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CITIPOWER

30 April 2001

Mr Michael Rawstron
Australian Competition and Consumer Commission
PO Box 1199
Dickson Act

Dear Michael,

re: Amendments to the National Electricity Code - "Network Pricing & MNSP Draft Determination"

CitiPower Retail makes the following submission on the issue of Network Pricing and the role of MNSPs.

CitiPower Retail participated in a recent intra-industry workshop in Newcastle, specifically on the issues outlined in the Determination. The attached submission outlines the agreements reached at that workshop and reflects CitiPower Retail's position on the issues raised in the draft determination. CitiPower is of the view that this document:

- accurately reflects a cross-industry view of the issues;
- addresses the major issues on a sound economic basis; and
- suggests solutions that are simple, robust and pragmatic.

As an additional issue, CitiPower Retail would suggest that while the ACCC should endeavour to resolve this issue in a timely manner, there is a need to consider an implementation timetable in the broader context of the NEM. To this end, CitiPower Retail believes that a delay in the proposed implementation date would allow existing businesses to take account of what is a fundamental change to the NEM.

If you have any questions please feel free to contact me on (03) 92978630.

Yours sincerely,

Steve Abbott
Group Manager Wholesale Energy

- 2 MAY 2001

Transmission Pricing and Access

'Newcastle Group' Positions Paper

18 April 2001, Boulevard on Beaumont Hotel, Newcastle

Introduction

The Newcastle Group was called together by Macquarie Generation to find a pragmatic and rational way forward on key issues in transmission access and pricing.

Attendees

- Russell Skelton (Macquarie Generation)
- Luke Welfare (Macquarie Generation)
- Con Van Kemenade (Macquarie Generation)
- Christine Feeney (Macquarie Generation)
- Carlo Botto (Intergen)
- Mike Bailey (AGL SA)
- Steve Abbott (Citipower Retail)
- Tim Baker (Delta)
- Rodney Ward (Delta)
- Don Hutt (TransGrid)
- Phil Gall (TransGrid)
- Paul Simshauser (Stanwell)
- Erin Bledsoe (Stanwell)
- Graeme Woodbridge (Frontier Economics)
- Danny Price (MIG)
- Rajat Sood (MIG)

- Don Anderson (MIG – afternoon only)

Key issues discussed

Criteria for acceptable regime

In no particular order, and recognising that trade-offs would be required, the Group suggested the following criteria to be used to assess and compare alternatives for an acceptable transmission regime:

- Simple and understandable;
- Non-distortionary;
- Economically efficient – in terms of productive, allocative and dynamic efficiency;
- Robust (not easily disputed or overturned);
- Politically acceptable;
- Risks managed appropriately;
- Practical/pragmatic;
- Able to be Codified;
- Promote reliable supply and price stability (both geographically and over time).

The role of transmission and firm access

The NEM was founded on the basis of an open access or 'common carriage' regime. This has been questioned by parties who see the grid as being in competition with themselves – in particular, embedded generation and market network service providers (MNSPs). The Group exhibited little interest in moving to a contract carriage regime that relied on nodal market prices to stimulate network investment and involved the transmission network service providers (TNSPs) effectively becoming market participants. It was generally agreed that combining a common carriage regime for the existing transmission network with contract carriage for new investment (ie. MNSPs) was problematic.

Consistent with a common carriage regime is the need to maintain and refine the regulated approach to new network investment.

Nevertheless, some parties have argued for promotion of firm access (in terms of access to the local regional reference node and other regional reference nodes), or improved negotiated access to the local reference node. In both cases, the role of NEMMCO as system operator is equally important as the role of TNSPs in allowing better access.[1]

Access to local RRN

The Group discussed the implications for the common carriage regime of moves towards firm access. In particular, it was agreed that wherever a party such as a TNSP is faced with a risk, the party should receive an appropriate return to compensate for that risk. This need not compromise TNSPs' non-participant position. Incentives could include a limited regime of punishments and/or rewards to ensure, for example, that TNSPs scheduled outages at times of least market impact. In relation to risks that TNSPs were not in a comparatively better position to manage, participants would need to seek commercial solutions, to self-insure or co-insure each other, possibly with the assistance of TNSPs in a coordinating role.

