Questions and responses

TPM options working paper

7 August 2015

BusinessNZ

Question (03/08/2015):

Can you tell me – if the Electricity Authority knows this yet – when the allocation method has been settled, will the new deeper connection charges be fixed for the 5 year period or will it be variable on a day-to-day, or monthly etc basis – I am finding it hard to tell.

Authority response:

Under the options we are consulting on, the deeper connection charge would be calculated every year. For each deeper connection asset, the parties subject to the charges for that asset would face a charge based on their share of the sum of the anytime maximum demand and injection for the relevant capacity measurement period (which, if the current approach is maintained, would be a September year) in relation to the asset.

The determination of which parties are subject to the deeper connection charge in relation to an asset would be done each 5 years, and uses flow tracing to do this. Flow tracing is also used to identify which assets are subject to the deeper connection charge.

The allocation method and the charge itself are all of course subject to consultation so could change depending on the outcome of the consultation.

Carter Holt Harvey

Question (19/06/2015):

Send workings of charges for Kinleith.

Authority response:

Cart Holt Harvey was provided with workings. The response was amended to reflect changes to the modelling. For changes to the modelling, please refer to the Authority's website: http://www.ea.govt.nz/development/work-programme/transmission-distribution/transmission-pricing-review/consultations/#c15374.

Question (23/07/2015):

1. A key part of this is trying to look at how the breakdown of costs for the various options affects us, or might change in the future.
2. You have modelled CHH Kinleith as a direct-connect? Whereas for RCPD and invoicing Powerco is currently the single connected party at the Kinleith Substation. Is there a specific reason for this?

(a) This is important as we are trying to understand what the costs will be and for residual charging the option between AMD or ICP basis. Sounds like for ICP's larger than 2500 kW it would likely be calculated from transformer size.

(b) We also have a substation rebuild coming in the next few years and the Transformer size is likely to expand by 10 MVA for T1, T2 and T3, primarily due to maintenance and standardisation reasons benefiting Transpower, while it does give some extra security in the case of a transformer issue for the consumer, but if the ICP is the basis this could add an extra 30 MVA to the charge and would change the economic basis for the sizing.

3. On the topic of ICP and AMD, what is the rationale for using sum of nominal capacities of active ICPs in EDB's. I may have missed it, but couldn't find a clear justification for the difference between them in the options paper.

4. In the model for Residual charging can you please provide the ICP rate used in the modelling, $ per kW.

   (a) We also assume the AMD rate is $7.356/kW ($640,000/87,000 kW) can you confirm if this is the case.

5. **(31/07/2015):** I'm seeking clarification on the basis for AoB and Residual charging. We've been trying to interpret the option paper and how Kinleith has been modelled, so can you please confirm if ICP's > 2500 kW ie, like Kinleith are being treated on an AMD basis like direct connects while only the ICP's in the meter category codes, 0-5 are being measured under nominal capacity.

Authority response:

1. Cart Holt Harvey was provided with workings.

2. The Authority modelled CHH Kinleith as a direct-connect. During the TPM options paper workshops the Authority heard a number of parties express concerns over the mechanism used to allocate costs between distributors and direct-connects. In particular, whether this created a potentially inefficient incentive to connect directly to the grid. The Authority welcomes submissions on this point.

3. The Authority sought capacity-based approaches that were difficult to avoid unless a customer sought to change the capacity of their connection. The ICP-based allocation was modelled for distributors because it was difficult to avoid. The Authority sought a similar approach for direct-connects and considered transformer capacity but noted that some direct-connects had transformer capacities that were substantially in excess of demand. AMD appeared to be a reasonable proxy for capacity. The Authority is still considering ways to apply transformer capacity because it appears to be a better proxy for capacity. The Authority welcomes submissions on the viability of using transformer capacity as an allocator.

4. CHH's AMD at Kinleith is assumed to be 87 MW. This determines the capacity-based residual charge, and (along with the site's location) also determines the deeper connection and area-of-benefit charges. Please refer to slides 33 to 35 of the TPM workshop presentation. These slides provide an example calculation of how the allocation mechanisms are applied. This is available at: http://www.ea.govt.nz/development/work-programme/transmission-distribution/transmission-pricing-review/events/tpm-workshops/

5. The Authority based Kinleith's deemed capacity on AMD rather than ICP category counts, for the purpose of the area of benefit and capacity-based residual charges.

