Hydro Tasmania
the renewable energy business

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Dr John Tamblyn,

Chairman

Australian Energy Market Commission

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Congestion Management Review
Draft Report

Dear John,

Hydro Tasmania would like to thank the AEMC for the opportunity to assist the Commission in its review of Congestion Management, (CM) in the NEM, by providing feedback on the analysis and recommendations as requested. We welcome the opportunity to contribute to the production of a final Congestion Management Report to the MCE, which addresses the Terms of reference and is free from errors and misconceptions.

In this submission, Hydro Tasmania expresses its dissatisfaction with the analysis done to date as part of the CM Review. We note that the Commission has indicated the need for future modelling to develop a better understanding of the productivity gains which may be achieved from improved dynamic efficiency arising from more developed congestion management arrangements.

Hydro Tasmania has studied the Commission's recommendation in relation to Congestion Management. In this submission we offer our support, sometimes qualified, to several of the Commission's recommendations.

In addition to the main submission, we provide two Attachments:-

- Attachment #1 consists of a detailed critique of the logic and assertions in the Summary section of the Draft Report. As mentioned above, this has been provided in a spirit of constructive criticism, so that the final report to the MCE may be an improved version of the Draft Report. In the event that the Commission declines to accept our suggestions or address our queries, this material is provided as a record of our views.
- Attachment #2 is a short description of one possible, relatively low cost, CM regime. This is also provided for the record and to challenge the assertion that a CM regime is either infeasible or costly to implement. On request, the algorithm is available as a spreadsheet, written around the South Morang Constraint. We appreciate that

variations in detail are possible, but wish to demonstrate clearly that a CM regime need not be complex in implementation to be effective.

Comment on the Analysis

Hydro Tasmania wishes to record its dissatisfaction with the Commission's review of the cost/benefit trade-off of a Congestion Management regime. In particular:-

1. The failure to assess the productivity gains from improvements to dynamic efficiency which may arise from a CM regime. Whilst we accept that the IES modelling had its shortcomings, (due to the timeframe in which it was done), we feel that the correct path forward would be to repeat the modelling with an agreed set of input assumptions and sensitivity studies based on divergent views of the correct input data.
2. The failure to assess the feasibility and implementation cost of a universal, unbundled CM scheme, based on allocated, non-firm financial rights. The Commission has instead made the un-supported assumption that such a scheme would be costly to implement.
3. The estimation of the scale of the problem (cost) in terms of a historical view of congestion, rather than a forward-looking view of dispatch volume risk under the "race-to-the-bottom" scenario.

Whilst we respect the role of the Commission as author of the Final CM Report to the MCE, in the event that the Commission declines to amend its positions, we wish to note for the record that we disagree with many points of detail and unsupported assertions in the Draft Report; [See Attachment 1] However, we hope that the Commission will accept our comments in the spirit in which they are presented.

Comment on the Recommendations

Recommendations #1 and 10 - Locational Signals

Given the above perspective on the analysis it is not surprising that Hydro Tasmania does not support the Commission's recommendations 1 and 10 in relation to the exposure of constrained generation to a greater locational signal, at least at the margins.

Recommendations #2 - Constrained-On Payments

Hydro Tasmania appreciates that the central issues in relation to compensation for being constrained-on are (a) How to set the price? and (b) Who pays?

Forcing a Generator to dispatch plant at a loss does not enhance the sustainability of the market. It is accepted that a "pay as offer" option could give rise to a local market power issue, but it is hard to see why some other pricing algorithm cannot be devised, eg related to independent arbitration. The alternative of a Generator declaring units "unavailable" and then being directed by NEMMCO is clearly a second best option and may give rise to disquiet in relation to clause 4.8.9 (c2), *'causing a NEMMCO direction'*.

Hydro Tasmania's view is that the source of funding should be the same as if the Generator were directed. If the alternative to constraining-on is load-shedding, then Market Customers are the beneficiaries.

Recommendations #3, #4 and #5 - Inter-Regional Settlement residues

Hydro Tasmania is broadly supportive of these recommendations; namely the extended timeframe for IRSR auctions and the recovery of negative residues on regulated interconnectors. We agree that these need to be worked through the SRC.

We note the interesting suggestion of Positive Flow Clamping. However, we are cannot give assent to that proposal; it needs to be further developed and defined. In particular, we have concerns that it could lead to unforseen and undesirable market outcomes, including oscillatory behaviour.

The concept of Generator-funded negative residues seems problematic. It is not clear how the set of eligible Generators is to be defined or whether it would be applied generally, to permit forcing non-optimal NEMDE outcomes on all regulated interconnectors. Hydro Tasmania could not support a solution which applied to the Tarong area only.