It was recognised that TNSPs' regulated return does not presently include compensation for more commercial policies in relation to matters such as planned outages.

Some problems were raised with the proposal for increased TNSP incentives:[2]

- How should TNSPs reconcile conflicting requests from different network users, for example, in relation to the timing of planned outages on the shared network;

- Could TNSPs earn revenue outside their revenue caps for behaving in a more commercially sensitive manner. If not, how should they be incentivised to behave more commercially.

It was suggested that conflicting requests could be managed by ensuring that TNSPs had defined minimum service standards to all network users so that no

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[1] For example, NEMMCO can affect transmission capability via judgements on system security limits, characterisation of limits in constraint equations, or by dispatch of NCAS capability contracted from generators outside the reach of TNSPs.

[2] TransGrid has raised several issues in the past regarding TNSP incentive schemes. One is whether TNSPs should face incentives to implement outages to minimise expected market impact or whether they should be incentivised to publish an outage schedule and stick to it, even if market conditions change. This issue would also have to be resolved before an incentive regime could work effectively. Further, public safety and legislated environmental standards should not be compromised for the sake of marginal improvements to market efficiency. Finally, any incentive regime must ensure that TNSPs do not use it to trade off short-term financial gains for long-term reliability and integrity of the network.

user was disadvantaged by a TNSP acting in accordance with any given user's request. It was also expected that such conflicts would be relatively rare.

Whether or not TNSPs could develop a 'firm access' business would depend on whether the services they provided could be characterised as contestable. In some instances, this might be the case. In other instances, such as the timing of planned outages, it was likely that this would be regarded by the ACCC as a monopoly activity and hence a 'prescribed' (regulated) service. However, even in this case, regulators should allow TNSPs reasonable compensation for increased costs due to more efficient maintenance timing, etc.

The performance of NEMMCO would need to be addressed through improved governance structures, which would involve consideration of participants on the board or outright transfer of NEMMCO to the industry. A key prerequisite for such moves would be removal of major policy functions from NEMMCO, such as the overarching market development role and evaluation of interconnector proposals. However, even this may not result in the required level and quality of interaction needed between TNSPs and NEMMCO to deliver the required level of accountability, control, and coordination for transmission transfer capability. This issue would need to be resolved through the MSORC process.

Access to inter-regional RRNs

It was suggested that firmer inter-regional access is a natural place to start applying firm access principles as certain, albeit limited, risk-management tools (SRAs) are already in place. In principle, it was agreed that firm SRAs were desirable. However, it was acknowledged that there are difficulties with this. For example, some risks were outside the TNSPs' control. Also, by implication, this issue involves more than one TNSP at a time, which raises coordination and accountability issues. The Group was in favour of some form of firming up of a portion, or 'firmness ranking' of, SRA products as a first step. This would require the ACCC to reconsider TNSPs' regulated revenue so as to properly reflect the risk they faced and reallocation of the SRA premium income to support higher value firmer products.

New network costs and the role of MNSPs

The key questions that arise for new network investment are as follows:

- When does investment occur;
- What is the role for MNSPs and
- Who pays and on what basis.

