.

AEMO acknowledges that increased intermittent generation penetration has no ability to produce ancillary services in comparable quantities to existing coal fired power stations which increases the NEM wide risks with regard to voltage control, system inertia, reactive power and frequency control. While it is noted that TNSPs are able to negotiate access standards that require intermittent power stations to provide these ancillary services BBP notes that it is not clear the choices that TNSPs make when balancing the needs of the NEM for ancillary services against the requirements of the power station.

Moreover, AEMO's dominate use of physical controls that is adjusting dispatch processes to constrain generation and network flows to ensure the power system operates in a secure manner, has the effect of undervaluing these services. Consequently, BBP considers that the AEMC should re-consider AEMO and TNSPs preference to use physical constraints to manage the impact of intermittent generation rather than financial contracts may further shorten the financial life of existing power stations.

Chapter 9 Questions

9a. Is it necessary to create formalised centrally coordinated contracting arrangements for the provision of power system inertia? If so, what is the nature of the process by which those arrangements should be developed?

Please refer to the above discussion.

9b. Is there adequate transparency in the process by which FCAS recruitment and interconnected capability is affected by the increasing penetration of intermittent generation?

Please refer to the above discussion.

Chapter 11: System operation with intermittent generation in Western Australia

AEMC Draft Recommendation

The AEMC's findings are that the current frameworks will not facilitate the achievement of efficient economic outcomes following the introduction of the CPRS and expanded RET.

The AEMC's draft recommendations are as follows.

- Transparency of dispatch and balancing actions, and the resulting costs, should be increased through mandated reporting by System Management (the ring-fenced part of Western Power responsible for system operation) and the Independent Market Operator (IMO).
- If this reporting process revealed the costs of balancing to be sufficiently high and inefficiently allocated, further reform options should then be considered through a formal review. These should include options to introduce greater competition and cost-reflectivity into balancing, to allow for better price discovery by System Management and, consequently, for efficient balancing actions to be taken.

BBP Response

BBP notes that the IMO recently engaged a consultant to provide it with preliminary advice on issues that might be associated with, and options for, establishing a competitive balancing market within current WEM arrangements. The consultant's analysis and conclusions were discussed with the Market Advisory Committee at its July 2009 meeting. The consultant suggested that economic efficiency might be improved through options that sought to reduce real time balancing needs and/or open up the provision of balancing to competition.

However, BBP strongly agrees with the Commission's draft recommendation that the transparency of dispatch decisions and balancing actions, and the associated costs, in the WEM should be increased in the first instance, and that this be an interim step ahead of considering further reforms of dispatch and balancing arrangements in the WEM.

BBP is concerned that efforts to increase the efficiency of balancing arrangements in the WEM may be well intentioned, but could ultimately be misguided in the absence of increased transparency around the dispatch decisions and balancing actions, and the associated costs.

BBP considers that making available publicly the following information would assist in increasing the transparency of dispatch decisions and balancing actions taken by System Management, and the associated costs:

- Market Participants' Short Term Energy Market (STEM) bids and offers (this information is already published, with a lag of around two to three weeks);
- facility level resource plans (Market Participants) and schedules (Verve); and
- actual output by Facility.

As with Market Participants' published bid and offer data, BBP suggests this information could be published with a two to three week lag. Such a lag would minimise the potential for Market Participants to seek to use the information to inform short term bidding and dispatch decision, while still remaining valuable in allowing the IMO, System Management and Market Participants in understanding the dispatch decisions and balancing actions taken by System Management, and the likely cost of these decision and actions.

Should it be determined that a competitive balancing regime would be more consistent with the efficient provision of balancing services in the WEM, the requirement that generators' bids reflect short run marginal cost (SRMC) should minimise concerns with respect to a dominant generator potentially abusing or misusing its market power.

However, a pre-Rule Change Discussion Paper was submitted to the July 2009 meeting of the Market Advisory Committee proposing an amendment to the Market Rules that would allow Market Generators to offer energy into the STEM below a Facility's SRMC. The reason given by the IMO, which initiated the Discussion Paper, was that the amendment would result in a more efficient STEM outcome by providing Market Generators with the pricing flexibility to avoid fixed avoidable costs that may be associated with shutting down and restarting a Facility.