Contact Energy

Question (2/07/2015):

1. Would the EA please provide the post-processing trace output data 2nd file that calculates the HHI as soon as possible? When can we expect to receive this?
2. Would the EA please run a scenario that models calendar 2014 offers and grid configuration to provide a full year of offers made under Bi-Pole operation?
3. Are you able to please advise what scenarios the Authority will be running and when you expect?
4. What Transpower pricing information are you using in your calculations? Is there a time James Collinson Smith and Mike Mayne could please call you to discuss this?
5. Can we please request the EA publish their results for CAL14 asap? From our brief chat yesterday, it sounds you have previously run this and it is just a matter of pulling the results together?
6. Also can the EA please send us the itemised breakdown of our charges for all options and the status quo (including HAMI assumption and rate used) as our numbers don't tally up.

Authority response:

1. The flow tracing post-processing files are available on Github (https://github.com/ElectricityAuthority/tracing)
2. The flow tracing for 2014 has been completed. The updated output for the 2014 vSPD trace is at: https://github.com/ElectricityAuthority/tracing/tree/vSPD_output/data/output/vspd/y

   The Authority is currently using the trace output to calculate deeper connection charges. The Authority will provide a link to the set of files once this work is complete.
3. The Authority is modelling high and low demand sensitivities, along with sensitivities for additional generation in Northland and the West Coast. Refer the document titled, “Demand and generation sensitivities for the TPM options working paper”. It has been uploaded onto the Authority’s website and is available at: http://www.ea.govt.nz/development/work-programme/transmission-distribution/transmission-pricing-review/consultations/#c15374.
4. A breakdown of Contact’s charges was provided to Contact that shows the HVDC and RCPD rates used in the calculations.
5. See (2) above.
6. A full breakdown of Contact’s charges was provided to Contact. Note: the response is based on the updated deeper correction results, so the numbers will not align with the numbers in the options working paper.

Question (14/07/2015):

Explain whether the charges in Table 15a took into account LCE or not.

Authority response:

All results shown are net of LCE. That is, they are lower than they would be if there were no rentals to offset transmission charges.

Question (31/07/2015):

I am aware that there were issues with including embedded generation/wind, so I was just wanting to know how Concept have managed these in the deeper connection calculations? Ie did Concept change VSPD or was this done post processing?

Authority response:

In order to include embedded generation / grid-connected wind in the deeper connection analysis:

- there has been no change to the vSPD analysis
- there have been some changes to the flow tracing code – see https://github.com/ElectricityAuthority/tracing
- there have been some changes to the post-processing files (ie, Python code, CSV mapping files and spreadsheet) – see http://www.emi.ea.govt.nz/Datasets/Browse?directory=%2FDeeper_connection&parentDirectory=%2FDatasets%2FSupplementary_information%2F2015%2F20150616_TPM_options_working_paper).

Counties Power

Question (29/07/2015):

1. Request further information regarding the allocation of transmission assets under the Deeper Connection charge that has resulted in Counties Power seeing a significant increase while New Zealand Steel on the same assets obtaining a $4m per annum saving. The map provided in the consultation process is insufficient because we can't see with certainty the necessary detail on the specific assets subject to the Deeper Connection Charge.
2. Could you please email me the Deeper Connection assets that have been allocated to Counties Power under the three HHI scenarios:
   - >3,000
   - 5,000
   - 7,000
   - Included in the breakdown are you also able to tell which other companies are included? I assume that these will be New Zealand Steel and Vector.

3. Presumably Counties would contribute to the costs of investments between Otahuhu and Wiri to the extent that their flows were involved in this new asset?

4. I would appreciate an explanation of why the EA is proposing that "for Counties Power, the deeper connection charge would cover the costs of modelled future investment between Otahuhu and Wiri" (5.15 (b) of the Transmission Pricing Methodology Review: TPM options working paper).

5. I am surprised by this finding because both Otahuhu and Wiri are substations supplying Vector and the investment is to maintain N-1 reliability at Wiri during periods of congestion on the 110kV network.

6. I am also unclear how the charge could be set against a future investment when the Deeper Charge is meant to be applied to the assets as a whole? I assume that the Deeper Connection Charge would be applied for all or part of the associated 110kV network?

7. In addition, unlike the Connection Charge Counties Power has no direct ability to control this investment because the investment decision is made by the Commerce Commission in 'negotiation' with Transpower. We have little input into this process.