When does investment occur

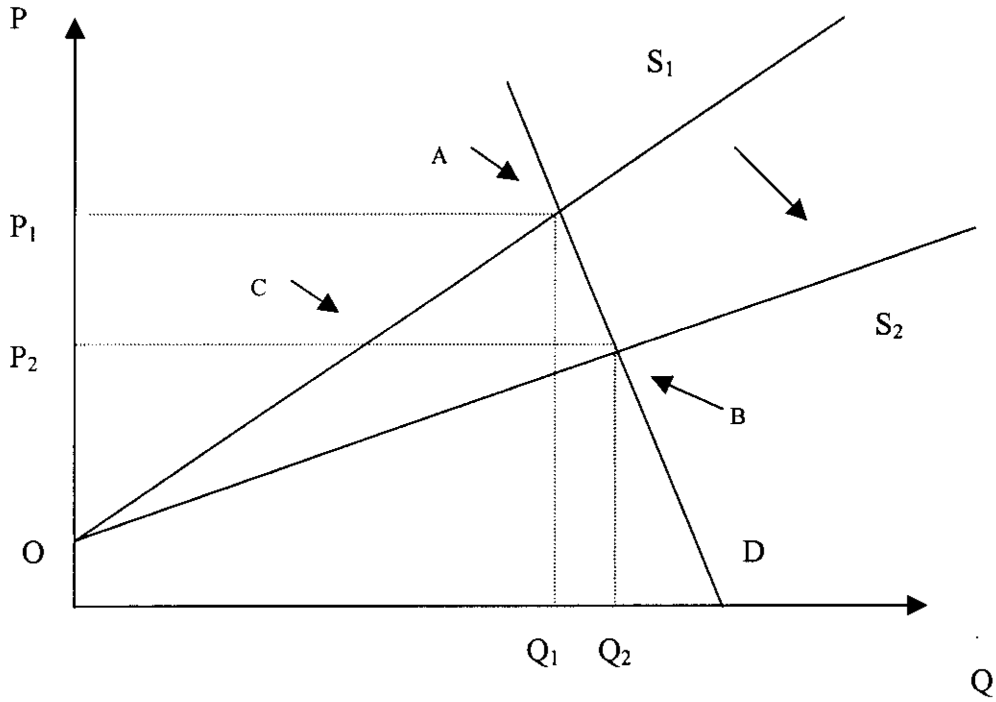
In the context of a common carriage regime, it was suggested that network investment should take place where it maximises net benefits, in line with the ACCC's regulatory test. The regulatory test requires that a proposed investment maximise expected net benefits *across the NEM* compared to a range of alternatives under a broad range of 'market expansion' scenarios. The test does not focus on customer benefits *per se* and it does not focus on benefits or costs on a jurisdiction-by-jurisdiction basis.

However, in practical terms, it is clear that other things being equal, those investments that minimise the cost of supply effectively maximise both market benefits and customer benefits across the NEM.

Consider Figure 1. The original supply curve is S_1, intersecting the demand curve at price P_1 and quantity Q_1. A new transmission investment has the effect of rotating the supply curve in a clockwise direction, to S_2, as it allows the dispatch of cheaper plant and thereby lowers the marginal cost of supplying electricity. The new equilibrium price and quantity are P_2 and Q_2, respectively.

- The net increase in overall public benefit is OAB;
- The net increase in consumer surplus is P_1ABP_2;
- The net increase in producer surplus is OCB - P_2P_1AC. This area could well be negative. The steeper the demand curve, the more likely that this area will be negative.

Figure 1: Share of benefits of *new* investment



Note that generally, with clockwise rotation or rightward shifts of the supply curve, consumer surplus and total market benefit are positively related. The further the supply curve rotates clockwise, the larger will be market benefit and the larger will be customer benefit, as the equilibrium price will fall and quantity traded will rise. Therefore, the investment option, be it grid investment or new generation, that has the largest clockwise effect on, or rightward shift of, the supply curve will maximise both customer and market benefit.

Given that demand for electricity is relatively inelastic, it is quite possible that generators, as a class, do not benefit from new network investment and in fact may suffer from the investment.

One area where the regulatory test had proved deficient was in relation to the definition of 'committed projects'. The test requires that, *inter alia*, committed projects be taken into account when assessing the benefits of a proposed augmentation. However, the definition of committed projects was relatively loose and prone to gaming by interest groups who were either opposed or indifferent to new network investment going ahead that was otherwise net beneficial. It was suggested that one way around this problem was to require that proponents of investments that sought to be included on the committed projects list be required to lodge a bond with an independent body (perhaps the ACCC or the IRPC) that would be forfeited if the investment did not go ahead. To promote incentives for active ongoing investment evaluation by proponents, it was further suggested that the size of the bond (and hence potential 'penalty') be increased at periodic intervals, perhaps annually. This proposal would give policy-makers and regulators much greater confidence that mooted investments would go ahead and reliability would be maintained.

