Hydro Tasmania
the renewable energy business

12 May 2009

Dr John Tamblyn,

Chairman, Australian Energy Market Commission,

PO Box A2449,

Sydney South NSW 1235

By email: submissions@aemc.gov.au

Dear Dr Tamblyn,

Re : consultancy paper by Dr Darryl Biggar

Hydro Tasmania would like to thank the AEMC for this opportunity to comment on the recent consultancy paper by Dr Darryl Biggar entitled, "A Framework for Analysing Transmission Policies in the Light of Climate Change Policies".

Hydro Tasmania is also a party to a submission by the National Generators Forum, which relates both to Dr Biggar's paper and the Commission's Public Forum Discussion paper, dated 1 May 2009.

If you require any further information, please contact me on (03) 6230 5775.

Yours sincerely,

D. Bowker

David Bowker

Manager Regulatory Affairs

Hydro Tasmania

Preliminary comments on

“A Framework for Analysing Transmission Policies in the Light of Climate Change Policies”, by Dr Darryl Biggar

In this submission, we provide preliminary comments in relation to the consultancy paper produced by Dr Darryl Biggar, entitled “A Framework for Analysing Transmission Policies in the Light of Climate Change Policies”, (referred to subsequently as BP).

Whilst we appreciate this additional opportunity for feedback provided by the Australian Energy Market Commission as it moves towards the release of the 2nd Interim Report, given the particularly short timeframe for response, we ask that our comments be read without prejudice. A more formal position will follow the 2nd Interim Report.

1 Structure of this Submission

This submission is in four parts:

1. A summary of BP,
2. Some concerns in relation to BP
3. Discussion of Hydro Tasmania's 2007 congestion management proposal, in relation to the Biggar framework,
4. Identification of issues highlighted in BP and not dealt with by Hydro Tasmania's proposal.

The text below contains several extracts from the BP, which are shown in this font.

2 A summary of the Biggar paper

This Section summarises the BP. The BP sets out a framework for developing transmission and generation policies. It divides potential policies into three sets:

A. Policies for promoting efficient short-term operational decisions by generators and loads;

B. Policies for promoting longer-term efficient investment and location decisions by generators and loads;

C. Policies for promoting efficient operational and investment decisions by the transmission sector.

The BP is an important contribution to the development of a perspective on the ways in which transmission policy and Climate Change policy goals can be developed consistently. In particular, the holistic approach and the attempt to draw out themes and links between policies and aspects of the NEM design is a valuable contribution to the development of consistent policies across a range of issues.

The BP stresses that since transmission is both a substitute for and a complement to generation, achieving short-term and long-term efficiency objectives requires closely coordinated or "co-optimised" action by both the generation and transmission sectors[1] including the extent of transmission losses, the real-time representation of transmission constraints, the control of load shedding, and the procurement of ancillary services, (pgs 4,5).

The first part of the paper describes how the NEM does this, in relation to short-term dispatch and long-term investment.

2.1 Central Planner and/or Market

The BP notes that whereas traditionally this coordination was achieved through vertical integration, in a liberalised electricity market, such as the NEM, where generation and transmission are under separate ownership, that coordination must take place through other mechanisms – such as price signalling, contractual arrangements, and explicit coordination rules and processes, (pg 5).

2.2 Short-term – Dispatch

The BP analyses the ways in which the NEM achieves optimal short-term dispatch of generation. It says:

> Improving the short-term marginal price signals is primarily a matter of:
>
> - ensuring that generators face the correct price at the margin;
> - improving the accuracy of the representation of the physical network in the dispatch process; and
> - improving competition. (pg8)

Dispatch Problem 1 – "mispricing"

Under the current NEM rules, in the presence of binding transmission constraints, a generator does not face the risk of settlement at its offer price. Exposure at the margin has been lost. It is suggested that this can be restored through introduction of constrained-on/constrained-off payments[2]. (pg 9)

Dispatch Problem 2 – lack of information

The quality of future price forecasts depends on the quality of information on future supply/demand and network outages. Embedded or non-scheduled generation is netted off the demand, leading to forecast uncertainty; (pg 11).