Authority response:

1. The Authority provided Counties with a detailed breakdown of the charges faced by Counties Power and NZ Steel.

2. The Authority provided Counties with a breakdown of deeper connection costs that would be allocated to Counties Power in the Authority's modelling, for three different HHI cutoffs. Note that the HHI cutoff has relatively little impact on the total amount allocated to Counties.

3. Yes, that is correct.

4. In the Authority's modelling of the deeper connection charge, the circuits between Otahuhu and Wiri are identified as deeper connection, with the main connected parties being Vector and Counties Power. The longer circuits between Wiri and Bombay are also identified as deeper connection, with the main connected party being Counties Power.

   Depending on the investment solution, which has not yet been determined, an investment might be deeper connection shared between Vector and Counties, or deeper connection paid by Counties only, or some other alternative. For the purposes of the analysis the Authority has assumed that the investment would be deeper connection paid by Counties only. Actual outcomes could differ.

5. The Authority's understanding of the purpose of this investment is that it was intended to support reliability at both Wiri and Bombay (please refer: https://www.transpower.co.nz/sites/default/files/uncontrolled_docs/OTA-WIR%20long%20list%20and%20RFI%20consultation.pdf)

   The Authority would appreciate submissions on this point.

6. The deeper connection charge is applied at the asset level rather than at the investment level. It applies to existing assets only although for the purposes of the Authority's modelling (for the years 2017-2019) it has been assumed that certain new assets will be in

place. The question of whether an asset is deeper connection depends on the flow trace and HHI of the asset.

7. Counties could participate in Transpower's investment approval process. Counties could also opt for a non-transmission solution (for example, a distribution network investment or demand-side alternative) in order to alter the need for Transpower to invest.

Question (29/07/2015):

Thank you for the information but some of the findings seem odd.

8. How is it possible that Counties Power share with Vector the transmission assets between Bombay and Otahuhu but Vector is not included in the supply from Arapuni to Bombay and Hamilton to Bombay? I would have thought that the power flow in the 110kV transmission network up to Bombay from Hamilton also goes on to supply Vector.

9. What is the split that comprises the OTA-WIR investment of $1.5m? This seems like a 100% allocation of the costs to Counties Power, given that the approved expenditure for this investment by the Commerce Commission is $14m ($1.5m per annum seems high on a $14m investment). This seems even more difficult to understand if the build is to improve reliability to Vector's Wiri supply point?

10. Why does the sum total of $12.5M for Counties Power below differ to the $13.17M in table 15a on page 128 of the Working Paper?

11. In table 15a you have Counties Power status quo as $7.14M. Where did this figure come from? Counties Power's current transmission charge is $9.26m (last year it was around $10m and next year it is again likely to be $10m).

12. **(5/08/2015)** Is Counties' load at Glenbrook included in charges other than the deeper connection charge?

Authority response:

13. The Wiri node (belonging to Vector) has a small share of the flows through these circuits, but not enough to reach the 3% deminimus. Other Vector nodes do not have a significant share of the flows through these circuits.

14. There are two separate issues in relation to this question: (a) whether the modelled allocation of OTA-WIR costs is consistent with beneficiaries-pay, and (b) how the modelled allocation of OTA-WIR costs was arrived at.

    In relation to (a), the deeper connection charge is not a beneficiaries-pay charge and thus charges will not necessarily align to benefits. Notwithstanding this, the Authority's understanding is that the (potential) investment is intended to support reliability at both Wiri and Bombay (please refer https://www.transpower.co.nz/sites/default/files/uncontrolled_docs/OTA-WIR%20long%20list%20and%20RFI%20consultation.pdf).

    Further, peak load at Bombay is projected to exceed peak load at Wiri by the time the investment is required (please refer https://www.transpower.co.nz/sites/default/files/uncontrolled_docs/Annual_Planning_Report_2014.pdf).

Based on the above, the Authority's understanding is that Counties would receive at least half of the benefit of the investment. However the Authority welcomes submissions on this point.

On (b), Counties is correct that the modelling assumes that OTA-WIR would be paid for by Counties Power. In practice, the way in which the costs of any investment would be allocated under the options modelled would depend on the nature of the investment. For instance (indicatively):

- an increase in the capacity of the circuits between OTA and WIR would likely involve a split allocation between Vector and Counties Power (as the two parties with significant flow shares through those circuits)
- a new 33kV cable to supply Wiri load might be a connection (rather than deeper connection) asset, paid for by Vector
- a new 220/110 kV interconnection at Bombay might be paid for primarily by Counties
- a new GXP at Bombay might be paid for primarily by Counties.

