FIRM ACCESS RIGHTS:
THE KEY TO EFFICIENT MANAGEMENT OF TRANSMISSION

SUBMISSION TO:
THE NECA TRANSMISSION PRICING REVIEW

ENERGY
ISSUES PAPER NO. 12
JUNE 1999

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Summary

Regulated Provision of New Transmission is Causing Market Distortion

Regulated determination of new transmission links is distorting the electricity supply industry. Efficient market outcomes are obstructed where transmission decisions are taken by a regulatory agency with the costs financed by a form of taxation. This also deflects suppliers' energies from customer orientation to wastefully focussing on lobbying the regulatory agencies.

Regulated provision could be avoided if there was a specification and vesting of property rights to transmission use. The lack of this denies the various parties confidence to take long term capital positions.

Recovering Costs of the Present Network

Transmission systems presently in place were built by government agencies. Although generators ostensibly bear no significant part of the transmission costs, in Victoria they were sold with implicitly assured, customer-financed transmission rights. Hence the sale price bundled in transmission rights and costs. In all States generators have contracted on the basis of the present cost recovery allocations.

Placing all cost recovery directly on customers is unlikely to be the optimal means of financing these costs. But, financing sunk costs is a secondary matter. There is little to be gained by now dividing payments between generators and customers, as those payments are only incidental to decisions on the assets' operations and augmentation.

In addition, transmission *revenue* caps undermine efficiency, as they offer transmission providers inadequate incentives to pare costs. The close regulatory oversight they require also will divert management resources from a customer focus. A more appropriate price cap procedure would apply a CPI-X formula to existing charges, using total factor productivity to determine the X factor.

Network Augmentations

Future decisions on augmentations should be made by market participants on a commercial basis. A non-regulatory regime would segment the transmission system for future lines into those parts (radial links) paid for by generators and those (the meshed network) paid for by customers. Accompanying the payment stream must be some rights to the capacity or the financial equivalent.

A means of reconciling the treatment of new and existing lines is also required. This is likely to entail an explicit vesting of the present implicit rights to capacity, particularly radial lines. New generators would need to

purchase transmission capacity, build their own capacity or operate without firm rights. If a generator operating without firm rights to a line constrains-off a generator with firm rights on the line, it must compensate the constrained-off generator.

Introduction: the NECA Review

Provisional Conclusions Arrived at by NECA

In its June 1998 paper examining the *Effectiveness of Current Arrangements*, NECA found:

- Although acceptable for the present transmission backbone, TUOS charges do not offer incentives to allow augmentation to be undertaken efficiently. Interconnector property rights would allow price hedges which would provide the incentives for the transmission provider to ensure optimal capacity is available.

- Full costs of dedicated connection costs should be recovered by the relevant participant.
    - Customer Use of System Costs are inadequate. Efficiency means having opposite incentives on generators and customers. CRNP actually diminishes to individual users at high usage levels because the revenue is shared over higher volumes (and if set high to reflect a projected increased need at some future times this may needlessly reduce the present level of usage).
    - There is no application to generators, even though generators upstream may benefit.
    - There is no particular justification for a 50/50 postage stamp/CRNP applied to customers in any event. And postage stamping creates the possibility of inefficient bypass.

- Network charges should be set so that they impose a progressively increasing premium cost as congestion becomes more likely and an opposite incentive for loads and generators to locate where congestion can be alleviated.

- Although welcoming the revenue cap approach as a means of encouraging efficient maintenance, the NECA review points out that the arms length nature of the regulated NSP from the users offers no incentives as to the correct amount of maintenance in the network and how to allocate spending priorities between different areas.

- The Code sees justification for augmentation where net benefit to customers is maximised. But, as seen in the SANI case, a benefit to one set of customers and generators will mean a loss to others–customers downsteam of the augmentation gain but those upstream lose, and conversely with generators. And as the SANI case demonstrated, it is impossibly difficult to determine the best possible expenditures. Where procedures are in place to allow blocking coalitions, as in Argentina, this has led to less augmentation than many observers consider desirable[1].

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[1] If there is inadequate new capacity, this is likely to be due to the interplay of *regulated* transmission and *market-based* generation providing incompatible incentive structures.

- In the case of postage stamp funding, even if the measure did not materially influence behaviour, those that were charged the same fees as high users for a system they used only sparingly would be inequitably treated.

The NECA review notes that the benefits of a new augmentation are potentially capturable if they exist but that steps to achieve this would need to be taken in advance of the expenditure. Charging higher than marginal costs once a facility exists is likely to reduce usage below optimal levels.

Because the congestion rentals are much smaller than the cost of the system, (and would be zero after an augmentation) most users would prefer to pay them rather than the fixed costs of the grid[2].

The NECA review also points to the "free rider" difficulty where subscribers might not come forward because they expect others to do so. Even if the subscribers are given rights to any rents (congestion premiums), post construction these rents are likely to be small. This is all the more the case as there are economies of scale which will be likely to result in a link in excess of that which is required immediately.

