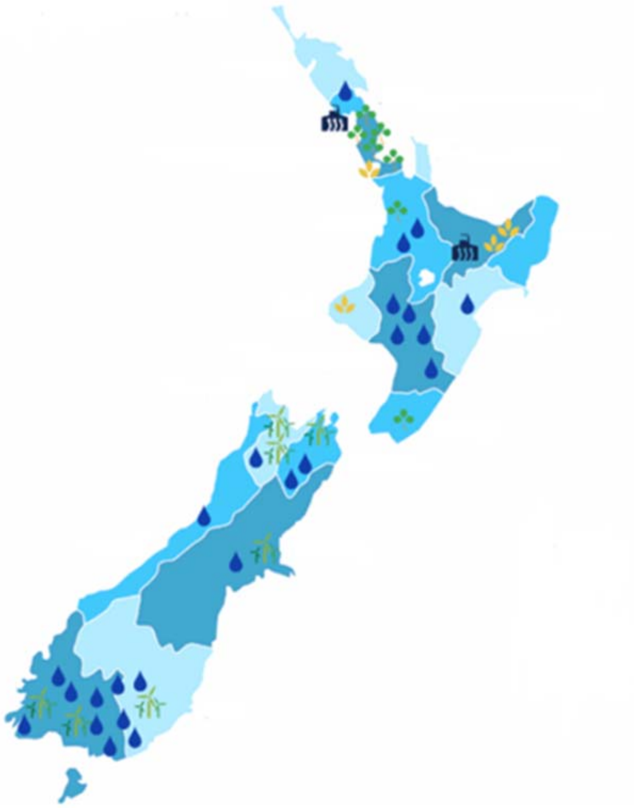
IEGA
INDEPENDENT ELECTRICITY GENERATORS ASSOCIATION



IEGA Submission to the Electricity Authority on

Review of Distributed Generation Pricing Principles: Consultation Paper 17 May 2016

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Name of submitter: Independent Electricity Generators Association

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1. Introduction

This submission is on behalf of the Independent Electricity Generators Association (IEGA). We appreciate the opportunity to make submissions on the Electricity Authority's (Authority's) consultation paper on the Distributed Generation Pricing Principles (DGPP). We have also read the Authority's Second Issues Paper on the transmission pricing methodology as the proposals are interrelated.

The IEGA does not support the proposed changes. Our view is that the status quo is more supportive of the Authority's statutory objective than the proposals. We conclude that:

- The key pricing issues identified by the Authority are due to economic sizing of transmission, not to the investment or pricing efficiency of distributed generation as alternatives to transmission services – as acknowledged by Oakley Greenwood in their TPM cost-benefit analysis. DG providers were not the causers of the over-capacity and in many cases transmission has been built around existing DG power stations that actually preceded those capacity services to consumers.
- The Distributed Generation Pricing Principles (DGPP) was regulated in 2007 after many years' consultation and regulatory due process. These regulations do not set the price of avoided system costs, but only the process by which these recognised locational benefits are contracted.
- By unilaterally removing the DGPP regulations from Part 6 of the Code, the Authority hasn't acknowledge the original competition policy objectives and the primary reasons for implementation of these regulations in 2007 (ref: Section 32(1)(a) of the Electricity Industry Act 2010)
- The DGPP proposal has not been adequately processed as required for code developments (ref: Section 21(1) Electricity Industry Act 2010). The Authority should have undertaken a Market Review and appointed an Advisory Group, as envisaged in the Code, to help fill in apparent knowledge gaps on existing and emerging distributed generation and demand side management market benefits.
- Any changes made to Part 6 of the Code following this review will need to be incorporated into the Transpower TPM proposal and implementation programme. Alignment of change process will ensure that fair bargaining principles are being applied, and that any regulated changes to existing market counterparty relationships, for payment of current and future locational capacity services, are also supported by the Commerce Commission through an approved price path revenue adjustments.

Appendix 4 covers an independent financial and market value review of the potential impacts of the Authority's DGPP proposal. This concludes that the potential sector wealth destruction is between $0.5bn and $1.5bn.

IEGA supports the submissions by Pioneer Energy and Trustpower. Individual members of the Association are also making their own submissions and are likely to cross-reference this submission as members.

