



12 November 2004

Manager – Energy Market Reform Team  
National Energy Market Branch  
Department of Industry, Tourism and Resources  
GPO Box 9839  
Canberra ACT 2601

Our ref: BN008/0833/0030

Dear Sir or Madam

**NEM – TRANSMISSION REGION BOUNDARY STRUCTURE CONSULTATION PAPER**

We refer to the above consultation paper released by the Ministerial Council of Energy for comment by 12 November 2004.

We thank you for the opportunity to provide comments on the consultation paper and ask that you accept this letter and the attached document as our submission on the issues raised.

We would welcome the opportunity to discuss the consultation paper and our comments if required and also to participate in any subsequent consultation process.

Should you have any queries, please do not hesitate to contact me on (07) 3228 8259.

Yours faithfully,

**Michael Callow**  
**Acting Manager Regulation**

ERGON ENERGY PTY LTD



Submission on "NEM - Transmission  
Region Boundary Structure"

# TABLE OF CONTENTS

EXECUTIVE SUMMARY .....	1
<b>1 INTRODUCTION .....</b>	<b>4</b>
<b>2 HIGH LEVEL COMMENTS .....</b>	<b>4</b>
2.1 Introductory Comments on the Review .....	4
2.2 The Proposal Allows Nodal Pricing by Stealth .....	5
2.3 Why Generators Should be Wary of Constraint Support Prices .....	10
2.4 The Impact of New Regions/Locational Pricing on Queensland .....	11
2.5 Other Specific Issues .....	14
2.5.1 Retail Pricing.....	14
2.5.2 Implications for Contracting .....	14
2.5.3 Ancillary Services.....	17
2.5.4 Market Power.....	17
2.5.5 Regulatory Issues.....	17
2.5.6 New Investment .....	19
<b>3 CONSTRAINT FORMULATION AND SYSTEM SECURITY .....</b>	<b>21</b>
3.1 Recommendation 1 .....	21
3.2 Recommendation 2 .....	21
3.3 Recommendation 3 .....	22
3.4 Overall Comments.....	22
<b>4 REGIONAL BOUNDARY CHANGE PROCESS.....</b>	<b>22</b>
4.1 Recommendation 4 .....	22
4.2 Recommendation 5 .....	24
4.3 Recommendation 6 .....	28
4.4 Recommendation 7 .....	28
4.5 Recommendation 8 .....	29
4.6 Overall Comments.....	30

5	CONGESTION MANAGEMENT.....	30
5.1	Recommendation 4 revisited.....	30
5.2	Recommendation 9 .....	31
5.3	Recommendation 10 .....	31
5.4	Overall Comments .....	32
6	CONCLUSIONS.....	32
6.1	Summary of Reactions to Recommendations.....	32
6.2	Concluding Remarks on the CRA Proposals.....	35
6.3	The Way Forward .....	38
	APPENDIX 1: CRA'S PROPOSAL AND FULL NODAL PRICING .....	39
	APPENDIX 2: THE IES REPORT.....	43

## EXECUTIVE SUMMARY

1. This paper is Ergon Energy Pty Ltd's (Ergon Energy) response to the Ministerial Council on Energy (MCE) report "NEM-Transmission Region Boundary Structure", and supporting documents, prepared by Charles River Associates (CRA).
2. We would like to alert the industry and jurisdictions to the fact that the presentation of the CRA recommendations obscures the potential for the proposed constraint support pricing and contracting approach to give rise to full nodal pricing by stealth, even if no new regions are created.
3. We argue that the current NEM model provides appropriate signals for generators if adequate transmission is available. Further, our analysis of the Queensland situation suggests that there will be little opportunity for locational energy prices to significantly impact generator investment decisions there for at least the next decade.
4. The real issue facing the NEM is that of transmission investment. Instead of looking at energy pricing, we believe that following on from the MCE December 2003 communiqué the focus of this review should be on establishing an independent Regional Transmission Organisation (RTO) for the NEM. This body would propose and coordinate the planning of transmission augmentations and then tender or auction the task of designing, building and maintaining such augmentations to TNSPS. This RTO would not own transmission assets but would operate them. The implementation of an RTO would streamline and optimise transmission planning and investment across the NEM in a cost effective manner. This will address the transmission constraint issues in the NEM more effectively, more reliably, and at a significantly lower risk than varying regional boundaries or using constraint support prices.
5. Ergon Energy commissioned Intelligent Energy Systems (IES) to study the implications of changes in regional boundaries in Queensland. This study covered the years 2005/6, 2008/9 and 2012/13, and considered cases with 1, 4, and 10 regions. The study accounted for generators maximising profits given a contract position, and simulated firm and non-firm transmission rights.
6. The IES study showed that while an increase in the number of regions in Queensland has little impact on average prices, and that the regional price variations will have little impact on investment incentives, the absence of firm transmission hedges can be expected to increase average prices faced by Queensland consumers relative to the status quo. But this is not the sole risk. In this report we have identified the following risks that together are likely to increase the costs to consumers by more than IES predict:

- risks around whether, how, and upon which generators, interconnections, and (potentially) loads constraint support prices will be applied;
- risks created by boundary reviews, a potential shift to full nodal pricing, the lack of firm transmission hedging instruments, and the need to maintain uniform retail prices; and
- risks created through trying to more closely align the process for boundary reviews with the regulatory test process for new transmission assets, while the bodies responsible for those processes are different. Each process will have to make assumptions about the decisions likely to result from the other, and mistakes could be made.

Thus, we conclude, the efficiency benefits of increased regionalisation will be small and consumers will actually be worse off on average than they are under the status quo.

7. Ergon Energy finds it very difficult to understand how the industry is expected to reach an informed decision based on the limited information presented by CRA and the rather open-ended nature of the CRA recommendations. The CRA report lacks, in our view, sufficient information to allow the industry and jurisdictions to make an informed decision. The CRA package of recommendations includes proposals that are ill-defined and under-developed. In a number of cases the meanings of recommendations are ambiguous or unclear. Numerical values have been included in recommendations without any supporting reasoning, making the numbers appear quite arbitrary. There has been inadequate exploration of alternative proposals and no useful, realistic modelling results have been presented.
8. We have no fundamental issue with Recommendations 1, 2, and 3 which promote improved dispatch quality, provided that such recommendations have no pricing or settlement impact.
9. We do see some potential benefit in very limited use of constraint support pricing and constraint support contracting as a means of funding ancillary services and for compensating generation required by the system that might otherwise not be viable. The approach may also have merit in moderating the abuse of generator market power and the practicality of this should be explored. We are, however, concerned about any wider application of the method and are not comforted that CRA's Recommendation 4 fails to place any upper limit on the extent to which constraint support prices and constraint support contracts can be used.
10. Recommendation 5 is not acceptable to Ergon Energy. It proposes quite arbitrary criteria for boundary reviews. The industry should have been provided with a range of options and some quantification of their impact.

11. Ergon Energy supports the proposal for a reduced frequency of boundary reviews as proposed in Recommendation 6, though more information is required as to how such reviews will work in practice and what review process will exist for constraint support pricing between boundary reviews.
12. Recommendation 7, which supports improved information disclosure, is a recommendation we support as a general principle under any regime. However, in our view, CRA understate the amount of information that participants will require to assess the future impact of their proposed regime. In addition to information on constraint shadow prices, market participants would need to understand the impact that their actions have on each constraint in the NEM. The recommendations also need to be broadened to ensure that both potential and current participants have access to information. We have concerns as to the practical use of some of the information, and the level of effort required in producing it.
13. We have no fundamental issue in concept with more closely aligning the processes for regulatory tests and NEM boundary reviews, as proposed in Recommendation 8, but we have concerns as to the practicality of this. Further examination of this issue is required.
14. We make no comment on Recommendation 9 as the recommendation seems inconsistent with the report section in which it is located and its meaning is not at all clear.
15. Recommendation 10 is not very specific as to the way forward. We propose that the focus in the short term should be on:
  - Continued work and implementation of the proposed changes to the dispatch process.
  - Continued work to assess the application of constraint support prices and constraint support contracts in the very limited context described above.
  - Either abandonment of a boundary review process or a refinement of the existing process to include a Net General Equilibrium cost test and to be performed at 5 year intervals with another 3 years elapsing before implementation of the results.
  - Development of specific proposals for improving coordination between regulatory bodies and boundary review bodies so as to avoid the negative potential of the CRA proposals.
16. In the longer term, but as quickly as possible, we would like to see the implementation of a NEM coordinates the planning of transmission investment and uses a competitive process to determine which TNSPs actually design, build and maintain the assets. The regulatory test process could then be abandoned in favour of a simpler public benefit test. Under this approach, we would not envisage the need for further energy market reforms.

# 1 INTRODUCTION

This report is Ergon Energy's submission on the document "NEM-Transmission Region Boundary Structure" prepared by Charles River Associates (CRA) as part of the Regional Boundary Review being conducted by the Ministerial Council on Energy (MCE).

The report "NEM-Transmission Region Boundary Structure" references and draws on the content of the following reports:

- NEM Regional Boundary Issues: Theoretical Framework
- Dealing with NEM Interconnector Congestion: A Conceptual Framework
- NEM Regional Boundary Issues: Modelling Report
- Network Constraint Formulation: Impact on Market Efficiency

Ergon Energy has reviewed all of these documents to some extent to form a view of the "NEM-Transmission Region Boundary Structure" report.

This report is structured as follows:

- Section 2 provides general comment on specific policy issues without necessarily referencing specific CRA recommendations.
- Section 3 discusses CRA recommendations 1 to 3, which relate to constraint formulation and system security.
- Section 4 discusses CRA recommendations 4 to 8, which relate to regional boundary reviews.
- Section 5 discusses CRA recommendations 4, 9 and 10, which relate to congestion management.
- A summary of our reaction to the recommendations and our conclusions are presented in Section 6, along with our view of the way forward.

## 2 HIGH LEVEL COMMENTS

### 2.1 Introductory Comments on the Review

The issue of modifying regional boundaries in the NEM is one that has been subject to a number of reviews over the preceding 5 years. In the past it has been the view of Ergon Energy that consultation papers released to the industry in regard to boundary reviews have tended to approach the issue by focusing on theoretical concepts and generalisations at the expense of evidence of the actual costs and benefits of change and regard for the impact of change upon prices to end-use customers.

Ergon Energy is disappointed to see that the latest consultation document, while containing a number of reasonable points, restricts its scope to

presenting a method for how the market might evolve without providing any hard evidence as to what the impact of that method is likely to be. We are told that the methodology will encourage economic efficiency, but not how many regions it will create, or what proportion of the market is likely to be exposed to locational pricing. As argued in the next section, Ergon Energy has a concern that the market may be lulled into accepting what appear to be a few minor changes to the market with little impact on participants, only to find that methodology will result in very significant change in practice for participant's, participant interactions, and, importantly, consumers.

While not included in CRA's scope, Ergon Energy would have expected to have seen not just a single methodology for conducting boundary reviews, but detailed multi-year simulation results of the application of a number of competing methodologies to the NEM. Given that CRA's boundary review process has the potential to create new regions if (relatively low) thresholds are reached, and to impose what is effectively locational pricing otherwise, we strongly suspect that the results of such a study would be very illuminating to the industry and jurisdictions.

