Submission to the Electricity Authority

On

Transmission Pricing Methodology - 2nd Issues Paper; 17th May 2016

"The TPM regulatory framework should encourage and enable healthy competition between competing suppliers and ensure that consumers receive efficient market pricing for the services they are provided. This proposal removes transmission price signals and substantially lessens competition from substitutes"

Submission made by Pioneer Energy Limited
In collaboration with advisors Morrison Low and Crowe Howarth

26th July 2016

Submission Overview

The following overview is Pioneer Energy's summary of the Authority's TPM problem definition, proposed Solutions and Consequences, together with Pioneers position on these.

TPM	EA View	Our Position
Problem definition	Current peak price signals do not encourage efficient outcomes, inferring; • Generators and Networks are not responding correctly; • Investments are being made in the wrong place	• Fifty years of engineering efficiency, based on the flatter the demand curve the better, is what has and should continue to drive lowest cost new investment • There is no evidence presented investment has been in the wrong place or that any investment previously made has not been the lowest cost • Security of supply has not been factored
Solution	• Service based and cost reflective pricing should apply so as beneficiaries pay (based on load flow) • An AOB based fixed charges will make it locationally more expensive/disadantaged for parties that require transmission upgrades to support new load or generation capacity.	• This signals that the only way to reduce unit costs of energy is to use more power. This is the opposite of the signal for consumers for energy efficiency i.e. use less, save more. • This approach must ultimately bring forward both transmission and generation investment, due to incentives to use more energy. • How is this in the best long term interests of consumers? • Better to tweak what we have, than taking a punt on this economic theory.
Consequence	• Prudent discounting for big business to alleviate financial stressed situations • $230m PV benefits as a consequence of delayed generation and dropping the South Island generation builds out of the market merit order.	• Incentivises even more rapid take up of new technologies to bypass the grid • Negative CBA value to consumers due to a -$1b error in the maths. • Return to the energy price rises seen through the mid 2000s- especially in dry years.

The Authority's stated objectives are made clear, to achieve more efficient transmission pricing and remove any barriers to pricing efficiencies. However, the analysis supporting these objectives is far less clear. Both the TPM and DGPP proposals can only be justified to the extent that they result in significant savings for consumers. The cost benefit analysis purport to demonstrate this, but once they are corrected for basic errors and omissions, the CBA's actually show that the combination of these proposals is likely to result in a large net loss for consumers. It would also be reckless to embark on such a major upheaval to the pricing structure that would result, according to the EA's own analysis, in most distributed generators being put out of business, when the economic benefits can only be demonstrated by utilising a flawed CBA.

Pioneer has concluded from its review that the proposed TPM cost-benefit analysis does not meet the Authorities statutory objectives and recommends the guidelines to Transpower should therefore be less prescriptive, allowing them to develop the Status Quo regime.

1. Introduction

1. This submission responds to the following consultation paper published by the Electricity Authority (the "Authority") on 16 May 2016:

   "Transmission Pricing Methodology – 2nd Issues Paper"

2. This submission has been prepared by Pioneer Energy with advisory support from Crowe Horwath and Morrison Low.

3. Pioneer's business is energy and its point of difference is the way it does business, the diversity of its products and energy options, partnerships and investments. Pioneer's core values are the essence of its business and have always been at the heart of the Pioneer brand being trust, service, community and partnership. Pioneer invests in local and renewable energy generation and customer on-site heat and power facilities. It has an enviable reputation for being able to partner with its customers.

4. Pioneer has grown a long retail market position to 2% market share. Our investment growth relies on shareholder confidence from stable regulations and incremental policy changes. These are important factors that contribute to promotion of competition into the market.

5. We trust that this submission provides useful incites on your consultation and would be happy to answer any questions the Authority may have arising from it.

Key Submission Findings:

6. Service-based charges are inferior, economically and technically, to RCPD pricing. Economic sizing of transmission and large scale generation is the pricing inefficiency issue, and this is being resolved globally by emerging distributed technologies – a *Market Study*[1] would fill the knowledge gaps.

7. Service-based, AOB and Residual fixed priced charges, based on gross installed network capacity, lessens competition for alternatives to transmission – reference Section 32.1a of Act. We recommend the DGPP and TPM implementation processes are aligned with Transpower's process requirements to ensure fair pricing and fair bargaining.

8. Replacing RCPD pricing with the weaker Area of Benefit and energy spot price signals removes market incentives to manage system demand peaks – ultimately exposing consumers to exponentially higher wholesale market spot prices and increasing costs of energy losses – we estimate the energy market value risk to consumers of up to $500m per annum.

9. The lack of information on future AOB costs, the arbitrary nature of the TPM cost-benefit analysis, and the material sensitivities relating to transmission alternative assumptions, bring Pioneer to conclude the long term benefits to consumers are inconclusive and the Code tie-breaker provisions should be invoked by the Authority Board.

10. This TPM proposal and the proposal to remove DGPP regulations from Part 6 of the Code will likely result in market wealth transfers of more than $2bn from consumers (ref: Pioneer Submission - TPM Cost-Benefit Review) and Distribution Generation owners (ref: Independent Generators Association Submission including PWC Market Value Report) – these market costs are not included in the TPM or DGPP cost-benefit analysis.

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[1] *Market Study* - would normally accompany a Code Development as far reaching at the TPM proposal.

2. Submission Summary

The TPM regulatory framework should encourage and enable healthy competition between competing suppliers and ensure that consumers receive efficient market pricing for the services they are provided. This proposal removes transmission price signals and substantially lessens competition from substitutes.

2.1 Market Competition

11. Pioneer Energy (Pioneer) has considered how these Transmission Pricing Methodology (TPM) guidelines could impact its customers, market operations and future investments, noting:

    - Current coincident peak pricing incentives support our energy services and efficiency business and customers manage regulated costs across industrial, institutional and commercial heat and power segments.
    - Pioneers local and embedded generation operates in six separate networks in direct competition with grid-supplied power and transmission capacity. The wider sector DG portfolio, together with consumer load management satisfy up to 25% of peak system demand, all co-ordinated by RCPD pricing signals.
    - Changes in market pricing structures from peak to long term fixed terms will influence, and potentially impact, on future market supply pricing risks for customers and on future market investment costs and risks.

    These potential market pricing dynamics have not been considered in the TPM proposal or cost-benefit analysis – with energy market pricing risks at estimated up to $500m per annum.

12. The TPM problem definition makes a number of broad assumptions that have not been substantiated by evidence-based analysis;

    "Poor price signals are incentivising inefficient use of the interconnected grid, inefficient levels of grid investment, and inefficient investment by grid users"

13. Inefficiencies in transmission pricing, like most other large centralised infrastructures including roads, water and waste management, are more often due to "economic sizing" coupled with low levels of natural competition.

14. Moving to Service-based and cost reflective charging will only exacerbate "economic sizing" issues, for both transmission and market generation, reinforcing current large scale investment paradigms at a time when the industry globally is experiencing a technology driven revolution driven by local solutions.

15. The application of Service-based fixed charges on a gross maximum anytime demand or network capacity basis, coupled with the loss of RCPD price signals, removes any pricing incentives for investment in incremental transmission alternatives and thus removes a level of competition from the electricity market. The system efficiency aspects are addressed in Section 2 of this submission.

16. This proposal seems out of touch with the changing global market environment and no market study has been undertaken to support the "material change in circumstances". We reference Australian practices and in particular the UK Ofgem's recent 2015 Flexible Grid[2] regulatory framework as being

[2] Ofgem UK - Flexible Grid Regulatory Framework 2015, refer Schedule 1 - Morrison Low commentary.

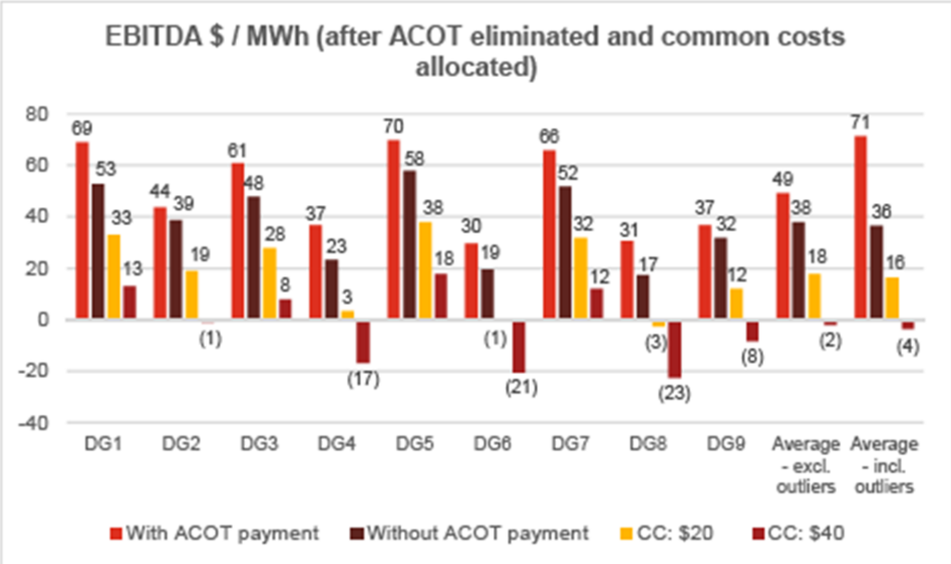
more appropriate for the material changes and higher levels of technology substitution to traditional monopoly providers.

The Authority has not undertaken robust Market Reviews to support its case for making radical change.

17. Pioneer's notes a number of knowledge gaps in this proposal and recommends the Authority simplifies its TPM guideline. Transpower should be requested to develop a more flexible transmission pricing mechanism that ensures system security of supply whilst also enabling further incremental change.

18. Pioneer supports the submission of the Independent Generators Association (IEGA), whom engaged financial advisers PWC to conduct a financial survey of members' last 3 years accounts to ascertain the Market Value impacts of the TPM and DGPP proposals.

Excerpt – PWC Market Impact Report, changes to TPM and DGPP mechanism



Summary

- The average annual ACOT payments in the last three financial years made to DGs included in the analysis in this report is $11.1 million. This is approximately 20% of the annual average total industry ACOT payments from 2013 to 2015 of $56.9 million.
- The financial information provided to us by the DGs included in our analysis suggests that most operate profitably and have prudent levels of financial gearing compared to wider industry benchmarks.
- Eliminating ACOT revenue from the DGs financial statements for the 2013 -2015 financial years results in an average reduction in EBITDA of 30.4% and an average increase in net debt / EBITDA ratio from 3.6x to 6.4x (excluding outliers).
- If ACOT revenue is eliminated and DGs are also required to pay network common costs at a level of $20 per MWh then the EBITDA of the DGs in our analysis reduces on average by 85% and net debt/EBITDA increases on average to 8x. If network common costs are assumed to be $40 per MWh then the average decrease in EBITDA and increase in net debt /EBITDA is considerably larger.
- The elimination of ACOT revenue could result in a reduction in enterprise value for the DGs in our analysis of approximately $106 million. The value reduction could be up to approximately $374 million if the DGs in the analysis lose ACOT revenue and are also required to pay network common costs at $40 per MWh.