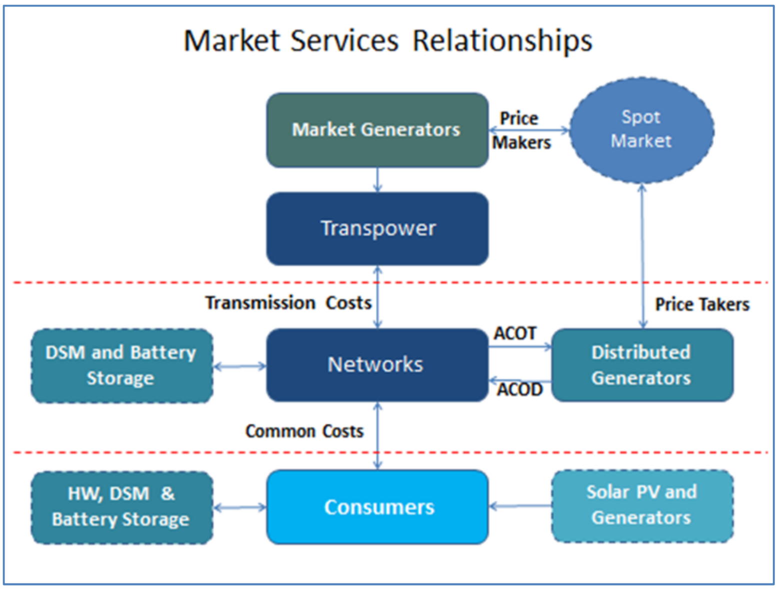
2. Background on the IEGA

The IEGA comprises approximately 40 members who are either directly or indirectly associated with predominately small scale power schemes throughout New Zealand for the purpose of commercial electricity production.

Our members have made significant economic investments in approximately 90 generation plant throughout New Zealand that is embedded within local distribution networks with 95% of their production being renewable energy. These are small, entrepreneurial businesses, essentially the SME's of the electricity generation sector, providing significant benefits to the regions in which we operate. The aggregate capacity of our member's plant make the IEGA the sixth largest generator in New Zealand and the combined portfolio benefits of DG to the energy market is material.

IEGA members own distributed generating plants that export electricity in to their local network and for the most part do *not utilise transmission services*. The services provided by our sector assets differ from market generators and from consumer-owned DG predominately for own use, and the regulatory approach should be commensurately different.

Figure 1 – DG Supply Chain and Services



The Distributed Generation Pricing Policy (DGPP) regulations were regulated specifically to account for this unique locational position in the electricity market supply chain. The revenue benefits, described as avoided and avoidable costs of transmission and networks (ACOT/ACOD) are locational benefits. Consumers and Networks also derive similar benefits by investing in load control, storage or smaller scale generation located behind the load meters that provide a similar service.

3. Distributed generation has been the backbone of the electricity system

The IEGA discussed our valuable contribution to New Zealand's electricity system with the Minister of Energy & Resources in March 2016. Earlier this year the Government provided their view of the value of distributed generation, writing:

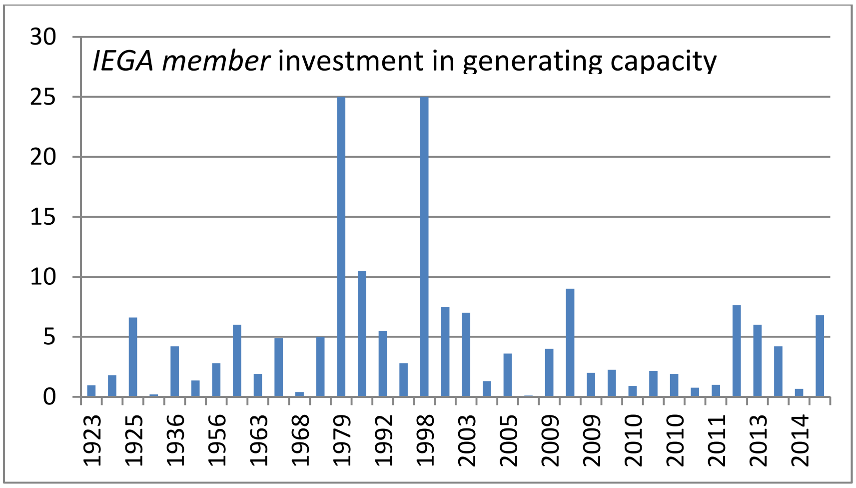
> *"The Government is very supportive of distributed generation and its contribution to our renewable electricity advantage. Distributed generation comprises a significant portion of New Zealand's generation and plays an important role in helping deliver New Zealand's energy objectives …"*

IEGA members currently operate 266MW of generating capacity. The commissioning dates for 35% of this capacity are unknown. For the plant where commissioning data are known:

- 70% of this capacity was in place in 2004 – prior to the cut off for historic transmission investment being applied in the TPM analysis
- 30% was commissioned since 2005 – when work had already begun on the Electricity Governance (Connection of Distributed Generation) Regulations had begun
- 28% was commissioned since the Regulations were promulgated
- 10%, or 17MW, was commissioned since the May 2013 TPM First Issues Paper conference was held when the impact of the TPM changes on DG was identified as an unintended consequence.

