Consultation
on
Transmission Pricing Review

Submission by Electric Power Optimization Centre

The University of Auckland

http://www.epoc.org.nz

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Executive Summary

1. The TPM review advocates the removal of the current Regional Coincident Peak Charge (RCPD) to be replaced by an ex-post beneficiary-pays charge. The investment incentives created by this change need to be carefully examined to determine if they lead to a generation / transmission system that is close to socially optimal.

2. Loss and transmission rentals arising from locational marginal prices are not retained by the transmission owner, but returned to consumers via payments for FTRs. This allocation to customers can distort the effect of locational marginal price signals on long-term decisions. EPOC recommends that loss and constraint rentals be retained by the grid owner.

3. The cost-benefit analysis carried out uses a counterfactual model in which electricity offers are unchanged from what they were historically. The most suitable counterfactual for benefits should treat market participants as perfectly competitive, and account for changes in water values that arise from changes in transmission capacity. This is important when considering the benefits accruing from the HVDC line.

Section 1: Introduction

1. This report is a submission by the Electric Power Optimization Centre (EPOC) on the 2019 issues paper for the Transmission Pricing Methodology Review. The issues paper presents a new proposal for transmission pricing, and the results of a cost-benefit analysis. The Electricity Authority is seeking submissions from stakeholders on these options.

2. EPOC is a research group at the University of Auckland that conducts independent research into wholesale electricity markets. EPOC has made previous submissions on the Transmission Pricing Methodology.

3. EPOC supports the general principle of beneficiary pays for electricity transmission, but does not agree with the phasing out of RCPD based on the arguments presented in the issues paper. It is possible that a combination of beneficiary pays and coincident peak charging will give better incentives than a methodology that uses only one of these charges. We discuss this in Section 2 below.

4. EPOC does not accept the stated justification for altering the current charging regime for the HVDC. It is true that benefits from the HVDC accrue to both South Island and North Island market participants. When generators are strategic, price signals can be distorted, yielding distorted investment incentives. We discuss this in Section 3 below.

Section 2: Peak demand charges

5. The issues paper presents several arguments in favour of phasing out RCPD. It is claimed that locational marginal prices on their own give the appropriate incentives to reduce transmission congestion. EPOC contends that these signals are muted by the regulated allocation of transmission constraint rentals to electricity consumers (as a rebate on TPM charges). The shadow prices on transmission constraints that generate these rentals are socially optimal congestion signals (assuming convexity, market completeness and perfect competition). EPOC argues that these should be retained by the grid owner.

6. If loss and constraint rentals are not retained by the grid owner then it is likely that some combination of peak charge and beneficiary-pays charge will a better second-best congestion signal, than a single charge on its own.

7. It is clear that RCPD creates winners and losers. The issues paper compares two market participants, Norske Skog in Kawerau and Ashburton Power in Canterbury. While Norske Skog manages to avoid RCPD charges using clever mill-scheduling, Ashburton's irrigation clients cannot avoid these charges, which have turned out historically to be significantly larger than forecast. EPOC contends that this apparent unfairness is an artefact of competition and on its own is not an argument for altering the charging system.

8. The incentive that RCPD gives to reduce consumption in peak periods is strong, and a reduction in peak load possibly obviates the need to build new transmission. So RCPD gives a signal for load shifting out of peak periods.

9. If the RCPD charge were to be removed, we should expect changes in behaviour that may lead higher coincident peaks, and new investments being needed sooner.

10. The main problem with RCPD is that, on its own, it is zero sum and, if avoided, the charge must adjust to spread the costs over a shrinking set of peak users. This is the essential point of the Norske-Skog vs Ashburton example.

Section 3: Costs and benefits

11. The issues paper is accompanied by a detailed cost-benefit analysis. This yields a net benefit of $2.7 billion over the status quo. The methodology to compute benefits has several weaknesses.

12. A large part of this $2.7 billion comes from consumer benefit (using electricity at times where it is most valued). Quantifying this benefit is not straightforward. Sometimes shifting electricity from a peak time has very little cost (e.g. for water heating) and sometimes it has a high cost (e.g. during the Rugby World Cup final). So figures like $2.36 billion need some care in interpretation.

13. The counterfactuals used in the cost-benefit analysis assumed that market participants behave similarly with and without the asset. In the case of the HVDC line this is an oversimplification. The offers made by generators are not constrained to be at short-run marginal cost and so they will change depending on the capacity of the grid.

14. Even if offers are constrained to be competitive, those of hydro generators will reflect their marginal water value. This is not accounted for in the cost-benefit analysis in the issues paper. To see how this makes a difference, one might compare a model with a 1000 MW HVDC line with a model with no HVDC line. In the former case, a perfectly competitive marginal value of water will be a function of thermal and potential national shortage costs, where the water is used optimally to minimize these costs in expectation. With no HVDC line the South Island will have excess energy and the reservoirs will fill. The marginal value of water will then be close to zero most of the time, and South Island prices will also be close to zero. So (perfectly competitive) generators in the South Island will offer at marginal prices close to zero.

15. A better estimate of the benefits of the HVDC line can be computed using a competitive counterfactual model of the NZEM. EPOC has developed such a model using vSPD, and used it to investigate market outcomes under various assumptions on the levels of risk aversion of market participants. This model can be used to compute constraint rentals from the HVDC.

16. In the calendar year 2017, our counterfactual model gave constraint rentals as shown in the following table.

	NI-SI	SI-NI
Historical	$ 773,412	$ 3,572,216
Counterfactual	$ 2,230,804	$ 81,045,614

Table 1: Historical and counterfactual HVDC rentals in 2017

The historical transmission rentals computed using vSPD are close to those reported by Transpower ($3,853,191) in [1]. The perfectly competitive counterfactual rentals are significantly larger than historical rentals. The differences occur when the HVDC is constrained.

17. Table 1 also shows an indication of the increase in HVDC constraint rentals that would accrue if the wholesale market were more competitive. In 2017 the HVDC line was less constrained than in the counterfactual, because offer prices in the South Island were bid up to North Island levels when flow is travelling North, and offer prices in the North Island were bid up to South Island levels when flow is travelling South. If the North Island prices and South Island prices are similar then the grid owner earns very little transmission rental from the HVDC during these periods. Our model finds that the historical (imperfectly competitive) bids have led to a transfer of about $80 million from the grid owner to generators in 2017, compared to our perfectly competitive counterfactual.

18. The issues paper mentions that investment in South Island generation is disincentivized by the amount that they are asked to contribute towards HVDC costs. On the basis of Table 1, EPOC argues that strategic bidding has inflated these incentives by yielding prices and water values above perfectly competitive levels.

19. If the market were perfectly competitive then in 2017, South Island water values would be lower, and 2017 South Island generators would have contributed a payment of $81M to the grid owner rather than $3.5M. These estimates should be taken into account when estimating the benefits of the HVDC to market participants.

References

[1] https://www.transpower.co.nz/industry/revenue-and-pricing/pricing