Transmission Pricing Methodology: issues and proposal

Submission by Electric Power Optimization Centre,

The University of Auckland

Professor Andy Philpott

Dr Golbon Zakeri

Dr Geoffrey Pritchard

Dr Tony Downward

http://www.epoc.org.nz

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Executive Summary

EPOC does not support the proposed transmission charging regime as it is described in the supporting documents. We find:

1. Under current wholesale market arrangements the proposal provides incentives for suppliers to change their offer strategies to increase prices on infra-marginal tranches. This biases the cost allocation towards agents who cannot do this.

2. Even in a perfectly competitive setting, the proposal might overstate the benefits accruing to agents (e.g. hydro generators) whose offers are different when transmission assets are changed.

3. The proposal (if benefits and losses are combined) can provide incentives to form coalitions to minimize payments. In cooperative game theory terms, the cost allocation scheme is not in the *core*. It might also provide incentives to disconnect from the grid. In a perfectly competitive setting, a different cost allocation scheme that is in the core can be computed via Shapley value, for example.

First-order incentives

The benefits proposal assumes that offers made by market participants are perfectly competitive. Under this assumption the total benefits from an SPD run can be computed using the difference in price between the marginal value of supply (or demand) and the clearing price. In a market in which offers are not made at marginal cost this charging scheme gives an incentive to markup the asking prices on infra-marginal bids. In a generator's case this would involve increasing the bid price on all tranches that were likely to be dispatched. For dispatchable demand this would involve decreasing the bid price on the first units of demand.

This incentive will be strongest in periods in which there is little uncertainty in the cleared system marginal price. Observe that if the clearing price is known then there is no penalty in the energy market from marking up all tranches to this price (minus one cent). This pay-as-bid (Bertrand) type offer will ensure that the benefits from the dispatch as computed using SPD will be (close to) zero. If this offer is then used in a system with a transmission asset removed, then it will either be fully dispatched at a clearing price greater than or equal to the offer price, giving a non-positive benefit for the addition of the line, or not dispatched at all giving zero benefit. In both cases the additional benefit of the line is not positive and so will not be counted in the cost-allocation procedure.

The incentive becomes weaker if there is more uncertainty in the dispatch point. However, recent results from symmetric supply-function equilibrium models[1] show that a tax placed on observed profits (rather than actual profits) makes supply-function offers more competitive to reduce the amount of tax collected.

With this incentive in place, the computed benefits will fall on agents who cannot change their offer, in particular suppliers such as wind that do not bid above zero price, and purchasers without demand-side bidding options, even though other agents receive considerable benefits. If all agents can change their offer to minimize the benefits payments then one might argue that the proportions will remain fair, and so result in an efficient allocation. Even if this were the case, the inefficiency implications for a wholesale pool market of pay-as-bid type offers are well-known as the optimal dispatch can switch wildly between those generators who have estimated the clearing price most accurately.

Lower bound

In 6.5.14 it is stated that the SPD method of determining benefits is preferred over using economic models as it:

> *"…unlike the Authority's proposal, it would not use direct wholesale market outcomes to determine benefit but rely instead on forecasts and modelling assumptions."*

This is true; however the issue is that SPD, while using direct wholesale market outcomes to determine the "profit" after the investment is only estimating the "profit" for the counterfactual. This means that it may not be more reliable, and in fact if the scheme were designed in such a way so as to allow participants to manipulate their offers in order to reduce their perceived benefits, the SPD option may be considerably worse.

[1] Philpott, A. Taxation and supply-function equilibrium, downloadable from www.epoc.org.nz, 2012.

Moreover, 5.6.37 and footnote 102 state:

> *"The Authority appreciates that SPD is not a full behavioural model, but it should provide reasonable lower-bound estimates of private benefits as participants will be free to alter the structure of their offers to the market when the beneficiaries-pay charge is introduced…"*
>
> *"Using a full behavioural model instead of SPD, as considered in chapter 6 of this paper, allows further adjustments in behaviour to be taken into account in assessing private benefits, but participants will only make these adjustments if doing so increases their net private benefits."*

This appears to be erroneous, even in the case where a firm ignores benefit payments in constructing its offer. This is because a firm will typically update its offer to reflect the addition of a new grid asset. Then, using that same offer in SPD without the grid asset may show a low profit, when in fact with the initial offer stack the profit would be high also. This means that using the same offer stack in each case, as the proposal suggests, will overstate the true benefit.