This demonstrates that our distributed generation capacity has been a core part of the systems used to deliver electricity to New Zealand consumers for nearly a century and in many instances preceded the transmission grid and provided all energy and capacity services to local consumers.

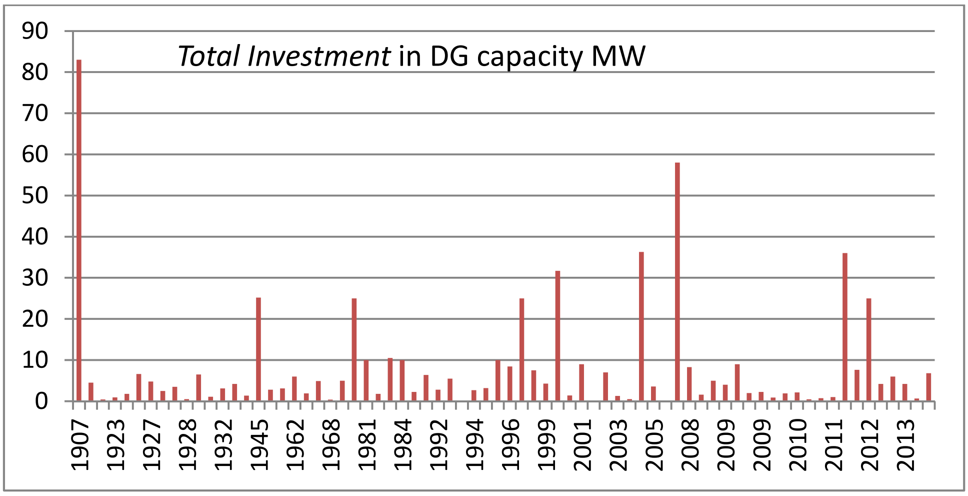
Figure 2 – History of Investments in DG



DG growth in the market is not a recent phenomenon that has materially changed the market environment, or given reason for the Authority to be making sudden reversals in policy and dramatic changes to the DG regulations.

The profile of total investment for all DG capacity (not just IEGA membership) in New Zealand is similar – note the different capacity scales on these two graphs.

Figure 3 – Total Investment in DG.

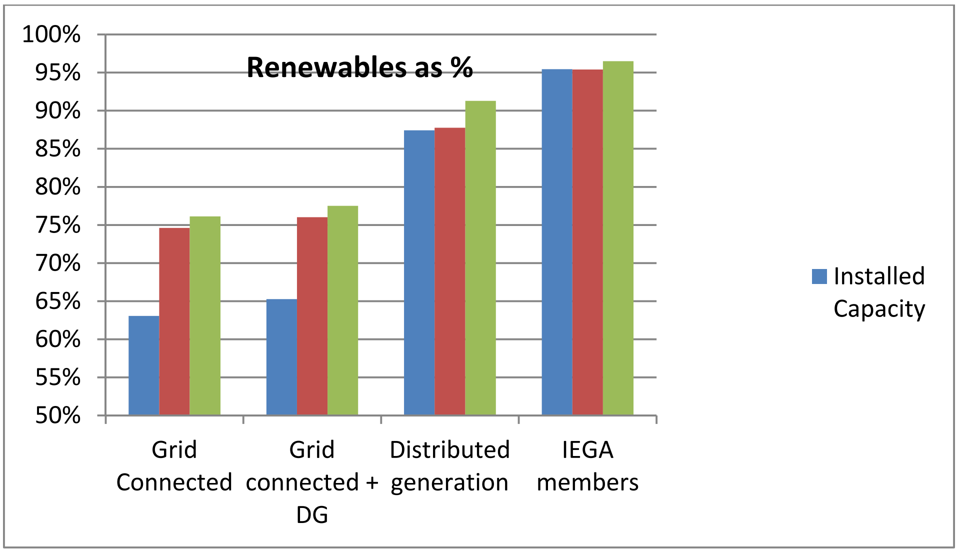


- 61% of this capacity was in place in 2004 – prior to the cut off for historic transmission investment being applied in the TPM analysis
- 32% was commissioned since 2005 – when work had already begun on the Electricity Governance (Connection of Distributed Generation) Regulations had begun
- 32% was commissioned since the Regulations were promulgated
- 4% was commissioned since the May 2013 TPM First Issues Paper conference was held when the impact of the TPM changes on DG was identified as an unintended consequence.