BBP understands that the wording of the proposed amendment to the Market Rules is to be further discussed between the IMO and the Economic Regulation Authority (the Authority). However, it is understood that the Authority is generally supportive of the intent of the amendment. Specifically, it has been suggested that the Market Rules provide sufficient power to the Authority to monitor market behaviour that might be considered to be inappropriate and anomalous even where the Market Rules permitted a Market Generator's offer to be set below (but not above) its reasonable expectation of a Facility's SRMC.

Chapter 11 Questions

11a. Do you agree with the Commission's draft recommendation that the transparency of dispatch and balancing should be increased, and that this should be the precursor to the consideration of further reform options?

As noted above, BBP strongly agrees with the Commission's draft recommendation that the transparency of dispatch decisions and balancing actions, and the associated costs, in the WEM should be increased in the first instance, and that this be an interim step ahead of considering further reforms of dispatch and balancing arrangements in the WEM.

11b. Under an option to increase the transparency of dispatch and balancing, what additional information should be released?

BBP considers that making available publicly the following information would assist in increasing the transparency of dispatch decisions and balancing actions taken by System Management, and the associated costs:

- Market Participants' Short Term Energy Market (STEM) bids and offers (this information is already published, with a lag of around two to three weeks);
- facility level resource plans (Market Participants) and schedules (Verve); and
- actual output by Facility.

11c. In a competitive balancing regime, would an obligation that generators' bids reflect short run marginal costs effectively counter any concerns regarding market power?

Should it be determined that a competitive balancing regime would be more consistent with the efficient provision of balancing services in the WEM, BBP is of the opinion the requirement that generators' bids reflect short run marginal cost (SRMC) should minimise concerns with respect to a dominant generator potentially abusing or misusing its market power.

Chapter 12: Connecting remote generation and efficient utiliation and provision of the network in Western Australia

AEMC Draft Recommendation

The AEMC's findings are that that the existing energy market frameworks will not ensure efficient outcomes following the introduction of the CPRS and expanded RET.

The AEMC's draft recommendations are as follows.

- the basis for generator access to the network should be reassessed as a matter of priority, including formalisation of non-firm generation connections, review of the planning standard currently used to provide "unconstrained" access for generation, and use of dynamic line ratings.
- the connections applications process should be modified in a number of ways, through the release of more information to the market, segregating applications in the connections queue on a regional basis, and potentially restructuring the connection application charge regime. The release of queue information is already under consideration, and should be implemented quickly.
- a formal regime for transmission connection and augmentation where multiple generator connections are likely should be implemented. This could be informed by the proposed NERG arrangements in the NEM and/or developed from Western Power's Generation Park proposals for the pre-emptive provision of deeper network reinforcements.
- the workability and clarity of the regulatory approval processes for transmission network augmentations should be reviewed, particularly in relation to the assessment of net benefits in the Regulatory Test and the apportionment of costs between those that meet the New Facilities Investment Test (NFIT) and those to be recovered through capital contributions.
- the charging regime for network augmentations should also be reviewed with the aim of, at least, improving the certainty and clarity regarding capital contributions and rebates, but potentially to more generally develop a regime that gives transparent, equitable charges that provide efficient locational signals.

BBP Response
The AEMC found that the current frameworks in the WEM for connecting new generation and providing an efficient transmission network are exhibiting signs of stress, and that this is likely to be exacerbated by the additional amount of wind plant being triggered by an expanded RET.

BBP considers there is substantial evidence to support this finding, and strongly agrees with the AEMC's draft recommendation in respect of options that should be considered in respect of the connection of generation (at the extremity of the network) and the efficient utilisation and provision of the network in the South West Interconnected Network (SWIN).

While acknowledging that the introduction of the Electricity Industry Network Access Code 2004 represented a significant shift in the regulatory environment within which Western Power is required to operate, the Authority's recent Draft Decision on Western Power's proposed revisions to the Access Arrangement for the SWIS highlighted significant concerns about the manner in which aspects of these regulatory arrangements had been applied, including the NFIT and the resultant calculation of required capital contributions.

For this reason, BBP strongly supports the AEMC's suggestion that the requirements of the Regulatory Test and the NFIT be clarified through the development of guidelines to guide the practical application by Western Power (and the Authority) of these tests.

