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Australian Energy Market Commission
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Congestion Management Review: Issues Paper

The Energy Retailers Association of Australia (ERAA) welcomes the opportunity to provide a submission in response to the Australian Energy Market Commission (AEMC) *Congestion Management Review: Issues paper*. The ERAA is an independent association representing ten retailers of electricity and gas throughout the National Electricity Market (NEM) and the National Gas Markets. ERAA members collectively provide electricity to over 98% of customers in the NEM and are the first point of contact for end use customers for both Gas and Electricity.

Congestion on the network is a key concern for retailers as it increases trading risk, reduces competitive electricity supply and increases electricity purchase costs. In light of this concern we commissioned a significant piece of research in 2003 reviewing the way transmission congestion is managed in overseas electricity markets and the implications of this for congestion management in the NEM. The ERAA also commissioned work to compare the CSP/CSC approach with the findings of our study of overseas approaches. Both pieces of work have significantly increased our understanding of the issues and we urge the AEMC to carefully consider these papers in the current review. To summarise them briefly:

A review of International Approaches to Electricity Transmission Pricing.

- This document analyses transmission pricing and congestion management approaches in 9 major Electricity Markets around the world. From these markets are derived five alternative approaches, or *strawmen*, for potential application in the NEM, with the advantages and disadvantages outlined for each. The ERAA does not specifically advocate any one particular approach; however, the AEMC may consider these a useful reference in understanding some of the possible strengths and weaknesses of different options.

Review of Interconnector Support Proposal

- This document reviewed in detail a proposal developed by Charles River Associates (CRA), commissioned by NEMMCO in 2003, dealing with the rationing of access to congested transmission capacity where an interconnector and generator interact. This was known colloquially as the "gatekeeper" proposal and was further generalised by CRA into its Constraint Support Pricing and Contracting (CSP/CSC) framework, which it developed for the MCE in September 2004.

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The ERAA draws the attention of the AEMC to this paper as it expands on some of the key issues addressed in the CRA report. In particular it provides views on the various efficiency impacts of different CSC allocations under the "unsupported", "natural" and "contract" approaches considered by CRA.

Scope of Review

The paper *A review of International Approaches to Electricity Transmission Pricing* showed that the cost of supplying a customer at a point on the transmission network is:
Consumer Cost = Energy Cost + Transmission Cost + Risk Management Cost

Consequently, along with the appropriate management of congestion; the pricing of transmission services and rules for new transmission investment are critical to the delivery of an efficient supply to consumers. We see the essential elements of the market's framework as including:

- Where congestion occurs, a mechanism to build it out (where efficient to do so);
- That the costs of congestion are appropriately allocated among participants; where possible, to those that cause it.
- Where efficient congestion remains, a mechanism to price it explicitly.

There is a danger that the division of scope between this review and the AEMC's Transmission Pricing & Revenue Review (Pricing Stream) may lead to a poor overall outcome. We suggest the AEMC consider ways of merging these two reviews where overlap exists.

Specific Needs of Retailers

It is the ERAA's view that whatever approach to transmission pricing and congestion management is adopted provides an appropriate balance between static, transactional and dynamic efficiency. In this context there are some specific concerns retailers wish to emphasise:

- **The ability to reasonably simply manage customer load and understand its risks**.

  Rapid partitioning of our customer bases into multiple price regions would present major challenges operationally, in risk management and in providing a Regulated price/service offering to all customers. As the vast majority of our customers are insensitive to electricity price it is unlikely that there would be much efficiency benefit in such a move.

  We recognise that the regional model simplifies retailing, whereas generators necessarily face the volume risk and therefore must consider its complexities. We believe that this division of risk is appropriate considering the better understanding generators have of their specific network circumstances and their much greater ability to respond to it.

- **The ability to effectively and reasonably simply contract with generators**.

  Retailers' core function is to manage customers' price risk by structuring contracts with multiple generating firms. A key consideration in the Congestion Management Review is how best to introduce price signals around intra regional constraints to elicit efficient behaviour responses. However, introduction of such signals will also create new financial risks for generators which will affect their ability to provide instruments to retailers. Effective locational hedging arrangements, possibly CSCs must be developed to allow generators to manage this risk. The arrangements must not degrade the total amount of customer load that can be hedged by generators whilst also reflecting a fair and efficient allocation of these instruments among generators.

- **Effects upon existing instruments for Managing Price Risk**

  Most existing generator/retailer instruments include re-opening provisions in the event there is a change to the market pricing arrangements for one party with the objective of restoring the original economic position. For example, a generator CSP arrangement could potentially trigger a re-opener.

  Inevitably such a re-opener will incur costs, especially if the economic change is contentious. These costs are likely to be minimised in the presence of a congestion management regime where:

  -Effects upon parties' existing economic value in trading are minimised; and
  -Where economic effects occur, that the cost of that effect is readily identifiable
  (for example through the price of an auctioned instrument).

- **Retailer Implementation costs**

  Retailers would be very concerned if they were required to bear significant new systems costs to manage additional risks imposed by new congestion management measures. Whatever measures are implemented should take appropriate consideration of such system costs.

- **NEMMCO implementation costs**.

  Retailers fund the majority of NEMMCO costs and therefore are keenly interested in their minimisation. We are however mindful that poor locational pricing and congestion management can also lead to increased costs for NEMMCO to manage which ultimately fall on participants.

Importantly, the ERAA is pleased that the CSC/CSP concept proposed by CRA and trialled in the snowy region had low NEMMCO and retailer system costs[1]. However we emphasise that the details regarding how best to implement CSPs and allocate CSCs remain critical and unresolved.

We also pose an open question to the AEMC that should it propose a congestion management regime, genuine thought should be given as to whether specific or generalised application best meets our concerns above.

Responses to AEMC Questions

We have attempted to address those questions in the paper of most importance to us:

1. *Do existing constraints have a material effect on the efficiency of the NEM? What is the nature and materiality of these constraints? Why is it that these constraints have not been addressed to date? Are there specific points of congestion that should be addressed in advance of the establishment of a new congestion management regime?*

2. *Given the development of the NEM and the recommendations of reviews undertaken to date, what are the significant priority issues for this Review?*

See the attached papers on these matters.

3. *What are the key questions the Commission should seek to examine quantitatively as part of the Review? What key factors should the Commission take into account in this modelling analysis?*

The ERAA is doubtful that detailed quantitative modelling will provide much insight into its deliberations regarding which scheme to propose, as the input data will necessarily be subject to many arbitrary judgements. It is often best to simply propose the best theoretical platform for the market to operate upon and make a qualitative assessment over whether the benefits this platform creates outweighs its implementation costs.

Should the AEMC perform a quantitative assessment, the modelling should as far as possible assess impacts of alternative measures on dispatch efficiency, generator competition (are prices more likely to reflect marginal costs), basis risk and probable behavioural responses on patterns of dispatch (in terms of whether more or less is generated by different generators in response to price changes and the quantum of such changes) and investment. AEMC should attempt to assess the impact upon all parts of the production chain described above. It is also critical to appropriately assess potential system costs and possible implications for trading risks of the congestion measures adopted.

[1] The ERAA has provided the AEMC some documentation reviewing the success of the "snowy trial".

7. How material are the reductions in dispatch and pricing efficiencies due to the management of negative settlements residues under the current arrangements? How can they be quantified?

13. Does the current design of IRSR units impact the ability of participants to efficiently manage inter-regional price risk?

24. To what extent will firming up IRSRs facilitate inter-regional trade? What is the best approach to firming up IRSRs and how would this work?

26. What would be the effect of ceasing NEMMCO intervention to manage counter price flows? To what degree does this depend on other factors such as the region boundary criteria and process?

27. How should negative settlements residues be funded? Should the current process of offsetting negative residues with positive residues within the current billing week be continued or changed?

Inter-regional settlement residue units are a key facilitator of trade in the NEM and the ERAA strongly supports improving their effectiveness. There is nothing wrong with the design of the IRSR units per se, and the market can repackage them as it wishes, the key concern is the reliability of the settlement residue stream as an effective inter-regional hedge. This unreliability comes about from three issues:

- The physical unreliability of the transmission system itself. ERAA recently provided data to the AEMC transmission revenue review showing that the vast bulk of price separation events are caused by transmission not operating to installed capacity which results in the IRSR instrument failing at the time retailers' need it. This is best addressed through market based incentives upon transmission performance.
- Intra-regional congestion affecting interconnectors. This is potentially an area where a congestion management regime could be effective, and we observe a stabilisation of IRSRs in the presence of the snowy trial.
- The clamping of inter-connectors to avoid negative residues. Although the incidence of negative residues should be greatly reduced where a congestion management regime is available, we recognise there will still be some potential for these as a natural outcome of dispatch. ERAA notes market debate regarding a number of potential solutions, all of which are superior to interfering with inter-regional trade.

Whilst the ERAA would support firmer IRSRs, we do not support firming via "artificial" means such as via a customer uplift which would create an unhedgeable risk to retailers. The ERAA recommends addressing these problems at their true source.

As an aside, we note that the regional boundary stability that a congestion management scheme will allow should permit consideration of a longer IRSR contract term that could have significant risk management benefits.

11. Do market participants face problems in managing risk due to the nature of the instruments available, or the liquidity of market for those instruments? If so, how are those problems related to the current approach to congestion management?

Retailers manage risk in the current regional market environment by obtaining both firm and non-firm supply offers for the current customer nodes in the NEM. As stated above, a rapid disaggregation of customer regions would present great challenges and could undermine the liquidity of trade in the NEM, particularly if suitable hedging instruments are not developed concomitantly.

Retailers recognise that introducing an element of locational pricing may be necessary to achieve efficient generator responses to congestion; and critically, by its nature that this will expose them to additional risk (in part to encourage them to engage in congestion reducing behaviour). An appropriately conceived CSC framework will be critical for generators to be able to mitigate such risks.

The volume of such hedging instruments should be maximised to the extent that the transmission system can support it. The total volume of CSCs and IRSRs available should be no less that the total physical generation capacity that can be dispatched onto the network.

18. Is the proposed 'staged approach' to congestion management an appropriate framework? Is it the most effective response to those problems? Is it technically and commercially feasible?

The "staged approach" is attractive in that it appears to address congestion in a graduated manner, from least cost to highest cost measures, which may be an efficient approach for dealing with congestion as it seeks to minimise disruption and cost to the market over time. However, trigger levels would need to be identified for each stage which could create uncertainty with regard to when particular measures may be implemented (for example, what would define "material" congestion justifying the introduction of a CSP/CSC regime).

By way of contrast, the research material we have attached to this submission identifies a number of possible congestion pricing designs which are envisaged to be rolled out broadly across the market in a single implementation step. The uncertainty identified above is therefore avoided. However, the AEMC will need to weigh the overall cost-benefits of a staged approach, as envisaged by the MCE, versus a once off complete roll-out canvassed in the attached material. The ERAA has no specific preference for one approach over the other and awaits further analysis by the AEMC of the likely implementation costs and benefits of each before providing more definitive views.

20. Are the costs of an interim congestion regime (discussed in greater detail below) clearly lower than the costs associated with region boundary change?

Prima facie the ERAA considers this to be the case as no new pricing reference nodes are created. New pricing nodes require considerable changes in systems, contracts and overall risk management systems for both retailers and generators. A CSP/CSC regime requires changes in settlements for generators only, which can be far more easily implemented without the need for significant systems changes or alterations to existing trading “hubs”.

The “interim” congestion regime would in fact appear to address all the issues that would make a regional boundary change desirable, in fact it could allow the aggregation of existing regions.

> *21. What triggers should be considered for the introduction of various congestion management tools under a staged approach? Which institutions should be responsible for recommending and approving the introduction of congestion management tools at each stage?*

A transparent cost/benefit approach including industry consultation is recommended. NEMMCO would appear best positioned to manage the task.

> *28. Are constrained-on payments an appropriate solution to generators being paid regional reference prices less than what they offer? If so, what principles should apply for determining the size of payments, who should apply them and how should they be funded?*

> *29. Would the funding of constrained on payments be likely to introduce a material financial risk for participants making the payments? How could this risk be managed?*

The discussion of constrained-on payments seems inconsistent with the thrust of the Issues paper that prefers a CSP/CSC regime in areas of congestion. The regime should eliminate the concept of being “constrained-on”. Retailers would be very concerned about a levy to pay generators for being constrained-on that we could not hedge. Such arrangements in other markets have been subject to market power concerns.

> *34. Is the allocation of CSCs a necessary element of a CSP/CSC regime, or would it be practical to introduce CSPs without simultaneously allocating CSCs?*

> *35. If CSCs are a necessary component, what is the optimal way to allocate CSCs? What effect will this have on the ability to introduce CSPs rapidly and flexibly?*

Simultaneous creation of CSCs are necessary for both risk management (see earlier discussion) and settlement balance.

ERAA has not formed a definitive position on the question of how such hedging instruments should be allocated; e.g. through auction, grandfathering or on some administratively determined sharing basis, but we recognise that this is an important policy decision on which the MCE will need to show leadership. We recognise that it requires a balance of the AEMC’s desires to:

- Promote competitive investment in generation;
- Promote locational efficiency of that investment; and
- Minimise regulatory disruption.

Although most NEM congestion affects generators by limiting their volume, there are some unusual circumstances of generation being constrained on in load rich zones. These circumstances may permit an exercise of market power that would result in the Constraint Support Price being very high. On its own, the CSP arrangement would not be self-funding. ERAA would oppose unhedgeable and volatile levies being passed onto market customers. If a commensurate CSC were to operate, it would have to be *negative,* i.e. a liability upon the generator.

We have considered this matter and can offer the following observations.

In the status quo, such generators are often required to be constrained on at low regional prices, potentially below even their marginal cost. They remain viable due to:

1. Refusing to operate, thereby provoking a NEMMCO direction that is compensated via an independent expert's determination of a fair value; and/or

2. Network Support Agreements (NSAs) negotiated over a long-term with the TNSP to provide local network support services;

ERAA believes the first mechanism is poor, as it is:
- Inefficient, costly and not market-based;
- Market power issues remain;
- Results in an unpredictable levy for market customers;
- More difficult for NEMMCO to manage security;
- Fails to provide a strong incentive for generator reliability; and
- Fails to encourage new entrants.

The second mechanism lessens the generator's market power by allowing the TNSP to consider alternatives. The recovery via TUOS is more manageable by market customers. However we recognise that as it is not market based, it does not necessarily have the benefits of exposing the generator (or new entrants) to a sharp locational signal.

The best solution may be to subject the generator to a CSP and allocate incumbents a *negative* CSC. However simultaneously the generator would need some amount of Network Support Agreement, i.e. a smeared long-term payment, to ensure its financial viability. Presuming it remains financially viable, the negative CSC would encourage the generator to be reliable whilst also discouraging its exercise of market power.

ERAA has not concluded what the best approach to achieve this solution.

> *36. Is it important to the design of a congestion management regime whether or not CSCs are firm? If so, what issues should the AEMC consider in reaching a view on the appropriate nature of CSCs?*

While firm CSCs may be desirable in principle we are unclear as to how such firmness may be guaranteed and would be very concerned if it would require an unhedgeable customer levy.

> *38. How can the Commission best draw on the partial Snowy CSP/CSC trial to evaluate the costs and benefits of the use of CSP/CSCs? How can the Commission best draw on the Snowy CSP/CSC trial to consider modifications to the proposed design of CSPs and CSCs?*

ERAA has provided a research paper on this matter already to the AEMC.

Dissenting Position

Ergon Energy does not endorse this submission.

Ergon Energy believes network congestion is a significant issue for Retailer's given the resultant trading risks, inefficient market dispatch and overall increased costs. However, Ergon Energy does not support the use of CSP/CSC applications for points of congestion given the prices effectively seen by market participants are 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.

Furthermore, a CSP/CSC arrangement will not deliver significant market benefits relative to the status quo as in many cases this arrangement will suffer from the same limitations.

These issues are addressed in further detail in Ergon Energy's separate submission.

Should you have any queries on the content of this submission, please contact me on (02) 9369 4296.

Yours sincerely,

[Transmitted electronically]

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A Review of International Approaches to Electricity Transmission Pricing

August 2003

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1 Introduction

1.1 Objectives

This paper has been prepared for the Energy Retailers Association of Australia (ERAA). Its reports the findings of an international review of transmission pricing[1] in wholesale electricity markets, with the specific aims of:

- examining how locational marginal pricing is used and the rules that apply to its use;
- examining any associated transmission rights and how they are defined, issued, traded, settled and underwritten;
- examining any linkages between these rights and transmission access, pricing, operations and investment;
- identifying the benefits and problems of the approach in that market; and
- critically assessing whether the models could be applied to the NEM.

Based on this review, it aims to identify a "preferred" transmission pricing model for the NEM and what would be required to design, implement and operate such a model.

1.2 Markets Reviewed

The markets that have been reviewed as part of this project are shown in Table 1 below.

Location	Market Name	Start
Australia	National Electricity Market	1998
New Zealand	New Zealand Electricity Market	1997
Philippines	Wholesale Electricity Spot Market	2004
Korea	Two-way Bidding Pool	2004
Singapore	New Electricity Market	2003
New England	Standard Market Design	2003
PJM	PJM	1997
California	MD02	2005?
Ontario	Independent Market Operator	2002

Table 1: Markets included in this Review

It will be seen that most of these markets have either yet to commence, have only recently commenced (Ontario), or have recently been redesigned (New England, Singapore, California). The redesigns are primarily concerned with improving the transmission pricing arrangements. The exceptions are PJM – which did redesign its transmission pricing some time ago – and Australia and New Zealand, which are actively considering ways to improve transmission pricing. Thus, with the exception of Ontario, every market that has commenced has either redesigned or is considering redesigning

[1] As is explained in section 2, "transmission pricing" in this paper refers to locational pricing of both spot energy prices and transmission services prices.

its transmission pricing arrangements. This demonstrates both the importance and the difficulty of getting these arrangements right.

1.3 Structure of Report

As one would expect, there is substantial overlap and common ground between the various market designs, so it would be long-winded to describe each market's arrangements in detail. Instead, this report categorises these alternative designs by firstly breaking transmission pricing down into four distinct elements, and then identifying and describing the different design options used for each element. Each market design can then succinctly be described in terms of which option has been chosen for each element. For example, the Australian NEM can be described as having "zonally modelled spot prices, flowgate option hedges with local non-firmness, network service priced using deemed-matching and distributed revenue allocation".[2]

To assess which arrangements could and/or should be implemented in the NEM, five "straw men" are developed. These are hypothetical, internally-consistent designs which cover the full spectrum of options identified in the reviewed markets and have been designed to be applicable to the Australian situation. They are then evaluated against specified market objectives to identify which model might be preferred under various assumptions.

The report is structured as follows:

- Section 2 of this report describes the market objectives.
- Section 3 describes the transmission pricing elements and the different design options used for each element.
- Section 4 defines the straw men and Section 5 then assesses these against the specified objectives.
- Appendices A to C provide more technical detail on transmission spot pricing and hedging arrangements.
- Appendix D describes the different design options used in each of the market studied.

[2] All of these terms are described and explained in the body of this report. They are just used here to demonstrate the advantages of this "taxonomic" approach to defining market designs.

2 Transmission Pricing Objectives

2.1 Introduction

To evaluate the different approaches to transmission pricing, it is important to state the objectives. These are considered to be:

- efficient use of the transmission network,
- ability to manage transmission price risk,
- efficient development of the transmission network,
- efficient operation and maintenance of the transmission network,
- low transaction costs, including both implementation and operation and
- consistency with government policies.

These are discussed below

2.2 Efficient Usage

Efficient usage means using the current and future transmission network to maximise value of electricity supply: ie maximise the difference between consumption value and production cost. Economist typically divide efficiency between static efficiency – maximising efficiency given the current capital stock – and dynamic efficiency, which broadly means investing in new capital in an efficient way.

In relation to transmission usage, therefore, static efficiency primarily means efficient generation dispatch, given existing generating capacity and costs. Dynamic efficiency primarily means making appropriate decisions on where on the grid to locate new generation capacity – and intensive-user manufacturing capacity - taking into account the impact that this will have on the cost of transmission over the life of that new capacity.

Because static and dynamic efficiency considerations are quite different, these two criteria will be considered separately in the evaluation process.

2.3 Managing Price Risk

The volatility inherent in electricity markets means that efficient transmission prices are also likely to be volatile. An effective hedging market is needed to manage transmission price risks, for two reasons: firstly, because risk raises the cost of capital and hence the cost of electricity supply; secondly, because a hedging market converts spot or short-term price signals into longer term price signals, which a much broader range of users can effectively respond to. The importance of hedging in the generation market is well recognised, and the California market is an example of what can happen when hedging is not allowed to take place. Transmission price hedging is of equal importance to generation price hedging.

2.4 Efficient Transmission Investment

In the generation market, it is unquestioned that generation prices should be the primary driver of generation investment, and yet in transmission the linkage generally receives scant consideration. Of course, this is because transmission is generally regulated, and so transmission companies will neither "see" nor respond to transmission prices. A second-best situation is that market participants respond to transmission prices by requisitioning new capacity from the transmission company, with the latter being then a passive build-own-operator agent for those participants. However, most markets settle for a third-best option, where transmission investment planning is undertaken – on a common-carriage basis - by the transmission company in isolation from transmission prices.

2.5 Efficient Transmission Operation

This refers to the transmission operator properly taking into account the impact that his decisions have on the wholesale market, and on generation costs in particular. In a sense, it is the counterpart to "efficient usage": efficient usage means that users must take into account transmission costs as well as their own; efficient transmission operation means that transmission operators must take into account users costs as well as their own.

In operational timescales, market designs generally ensure that transmission companies are insulated from transmission prices and therefore will not respond to them. However, some markets are introducing price-based incentives on transmission, and some pricing mechanisms are more suited to this than others.

2.6 Transaction Costs

Transmission costs are typically around one fifth the size of generation costs and therefore transaction costs are magnified in importance. This is exacerbated by the fact that transmission pricing mechanisms are generally more complex than generation pricing, particular when the need for regulation or quasi-regulation is factored in.

There is a secondary difficulty that many markets have commenced without satisfactory transmission pricing arrangements and so introducing them now can bear directly on market participants, whereas initial market implementation costs are often borne by taxpayers or consumers.

Finally, any change will always create winners and losers, and transmission pricing often exacerbates this effect. Thus implementation must include transitional arrangements to manage the extent of wealth transfers, and these arrangements may also add complexity to the pricing mechanisms.

Therefore, three different evaluation criteria will be applied in relation to transaction costs:

- the cost of implementing the new systems and processes required to support the proposed arrangements;
- the ongoing additional costs of operating these systems and processes; and
- the "shock" that the new arrangements create on existing participants (ie the amount of change to expected profitability of market participants or consumers directly caused by the introduction of the new arrangements) and the cost and/or complexity of mitigating this shock to ensure broad acceptance[3].

In assessing transaction costs, it is important to consider the costs to market participants as well as to the market operator and transmission owner.

2.7 Acceptability to Governments

Through the NEMMF and Ministerial Council for Energy (MCE) processes, it has been seen that governments regard significant changes to transmission pricing arrangements as a matter of public policy, and therefore any proposed changes must be acceptable to governments and consistent with their policy objectives and priorities. Thus, "acceptability to governments" would seem to be an important evaluation criterion.