## 2.2 The Proposal Allows Nodal Pricing by Stealth

Based on informal discussions with industry members, it is apparent to Ergon Energy that the industry does not appear to appreciate the implications of what CRA is proposing. The common view, and one fostered by the examples used in CRA's reports, is that the proposals only amount to an incremental variation of the current market design. However, it is Ergon Energy's view that the proposed constraint support pricing methodology is simply a repackaged nodal pricing model and that, if adopted without significant limitations on its use, the proposed methodology could relatively quickly give rise to something close to a full nodal pricing regime, even if no regional boundary changes occur. In this regard we find the nature of the CRA report to be almost misleading by not highlighting the major implications of its key proposals.

The industries confusion on this issue is, in our view, driven by CRA's focus on theoretical derivations and discussions that are beyond the interest of the average reader, and the lack of a succinct, accessible discussion of the full implications of that theory. Readers must rely on a small range of simple examples involving one or two constraints. These examples create the potentially false impression that the CRA's proposals will lead to only minor impacts on the market.

CRA propose that a process for valuing intra-regional constraints should be developed and applied in the event of constraints arising that do not justify creation of a new region. This "constraint support price" / "constraint support contract" approach involves determining a measure of the influence of each interconnection and each generator on constrained quantities (such as transmission line flows) and then allocates the costs caused by such constraints (based on shadow prices) between those

generators and interconnections. A constraint support contract would provide some level of constraint “usage” before exposure to the constraint support price applies.

We introduce the simple example in Figure 1 to help illustrate what CRA is proposing, and why that can lead to full nodal pricing.<sup>1</sup>

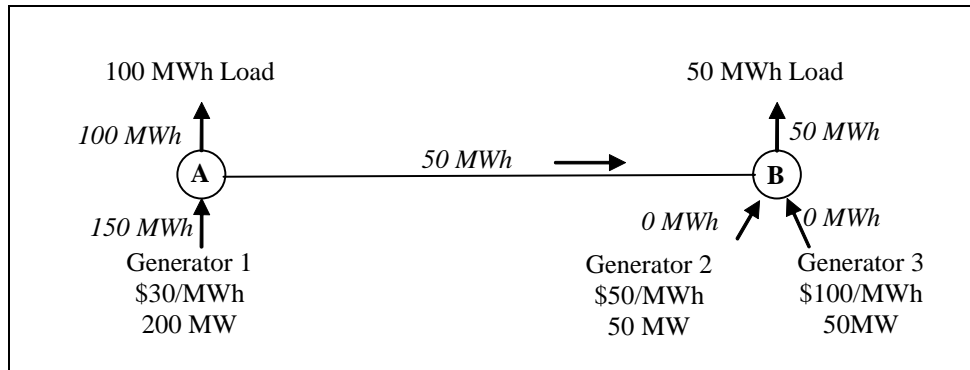


Figure 1: A simple unconstrained network.

The example in Figure 1 focuses on a single region with two loads and three generators. We ignore transmission losses in this example. The total load is 150 MWh. To supply this load most economically we first use the lowest cost generator, Generator 1 at Node A. This generator has a capacity of 200 MW so over an hour can easily supply all 150 MWh of load. It serves 100 MWh of load at Node A and, via the transmission system, 50 MWh at Node B. Generator’s 2 and 3 are more expensive than Generator 1 and are not needed, so their output is zero.

If demand were to increase or decrease by 1 MWh at either Node A or Node B then the change in energy would be supplied or absorbed by changing the output of Generator 1 accordingly. Consequently the price of supplying energy to either Node A or Node B is \$30/MWh, the cost of Generator 1.

Due to the lack of constraints the example in Figure 1 produces the same pricing result for both a regional model and a nodal pricing model.

In Figure 2 we show how the solution changes if the line carrying 50 MWh into Node B in Figure 1 can only support a flow of 30 MWh.

<sup>1</sup> A more theoretical demonstration is given in Appendix 1. We show how by re-arranging the shadow price terms that drive nodal prices we can produce the regime proposed by CRA, showing how the proposal actually delivers nodal pricing.

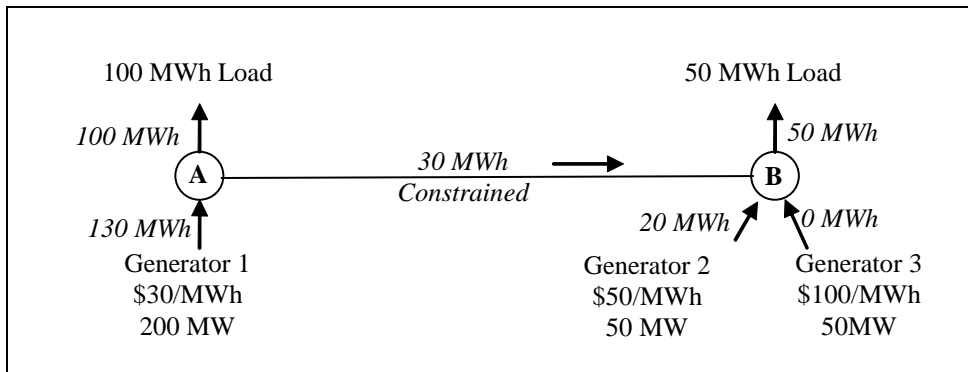


Figure 2: A simple constrained network.

The impact of the constraint is that Generator 1 has to back-off its generation from 150 MWh to only 130 MWh. To serve the load at Node B we must rely on Generator 2 to supply 20 MWh.

A change in load at Node A can be supplied by Generator 1 at a cost of \$30/MWh. But a change in load at Node B will be supplied or absorbed by Generator 2, the lowest cost generator there.

It follows that the nodal price at Node A is \$30/MWh while that at Node B is \$50/MWh. If we had 1 MWh more of transmission capacity between Node A and Node B we could decrease the output of Generator 2 by 1 MWh, saving \$50, while increasing the output of Generator 1 by 1 MWh, costing \$30. The net savings would be \$20. Hence the unit value, or “shadow price”, of the constrained capacity is \$20/MWh.

Under the current NEM model all generators and loads would see the same price, being the price at a reference node. Suppose that Node A is the regional reference node (since it has the greatest load). Then all generators and loads in this example would be settled at the Node A local price of \$30/MWh. Generator 2 would be operating at a loss and would be said to be “constrained-on”.

Under the CRA proposal, everyone would be settled as now at the regional reference price of \$30/MWh. However, a separate constraint support price, or CSP, can then be applied. Thus we might apply a CSP to Generator 2 and Generator 3. In addition to being paid for energy, each of these generators would make a payment to the market equal to the incremental impact that it is deemed to have on the constrained flow, multiplied by the shadow price of that constrained capacity. Thus if either Generator 2 or Generator 3 were to increase its output by 1 MWh, then flow on the transmission line would have to drop by 1 MWh (with Generator 1 backing off). Thus the incremental impact that Generator 2 or Generator 3 output has on the flow is -1. The shadow price of the constraint is \$20/MWh. Hence the CSP is -\$20/MWh. In other words, for every additional MWh produced by Generator 2 or 3, that generator must pay NEMMCO at a rate of -\$20/MWh. In effect, therefore, NEMMCO will pay Generator’s 2 and 3 at a rate of +\$20/MWh.

Thus, in the first instance, all generators and loads are settled at the prevailing regional energy price of \$30/MWh. In addition, Generators 2

and 3 are paid a CSP of \$20/MWh for each unit of their output. Generator 3 produces nothing, so gets no payment, while Generator 2 is made whole.

It should be apparent that the net effect of a CSP is to “selectively” make Generators 2 and 3 see their local nodal price. But this is because the method for determining the CSP is *exactly* the same methodology by which the constrained transmission line would be factored into a nodal price. To see this more clearly, note that the nodal price applied to an injection at a node is:

- a reference energy price, such as the regional reference energy price,
- plus, for each constraint:
  - the marginal cost impact that the injection has on the constrained quantity, such as the incremental impact of the injection on transmission line flow,
  - multiplied by the constraints shadow price.

This is just the same as:

- a reference energy price, such as the regional reference energy price,
- plus, for each constraint, the CSP price.

In other words, a nodal price is the combination of the regional reference price and one or more CSPs. CRA talk about bundled CSPs which account for the impact of many constraints. Again this is just like nodal pricing. If there were ten constraints to account for then the equation for a nodal price includes a reference energy price plus ten constraint terms, where each constraint term is just the CSP for that constraint.

If CSPs were applied to all constraints, then all generators would see nodal pricing while loads would see a single regional reference price (assuming CSPs were not applied to loads). However, there is no fundamental reason why CSPs could not be applied to wholesale load, in which case all generators and loads would be exposed to nodal prices. If constraint settlement prices are applied to enough constraints then even with the current regional boundaries the regional reference prices will be irrelevant and the market might as well be operating under full nodal pricing.

Full nodal pricing is an approach that has already been widely rejected by the market. Full nodal pricing is considered to complicate market trading as there are more locations to trade at with fewer people trading at those locations. With people buying and selling at a wide variety of locations it becomes important to be able to hedge against uncertainty in these price differences, and, as we discuss below, it is actually very difficult to fully hedge such risks in practice. Elsewhere in this paper we argue that the issues which have proved problematic in the context of nodal pricing generally prove at least equally problematic in the context of constraint support pricing.

An interesting question is “where does the money come from to support the \$20/MWh payment to Generator 2?” In our simple example the

market as a whole would have to fund the payment. However, there are more intricate constraint examples presented by CRA where one generator can “block” another generator from getting to market by influencing a constraint. In these situations CRA propose the use of constraint support contracts that define the output “expected” of each generator. If one generator goes above its contract level it will force the other generator below its contract level. The generator that goes above its contract might be charged a CSP on the excess generation, where this payment is used to fund the CSP payments on downward deviations to the generator that is constrained down. Of course, the two generators may not have the same absolute impact on the constraint, so the market as a whole will still have to fund or absorb the cost of any such differences. If this arrangement is configured so that the generator in a position to exert market power is disadvantaged by exerting that power, then market power issues are partly resolved. In principle these contracts could be imposed on generators without payment, or generators could pay for them (if providing a benefit) or they could be paid to take them (if detrimental). These arrangements are basically identical in nature, if not in form, to non-firm Financial Transmission Rights (FTRs). This is true even to the extent that if the constrained capacity is not available, e.g. due to a transmission outage, in which case their value as a hedging instrument will be limited.

While it appears that many market participants think that the constraint support price proposal will just affect a few constraints, the reality is that the CRA proposal as written without limitation on CSP application could easily give rise to market participants seeing “effective prices” identical to those seen under full nodal pricing. This could be the case even without the number of regions in the market changing at all.

This conclusion should not be a surprise to anyone who has reviewed the CRA reports closely and who has understood its implications. Indeed, CRA go to some lengths to argue that their regime produces the same outcomes as full nodal pricing. It should be no surprise therefore that CRA indicate that their hedging instruments suffer the same kinds of problems as those encountered under financial transmission rights.