The DGPP proposal and the Authority's public presentations have elected to compare DG vs Grid Renewable MW capacity, rather than comparing actual renewable energy production. This is a mistake that is misleading to stakeholders and a fact that has been ignored by the Authority in its TPM DG input assumptions that materially changes the present value benefits of TPM and DGPP cost-benefit analysis (cross-reference; Pioneer Submission on the relationships between the TPM and DGPP cost-benefits reviews).

The following graph demonstrates that IEGA generation capacity is more renewable producing than grid connected generation and the system as a whole.

Figure 4 - % of Renewable Production from DG vs Grid Connected Generation



For clarity to the Authority and government stakeholders, we summarise the key attributes of the DG sector;

- Most DG is renewable and is market competitive.
- Most DG are spot price-takers in the NZEM market, so are priced as efficiently as the larger scale Market Generation.
- Most DG can compete in the NZEM due to their unique supply chain position and generation location benefits of not requiring access to grid transmission services.
- Many of these DG plant have supplied their local regional networks prior to the grid being built around them, so have a proven track record of reliable service.
- In many instances, DG plant still provides an important security of supply and network "islanding" service capacity. This includes DG servicing many hospitals, institutions and large industrial producers.
- There are significant portfolio benefits of DG in the national electricity market context, from a sector which totals more than 950MW of capacity and 3,200GWh of local production (ref; Commerce Commission Information Disclosures 2015). These benefits have not been assessed by the Authority but were assed previously under a multi-agency Government review when regulations were made in 2007.
- Together with complimentary consumer load management, these combined network connected peak capacity services flatten more than 20% of New Zealand system peak demands. This valuable market service to consumers is paid only at the avoided marginal costs of transmission services, and at lower prices than paid to consumers for the same network services.

  - Current ACOT pass through network payments for DG provision of those consumer service benefits is \$52m per annum or an average of \$16/MWh. The average ACOT payments over 5 years are nearer to \$35m per annum, however the average MWh costs have been reasonably steady at \$14/MWh to \$16/MWh.
  - For comparison, the transmission capacity services costs are between \$16/MWh and \$25/MWh and controlled/uncontrolled tariff incentives to consumers for the provision of similar demand management capacity average \$34/MWh, with range from \$10/MWh through to \$80/MWh. (Calculated from ComCom 2015 Information Disclosures).
  - Pioneer has calculated in its TPM and DGPP Submissions that these market services enable consumers to avoid an estimated \$500m per annum of peak spot market energy costs and system energy losses.

IEGA believes that the Authority has misrepresented ACOT payments as a market subsidy, when in fact the wholesale spot market benefits to consumers from DG far outweigh the economic costs to consumers of those pass-through payments. IEGA contends that DG is currently underpaid for the market benefits that are accrued and this view has been acknowledged in many overseas regulations.

This debate is not uncommon and we note following commentary from a recent USA regulatory advisory project (RAP[1]):

> *"Some utilities have expressed concern that DG adopters are undermining the financial foundation of the electric system. They argue that DG is failing to pay its fair share for its use of (and the ongoing dependence of its owners on) the electric grid. DG developers and advocates argue that the value being provided to the electric system exceeds the cost that ratepayers contribute, and so, if anything, they are being under-compensated for the services they provide."*

Our issue is that the required Market Study and Advisory Group inputs have not been undertaken to support removing the current Code. The balance of the RAP report outlines the different DG value components that would need to be investigated to make an informed decision on changing the regulations.

[1] RAP – Regulation Assistance Project October 2013 – Designing Distributed Generation Tariffs Well Fair Compensation in a Time of Transition Report on Distributed Generation Regulations

3. Authority's proposals place distributed generation at a competitive disadvantage

The Authority's proposal to remove Part 6.4 from the Code is an irreversible change. The Authority recognises this but places little weight on the fact that this change is contrary to Principle 4 of the Consultation Charter. This change is not small scale 'trial and error' or reversible but a dramatic sweeping change for minimal positive benefit. Further, the CBA is based on spurious assumptions.