One solution it proposes is to apply a surcharge to users who had not pre-paid for the transport rights. The issue is how to do this.

The Ernst and Young Proposals to NECA

The Preferred Approaches

The four Ernst and Young papers on Cost Reflective Network Pricing, noted that NECA had concluded that we should retain the present arrangements for treating sunk costs in the existing network (i.e. not imposing a charge on generators). They argued that new investments, including replacement and renewal expenditure, should be charged for on the basis of the benefits derived.

For new investment they outlined three principles. The first of these: *competition in network services should be promoted wherever practicable* was treated as less relevant because the work sought to evaluate the procedures for new investment that is not subject to competitive market considerations.

The other two criteria focussed on

- *transparency, stability and non-discrimination between users;* and
- *regulation that mirrors the outcomes likely in competitive markets*.

The papers' preferred approach, labelled Option B, would:

[2] London Economics have found short run charging for losses and congestion rarely covers more than 20 per cent of transmission costs in any jurisdiction and is commonly much less than this. London Economics, Review of Australian Transmission Pricing, A Report for the ACCC, April 1999, p. 67

Determine a split between customers and generators (as a group) to apply to each individual transmission investment, ie the split may be different for each specific transmission investment. This allocation can then be translated into a use of system tariff which is applied differentially to generators based on their usage of the asset

The papers reject a market based approach as being outside its terms of reference which presume a continuation of central planning. They also say, *We should not under-estimate the consequences of market failures in the provision of transmission augmentations.* (Paper 2). The market failures refer to the benefits that small customers gain from augmentations and the free rider phenomenon which entices those gaining from augmentations to avoid contributing in the expectation that someone else will incur the costs and risks.

The favoured approach seeks to allocate benefits of a transmission to different participants on the basis of;

- *fuel cost savings (constraint costs) to generators;*
- *avoided load curtailment to customers; and*
- *reduced losses 50% to customers and 50% to generators.*

Difficulties are acknowledged in allocating the increased benefits, and therefore charges, to individual generators. Although these difficulties are not spelled out, they would include the failure of the actual benefits to emerge in line with those forecast due to changes in bidding behaviour and new plant commitments.

At the end of the fourth Issues Paper there is a suggestion that those who pay for new investments might receive a form of property right such as preferential access or rights to settlement residues.

Three papers that examined the Cost Reflective Network Pricing approach accompanied the four Issues Papers. They examined how greater flexibility could be introduced so that the overall costs are not smeared across the network but instead take marginal costs into account. This is so that the prices better reflect spare capacity and offer signals to new investment while minimising uneconomic bypass.

Appraisal of the Ernst and Young Preferred Approach

These papers represent a well-considered attempt to construct a synthetic market to mirror what might occur in a real world with genuine competition.

In aiming at more flexible pricing structures, the papers are consistent with recent FERC approaches announced by Commissioner Hebert[3]. But they say little with regard to a further point by Hebert concerning "merchant plants" like Transenergie's NSW-Queensland link and to distributed generation. Hebert suggests, "with competition coming, the useful life of

[3] Hebert, C.L., and Rokach, J.Z., *Where We Go From Here*, Public Utilities Fortnightly, May 1 1999.

transmission facilities may become the life of the contract rather than the life of the line as it has been until now". Such an outcome would have profound effects on establishing a regulated rate of return.

Ernst and Young addressed the issues to be considered in allocating new investment: efficiency, cost recovery, eliminating "free riders" and so on. All of these are highly commendable and should be–perhaps always have been–the goals of a sensible regulator. But they only give general guidance for implementation. Indeed, one of the criteria, price stability, seems to be redundant. Price instability to customers from transmission charges would typically be about 1.4 per cent for every 20 per cent change in price, which in any case can be insured against. Moreover, price volatility may be desirable to encourage better line utilisation.

One of the positions tentatively arrived at is that the losers from an augmentation should not be compensated. This accords with sound economic principles–a supermarket should not be compensated if a rival locates nearby[4]. The papers also note that:

- there is no hard and fast definition of an augmentation;
- a system wide tariff has merit but offers more advantage to some than to others.

The general thrust envisages a continued form of planned transmission with new links decided upon after consultation but without the parties paying for the links having any veto powers.

The Ernst and Young prescriptions are market contrivances. They can never capture the full diversity of costs and opportunities that the stimulus of a Profit and Loss Statement forces on market participants. As synthetic market structures, the proposals will fail to provide commercial parties the appropriate signals and will lead to the participants continuing to "socialise their costs and capitalise their profits". Regulated prices are a poor substitute for market determined prices founded on known and tradeable property rights. For electricity, the basis of these are nodal Transmission Congestion Contracts (TCCs).