Lastly, we note that many of the problems associated with counter-price flows would not arise if there were not "disorderly bidding". We note that as the Commission has recognised, "disorderly bidding" arises as a response to network congestion. We remain of the view that what the Commission has called 'disorderly bidding' is often a natural outcome of regional pricing distortions in the face of potential economic loss due to congestion, the 'race-to-the-bottom'. It seems to us perverse to declare that congestion is non-material and at the same time complain about "disorderly bidding" as a response to dispatch-volume risk.

The incentives for "disorderly Bidding" would disappear if there were a CM scheme in place, [See Attachment 2].

It is clearly important to retain recognition that counter-price flows can often be economically efficient; the issue is managing NEMMCO's funding. In the face of transfer limitations, it is difficult to maintain the value of IRSR, unless there is some uplift funding. In the absence of uplift, Generators must balance the despatch volume and pricing risks associated with congestion.

Recommendation #6 - Option #4 Formulation

Hydro Tasmania has always supported the use of fully optimised constraints, but has simultaneously encouraged the search for a mechanism to manage the gatekeeper issues.

Hydro Tasmania is of the view that any temporary departure from Option #4 formulation should be transparent to and predictable by Market Participants.

Recommendations #7, #8 and #9 – Information provision by NEMMCO

Hydro Tasmania is supportive of better information provision to the market, where the benefits outweigh the costs. Improvements could be in relation to the data itself or the format in which it is presented.

We believe that this area needs to be developed in consultation with Market Participants and suggest a working group to clarify:-

- what is currently available,
- what could be better presented and
- the scope for feasible and economically efficient future development.

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

Yours sincerely,

D. Bowker

David Bowker

Manager Regulatory Affairs

Attachment 1 – Points of Detail (Restricted to Draft Report Summary Only)

Summary pg xvii

"It is negative mis-pricing for which the Commission has the greatest concern"	This ignores the very real impact on the contract market of the risks of being constrained off in a race-to-the-bottom scenario or where the remote local generation is preferentially dispatched in relation to an interconnector, due to regional approximations and failure to provide any intra-regional locational signal behind a binding constraint.

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"the Commission considers that the incidence of congestion is unlikely to escalate in the near future and there does not appear to be any location in the NEM where material congestion is likely to persist"	Congestion should be material – The efficient level is just below the threshold cost of transmission network augmentation. Persistent congestion can be dealt with by regional reconfiguration. A CM regime could deal with congestion which is material enough to cause dispatch anomalies but not material enough to drive either a region change or augmentation. This could be an economically efficient solution, but has not been tested – no cost benefit analysis has been done.

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"Same bids and offers"	Hard to imagine why the same bids and offers would occur in the absence of congestion, given that regional distortions and competition for access drive "disorderly bidding".

$8.01 million	Agreed a small percentage of dispatch cost but how does it relate to the implementation cost of a CM regime? Also, this ignores the possibly material impact on dynamic efficiency and transmission/generation investment balance.

Summary pg xx

IES modelling – "implementation costs of introducing nodal pricing"	There never was any intention to introduce nodal pricing, this was a modelling benchmark. The IES modelling was done quickly in response to a deadline. The correct response to its flaws is to correct them, not to ignore dynamic efficiency. This is recognised by the Commission at the top of the following page, xxi. We look forward to this modelling being done.

Summary pg xxi

Unbundled or bundled?	This is an artificial distinction, both CSC and CBR could in concept be either bundled or unbundled. Whilst the specific proposals by CRA and Dr Biggar were for bundled CSC/CSP and unbundled CBR respectively, unbundled CSC/CSP are also possible, (thus removing the need to identify specific sets of constraints).

Distributing rights	The problem is over-stated. Rights are currently allocated. The present administrative rule is set through the dispatch process, and gives Generators in a region the right to access the RRP for all dispatched volume. A CM regime may modify this rule but in concept, it's the same process.

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"the ability of market participant to hedge price risk effectively"	There is little ability of participants to hedge dispatch volume risk in a race-to-the-bottom scenario. There is a volume/price risk trade-off.

Summary pg xxiv

Need for and timing of intervention	If the CM regime were comprehensive, algorithmic and pre-existing, there would be no need to pre-select sets of significant constraints, to invoke or revoke. Each binding constraint would result in a post-dispatch, zero-sum, settlement adjustment on the LHS. Generators would know this and it would impact on their offers at the margin. Because of uncertainty in transfer capacity, the location of this margin in the volume space would be imprecise, driving a tendency to caution with regard to negative pricing offers.

Lead time and "time to adjust"	Again, if a CM regime is in place well in advance, there is no need for adjustment or lead time. All dispatched Market Participants would know the algorithm and be aware of the post-dispatch adjustments that would be made once any constraint binds. The issue of when to introduce a new constraint to the CM regime is therefore irrelevant. The marginal cost of including an additional constraint in an algorithm is close to zero. At some point, the TNSP may be able to justify transmission augmentation, the RHS is then increased and the constraint ceases to bind. Alternatively, if a region change is enacted, then exposure would move from the margins to the full dispatch volume.