The revenue of the DGs in our analysis is approximately 20% of total DG sector revenues. If the impact on value of eliminating ACOT revenue and paying network common costs on the DGs in our analysis is representative of these changes on the sector as a whole, then the total sector value impacts could be between $0.5 billion and $1.5 billion or possibly more.

19. These excerpts taken from the IEGA submission PWC report, illustrates that potentially more than $1bn of wealth transfers from current DG owner/investors to consumers and regulated monopolies , from competitive market interventions by the Authority and by not reconciling the double accounting issues introduced through TPM and removal of locational cost benefits to DG providers.

2.2 *Reliability and Durability*

Transmission design and investment cost-reflective pricing has been used with coincident peak demand price signals for more than 50 years, based on sound engineering principles relating to building economic scale and minimising energy losses. This change proposal has material knowledge gaps in the understanding of system engineering efficiencies gained through co-ordinated regional pricing signals, which will test the durability of the proposed fixed price Service-based and Beneficiaries pay approach.

20. The proposal lacks for any evidence-based analysis supporting the Authority's assumptions in their problem definition of market inefficiencies in consumer, generation and investment responses to current TPM pricing. In fact, our review of the Oakley Greenwood TPM cost-benefit analysis (ref: Pioneer's Submission on TPM Cost-Benefit) shows that if more realistic and evidence based market input assumptions had been applied, then the TPM present value analysis has a large negative outcome nearer to (-$1bn) as a scenario baseline.

21. Service-based and Beneficiaries-pay methodology's are theoretically inferior, economically and technically, to the current regional peak demand pricing regime. The current regime is more Market-like by allowing all market participants, including consumers, to respond to a range of short and long term transmission investment price signals. Transpower can incrementally develop the existing pricing regime by moving the N-periods as they recently did for South Island, or by refining an LRMC type mechanism, without the level of financial disruption and future market risks of this proposal.

22. The Area of Benefit (AOB) fixed charges have very weak demand side signals and will increase future investment cost uncertainty and also add future pricing risks for larger scale Market Generation. The Authority in its TPM analysis arbitrarily applies new transmission cost signals and these allocations are fundamentally different from the AOB calculations published by Concept. It is therefore very difficult for stakeholders to determine what the proposal holds for the future.

23. The AOB analysis by Concept is a "black box" outcome and we believe only reflects sunk cost investments. The AOB forecasts do not reflect Transpower's current long term asset plans so this analysis fails to more fully develop the new price signalling proposition, nor provide any guidance on potential ranges of future regional AOB costs. How can a future cost-benefit analysis be based on extrapolation of historic sunk costs?

24. Prudent discounting, introduced into this 2nd round of TPM consultation, raises many questions as to the durability and integrity of this proposal and inconsistencies in the treatment of different market players. The Authority in this TPM proposal is contemplating market subsidies to selected classes of consumers that are not warranted and are administratively complex.

25. In its companion DGPP paper, the Authority's is advocating wealth destruction and no grandfathering provisions for existing investors facing financial hardship. So on the one hand, the Authority is prepared to acknowledge financial and pricing impacts, wealth transfers, and subsidies in this TPM; whilst on the other hand it has elected to distance itself from such considerations in its companion DGPP proposal. We expect more consistency in applying regulatory principles so that all players are treated equitably, and so that competitive market based outcomes are allowed to prevail.

2.3 Market Pricing Efficiency and Investment Incentives

The original rationale for changing the TPM guidelines, being a "material change in circumstances" (after various iterations and stakeholder rejections), has now turned into a proposal justified by large scale generation investment outcomes. These outcomes have been created by way of a central-planning based cost-benefit model used to derive notional "*coefficient investment benefits out of generation and transmission".* In the process it has lost its way, straying into uncharted territory with large wealth transfers likely, along with unquantified sensitivities that will likely have material unintended consequences and value losses to consumers of more than $1bn.

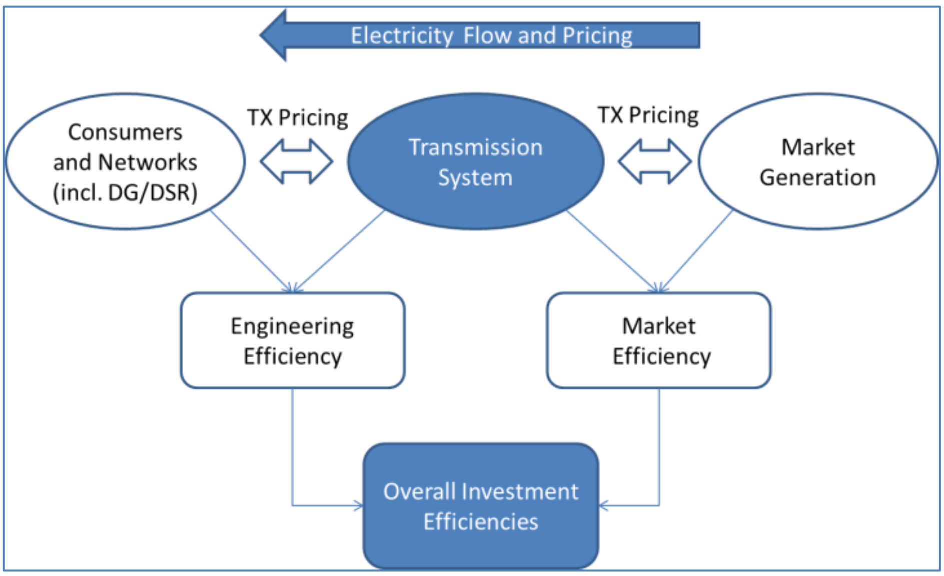
26. The Authority alleges that current regional coincident peak demand (RCPD) pricing is not as effective or efficient as energy spot market locational signals. However, by definition, the spot market should be pricing generation supply at marginal costs of meeting coincident peak demand. If not, we would conclude that the energy spot market is not pricing efficiently.

27. In the New Zealand market, with high and increasing percentage of intermittent renewable supply, it is clear that spot market pricing is more reflective of market storage, hydrology and weather events, than directly to actual system demand. Nodal pricing signals are ex-post so are poor surrogates for coincident peak demand signals. RCPD signals are more consistent and durable for new capacity investment.

28. Separating transmission pricing signals from other market pricing will have unintended consequences and materially lessen competition in the electricity market. The proposal ignores a long history and the knowledge of core physical and engineering outcomes relating to transmission and network costs. Peak demand is known to drive up consumer costs from energy losses and the requirement for less efficient market peaking generation.

29. Generally, *the flatter the demand curve in any market the more efficient the system investments*, therefore the more inter-connectivity of supply chain price signals, the better – Figure 2.3.1

Figure 2.3.1 – Pricing Relationships flowing through to Overall System Efficiencies



30. Schedule 2 of this submission provides two simple worked examples of how the core grid design principles are applied. This preliminary analysis (given the short consultation time made available) is used to demonstrate how consumer load management and DG, when co-ordinated by the RCPD price signals, and applied at portfolio levels will influence the wholesale energy spot market prices. This co-ordination currently delivers significant benefits to consumers, estimated at more than $500m per annum - well in excess of the proposed TPM benefits.

31. This pricing effect is no better demonstrated than with reference to the Upper South Island transmission region. Orion co-ordinates USI demand management signals that we understand will initiate more than 120MW of peak system demand management. The portfolio of DG in the USI region also exceeds 100MW of dispatch capability, so when coordinated these two regional responses to peak demand prices are more than 30% of the USI transmission capacity, avoiding transmission constraints and much high spot prices that would apply to all 550 MW of peak market generation.

32. Likewise, Orion is incentivised to shift some 70MW of peak demand load into the spot market at midnight when switched back on. A good portion of this 70MW, if not incentivised by avoided peak prices, would be added to current peaks and this would bring forward all USI transmission upgrades, at an AOB cost increase to all consumers in the USI.

33. These RCPD pricing derives system cost efficiencies have been largely ignored under this TPM proposal. Nevertheless, these benefits have been acknowledged by Oakley Greenwood (OGW) in its TPM cost-benefit analysis, are assumed in deriving Transpower's current revenue price path and in transmission investment forecasts. They need to be recognised by grandfathering provisions, or by introducing a new LRMC based component of Transpower's revenues that will provide fair market rewards for existing and future transmission capacity alternatives.

34. An LRMC pricing mechanism should be long term to support long life and incremental capacity investment options, and be included in the Commerce Commission Part 4 price-quality paths to ensure transparency, market independence and consistency with the LRMC price path for new transmission supporting new Load. This pricing mechanism could be dampened to reflect long term averages and reduce cyclical variations due to grid economic sizing issues.

2.4 Consumer Long Term Benefits

The quantitative assessment of long term consumer benefits is inconclusive. Many of the TPM cost-benefit input assumptions are not market cost-reflective, are removed from reality, and so will be substantively unfair. Assumptions and coefficients have been used to derive benefits that are not evidenced-based, have material untested sensitivities and open to future challenge.

35. Oakley Greenwoods (OGW) cost-benefit analysis has a number of flawed input assumptions, and relies on arbitrary coefficients and adjustments to deliver the outcomes desired by the Authority to meet its statutory objectives. OGW's cost-benefit analysis is separated from the Concept AOB forecasting, making it very difficult for market participants and public stakeholders to fully evaluate any future market impacts, which reduces investor confidence and bring to question the adequacy of this analysis for the levels of change and significant market wealth transfers proposed.

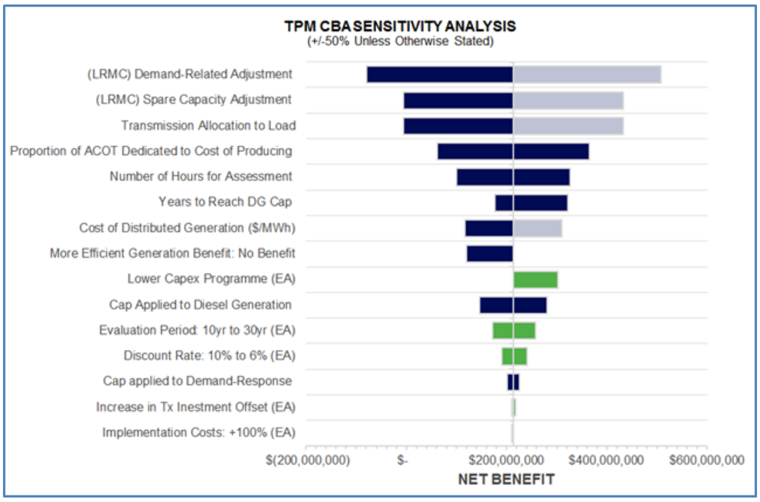
36. Both the TPM and DGPP proposals can only be justified to the extent that they result in significant savings for consumers. The cost benefit analysis (CBA) purports to demonstrate this, but once it is corrected for basic errors and omissions, the CBA's actually show that the combination of these

proposals is likely to result in a large net loss for consumers. (refer Pioneer Submission – TPM Cost Benefit Review).

