Transmission pricing methodology (TPM) review: second issues paper: Question and Answer session on CBA calculations

Questions and responses from the session are provided below.

How does OGW's calculation of net benefits reflect that charges to individual customers under the area of benefit (AoB) charge may be higher or lower than LRMC?

As noted in our response to issues raised on the CBA for the second issues paper, the CBA is intended to reflect future decisions, not to model detailed decision processes that would be undertaken on a project by project basis with contemporary information about costs and specific locations.

Put another way, the CBA was designed to assess future system-wide economic impacts of the proposed TPM as a result of the incentives it creates for future decisions by affected stakeholders. LRMC assessments are considered to be valid indicator of the long-term economic implications over multiple projects but may be above or below individual project costs.

Would OGW's calculation of net benefits change if the AoB charge applied to all major existing transmission investments?

If we understand this question correctly, this refers to the revision that was made to the proposed Guideline (the revision was contained in the December 2016 supplementary consultation paper) that Transpower must include: "*a method for including further assets as eligible investments, if doing so would promote the Authority's statutory objective.*" In our December 2016 document in which we outlined our assessment of changes to the proposed Guidelines relative to the original set published for the second issues paper, we provided the following response.

"The effect of the above additional component would be to recover more of the costs related to sunk investments via the AoB charge, as opposed to the residual charge. In our original proposal, we did not quantify any economic benefit from using the AoB charge as compared to a residual charge. For existing customers, we stated that both recovery mechanisms will be efficient, if they don't:

- *Distort the future usage of the existing network (e.g., consumption decisions); and*
- *Lead customers (including generators and distributed generators) to make inefficient connection, disconnection or other investment decisions.*

The proposed adjustment, which would allow Transpower to extend the scope of the AoB charge if it is consistent with the Authority's statutory objective, does not change our position that for existing customers, both recovery mechanisms are likely to lead to efficient outcomes. Regarding new customer connections, both the AoB charge and the residual charge involve levying a fixed charge on a new customer. In both cases, as well as under the current TPM arrangements, there is the possibility that the overall charge may exceed a potential new *customer's willingness to pay, despite that customer's willingness to pay being greater than Transpower's incremental cost of supply. In short, we didn't model any potential distortions stemming from the use of the residual charge versus the AoB charge versus the current TPM arrangements on the efficient connection of new customers, because they all have similar attributes, hence we do not propose to change our CBA based on the Authority's proposed refinement."*

Would OGW's calculation of net benefits change if the AoB charge did not apply to any existing transmission investments?

We are not able to answer this question, as it is not clear from the question what the alternative charging arrangement would be in relation to existing transmission investments. It would be the (relative) efficiency of this alternative charging arrangement that would need to be assessed in order to provide a specific answer to this question.

How does OGW's calculation of net benefits reflect the method of valuing assets for both existing and new investments? Would the calculation of net benefits change if depreciated historic cost (DHC) were used instead of indexed historic cost (IHC)?

Regarding new investments, our CBA for the proposal in the second issues paper assumed that the valuation technique that applied to transmission investments would result in cost-reflective AoB charges, therefore promoting efficient investment in, and efficient operation of those investments. To this end, the ex ante price signal that customers will face for new investments will reflect the estimated costs of constructing and developing those investments, hence being cost-reflective and consistent with our original CBA.

Regarding historical investments, our original CBA also assumed that the valuation technique that applied to historical transmission investments would not distort future consumption or investment decisions in relation to transmission services. The valuation technique used to value historic investments, could, in theory, lead to inefficient disconnection from the network (e.g., if the valuation technique leads to a charge that is above a customer's standalone cost). To this end, we are of the view that neither depreciated historic cost (DHC) or indexed historic cost (IHC) would directly or indirectly lead to inefficient disconnection from the network, namely because both are linked to historic cost, which in turn is likely to be below any individual customer's standalone cost. Furthermore, in the unlikely event that it was above standalone cost, the prudent discount policy would be available to avoid the inefficient disconnection.

How does OGW's calculation of net benefits reflect how charges under the proposed TPM guidelines will be phased in under a proposed cap on transmission charges (effectively replacing clause 19 in the existing guidelines)?

We covered this matter in our December 2016 report that related to the impact on the CBA of the revisions made to the proposed Guidelines (the revisions were contained in the

December 2016 supplementary consultation paper), noting as follows:

"*the impact on the CBA of any price capping arrangement depends on how this price cap is implemented in practice. If the transitional arrangements compromise the introduction of the AoB charge as it relates to aspects of our analysis that have contributed to positive economic benefits, in particular:*

The application of the AoB charge to forward-looking, demand-driven, investments, or the removal of the RCPD charge and subsequent replacement with a:

- *residual charge that is non-distortionary ; and*
- *an AoB charge that is applied to some historical assets,*

then it would affect the results of the original CBA.