Chapter 12 Questions

12a Do you agree with the Commission's draft recommendation as to options that should be considered in respect of the connection of remote generation and the efficient utilisation and provision of the network in the SWIS?

BBP strongly agrees with the Commissions draft recommendations in respect of options that should be considered in respect of the connection of generation (at the extremity of the network) and the efficient utilisation and provision of the network in the South West Interconnected Network (SWIN).

12b Do you agree that the planning standard used as the basis for generator access to the network should be reviewed as a matter of priority?

BBP strongly supports the AEMC's suggestion that the requirements of the Regulatory Test and the NFIT be clarified through the development of guidelines to guide the practical application by Western Power (and the Authority) of these tests.

12c Are there any other options that should be considered?

Please refer to the above discussion.

Chapter 13: Convergence of gas and electricity markets in Western Australia

AEMC Draft Recommendation
The AEMC's finding is that the existing energy market frameworks in Western Australia are sufficiently robust to manage any increased interaction between gas and electricity markets triggered by the CPRS and expanded RET

BBP Response
BBP considers that to the extent that the economic efficiency of balancing in the electricity market might be improved through options that sought to reduce real time balancing needs and/or open up the provision of balancing to competition, this will also assist in managing this increased interaction between the electricity and gas markets.

Chapter 14: Reliability in the short term and longer term in Western Australia

AEMC Draft Recommendation
The AEMC's findings are that the existing energy market frameworks are sufficiently robust with respect to generation capacity reserves and the management of reliability in the short and longer term in Western Australia, due to the existing Reserve Capacity Mechanism (RCM).

BBP Response
BBP agrees with the AEMC's finding that the existing energy market frameworks are sufficiently robust with respect to generation capacity reserves and the management of reliability in the short and longer term in Western Australia, due to the existing RCM.

Attachment A

Table 3 – Summary of BBP's Assessment and Position against AEMC's Second Report Findings

AEMC Identified Risk ***BBP Position***	**Priority to be addressed**	**NEL Objective**	**Competition** **Market entry** **Fair treat of technologies**
Connecting of remote generation Key elements of NERG: • new framework in NER • new network service for remote clusters of generation • adjust planning, charging and recovery • customers underwrite right sized capacity.	Next 6 – 12 months to be ready for 2010-2015 ***BBP considers this to be a priority to be addressed within transmission regulation not separately and not only for new entrants.***	NEL objective not explicitly considered ***BBP considers that if AEMC is to maintain current position then there at least needs to be consideration of how the NERG meets the NEL objective. More critically given the matters it identifies as addressing also exist with existing transmission networks there remains a substantial gap in the AEMC's analysis to explain why such a divergent approach between new generators connecting, and existing generators connected or looking for more transmission services.***	Localised consideration of competition, designed to favour new entrants, and favours a type of technology. ***BBP considers that if the AEMC is to maintain current position it most clearly demonstrate the long term interest of consumers is being maximised through price and quality of electricity supply, and this must be compared to the costs associated with favourable treatment to new entry (NERG) and a type of technology (intermittent/wind).***
Efficient utilisation and provision of the network Key elements of G-TUOS on all generators: • reflect forward looking LRIC at particular location • two part tariff proposed, fixed charge per Kw of generating capacity	Beyond 12 month to be ready towards later and end of 2010-2015 period ***BBP considers this to be a priority to be addressed within transmission regulation and not separately. Moreover, G-TUOS has same design features as NERG apart from the charging being soley levied on generators. NERG and G-TUOS and***	NEL objective not explicitly considered. ***BBP considers that the AEMC's statutory responsibility is to examine the likely costs and benefits between the NERG, G-TUOS and congestion prices, and the effectiveness of current transmission services regulation and then based on the quantification of the costs and benefits choose the option that***	Generator competition determined to be the basis of achieving policy gains Market entry encouraged Does not look to address capacity or congestion problems as transmission businesses do not have to build out capacity/constraints ***BBP considers that if the AEMC is to maintain current position it most clearly***

