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TPM Problem Definition: Interconnection and HVDC

FINAL REPORT

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Prepared For:

Independent Electricity Generators Association

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1. EXECUTIVE SUMMARY

This report has been prepared by Andrew Shelley Economic Consulting Ltd in response to the Electricity Authority's Working Paper *Transmission Pricing Methodology: Problem definition relating to interconnection and HVDC assets*, 16 September 2014 ("the Problem Definition Working Paper"). The report was commissioned by the Independent Electricity Generators' Association.

The Authority incorrectly states that generators are cross-subsidised by interconnection. This statement is based on an over-simplified assumption of a transport system, rather than a robust analysis based on the economic definition of a cross-subsidy. With an appropriate definition of connection, there is no cross-subsidy to generation. The Authority's position also fails to take account of the inefficiencies that would arise if generators were to factor transmission charges into their offers.

There are some problems with investment incentives under the existing TPM. Those problems could largely be addressed by adopting an element of causer pays for significant transmission investments that have occurred since the approval of the existing TPM. The introduction over time of a locational component to the interconnection charge was envisaged by a number of parties when the current TPM was approved.

The Authority incorrectly concludes that Transpower's review of the number of peaks used for the RCPD charge indicates that there is a lack of durability in the RCPD mechanism. The number of peaks used in the RCPD charge could vary anywhere between 1 and 17,520, with the former providing a very strong signal to reduce demand at the single highest incidence of regional peak demand, and the latter providing an energy charge with no incentive to control peak demand. At a practical level, it should be reasonably *expected* that the number of peaks included in the RCPD charge will be reviewed over time to reflect the level of spare capacity in regional transmission. This is not an indication of a lack of durability, but an indication that the system is working as it should.

The HVDC charge does threaten the durability of the existing TPM, and failure to address the issue of causer pays for transmission investment may also threaten its durability. However, it is likely that a complex and potentially volatile transmission charging mechanism with little support would be even less durable. The lesson from past iterations to the TPM is that market participants want simplicity, transparency, and predictability.

The existing interconnection charge and ACOT will likely over-signal the benefits of net load reduction in some locations, but under-signal the benefits in other locations. When much of todays distributed generation was constructed the variable component of transmission pricing was more heavily weighted towards the cost of local transmission assets, but still had no relationship to capacity utilisation.

In <u>any</u> market the benefits of centralised co-ordination are given up in exchange for decentralised co-ordination in response to a necessarily imprecise price signal. The benefits of decentralised competition and investment outweigh the benefits forgone from the loss of centralised co-ordination. That the price signal does not deliver the theoretically optimum outcome is not necessarily cause for concern if the outcome is generally right.

The HVDC charge based on Historical Anytime Maximum Injection (HAMI) is a clear disincentive to investment in generation capacity in the South Island, both grid-connected capacity and embedded capacity. These disincentives are likely to exacerbate any capacity constraints and bring forward investment required in the Upper South Island (USI).

The Authority suggests that the very existence of a Prudent Discounts Policy means that there is a problem with the TPM. This suggests a lack of understanding of the realities of calculating prices under any methodology, and an unfounded over-confidence that a super methodology can be developed that somehow takes account of the circumstances of every industrial consumer or generator that might want to connect to the transmission network. That is exceptionally unlikely to ever be achievable, and it will always be necessary to have a PDP to accommodate the cases where charges calculated according to the pricing methodology provide inefficient incentives to bypass the network.

2. INTRODUCTION

2.1. BACKGROUND

In 2012 the Electricity Authority ("the Authority") introduced a radical proposal to reform transmission pricing. Following submissions on that proposal, and on other subsequent working papers, the Authority issued a revised "problem definition working paper" on 16 September 2014.[1]

The problem definition working paper focusses on the following three issues:

- the Authority's view that HVDC and interconnection charges fail to promote efficient investment in transmission, generation, distribution, and by load;
- the Authority's view that the current TPM is not durable, creating uncertainty for investors and therefore inefficient investment; and
- the Authority's view that HVDC and interconnection charges and PDP fail to promote efficient operation of the electricity industry.

The Independent Electricity Generators' Association (IEGA) commissioned Andrew Shelley Economic Consulting Ltd (ASEC) to prepare this report in response to the September 2014 Problem Definition Working Paper. The relevant qualifications and experience of ASEC's Principal, Mr Andrew Shelley, are set out in Appendix B.

2.2. STRUCTURE OF THIS REPORT

This report is structured as follows:

- Section 3 addresses the Authority's first three questions, as well as the issue of whether there is a cross-subsidy to generators;
- Section 4 addresses questions 4 to 9, which all deal with investment incentives;
- Section 5 address questions 10 to 14 on durability of the TPM;
- Section 6 addresses questions 18 and 19 on interconnection and ACOT;
- Section 7 addresses questions 20 to 23, which all relate to the HVDC charge and South Island generators; and
- Section 8 addresses prudent discounts (question 24) and other material issues (question 25).

1 Electricity Authority, *Transmission Pricing Methodology: Problem definition relating to interconnection and HVDC assets*, Working Paper, 16 September 2014.

3. FRAMEWORK ISSUES

Question 1: Do you agree that, in relation to decisions around transmission pricing, the Authority should focus on overall efficiency of the electricity industry for the long-term benefit of electricity consumers? Why or why not?

A focus on long-term benefit of consumers is entirely the correct focus. The fundamental reason for the existence of the entire electricity system is to supply electricity to consumers, and to do so at the lowest cost over the medium to long term. It is therefore entirely appropriate to focus on pricing and contracting mechanisms that will provide lowest cost over the long term.

The Authority should also recognise that the very existence of the wholesale electricity market involves a trade-off between short-run and long-run efficiency. Arguably the market would be more efficient in the short run if dispatch of the entire system occurred by a centralised party that had access to the opportunity cost functions of all generation plant and could internalise the trade-offs between different plant, i.e. if ECNZ had never been disaggregated. However, the decision was rightly made that long-term dynamic efficiency would be much enhanced if independent competing parties could bid into the market on a price basis and bear the gains and losses on investment decisions.

Gains and losses on investments necessarily involve uncertainties around future fuel prices, future demand, and future dispatch decisions. All of these factors increase risk and raise the threshold at which investors will commit to a new plant.

Risks are further increased by the instability in regulatory arrangements. On this point, it is not clear that the Authority understands the impact that some of its decisions will have. Arbitrarily terminating historical arrangements might have the theoretical outcome of a more efficient future if the agents involved are assumed to instantly forget the past. But when a more realistic game-theoretic framework is used, where agents are participating in a repeated game and learn from past regulatory behaviour, the over-turning of historical agreements can have a chilling effect on future investment.