However, given that the net charge on which the cap is placed excludes recovery of the cost of new investments ('any charge attributable to assets commissioned after the end of the 2019/20 pricing year'), the cap would not appear to compromise the AoB price signal as it relates to forward-looking demand-driven investments.

Furthermore, it is our understanding that the cap would not involve the retention of the existing RCPD price signal to recover the costs of sunk investments, therefore we consider the original CBA does not need to be amended".

How does OGW's calculation of net benefits reflect the marginal price adjustment mechanism, which allows a customer to face a marginal price for credible commitments to reduce demand equal to the marginal costs saved by Transpower?

Why is OGW's calculation of net benefits not affected by the changes that the EA has made to the specification of the marginal price adjustment mechanism to make it asymmetric in nature?

How would OGW's calculation of the net benefits be affected if the marginal price adjustment mechanism were not part of the TPM?

In the CBA for the proposal in the second issues paper, we stated that one of the potential benefits of the AoB charge over the deeper connection-based charge was its structure, namely that it was proposed to include a cost-reflective marginal price signal (which is analogous to the 'marginal price adjustment' mechanism). Notwithstanding this, we did not explicitly reflect the marginal price adjustment (MPA) mechanism in our CBA values (i.e., it was a *qualitative* benefit of the AoB charge as compared to the deeper connection-based charge).

Hence, despite the revised Guidelines as detailed in the December 2016 supplementary consultation paper making this an "additional component", we did not change the CBA as it did not affect our original CBA values. The corollary is that the CBA quantifications wouldn't be affected if it were not part of the TPM. However, to be quite clear, it is our understanding that the proposed Guidelines will allow Transpower to introduce it if it is practicable and consistent with the requirements of clause 12.89 of the Code.

How does OGW's calculation of net benefits reflect the ability of transmission customers to seek optimisation of asset values?

It is our understanding that any optimisation of asset values would result in the recovery of some costs that were originally being recovered via the AoB charge, subsequently being recovered via the residual charge. In our view, as long as the allocation of residual costs is:

- very difficult for customers to avoid in the future, and
- broadly reflects a customer's reliance on the transmission system

then this would have no impact on our CBA for the second issues paper. It is our view that the proposed basis for recovering residual costs meets these criteria.

The above position reflects the statements that we made in our CBA for the proposal in the second issues paper that subject to two provisos, the way in which historical investments are recovered should not materially influence economic efficiency, as these costs have already been incurred and therefore, cannot be reversed. The two provisos are that the recovery mechanism minimises the extent to which it:

- distorts the future usage of the existing network (e.g., consumption decisions); and
- leads customers (including generators and distributed generators) to make inefficient connection, disconnection or other investment decisions.

How does OGW's calculation of net benefits reflect the default proposal that if the AoB charge cannot be calculated then the allocation is made on the basis of each customer's average injection?

Consistent with the answer to the previous question, as long as the allocation of the residual costs is:

- very difficult for customers to avoid in the future, and
- broadly reflects a customer's reliance on the transmission system

then this would have no impact on our CBA. It is our view that the proposed basis for recovering residual costs meets these criteria.

In calculating the benefits of attracting additional investment in substitutes for transmission:

How did OGW's calculation of LRMC for demand response, using information from Transpower's trial, calculate an annual estimate of costs from a trial that ran for six months?

The basis for this calculation is outlined in Appendix C of our CBA for the proposal in the second issues paper. This shows that the calculation is based on the cost of the program divided by the demand response delivered. This also shows that the cost of the program is predominately related to the demand response provided (i.e., dispatch payments), not the time the program ran for.

How did OGW calculate a 15% upward adjustment to the LRMC of demand response to account for its lack of reliability compared to network solutions? Did it cross-check this adjustment against the results of Transpower's trial?

This was an estimate based on our experience having worked in and having advised electricity network businesses and regulators in relation to demand response services in the past. In particular, once DR programs move from trial phase to business as usual, network businesses generally have to over-contract for demand response (relative to the actual amount they need), in order to account for the risk that some parties will not provide DR services when required.

How did OGW arrive at each of the assumptions underpinning its example of a 10 MW diesel generator, which defers five transmission projects, each costing $40 million, by one year?