Addressing the Issues

The Major Concerns of Market Participants

Transmission issues impact both the customer and the supplier. Where customers pay the same price irrespective of location, they will tend to disregard costs in their site decisions and engender increased costs. Similarly, if the generator pays nothing for transmission other than the costs associated with line losses to the node, the generator will have every

[4] Even so, there are situations where compensation should be paid. These occur where the actions of a rival or an entity engaged in business that bears no relation to that of the incumbent are detrimental. Structures that take light from existing structures are common cases. In transmission, the building of a new line can result in diminished access to a market for some suppliers because of the physics of electricity flows. Such new building would require compensation for those who lost access.

incentive to locate close to fuel supplies even where a closer location to the market may, overall, be a lower cost solution.

For generators, the concerns are:

- ensuring the upkeep of existing links in the context of asset sales that gave them an implicit right to use the transmission system, without directly paying for the costs;
- arranging for the transmission system's expansion;
- arranging for optimal levels of service, with assurances on the certainty or degree of certainty that transmission is available for all power generated (or that compensation is available).

For customers, additional issues are the lack of pricing transparency and the politically inspired rolling-in of many costs irrespective of the location. Even where cost reflective pricing is involved, as is largely the case in Victoria at present, the ability of only a few customers (three in Victoria) to pay separately for transmission and distribution line charges and the standard distribution costs across distribution business areas gives very weak locational incentives.

The issues concerning transmission are considerably magnified by the uncertainty about the capacity of transmission links. Merril[5] analyses the transmission capacity between two US systems (AEP and Commonwealth Edison). He notes that the theoretical capacity of 3,500 megawatts can actually vary between 1,600 MW and 6,000 MW. Establishing firm access rights for any more than 1,600 MW is not possible unless there is an offsetting insurance.

The highly complex interactions and loop flows in the USA create much more difficult situations for generators than those found in Australia. Thus whereas Sydney has one main generator-customer interface node (Western Sydney) and Melbourne is similarly placed (at Thomastown), Los Angeles has five different nodes where lines supply power into the meshed network. Some power stations use more than one of these lines and there is significant loop flow that could reduce effective capacity of individual lines by up to six sevenths.

The Importance of Property Rights as Efficiency Drivers

> *"If prices don't provide the right incentives, consistent with the impacts on the overall electric power system, the participants will respond in their own self interests without concern for the system effects and the market operator will be driven inexorably to intervene in the market and restrict choice".*

The GPU Submission to the NECA Transmission Pricing Review, from which the above quote is taken, seeks to avoid having transmission centrally planned. It advocates comprehensively defined and individually owned property rights, and tradability of those rights. For generators, such rights comprise access to the network on a firm basis or

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[5] Hyde M Merrril, *Exploiting the Random Nature of Transmission Capacity*, Public Utilities Fortnightly, September 15 1998.

some other basis that is fully understood. A key adviser to GPU, William Hogan, has written elsewhere

> *To support a competitive market…. the old implicit allocations of rights must be made explicit.*[6]

Markets operate most efficiently when all valued assets are individually rather than collectively owned. This is because owners use assets for their highest valued purposes. Even though transmission assets may be privately owned, where their usage rights are communal the incentives to frugality are absent–there is a "tragedy of the commons" effect[7]. Attempts to combat the deficiencies stemming from lack of ownership mean a permanent role for an intrusive regulatory agency.

It follows that the area of communal rights should be narrowed as much as possible. It may be the case that the meshed transmission beyond major nodes has "public goods" characteristics and must remain communal but the transmission lines to these nodes serve clearly identifiable generators. These generators must, as Hogan says, have their implicit rights and associated usage charges specified and made explicit.

Not only should this apply to new transmission links but it should be put in place for existing facilities. This encourages considered decision making by those with the rights on their usage and, where they are of value, allows rights holders to negotiate sharing arrangements or sales to others better able to profit from them. Such actions can be expected to bring deferral of capital expenditure and better use of existing lines.

The merits of this approach are not materially affected by the present arrangements under which customers rather than generators pay for transmission. If, as generators strongly maintain, disturbing these arrangements on existing transmission would diminish their aggregate asset values and upset contractual commitments, the present arrangements should be left in place but vested as a transferable contractual property right.

These principles must be the bedrock for the approach to the issues raised in the various NECA review documents. These include efficient locational signals, bypass rights, the incidence of TUOS charges, and the treatment of embedded generators.

Because Australian transmission systems have been State owned, the access has been assumed to be statewide for both generators and customers. This will need to change as the monopoly of the incumbent transmission businesses is eroded. Differences in supply availability may mean more rather than fewer Australian regions and the rights to the system by generators will need to be more clearly defined. There certainly cannot be a single Australian region.

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[6] *Transmission capacity reservations and transmission congestion contracts*, Scott M. Harvey, William W. Hogan, Susan L. Pope, June 6, 1996 (revised March 8, 1997) p.55.

[7] Where it is argued that the common ownership of agricultural land brought overgrazing, inadequate maintenance and land degradation.