IEGA submits that this change will place our distributed generation at a competitive disadvantage to other entities providing the same services. This is not consistent with the Authority's statutory objective to promote competition or efficient operation and investment in the sector. It could also have consequences for reliable supply of electricity given that all distributed generation supplies nearly 10% of the electricity consumed at ICPs.

This competitive disadvantage is discussed below:

Our DG will be at a competitive disadvantage to grid connected generation

Our distributed generation will:	**Grid connected generation:**
• be exposed to a different unregulated methodology by each of the 29 network companies for calculating connection costs	• face connection charges that are consulted on and form part of the TPM in the Code. Transmission connection charges are set in a transparent and consistent way across the country
• not have access to a dispute resolution process as there will be no rules to breach	• can use the dispute resolution process for any disputes with Transpower
• face an allocation of the common costs of network companies	• does not pay the network company any charges
• be considered as part of 'load' in the proposed TPM – being allocated transmission charges by network companies on the basis of capacity	• face MWh volume charges for the use of the transmission grid which can be included in wholesale market offer prices
• continue to be price takers and unable to recover the increase in network and transmission charges through offers into the wholesale market	• can alter their offers into the wholesale market to recover any increase in transmission charges

Our DG will be at a competitive disadvantage to DG behind load

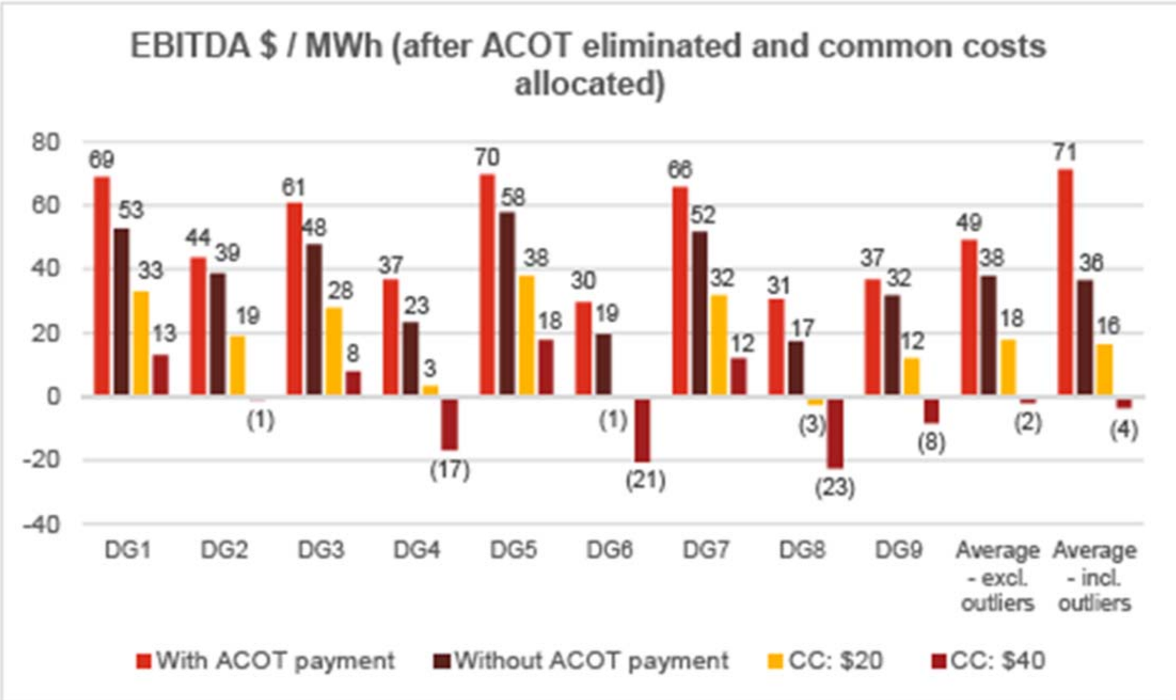
Our distributed generation will:	**DG behind load:**
• be exposed to a different unregulated methodology by each of the 29 network companies for calculating connection costs	• does not face connection cost from the network company
• face an allocation of the common costs of network companies	• does not pay the network company any charges
• be considered as part of 'load' in the proposed TPM – being allocated transmission charges by network companies on the basis of capacity	• may also considered as part of 'load' in the proposed TPM – being allocated transmission charges by network companies on the basis of capacity
• pay transmission charges on a MWh basis for any volumes exported on to the transmission grid	• does not pay transmission charges
• continue to be price takers and unable to recover the increase in network and transmission charges through offers into the wholesale market	• contract with attached load likely to allow recovery of increased charges

