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26 July 2016

Electricity Authority Board Members
C/- Submissions
Electricity Authority
P O Box 10041
Wellington 6143

By email: submissions@ea.govt.nz

Dear Board Members,

RE: Cost-Benefit Analysis of the TPM Proposal

Pioneer Energy Limited (Pioneer) appreciates the opportunity to make submissions to the Electricity Authority (Authority) in relation to its review of the guidelines that Transpower and the Authority must follow in setting the transmission pricing methodology (TPM). The Authority is proposing to replace two charges in the current TPM with two new main charges – an area of benefit charge on generation and load and a capacity-based ‘postage stamp' residual charge on load customers only. The Authority's proposal is outlined in full in its Transmission Pricing Methodology: Issues and Proposal, Second Issues Paper dated 17 May 2016 (Proposal).

The Authority's Code Amendment Principles[1] require it to undertake a quantitative cost-benefit analysis (CBA) of any proposal to assess long-term net benefits for consumers.The Authority commissioned economic consultants Oakley Greenwood (OGW) to undertake a quantitative CBA of the Proposal against the counterfactual of the status quo. The OGW CBA estimated the net present value from implementing the Proposal as $213 million compared to the status quo and that it exhibits a positive benefit-cost ratio in all sensitivity analyses undertaken. The Authority has relied on the results of this CBA to conclude that the Proposal provides net benefits that are large and positive under any reasonable assumption, and therefore promotes its statutory objective.

Pioneer has completed a review of the CBA, and relevant supporting information[2], given its importance to the Proposal and the Authority's application of its Code Amendment Principles. This submission covers the findings from our review of the CBA and the Authority's reliance on its results to conclude that the Proposal promotes its statutory objective.

[1] Consultation Charter dated 19 December 2012, Section 2, Part 1
[2] CBA_model_2nd_issues_paper_TPM_proposal.xls and CBA_input_file_TPM_scenarios.xls

1. Overview

1.1. The Authority's Code Amendment Principles require it to undertake a quantitative CBA of any proposal to assess long-term net benefits for consumers.

1.2. The Authority commissioned economic consultants Oakley Greenwood (OGW) to undertake a quantitative CBA of the Proposal against the counterfactual of the status quo.

1.3. The Authority has concluded in its Second Issues Paper[3] that:

"*8.48 The OGW CBA quantifies the net present value from implementing the Authority's proposal as $213m compared with continuing with the status quo TPM. It exhibits a positive benefit-cost ratio in all sensitivity analyses undertaken.*

8.49 The Authority's view is that the net benefit from implementing the Authority's proposal is likely to be considerably larger than the quantitative net benefits estimated by OGW."

1.4. The Authority has relied on the results of this CBA to conclude that the Proposal provides net benefits that are large and positive under any reasonable assumption, and therefore promotes its statutory objective.

1.5. We submit that the CBA outcomes are prejudiced by the Authority's hypothesis that its Proposal is efficient with insufficient objective evidence provided to support this hypothesis and no consideration given to any potential inefficiencies.

1.6. We submit that the CBA, and its presentation, is highly selective and downplays or ignores a number of material caveats that would be given much greater prominence in an objective evaluation of the Proposal. For example, the sensitivity analysis presented by OGW (green) ignored the majority of other key CBA sensitivities (blue):

[3] Electricity Authority Transmission Pricing Methodology: Issue and Proposal, Second Issues Paper, dated 17 May 2016

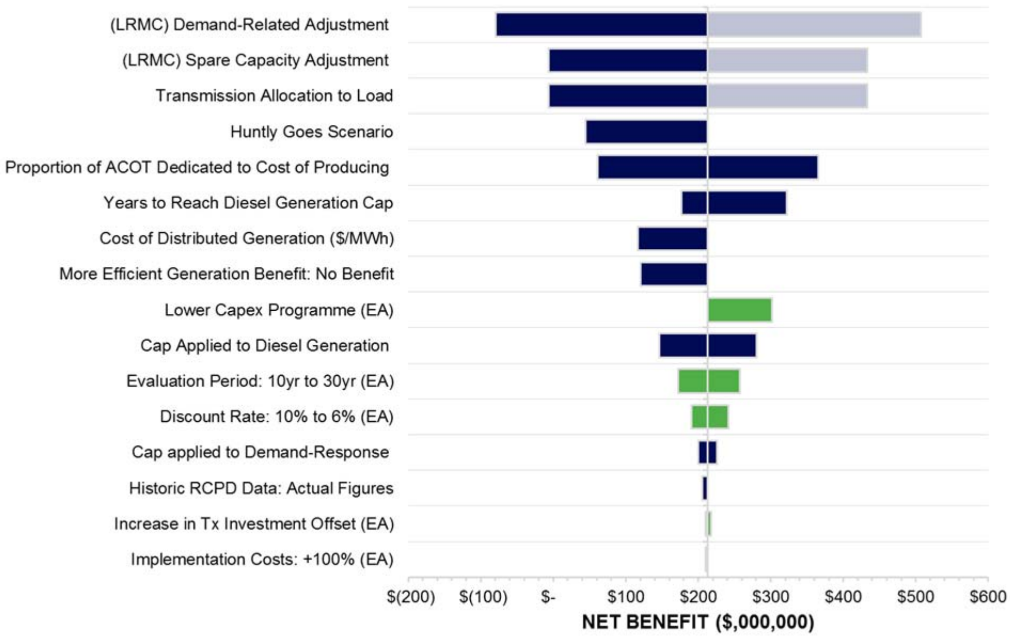

Figure 1 – CBA Sensitivity Analysis (+/- 50% Unless Otherwise Stated)

1.7. We submit that the quality of the CBA itself is substandard for a Proposal of this nature, contains a number of errors and inaccuracies, and it can be easily demonstrated through reasonable changes to the Authority's assumptions that the net benefits from implementing the Proposal are likely to be materially negative (a net cost).

Figure 2 – Conservative Estimate of Revised Net Benefits from Implementing the Proposal

1.8. Furthermore, the full extent of the revised net benefits from making reasonable changes to the Authority's assumptions is expected to be substantially greater (more negative), at up to -$2.16b or greater.

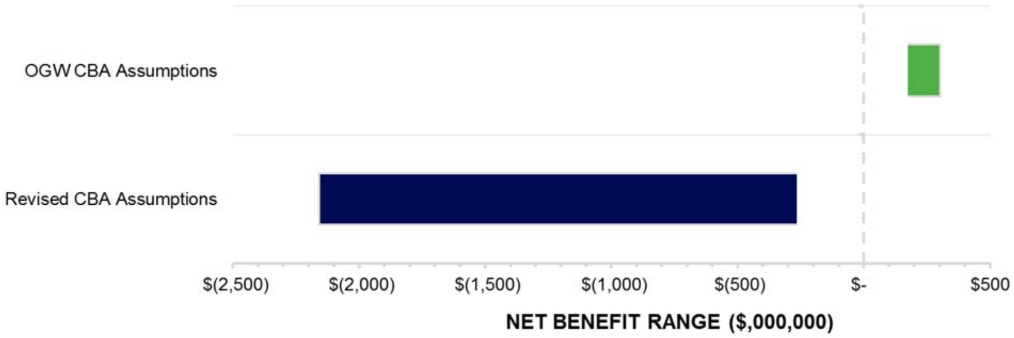

Figure 3 – Potential Range of Net Benefits from Implementing the Proposal

1.9. The Authority has presented its own qualitative analysis in support of its view that the net benefit from implementing the Authority's proposal is likely to be considerably larger than the net benefits quantified by OGW. The Authority's qualitative analysis is highly subjective, lacks any substantive supporting evidence, and is not materially relevant to its Code Amendment Principles to the extent that the benefits of implementing the Proposal have been quantified.

1.10. We submit that the CBA does not represent a robust, accurate or impartial analysis of the Proposal and therefore does not support the Authority's conclusion that the Proposal promotes its statutory objective.

1.11. Furthermore, as the CBA does not model the Authority's actual Proposal, but a generic proposal that is assumed to be efficient, we submit that it should not be relied upon by the Authority to support its Proposal.

1.12. We have elaborated on the above in the proceeding sections of this submission.

2. Proposal Effectiveness

2.1. The CBA and much of the benefits ascribed to the Proposal have been predetermined by the hypothesis that the Proposal is efficient. However, this hypothesis is not supported by;

a) quantitative analysis of the actual charges being proposed; or

b) objective evidence that the actual charges being proposed are efficient.

2.2. OGW's analysis does not model the Authority's actual Proposal but rather a generic proposal that is assumed to be efficient. As such, the CBA could be used to support any proposal that is assumed to be efficient, including moderate changes to the status quo.

This perhaps best exemplified in OGW's own analysis where the only differentiation made between the AoB Charge and the Deeper Connection Charge, two distinctly different proposals, is the percentage inputs for Capital Programme Impact and Avoided Disputation Costs. That is to say there is no difference between the analyses of the actual charges being proposed other than limited and arbitrary assumptions about their relative effectiveness.

2.3. Equally, in assuming that the Proposal is efficient OGW have not given any consideration to any aspects of the Proposal that may be inefficient. That is to say that in its analysis OGW has assumed that the Proposal is considered to be entirely efficient. This assumption is an inherent implausibility of any proposal of this nature.

2.4. The CBA also includes a number of material caveats to the hypothesis that the Proposal is efficient and the corresponding benefits that have been derived.

2.5. OGW state that a fundamental issue affecting the benefits of the Proposal is the level of future expenditure that will be signalled to the end customer by the new pricing arrangements, and that this remains a significant area of uncertainty[4];

"*A fundamental issue that will affect the benefits of any transmission pricing arrangement is the level of future expenditure that will be signalled to the end customers by the new pricing arrangements.*"

2.6. OGW state that another fundamental issue affecting the benefits of the Proposal is the effectiveness of the price signal, in particular its ability to influence customer behaviour, and that this also remains a significant area of uncertainty. This is best exemplified in OGW's commentary on marginal price signals where they acknowledge that[5];

"*If any of these factors* [influencing customer behaviour] *do not hold true, the benefits described and quantified in this CBA will exceed those that will occur in practice.*"

The Authority goes on to acknowledge that[6]:

"*The OGW CBA:*

(a) *Assumes that the price signals sent by the Authority's proposal are accurate. While they are unlikely to be perfectly accurate, the Authority is confident that the price signals sent by the Authority's proposal will be sufficiently service based and cost reflective to engender the type of response that OGW model.*"

This statement is extremely indifferent with regards to a material assumption affecting the Proposal and serves to further demonstrate that any counterfactual to the hypothesis that the Proposal is efficient has not been properly considered.

[4] OGW Cost Benefit Analysis of Transmission Pricing Options, Section 6.2, page 21
[5] Ibid, Section 7.2.1, page 23
[6] Electricity Authority Transmission Pricing Methodology: Issue and Proposal, Second Issues Paper, dated 17 May 2016, section 8.2, page 155.