However, this criterion is problematic, for a number of reasons:

- it is not entirely clear what government policy objectives and priorities are, and so evaluation would require "second guessing" in this respect;
- different governments are known to have different policy objectives or priorities, which therefore cannot necessarily all be accommodated within a single, national market design;
- policy objectives in some cases may be better addressed outside of the market design; indeed, this has been the approach taken by governments on a number of occasions.

Furthermore, the purpose of this review is to assist retailers in identifying *their* preferred model. It would seem to be inappropriate for the retailers to promote a "second best" model, on the basis that this is considered to be more acceptable to government.

On the other hand, government acceptability is critical to the success of a new model, and therefore should be evaluated to the extent possible. Therefore, the models will be assessed against this criterion, but it will not be included in the overall evaluation rankings.

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[3] Introducing shock through regulatory change increases the perceived level of regulatory risk in the market, which will raise the cost of capital of market participants (and, to a lesser extent, consumers) and deter new entrants, even though the latter are not directly affected by the shock. Potential "losers" also have a strong incentive to attempt to block the changes.

So what considerations are likely to be important to governments? Efficiency and cost considerations have already been addressed by the other evaluation criteria. “Equity” considerations – such as geographical differentiation of retail prices within a State[4] – have not, and this is likely to be the main additional area of government concern.

Some governments have also expressed a position on what has become known as the “role of transmission” in the wholesale market: for example, whether transmission is market player or a market facilitator. However, it is not clear whether this regarded as a prime policy objective or whether it is just a mechanism for achieving other objectives: ie whether it is a “means” or and “end”. It will not be considered further in the evaluation.

[4] Queensland and South Australia have a policy of “uniform retail prices” for small customers. NSW and Victoria do not, but may nevertheless be concerned about any further increases in geographical price differentiation.

3 Transmission Elements

3.1 Elements Covered

This paper covers elements of transmission pricing. Typically, these are set in two timescales:

- transmission spot prices – determined as part of energy market clearing; and
- transmission service tariffs – determined annually through regulation and rate setting.

Most markets also have mechanisms for hedging transmission spot price risk: eg financial transmission rights (FTRs) or settlement residue auction (SRA).

Transmission service tariffs are typically designed only to recover the costs of transmission assets and associated operations and maintenance and, furthermore, regulated transmission owners are not allowed to retain revenue from transmission spot prices and associated hedging products. Therefore, there is also a need to define how the transmission spot revenue is allocated to market participants. Therefore, there are 4 elements:

- transmission spot pricing methodology,
- transmission spot price hedging mechanisms,
- transmission service tariff methodology and
- transmission spot revenue allocation methodology.

These elements are described in the following sections. The overall transmission price is then determined by the formula:

Tx Price = Tx Spot Price[5] + Tx Services Price – Tx Revenue Recovery

It is important, therefore, that the four elements described are consistent. For example, the spot price and services price may each efficiently reflect transmission costs but, when added together, might lead to double counting. Or the revenue recovery methodology may have the effect of cancelling the price signals provided by the other elements.

Therefore, a theme of this paper is the importance of ensuring these elements are aligned and that any evaluation considers the aggregate effect of the four elements, rather than considering them individually.

[5] recognising that the spot price will be hedged to a greater or lesser extent

3.2 Spot Pricing

3.2.1 Nodal Pricing

The principle and practice of nodal pricing of transmission – often referred to as Locational Marginal Pricing – is well established. As part of the energy market clearing process, a network model – a mathematical approximation to the physical transmission network – is defined. The energy market is cleared using this model, giving rise to a different energy clearing price at each "node" of the transmission model. The transmission spot price at a node can then be considered to be the difference between the nodal energy price and the "reference" energy price (eg the energy price at a designated reference node); or, alternatively, the spot price for transmission between two nodes is the difference in nodal energy price between the two nodes[6].

The network model must be "physical" in that it closely approximates the physical network, representing each "node" (busbar) and "link" (line, cable or transformer) of the network. Some approximations may be made: for example groups of nodes or busbars that are electrically clustered may be represented in the model as a single node. Typically, the models are DC, so reactive power dispatch and pricing is carried out separately.

The performance of modern computing hardware means that real-time clearing on a physical network model can easily be done on a five-minute interval, so the model can be used to calculate real-time dispatch targets as well as nodal energy prices[7].

Network models will typically include the following characteristics:

- "*branch constraints*" representing thermal limits on individual transmission links;
- "*group constraints*" representing stability limits (voltage, transient or steady-state) across a network boundary[8];
- "*loss factors*" representing electrical losses on transmission links; and
- "*security constraints*" representing the need to ensure power system stability following a "credible" transmission or generation outage.

However, some markets only model a subset of these characteristics.

[6] Given that transmission is a transport service, to be meaningful it must be a service from "A" to "B". Sometimes the two points are explicit, whilst at other times one point is unstated, but must be assumed to be some actual or virtual "reference point" at which the market is notionally located.

[7] "Ex ante" markets calculate the nodal prices as part of the dispatch process, whereas "ex-post" markets calculate nodal prices based on dispatch outcomes. The difference is minor and not relevant to this paper.

[8] Since these constraints limits cannot be determined with a simple DC model, they are usually derived off-line using sophisticated AC analysis tools and then represented in the DC model as "generic constraints", typically limiting import or export across a defined constraint boundary.

Mathematically, the "price" of each constraint to be identified separately and so the nodal energy price can be broken down into 3 components:

- the reference energy price (ie the nodal price at the market reference point[9])
- the marginal losses (the price component created by loss factors)
- the congestion price (the price component created by constraints)

Thus:

$$P_{node} = P_{energy} + P_{losses} + P_{congestion}$$

Although spot prices are generally not broken down into these components for spot market settlements, these components are useful conceptually for differentiating between "energy" spot price and "transmission" spot price[10]. In a nodally priced market, load pays – and generation is paid - the nodal energy price at their local node. For markets that allow bilateral schedules, schedulers pay the difference in nodal price between the receiving and sending nodes.

We will define the transmission spot price for load to be the sum of the losses and congestion components and, for generation, the negative of this amount. Thus, in the spot market, load pays the transmission spot price plus the energy spot price, whilst generation pays the transmission spot price but receives the energy spot price. The reason for this "symmetry" between generation and load transmission spot prices is that the transmission price for generation is, in effect, the price for transport from the local generation node to the market reference point, whereas the transmission price for load is the price for transport from the reference point to the local node[11].

For example, suppose that the energy reference price is $50/MWh and the energy price at a node is $80/MWh. Then the transmission spot price for demand at that node is +$30/MWh and the transmission spot price for generation is -$30/MWh.

In addition to nodal energy prices, market clearing on a physical network model determines "flowgate prices". These are prices associated with each branch constraint and so a separate flowgate price is determined for each transmission link, and is non-zero only if the link is constrained. In Appendix A, nodal and flowgate prices are determined for a simple network model and their main characteristics are discussed.

[9] Markets do not necessarily have an explicit reference point, nor separate nodal prices into energy and transmission prices. However, this convention is helpful for conceptual purposes.
[10] the components are also important in the design of hedging mechanisms, discussed in the next section
[11] For similar reasons, there should be some symmetry between generation and load in transmission service prices. However, this is rarely the case.

3.2.2 Zonal Pricing

Having a separate transmission price at each node is sometimes considered to create undue complexity in an energy market: for example, in settlements, hedge trading, retail pricing and so on. For this reasons many markets use a zonal design. In such markets, geographical pricing zones are defined, and a single transmission price is calculated for each zone. There are two methods used for calculating zonal prices: zonal averaging and zonal modelling.

Zonal averaging simply takes the nodal prices described above and averages these across a defined zone. To maintain the same aggregate settlement flows, the averaging is weighted by the load or generation at each node.

In *zonal modelling*, a "logical" network model is used, which represents each zone as a single node and any network constraints between zones as a single link. To the extent that there are network constraints within zones, these are represented by generic constraints[12] which are derived off-line using a physical network model. Thus, market clearing gives a single price for each zone rather than for each node[13].

A zonal/nodal hybrid model may be used, which retains the zonal model but adjusts nodal prices within each zone by a node-specific loss factor. In effect the "loss factor" component is nodal but the "congestion price" component is zonal.

A characteristic of any pricing mechanism other than nodal is that it leads to "price-dispatch inconsistency" meaning a generator with an offer price below the local spot price may not be dispatched (and is said to be "constrained off") or, conversely, a generator with an offer price above the spot price may be dispatched (and is "constrained on"). A similar (but reverse) characteristic applies to dispatchable load. This inconsistency creates significant behavioural problems, whereby a generator will not reveal its true variable costs in its offer price[14], and therefore leads to dispatch inefficiency.

For this reason, all markets either have nodal pricing for generation, have "side payments" to constrained generators to correct the price signal (discussed in section 3.2.3 below) or have zones "small" enough so that the price-dispatch inconsistency created by zonal pricing is immaterial. Some markets also have nodal pricing or side payments to dispatchable demand.

Although zones should, in principle, be defined around electrical regions – to give a better approximation to nodal prices – in practice they are often defined along political or utility boundaries. The main reason for this is to encourage or facilitate uniformity of retail prices across such zones.

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[12] A generic constraint is simply a linear constraint containing generation and load variables.

[13] Or, to be exact, it gives a clearing price for each node in a logical network model (which represents a zone) rather than for each node in a physical network model (which represents a busbar or substation).

[14] In a competitive, nodal market, a generator should reveal its true costs. Of course, in an uncompetitive market, a generator with market power may increase its offer price above its true costs.

3.2.3 Unconstrained Pricing

A final method to set energy prices is to ignore the network altogether and clear the market as though all generation and demand is connected at a single node. Thus, all generation and demand pays the same price, irrespective of location, and transmission spot prices are effectively set to zero[15].

Without a network model, the "unconstrained" clearing mechanism does not provide a feasible dispatch solution. Thus actual generation dispatch will vary from cleared generation volumes and may be higher ("constrained on") or lower ("constrained off") for individual generators, depending upon the effect of network constraints. In this mechanism, generators are paid as follows:

- *constrained-on generators* are paid the clearing price for their "unconstrained" volume, and paid their offer price for any dispatch above this level.
- *constrained-off generators* are paid the clearing price for their "unconstrained" volume, and must repay at their offer price the amount that they are dispatched below this level.

In this model, total payments to generators will exceed payments from load. This is because, although the aggregate volume of constrained-on generation must – by definition – equal that of constrained-off generation, offer prices of the former will generally be higher than offer prices of the latter. This shortfall is typically collected from retailers through an "uplift" charge to the energy price, but can also be recovered from transmission[16].

Note that, at the margin, each constrained generator is paid its offer price rather than the energy price: ie the payment for an additional 1MW of dispatched output will be its offer price, not the clearing price. This price will be similar to the nodal energy price, particularly as informed constrained generators will reoffer to "what the market will bear" and thus converge on the nodal energy price just as bidding in "pay-at-bid" energy markets will converge on the system marginal price[17].

The original market using the unconstrained design was the England & Wales Pool, where the unconstrained market clearing was carried out day-ahead. Modern unconstrained markets[18] have the unconstrained market clearing in real-time, in parallel with the real-time constrained dispatch.

In principle, a "semi-constrained" design could be used, where the "unconstrained" clearing mechanism incorporate certain network constraints but not others. For example, in a zonal market, constraints between zones could be included in the clearing

[15] A variant on this model is to include loss factors but not constraints. Thus, transmission spot prices are set equal to marginal loss factors.

[16] In fact, the only market that does this at present is the England & Wales market (NETA)

[17] For example, suppose that two generators at a node are constrained-on: Gen A has an offer price of $50/MWh and is fully dispatched, whereas Gen B has an offer price of $80/MWh and is marginal. In this case, the nodal energy price is $80/MWh. Gen A is getting paid – at the margin – less than the nodal price but will have an incentive to increase it bid price towards $80/MWh.

[18] In South Korea and Ontario

mechanism but not constraints within zones, leading to a single "unconstrained" price in each zone, and then compensation for generators constrained by intra-zonal constraints[19]. There is no implementation of such a hybrid, but it is discussed further in section 4.5.

3.2.4 Assessment

Under assumptions that:

- the generation market is competitive, so generators bid at their variable costs,
- load can respond effectively to price and
- the short-run marginal cost (SRMC) of transmission services is zero,

then nodal prices represent the true SRMC of transmission and therefore lead to *statically efficient* clearing outcomes: ie outcomes which maximise value to the market as a whole, given the existing capital stock. For nodal prices to also be dynamically efficient, they must also, over time, be sufficient to signal the true long-run marginal cost (LRMC) of transmission or, put another way, transmission spot revenue should be sufficient to fund economic new transmission investment.

It is generally considered that – in an efficiently planned transmission network – transmission spot revenue will be insufficient to cover the total cost of transmission[20]. However, this does not necessarily mean that nodal prices are dynamically inefficient as:

- LRMC for transmission may be lower than historical average costs (eg due to economies of scale);
- existing transmission networks may be "overbuilt" in the sense that some network assets exceed their deprival value[21]. This may reflect the fact that transmission planning standards use a higher implied VoLL than that used in the wholesale market.

Nevertheless, the fact that market designs generally do not rely on transmission spot revenue to fund new transmission, suggests that regulators at least consider that this revenue will be insufficient[22]. This paper, therefore, will assume that nodal prices alone will not promote dynamic efficiency.

All of the models pay generation at nodal prices – or a close approximation to them - at the margin, and so should achieve similar levels of static efficiency. Zonal or uniform pricing for load will reduce this efficiency, but only to the extent:

- in the short run, that load can and will respond differently to the zonal or nodal prices;

[19] This is a variation of the "zonal modeling" described in section 3.2.2. The introduction of the semi-constrained clearing allows compensation to be calculated.
[20] It is generally estimated that transmission spot prices will only recover around 30% of transmission costs. This contrasts with a balanced generation market, where spot prices should, on average, recover the full cost of generation.
[21] ie the increase in costs in the wholesale market if the asset were to be withdrawn from service
[22] Although it also may reflect regulator concerns about monopoly power

- in the long run, that these pricing "distortions" are not offset by the other price elements (ie transmission services and revenue allocation).

The preceding discussion assumes a competitive wholesale market, but this is often not the case. To the extent that generators have local market power, transmission spot prices may be distorted, giving rise to reduced efficiency. It is important then to consider, firstly, the extent to which transmission pricing arrangements may exacerbate or mitigate local market power and, secondly, the extent to which this market power can cause distortions in transmission prices.

On the first question, since all the pricing arrangements described pay generators at nodal prices, the ability and motivation of generators with market power to manipulate those nodal prices may differ little between the options. The exception is the unconstrained pricing arrangement, where a generator in effect sells its constrained-off generation back to the market at its bid, and therefore has an incentive to bid low or negative to increase its profitability. This problem does not arise in the other options[23].

In terms of distortion, nodally priced markets may allow a generator to create large local price distortions, whereas in zonal or uniformly priced markets the effect will be a smaller distortion but over a wider zone.

Most market designs also have some form of market power mitigation mechanisms which target those generators with market power, whilst leaving the competitive market alone.

To conclude, it is considered that market power considerations are unlikely to significantly affect the relative efficiencies of the different spot pricing options.

Under current regulation, transmission is not exposed to spot prices and so the spot price mechanism is unlikely to affect transmission investment, except to the extent that user coalitions promote transmission development in response to spot prices[24]

Nodal prices will usually be more volatile than zonal or uniform prices and so create greater risk for participants. However, this can be offset by hedging arrangements, discussed next.

Nodal prices will create higher transaction costs than zonal or uniform prices, because of the need to calculate, analyse and hedge more price variables. This is a particular issue for retailers, whose customer base may cover a large number of different nodes, but less so for generators who generally have plant at only a handful of locations. Surprisingly perhaps, nodal pricing does not necessarily create high transaction cost within the market operator, since most modern dispatch software generates nodal prices as a matter of course and metering is usually done nodally irrespective of the market design.

In many markets, there is a policy – often a legacy of vertical integration – that retail prices over a political or utility region should be uniform. Zonal transmission pricing

[23] Although, under nodal pricing, a generator which holds an FTR from its local node may have a similar incentive to bid low.
[24] And it has to be said that, although most markets allow such coalition-funded projects, few if any such projects have actually taken place.

allows this to be achieved – with appropriately defined zones - whilst nodal pricing makes it more difficult, particularly if there is also retail competition[25]. Thus, full nodal pricing may be inappropriate in a market which has such a retail policy. On the other hand, if the uniform pricing policy only applies to small customers – and efficient pricing is desired for larger prices - then it may be more appropriate to effect uniform pricing by mechanisms outside of the wholesale market design.

3.3 Spot Price Hedging

3.3.1 Introduction

The use of transmission spot pricing creates substantial price risks for market participants, just as energy spot pricing does. The latter risks are managed by voluntary trading of hedging instruments – such as financial swaps or options – between generators and retailers. These sectors are natural counterparties, since generators have a "long" exposure to spot prices (they are at risk if spot prices fall) and retailers have a "short" exposure (at risk if spot prices rise).

In relation to transmission price hedging, generators and retailers are only natural counterparties if they are located at the same pricing node or zone. Otherwise, the natural counterparty is transmission, who is the "seller" of the spot transmission. However, transmission usually has its revenue regulated, meaning it is deliberately insulated from the revenue risks that spot prices create and therefore has no incentive to offer hedges; it may even have a disincentive if the hedge income is treated as unregulated.

Thus market designs with spot transmission pricing generally include arrangements which oblige transmission to offer hedges. This is often done through an agent such as the ISO to manage perceived conflicts of interest. Just as prudent market participants should only trade energy hedges to the extent it reduces their spot price risk, transmission hedge issuance arrangements should also ensure it does not create undue "risks" on the issuing body. What this means in practice is that the contingent liabilities arising from the issuance of such hedges – ie the payouts which must be made under the contracts – should be fully funded, under normal circumstances, by the transmission spot revenue received. This is referred to as "revenue adequacy"

Mathematically, there are two different hedge structures that are used:

- "*point-to-point*" rights (usually referred to as Financial Transmission Rights or FTRs) which hedge the buyer against congestion prices between the two points; and
- "*flowgate*" rights on each network link, which hedge the buyer against the flowgate price arising from any constraint on that link

These are described in the following sections.

[25] And even if uniform retail pricing can be achieved in a nodal market, the rationale of generating nodal wholesale prices simply to bury them within zonal retail prices must be questioned.

3.3.2 *Financial Transmission Rights*

FTRs are defined by:

- the source point
- the destination point
- the MW volume
- the structure: swap or option
- the trading periods which it is active for

The payout on an FTR in each active trading period is given by the formula:

payout = MW volume * (destination price - source price)

With "swaps" the payout may be positive or negative, whereas with "options" the payout is positive or otherwise set to zero. The destination and source points may be a single node, or a specified group of nodes: variously referred to as "zones", "hubs" or "aggregates". The price for a group of nodes is the average of the included nodal prices; the average may be weighted by load, by specified parameters, or unweighted. Typically, where node groups are traded, the group spot prices will be calculated and published by the market operator.

With FTRs, a sufficient condition for revenue adequacy is that the network can physically accommodate the power flows implied by every market participant simultaneously scheduling energy from point-to-point[26] according to their active FTR holding. Thus, the issuance of FTRs must be restricted to the network capability. This is referred to as the Simultaneous Feasibility Condition[27] (SFC). If issued FTRs are all swaps, the volume of active FTRs is easily calculated and can be checked against network capability. Where FTR options are issued, these are only active when payments to the holder are positive and so are depend upon nodal price outcomes. This makes the SFC much harder to check; typically the SFC is assessed by assuming that the "worst" possible combination of FTR options is active.

The SFC requires future network capability to be forecast and, for this reason, FTRs are typically short to medium term instruments of between one month and one year. Planned network outages are usually incorporated but forced outages are not. Thus, revenue *inadequacy* may occur during a forced outage, as this reduces network capability but does not reduce the aggregate quantity of issued FTRs.

There are several different ways of dealing with occasional revenue inadequacy:

- make the hedges "non-firm" by scaling down payouts during any trading period of revenue inadequacy;
- use any revenue surplus from other periods to support the shortfall period. Typically this is done on a monthly or annual basis;

[26] Where the FTRs are referenced to node groups, the power flow is from the node group to another node group, split according to the weighting factors.

[27] The theory provides that every feasible market clearing on the network will lead to transmission spot revenue in excess of the FTR payouts, except for the market clearing which is identical to the FTR holding, in which case the spot revenue matches the FTR payout. Thus, there should normally be a revenue surplus, unless there is a shortfall in transmission capability.

- use the proceeds from the FTR issuance to make up any revenue shortfall;
- recover the shortfall from market participants: eg through an uplift to energy or transmission service prices; and
- recover the shortfall from the transmission company which caused it.

The "firmness" of the FTRs depends upon the size of surplus or fund that can be drawn upon and the potential size of any revenue deficit from credible forced outages. The markets reviewed that issue FTRs manage inadequacy through just the first two points above. Any scaling back is done "globally": ie all FTRs across the market are scaled back equally, irrespective of where within the market the forced outage occurred.

Hedges may also be broken down by time-of-use: eg peak and off-peak. This is particularly useful where flows on a network are "tidal", and so significant time-of-use price differences may otherwise be averaged out to zero over the FTR period.

FTRs may be issued through an allocation process or through an auction (or both). Allocation mechanisms are described in section 3.5. Auctions are described below.

An FTR auction mechanism is very similar to the energy clearing process. Participants submit orders specifying bid prices, bid quantities and FTRs desired. These orders are then "cleared" using a network model to meet the SFC and to calculate nodal (and node group) auction prices. The clearing price for each point-to-point FTR is then the difference in prices between the source and destination points. All market clearing then occurs at these clearing prices which, for cleared orders, will be higher than the offer prices and lower than the bid prices. An example auction is described in Appendix C.

Buyers in the auction will be market participants and, in some cases, the transmission agent buying back to cover an unanticipated transmission outage. Sellers will be the transmission agent, plus (in some designs) participants who are selling FTRs allocated to them or acquired from earlier auctions[28]. Because the FTRs are financial there is no requirement to demonstrate a physical position (eg generation capacity) in order to order FTRs[29], although for practical and credit reasons, participation is generally restricted to market participants.

Some markets provide a platform for secondary trading between market participants outside of auction periods. Secondary trading may be direct (ie the bought and sold FTRs are the same) or indirect (where different hedges are bought and sold, but the new aggregate of issued hedges continues to pass the SFC. Indirect trading is only possible if the relevant auctions cleared fully.

[28] For swaps, the "buy" or "sell" is determined by the direction of the FTR: for example, buying an FTR from A to B is exactly the same as selling an FTR from B to A.

[29] Although in some markets, FTRs can also provide physical dispatch priority. However, even then, the physical position is not verified in the auction process.

3.3.3 *Flowgate rights*

Flowgate rights have become unfashionable in market design and in fact are now only traded in the Australian market, which has a radial network model[30] and so simplifies many of the complexities of flowgate trading. A flowgate right provides a hedge against the flowgate price on each transmission link. It takes the form of an option: a flowgate right from A to B pays out only if the relevant link is congested with power flow in the direction from A to B, and never incurs a negative payment.

The relationship between flowgate prices and congestion prices is complex and depends upon the topology of the network model. Generally, to provide a reasonable hedge against congestion prices, a number of different flowgate hedges will be needed and the hedging process becomes extremely complex for all but radial or weakly-meshed networks. This issue is described further in Appendix B.