It is true that the CRA regime does allow the option for some features of nodal pricing to be included in the market while others are ignored, but this could be achieved under a full nodal pricing regime by simply “turning off” some constraints in the pricing model. While a case could be made for using CRA’s proposed regime to address some specific issues in the market, CRA’s recommendations include no criteria to limit the extent to which their proposal could shift the market towards full nodal pricing, or over what timeframe.

As will be argued in this report, Ergon Energy is not in favour of increased locational pricing or changed regional boundaries. Given the ineffectiveness of section 46 of the Trade Practices Act, Ergon Energy is not opposed to “off market” contracts being used to address generator abuses of market power. However, Ergon Energy cannot support the widespread

exposure of generators to locational prices while retailers only see a regional price, at least not without further modelling and analysis being presented of the true effects/impacts of this upon the market and consumers. Ergon Energy is concerned that limitations of hedging arrangements will ultimately create greater risks for retailers, with little tangible benefit.

### 2.3 Why Generators Should be Wary of Constraint Support Prices

A generator facing a constraint support price is likely to have a number of concerns. The constraint support price will be based on some deemed impact that the generator has on a constraint. The real-time contribution will not always be constant, being subject to power flow patterns, so the fixed contribution used at any given time will be some form of average. Network loops will be a particular headache for those subject to constraint support contracts as power flows around loops can have quite complicated behaviour when constraints arise at different points around the loop. The value of each generator's contribution is likely to be at least as fickle an issue as intra-regional loss factors, and may require regular review.

A further issue for generators is that the constraint support contract levels they might be exposed to are still unclear. A generator might like the idea of a CSP if it thinks the contract will compensate it when it is constrained-off, but this rather depends on what constraint support contract level is applied. Depending on how the regime is implemented it is quite possible that individual generators will be no better off, and may be worse off. A generator may even find that a constraint support pricing/contracting measure could be imposed on it by NEMMCO or some other agency, with the effect that some of the generator's spot market income is transferred to one of its competitors.

While CRA recommend that boundary reviews be performed once every 5 years, with the results implemented after 3 years, this will be unworkable for constraint support pricing arrangements as the parameters involved will need to be updated more regularly so as to maintain some degree of consistency with physical power flow behaviour. Hence, generators will almost certainly be subject to changing constraint support prices and constraint support contracts over a timeframe that is short relative to the term of their energy contracts. This will create increased regulatory risk for generators that will lead to higher average prices to consumers.

We understand that generators could be interested in constraint support contracts as they provide a property right in regard to accessing a constrained resource. The right that a generator gets could be determined in a number of ways. For instance, it could be based on historic usage. However this will "lock in" any historic inequities that a generator may believe it has suffered. Alternatively, the right could be based on some measure of optimal efficient usage, which should produce a right that lowers generator revenues on averages and "locks out" any historic market power capability or other locational advantage that a generator has.

Hence there will almost certainly be winners and losers in the allocation of such property rights to individual generators, while overall there is a possibility that to the extent that generators can hold prices above competitive levels, any such advantage could be transferred to consumers.

We believe that a generating company should be wary of the pricing arrangements proposed by CRA unless it is quite prepared to be exposed to:

- A regime something like nodal pricing with non-firm hedging instruments.
- A regime whereby different generators may be subject to different pricing rules, and different hedging arrangements, depending on their location in the network.
- A regime which could change the asset value of a generator from year to year.
- A regime to be applied to individual generating plant by NEMMCO, or some similar body, without necessarily being the result of commercial negotiation.
- A regime that will re-distribute wealth between generators, and is capable of transferring wealth from generators to consumers.

## 2.4 The Impact of New Regions/Locational Pricing on Queensland

Queensland was used as a case study in CRA's work. However, it was only used for illustrative examples and for very limited modelling. In Ergon Energy's opinion a more rational approach would have been to model the behaviour of Queensland prices under a range of different regional models and over the long term. In the absence of any such study being provided, Ergon Energy here reports on its own study.

The study was prepared independently by Intelligent Energy Systems (IES). The resulting report is included in Appendix 2. This study investigated the impact on the Queensland market of having 1, 4 or 10 regions within Queensland for each of the years 2005/6, 2008/9 and 2012/13. Planned generation and transmission augmentations were accounted for, as well as load growth.

Unlike CRA, IES did not assume simple marginal cost based generator bidding, but instead assumed that generators maximised profits based on a given contract position. This means that IES results are likely to demonstrate more realistic market behaviour than CRA's results and that the IES model can capture market power effects.

The following eight scenarios were modelled:

- Each of the three regional models with firm FTRs but no co-optimisation between generation and transmission constraints.<sup>2</sup>
- Each of the three regional models with firm FTRs with co-optimisation between generation and transmission constraints.
- The 4 and 10 region models solved with non-firm FTRs and no co-optimisation between generation and transmission constraints.

IES report that the zonal prices under the various scenarios were quite similar. Prices for the Central West and South West regions, where most of the generators are, were slightly higher in 2005/6 under the 4 and 10 region models. IES believes that this is due to the generators artificially increasing prices by withholding capacity from the market. In the 1 region case, however, IES argue that intra-regional constraints actually encourage generators to lower their prices and try to maximise volume.

IES report that load weighted average Queensland prices with firm FTRs are very close to the average single region price, though slightly lower. The price differences for both the 4 and 10 region models relative to the 1 region model are very similar in all cases, and no more than \$0.4/MWh, \$0.25/MWh, and \$2.80/MWh for 05/06, 08/09 and 12/13 respectively.

When non-firm FTRs are used the average price with 4 regions is about the same as for 1 region except in 2008/9 when the average price with 4 regions is \$1.90/MWh, or about 5%, higher than with 1 region. Differences are not significant in earlier and later years as transmission constraints do not have much impact in those years. The situation with 10 regions is more pronounced, with the average price with 10 regions and non-firm FTRs exceeding the 1 region average price by \$0.5/MWh, \$4.3/MWh, and \$0.9/MWh for 05/06, 08/09 and 12/13 respectively.

The IES results for firm and non-firm FTRs illustrate the importance of firm hedging instruments should new regions be created. If firm hedging instruments are in place then increased regionalisation can lower average prices reliably (ignoring other regulatory risks). Without firmness, though, and with generators maximising profits, the IES results show that average prices will rise. This is an important observation since, as we argue in section 2.5.2, no satisfactory firm FTRs (or the equivalent instruments that CRA propose) are expected to be available.

IES show that co-optimisation has no material impact on average prices in Queensland, except in the Far North Queensland region. The change in the Far North Queensland price with co-optimisation areas follows:

- 2005/6 with 4 regions: Prices drop from \$38.14/MWh to \$31.28/MWh, or about 18%. For the 10 region model the decrease is from \$34.89/MWh to \$30.83/MWh, or about 11%.

---

<sup>2</sup> A co-optimised limit means that the flow allowed on a transmission limit is a function of generation rather than a fixed limit.

- 2008/9 with 4 regions: Prices drop from \$43.28/MWh to \$42.89/MWh, or about 1%. For the 10 region model the decrease is from \$44.31/MWh to \$42.21/MWh, or about 5%.
- 2012/13 with either 4 or 10 regions the prices are largely unchanged by co-optimisation, lying between \$41.36/MWh and \$41.46/MWh in all 4 cases.

These results reflect planned increases in transmission to the north in 2008/9 and 160 MW of new generation capacity at Ross in Far North Queensland.

We can conclude from the IES study that:

- Given current planned transmission investment in Queensland, the average spot energy price faced by Queensland electricity users will be little different if more regions are created.
- While spot price changes with more regions may not be huge on average, it is apparent that consumers will tend to see higher prices if more regions are created without adequate firm hedging instruments being available. Based on international experience and experience to date in the NEM, we believe it unlikely that such instruments will be available.
- Over the next decade the potential benefits of increased locational pricing appear small in the best case scenario where firm FTRs are available.
- Improved efficiency of scheduling using co-optimisation appears to have only small and isolated impacts in Queensland.

While the IES study indicates that there is not much price difference between regions over the long term, any difference is unlikely to be a trivial issue at the state government level. It should also be noted that the regional price variations observed are unlikely to have any significant implications for generator investment decisions.

In conclusion, the IES study predicts that there will be no profound benefits from increased regionalisation during the next decade. IES even show that an increase in the number of regions can increase average prices to consumers if the available FTRs are non-firm. Given the small and uncertain gains to be made from increased locational pricing and the lack of firm FTRs, Ergon Energy would view an increase in locational pricing as being a high risk, low return development of the market at the current time. The better option is to retain something very close to the status quo, with coordinated transmission planning across the NEM being used to mitigate transmission constraints in situations where generation investment is not otherwise viable.

## 2.5 Other Specific Issues

### 2.5.1 Retail Pricing

We are puzzled by the logic put forward by CRA in regard to retail pricing. They argue that increased regionalisation will have a benefit, but then propose various mechanisms for ensuring that all consumers in a jurisdiction see the same price. Our views on this are:

- If the end result is that all consumers see the same retail price, we cannot see the point in having more than one wholesale pricing region in a jurisdiction.
- Even if locational prices are faced by generators alone, this will impact retailers because in the absence of firm and permanently grandfathered transmission hedges, they will have to buy energy contracts at different prices from different generators, and even with transmission hedges, their non-firm nature will increase the risk faced by retailers (and as a result place upward pressure on wholesale prices).

Further, we would oppose any regime that caused retailers to see an increase in locational price signals beyond the status quo (which has locational TUOS and loss charges) while retailers operate in an environment where they may not be able to pass on the corresponding risks to end users. Thus we prefer either:

- to have both generators and retailers see the same single price in a jurisdiction as per the status quo, or
- to have retailers see a single price with generators seeing locational prices, but with firm transmission rights permanently grandfathered to retailers so as to minimise the impact of risk premiums on retailers. We would also want to see a liquid market in the trade of these hedge instruments to allow participants to remain hedged as supply and demand patterns change over time.

### 2.5.2 Implications for Contracting

As a retailer that is ultimately exposed to any changes to pricing in the NEM, Ergon Energy is particularly interested in the impact of any boundary or pricing changes on energy contracts and transmission hedging arrangements. In this section we express our thoughts and concerns in this regard.

#### *Risk Management*

In the present market, retailers can purchase energy contracts at their regional reference nodes and use fixed and relatively predictable loss factors to translate the contract price to their local nodes. This regime

gives retailers certainty and is not overly complex nor does it involve great transaction costs.

We argued above that it makes no sense to have retailers exposed to different reference prices within the same jurisdiction. If retailers are exposed to such price variations then firm and known transmission hedging instruments become critical. On the other hand, if retailers see just one price within a jurisdiction while generators see something close to full nodal pricing, then generators face a range of risk management issues themselves. CRA is proposing to address these risks via the use of constraint support contracts which act to allow generators to see the regional reference price if they perform as expected, while exposing them to locational prices if their behaviour deviates. But it seems to us that the process of setting constraint support contract levels is likely to be an imperfect art, especially since contract support prices will be based on fixed factors that may not reflect actual power flow conditions at any particular time. Thus these arrangements are likely to be as, if not more, controversial and contentious as setting loss factors has been in the past.