Dispatch Problem 3 – ancillary service free riders

Both reactive support to the network and inertia are not part of the current ancillary services market. In addition, embedded or non-scheduled generation is excluded from ancillary service cost recovery and large variable loads often do not face any explicit ancillary service cost incentives; (pg 38-39).

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[1] Noting that gas transmission can be a substitute for electrical transmission.

[2] The theoretical option of nodal pricing is recognised but not advocated.

Dispatch Problem 4 – 5-30 Smoothing

The presence of price spikes is seen as a necessary part of the market; for example, to signal lack of ramping ability. The 30-minute settlement process smooths this out and hence weakens the signal; (pg 35-36).

Dispatch Problem 5 – Marginal Loss Factors (MLF)

The approximation of fixed MLF leads to a distortion of the dispatch pricing signal. Loss factors do not vary with duty cycle, eg baseload and peaking plant at the same location have the same MLF; (pg 36-37)

2.3 Long-Term – Investment

Efficient decisions regarding where, when and by how much to expand generating capacity, using which technologies, and what fuels, the number of units to install, and the size of each unit, what ramping capability to provide, what ancillary services capability to provide, and when to shutdown existing generating plant must be co-ordinated with investment decisions in the transmission sector, including decisions regarding where, when and by how much to expand transmission capacity to achieve an overall efficient (least cost) transmission expansion path taking into account possible future evolving demand and supply scenarios.

This coordination must take place through either (a) arms-length price signals; (b) contractual arrangements; or (c) explicit coordination rules and processes; (pg 5).

At this point the paper introduces the notion of "spatially-differentiated fixed transmission charges" as a mechanism for ensuring that there is a strong locational signal for new generation investment. The impact of "shallow" or "deep" connection charges policies is discussed as well as the option of building out all intra-regional transmission congestion.

Investment Problem 1

The key problem is how to ensure that neither under nor over building of the transmission network occurs. At first sight, the paper appears to be ambiguous here with suggestions both that there is a need for

> "an instrument which provides assurance to generators that certain inefficient transmission investment will not be carried out"; (pg 23).

and later

> "it may in fact be efficient to over-build transmission, even to the point where there is no intra-regional network congestion in normal operation"; (pg 28).

This apparent contradiction is discussed in Section 3.2 below.

Investment Problem 2 – Information Flow

The transmission planner therefore must determine which potential generation resources will be exploited and which will not. Vertical separation of transmission and generation limits information flow.

In fact, one of the primary benefits of vertical separation is that it creates strong incentives for private generation entrepreneurs to discover and make use of new information – including possible new generation locations, new technologies, or new ways of operating old technologies; (pg 29).

Investment Problem 3 – Gaming the RIT-T

The potential problem is raised of a generator locating at a weak part of the network, knowing that once committed, the sunk costs will be excluded from the RIT-T assessment. The risk of this occurring is said to be low, due to constrained financing in the presence of access limits; (pg 29).

Investment Problem 4 – Marginal Loss Factors (MLF)

The risk of future large changes in MLF is seen as a disincentive to invest. Some form of guaranteed certainty is suggested – (no mechanism offered); (pg 36-37).

3 Some concerns in relation to Biggar paper

Given its somewhat theoretical and wide-ranging approach, it is not surprising that there are many alternative approaches presented in the paper. Consequently, it is open to selective quotation to support opposing points of view. This is not a criticism of the paper, but a cautionary note to the casual reader. To be understood correctly, the paper must be read as a whole.

This section discusses the BP treatment of:

- Spatially differentiated fixed transmission charges,
- Over-building to remove all intra-regional constraints; and
- Other minor issues

3.1 Spatially Differentiated Fixed Transmission Charges

The BP both advocates Generators facing spatially differentiated fixed components of transmission prices and says that the allocation of cost recovery to generators versus loads is essentially arbitrary. However this must be understood in the context of the second statement.