The Authority should also assume that past agreements were negotiated to achieve a pareto improvement, in particular in the following two areas:

- Negotiations to secure the introduction of the wholesale electricity market included an agreement that the previous transmission pricing regime, which had much more stable charges for the core grid that were difficult to avoid, would be replaced by a methodology that had much more responsive prices so that if a connected party reduced demand it would see a reduction in transmission charges. Simplicity and transparency were key demands from demand-side representatives of the day.
- Most distributed generation that exists today was developed in an era when the distribution company was responsible for optimising arrangements for supply, including whether to install additional local generation capacity or additional local transmission capacity. The separation of lines and energy required the previously internalised arrangements to be embodied in contracts, and those contracts necessarily contained a pricing provision that reflected the benefits that the distribution company assessed that the generation provided.

QUESTION 2: DO YOU AGREE WITH THE AUTHORITY'S VIEW ON WHAT CONSTITUTES AN EFFICIENT CHARGE? WHAT ROLE DO YOU CONSIDER DURABILITY PLAYS IN DETERMINING EFFICIENT CHARGES?

The Authority is correct in its broad statement about investment efficiency in paragraph 5.13:

> *For investment efficiency, in a broad sense, the transmission system should be augmented when the increased (marginal) benefits from an investment exceeds the costs of that investment (marginal cost). Accordingly, an efficient price, in an investment sense, might be defined as the price that adequately signals the cost of efficient investments.*

At a theoretical level the Authority is also correct in its statements about Ramsey pricing in paragraph 5.14. However, the Authority fails to recognise that:

a) the practical measurement of price elasticity is exceptionally difficult; and

b) the transmission system does not serve consumers directly; instead the transmission system generally provides service to an aggregation of consumers of different types with different price elasticities.

Ramsey pricing is therefore of very little benefit at a practical level.

The real pricing question is how to allocate charges in such a manner that each connected party pays at least the incremental cost of connection, and that the costs of the rest of the grid are recovered in a way that do not distort consumption and production (noting that reflecting forward-looking economic costs does not result in distortions). The Authority neither poses nor answers this question.

The following statement by the Authority is not a sufficient justification: (p. 34)

> *The Authority considers that charges that seek to reflect costs are likely to best promote efficient outcomes. A smeared charge is unlikely to do this as it does not reflect the actual cost of supply for different consumers across the grid. A smeared charge is likely to create inefficient incentives in relation to investment and operation, and can adversely affect the durability of charges.*

The Authority's statement is full of assumptions which render the conclusion dubious:

- The statement assumes that the correct service provided by the transmission grid has been identified;
- The statement assumes that the cost of that service can be identified with any accuracy;
- The statement assumes that the users of the transmission system would not negotiate a charging regime which, optimally reflecting trade-offs made by those users, would differ from the Authority's assumed optimal regime.

As noted, the Authority asserts a particular model of the service provided by the transmission grid (i.e. transport), and then asserts that there is a single logical conclusion for the pricing structure. While the transport-pricing analogy has historically been a *part* of the transmission pricing structure in New Zealand (although it is not part of the current TPM), there has been general acceptance that the transmission system provides services other than just a transport service. It is helpful to understand part of the journey that transmission pricing has undertaken in New Zealand:

1) Guided by the seminal contributions of Prof E. Grant Read, Transpower introduced transmission pricing that was based on connection, network, and capacity charges. Connection charges were shallow connection only. Network and capacity charges recovered the balance of the transmission network, with locational network charges reflecting the transport analogy, and postage stamp capacity charges reflecting the idea that the transmission network provides more than just a transport service. The locational network charge was based on a slow-moving backward-looking rolling average of network utilisation at the top 25% of peak periods.

2) With the pending introduction of the wholesale electricity market, the demand-side of the market wanted a transmission pricing methodology that was more transparent and more responsive. For generators the connection charge was replaced with deep connection. The long-period moving average of the network charge gave rise to the concern about lack of transparency (cluster analysis was used to compute representative half hours from the top 25% - a perfectly reasonable statistical solution, but barely intelligible to much of the industry) and lack of responsiveness (a reduction in demand in the current year would take years to “roll in” to the moving average). The network charge was therefore replaced with a “transport” charge based on a single load flow. The capacity charge was restyled as the “access” charge. Both charges were repackaged in a way that allowed for forward-contracting for capacity. Importantly, the characterisation of the service provided by the network as being both a network/transport service and a capacity service remained.

3) Squeezed between delayed decisions from the Grid Services Working Group and the pressure to implement a new methodology in conjunction with the new market, changes from the network charge to the transport charge were inadequately investigated. The use of a single load flow for the allocation of the charge resulted in a charge that was volatile with significant changes from year-to-year. At the same time, a restructure at Transpower saw almost the entire pricing team made redundant, and the expertise for using load flows as a cost allocation mechanism was lost. The volatile transport charge was eliminated and the access charge was increased to recover the full costs of the network. This change was essentially based on the practicality of removing a volatile and unpredictable charge rather than a change in the philosophy underpinning the pricing methodology.

Important lessons from this experience are:

a) Historically there has been broad acceptance that the transmission network provides more than just a transport service and does provide a service that is more related to capacity than to transport.

b) Complex and opaque allocation mechanisms are not durable.

c) Volatile and unpredictable charges are not durable.

d) Responsiveness of charges to permanent changes in demand is a feature desired by directly-connected industrial customers and consumer representatives, even if it is not the first-best most efficient outcome.

Finally, durability is extremely important. Lack of durability will result in further changes to the TPM that increase investment uncertainty and result in unnecessary wealth transfers. In that respect it should be noted that changes which have almost universal condemnation will not be durable, regardless of how much the Authority believes that proposed changes offer a superior economically efficient solution. Complex and opaque solutions, such as the previous Transpower network charge and the Authority's proposed half-hourly beneficiaries pays charges, generally lack the support of market participants and are not durable.

Transpower's operational review, on the other hand, enjoys significant support and does not indicate a durability problem.

The Authority also suggests that the very existence of a Prudent Discounts Policy (PDP) means that there is a problem with the TPM. This suggests a lack of understanding of the realities of calculating prices under any methodology, and an unfounded over-confidence that a super methodology can be developed that somehow takes account of the circumstances of every industrial consumer or generator that might want to connect to the transmission network. That is exceptionally unlikely to ever be achievable, and it will always be necessary to have a PDP to accommodate the cases where charges calculated according to the pricing methodology provide inefficient incentives to bypass the network.

Question 3: Do you agree with the Authority's position on the problem definition, described above?

The Authority's position is set out in paragraph 7.6. There is nothing in that paragraph to actually agree or disagree with, it is simply a statement of what the Authority thinks it has done.

No Cross-Subsidy to Generators

The Authority states, or implies with minimal supporting analysis, that:

1) There is a cost in providing interconnection services to generators;
2) Interconnection services to generators are fully cross-subsidised by load;
3) Transmission charges do not broadly reflect the cost of supplying transmission services to each customer, and as a result:
    a) There will be inefficient investment;
    b) There will be inefficient use of the grid; and
    c) The durability of the TPM is undermined.

The Authority uses the term cross-subsidy in a pejorative manner, alleging that generators are being cross-subsidised because they are not paying for interconnection. There is no substantive analysis to support this position. The Authority simply claims that a cross-subsidy occurs and supports this claim with a stylised chart.