CRA admits itself that its contract proposals suffer the same firmness issues as Financial Transmission Rights. While proposals exist in theory to provide firm transmission hedges, the only practical examples of these we are aware of are:

- The practice employed in New York whereby transmission companies guarantee the firmness of transmission rights, but simply pass those costs through to consumers via transmission tariffs.
- The practice of limiting the availability of hedges to be less than the available capacity. This can provide a firm instrument to some grid users but not to all. Consequently it would not be possible to hedge every existing user, even if they all placed the same value on holding a transmission hedge.

We do not consider these to be satisfactory options.

Constraint support contracts may also be detrimental to hedge liquidity relative to an FTR regime because the different impact that each participant has on each constraint combined with the number and variety of constraints is likely to mean that there is no single, simple and uniform hedge product that can be traded.

We are not comfortable with any proposal that exposes retailers to locational price risk, even if this is via cost pass through by generators. It is apparent to use that the constraint support pricing and constraint support contracting regime is not likely to be any more successful in this regard than FTRs, and they may actually perform worse.

### *Liquidity*

Increased regionalisation or increased locational pricing will not create more players in the market. The major change will be that there will be more transmission paths to hedge, with fewer players trading on those

paths. This will presumably lead to a drop in hedge market liquidity and hence a reduction in competition. The New Zealand market illustrates starkly the impact on competition of a lack of hedge availability. It is a market that has operated with full nodal pricing but no transmission hedges for almost a decade. That market has, as a result, become quite vertically integrated on a regional basis, with very little competition occurring between regions.<sup>3</sup> It could also be argued that the lack of firm hedges between the existing regions in the NEM has limited national competition in Australia.

A contrary view is that increased localisation of pricing would create more competition over time and increased competition will increase the opportunities to trade hedges, and hence increase hedge liquidity. However, it seems unlikely that the level of competition will change significantly in the foreseeable future.

It is implied by the CRA work that constraint support contracts might be granted to generators, rather than being auctioned or traded. Ideally we would expect some process by which these contracts could be traded so that generators can overcome any limitations in the original assignment. However, the potential for this will be limited in practice, and hence liquidity reduced, because:

- Many generators will not want to be exposed to constraint support contracts at all when they are negatively valued. Consequently, either someone must be prepared to be paid to take these contracts, or they must be forced on generators.
- Some generators would have to be barred from trading the constraint support contracts if those contracts are intended to moderate market power incentives.
- Differences between constraint support price factors (i.e. the impact that a generator has on a constraint) and the real dynamic impact that a generator has, creates anomalies that cannot be traded. In other words they expose generators to unhedgable risk.
- It is not clear from CRA's proposal as to whether or not retailers would be excluded from holding these contracts, or buying in to them. If retailers cannot hold them, then this will limit market liquidity but if retailers are required to hold these contracts, then implicitly they must be exposed to locational pricing, which we oppose.

---

<sup>3</sup> Some argue that the New Zealand market is vertically integrated because distribution lines businesses were required to divest their retail businesses. However, this change did not require that retail businesses be owned by generators in the same geographic area. The only reason that this has occurred is because the generating companies obviously have uncontrolled transmission price risk if they are distant from their retail businesses. Even more telling is that there has been at least one incidence in New Zealand where retail businesses in different parts of the country swapped large groups of customers so as to minimize their exposure to locational risk.

An appropriate level of hedge liquidity, and the availability of firm transmission hedges, needs to be demonstrated before Ergon Energy could support increased locational pricing.

### **2.5.3 Ancillary Services**

We are not opposed to an exploration of the use of instruments like constraint support prices and constraint support contracts as a measure to fund Frequency Control Ancillary Services or other ancillary services. Such an approach may provide a more efficient means of settling such arrangements. Since the shadow price of an ancillary service constraint is the spot price for that ancillary service, this approach could be a transitional step to creating a spot market for some ancillary services.

### **2.5.4 Market Power**

Constraint support contracts can be used to moderate the incentives of generators. If a generator is heavily contracted and is penalised by the constraint support price for not covering the contracted quantity then the generator will produce more energy than it would have otherwise. Thus we consider these instruments to have potential in moderating the potential abuse of market power by generators. We concede, though, that regardless of the instrument used, the problems of identifying potential offenders and legally enforcing a mitigation measure remain. However, this is an avenue that could warrant further exploration.

### **2.5.5 Regulatory Issues**

We suspect that the CRA report understates the amount of central control / regulatory intervention required to implement the proposed regime. It would appear to us that one or more agencies need to make judgements about:

- The costs of new entrant generators (as part of the boundary review process);
- The costs and benefits of any potential boundary adjustment;
- Whether any hypothetical transmission investment is likely to pass the regulatory test;
- The impact that each generator (and possibly load) may have on every constraint in the NEM, where this value has to be determined in the context of:
  - potential generator market power, which may change over time,
  - changes in generating plant capabilities over time; and
  - changing demand patterns, power flow patterns and loss factors over time.

These uncertainties mean that the assessed impact that a generator has on a constraint may be quite wrong.

- The constraints that will be subject to constraint support pricing if no boundary changes are deemed necessary.

Further, CRA's recommendations appear to suggest that every time a regulatory test is applied aspects of the boundary review process must be followed and whenever a boundary review is conducted aspects of the regulatory test must be followed for each potential investment option.

It would seem therefore, that while the CRA proposal might at first glance provide a formulaic approach to addressing boundary review and investment issues, the work required could be overwhelming, achieving a result difficult, and the results highly contentious. The amount of decisions that impact on both incumbent participants and potential investors are large and the consequences of getting them wrong could be great. Further it could be very difficult to actually formulate rules that adequately and unambiguously capture any agreed position on the approach. The necessary complexity of the rules, and complexity of any decision made under those rules, may lead to many disputes. These difficulties need to be factored into any consideration of the CRA proposal as they all imply costs to the market.

A current or potential market participant could, at various times, face any of the following regulatory risks:

- A constraint support price could be imposed on it, changing its effective spot market revenue.
- A constraint support contract could be imposed on it, changing its overall value.
- The creation of a new region could create basis risk for two parties trading via an energy contract. As no firm hedge instrument exists one or both of these parties will face increased costs.
- Implementation of constraint support prices and contracts will also create basis risk and increase costs. Further, we believe that the parameters in constraint support prices and contracts will almost certainly have to be updated more frequently than the proposed 5 year boundary review period.
- New investors may be told the outcome of a regulatory test based on the assumption that regional boundaries will be changed at the next boundary review. However, the formal regional boundary review process may reach a different conclusion. Conversely, the fact that an investment has been accepted or rejected as part of the regulatory test might bias the boundary review process. Each of these possibilities creates risks that could impact the financial positions of investors and incumbent market participants.
- Retailers face risks that they will be required to offer services to retail customers within a jurisdiction at uniform prices, despite facing a

range of different locational wholesale spot prices or energy contract prices. This will increase costs to retailers.

All these possibilities impose a cost risk on market participants, even if the event described never actually happens. This is much like owning a house – there is a risk that the house will burn down which creates costs for the home owner, in terms of insurance premiums if insured and in terms of reduced expected net wealth if the house is not insured.

CRA's proposal will create new risks and new costs. While CRA has not quantified the value of these risks, Ergon Energy is concerned that any increased risks will ultimately increase costs to consumers. Without being fully compensated for the costs these risks impose, whether via firm and grandfathered transmission rights or equivalent regimes, it is unreasonable to expect retailers or other market participants to accept such a regime.

### 2.5.6 New Investment

CRA's proposals are based on the view that most new transmission investment will be driven by energy market prices. Thus the advantage of improved locational pricing will be primarily limited to encouraging improved locational generation investment signals.

Ergon Energy does not consider generation investment incentives to be a major problem in the NEM. Indeed, efficient entry by generators has occurred in the NEM, with CRA even acknowledging that "to date there is no evidence of manifestly poor decisions"<sup>4</sup>, and in our view this can continue to be the case without changes to regional boundaries being made. Further, if loads are exposed to locational pricing, either directly through the creation of more regions or the imposition of constraint support prices, then this may actually undermine economic efficiency given that loads already face locational TUOS charges. The resulting price signals will be excessive and will distort investment signals. Even if loads are not exposed to locational prices via the spot market they could still be indirectly exposed via the contract market with generators. While firm hedges could mitigate this effect, we are yet to see any proposal that will ensure that a firm hedge will be provided.

Factors other than just energy prices also drive generation investment decisions, factors such as the availability of low cost fuel and access to the transmission network. Further, if the coordination of transmission planning across the NEM produces an optimum mix of transmission capacity then we do not believe that increased locational pricing regime will have any significant impact on generator investment decisions. In the case of Queensland, the IES study shows that currently planned transmission augmentations will largely remove transmission constraints in the foreseeable future, making a move to more regions of limited or no benefit.

---

<sup>4</sup> Page 2 of "NEM – Transmission Region Boundary Structure".

The MCE's December 2003 communiqué places increased emphasis in the NEM on transmission investment and non-entrepreneurial transmission investment in particular. Ergon Energy agrees with this view, and considers measures that will improve transmission investment to be a more important and more urgently required than measures to address energy spot pricing issues. If we do not get the right mix of transmission capacity in the NEM then we are not going to get the right mix of generators and no amount of locational pricing will improve long term dispatch efficiency. On the other hand, getting transmission investment right should leave the NEM largely unconstrained, meaning there is no real benefit in having increased locational pricing. It is well established both in theory and in practice that locational pricing cannot drive investment in optimally sized AC transmission assets due to economies of scale and the difficulties in protecting property rights. But locational pricing is not required to drive efficient coordination of transmission investment.

For these reasons Ergon Energy would rather see the NEM move quickly towards developing a national transmission planning and coordination body. This body would be an independent Regional Transmission Organisation (RTO) that coordinates and plans transmission investments based on economic efficiency criteria but does not own transmission assets itself. VENCORP in Victoria, where transmission assets have been privatised, provides a good starting model for such an RTO. However we propose an extension of the VENCORP model, with the NEM RTO planning new transmission assets and then using an auction or tender process to determine a licensed TNSP to design, build, and maintain the asset. The RTO would operate the asset.

The implementation of such an RTO would:

- Allow multiple transmission networks, and the augmentation of those networks, to co-exist without one network restricting the access of another.
- Encourage competition between TNSPs to gain ownership of assets, hence encouraging cost minimisation.
- Simplify the regulation of assets. The independent nature of the RTO means no regulatory test is required, just a public benefit test for the winning proposal. The TNSP would earn regulated revenue as it does today.
- Avoid the failings of entrepreneurial transmission investment, which has resulted in DC links with less than ideal capacities securing easements and limiting the opportunities for more rational AC transmission investments; and would

Ergon Energy believes that an improved transmission investment model will address the transmission constraint issues in the NEM more effectively, more reliably, and at a significantly lower risk than varying regional boundaries or using constraint support prices.