37. It would be reckless in our view for the Authority to embark on such a major upheaval to the pricing structure that would result, according to the EA's own analysis, in most distributed generators being put out of business, when the economic benefits can only be demonstrated by utilising a flawed CBA.

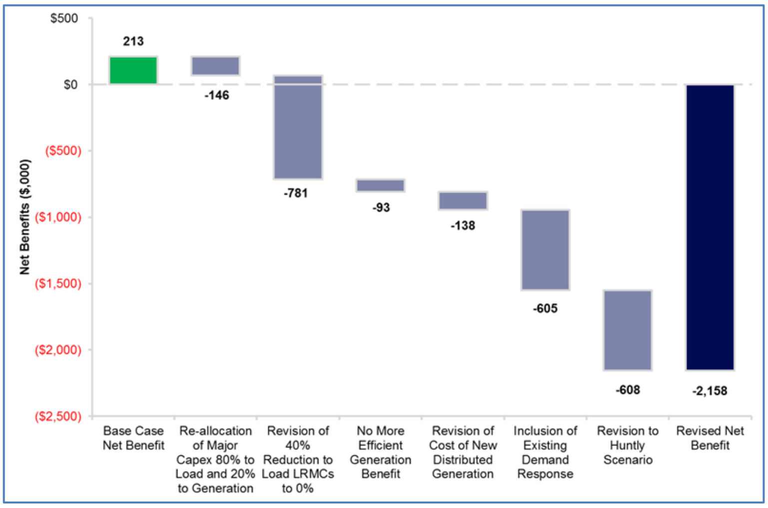
38. Figure 2.4.1 illustrates how influential these arbitrary coefficients are compared to the selected sensitivities (shaded green) that were published with the proposal;

Figure 2.4.1 – TPM Cost Benefit Sensitivities



39. The Top 7 of sensitivities in Fig. 2.4.1 are important input assumptions for distributed generation, demand side management as transmission alternatives, which OGW has incorrectly modelled for future capacity alternatives in the NZ market context. The future DG assumptions should reflect consented renewable sites (not 100% diesel as assumed) and the DG investment cap of 5% of incremental future demand should be removed as it implies an artificial competitive market cap.

Figure 2.4.2; Pioneer Submission – TPM Cost Benefit Sensitivities



40. This figure illustrates how sensitive these arbitrary assumptions to market input assumptions, which, when applied correctly, will cascade the present value into a strongly negative position.

2.5 Other Matters

41. Local DG embedded in networks will be allocated a component of AOB for local export, but the allocator from Networks to DG owners is likely to be made on the same MW basis as for Load, and not on the MWh basis of competing Market Generators. This pricing anomaly was first raised by Pioneer in its prior (TPM Issues Part 1) submission but has not been addressed and thus raises further market competition issues for smaller generators in Networks.

42. TPM and DGPP implementation programmes need to be aligned. The TPM will provide a basis for future grid pricing but remains unresolved until 2020 so commercial negotiations relating to DG alternatives cannot be conducted in good faith, or on fair terms, before 1 April 2017. Pioneers DGPP submission notes these issues and that, as proposed the TPM implementation will be fractious, lead to legal challenges, resulting in protracted and complicated commercial negotiations over Prudent Discounts for financially stressed companies and for Network grid bypass.

43. Alternatively, Transpower could be requested to simply modify the existing TPM regime, for example, by changing the N=100 pricing periods and/or introducing an LRMC component of revenues, to incrementally deliver any additional pricing efficiency benefits sought from Day 1. This more pragmatic solution is recommended as a more appropriate and less disruptive way forward.

44. Schedules supporting this Submission summary include:

i) Schedule 1 - Economic Sizing and Pricing of Transmission Infrastructures (Morrison Low)

ii) Schedule 2 – Market Analysis of Grid Alternative benefits

iii) Schedule 3 - TPM Cost -Benefit Analysis Review (Pioneer)

Pioneer advisors supporting this submission include:

- Crowe Howarth supported by local regulatory specialists Allen and Clarke.
- Morrison Low commentary supported by Australian specialist partner, Thang Nguyen.
- PWC in collaboration with the Independent Generators Associations, NZ (IEGA)

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26th July 2016

Schedule 1: Morrison Low report: Review of relevant economic issues

S1.1 Competition and Economic Regulation

Definition/specification of a proper regulatory framework for the market for 'electricity delivery services'

i) Transpower, given its dominant market position, is effectively a monopoly and/or exercises market power over many aspects of the electricity transmission/delivery market. Therefore, it needs to be recognised that the ultimate purpose of the existing economic regulation is to prevent possible abuse of monopoly power by Transpower to protect consumer interests, and to promote (and definitely not to shield it against) potential competition from other (smaller) suppliers in the market.

ii) The independent determination of a transmission pricing methodology by the EA, together with regulatory control by the Commerce Commission, was instituted so that transmission prices charged by Transpower would be similar to those that would result from a competitive market. This arrangement should not be meant to ensure that Transpower can always recover for all investments that it makes, irrespective of:
   - the economic efficiency of the investment decisions and the resulting market conditions e.g. surplus capacity; and
   - the regulatory crowding out of pre-existing capacity invested in by other suppliers including DGs and demand management (DM) programs.

S1.2 Transpower recent investments and transmission excess capacity

i) Transpower has made substantial investments in recent years (See Table 1) which must have significantly increased the transmission grid capacity, possibly resulting in surplus capacity at this stage (though there are regional differences).

Table S1 ***Post-2004 approved investment by Transpower***

Region	Post 2004 investment
UNI	$1,342 million
LNI	$237 million
USI	$77 million
LSI	$81 million

ii) The TPM, together with Transpower's Individual Price-Quality Path Determination, would allow for the recovery of these investments even if there is excess capacity in the market for transmission/energy delivery services. Concurrently, there is a proposal for removal of ACOT payment to DGs.

iii) Thus, while TPM was meant to be the main instrument of an incentive-based economic regulatory regime for a monopoly business, practically it has the reverse effect, that is:

   - It enshrines the transmission grid as the favoured means of energy delivery;

   - It preserves the position of the incumbent monopoly and allows Transpower's assets to crowd out other pre-existing capacity in the 'electricity delivery service' market i.e. DGs and DM.

iv) Transpower's grid, DGs and DM should be considered as alternative supply options within the same market for 'electricity delivery services' because either transmission supply, non-transmission supply or customer solutions could be used to deliver the common objective which is to balance market supply and demand.

v) If it is recognised that both transmission and non-transmission services are part of a single supply market, a broader market perspective must be taken in framing the TPM and legitimate cost recovery for alternative services. Additional regulatory mechanisms also need to be developed to ensure that consumers are protected from being required to pay for the cost of excess capacity (unless this results from economic sizing decisions).

vi) Further, transmission system planning rules make it very difficult for the broader market to implement less costly, non-powerline alternatives. The central planning process used for transmission investment therefore needs to be integrated with distribution level planning, so as to reduce the risks of excess capacity.

S1.3 A level playing field is required for all market participants

The transmission service with its monopoly characteristics should be established as a common carrier service.

i) Transpower, as the utility that owns, controls and operates the grid network, should provide an open access transmission service and set non-discriminatory tariffs that are based on cost reflective network pricing. Various international jurisdictions have adopted this regulatory approach.

ii) Under TPM, Transpower receives preferential treatment as it alone can have certainty of recovering its costs (investment and O&M) while other investors are exposed to the full risk associated with lack of market alignment e.g. premature or oversized grid investment.

iii) Once Transpower's investments are made it crowds out all other existing private investments on local generation and DM programs. Regardless of the economic efficiency of investments, they lead to these outcomes.

iv) That is, the TPM and price path determination by the Commerce Commission provide Transpower with full recovery of its capacity upgrade cost, so;

   - Without retention of DGPP in Part 6, DGs will lose the ability to recover the respective cost for their investment; and
   - With the departure from cost reflective network pricing based on RCPD, and no recognition is given to the contribution made by DGs and DMs to reducing transmission demand peak (and the ability to defer the need for new capacity).

v) A fair and efficient market framework should treat service providers on an equal footing and promote competition between them. Customers should be able to choose their suppliers. That is, either to purchase energy sent through the grid (Transpower) or by local generation (DGs) at the lowst cost to them. This customer choice, in a competitive market dynamic, needs support by preserving the ability of local distributors to choose suppliers on their customers' behalves.

S1.4 A stable regulatory environment is required for efficient investment in DGs and DM.

i) It should be recognised that the Grid is only one of the electricity delivery means and Transpower one supplier in a single market with various suppliers. Allowing only Transpower the ability to recover its cost, while 'services' are being provided by a range of suppliers introduces an uneven playing field.

ii) A competitive market, under any situation, including that of excess capacity, would allow suppliers to compete for the business of their consumers. This means a significant proportion of the electricity delivery market will still be serviced by DGs and DM, while the major proportion will remain serviced by Transpower.

iii) An example of an unbiased consistent regulatory regime is the National Electricity Rule (NER) in Australia which requires distributors to pay avoided TUOS to local generation (>5MW). This provides equal treatment to both the transmission utilities (earning TUOS) and the local generators (receiving avoided TUOS). The rule is applied regardless of the possible existence of local surplus capacity since in this situation, the local transmission charge component based on cost reflective transmission network (CRNP), would be zero or negligible.

iv) This is consistent with how the majority of current ACOT is calculated and paid. Thus removing ACOT gives rise to a more uneven playing field and a less competitive overall market.

S1.5 Fluctuations in LRMC and transmission cost savings

i) The fluctuation of LRMC during periods of transmission capacity over-building following major investments being made is a well recognised phenomenon. As the need to invest in new transmission capacity approaches in a location, the long-run transmission cost savings from additional embedded generation output will increase, because the value created through any potential deferral or down-sizing of that imminent transmission investment is closer in time.