The term cross-subsidy is a technical economics term and should be used correctly. Appendix A reproduces a discussion of cross-subsidy from a 2007 TPM submission co-authored by the author of this submission. The key lesson from that discussion is that cross-subsidy <u>only</u> occurs if the price charged is less than the incremental cost of the service. Price discrimination is not cross-subsidy, and uniform prices in the presence of differential costs is also not cross-subsidy so long as all prices are not less than incremental cost.

The Authority's allegation is a testable proposition. What then is the incremental cost of providing *interconnection* to a generator? The transmission network is sized to provide energy to consumers at least cost. Connection of a new generator increases competition for dispatch, but it does not generally require the core transmission network to be expanded. Assuming that connection is correctly defined so that the generator pays the incremental cost of connecting it to the core transmission network, then the incremental cost of providing *interconnection* is *zero*. That being the case, there is no cross-subsidy in the current interconnection rate to generators.

4. INVESTMENT INCENTIVES

QUESTION 4: TO SUPPLEMENT INFORMATION ALREADY PROVIDED BY TRANSPOWER, DO YOU HAVE ANY COMMENTS ON THE STEPS TAKEN BY TRANSPOWER OR BY OTHER PARTIES AFTER APPROVAL OF THE NAAN, NIGU, AND OTHER INVESTMENTS SUCH AS THE LSI RELIABILITY UPGRADE INVESTMENTS, TO REVIEW WHETHER IT MIGHT HAVE BEEN EFFICIENT TO POSTPONE ELEMENTS OF THEM?

No comment.

QUESTION 5: TO WHAT EXTENT DO CURRENT INTERCONNECTION CHARGES PROMOTE EFFICIENT TIMING OF INVESTMENTS?

No comment.

QUESTION 6: TO WHAT EXTENT DO YOU CONSIDER PARTICIPANT SUPPORT FOR TRANSMISSION INVESTMENTS TAKES INTO ACCOUNT THE COST IMPLICATIONS FOR THEM AND FOR OTHER PARTIES? TO WHAT EXTENT DO YOU CONSIDER THE EFFORTS MADE BY PARTICIPANTS TO PROVIDE RELEVANT INFORMATION ON TRANSMISSION INVESTMENTS TAKE INTO ACCOUNT THE COST IMPLICATIONS FOR THEM AND FOR OTHER PARTIES?

Much of the Authority's concerns seem to stem from an institutional unhappiness about the North Auckland and Northland (NAan) and NIGU investment projects. While there may be valid questions over the timing of those projects, this is not a reason for a wholesale redesign of the entire TPM.

It is agreed that the current interconnection charges do not promote efficient timing of investments. However:

a) current charges were only ever intended to recover the cost of existing assets;

b) the timing of major investments is best justified by regulatory hearings; and

c) the opportunity has always existed to link future interconnection charges to grid upgrades.

When a utility has regulatory approval to recover the costs of major investments it is important that the case for those investments is tested by the regulator. In particular, the regulator should test that reasonable estimates of costs and benefits have been established, that the benefits outweigh the costs, and that more preferable options have not been discarded. Regulatory approval says nothing, however, about the allocation of charges for recovering the cost of the major investment.

Considering the investment on its own, the investment will have cost-causers and it will have beneficiaries. An efficient pricing framework within a single-period model would ensure that the agent causing the cost pays for those costs, whether directly or via a Pigovian tax. Requiring the cost-causer to pay for the investment has the desirable and efficient outcome that the cost-causing activity (which may be consumption, or it may be generation in a constrained ring) will only continue if the benefits from that activity exceed the costs (i.e the transmission investment). This very simple model has important implications for both transmission investment and transmission pricing:

a) An important component of identifying the need for a major investment is identifying why the investment is required.

b) If the primary driver of the need for investment is demand growth in a particular region, then that region causes the need for the investment and it would be inefficient for any other market participants to pay for the cost.

This regime would, over time, result in a locational component to interconnection charges. Such a regime was contemplated at the time of the introduction of the current TPM. It is important to note that in this simple example the cost-causers are also the beneficiaries of the investment. It is also plausible that some transmission investments will provide benefits to parties other than those who have caused the need for the investment, and impose costs (such as dispatch constraints) on yet other parties. In such a situation there is no harm in recovering part of the cost from those that benefit but have not caused the need for the investment, and compensation should be provided to those that would suffer additional costs (this would be consistent with an efficient Pigovian tax).

Some of the Authority's most important findings are contained in paragraph 9.30 (p. 54). To paraphrase, transmission investment projects are supported by parties who will benefit from the project and opposed by parties who will bear the cost. This is unsurprising, and supports the position that the problem is not the recovery of the costs of existing assets, but the recovery of the cost of new transmission investments.

Question 7: Do you agree that the Kawerau investment proposal described is an example of an inefficient investment resulting from the TPM?

It is not possible to determine whether the example identified is inefficient from the information presented.

Question 8: Do you consider that the current TPM can incentivise parties to prefer interconnection assets over connection assets or building and owning their own assets (which would require them to pay a higher portion of transmission costs)?

It is agreed that the current TPM can incentivise parties to prefer interconnection over connection, or building and owning their own assets. This suggests a need to:

a) Revisit the definition of connection to ensure that it is sufficiently "deep"; and

b) Focus attention on the link between approval of investment projects and development of a locational interconnection charge over time (as suggested in the answer to Question 6).

Materiality

The Authority notes that, using a real discount rate of 8%, the five-year deferral of a $200m investment that would otherwise occur in 5 years' time has a value of $43.5m. The Authority also notes that with a real discount rate of 8%, the avoidance of a $1b investment that would otherwise be required in ten years is $463m.

Through its choice of discount rate the Authority has potentially overstated the benefit of deferral and understated the benefit of avoidance. A real discount rate of 8% might be appropriate for an analysis of commercial viability, but it is not appropriate for a question of social benefit. The benefits of the deferral of transmission investment accrue to society as a whole, and a social discount rate should be used in such an analysis. Shelley *et al* (2007) estimated a post-tax real social discount rate for New Zealand of 3.5%, within a range of 2% to 6%.[2]

It is worth noting at this point that if the Authority's focus is on avoiding or deferring transmission investment, then this can be achieved in part by ensuring that pricing policies for distributed generation allow for that generation to capture the social benefits provided by transmission investment deferral. Investors will then include the value of those social benefits in their private investment decisions.

Question 9: Do you agree that the TPM can materially impact investment efficiency? Please explain why or why not.

The TPM can materially impact investment efficiency. A TPM that (a) provides no incentives to reduce demand and (b) does not pass the costs of investment through to the cost causers will not produce efficient outcomes. Under these conditions there will be little or no incentive to reduce demand and the costs of transmission investments will be recovered from parties other than those who cause the need for the investment.

A price signal that provides incentives to reduce demand will in itself provide an improvement on the above situation as it will reduce the need for some transmission investment that would otherwise occur. While an untargeted signal will not necessarily produce the most optimal outcome, there are few markets where price signals are precisely targeted.