Summary pg xxv

Allocation of rights	Agreed that a base scenario would be hard to define. Better to use an approximation such as registered capacity. Simpler implementation. Settlement at the RRP for dispatched volume is the status quo, what is uncertain is the dispatch volume, which could be zero in the face of congestion. Internalisation of transmission costs within each new investment proposal is the only way to ensure that inefficient investments are excluded and don't free-ride. The non-allocation of access rights to a new investor could lead to generator-funded network upgrades with subsequent ownership of the increased RHS financial access rights, (part of connection negotiations cf Chapter 5).

Regulatory intervention	Again, with a universal regime, once it is in place, no need for intervention. Agreed that predictability with regard to access is a pre-requisite for future generation investment. The 'race-to-the–bottom' does not allow this – dispatch price may be certain but dispatch volume is a lottery.

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Is the Commission saying that because a Generator can withdraw availability and be directed on, there is no need to have constrained-on payments?	If so, then how does this sit with regard to clause 4.8.9 (c2) of the Rules?

Local market power	Agreed that pay-as bid is unworkable but some form of arbitrated payment is probably a compromise ie probably higher than the RRP.

Pre-empting a transmission response	Surely not. If a constrained-on payment results in costs to customers and this cost can be relived by a transmission augmentation, then surely this would count towards the regulatory test justification for the upgrade? The alternative to constrained on is usually load shedding or more expensive generation, so surely there is a customer benefit.

Summary pg xxxiii

Generator locational decisions do not compel transmission investment	The issue is rather that a generator which wishes to improve its access by funding an upgrade in the shared network, cannot thereby get any access rights over the enhanced transfer capacity. This acts as an unmanageable risk for potential investors, ie risk of future constraint. Delta's proposal would ensure that the access status quo is accepted and future investors include transmission impacts in their economic assessment. An automatic, universal, unbundled CM regime, as described in Attachment 2, is one mechanism for implementing the Delta proposal.

Attachment 2 – A Congestion Management Regime

A simple, relatively low-cost CM system can be set up, which would create incentives for more economically efficient dispatch offers, reduced "disorderly bidding" and generator-funded investment in transmission.

The main aim is to limit the dispatch volume for which each constrained generator 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. Beyond their residue holding, the generators would receive (net) their local nodal price. This is true whether the residues are allocated or auctioned.

The proposed scheme would apply to each constraint equation individually, with zero-sum[1], post-dispatch settlement adjustments[2] for all dispatched quantities on the LHS. Non-firm financial rights would be allocated on the basis of registered capacity at the time of inception of the scheme. Participants would be free to negotiate with TNSP to fund transmission augmentation, over and above the regulatory test, and receive additional financial rights.

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

[1] 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.

[2] There is a potential 5/30 issue, but with 5-minute market metering on all LHS quantities, this should be resolvable.

	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.
FEATURE	JUSTIFICATION
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 the perceived risk that it may bind 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, **including the status quo** is a trade off between volume risk and price risk.
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.

Chapter 5.4A Compensation

Clause 5.4A (h)

Where the *Connection Applicant* is a *Generator*:

(1) the compensation to be provided by the *Transmission Network Service Provider* to the *Generator* in the event that the *generating units* or group of *generating units* of the *Generator* are *constrained off* or *constrained on* during a *trading interval*; and

(2) the compensation to be provided by the *Generator* to the *Transmission Network Service Provider* in the event that *dispatch* of the *Generator's generating units* or group of *generating units* causes another *Generator's generating units* or group of *generating units* to be *constrained off* or *constrained on* during a *trading interval.*

This section of the NEM Rules has never been implemented. Its inclusion in the original Code indicates that there was always the intention of the drafters to recognise some "implied access right". The implication of 5.4A (h) is that an incumbent would receive compensation for subsequent reduced access and the causer of the congestion would incur liabilities.

What is needed is a mechanism for implementing this clause in a consistent manner throughout the NEM. It is likely that if left as is, there would be little or no take-up of this provision and in the few cases where it occurred, it is unlikely that the negotiated outcomes would be consistent across a range of TNSP.

It is argued that the provisions of this paper provide one convenient mechanism for uniform implementation of the provisions of 5.4A (h), and as such, are not particularly revolutionary. The discovery and publication of local generation pricing behind a binding constraint is not to be feared, but is rather a mechanism for achieving access certainty and efficient investment balance between (market) generation and (regulated) transmission. There may be other mechanisms for encouraging the implementation of Clause 5.4A (h) and if so then these need to be discovered and clarified.

End of submission