2.7. OGW have provided no evidence to support the supposition that the price signals sent by the Proposal will be either accurate or efficient, instead relying on the assumption that this will be the case.

2.8. In contrast, the OGW analysis suggests that the new pricing arrangements will signal to the end customer only 3% of the total annual Transpower expenditure, indicating that this price signal would not be very effective from an economic perspective.

2.9. We contend in our main submission that the Proposal does not provide an effective price signal to influence change in customer behaviour in response to that price signal. There are many reasons why the price signals are unlikely to be effective, but inherent to the Proposal is the fact that a customer's charges will not just depend on its own behaviour but the behaviour of others. Any price signal that relies on this real world dynamic is likely to be inherently inefficient.

2.10. Given the inherent uncertainties acknowledged by both the Authority and OGW, and present in the Proposal, it is unclear as to why the CBA does not include any allowance relating to the effectiveness of the Proposal, either as a key input assumption or sensitivity? This would be considered prudent in an objective evaluation of a proposal of this nature.

2.11. Furthermore, as the OGW analysis does not model the Authority's actual Proposal it cannot be relied upon by the Authority to support the Proposal or its conclusion that the Proposal promotes its statutory objective. That is to say that we submit that there is a high level or uncertainty regarding the likelihood that the Proposal will deliver the benefits that have been quantified.

3. LRMC Calculations

3.1. OGW have calculated Long Run Marginal Cost (LRMC) of Load and Generation driven transmission capital expenditure as the basis for determining $184m, or over 85%, of the net benefits from implementing the Proposal.

The methodology for calculating the LRMCs has been illustrated in the figure overleaf.

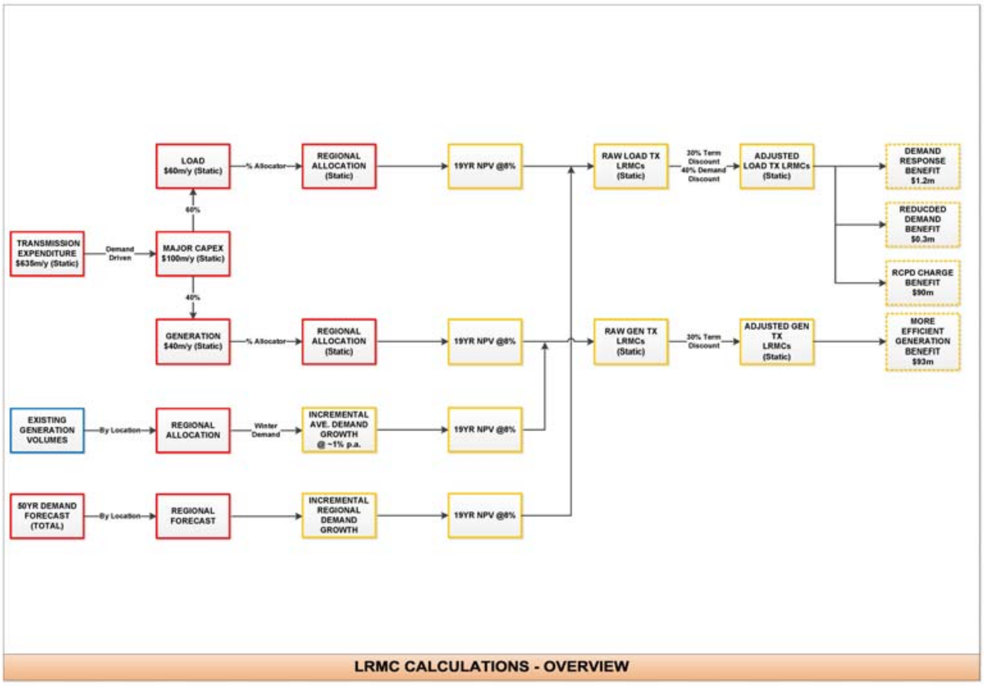

Figure 4: LRMC Calculation Methodology Overview

3.2. OGW's LRMC calculations rely entirely on capital expenditure information and assumptions provided by the Authority[7];

"*All capex related information, as well as underlying demand forecasts, have either been obtained directly from the Authority, or derived primarily from information provided by the Authority.*"

As such, it should be noted that the LRMC calculations themselves do not represent an independent evaluation of the Proposal.

3.3. The capital expenditure data set provided by the Authority included new transmission expenditure of $635m/y in total, broken down into Major Capex, Base Capex and Opex components. The Authority has forecast new transmission expenditure to remain static year-on-year regardless of any factors that may influence the extent or timing of any future expenditure.

It should be noted that this itself fundamentally conflicts with OGW's application of LRMC pricing as the basis for the CBA, given an integral feature of LRMC pricing is it's variability with regards to the extent or timing of capital expenditure.

3.4. OGW have used only Major Capex ($100m/y or 16% of total) in its LRMC calculations in all scenarios, on the assumption that this capital expenditure is demand driven, whereas Base Capex and Opex are assumed to be likely to be primarily related to other drivers.

[7] Ibid, Appendix A: The basis for the LRMC of transmission estimates, page 77

3.5. Major Capex has been allocated by the Authority on a percentage basis 60% ($60m/y or 9% of total) to Load and 40% ($40m/y or 6% of total) to Generation. The Authority has subsequently confirmed that[8]:

"*The 60:40 split between load and generation is an approximation. It reflects a high level understanding that economic investments benefit generation and load while reliability investments are of greater benefit to load.*"

The allocation between Load and Generation appears to be arbitrary and contrasts significantly with the Authority's separate assessment of historic transmission investment, which allocates 79% to Load and 21% to Generation[9].

Re-aligning the allocation of Major Capex 80% to Load and 20% to Generation in the CBA would reduce the total net benefits by $146m, from $213m to $67m. This excludes the corresponding effect on the More Efficient Generation Benefit which has been addressed in the proceeding section.

3.6. Load and Generation Capex has then been allocated by the Authority on a percentage basis into four regions, being the Upper North Island (UNI), Lower North Island (LNI), Upper South Island (USI) and Lower South Island (LSI). The Authority has subsequently confirmed that[8]:

"*Given the uncertainty around major capex over the 20 to 30-year analysis timeframe, assumptions were necessary. For the final load split, a table was compiled using historical and forecast major capex information, as discussed below. The assessment of benefits of investments and location of investments required some judgement. Transpower's updated "RT06" file was used to source this information.*"

The Authority further clarified that[8]:

"*The split between regions for load is based on historical data as outlined in the table below. The split between regions for generation is based on GWh produced in the 2014 calendar year.*"

With specific reference to the regional allocations for Generation, it is unclear why the benefits of future transmission investments have been predetermined on the basis of historic generation data? Particularly as the Authority, in their separate assessment[10], has deemed South Island Generation to have already been the major beneficiary of historic transmission investment and therefore would be unlikely to also be the major beneficiary of future transmission investment.

The result is LRMC values for Generation that are highest in the LNI and LSI regions and which contrast with anecdotal evidence from Transpower that

[8] Electricity Authority responses to Pioneer questions, dated 14 July 2016
[9] Results_20160517b.xlsx, Charges as $M per year
[10] Ibid

suggests the LRMC of incremental generation investment in these regions is lowest as the result of the historic investments that have been made.

This is also contrary to the Authority's views in their related Review of Distributed Generation Pricing Principles[11] where they conclude distributed generation is of least value in these regions despite considering the LRMC of Generation driven transmission investment being the highest.

The regional allocation only materially affects the More Efficient Generation Benefit which has been discussed in the proceeding section.

3.7. OGW have used the Load and Generation Capex figures provided by the Authority, along with estimates for growth in customer demand and growth in grid connected generation, to estimate the Raw LRMCs of Load and Generation driven transmission investment, each determined regionally.

3.8. OGW have then adjusted the Raw LRMC calculations downward by[12]:

a) 30% for both Load and Generation "*to account for the fact that the analysis was undertaken over 19 years (due to data availability), yet these assets generally have lives of 50 years or more*"; and

b) By a further 40% for Load "*to reflect advice from the Authority that some investments are based on changing patterns of demand caused by exit and entry of large plant; it is not all caused by standard percentage growth in demand in regions leading to capacity becoming constrained*".

The adjustments of the Raw LRMC calculations are the two single biggest sensitivities to the benefits determined in the CBA. The first adjustment has been adequately explained but with specific reference to the 40% reduction for Load, this is the single most material input assumption to the CBA and the Authority has subsequently confirmed that[13]:

"*OGW have advised that the discount was derived, having regard to the long run marginal cost (LRMC) outcomes in other jurisdictions. The 40% itself is not based on "empirical evidence", but the results derived from adopting the 40% is based on empirical evidence (i.e., it generates LRMC results that are in the range reported in other markets, namely Australia).*"

There are some fundamental issues with this explanation given the significance of OGW's assumption in determining the benefits in the CBA, namely it confirms that:

c) the main reasoning provided in the Second Issue Paper that the discount factor reflects changing patterns in demand is not actually a determining factor of the Adjusted Load LRMCs, which was in itself a conflict with the

[11] Electricity Authority Review of Distributed Generation Pricing Principles: Consultation Paper, dated 17 May 2016
[12] OGW Cost Benefit Analysis of Transmission Pricing Options, Appendix A, Section A.1 page 77
[13] Electricity Authority responses to Pioneer questions, dated 14 July 2016

fact that demand drivers have already been accounted for in OGW's consideration of Major Capex only (ref Item 3.4 above);

d) the discount factor applied is in fact an arbitrary figure used by OGW to manufacture Adjusted Load LRMC figures that are consistent with Australian Load LRMCs. OGW provide no explanation as to why they believe Australian Load LRMCs would be analogous to New Zealand Load LRMCs; and

e) the resulting Adjusted Load LRMCs do not reflect any evidence based determination of the actual Load LRMCs for transmission investment in New Zealand.

It is therefore unclear why, having used empirical transmission investment and demand data for New Zealand as the basis for determining the Raw Load LRMC figures, these have been discounted so significantly to derive Adjusted Load LRMCs that are based on other jurisdictions?

There is strong evidence in OGW's own analysis to suggest that the actual Load LRMCs should be higher than the Adjusted Load LRMCs used by OGW to the quantify the benefits from implementing the Proposal.

As such, between either this or Item 3.5 above, any reasonable adjustment to the Load LRMCs in the CBA would reduce the total net benefits by a minimum of $146m, from $213m to $67m.

Moreover, revising the 40% discount to 0% in the CBA would reduce the total net benefits by $586m, from $213m to -$372m.