In conclusion, Ergon Energy knows that increased regionalisation/localisation of pricing cannot drive transmission investment and Ergon Energy is not convinced that simply implementing increased locational pricing will have material impact on generation investment. Instead, a more reliable and effective approach, which will create less risks for the market, is to improve the coordination of transmission planning on a national scale.

### 3 CONSTRAINT FORMULATION AND SYSTEM SECURITY

#### 3.1 Recommendation 1

1. *On the basis that no change to the current economic objective of the five-minute spot market dispatch process is made, NEMMCO should apply the Direct Physical Representation (DPR, or “fully optimised”) form of constraints (Option 4/5) to all network constraints. The Code should be amended to confirm this.*

Ergon Energy has no substantive issues with Recommendation 1 in principle.<sup>5</sup> Our view is that it is appropriate to represent constraints in a correct and consistent manner.

#### 3.2 Recommendation 2

2. *Following resolution of the form of constraint equation NEMMCO should review if it believes a full network model is necessary in order to meets (sic) its obligations for system security.*

We have some concerns in regard to the wording of Recommendation 2. As written, it appears to leave it to NEMMCO to determine to what resolution it will represent the power system for dispatch purposes. While we have no problem with this in the context of dispatch, the recommendation is silent as to what this means for pricing? As stated, the recommendation could be interpreted to mean that if more regions are added to the existing dispatch model, they might also be added to the pricing model. We do not believe that this is CRA’s intent, but the wording needs to be clarified.

If Recommendation 2 means that NEMMCO can add constraints to the dispatch and pricing model to satisfy its obligations, but that of itself Recommendation 2 does not give rise to any constraint support prices or additional pricing regions, then we can accept this recommendation in principle.

We are curious though, as to whether any cost/benefit analysis has been employed in reaching the first two recommendations? How much will it cost NEMMCO to implement these recommendations and what is the

---

<sup>5</sup> We would request, however, that the final version of these recommendations make it clear what Options 4 and 5 are, as these options are only described in other documents.

potential value of the benefits? It would seem fitting for the industry to be provided with information as to whether this is a trivial change with quantified benefits or whether, at the other extreme, it will actually be quite expensive to implement with no clearly identified benefits.

### 3.3 Recommendation 3

*3. Concerns about inappropriate bidding behaviour should be referred to the relevant authorities. If it is deemed necessary:*

*3.1 NEMMCO should after due account is taken of the impact on efficiency in the short and long term, when the existing derogation to the code expires in December 2004, be instructed to continue to impose a simple constraint on network transfers as a function of the settlement residues in the short term in preference to altering the form of network constraint; and*

*3.2 If and when new network elements that will create major network loops emerge are planned (sic) a mechanism external to the operation of the dispatch process should be investigated – intra-regional pricing and contracting mechanisms provide a ready mechanism for this.*

Our view of Recommendation 3 is that all it means is that the status quo should be retained for the time being, and that this situation should be reviewed once major AC transmission loops appear between pricing regions. We consider this to be a rather empty recommendation so see little value in commenting on it.

### 3.4 Overall Comments

While Ergon Energy has a number of minor issues with the wording of these recommendations and the level of analysis reported in regard to how the recommendations were reached, we have no fundamental objections to Recommendations 1 or 2. However, this position is based on these recommendations only impacting on the status quo with respect to the dispatch process, not the operation of pricing or settlement processes. In our view, Recommendation 3 means very little in practice.

## 4 REGIONAL BOUNDARY CHANGE PROCESS

### 4.1 Recommendation 4

*4. Within the regulatory framework for transmission established for the NEM, on balance, an evolutionary region structure, reviewed at relatively lengthy intervals in parallel with a flexible congestion contracting/pricing regime is recommended.*

Recommendation 4 amounts to a regime where regions will be added once certain thresholds are reached, while in the meantime the settlement

position of individual market participants may be altered via other arrangements to make them see some form of effective locational price.

Ergon Energy has numerous concerns in regard to the creation of new pricing regions and to exposing participants to effective locational prices without officially creating new regions. Ergon Energy does not consider this latest study to have addressed its concerns about locational pricing. Some specific concerns are:

- New regions or locational pricing within a jurisdiction will expose retailers to price risk if retail customers are to face uniform tariffs. While CRA's paper describes methods for equalising tariffs between retailers across a jurisdiction, such solutions are inferior to simply maintaining one price for each jurisdiction.
- If no new regions were created, but constraint support prices were to be applied to generators, then this would mean that retailers in a jurisdiction would all see the same spot price. However, if generators are all seeing different effective spot prices, and are hedged via non-firm constraint support contracts that do not reflect the dynamic nature of the power system, then generators will face greater price uncertainty, increasing the premium on energy contracts. CRA concede that firmness issues applicable to Financial Transmission Rights apply equally to constraint support contracts. Ergon Energy has always been of the view that an absolutely firm transmission right is required in the presence of locational pricing (and prior to locational pricing being deployed or new regions created). Ergon Energy cannot support this option without being provided with convincing evidence that energy contract premiums would not rise as a result of this change.
- Even if firm constraint support contracts did exist, Ergon Energy is concerned that consumers might have to pay generators to accept these contracts. This also amounts to increased hedging premiums for consumers. Ergon Energy believes that generators should be equally concerned by the alternative possibility that these contracts could be forced on generators without regard for the commercial consequences.
- We do not believe that increased locational energy pricing will significantly impact on generator investment, and have certainly not been presented with evidence to the contrary by CRA. But Ergon Energy can state with certainty that an increased focus on coordinated transmission planning will reliably address transmission constraint issues.

If Recommendation 4 were to be adopted and constraint support prices applied to generators, and possibly loads, then all market participants could be exposed to locational pricing without regional boundaries changing. It is Ergon Energy's view that Recommendation 4 opens the door to full nodal pricing, an action that for reasons discussed above, we

cannot support. If these instruments were to be adopted we would prefer to see their use limited to the settlement of ancillary services and ensuring the viability of existing generators that would not otherwise be viable. We would also be interested in exploring the practicality of using these instruments as market power mitigation measures.

However, we do see some potential for benefit in the very limited use of contracting to address market power issues with generators and to compensate generators providing what are effectively ancillary services. However CRA has not presented any evidence that such constraint support prices and constraint support contracts will be superior to current contractual regimes. Further, and of more concern, CRA's recommendations fail to place any upper limit on the extent to which these instruments can be used.

## 4.2 Recommendation 5

5. *At each review a transmission connection point should be (sic) become part of (sic) region where it can be demonstrated that compared to the next best alternative there is expected to be*

- *An increase in economic efficiency of dispatch (including as a result of the treatment of inter-regional loss factors) within the NEM determined in accordance with an endorsed methodology, less demonstrable costs, exceeding \$1Mp.a; or*
- *A change in locational price indicators sustained over the review cycle in excess of levels to be published annually that would provide indicative investments in generation plant an increase in annual revenue of 25% of reasonable new entrant costs for each*

*Provided that*

- *No region shall have a maximum demand of less than 200MW; and*
- *A separate region shall not be created where in the reasonable opinion of the relevant authority there is little prospect of market based investment within the review period.*

The thresholds in Recommendation 5 seem quite arbitrary. Why \$1 million? Why a 25% increase in revenues for new entrant generators? Why 200 MW of demand?

A \$1 million threshold might result in efficiency being improved in a relatively minor way (e.g. some fuel savings), but could (a) have a big impact on what consumers pay and (b) will not necessarily produce any tangible change in investment. Further, the \$1 million figure seems quite low, especially since it may be of a similar order of magnitude to the cost expended in determining the efficiency gains associated with creating a region.

One of the arguments put forward in the CRA paper is that a move to more regions will increase the efficiency of the dispatch. While this is no doubt true, it needs to be remembered that the existing 5-region dispatch model includes features that already allow it to approximate a nodal dispatch model solution, and changes described under Recommendations 1 to 3 will further improve this. Specifically, whereas a nodal representation might explicitly model all flow constraints, the 5-region model has generic constraints that allow NEMMCO to model those constraints materially impacting on the solution. Thus while a jurisdiction might currently be represented as one region, generic constraints restrict generation and demand within that jurisdiction so as to respect intra-regional constraints. The use of generic constraints means that the schedules produced at the moment are not likely to be significantly different from those that would be produced under full nodal pricing. The implication of this is that any short run efficiency gains from moving to an increased number of regions or nodes is likely to be quite small, and the overall fuel usage in the two cases is likely to be about the same.

The 25% revenue criterion appears to favour generation investment over transmission investment and seems an entirely arbitrary number. We would have expected a broader discussion of the options and analysis to be presented to support any thresholds provided.

The requirement that no region have less than 200 MW of demand is interesting in that it means that it will be impossible for a generator to be in a region on its own. This actually appears to guarantee that generators in a region will always have “captive load” if hedging instruments are not satisfactory. Further, it is interesting to note that if every region had only 200 MW of demand then the NEM would have about 100 regions. While do not know how many regions CRA expects to result from their boundary review criteria, we find this 200 MW minimum to be rather small, with the exception that it should be possible to establish a region containing only generators.

Recommendation 5 makes reference to losses and regional boundaries. Clause 3.5.1(b)(2)(v) of the Code requires that NEMMCO aim to minimise the variation between the loss factors and the averaged losses while Clause 3.5.1(b)(2)(vii) requires that the number of regions be minimised. These requirements imply a trade-off between the number of regions and the accuracy of loss modelling. The view of Ergon Energy is that the minimisation of the number of regions should be the highest priority, even if this means accepting a higher variation in the losses than might be possible with more regions. Appropriate criteria for determining the precise trade-off might be where the total cost to the market of increasing the number of regions is significantly smaller than the gains made through increased accuracy of loss modelling and transmission constraint valuation. The costs that would need to be considered in any assessment include:

- Costs of revising wholesale energy contracts.

- Costs associated with transmission hedging (both acquiring them and the level of risk protection they provide)
- Revision of internal participant models and tools.
- Any impacts on scheduling model speed and performance.

The last point in Recommendation 5 states that no region should be created if there is no expectation of market based investment. This should be modified so as to also account for any reasonable expectation that a regulated transmission investment will occur.

Ergon Energy would prefer to have seen a simulation as to what the impact of different thresholds would be so that the industry could assess the impact of the different thresholds. Without such information we are quite limited in our ability to assess the threshold. Further, a detailed description of what factors actually count towards benefits and costs would appear critical to assessing the CRA recommendations. We believe that efficiency alone is not the best criteria for such a review, and would prefer to see more holistic criteria that might account for some or all of the following factors:

- The wealth redistribution stemming from a regional boundary change. Such redistributions will affect the value of incumbent generators and retailers. While efficiency objectives are normally related to changes in resource usage, our concern is that a boundary change that produces trivial efficiency gain might have pricing impacts that creates extreme wealth transfers between market participants.
- The potential for any efficiency gains to be realised in practice. While an idealised study might show that fuel costs will drop if a change is made, the actual introduction of a boundary could create new opportunities for quite different market behaviour that actually undermines the savings made in fuel.
- Whether a change in regional boundaries would produce price signals sufficient to justify efficient generation or transmission investment that could not be justified otherwise. We would anticipate that more realistic efficiency gains would have to be of the order of several tens of millions of dollars before any serious impact on investment will occur.
- The impact on average prices, including risk premiums, faced by end-users.