For flowgate rights, a condition for revenue adequacy is that the aggregate volume of flowgate rights issued on a link, in a particular direction, does not exceed the capacity of that link. It is derived in Appendix B. This means that, in the event of a link outage, so long as the flowgate rights on that link are made inactive (ie the right is non-firm), the revenue adequacy of the remaining active links is preserved. Thus flowgate rights can be made "locally non-firm" as opposed to the "global non-firmness" used to address revenue inadequacy in FTRs.

In the Australian market, non-firm flowgate options (referred to as Settlement Residue Auction, or SRA, instruments) are auctioned quarterly. The MW volumes on these instruments are nominal, and payouts vary according to the actual transmission spot revenue accruing in relation to each notional flowgate. Unlike the flowgate rights described above, the SRA instruments also provide a partial hedge against losses. Because the Australian logical network model is radial, the relationship between flowgate prices and congestion prices is straightforward and does not create trading complexities[31].

3.3.4 *Assessment*

Transmission hedges are a vital component of any market with zonal or nodal transmission spot pricing. Indeed, the only such established market without them is NZEM, which has been unable to introduce them due to governance and regulatory problems.[32] Furthermore, all hedges are issued through an auction process managed by the market operator and incorporating a simultaneous feasibility condition, and there appears little reason to do anything different to this.

FTRs are preferred to flowgate rights in most markets, due to the complex relationship between flowgate prices and congestion prices. The exception is the Australian NEM, in

[30] For the time being, although new transmission interconnections or new zones may change this situation.

[31] In fact, the SRA instruments are describe in the Code as line rental rights: ie the right to the price difference across the interconnector multiplied by the flow (and allowance for losses). It is assumed that, when the zonal network model becomes looped, these instruments will have to become explicit flowgate rights, to prevent the problems of counter-price flows: ie where the flow is in the direction of decreasing price and the SRA instrument receives a negative payout.

[32] It is not clear in NZ who has "ownership" of the spot price revenue, which is required to underwrite issued hedges.

which, because it is radial, this complexity does not arise. However, flowgate rights have the possible advantages of a natural "option" structure and an ability to have local non-firmness rather than the global non-firmness characteristic of FTRs.

Are option structures important for transmission hedges? The majority of energy hedges are swaps, although "cap" options are often sold by peaking generators who are only dispatched at times of high prices. But could a generators' dispatch be determined by internodal or interzonal transmission prices? It seems unlikely, which suggests that options are not a natural hedge structure and, given the complexity they introduce into FTR auctions, may not be beneficial to the market. Hedging of tidal flows, on the other hand, is important, so swaps should be structured by time of use (eg peak/off-peak) as appropriate.

The final question is on firmness. This is seen by many participants as a vital aspect of a hedge, since spot price differences are likely to be highest at exactly the times that hedges may be scaled back. The US market approach - of revenue surplus periods being used to cover occasional revenue deficits – appears to make their FTRs substantially firm. However, this might be a result of the auction structure underselling FTR, or a characteristic of the strongly-meshed US networks. FTRs in weakly meshed markets – such as Australia and the Philippines – may be much less firm.

Some argue against the "portfolio firmness" approach on the basis that local non-firmness can be managed through appropriate "insurance" arrangements with peaking generators in the import zone, whereas portfolio non-firmness is not easily managed. Thus, perhaps flowgate rights – with local non-firmness – are preferable in weakly meshed markets, particularly on radial links (of which, for example, the Philippines has many).

Although an obvious solution to non-firmness is to have the relevant transmission company make up any revenue shortfall caused by a forced outage on their network, none of the market studied have introduced this. The primary reason for this is the separation of transmission regulation from market governance, leading to other "fault lines" in transmission design, such as between the transmission spot and service markets. Only the UK (in both the England & Wales Pool and NETA) has placed (partial) liability for congestion costs on Transmission. This solution not only increases the firmness of the hedges but, more importantly, provides the right operational incentives on transmission to minimise revenue shortfalls.

3.4 Transmission Services

3.4.1 Introduction

Transmission service prices are set at a level sufficient to recover the regulated cost of transmission assets. Given that this revenue requirement is typically 3 to 4 times greater than transmission spot revenue, it is perhaps surprising how little attention is given to transmission pricing. There is also a certain amount of confusion about what transmission services prices should signal, or even whether they should signal anything at all, given that locational price signals are already provided in the spot price.

There is a similar vagueness about what the "transmission service" actually is, and how this relates to the service provided by the spot market. Of course, given that transmission is a monopoly, and users are generally unable to avoid transmission services charges, there has been little need for transmission companies to identify exactly what the user gets for their dollar.

3.4.2 Service Categories

Transmission services typically come in the following forms:

- a "*network service*" which gives the load the right to withdraw a certain amount of power from the grid and buy it either from the spot market or from unspecified, or broadly specified, generation.
- an "*interconnection*" service, which provides a generator with the right to connect to the grid and export power up to its rated capacity.
- a "*point-to-point service*" which gives the user a right to transfer a certain amount of power between two specified nodes on the network[33].

Services may be paid for on a "*booked*" basis (and paid for whether the booked capacity is used or not) or on an actual "*usage*" basis, or possibly on a combination of these. Service prices are usually "tariffed": a published rate for all similar users, updated each year or so. In some markets, services may be "*firm*" or "*non-firm*". The latter may be interrupted when congestion occurs.

3.4.3 Methodologies

Spot prices, as we have seen, are generally determined as part of an auction process undertaken in combination or parallel with dispatch. In contrast, transmission service pricing generally follows a cost allocation methodology, whereby an algorithm is used to determine which assets a market participant is deemed to make use of, and then the regulated cost of each asset is allocated accordingly. From an economic point of view, cost allocation methodologies are unlikely to give rise to efficient prices[34]

The following allocation methodologies are used in setting transmission service prices:

- *postage-stamping*: allocation of costs to all loads at a single price.
- *zonal*: allocation of costs to load within each zone on a postage-stamp basis.
- *deemed usage*: deemed matching of generation to load to model the deemed usage of each transmission element by each load[35].
- *beneficiary pays*: allocating the costs of new transmission to the deemed beneficiaries of this new investment (usually coupled with postage-stamping for historical transmission costs).

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[33] Applicable only in "net pools" which allow participants to schedule flows across a transmission network

[34] To take a simple example, suppose the (fixed) cost of an asset is divided between its users. Then, as use of the asset rises, the price will fall, and vice versa. This is contrary to the usual movement of efficient prices.

[35] It is not possible to determine which assets are used by a connected load, unless it is known which generation the load is supplied by. In a pooling mechanism, this is not defined. Thus, arbitrary rules are developed for matching generation to load.

- *developer pays*: a market participant – or "coalition" of participants – can request that a transmission project is undertaken, and then pays for the cost.
- *deep connection charges*: costs to upgrade the network to accommodate a new connected party are charged to that party.

Commonly, transmission service charges only to apply to load: following the taxation principle of minimising distortion by levying on the least price-elastic users.

3.4.4 Assessment

There are three fundamental difficulties with transmission services pricing:

- prices are based on cost-allocation methodologies, which will not give rise to efficient prices;
- services are not clearly defined, and so prices cannot be based on the service provided; and
- pricing methodologies are not aligned with the spot market design, so it unlikely that aggregate transmission prices (spot price plus service price) are efficient.

The philosophy behind postage stamping is that transmission spot prices already provide efficient signals, so any signals in transmission services would distort these. Recovering transmission costs is treated as a taxation exercise and is done in a way which minimises distortion to the efficient "market". This philosophy relies on the belief that spot prices by themselves will promote dynamic efficiency.

The philosophy behind beneficiary pays is that some locational signals are required in transmission service prices, but only when new assets get built, with "new" typically meaning those built after a certain date. On this basis, eventually all assets will be "new" and the beneficiary pays methodology will look similar to the "deemed usage" approach: ie the beneficiary pays approach is simply a 40 year[36] transition path from postage-stamping to deemed usage.

The deemed usage method is inevitably rather arbitrary, but at least attempts to create price signals which are related to transmission costs. This then raises a concern over whether the combination of locational spot and service prices may oversignal transmission costs.

Finally, the developer pays approach is relies on a coalition to prevent free riding. The result of these flaws is often that need transmission projects just do not get built.

The problem of aligning transmission service prices with spot prices can to some extent be addressed through appropriate design of the revenue allocation methodology. This is described in the next section.

[36] Being the approximate commercial life of a transmission asset

3.5 Allocation of Spot and Hedge Revenue

3.5.1 Introduction

With the regulated amount of transmission revenue typically recovered through transmission service charges, transmission spot revenue cannot be retained by transmission and must somehow be returned to transmission users. This section describes the methods for doing this.

The allocation methodology is often predicated on the property rights – generally implied rather than expressed – acquired by users as part of their transmission service. For example, if a user has paid for a transmission line, they should be entitled to the spot and hedge revenue “earned” by that particular line. Similarly, if a user has a point-to-point service which guaranteed transmission between these two points without being interrupted or penalised for congestion, they should be relieved of any spot congestion prices applying to them between these points. Non-firm users, on the other hand, are generally perceived not to have any such property rights in this regard.

Property rights may also be conferred as part of a deregulation or reform process. For example, participants that trade under a zonal spot market may require, when a nodal market is introduced, that their prior “rights” to transmit freely within a zone are preserved. Such rights might only be “grandfathered” to the existing participants and may not apply to new participants joining the nodal market.

The next section describes the mechanism through which revenue is returned to users. The following section then describes methodologies for allocating revenue, based on implied property rights.

3.5.2 Allocation Mechanisms

In the markets reviewed, there are 3 different mechanisms used to allocate the transmission spot price and hedge revenue to “rights” holders:

- allocated FTRs
- auction revenue rights (ARRs)
- distribution of net revenue

Allocated FTRs are provided to rights holders at zero cost. Allocated FTRs – plus any FTRs issued by auction - must not exceed transmission capability as required by the SFC. To allow the SFC to be checked, allocated FTRs must be in the same form as issued FTRs: eg point-to-point, fixed MW, one-year term etc. Holders of allocated FTRs are usually allowed to sell them in the FTR auction or secondary market if they desire.

ARRs are specified like FTRs, but rather than providing the holder with a hedge, they instead give them the right to receive an equivalent cash amount. Thus, an ARR for X MW from point A to point B gives the holder the right to receive cash based on the auction clearing price of the A-to-B FTR[37]. Generally, aggregate ARRs are also subject to the SFC, to ensure that an excessive amount of ARRs are not awarded.

[37] The nature of the auction clearing mechanism means that clearing prices are calculated for all FTR combinations, even when these have not actually been traded in the auction.

The holder of an ARR may choose to bid for the equivalent FTR in the auction – at a very high price to ensure they receive it – and will then receive that FTR "for free" in the sense that the amount paid for that FTR exactly matches the revenue received under the ARR. Similarly, a holder of an allocated FTR can sell its FTR at auction and receive a cash amount. Thus, allocated FTRs and ARRs are broadly equivalent in that they can be "exchanged" in the FTR auction.

The practical difference between ARRs and FTRs appears to be that, as there is no mathematical guarantee that the revenue awarded under ARRs will not exceed the revenue received from the FTR auction (even where the aggregate ARRs satisfy the SFC), the revenues awarded to ARR holders may need to be scaled down to ensure that there is no funds shortfall. On the other hand, allocated FTRs do not appear to be subject to this scaling.

The final mechanism – distribution of net revenue – is a simpler and less elegant mechanism than the others. Each rights holder is simply awarded a certain percentage of the net revenue. Typically, this percentage will be proportionate to the transmission service charge that is paid, and is equivalent to a percentage discount on all transmission service tariffs. As the net revenue typically forms a single pot of money, there is no obvious way to distribute it according to the type of the location of the rights, and if this is desired, it is better done through the allocated FTR or ARR mechanisms.

Most markets use distribution as a final mechanism to dispose of any residual revenue after other mechanisms have been used.

3.5.3 Allocation Methodologies

There are 3 methodologies typically used for allocating FTRs or ARRs to rights holder:

- direct allocation for point-to-point rights
- incremental capacity calculation for new transmission investment
- generation-to-load matching for network service rights

The direct allocation is simply to match a booked point-to-point transmission service with the equivalent FTR or ARR.

Incremental capacity provided by new transmission investment is calculated by comparing the FTR volumes cleared in the FTR auction with the FTR volume that would have been cleared on a network without the relevant investment[38]. Where a number of new investments have occurred, this calculation is done repeatedly, starting with the full network and then removing its investment in reverse chronological order[39]. The incremental capacity method may be applied to new assets charged through deep connection, "developer pays", or "beneficiary pays" pricing methodologies. So, for example, a "beneficiary" receives allocated FTRs based on the incremental capacity and their share of the incremental cost in relation to the transmission project they are paying for.

[38] In other words, the SFC is applied to a network with and without the new transmission assets

[39] Presumably, this process can become quite complex after 40 years, but fortunately no such process has been operating for this long.

Generation-to-load matching makes assumptions about where the load user sources their energy[40]. Given the matching is made, the load is allocated FTRs/ARRs based on its deemed sourcing of generation. So for example, a 100MW load at point A may be matched with 70MW of generation at point B and 30MW at point C, and receives FTRs/ARRs for 70MW of B-to-A and 30MW of C-to-A.

In New Zealand, a slight variation of this method has been proposed, which deems that load receives generation from a local reference node on the "main transmission backbone". This has the effect of allocating local FTRs/ARRs in each region, but leaving the main "inter-regional" transmission capacity unallocated. This is done for market power mitigation purposes.

Where the FTRs/ARRs that are allocated are "obligations" and may have negative value, rights holders may be allowed to opt for zero or scaled back allocations.

There is often a complex process of scaling back FTR or ARR allocations to ensure that the SFC is satisfied. Different priorities may be assigned: for example, network service allocations may be scaled back in preference to point-to-point allocations.

It will be seen that the allocation methodologies can be reasonably aligned with the transmission service pricing methodologies, to ensure that implied rights are respected and users are not "double charged". For example, the matching of generation to load used in determining FTR allocation should be the same matching as that used to calculate network service prices.

3.5.4 Assessment

As noted previously, the main problem in designing an allocation methodology is that transmission services rarely spell out the rights that the service confers (in relation to the spot market), and the service pricing methodology also rarely attempts to determine or reflect the value that the transmission service provides.

Nevertheless, the allocation methodology should attempt to reflect the transmission services situation and reconcile this with the spot market, and it is fair to say that most markets achieve this to the extent possible. Given this objective, it is not possible to fully assess the allocation methodology in isolation from transmission services and spot pricing.

A major problem in any allocation methodology is the need to return all of the spot and hedge revenue: no more, no less. This stems, of course, from the transmission regulation paradigm, and leads to deemed property rights artificially being scaled back when the available revenue cannot support them. It would be preferable for property rights to be firm, with any revenue shortfall to be made up by the transmission company as needed.

It is interesting that the US markets use two different allocation mechanisms: allocated FTRs and auction revenue rights. The difference between them is subtle, and it is not entirely clear why one mechanism should be preferred over another. The ARR approach introduces an additional instrument, and hence an additional layer of

[40] The process is similar to the "deemed usage" methodology applied to calculate network service prices.

complexity, although it must be said that US markets do not seem to be averse to complexity. Perhaps for smaller markets, the simpler FTR allocation mechanism would be preferred.

4 Straw Men

4.1 Introduction

Nine different markets have been reviewed for this report. Each market has different physical, commercial and cultural characteristics and the market design has to a large extent been dictated by these. Most of the markets do not really attempt to address some of the key transmission issues for Australia: eg efficient investment and operation. Therefore, it would be a long-winded, and not necessarily fruitful, process to evaluate the benefit of implementing each of these nine different market designs in Australia.

Instead, an approach has been taken to develop five different "straw men". These design options cover all of the major design elements and options described in the previous section. They have been constructed to, as far as possible, be internally self-consistent and to align the spot price, service price and revenue allocation methodologies in order to provide efficient transmission prices in aggregate.

The details and practicalities of implementing these straw men have not been worked through, and there is no guarantee that they would all be workable or even feasible. Nevertheless, it is believed that this approach is helpful in evaluating the relative benefits to the Australian market of going down the different design paths.

4.2 Hogan Heaven[41] (Full Nodal Pricing)

4.2.1 Introduction

This is a full nodal market with FTRs, similar to PJM and NEPool. It preserves, however, the current NEM transmission services arrangements, and designs the revenue allocation methodology to align as far as possible the spot and service markets. There are no grandfathered property rights.

4.2.2 Spot Pricing

Full nodal pricing for both generation and load, incorporating loss factors and thermal and stability constraints.

4.2.3 Spot Price Hedging

FTRs are swaps (obligations), defined for quarterly and annual terms and also for peak and off-peak periods. Hubs are defined, based on existing regions or, alternatively, based on major load centres. FTRs are issued through quarterly and annual auctions, using a SFC to ensure revenue adequacy.

FTRs are backed by spot price revenue and, where this is inadequate on a monthly/annual basis, FTRs payments will be scaled back across the market.

[41] Apologies to Bill Hogan for using his name facetiously and without permission. However, this model is based on his preferred market design.

4.2.4 Transmission Services

Historical costs are allocated to load, based on a CRNP or similar allocation methodology, which is market-wide rather than within each TNSP. New transmission costs are allocated to deemed "beneficiaries" or may be voluntarily funded by willing coalitions[42].

4.2.5 Revenue Allocation

ARRs are first allocated on an incremental capacity basis to those funding the new capacity: deemed beneficiaries or coalition members.

Remaining ARRs (for the "historical" network) are allocated using a generation-to-load allocation methodology, aligned with the transmission services pricing methodology. These are scaled back to satisfy the SFC.

Any residual revenue remaining after FTRs and ARRs have been fully paid out (on an annual basis) will be returned to transmission users across the market in proportion to their transmission service charges.

4.3 Policy Pragmatism (Zonal Averaging)

4.3.1 Introduction

This model introduces nodal pricing for generation, but preserves zonal pricing for load, which may improve government acceptability in relation to a uniform retail pricing policy. FTRs are introduced which reflect this nodal-zonal approach. It aligns transmission services with this model, by notionally separating transmission into "inter-zonal" and "intra-zonal". Existing generators have their current "rights" to receive the zonal price grandfathered through allocated FTRs.

4.3.2 Spot Pricing

Nodal prices are calculated as for the nodal pricing model. Zones are defined: either existing NEM regions or a one-off change to new zones. Zonal prices are defined as the load-weighted average of nodal prices within a zone. Generation is paid nodal prices, whilst load pays zonal prices.

4.3.3 Spot Price Hedging

FTRs are defined node-to-zone or zone-to-zone, and are otherwise defined as for the "Hogan Heaven" model. The FTR auction process also follows this model.

4.3.4 Transmission Services

Historical transmission costs are separated into "intra-zonal" and "inter-zonal". Historical intra-zonal transmission are priced using a similar methodology to the "Hogan Heaven" model, except that the generation to load allocation is applied within each zone rather than across the market. The cost of historical inter-zonal transmission is allocated to load and postage-stamped across the market.

New transmission capacity will be paid for by deemed beneficiaries or willing coalitions.

[42] This begs the question as to whether these pricing methodologies can be satisfactorily developed and agreed. However, this question is outside the scope of this paper.

4.3.5 Revenue Allocation

Existing generators are allocated once-off long-term FTRs (which may have negative value) between their node and the zone. Incremental FTRs are allocated at each auction to those funding new transmission.

Loads are not allocated FTRs or ARRs as they have no intra-zonal price risk. Residual revenue is allocated to load in proportion to the transmission service charges for historical transmission.

4.4 Firmer Flowgates (Zonal Modelling)

4.4.1 Introduction

This model retains the current codified NEM approach of using a zonal model for simplicity but developing new zones as needed to avoid intra-zonal constraints. It recognises that once loops are introduced into the zonal model, the current SRA model will need to evolve into a flowgate mechanism[43]. It also uses the "local non-firmness" property of flowgate rights to introduce operating incentives on transmission to optimise inter-zonal link availability and "firm-up" the flowgate rights. It preserves the existing transmission services regime, and improves – through the revenue allocation methodology – the alignment between this and the zonal spot market.

4.4.2 Spot Pricing

Zonal prices are calculated based on a zonal network model, as used currently in the NEM. New nodes will be introduced as intra-zonal congestion arises.

4.4.3 Spot Price Hedging

Directed flowgate options are auctioned on each notional inter-zonal link used in the zonal network model. As long as the network model remains radial, these hedges will be similar to the current settlement residue auction (SRA) instruments issued currently.

Each flowgate has a nominal capacity, recommended by NEMMCO and agreed by the transmission regulator, and flowgate options are auctioned up to this capacity. Where there is a revenue shortfall – eg due to transmission outages – this shortfall will be made up by the relevant TNSPs, up to a limit agreed by the transmission regulator, and the regulator will also allow an increase in regulated revenue to cover this risk. Beyond this limit, the flowgate rights are non-firm.

4.4.4 Transmission Services

Costs for the existing transmission network are recovered using a CRNP or similar methodology, applied across the market, and applied symmetrically to generation and load[44]. Costs for new transmission will be paid for by beneficiaries or coalition members.

4.4.5 Revenue Allocation

Auction revenue from each flowgate option is used to reduce the regulated revenue requirement on the corresponding network elements, which– through the CRNP

[43] The alternative would be to introduce FTRs, in which case the NEM becomes much like the Hogan Heaven model.

[44] This is straightforward to do and, indeed, was proposed at an early stage of the NEM design.

methodology – feeds through into lower transmission service prices for deemed users of these elements.

There is no residual inter-zonal spot revenue, since this is all allocated to flowgate option holders. Intra-zonal spot revenue (arising from the application of loss factors to prices within a zone) is allocated to transmission users within each zone, in proportion to transmission service charges.

4.5 Controlling Congestion (Semi-constrained Zonal)

4.5.1 Introduction

This model places responsibility on TNSPs for congestion within their networks, and defines zones around the TNSP areas (which are also the current NEM zones[45]). It does this by adopting the UK model of unconstrained pricing and constraint compensation payable by the TNSP, as well as UK-style transmission services. It takes a further step of "deregulating" interzonal transmission by making it reliant on flowgate hedge revenue. It begs a number of questions about how intra and inter-zonal assets and congestion costs can be separated and answering these questions may be problematic.

4.5.2 Spot Pricing

Zones are based on current NEM regions. Zonal prices are determined through a "semi-constrained" dispatch which includes inter-zonal constraints but removes intra-zonal constraints[46]. The methodology for determining inter-zonal constraints will be included in the Code. Nodal prices are determined by a fully-constrained physical dispatch, using the usual nodal pricing methodology.

Generators are paid the zonal price for their semi-constrained dispatch quantities and the nodal price[47] for the difference between the metered output and the semi-constrained dispatch. Load pays the zonal price. The cost of congestion – ie the difference between total generator payments and total load payments in each zone[48] – is paid for by the relevant TNSPs, using an appropriate allocation methodology, and they are allowed to charge an additional regulated component to transmission service users to cover the expected cost of congestion. TNSPs are allowed to enter into "must-run" contracts with generators to manage congestion costs.

[45] Except for the Snowy region, but Snowy could be treated as a separate TNSP area for this purpose

[46] This approach appears similar to that used in the ERCOT market in Texas, although ERCOT has not been reviewed in detail. However, ERCOT allocates the intra-zonal congestion costs to load through "uplift" rather than making TNSPs responsible. The ERCOT model is currently being reviewed by the regulator to see if it should be replaced by a nodal pricing approach.