A more optimal outcome can *potentially* be achieved where investment costs are passed to cost causers via the TPM. However, such a price signal is necessarily post-fact and will only affect consumption decisions (and hence the need for transmission investment) for sophisticated electricity consumers who are capable of estimating the impact of their consumption on future investment needs and costs. Construction of economic optimisation models reveals that only the largest of consumers (i.e. large industrials) are capable of this optimal decision making. Even then, as the Authority notes, scrutiny of transmission investments requires specialist knowledge, which is rare in New Zealand (paragraph 9.6, p. 44).

Smaller consumers require a forward-looking price signal that reflects the costs of future transmission investment. Such price signals should also be known in advance over a reasonably lengthy timeframe so that they can be factored into consumption and purchase decisions that are made over periods of months or years. A price signal that varies from half-hour to half-hour and is difficult to anticipate contains little useful information for smaller consumers and could generally be expected to fall well short of the theoretical gains that might be calculated.

2 Andrew Shelley, Jeremy Hornby, and Michael Thomas, *Discount Rate for the Grid Investment Test*, 29 March 2007.

5. DURABILITY

5.1. Interconnection

The Authority should separate its discussion of interconnection into a discussion of the recovery of the cost of existing assets (as at the date that the current TPM was implemented) and a discussion of the recovery of the cost of new assets. The problems that the Authority identifies with the interconnection charge are primarily related to the recovery of the cost of investments that have occurred since the TPM was implemented (para. 10.11 – 10.16).

5.2. RCPD

The Authority correctly identifies the logic for the RCPD-based charge: (para 10.19)

> *The RCPD mechanism will discourage offtake customers from using electricity at times of peak demand and so, in circumstances where peak demand is close to capacity, will forestall the need to invest in additional grid capacity.*

The Authority also correctly identifies that basing the charge on fewer half hours provides a stronger signal to reduce demand at peak periods.

However, the Authority then makes the incorrect leap to assuming that: (para 10.19)

> *if there has been, or will likely be in the foreseeable future, investment in capacity so that capacity is no longer constrained, the effect of RCPD is to promote inefficient avoidance of the grid during peaks.*

And from there the Authority incorrectly concludes that Transpower's review of the number of peaks used for the RCPD charge indicates that there is a lack of durability in the RCPD mechanism.

It is important to note that the number of peaks used in the RCPD charge could vary anywhere between 1 and 17,520:

a) A value of 1 provides a very strong signal to reduce demand at the single highest incidence of regional peak demand;

b) A value of 17,520 results in an energy charge that effectively provides no incentive to control peak demand.

A lower number of peaks is appropriate when regional transmission capacity is close to capacity, and a higher value is appropriate when there is spare capacity. One would rationally expect that there would either be periodic reviews to adjust the number of peaks over time, or that the TPM would include a schedule of the number of peaks to include in the RCPD charge vs the forecast capacity utilisation at peak. While a schedule might sound appealing, there are significant practical difficulties in specifying a precise methodology for calculating capacity utilisation at peak.

At a practical level, therefore, it should be reasonably *expected* that the number of peaks included in the RCPD charge will be reviewed over time. This is not an indication of a lack of durability, but an indication that the system is working as it should do.

Question 10: Do you agree that cross-subsidisation of TPM costs between consumers may affect the durability of TPM charges?

The Authority has failed to identify cross-subsidy. While it seems likely that when narrowly focussing on just the NIGU and NAan the Auckland and Northern region consumers have received a cross-subsidy, the Authority has not demonstrated that total transmission charges to the Auckland and Northern region are less than incremental cost. The definition of incremental cost is discussed in Appendix A and in the answer to Question 3 (p. 5 above).

Question 11: Do you consider that the current TPM is durable? Why or why not?

The simplicity, transparency, and stability of charges under the current TPM contribute significantly to the durability of the methodology.

However, there are certain features of the methodology that are not durable, in particular the HVDC charge and the lack of a linkage between new transmission investments and charges to the parties causing the need for the investment.

Question 12: Do you agree that the examples provided above are examples of a durability problem?

The examples provided in respect of interconnection only illustrate that an extension to the interconnection methodology is required to recover the costs of new investments from those who cause the need for the investment.

The Authority is incorrect in its assessment of the RCPD-based charge. On-going regular review of the number of peaks included in the RCPD charge is a necessary part of the wider application of the methodology and ensures that the charge remains efficient.

Question 13: If you consider there to be a durability problem, do you know of any further examples of durability problems with the TPM?

It is important to recognise that there is a significant durability problem with the Authority's proposed alternative to the TPM. The demand side wants charges that are stable, transparent, and predictable, and there is no support for the Authority's complex proposal that would produce highly unpredictable and volatile charges. Such a TPM will be far less durable than the current TPM.

Question 14: Do you agree that durability is a particularly difficult problem to measure? Please explain why or why not. Are you aware of an appropriate methodology for measuring durability? If so, please provide details of that methodology.

No comment.

6. INTERCONNECTION AND ACOT

Question 18: Do you agree that the interconnection charge and ACOT payments may over-signal the value of embedded generation?

It is agreed that the interconnection charge and ACOT payments may both over-signal and under-signal the value of net load reduction. Embedded generation is one form of net load reduction.

Logically any form of net load reduction, including embedded generation, will have the greatest impact on local transmission, a smaller impact on core transmission, and negligible impact on remote transmission. This is an important characterisation as it reflects the decision making framework under which most existing distributed generation would have been constructed, it reflects historical (but not current) transmission pricing, and recognition of these impacts is necessary for efficient investment decision-making.

When most existing distributed generation was constructed it was done so by an Electric Power Board or Distribution Company seeking to provide an efficient supply of electricity for its connected customers. The decision to expand capacity could be characterised as a decision between expanding local (embedded) generation or potentially expanding local transmission and purchasing electricity generated remotely. To restate the point, the decision was between local generation or local transmission. Once that decision had been made, the Electric Power Board (EPB) would either have a long term investment or have a long term contract to pay for additional transmission.

In making a long-term cost-minimisation decision the EPB would internalise the benefit of any avoided transmission charges from forgone transmission investment. With the separation of lines and energy, a step deemed to be in the best interest of obtaining a competitive and efficient market, it was necessary to implement a price signal so that the investment decision that was previously undertaken by the EPB could now be undertaken in a decentralised manner by investors. The resulting decisions will at times appear to be less efficient than would have been made by a knowledgeable and efficient central planner, but this is a trade-off common to all markets: the efficiencies from the market as a whole outweigh the inefficiencies that arise through loss of co-ordination.

Under the pre-market TPM, distributors were charged on the basis of a long-period average measure of peak. The capacity charge reflected the benefits provided by the system as a whole, and the network charge was weighted heavily towards local assets. When distributed generation resulted in a reduction in transmission charges, those charges were partly system-wide and partly for local assets. Basing ACOT on these charges provided a reasonable estimate of the benefit that the distributed generation may have had on future transmission investment.