The concern is that if potential investors do not face a strong locational signal, there will be a tendency to locate at already constrained parts of the network. Similarly, if generation proponents face significant costs for gas network expansion but electricity transmission costs are smeared in the market or more broadly socialised, then this will bias investment decisions and lead to inefficient investment.

3.1.1 Barriers to entry and marginal energy pricing

In suggesting that efficient investment requires a strong locational signal, the Biggar paper does not discuss the "barrier to entry" argument, ie that forcing prospective generation investors to face the efficient transmission augmentation costs consequent upon their decisions constitutes a barrier to entry – on the grounds that incumbents do not face these charges.

We believe that this "barrier to entry" argument should be dismissed. Given that the focus is on developing a price signal to ensure that the next marginal MW of generation capacity is optimally located in relation to the transmission network, it is obvious that gross inefficiencies and investment distortions would arise, if consequential gas or electrical transmission augmentation costs were externalised. By its very nature, there is no point in providing a locational signal to established generation; the signal is intrinsically focussed on current investment decisions. However it would have better if the “barrier to entry” objection to a strong locational signal had been addressed in the BP.

It is important to recognise that as a consequence of a negotiated payment to upgrade the transmission network, the Generation proponent may receive in return a defined access arrangement, which may in fact be better than the arrangements applying to incumbents.

3.1.2 Generator TUOS and Access Rights

From time to time the BP implies that Generator TUOS is a necessary outcome if any form of congestion management scheme is instituted. Whilst this may be true if a firm CSC/CSP-type arrangement were contemplated, it does not necessarily follow if what is ‘given’ is essentially not more that what already exists – a non-firm right to be paid the regional price for dispatch.

This is one example where a conditionally restricted conclusion could, out of context, quickly become an article of faith. Given that the objective of the discussion was to provide efficient locational investment signals, there is little point in signalling to long-sunk incumbent Generators.

In summary, under the current arrangements, remote intra-regional generators face no price risk in trading with the regional reference node, but do face some quantity (dispatch) risk. This lack of firmness is something of a deterrent to selecting remote intra-regional locations. At the same time, however, generators in the NEM do not currently pay charges for the use of the shared network (as discussed below), which offsets this disincentive to remote location somewhat. However, it would be wrong to give the impression that these two effect in some way “cancel each other out”. In theory the optimal location for a generator depends on the type of the generator, the different input costs it faces in different locations, and the different levels of congestion it would face in different locations. There is not likely to be a link between the magnitude of the deterrence to choosing remote locations noted above and the relative productive efficiency of a generator. That is, while it may be fully efficient for a low-cost generator to locate in a constrained location (even if that means displacing some of the output of incumbent generators) under the existing arrangements a generator will be deterred from doing so to the same extent whether it is high cost or low cost; (pg 44).

The Hydro Tasmania proposal of Section 6 of this paper provides a mechanism for each Generation proponent to assess the level of access it needs and to fund accordingly. It is conceivable that under such a regime, a low-cost new Generator could physically displace a costly incumbent, with appropriate payment, so that some of their generation is settled at local price. However, this is a rather theoretical scenario, given that most new renewable generation will be considerably more expensive that established generation, at least until there is a carbon price somewhat greater predicted for the foreseeable future.

3.2 Removal of all Intra-Regional Constraints

The paper at times advocates transmission augmentation to remove all intra-regional constraints under system normal conditions, (“Alberta copper sheet”) and yet later acknowledges, (pg 51) that this is a second-best solution, (clearly sub-optimal compared to the decisions of a wise central planner). This apparent contradiction is resolved by examining the conditions under which the copper sheet is advocated.

The pre-condition for justifying the copper sheet is that nothing can be done to manage dispatch timeframe “mispricing” or limit generator misuse of market power, (with a “copper sheet” all Generators have equal access to all load points).

