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ACF Submission to ACCC Re: NECA Review of Transmission and Distribution Pricing

Evaluation Framework

> The key principles which should underlie network pricing are that:
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> - competition in network services should be promoted wherever practicable;
> - the commercial environment should be transparent and stable, and should not discriminate between users; and
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> for non-competitive services, regulation should seek outcomes which mirror those of competitive markets.

The shift towards fully functioning energy markets is still in its early stages. Full contestability is planned to be implemented progressively over a number of stages. In addition, industry participants and regulators have sought ‘derogations’ — temporary exemptions from market driven outcomes — limiting full competition in many important areas. The underlying aim of these arrangements has been to facilitate an orderly transition to market driven outcomes. The effect has been to defer many of the greenhouse benefits that were once widely expected to result from reform. The majority of the derogations that have been proposed are on the basis of jurisdictional self interest. e.g. the NSW vesting contracts.

Of even greater significance, the starting point — a predominance of large, cheap coal fired thermal electricity generation capacity — will continue to dominate outcomes, particularly given their existing free access to the transmission system. This pattern of supply was favoured by the former planners of the system reflecting the abundance of cheap fuel, and efficiencies that stem from economies of scale. With some important exceptions, market dispatch of electricity still follows closely the merit order dispatch set by the planners. The most significant problem relates to ramp rate to meet rapid changes in load and plant failure. Because coal fired thermal electricity generation stations have an operational life of 20 to 30 years, or more, the planners’ decisions are likely to fundamentally shape market outcomes for years, if not decades. The same argument applies to transmission assets. The average age of GPU PowerNet assets for instance is 30 years.

Market reform has discriminated against the demand management industry. This is partly through perverse incentive structures for retailers/distributors and partly through the poor network investment decision making process. Setting a cap on overall revenue or margins rather than average prices would reduce the link between revenues and sales of electricity. This would significantly reduce the incentive to promote electricity sales and increase the range of demand management and energy efficiency options which are commercially feasible.

Institutional barriers include market supervision and other regulatory arrangements. The Vesting Contracts between retailers, franchised customers and the existing generators have led to low spot prices. Franchised customers have in effect cross subsidised the low energy prices currently paid by contestable customers. Transmission access and investment cost act as a substantial barrier to entry in enabling new efficient generation to supply the market. This barrier lifts the energy bid price of the new entrant. This benefits the incumbent generators who gain greater income from the high new entrant bid price in the market stack.

Who should pay transmission charges?

> All the beneficiaries of new regulated investment in the transmission and, where there are shared benefits, the distribution networks should contribute to the costs of that investment in proportion to the estimated share of the benefits they derive from it.
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> For individual projects estimated to cost over $10 million, or an alternative threshold determined by the ACCC for the purposes of its revenue determination process:
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> - the analysis which NSPs will anyway be required to undertake in order to satisfy the ACCC's proposed net public benefit and market failure tests for new regulated investment in the network should be expanded to include an assessment of the project's relative benefits to, respectively, generators and other network customers. The assessment of the relative benefits should also include an appropriate allocation of costs to individual generators;
>
> - the consultation exercise that NSPs are already required to undertake in relation to large proposed new investment projects should similarly be expanded to include consultation specifically on the relative benefits of the project;

Ultimately, the consumer pays all of the costs incurred in the supply of electricity, but the price signals in a competitive market depend on the distribution of intermediate costs. In the current National Electricity Market, transmission charges are paid by the consumer, not the generator. That is, the generators do not have to pay for the cost of transporting their power to the market – contrary to what happens in any other competitive industry. For economic efficiency, all transmission-connected generators should pay for the transmission assets that are in place to transport their product to market. This is the approach that is being adopted in other countries such as the England/Wales electricity market. Other issues relevant to the distribution of costs include: operating and maintenance costs, transmission optimisation and perverse price signals provided by NECA’s proposal for new investment. Electricity market reform and deregulation has been driven by the existing industry participants, with key considerations being the protection of their commercial position and revenue base. As an example, transmission pricing has been developed and implemented by market institutions in a manner that clearly discriminates against low emission distributed generation in favour of high emission coal fired electricity generation[1].

The regulatory regime rewards new fixed asset investment. Both Transgrid and Powerlink have embarked on billion dollar system augmentations. These developments assists current incumbent market participant generators access the market. The Victorian Power Exchange Annual System Planning Review 1999 indicates that a number of constraints are developing in the GPU PowerNet Victorian Transmission system. The report suggests that there are three options to minimise the constraints.