This assertion is true even when the offers are perfectly competitive. Since transmission assets affect dispatch and this affects water releases, marginal water values will be different with and without the asset. For example, the marginal value of water for a South Island hydro generator will differ greatly depending on the capacity of the HVDC link. If the capacity is small then the optimal competitive offer stacks of the generator will be priced lower. Applying the procedure using observed offer stacks from periods with high capacity will give lower benefits. This will overstate the benefits of the increase in capacity of the line.

Non-monetary benefits

The question of who is paying for the reliability benefits of additional grid assets is important, and some analysis should be conducted around the additional reliability that the asset provides.

Net-benefits for gentailers

In 5.6.20 it is not clear whether, for example, a gentailer would be considered to be one entity or two. It appears preferable to treat it as one entity, which will deliver a net benefit.

If it were treated as two separate entities, then if the demand side of their business benefitted, but the supply side had a significant reduction in profits (exceeding the benefits on the demand side), then the gentailer would still be required to pay for the transmission asset even though it had sustained a loss in total from the asset being installed.

The aggregation of benefits raises the possibility that the benefits charging scheme might produce incentives to merge or break apart existing companies. If this is prevented from happening for other reasons, the incentive remains, and will provide an incentive for organisations to lobby for changes to the cost allocation. A potential solution is to seek a cost allocation in the core of the cooperative game (using, say, a Shapley value). This has been discussed in the literature[2].

Total benefits less than cost of transmission upgrade

In the situation where the total benefits are less than the cost of the grid asset, this means that all benefits will be paid towards the upgrade cost. This will increase the incentive for firms to attempt to understate their benefits as computed through the SPD mechanism stated.

Without demand-side bidding the consumer benefits are overstated

Without explicit demand-side bidding it is likely that consumer behaviour will be overstated, as historic fixed demands will be used when in fact, without the grid asset demand may have been very different.

Time frame of benefit calculations

In section E7 of Appendix E, there is a discussion around the timeframe over which the benefits will be computed. It appears the preferred option is to consider the benefits on a daily basis. This leads to two issues, the first of which is outlined in paragraph 55, which points out that by capping the maximum revenue that can be gathered in each day, the chances of a revenue shortfall is very high.

The second concern is that by computing the benefits each day, some firms whose benefits are seasonal, will be charged when their benefits are positive, however, will not be compensated when the benefits are negative. This may lead to situations where firms with an overall disbenefit from the transmission asset, still must pay a considerable amount in transmission charges.

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[2] Contreras, J.; Wu, F.F., Coalition formation in transmission expansion planning, *IEEE Transactions on Power Systems,* vol.14, no.3, pp.1144-1152, 1999.

Appendix: Example of marking up infra-marginal offers

The example considers two generators and an elastic demand. Generator 1 is located at the same node as the demand. The transmission asset connects generator 2 (a geothermal plant) to this node. Generator 2 offers at zero marginal cost (shown in green in Figure 1 below). Generator 1 offers a linear curve. Solve 1 of SPD includes the asset (and the offer of generator 2). Solve 2 removes the asset (and the offer of generator 2).

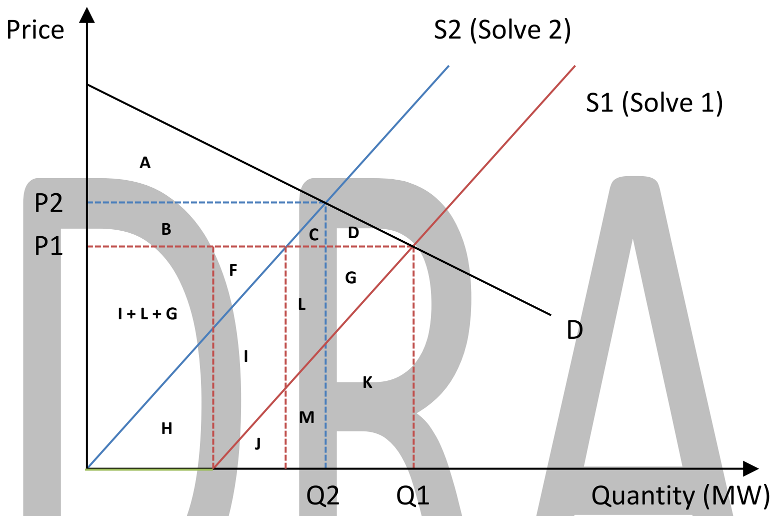

Figure 1: Initial offer stack.