<table>
<tr><th>AEMC Identified Risk

BBP Position</th><th>Priority to be addressed</th><th>NEL Objective</th><th>Competition
Market entry
Fair treat of technologies</th></tr>
<tr><td>set annually
revenue neutral in aggregate consisting of positive and negative charges around an average charge PLUS
congestion pricing to include:
geographic scope
duration
proportion of generator's output exposed to local nodal price
allocation of risk management instrument (FTR)
may apply to only new generators or all generators.</td><td>congestion pricing needs to be considered in the context of the effectiveness of the regulation of transmission services.</td><td>minimises costs, and maximises benefits. The AEMC's analysis falls short.</td><td>demonstrate the long term interest of consumers is being maximised through price and quality of electricity supply, and this must be compared to the costs associated with the allocation of further transmission costs without necessarily solving the capacity and congestion barriers the price signal is meant to address.</td></tr>
<tr><td>Inter-regional transmission charging

Key elements of transmission on transmission charging:
all calculate a load export charge
charge follows electricity
charge reflects cost of new and current assets to support transfer
transmission passes the charge through to users based on proportionate use of network
no change in total permitted revenue – re-allocation of transmission revenues.</td><td>Beyond 12 month to be ready by 2011 for 2010-2015.

BBP supports the AEMC's prioritisation.</td><td>NEL objective implicitly considered. Long term interest of consumers considered with regard to:
pricing inter-regional flows
charging supports building out of congested assets
actually builds out the congestion
removes a cross-subsidy.
BBP in principle supports the AEMC's analysis but reserves its final position until quantification of the costs and benefits.</td><td>Competition between transmission business
Regulatory proxy for competition in use of funds to build out congestion
Supports equal market entry
Does not favour technology as levied at the network level.

BBP in principle supports the AEMC's analysis but reserves its final position until quantification of the costs and benefits.</td></tr>
<tr><td>Regulated retail prices</td><td>No prioritisation.</td><td>NEL objective not addressed.</td><td>Regulation of retail prices considered a</td></tr>
</table>

AEMC Identified Risk ***BBP Position***	**Priority to be addressed**	**NEL Objective**	**Competition** **Market entry** **Fair treat of technologies**
Key elements of proposal: • by the time of CPRS start retail regulators would have a mechanisms in place to pass through if CFD market remains illiquid further flexibility may be needed.	***BBP considers that the AEMC should have set down a timetable of prioritisation to implement its recommendations as there are substantial risks that it may not be implemented in time, and even if implemented may not solve the problem.***	***BBP considers that the current regulation of retail prices represents the most significant risk to the market. The AMEC's proposed options are poorly designed, place no onus on having regulators demonstrate why they should continue regulation on a cost/benefit basis. The AEMC should articulate how the proposals will support consumers long terms interests being maximised through price and quality of electricity supply by leaving in current regulation of retail prices, albeit with more flexibility compared with the alternative – such as no retail price regulation.***	proxy for competition Market entry distorted as no head room in retail price ***BBP considers that the AEMC needs to reconsider its proposal within the framework objectives set out in the NER, and NEC.***
Generation capacity in the short run Key elements of proposal: • expanded RERT • more accurate reporting (& use) of demand side capability • using distribution connection • load shedding • long term reserve procurement. •	Next 6 – 12 months to be ready by 2011 for 2010-2015. ***BBP supports the AEMC's prioritisation although given the structure of the proposals there are substantial risks that even if implemented in time it may not resolve the problem.***	NEL objective implicitly addressed. ESAS of $3.5B prevents existing generators from exiting early, and balance of measures forecast to achieve security of capacity, and reliability of supply. ***BBP considers that the ESAS of $3.5B does not address retirement issues. Of the AEMC's remaining proposals do not quantify the costs/benefits, and the likelihood of being able to address on a risk weighted estimate. (need to review***	Competition considered in static sense Equal market entry not considered Equitable treatment of technologies ***BBP considers that the AEMC needs to reconsider its proposal within the framework objectives set out in the NER, and NEC.***