- Invest in new transmission assets to benefit the asset owners.
- Demand side management of the load so the system doesn't constrain.
- Invest in cogeneration to minimise the constraint.

There are some unexpected outcomes from constraint and adding new generation to the transmission system at existing sites. The proposal by Mission Edison to build a 300-350 MW turbine set along side their Loy Yang B power station will cost them $ 3 m for a transformer and the switch gear to enable them to access the transmission system. This investment upgrades a 220 KV transmission asset to a 500 KV asset . The return of capital (DORC/depreciation), O&M and return on capital (WACC) will add $ 6m to customer recurrent transmission costs per annum. Alternative investments in load management and cogeneration could stop the investment in the turbines and the $ 3 m system upgrade.

Removing the electricity market impediments to low emission generation and demand management is a "no regrets" action, ie. no net cost to the community, and therefore should be implemented without delay. A number of impediments currently limit and constrain the ability of embedded generation, particularly cogeneration and renewable generation, to compete. The avoided transmission charges caused by the operation of the embedded generator should be fully recognised and rewarded. By implementing the unbundling of network prices and making them transparent, it would enable network users to negotiate service levels and promote efficient investment in the industry.

Information asymmetry disadvantages new entrants who are embedded generators – efficiency gains are essentially an externality which is not costed.

It is also necessary to remove all cross subsidies in network pricing to provide efficient signals to DSM and local generation projects in regional and rural communities. The legitimate equity concerns of these communities should be met by explicit Customer Service Orders (CSOs) through mechanisms such as the Victorian Smelter Levy. The results of this approach will generate further jobs and investment

[1] The Commonwealth Government recognised this in its submission to the NECA transmission and distribution review where it stated that:
"Current arrangements, which restrict transmission charging to generators to shallow entry costs, while leaving the bulk of costs to be recovered from customers, provide a substantial subsidy to remote, usually coal-fired generation to the competitive disadvantage of more greenhouse friendly natural gas and renewable generation typically located closer to loads. Pursuit of demand management options is also acutely disadvantaged." [Page 7]

in rural and regional communities where renewable generation projects will have a natural competitive advantage and can be implemented at lowest cost.

How should network charges be levied?

> The existing specific CRNP methodology set out in the Code should be revised and refined, consistent with the key principles enunciated in chapter 1, to enable it better to ensure that:
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> - prices should reflect the level of spare capacity on the existing system;
> - costs should not be allocated to specific customers or customer groups if the service provided delivers system-wide reliability or security benefits;
> - prices should signal anticipated future new investment costs;
> - prices should be designed to minimise uneconomic bypass and;
> - account should be taken of the merits of price stability.

In markets that are effectively competitive, the forces of demand and supply tend to yield prices that are efficient.[2] By efficient prices, we mean the prices that maximise economic benefits net of costs. This is sometimes termed "maximising the benefits of trade" or "maximising the sum of producer and consumer surplus". It is rare that anyone is called upon explicitly to design an efficient price or price structure for a competitive market. The current proposed amendments to the Code encourage transmission upgrade to benefit the incumbent generators and add to the costs of new entrants and discount demand side management and embedded generation.

In monopoly supply markets that are subject to regulation, however, the problem of designing efficient prices becomes a task of crucial importance. Such is the case with transmission and distribution networks. Network prices may influence the production and usage of electricity in the short run and the location of loads, generation and network facilities in the long run.[3] Efficient network prices will help to ensure that these activities are optimised.

The ability to bypass adds a cost and efficiency driver on to the transmission and distribution businesses. This provides a theoretical cost reduction driver to address the outrageous draft determination by IPART to increase the DORC by 30% through asset revaluation in the draft NSW transmission and distribution price review.
One positive outcome in this direction has been the Victorian Supreme Court judgement on the ORG determination for the Docklands insert distribution business favouring PowerCor rather than the appellant Citipower.

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[2] The presence of externalities or failures of competition in closely related markets may cause competitively determined prices to be less than fully efficient.

[3] A separate paper prepared by NERA, titled *Transmission Pricing: International Development*s, discusses approaches adopted by other countries, both in terms of short-term pricing signals, and the longer term investment framework

By definition, the physical facilities of the transmission network are fixed in the short run unless stranded by the change of load centres. The majority of the nation's transmission assets are around twenty five to thirty years old.