15. The $12.5M below is consistent with the updated analysis published on 31 July 2015 (please refer to: http://www.ea.govt.nz/development/work-programme/transmission-distribution/transmission-pricing-review/development/tpm-options-working-paper-and-related-documents-revisions-to-indicative-modelling/). The $13.17M figure in the working paper has now been superseded.

16. This figure is calculated as an average RCPD rate of $115/kW, multiplied by an average RCPD quantity of 66 MW, less an LCE rebate of $0.48M. The RCPD quantity covers BOB0331 and BOB1101 only - Counties' share of GLN load is not included (as noted in paragraph A.71(a) of the options working paper).

    In general, participants should consider the Authority's calculations of status quo charges as indicative. Transpower is the party that is best placed to advise on the calculation of existing charges.

17. The Counties Power load at Glenbrook is:

    - attributed to NZ Steel in the calculation of RCPD (this is a simplifying assumption of the modelling)
    - attributed to Counties in the calculation of the deeper connection charge (but GLN attracts little deeper connection charge)
    - attributed to Counties in the calculation of the area-of-benefit charge
    - attributed to Counties in the calculation of the residual charge
    - attributed to NZ Steel in the calculation of the SPD charge (again, a simplifying assumption)
    - attributed to Counties in the calculation of the LRMC charge.

Question (06/08/2015):.

1. Could you please confirm how the residual deemed capacity is calculated for the residual and AoB charges?
2. Is it the summed meter capacity or the summed ICP capacity based on the meter capacity?
3. This makes a difference because Counties Power has 39,000 ICPs but around 46,800 meters.
4. As mentioned, a lot of our rural homes have two meters so does that mean they are deemed to have doubled the capacity of an urban home? (the dual metering is because they have multiple phases to ensure we balance the phase supply in rural areas)

Authority response:

1. Where an ICP has two or more meters, it has only been counted as one ICP for the calculation of deemed capacity (ie, for the AoB and residual charges)
2. Where rural homes have two meters they are not deemed to have double the capacity of an urban home – in the modelling we have carried out, these homes are not assigned a double share of costs.
3. Is should be noted that if the meters are of different category codes, the ICP is assigned to the highest of these category codes.

Marlborough Lines

Question (16/07/2015):

Requested October 2012 TPM information.

Authority response:

The October 2012 consultation information including the consultation paper, submissions and cross submissions is available on the Authority's website at: http://www.ea.govt.nz/development/work-programme/transmission-distribution/transmission-pricing-review/consultations/#c2119.

Meridian Energy

Question (18/06/15):

Clarify the meaning of table 15b of the Options working paper. Ie, it is averaged over ICPs, not for a typical residential household.

Authority response:

The Authority provided a revised calculation of charges for a typical residential household in various regions. The analysis is provided in the document titled "Modelled charges on mass market residential load, adopting a per-MWh pass-through basis", which is available on the Authority's website: http://www.ea.govt.nz/development/work-programme/transmission-distribution/transmission-pricing-review/consultations/#c15374.

Question (18/06/15):

1. Clarify the treatment of LSI Renewables.
2. The GIT approved $197M for 5 upgrades. Only 3 are in progress with the remaining 2 contingent on NZAS reducing demand. For the modelling, what was assumed about the upgrades (3 or 5 components) and cost (~$130m or $197m)?

Authority response:

1. The entire LSI Renewables upgrade is assumed to be completed, both when modelling the grid and when determining the revenue to be recovered.

   In terms of the modelling of the physical grid – using vSPD and flow tracing – all five upgrades (LIV_NSY_ROX, AVI_WTK_LIV, AVI_BEN, CYD_ROX and CML_TWZ) are modelled as being present.

   In terms of the calculation of charges, the full revenue requirement of $27 million per year is modelled as being recovered.

   The modelling assumes that half the revenue requirement of LSI Renewables relates to assets commissioned after the publication of the Guidelines. Therefore, this portion of the revenue requirement - $13 million per year:

   – is counted as 'new investment'

- is recovered using new charges under Application B
- is not subject to caps or transitions under Application A.

The implication is that the last two upgrades comprising LSI Renewables are assumed to be commissioned in late 2016 or 2017.