3.9. The cumulative effect of the above is that the resulting Adjusted LRMCs for Load and Generation represent only 7% of the total annual transmission expenditure, or only 13% of the total annual transmission capital expenditure. That is to say that the CBA assumes over 90% of all transmission expenditure will not be effectively signalled to the end customer by the new pricing arrangements. In OGW's own words[14]:

"*a price signal from a new pricing arrangement will be less effective from an economic perspective when the pool of future investments covered by the price signal is smaller and when the proportion of future capital expenditure that can be influenced as a result of customers changing their future consumption or investment behaviour is smaller."*

3.10. We submit that the LRMC calculations bear no relationship to the actual charges being proposed, and regardless do not demonstrate that those charges would be effective, are highly subjective, static and contribute to predetermined outcomes. That is to say we do not believe the LRMCs calculated present a reliable basis for quantifying the net benefits from implementing the Proposal.

[14] OGW Cost Benefit Analysis of Transmission Pricing Options, Section 6.2, page 20

3.11. Furthermore, the Authority's assumptions relating to the allocation of transmission expenditure have a direct influence on over 85% of the net benefits that have been attributed to implementing the Proposal, and it can be demonstrated that reasonable changes to these assumptions can have a significant impact on the net benefits that have been quantified.

4. More Efficient Generation Benefit

4.1. OGW have determined that the Proposal may lead to more efficient co-investment in generation and transmission services leading to a reduction in the overall cost of providing electricity services. OGW have estimated the net benefit (the More Efficient Generation Benefit) of this to be $93m, or around 43% of the total net benefits from implementing the Proposal.

The methodology OGW have used for calculating the More Efficient Generation Benefit has been illustrated in the figure below.

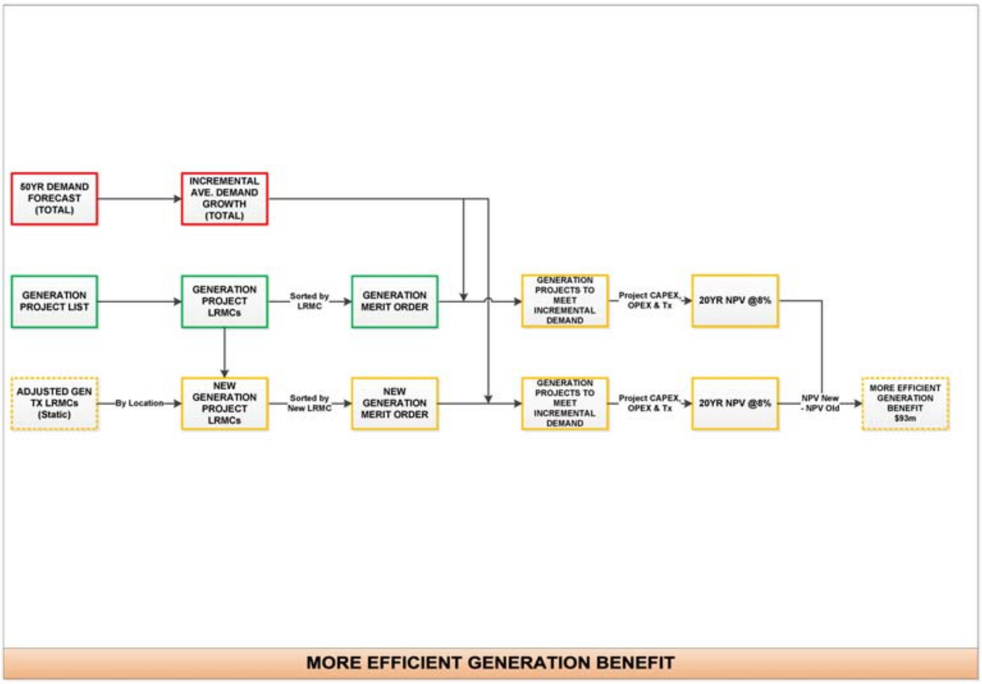

Figure 5 – More Efficient Generation Benefit Calculation Methodology

4.2. OGW have used the adjusted Generation LRMCs and the Interactive Electricity Cost Model – 2015 from the Ministry of Business, Innovation and Employment (MBIE) as the basis for determining the More Efficient Generation Benefit; with the net benefit resulting from the change in economic cost between the old and new generation project schedules as a result of including a transmission price signal for Generation.

4.3. OGW make the following acknowledgement regarding the methodology for determining the More Efficient Generation Benefit[15]:

[15] OGW Cost Benefit Analysis of Transmission Pricing Options, Section 8.3.2, page 43

"*The transmission LRMC's underpinning this calculation have been predominately based on information provided by the Authority – in particular, the additional capex requirements required to service growth in generation output across four regions. These figures are not able to reflect the dynamic, real world effects on transmission investment stemming from the impact of locating generation in certain regions in response to the transmission price signal*"

4.4. OGW go on to acknowledge that there is inherent uncertainty in this analysis and conclude that[16]:

"*the lower bound economic benefit for this component* [the More Efficient Generation Benefit] *of the CBA should be considered to be zero*"

While OGW have maintained that this is a worst case scenario we contend that there is sufficient evidence to suggest that this outcome is entirely more probable than the net benefit that has been quantified.

4.5. OGW have assumed that the co-investment in generation and transmission services is perfectly efficient, being that incremental Generation and Generation driven transmission investment is perfectly aligned with underlying demand growth. There is a significant amount of uncertainty in this key assumption alone as it only considers 4% of the total annual transmission expenditure that will ultimately be reflected in transmission price signals under the Proposal. It also ignores the fact that in reality transmission investment is subject to economic sizing effects, the benefits of which are not easily isolated to either Load or Generation, and that Generation investment is primarily influenced by a myriad of non-transmission related factors.

4.6. As noted in the previous section, the key input information and assumptions provided by the Authority are highly subjective, static and contribute to predetermined outcomes. With specific reference to the calculation of the More Efficient Generation Benefit:

a) The percentage allocation of Major Capex to Generation has a direct influence on any change to the generation project schedules. For example, a reasonable adjustment to this percentage allocation to Generation from 40% to 20% would mean that the first and most material change to the generation project schedule would no longer take place – noting again that the Authority has only allocated 21% of historic transmission investment to Generation under its proposed Area of Benefit charges.

b) The percentage allocation of Generation Capex to each region has a direct influence on any change to the generation project schedules. For example, a reasonable adjustment to this percentage allocation to the LSI from 45% to 40% would mean that the first and most material change to the generation project schedule would no longer take place.

[16] Ibid

Making reasonable adjustments to either of the above assumptions in the CBA would significantly reduce the More Efficient Generation Benefit that has been quantified.

4.7. Additionally, the Interactive Electricity Cost Model – 2015 used by OGW as the basis for the generation project schedules contains a number of generation projects that have been permanently abandoned, namely:

a) Hauaurumaki Stage 1 & 2 (504 MW)

b) Rodney CCGT Stage 1 & 2 (480 MW)

c) Proposed CCGT (194 MW)

These projects make up approximately 1,000 MW or 77% of the seven projects included in the generation project schedule that has been used for determining the More Efficient Generation Benefit. Furthermore, they also happen to be the projects whose positions in the generation project schedule are most materially influenced by the inclusion of the assumed transmission price signal.

Removing the above projects from the CBA would significantly reduce the More Efficient Generation Benefit that has been quantified.

4.8. We submit that there is sufficient evidence in OGW's own analysis to suggest that the Proposal is unlikely to lead to a more efficient co-investment in generation and transmission services leading to a reduction in the overall cost of providing electricity services. This to say that the More Efficient Generation Benefit from implementing the Proposal is likely to be zero, a possibility that has been acknowledged by OGW in their analysis.

Making this adjustment to the CBA would reduce the More Efficient Generation Benefit that has been determined by OGW from $93m to $0m.

4.9. While OGW's methodology for calculating the More Efficient Generation Benefit does not enable the net benefits to be less than zero, it should be noted that OGW have elected to ignore any impact on the wholesale electricity market of providing a material transmission price signal for Generation. In the instance it is expected that the costs to consumers would significantly exceed the More Efficient Generation Benefit that has been quantified.

4.10. We also note that OGW's analysis of the More Efficient Generation Benefit only considers grid connected generation projects. It is inherent to this analysis that equivalent distributed generation projects will be more efficient than grid connected generation projects to the extent that they will not be subject to this transmission price signal. This contrasts with the Authority's general conclusion that distributed generation is inefficient.

5. RCPD Charge Benefit

5.1. OGW have determined that the Proposal may lead to a benefit from more efficient pricing of historical investments through the replacement of the Regional Co-Incident Peak Demand (RCPD) charge with a charge based on physical capacity. OGW have estimated the net benefit (the RCPD Charge Benefit) of this to be $90m, or around 42% of the total net benefits from implementing the Proposal.

The methodology OGW have used for calculating the RCPD Charge Benefit has been illustrated in the figure below.

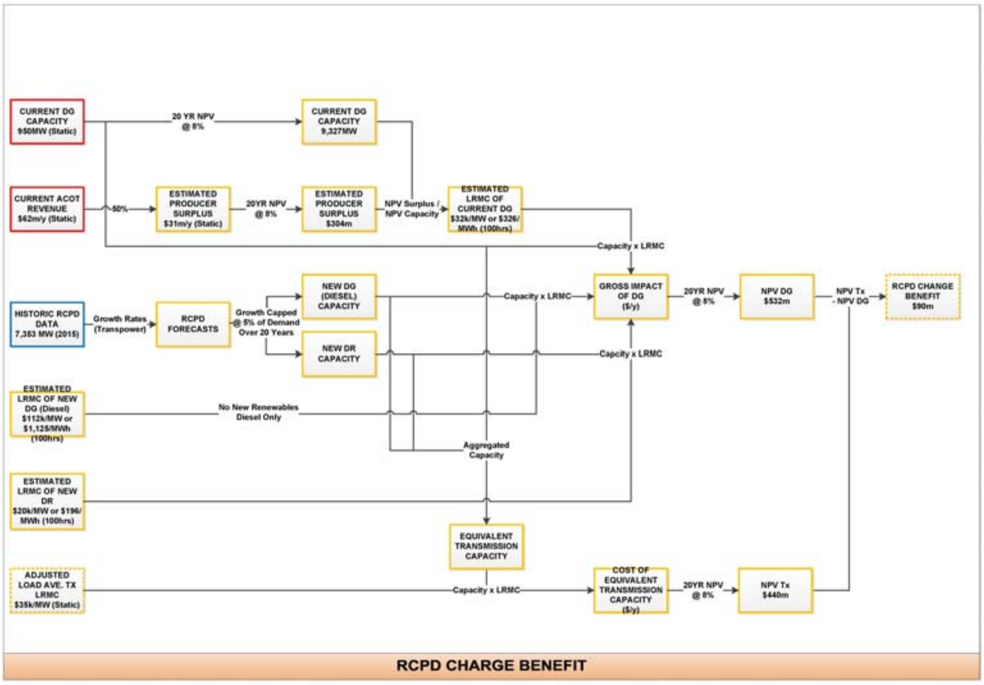

Figure 6 – RCPD Charge Benefit Calculation Methodology

5.2. OGW have compared the economic cost of existing distributed generation, new distributed generation and new demand response programmes and offset these costs against the benefits of those investments, with this based on the Adjusted Load LRMCs multiplied by the equivalent transmission capacity requirement.