There are significant problems with the design of the east-coast transmission system. In the past interstate interconnection was designed to provide system security and reliability. The interconnectors were not designed for trading. The current crop of entrepreneurial interconnectors give generators market access across the constrained nodes, particularly Qld and SA. However the current proposed arrangement to use nodal market divergence as the source of revenue raises some interesting questions as to whether this arrangement will be profitable or whether it will further increase system losses. It should however provide some pressure on the SA and Qld generators to lower their energy prices.

The major cost revenue requirements are determined by the asset value DORC, which is returned to the owners in the form of depreciation and interest on investment. In the case of long life assets, interest (WACC) and O&M are significant items in the cost structure. The behaviour drivers are to reward the business owners with a rate of return on capital. The return currently set by ACCC and IPART of 7.75 % real for 5 years for the WACC and real asset growth provided by DORC provides a generous reward. Transgrid and Powerlink are both in the process of adding approx. $1 b to their asset bases. One small offset is that Transgrid has a revenue cap, but unfortunately, a high rate of return encourages new asset investment. Currently transmission investment continues to dominate electricity industry investment at the expense of embedded generation and demand side management.

The consequences of significant energy flows over long distances and on occasions high temperatures gives significant system losses. The short-run marginal cost of transmission therefore reflects marginal transmission losses and the marginal value of transmission constraints. Consider first line losses. As more electric power is transmitted over a line, the proportion of energy lost increases. Typically, losses increase more or less in proportion to the square of load, so that the marginal rate of loss on a line tends to be about twice the average rate of loss. That is, if the average loss on a line is, say, 5 per cent, then the loss on the last kW transmitted is likely to be about 10 per cent.[4]

The marginal value of a constraint is measured by the economic benefit of the last increment of constraining capacity. It depends upon the demand and supply for energy, the physical characteristics of the network and the procedures of the system operator.

The most important implication of this analysis is that efficient pricing of transmission services can be achieved in principle through pricing at SRMC, as

[4] We adopt the convention of measuring the per cent loss relative to the amount of energy delivered. That is, if 100 MWh are received net of losses and the average rate of loss is 5 per cent, then the amount of energy injected is 105 MWh. If the marginal rate of loss is 10 per cent, then the last kWh delivered requires an injection of 1.1 kWh.

described above, combined with methods and/or incentives for efficient expansion of the network over time.

Ancillary services may include such things as various types of reserve (spinning, warm, cold quick-start, etc), voltage support (reactive power) and black-start capability. The provision of any of these services will affect the SRMC of transmission to the extent that it influences the dispatch of the generation-transmission system and therefore losses, congestion and locational energy prices.

A transmission line may transmit both energy and an ancillary service. For example, it may serve as a means of making reserve generating capacity in one area available to another area. In effect, a portion of a line's capacity may be held in reserve along with the reserve generating capacity.

The short-run costs of transmission are those that vary with respect to the flows of energy over existing facilities, ie, with respect to the scheduling and dispatch of generation and load. In the long run, all costs are variable. Therefore, we focus on costs other than those discussed immediately above. These costs include all or most O&M costs. At first glance it may seem strange to include O&M in the long-run category, since O&M can increase or decrease over time even if facilities are not added or removed and it can be scheduled in different ways within fairly short periods of time. But because it varies little if at all with respect to the flows of energy over existing facilities we include it here.

Connection costs also fall under the long-run heading because they depend directly upon investments made to provide network users with access to the grid. Finally, long-run costs include those costs related to the investment in network capacity.

Network investments tend to be lumpy because large projects may allow the investor to capture significant economies of scale or scope. This has two consequences. First, prices equal to SRMC will not be sufficient to recover total cost under a program of efficient capacity expansion (nor will prices equal to LRMC). Second, the standalone cost of increasing network capacity is likely to exceed the LRMC of expansion by the network owner.

It is important to recognise that system growth is rewarded by real rates of return on real DORC'ed assets.

For network prices to be efficient, it is not sufficient that they signal economic value or scarcity on the appropriate margin. They must also provide the regulated network service provider with a reasonable opportunity to recover costs, including a risk-adjusted commercial rate of return on, and a return of, investment. If prices do not satisfy this objective, the cost of capital to network service providers is likely to be unnecessarily inflated, and the incentive to invest in new capacity will be inadequate.