MNSPs

The Group briefly considered the role of MNSPs in the NEM. In the context of an open access network with a robust framework for regulated transmission investment and the potential for gaming diminished, the Group questioned the purpose of MNSPs.

In comparison to the alternative of regulated interconnects it was unclear that MNSPs created a public benefit, or that they were compatible with an open access/common carriage regime. If MNSPs were authorised, then the Group believed that they should at the least be subject to the same bond requirements as other 'committed projects'.

Finally, any comparison or evaluation of a MNSP project in a net benefits test should recognise the operational capacity constraint. That is, 1MW of MNSP capacity is not equal to 1MW of regulated link capacity.

Who pays for new investment

It was accepted that once a new investment has been approved under the regulatory test, two issues are important:

- How should new investment costs be allocated; and
- What location signals could and should be given to network users.

New investment costs

The Group agreed that the payment of new network costs should be determined on a *national basis*. This is consistent with the ACCC's regulatory test, which looks at the NEM-wide or aggregate benefits and costs of a proposed augmentation, rather than on a jurisdiction-by-jurisdiction basis. The example of QNI showed that attempting to determine net benefits between jurisdictions (let alone amongst participants) in advance was fraught with difficulties. Before construction of QNI began, common knowledge was that NSW generators and Queensland customers would be the major beneficiaries of the link. Excess NSW generation capacity would be exported to Queensland customers. However, history now shows that during the construction period, a number of generator projects came forward in Queensland. This could potentially switch the key beneficiaries to

Queensland generators and NSW customers. However, it was clear that QNI was still highly net beneficial across the market and that customers, as a class, across the NEM, were the key beneficiaries.

NECA has suggested that a 'beneficiary pays' approach could apply to new investment costs and has proposed various methodologies for the determination of beneficiaries. It was pointed out that allocating costs on the basis of expected benefits has little basis in economic theory. The efficient way to allocate costs is on the basis of who requires that additional costs be incurred – a 'causer pays' type of methodology. That is, from an economic efficiency perspective the primary issue is to allocate costs to the party whose decision results in those costs being incurred.

In the case of reliability-driven investments, the causers of the investment were clearly customers.

In the case of market-benefit driven investments, the causers could be seen, on one level, as the market as a whole. The regulated augmentation proponent (and indirectly the ACCC as transmission regulator) makes the decision to impose the costs on the market due to clearly demonstrated net market benefits.

In such a case, perhaps beneficiary pays could prove a sensible way forward for allocating costs.

It was demonstrated above in Figure 1 that customers, as a class, rather than generators as a class, are the typical beneficiaries of efficient network investments across the NEM.

The diagram shows that where demand is relatively inelastic, as is the normal case with electricity, and competitive costs are considered, customers benefit from a grid investment through a lower cost of supply. The regulatory test is based on competitive costs, rather than predicated market outcomes, as this is the only non-arbitrary way to assess the market benefits of a new investment. Whilst some generators may benefit at the expense of others, as a class, generators will not benefit from a network investment under these assumptions. This is because with inelastic demand, the effect of an augmentation is felt primarily on the cost of supply rather than on an expansion of output.

It may be possible to single out some generators as benefiting from a network investment. For example, if a very cheap generator located remotely, it may make sense from a market benefit view to grant regulated status to a transmission extension or augmentation that allowed that generator to reach loads. This would obviously be to the benefit of the remote generator. It would almost certainly be to the detriment of other generators and their collective detriment would be expected to outweigh the remote generator's benefit.

Therefore, in theory, it could be appropriate to impose a charge on the remote generator. However, this would be a highly difficult, unstable and controversial exercise. It is unlikely to be robust in the long term.

Moreover, it cannot be said that the transmission augmentation was 'caused' by the generator or its locational decision – the investment is approved under the regulatory test because, and only because, it brings benefit to the market as a whole, which, as seen above, is conferred largely, if not wholly, to consumers as a class.

Furthermore, it can be seen from the diagram that customers, as a class, benefit by *more* than the overall increase in economic surplus. This is because much (but not all) of the increase in consumer surplus is a wealth transfer from generators – ie. increases in consumer surplus arise largely from a *reduction* in producer surplus.