5.3. OGW's analysis of the RCPD Charge Benefit appears to contain a number of fundamental input assumption and logic errors, and it can be demonstrated that reasonable changes to this analysis would have a significant impact on the net benefits from implementing the Proposal.

5.4. OGW's analysis includes historical RCPD input data that differs significantly (regionally and in total) from available Transpower RCPD data and forecast information. The Authority has subsequently confirmed that the RCPD data referred to in the CBA actually represents Transpower's regional (winter) peak demand data provided by the Authority to OGW[17]. The Authority further clarified that[18]:

[17] Transpower National-Regional Peak Demand Forecasts Feb2015.xlsx
[18] Electricity Authority responses to Pioneer questions, dated 14 July 2016

"*OGW assume that peak demand is the underlying driver of the need to make investments to augment the transmission network, therefore they have linked the uptake of DG (where economic) to peak demand figures, not the RCPD figure. This is reasonable.*"

We are not entirely convinced that peak demand is a more appropriate basis than coincident peak demand as the underlying driver of the need to make investments to augment the transmission network. Regardless, OGW have incorrectly allocated peak demand between the USI and LSI regions, and appear to have overlooked the fact that Transpower's estimate for the national peak demand, used for calculating the RCPD Charge Benefit, does not equal the sum of the regional peaks.

Correcting the regional allocations and the national peak demand figure to 6,812[19] in the CBA would reduce the RCPD Charge Benefit by $8m, from $90m to $82m.

5.5. OGW has assumed ACOT revenue of $62,000,000 per annum. However, ACOT revenue for the most recently completed 2015 pricing year was $52,000,000, a figure which the Authority had access to at the time of publication as it has been included in its separate analysis of the Proposal[20]. While the Authority correctly notes that ACOT payments in aggregate have increased significantly during the period of 2008 to 2014, the significant decrease in 2015 bucks this trend and should not have been selectively omitted from the CBA.

Revising the ACOT Revenue to $56,000,000 (3 year average) in the CBA would reduce the RCPD Charge Benefit by $3m, from $90m to $87m.

5.6. OGW have assumed that there are no low cost alternatives to transmission investment (e.g., hydro, geothermal, solar) on the assumption that the most economic sites have already been identified and developed[21]. The Authority have subsequently confirmed that there was no empirical basis for this assumption and that[22]:

"*The assumption that there are no low-cost alternatives to transmission is intended to simplify the analysis. The OGW CBA assesses that this modelling assumption is conservative; that is, making the assumption will not lead to an overstatement of the benefits of the proposal. Changing this assumption would make little, if any difference to the results, because if there were additional low cost (i.e., lower than the cost of the alternative investment, being a transmission investment) alternatives available in the future, these solutions would be dispatched under both the existing RCPD charge and the proposed AoB charge.*"

The assumption that there is no low-cost low cost generation alternatives to transmission investment (e.g., hydro, geothermal, solar) is a gross over

[19] Ibid, Winter Prudent Peak Forecast (MW), New Zealand
[20] Results_20160517b.xlsx
[21] Ibid, Footnote 35, page 35
[22] Electricity Authority responses to Pioneer questions, dated 14 July 2016

simplification of a material input assumption to the CBA, with c. 200 MW of consented or proposed low-cost renewable distributed generation projects in the public domain[23].

Furthermore, the statement that changes to this assumption would make little, if any difference to the results, is factually incorrect in the context of the methodology OGW have used for calculating the RCPD Charge Benefit; where any benefit calculated is a direct result of the economic cost of constructing and operating new distributed generation facilities – in the case of OGW's analysis high cost diesel generation. The construction of available new low-cost distributed generation facilities in response to incremental demand growth would have a significant impact on the net benefits from implementing the Proposal.

5.7. OGW have also concluded that existing distributed generation provides a positive economic benefit and would do so in the future even with the continued use of the current RCPD charge[24]. This conclusion further supports fact that a more reasonable assumption around the cost of new distributed generation would have a significant impact on the net benefits from implementing the Proposal.

Revising the Cost of New Distributed Generation to $32,632/MW (OGW estimate of existing) in the CBA would reduce the RCPD Charge Benefit by $137m, from $90m to -$48m.

5.8. OGW's analysis of the RCPD Charge Benefit compares the economic cost of existing distributed generation, new distributed generation (diesel only) and new demand response programmes and offsets these costs against an estimate of the benefits of those investments. OGW's analysis excludes existing demand response programmes that respond to the current RCPD price signal, estimated by Transpower to be at least 700 MW in aggregate. The Authority has subsequently confirmed that[25]:

"*OGW did not take into account the impact of existing demand response programmes on the CBA. OGW's view is that this is a conservative assumption. This is because if the costs of these existing programmes are below the estimated cost of transmission, then these would continue to operate in response to the more cost-reflective AoB charge, hence there would be no net change in the CBA (i.e., they would run, whether or not it was in response to the RCPD charge, or the more cost-reflective AoB charge).*"

We believe that the assumption that existing demand response will respond to the proposed AoB charge is fundamentally flawed as the AoB charge does not provide a an effective price signal to influence change in customer behaviour in response to that price signal. However, while we expand on this point in our main submission it is acknowledged that this is somewhat subjective in the context of this submission on the CBA. Regardless, the statement that there would be no net change in the results of the CBA from the inclusion of existing

[23] http://www.energynews.co.nz/resources
[24] Ibid, Footnote 52, Section 8.4.2, page 45
[25] Electricity Authority responses to Pioneer questions, dated 14 July 2016

demand response programmes is again factually incorrect in the context of the methodology OGW have used for calculating the RCPD Charge Benefit; where the benefit and cost of any existing demand response should be accounted for on the same basis as existing distributed generation.

Including the conservative assumption of 700 MW of existing Demand Response (at $19,600/MW) in the CBA would reduce the RCPD Charge Benefit by $103m, from $90m to -$13m.

This is considered to be extremely conservative as the average cost of existing demand response programmes is expected to be significantly less than the LRMC of $19,600/MW that OGW have determined from the limited Transpower programme.

5.9. Notwithstanding the above, we believe there is a significant logic error contained in OGW's calculation of the RCPD Charge Benefit.

OGW's methodology for calculating the RCPD Charge Benefit assumes that the construction and operation of new diesel distributed generation facilities will take place if the cost of these facilities, in $/MWh, is lower than the current RCPD charge of $2,132/MWh, calculated from 100 half hour RCPD periods. In doing so, OGW have assumed that the new diesel distributed generation facilities would operate for 200 half hour periods to ensure that all 100 half hour RCPD periods are met. However, OGW have neglected to account for the fact that RCPD charge revenue can only be obtained during the 100 half hour RCPD periods and therefore the actual average RCPD revenue should be divided over the number of half hours run, in this instance $2,132/MWh x 100 / 200, or $1,156/MWh.

This error is confirmed by the Authority's statement in the separate DGPP paper[26]:

"*An RCPD charge of $110/kW, calculated over 100 half hours per year, creates an incentive of $110/kW * 1000 / (100 * 0.5 hours) = $2,200/MWh in each of those half hours. Even if a generator finds it needs to operate in 200 half hours per year in order to be sure of 'hitting' all 100 regional peak periods, the incentive is still $1,100/MWh.*"

5.10. The above error in itself does not change the level of benefit OGW have determined as the LRMC of new diesel distributed generation, $132,000/MW or $1,125/MWh over 200 half hours, calculated by OGW is marginally (3%) lower than the revised RCPD charge of $1,156/MWh.

However, OGW's estimate of the cost of new diesel distributed generation is considered to be unrealistically low when compared to New Zealand market experience and publicly available information. Specifically, the construction cost of $550/kW is considered to be below any reasonable lower bound for this type of application, and is thought to include plant purchase costs only and

[26] Review of distributed generation pricing principles: Consultation Paper dated 17 May 2016, Footnote 95, page 77.

exclude wider project costs associated with resource consent, storage, electrical connection and transmission infrastructure, transport and civil works.

OGW have stated that their costs have been based on[27]:

"*publicly available data and OGW experience. We did not conduct widespread consultations to source primary data, as this was not feasible at the time.*"

It is unclear why in the time available, and given its materiality to the CBA, OGW was unable to obtain a more reliable estimate for the construction cost of new diesel distributed generation? Both the Authority and MBIE, variously referenced throughout OGW's analysis, have published estimates for the cost of diesel plant:

a) The Authority estimates the cost to be $1,200/kW in their Marginal Cost Calculator[28].

b) MBIE estimates the cost to be between $1,913/kW and $2,524/kW in their Electricity Demand and Generation Scenarios[29].

Conservatively applying the Authority's own estimate of $1,200/kW OGW would have determined the LRMC of new diesel distributed generation as approximately $200,000/MW, or $1,800/MWh over 200 half hours. This is considerably higher than the equivalent RCPD charge of $1,156/MWh, and therefore no new diesel distributed generation would be constructed in determining the RCPD Charge Benefit. Alternatively, the cost of new diesel distributed generation assumed by OGW would only have to increase by 6%, to $585/kW, for the same outcome to be obtained. This is without considering that no plant is entirely reliable, and any input assumptions should be derated accordingly, and that running hours a likely to increase as the load duration curve flattens out.

In addition, OGW calculated that nearly 500 MW of new diesel distributed generation will be constructed in the response to the RCPD charge. This outcome is considered to be fundamentally implausible and is entirely inconsistent with the reality where no new diesel plant is being constructed in response to the RCPD charge signal as it is not economically feasible.

There is more than sufficient evidence to conclude that OGW's methodology for calculating the RCPD Charge Benefit is fundamentally flawed and that there is unlikely to be a positive net benefit from removing the RCPD charge.

Correcting the above errors in the CBA would reduce the RCPD Charge Benefit that has been determined by OGW by $134m, from $90m to -$44m. Between either this or Item 5.7 above, the maximum possible benefit from the RCPD Charge is -$44m. That is to say that the RCPD Charge Benefit from implementing the Proposal must be negative.