"Further consideration may need to be given to mechanisms for either eliminating intra-regional congestion, or for ensuring that generators face the correct price signals at the margin.",

(pg 42, emphasis added)

That is, we need to examine the relative economic costs of :

a) over-building transmission to completely remove intra-regional congestion under system normal conditions, and

b) implementing a congestion management scheme which restores generator exposure at the margin.

Even if the provisions within the RIT-T for the inclusion of competition benefits are utilised, it is unlikely that the outcome will be the complete removal of system-normal transmission congestion. Given that the power system is rarely in "system normal" conditions, if (a) is seen as the preferred option, then the issue arises of what how to deal with "mis-pricing" under transmission outage conditions, (planned or forced).

Finally, if there is a belief that market power is being abused, then surely that is a matter for the AER/ACCC. It seems unnecessary, economically inefficient and a disproportional response to over-build transmission to prevent activities which are illegal!

3.3 Minor Issues Raised in BP

1) STPASA and MTPASA – These provide information on availability but not on pricing; (pg 37).

2) Wind generator hedging - This is generally confidential but may well occur at present, perhaps even as a condition of financing; (pg 36).

3) Discussion on how "clusters and hubs" improves information flow – Sadly, little was said as to how this would work in practice. We'll have to await the Second Interim Report; (pg 29).

4) Figure 4 ; (pg 34): - a link is shown between the two boxes relating to [a CSP/CSC scheme] and [spatially differentiated fixed transmission costs]. The spatial differentiation is intended to provide a locational signal for new investors. If well designed, such a link could be provided by the CSP/CSC scheme itself. However, there is no point in applying this locational signal to existing generation plant with sunk costs.

5) Pricing offers are not a statement of costs but rather a mechanism for achieving a required dispatch, to manage amongst other things contract exposure. The use of the phrase "misrepresentation of costs", is therefore incorrect.

   Generators may also try to manipulate the other parameters in the bidding process, such as the use of ramp rate constraints or "fixed load" bids in order to prevent being dispatched for less. The AER has, on occasions, successfully prosecuted such behaviour as a breach of market rules. However a mere misrepresentation of costs (bidding $-1000/MWh) is not a breach of the market rules; (pg 40).

4 Discussion of Hydro Tasmania's 2007 congestion management proposal in relation to Biggar framework,

Appendix 2 of Hydro Tasmania's submission to the AEMC's 2007 Congestion Management Review contained a brief description of a proposed congestion management scheme, which was intended to restore exposure of a generator to locational pricing at the margin, whenever constraints were binding.

This Appendix to the 20007 submission is reproduced as Section 6 of this submission, but unfortunately, it has never been the subject of serious consideration by the AEMC.

On reviewing the original Hydro Tasmania proposal in the light of the BP, it was found that several of Dr Biggar's criteria are satisfied by the 2007 Hydro Tasmania proposal. In particular, the proposal fits well to the structure of BP's Figure 4, with the assumption that "spatially differentiated" fixed transmission costs are negotiated by new entrants, based on the degree of available headroom in the network and the relative need for firm access by the proposed generation technology, eg a low-capacity, large-storage hydro plant may require a different transmission network access structure than a peaking gas plant or wind farm. That is, spatially differentiated fixed transmission costs would arise as a negotiated outcome of the proposed congestion management scheme.

The Hydro Tasmania proposal:

<u>In the Dispatch Timeframe</u>

1) Has no impact on the market when intra-regional congestion does not occur – inherently a proportional response;

2) Has no direct impact on dispatch – though it significantly changes the incentives for "mis-pricing" when intra-regional congestion does occur;

3) Increases the information flow into the market under times of stress, since Market Generators will be more inclined to reveal the point of indifference – given that they may face a risk of settlement of at least part of their dispatch volume at offer price;

4) Sits well with the Clause 5.4 obligation of TNSP to manage the impact on incumbents of proposed new generation;

5) Does not change the non-firm[3] nature of the current access enjoyed by incumbent generators – That is, it provides an orderly mechanism for allocating available access under conditions of scarcity;

6) Does not require any "what-if" dispatch re-runs to establish levels of compensation to be paid by one generator to another;

[3] The Hydro Tasmania proposal did not attempt to develop a scheme for the provision of financially firm access. It noted that such a scheme would require some form of external funding and that TNSP were not currently set up to manage this level of risk.