Our DG will be at a competitive disadvantage to DG owned by network companies

Our distributed generation will:	**DG owned by network companies:**
• be exposed to a different unregulated methodology by each of the 29 network companies for calculating connection costs	• face no regulatory control of the connection charges their network company charges its arms' length generation entity
• face an allocation of the common costs of network companies	• potentially face an allocation of common costs from their arms' length network entity which is unlikely to be transparent
• no longer have a backstop process (in the DGPPs) to negotiate connection with network companies	• will be negotiating with its own arms' length network entity
• no longer have access to a dispute resolution process	• unlikely to have a dispute with its own arms' length network entity
• be attempting to negotiate service based payments for the services provided by existing and new DG with a monopoly network company with asymmetry of information	• will have more information about the state of the network and how its DG is assisting the network company in deferring or avoiding investment

4. Financial implications of the proposals for our members

IEGA contracted financial advisors PwC to assess the market value impact of the proposals on members' generation investments. PwC's report is attached. A reduction in ACOT payment and increase in connection costs have been analysed by PwC and the key conclusions of this report are illustrated in the figure below:



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.

We note the potential sector wealth destruction is between $0.5bn and $1.5bn.

In addition to these regulatory imposed changes our members are expected to incur costs in establishing agreements with Transpower and our network companies. The Authority has made no attempt to value this cost and disruption, despite annual costs across the entire DG sector (comprising 90 small power stations) of only $206,000 being sufficient to change the Authority's CBA's positive NPV to a negative value, which would indicate the Code change is not consistent with the Authority's statutory objective.

Some of our members are and will be spending money investigating the cost of by-passing the network company (being standalone) in order to be in an informed position to discuss the allocation of common costs. These investigation costs are an inefficient use of scarce resources when our assets are well established part of the assets and management of the local network.

This is a considerable negative impact on investor confidence arising from a proposed rule change that has a negligible net positive value. Many members have relied on the 2007 regulations and government endorsement of those changes when making investment in high capital value, long term assets.

Further, it is a transfer of wealth from commercially successful small to medium business owners, to electricity consumers, for no assumed impact on electricity prices. New Zealand has a high proportion of small to medium business owners across the economy. The possibility of a regulator destroying their personal wealth for an ill-defined 'economic efficiency gain' could have consequences for investment by SME's in other parts of the economy.

The Authority's Chair, seemingly now oblivious to creating regulatory wealth transfers, has in the past issued warnings to consumers of the impact of the opposition parties' NZ Power proposal on investor confidence[2], quote;

> *"…unilateral and ex post wealth transfers from producers to consumers that would have a chilling effect on investment in the electricity sector, and probably elsewhere in the economy."*

This quote now applies equally to the Authority's current proposal to disrupt the operation and investment in DG.

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[2] Source: https://www.ea.govt.nz/dmsdocument/15066 page 27-28

5. The Authority has an inconsistent view of the value of distributed generation

The Authority expresses inconsistent views about the value of distributed generation in its DGPP and interrelated TPM papers.

- The DGPP CBA claims that 80% of the positive value from the proposals arises from the impact of the changes on new investment in DG. There is therefore minimal value from applying the proposed changes to existing DG.
- The Oakley Greenwood TPM CBA assumes all existing DG is efficient and continues to operate. OGW comments in footnote 52[3] that existing distributed generation "is actually contributing slightly positive economic benefits in the future even with the RCPD charge".
- The TPM CBA states that "the cost of providing transmission services to load customers is inextricably linked to the level of peak demand that end customers place on the network"[4] and recognises that DG is an efficient and effective way to reduce peak demand levels as an alternative to transmission investment[5].
- There is no factual explanation of way the Authority considers DG to be inefficient. The Authority's concern seems to be more about the signals for operation and investment in DG arising from the current transmission pricing methodology. This methodology will in the near term be more "efficient" – resulting in the value of any change to the DGPP's being almost zero under the Concept DGPP CBA.
- There are numerous renewable consented and proposed new generation projects that are likely to be embedded. The Resource fact file database on Energy News lists 98MW total or 10 consented renewable projects which are each no more that 20MW capacity. A further 80.8MW and 9 projects respectively are under investigation or on-hold. Using this information means the CBA for changing the TPM would be approximately negative $50million on this assumption alone.
- The Authority proposes to remove the DGPP for DG based in the LNI and LSI from 1 April 2017 because this will "deliver most of the net benefit of the proposed new ACOT payment regime early in the transition, as distributed generation located in the LNI and LSI transmission regions are considered least likely to deliver avoided transmission benefits"[6]. However, the LRMC for transmission in the TPM CBA is highest in the LSI – implying DG has the highest value in that area to defer transmission investment.