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[27] OGW Cost Benefit Analysis of Transmission Pricing Options, Appendix B, Section B.1, page 84
[28] https://www.ea.govt.nz/dmsdocument/10191
[29] http://www.mbie.govt.nz/info-services/sectors-industries/energy/energy-data-modelling/modelling/electricity-demand-and-generation-scenarios/draft-edgs-2015/resolveuid/557545b55f044b7aa71dc0ed8dfa0dc

5.11. We also contend that OGW's analysis of the RCPD Charge Benefit contains a major omission relating to the inefficiency of removing a peak demand price signal (the RCPD Charge) and the corresponding impact on the wholesale electricity market. The presence of a peak demand signal enables an efficient market response that in aggregate delivers lower overall wholesale electricity market prices.

We elaborate on this point in our main submission, however the net costs from removing an effective peak demand signal are conservatively estimated to exceed $500m/y, or $5b in equivalent NPV terms. Even a fraction of this cost would greatly exceed the net benefits of implementing the Proposal that have been quantified, and this significant risk of unintended consequences alone suggests that the Authority should reconsidered its conclusion that that the Proposal promotes its statutory objective.

6. Other Issues

6.1. In calculating the More Efficient Generation Benefit OGW have considered scenarios where either Huntly stays or Huntly goes, with an equal weighting given to each scenario. However, in quantifying the other net benefits from implementing the Proposal OGW have assumed that Huntly stays indefinitely, with no explanation given as to why different assumptions have been used for different parts of the CBA. OGW's decision to give the Huntly stays scenario greater weight in the CBA is somewhat surprising given the fact that there is a higher probability that Huntly goes than stays; with it being publicly known that Huntly is expected to close in 2022, only 3 years into the term of OGW's analysis.

The assumption around these scenarios is material as OGW has estimated that the LRMCs of transmission will be significantly higher in the event that Huntly goes.

Revising the Load and Generation LRMCs to reflect the scenario in which Huntly goes in the CBA would reduce the total net benefits by $169m, from $213m to $44m.

6.2. OGW have modelled two benefits relating to the future investment in services or equipment that may otherwise be substitutes for transmission services, namely the Demand Response Benefit and the Deferral Benefit. It is unclear from OGW's analysis why the Proposal would be expected to provide these benefits over and above the status quo? That is to say that the benefits from investment in substitutes for transmission services should exist irrespective of the Proposal.

Furthermore, in calculating these benefits OGW have not provided any evidence that the quantitative analysis relates to the actual charges being proposed. That is to say, the OGW analysis of the Demand Response Benefit and the Deferral Benefit is not specific to the Proposal and could therefore apply to any proposal including the status quo.

Removing the Demand Response Benefit and the Deferral Benefit from the CBA would reduce the benefits that have been quantified by OGW by $4m, from $213m to $209m.

6.3. In addition to the More Efficient Generation Benefit discussed earlier, OGW have also assumed that there will be a benefit from more efficient investment in generation from removing the HVDC charge (SIMI Benefit). Similar to the More Efficient Generation Benefit, OGW have used the adjusted Generation LRMCs and the Interactive Electricity Cost Model – 2015 as the basis for determining the SIMI Benefit associated with a change in the generation project schedules.

It is not possible to comment on the OGW analysis specifically as the corresponding SIMI model has not been provided by the Authority. However, it is unclear how the Proposal, as a one-off change to transmission pricing, could generate two independent and mutually exclusive benefits from changes to the same generation schedule? That is to say that it is not considered possible for the Proposal to produce both the More Efficient Generation Benefit and the SIMI Benefit to the extent that has been quantified.

Regardless, there is a high degree of uncertainty regarding the likelihood that the Proposal would deliver the SIMI Benefit that has been quantified.

Removing the SIMI Benefit from the CBA would reduce the benefits that have been quantified by OGW by $14m, from $213m to $199m.

6.4. OGW have assumed that there would be a benefit from a lower probability of some customers exiting the grid inefficiently as a result of the proposed Prudent Discount Policy (PDP Benefit). While it is acknowledged that there may be some benefits from avoiding inefficient exit, the OGW's analysis of the PDP has a number of major deficiencies, in particular:

a) OGW's methodology for calculating the PDP benefit is artificial and highly sensitive to changes in assumptions;

b) It does not represent a robust analysis of the PDP proposal but rather a hypothetical PDP arrangement with a single transmission customer, being New Zealand Aluminium Smelters; and

c) It quantifies the potential impact of this PDP arrangement on the profitability of this transmission customer, with no explanation or evidence provided as to how this translates to a net benefit to all transmission customers.

OGW analysis also fails to consider the likelihood of potential inefficiencies that may result from the PDP, namely that the PDP will, amongst other things:

d) have a material adverse effect on the durability of the Proposal as a result of a significant increase in bi-lateral arrangements with Transpower and the likelihood of adverse consequences, and a corresponding decrease in transparency; and

e) dilute the effectiveness of the AoB price signal as a result of reallocating costs to the Residual Charge.

We have not attempted to quantify the effect of the above on the PDP Benefit, however there is a high degree of uncertainty regarding the likelihood that the Proposal would deliver the PDP Benefit that has been quantified, and further serves to demonstrate that any counterfactual to the hypothesis that the Proposal is efficient has not been properly considered.

Removing the PDP from the CBA would reduce the benefits that have been quantified by OGW by $10m, from $213m to $203m.

OGW have also again elected to ignore any impact on the wholesale electricity market under the counterfactual scenario of a major Load customer exiting. In this instance it is expected that the benefits to consumers would significantly exceed the PDP benefit that has been quantified.

6.5. OGW have modelled the Incremental and Avoided Costs of the Proposal, being the Incremental Costs that will be incurred by the industry compared to the status quo and the Avoided Incremental Costs as a result of implementing the Proposal. OGW have concluded that the Incremental Costs will be more than offset by the Avoided Incremental Costs and therefore there would be a net benefit from implementing the Proposal.

We consider that the upfront and ongoing costs for all industry participants have been grossly underestimated and are likely to be materially higher than those that OGW have quantified. In particular, OGW have assumed that Transpower will be able to administer the Proposal for the equivalent cost of half a FTE; despite Proposal including a considerably more complex charging arrangement in the AoB, a significant increase in bi-lateral arrangements and the associated administrative overheads, and somewhat incredulously assume that there will be no material additional costs to other industry participants. This demonstrates that OGW are completely out of touch with the reality of implementing the Proposal that has been put forward.

This conclusion is supported by the Authority who acknowledge that[30]:

"*The OGW CBA:*

Has an estimate of implementation costs that is lower than is likely to occur in reality. However, the sensitivity analysis shows that any reasonable estimate of the implementation costs would not significantly alter the net benefit estimated by the CBA."

Furthermore, OGW's assumption that the Proposal will provide positive Avoided Incremental Costs is entirely subjective and at odds with likelihood that the Proposal will reduce durability as has been outlined previously in this submission.

[30] Electricity Authority Transmission Pricing Methodology: Issue and Proposal, Second Issues Paper, dated 17 May 2016, Section 8.2, page 155.

We have not attempted to quantify the effect of the above on the costs that has been quantified by OGW, however there is strong evidence to suggest that OGW have significantly overstated the net benefit from implementing the Proposal. That is to say that the Avoided and Incremental costs of implementing the Proposal are expected to be materially negative.

Revising the lower bound Incremental and Avoided Costs in the CBA to match OGW's sensitivity analysis outcomes would reduce the Incremental and Avoided Costs by $4m, from $2m to -$2m.

7. Sensitivity Analysis

7.1. We have reviewed the sensitivity of the CBA to changes in key input assumptions that have been made by OGW in quantifying the benefits of implementing the Proposal.

The outcomes of this review have been presented in the figure below, with the OGW sensitivities that could be replicated shown in Green and other key CBA sensitivities shown in Blue.

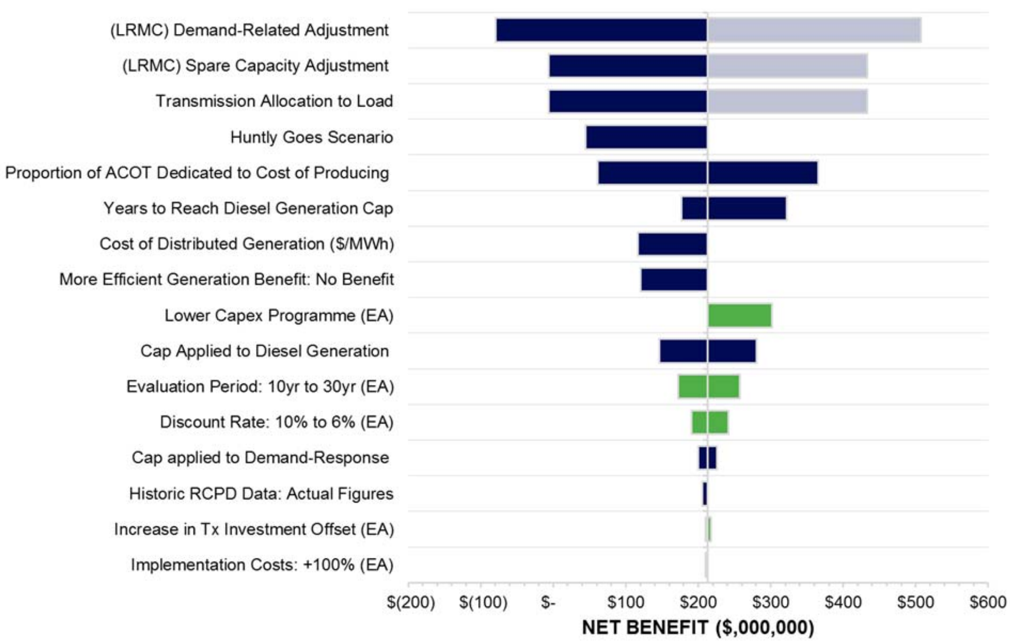

Figure 7 – CBA Sensitivity Analysis (+/- 50% Unless Otherwise Stated)

7.2. The above demonstrates that OGW's sensitivity analysis of the Proposal ignored the majority of key sensitivities that are material to the net benefits that have been quantified. In particular, the four most material sensitivities all relate to the calculation of the LRMCs for Load and Generation, the associated issues of which have been discussed in detail in Section 3.

7.3. The sensitivity analysis also demonstrates that changes to these input assumptions can only reasonably be expected to reduce the net benefits from implementing the Proposal; with the initial input values that have been used by OGW being favourably weighted towards determining net benefits that are positive. That is to say that the Authority's conclusion that the net benefits are likely to be considerably larger than the net benefits that have been quantified by OGW is extremely dubious.

7.4. We submit that the above is further evidence that the CBA, and its presentation, is highly selective and downplays or ignores a number of material assumptions that would be given much greater prominence in an objective evaluation of the Proposal.

7.5. Furthermore, contrary to the Authority's conclusion it can be easily demonstrated through reasonable changes to the input assumptions that the net benefits from implementing the Proposal are likely to be significantly lower than those OGW have quantified.