It is not necessarily the case that LSI Renewables will be completed during 2017. In reality, it might be completed later, or never. However, in this paper (and the October 2012 issues paper, and the beneficiaries-pay working paper), the Authority has taken the approach of assuming that LSI Renewables will be completed in the near term – largely because it provides an opportunity to demonstrate how the various transmission charges would apply to such an investment.

2. The Authority assumes that the remaining two components of the LSI Renewables upgrade will be commissioned after the new Guidelines come into force, but before (or early in) the modelled period – ie late 2016 or early 2017. Thus, their revenue requirement (an assumed $13 million per year) would be recovered using the new charges under Application B. This may or may not happen in reality.

MEUG

Question (17/07/2015):
I wonder if a discussion on how the options or at least each layer of the proposed pricing components in the TPM options would work in practice for the North Taranaki Interconnection Investigation example? This might be a discussion where input from Transpower, Powerco and the Commerce Commission might assist.

Authority response:
Transpower undertook an investigation on non-transmission investments for North Taranaki. The paper prepared by Transpower in June 2015, titled: “North Taranaki interconnection investigation - long-list consultation and request for information on non-transmission solutions” is available at:
https://www.transpower.co.nz/sites/default/files/uncontrolled_docs/North%20Taranaki%20Interconnection%20Security%20Long%20List%20Consultation%20Paper.pdf.

The response provided below is indicative and is based on a high level analysis.

- The need for this investment is a mixture of condition and land availability.
- The main beneficiaries are likely to be North Taranaki loads (relative to a counterfactual in which the substation is decommissioned and Transpower takes no further action to address security in the area).
- Under all TPM applications, options, and all of Transpower’s long-listed investment options, the investments would be a mix of connection (eg 33 kV assets) and deeper connection.
- The connection part of the cost would be allocated to Powerco (as the distributor for the North Taranaki load).

- It is considered likely that the deeper connection part of the cost would largely be allocated to Contact because Contact's TCC power station, which has a very high AMI, is deemed to be 'connected by' NPL substation, with a small proportion allocated to Powerco.
- In the longer term this allocation might change. For example, if Contact closed TCC, then an increased proportion of the cost would be allocated to Powerco.

Mighty River Power

Question (19/06/2015):

Confirm whether the Authority has modelled a Tiwai exit scenario.

Authority response:

The Authority has not carried out such a scenario in the context of the options working paper.

Norske Skog Tasman

Question (26/06/2015):

1. Can you please tell me why in your modelling you scaled down the demand at KAW0112 and KAW0113 by 40%?
2. In Table 2 in the options paper, Application B, there is a comment that the residual will be recovered through the current interconnection charge with one exception being that all load customers must pay at least the variable cost from their connection to, and use of, interconnection assets. Can you please tell me what sorts of things make up variable costs of interconnection assets and how much they amount to?
3. Why did you assume a 40% reduction in demand at Kawerau?
4. Why do you think that opex is a variable cost? Can you show evidence that Transpower's opex is dependent on usage?

Authority response:

1. The modelling assumes a reduction in demand at the Kawerau site. This is consistent with earlier modelling undertaken for the beneficiaries-pay working paper. The Authority appreciates that actual demand outcomes at the site may differ.
2. In the modelling, all Transpower's opex (excluding HVDC and connection opex) is deemed to be 'variable'. This sums to approximately $240M per year, which over 42 TWh per year of load, comes to $5.7/MWh.
3. The original reason for this adjustment, in the beneficiaries-pay paper, was to construct plausible future demand data for Kawerau. The modelling for the beneficiaries-pay paper was based on a 4-month period in mid-2012. Noting that Kawerau consumption reduced from late 2012 to early 2013, and believing that this reduction would be enduring, the Authority adjusted the mid-2012 demand data downwards.

The same adjustment was applied in the modelling for the options paper – reflecting the Authority's expectation that average Kawerau demand in 2017-19 is likely to be lower than it was in 2011-13.

4. The view the Authority took for the options working paper was that the size of Transpower's operating expenses is correlated to the size of Transpower's grid and its various operations, e.g., if the grid consisted of the South Island only, the operating expenses would likely be much lower than they currently are. The Authority recognises that parties might disagree with this view and welcomes submissions on this matter.

Question (18/06/2015):

1. Provide a breakdown of components of charges under different options. Why are NZ Steel's charges reduced, when Counties Power's have doubled? Why are Winstones charges so low? Why Daikin's charge is negative under the LRMC variant?