We are also very concerned that this recommendation combined with recommendations 4, 9, and 10 appear to imply that if no regional boundary change occurs as a result of a review, constraint support pricing can still be introduced within the existing region. The process for introducing constraint support prices is rather open ended. We are therefore concerned that if a regional boundary change cannot be justified, constraint support prices could be introduced instead, potentially resulting

in everyone in the region seeing different prices. We believe that the recommendations need to be modified to specify:

- When new regions can be created; and
- If no new region is created, the situations in which constraint support pricing can be used, and the limits on the extent to which it can be used.

In conclusion, given the seemingly arbitrary nature of Recommendation 5, and the apparent lack of analysis or justification that has gone into it, we cannot support this recommendation. Further, Ergon Energy is broadly satisfied with the existing regional boundary review criteria and believes that there is no need for new regions. However, if the current boundary review criteria are to change, the changes that Ergon Energy would support include:

- The conditions for modifying boundaries should still factor in the incidence that constraints occur, with a significant number of hours of constraint being required before any change is considered.
- A Net General Equilibrium cost test should be implemented that factors in a wide variety of social impacts of any proposed boundary change, including their impact on past decisions that would be undermined by a boundary change and their implications for wealth transfers. We would also expect that boundary changes should only occur if there is clearly a reduction in the overall costs faced by consumers over the long term.
- No boundary changes should occur if either market or regulated investment is likely to mitigate the constraints.
- No new regions should be created if there are jurisdictional limits requiring retailers to impose uniform rates to retail customers across the jurisdiction.
- If new regions are created then firm hedging instruments must be granted without charge to existing retailers so as to ensure that they will be no worse off given the change, provided that the retailer at least maintains its historic purchase patterns.

If it is decided to continue development of constraint support pricing, a process should be put in place for the creation and revision of constraint support prices and constraint support contracts (or the equivalent arrangements currently used) that clarifies the timing of their creation and review, and that expressly limits their application to generators and interconnections and solely for the purposes of:

- Moderating a generators' potential to abuse market power, and
- Providing compensation to existing generators that would not otherwise be viable given prevailing constraints, but where the system requires the retention of those generators.

Such modified boundary criteria and provisions for use of constraint support prices and contracts when combined with coordinated transmission planning, will, in our view, provide a good model for moving forward.

### 4.3 Recommendation 6

*6. NEM boundaries should be established for a 5 year period commencing no earlier than 3 years after the date of the final determination*

Ergon Energy has no issue with the principle of Recommendation 6. Having reviews every 5 years seems a more sensible timeframe than annual reviews, while allowing 3 years for implementations of the results is realistic. However, CRA does not address the problem of contingencies. What happens, for example, if at a boundary review it is decided to create a new boundary in response to some investment coming on line just before the boundary takes effect, but that investment gets delayed by several years? Will the creation of the boundary be conditional on prescribed events having transpired? What ever the outcome, this situation will complicate energy contracting in the NEM. Deviations between reality and the expectations at the time of a boundary review could materially change:

- the value of energy contracts,
- the coverage require, and
- the node at which they are defined.

Thus while Ergon Energy supports the concept of less frequent reviews, it is not sure how the recommendation will work in practice, or whether it will create a new range of unintended complexities and risks for the market.

Further, as noted above, we do not believe that a 5 year review process will be workable for constraint support prices and constraint support contracts, and request that more information be provided on this aspect of the proposal.

### 4.4 Recommendation 7

*7. Improve information available for potential investors concerning:*

*7.1 The likely evolution of congestion as part of information available to intending participants;*

*7.2 Broad indications of possible network augmentations that would pass the regulatory test or that will be required to meet reliability or security standards; and*

*7.3 Routine reporting of shadow prices at relevant nodes to inform the market of emerging conditions.*

Recommendation 7 needs to be broadened to make it clear that information should be available to existing market participants as well as new entrants.

We have concerns in regard to clause 7.2 in that we find it difficult to understand how an indication can be made that a hypothetical investment will pass the regulatory test. This could be quite demanding given that there may be a huge range of potential investments to examine, while each option examined is unlikely to exactly comply with any real proposal. Further, any investor would exercise caution in regard to any such indication, as it will have no bearing as to whether the actual proposal will pass the regulatory test.

In regard to clause 7.3, the shadow prices alone are not sufficient to assess the likely impact of a constraint support price/contract. Market participants would need to have both the constraint factor that will apply to them if such a constraint support price were applied, as well as information required to assess how that fixed factor compares with the dynamic impact that they actually have on the constraint. Constraint support prices and constraint support contracts are likely to be as contentious (particularly for generators) as fixed loss factors.

#### 4.5 Recommendation 8

*8. To ensure consistency between the application of the regulatory test and NEM boundary reviews, these processes should be augmented as follows:*

*8.1 In assessing the benefits of network investment, the regulatory test should consider whether boundary change or specific contracting/pricing of congestion would bring benefits either to dispatch or to alleviate congestion; and similarly*

*8.2 At each review of region boundaries the potential for new network not already declared as part of the planning process should be explored as part of consultation on a proposed boundary change.*

Conceptually, Recommendation 8 would not be unreasonable if the other recommendations were to be accepted.

However, Ergon Energy is of the view that the additional complexity created by Recommendation 8 will prove problematic. That body performing the regulatory test and the body performing the boundary reviews will have to “second guess” each others decisions based on hypothetical cases. The work load of this could be very great as, for example, the body performing boundary reviews has to predict regulatory test outcomes of all potential investments that might mitigate the need for a boundary, where different boundaries might apply depending on what investments actually go ahead.

Consider the situation where the body conducting the regulatory test believes that no boundary change will occur at the next review, and on that basis approves a new transmission investment, and the construction of that asset begins prior to the next scheduled boundary review. It may transpire that, in the judgement of the body doing the boundary review, the new transmission asset does not mitigate the need for a boundary change. However, given that such a decision could undermine the economics of the

new investment, there may be pressure to distort the boundary review process to reach a conclusion consistent with the regulatory test conclusions. Clearly, having two processes conducted at different times that must second guess each other creates a potentially significant regulatory risk for investors and market participants.

Some discussion and quantification of these issues would be helpful.

## 4.6 Overall Comments

Overall, Ergon Energy is of the view that the market is being presented with a conceptual model that:

- Is significantly under-developed;
- Is focussed too heavily on the view that locational prices are the panacea for all issues in the NEM;
- Includes features that seem quite arbitrary and do not appear to reflect a consideration of a wider set of options. Indeed, we would have preferred to have been presented a wide range of options rather than one;
- Has not been tested via long time horizon market simulations to assess its practical implications;
- Leaves a greater deal of flexibility as to how market participants will be treated with respect to constraint support pricing when new regions are not justified;
- Lacks any limits as to how much the market can change at each review; and
- Has the potential to rapidly move the market towards full nodal pricing, despite CRA's protestations that this is not a justifiable outcome.

Based on these observations and views, Ergon Energy finds it difficult to understand how anyone in the current market could make an informed decision on the proposed boundary review process other than to conclude that the regime has the potential to lead to radical changes in locational pricing signals. While having reservations, Ergon Energy is broadly supportive of the general directions implied by Recommendations 6, 7, and 8. However we have strong reservations about Recommendation 4 and are not at all supportive of Recommendation 5, and hence cannot support the overall package of proposals.

## 5 CONGESTION MANAGEMENT

### 5.1 Recommendation 4 revisited

This recommendation has been discussed previously and is repeated as it relates to the handling of congestion.

4. *Within the regulatory framework for transmission established for the NEM, on balance, an evolutionary region structure, reviewed at relatively lengthy intervals in parallel with a flexible congestion contracting/pricing regime is recommended*

Ergon Energy interprets “flexible congestion contracting/pricing” to mean CRA’s constraint support pricing and contracting regime. As noted elsewhere, we have no objection to the use of such instruments to fulfil roles for which contracts are already used in the NEM. However, because CRA has not proposed any restriction as to how far this regime could be employed, and because we see this as leading to nodal pricing, we cannot support the use of such contracts in the open ended, ill defined manner proposed by CRA.

## 5.2 Recommendation 9

9. *Subject to a development of details for implementation within the market, inter-regional pricing/contracting should be adopted as part of the package for a Stable Boundary approach.*

We are not clear as to what this recommendation actually means. Given that the recommendation is made within a section titled “Intra-Regional Contracting / Pricing” and that the section makes no reference to “inter-regional” issues, we suspect that Recommendation 9 should refer to “intra-regional pricing/contracting”. If this is the case then, as for Recommendation 4, we only support this to the extent that similar contracting arrangements are currently employed in the NEM.

If the recommendation is correctly worded, then we wonder if the proposal is that interconnection constraint support contracts replace the current Settlement Residual Auction. If this is the intent, then significantly more discussion is required in the report as to what this actually means in practice. What, for instance, happens to the settlement surpluses? Why must interconnection constraint support contracts be used as opposed to FTRs, SRAs or other arrangements, and what are the relative merits of each?

We are also curious at the use of the term “Stable Boundary”, given that this term does not appear in capitals elsewhere in the CRA report.

More information as to what this recommendation actually means is required before Ergon Energy can finalise its response.

## 5.3 Recommendation 10

10. *The MCE should request market authorities to develop proposals for implementation of intra-regional contracting/pricing mechanisms. The broad design of CSP/CSC regime presented in this report should be used as the basis for this development.*

In effect Recommendation 10 is stating that the market should adopt the broad approach of constraint support pricing and constraint support

contracting proposed by CRA, and only then, having adopted the concept, work on what the proposal actually means in practice. We would rather be presented with steps for taking this process forward. In our view, the following steps should be taken:

- Finalisation and implementation of the proposed changes to the dispatch process.
- Consideration of the very limited application of constraint support prices and contracts.
- Either abandonment of a boundary review process or a refinement of the existing process.
- Development of specific proposals for improving coordination between regulatory bodies and boundary review bodies so as to avoid the negative potential of the CRA proposals.
- Establishment of an RTO for the NEM.

## 5.4 Overall Comments

We do not believe sufficient detail or specificity has been provided for us to currently fully support the proposed congestion management regime. This is not to say that we could not support a version of the proposal with specific restrictions on what circumstances the regime can be applied in. Such restrictions would be intended to preclude the market shifting to nodal pricing by stealth. However, we would require more information to determine what the most desirable restrictions would be.

## 6 CONCLUSIONS

### 6.1 Summary of Reactions to Recommendations

The following table summarises Ergon Energy's position with respect to the recommendations. Additional comment is available in the sections above devoted to each recommendation.