[47] This is slightly different to the UK, Ontario and Korean models, which base compensation payments on offer prices. Nodal prices (which approximate to offer prices) are preferred here for simplicity and transparency

[48] In fact, some of this will be attributable to FCAS requirements and should be separated out. This has been achieved in the Korean market.

4.5.3 Spot Price Hedging

Directed flowgate options are issued on each "virtual" inter-zonal link modelled in the semi-constrained dispatch. These are non-firm to the extent that the inter-zonal constraint limits are variable. The options pay out based on the flowgate prices determined in the semi-constrained dispatch and are underwritten by inter-zonal spot revenue.

4.5.4 Transmission Services

Users only pay for "intra-zonal" transmission services, which are regulated to recover allowable revenue for intra-zonal transmission costs, plus an allowance for expected intra-zonal congestion costs. The charging methodology apples symmetrical locational prices at each node to generation and demand (ie the locational generation price is the negative of the locational demand price) based on a UK-style LRMC analysis, plus a postage-stamp charge on load to recover "sunk" costs[49].

Interzonal transmission costs are paid for by the flowgate auction receipts. Where there are multiple owners of transmission on a single notional flowgate, an allocation methodology allocates the auction revenue.

Merchants or user coalitions have the right to develop incremental interzonal capacity and receive auction revenue based on the allocation methodology. Existing TNSPs would have a franchise on developing intra-zonal transmission.

4.6 Merchant Mania (MNSP Adaptation)

4.6.1 Introduction

Australia is unique in having an MNSP model which allows MNSP owners to bid their transmission into the market and receive the spot price revenue, but no transmission services revenue. A similar approach is used for gas pipelines (under contract carriage), although in this case transport prices are tariffed rather than bid day-to-day.

While the current MNSP model only applies to simple, controllable links between price regions, the Merchant Mania generalises this to a meshed AC network in which every link of the network operates as an MNSP. In reality, dealing with issues such as loop flows, ancillary services, security constraints and market power mitigation in such a model would be extremely problematic, if not impossible. Nevertheless, it is included here for comparison purposes, and also to draw out what is lost under the current electricity transmission regulation paradigm[50].

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[49] The UK approach has similarities to the CRNP method, but configures and optimal grid topology and capacity to meet the peak demand requirements and uses an LRMC estimate for transmission (stated in terms of $/MWkm) instead of recovering revenue based on ODRC-based asset valuation. The "sunk" costs are any revenue shortfall arising from the LRMC-based prices.

[50] It should be remembered that gas pipelines are regulated almost as heavily as electricity transmission, but using a different regulatory paradigm.

4.6.2 Spot Prices

Each transmission owner bids each link that they own into the spot market, in a similar manner to that allowed currently for MNSPs. The dispatch process seeks to maximise value, treating these bids as transmission costs. Nodal prices are calculated, as usual, based on the marginal energy price at each node, again taking into account the transmission bids[51].

Generation and load pays the nodal prices. Transmission receives the difference in value of the energy flows at each end of each link that they own.

4.6.3 Spot Price Hedging

Hedge trading is undertaken voluntarily between transmission owners and market participants. There are no market rules specifying the structure of hedge products or the design of the trading market (cf generation hedging). However, there may need to be some regulation of prices for standard hedge products where transmission owners are perceived to have market power[52]

4.6.4 Transmission Services

There is no separate payment for transmission services. TNSPs recover all of their revenue through the spot market or the sale of hedges.

4.6.5 Revenue Allocation

All revenue from the spot and hedge markets is paid to the relevant TNSP.

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[51] It is recognised that dealing with the effect of loop flows in dispatching AC transmission is complex, and may not be soluble. This model assumes that it is solved, or that all AC transmission is controllable through FACTS or similar.

[52] This regulation could be similar to that used for gas pipelines, where “covered” pipeline must offer standard haulage services – up to pipeline capacity - at a regulated tariff.

5 Evaluation

5.1 Introduction

For the evaluation, we will consider each of the straw men against each of the assessment criteria, building up an evaluation matrix. The evaluation will compare the benefit (or detriment) of each straw man against the current NEM design and policy. For this purpose, it is assumed that:

- the current NEM design is the one set out in the Code: that is that new price regions will be created whenever there is significant intra-regional congestion;
- to facilitate this, a full network model will need to be included in the dispatch engine;
- once loops are created in the regional model, the SRA instruments will need to become flowgate options[53]; and
- acceptability to governments will depend upon the ability to maintain uniform retail prices, at least for some customer classes in some States, although this need not be done with the wholesale market.

The lack of clarity in the NEM design and policy means that these assumptions are arguable, and changing them will change the relative merits of the different straw men.

No new regions have been introduced since NEM commencement and some Governments have expressed opposition to their introduction, notwithstanding the Code provisions, and there is a real possibility of this situation continuing for some time. This situation will be reflected in the evaluation by including a sixth straw man, labelled "Governance Gridlock", which is similar to the NEM benchmark, but has the following additional characteristics:

- no new regions will be introduced;
- pricing will be based on price at the current regional reference node, adjusted for losses;
- intra-regional congestion will be managed through application of generic constraints in dispatch and, where necessary, direction;
- intra-regional constraints will be adapted where necessary to limit the amount of negative settlement residue accruing due to counterprice flows on notional interconnectors.

[53] As noted earlier, as the Code is currently written, the SRA instruments are line rental rights so, in this respect, a Code change would be required.

For simplicity, we will use the following notation. The "values" are used in enumerating the overall benefits of each model.

sign	value	meaning
++	+2	highly beneficial
+	+1	somewhat beneficial
=	0	no material impact
-	-1	somewhat detrimental
--	-2	highly detrimental

5.2 Transmission Usage (Static Efficiency)

Firmer Flowgates will have the same spot pricing zones and methodology as the current design, and so will have similar efficiency (=). Hogan Heaven introduces dynamic loss factors and also captures sporadic "intra-zonal" congestion, which would not be included in the current design, and so will improve static efficiency (+). Policy Pragmatic and Congestion Controller, on the other hand, whilst both retaining nodal pricing for generation at the margin, lock in uniform State-based prices for load, thus reducing static efficiency (-). Arguably, Congestion Controller will have somewhat better inter-regional pricing, but this is unlikely to have a material impact.

Merchant Mania allows transmission to levy spot prices even when there is no congestion. It is assumed that regulation will prevent transmission earning monopoly rents but, nevertheless, any "throttling" of transmission will discourage use of spare capacity and therefore reduce static efficiency (-).

Governance Gridlock may lead to intra-state or inter-state generation being inappropriately constrained off, depending upon the formulation of intra-regional constraints. (-)

5.3 Transmission Usage (Dynamic Efficiency)

Remember that, for investment decisions, all components of transmission price will be taken into account, rather than just the transmission spot prices.

Again, as Policy Pragmatic and Congestion Controller lock in regional prices for load, they will remove efficient intra-region price signals. Furthermore, Congestion Controller guarantees a regional price for generation, although this will be offset to some extent by LRMC-based locational price signals for transmission services. (-)

Hogan Heaven does not change the transmission service pricing, but improves transmission spot pricing so, again, should overall have some beneficial effect. It also removes the uncertainty associated with the introduction of new zones in the current NEM design. (+)

Firmer Flowgates, whilst providing broadly equivalent spot prices, improves transmission service pricing to G by introducing CRNP pricing. It also should improve contracting across region boundaries through firmer flowgate rights, thus also encouraging generation investment in the right region, rather than just in the same region as the demand. (+)

Merchant Mania allows transmission to design and price long-term hedging agreements with market participants – in particular generators - and so, assuming appropriate mitigation of market power, this should lead to improved locational investment. Recovering all transmission costs through the spot market also ensures that local embedded generation does not pay transmission costs[54] (+).

Governance Gridlock may mean that generators locate within the “right” region but in the wrong place within the region (since intra-regional congestion costs only partially impact on generators). (-)

5.4 Managing Price Risk

Hogan Heaven introduces nodal price risk for generation and load. Whilst this can be hedged through the issued FTRs, these cannot fully hedge everyone’s needs (since issuance volume is limited by network capacity) and there is also a question as to how firm these FTRs will be in Australia’s weakly-meshed network. Retailers may find it hard to match FTR volumes to customer load, particular when there is significant customer churn. Finally, there is a concern that nodal pricing could fragment the energy hedge market, although this should be largely addressed through the design of appropriate hubs in the FTR market (-).

Policy Pragmatic does not introduce any new price risk for retailers[55]. While it introduces nodal price risk for generators, this is largely hedged for existing generators by the grandfathered FTRs. In fact, because also Policy Pragmatic removes the current NEM risk of new pricing regions being introduced, Policy Pragmatic implies lower price risks than the current arrangements (+).

Firmer Flowgates retains the current zonal model, but firms up the flowgate rights, thus reduce inter-zonal price risk. Of course, this risk is just transferred to TNSPs, but they should be in better position to manage this risk. (+)

Like Policy Pragmatic, Congestion Controller removes the risk of future new zones. It also firms up inter-zonal hedges by “removing” intra-zonal constraints. Again, the risk is passed to TNSPs, who should be in a better position to manage it. (+)

Merchant Mania increases price risk and leaves it to the market to come up with appropriate hedging instruments. Although TNSPs should have the incentive to offer firm hedges (just as generators do currently), there must be some doubt as to whether these hedges will be made available in sufficient volumes at reasonable prices. (-).

Governance Gridlock removes the risk of new zones being introduced. However, the effect of intra-regional constraints risks substantially eroding the firmness of the SRA instruments, thus exacerbating inter-regional price risk (=).

[54] assuming that is supplies local demand
[55] It is assumed in this model that energy hedges – existing and future - will be reference to the zonal price rather than the nodal price at the current RRN.

5.5 *Efficient Transmission Investment*

Whilst Hogan Heaven and Policy Pragmatic introduce new nodal price signals, there is no nexus between these and transmission investment, and no reason to suppose that TNSPs will voluntarily respond to them. (=).

Firmer Flowgates could introduce incentives for minor investment to improve inter-zonal transmission reliability, but this is likely to be limited. (=)

Congestion Controller places responsibility on TNSPs to manage intra-regional congestion efficiently – by investing in new transmission, or bearing congestion costs, whichever is cheaper. Thus, investment planning will become more focused on the effect on the market. By de-regulating inter-regional transmission, it may encourage new entrant investment where the price signals support it (+).

Merchant Mania has all investment fully driven by market prices, just as for generation, and therefore – assuming market power is addressed – should create an environment for efficient, competitive investment in transmission (++).

Governance Gridlock does not introduce any signals for transmission investment. Indeed, given the adverse impact of intra-regional constraints, there may be a tendency for TNSPS to seek to uneconomically remove these constraints (-).

5.6 *Efficient Transmission Operation*

Neither Hogan Heaven nor Policy Pragmatic introduces incentives for more efficient transmission operation, although, arguably, the impact of inefficient operation is made more transparent by nodal prices (=).

Firmer Flowgates provides strong incentives on TNSPs to operate so as to maximise the firmness of inter-regional links during periods of congestion (+).

Congestion Controller takes this further by providing congestion management incentives on both intra-regional and inter-regional transmission. Accountability for intra-regional congestion becomes very clear (++).

Merchant Mania places the same operating incentives as is currently seen by generation, and could be expected to spark innovation in operating practices. However, this depends upon introducing effective competition in transmission (++).

Governance Gridlock does not introduce any operational incentives on TNSPs (=).

5.7 *Transaction Costs (Operation)*

Note that this section and the following two sections represent detriment. Thus an increase in costs is detrimental and is labelled by a minus sign, and conversely a decrease in costs is beneficial and labelled with a plus sign.

Firmer Flowgates is basically the same as the current NEM and operating costs will be similar. The exception is for transmission, which will have the new cost of managing the firmness of interconnectors: it is assumed that this cost will be allowed for in the revenue cap (=).

Policy Pragmatic retains zonal settlement for retailers and, while generators now have nodal settlement, most generating companies will only be trading at a handful of nodes anyway[56]. It is assumed that a full network model will be included in the dispatch process in all models, so nodal pricing does not create any additional operating cost in the dispatch process[57]. Policy Pragmatic introduces the need for FTR auctions, but these will only be quarterly, and will not be substantially more complex to operate than the current settlement residue auctions[58]. In its favour, Policy Pragmatic removes the current risk of new NEM regions being introduced. Overall, Policy Pragmatic will create little net change in operating costs. (=)

Hogan Heaven introduces nodal pricing for retail, which will substantially complicate the trading and retailing processes for retailers, compared to a benchmark NEM of perhaps 10 to 20 zones. (-)

Congestion Controller introduces a more complex settlement model with the parallel operation of a "semi-constrained" dispatch, separation of intra- and inter-zonal constraints, constraint compensation payments, zonal and nodal prices and so on. In it favour, Congestion Controller locks in the current regions and so removes the risk and costs of introducing new NEM regions (-).

Merchant Mania introduces substantial complexity in all aspects of market operation: bidding, dispatch, settlement, trading and retailing. It will introduce the need for complex new trading operations for TNSPs. The market design will probably need to be quite complex to manage the effect of loop flows etc (--)

Governance Gridlock avoids the need for changes relating to the introduction of new regions (+).

5.8 Transaction Costs (Implementation)

All of the straw men entail some changes to transmission service pricing, but then changes are needed anyway in the current NEM benchmark. Furthermore, the development of new transmission service pricing models is relatively low cost compared to spot market systems. Therefore, transmission service impacts are ignored in this assessment.

Hogan Heaven should have little impact on wholesale pricing dispatch and settlement, since a full network model – together with nodal settlement – is included in the current NEM benchmark.[59] However, nodal pricing will require major changes to retailers

[56] In any case, settlement in the current NEM is nodal, although there is not significant intra-regional price risk.
[57] In fact, introducing a full network model will substantially simplify dispatch operations, by removing the need to identify and input generic constraints to represent thermal limits.
[58] Remembering that the "benchmark" is for new regions to be introduced in the NEM
[59] It is assumed that the current NEM uses full nodal settlement. This assumption has not been confirmed.

trading and pricing systems, and some minor changes to generators systems. It will also require FTR auction and ARR allocation systems to be built. (--)

Policy Pragmatic will also require FTR auction systems and some changes to retail and generator trading systems. However, the impact on retail pricing systems will be much less[60] and is offset by removing the current threat of new zones being introduced. (-)

The Firmer Flowgates model is the same as the current NEM, except for some minor changes in the SRA process. (=)

Congestion Controller will require substantial new dispatch and settlements systems within NEMMCO, and some significant changes to generator trading and settlement systems to manage constraint positions. On the other hand, the model will have minimal impact on retailer systems and removes the threat of new regions being introduced (-).

Merchant Mania will involve substantial design and implementation costs (--).

Governance Gridlock is achieved by the current implementation (=).

5.9 Shock

Any "shock" assessment needs to be benchmarked against the urgent need for new zones to be introduced in the current NEM which will itself create shocks. Given this, the introduction of nodal prices should not create significant additional shocks compared to introducing new zones, since the main price effects will be from congestion pricing, which should be almost fully captured in the current new-zone NEM. Therefore, there will be limited shock from Hogan Heaven (=). Similarly, any shock from Firmer Flowgates in introducing new zones will be matched in the benchmark. The shock from applying TUoS to generators can be phased in gradually[61], as can the impact of placing congestion risks on the TNSPs. (=).

Against this benchmark, Policy Pragmatic actually has a "negative" shock. It locks in current regions for retail and therefore removes the shock from new regions. It also grandfathers existing generators against the shock of new intra-regional congestion pricing, which the current NEM benchmark does not. There may be some fall in Queensland prices, as nodal prices fall in export-constrained regions such as Tarong and Central Queensland, and these are included in the zonal averaging. It is assumed, however, that existing hedge contracts are re-referenced to the zonal price, rather than remaining referenced to the nodal price at the RRN[62], so much of this shock will be hedged and will not outweigh the "negative" shock described above.(+)

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[60] It might be argued that full nodal models will be needed to calculate nodal prices in order that zonal prices (being the average of nodal prices) can be calculated. However, given that the overwhelming majority of load is close to the current RRN (Queensland excepted), the zonal prices are in fact likely to differ little from the current RRN prices.

[61] A gradual transition means that the average level of new generator TUoS will be passed through to retailers through a rise in spot prices. An abrupt transition means that generators will bear the shock, as spot prices are largely hedged in the short term.

[62] This would need to be part of the implementation "deal" by which generators get vested with allocated FTRs.

Congestion Controller will have some effect on regional prices – particularly in Queensland where previously constrained generation can now fully participate in the price-setting schedule. To avoid a shock on the TNSPs, expected levels of intra-zonal congestion costs would be passed through in TUoS, leading to some TUoS changes. The change from the current CRNP transmission service pricing to a symmetric LRMC pricing arrangement will create significant shock on some generators, although this can be phased in. Inter-regional price differences will need to increase somewhat over time to cover the inter-regional transmission costs. Overall, then, Congestion Controller will create some shock. (-)

Merchant Mania will introduce significant changes to prices as the full cost of transmission is included within spot prices. This will lead to greater peak/off-peak price differentials in relation to "tidal" interconnectors (eg Vic to NSW) and a slight rise in prices in importing regions (eg SA). However, prices should not rise overall, because any increase in spot prices will be offset by the removal of transmission service charges. Price impacts will be hard to predict and the ability of existing energy contracts to hedge them is unclear[63]. Thus, the shock could be substantial (--).

As Governance Gridlock is the status quo, there is no shock (=).

5.10 Acceptability to Governments

We have assumed that the main "acceptability" consideration for governments will be one of "equity": in particular, geographical differentiation of wholesale prices to load within a State. In the benchmark, new regions will be introduced as intra-regional congestion occurs, but this may well be a gradual process.

Both Congestion Controller and Policy Pragmatic preserve the current regional structure as far as load pricing is concerned, and therefore would be more acceptable to governments than the benchmark (+). Firmer Flowgates has the same regional structure as the benchmark and therefore should make little difference to government acceptability (=).

Hogan Heaven introduces nodal pricing based on congestion and losses and so increases geographical price differentiation (-). Merchant Mania goes further, and incorporates transmission costs within spot prices and so is likely to further increase differentiation (--).

Given the number of government reviews of transmission arrangements, it appears that the status quo, Governance Gridlock, is not acceptable to governments (-).

[63] Although it is likely that "vesting" transmission hedges would be introduced with MM, both to reduce price shock and to mitigate transmission market power.

5.11 Summary of Evaluation

Table 2 below provides an evaluation matrix based on the assessment above.

	HH	*PP*	*FF*	*CC*	*MM*	*GG*
Static Use	**+**	**-**	**=**	**-**	**-**	**-**
Dynamic Use	**+**	**-**	**+**	**-**	**+**	**-**
Price Risk	**-**	**+**	**+**	**+**	**-**	**=**
Tx Investment	**=**	**=**	**=**	**+**	**++**	**-**
Tx Operation	**=**	**=**	**+**	**++**	**++**	**=**
Transaction (Operations)	**-**	**=**	**=**	**-**	**--**	**+**
Transaction (Implementation)	**--**	**-**	**=**	**-**	**--**	**=**
Shock	**=**	**+**	**=**	**-**	**--**	**=**
Overall Value	***-2***	***-1***	***+3***	***-1***	***-3***	***-2***
Efficiency – overall value	*+1*	*-1*	*+3*	*+2*	*+3*	*-3*
Costs – overall value	*-3*	*0*	*0*	*-3*	*-6*	*+1*
Government Acceptability	**-**	**+**	**=**	**+**	**--**	**-**

Table 2: Evaluation Matrix

The "overall" row provides an overall evaluation of each model based on valuing the assessments between +2 and -2. On this basis, Firmer Flowgates is the preferred model. A more realistic approach would be to weight each criterion and then calculate the overall "mark" as the weighted sum. Choosing the weights, however, is a matter for each individual reader and is not going to be attempted in this paper.

The next rows separate out the overall efficiency benefits (the first 5 criteria) from the various costs (the next 3 criteria). The last row summarises likely government acceptability, based on "equity" considerations.

It is noticeable then that improved efficiency largely comes at the expense of increased cost, and so depending upon the relative weights of these two aspects, one might either choose a low-cost-low-efficiency option such as Policy Pragmatic, or a high-cost-high-efficiency option such as Congestion Controller or Merchant Mania. Notwithstanding these considerations, however, Firmer Flowgates appears to excel as a low-cost-high-efficiency option, whereas Hogan Heaven suffers from being a high-cost-low-efficiency option.

Recognising the deficiencies in this evaluation process, it nevertheless provides some interesting insights:

- the Firmer Flowgates design appears attractive because the benchmark NEM design is generally efficient, with the exception of transmission investment and operation - the latter is addressed by the Firmer Flowgates changes to the NEM design;
- the Hogan Heaven model does not deliver much in the way of increased efficiencies, because the current NEM design is already quasi-nodal, and the Hogan Heaven model does not *per se* address the major deficiencies in transmission incentives;

- ”equity” policy can be delivered either by Policy Pragmatic or Congestion Controller: the former is low-cost-low-efficiency whilst the latter is high-cost-high-efficiency.
- the efficiency benefits of the Firmer Flowgates rely on the ability of the flowgate model to deliver more effective price hedging than the Hogan Heaven FTR approach; this assumption goes against North American experience and, whilst this is justified on the basis of the weakly-meshed character of the Australian network, it does need to be substantiated; and
- finally, the panacea for efficiency transmission investment and operation may lie in the Merchant Mania model, if such a model can be designed and implemented at reasonable cost (which is doubtful); it does not lie in the Hogan Heaven model, in spite of this model's other merits.

It will be seen that almost any of the models can be seen as preferred if the appropriate weights are chosen. This is deliberate: there is no point in developing and describing a model which does not deliver under any circumstances.

5.12 Proposed Voting Process

The evaluation described above is based on the views of the author. Furthermore, because there has been no attempt to weight the criteria according to relative priorities, the straw man with the highest “overall value” in the table above (ie Firmer Flowgates) does not necessarily represent the preferred overall option. On the other hand, the development of straw men and an evaluation matrix is considered to be a useful tool for assessing the relative merits of different transmission arrangements.

It is therefore recommended that the Transmission Working Group of the ERAA undertake a “voting” process, by which each member decides a weighting for each criterion and a value for each cell in the evaluation matrix. These individual “votes” can then be aggregated to determine an overall value for each straw man and the “preferred” option. Whilst there will not necessarily be a consensus around this preferred option, the voting will form a useful basis for further discussion between group members, from which – hopefully – a consensus view will emerge.

The voting process will be as follows:

- each member will assign a percentage weight to each criterion, with a requirement that the summed weights add up to 100 percent
- for each straw man and for each criterion, each member will decide a value between -5 and +5 representing the relative detriment or benefit of the propose straw man, compared to the current NEM benchmark
- weights for the overall evaluation, for each criterion, will be equal to the average of the weights assigned by individual members.
- the overall value for each cell in the evaluation matrix will be based on the summation of the values submitted by members;

6 Conclusions

There are a number of general observations that can be made based on the research and analysis undertaken in this study.