The costs that network service providers must recover comprise administrative costs, O&M costs, taxes and the return on and of investment in plant and equipment. The potential sources of revenue include the settlements residue, connection charges and network charges, such as TUOS and DUOS under present arrangements.

NB. Transmission and distribution losses vary with the region, but average about 9% of energy generated. Transmission is about 3% and distribution about 6%. However, in the NEM, it is possible to trade energy generated in Qld to a SA customer without effectively considering the losses.

Unbundling Transmission and Distribution Charges

> End use customers with a load of greater than 10MW or 40 GWh should be able to receive unbundled network charge information from their DNSP, if they request it, with effect from 1 July 1999.
>
> For all other end-use customers, unbundled data should be published by DNSPs on a customer class basis. The published data should include the proportions of TUOS and DUOS recovered from each customer class demonstrate how the allocations to each class are determined.

Transmission and distribution charges should not only be unbundled, but the TUOS should vary with the location to account for the losses involved in taking power from remote generators. State boundaries are too far apart to justify common charges within the large areas corresponding to the old state electricity systems. The continuation of administrative convenience cannot remain in a fully competitive market.

For unbundling to be effective and to deliver its potential benefits TUOS and DUOS need to be charged in a more "cost reflective" manner. The fixed component of TUOS should be removed or substantially reduced and charged in a manner that reflects the "end use" customers' use of the network and metering installation.

The ACCC in their draft determination and in their final decision on the National Electricity Code Access arrangements saw the pass through of TUOS (based on IPART's "with and without" basis) as a means of levelling the playing-field vis a vis large thermal generators who were not paying TUOS —which in effect amounted to their deep connection costs.

.... network charges are unlikely to systematically influence generators' location decisions. Moreover, as generators will be dispatched into the wholesale market largely on the basis of generation and connection asset costs, the incidence of network charges appears to disadvantage embedded generation which competes on a delivered cost basis. [Page 62 of the ACCC's final decision on the NEM Access Code]

Service Standards

> Service standards should be set for tariffed services provided by all NSPs from 1 July 2001. Subsequently service standards should be proposed by NSPs, and determined by the relevant regulator, as part of the regulatory review process.
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> NSPs should be required to publish consistent and compatible annual statistics on operational. The performance measures should be based on a combination of those currently published by OFFER, ORG, IPART and those suggested by

> the NECA working group, which are now mentioned in the ACCC statement of principles for the regulation of transmission revenues. The regulators' forum should consider commissioning a bench marking study including a comparison of relevant financial performance measures commencing with 2000-2001 statistics.

Regulators of monopoly distribution businesses should be independent of government and regulate both the setting of prices and access arrangements as well as quality and service standards. Price setting cannot be undertaken independent of quality and service considerations. Independent jurisdictional regulators should oversee both economic and technical regulation as currently happens in Victoria through the Office of the Regulator General.

Network Bypass

> There should continue to be an unrestricted right to bypass the network.
>
> An NSP should remain free to negotiate a discount if it judges that appropriate in all the circumstances. The promoter of a bypass proposal should not, however, have an absolute right to an automatic discount on network charges in order to obviate the need for bypass.

In the case of embedded generation, bypass occurs where contestable electricity customers are directly supplied by a local generator. New network elements may be built that supply electricity to a number of customers directly from the generator thereby avoiding elements of transmission and distribution service. Bypass creates a strong discipline to ensure that network prices are efficient. Bypass may well not be the preferred option for an "access seeker" to the network as project proponents and "end use" customers will only implement "direct supply" or bypass if it provides a more cost effective and / or reliable service than that supplied by the NSP.

Reductions in network charges that may be negotiated by a NSP to prevent economic bypass could be deducted from the NSP's revenue cap (ie. the DNSPs assets would be written down to the value of the alternative bypass assets). Where network charge reductions are negotiated so as to avoid bypass which is viable because of imperfections in pricing (or cross subsidies), they should not result in a reduction in the revenue cap. This provision should be qualified to ensure the NSP has made appropriate endeavours to reduce the scope for uneconomic bypass through:

- providing network charges to "end use" customers that better reflect the costs that they impose on the system (ie. movement towards pricing that better reflects future network investment); and
- unbundling of transmission and distribution pricing.