<b>CRA Recommendation</b>	<b>Ergon Energy Reaction</b>
1 On the basis that no change to the current economic objective of the five-minute spot market dispatch process is made, NEMMCO should apply the Direct Physical Representation (DPR, or "fully optimised") form of constraints (Option 4/5) to all network constraints. The Code should be amended to confirm this.	It is appropriate to represent constraints in a correct and consistent manner.
2 Following resolution of the form of constraint equation NEMMCO should review if it believes a full network model is necessary in order to meets (sic) its obligations for system security.	If Recommendation 2 means that NEMMCO can add constraints to the dispatch and pricing model to satisfy its obligations, but that of itself Recommendation 2 does not

CRA Recommendation	Ergon Energy Reaction
	give rise to any constraint support prices or additional pricing regions, then we can accept this recommendation in principle.
<p>3 Concerns about inappropriate bidding behaviour should be referred to the relevant authorities. If it is deemed necessary:</p> <ul style="list-style-type: none"> <li>• NEMMCO should after due account is take of the impact on efficiency in the short and long term, when the existing derogation to the code expires in December 2004, be instructed to continue to impose a simple constraint on network transfers as a function of the settlement residues in the short term in preference to altering the form of network constraint; and</li> <li>• If and when new network elements that will create major network loops emerge are planned (sic) a mechanism external to the operation of the dispatch process should be investigated – intra-regional pricing and contracting mechanisms provide a ready mechanism for this.</li> </ul>	We consider this to be a rather empty recommendation.
<p>4 Within the regulatory framework for transmission established for the NEM, on balance, an evolutionary region structure, reviewed at relatively lengthy intervals in parallel with a flexible congestion contracting/pricing regime is recommended.</p>	Ergon Energy has numerous concerns in regard to the creation of new pricing regions, including exposing participants to effective locational prices without officially creating new regions. That said, we do see some potential benefit in very limited use of contracting to address market power issues with generators and to compensate generators that are providing ancillary services or which would otherwise not be viable. Our primary concern is that CRA's recommendations fail to place any upper limit on the extent to which these instruments can be used.
<p>5 At each review a transmission connection point should be (sic) become part of (sic) region where it can be demonstrated that compared to the next best alternative there is expected to be</p> <ul style="list-style-type: none"> <li>• An increase in economic efficiency of dispatch (including as a result of the treatment of inter-regional loss factors) within the NEM determined in accordance with an endorsed methodology, less demonstrable costs, exceeding \$1Mp.a; or</li> <li>• A change in locational price indicators</li> </ul>	Given the arbitrary nature of Recommendation 5, and the apparent lack of analysis of justification that has gone into it, we cannot support this recommendation.

CRA Recommendation	Ergon Energy Reaction
<p>sustained over the review cycle in excess of levels to be published annually that would provide indicative investments in generation plant an increase in annual revenue of 25% of reasonable new entrant costs for each</p> <p>Provided that</p> <ul style="list-style-type: none"> <li>• No region shall have a maximum demand of less than 200MW; and</li> <li>• A separate region shall not be created where in the reasonable opinion of the relevant authority there is little prospect of market based investment within the review period.</li> </ul>	
<p>6 NEM boundaries should be established for a 5 year period commencing no earlier than 3 years after the date of the final determination</p>	<p>Ergon Energy supports the concept of less frequent reviews, however we are not sure how the proposed process will work in practice, or whether it will create a new range of unintended complexities and risks for the market.</p>
<p>7 Improve information available for potential investors concerning:</p> <ul style="list-style-type: none"> <li>• The likely evolution of congestion as part of information available to intending participants;</li> <li>• Broad indications of possible network augmentations that would pass the regulatory test or that will be required to meet reliability or security standards; and</li> <li>• Routine reporting of shadow prices at relevant nodes to inform the market of emerging conditions.</li> </ul>	<p>Recommendation 7 needs to be broadened to provide more information to incumbent participants. The MCE needs to address the practical complexities associated with “indications” that a hypothetical augmentation will pass the regulatory test. Shadow prices alone are not enough information, participants need information on the quantities to which those shadow prices will be applied, including both actual dynamic values and the fixed values assumed for pricing purposes.</p>
<p>8 To ensure consistency between the application of the regulatory test and NEM boundary reviews, these processes should be augmented as follows:</p> <ul style="list-style-type: none"> <li>• In assessing the benefits of network investment, the regulatory test should consider whether boundary change or specific contracting/pricing of congestion would bring benefits either to dispatch or to alleviate congestion; and similarly</li> <li>• At each review of region boundaries the potential for new network not already declared as part of the planning process should be explored as part of consultation on a proposed boundary change.</li> </ul>	<p>Ergon Energy is concerned that Recommendation 8 will create complexities for the boundary review process and the application of the regulatory test. Some quantification of the issues we raise would be helpful.</p>
<p>9 Subject to a development of details for</p>	<p>More information as to what this</p>

CRA Recommendation	Ergon Energy Reaction
implementation within the market, inter-regional pricing/contracting should be adopted as part of the package for a Stable Boundary approach.	recommendation actually means is required before Ergon Energy can finalise its response.
10 The MCE should request market authorities to develop proposals for implementation of intra-regional contracting/pricing mechanisms. The broad design of CSP/CSC regime presented in this report should be used as the basis for this development.	Recommendation 10 is stating that the market should adopt the broad approach of constraint support pricing and constraint support contracting proposed by CRA, and only then work on what the proposal actually means in practice. We find this an unsatisfactory choice, and would rather see the constraint support pricing/contracting regime limited in use, while the market focuses on improving dispatch efficiency in the short term. In the longer term, but as quickly as possible, we would like to see the establishment of an RTO for the NEM.

## 6.2 Concluding Remarks on the CRA Proposals

While there are many potential options for the development of the NEM, the CRA study presents just one. The single option presented by CRA is highly theoretical in nature and still at an early stage of development. While very limited modelling has been done, no detailed and comprehensive simulation of the implications of the CRA proposal has been presented. The lack of presentation of evidence makes many features of the CRA proposal appear quite arbitrary.

Ergon Energy finds it very difficult to understand how the industry is expected to reach an informed decision based on the limited information presented and the rather open-ended nature of the CRA recommendations. Further we believe that the presentation of the CRA recommendations, and CRA's protestations that nodal pricing is not justified (despite CRA championing the approach in the past), obscures the potential implications of the adoption of their proposals. As a consequence, the industry and jurisdictions may be misled into accepting a regime that they have previously rejected, namely full nodal pricing.

In an effort to redress the limitations of the CRA report, Ergon Energy has had to commission an independent detailed modelling study of the implications of regional changes to Queensland. This study showed that:

- Increased numbers of pricing regions will have little material impact on energy prices in the Queensland market.
- To the extent that there are differences, these differences are likely to lead to an increased cost to consumers unless firm transmission

hedges are available. We are not aware of any satisfactory regime for implementing firm transmission hedges.

We conclude that the benefit of having more regions in Queensland is small, but, given the absence of firm hedging arrangements there will be a real increase in costs to consumers. Consequently we do not believe that a shift to more regions is justifiable.

Further, Ergon Energy has devoted some effort to understanding the implications of the theory of constraint support prices and contracts. We see nothing in the CRA recommendations that would stop the market rapidly evolving towards full nodal pricing even if no new regions are created. CRA devote a huge amount of report content to present a new concept which is basically just a repackaging of the theory of nodal pricing, and which could be equally implemented using nodal pricing models. The examples presented by CRA, which only involve one or two generators in a region and one or two constraints, divert attention from the fact that the CRA approach could be applied to hundreds or thousands of constraints simultaneously.

We believe that there are numerous risks in adopting the CRA recommendations. In particular:

- It is regime whereby different participants may be subject to different (and as yet not fully developed) pricing rules, and different hedging arrangements, depending on their location in the network. Not only is this a risk, but it could be regarded as discriminatory depending on exactly how the regime is implemented.
- The regime has the potential to be applied to individual generating plant by NEMMCO, or some other agency, without necessarily being the result of commercial negotiation. We would expect that this would be an unattractive and possibly unacceptable risk for many generators.
- There is nothing in CRA's recommendations that prevent constraint support prices being applied to retailers. Ergon Energy, as a retailer, has consistently opposed such an approach because of the increased risks this creates for retailers.
- There are no adequate proposals for firm transmission hedges for addressing the basis risk created by increased locational pricing. We expect the market will be left exposed to at least some of these risks.
- The impact that each generator (and possibly load) has on a constraint must be determined by some agency, and must be determined ahead of time, and could be very difficult to determine reliably in the context of complex transmission loops. This is a regulatory risk for anyone subject to these instruments.
- The parameters used in constraint support prices and contracts will almost certainly have to be updated more frequently than the proposed 5 year boundary review period. This means that the risks

associated with reviews of these instruments will be encountered more frequently than stated by CRA in the context of boundary reviews, and may result in financial losses with respect to pre-existing energy contracts. This creates very serious risks for anyone subjected to constraint support prices/contracts.

- New investors may be told the outcome of a regulatory test based on the assumption that regional boundaries will be changed at the next boundary review, but a different boundary change could occur in reality. This creates risks for investors.
- Retailers face risks that they will be required to offer services to retail customers at uniform prices while purchasing in the wholesale market at a range of different prices. This leaves retailers exposed to risk.

In electricity markets, risks create costs, and costs ultimately get passed to end users. Our modelling analysis has shown that just one of the points listed, the lack of firm hedging arrangements, can result in Queensland consumers paying more for energy as the number of regions is increased. We have not quantified the costs of the other risks but they must logically further increase costs to consumers.

We conclude therefore that the adoption of the CRA proposals is likely to increase costs to the market. But what are the benefits of the CRA proposal? While more locational pricing may promote different generator investment patterns in theory, this view must be tempered by other generator considerations, such as fuel availability and transmission access. We argue that the current NEM model provides appropriate signals for generators given adequate transmission capacity. Further, our analysis of the Queensland situation suggests that there will be little opportunity for locational energy prices to significantly impact generator investment decisions for at least the next decade.

We believe that the real issue facing the NEM is that of transmission investment, not locational pricing. Without adequate transmission capacity the NEM will never be able to adequately address transmission issues.

Ergon Energy would rather see that no significant change be made to the energy market, but instead we would like to see a move towards developing an independent Regional Transmission Organisation (RTO) that plans transmission investments throughout the NEM. The implementation of an RTO would streamline transmission planning and investment across the NEM and allow optimised transmission investment. We have argued that such a model will address the transmission constraint issues in the NEM more effectively, more reliably, and at a significantly lower risk than varying regional boundaries or using constraint support prices.

## 6.3 The Way Forward

In this section we present our view as to how this process should continue. In the short term we would support the following steps being taken.

- A: Continued work and implementation of the proposed changes to the dispatch process.
- B: Continued work to assess the application of constraint support prices and constraint support contracts that could be used: in place of existing ancillary service contracts; to support generators that would otherwise be made unviable by intra-regional constraints, and to mitigate generator market power.
- C: Either abandonment of a boundary review process or a refinement of the existing process such that reviews are conducted on a timeline consistent to that proposed by CRA, but with a Net General Equilibrium cost test used as a basis of assessing the gains to be made from regional boundary changes.
- D: Development of specific proposals for improving coordination between regulatory bodies and boundary review bodies so as to avoid the negative potential of the CRA proposals.