The Authority is also proposing different treatments in relation to existing assets. Existing investments by load customers are protected as load customers that face residual transmission charges above their willingness to pay under the proposed TPM can apply for a discount. Customers facing an AoB charge that is above their willingness to pay can initiate a review by claiming a material change in circumstances or optimisation of the transmission assets. There does not appear to be a similar mechanism for small generation businesses connected to a local network. The Authority is not proposing the same type of discretion or flexibility to investors in DG. In fact the above TPM proposals introduce a subsidy from one group of transmission customers to another as the total amount of revenue collected by Transpower remains unchanged.

[3] Source: https://www.ea.govt.nz/dmsdocument/20716 page 45
[4] Page 51 Oakley Greenwood Report in TPM Second Issues Paper
[5] Ibid Page 35
[6] Source: https://www.ea.govt.nz/dmsdocument/20718 page I

6. Concern about the specific proposals

IEGA is significantly troubled by the Authority's proposals that:

1. mean network companies can charge existing and new DG anything they like for connection costs, with no recourse to a dispute resolution process
2. requires individual DG owners to negotiate with monopoly transmission and distribution network providers that compete with DG.

We discuss these two proposals below.

1. Connection charges

The proposal is that network companies can charge what they like for connection costs – up to the cost of the DG being connected to the transmission grid.

This is an open-ended exposure to costs that is unlikely to be settled for some years – we refer to the letter to IEGA from Authority General Manager, John Rampton which states:

"Information at the level of detail that your members would require to assess the impact of the DGPP proposals on their businesses will not be available for some years."

If this information is not available for years how can the Authority be definitive that the benefits of the proposal are positive?

The Authority assumes network companies are incentivised to implement efficient charges for connection – incremental charges are economically efficient. It is not clear that existing DG is currently paying only incremental costs. The DGPPs are a backstop arrangement that applies if the network company and DG owner cannot agree. In order to achieve agreement some DG owners may already be paying more than incremental costs.

There will be no restriction on network companies allocating common costs to DG to the point where the DG owner is financially stressed and puts the DG assets on the market. The network company could then purchase these assets at a knock down price, put the assets in its unregulated arms' length generation entity and adjust the common costs charges to reallocate them away from their DG to the other regulated consumers on their network. The allocation of common costs is currently not transparent and likely to result in market competition issues. Further each network company has its own methodology.

We are very concerned that network companies have complete discretion to apply the voluntary distribution pricing principles in a way that is 'efficient' or suits their network assets and management of assets. We note that the Authority expressed concern, in a recent letter to the Commerce Commission, about the asymmetry of information and the Authority's ability to monitor the efficiency of distribution pricing. While this concern related to a proposed change to the determination of total network revenue – it is unclear to the IEGA how the Authority will monitor the efficiency of network charges even under the current revenue determination methodology.

Proposed changes to the TPM are also relevant to this. The proposal is for network companies to pay an increased proportion of transmission charges (80%) and based on capacity. The proposal is for this capacity to include DG capacity – penalising network companies with a high proportion of DG supplying electricity to their consumers. As a network company faces higher transmission charges and reallocates 'common costs' it is conceivable that DG could be allocated a higher proportion of common costs than is 'efficient'.

Does the Authority plan to monitor how network companies allocate common costs to DG to ensure the allocation is 'efficient'?

Further, the proposal results in removal of any backstop arrangements and the opportunity to use the Rulings Panel if there is a dispute. As there will be no rules a DG owner cannot claim a breach. We have asked the EGCC if their jurisdiction would cover a dispute between a DG owner and charges by a network company – the answer we have received is **NO**.