A more accurate signal may have been provided if there was a means of linking the variable component of transmission pricing to expected capacity utilisation over the medium term. The reality is, however, that this is exceedingly difficult to achieve with an administered price mechanism and is not even achieved in real-world markets.[3]

Returning to the Authority's question, it is clear that the interconnection charge will only approximate the charge achieved with a more complex pricing structure. In particular, the interconnection charge does not reflect local transmission assets and it does not reflect capacity utilisation. Of necessity this means that interconnection and ACOT will over-signal the value of net load reduction in some locations and under-signal the value of net load reduction in other locations.

Question 19: Do you agree with the Authority's assessment that, although the interconnection charge may over-signal the value of generation to direct-connect consumers, any resulting efficiency loss is likely to be relatively small?

It is important to reiterate that the interconnection may both over-signal <u>and under-signal</u> the value of <u>net load reduction</u> to direct-connect consumers. There may be some inefficiencies from over-investment in embedded generation, but there are also likely to be some inefficiencies from under-investment in load reduction (including by way of embedded generation) by other direct-connect consumers.

The Authority's logic in paragraph 11.104(d) confuses (a) embedding generation within a distribution network or a direct-connect consumer and (b) embedding generation in the UNI or LNI. There should be little practical difference in embedding within a distribution network or embedding behind a direct-connect consumer where the two are located within the same region. Individual distributors or direct-connects may be easier or more difficult to deal with, but the primary issue is the level of demand that will be offset by the generation. The question of UNI or LNI is an entirely separate question. The Authority's reasoning suggests that, all else being equal, there should be more embedded generation in the UNI than the LNI.

3 Note that the medium-term would be at least 5-10 years, and possibly as far out as 15 years. The prices of forward contracts in financial markets become increasingly heavily influenced by the liquidity premium and default premiums. This means that the price of forward contracts is not an unbiased estimate of future prices and decisions made on the basis of those prices will not be optimal compared to the decisions that would be made if unbiased estimates of future prices were available.

7. HVDC CHARGE TO SOUTH ISLAND GENERATORS

QUESTION 20: DO YOU AGREE THAT THE HAMI ALLOCATION MAY INCENTIVISE SI GENERATORS TO WITHHOLD EXISTING CAPACITY? DO YOU AGREE WITH THE AUTHORITY'S ESTIMATE OF INEFFICIENCY?

It is agreed that the HAMI allocation may incentivise South Island generators to withhold existing capacity. The HAMI-based charge means that the marginal cost of an additional half hour of generation is extremely high. The quote from Contact Energy on p. 86 indicates the scale of the problem: increasing output by 1 MW above the existing HAMI results in additional charges of $44,600. Graphically, this would be represented by the supply curve for the relevant station(s) stepping up from approximately $80/MWh at the HAMI (the Authority's assumption in para. 11.122) to $44,680 at HAMI + 1, in effect a near-vertical line that would be extremely unlikely to ever result in dispatch above HAMI. Practically, the same effect is achieved by placing a hard limit on generation to avoid exceeding the HAMI.

QUESTION 21: DO YOU AGREE THAT THE HAMI ALLOCATION MAY DISCOURAGE UPGRADES TO EXISTING SI GENERATION CAPACITY? DO YOU THINK THIS IS A MATERIAL PROBLEM?

The HAMI allocation does discourage upgrades to existing South Island generation capacity, whether or not that capacity is grid connected.

As noted in the answer to the previous question, a grid connected generator directly faces a very high marginal cost of increasing maximum injection. Additional capacity could be used to the extent that it can be dispatched at times other than peak, but this would generally be expected to depress wholesale prices because more capacity would be competing for dispatch. It is unlikely, therefore, that the cost of upgrading existing capacity will be incurred when the result is lower prices for existing injection.

Distributed generation may face the same financial penalties as grid-connected generation. Expansion of existing generating capacity may create the risk of a connection changing from net export from the transmission grid (i.e. a net load) to net injection into the transmission grid (i.e. net generation) at particular times, or increasing an existing level of net injection. If that occurs then the distributors' existing ACOT policies would pass those transmission charges to the distributed generator. Given that distributed generation does not generally belong to a portfolio that would benefit from a reduction in HVDC charges on other generation in the portfolio, distributed generation may face a greater cost than the $44,600 for increasing generation by 1MW above existing injection that was suggested by Contact Energy.

QUESTION 22: DO YOU AGREE THAT THE HVDC CHARGE MAY DISCOURAGE INVESTMENT IN SI GRID-CONNECTED GENERATION? DO YOU AGREE WITH THE AUTHORITY'S INEFFICIENCY ESTIMATE?

As described in the answer to the previous question, the HVDC charge may discourage investment in <u>all</u> generation in the South Island, not just grid-connected generation.

Except for the use of a discount rate that is too high, TPAG's central estimate of inefficiency of $24m remains reasonable, particularly given that the estimates focus on grid-connected generation rather than all generation. Correcting the discount rate to a lower social discount rate will produce a higher estimate of inefficiency from the HVDC charge.

Question 23: Do you agree that the HVDC charge may bring forward the need for upper SI transmission investment? Do you agree with the Authority's estimate of inefficiency?

It is agreed that the HVDC charge may bring forward the need for upper South Island transmission investment. As already established, the HVDC charge discourages the expansion of generation capacity in the South Island. It also provides a reason for any new South Island generation to be small scale generation embedded within a distribution network and never export more than the load on the network. As a result, generation investment – whether new capacity or expansion of existing capacity – is suppressed, including in the constrained upper South Island.

Except for the use of a discount rate that is too high, the Authority's estimates are reasonable. Correcting the discount rate to a lower social discount rate will produce a higher estimate of inefficiency from the HVDC charge.

8. PRUDENT DISCOUNTS AND OTHER MATERIAL ISSUES

QUESTION 24: DO YOU AGREE WITH THE AUTHORITY'S VIEW ON THE PRUDENT DISCOUNT POLICY? DO YOU AGREE WITH TRANSPOWER'S VIEW THAT A PDP FOR NOTIONAL GENERATION IS NOT PRACTICALLY ACHIEVABLE BECAUSE OF THE DIFFICULTIES IN VALUING NOTIONAL DISCONNECTION?

The Authority's view as stated in paragraph 12.17 is "that the PDP for load is an alternative to having a TPM that sets prices according to consumers' elasticity of demand."

The Authority is only partially correct. It is impossible to set prices in any mechanistic or formulaic fashion that correctly takes account of all customers circumstances. Even if the price elasticity of demand could be accurately estimated and taken into account, no formulaic allocation of costs (even on a half-hour by half-hour basis) could possibly take account of other factors. Consider, for example, two industrial customers which have exactly the same price elasticity of demand, but one of those customers has ready access to cheap biomass and the other does not. While delivered electricity prices are below the cost of biomass generation the two customers will behave exactly the same. But once the delivered electricity price is equal to the cost of biomass generation or higher, then the two customers will behave differently. Note also that high volatility in delivered electricity charges, with unpredictable price spikes, will also provide an incentive to move to on-site generation: even if the on-site generation is slightly more expensive than the usual price of delivered electricity, the one-site generation provides an effective insurance policy against price spikes. Furthermore, if the PDP is removed, then the action to install generation will be taken regardless of whether it is efficient to do so – the only consideration will be the financial benefits to the customer that has the ability to bypass.