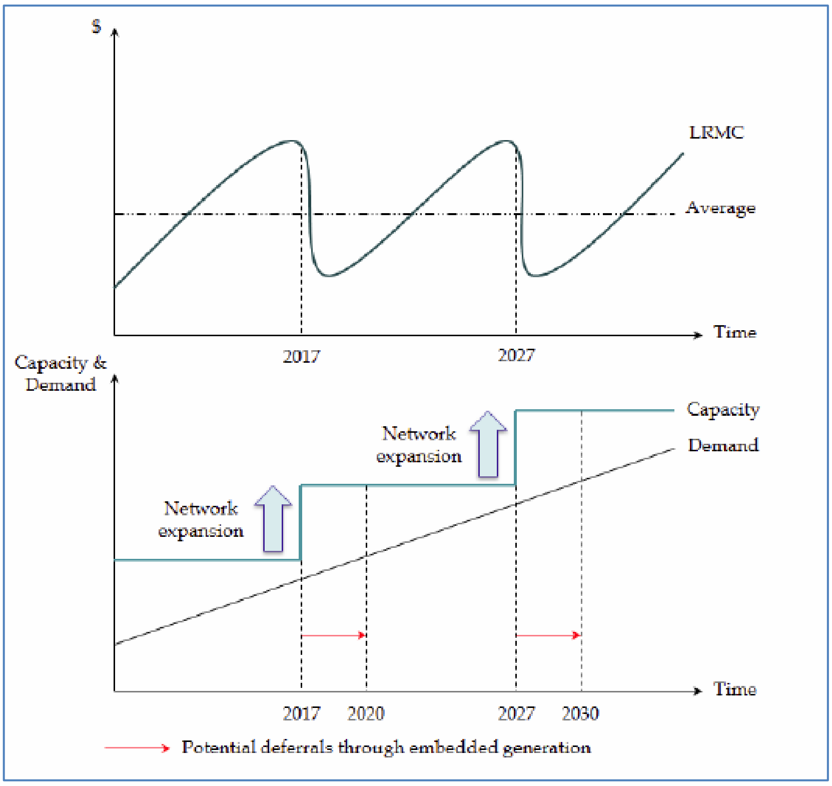
ii) However, following a major grid upgrade, there would be sufficient spare capacity to meet current and forecast future electricity demand. In this situation, the long-run transmission cost savings from embedded generation connecting (or connected) are likely to be low or zero, because the value of any potential deferral or down-sizing of future transmission investment is relatively low. Costs may even increase if the additional generation output results in bi-directional flows and increases fault levels.

iii) In general, Transpower has the tendency to invest prematurely or over invest because its centralised planning process is unable to give adequate consideration to:

- Potential local generation solutions to solve a range of system problems.
- The impact of grid capacity expansion on the potential redundancy of local non-transmission assets and thus the recovery of investments by other suppliers, including DGs and DMs.

iv) In other words, the efficiency benefits of additional embedded generation in a location (as opposed to competition benefits) will vary substantially over time. Figure 1 illustrates that the potential cost savings (measured by long-run marginal cost (LRMC)) that can be made by pushing back an imminent transmission investment (eg in 2017 in Figure 1) are significant. But once an investment in the transmission has been made, the potential for further savings falls away and efficiency is instead maximised – and the costs for consumers minimised – by utilising that new transmission capacity rather than encouraging further investment (or additional export from existing embedded generation). That remains the case until the need for new transmission investment re-emerges

Figure 1: Fluctuations in LRMC and transmission cost savings



v) Correct assessment of the need for new transmission in a particular location based on locational market prices i.e. Financial Transmission Rights (FTRs) may fail to signal the true scarcity of supply when the nodal price differentials between two zones or within a zone do not fully reflect the value of additional transmission investment.

vi) Transpower's unilateral power to decide on transmission capacity expansion increases the uncertainty of the return for the FTRs and has impacts on their value in the nodal wholesale market. As a result, FTRs have not been found to incentivise new merchant transmission investment. Rather their key benefit has been to facilitate bilateral contracting among market participants.

vii) A consequence of substantial economies of scale is that transmission networks are commonly over-built, with the cost of doing so being minimal. Especially when cost recovery is assured through the regulator's endorsement of TPM, Transpower has a clear financial incentive to use transmission solutions.

viii) Therefore, a more innovative approach is required to integrate the centralised transmission planning process with distributed generation planning and the operation of FTRs.

S1.6 TPM Economic Efficiency

i) Economic theory suggests that, to promote economic efficiency in capacity investments, transmission pricing needs to be based on long run marginal cost (LRMC) or a cost reflective network pricing (CRNP) methodology and demand at times of greatest transmission system utilisation for which network investment is likely to be contemplated. Thus;

   - The locational component of the transmission price is often designed to reflect this approach where the regional coincident peak demand (RCPD) is used as the measure of the system peak.
   - The non-locational and common transmission services price components are usually based on a postage stamp basis which applies a uniform price (per MW) for all customers regardless of their system use i.e. these components are not meant to provide economic signals.

ii) Once pricing methods involve a departure from the above economic theory, it is difficult to assess their economic efficiency merits[3.] The AOB charges is one of these methods, because their focus is primarily based on the recovery of past capacity investments made in the specific supply regions. Strictly speaking, there would not be any economic efficiency gains in reflecting sunk costs as a price signal4. In fact, this would more likely result in distortions to allocative efficiency when these sunk costs differ substantially from proper CRNP measures.

iii) Similarly, service based pricing that is predominantly aimed to recover past costs rather than being forward looking, would not likely deliver more economically efficient outcomes (equity considerations aside). If there is a requirement to recover the revenue cap, a postage stamp price would be more economically efficient because they would not send out false and distorted signals about the avoidable cost of future capacity augmentation. The Authority has presented no analysis of whether service based pricing would produce a Ramsey-like outcome.

iv) As discussed in the section above, if recent major capacity additions based on economic sizing, and thus economically efficient planning, resulted in capacity oversupply and consumers should be required to pay for the costs of all supply capacity provided (both by Transpower, DGs and DMs).

v) If contrast, if the overinvestment was caused by planning mistakes, suppliers should absorb the cost of excess supply. A logical response would be to set a low local price component to signal the situation of ample supply to consumers. Instead, the proposed TPM and DGPP, when combined, would send out a set of disparate price signals for equivalent services, with high levels of AOB charges not based on RCPD for the transmission grid and zero charges for non-transmission services provided by DGs and DMs. The confusing pricing signals that resulted from Transpower having full protection of its revenue and other supplies are thus unlikely to deliver allocative efficiency for the market.

vi) There is thus a need to review, as part of the development of TPM, whether the preferential treatment enjoyed by Transpower may have an adverse impact on long term market efficiency. If Transpower, the single dominant supplier, was insulated from the risks associated with imbalanced demand and supply, it would have the wrong incentive to overbuild, especially when the consequences are to be borne by other suppliers (i.e. through crowding out pre-exiting DGs and DM programs). The primary regulatory consideration with grid over-investment is competition.

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[3] If a fixed revenue collection is required, Ramsey's pricing rule offers an approach to maximise net benefit.

[4] Though the proposed TPM allows for the possibility of adding a LRMC charge supplement

vii) The above could be more clearly illustrated with an example.

When high CRNP transmission charges were set based on assessment of the RCPD and system supply stress, a local manufacturer decided to invest in a co-generation plant to manage its peak load. Other DG and DM initiatives concurrently implemented. This would defer the need for capacity augmentation by Transpower. When there was sufficient volume of demand serviced locally to be transferred to the transmission network; Transpower would decide to invest in augmenting its network. With the TPM protecting its revenue collection, Transpower would crowd out all services of the pre-existing local facilities but continue to set 'AOB' charges that are irrelevant to the resulting demand supply balance and only Transpower can collect.

S1.7 Economic efficiency in electricity generation market

i) The electricity generation market in NZ is a fully competitive market. Electricity is traded at a wholesale level in a spot market. There are existing market instruments such as FTRs that provide a measurement of capacity requirement and can be used to incentivise new merchant transmission investment.

ii) It is disputable that an objective of the TPM should be to influence and produce more efficient operation of and better outcomes for the generation market. We suggest that the focus of TPM is to provide cost reflectivity pricing for its own network, thus delivering an optimum path for capacity augmentation mix of supply sources and, in turn, the lowst possible transmission prices for consumers.

iii) We submit that using transmission charges, in particular determination of AOB charges, to manipulate the order of merit of generation plants is not justified in consideration of EA statutory objectives or broader market efficiency as follows:

- Transpower's transmission grid should operate as a common carrier service and provide competitive neutrality to different generators in the electricity generation market. The nature of the generation market is substantially different from that of the transmission network. In the former, bid prices and price competition are determined based on short run marginal cost; in the latter, bulky capacity additions are required and the avoided cost of investment needs to built in as a price signal. There is thus no certainty that long term economic benefit would be achieved by favouring certain generators (particularly those making more use of the grid) over other generators, and other market solutions including local generation and demand management options.

- As AOB charges are already different from CRNP, thus not producing the best transmission market efficiency outcome, they should not be further designed to influence outcomes in the generation production and investment market.

- We understand that an assessment of surplus system capacity supports EA selection of AOB charges rather than CRNP charges. However, the current relative cost advantages of the transmission grid are likely to be transitional (due to fluctuating LRMC) and do not form a suitable basis for developing TPM to provide an incentive structure for the transmission and generation markets over the long term.

We believe that the design of TPM should focus on sending signals to promote optimum planning and investment in transmission and non-transmission services.

S1.8 Analysis of current apparent excess capacity

i) Presently, a general situation of excess market supply appears to exist[5], with the total capability for delivering peak energy to consumers well exceeding their peak demand (though this varies across supply regions). As discussed above, during a period with excess supply, there is really no need to provide signals on the avoidable cost of future capacity augmentation.

ii) The major transmission investments by Transpower over the period 2004-15 (shown in Table S1) have most likely created the current excess capacity situation, especially for the Central North Island and further north.

iii) It is, however, important to examine the possible explanations for the current excess capacity situation. These include:

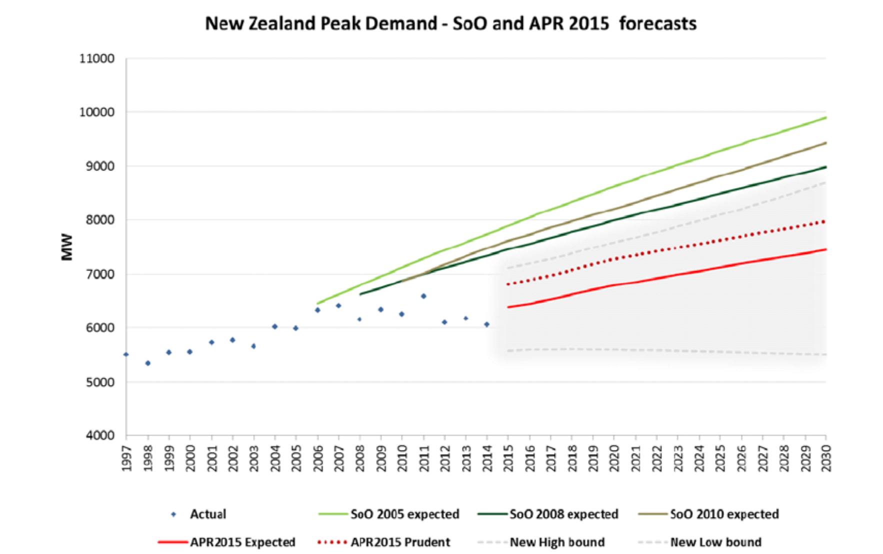
- Preparation of overly optimistic forecasts by Transpower.
- Since transmission investments are lumpy and there are economic sizing considerations, recent capacity additions though being well in excess of demand projections in the medium term may still represent 'economically efficient' investment.

iv) We consider the above explanations in the following.