2. What happens to Top Energy and Vector's charges if Ngawha adds 100 MW of generation? Ditto for the West Coast. In fact I'd like to know if there is some sort of tipping point for MW generation added (or demand reduced) that has a significant effect on these regions.

Authority response:

1. This is because:

   - the capacity-based residual charge for NZ Steel is calculated on AMD, while the residual charge to Counties Power is based on ICP counts
   - under the deeper connection charge, Counties Power is deemed to be 'connected to' more assets than NZ Steel. In particular, Counties Power is modelled as paying for possible future upgrades between Otahuhu and Wiri.

   In answer to your question, 'why are Winstones charges so low?' this is because:

   - the capacity-based residual charge to Winstones, as for other direct connect consumers, is based on AMD, compared with the residual charge to distributors based on ICP counts
   - under the deeper connection charge, Winstones is not deemed to be 'connected to' any assets for which the revenue requirement is material.

   Regarding why Daikin's charge is negative under the LRMC variant, the LRMC charge provides for a negative charge where load or generation would delay an investment. In the case of Daikin, its load would delay investment in the upper South Island and increasing its load would assist in this.

2. The Authority explored the Top Energy and West Coast generation scenarios in its "Demand and generation sensitivities for the TPM options working paper" document. It has been uploaded onto the Authority's website and is available at: http://www.ea.govt.nz/development/work-programme/transmission-distribution/transmission-pricing-review/consultations/#c15374.

   Please refer to this document. Note that flow tracing is used to identify what assets are deeper connection assets, not to assign charges. Assignment of charges is based on shares of the sum of anytime maximum demand and injection at connection nodes involved in flows across the deeper connection assets. However, it is proposed to redo the flow tracing every five years to take into account that a major change in flows could affect who uses the assets. Note though that, even if changes in flows were sufficient to affect whether the asset was subject to the deeper connection charge, the asset may still be subject to the area-of-benefit charge.

Nova Energy

Question (19/06/2015):

Clarify treatment of NZ Refining.

Authority response:

The modelling treats NZ Refining as a mass-market customer since it is not directly connected to the grid. Accordingly, NZ Refining's notional capacity is incorporated in Northpower's residual charge. Northpower's ICP counts for the purpose of calculating residual charges are as follows:

Category	ICP count
Unmetered	215
1	54,385
2	476
3	45
4	2
5	7

Please refer to slide 35 of the TPM workshop presentation for an example on how the ICP count converts to notional capacity. The presentation is available at: http://www.ea.govt.nz/development/work-programme/transmission-distribution/transmission-pricing-review/events/tpm-workshops/.

NZAS

Question 8/07/2015:

At the bottom of Table 3 of the options working paper, either the figure of $81 million is too low or $39 million is too high.

Authority response:

That is correct. The $39 million figure is too high. The error is due to an unintentional hard-pasted value. The correct figure for column 2 should be 15% of $81 million or $12.15 million. The response was provided verbally at the TPM workshop in Wellington on 08/07/15.

The corrected table is provided below:

Region	Post 2004 investment	Impact on revenue requirement	Actual increase in transmission charges	% increase in charges compared to increase in revenue requirement
UNI	1,342	$201	$87	43%
LNI	237	$36	$80	225%
USI	77	$12	$40	343%
LSI	81	$12	$40	327%
Total	1,737	$261	$246	

NZ Steel

Question (05/08/2015):

The links I am after please are:

1. The pack you had with HHI information and in particular the number of EDBs/direct connects.

2. The info you have put together re the Counties Power split for Bombay and Glenbrook.

3. Any information that has been put together on the split within EDBs, in particular Counties Power and Vector, and potential impact on our non-connect sites.

Authority response:

1. Please refer to the TPM workshop slides, available at: http://www.ea.govt.nz/development/work-programme/transmission-distribution/transmission-pricing-review/events/tpm-workshops/. In particular, note slides 16-22 and 34-35.

2. The Authority provided NZ Steel with the charge information that was provided to Counties Power.

3. Pacific Steel provides an example of a “non-connect” site.

   The Authority modelled Pacific Steel as a direct-connect customer, allocating it (under the Base Option, Application A):

   (a) a deeper connection charge averaging $0.72M per year

   (b) an AoB charge averaging $0.11M per year (based on AMD)

   (c) a residual charge averaging $0.41M per year (based on AMD).

   (The above figures are net of LCE, and do not include connection or static reactive charges.)

   Note that these charges are modest relative to the interconnection charges currently incurred by Pacific Steel’s load.