1. Transmission pricing is probably the area of energy market design which is most actively being reviewed at present, in almost all markets internationally.
2. There is certainly no agreed “right” answer, or preferred design option, although designs are “clustering” around a few competing alternatives.
3. Each of the design elements and options is being enhanced and refined over time, assisted by developments in the underlying theory and in the supporting computer systems. The exception to this is, perhaps, transmission services, where there seems to be little progress in replacing or improving long-established pricing methodologies.
4. The design emphasis has been on improving price signals for market participants and transmission users, with relatively little consideration given to improving incentives for transmission owners and operators.
5. There has been little challenge to the dominant transmission regulatory “paradigm” of a monopoly service provider subject to cost-of-service regulation, so all pricing options are predicated on this paradigm.
6. Based on a qualitative assessment, there is no obvious preferred approach for Australia. Quantitative analysis – and a weighting or prioritising the potentially competing objectives – would be required to identify the best way forward.
7. The current NEM design is a valid option and, whilst it could be refined, it does not necessarily need a major overhaul or change. Specifically, the competing design options do not obviously address the main areas of concern arising in the NEM.
8. To a significant extent, the preferred option will be predicated on government policy objectives for the industry. In Australia, these objectives need to be clarified.

Whilst this study has failed to answer the question of which is the preferred transmission pricing arrangement for Australia, it has hopefully both clarified the question – by defining the scope of such arrangements and their objectives – and described and rationalised the set of possible answers.

Appendix A: Nodal Spot Pricing

Triangle Example

A simple "triangle example" is used to illustrate the main characteristics of nodal spot pricing on a meshed network. The network model is shown in Figure A1 below. For simplicity, this model does not include security constraints, group constraints or losses.

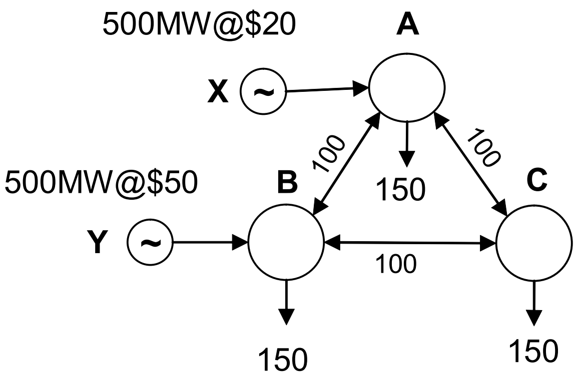

Figure A1: Triangle Model

The branch limit on each link is 100MW, and the lines have identical admittance.

The optimal dispatch on this network is shown in Figure A2 below. This is optimal since any further substitution of expensive Gen Y generation with cheaper Gen X generation would lead to the A-C line being overloaded.

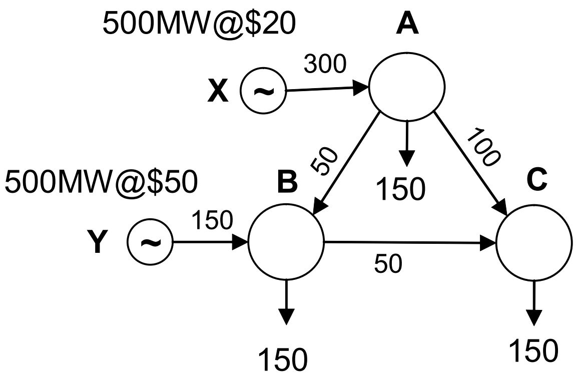

Figure A2: Optimal Dispatch

Nodal Spot Prices

Nodal energy prices are based on location marginal prices: ie the incremental cost of supplying an additional 1MW of load at a particular node. Trivially, node A can be supplied incrementally by Gen X and so has a nodal price of $20. Incremental load at B must be supplied entirely by Gen Y – since any supply from Gen X would over load link A-C - and so has a nodal price of $50.

Incremental load at C cannot be supplied by Gen X or Gen Y individually, since either will cause link A-B to be overloaded. As Figure A3 shows[64], the only way to manage flow on A-B is to provide the incremental load with Gen Y and, at the same time, substitute 1MW of Gen X output for Gen Y to "back-off" the higher link flow.

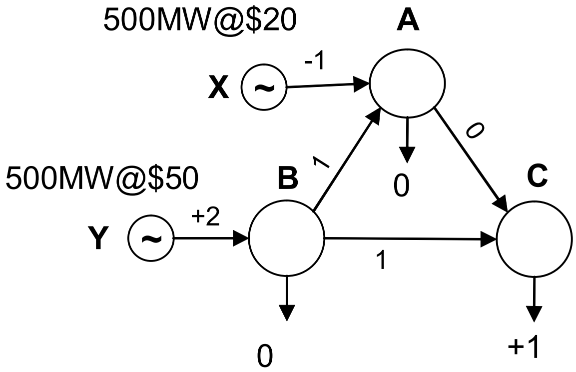

Figure A3: Incremental Load at C

Thus, the cost of 1MW at C is: 2MW * $50/MWh – 1MW * $20/MWh = $80/MWh

The nodal prices for the network are shown in Figure A4 below.

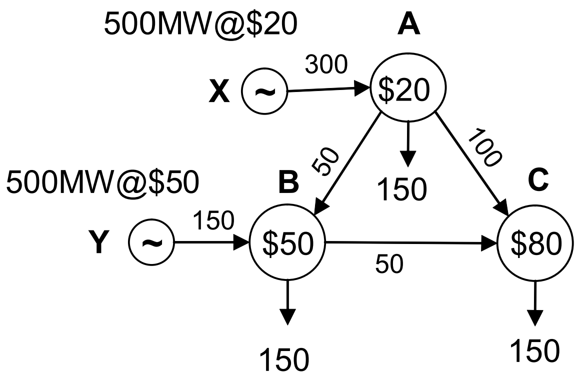

Figure A4: Nodal Prices

This simple model illustrates some fundamental characteristics of nodal prices:

- there are N+1 "marginal" generators, where N is the number of network constraints which are active (ignoring other constraints: eg ancillary services).
- the nodal price at the node of each marginal generator is the generators bid price.
- nodal prices at other nodes are a linear combination of the marginal generators bid prices, with the combination weights depending upon the admittances of the network links and the network topology.
- nodal prices around a loop which includes an active branch constraint have a "spring washer" characteristic, with the open part of the washer being on the constrained link.
- thus, nodal prices between two adjacent nodes will "separate" whenever they are on a loop which contains an active constraint. Or, put another way, at least one link on one path (not necessarily the direct path) between the two nodes is constrained.

Flowgate Prices

The other prices that are derived as part of the dispatch process are the "flowgate" prices which represent the "value" of the capacity on each link. This value is the increment in dispatch costs that would be caused as a result of a 1MW reduction in capacity on that link. For example, if the capacity on A-B was reduced to 99MW, the network would need to be redispatched as shown in Figure A5.

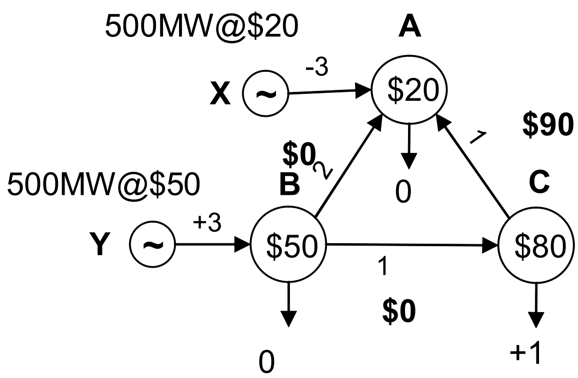

Figure A5: Decremental Capacity on A-C

64 Because the network model is linear, we can find solutions by the principle of "superposition". This means by adding the incremental flows to the basic flows, we find the flows for the incremented solution: thus the load at C is 100+1 = 101 and the flow on A-C is 100+0 = 100 etc.

The change in cost is then:

$$3MW * \$50/MWh – 3MW * \$20/MWh = \$90/MWh$$

The other links are not constrained, so a 1MW reduction in capacity has no effect on dispatch and they have a flowgate price of zero. Flowgate prices are shown next to each link on Figure A5. This model illustrates the following fundamental characteristic of flowgate prices:

- flowgate prices are only non-zero where a link is congested;
- flowgate prices are a linear combination of the bid prices of marginal generators; and
- nodal prices differences are a linear combination of the flowgate prices on all links on a path (not necessarily a direct one) between the two nodes.

This last point is not clear from the example, but is important. For example, the nodal price difference between A and B can be expressed as:

$$NP_B – NP_A = 2/3 * FGP_{AB} + 1/3 * FGP_{AC} + 1/3 * FGP_{BC}$$

where:

NP_i is the nodal price at node i

and

FGP_{ij} is the flowgate price on link i-j

Because the network has triangular symmetry, similar formulae apply for other nodal price differences.

The characteristics of flowgate prices are quite intuitive (in that the price is only non-zero if the link is constrained) and are what one might – mistakenly – expect for nodal prices: ie that prices at adjacent nodes only separate if the direct link between them is constrained[65].

Transmission Spot Revenue

It is well known that there is a “settlement surplus” arising on a nodally priced network whenever nodal price differences occur. In this paper, this is referred to as transmission spot revenue since, in an economic sense, it is “earned” by the transmission network. There are 3 different, mathematically equivalent, ways of expressing this revenue:

[65] As we noted above, the prices in fact separate whenever there is a constraint on any *indirect* link between them

Energy settlement surplus = load receipts – generator payments

Line Rental = sum of line flows multiplied by price difference across line

Flowgate revenues = sum of line flows multiplied by flowgate price

These equivalent measures are shown for the triangle example in tables A1 to A3, below:

Participant	Offtake	Nodal price	Revenue
Gen X	-300	20	-6000
Gen Y	-150	50	-7500
Load A	+150	20	+3000
Load B	+150	50	+7500
Load C	+150	80	+12000
Total			*+9000*

Table A1: Settlement Surplus Calculation

Link	Flow	Price diff	Revenue
A-B	+50	+30	+1500
A-C	+100	+60	+6000
B-C	+50	+30	+1500
Total			*+9000*

Table A2: Line Rental Calculation

Link	Flow	Flowgate Price	Revenue
A-B	+50	0	0
A-C	+100	+90	+9000
B-C	+50	+0	0
Total			*+9000*

Table A3: Flowgate Revenue Calculation

In a radial network, there are no loops and flowgate prices are identical to the nodal price difference across the link. Therefore, the line rental and flowgate revenue tables would look identical. No major transmission networks are radial, although some networks may have radial sections.

The equivalences demonstrated in the tables above are important in designing transmission hedging mechanisms.

Appendix B: Transmission Hedging Mechanisms

Introduction

This appendix discusses transmission hedging mechanisms. As described in the main body of this paper, two types of hedges may be used:

- financial transmission rights (FTRs)
- flowgate rights (FRs)

Each of these entitles the holder to a target cash payment (positive or negative) based on nodal price outcomes. Typically, the liabilities are underwritten by transmission spot revenue, to the extent possible, and the target payments will not be fully met if the revenue is insufficient. Thus, the “firmness” of the hedges - the extent to which target payments are actually paid - depends upon the likelihood and extent of revenue shortfalls given possible circumstances and outcomes on the network.

Financial Transmission Rights

An FTR of “x” MW between point A and point B on a network, entitles and obliges the holder to receive (or pay, if negative) an amount of “x” times the price difference between point B and point A. For simplicity, the “points” are assumed to be nodes in our example. Thus 6 different FTRs are possible: A-B, A-C, B-A, B-C, C-A, C-B.

The “simultaneous feasibility condition” (SFC) states that, if all of the injections and offtakes implied by a set of issued FTRs can be accommodated on a network, then the transmission spot revenue on that network will always equal or exceed the aggregate target payments. “Implied” means that the injection (offtake) at each node is the aggregate volume of FTRs referenced from (to) that node.

Suppose that the set of issued FTRs is as shown in Table B1 below. It will be seen that the flows implied by these FTRs is the same as the spot market dispatch, and therefore the SFC is satisfied, as the dispatch must be feasible. In fact, the summated target payments in this case exactly equal the spot market revenue: this is a special case of the SFC theorem.

Point-to-Point	Volume	Price Diff	Target Payment
A-C	150	+60	+9000
A-B	150	+30	+4500
B-A	150	-30	-4500
Total			*+9000*

Table B1: Issued FTRs equal Dispatch

Tables B2 and B3 below show feasible and infeasible FTRs sets, respectively.

Point-to-Point	Volume	Price Diff	Target Payment
A-B	150	+30	+4500
B-A	150	-30	-4500
B-C	150	+30	+4500
Total			*+4500*

Table B2: Issued FTRs simultaneously feasible

Point-to-Point	Volume	Price Diff	Target Payment
A-B	300	+30	+9000
B-C	150	+30	+4500
Total			*+13500*

Table B3: Issued FTRs not simultaneously feasible

FTR issuance processes are designed to ensure that the issued set of FTRs is feasible

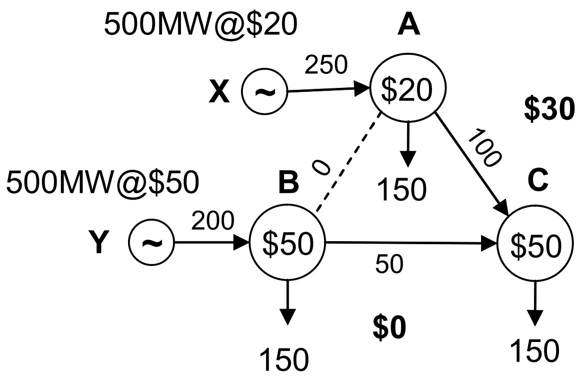

Figure B1: Line Outage

on the *expected* network. However, forced outages cannot be anticipated and may lead to infeasibility and therefore revenue shortfall. Suppose, for example, the link A-B was out-of-service. The new dispatch on the (now radial) network is shown below, together with nodal prices and flowgate prices.

The spot price revenue has now fallen to $3000. It is seen that the dispatch implied by the first set of FTRs from table B1 (repeated in table B4 below) is no longer feasible, and there is a revenue shortfall.

Point-to-Point	Volume	Price Diff	Target Payment
A-C	150	+30	+4500
A-B	150	+30	+4500
B-A	150	-30	-4500
Total			*+4500*

Table B4: Revenue Shortfall due to Forced Outage

This is perhaps an unusual example, as the price has fallen at C following the outages. Nevertheless, it demonstrates that forced outages can lead to revenue shortfall, meaning target payments cannot be met in full.

An intuitive response to this would be to "cancel" the FTRs that are "using" the link that is out-of-service: ie FTRs A-B and B-A. However, in this example, this does not help the revenue shortfall situation. The intuitive response is in any case quite arbitrary, since in a meshed network, all of the issued FTRs will be "supported" to some extent by the link A-B.

The approach used in market designs is to scale back the target payments to *all* issued FTRs pro-rata[66]. Thus, in our example, actual payments would be just two thirds of target payments on each of the 3 FTRs.

This paper refers to the pro-rata approach as "global non-firmness", since all FTRs are equally non-firm, irrespective of their location on the network. Is this a good or bad design feature? In a sense it is good, as it diversifies the non-firmness risk across the entire network, thus (hopefully) making all FTRs quite firm. On the other hand, it is hard to hedge against global non-firmness. For example, an FTR between Latrobe and Melbourne could be scaled back when there is an outage in Queensland. It would be difficult to insure against this sort of non-firmness.

Flowgate Rights

A flowgate right on a link entitles the holder to target payments based on the contract volume multiplied by the flowgate price on the link. A flowgate right takes the form of a directed option: thus a flowgate right from A to B only pays out if the link is constrained in that direction.

The major drawback with flowgate rights is that they do not relate directly to nodal price differences. Thus, the flowgate right A-C does not perfectly hedge the price difference between A and C: in our example, the flowgate price is \$90/MWh, but the price difference is only \$60/MWh and, similarly, the flowgate price from B to C is zero, against a nodal price difference of \$30/MWh. In fact, because the nodal price difference is a linear combination of flowgate prices (see Appendix A), a perfect nodal price hedge would require an equivalent holding of flowgate rights. On the other hand, a reasonable hedge could be obtained by ignoring those flowgates which are unlikely to be constrained or which have only a small weighting in the linear combination formula[67].

In their favour, revenue adequacy conditions for a set of issued flowgate rights are straightforward to determine. Because the flowgate price is only non-zero (and so target payments are zero) when the link is constrained (ie the flow is equal to the link capacity), any non-zero flowgate revenue is equal to the flowgate price multiplied by the link capacity. This will be sufficient to underwrite issued flowgate rights, so long as the total

[66] This is due to the difficulty in deciding which FTRs should be affected by a line outage, since all may be to some extent. There may be a theoretical approach to improving the pro-rata scaling but, if so, this is not used in any of the market designs reviewed.

[67] Analysis undertaken in the US has shown that, due to security constraints and line outages, a large proportion of the links on a network can become constrained under certain credible circumstances and thus hedging using flowgate rights is problematic.

issued capacity of flowgate rights on a link is no more than the link capacity. Table B5 below shows target payments when a "full" set of flowgate rights have been issued

Flowgate	Volume	Flowgate Price	Target Payment
A-B	100	0	0
B-A	100	0	0
A-C	100	90	+9000
C-A	100	0	0
B-C	100	0	0
C-B	100	0	0
Total			*+9000*

Table B5: Flowgate target payments

However, as for FTRs, revenue inadequacy may occur when there is a forced transmission outage. In this case, revenue adequacy can be restored simply by scaling down or cancelling the flowgates rights issued on the failed link. The remaining issued flowgates can be adequately funded from flowgate revenue on the remaining links. Thus we can have "local non-firmness" of flowgate rights[68]. This is demonstrated in Table B6 below, assuming an outage on A-B as before. Note that the flowgate price on A-C then becomes $30/MWh and on B-C remains at zero.

Flowgate	Volume	Flowgate Price	Target Payment
A-B	0	0	0
B-A	0	0	0
A-C	100	30	+3000
C-A	100	0	0
B-C	100	0	0
C-B	100	0	0
Total			*+3000*

Table B6: Revenue Adequacy using Local Non-firmness

Although the NEM network model is radial, the transmission hedge model is one of flowgate rights (SRA instruments) and local non-firmness rather than FTRs and global non-firmness. Thus, a holder of the Vic-SA flowgate right can hold insurance with an SA generator to cover any possible outages on the Vic-SA interconnector. The non-firmness risk is higher compared to global non-firmness (due to the loss of diversity) but easier to insure against.

To summarise, the choice of FTRs versus flowgate rights depends upon the relative importance of a purer hedging mechanism (FTRs) versus optionality and local non-firmness (flowgate rights).

[68] Of course, we could alternatively have global non-firmness, though, if this design was preferred.

Appendix C: FTR Auctions

Process

In any FTR auction process, market participants bid to buy FTRs. Each bid will specify:

- the FTR required: ie the “sending” and “receiving” points, month, time-of-day etc
- the maximum volume required in MW
- the bid price in $/MWh: ie the highest price that the bidder is prepared to pay

The FTR auction objective is to maximise the value of FTRs cleared (based on the bid prices) subject to satisfying the simultaneous feasibility condition: ie that the flows implied by the aggregate cleared FTRs (plus any pre-existing FTRs) can be accommodated on the forecast network.

The results of the auction process will specify:

- the clearing price for each FTR[69]
- the volume of each order that has been cleared

Each cleared order should have a cleared volume no greater than the bid volume and a clearing price no higher than the bid price.

Example

Table C1 below shows the orders and outcomes for an FTR auction taking place on the triangle network described in Appendix A

Order Ref	From Node	To Node	Bid Quantity	Cleared Quantity	Bid Price	Clearing Price
1	A	B	150	150	22	16
2	A	C	150	50	32	32
3	B	C	50	50	48	16

Table C1: FTR orders and auction results

Note that orders 1 & 3 have been fully cleared, and the clearing price is below the bid price, analogous to an intra-marginal, fully-loaded generator in the dispatch process. Order 2 has been only partially cleared, and the clearing price is equal to the bid price, analogous to a part-loaded, marginal generator.

Note also that the clearing prices are self-consistent. An FTR from A to C is equivalent to a combination of FTRs from A to B and from B to C, and both have the same aggregate clearing price of $32/MWh.

[69] In fact, it will provide clearing prices for all possible FTR types, even those which have not been bid in the auction

Finally, we can show that the aggregate ordered quantities satisfy the SFC. The flow implied by the cleared FTRs is shown below in figure C1. Two of the lines are fully loaded and any additional cleared volume would lead to overloading. The nodal prices shown are relative to the “reference node” which, for the purposes of the figure only is assumed to be node A[70]. Note that FTR clearing prices only imply nodal price relativities, not absolute levels.

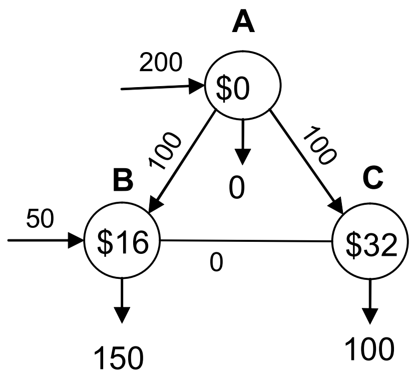

Figure C1: Implied FTR flows

[70] Choosing a reference node is not part of the FTR auction process, and is just done for illustration purposes here.

Appendix D: International Market Designs

Market	Spot Pricing	Spot Price Hedging	Transmission Services	Revenue Allocation
Australia (NEM)	Zonal pricing using zonal network model. Zones defined to limit intra-zonal congestion Static intra-zonal losses factors.	Quarterly, Non-firm, directed flowgate options (SRA instruments) issued through quarterly auction.	TUoS charges paid by load based on usage. Pricing based on deemed usage using deemed generation-to-demand matching ("CRNP"). New investment costs paid by deemed beneficiaries or coalition members	Auction revenue allocated to TNSP for importing zone, and passed through to users in reduced TUoS charges. No inter-zonal surplus or deficit. Intra-zonal surplus allocated to local TNSP and passed through to users
New Zealand (NZEM)	Nodal pricing including losses and thermal constraints. Applied to generation and load	None at present. Transpower proposes FTRs between hubs, nodes or zones. FTRs would be issued through auction.	Current service costs allocated to load on postage stamp basis Proposed "non-distortionary" allocation of "sunk" costs and "efficient" allocation of new investment cost. New Pricing methodology not yet defined	Spot price revenue allocated to users in proportion to transmission service charges. Proposal (Grant Reid) to allocate LT FTRs to load, between nodes and local reference node. No discussion on allocation of possible FTR auction revenue
Philippines (WESM)	Nodal pricing including losses, thermal and stability constraints applied to generation. Zonal prices – based on load weighted average nodal price in zone – applied to load.	FTR auction process mentioned in market rules, but unlikely to be implemented at market commencement. FTRs would hedge congestion and losses.	Currently paid for by load on zonal tariff. Maybe on booked or usage basis.	Spot price revenue paid to transmission and deducted from regulated revenue allowance.
South Korea (TWBP)	Unconstrained pricing, with marginal loss factors applied Compensation for constrained generators based on generator offer prices, but with a regulated	No hedging arrangements.	Not known	Congestion costs recovered through uplift charge to load. Congestion uplift separated from FCAS uplift, so could be allocated to transmission at future date.