8. Conclusion

8.1. The CBA is of a substandard quality for a Proposal of this nature, with a number of fundamental errors and inaccuracies that have a material impact on the net benefits that have been quantified. These have been discussed in detail in the preceding sections of this submission, with a summary of the individual issues that have been identified provided in the table below.

Table 1 – Summary of Individual Changes in Net Benefit

REFERENCE	DESCRIPTION OF CHANGE	CHANGE IN NET BENEFIT
3.5	Re-alignment of the allocation of Major Capex 80% to Load and 20% to Generation	-$146m
3.8	Revising of 40% reduction to Load LRMCs to 0%	-$586m
4.8	No More Efficient Generation Benefit	-$93m
5.4	Correction to historic RCPD data	-$8m
5.5	Correction to ACOT revenues	-$3m
5.7	Revision to the cost of new distributed generation	-$137m
5.8	Inclusion of existing demand response programmes	-$103m
5.9	Correction RCPD Charge Benefit error	-$134m
6.1	Revision to Huntly scenario	-$169m
6.2	No Demand Response Benefit	-$1m
6.2	No Deferral Benefit	-$3m
6.3	No SIMI Benefit	-$14m
6.4	No PDP Benefit	-$10m

REFERENCE	DESCRIPTION OF CHANGE	CHANGE IN NET BENEFIT
6.5	Revision to Incremental and Avoided Costs	-$4m
TOTAL		**-$1,411m**

8.2. The above individual changes to the net benefits from implementing the Proposal total -$1.41b. However it is acknowledged that the individual changes are not necessarily additive, and that the compounding effect of changes to the input assumptions to the CBA is expected to be substantially greater (more negative).

8.3. To demonstrate the extent to which reasonable changes to the input assumptions would have an impact on the net benefits from implementing the Proposal, we have considered only those changes that are materially large (> ABS $50m) and that can be demonstrated by making changes directly to the input assumptions used in OGW's CBA model.

8.4. A conservative estimate of the revised net benefits from implementing the Proposal is expected to be -$262m as illustrated in the figure below.

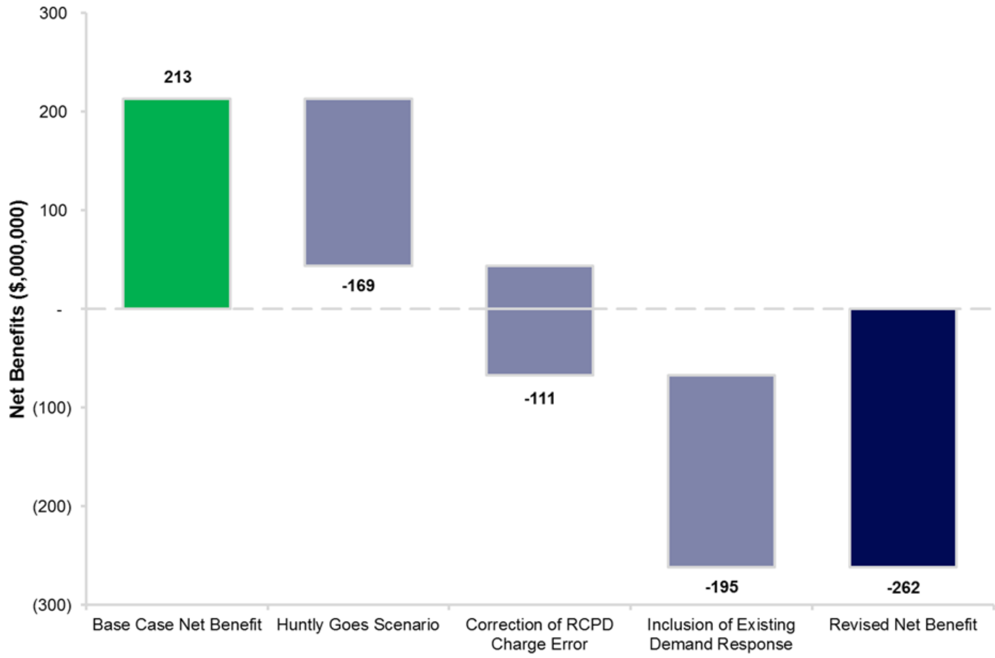

Figure 8 – Conservative Estimate of Revised Net Benefits from Implementing the Proposal

8.5. However, the full extent of the revised net benefits is expected to be substantially greater (more negative), at up to -$2.16b or greater as illustrated in the figure below (in order of submission reference).

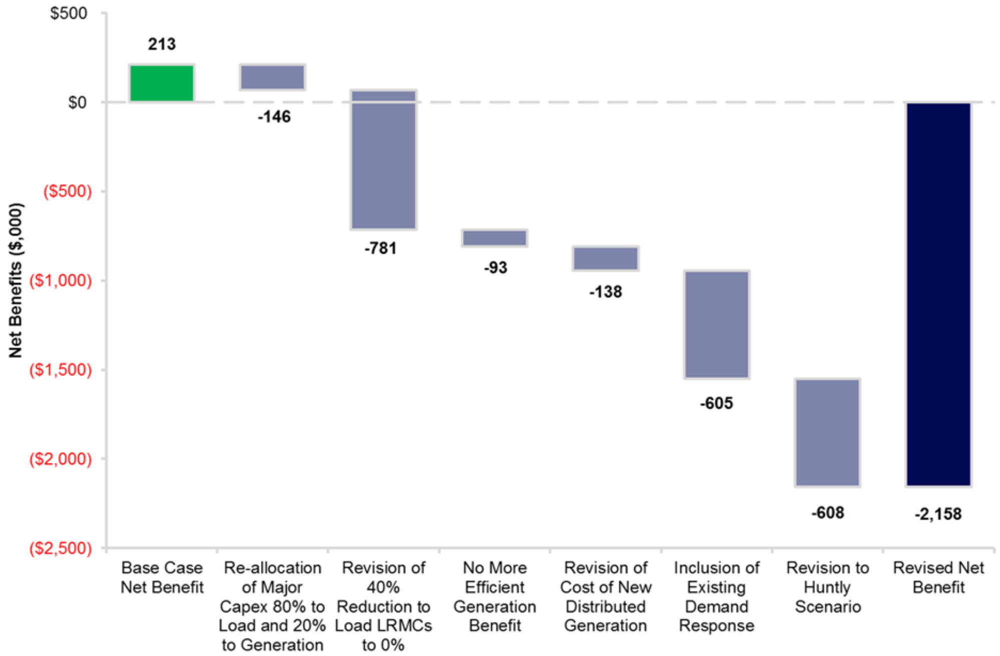

Figure 9 – Full Extent of Revised Net Benefits from Implementing the Proposal

8.6. In summary, the revised net benefits are conservatively estimated to be in the range of -$262m to -$2.16b, or greater (more negative), as a result of making reasonable changes to the input assumptions that have been used by OGW to quantify the net benefits from implementing the Proposal.

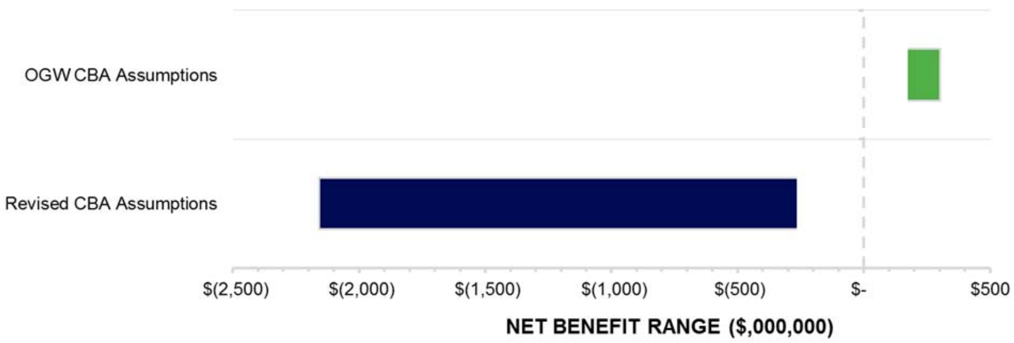

Figure 10 - Potential Range of Net Benefits from Implementing the Proposal

8.7. The figures above clearly demonstrate that the net benefits from implementing the Proposal are likely to be materially negative (a net cost) under any reasonable assumption. This is in direct conflict with the Authority's conclusion that the Proposal provides net benefits that are large and positive under any reasonable assumption.

8.8. Furthermore, the conclusion that the net benefits from implementing the Proposal are likely to be materially negative does not contemplate any other inefficiencies or unintended consequences of the Proposal that have not been considered by OGW in the CBA. The potential inefficiencies or unintended consequences, variously outlined in this submission, can only result in net benefits from implementing the Proposal being materially more negative than the net benefits that have been quantified, revised or otherwise.

8.9. We submit that there is more than sufficient evidence to conclude that the CBA does not represent a robust, accurate and impartial analysis of the Proposal and therefore does not support the Authority's conclusion that the Proposal promotes its statutory objective.

8.10. Notwithstanding the above, as the CBA does not model the Authority's actual Proposal, but a generic proposal that is assumed to be efficient, we submit that it should not be relied upon by the Authority to support its Proposal.

Regards,

Jonathan Suggate	Grant Smith
Commercial Manager – Business Development & Strategy	GM – Business Development & Strategy

APPENDIX 1 – QUESTIONS AND ANSWERS

ELECTRICITY AUTHORITY
TE MANA HIKO

14 July 2016

Jonathan Suggate
Commercial Manager
Pioneer Energy
PO Box 9284
Wellington 6141

By Email

Dear Jonathan

TPM cost benefit analysis questions

Thank you for your letter seeking clarification from the Authority on a number of aspects of the independent cost benefit analysis of the TPM proposal undertaken by Oakley Greenwood (OGW CBA).

Our responses to your specific questions are set out below.

As a general comment, the purpose of cost benefit analysis is to provide the Authority with an estimate of the costs and benefits of the proposal, to assist the Authority in its decision-making process.

As you note, the Authority's Code Amendment Principles require it to use quantitative cost-benefit analysis. However the Code Amendment Principles also recognise that quantitative analysis may not always be possible.

As set out in the second issues paper, the Authority considers that, in addition to the benefits quantified in the OGW CBA, there are also some very substantial net benefits that have not been quantified.

Question 1: *The CBA considers the incremental costs and benefits of both the area of benefit (AoB) charge and deeper connection charge. The CBA appears to differentiate between the two options based only on percentage inputs for Capital Programme Impact and Avoided Disputation Costs. Can the Authority clarify if there is any relationship between the CBA and the actual charges being proposed in its Proposal?*

As you note, the OGW CBA quantified only a limited number of differences between the AoB charge and the deeper connection charge. The major differences between the two approaches are set out in the qualitative analysis contained on pages 74 and 75 of the OGW report. The Authority is of the view that the OGW CBA adopts a reasonable approach to modelling the costs and benefits of the AoB based proposal and the deeper connection option.