QUESTION 25: DO YOU CONSIDER THAT THERE ARE ANY OTHER MATERIAL PROBLEMS WITH THE TPM (IN PARTICULAR, THE HVDC CHARGE, INTERCONNECTION CHARGE, AND THE PRUDENT DISCOUNT POLICY) THAT THE AUTHORITY HAS NOT CONSIDERED IN THIS PAPER.

Continuing the TPM review will involve considerable resources. Those resources will continue to be expended on the basis that millions of dollars of inefficiencies have been identified with the existing TPM and that there must be a better way.

However, the most material problem of all is that the Authority's proposed alternative is viewed as costly, unpredictable, and has little support.

INEFFICIENCY FROM VOLATILE TRANSMISSION CHARGES

The Authority should reasonably assume that direct-connects will be willing to pay a premium to avoid volatile and unpredictable transmission charges. This principle underpins all forms of insurance and all forms of hedging. If a volatile and unpredictable transmission charging regime were implemented then a rational direct-connect consumer will seek to avoid that unpredictability, and will be willing to pay a premium in order to do so. This may take the form of paying additional costs to purchase a hedge product, but it may also involve reducing demand as much as possible and identifying ways to use energy sources other than electricity. It is highly likely that this would be inefficient, although no estimate is provided here.

The Transport charge component of the TPM introduced in conjunction with the NZEM was not durable because it was unpredictable from one year to the next. Before continuing with a costly review, the Authority should be sure that the proposed alternative to the TPM will not suffer the same lack of durability.

VARIABLISATION OF CHARGES LEVIED ON GENERATORS

It is also important to consider the effect of levying interconnection charges on generators. Assuming that generators already optimise their bids into the wholesale electricity market, those bids will not change if transmission charges are fixed in the medium term. However, if transmission charges are variable – whether based on peak or some complex half-hourly assessment of power flow or benefits – then generators will change their bids to optimise their position. Transmission interconnection charges will be a real cost faced by generators, and as such any variable element of transmission interconnection charges *should* be included in generator bids.

Right from the very beginning of the New Zealand wholesale electricity market it has been recognised that charges to recover fixed costs should be recovered in as fixed manner as possible. It has also long been recognised that it is most efficient to levy the charges as close to the end-consumer as possible, and that levying charges for fixed costs on generators risks those charges being converted to a part of the variable energy price signal. When fixed costs are converted to a variable energy price signal then short-run despatch, reserves optimisation, consumption, and load shedding will all be influenced by the ability to capture or avoid the higher price signal that includes the variablised fixed cost recovery.

The Authority should demonstrate how the efficiency losses from variablising the fixed transmission charges into the wholesale energy price signal will be offset by some other form of economic gain.

APPENDIX A: CROSS SUBSIDY

This appendix reproduces the discussion of cross-subsidy that was provided in:

Shelley, A. and E. Westergaard, *Consultation on the Proposed Transmission Pricing Methodology*, CRA International, 2 February 2007, pp. 47-49. Available online at https://www.ea.govt.nz/dmsdocument/3457.

The economic definition of cross-subsidy is generally attributed to Faulhaber (1975).[4] Faulhaber defines a subsidy-free pricing structure thus:[5]

> *If the provision of any commodity (or group of commodities) by a multi-commodity enterprise subject to a profit constraint leads to prices for the other commodities no higher than they would pay by themselves, then the price structure is **subsidy free** [emphasis in original]*

To paraphrase, subsidy-free prices are less than or equal to stand-alone cost, for each service or group of services.

Faulhaber and Levinson (1981) extended Faulhaber's (1975) analysis to consider subsidies between and among consumer groups, as opposed to just subsidies between and among commodities or services. For this analysis Faulhaber and Levinson utilise the concept of "anonymous equity", which requires that "if any arbitrary set of customers were eliminated then the remaining set of customers would be no better off by being able to cover lower total cost".[6]

If this definition of anonymous equity is to hold then it must be true that each arbitrary set of customers pays at least the incremental cost associated with providing service to those customers. If they paid less than this amount, then the remaining customers would be made better off by eliminating the "arbitrary set".

Thus we have two tests for assessing whether a cross-subsidy is present, assuming normal profits. No cross-subsidies are present if:

- Prices for each service or group of services are greater than or equal to incremental cost; and
- Prices for each service or group of services are less than or equal to stand-alone cost.

Assuming normal profits, then it is only necessary to test for compliance with either the stand-alone cost test or the incremental cost test. If one test is violated then so will the other. To see that this is true, divide the firm's services into two groups, X and Y. Assume that the firm only produces service X (which may be interconnection). The cost of providing X is the stand-alone cost of X, SAC_X. To be earning normal profits, it must be true that the firm's revenues are equal to SAC_X.

4 Other authors also contributed to the general approach adopted by Faulhaber. For a summary of relevant authors, see Ralph, E. (1992) "Cross-Subsidy: A Novice's Guide to the Arcane", mimeo, Duke University, 27 July, footnote 5. Dr Ralph's paper may be obtained from his website http://ekonomicsllc.com. [Update October 2014, the paper may be obtained direct from the link http://ekonomicsllc.com/Ralph1992Cross-subsidy.pdf]

5 Faulhaber, G.R. (1975) "Cross-Subsidization: Pricing in Public Enterprise", *American Economic Review*, 65(5):966-977, p. 966.

6 Faulhaber, G.R. and S.B. Levinson (1981) "Subsidy-Free Prices and Anonymous Equity", *American Economic Review*, 71(5):1083-1091, p. 1088.

Now assume that the firm decides to also provide service Y (which may be connection). The additional cost of service Y is the incremental cost of Y, ICY. To continue to earn a normal profit, it must be true that the firm's revenues are equal to the stand-alone cost of providing only X plus the incremental cost of providing service Y:

$$SAC_{X+Y} = SAC_X + IC_Y$$

Now define R_X as the revenues earned from service X and R_Y as the revenues earned from service Y. The normal profit condition requires that:

$$R_X + R_Y = SAC_{X+Y} = SAC_X + IC_Y$$

Let the revenue from service Y equal the incremental cost of providing Y plus an amount Δ:

$$R_X + (IC_Y + \Delta) = SAC_X + IC_Y$$

Solving for revenue from service X we have:

$$R_X = SAC_X - \Delta$$

If $\Delta \geq 0$ then revenue from service Y is at least equal to incremental cost, and revenue from service X is less than stand-alone cost. If $\Delta < 0$ then revenue from service Y is less than incremental cost and revenue from service X is greater than stand-alone cost. Thus, in the presence of normal profits, as long as the incremental cost test is satisfied for each service and group of services, then the stand-alone cost test is also satisfied.[7]

If we assume that the Commerce Commission ensures that Transpower always earns an appropriate level of profit, then the only test that needs to be applied to ensure that prices are subsidy free is that prices are at least equal to incremental cost.