This was an estimate based on our professional experience, as well as reference to the New Zealand electricity market. As we noted in our CBA for the proposal in the second issues paper, this "represents, in NPV terms, less than 6.5% of the total capex that our modelling assumes will be spent over the evaluation period for the base case, hence this is considered relatively conservative". Moreover, in a footnote in the CBA document, we stated that "the sizing of the generator is based on our assessment of the scale of investment that would facilitate the deferral of a project by one year. This is based on the expected annual growth in MW in the NZ market that will drive individual transmission projects to occur". We outlined our assumptions in relation to the cost of diesel generation in our CBA, in both section 8 and Appendix B.

Moreover, we provided a significant amount of detail in support of our assessment of the cost of diesel generation in Section 5 of our response to submitters' comments report, which was published in December 2016.

Did OGW consider the impact on future transmission investment of new battery technologies?

Yes, this is addressed in Appendix B of our CBA for the proposal in the second issues paper, as well as Section 8 of the main body of the report.

In calculating the benefits of deterring additional investment in substitutes for transmission:

Why did OGW's calculation of net benefits adopt different assumptions in relation to the probability of Huntly remaining open – assuming 100% for deterring additional investment in (and use of) substitutes for transmission, but only 50% for sending network cost signals to investors in generation?

As we stated in our CBA for the proposal in the second issues paper, only the Scenario 1a result (Huntly stays), "which is based on information provided by the Authority and is assumed to reflect the most realistic forward-looking demand-driven investment programme - has been used in the base CBA where a load LRMC is required to undertake a calculation". Whereas Scenario 1a and 1b (Huntly stays and Huntly goes) "have been used to calculate two separate amounts for the benefit stemming from the co-optimisation of transmission and generation – which, as discussed elsewhere in this report, have been averaged under our base case". The key reason for making this differentiation was simply due to materiality of the impact of this decision on the results. The decision around Huntly was much more material, in the context of the assessment of the "More efficient generation" benefit, because it changes the amount of new generation that gets built as well as the LRMC, hence it has a large impact on the results. Conversely, it is not overly material in the context of the assessment of "future investment in services or equipment that may otherwise be substitutes for transmission services", as it only has a marginal impact on the LRMC for load.

Did OGW take any steps to validate or assure itself of the reasonableness of forecasts of network investment supplied by the EA that it used in its calculation of LRMC? If so, what steps did it take?

Did OGW take any steps to validate or assure itself of the reasonableness of the split of network investment into a 60% share for load and a 40% share for generation supplied by the EA? If so, what steps did it take? How does this split relate to the estimates of transmission benefits modelled by the EA?

We relied on a number of pieces of information provided to us from the Authority. It should be noted that we discussed with the Authority, exactly how we would be using this information, hence the Authority was able to ensure that any data was 'fit-for-purpose'. We had a number of interactions with the Authority in relation to the development of the data to further ensure that the Authority was aware of exactly how we would be using the data. Given the Authority's role in the market, and their knowledge of the issue, we are comfortable that it was reasonable to assume that the information that the Authority provided to us for the purposes of the analysis was reasonable and 'fit-for-purpose'.

In relation to Q16 specifically, we assured ourselves of the reasonableness of the outturn LRMC results for transmission investments (which were a function of the information provided by the Authority) by comparing them to published LRMC estimates from Australia. In relation to Q17 specifically, we did not relate the 60:40 split to the estimation of the indicative initial transmission charges modelled by the Authority.

Did OGW undertake or report any sensitivity analysis in which it examined the effects of relaxing its downward adjustment to LRMC for load?

All sensitivity analyses were outlined in the CBA for the proposal in the second issues paper. In relation to the question, if this refers to the downward adjustments in the LRMC calculations for load that were outlined in Appendix A of the CBA report, we did not undertake such a sensitivity. However, we did undertake a number of other sensitivities on the key input parameters that we believe are likely to affect the results.

How did OGW arrive at the estimates in its description of Victorian locational charges sourced from AEMO as ranging "from around $14,000/MW (AUD) through to $52,000/MW (AUD) depending on the region, with an average of around $25,000/MW (AUD)"?

The source for this was provided in the original CBA (footnote 33). The broad range has been derived from information published by the Australian Energy Market Authority (AEMO).

How did OGW arrive at estimates in its description of sub-transmission LRMC in Australia as ranging from $5 per MW through to $35 per MW?

We outlined these results in Table 3 of our December 2016 report that responded to submitters' issues on the CBA. The figures in that table were all sourced from the stated business' Tariff Structure Statements, all of which had (at the time) been published in the last 12 months.

How did OGW estimate that, under the status quo, the capacity of reciprocating diesel generation in New Zealand will increase to provide around 5% of total customer demand?