Market	Spot Pricing	Spot Price Hedging	Transmission Services	Revenue Allocation
	ceiling price.			
Singapore	Nodal pricing including losses, thermal and stability constraints applied to generation. Single “uniform” price– based on load weighted average nodal price across market – applied to load.	No hedging arrangements. Generators want vesting contracts (currently referenced to zonal price) to reference generator nodal prices to remove basis risk. Market rules provide for FTRs between node and “hub”, but not yet implemented.	Not known	Spot revenue returned to load through uplift “credit”.
New England (NEPool)	Nodal pricing including losses, thermal and stability constraints applied to generation and load. Prices calculated for defined “load-zones” and “hubs” using weighted average and unweighted average of nodal prices, respectively	FTRs (swaps) based on day-ahead congestion prices (ie nodal prices excluding losses). Peak and off-peak, monthly. Monthly and six-monthly auctions. Secondary trading allowed Backed by spot revenue and payments scaled back if annual shortfall	Similar to PJM	Uses ARR mechanism ARRs first allocated to “qualified upgrades” funded by coalitions, based on incremental capacity calculation. Remaining ARRs allocated to load, based on deemed load-to-generation matching and reconciliation with SFC. ARRs scaled down to match auction revenue. Annual residual spot revenue shared in proportion annual spot congestion charges.
Ontario (IMO)	Unconstrained Pricing – without losses - except for nodes that interface with neighbouring markets. Compensation for constrained generators based on generator offer prices.	FTRs (“transmission rights”) available for tie-lines only.	Postage-stamp usage charge to all load.	Congestion costs recovered through uplift charge to load

Market	Spot Pricing	Spot Price Hedging	Transmission Services	Revenue Allocation
	Regulation of “must-run” plant			
PJM	Nodal pricing including thermal and voltage constraints (but excluding losses) applied to generation and load. Prices calculated for “zones”, “hubs”, “aggregates” based on weighted average nodal prices, used in FTRs.	FTRs (swaps and options on some “paths”), peak and off-peak, monthly and annual Between nodes, zones, hubs or aggregates Settled against day-ahead nodal prices. Auctioned annually and monthly using 4-round process. Worst-case assumption used for options in SFC. Secondary market run by ISO. Backed by spot revenue and payment scaled back if monthly/annual revenue shortfall	Firm and non-firm booked point-to-point service and network service Network service must specify which generation serves load (not clear how), based on peak load usage Queuing process to ensure service requirements can be accommodated by network (not clear how) Zonal network charges and postage-stamped (apparently) point-to-point charges Deep connection charges for new generation	ARR mechanism Deep connection and merchant transmission allocated ARRs for up to 30 years (not clear how) based on incremental capacity. Have one-shot option to switch to annual nomination (eg to avoid negatively valued ARRs) Point-to-point service users can request equivalent ARR. Network service users can request zone-to-zone ARRs, up to peak load and aggregate generation capacity in each zone Requests reconciled with SFC through clearing engine ARR payments scaled back if insufficient auction revenue Annual revenue surplus (after making good FTRs), first makes good ARR payments and then allocated to transmission service users

Market	Spot Pricing	Spot Price Hedging	Transmission Services	Revenue Allocation
California (CAISO – MD02)	Nodal pricing including losses, thermal and stability constraints applied to generation and dispatchable load Zones based on IOU service areas. Loads pay zonal prices – based on load-weighted average nodal prices. Use a semi-constrained day-ahead schedule to identify "must run generation". Hub prices calculated – based on current "congestion zones"	FTR swaps (called "congestion revenue rights" to distinguish from old-market FTRs) Hedge congestion price only in day-ahead market Existing transmission contracts (ETCs) preserved ETCs and CRRs give dispatch priority over congested lines. Most CRRs allocated (see revenue allocation). Remainder auctioned. CRRs may be between nodes, zones, hubs. Linear combinations of CRRs ("network service CRRs") also allocated Backed by spot revenue, with monthly and annual scale back where revenue shortfall	ETCs provide "firm access" – exemption from congestion charges, but no new contracts being offered. Load pays uniform "access" charge across IOU area based on usage. Over time, IOU access charges will converge to single postage-stamp price.	ETCs can be converted to CRR swaps or options. Remaining CRRs available allocated to load based on 0.5% exceedance peak load and "typical grid usage" (ie generator source)(not clear how policed) If retail churn, CRRs follow customers. Incremental CRRs allocated to those funding new transmission. Auction revenue and residual revenue allocated to transmission companies and deducted from regulated allowable revenue.

Review of Interconnector Support Service Proposal

October 2003

CreativeEnergy

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1. Introduction

Background

A previous report[1] prepared for the ERAA reviewed international approaches to transmission pricing, through the spot market and through regulated tariffs. Five "straw men" were developed which covered the spectrum of international approaches and these straw men and the merits of implementing each of these straw men in the NEM were evaluated against a set of evaluation criteria.

Transmission pricing has been under review by NEMMCO as part of their review of intra-regional constraint formulation. In particular, Charles Rivers Associates (CRA) has prepared a report[2] for NEMMCO setting out a proposed framework for dealing with interconnector congestion. They call this framework "interconnector support services" (ICS).

The ICS framework is different in detail to all of the straw men developed for the ERAA, although there are strong similarities with two of them in particular:

- Political Pragmatism (PP); and
- Congestion Controller (CC)

This report, therefore, compares the ICS approach to the PP and CC straw men, and evaluates its relative merits.

Approach

The earlier ERAA report compared the merits of the straw men to a benchmark "status quo". However, given the similarities between ICS and PP, the ICS approach has been compared to and evaluated against the PP. The CC model has only been considered in relation to one aspect of the ICS approach.

A difficulty with evaluating the ICS approach is that it is only described on a very simplified network. Thus, this report has attempted to deduce from comments in the CRA report how the ICS approach would be implemented on a generalised network such as the Australian grid.

The same evaluation criteria and approach have been used in this report as in the earlier ERAA report. Thus, by implication, the ICS approach can also indirectly be evaluated against the other straw men.

Both the PP and the ICS models assume that a certain quantity of FTRs will be allocated to generators. This report also considers how this allocation might be undertaken.

[1] A Review of International Approaches to Transmission Pricing, August 2003
[2] Dealing with NEM Interconnector Congestion: A conceptual Framework, March 2003

2. Generation Spot Pricing

ICS Proposal

The CRA proposal in relation to generation spot pricing is for the current regional pricing of generation to be complemented by an additional generation price, referred to as the interconnector support (ICS) price. The ICS price is related to the marginal value that each generator provides in relation to facilitating an increase in interconnector flow between the low-priced and high-price region. Because this value depends upon the particular location of each generator in the network, the ICS price is “nodal”: ie each transmission node will potentially have a different ICS price associated with it.

CRA only explain how the ICS price will be calculated and applied in a simplified model of the network. This model has:

- two regions;
- a single physical link between the two regions;
- a single node in one region;
- a single loop[3] in the other region, where every node – including the regional reference node (RRN) and the node at which the inter-regional link connects – is on the loop
- just one transmission constraint, on the intra-regional loop

In this simple model, the sum of the regional reference price (RRP) and ICS price (ie the effective price paid by generation at the margin) is mathematically identical to the conventional locational marginal price, or “nodal” price: eg as used in the PJM market.

An example of the nodal prices arising in this simplified network is shown below. In this example, there is no “intra-regional generation” or load connected between the two reference nodes. The inter-regional flow is constrained to 500MW by the 200MW intra-regional constraint at the base of the pentagon. In the terminology of the CRA, 500MW is the “unsupported” interconnector capacity. The nominal interconnector capacity (ie the capacity of the inter-regional link) is 1000MW.

The nodal prices show the classic “spring washer” effect. For simplicity, all line impedances are assumed to be equal.

[3] A loop is a path made up of a chain of physical links on the network which starts and ends at the same node and passes through other nodes at most once.

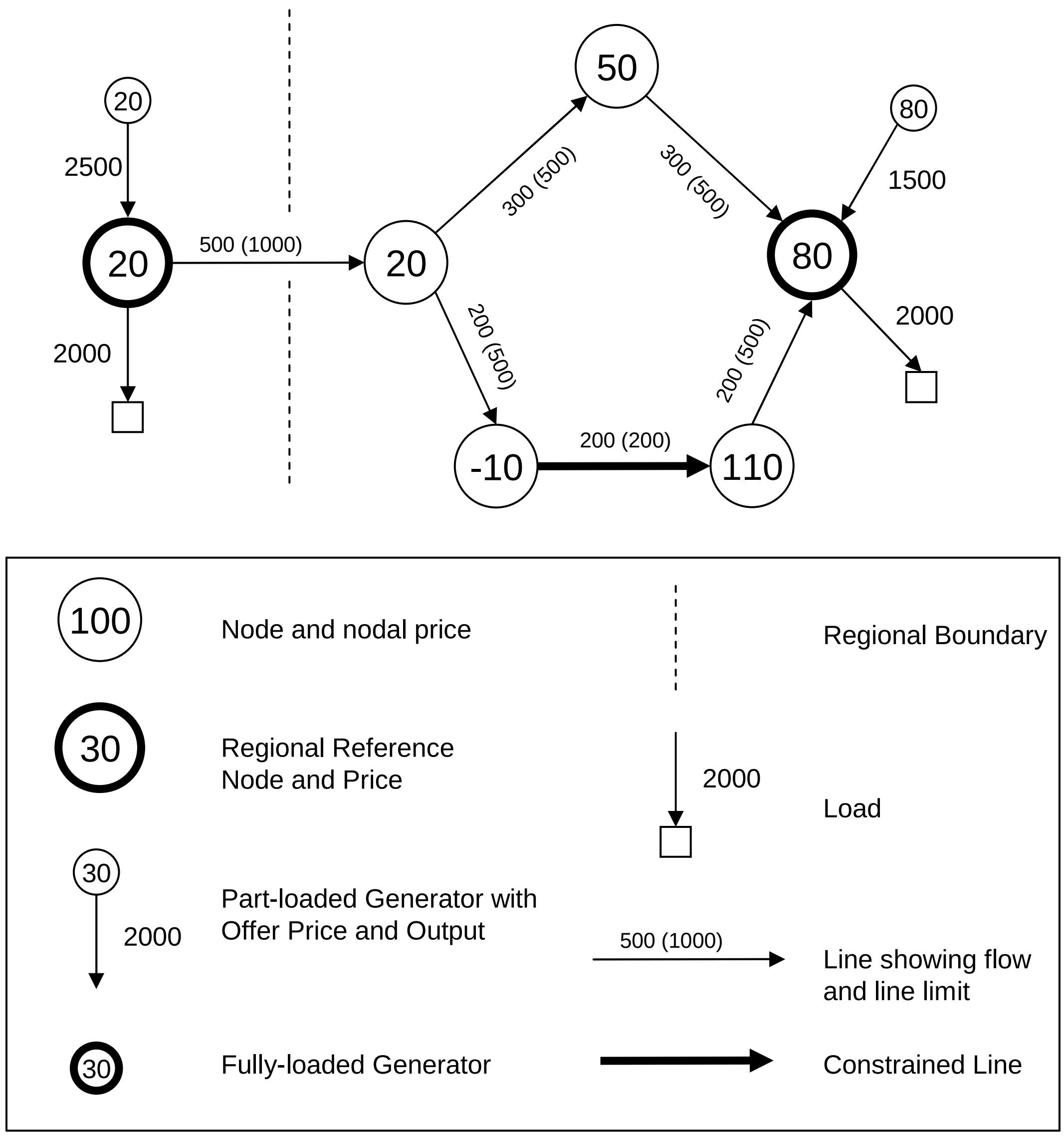

Figure 1: Simple Network Model and Key

Generalising the ICS Approach

It is not clear from the CRA report how the ICS pricing methodology would be generalised to apply on a real network where:

- there are more than two regions;
- there are parallel physical links between two regions;
- there are loops which cover three or more regions
- there are multiple loops in a region
- there are multiple constraints, on both intra-regional and inter-regional links

The objectives of the ICS approach are to encourage generators to behave in a way which maximises the benefits of inter-regional flows. Thus, it will be assumed that every constraint that potentially affects inter-regional flows should be included within a generalised ICS pricing methodology.

Nodal pricing theory means that a constraint on a single transmission link will affect the price at every node which lies on a loop which includes that constrained link. A link constraint will affect interconnector flows if it affects the nodal price at an "interconnection point" - a node at which the inter-regional link connects to the regional network. Thus, a constraint on a link will affect interconnector flows *if and only if there exists a loop which contains both the constrained link and an interconnection point*.

Therefore, the ICS pricing methodology may differ from full nodal pricing in that the former excludes consideration of constraints on links which don't meet the criterion described above. Such excluded links may constitute significant parts of the network, including:

- any radial links which, by definition, do not lie on any loop; and
- any "intra-regional sub-sections" of the network, meaning sections of the network that do not contain any interconnection points and which are connected to the rest of the network only at a single node[4]

The diagram below shows the "intra-regional sub-sections" and "inter-regional sub-section" (remaining network) on an example network. In the ICS approach, only constraints within the inter-regional sub-section would be priced.

If constraints on "excluded" links are not incorporated within the ICS prices, there will be no ICS price differentiation across excluded links[5], and so each intra-regional sub-section of the network will have a single ICS price: the price at the node connecting the sub-section to the remainder of the network.

[4] We can see that a link within an intra-regional subsection cannot lie on a loop including an interconnection point, since there is no way to get from the link to the interconnection point and back without twice going through the single interconnecting node.
[5] ignoring loss factors

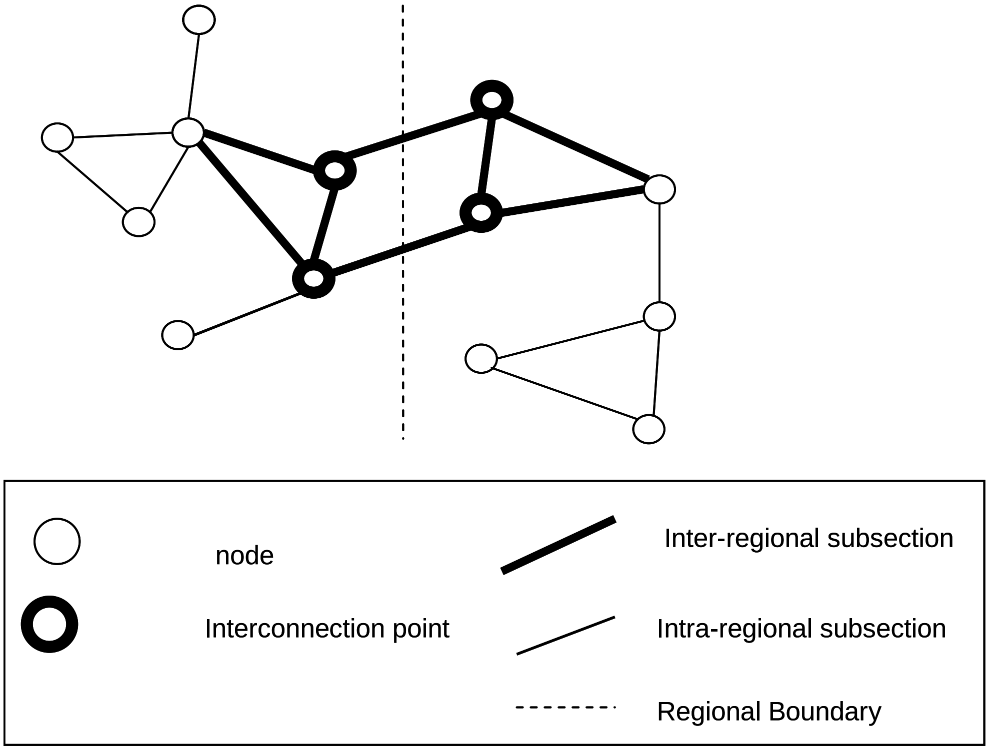

Figure 2: Network Subsections

In the NEM, possible[6] intra-regional sub-sections include:

- Far North Queensland: eg North of Nebo
- South Australia, North and West of Tailem Bend
- radial intra-regional networks in Western Qld and North and Western NSW

Apart from in SA, intra-regional sub-sections are peripheral parts of the network, where there is likely to be relatively little demand and little or no local competition in generation. Therefore, removing constraint pricing in these regions may mitigate local generator market power. However, this will only be effective if the transmission constraints that prevent competition from remote generators are within the intra-regional sub-section (and so not priced).

Conclusions

Generation spot pricing at the margin under the ICS approach will be the same as the LMP pricing which is also used in the PP and CC straw men, except within intra-regional sub-sections of the network.

[6] It is not always clear where loops exist, as nodes can be "split" into two, depending upon the substation configuration.

3. FTR Allocation

Allocation Objectives

The CRA report proposes that the ICS price is only applied to the difference between generator output and a specified "reference point". It recognises that, in effect, this proposal is identical to a LMP/FTR design where the reference point is the volume of FTRs allocated to each generator. Each FTR is a node-to-node FTR applying between the generator node and the RRN.

The FTR allocation methodology attempts to achieve two conflicting objectives:

- give generators financial access rights to the RRN (or, equivalently, provide them with financial hedges against the basis risk between the nodal and regional prices);
- preserve the settlement surplus to allow it to underwrite settlement residue auction (SRA) instruments which are as firm as possible compared to the nominal interconnector capacity.

These competing objectives are similar to those that informed the debate over intra-regional constraint formulation and ask the same question: ie how should constrained intra-regional transmission capacity be allocated between intra- and inter-regional generation? The difference is that the constraint formulation asked the question in relation to *physical* rights, whereas the debate is now over *financial* rights: the physical issue has effectively been "solved" by the move to nodal pricing for generation[7].

In the remainder of this section, we assume that all demand is located at the RRN, so that there is no practical difference between using the RRP or the demand-weighted average (DWA) nodal price[8] for regional demand pricing. This assumption is relaxed in the next section.

Allocation Processes

FTR theory provides a test for "revenue adequacy" such that total payments due under centrally-issued FTRs can always be met from the settlement residue. The test is that the generation-demand pattern implied by the set of issued FTRs must be physical feasible over the transmission network.

In the ICS approach, generators are in effect allocated intra-regional node-to-RRN FTRs by the setting of the "reference points". There are no inter-regional FTRs. Instead, any settlement residue which remains after the intra-regional FTRs are paid out is sold through SRA process. Thus, the SRA instrument is not an FTR as such.

[7] And by the choice of "Option 4A" that formulate constraints based on the true physical network constraints
[8] Which is adopted in the PP model

However, our objective is to provide "firm" SRA instruments, by which we mean to have the SRA instrument looking as much like a firm inter-regional FTR as possible[9]. So, one way of measuring the "firmness" of the SRA is to see what volume of firm inter-regional FTR could be underwritten by the residual settlement residue. This can be done by essentially undertaking a simultaneous feasibility test for a specific level of inter-regional FTR plus the allocated level of intra-regional FTRs.

The CRA paper proposes three alternative FTR allocation processes:

- "unsupported": the reference point is zero – ie generators get allocated no FTRs;
- "natural": the FTR quantity is determined by the amount of the generator's capacity that is "in-merit" in relation to the RRP;
- "contract": generators have a fixed quantity of FTRs, although the process for determining this quantity is not specified.

The "ICS Contract" approach is similar to that used in the PP straw man, which specified that FTRs would be allocated to existing generators to grandfather them against the changes introduced by nodal pricing.

The "ICS Natural" approach is similar to that used in the CC straw man, although in that case, the in-merit capacity is in relation to the semi-constrained zonal price rather than the RRP[10]

Therefore, the ICS Unsupported, ICS natural (including the CC straw man) and ICS Contract (including the PP straw man) are considered further in the next sections.

Unsupported Approach

In this approach, there are no intra-regional FTRs allocated. Therefore, the simultaneous feasibility test for assessing what volume of inter-regional FTR can be supported by the settlement residue will essentially look at how much power can flow through the interconnector when all intra-regional generation (excluding that at the RRN) is dispatched to zero. CRA refer to this as the "unsupported interconnector capacity".

CRA show how intra-regional generators may either be constrained-on or constrained-off to maximise the interconnector flow. Thus, assuming zero allocated FTRs will support the interconnector capacity (and hence the SRA firmness) in relation to constrained-off generation, but impede it in relation to constrained-on generation. Therefore, the effectiveness of this approach will depend upon whether intra-regional generation is constrained on or off. In the simple example, the unsupported interconnector capacity is 500MW.

[9] Except in relation to "tidal flows" where the direction of inter-regional flows reverses. This is addressed further below.
[10] remembering that the RRP is simply the nodal price at the RRN

Natural Approach

The natural approach allocates potentially high volumes (generally equal to the generator capacity) of FTRs to constrained-off generation whilst allocating no FTRs to constrained-on generators. Thus the physical flow implied by the "constrained-off" FTRs will impede the interconnector flow, whilst there is no offsetting benefit from constrained-on generation. As a result, there is likely to be a substantial reduction in the effective inter-regional FTR capacity available through the SRA. In fact, in some cases, the implied dispatch of intra-regional generation may be infeasible, even with no inter-regional flows: in other words, there may be a settlement deficit, after the intra-regional "natural" FTRs have been paid out.

This problem may be exacerbated through "constrained-off gaming" where a generator knows that it will be constrained off whatever its offer price, and so reduces its offer price so as to increase the value of its allocated FTRs. Because the generator is constrained off, reducing its offer price will not affect the level of the RRP. The figure below shows an example of a constrained-off generator bidding a low price, knowing that its revenue is guaranteed by its "natural" FTR cover.

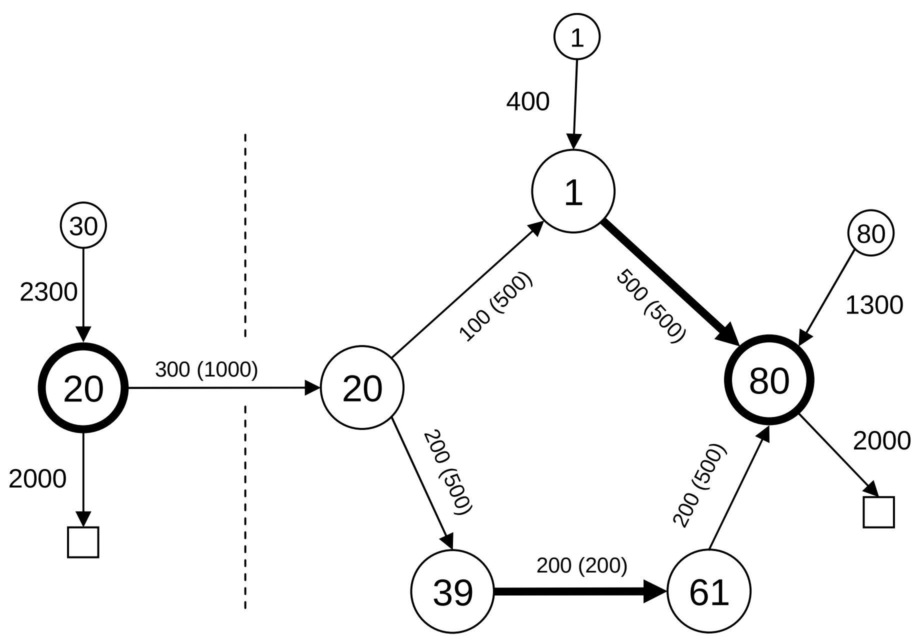

Figure 3: Constrained-off Game

The settlement of this example is shown in the table below: "L" and "R" refer to the regions on the left and right of the diagram, respectively.