Figure 1 shows the situation graphically. Because the offer curve of solve 2 is shifted horizontally the triangular area F+I+L+G is the same above both red and blue lines. The benefits to each player are listed in the following table.

	Solve 1	**Solve 2**	**Change**
Demand	A + B + C + D	A	B + C + D
Gen 1	F + I + L + G	B + F + I + L + G	–B
Gen 2	I + L + G + H	0	I + L + G + H

Under this bidding strategy, SPD would compute the benefits to generator 1 (red/blue) to be –B (i.e. the benefits are negative), whereas the benefits to generator 2 (green) would be I + L + G + H, which is positive. The benefits to the demand are B + C + D. This means the contribution to the cost of the line are made in the following proportions:

Demand: $\frac{\mathrm{B+C+D}}{\mathrm{B+C+D+I+L+G+H}}$

Generator 1: 0

Generator 2: $\frac{\mathrm{I+L+G+H}}{\mathrm{B+C+D+I+L+G+H}}$

However, suppose generator 2 chose a different offer which aimed to pass through the same dispatch point, as shown in figure 2, below. Under this bidding strategy SDP would again compute the benefits to generator 1 to be –B, however, now the benefits to generator 2 would be 0, since its offer is assumed to be its cost. The benefits to the demand are unchanged at B + C + D. This means the contribution to the cost of the line are made in the following proportions:

Demand: $\frac{\mathrm{B+C+D}}{\mathrm{B+C+D}} = 1$

Generator 1: 0

Generator 2: 0

Thus we can see that by altering its offer to a *pay-as-bid* type offer (i.e. the offer is flatter and all its quantity is offered at the anticipated clearing price), generator 2 was able to appear to have received no benefits from the line, when in fact there were benefits. In fact, it can be shown that by adopting this approach of offering in a pay-as-bid manner, one can always substantially reduce the apparent profits, leading to no (or possibly negative) benefits.

Of course the potential downside of this approach is that if one were to over-estimate the market clearing price, they would not be dispatched. However, it is clear that incentive still exists to mark-up the offer curve to try to reduce the perceived benefits.

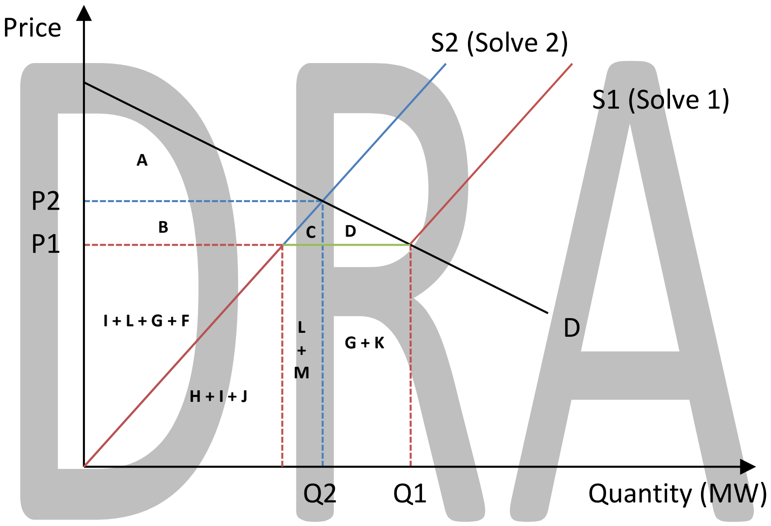

Figure 2: Modified offer stack.

	Solve 1	**Solve 2**	**Change**
Demand	A + B + C + D	A	B + C + D
Gen 1	F + I + L + G	F + I + L + G + B	–B
Gen 2	0	0	0

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