In the Investment Timeframe

7) Does not interfere with the operation of the RIT-T, (including competition benefits) nor with any decision by a TNSP to augment the shared transmission network to improve supply to loads;

8) Provides a strong incentive for a generation proponent to assess the economically optimal location of new generation plant;

9) Does not force a generation proponent to upgrade the network but rather exposes them to the consequences of not doing so[4];

10) Increases the reliability of information flow to the TNSP in relation to serious generation development options, clearly any Generator who offers to fund network augmentation is a serious player;

11) Sits well with the AEMC's proposed hub & spoke model for the development of NERGS[5] and further allows this to be extended to permit groups of Generators (proponents and incumbents) to negotiate Generator-funded shared network augmentations, with consequential financial access rights;

12) Does not require the TNSP or a national Transmission Planner, to separate the Australian transmission network into zones with different fixed cost levels. It recognises the fact that the same level of access will be valued differently by different generation types and gives the role of negotiating value/price to the TNSP/Connection Applicant at the time of connection application.

13) As a consequence, over time, it will result in a transmission network where different access packages are either (a) historically grandfathered or (b) funded by a Generator (or group of) but treats both of these in the same way in terms of settlement adjustments subsequent to a binding constraint occurring.

In relation to TNSP and NTP

The Hydro Tasmania submission to the first Issues Paper on the Frameworks review referenced the above proposal in its discussion of the AEMC's hub & spoke transmission investment model. It noted that under the Hydro Tasmania proposal, a TNSP would remain free to apply the RIT-T and proceed with augmentations which passed this test.

However, where there was a funding shortfall, it would open up the possibility of a TNSP going to tender for additional access provided by the network upgrade. Any Generator-funded augmentation of this kind would be accompanied by a negotiated access right, which would be administered through the same post-dispatch settlement adjustment process as that created for the grandfathered access arrangements. However, in this case the way would be open for the Generator(s) to negotiate a financially firm access arrangement – subject to a mutually acceptable balance of rights, risk management and funding cost.

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[4] A subtly different approach, since a generation plant investment with a low capacity factor may decide to wear the risk of curtailment rather than fund making the network whole – the decision lies with the investor, not the TNSP.

[5] Network Extensions for Remote Generators – identified extensions to renewable rich areas.

Because the TNSP would be able to engage with a Generator or group of Generators in relation to potential network upgrades, the flow of information will be improved and consequently the network augmentation more efficient. This will apply not only to the development of hubs, as described by the AEMC, but also to the funding of shared network augmentations, over and above that which is supported by the RIT-T.

In Hydro Tasmania's Submission on 1st Interim Report, "Review of Energy Market Frameworks in light of Climate Change Policies" the potential to integrate this mechanism with the AEMC's proposed hub & spoke model for pro-active transmission development was enlarged on as follows:

"We support a new process which includes:

- integrated strategic network development across the NEM to achieve the renewable goal at least cost, – This includes an enhanced National Transmission Planner;
- a national, rather than solely regional, perspective, so that competing projects are assessed together, eg any proposal to strengthen the SA-VIC interconnector to support SA wind, should be considered alongside possible improvements to the TAS-VIC interconnection or NSW-QLD;
- some form of internalisation of transmission costs, to preserve economic efficiency and avoid picking renewable technology winners. That is, If development of the shared transmission network is required to support specific new renewable generation, then this should be reflected in higher costs for those projects; and
- a level of MRET penalty or carbon price which reflects the marginal cost of the required[6] volume of renewable technology, (including project-related, shared transmission costs).