Therefore, whilst there is no particular 'causer' of a regulated net market benefit transmission investment, it could be argued that the beneficiaries should practically be seen as customers. Generators, as a class, would seldom benefit from a new investment, even though it is true they benefit from the existence of the existing network.

This approach suggests that customers should pay for new network investments that are approved under the regulatory test.

One refinement to this proposition is that if a particular generator feels that a particular investment would be of benefit to itself, but may not pass the regulatory test, it could agree to fund the investment to the extent that would enable it to pass the test. This 'pledge' would need to be subject to the same non-refundable deposit policy as with committed projects. If this were to happen, the asset would be a 'hybrid' augmentation. It would be operated by the TNSP on an open access basis, but the TNSP would only be able to earn a regulated return on that portion that was not funded by the generator. The generator would not receive property rights on the portion of the hybrid asset that it contributed to, as this could create a vested interest group against a further augmentation in the future. However consideration could be given to allocating the premium income from the sale of settlement residues to the contributor in proportion to their contribution towards the total project.

Locational and usage signals

One issue of concern raised in response to the framework discussed above is that locational and usage signals would be reduced. The ACCC's approach in its draft determination is designed to send price signals to all network users about utilisation of the network and the effect of an individual user's consumption or production of electricity on network utilisation. The approach agreed by the Group would not send explicit price signals to generators and would only send price signals to customers following an investment. This could be seen to reduce the forward-looking, dynamic efficiency properties of the transmission pricing regime. However, there are a number of reasons why this may not be a problem.

First, the ACCC's approach effectively forces users to pay for investments that may never occur. This is one attraction of NECA's alternative beneficiary pays proposal. In reality, the TUoS usage charge approach involves setting a long run incremental cost (that will typically exceed short run incremental cost) for usage of the network. The determination of the long run incremental cost, across the network as a whole is an extremely difficult exercise.[3] At least under the regulatory test, predictions about the timing and location of new investments are made transparently through a public process with opportunities for debate and with risks of optimisation. Individual network charges will not be subject to such scrutiny.

Second, the ACCC approach is difficult for participants to understand and involves a number of arbitrary assumptions. Moreover, it is likely to lead to severe volatility in prices with the location of large loads or generators within an area. Charges may rapidly switch to rebates or vice versa. This is unlikely to be conducive to a predictable investment environment with consequential implications for reliability. It was noted that parties who are contemplating new investment in generation will normally seek to understand the physical capabilities of the network. Price signals are far less important because *pre-entry* prices may not signal what happens *post-entry*.

Members of the Group indicated that non-price signals (such as risks of being constrained-off), risk of a new region being created and dynamic inter-regional loss factors may actually be clearer and more predictable than pricing signals that were largely driven by a non-transparent transmission pricing methodology. Some commented that forming a view on the future direction of transmission prices would require them to understand and predict the thinking of particular individuals responsible for developing or implementing the methodology.

It should also be noted that the regulatory test itself creates locational signals to generators, even where generators do not pay for new network investment. This is because generator proponents understand that if they locate in a remote area with limited transmission capacity, other things being equal, the chances of an augmentation passing the regulatory test to allow them to reach the RRN is reduced. On the other hand, if a generator locates remotely and a proposed augmentation still passes the regulatory test, then the generator's remote location may actually be efficient. It should be remembered that as part of the

[3] Cf discussion below regarding calculation of a LRIC figure in a particular area or particular line for discounting purposes.

regulatory test, it is necessary to consider a range of alternative investments. Therefore, if there is a committed proposal to build a local generator and its cost is less than the combined cost of the remote generator and any required transmission augmentation, then the augmentation will not pass the regulatory test and the remote generator will be stranded (subject to funding an augmentation itself). This risk sends a powerful locational signal by creating an incentive for proponents to locate generators as close as possible to load centres and existing transmission capacity to minimise exposure to the risk of non-augmentation and hence the risk of being constrained-off.

To re-emphasise an earlier point, although such signals are not price signals, in many ways they are more transparent to the market than price signals based on a non-transparent methodology. There is a high level of transparency in TNSPs' annual planning statements and there is general industry understanding and acceptance of the ACCC's regulatory test. The combined consequence of these two factors is that participants have more faith in their ability to predict the basis on which network investments will go ahead than their faith in TUoS usage prices to signal where and when new transmission assets may be built and hence where they should locate.