- Transpower has over-forecast market demand in previous years which resulted in continuing build-up of capacity (over-investment) by both Transpower and in generation capacity (see Figure A).

Figure A – *Past overly optimistic forecasts led to overinvestment in transmission capacity*

Comparison of Transpower's April 2015 projections with previous forecasts



- In this context, provision of full cost recovery to Transpower (via TPM and price path) means giving it preferential treatment and rewarding it for preparation of incorrect forecasts. At the same time, if payments to DGs and DM are removed to ensure that consumers do not pay for the cost of excess supply, this would mean penalising pre-existing non-transmission supply sources for something they did not do i.e. causing excess supply.

[5] though the degree of excess varies across the supply regions.

iv) Because transmission capacity additions often need to be lumpy, the recent upgrades by Transpower may still represent economically efficient investments if they were based on economic sizing i.e. it is cheaper to have one large capacity addition instead of many increments even though the benefits are further into the future and thus more marginal.

v) In these situations, even when an excess supply has resulted, the full cost recovery of transmission investments from consumers remain justified. It is also justified for pre-existing non-transmission supply to recover their capacity investments because the most economically efficient investment/upgrade path has been implemented. The pattern of this path often involves investment in incremental capacity additions with small scale local generation plants or DM programs, until there is sufficient additional demand volume and growth to invest in an expansion of the grid (which often brings economy of scale benefit).

vi) It is noted that while a major transmission upgrade often immediately results in redundancy of capacity (on the grid or for local supply sources), the above described investment/upgrade path still represents an economically efficient process, with savings achieved from deferring the need for an early transmission upgrade. Consequently, it is logical to allow the pre-existing non-transmission facilities to continue to recover their investment at a (charge) rate equivalent to that earned by the transmission option. As mentioned above, this concept was recognised and adopted in the Australian NER where embedded generators receive payment of avoided TUOS irrespective of the cycle of investment implemented by their transmission providers.

vii) The above investment planning path implicitly assumes that the transmission provider takes into account, in their capacity planning process, the provision of services by DG's and other non-transmission delivery sources.

S1.9 Distributed Generation should continue to be compensated

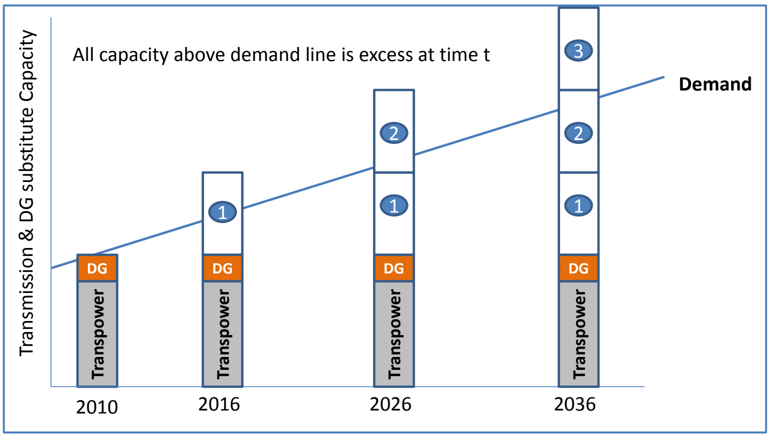
i) To be able to evaluate the Authority's DGPP proposal, a thorough understanding needs to be developed of how the market has progressed to its current state of excess capacity. This progression is analysed below.

ii) The economic theory of economic sizing is applied to prove that existing DG should continue to be compensated for the equivalent transmission capacity that it is providing to deliver electricity to consumers. DG existing before the recent transmission investment – and has not created any excess capacity. Any excess capacity is located in the transmission grid.

iii) DG has not been the cause of the current excess of delivery capacity. Figure B and C show two different perspectives of how DG might be considered to have contributed to the current excess supply. Figure B below represents the correct analysis of the economic efficiency impacts of DG on excess supply of delivery capacity, based on market development to date. Further, it is common and acceptable to have surplus capacity following an economically sized infrastructure expansion that meets future demand projections.

iv) Investments by both Transpower and DG are deemed efficient and should be supported through the approval of adequate cost recovery (just as Transpower is allowd to do under its regulatory regime).

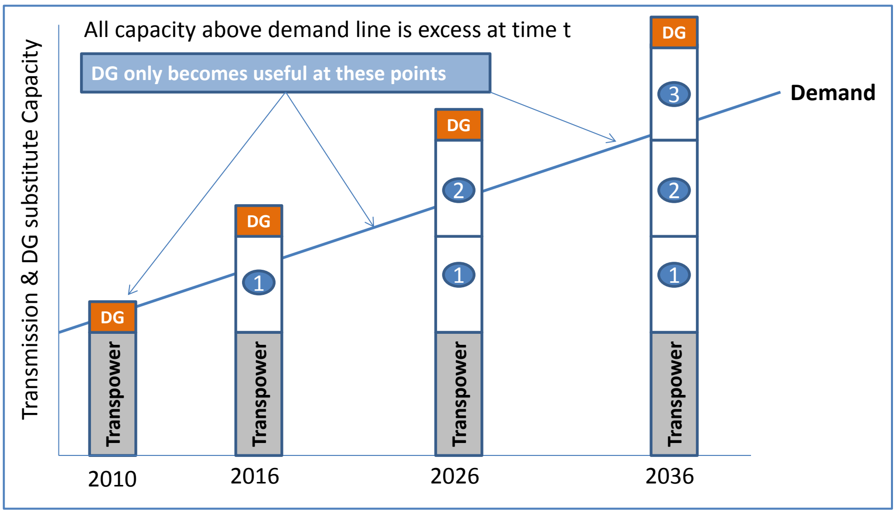
Figure B - *Correct Economic Perspective: DG is part of in-use capacity, Transpower upgrade results in excess capacity (AIEG)*



v) Figure C depicts the Authority's perspective - where DG is perceived to have changed from a position of in-use capacity to one that is surplus to the system needs following every major investment in the transmission network.

vi) We believe this is not supported by valid economic theory and so cannot be properly applied in the way the Authority has to meet the EA's statutory obligations. The Authority's approach is also not the correct application of its decision making framework.

Figure C - *Authority's Incorrect Perspective: DGs have become excess capacity following Transpower capacity expansion*



vii) Assuming that recent transmission investments have been made on the basis of efficient and prudent planning, and that economic sizing of system augmentation has resulted in the current excess capacity, the investment cost would still reflect the Long Run Marginal Cost (LRMC) of adding new capacity. OGW has calculated LRMC for different regions in its CBA report ranging from $20,000 to $50,000 per MW. In our view Transpower and DG should continue to be compensated by consumers based on the cost of providing efficient services, i.e. LRMC.

viii) In a situation of excess capacity, no party can help avoid future infrastructure investment, in the near term. Presently, Transpower is recovering the full cost of their investment through its 5 year price path. So by comparison, DG is entitled to receive payment for providing non transmission solutions to its customers, currently representing 9.6% of the market. We have reviewed the DG compensation practices of international regulators and found that they are comparable to Part 6 of the Code.

S1.10 Pricing for embedded generation in international jurisdictions

Australian National Electricity Rules (NER)

i) The Australian Energy Market Commission (AEMC) reviewed payments to distributed generation in 2011. The AEMC recognised that

"*Generators that connect to the distribution network (embedded generators) have the potential to reduce the long term need for investment in transmission infrastructure. This is because embedded generators may be able to reduce the distribution network's need to be supplied from the transmission network.*"

ii) At that time it concluded it was efficient for embedded generators greater than 5MW to receive two payments to reflect the different services provided by DG:

- Avoided Transmission Use of System (TUoS) payment from the Distribution Network Service Provider (DNSP). This compensates an embedded generator where its existence leads to a decrease in a DNSP's use of the transmission network at peak times. A reduction in the peak use of the transmission network reduces the need to augment the transmission network.

- A network support payment negotiated directly from a Transmission Network Service Provider (TNSP) where this seeks to defer specific shared network assets.

iii) The AEMC considered that;
"…the rule … is likely to promote efficient investment in electricity services for the long term interests of consumers of electricity with respect to price and reliability of supply of electricity. This is because it will ensure an embedded generator is efficiently compensated for the benefits it provides. This will provide incentives consistent with an efficient level of investment in embedded generation which, in turn, can contribute toward facilitating an efficient level of transmission investment. Additionally, the rule as made will promote greater certainty and consistency when negotiations for network support payments occur between a TNSP and an embedded generator."

iv) As recently as 2011 the AEMC confirmed that compensation payments for services provided by DG should be part of the rule structure;

- These rules put in place a payment from distribution companies to DG which is the equivalent of the current DGPP ACOT payments;

- An additional compensation arrangement can be agreed with the transmission network provider for network services;

- The form of both payments are regulated providing certainty and consistency.

v) The rationale for making payments to DG for their contribution of network savings has been found to include:
- Proliferation of new business models that are currently not available, and would broaden customer choice for delivery of electricity [this refers to consumer owned DG for own use]

- Allow greater utilisation of existing network assets and mitigate grid defection.

- Network Credits lead to more consumers staying on the grid than would otherwise be the case. Average electricity prices would be lowr than in the alternative scenario as the network costs would be recovered from a larger number of consumers [this refers to consumer owned DG for own use]

- Reduced grid defection results in lowr network fixed charges in Distributors' Tariff Structure
- Retailers have more incentive to offer tariffs that would allow 'netting-off' of local generation from consumed energy [this refers to consumer owned DG for own use]
- 'Side benefit' of starting to shift the culture of network businesses with regard to non-network solutions

vi) In effect, the Authority's approach is the opposite of the AEMC. It is hard to understand why DG can be considered efficient in Australia and inefficient in NZ. The Transmission Network Use of System (TNUoS) charges are based on a combination of locational charges and additional flat charges (residual elements) separately to demand and generation to balance with allowd revenue. The two elements are:

- A locational element reflecting the unit cost of transmission investment at a point on the GB system. At a high level, the locational elements for generation and demand users can be considered (subject to zoning) equal and opposite. Through its netting, an embedded generator can be considered to have an implicit value equal but opposite to the demand signal and therefore equivalent to the signal received by a transmission connected generator.
- A residual element added on a capacity basis to ensure TNUoS charges recover the correct revenue. Residual elements differ for generation and demand customers.

vii) At present, unlicensed DG[6] is treated as negative demand in TNUoS charging, thereby avoiding the generation TNUoS charges and being paid the demand TNUoS charges. Through the negative demand TNUoS charges, DG's see broadly the same impact from locational charges as transmission connected generation.

viii) The industry is reviewing the residual elements of TNUoS but has not reached final arrangements for them, that is whether DG's should be:

- Paid the demand (D) residual element (that the supplier would be liable to pay); and
- Allowd to avoid the generation (G) residual element of the charge (that transmission generation is liable to pay).