Embedded Generation

> The full reductions in TUOS charges to DNSPs as a result of an embedded generator locating in their area should be passed through to the embedded generator. This will both provide the appropriate locational decisions to embedded generators and, crucially, place embedded generators in the same competitive position compared to conventional generators as if those

generators paid, in broad terms, 50 per cent of total TUOS charges.

All generators should pay deep connection costs provided that they are also able to capture the reduced costs incurred by the DNSP as a result of the operation of the embedded generator which includes avoided TUOS and avoided distribution network augmentation. Where a new embedded generator pays deep connection costs then it should receive preferential access to future network users that may connect and who make use of the deep connection assets.

By prescribing the TNSP to recover charges from the DNSP on a fixed annual basis, unrelated to use of the network, the Code systematically discriminates against embedded generation and unduly protects the TNSP from competition. The Code would therefore fail as an access regime. Better options are available, as shown by recent experience in the gas industry where pricing is related to capacity and volume utilisation.

Conclusion

- Without Integrated Resource Planning and open access to the grid at a reasonable cost, it will be impossible to contain demand growth and there will be no incentive to supplement conventional sources of power with cogeneration and renewables;
- The new National Electricity Market is structured in such a way that smaller, dispersed sources of electricity are disadvantaged. Barriers to the use of such dispersed sources must be addressed if they are to make any significant contribution;
- The market power of transmission and distribution network providers is so great that embedded generators and proposals for Demand Side Management have little bargaining power and market signals are stacked against them;
- The large area of existing networks, the fact that existing generators do not pay deep connection costs and the artificially low price of coal-fired generation make it very difficult for embedded generators or demand side management to compete, even when they would otherwise be the least cost alternative;
- TUOS and DUOS charges should be unbundled and the TUOS should vary with the location to account for the losses involved in taking power from remote generators;
- The fixed component of TUOS should be removed or substantially reduced and charged in a manner that reflects the "end use" customers' use of the network and metering installation;
- Network cross subsidies that discriminate against regional and rural generation and demand side management (DSM) should be removed;
- Independent state based regulators should be established that oversee both distribution pricing arrangements and also quality and service standards (as currently occurs in Victoria) to:
  - Reflect the cost of the network in place to meet customers peak electricity requirements;
  - Remove distortionary high priced vesting contracts to existing generators that are not available to other new entrant generators; and
  - Set a cap on overall revenue or margins rather than average prices to reduce the link between revenues and sales of electricity. This will reduce

the incentive to promote electricity sales and increase the range of demand management and energy efficiency options that are commercially feasible.

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Glossary

Code	National Electricity Code
Cogeneration	The generation of electricity as part of some other process such as the supply of low pressure steam to a chemical plant or the recovery of heat waste and gases from a blast furnace.
CRNP	Cost Reflective Network Pricing (Locational Pricing). Approach proposed by the National Grid Management Council to network pricing.
Customer Service Orders	Community service obligations
DSM	Demand Side Management, commonly defined as the systematic planning and implementation of energy utility services designed to influence customer use of energy in ways that will produce desired changes in the utility's load. It encompasses both load management and energy conservation.
DNSP	Distribution Network Service Provider
DORC	Depreciated Optimised Replacement Costs. The conceptual underpinning for the DORC approach is that this is the maximum price a new entrant would be prepared to pay now to take over the existing assets, rather than to rebuild an entirely new system.
DUOS	Distribution Use of System
Embedded Generator	A generator connected to a distribution network
ESI	Electricity supply industry
Franchise Customer	A (non-contestable) customer who may buy electricity only from the customer's local retailer.
IPART	***Independent Pricing and Regulatory Tribunal, New*** South Wales
LRMC	Long Run Marginal Cost
MNSP	Market Network Service Provider
NECA	National Electricity Code Administrator
NEM	National Electricity Market

NEMMCO	National Electricity Market Management Company
NSP	Network Service Provider
O&M	Operation and Maintenance
ORG	Office of the Regulator General, Victoria
Postage Stamp Pricing	A pricing arrangement where network costs are covered by a uniform price per unit of capacity used irrespective of distance, similar to prices in the postal system.
RRN	Regional Reference Node
SRMC	Short Run Marginal Cost
TPA	*Trade Practices Act 1974*
TUOS	Transmission Use of System
TNSP	Transmission Network Service Provider
Vesting Contracts	Contracts between generators and distributors on behalf of franchise customers
WACC	Weighted Average Cost of Capital. Measure of required return on assets based on assessment of the cost of debt and equity. It includes a risk factor.