Transmission fixed charge discounts

The Group understood that discounts on charges for sunk transmission asset could promote economic efficiency by increasing network utilisation and reducing the risk of inefficient by-pass.

Two concerns were raised by the ACCC in its draft determination.

First, the ACCC cited concerns by the Australian Cogeneration Association (ACA) that allowing TNSPs to discount TUoS general charges was anti-competitive. However, the discounts would only apply to the fixed component of TUoS charges, not the usage price that is designed to signal long-run incremental cost (LRIC). So long as a customer pays at least LRIC, they are not being cross-subsidised by other customers. In fact, so long as such customers make some contribution to the costs of the sunk network, they are allowing general charges to be reduced to other customers.

As suggested, this approach relies on customers receiving discounts paying at least LRIC. The earlier discussion points out how difficult and arbitrary it is to calculate LRIC charges *across the network.* However, TNSPs have suggested that determining LRIC on a particular line or defined group of assets is a far easier exercise. If this can be done, then the argument that discounts are anti-competitive is refuted.

Another concern raised by the ACCC is that where a discount increases network utilisation and reduces the risk of regulatory optimisation, other customers should not have to suffer due to higher network asset value than would otherwise be the case. The issue here is that where a discount draws a new customer to a network and that new customer prevents a network asset being optimised, other customers face charges based on higher network asset valuations that otherwise. The ACCC is concerned that the other customers could in this way actually indirectly be made worse off by the discount.

However, it was suggested that such an incident was highly unlikely in most parts of at least TransGrid's transmission network. Further, such a concern raises only equity issues, not efficiency issues. It would still be efficient for a discount to be given to a price sensitive customer even if some other customers could theoretically be made worse off by a discount in certain circumstances. The ACCC should not sacrifice efficiency for equity where competition is not compromised. That type of trade-off is a role for jurisdictions, not regulators, to make.

Embedded generation

The Group briefly considered whether it was necessary to mandate 100% TUoS pass-through by distribution network service providers (DNSPs) to embedded generators. The issue is that an embedded generator may, by obviating the need for a network augmentation, save the DNSP (and its customers) from paying TUoS in relation to the avoided augmentation.

The approach proposed by NECA (and generalised by the ACCC) was that embedded generators receive the full benefit of avoided TUoS. The alternative is negotiation between the DNSP and embedded generator over how benefits could be shared. There was concern in the Group, echoing concerns in NECA's Review, that DNSPs were monopolies with little incentive to negotiate with other parties, even if it results in lower TUoS charges. Partly, this was because DNSPs typically view TUoS charges as a pass-through to customers and hence have little incentive to negotiate with a view to reducing TUoS charges. Even so, to the extent that TNSPs cannot invest in new augmentation without considering alternative options, embedded generators could still receive some support from TNSPs.

A key issue in this context is whether an embedded generator actually obviates the need for network augmentation. As a substitute for transmission augmentation, embedded generators have a reputation for lower reliability. Therefore, it may not be appropriate to award 'avoided TUoS' to embedded generators. Further, the issue can become circular in that an augmentation will only be avoided, as a matter of logic, where it is the most net beneficial option. If this is the case, it should go ahead and the 'avoidance' of it should not subsidise an investment that is less net beneficial (ie. the embedded generator). If the augmentation is not the most net beneficial option, then it would not pass the regulatory test and hence would not be 'avoided' by the location of the embedded generator.

Finally, where embedded generator options are considered in the regulatory test, they should be subject to the same committed project bond that all other projects would be required to lodge with the ACCC or the IRPC.

These issues suggest that TUoS pass-through should be a matter of negotiation between TNSPs, DNSPs and proponents, rather than completely automatic. However, the Group did not reach a firm conclusion on this matter.

Note that embedded generators may be a suitable substitute for distribution network due to the lower reliability of the latter in comparison to transmission networks. This is a matter that should be part of assessment of any proposed distribution network augmentation.