AEMC Identified Risk ***BBP Position***	**Priority to be addressed**	**NEL Objective**	**Competition Market entry Fair treat of technologies**
		congestion and reliability panel review.	
Investment in capacity to meet reliability standards • Existing frameworks are robust.	Beyond 12 months to be ready in mid to later part of 2010-2015 time line. ***BBP considers that the AEMC needs to reconsider the prioritisation of this risk based on our proposal.***	NEL objective not considered ***BBP considers that the AEMC needs to examine the impact and contribution of intermittent generation on USE, firm capacity, meeting MPC events, and price and quality of electricity supply on a least cost and maximising benefits to end users. Should have regard to BBP proposal incorporating:*** • ***general registration for all above 30MW*** • ***approval around contribution to USE and security, reliability and quality of supply*** • ***lift in MPC (VOLL)*** • ***review of the regulatory arrangements for transmission businesses.***	
Convergence of gas and electricity markets • Existing frameworks are robust.	Beyond 12 months to be ready in mid to later part of 2010-2015 time line. ***BBP supports the AEMC's prioritisation.***	NEL objective not considered ***BBP considers that the AEMC needs to examine the gas markets' lack of OTC/CFD market as a risk management tool, and its potential impact on the electricity market as gas fired generation penetration increases. The***	Competition considered in static sense Equal market entry not considered Equitable treatment of technologies ***BBP considers that the AEMC needs to reconsider its proposal within the framework objectives set out in the***

AEMC Identified Risk ***BBP Position***	**Priority to be addressed**	**NEL Objective**	**Competition Market entry Fair treat of technologies**
		consideration of long term interest of consumers in terms of the potential costs from not having such a market, in terms of lack of gas price transparency and volume risk management, and the potential maximisation of benefits to the electricity market by having such a market. BBP considers that this is also relevant when considering competition in upstream gas markets.	***NER, and NEC.***
System operation with intermittent generation • Existing frameworks are robust.	Beyond 12 months on an as needed basis. ***BBP considers that the AEMC needs to reconsider the prioritisation of this risk based on our proposal.***	NEL objective not considered ***BBP considers that the AEMC needs to examine the impact and contribution of intermittent generation on system operator performance, and impact on USE, firm capacity, meeting MPC events, and price and quality of electricity supply on a least cost and maximising benefits to end users. Should have regard to BBP proposal incorporating:*** • ***general registration for all above 30MW*** • ***approval around contribution to USE and security, reliability and quality of supply*** • ***lift in MPC (VOLL)*** • ***examine better notion for pricing of ancillary services particularly those services:***	Competition considered in static sense Equal market entry not considered Equitable treatment of technologies ***BBP considers that the AEMC needs to reconsider its proposal within the framework objectives set out in the NER, and NEC.***

AEMC Identified Risk ***BBP Position***	**Priority to be addressed**	**NEL Objective**	**Competition** **Market entry** **Fair treat of technologies**
		o ***provided free by way of performance standards (reactive power)*** o ***promote better pricing to reflect future scarcity (NERG/congestion pricing)*** o ***facilitate more robust ancillary services CFD market.***	
Distribution networks Existing frameworks are robust. •	Beyond 12 months on an as needed basis. ***BBP supports the AEMC's prioritisation.***	NEL objective not considered ***BBP supports the AEMC's considerations.***	Not considered

Attachment B

BBP Submission to ESCOSA Draft Determination – Licence conditions for wind generators.

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16 July 2009

Margaret Cross
Executive Director
Regulatory Development and Implementation
ESCOSA
GPO Box 2605
Adelaide SA 5001

Dear Ms Cross,

Essential Services Commission of SA Draft Decision
Licence Conditions for Wind Generators

As per recent discussions between Babcock & Brown Power (BBP) and officers of the Essential Services Commission of SA (ESCOSA) we commend the Authority for its work in relation to the licensing regime for wind generators in SA as set out in its Draft Decision (June 2009).

BBP owns and operates the Northern Power Station and Playford Power Stations, which are located at Port Augusta. The Flinders Power Stations provide up to 786MW of energy capacity and in 2008/09 provided 33% of South Australia's electricity.