In the longer term, but as quickly as possible, we would like to see the implementation of a NEM RTO which would coordinate the planning of transmission investment and use a competitive process to determine which TNSPs actually design, build and maintain the assets. The regulatory test process could then be abandoned in favour of a simpler public benefit test. Under this approach, we would not envisage the need for further energy market reforms.

## APPENDIX 1: CRA'S PROPOSAL AND FULL NODAL PRICING

This appendix presents an equation orientated explanation as to why we believe that the CRA proposal is just a different way of presenting nodal pricing. A simpler, but equivalent, explanation is provided in the body of the report.

Figure A provides a representation of a single region.

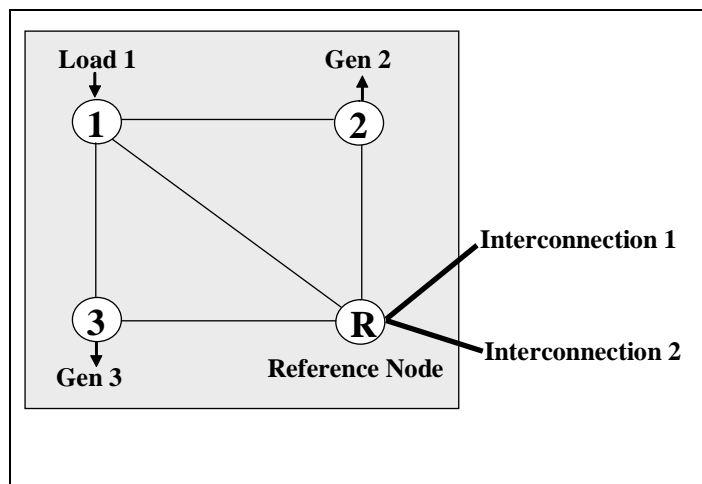


Figure A: A Representation of a Region

The region in Figure 1 has the following features:

- The region contains a Reference Node. Losses and prices are defined relative to this point.
- The region is connected to two other regions (not shown) via interconnections.
- Node 1 is purely a load node.
- Nodes 2 and 3 are generator nodes.
- The transmission network shown is intended to be a generic representation of a general network.

In addition to the energy balance and transmission limits applicable to this region, we assume that there are other “non-energy” constraints imposed on the problem, such as a requirement that the generators and interconnections maintain adequate spinning reserve.

To understand the CRA proposal, it is useful to consider the form of prices that would apply to this problem if full nodal pricing were to be employed. Nodal pricing defines the energy price ( $ER_x$ ) at a particular node ( $x$ ) to be the sum of the following terms:

- The price at the reference node ( $ER_R$ ) modified by the marginal impact on losses defined relative to that reference node ( $L_R$ ) stemming from an incremental change in net injection ( $P_x$ ) at the node. An increase in net injection corresponds to increased generation or decreased load. Thus the impact of losses on the

nodal price at node x is:<sup>6</sup>

$$EP_R \left(1 - \frac{\Delta L_R}{\Delta P_x}\right)$$

- The impact of each intra-regional constraint (i) on the price at the node, where this is the constraint shadow price ( $\phi_i$ ) multiplied by the impact of a change in net injection ( $P_x$ ) at node x on the constrained quantity ( $RC_i$ ).  $RC_i$  could be a constrained transmission line flow. Constraint i's contribution to the nodal price at node x is:

$$-\sum_i \phi_i \frac{\Delta RC_i}{\Delta P_x}$$

- The impact of each inter-regional constraint (j) on the price at the node, where this is the constraint shadow price ( $\mu_j$ ) multiplied by the impact of a change in net injection ( $P_x$ ) at node x on the constrained quantity ( $IC_j$ ).  $IC_j$  could be a constrained interconnection flow. Constraint j's contribution to the nodal price at node x is:

$$-\sum_j \mu_j \frac{\Delta IC_j}{\Delta P_x}$$

- The impact of each non energy constraint (k) on the price at the node, where this is the constraint shadow price ( $\gamma_k$ ) multiplied by the impact of a change in net injection ( $P_x$ ) at node x on the constrained quantity ( $NEC_k$ ). Depending on the constraint,  $NEC_k$  could be a constraint related to Frequency Control Ancillary Services, other ancillary service constraints, or constraints to correct market power issues. Constraint k's contribution to the nodal price at node x is:

$$-\sum_k \gamma_k \frac{\Delta NEC_k}{\Delta P_x}$$

If we consider the two generator nodes and one load node in our example region, the constraints that define their prices are as follows:

$$EP_{L1} = EP_R \left(1 - \frac{\Delta L_R}{\Delta P_{L1}}\right) - \sum_i \phi_i \frac{\Delta RC_i}{\Delta P_{L1}} - \sum_j \mu_j \frac{\Delta IC_j}{\Delta P_{L1}} - \sum_k \gamma_k \frac{\Delta NEC_k}{\Delta P_{L1}}$$

$$EP_{G2} = EP_R \left(1 - \frac{\Delta L_R}{\Delta P_{G2}}\right) - \sum_i \phi_i \frac{\Delta RC_i}{\Delta P_{G2}} - \sum_j \mu_j \frac{\Delta IC_j}{\Delta P_{G2}} - \sum_k \gamma_k \frac{\Delta NEC_k}{\Delta P_{G2}}$$

$$EP_{G3} = EP_R \left(1 - \frac{\Delta L_R}{\Delta P_{G3}}\right) - \sum_i \phi_i \frac{\Delta RC_i}{\Delta P_{G3}} - \sum_j \mu_j \frac{\Delta IC_j}{\Delta P_{G3}} - \sum_k \gamma_k \frac{\Delta NEC_k}{\Delta P_{G3}}$$

Other terms constraining  $\phi_i$ ,  $\mu_j$ , and  $\gamma_k$  in terms of generator costs.

---

<sup>6</sup> The use of positive and negative signs in this and subsequent mathematical terms is not material to the example. The signs used are a function of whether the prices are defined as payment per unit of injection or off-take and the conventions applied in defining shadow prices. The conventions used here are based on those used in the report "Dispatch Based Pricing", Transpower New Zealand Limited, 1995.

Given the generator costs and the marginal impact that each (optimised) nodal injection has on each constraint, we can derive the nodal prices using these equations.

We now use these equations to highlight why the CRA proposal is effectively nodal pricing.

Under the CRA proposal the energy price determined at each node in the region would be:

$$EP_{L1} = EP_R \left(1 - \frac{\Delta L_R}{\Delta P_{L1}}\right)$$

$$EP_{G2} = EP_R \left(1 - \frac{\Delta L_R}{\Delta P_{G2}}\right)$$

$$EP_{G3} = EP_R \left(1 - \frac{\Delta L_R}{\Delta P_{G3}}\right)$$

That is, the energy price at each node would just be the loss adjusted reference node price. The reference price would reflect the cost of supply and demand within the region, and already accounts for inter-regional trade costs.

CRA proposes the use of constraint support prices. CRA develops the theory for these under the assumption that demand is fixed, and hence they ignore demand related terms. In the case of an intra-regional constrained quantity  $RC_i$ , the constraint support prices for each of the generators in the region would be:

$$CSP_{G2} = -\phi_i \frac{\Delta RC_i}{\Delta P_{G2}}$$

$$CSP_{G3} = -\phi_i \frac{\Delta RC_i}{\Delta P_{G3}}$$

If an increase in generator 2's output takes pressure off this constraint, while an increase in generator 3's output puts pressure on the constraint, then we would expect the constraint support price paid to generator 2 to result in generator 2 earning more money (causing it to face a higher effective price) while generator 3 earns less money (causing it to face a lower effective price).

CRA correctly argue that this approach allows Generator's 2 and 3 to effectively receive signals consistent with nodal pricing incentives. While we agree with this, we believe CRA's reports to be misleading in that the examples presented tend to focus on one-or-two constraints. CRA note, however, that multiple constraints could be bundled into a single constraint support price. If we were to bundle all constraints in this manner we would have:

$$CSP_{G2} = -\sum_i \phi_i \frac{\Delta RC_i}{\Delta P_{G2}} - \sum_j \mu_j \frac{\Delta IC_j}{\Delta P_{G2}} - \sum_k \gamma_k \frac{\Delta NEC_k}{\Delta P_{G2}}$$

$$CSP_{G3} = -\sum_i \phi_i \frac{\Delta RC_i}{\Delta P_{G3}} - \sum_j \mu_j \frac{\Delta IC_j}{\Delta P_{G3}} - \sum_k \gamma_k \frac{\Delta NEC_k}{\Delta P_{G3}}$$

The effective price then send by the market participants would be:

$$EP_{L1} = EP_R \left(1 - \frac{\Delta L_R}{\Delta P_{L1}}\right)$$

$$EP_{G2} = EP_R \left(1 - \frac{\Delta L_R}{\Delta P_{G2}}\right) + CSP_{G2}$$

$$EP_{G3} = EP_R \left(1 - \frac{\Delta L_R}{\Delta P_{G3}}\right) + CSP_{G3}$$

But if we substitute for the constraint support prices we end up with:

$$EP_{L1} = EP_R \left(1 - \frac{\Delta L_R}{\Delta P_{L1}}\right)$$

$$EP_{G2} = EP_R \left(1 - \frac{\Delta L_R}{\Delta P_{G2}}\right) - \sum_i \phi_i \frac{\Delta RC_i}{\Delta P_{G2}} - \sum_j \mu_j \frac{\Delta IC_j}{\Delta P_{G2}} - \sum_k \gamma_k \frac{\Delta NEC_k}{\Delta P_{G2}}$$

$$EP_{G3} = EP_R \left(1 - \frac{\Delta L_R}{\Delta P_{G3}}\right) - \sum_i \phi_i \frac{\Delta RC_i}{\Delta P_{G3}} - \sum_j \mu_j \frac{\Delta IC_j}{\Delta P_{G3}} - \sum_k \gamma_k \frac{\Delta NEC_k}{\Delta P_{G3}}$$

That is, the prices seen by the generators are just the full nodal prices developed above.

While loads are not obviously subject to constraint support prices, this is only because CRA has made the assumption that loads are fixed, so that they have no impact on constraints on the margin. If this assumption was to be abandoned (and the assumption is not strictly embodied in CRA's recommendations) then the effective price seen by both generators and loads would be those seen under full nodal pricing, even though the number of regions may not have been expanded.

It is also important to note that the equivalency between nodal pricing and the CRA approach as determined here assumes that the contribution of each market participant to a constraint is determined dynamically under both approaches. In reality, it seems more likely that a full nodal pricing model would use some form of power flow that accurately reflects the real-time contribution of a market participant to each constraint, whereas the CRA approach would use some form of "average" contribution. If the contribution of a market participant to a constraint is fixed for a year based on some expectation of power flow patterns, and different power flow patterns occur, then this causes wealth to be redistributed between market participants. Consequently, the CRA approach is likely to create an additional unmanageable risk that market participants would not face under a more typical full nodal pricing regime.

## APPENDIX 2: THE IES REPORT