Pursuit of a myth of a single region where there are demand/supply imbalances within the region can lead to serious consequences and undermine a market structure. This can be observed with the Pennsylvania-New Jersey-Maryland system's single transmission zone. June 1997 saw prices vary between $12 and $89 and the Systems Operator was unable to arrange sufficient transmission. The incident produced striking evidence, if this was needed, of the potency of profit driven decisions to undermine a scheme with ill-devised prices and usage rights.

The Code

The transmission and distribution systems were envisaged under the Code to remain fundamentally centrally planned. It was the general view that these assets would remain largely as natural monopolies and the various parties would not be able to arrange their augmentation and maintenance except under central direction. The Code specifies that revenues should be raised solely from customers with prices regulated based on a 50/50 share between Cost Reflective Network Prices and a "postage stamp' price.

For the most part the Code took the view that interconnectors and network augmentations would be established following recommendations of the Inter-regional Planning Committee (IRPC). The IRPC would develop a *statement of opportunities* and an annual review recommending augmentation options to NEMMCO (5.6.5). Provision was made for augmentations that are not deemed justified by NEMMCO to be undertaken. These provisions were spelled out more in the section covering interconnectors across regions (5.6.6). But it was left, under clause 3.12.2, to NECA to establish rules for non-regulated interconnectors.

The relatively low share of transmission in total supply costs, the abundance of capacity for most purposes, and the inevitable co-mingling of electrons brought the general view that, aside from shallow connection and some other participant specific costs, the service should be charged as a compulsory levy on customers. This has started to break down as:

- embedded generators object to having their customers pay for a service they do not require;
- participants substitute a regulated "free" good for one that they must pay for directly; one notable example was the $104 million augmentation linking Tarong power station which was paid for by customers;
- the SANI debate and the recognition that the producer beneficiaries could be paid by customers, including customers that may be prejudiced by an augmentation;
- the TransEnergie proposal (now underway) for an entrepreneurial link indicated that commercial opportunities are a potential option.

The Prospective Solutions

The GPU Proposals

GPU's submission focuses is on competition and incentives within the framework of well established property rights. It takes the view that if such solutions are not used for transmission, the regulatory arrangements are likely to pollute the entire market.

It builds a simple case of a new stand-alone radial servicing just one plant. In that case it sees the costs as being unambiguously allocated to the plant being served–an outcome that did not occur with Queensland's Tarong upgrade where Powerlink used regulated revenues to pay for the radial upgrade from the Tarong plant. However the difficulty of defining capacity is magnified where the link is interconnected. This rules out a literal system of physical property rights.

A transmission congestion contract provides the financial equivalent. A transmission business would be paid the long term costs of expanding transmission and provide a contract to the participant who pays for it to ensure the price of the power was that in the target market. This could be done either by maintaining the wires or assuming the financial responsibility. Contracts would be specified to hubs, passing through one regional hub and into another. They would be the equivalent of firm rights to and from the hubs and a hedge across interconnectors between the hubs.

The firm access rights could be priced on the basis of previous bid patterns to establish an estimate of the incremental cost of the plant. The difference between these bids and the grid price could be used to define the estimate of losses and the implied obligation. The typical contract would allow for some normal period of outages as a result of maintenance. These features need to be structured so that the incentive is on the transmission provider to schedule outages when demand and price is low.

Where there are congestion limits, low cost power plants may be constrained-off and replaced by higher cost power plants. There are therefore two sets of prices. If the customer pays the pool price at the constrained area, say six cents, and the generator is constrained so that it receives only four cents, it may negotiate a congestion contract with an NSP to receive the additional two cents[8]. The NSP has the incentive to minimise the occasions when it pays the congestion contract by augmenting the line capacity.

With multiple participants and transmission businesses, this becomes more complicated as there are many different transmission combinations. A feasibility test can be used to arrange specific contracts, as occurs at five minute intervals with the present dispatch. With multiple owners of the transmission grid there would need to be a sharing mechanism for responsibility.

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[8] Although, as discussed later, where the increased supply would have led to a lower price, the two cents would actually overcompensate the generator.

The PJM system, which was the testing ground for this approach, overcomes disincentives by requiring participants to have adequate transmission capacity. Even so, the compensation for expanding the system, based on congestion cost differentials, has meant rationing of Firm Transmission Rights. Some means of vesting ownership in these is therefore required.

The PJM approach was a half-way house between common carriage and individual ownership has tended to adopt the features of the former. Spiwak[9] is one writer who considers the entire common carriage regime for transmission is doomed to failure. Rejecting "regulated" transmission expansions, he considers that open access at controlled prices will not offer sufficient incentive for the building of new lines; this lack of incentive is exacerbated if prices are based on short run marginal costs.

Price discrimination is essential if new facilities are to be provided without the colossal waste and inefficiency of central planning. Discrimination would be based on certainty of access to a line, initial capital funding and so on. This allows competition to play a crucial role bringing efficiency for which more choices is only one element.