Ofgem (UK):

i) Transpower's recent "Tomorrows Transmission" publication is much closer to the mark than the Authority's current views on future value drivers and creating a more open access regime for existing and new entrant players. That is, to recognise that over this time frame, a return to cost reflective network pricing is necessary to indicate the emerging stress on system supply. Pioneer explores this further in Section 3 and makes recommendations on how a revised TPM might be further developed.

ii) Ofgem is an example of a more inclusive and innovative approach to ensure policies for transmission and alternatives to transmission will be durable and can support economic efficiency in the long term, in particular how optimum incentives are given to investment by different suppliers over the cycle of fluctuating LRMC.

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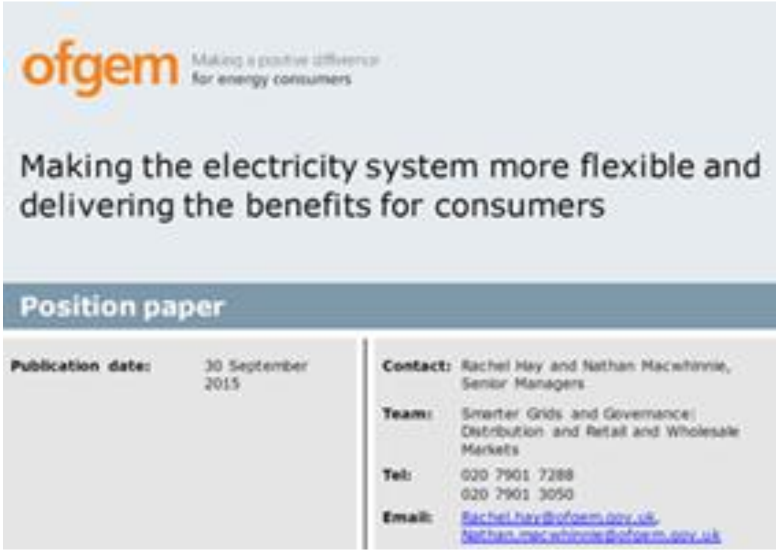
[6] With the exception of licensable embedded generators with a capacity of greater than 100MW, embedded generators do not pay TNUoS charges

iii) Ofgem Position issued a Paper in 2015 on how to create more flexible grids and pricing structures that accommodate, not deliberately isolate, consumers and service providers in a changing market.


ofgem Making a positive difference for energy consumers

Making the electricity system more flexible and delivering the benefits for consumers

Position paper

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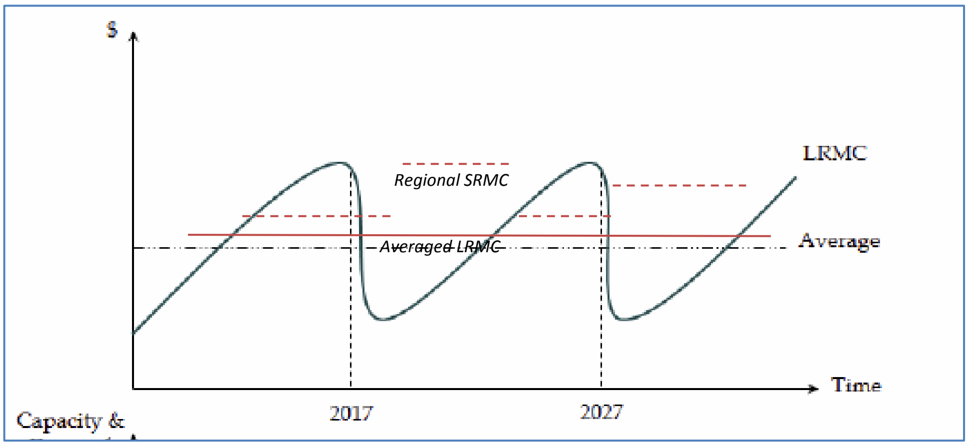
S1.11 Proposed LRMC and Market-like Solution

i) The economic sizing issue and interconnection pricing inefficiencies could be improved through a much simplified and less divisive regulatory change. Our analysis shows that capacity plus spot energy pricing regimes work well together and cover investment pricing signals in the both mainstream Market Generation and signal efficient and incremental investment in Local Distributed and Demand side solutions.

ii) Our proposal is Transpower modify current TPM RCPD prices, so as to dampen the RCPD cyclical prices nearer to a long run Average, – Figure D

Figure D – TPM using two LRMC Capacity price signals



iii) The Averaged LRMC could be set by the Commerce Commission as part of the Transpower Price-Quality revenue paths in the same way that new Grid Investment Pricing is applied. This price could be paid on the same or similar terms as current ACOT payments, either through Networks or through Transpower directly.

iv) The Regional SRMC would be managed more directly by Transpower, who would contract for up to 5 years with providers, and include the current Economic and Security dispatch options being run as part of the current Transpower DSR programme.

The DGPP Part 6 Code provisions would remain in place and be reviewed as part of the upcoming Authority Network Pricing Reviews and ComComs Input Methodology for Emerging Technology's Part 4 Code reviews to ensure they were kept up to date.

S1.11 Conclusions on Transmission Investment and Economic analysis:

a) The Authority has ignored "economic-sizing" of transmission investments and principles of "causer" when assessing the efficiency of DG as an alternative to transmission.

b) The existing DGPP regulations were put in place to protect DG from these effects, and ensure DG maintained the benefits already provided prior to new transmission being built.

c) The TPM needs to adequately address the need for cost recovery in the following non-transmission segments of the market. It should also be verified that the current excess capacity situation has resulted from Transpower's lumpy capacity additions which was based on economic sizing considerations.

d) ACOT is being pulled from DG - undermining the financial viability of these existing investments; and

e) AOB charges will reduce the financial return by pre-existing DM programs

f) DGPP provisions should remain and Transpower should include a new LRMC based pricing mechanism in the TPM to account for existing and future embedded generation capacity.

Schedule 2 - Market Analysis of Grid Alternative Benefits

S2.1 Market Pricing Relationships

1. The Authority's problem definition states;

   "Poor price signals are incentivising inefficient use of the interconnected grid, inefficient levels of grid investment, and inefficient investment by grid users"

2. This statement is more of an assumption than a problem definition as there is little evidence-based analysis presented, as required by government, to support this problem definition. The analysis presented is singularly focussed on forecasting future competitive market outcomes.

3. The Authority's proposal does not recognise how system and market efficiencies are derived from current grid pricing methodologies, by signalling peak avoidance through to DG and Consumers. Their market price response in aggregate, by reducing system energy losses and overcoming Market Generation scale inefficiencies at peak demand period, contribute significantly more towards achieving long term consumer benefits than do the proposed TPM co-investment pricing signals.

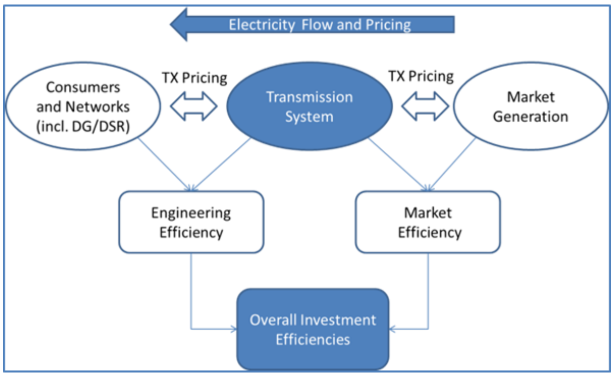
4. There is ample evidence in many other international markets7 that both energy spot and capacity markets can and do work more effectively together to deliver all of the system efficiencies. Separation of transmission pricing and pricing signals from downstream pricing of network and consumer services is a retrograde step and a move away from the most efficient and Market-like system pricing solutions.

5. The TPM analysis, rather than focussing on future Market Generation investment decisions should instead be considering system engineering efficiencies and energy market pricing dynamics that, when combined, make up the current ACOT and ACOD benefits to consumers, by;

   - Reducing overall system energy losses
   - Reducing wholesale market spot prices due to lowr marginal clearing costs
   - Reducing future transmission and peak generation investment needs.

6. Figure S2.1 below illustrates that transmission pricing signals influence market and engineering efficiencies. There are significant co-ordination benefits from ensuring we have one market and pricing delivery for energy and capacity. This co-ordination is recognised in most developed electricity markets.

Figure S2.1 – Grid and Network Pricing and Efficiency



[7] Refer Schedule 1 – Morrison Low exhibits from other electricity markets.

7. Importantly, *system demand relationships all exhibit exponential market cost outcomes*. The problem definition notes RCPD coincident peak capacity prices are separated from energy spot prices and suggest this reflects inefficiencies in RCPD. Efficient energy spot market and nodal locational prices should, by definition reflect short run marginal costs of the next MW of supply to meet demand. In theory at least, energy spot prices should therefore be coincident with regional peak demands. If not, then the energy spot market is not pricing efficiently.

8. The concentration of market price-makers and New Zealand's target of 90% renewable generation will see future spot market prices driven more by intermittent hydrology and wind supply risks and less by marginal thermal generation dispatch costs. This trend is already apparent, with spot market prices reflecting modelled risks rather than marginal peak demand (RCPD's).

9. Capacity markets will need to grow with renewable supply, otherwise consumers will be exposed to exponential market cost risks and higher losses at system demand peaks. These exponential costs are illustrated in the TPM proposal (Fig: 38 on page 255) to promote AOB service cost-benefits. The same economic arguments support RCPD based ACOT payments made to Demand Management and local DG to avoid spot market constraints and scarcity prices to consumers. This is a far more economically efficient investment signal than fixed-price Service charges to large Market Generators.

10. Removing RCPD signals and replacing these with fixed costs at peak offtake nameplate ratings or gross anytime maximum demand (AMD) will ultimately result in higher network demand peaks, as there is no incentive for avoidance. Higher spot prices will result for all Market Generation dispatched at peak demand periods.