The Authority notes that, depending on how boundary issues are resolved, in practice:

(a) the transmission charges incurred by Pacific Steel's load might actually be paid by Vector

(b) Pacific Steel might not be directly subject to deeper connection charges

(c) Pacific Steel's area-of-benefit and residual charges might be based on ICP category counts (if charges are allocated to Vector), rather than AMD (if charges are allocated as though Pacific Steel were a direct-connect).

Note also that, if the charges in relation to Pacific Steel's consumption of transmission grid services was allocated to Vector, then Pacific Steel's charges would depend on the distribution tariff.

Through consultation on the options working paper undertaken to date, the Authority has identified a potential problem where there may be an inefficient incentive to connect directly to the grid. This is because charges may by lower under the AMD allocator that is applied to direct-connects than under the ICP category counts allocator that is applied to distributors. The Authority is investigating this potential problem. The Authority encourages parties to provide their views on this potential problem in their submissions on the options working paper.

NZIER

Question (17/07/2015):

Is it possible to provide us with ICP count x category x GXP node please? For the deeper connection charge, we want to model the impact on our client if we used MVA as opposed to AMD as the weighting for allocating the charge.

Authority response:

Please refer to the following link:
http://www.emi.ea.govt.nz/Datasets/download?directory=%2FDatasets%2FSupplementary_information%2F2015%2F20150616_TPM_options_working_paper%2FAdditional_info%2F%2FICP_counts_by_NSP_and_meter_category.csv

Question (27/07/2015):

1. Advise whether some or all of the trading periods in the 2009 - 2011 and 2012 - 2014 market solves were used in the flow tracing analysis described in paragraph C.6 p35 of the Deeper Connection Companion paper? If only some of the trading periods were used, how were they selected?

2. How was the AMD/AMI calculated for the nodes i.e. over what time period, how many trading periods were used and was the choice of trading periods driven by node alone or the asset to which it was connected?

3. How does the flow tracing deal with constraints and outages?

Authority response:

1. All trading periods.

2. Throughout the working paper, all references to AMD/AMI in the context of the new charges refer to a single trading period, rather than an average over eg, 12 trading periods.

   Further, in the context of the deeper connection charge:

   – all references to AMD refer to the node's maximum demand, rather than the node's maximum usage of the transmission asset

   – all references to AMI refer to the node's maximum injection, rather than the node's maximum usage of the transmission asset.

   In the modelling described in Appendix C, AMD and AMI were calculated using:

   – the single highest value during 2009-11, for the calculation of 2009-11 charges, and

   – the single highest value during 2012-14, for the calculation of 2012-14 charges.

3. Flow tracing is performed after a market solve. So long as outages and constraints are in the market model, these would also be taken into account. The 2009-2011 and 2012-2014 market solves described in Appendix C of the Deeper Connection Companion paper did include outages and constraints, in the same way that real final pricing does.

Pioneer Generation

Question (30/07/2015):

The paper published today includes numbers for Pioneer in terms of modelled total transmission charges payable. But the Authority have elected not to publish the variablised rates for Pioneer. Please either advise what those modelled variablised rates are for Pioneer, or the injected volumes basis so that we can calculate them correctly ourselves.

Authority response:

In the modelled scenario, the net injected volume for Pioneer is an average of 41.5 GWh per year (all at CYD0331).

It should be noted that much of Pioneer's output is used locally and therefore calculating a variable rate using net injection leads to a misleadingly high figure. For a better point of comparison it may be preferable to use Pioneer's total generation volume.

For the deeper connection charge, Anytime Maximum Injection (AMI) is used to allocate charges across parties deemed to be connected to assets on which charges are being calculated. Pioneer's total AMI is 13.8 MW.

The Lines Company

Question (13/07/2015):

The figures for Pole 3 in Table 6 of the options working paper (page 47) add up to more than 100%.

Authority response:

This is an error in the options working paper. The correct allocation amounts for Pole 3 should be 40% to South Island generators, 17% to South Island loads, and 43% to North Island loads.

Transpower NZ

Question (14/07/2015):

Whether there is any published excel analysis that details the area of benefit and the residual charge for each customer. This is to assist us in being able to test the price effects we get when applying the charging methods (based on our information for asset values and operating costs), so we need something to check against.

Authority response:

Excel spreadsheets were provided to Transpower.