7 For a further exposition of cost standards and the combinatorial version of the incremental and stand-alone cost tests (i.e. the version that applies to groups of services) see Sappington, D.E.M. and J.G. Sidak (2003) "Competition Law for State-Owned Enterprises", *Antitrust Law Journal*, 71(2):479-523. These tests are also described in many other papers.

APPENDIX B: CURRICULUM VITAE

ANDREW SHELLEY

Consultant

MA (first class honours) Economics
Massey University

B.B.S. Information Systems
Massey University

Andrew Shelley is a regulatory economist with over 15 years' experience analysing complex economic and regulatory issues for energy-intensive, network and infrastructure industries. His recent work focuses on analysing the firm's response to regulation, including the impact of New Zealand's proposed emissions trading scheme on energy-intensive and emissions-intensive firms, and the impact of formal price control on utility revenues, cash flows, and investment.

Andrew has particular expertise in the electricity and telecommunications industries. He has advised on electricity transmission and distribution regulatory issues such as asset valuation, cost of capital, revenue requirements, pricing structure, and cash flow modelling. In addition to providing regulatory advice he has appeared as an expert witness in commercial arbitrations relating to New Zealand's electricity market, and developed expert evidence for a number of court cases. He has also advised firms in industries such as gas transmission and distribution, forestry, postal services, and rail networks.

Andrew's previous employment includes the positions of Principal at CRA International, Senior Consultant at PHB Hagler Bailly Asia Pacific Ltd, Costing & Economics Manager at Telecom New Zealand Ltd, and Strategic Analyst and Pricing Analyst at Transpower New Zealand Ltd. Mr Shelley is located in Wellington, New Zealand.

Andrew is a member of the New Zealand Institute of Directors and a member of the New Zealand Safety Council.

PROFESSIONAL HISTORY

2013 – **current**	President, Fly DC3 New Zealand Inc Director, Flight 2000 Ltd
2010 – **current**	Director, Aviation Safety Management Systems Ltd Senior Consultant, The Lantau Group
2008 – **current**	Director, Andrew Shelley Economic Consulting Ltd Senior Consultant, Oakley Greenwood Pty Ltd
2008 – 2010	Consultant, CRA International
2001 – 2008	Senior Associate, Associate Principal, and Principal, CRA International
1999 – 2000	Senior Consultant, PHB Hagler Bailly – Asia Pacific Ltd
1998 – 1999	Costing and Economics Manager, Network Group, Telecom New Zealand
1995 – 1998	Pricing Analyst and Strategic Analyst, Transmission Services, Transpower New Zealand Ltd
1995	Analyst Programmer, Foodstuffs (Wellington)
1993 – 1994	Study for Master of Arts
1990 – 1993	Analyst Programmer, Farmers' Mutual Insurance Group

Consulting Experience

Utility Price and Revenue Regulation

- Advising Vector Ltd on various aspects of pricing for electricity distribution and gas transmission and distribution.
- For Contact Energy, preparation of a report analysing whether the balance of Transpower's "economic value" (overs and unders) account was consistent with what would be expected in a workably competitive market.
- Advising Unison Networks Ltd in its responses to the New Zealand Commerce Commission's implementation of the price control provisions contained in the Commerce Amendment Act. This has included preparation of advice in respect of, and preparation of submissions and expert reports in response to the Commission's consultations on "Regulatory Provisions of the Commerce Act", "Input Methodologies", regulatory taxation, asset valuation, and cost allocation.
- For Energex distribution network (Brisbane), development of a cost-based pricing model for regulated distribution services. This project also included the provision of advice on pricing policy, particularly with regard to developing prices that reflected the impact of demand growth on capital expenditure. Delivery of the pricing model also included provision of a user guide, technical documentation, and user training.
- On behalf of Unison Networks Ltd, preparation of a submission in response to the New Zealand Commerce Commission's initial proposals for resetting the price path and quality thresholds in 2009.
- Advising Vector Ltd on economic issues arising from the New Zealand Commerce Commission's draft decisions on price control for gas distribution services.
- For the Electricity Networks Association, preparation of a submission to the New Zealand Electricity Commission on Transpower's proposed transmission pricing methodology, and on proposed changes to the Benchmark Transmission Agreements.
- Advising a New Zealand generator on the principles of utility revenue requirements.
- Advising a New Zealand utility on issues of cost allocation related to setting regulated prices.
- For Vector Ltd, a detailed financial analysis of the implications of placing Vector under formal price control.
- For a New Zealand electricity lines business, development of a financial model to assess the relative performance of all electricity lines businesses under the Commerce Commission's CPI-X price path vs formal "building block" revenue regulation.
- Preparation of a series of expert reports for Unison Networks Ltd in response to the New Zealand Commerce Commission's draft intention to declare control of Unison, and for use by Unison in its subsequent Administrative Settlement negotiations. This work included analysis of the cost of capital, cash flows, financial ratios, and capital expenditure under various price control scenarios, as well valuation issues.
- An assessment of the costs and benefits of Transpower being placed under formal price control.

- Advising NGC on the calculation of excess profits, including detailed consideration of the theoretical basis for calculating excess profits, arguments on the treatment of gains on sale and the appropriate treatment tax effects.
- Advising a major Asian utility on recent developments in the regulation of infrastructure industries in selected countries.
- Developing a comprehensive financial model for an Australian Distribution Network Service Provider to analyse how the firm's financial performance would respond to different forms of regulation and price and revenue controls.
- Development of a comprehensive simulation model to assess the impact of a wide range of potential regulatory changes on a major Asian utility.

Cost of Capital

- Advising Unison Networks Ltd in its responses to the Commerce Commission's implementation of the price control provisions contained in the Commerce Amendment Act 2008, including advice on the appropriate weighted average cost of capital (WACC) for electricity distribution.
- For the Economic Regulation Authority in Western Australia, providing advice on the WACC to apply to a regulated railway.
- Advising various energy sector clients on the cost of capital appropriate for investment in electricity generation in Australia, Hong Kong, Malaysia, and the Philippines.
- Advising Transpower on the appropriate discount rate for use in the Grid Investment Test.
- Advising an Australasian transmission network owner on the appropriate asset beta for its WACC calculation.
- For an Australian telecommunications operator, advising on the cost of capital and method of asset value annuitisation for a submission to the Australian Competition and Consumer Commission.
- Assessment of the WACC for various activities of a major Australasian telecommunications firm, with particular emphasis on the impact of the regulatory regime. This included a detailed review and critique of approaches to setting regulated rates of return for telecommunications firms in Australia, North America and the United Kingdom.