GENERATION							
Node	*Node Price*	*Regional Price*	*Gen Output*	*Natural Output*	*Nodal Payment*	*"FTR" Payment*	*Total Payment*
RRN "L"	20	20	2300	n/a	46000	0	46000
RRN "R"	80	80	1300	n/a	104000	0	104000
i/r Gen	1	80	400	1000	400	79000	79400
Total			**4000**				**229400**
DEMAND							
Node		*Regional Price*	*Demand*				*Total Receipt*
RRN "L"		20	2000				40000
RRN "R"		80	2000				160000
Total							**200000**
SETTLEMENT RESIDUE							
						Residue	**-29400**

Therefore, we can see that there is a substantial settlement deficit, caused by the constrained-off payments and not by "counterprice" flows on the interconnector.

The CC model also suffers from this constrained-off problem. However, it is mitigated by two design features:

- the FTR is referenced to the "semi-constrained" price, which is more likely to respond to a reduction in a generator's offer price; and
- the TNSP is responsible for intra-regional congestions costs, thus incentivising them either to remove the constraints or to contract with generators to prevent gaming.

The CC model, in effect, requires the TNSP to "top-up" the settlement shortfall, so that the settlement residue underwrites a firm SRA based on the nominal interconnector capacity[11]. Therefore, if a "natural" approach to determining generator financial access rights is desired, the CC model is preferable to the ICS approach.

Contract Approach

The contract allocation methodology is not described in the CRA report. To aid comparison, it will be assumed that the same methodology is used for both the PP model and the ICS Contract model. But what should this approach be?

The intent of the PP model is to use the allocated FTRs to preserve the status quo in financial terms: ie a generator should be receiving the same revenue from the market pre- and post-transition, when revenue from the allocated FTRs is included.

[11] Although the SRA would still be non-firm to the extent that there are outages on the inter-regional links themselves

But what is this status quo? The problem that the intra-regional constraint review had to address was that the Code is unclear how intra- versus inter-regional dispatch should be prioritised. The choice of “Option 4A” (ie using the constraint formulation implied by a full network model) and this would, in practice, allow intra-regional generation to take priority, by reducing their offer prices. However, this Option was only recommended assuming that an ICS approach was adopted to correct this apparent inequity. So we have gone full circle.

This issue will not be resolved here. However, the strength of the contract approach is that, whatever objective is decided, contracts can be allocated to implement it. This is done by assuming the desired level of SRA capacity (inter-regional FTRs) has been allocated, and then allocating the remaining network capacity through intra-regional FTRs, using the “simultaneous feasibility” condition. Of course, this also begs the question of how the competing requirements of the different intra-regional generators should be prioritised. However, again, whatever is decided can be incorporated into the FTR allocation process.

To the extent that intra-regional generators get allocated FTRs, there may still be some constrained-off gaming. However, because the simultaneous feasibility condition has been enforced, this gaming should not lead to a shortfall in the settlement residue available for underwriting the SRA instruments.

The figures below show the calculation of two alternative FTR allocations to the intra-regional generators on the example network: the former favours the inter-regional generation (ie the SRA instrument) whilst the latter favours intra-regional generation. Note in each case that the implied generation-demand pattern is simultaneously feasible on the intact network. The sharing of the FTRs between the 3 generators has been achieved by assuming that they all “bid” the same price for their FTRs, but other allocation methods could also be used.

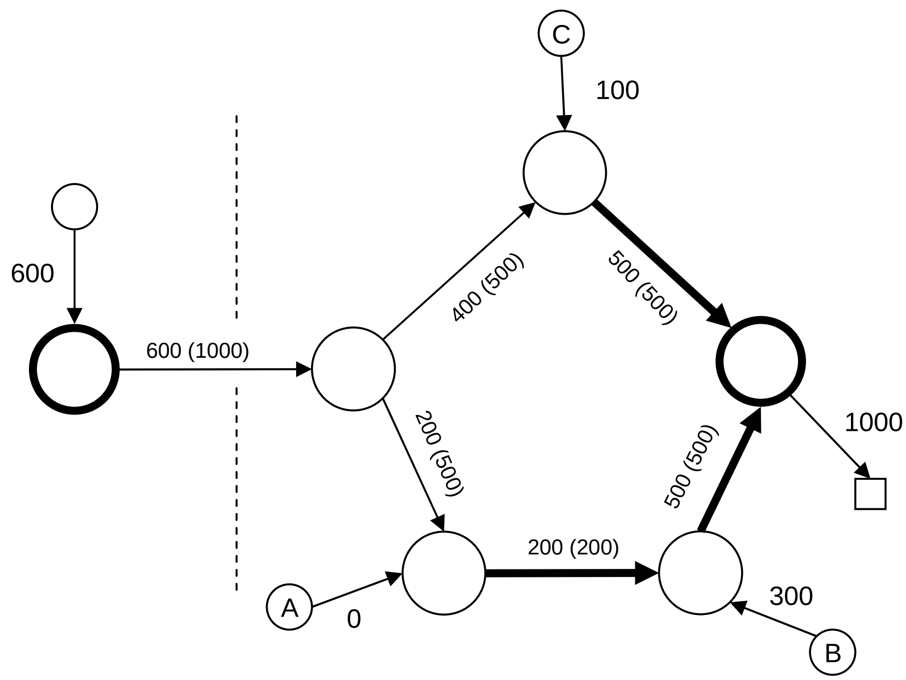

Figure 4A: Example FTR Allocation: maximum to inter-regional

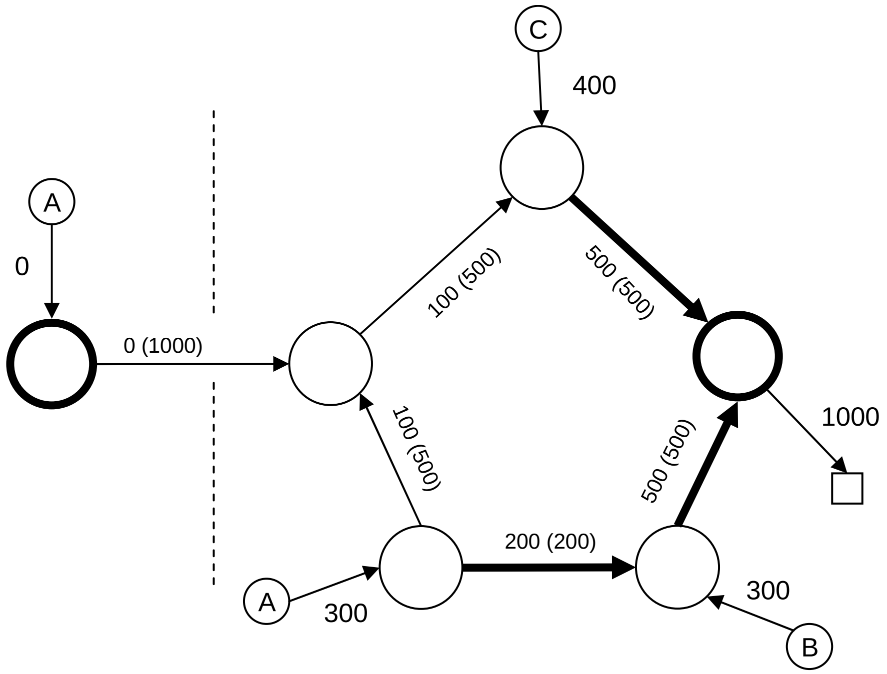

Figure 4B: Example FTR Allocation: maximum to intra-regional

We now look at how the different FTR allocations affect the settlement residue for a typical dispatch. The assumed dispatch and pricing is shown in the diagram below.

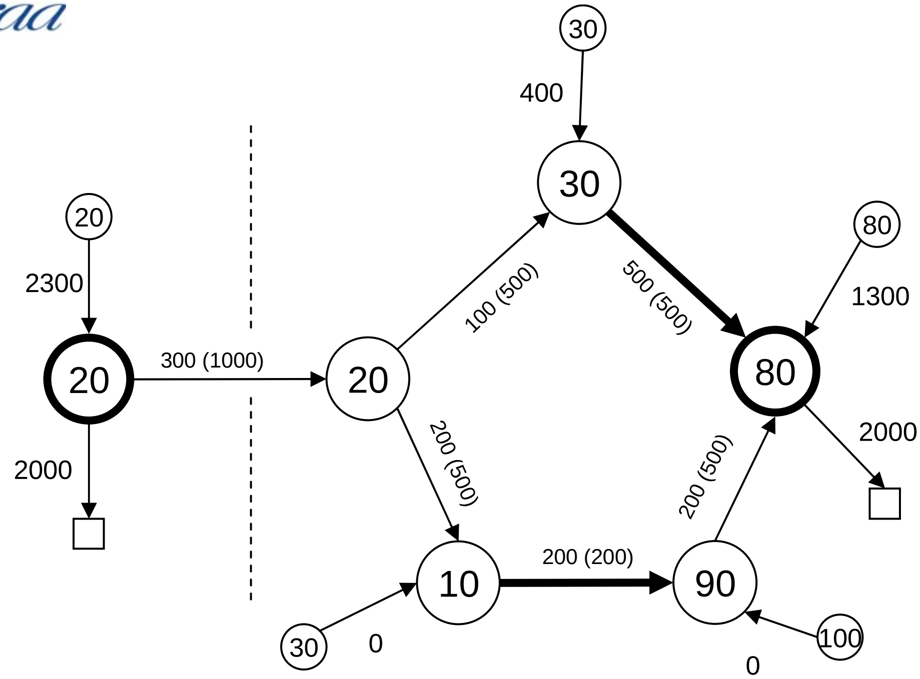

Figure 5: Example Dispatch - Import

The table below shows how the different FTR allocations affect settlements. With the inter-regional favoured, there is sufficient settlement residue to provide 600MW of inter-regional hedge cover through the SRA instrument, which corresponds to the volume of FTR that has been “allocated” to the inter-regional generator in Figure 4A. FTR theory means that – so long as the network is intact - this minimum amount is guaranteed, irrespective of generation dispatch. With intra-regional generation favoured, the settlement residue is fully allocated to intra-regional generators, leaving nothing for the SRA instrument.

GENERATION: FTR Allocation Favours Inter-regional							
Node	*Node Price*	*Regional Price*	*Gen Output*	*Allocated FTRs*	*Nodal Payment*	*"FTR" Payment*	*Total Payment*
RRN "L"	20	20	2300	n/a	46000	0	46000
RRN "R"	80	80	1300	n/a	104000	0	104000
Gen A	10	80	0	0	0	0	0
Gen B	90	80	0	300	0	-3000	-3000
Gen C	30	80	400	100	12000	5000	17000
Total			**4000**				**164000**
GENERATION: FTR Allocation Favours Intra-regional							
Node	*Node Price*	*Regional Price*	*Gen Output*	*Allocated FTRs*	*Nodal Payment*	*"FTR" Payment*	*Total Payment*
RRN "L"	20	20	2300	n/a	46000	0	46000
RRN "R"	80	80	1300	n/a	104000	0	104000
Gen A	10	80	0	300	0	21000	21000
Gen B	90	80	0	300	0	-3000	-3000
Gen C	30	80	400	400	12000	20000	32000
Total			**4000**				**200000**
DEMAND							
Node		*Regional Price*	*Demand*				*Total Receipt*
RRN "L"		20	2000				40000
RRN "R"		80	2000				160000
Total							**200000**
SETTLEMENT RESIDUE & SRA Firmness							
			Inter-regional Favoured			**Residue**	**36000**
						SRA MW	**600**
			Intra-regional Favoured			**Residue**	**0**
						SRA MW	**0**

Tidal Flows

FTR theory operates on the basis that allocated FTRs are "swaps": ie they can have positive or negative value depending on the direction of the price difference. However, the SRA instrument is treated as two separate directed options, so that settlement residue feeds into one option when interconnector flows are northerly (say) and then into the other option when they are southerly. Thus, excluding counterprice flows, the SRA instruments always return positive cashflows.

Thus, if we are allocating intra-regional FTRs on the assumption that the SRA instrument is equivalent to an inter-regional FTR in a particular direction, this assumption will breakdown should interconnector flows reverse, thus potentially leading to revenue shortfall. In addition, should we allocate the intra-regional FTRs with the objective of maximising northerly (say) MW for the SRA, this will probably not also maximise the SRA MW available when flows turn southerly.

There are a number of ways of dealing with this:

- Assume, when allocating FTRs that the flow is in a particular direction, and accept that the SRA instrument firmness may be poor in the reverse direction.
- Allocate time-dependent FTRs (eg peak and off-peak) broadly corresponding to the tidal direction. Thus peak FTRs could be allocated assuming a northerly flow, and off-peak assuming a southerly.
- Specify the allocated FTRs as flow dependent, so that the allocated volumes change when flow direction changes. The "northerly" volume would be allocated assuming the SRA instrument was a northerly FTR and the "southerly" volume would assume a southerly SRA instrument.

The latter option may look peculiar, but remember that all of the nodal prices for generators will also change as the flow direction changes: so a generator which is "constrained on" when flows are northerly may become "constrained off" when flows are southerly. Thus, a "tidal" FTR may have the characteristics of an option, and actually be preferable to a conventional FTR.

In the PP model, we do not have an SRA instrument, but instead have inter-regional (zone-to-zone) FTRs. Thus we do not have any potential difficulty of revenue inadequacy. However, it is likely that participants would like to have the inter-regional FTRs similar to the SRA instrument they are used to. This would probably be best done by allocating time-dependent FTRs, based on expected tidal flows.

The previous allocation of FTRs assumed an inter-regional "import" (into the right-hand region). If we aimed to allocate FTRs to maximise inter-regional "*export*", then we would have a different set of FTRs as shown below. Note that, although the flow direction has reversed, the intra-regional FTRs are still referenced to the generators' local (ie right-hand) regional reference node. Thus, we can simultaneously allocate 1000MW of inter-regional FTRs (from right-hand to left-hand region), although the generator at the right-hand RRN only has an output of 600MW.

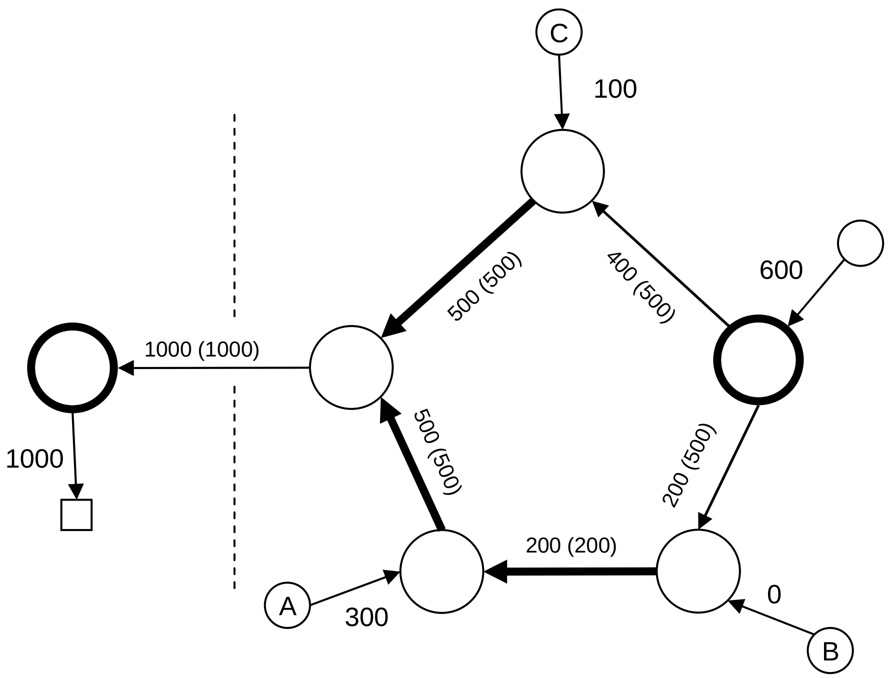

Figure 6: Example FTR Allocation: maximum to inter-regional export

Now we can look at how, under export conditions, the alternative FTR allocations affect the firmness of the "export" SRA. The assumed export dispatch is shown below.

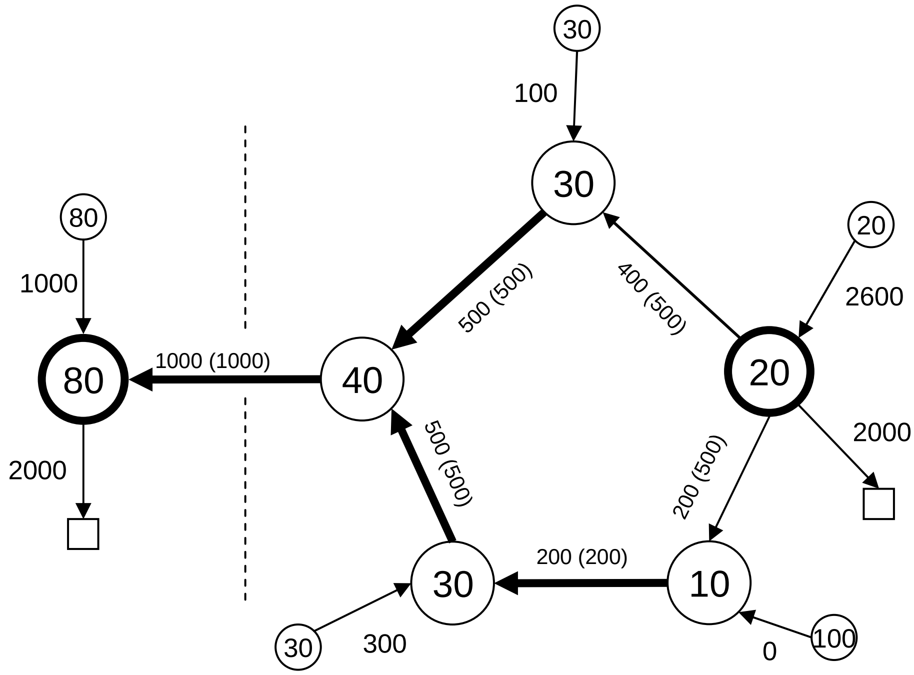

Figure 7: Example Dispatch: Export

The settlement of this dispatch under the two alternative FTR allocations is shown in the table below.

GENERATION: FTR Allocation Favours Inter-regional Import							
Node	*Node Price*	*Regional Price*	*Gen Output*	*Allocated FTRs*	*Nodal Payment*	*"FTR" Payment*	*Total Payment*
RRN "L"	80	80	1000	n/a	80000	0	80000
RRN "R"	20	20	2600	n/a	52000	0	52000
Gen A	30	20	300	0	9000	0	9000
Gen B	10	20	0	300	0	3000	3000
Gen C	30	20	100	100	3000	-1000	2000
Total			**4000**				**146000**
GENERATION: FTR Allocation Favours Inter-regional Export							
Node	*Node Price*	*Regional Price*	*Gen Output*	*Allocated FTRs*	*Nodal Payment*	*"FTR" Payment*	*Total Payment*
RRN "L"	80	80	1000	n/a	80000	0	80000
RRN "R"	20	20	2600	n/a	52000	0	52000
Gen A	30	20	300	300	9000	-3000	6000
Gen B	10	20	0	300	0	3000	3000
Gen C	30	20	100	400	3000	-4000	-1000
Total			**4000**				**140000**
DEMAND							
Node		*Regional Price*	*Demand*				*Total Receipt*
RRN "L"		80	2000				160000
RRN "R"		20	2000				40000
Total							**200000**
SETTLEMENT RESIDUE & SRA Firmness							
			Inter-regional Import FTRs			**Residue**	**54000**
						SRA MW	**900**
			Inter-regional Export FTRs			**Residue**	**60000**
						SRA MW	**1000**

In this case, the "export FTRs" give rise to only a slightly firmer SRA MW than the "import FTRs". However, FTR theory means that the 1000MW is guaranteed (for an intact network), whereas the 900MW under the "import" FTRs is not.

Topping Up FTR Cover

Scarce network capacity means that neither intra- nor inter-regional players will obtain their desired requirements through the FTR allocation process, and both will be seeking to “top-up” this cover through other markets where possible. Two potential sources of “top-up” exist:

- secondary trading, where some players sell part of their allocated FTRs to other players who value them more highly;
- allocation of augmented network capacity, where incremental network capacity is issued to the market through additional FTRs

Secondary trading of FTRs is complex, because different FTR “products” are related: for example 1MW of FTR from A to B may be similar, in most circumstances, to 1.5MW of FTR from A to C. Participants could potentially manage this complexity through network analysis and portfolio management processes. However, a simpler approach (from the participants’ viewpoint) is for this complexity to be managed centrally, through a centralised FTR auction. The auction design allows participants to offer specified FTRs for sale and to bid for other specified FTRs. The auction process itself then appropriately “transmutes” a subset of the offered FTRs into a subset of the bid FTRs, and clears the market accordingly, whilst ensuring that simultaneous feasibility for the (new) total portfolio of issued FTRs is maintained. This FTR auction is included in the PP model, but not in the ICS or CC models. In the “natural” models, secondary trading is probably less important, as generators are allocated a reasonably good hedge and can manage their nodal price exposure through bidding. However, the lack of a secondary market in the ICS Contract model – and in particular in the ICS Unsupported model - represents a significant weakness.

The SRA is assumed to continue operating under all of the ICS approaches. The settlement residue can be considered to be analogous to crude oil, aggregating the value of all the different residual FTR capacity – intra- and inter-regional - not issued through the allocation process. An SRA purchaser will typically only be seeking the “inter-regional fraction” of this crude residue, and while it is possible that a sophisticated player could “refine” this residue and sell of some of the refined products into the secondary market – whilst retaining the inter-regional fraction for their own needs – this is unlikely to occur in practice. Thus, the secondary markets for neither the intra-regional nor the inter-regional FTRs appear to be very effective in the ICS model.

In relation to incremental network capacity, the PP model would issue this capacity through the regular FTR auction, and the revenue from the incremental FTR capacity sold would be allocated to those funding the network augmentation (either the “beneficiaries” or the funding “coalition”). By bidding into the FTR auction, this allocated revenue can be converted to FTRs: so the funding parties have the choice of cash or FTRs.

The ICS model does not specify any mechanism for allocating incremental network capacity. By default, the value of the incremental capacity would flow into the settlement residue and so the incremental FTRs are effectively incorporated into the SRA instruments. However, under the ICS Contract approach, a process could be designed to auction this incremental capacity to intra-regional generators, after providing for the needs of the SRA.

Conclusions

Of the three alternative FTR allocation methods proposed, the “natural” method is similar to the CC model and the “contract” method is similar to the PP model.

ICS natural is, however, substantially inferior to the CC model, as it increases the scope for constrained-off gaming, whilst giving no institutional responsibility for managing it. This is likely to lead to very poor SRA firmness and potentially settlement deficits.

Both the ICS Contract and ICS Unsupported methods are inferior to the PP model in that no FTR auction process is provided to allow generators to top-up their allocated FTRs through secondary trading or from incremental network capacity. This problem is particularly acute under ICS Unsupported where generators have no FTR allocation.

The absence of an FTR auction also means that the SRA instruments will increasingly become a blend of inter- and intra-regional FTRs, and may therefore be less effective as hedges of inter-regional price risk.