Question 2: *The Proposal provides for Transpower to impose an additional charge to recover its residual costs (the Residual Charge). Can the Authority explain how the relative allocation of charges, both initially and over the term, between the AoB and Residual Charges has been addressed in the CBA?*

The OGW CBA does not take account of the relative allocation between the AoB and the residual charge. The Authority's view is that this approach is reasonable because the modelled benefits arise from, amongst other things, the change in marginal price signal that investors face with respect to new investments (ie, the application of the AoB charge to future, demand driven investments), and the way in which the cost of historical investments is recovered. The

Authority's proposal is that the latter would be achieved by a charge that is based on a measure of physical capacity. The OGW CBA assumes that this will not distort marginal consumption or investment behaviour, so that its magnitude is of no particular relevance, except to the extent that it would lead to prices that are above a customer's stand-alone cost of supply. The latter is captured separately as part of the analysis of the enhanced prudent discount policy (PDP).

Question 3. *OGW have stated on a number of occasions that a key issue affecting the benefits of the Proposal is the effectiveness of the price signal, and that there remains some uncertainty in this regard. This is best exemplified in OGW's commentary on marginal price signals where OGW concludes that "If any of these factors do not hold true, the benefits described and quantified in this CBA will exceed those that will occur in practice". Can the Authority explain why the CBA does not include any allowance relating to the effectiveness of the Proposal, either as an input assumption or a key sensitivity?*

The OGW CBA states that "...both of the proposed transmission pricing options appear to meet [the] threshold tests..." necessary to ensure that the price signal is not diluted (page 23 of OGW report). In addition, the Authority explicitly commented on this point in the second issues paper. It stated that while the price signals sent by the Authority's proposal are unlikely to be perfectly accurate, the Authority is confident that the price signals sent by the Authority's proposal will be sufficiently service-based and cost-reflective, and provided with sufficient lead time, to engender the type of response that OGW model.

Question 4. *OGW have assumed that there are no low cost alternatives to transmission investment (eg, hydro, geothermal, solar) on the assumption that the most economic sites have already been identified and developed. Can the Authority please provide the evidence used to support of this assumption?*

The assumption that there are no low-cost alternatives to transmission is intended to simplify the analysis. The OGW CBA assesses that this modelling assumption is conservative; that is, making the assumption will not lead to an overstatement of the benefits of the proposal. Changing this assumption would make little, if any difference to the results, because if there were additional low cost (ie, lower than the cost of the alternative investment, being a transmission investment) alternatives available in the future, these solutions would be dispatched under both the existing RCPD charge and the proposed AoB charge.

Question 5. *OGW have stated a number of times that there is a degree of inherent uncertainty in its analysis of the benefit from more efficient co-investment in generation and transmission services and therefor the lower bound economic benefit for this component of the CBA should be zero. Can the Authority please explain why this realistic lower bound was not presented as part of the results or the sensitivity analysis?*

The lower bound was described in the OGW CBA as a "worst case scenario", not a "realistic" lower bound as you suggest. The OGW CBA identifies that even under the most extreme and unrealistic assumptions, the net benefits modelled will not turn negative, and therefore the overall net benefit of the proposal would remain positive. OGW does not see the lower bound as realistic, as shown in its quantitative modelling.

Question 6. *OGW have concluded that existing distributed generation provides a positive economic benefit and would do so in the future even with the continued use of the current RCPD charge6. This is in direct contrast to the conclusions reached by Concept Consulting in their CBA of the Distributed Generation Pricing Principles. Can the Authority explain how they have reached these* *conflicting conclusions relating to the efficiency of existing distributed generation?*

The two CBAs do not reach different conclusion about the benefit of exiting DG. In particular, as indicated in paragraph D.8 of the Authority's paper *Review of Distributed Generation Pricing Principles: Consultation Paper*, Concept assumes that most DG will continue to operate. As stated in the OGW report, OGW make the modelling assumption that all existing DG stops operating, but this is a conservative assumption because some DG will continue to operate. (Footnote 54 of the OGW report states that "The estimated gross benefit from more efficient pricing of historical investment comes entirely from transmission being more efficient than other new investments such as diesel generation. However, it should be noted that the modelling of this benefit (from more efficient pricing) in isolation implicitly assumes that existing distributed generators might cease operations straightaway in response to the effective removal of the RCPD price signal. This is a conservative assumption, as this: a) actually leads to a reduction in the benefit of removing the RCPD charge (because the cost of existing distributed generation is assumed to be less than the LRMC), and b) does not reflect the fact that many of these existing plants will continue to operate in response to the new cost-reflective transmission charge (eg, the AoB charge). To be conservative, we have not explicitly modelled this in the "Future investment in services or equipment that may otherwise be substitutes for transmission services" section – but this the likely outcome").

Question 7. *OGW have assumed two separate benefits associated with a change in the cost of the generation schedules, being the more efficient co-investment benefit and the removal of the HVDC charge, as a result of the Proposal. Can the Authority explain how a single change in price signal (the Proposal) would influence independent benefits from different changes to the same generation schedule? ie, these benefits must be mutually exclusive and not additive.*

As is summarised in table 1 of the OGW report, OGW has modelled separately a number of benefits that would arise from the proposal to replace the current TPM with the Authority's proposal. We understand from OGW that it has done this so that readers can gain an understanding of what is contributing to the overall net benefits. Even though these benefits are modelled separately, they would all arise as a consequence of implementation of the Authority's proposal and are therefore additive.

Question 8. *OGW have assumed in their analysis that there will be no material upfront or ongoing costs for Load Customers or Generation, and significant avoided dispute related costs. Both of these assumptions appear to be arbitrary given the Proposal promotes a significant increase in bi-lateral agreements between Transpower and Industry participants which will inherently have a corresponding impact on transaction costs and durability. Can the Authority please provide some evidence that supports their assumptions for upfront and ongoing costs?*

As noted in paragraph 8.20 of the second issues paper, the Authority agrees that the implementation costs are underestimated. However, it also notes that the sensitivity analysis shows that any reasonable estimate of the implementation costs would not significantly alter the net benefit estimated within the OGW CBA, and would remain positive.

Question 9: *The Authority provided OGW with the capex data set as a basis for modelling the LRMCs of providing transmission services. Can the Authority please confirm the following:*

a. *The source of the capex data set information that includes major capex, base capex and opex on an annualised basis, and why this expenditure is assumed to be static over the modelling period?*

b. *The source of the split in the capex data set components between Load and Generation, specifically the percentage input assumptions (60:40) that have been used for allocating major capex between Load and Generation?*

c. *The source of the split in the capex data set components between regions, specifically the percentage input assumptions that have been used for allocating major capex between Load and Generation regions?*

(a) Given the uncertainty around major capex over the 20 to 30-year analysis timeframe, assumptions were necessary. For the final load split, a table was compiled using historical and forecast major capex information, as discussed below. The assessed benefits of investments and location of investments required some judgement. Transpower's updated "RT06" file was used to source information. This spreadsheet is published by Transpower and is available from Transpower's website. Note the average major capex in the RT06 file between 2004 and 2025 was $154m pa whereas the major capex scenarios were based on the more conservative assumptions of $50m and $100m pa respectively.

The allocation to regions for generation was based on GWh produced in each region. 2014 generation data was used. A simplified allocation method was applied here because of the difficulty of allocating the benefits of investments to specific generators.

The RT06 file was the source for base capex and operating expenses data. For major capex, base capex and opex, expenditure was assumed to be static over the period so to be conservative.

(b) The 60:40 split between load and generation is an approximation. It reflects a high level understanding that economic investments benefit generation and load while reliability investments are of a greater benefit to load.

(c) The split between regions for load is based on historical data as outlined in the table below. The split between regions for generation is based on GWh produced in each region in the 2014 calendar year. The 2014 year was seen to be an appropriate year as there were both northward and southward flows across the HVDC in that year and the flows were seen to be broadly representative of a "typical" year.

Year	UNI	LNI	USI	LSI	Total	Source
2004	2062536.938	1,719,583	1,688,558	81,113	5,551,791	Actual based on where investment is located
2005	154769.839	78,852,633	7,310,984	65,501,658	151,820,044	Actual based on where investment is located
2006	6137163.249	5,788,269	5,782,413	1,975,821	19,683,666	Actual based on where investment is located
2007	105763.014	4,536,760	737,799	364,244	5,744,566	Actual based on where investment is located
2008	3477821.515	2,030,953	6,454,077	669,293	12,632,144	Actual based on where investment is located
2009	5825516.683	479,483	213,653	2,970,147	9,488,799	Actual based on where investment is located
2010	188,200,191	80,022,532	44,731,776	23,862,771	336,817,270	Actual based on assessed benefits
2011	319,388,502	110,140,416	35,233,930	31,778,072	496,540,920	Actual based on assessed benefits
2012	383,958,039	136,269,870	59,023,865	44,455,558	623,707,333	Actual based on assessed benefits
2013	242,827,953	85,970,234	29,131,337	33,680,394	391,609,919	Actual based on assessed benefits
2014	121,071,738	55,351,271	25,445,769	31,400,063	233,268,841	Actual based on assessed benefits
2015	37,174,756	23,775,571	11,644,091	19,735,142	92,329,560	Actual based on assessed benefits
2016	33,526,077	24,905,962	10,627,750	20,627,750	89,687,539	Forecast based on assessed benefits
2017	38,059,947	28,491,974	9,109,550	23,589,550	99,251,021	Forecast based on assessed benefits
2018	44,362,395	46,848,238	5,561,250	15,503,250	112,275,132	Forecast based on assessed benefits
2019	34,649,116	51,775,282	975,000	975,000	88,374,398	Forecast based on assessed benefits
2020	14,738,164	38,336,235	433,000	433,000	53,940,399	Forecast based on assessed benefits
2021	24,450,350	27,619,255	24,673,582	8,525,456	85,268,642	Forecast based on assessed benefits
2022	35,487,910	27,584,209	25,557,647	6,370,234	95,000,000	Forecast based on assessed benefits
2023	47,027,855	41,044,264	25,557,647	6,370,234	120,000,000	Forecast based on assessed benefits
2024	50,297,293	35,338,403	10,376,861	13,987,443	110,000,000	Forecast based on assessed benefits
2025	71,288,240	55,132,299	16,691,798	18,916,663	162,029,000	Forecast based on assessed benefits
Average capex	77,466,913	43,727,895	16,225,561	16,898,766	154,319,136	
	50%	28%	11%	11%	100%	
Allocation for $100m annual major capex	50,199,162	28,336,016	10,514,290	10,950,532	100,000,000	
Allocation for $50m annual major capex	25,099,581	14,168,008	5,257,145	5,475,266	50,000,000	

A number of sensitivity analyses were undertaken of the allocation of major capex between regions for load and generation. This was not reported in the OGW CBA. Sensitivity analysis was also undertaken in relation to the change in cost of a given quantity of capex. None of the sensitivity analyses had results that were inconsistent with the broad conclusions of the OGW CBA.