How did OGW estimate that, under the status quo, the level of demand response in New Zealand will increase to provide around 5% of total customer demand?

The CBA analysis compared the economic cost of both diesel generation and DR to estimates of the RCPD charge. The CBA analysis indicated that both were economic in the face of the level of the RCPD charge. As noted in Appendix D of the CBA for the proposal in the second issues paper, the 5% cap on take-up was an OGW assumption. This was based on a qualitative assessment that the economics of these alternatives to transmission investments would slowly dissipate as their take-up led to changes in the shape of the load duration curve.

More particularly, in our CBA, we stated that: "*there is likely to be a cap on the cost effective use of distributed generation facilities as the shape of the load duration curve flattens in response to increased penetration of distributed generation*" and …."*it will take time for that cap to be reached*". We further stated in a footnote that: "*As more distributed generators (and demand response) operate during peak periods, the load duration curve will, everything else being* *equal, flatten out, thus making it less economic for future distributed generators (and providers of demand response) to enter into the market, as they would likely have to operate over more hours in the year to ensure they operate during the 100 pricing periods*."

Did OGW's calculation of net benefits rely on estimate of the strength of the RCPD price signal from regions other than the upper North Island?

The assumption for the RCPD price signal did use analysis conducted by Transpower as part of its TPM operational review for the upper North Island, but since all regions are subject to n=100, as a result of the review, and that the interconnection charge is a postage stamp charge, it is reasonable to assume the signal is the same for all regions.

In calculating the benefits of sending network cost signals to investors in generation:

How does OGW's calculation of net benefits account for the disincentive that an AoB charge on existing assets will place on parties (including generators) to invest in locations where they would benefit from (and incur AoB charges for) those investments?

This was not quantified in the CBA, for the following reasons: a) it is almost impossible for distribution businesses to change locations, hence there is no efficiency loss stemming from the application of this price signal to this group of transmission customers; and b) we assumed that many of the existing transmission assets servicing generators and very large transmission connected customers, will be captured by the existing definition of assets under the AoB charge. Further to this, the revised proposed Guidelines we reviewed in December 2016, provide Transpower with the flexibility to further extend the coverage of the AoB charge beyond the set of historical assets provided for in the original TPM proposal, if doing so would further promote the Authority's statutory objective.

Why did OGW's calculation of net benefits assume that new generation entry will occur so as to maintain system capacity at a level permanently below system demand?

It is not clear what the exact basis for this question is. Notwithstanding this, the modelling of the 'More Efficient Generation' benefit illustrated that the more generation that needs to be built, the larger the benefit from sending more cost-reflective transmission prices. This is consistent with a statement we made in the CBA for the proposal in the second issues paper, that the magnitude of this benefit will be linked to the "amount of new generation investment that is required to service forecast demand – everything else being equal, the lower the amount of new generation that is required (or the larger the amount of spare capacity), the smaller will be the benefit from sending a more cost-reflective price signal around transmission investment". So increasing the amount of generation built in the model will only increase the level of benefits accruing from sending more cost-reflective transmission prices.

Does OGW's calculation of net benefits capture all the costs of generation measured in the calculation of MBIE's LRMC estimates? If not, why not?

We assume that this is the case, given that we are picking up the major cost categories of: capital costs, fixed O&M costs and variable O&M costs, and we are picking up the LRMC figure from the same data source.

Is the cost of capital used in OGW's calculation of net benefits consistent with the cost of capital underlying MBIE's estimates of LRMC?

We did not explicitly check for this consistency. However, it is important to note that we are just using the MBIE's published LRMC to "order" generation. The MBIE's published LRMC, in and of itself, does not affect the results, as the results are based on the NPV of the MBIE's capital costs, fixed O&M costs and variable O&M costs for each candidate generator that is dispatched in the model under both the "old schedule" and the "new schedule". To be clear, we do not model the costs of generation based on the MBIE's published LRMC, we have just used this to order the construction of the plants.

Why did OGW's calculation of net benefits assume that all forms of generation, including wind farms, are equally reliable in being able to provide full capacity to meet peak demand?

We have previously acknowledged this issue in our December 2016 response to issues raised on the CBA by submitters, where we said:

"It is correct that we did not discount the capacity of wind to reflect its reliability to contribute their rated capacities at peak times. This was an oversight on our part, given the broader methodology that we proposed. That said, the assumption about the wind farm's capacity affects both states within the modelled time frame of 20 years (i.e., if we had de-rated the wind farms, then the model would build a different number of generators but exactly the same amount of additional peak capacity under both the proposal and the status quo cases), hence diminishing its effects in the overall result."