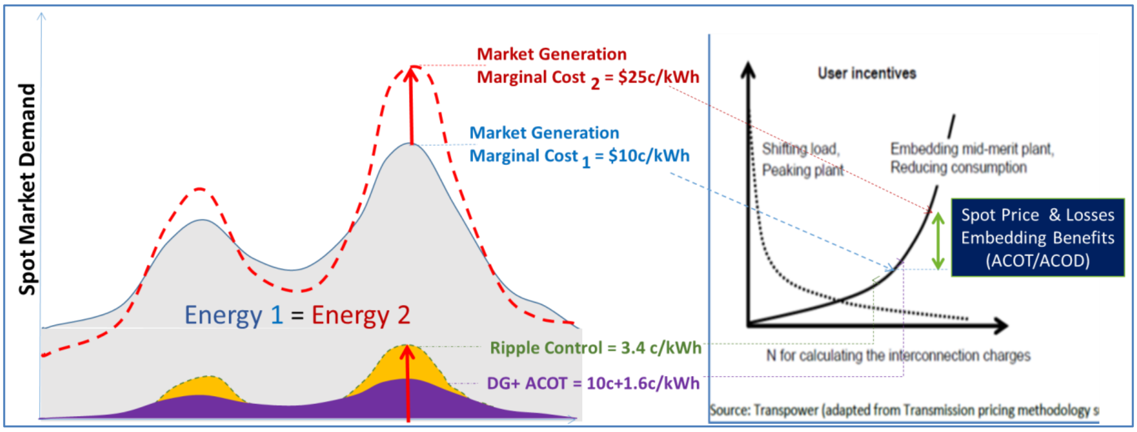
11. Taking a simple example, the long run thermal fuel costs of Market Generators supporting system peaks (e.g. Huntly and TCC generators) are at least $50/MWh higher than the marginal dispatch costs of local demand and embedded renewables. Under normal market conditions energy spot market marginal costs for system peaks will be set up to:

    Marginal price at:

    $50 x 6,500 MW x 2hrs day at peak demand = $0.65m per day of wholesale market spot costs due to uncontrolled system demand peaks.S2.2 Inefficiencies in the Centralised Market

12. These peak market pricing relationships are illustrated in Figure S2.2.

Figure S2.2 – Avoidable Spot Market Costs



13. At higher peak demand periods, system constraints in transmission, market reserves, wind intermittency and hydro storage will increase the marginal spot clearing costs exponentially, for

example to more than $250/MWh for Gas Peaker's, increasing spot market peak marginal costs to consumers exponentially to more than $3m per day.

14. DG in New Zealand is 95% renewable generation and produces an average of 3,200GWh per year, with a current marginal cost to consumers of DG for ACOT payments of $16/MWh, or $55m per annum to offset more than 10% of peak system demand. Discussion with Networks, supported by Commerce Commission Information Disclosures, reveals RCPD prices signal more than 10% of other local capacity offsets.

15. It's clear from this example and from Network disclosures that the flatter the system demand profile, the lower the peak costs and the more efficient the investment in Market Generation. OGW acknowledges this fact within their CBA analysis, but then conveniently side-steps this DSM and DG benefit to consumers.

16. As reviewed in Schedule 1, there is ample evidence in many other countries and regulations that recognise this market sizing and investment efficiency outcome, so have a preference for both energy and capacity pricing mechanisms. The total benefits of local and DG offsets incentivised to avoid peak demand periods through RCPD prices are likely to be more than $500m per annum.

S2.3 Grid Efficiencies

17. The Authority has ignored system engineering efficiencies that are supported by a long history of grid coincident peak pricing signals. These signals have created more than 1,000 MW of hot water peak demand ripple control and incentivised some 950 MW of Distributed Generation currently embedded into the market at the Network and Consumer levels.

18. Transpower in its 2015 Electricity Peak Demand Forecasts state;

    "Peak demand forecasts are an important input into our planning process and are a key driver of many of our new investment decisions. As peak demand grows it gets closer to the capacity of the grid to deliver electricity. This can result in transmission constraints occurring, which may result in the uneconomic dispatch of generation, or periods of reduced security, where there are higher risks (and likely costs) associated with a power outage."

19. Grid physical losses are calculated by a simple empirical physics relationship that underpins the design of all electrical delivery systems:

    Power Losses = I^2 R

    where;

    I^2 is the Current empirically squared
    R is the Wire resistance which increases with load and heat

20. Voltage and Wire Resistance are fixed, therefore the system power or energy losses are directly proportional to the square of current or demand. Transmission system losses are therefore directly correlated and increase exponentially with coincident peak demand. These losses occur on all wires at regional coincident peaks therefore the RCPD peak pricing signal has relevance at every part of the national grid.

21. Peak Demand pricing was designed to ensure the minimisation of system engineering losses which at 3,600 GWh per annum represent some 9% of all energy sold to consumers. New Zealand's system energy losses are measured annually and included in the Commerce Commission Information Disclosures, noted for 2015 in the table below;

Table 3.1 – System Energy Losses from Information Disclosures

Component of Delivery Supply Chain	Average Energy Losses (2015 Disclosures)	Range of Energy Losses at Regional GXP's
Transmission System	3.4%	1% Low to 6% High
Distribution Networks	5.6%	4% Low to 10% High
Total System Energy Losses	Average 9% of Generation Production or Total 3,600GWh	

Source: Commerce Commission Information Disclosures 2015

22. The cost of system physical losses to the market and consumers are therefore considerable:

   - Losses total ~3,600 GWh per annum or around 9% of generation supply.
   - Losses are exponentially higher at demand peaks (Losses = $I^2 R$), so ~60% of system losses occur over the peak day periods and during seasonal peak demands.

23. OGW and Concept have assumed an average market spot price of $100/MWh for peak day wholesale prices, so a simplified estimation of loss costs are:

Peak Period Losses = 3,600 x 60% x $100/MWh or ~$216m per annum
Off Peak Losses = 3,600 x 40% x $40/MWh or ~$ 58m per annum
Energy Loss Cost to Consumers = $ 274m per annum

24. These system energy losses are most efficiently managed through a coordinated peak demand management responding to coincident peak price signals.

S2.3 Conclusions on Market Price Relationships

25. The combination of system peak demand spot energy marginal costs and costs of energy losses, both of which are exponentially derived, are important considerations of TPM to understand and avoid.

26. Any changes contemplated to system pricing regimes that have been in play for more than 50 years should be undertaken with great caution, *on an incremental and reversible basis*. To do otherwise and without adequate analysis would in our opinion be reckless.

27. The *unintended consequences* of removing coincident peak demand pricing and co-ordinated price signalling that could add significant annual costs to consumers estimated at more than $500m per annum.

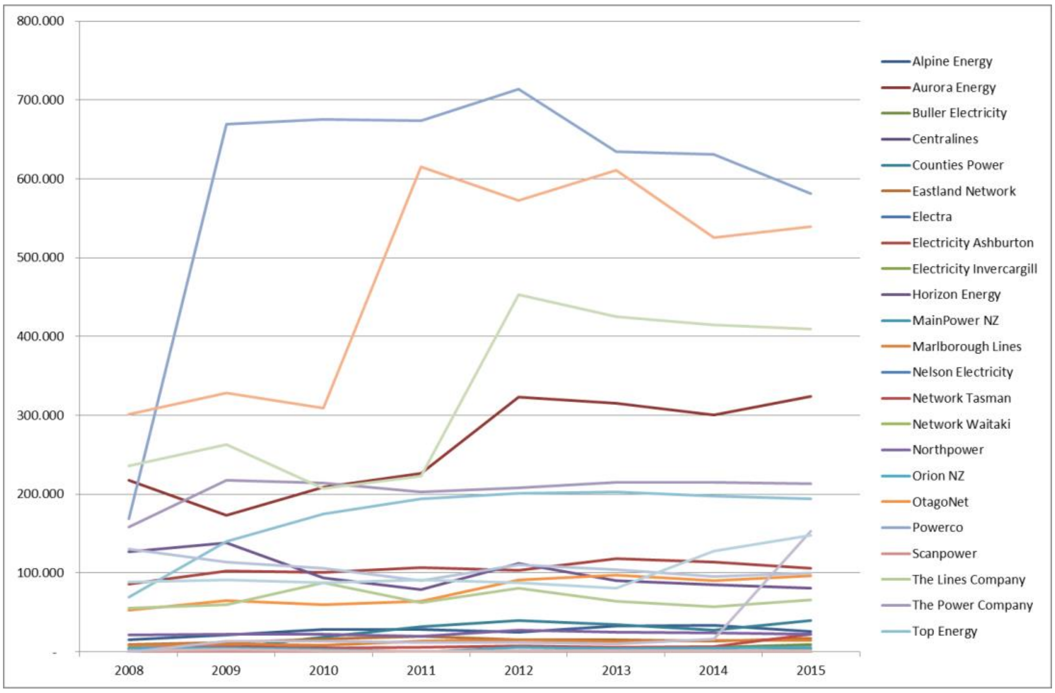
28. In Pioneers view, there is enough uncertainty in the quantitative cost-benefit analysis, and in a reasonable and objective qualitative review, for the Authority to reasonably invoke the tie-breaker provisions of the Code.

Appendix S2 Information Disclosures – Commerce Commission

Volume supplied from DG GWh	2008	2009	2010	2011	2012	2013	2014	2015
Alpine Energy	15.6	21.0	28.3	28.6	24.8	33.2	33.6	25.5
Aurora Energy	218.0	173.2	208.5	226.7	323.3	315.1	300.2	324.1
Buller Electricity	-	-	-	-	-	-	5.3	9.1
Centralines	-	-	-	-	-	-	-	-
Counties Power	3.0	3.7	18.6	31.6	40.0	34.7	27.5	39.9
Eastland Network	9.3	12.1	16.0	20.0	15.0	15.0	14.0	17.4
Electra	-	-	-	-	-	-	-	-
Electricity Ashburton	86.0	102.4	100.5	107.3	103.3	118.3	113.9	106.1
Electricity Invercargill	-	-	-	-	-	-	-	0.1
Horizon Energy	126.9	138.1	93.7	78.6	112.1	90.5	85.2	80.8
MainPower NZ	-	-	-	-	-	-	-	4.3
Marlborough Lines	8.6	10.0	8.0	13.6	15.0	12.9	14.5	14.4
Nelson Electricity	-	-	-	-	-	-	-	0.1
Network Tasman	5.1	6.6	5.0	6.0	7.3	6.1	6.4	22.0
Network Waitaki	-	-	-	-	-	0.2	-	-
Northpower	21.0	22.7	22.0	20.0	27.4	25.0	24.0	22.0
Orion NZ	5.0	4.5	2.7	-	6.1	4.1	5.0	5.5
OtagoNet	52.7	65.4	60.0	64.6	91.4	97.1	90.1	96.2
Powerco	169.0	669.0	675.0	673.6	713.9	634.1	631.2	581.3
Scanpower	-	-	-	-	-	-	-	-
The Lines Company	55.4	60.2	88.0	62.0	81.0	64.0	57.0	66.0
The Power Company	158.2	217.7	214.3	203.0	207.8	215.0	214.8	213.6
Top Energy	69.7	139.8	174.8	194.2	201.5	202.4	197.2	194.0
Unison Networks	301.6	328.0	309.0	615.3	572.2	611.1	525.0	539.0
Vector Lines	130.5	114.0	105.8	90.0	110.0	104.5	95.8	100.2
Waipa Networks	1.5	2.7	1.4	0.9	1.8	1.0	1.2	1.7
WEL Networks	236.2	263.0	207.1	222.5	453.4	424.8	414.3	409.3
Wellington Electricity	-	13.5	14.0	11.9	12.0	10.1	16.6	153.0
Westpower	89.0	91.0	88.0	91.0	88.0	81.0	128.0	147.8
Grand Total	1,762.6	2,458.7	2,440.7	2,761.3	3,207.2	3,100.2	3,000.6	3,173.0