Trustpower

Question (13/07/2015):

1. [Re] Brian Bull's comment made at the Wellington TPM workshop on 8 July 2015 re the modelling of the DC charge for the 2017-19 that “neither grid-connected wind nor distributed generation injecting into the grid had been included in the HHI & DC charge allocation”: Please could you let me know when this adjustment would be made so that we can assess impacts?

2. Re: the use of AMI at the GIP to allocate the costs of transmission lines to generators for the DC charge - presumably you have the data to use instead of the AMI at the end of the actual transmission line in question? That would get around the issue I raised in Auckland of a large generator a long way upstream of a line potentially having to pay the lion's share of that line simply because it has a large capacity. I don't have a concrete example of where this could occur (and there may not be one currently) but I can see use of AMI at the GIP being problematic from a durability perspective.

3. The second is also in relation to the Deeper Connection charge. Given that the allocation is based on flows and share of total AMI, is there a risk that the charge allocated to a party could exceed its private benefit from the line? I’m considering the case of a large new line being built to facilitate the development of a number of new wind farms. The first wind

farm built would be the only user of the line and hence pick up all the charges of the new line, which, if the wind farm is very small relative to the line, may exceed its private benefit. Or would the charges for a new line be recovered via Area of Benefit? The scenario also has similarities to the West Coast load situation, in which some large consumers have left the region and others have not eventuated, leaving not much load to cover the cost of a relatively large investment.

Authority response:

1. The document titled "TPM options working paper – revised modelling results" has been uploaded onto the Authority's website and is available at: http://www.ea.govt.nz/development/work-programme/transmission-distribution/transmission-pricing-review/consultations/#c15374. This document provides the updated modelling results. This modelling is adjusted to include wind and embedded generation injecting into the grid.

2. The allocation of the deeper connection charge is to generation or load at nodes involved in flows across the line (ie not just to nodes directly connected to the asset) that are above the 3% de minimus. As you will have seen from the LSI renewables example the Authority presented at the workshop, the flow tracing was used to identify those assets subject to the charge. It is the AMI at the nodes identified as involved in flows that is used to allocate the charge. Since the method for applying the charge applies charges only in relation to assets for which flows are concentrated, and since flows are normally only concentrated either close to generation or load, it is probably unlikely that a generator a long way upstream from an asset would be subject to a deeper connection charge in relation to that asset. The LSI renewables example from the workshop illustrates this, as it only assigns charges to Clyde, Roxburgh and Waitaki, and not other generators in the region.

3. As the Authority indicated at the workshops, the deeper connection charge is based on use and not benefit, ie, it just identifies assets where in principle the parties that would be connected to it would be prepared to invest in it. It makes no attempt at assessing whether the charge reflects private benefit, ie it is not beneficiaries-pay, nor does it attempt to be. Therefore it is possible that the charge would exceed a party's private benefit. It's possible that's the case in the West Coast example, where major loads have exited or not materialised, and as the Authority indicated, it will consider how best to manage that situation. The Authority has attempted to manage the risk of charges exceeding private benefits by restricting the charge to situations where flows are sufficiently concentrated that, in principle, it is likely that a party would have been prepared, or would be prepared, to invest in the asset.

   (a) Regarding your example, it's difficult to say a priori what charge would apply as it depends on the configuration of the asset. It is possible that the asset would be a connection asset if it is either a spur or a "small regional loop", as defined in the Code. On the assumption that it isn't, the asset may be a deeper connection asset if the flows across it were only from a single party initially (ie it would have an HHI = 10,000). That party would be responsible for the charges initially (5 years under our proposal, although as suggested in footnote 6 of the companion paper there could be a re-run of the flow share calculation between the 5 yearly re-calculations, such as because of a major connection). If that meant that they decided not to proceed until other parties also connected, Transpower may delay building the line. The Authority considers that this helps promote efficient investment as it helps avoid the risk of lines being built but parties not connecting, and the costs having to be recovered from parties that do not benefit from the line. Note that the situation is no different for a connection asset in the situation where one party decides to connect initially but then other parties subsequently connect.

(b) It is possible that the line may be subject to an area-of-benefit charge if the line was built in a part of the grid that meant the flows would not be concentrated. An example of this is some of the Wairakei Ring assets. If that were the case, the parties charged for the line would depend on whether the beneficiaries were just generators, in which case the pattern of recovery would be similar to above, where if there was just one generator connecting initially they would pay the full costs of the asset until other generators connected. However, if the beneficiaries were both load and generation, the generator would just pay the generation share of the benefit from the line.