Wind and other renewable technologies have a competitive advantage over power stations like Northern Power Station and Playford Power Station, this advantage would exist without the Commonwealth Government's expanded RET and even the Carbon Pollution Reduction Scheme (CPRS). This competitive advantage exists as a function of renewable technology's short run marginal cost of generation being near or at zero over its entire load profile. Accordingly, providing that an intermittent generating plant can connect, which represents an outcome of the robustness of the regulatory arrangements applied to transmission businesses, than a non-discriminatory market is facilitated by each power station facing the same licence conditions to participate in the market. For consumers the most important characteristic of energy consumption is the security and reliability of its supply and it is BBP's position that this is achieved by licence conditions treating power stations equally with regard to their own technical performance, and their impact on the power system.

BBP acknowledges the leading work undertaken by ESCOSA when determining licence conditions for wind farms, and as noted in the ESCOSA Draft Decision that amendments to the NER creating the license category of "semi-scheduled generator" has gone a substantial way to establishing a national framework for intermittent generation. It is also noted that ESCOSA decided to maintain the two additional technical standards in licence conditions relating to fault ride through and reactive power of registered wind farms.

BBP substantially supports ESCOSA's Draft Decision, particularly, the requirement for fault ride through and reactive power capabilities as these recommendations provide a sound basis for ElectraNet and the Australian Energy Market Operator (AEMO) to maintain reliable and secure energy supply to customers.

However, BBP is concerned with ESCOSA's Draft Decision to maintain the pre-2005 wind farm licences as non-scheduled generators despite these wind farms having an installed supply capacity greater than 30MW and being technically capable of being semi scheduled. The consequences of grandfathering of these licences has created a regulatory environment whereby power system management, particularly in times of contingency events, is being fragmented between ElectraNet and AEMO.

In recent times, as reported in the AEMO (NEMMCO) (23 June 2009) Incident Report Violation of the secure operating state for the network in the Cultana system, Playford Power Station has been constrained off by the binding of the Cultana system constraint. As a contingent constraint AEMO applies it to the operation of Playford Power Station and Port Lincoln to maintain power system security because:

"...Mt Millar and Cathedral Rocks are not included in this constraint equation for dispatch as these are non-scheduled wind farms."[1]

As non-scheduled generators ElectraNet is responsible for imposing limits or constraints on Mt Millar and Cathedral Rocks.

From BBP's perspective such an arrangement represents a potential risk to the effectiveness of the market operator as it effectively fragments AEMO's powers to coordinate the central dispatch process with regard to power system security and reliability. AEMO must depend on ElectraNet's application of operating instructions with regard to the non-scheduled generators, and more critically, the market is depending on ElectraNet having perfect foresight with regard to establishing a full suite of ex-ante operating instructions capturing all possible network constraints for the non-scheduled wind farms.[2]

Without diminishing the substantial expertise of ElectraNet and AEMO, BBP maintains that with energy and how it flows through transmission networks is something that will never be able to be planned with perfect foresight. Accordingly, the best operational, market and system security outcome is for AEMO to solely carry market operating responsibilities.

BBP considers that this is best achieved by having the pre-2005 licence arrangements for wind farms that are technically capable of being semi-scheduled removed, and for these wind farms to be required to move to the semi-scheduled wind farm arrangements. This would provide AEMO with a maximum amount of flexibility to keep the system in a secure operating state when dealing with the impact of network constraints.

Importantly, BBP considers that by removing the special licence arrangements this would be more cost effective in the long run. For instance, the current arrangements result in AEMO and ElectraNet having to coordinate constraint requirements for dispatch to ensure that the system is held in a steady state. These arrangements impose costs to all market participants, and ultimately to consumers.

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1 NEMMCO, (23 June 2009), Incident Report Violation of the Secure operating state for the network in the Cultana system, page 4

2 Wattle Point (90.75MW), Lake Bonney Stage 1 (80.5MW), Cathedral Rocks (66MW), Canunda (46MW), Mt Millar (70MW), Starfish Hill (34.5MW).

Ultimately, as wind penetration increases in SA the need for coordination will increase, and logically the costs of coordination will increase, as will the costs incurred when coordination fails. As these costs are unknown, and potentially uncapped, a more cost effective option would be move the non-scheduled pre-2005 wind farms to be semi-scheduled where they are technically capable.

If you require any additional information or would like to discuss this matter further please contact Mark Williamson on (07) 30117629 or James Reynolds on (07) 3011 7646.

Yours sincerely,

Mark Williamson
General Manager Wholesale Energy
Babcock and Brown Power