What we propose for consideration is a process where an enhanced National Transmission Planner in co-ordination with the relevant TNSPs:

- evaluates competing large scale new wind developments[7];
- plans the required transmission upgrades;
- completes the environmental and development approvals;
- auctions the shared network access development rights to recover costs, (with a risk premium); and
- tenders for the transmission projects, once sufficient generation development is committed, (cf the AEMC's 50% NERG hurdle, pg 40 of 1st Interim Report).

Some of these functions may in fact be better managed by the local TNSP. This is certainly true for the radial connection assets, the "spokes". The responsibilities and coordination needs to be agreed between the parties. However what is required is a greater degree of coordination than has occurred previously. This is likely given the emergence of the NTP. "

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[6] Required by Climate Change policy, rather than the Market objective.

[7] That is, broad planning options for which priority ranking may need to be assigned and which could include say 2000MW of wind in each of SA, VIC, NSW and TAS, each split into say five clusters of 400MW. The ultimate development choice would be with the Market.

5 Identification of Biggar's issues which are not dealt with by Hydro Tasmania's 2007 proposal

Even if Hydro Tasmania's 2007 congestion management proposal, (or a variant of it) were adopted by the NEM, several issues highlighted by the BP remain unresolved. We believe that most of these issues are capable of being resolved within the normal Market consultation processes.

Confounding of demand variations and Non-Scheduled generation

There has been some movement towards basing the SOO on what is called "native demand" – however, from time to time the SOO still reports on (and produces graphs which show) the sum of scheduled generation as a proxy for true demand. Whilst it is recognised that it takes time to modify NEMMCO's reporting systems, it , is appropriate to keep in mind the end-point of reporting true customer demand, with separation of non-scheduled generating unit output, if required. (pg 39).

ancillary services

The treatment of both reactive support to the network and inertia in the market is under review by NEMMCO. In a similar way, the extent to which the treatment of embedded or non-scheduled generation is a material problem can be reviewed by AEMO from time to time. The option of "runway pricing" for contingency FCAS has been considered and rejected, but could be re-visited.

5-30 Smoothing

The weakening of price signal due to 30-minute settlement could be reviewed again. The last review concluded that it was too complex and not cost effective. With more sophisticated load metering, this may not be as much of a problem.

Marginal Loss Factors (MLF)

The BP suggested that this problem could be solved through the introduction of both (a) more frequent updates to loss factors (such as loss factors computed dynamically, on a five-minute basis); combined with (b) mechanisms which allow generators to insulate themselves against changes in the marginal loss factors over time.

The practicality of (a) would need to be assessed by AEMO. It may not be economic to do this.

In relation to (b), whilst the shielding of Generators from future variations in MLF would provide certainty, the question then arises of who would wear the financial risk, which could be significant.

Gaming the RIT-T

The materiality of this problem could be reviewed, both in terms of past experience and future potential,. Is there a role for the AER here?

6 Summary of Original Hydro Tasmania Proposal

The original Hydro Tasmania proposal was provided as Attachment 2 to its submission to the AEMC's Congestion Management Review. The proposal was for a type of CSP/CSC arrangement to manage the recognised limitations of a zonal market and the consequential "race to the bottom", "mis-pricing" and "disorderly bidding" scenario, by restoring a locational price signal **at the margin**. If implemented, the proposal would create incentives for more economically efficient dispatch offers, reduced "disorderly bidding" and generator-funded investment in transmission.

This proposal has never been discussed in any depth by the AEMC.