Spiwak argues that central planning of transmission in the US has been a failure because of its inevitable pricing rigidities. He points out that in the US, since FERC Order 888 required divestment of transmission from generation, there has been little new entry other than marketing firms, and new transmission build has fallen 46 per cent. This is creating considerable reliability difficulties in the US and is doubtless a factor in the issues raised by FERC Commissioner Hebert (see page 4).

Firm Access

Defining Access Rights and the Different Components of Transmission

Generator firm access rights are used in several different senses.

- First, at their most fundamental, they refer to the rights an individual facility has to tap into a main transmission line that carries power from several sources into a major market. These "shallow" connections are paid for by the generator concerned and are undeniably best left to that generator to ensure optimum expenditure levels on them.

- A second notion of access rights concerns those shared between several generators to a major node. The previously integrated electricity supply system maintained a level of transmission sufficient to serve specific generators or clusters of generators. It is said that in Victoria the transmission capacity serving the Latrobe Valley was designed to allow all stations to operate at their maximum capacity for some 99.8% of the time.

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9 Spiwak L.J., *You Say ISO, I Say Transco, Let's Call the Whole Thing Off*, Phoenix Center Policy Paper. No. 4, www.phoenix-center.org

Derived from this, the incumbent generators could claim to have a degree of firm access rights implicitly vested in them. If these are made explicit, new or augmented supply would need to accept a diminished level of certainty (perhaps generating but compensating another generator that is constrained-off), arrange for a level of availability from an existing generator to be transferred to it, or augment the shared transmission line.

An alternative, more conventional view is that the NSP operates an open access line of a given capacity and no generator has any preferred rights to the line. If the NSP has, indeed, operated along these lines, it is in a strong position to obtain increased revenue from customers by offering certainty to some (but correspondingly less certainty to others). But this open access approach is likely to result in free riders bringing sub-optimal line usage.

- A third notion of firm access rights concerns the residual level that was never planned to be met, the 0.2% of the time that the access would be expected to be not available. One issue to be addressed, if this is taken to be the implicit contract, is what does the 0.2% comprise? Often it would, in reality, be power at or near VoLL, hence the reason why it may be sought. If firm access is to be bought, it would need to be specified. The parties involved would need to agree at the price or compensation that would be offered for firm access in addition to that already available In that case, the NSP is in a position to offer insurance or improved reliability through, for example, contracting some reserve power or building in greater redundancy.

- Fourthly, firm access rights can be applied to an interlink between two major load centres.

- Finally, although not usually thought of as a firm access right, the generator might come to regard its loss factors as "firm". Thus, if a generator in year one is given a static loss factor of 0.025 and, due to supply growth on the lines it shares with other generators, this is increased in year 2 to 0.035 (without any generator actually requiring to increase its capacity rights) it may arrange for the NSP to improve line cooling so that less power is lost in transmission. In order to recoup the expenditure concerned, it will need to negotiate a lower line loss factor.

Specifying Access Rights

Attachment 1 specifies the Code's connection agreements. These are vague in terms of concrete obligations on the part of the transmission business. As previously argued, efficiency requires rights to be specified and both these and the corresponding obligations should rest with the party best able to act in ways that maximise their efficient use. Fundamental to any arrangements on what firm access rights comprise is a definition of what rights, if any, each generator currently has to transmission capacity. If such rights are properly specified, the requirement to have a regulator determine the appropriate levels of service and expenditure is reduced.

Unless a level of access is specified in the connection agreements, there is no basis for seeking an improvement in the level of service or otherwise modifying it. There is, for example, no incentive for the transmission business to undertake maintenance at times when the value of the link to the generators is low.

Designating the transmission system beyond the "shallow" connections as a single entity with open access and assigning the costs to consumers is operationally sound where there is an abundance of capacity. But as capacity need increases, this procedure creates distortions. It impedes the building of new capacity, imposing reduced certainty on each generator's ability to transport power to the customers.

In addition, if the existing transmission lines to the meshed network are open access, new generating capacity, unless it is accompanied by new transmission capacity, will mean that the existing generators will face an increased likelihood of being constrained-off. This introduces a risk dimension to incumbent generators without offering them any means of defraying it.

Moreover, as gas and electricity are rival fuel sources of power (and gas is a rival source of generation), the allocation of true distance related costs to gas haulage and the lack of such costs, aside from line losses[10], to electricity is likely to distort decisions on the optimal location of new energy capacity. If, for example, a gas fuelled generator obtains costless carriage for its electricity, it will locate close to the gas source while its less costly location might be close to the market. Averaging of charges for electricity costs may also introduce distortions between gas and electricity as rival fuel sources.

Generator Payments

It is difficult to envisage why any future radial transmission developments should be other than entrepreneurial. Leaving an option for lines financed by consumer levies offers a hostage to those seeking to enlarge the notion of "market failure" into a concept where the market is deemed to have failed when it does not produce the outcomes the regulatory agency considers appropriate. The stated aim of modern regulators is simply to produce outcomes that a competitive market would produce[11].