Why did OGW's calculation of net benefits exclude costs associated with fuel and carbon emissions from thermal plants over the modelling horizon?

As stated in response to an earlier question, we are picking up all of the major cost categories (capital costs, fixed O&M costs and variable O&M costs) that are outlined in MBIE spreadsheet.

Why did OGW's calculation of net benefits include the costs of several projects that have been scrapped by their former developers – including Rodney CCGT and Hauāuru mā raki wind farm?

The question relates to the "information base" that we used to underpin our CBA. We based our CBA analysis on information that was publically available at the time the CBA was being prepared. This includes the list of potential future generators (which was based on published data from MBIE). It is inevitable that over time (including post the derivation of the CBA) that specific project-by-project assessments will be made which will mean that the project development schedule will differ from those modelled in the CBA project schedules.

We have not 'rerun' the CBA to take into account that some of the generation projects modelled in our schedule are now not forecast to proceed (noting that these decisions can also be potentially reversed by the proponents). However, we are confident that the CBA will remain strongly positive, notwithstanding these recent decisions, simply because alternative generation capacity (to the projects mentioned) will need to fill the breach, and these alternative generation investments will also be subject to re-ordering as a result of the application of the transmission pricing signal.

Why did OGW's calculation of net benefits assume that Huntly closes down in 2020, when Genesis Energy announced last year that it will operate these generators until at least 2022?

Our CBA for the second issues paper assessed two scenarios, one where Huntly remained open and one where it closes in four years hence. We took the average of these scenarios. A 2022 closure date is within the bounds of these two scenarios and hence is covered. In any event Genesis could change their mind and close the plant earlier than 2022.

It is inevitable that over time (including post the derivation of the CBA) that specific project-by-project assessments will be made which will mean that the project development schedule will differ from those modelled in the CBA project schedules.

Why did OGW's calculation of net benefits assume that power can flow freely around New Zealand and between the two islands, and so does not accurately capture the ability of new generation to meet increases in demand?

The CBA made no explicit assumption about whether power flowed freely. As detailed in our CBA report that was contained in the second issues paper, the analysis was undertaken on the basis of forecasts of future transmission costs and demand forecasts on a regional basis (UNI, LNI, USI,LSI) provided by the EA. OGW derived LRMC values from this information.

In calculating the economic gains from improved transmission investment decisions, did OGW include the potential investment in real expected transmission investments?

As stated in our December 2016 document which responded to issues raised by submitters on the CBA for the second issues paper, the CBA is “intended to reflect future decisions, not to model detailed decision processes that would be undertaken on a project by project basis with contemporary information about costs and specific locations. That is to say, the model presents a simplified picture of the real world so as to estimate the benefits of the proposal it is modelling. For example, the CBA analysis does not reflect a bespoke analysis of the exact transmission costs that would need to be incurred to connect each potential new generator, rather, an estimate of the LRMC by region has been used to estimate this. The key question to our mind was: can transmission costs vary from one generator to the next, and in the absence of detailed, bespoke modelling (which itself would be more precisely modelling significant uncertainty), is an estimate of the LRMC within particular regions within NZ a reasonable way of measuring this difference? We answered these questions: yes and yes. Note we are not suggesting that in the real world that the actual transmission cost that will be incurred by a generator will perfectly reflect the LRMC that we have used for modelling purposes – rather they will almost certainly be higher or lower”.

Is the WACC used by OGW in its CBA calculations calculated on the same basis as the one used by MBIE in its calculations of new generation projects’ LRMCs?

We did not explicitly check for this consistency. However, it is important to note that we are just using the MBIE’s published LRMC to “order” generation. The MBIE’s published LRMC, in and of itself, does not affect the results, as the results are based on the NPV of the MBIE’s capital costs, fixed O&M costs and variable O&M costs for each candidate generator that is dispatched in the model under both the “old schedule” and the “new schedule”. To be clear, we do not model the costs of generation based on the MBIE’s published LRMC, we have just used this to order the construction of the plants.

In calculating the benefits of removing the HVDC SIMI charge:

How does OGW’s calculation of the net benefits of replacing the HVDC SIMI charge with the new HVDC AoB charge account for the fact that the new HVDC AoB charge on South Island generators – indicatively recovering from South Island generators around 45% of the current level of the HVDC charge – will increase the costs of developing new South Island generators, relative to new North Island generators (i.e. creating a similar (albeit likely weaker) investment disincentive to the existing HVDC charge)?