4. Demand Pricing

Theoretical Benefits of Average Pricing

An important difference between the ICS approach and the PP model is that the former preserves the pricing of demand at the regional reference price (the nodal price at the regional reference node) whereas the latter prices demand at the demand-weighted average (DWA) of the nodal prices across the region.

The DWA price has some theoretical advantages. Firstly, the total payment by retailers is the same as if nodal pricing were applied to demand. This means the settlement residue is the same as for full nodal pricing (since generators are paid nodal prices in both PP and full nodal pricing) which, in turn, means we can use the FTR theory in relation to "revenue adequacy".

Secondly, we can allocate FTRs to generators (intra- and inter-regional) based on a simultaneous feasibility test which are effective hedges against the DWA price. For example, suppose we have a feasible generation-demand pattern as follows:

Node	Generation	Demand
A	600	0
B	400	0
C	0	800
D	0	200

Then we can allocate a simultaneously feasible set of FTRs to generators A and B as follows:

Generator	From node	To node	MW
A	A	C	480
A	A	D	120
B	B	C	320
B	B	D	80

This set of FTRs implies the same feasible generation-demand pattern as in the previous table and therefore satisfies revenue adequacy. Generator A's two FTRs are equivalent to a 600MW node-to-region FTR, where the "region" means reference to the DWA price. Similarly, Generator B has been allocated the equivalent of 400MW of node-to-region FTRs.

However, this assumes that the demand distribution between C and D remains in the ratio 4:1. If this ratio changes, then the ratio used in calculating the DWA price will differ from the ratio of the allocated FTRs. Thus, the generators will not have a perfect hedge against the regional price and will bear some basis risk.

Alternatively, we could deem the generators to have been allocated node-to-region FTRs, so they are fully hedged, but now the effective set of issues node-to-node FTRS will vary as the demand distribution varies, so the revenue adequacy condition may no longer be satisfied[12].

Theoretical Problems with RRN Pricing

If demand is price at the RRP, then the settlement residue will now be different to that implied by nodal pricing and so the FTR theory no longer applies. We need to make an adjustment to the revenue adequacy test for allocating FTRs.

To see how we should do this, consider a different model where we *do* have full nodal pricing (and so FTR theory applies) but we have also "pre-allocated" RRN-to-node FTRs to each retailer, based on their actual demand at each node. So the net payment by the retailer is:

$$\begin{aligned} \text{Retailer Payment} \quad &= \text{spot payment} - \text{FTR payout} \\ &= P_{local} * \text{demand} - (P_{local} - \text{RRP}) * \text{demand} \\ &= \text{RRP} * \text{demand} \end{aligned}$$

Thus, the retailer actually pays the RRP for demand (due to the hedging effect of the allocated FTRs), and this alternative model is financially identical to the RRP regional model. The revenue adequacy test in the alternative model now requires that all of these "pre-allocated" retailer FTRs, together with any node-to-RRN FTRs allocated to intra-regional generators *and* any inter-regional FTRs required to support the firmness of the SRA instrument are simultaneously feasible. Because these notional retailer FTRs are based on actual demand, the revenue adequacy test would need to be applied over all demand scenarios[13]. This is still possible, but makes the FTR allocation much more complex.

It is even possible that these notional "pre-allocated" FTRs are, by themselves, infeasible, even without any real FTRs being allocated. This is equivalent to saying that it is not possible for all of the demand across the region to be met solely from notional generation at the RRN[14]. In this case there may be a settlement deficit, even without any "real" FTRs being allocated. We can see that this might happen if the RRN is located within an "export-constrained" zone of the region, meaning that many generators will be constrained-on at a nodal price above the RRP, so that the average price paid to generation is higher than the RRP. Thus, it will be important to ensure that the RRN is located at the major demand centre in the region.

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[12] This presumably is an issue for those international markets that have adopted the PP model, or similar. It is not known how - if at all - they deal with this particular issue.

[13] In contrast, because normal FTR volumes are fixed, the simultaneous feasibility is in effect tested for a generation-demand "snapshot"

[14] Because this is the load flow implied by the "pre-allocated" region-to-node FTRs

In contrast, and in the absence of allocated FTRs, settlement deficits *cannot* occur when the DWA price is used[15].

Practicalities

In practice, the choice of RRNs in the NEM means that the majority of demand will be close to the RRN, and so the DWA price should generally be similar to the RRP. Thus the "basis risk" problems identified above may not be substantial, especially considering that "revenue adequacy" in practice means that there will be a revenue surplus most of the time, which should help to fund any deficit periods caused by the basis problems.

Thus, for the PP model, node-to-zone FTRs would be allocated to generators based on expected generation-demand conditions, and these FTRs would be designed to properly hedge the DWA price. Revenue inadequacy is possible – just as it is during network outages – and these would be funded from earlier settlement surpluses or, as a last resort, through an uplift charge on the market.

Similarly, for the ICS Contract model, contracts would be allocated using a simultaneous feasibility test for a generation-demand "snapshot". While this would not necessarily be revenue adequate as demand varies, any surplus or shortfall will feed into the SRA instruments and would, hopefully, not substantially affect the "firmness" of these[16].

Other Considerations

Apart from the FTR issues, there may be other attractions of using the DWA price rather than the RRP. Firstly, it avoids the arbitrariness of selecting a RRN, although given that this selection was done pre-market – and market participants are used to this – this issue would only arise should new regions be introduced and new RRNs need to be selected.

Secondly, it is likely to reduce the volatility of the regional price somewhat, in particular by making it less susceptible to localised constraints close to the RRN.

Thirdly, the DWA price has the theoretical attraction that, assuming that demand is geographically homogeneous, it is the regional price that maximises static efficiency[17], although, the efficient benefit of this is likely to be small as:

- a large proportion of demand in each region is located close to the RRN, and so the RRP and the demand-weighted average may not differ substantially;
- demand is quite inelastic in the short-term

[15] This is a special instance of the FTR theory: zero issued FTRs (ie zero generation and demand) must be feasible on all networks and must therefore be revenue adequate.

[16] This is something that could be tested through detailed modeling. It might be necessary to scale back the allocated FTRs somewhat, in order to mitigate the impact on the SRA firmness.

[17] This result was derived by Darryl Biggar of the ACCC in an unpublished paper.

Conclusions

There are some theoretical benefits of using the DWA-based regional price, rather than the price at the RRN. In particular, where there is a significant load centre remote from the RRN, the ability of the RRP-based settlement residue to support intra- and inter-regional FTRs may be significantly poorer than with the DWA price. It is even possible that the RRP model could lead to settlement deficits in the spot market: ie “white hole money”. However, with current RRNs located at the major load centre in each region[18], these impacts may be small and the DWA price and RRP may only differ slightly. However, this needs to be confirmed through detailed modelling of the actual network.

Furthermore, should there be specified identified benefits from using the DWA price rather than the RRP – or vice versa - there is no practical reason why the ICS or PP models cannot be varied to instead use the preferred regional pricing method.

[18] Although in Queensland there are significant load centres remote from the RRN

5. Cost versus Price

Market Design Issues

The CRA report also considers whether ICS Natural should base ICS payments on generator offer prices rather than nodal "clearing" prices. This differs from the PP and CC approaches, where all settlements is based on clearing prices.

In fact, a third possibility is for payments to be based on "costs" (eg SRMC), where these are somehow verified, rather than relying on offer prices reflecting costs. Offer prices will differ from costs, of course, where there is market power.

Most market designs have a mixture of price-, offer- and cost-based payments. For example the NEM has:

- clearing prices for energy and FCAS
- offer (ie contract) prices for NCAS
- cost-based compensation for directions

The benefit of a clearing price is that it provides a "two-way" price that is seen by both buyers and sellers, allowing mutual hedging around that price. This benefit is less relevant in "one-way" markets, where the buyer is a central authority who then passes the purchasing costs on through some sort of market "uplift".

In a competitive situation, clearing prices are also preferred, as they encourage players to reveal their true costs in their bids, thus facilitating efficient dispatch.

However, in uncompetitive situations, the relative merits of the 3 approaches are less clear. Theoretical comparisons of the clearing price and "pay-at-bid" market designs have failed to resolve which design better mitigates market power, although clearing price designs are much more common, mainly due to their simplicity and transparency.

Cost-based regimes normally apply where there are genuine market power problems, and pay-at-bid regimes will be ineffective at mitigating this, since a player is able simply to increase their bid. Most cost-based regimes are strongly targeted, by analysing which players may have market power and then regulating their bids or payments directly, rather than covering all of the market with a cost-based design.

Pay at Bid in ICS

In relation to nodal markets – as for other markets – a pay-at-bid design simply allows a generator to increase its offer to the local marginal price, assuming that it can estimate what this is. As constraints come and go, this price will vary, requiring generators to frequently rebid. Therefore, the cost-based approach seems to introduce additional transaction costs and market volatility without necessarily being effective at mitigating market power. For this reason, a clearing price approach is preferred to a pay-at-bid design. To the extent that there is a need to mitigate market power, this could be done by regulating the payments or bids of particular generators, rather than applying this across the market. Alternatively, if market power is thought to be widespread and a major concern, a cost-based design could be used.

Note, anyway, that we have already concluded that the ICS natural approach is inferior to the ICS Contract option. Under this latter option, any gaming should not lead to settlement deficit (except, perhaps, during network outages) and so is less of a concern.

Conclusion

A pay-at-bid design in ICS Natural does not seem to offer any benefits over the clearing price approach. Therefore, this option will not be evaluated further

6. Evaluation

Evaluation Framework

In the previous report on transmission pricing options, the following evaluation criteria were used:

- transmission usage (static efficiency)
- transmission usage (dynamic efficiency)
- managing price risk
- efficient transmission investment
- efficient transmission operation
- transaction costs (operation)
- transaction costs (implementation)
- shock
- acceptability to governments

The exact meaning of these criteria is described in the previous report.

The following models are evaluated against each of these criteria:

- ICS Unsupported
- ICS Natural (price-based)
- ICS Contract

The benchmark for comparison is the PP model[19]. The CC model is not evaluated here, as it has already been evaluated in the previous report.

Static Efficiency

Apart from within intra-regional sub-sections, both the ICS and PP models use nodal (LMP) pricing for generation pricing the margin. Thus static efficiency of each ICS approach is similar, but ICS is slightly inferior to the PP benchmark because of inefficient prices within the intra-regional sub-sections.

ICS natural encourages constrained-off gaming, therefore distorting the nodal prices. However, this only distorts usage to the extent that the constrained-off generator is dispatched to a higher level as a result of the gaming, and this effect will be mitigated given that the generator has been constrained-off and so has its output limited.

For the other approaches, FTRs are fixed in the short-term and so their effect on static usage will be “second order”: ie they may affect generator market power, which may affect offer prices, which may affect usage. It is assumed this effect will be small,

[19] Note that in the previous report the benchmark was the “status quo”. However, since that report evaluated the PP model against this status quo, the relative merit of the ICS options against the status quo can be deduced.

The DWA pricing for demand used in the PP model is theoretically slightly more efficient than the RRP used in the ICS model. However, this effect is likely to be small. In any case, the ICS model could adopt DWA pricing if preferred.

To conclude, ICS Unsupported and ICS Contract will be slightly inferior (-) to the PP benchmark, due to the combined effects of lack of pricing on intra-regional sub-sections and a slightly less efficient demand price. ICS natural will be significantly inferior (--) due to the additional impact of constrained-off gaming on usage.

Dynamic Efficiency

For dynamic efficiency, new generators should see the nodal price on all of their new capacity. This is the case in the PP model (since only existing generators receive an FTR allocation) and also for the ICS Unsupported (=). The ICS Contract model is less clear, but we have assumed that it uses the same contract allocation method as PP model (=).

However, ICS natural provides FTRs to new constrained-off generation, and thus may actually encourage generators to locate in constrained-off regions, especially given the constrained-off gaming opportunities. Therefore, this is significantly inferior[20] (--)

Managing Price Risk

It has been noted that managing price risk is one of the key objectives of the ICS approach. In relation to the PP and ICS models, price risk can be separated into:

- intra-regional risk (between local node and reference node[21]) borne by intra-regional generators[22]
- inter-regional risk (between regional reference nodes) borne by inter-regional generators and retailers

Since there is limited network capacity, these two objectives are conflicting and must be traded off.

In relation to intra-regional risk, the ICS natural approach gives generators the highest level of cover. Whilst constrained-on generators do not receive allocated FTRs, they are at least guaranteed to receive a price higher than the regional price, and so only have "upside" risk. The PP model and ICS Contract approaches are assumed to provide the

[20] Note that the CC model mitigates this distortion by levying transmission service charges on generators, based on LRMC. Also, the TNSP bears the cost of any resulting constrained-off payments. Therefore, the TNSP should have both the revenue and the motivation to invest to relieve the relevant constraint.
[21] In the PP model, the reference node is a "virtual" one, which is the demand-weighted average of the physical nodes in the region
[22] It is assumed that retailers will always contract at the regional reference node

same level of cover initially. However, the PP model also provides an FTR auction through which cover can be topped up.

The ICS Unsupported approach gives generators no FTRs.

Regarding inter-regional risk, the contract approach in both the PP and ICS models allows intra-regional FTRs to be allocated which preserve a defined level of inter-regional FTR capacity to be auctioned through the FTR auction or SRA processes, respectively. Thus, this allows the most effective trade-off of the two competing objectives. The inter-regional FTR capacity under these models may be higher or lower than the "unsupported" approach, depending upon the relative contributions of constrained-on and constrained-off generators in supporting inter-regional transfers. The intra-regional components left in the settlement residue under the ICS Unsupported may also degrade the hedging effectiveness of the SRA instrument.

The ICS natural approach is likely to seriously degrade the value of the settlement residue in hedging inter-regional risk, and may even lead to settlement deficits.

With nodal pricing for generation, there is a concern that local constrained-on generators within "load pockets" may be able, in the absence of effective local or remote competition, substantially to increase local nodal prices. In the PP model, these higher prices would, in effect, create an "uplift" to the regional DWA price[23]. However, existing generators would be hedged against this through allocated FTRs and so would, presumably, continue to offer retailers hedges against the DWA price. The low demand level in the load pocket would mean that the magnitude of the "uplift" would probably remain small. Furthermore, the FTRs allocated to existing local generation would reduce their ability to exert market power.

Where the transmission constraints giving rise to the local market power are within intra-regional sub-sections, the ICS approach will automatically mitigate this market power by not pricing these constraints. It will not be effective in this respect, however, where the constraints are within the inter-regional sub-section. Therefore, a more systematic approach to market power mitigation (as seen in other nodal markets) is probably required (in both the ICS and PP models), such as enforcing "reliability must run" obligations[24] on such constrained-on generators.

In conclusion, the ICS Contract approach is slightly inferior to the PP model (-), whereas the ICS Unsupported and natural approaches are substantially inferior (--).

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[23] In the ICS model, the RRP is unaffected, and the "uplift" cost is in effect taken out of the settlement residue, potentially degrading the firmness of the SRA instruments and possibly even leading to settlement deficit.

[24] These obligations are similar to the "network support agreements" currently seen in the NEM in relation to constrained-on generation. However, in nodal markets, these agreements must be enforced, rather than freely negotiated.

Transmission Investment

To be fair to the ICS model, CRA admit that they have not considered the "institutional" issues – in particular how the outcomes generated by the model might create incentives for TNSPs – and considered it beyond the scope of their study. Therefore, the absence of these incentives should not necessarily be considered a disadvantage. However, what is important is for there to be *potential* for the ICS outcomes to drive a future TNSP incentive model.

The PP model assumes that the transmission investment framework is the same as the current NEM: ie central investment planning through a regulatory test or funded investment by coalitions. In both cases, those paying for the investment would receive allocated revenue rights in relation to any incremental FTR capacity sold through the FTR auction as a result of the new investment. This provides a weak incentive for beneficiaries to support network investment.

As discussed earlier, it is not clear how this would work in the ICS model, in the absence of an FTR auction mechanism. Therefore, it is assumed that an analogous mechanism will not exist in the ICS approach. On the other hand, constrained-off generators without FTR cover (eg in ICS Unsupported) will have an incentive to support or fund new investment, albeit at the risk of encouraging free riders. Constrained-off generators with excess FTR cover (eg in ICS natural) will have the opposite incentive.

Therefore, overall it is considered that ICS Contract is slightly inferior (-), ICS Unsupported is broadly the same (=) and ICS natural substantially inferior (--) to the PP benchmark.

Transmission Operation

None of the ICS or PP models provide any operational incentives on TNSPs, nor do they provide a mechanism for market participants to influence TNSP operation. Thus, all of the ICS models are equivalent to the benchmark (=)

Transaction Cost - Operations

All of the models require that nodal prices are calculated. The ICS models involve a slight complexity in relation to ensuring that constraints within intra-regional sub-sections are ignored for pricing purposes but – assuming that these sub-sections are definitionally stable – this should not create significant difficulty.

The PP model requires a demand-weighted average nodal price to be calculated and modelled. This may introduce a slight complexity in relation to retailer price analysis, but in practice the difference in pricing is likely to be small[25]. It also requires the introduction of a regular FTR auction, which introduces more complexity

[25] In order to model the RRN price, retailers must – in principle – do a full nodal pricing analysis anyway, so that little extra work is involved in averaging these prices.

The ICS natural model requires that a parallel "dispatch" is performed in order to calculate "natural" generation dispatch against the RRP, taking into account FCAS and dynamic constraints. This could create significant operational complexity.

Overall, therefore, the ICS natural is broadly similar to PP (includes "natural" dispatch, but excludes FTR auction) (=), whereas the other ICS approaches are slightly simpler (+).

Transaction Cost – Implementation

The relativities of implementation costs are likely to be similar to those for operating costs. Thus we have ICS natural (=), ICS Contract and unsupported (+).

Shock

The PP and ICS Contract approaches allow contracts to be allocated which mitigate shock on intra-regional and inter-regional participants (=). The ICS Unsupported approach provides no such grandfathering (-), whilst the ICS natural grandfathers intra-regional generators, but at a potential cost of substantially impacting the value of the settlement residue, and hence retailers (who are the end recipients of this) (-).

Acceptability to Governments

Each model preserves and sustains regional pricing for demand, which is assumed to be the most important criterion for government acceptability. The ICS approaches may be slightly more acceptable to governments in that they do not implement nodal pricing for generation in intra-regional subsections of the network. (+)

Evaluation Summary

The evaluation of each ICS approach against the criteria is summarised below.

	Unsupported	***Natural***	***Contracted***
Static Use	**-**	**--**	**-**
Dynamic Use	**=**	**--**	**=**
Price Risk	**--**	**--**	**-**
Tx Investment	**=**	**--**	**-**
Tx Operation	**=**	**=**	**=**
Transaction (Operations)	**+**	**=**	**+**
Transaction (Implementation)	**+**	**=**	**+**
Shock	**-**	**-**	**=**
Overall Value	***-2***	***-9***	***-1***
Efficiency – overall value	*-3*	*-8*	*-3*
Costs – overall value	*+1*	*-1*	*+2*
Government Acceptability	**+**	**+**	**+**

To summarise, ICS Natural scores very poorly on efficiency criteria. ICS Unsupported and ICS Contracted are not substantially different to the PP model: they score slightly worse on efficiency but slightly better on cost. These differences are mostly related to absence of an FTR auction mechanism. Although this evaluation is non-quantitative, one would expect that the transaction costs of an FTR auction mechanism are relatively low compared to the efficiency benefits. This has certainly been true of the SRA.

The slightly higher government acceptability to governments is probably marginal and unlikely to make much difference to the choice of model. For example, if it governments preferred to quarantine intra-regional sub-sections from nodal pricing, this could equally well be done by varying the PP model.

On the other hand, the major difference between the ICS Unsupported and contract approaches is the higher price risk on generators with the former. This *is* quite likely to be decisive in swinging generator preference to the contract approach (either with ICS or with PP).

7. Conclusions

The following conclusions can be drawn from the analysis in this report:

1. the ICS approach is quite similar to the PP model. However, the differences are material and will affect the relative merits of the two models.
2. Whilst the ICS approach prices intra-regional constraints in the same way as conventional nodal pricing, it is not clear that it does this for constraints over the whole of the network. In particular, “intra-regional sub-sections”, where constraints do not affect interconnector flows, may not be fully priced. Outside these sub-sections, effective prices seen by generation at the margin in the ICS approach are identical to conventional nodal (LMP) prices.
3. Whilst the ICS approach of not pricing constraints within intra-regional sub-sections may mitigate some instances of local market power, a more systematic market power mitigation approach is probably required (in both models), to ensure gaming of constraints in the inter-regional sub-section is also mitigated.
4. Setting “reference points” for generators that are charged the ICS prices is equivalent to allocating these generators FTRs between their local node and the regional reference node. The ICS approach uses three methods for setting the reference points.
5. The first “unsupported” approach is equivalent to allocating no FTRs to generators. This may expose generators to substantial new price risk and is therefore unlikely to be supported by generators.
6. The second “natural” approach gives generators effective financial access rights to generate “in-merit” against the RRP. This is likely to substantially erode the residual settlement residue available for backing the SRA instruments. In some circumstances, it could even lead to settlement deficit.
7. Providing generators with such “natural” access rights may lead to constrained-off gaming, of the sort seen in the UK for example, where generators deliberately lower their offer price to increase the value of their “natural” FTRs. If “natural” rights are desired to be implemented, the “congestion controller” would be a better model, as it will create more moderate regional prices and places the exposure to constrained-off costs on the local TNSP who may be able to manage such exposure.
8. The third “contract” approach allocates a fixed volume of FTRs to the generators, but CRA do not describe how this should be done. The allocation methodology is an issue also for the PP model, so it is assumed that the allocation objectives and methodology are the same in both models.
9. FTR contracts can be allocated to strengthen the firmness of the SRA instrument or to grandfather intra-regional generators against the new intra-regional price risk. Due to scarce network capacity, they will probably be unable to do both at once. Thus these competing objectives must be prioritised.

10. FTR theory provides a mechanism for allocating the settlement residue between intra-regional FTRs and the SRA instrument so as to achieve whichever priority is agreed.

11. FTR theory does not provide for “optional” FTR instruments such as the SRA instruments. Thus, the FTR allocation may need to change depending upon the direction of the inter-regional power flow.

12. Whilst the CRA report considers the alternative of setting ICS prices based on generator offer price rather than the nodal clearing price, this alternative does not have any obvious merit, and has not been evaluated in detail.

13. The ICS approach retains the use of the RRP (the price at the regional reference node) for demand pricing, whereas the PP model calculates a demand weighted-average (DWA) of the nodal prices. The DWA price conforms better to FTR theory and so should better ensure revenue adequacy and FTR firmness. However, there appears to be no overriding reason why the ICS approach should not adopt the DWA pricing methodology.

14. The major difference between ICS and PP approaches are that the former retains the settlement residue auction for allocating the remaining settlement residue (after the allocated FTRs have been underwritten), whilst the latter introduces a full FTR auction. The FTR auction is likely to provide both a better market for generators seeking to “top-up” their FTR cover, and a “purer” instrument for hedging inter-regional risk. Thus, although it may have some implementation cost, the FTR auction should provide net benefit.

15. Overall, it is considered that all three of the ICS approaches are somewhat inferior to the PP model. The “uncontracted” and “natural” ICS models perform quite poorly and should be rejected. The “contract” ICS approach is similar to the PP model, and has the possible benefit that it represents a smaller change from the status quo than the PP model and so may be more acceptable to stakeholders.