Entrepreneurial electricity lines will almost always be financed (and perhaps owned) by generators. As generators pay few of the costs of existing lines, this may give rise to some distortions. These however are unlikely to be significant because the present arrangements have been factored into the energy price generators offer (and, in the case of privately owned generators, the purchase price for the asset). Efficiency rests

[10] Because line losses are based on marginal rather than average losses, they are actually about double the true losses and this partly compensates for a lack of explicit transport costs.

[11] Markets "fail" for highly specific reasons: the presence of monopoly, overwhelming externalities, or because the benefits they bring are "public goods" like defence. While the meshed network might have some public goods characteristics, this cannot be claimed of radial lines the benefits from which can be appropriated by particular parties.

primarily on clear and unchangeable arrangements with the original specification of these arrangements a second order matter.

One distortion stemming from charges to the generators is “economic” by-pass will not be contemplated by them. It may help efficient decision making in this regard, if the customer funding for existing transmission links were to be allocated to and notionally passed through specific generators, though the basis of such an allocation would require some consideration.

Attachment 2 suggests how the costs of transmission might be best allocated to correspond to market signals. In the attachment, these are based on an ideal system that neglect decisions previously taken. This involves retracing the root of the implicit contracts that were part and parcel of the original integrated system and assigning them to the party best able to ensure efficiency. Aside from the “shallow” connection costs, in the example given (which is a simplified version of the Victorian system), this breaks the payments into different parts, each with its own transaction structure.

Attachment 2 recognises a fundamental difference between the “meshed” transmission assets and those representing radial lines. As previously argued, while the former may need to be regulated along the lines of common carriage road systems, the latter serve specific and identifiable (normally generator) interest. The rights to them and (in the case of new facilities) their costs are best allocated to specific parties. This gives a generator, or a coalition of generators, firm and exclusive tradeable rights to the lines themselves. It would encourage efficient new build.

Existing Facilities

Customers have been required to pay for the existing network on the basis of their usage rates. This system is in place and would require a demonstrably superior system to be devised if it is to be replaced. But the existing network is not sunk for all time.

There are options in expenditure on maintenance and network operations on which the different parties may place different valuations. The NSP with a regulated network may see the best value in expenditures in one area while suppliers may wish to have a greater certainty of reliability of the lines carrying their own energy. Some means of ensuring the appropriate expenditure and service is achieved on specific parts of the network is required. This is best accommodated by assigning the rights as fully as possible and ensuring the different parties have the correct incentives to meet the corresponding obligations.

> **Principle 1: Existing generators have already purchased firm access reflected in the prices paid for the assets.**
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> The precise rights involved in this need to be specified, or in the Victorian case, determined by examining the basis of the acquisition payments. But, it would seem likely that a high degree of firm access for Latrobe Valley generators could reasonably have been

assumed given the surplus transmission capacity then (and now) in existence.

It is unlikely that the level of firm access rights would have been 100% since this would obligate the NSP to provide compensation should a line be out of service. In Victoria, GPU would argue that it would not have paid as much as it did if its assets carried a contingent liability to pay compensation to generators in such circumstances. In addition, there are rare occasions when part of a Valley generator's output is constrained-off, reflecting some of the difficulties in fully defining capacity at all times, in all weather conditions, etc.

For existing generator capacity, total firm access would therefore be likely to require some form of additional payment.

With a designated level of capacity rights, any generator would then have an option to purchase more than its allocated firm capacity from the NSP in the form of a hedge contract. This would offer the NSP, which is in the best position to improve access in the most cost-effective way, opportunities to be the counterparty to such a hedge. The hedge price might be specified at a particular hub (probably Thomastown in the case of Victoria). It may also contain *force majeur* clauses.

In effect, this would lead to a segmentation of the transmission network with one part constituting the transport of generated power to a hub and the other part comprising the meshed network from the hub. If the generators were prepared to pay enough to remove congestion at a particular point, it would be removed in this way; the degree to which a constraint remained would be dictated by the value placed on ensuring a levelised price.

Of course, a generator's rights to the network does not guarantee it will run whenever it wishes. Scheduling would remain the task of the system coordinator (NEMMCO) with the decision based on bids, line losses, constraints, etc.. The generator owning the rights to a line would be entitled to the revenue it brought in, whether or not its plant was running[12].

New facilities

The SANI process has illustrated some of the difficulties with the expansion procedures envisaged under the Code. With the SANI proposal a central planner was determining the best outcome and charging customers for the costs, even though some customers (those in NSW) would actually incur higher prices as a result of the investment.

New interconnects allow lower prices, to the benefit of all customers served and to the detriment of the producers in that area. Ideally, the costs should be apportioned between the beneficiaries but no market operates

[12] The revenue to the generator would need to be determined by its bidding. Where the generator without firm rights set the price, it could expect to obtain all the revenue; its share would be determined by its previous bidding pattern in other cases.

that perfectly, while regulatory decision frames are even further from perfection. But the sponsors of any innovation will rarely capture all the benefits from it. Workable outcomes are nonetheless seen in other markets, including those where a new source of supply, paid for by a particular producer results in lower prices to all consumers, not only those using the new supply sources.