DG as % of electricity supplied to ICPs	2008	2009	2010	2011	2012	2013	2014	2015
Alpine Energy	2.2%	2.9%	3.8%	3.9%	3.5%	4.4%	4.5%	3.2%
Aurora Energy	16.1%	12.9%	15.5%	17.2%	24.2%	23.7%	22.7%	24.1%
Buller Electricity	-	-	-	-	-	-	8.5%	15.7%
Centralines	-	-	-	-	-	-	-	-
Counties Power	0.6%	0.7%	3.7%	6.1%	7.7%	6.5%	4.9%	7.0%
Eastland Network	3.1%	4.0%	5.3%	6.6%	4.9%	4.9%	4.7%	5.8%
Electra	-	-	-	-	-	-	-	-
Electricity Ashburton	16.7%	18.7%	17.5%	18.6%	20.6%	20.1%	20.1%	15.9%
Electricity Invercargill	-	-	-	-	-	-	-	-
Horizon Energy	22.5%	26.0%	16.6%	13.9%	20.1%	16.4%	15.9%	15.0%
MainPower NZ	-	-	-	-	-	-	-	0.7%
Marlborough Lines	2.3%	2.7%	2.0%	3.5%	3.9%	3.3%	3.8%	3.6%
Nelson Electricity	-	-	-	-	-	-	-	0.1%
Network Tasman	0.8%	1.1%	0.8%	1.0%	1.2%	1.0%	1.0%	3.5%
Network Waitaki	-	-	-	-	-	0.1%	-	-
Northpower	2.1%	2.3%	2.2%	2.0%	2.7%	2.5%	2.4%	2.1%
Orion NZ	0.2%	0.1%	0.1%	-	0.2%	0.1%	0.2%	0.2%
OtagoNet	13.5%	15.9%	14.5%	15.7%	22.1%	23.0%	21.3%	22.6%
Powerco	7.6%	14.8%	14.8%	14.5%	15.4%	13.2%	13.6%	12.3%
Scanpower	-	-	-	-	-	-	-	-
The Lines Company	16.9%	18.9%	24.8%	19.1%	25.5%	19.2%	17.0%	18.3%
The Power Company	23.2%	30.8%	29.9%	28.2%	27.7%	28.5%	29.1%	28.3%
Top Energy	19.8%	39.3%	48.9%	54.2%	55.4%	55.6%	54.9%	54.3%
Unison Networks	18.3%	19.9%	18.6%	36.7%	34.4%	36.7%	32.0%	32.9%
Vector Lines	1.2%	1.3%	1.2%	1.0%	1.3%	1.2%	1.1%	1.2%
Waipa Networks	0.5%	0.8%	0.4%	0.2%	0.5%	0.3%	0.3%	0.4%
WEL Networks	19.6%	21.8%	16.9%	18.0%	36.4%	33.9%	32.9%	32.3%
Wellington Electricity	-	-	-	-	-	0.4%	0.7%	6.3%
Westpower	34.1%	31.8%	28.5%	29.4%	29.5%	28.6%	45.1%	52.1%
Grand Total	5.9%	7.9%	7.5%	9.4%	9.9%	9.5%	9.3%	9.6%

ACOT Payments	2008	2009	2010	2011	2012	2013	2014	2015
Alpine Energy	-	-	-	-	-	-	-	-
Aurora Energy	2,819	4,312	2,416	1,250	4,580	7,618	6,701	6,656
Buller Electricity	-	-	-	-	-	-	-	103
Centralines	-	-	-	-	-	-	-	-
Counties Power	-	-	-	-	-	-	-	-
Eastland Network	2,444	2,083	2,083	2,438	2,815	2,629	2,662	2,574
Electra	-	-	-	-	-	1,234	1,529	-
Electricity Ashburton	173	548	339	716	836	871	1,314	980
Electricity Invercargill	-	-	-	-	-	-	-	-
Horizon Energy	2,181	2,432	2,696	2,845	2,919	3,721	3,069	4,526
MainPower NZ	-	-	-	-	-	875	954	-
Marlborough Lines	57	49	46	82	161	161	151	261
Nelson Electricity	-	-	-	-	-	-	-	-
Network Tasman	-	-	-	-	72	41	105	790
Network Waitaki	178	178	178	182	186	-	-	-
Northpower	25	-	-	175	300	1,009	5,587	-
Orion NZ	21	60	458	-	236	1,020	1,432	214
OtagoNet	167	222	446	570	574	934	1,101	-
Powerco	3,544	6,590	6,251	8,388	9,727	9,306	9,105	9,836
Scanpower	-	-	-	-	-	-	-	-
The Lines Company	524	738	775	871	874	1,200	1,501	1,585
The Power Company	225	323	521	1,160	1,847	2,764	1,518	-
Top Energy	738	767	709	-	1,843	3,888	4,006	2,719
Unison Networks	-	-	2,611	3,226	4,526	5,817	6,178	5,951
Vector Lines	7,974	10,550	13,129	10,099	4,997	9,916	9,033	10,519
Waipa Networks	-	-	-	-	-	-	-	-
WEL Networks	556	836	2,725	711	710	3,675	3,771	3,289
Wellington Electricity	-	7	71	151	246	185	166	137
Westpower	554	964	680	946	-	-	1,634	2,171
Grand Total	22,180	30,659	36,135	33,811	37,449	56,862	61,517	52,312
RCPD Rate charged by Transpower $/kW		64	71	69	76	91	99	114

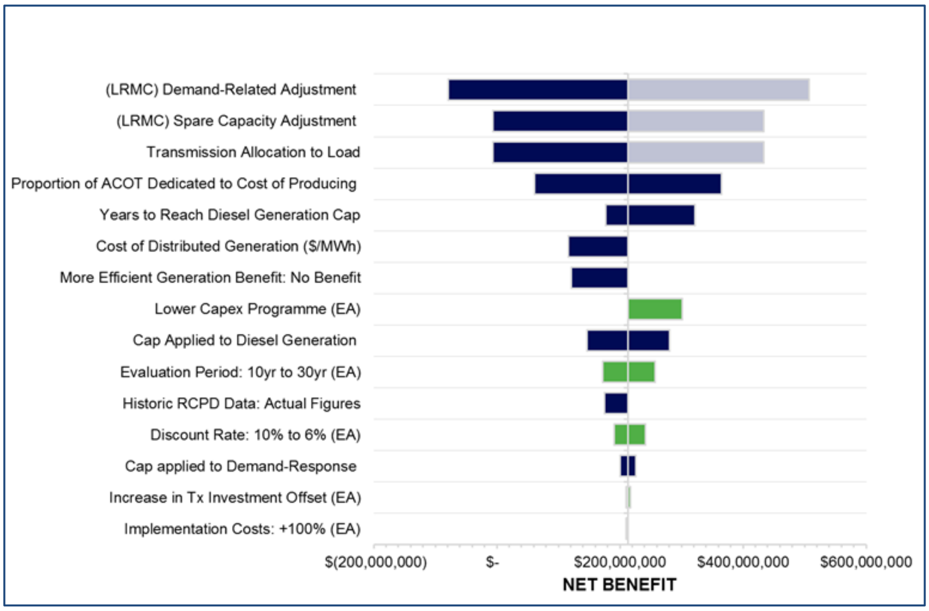


Schedule 3 – TPM Cost Benefit Analysis Review

1. Pioneer has made a separate submission covering both the TPM and DGPP cost-benefit analysis work. This section of the TPM paper summarises the key sensitivities of the analysis and how they highlight the likely unintended consequences of this TPM proposal.

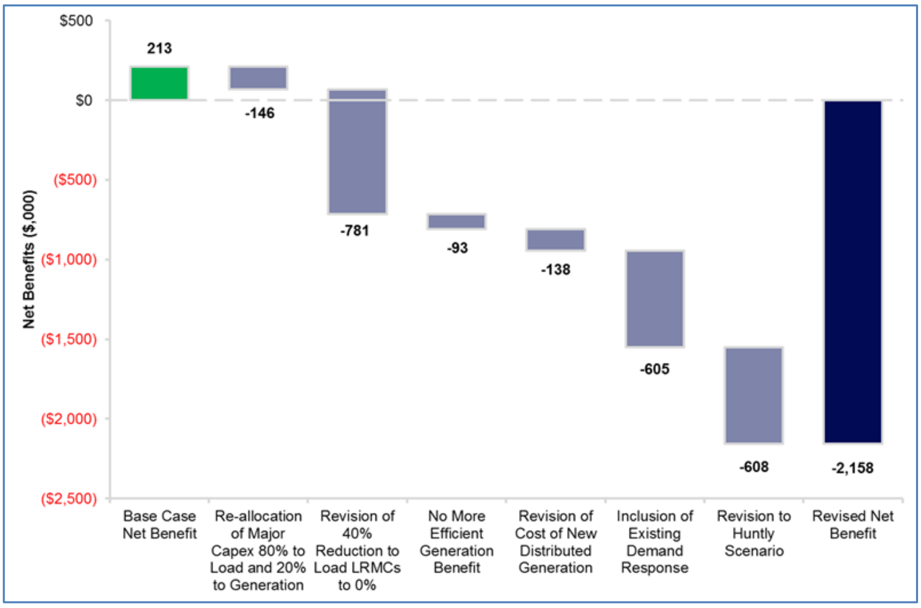
2. Figure S3.1 below summarise the key sensitivities and highlights in green shaded the sensitivities presented with the proposal vs blue shaded key sensitivities identified by Pioneer in its review:

Figure S3.1 – Key Sensitivities of the TPM cost-benefit analysis



3. Figure S3.1 illustrates how those sensitivities may compound, against the TPM cost benefit baseline assumptions presented in support of this proposal.

Figure S3.1 – TPM Cost-Benefit Sensitivities



4. The figure highlights the potential effect of those sensitivities for good reason, because many of these modelling parameters have been arbitrarily set and they do not reflect current New Zealand market realities. For example,

   - The Load/Generation balance as shown above actually reflect Concepts forecast AOB charges
   - There is more efficient generation in the market than as modelled
   - The 40% reduction to Load Forecast has a double counting issue
   - The existing demand response levels are maintainable, rather than capped at 5%
   - The Huntly goes scenario is more appropriate for the long term forecast
   - The RCPD Charge error assumption as modelled are incorrect

5. Given these 5 inputs are so influential in the cost-benefit outcomes, Pioneer has ascertained that the OGW analysis, had it been modelled using evidence-based input assumptions, would return a negative present value for this proposal. At best, the outcomes would be -PV500, with +/- sensitivities of PV1000m.

6. Pioneer concludes that the TPM CBA does not meet the Authorities statutory objectives and the guidelines to Transpower should therefore be less prescriptive and allow them to consider developing the Status Quo regime.