New Zealand Electricity Market and Transmission

- Advising two providers of DG in negotiations concerning prices with a distributor.
- Advising a New Zealand electricity retailer and generator on economic issues related to the Ministerial Inquiry into the Wholesale Electricity Market.
- For a New Zealand electricity lines business, providing expert testimony in a commercial contract arbitration on the relationship between transmission charges and embedded generation.
- Advising Transpower on the appropriate discount rate for use in the Grid Investment Test.
- For the Electricity Networks Association, preparation of a submission to the New Zealand Electricity Commission on Transpower's proposed transmission pricing methodology, and on proposed changes to the Benchmark Transmission Agreements.

- Advice on forecast prices in the New Zealand wholesale electricity market.
- For Meridian Energy, analysing the magnitude of the potential benefits that might arise from the Electricity Commission encouraging investment in transmission alternatives.
- For a New Zealand electricity generator, preparation of a report on the economic consequences of short notice extension of transmission outages.
- For a New Zealand electricity market participant, providing a review of the principles of electricity transmission pricing.
- Critique of Transpower's valuation and pricing for a small New Zealand electricity lines business. This work included a detailed revaluation of parts of the Transpower network based on an alternative engineering assessment of the required network assets.
- Development of "opportunity cost" valuations of the power generated by a hydro scheme. The valuations were based on the forecast cost of alternative generation schemes, and included the effects of potential carbon taxes or tradable emissions permits.

Other Projects

- For Pacific Steel, development of a financial model to assess the relative impact on competitiveness of the New Zealand Emissions Trading Scheme (NZETS) and proposals under Australia's Clean Energy Futures Plan (CEFP).
- For the Ministry for the Environment (MfE), quantifying the potential impact of the proposed New Zealand Emissions Trading Scheme on three energy-intensive businesses. This work included the development of spreadsheet-based financial models for each of the three businesses, including separate models for "manufacturing", "full import" and "importation of intermediate product".
- Advising the Inland Revenue Department on economic issues related to tax avoidance litigation.
- Provision of advice on the costs and benefits of converting plantation forestry to dairy farms, including valuation of the impacts on greenhouse gas emissions.
- Providing economic advice and analytical support to the New Zealand Commerce Commission in a Commerce Act s36 case.
- For the New Zealand Ministry of Health, collation and analysis of data on the operating costs of air ambulance services.
- Advising an Australian electricity generator on the market for renewable energy certificates (RECs).
- For the New Zealand Electricity Efficiency and Conservation Authority (EECA), quantifying the benefits of the direct use of natural gas.
- Assessment and valuation of strategic options (including sale and acquisition options) for a New Zealand electricity lines business.
- For an Australian electricity generator, developing a framework for the valuation of easements used by electricity networks, including a review of the regulatory approach to easement valuation.

- For Telecom NZ Ltd, contributing to a number of public submissions to the New Zealand Telecommunications Commissioner, with particular emphasis on incentive effects of regulatory proposals and dynamic efficiency, cost recovery, reasonable rate of return on capital, funding of telecommunications service obligations (TSOs), and accounting for intangible benefits when calculating the cost of TSOs.
- Providing advice on how to adjust for differences in wage rates, cost of capital, and factor intensities in an international benchmarking study.
- Valuation and assessment of a proposed long-term contract for rail transportation, including a review of the approaches to rail price regulation in Australia.
- Review of the process and rules for the New Zealand Government's 2GHz radio spectrum auction.

SELECTED PUBLIC CONSULTING REPORTS

Selection of the WACC Percentile in the Context of Risks faced by Electricity Distribution, Final Report, Prepared for Unison Networks Ltd, 29 April 2014.

Use of The Loss & Constraints Excess to Offset Transmission Charges, letter to the Electricity Authority, 3 March 2014.

Value of Pulse Energy to Residential Consumers of Buller Electricity Ltd, Final Report, Prepared for Buller Electricity Ltd, 14 February 2014.

Avoided Cost of Transmission (*ACOT*) *payments for Distributed Generation*, Final Report, Prepared for the Independent Electricity Generators Association, 31 January 2014.

with Heather Andrews, *Submission in Response to "Safety Regulation of Aviation: Considering a Risk Management Approach"*, Aviation Safety Management Systems Ltd, 8 July 2013.

with Heather Andrews, *Review of Joining Procedures at Uncontrolled Aerodromes*, prepared for the Civil Aviation Authority, Aviation Safety Management Systems Ltd, 2 July 2013.

with Heather Andrews, *Submission in Response to Draft Advisory Circular AC00-4 Safety Management Systems*, Aviation Safety Management Systems Ltd, 28 June 2012.

Cost of Capital and Leverage, Final Report, Prepared for Unison Networks Ltd, 2 September 2010.

Rents, Regulatory Commitment and the Role of Long Term Contracts, Final Report, Prepared for Unison Networks Ltd, 19 August 2010.

Regulated Returns for Australian and New Zealand Electricity Distribution, Final Report, prepared for Unison Networks Ltd, 15 August 2010.

Balance of the EV Account for Transpower's HVDC Assets, Prepared for Contact Energy, 8 August 2010.

Comments on Cost Allocation and the Regulatory Asset Base, Prepared for Unison Networks Ltd, 15 March 2010.

Implementing the Deferred Tax Approach, letter to Unison Networks Ltd, 26 January 2010..

Input Methodologies: Economic Issues, Prepared for Unison Networks Ltd, 13 August 2009.

with Anna Kleymenova and Tim Giles, *WACC for TPI's Iron Ore Railway*, Prepared for Economic Regulation Authority, 11 June 2009.

with Mike Thomas, *Regulatory Provisions of the Commerce Act*, Prepared for Unison Networks Ltd, 16 February 2009.

with Jeremy Hornby and James Mellsop, *Response to Commerce Commission's Discussion Paper: Threshold Reset 2009*, Prepared for Unison Networks Ltd, February 2008.

with Lewis Evans, Jeremy Hornby, and James Mellsop, *Comments on Commission's Draft Decisions Paper on Supply of Gas Distribution Services*, Prepared for Vector Ltd, 29 November 2007.

with Jeremy Hornby and Michael Thomas, *Discount Rate for the Grid Investment Test*, Final Report, prepared for Transpower NZ Ltd, 29 March 2007.

with Erik Westergaard, *Consultation on the Proposed Transmission Pricing Methodology*, Final Report, prepared for Electricity Networks Association, 2 February 2007.

with Jeremy Hornby and James Mellsop, *The Costs and Benefits of Regulating Transpower*, Final Report, prepared for Transpower NZ Ltd, 27 February 2006.

with Lewis Evans, Jeremy Hornby, and James Mellsop, *Cross Submission on the Intention to Declare Control of Unison*, Final, Prepared For Unison Networks Limited, 21 December 2005.

with Lewis Evans, Jeremy Hornby, and James Mellsop, *Review of the Commerce Commission's Intention to Declare Control of Unison*, Final Report, Prepared For Unison Networks Limited, 28 October 2005.

with Michael Thomas, *Net Benefits of Transmission Alternatives*, Final, Prepared for Meridian Energy Limited, 22 July 2005.