This indicates that it is workably efficient if the producer(s) who benefit pay for augmentations. Those making the payments would naturally receive an exclusive right to the property. However, this interfaces with a system in which the network is in place and its on-going costs are paid for by customers. Producers will seek to ensure they are served by the existing system rather than paying for a new one, hence the need to formalise the present implicit rights to existing networks.

Principle 2: New or expanded generators must purchase firm access.

If all the firm access is allocated, new generators must:

- tolerate a lack of firm access;
- purchase firm access from an existing generator; or
- negotiate with an NSP for new capacity

Where there is excess capacity on a line, (the existing generators could not feasibly use all the capacity available), the NSP should be obliged to offer it to any party on the same conditions that describe the formerly implicit contract of the existing suppliers. Should there be a surplus demand, the NSP should be free to obtain better terms. If this were not permitted, queuing for capacity would occur and it is likely that "black market" transactions would take place.

Principle 3: A Generator Transmitting Power Beyond its Rights

Generation in excess of firm access at a time of constraint would be handled by the generator having to compensate the NSP, which would in turn compensate the generator that was constrained-off. There would be no penalty for excess generation if the lines were not constrained since no cost is involved.

Price and Revenue Caps

Generators' rights to the network also have a bearing on the price setting for transmission. Based on discredited notions of a wish to save energy rather than maximise efficiency, price caps have often been set on the basis of revenue needs. This offers inadequate incentive for the transmission business to seek greater line utilisation and could bring considerable social costs. In the UK revenue caps bring interminable wrangling over appropriately justified expenditure allocations. Furthermore, the revenue caps very quickly collapse into a form of profit regulation, the very outcome they were intended to prevent.

Line charges are best set as a contractually fixed price (perhaps with a reducing rate) at a designated level of service. This leaves the transmission business every opportunity to profit from making efficiency gains while protecting captive customers. The possibility of by-pass places a discipline on an incumbent NSP to reduce prices (beyond any stipulated reduction) where these are excessive. Of course, it would be illogical to allow the NSP to recoup from captive customers revenues lost from any consequential "stranding" of assets.

Issues to be Resolved

With both existing and expanded links, consideration needs to be given to the monopoly aspect of the transmission network:

- If the NSP is already being adequately compensated by TUOS, does the opportunity for improving the access of a particular generator offer a windfall? Probably not if the parties have a defined level of reliability at the point of hub connection.
- Does an incumbent NSP have leverage over a generator seeking improved reliability as a rival NSP would be in an inferior position to offer this? Probably the incumbent NSP is advantaged.

Other key problems are:

- Unless there is a constraint, the vast bulk of transmission costs are sunk, with only minor costs related to throughput. Yet, cost recovery through TUOS is based on throughput. This tends to be prejudicial to large users and beneficial to smaller users, since all should pay a similar access charge. In other markets with a high fixed cost component but with charges based on usage, large users tend to be able to negotiate discounts, particularly where the service is contestable. This is seen in water, gas, rail, etc.

- Once a link is constrained, losses rise considerably but the major beneficiaries of augmentation are customers in the constrained area since the augmentation leads to a reduction in the price for all electricity. This was a rationale behind loading the charges solely onto customers but begs the question of how they might organise themselves to ensure delivery from a low cost source.

  In fact where power is deliverable through a constraint, a generator, unless it delivers only a trivial quantity of power, is unlikely to see the full benefit of the higher price. Its own increase in supply will tend to equalise prices across the board. Generators in the previously constrained area will tend to see lower prices. Outside of that area, prices will rise for all generators. However, this is a problem with all forms of trade and does not require regulatory intervention.

Concluding Comments

The complexities of the different incentive structures comes back to some need for reassignment of payments and therefore of rights and obligations to the transmission system.

For new transmission lines, there is wide agreement that the costs are best paid by the parties benefiting most. Thus, in the SANI case, these are NSW generators who gain a new market in South Australia and South Australian consumers who obtain cheaper power. This would be difficult to arrange in a commercial market and the outcome would be that the suppliers would pay all of the costs, just as they do with, say, a satellite link. In any event none of the costs should be borne by NSW consumers who would actually see *higher* prices as a result of the link. If the procedures are to mirror market outcomes there would be no payment required of consumers in this and most other radial links. Exceptions would comprise isolated areas or new townships where it is not profitable for particular generators to finance supply.

It would be preferable to integrate past and future charging for transmission lines by revisiting the cost allocations originally set. For existing lines this would confer an agreed form of firm access on to generators up to the node prior to the meshed network. The generators would pay fees for the rights that correspond to the implicit costs (and TUOS charges by customers would be reduced accordingly). Given decisions already taken, the generators' fees would be paper transactions raised from customers.

The generator fees would best be structured as a two part tariff to incorporate fixed costs (about 90 per cent of the total) and variable costs for actually running (about 10 per cent of the total). A generator with firm rights would receive compensation if it was constrained-off by a generator without such rights. The compensation would be payable by the generator without the rights.