The SIMI charge is a per MWh charge on South Island Generators, and is set at a level that is designed to recover the full revenue requirement associated with the existing HVDC link. Given that the majority of that revenue requirement is likely to be related to the recovery of the sunk investments that have been made in the existing link, it means that a variable charge is in effect being used to recover the costs of a sunk investment (or investments whose costs cannot largely be reversed). This potentially means that existing and future investment decisions (by generators) may be affected by this charge, even though any response to that charge will NOT change those otherwise sunk costs.

Further to the above, a per MWh charge over the entire year, to our mind, cannot reflect the forward-looking costs of the HVDC link (i.e., this charge couldn't, by "accident", be cost-reflective) simply because of its structure. In particular, it is our assumption that the forward-looking costs of the HVDC link (i.e. those costs that will be incurred in the future) will not be materially driven by overall throughput. Or put another way, it is implausible to make the case that every single MW that is transmitted over every single one of the 8760 hours in a year in the future has the same impact on the future costs of operating/maintaining/augmenting the HVDC link. Rather, the future costs of the HVDC link (that can be influenced by a generators future investment behaviour) will be predominately driven by throughput when the link is constrained (as this is what will drive the future augmentation of the link).

So everything else being equal, we believe that it is entirely reasonable to assume that in isolation, the SIMI charge can only lead to inefficient outcomes. The SIMI modelling is focused on assessing what the potential economic loss from applying the SIMI charge is.

As the questioner alludes, this SIMI charge will be replaced with another charge. The comment implies that there may be an economic loss stemming from the alternative arrangements. In particular, they state that "How does OGW's calculation of the net benefits of replacing the HVDC SIMI charge with the new HVDC AoB charge account for the fact that the new HVDC AoB charge on South Island generators – indicatively recovering from South Island generators around 45% of the current level of the HVDC charge – will increase the costs of developing new South Island generators". In response, our view is that this does not create a similar investment disincentive (even proportionally, i.e. 45%), because the recovery of historical investments made in the HVDC link under the proposed AoB arrangements are predominately de-linked from future investment behaviour.

What was the basis for OGW's calculation in its original HVDC workbook that predicted net benefits associated with the removal of the HVDC charge, notwithstanding that calculated costs with the charge were lower than calculated costs without it?

What was the basis for OGW's calculation in its original HVDC workbook that estimated annual fixed operating and maintenance costs – measured in billions of dollars – and added these to fixed costs and variable operating and maintenance costs – measured in dollars?

What was the basis for OGW's calculation in its original HVDC workbook that assessed the effect of the HVDC charge on new generator LRMC with an adjustment of $7.14 per MWh for some North Island generators (which do not pay the HVDC charge) and not for all South Island generators (which do pay the charge)?

What was the basis for OGW's calculation in its original HVDC workbook that computed the future capital cost expenditure for some generators (e.g. Hawkes Bay windfarm and Waitahora windfarm) by multiplying their capacity in MW by $1 million, instead of using the capital costs estimated by MBIE?

There were errors in the original modelling in relation to the HVDC charge (termed HVDC workbook in the questions) that have been corrected for. We have corrected these errors and understand that the Authority has released the revised version of this model.

Why does OGW's calculation of net benefits assess the costs of new generation with and without the HVDC charge, without capturing the intra- and inter-island network costs associated with different generation options? How will this calculation capture any benefits that the HVDC charge may offer in signalling higher network costs associated with new generation capacity in the South Island? How is this calculation consistent with the approach that OGW takes to calculating the benefits of sending network cost signals to generators?

We focused on "with and without the HVDC" charge, in the SIMI model for the HVDC charge excluding intra- and inter-island network costs to avoid double counting with benefits in the More Efficient Generation model which does capture these benefits. That is, any future transmission costs (including those in the South Island) that are driven by future generation investment would be signalled to the beneficiaries of those investments via the AoB charge that would be applied to new investments. In these circumstances, new generation (wherever located in NZ) would face an appropriate forward-looking price signal (and hence, be incentivised to co-optimise transmission and generation costs).

What is the basis for OGW's assumed asset lives in its revised HVDC workbook, and why do these differ from the asset lives set out in the MBIE LRMC model?

These are assumptions reflecting our understanding of the electricity generation sector. It is noted that we asked the Authority to review these assumptions, and the Authority informed us that they were comfortable with these assumptions.

Why does OGW's revised calculation of net benefits assume that new generation capacity is perfectly divisible in both its costs and capacity (i.e. new plant can be built and become operational in multiple stages, over multiple years, with capital and O&M costs incurred on a pro rata basis)? Why does it not also apply this approach in calculating the net benefits of sending network cost signals to investors in generation?