6.1 Hydro Tasmania's 2007 Congestion Management Proposal:

A simple, relatively low-cost congestion management system can be set up, which would have the following features:

1. The proposed scheme would apply to each and every constraint equation individually, with zero-sum[8], post-dispatch settlement adjustments[9] for all dispatched quantities on the LHS, (including interconnectors).
2. It would limit the dispatch volume for which each constrained generator or interconnector is guaranteed the RRN price and thus provide an incentive at the margins. For dispatch up to their residue holding, the generator would receive the RRN price, as at present.
3. Beyond their residue holding, the generators (interconnectors) would receive (net) their local nodal price.
4. Non-firm financial rights (residue holding) would be allocated on the basis of registered capacity at the time of inception of the scheme. [a variant would limit to lesser of registered capacity and available capacity – but this would be more complex]
5. Participants would be free to negotiate with TNSP to fund transmission augmentation, over and above the regulatory test, and receive additional financial rights.

It is not suggested that this scheme is perfect and incapable of improvement. However we believe that this scheme should be discussed and assessed in terms of the relative economic efficiency of the alternatives, such as a more complex CSP/CSC scheme (eg with auctioning of residues), the do-nothing option or the "copper sheet" approach.

[8] This assumes no uplift payments to constrained-on generation. Alternatively the constrained-on scenario could be managed by reducing the allocations of other LHS entities and not assigning negative CSC to dispatched elements with negative coefficients.
[9] There is a potential 5/30 issue, but with 5-minute market metering on all LHS quantities, this should be resolvable.

FEATURE	JUSTIFICATION
comprehensive automatic scheme	Does not rely on selection of a sub-set of 'significant' constraints or require continuous monitoring and regulatory action. Provides a well-defined set of future processes to deal with congestion as it emerges and recedes; delivering investment certainty in relation to transmission access.
adjustments to post-dispatch settlement	Does not impact directly on operational timeframes.
Allocation based on registered capacity, (possibly modified by availability factor)	Avoids superficially precise modelling. Allocation of congestion residues effectively occurs at present. A generator receives an allocation of congestion residues for a particular constraint equation, if they are located in a "remote local" location but not if located in the adjacent NEM region.
Avoids auctioning of residues	Whilst it may be possible to select a limited set of critical constraint equations by examining past market performance, it is doubtful if this could be done looking forward, say into the next financial quarter or typical hedge-contract period of two years. In the NEM, there are typically some 12 000 constraint equations in which a generator at a connection point would need to take an interest, either because their plant appeared directly on the LHS or because the equation could potentially affect regional price separation.
Non-firm allocation	No attempt to firm up allocations from external funding. This creates a risk at the margins that net settlement may be at offer price.
Managing trading risk	It is important to recognise that even if a constraint equation only binds on rare occasions, the impact on willingness to enter the contract market is based on <u>the perceived risk that it may bind</u> at some time in the foreseeable future. The dispatch volume risk associated with the 'race to the bottom' is a significant barrier to inter-regional trade. Any CM regime, <u>**including the status quo**</u> is a trade off between volume risk and price risk.

FEATURE	JUSTIFICATION
congestion residues not allocated to new generation plant	This internalises the transmission costs for each project, as is economically efficient. New generators would then have the options of : • Accepting occasional constrained output, • Paying to upgrade and receiving a share in the total congestion residue equal to the RHS increase, or • Accepting a lower price than incumbents and thereby winning a share of their network access. If the cost of transmission is excluded from consideration, the real risk is that this will bias the outcome towards cheap remote generation with a requirement for expensive transmission, (with an overall higher cost to customers in the long term).
Proportional response	The process described in this paper is inherently proportional, because if congestion is limited, then so is the impact of the proposed measures on the market. That is, if there were no congestion, then there would be no binding constraints and no need for application of the suggested post-dispatch, settlement-adjustment algorithm. The impact of the proposed measures increases directly as more congestion occurs. However the existence of the measures would provide certainty to the market as to what the response would be in the event that congestion emerged, either as a consequence of new investment or through the application of temporary network constraints by NEMMCO to manage system security.

For original Hydro Tasmania submission, see

http://www.aemc.gov.au/pdfs/reviews/Congestion%20Management%20Review/Draft%20Report/submissions/004Hydro%20Tasmania%20Submission%20-%203%20December%202007.pdf

End of Hydro Tasmania's Submission