Question 10. *OGW have only used major capex in its calculation of the LRMC in all scenarios, on the assumption that this is the category of capex that would primarily be driven by growth in peak demand. However, the Proposal ultimately allocates all future capex under an AoB which implies that in reality these charges will be much higher than modelled. Can the Authority comment on the relationship between the use of a muted LRMC for modelling purposes and the actual charges under the Proposal, and the corresponding impact on the benefits being reported?*

Base capex is largely replacement and refurbishment capex. OGW has assumed that replacement and refurbishment capex has no impact on the LRMC, hence its exclusion. OGW has assumed that to a large extent the timing and capacity of replacement capex is determined by technical considerations and so not affected by sending a cost reflective price signal, so including replacement capex in the area-of-benefit charge would alter neither the optimisation nor the benefits as they are assessed by OGW. However, as the Authority makes clear in the second issues paper, it is of the view that sending a service-based and cost-reflective price signal for replacement capex is also like to lead to more efficient investment, and so the Authority's view is that from this perspective, the benefits will be larger than OGW assesses.

Question 11. *OGW have adjusted all raw LRMC calculations downward by 30% to account for the fact that the analysis was undertaken over 19 year due to data availability. Can the Authority confirm which input data assumption or set was limited to 19 years?*

The analysis was limited to 20 to 30 years. The capital expenditure programme provided by the Authority was also for 20 years. In reality the assets will serve customers for far more than 19 or 20 years. The OGW CBA has made adjustments to take account of this difference.

Question 12. *OGW have used the Interactive Electricity Cost Model – 2015 from the Ministry of Business, Innovation and Employment as the basis for determining the generation project schedules. Of the seven projects included in the project schedule and used for determining the benefit, approximately 1,000MW or 77% of those projects have been abandoned. Can the Authority comment on the robustness of the CBA in the context that some of the key input data is no longer relevant?*

OGW has relied on the information that it was aware of and that was available in the public domain at the time of developing the CBA. The Authority informed OGW of a number of changes that it was aware of in relation to the projects that were included in the project schedule, which OGW subsequently used to make adjustments for in its modelling. The Authority is satisfied that the OGW CBA provides a reasonable assessment of the costs and benefits it has quantified. In addition, as noted above, the Authority is of the view that the unquantified benefits are likely to be substantial.

Question 13. *Can the Authority clarify why the more efficient co-investment in generation and transmission services benefit has been calculated based on overall costs (ie, upfront capital costs, fixed operating costs per MW, variable operating costs per MWh, and transmission costs per MWh) and not just the transmission costs? ie, presumably the balance of these costs could only have an influence of market prices, the effect of which has been excluded elsewhere by the Authority and OGW.*

OGW has made the assumption that when faced with a service-based and cost-reflective price signal for new transmission, potential investors in generation will take account of both the total cost of generation and the additional cost to them of transmission. That is, if nodal prices were the same everywhere, it would maximise its return on investment by minimising the total cost of investment in and operation of generation profits plus the cost of transmission charges they face. This means that from an economic perspective, a potential investor might trade off higher generation costs, for lower transmission costs, if this led to the lowest overall costs. This is why both sets of costs (ie, transmission and generation) must be included in the analysis – otherwise, this trade off (higher generation costs stemming from a generator seeking lower transmission costs) would be incorrectly omitted from the analysis. The Authority agrees that this assumption is appropriate.

Question 14. *OGW have adjusted the raw Load LRMC calculations downward by 40% to reflect advice from the Authority that not all transmission investment is caused by standard percentage growth in demand in regions leading to capacity being constrained. This adjustment is in addition to the related assumption about the proportion of annual capex influenced by demand (question 10 above). Can the Authority confirm the basis for this assumption, specifically the 40% discount factor that has been applied?*

The basis is documented in the Appendix A, page 81 of the OGW report. ("The load related LRMCs have also been adjusted downward to reflect advice from the Authority that some investments are based on changing patterns of demand caused by exit and entry of large plant; it is not all caused by standard percentage growth in demand in regions leading to capacity becoming constrained. The LRMC's revealed in other jurisdictions have also been considered when making this assessment").

Question 15. *OGW have included historical RCPD data that differs significantly (regionally and in total) from available Transpower data and forecast information. Can the*

Authority confirm the source of the RCPD data that has been used in the CBA?

The regional coincident peak demand (RCPD) numbers referred to actually represent regional (winter) peak demand numbers provided by the Authority to OGW on 7 December 2015. (This data was sourced from the file Transpower National-Regional Peak Demand Forecasts Feb2015.xlsx).The use of these numbers impacts on the calculation of three impacts within the CBA:

- Benefits of removing the RCPD charge
- Demand response (as a transmission substitute) and
- Reduced demand (through the elasticity impact).

In terms of the RCPD benefit, this is based on a gradual take-up of distributed generation (DG) to a cap of 5% of demand over 20 years. Take up only occurs where the cost of DG is less than the current RCPD charge (around $2300/MWh). This is then converted to a forecast level of electricity (based on regional peak demand information provided by the Authority) that would be provided through DG. The benefit is then that the investment in DG delays the need to augment the transmission network. OGW assume that peak demand is the underlying driver of the need to make investments to augment the transmission network, therefore they have linked the take up of DG (where economic) to peak demand figures, not the RCPD figures. This is reasonable.

Similarly, the incentive for demand response (ie, as a transmission substitute) is based on the cost of demand response (DR), relative to the cost of augmenting the transmission network. Again, given peak demand is assumed to be the underlying driver of the transmission augmentation, OGW have linked the take up of DR to the forecast of peak demand provided by the Authority.

OGW agrees that the reduced demand (or elasticity impact) should have been explicitly based on the RCPD numbers. However, it considers that the impact of changing these numbers is immaterial (eg, less than $200k impact to overall NPV).

Question 16. *OGW have modelled two benefits relating to the future investment in services or equipment that may otherwise be substitutes for transmission services, namely the Demand Response Benefit and the Deferral Benefit. We understand the principle of deriving benefits from substitutes for transmission services; however it is not clear how the new price signals from the Proposal will provide these benefits over and above the status quo? Particularly as OGW separately concludes that the current TPM price signals incentivise substitutes for transmission services. Can the Authority clarify how a benefit can be derived from contrasting treatment of the same substitutes for transmission services? ie, these benefits must be mutually exclusive and not additive.*

As modelled by OGW the Authority's proposal removes the incentive for inefficient transmission substitutes – that is distributed generation and demand response that does not efficiently substitute for transmission. In addition, OGW models the Authority's proposal as incentivising distributed generation and demand response that does efficiently substitute for transmission. Since OGW models both benefits as arising from the Authority's proposal, the benefits are additive.

Question 17. *The OGW analysis of the RCPD Charge Benefit assumes current ACOT revenue of $62,000,000 per annum. However, ACOT revenue for the more* *recently completed 2015 pricing year was $52,000,000, a figure which the Authority had access to at the time of publication as it has been included in the Concept Consulting analysis of the Proposal8. Can the Authority explain why an outdated ACOT revenue figure was used as the basis for the CBA as opposed to the most recent figure or a historic average?*

Avoided cost of transmission (ACOT) payment information was taken from Commerce Commission disclosures for the year ended 2014. The Authority notes that ACOT payments have grown significantly, from $22m in 2008 to $62m in 2014–an increase of 177% over 7 years.

Note the indicative modelling for impact of the TPM second issues paper is intended to reflect the 2019 calendar year. Given the growth rate of ACOT payments, the use of 2014 data is conservative.

Question 18. *The OGW analysis of the RCPD Charge Benefit compares the economic cost of existing distributed generation, new distributed generation (diesel only) and new demand response programmes and offsets these costs against an estimate of the benefits of those investments. Can the Authority explain why this analysis excludes existing demand response programmes (c. 1,000MW) that respond to the current RCPD price signal?*

OGW did not take into account the impact of existing demand response programmes on the CBA. OGW's view is that this is a conservative assumption. This is because if the costs of these existing programmes are below the estimated cost of transmission, then these would continue to operate in response to the more cost-reflective AoB charge, hence there would be no net change in the CBA (ie, they would run, whether or not it was in response to the RCPD charge, or the more cost-reflective AoB charge). However, if they were in fact inefficient programmes (ie, their costs were higher than the transmission alternative), then their inclusion would result in the benefits of introducing the AoB option being larger than those that have been modelled (because the AoB charge would lead to the cessation of demand responses programmes that are in fact, inefficient).

We trust this answers your questions. We would welcome submissions on any issues that you would like to raise.

Yours sincerely

pp

John Rampton
General Manager Market Design

Pioneer questions and responses (2)

Authority responses in red.

From: Jonathan Suggate [mailto:jonathan.suggate@pioneerenergy.co.nz]
Sent: Friday, 15 July 2016 10:20 a.m.
To: Saltanat Cole
Cc: Roger Procter; John Rampton; Work Grant Smith; Mary Ann Mitchell; Alistair Dixon; Tim Street
Subject: Re: Questions on the TPM CBA

Hi Saltanat,

Thank you for the detailed responses to our questions, this will greatly assist us in making our submission.

If I may, there is one basic clarification I would like to your response to question 14 regarding the 40% discount factor that has been applied to the Load LRMCs. Your response references Appendix A, page 81 of the OGW report which is also referenced in the original question. However, the question itself was more specific to the 40% figure which has been used. Has the value of 40% been based on any empirical evidence or was this figure established by OGW at their discretion? If the former, can you please provide a reference? If the latter, can you please provide an explanation of how they arrived at 40%, as opposed to 30%, or 20% etc.?

Many thanks in advance.

OGW have advised that the discount was derived, having regard to the long run marginal cost (LRMC) outcomes in other jurisdictions. The 40% itself is not based on "empirical evidence", but the results derived from adopting the 40% is based on empirical evidence (i.e., it generates LRMC results that are in the range reported in other markets, namely Australia). See footnote 33 of the cost benefit analysis document and the associated text, which references an Australian Energy Market Operator (AEMO) document that has Transmission Use of System (TUoS) locational prices (which, as the document states, are based on the LRMC of supply) for one year. Note also that on the AEMO website, there are prices for a number of years, all of which were considered.

OGW also considered the LRMC's reported by various distribution business in Australia, particularly for their sub transmission network (which has the voltage most likely related to transmission. Almost all of these are between \$10/kVA (\$10,000/mVA) to \$32,000/mVA. NOTE: The LRMCs will have been calculated by different parties (because there are multiple businesses), yet they come out with fairly consistent numbers across the board. So again, this informed the range, which informed the 40%.