This is simply to ensure that exactly the same amount of capacity is being built in both the new and old schedule, so that the results (being the "sign" ie whether it's positive or negative) are not skewed by differing inputs regarding when and how much capacity is built under the two schedules. We didn't apply the same methodology to the "net benefits of sending network cost signals to investors in generation", quite simply, because it would not change the results (with this again being defined as the "sign" of the benefit/cost).

Why does OGW's calculation of net benefits adopt terminal values that assume operating costs are incurred for up to 50 years beyond the modelling period, while capital costs are only expressed on a residual asset lifetime basis (pro rata over the 30-year modelling period)?

The intention of our modelling was to put OPEX and CAPEX on an equal footing. Put another way, if a terminal value for CAPEX is included (reflecting the remaining value, beyond the evaluation period, based on that generator's assumed useful life), we felt it was important to also include the PV of future OPEX that would need to be incurred to continue to operate that CAPEX, so as to not skew the analysis in favour of generators of a certain CAPEX/OPEX mix.

The formula is designed to calculate the PV of future annual OPEX for a period that will equate to 50 years beyond when the generator is assumed to be originally constructed. We picked 50 years, as (a) this reflects the minimum life of any of the generators that are assumed to be constructed (except wind, which is discussed later), and (b) cashflows beyond this timeframe will have no material impact on the results (i.e., OPEX that far into the future, and beyond, once discounted back, will have no material impact on the results). To be clear, we also used the same methodology for wind, that is, we assessed the PV of the future costs of operating wind generators for 50 years beyond when they are originally constructed in the model, despite those wind generators having an asset life of only 25 years. To overcome this "difference" in lives, we estimated the replacement cost of wind generators, and included this in the model to equate capital and operating cost assumptions.

Why does OGW's calculation of net benefits adopt terminal values for wind generators, even when its model assumes the replacement of these generators after the modelling period?

When it comes to calculating a terminal value, we believe we have treated wind generators in exactly the same way as all other generator types (except for the application of a different economic life) in the revised HVDC model. This terminal value was included in response to submitter comments on the CBA, and reflects the remaining value of the asset at the end of the 30 year evaluation period. However, despite making this change, the capacity that is assumed to be provided by other generation investments (not wind) last for a minimum 50 years from construction, as compared to wind generators, which are assumed to last 25 years from construction. Therefore, to place wind generation capacity on an equivalent basis to other generation investments, we included an estimate of the replacement cost of those wind generators beyond the evaluation period.

Why does OGW's calculation of net benefits assess the terminal values for capital costs on a straight line depreciation basis, instead of an economic basis?

In our professional judgement, we believe this is a reasonable simplifying assumption.

In calculating the benefits from a more efficient quantity of services demanded:

How did OGW arrive at the view that that higher electricity prices will give rise to lower quantity demanded, yet also immaterial changes in consumer and producer surplus?

Our analysis reflects our assumptions with regards to (a) the assumed price elasticity of demand for electricity, which was -0.4, and the (b) overall magnitude of the retail price change.

In relation to the (a), please See Appendix D of the original CBA report for assumptions around the basis for the price elasticity of demand input parameter. Inelastic demand for electricity reflects that for any given price change (in percentage terms), there will be a less than proportionate (percentage) change in demand. This less than proportionate impact on demand from any price change flows through to the (relatively minor) impact on consumer and producer surplus.

In relation to (b), the overall percentage impact of a change in transmission prices on end customer *retail* prices is relatively small, quite simply, because transmission costs makes up a relatively small, (around 10%) proportion of most customers' retail bill.

In calculating the benefits resulting from reducing the costs of disputes:

How did OGW arrive at a view that the EA's proposals would be "well documented and understood", and indeed that they would be better documented and understood than the status quo?

The implication in our statement was that we assumed the EA (and Transpower through the development and implementation of the TPM) would ensure the proposal is well documented and also ensure the proposals are well understood.

How did OGW arrive at estimates of savings of 30 per cent of the EA's costs relating to disputes, 35 per cent of other parties' costs relating to disputes and 40 per cent of the cost of regular reviews every five years?

These were our estimates of the potential savings. We would expect that there would be some reduction in costs due to the more robust TPM that would arise from proposal. However, the extent of this potential saving is unclear. We considered the estimated cost savings are reasonable and reflect that we expect there will still be some costs related to disputes even if the proposal was implemented. We note that the costs and associated savings referred to in the question are not material to the conclusion of the CBA given that the benefits modelled in the CBA far outweigh these costs.

In calculating implementation costs:

How did OGW calculate implementation costs an order of magnitude less than those estimated by the EA?