Attachment 1

Connection Agreements Under the Code

5.5 (f) of the Code specifies

The *Network Service Provider* and the *Generator* shall negotiate in good faith to reach agreement as appropriate on the:

(1) *connection service* charge to be paid by the *Generator* in relation to *connection assets* to be provided by the *Network Service Provider*;

(2) *use of system services* charge to be paid by the *Generator* in relation to any *augmentations* or *extensions* required to be undertaken in respect of all affected *transmission networks* and *distribution networks;*

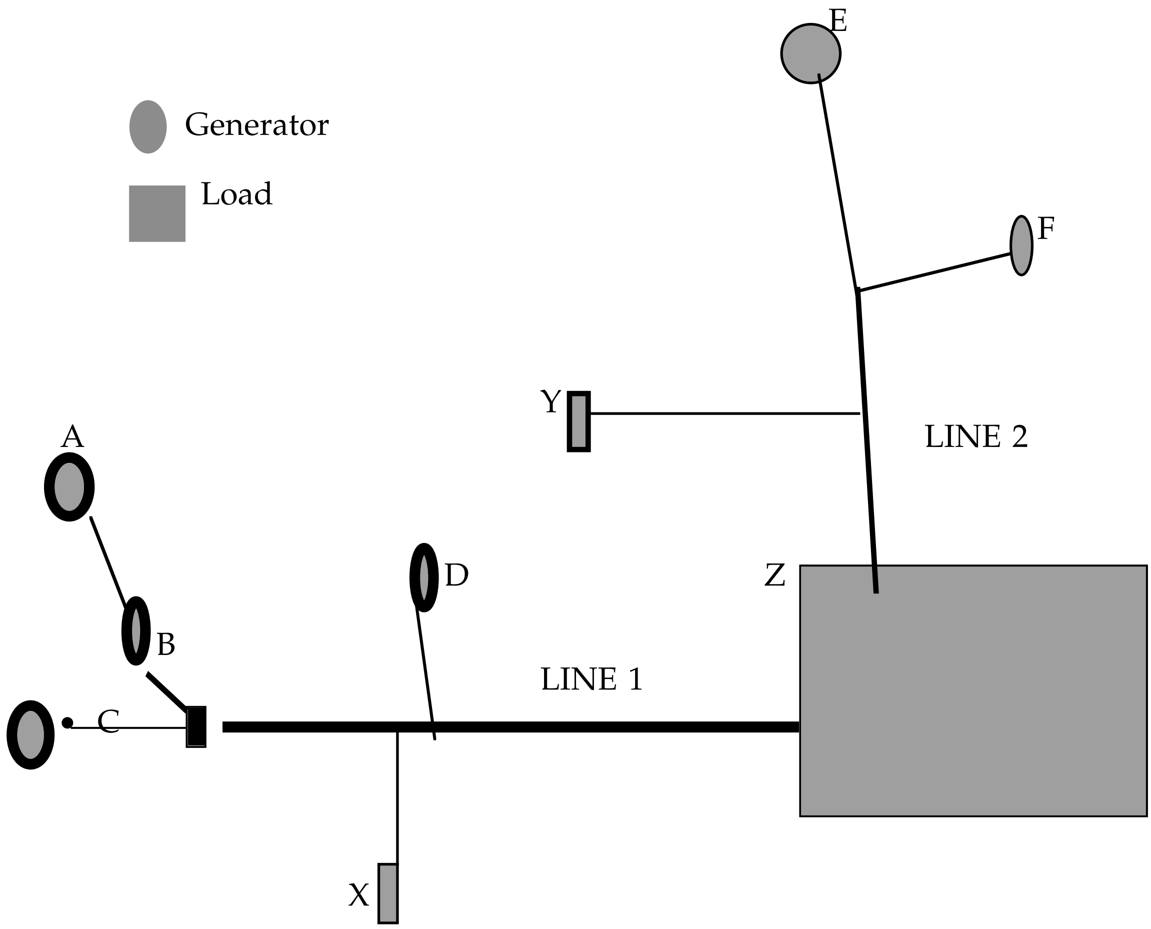
(3) amount to be paid by the *Generator* to the *Network Service Provider* in relation to the costs reasonably incurred by the *Network Service Provider* in providing *generator* access;

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

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

Attachment 2

A Stylised Depiction of the Cost Allocations



- Generator A should pay for A to B.
- Generators B and A should share the costs of B to main transmission line 1.
- Generator C should pay for C to main transmission line 1.
- Generator D should pay for the link to main transmission line 1.
- Generators E and F should pay for the lines to main transmission line 2.
- Generators A,B,C, and D should pay for main transmission line 1 with the share of generator D being reduced as a result of the diminished distance involved.
- Customers in X and Y should pay for the lines and the meshed networks connecting them to the main transmission lines.
- Customers in Z should pay for the meshed network within their areas.