We took an independent approach based on our best judgement that focused on the incremental costs associated with implementing the proposed approach.

How did OGW arrive at an estimate that transmission customers will incur no additional upfront or ongoing costs to engage with the AoB charge?

How did OGW arrive at an estimate that the ongoing application of the AoB charge will require a single additional full-time Transpower employee?

How did OGW arrive at an estimate that the upfront costs of the AoB charge amount to three employees at 75 per cent utilisation each for the EA and for Transpower?

In relation to the above three questions, our December 2016 document, which contained our response to submissions made on the CBA for the second issues paper, detailed that we did not expect there to be major additional resourcing requirements for implementation or on-going administration (i.e. over and above resources that would be required in any event). However, we considered there will be some impact and for the purposes of the CBA we considered the additional resourcing noted in the question as reasonable.

OGW has provided answers to numerous submissions, including Pioneer's CBA issues. These answers confirm for us the CBA modelling is more theoretical in construction, than actually representing the specifics of the EA's TPM Proposal. It is therefore difficult for us to connect outcomes from this CBA model with the Results modelled by Concept and published by the EA in support of its proposal.

Has OGW cross-referenced their modelling outcomes with Concept's AoB modelling and made adjustments to reflect Concept's assumptions?

Not specifically, however as the EA is across both pieces of work, we have (we think reasonably) assumed that they would have brought any areas of risk/issues to our attention for our consideration / review.

For example, Concept has made a number of different Load/Generation allocations for different transmission assets. How do those adjustments relate to the OGW allocation assumptions?

See response to the above. The EA has not made any changes to the load/Generation allocations for different transmission assets that they provided to us for use our CBA for the proposal in the second issues paper.

Materiality testing is difficult to determine, given that the long term benefits to consumers would be measured by consumers as pricing outcomes and by economists as modelled changes of future investment outcomes.

For example, in its December report OGW notes a future $850m allocation of Transpower costs is not that material in the context of long term transmission costs. However, these CBA benefits to consumers, at $230m are in comparison considerably lower than $850m, so themselves would then also be considered as immaterial benefits?

The reference to the $850 million was in relation to the proportion of "retail electricity bills over a 20-year period", not long-term transmission costs, as stated in the question. With regards the relative materiality or lack thereof of the $230m, our role is to assess whether there are net economic benefits stemming from the proposed changes to the TPM, not to provide a broader commentary as to their "materiality".

In comparison, fuel assumptions for different Generation investments are very material to consumer costs and benefits. OGW appears to have ignored sensitivities of new generation investments for things such as fuel costs and has located new thermal plant in their model where there is no access to low cost fuels. This is inconsistent with MBIE assumptions that these new thermal stations would be fuelled on diesel. What would the OGW analysis sensitivities be to fuel changes?

We have run a number of sensitivities as part of the CBA process. We have not "ignored sensitivities of new generation investments for things such as fuel costs", rather, there needs to be a recognition that it is simply not possible to test the sensitivity of the model outcomes to changes in every single input parameter. Instead, we have sought to focus our sensitivity analysis on the key input parameters that we believe are likely to affect the results.

Pioneer's concerns with the CBA are focussed on how sensitive the CBA is to different input assumptions. Our submission highlights that, in diluting all the actual LRMCs through various quite arbitrary adjustments, the analysis is not representative of the likely sensitivities of future outcomes, in particular that many of these sensitivities would have negative benefits.

How did OGW identify that the three sensitivities it undertook (lower capex pricing; evaluation period; discount rate) were the most appropriate / material sensitivities to use for this CBA analysis?

This was based on our knowledge of the input parameters that were driving the CBA. We also cross-checked these with the EA

We would like OGW to undertake more sensitivity analysis of the issues raised by submitters, rather than debate whether their assumptions are just better than others.

We are not in a position to answer this question, rather this request would need to be addressed by the EA.

There are numerous assumptions in the CBA – which are cumulative or not mutually exclusive. Has OGW undertaken a Monte Carlo type analysis to indicate the range of possible CBA $m outcomes from this TPM proposal.

No, we have not undertaken a Monte Carlo analysis. However, our sensitivity testing was designed to assess the reasonable range of potential outcomes, and all sensitivities showed that the proposed TPM refinements would lead to positive economic benefits.

How were the inaccuracies that are claimed to have been identified in the CBA by Trustpower been addressed by Oakley Greenwood in the subsequent modelling undertaken. Can you please provide this detail?

We have provided an updated model addressing the errors identified by Trustpower. This has been published by the EA on their website. This revised modelling shows a benefit of removing the SIMI charge of around $50m.