2. Negotiating with two monopoly network owners for service based payments

The Authority expects DG to negotiate with Transpower and network companies for service based cost reflective payments. We question what incentives Transpower and the network companies have to enter the negotiations. This is especially the case when neither monopoly will be funded to make the payments:

- Transpower will have to seek approval from the Commerce Commission for an increase in its Maximum Allowable Revenue
- If Part 6.4 is deleted from the Code the network companies cannot pass any distributed generation allowance through to their customers. As well as developing an approach to make service based payments to DG as part of its overall expenses, the network company will have to decide how to pass this cost on to its customers.

Negotiating with Transpower

There are a number of other reasons why the Authority's proposal for DG owners to negotiate with Transpower is disingenuous, namely:

- The Authority has made it clear in the Consultation Paper that it has pre-determined the outcome of these negotiations, for example:

  "For these regions [LSI and LNI], it is unlikely that Transpower will contract with many distributed generators for transmission support. This is because distributed generation in these regions is less likely to deliver avoided transmission benefits." (para 4.3.7)

- The timeframe for implementing this proposal is completely unrealistic. We consider the following process is necessary to ensure robust negotiations:
  - Submissions on DGPP received late July – at the same time as the TPM submissions.
  - The Authority must take the appropriate length of time to consider submissions on the DGPP consultation paper before making a decision. A reasons paper should be issued at the same time as announcing the decision.
  - The Authority informs the Commerce Commission under section 54V, as soon as practicable, following any change in the Code that result in increased costs to Transpower or to any distributor or class of distributors.
  - Transpower has to apply to the Commerce Commission for additional funding to cover the cost of developing the mechanism for payment (set up costs) and for funds that are available to pay DG for its services.
  - Transpower can only start any negotiations with DG owners that could be legally viewed as 'good faith' once it has sufficient funds to pay for any agreement reached.
  - Transpower has to develop the economic, commercial and legal framework before commencing any negotiations to ensure a consistent and fair process and approach.
  - At the same time the Authority expects that Transpower to be prioritising development of the TPM guidelines. The Commerce Commission is yet to approve any funding for this TPM work.

The transmission grid has been built around many of the DG. Transpower currently do not have the information it needs to establish what the grid would look like without the existing DG – and thus the value that DG provides. In addition to the above process, Transpower must model the grid assuming there is no signal to reduce consumption during periods of potential peak demand. Following that scenario, created by the proposed changes to the TPM, Transpower must adjust the volumes transported on the grid assuming there is no load control and no DG exporting into local networks. This is complex modelling but must be completed for the whole system before any negotiations can commence with any DG owner.

In addition to the above, until the TPM is settled (maybe April 2019) Transpower does not know what form transmission charges will take and how these charges can be reflected in service payments to DG. This is a significant flaw in the Authority's proposed timeframe for changing the DGPP. This cannot be consistent with the efficient operation and investment in distributed generation.

We submit it will be difficult for our DG to be competitive with non-transmission solutions initiated by Transpower, such as its Demand Response Programme as:

Our distributed generation will:	**Transpower transmission planning:**
• offers incremental capacity increases to meet growth in demand	• involves economies of scale and potential for efficient investment in over capacity
• require aggregation to be comparable with transmission investment	• results in lumpy investment
• have limited access to up-to-date information about potential areas of the transmission grid	• identifies non-transmission solutions at an early point in its planning process with little ability to revisit investment decisions
• has different planning timeframes for new investment	• has different planning timeframes for new investment
• be attempting to negotiate service based payments for the services provided by existing and new DG with a monopoly network company with asymmetry of information	• will have more information about the state of the network and how its Demand Response programme can assist in deferring or avoiding transmission investment
• be offering electricity volumes beyond the connection with the grid that is not dispatched by the System Operator	• has experience in the System Operator at working with reductions in demand and therefore may have a bias for demand response

Further there is evidence the Authority has not used, to show that DG has more value and provides consumer benefits in every region of New Zealand. These portfolio benefits are discussed in Pioneer Energy's submission on the TPM.

Negotiating with network companies

DG has and is providing a service to network companies. We have been incentivised to generate during periods of peak demand on the network, reducing or avoiding the need for distribution investment. While there has been only one network company that has paid the avoided cost of distribution (ACOD) there have been other arrangements between DG owners and the network company to recognise the value of DG. Networks have also built their assets around distributed generation, and implemented load control initiatives – such as offering a discount for customers on a controlled tariff. As discussed in Pioneer Energy's TPM submission network payments to DG are considerably lower than the revenue they forgo for customers electing load control tariffs.

Network companies value management of peak demand. Numerous of their pricing methodology reports and asset management plans describe how peak demand management is used to avoid or defer network investment. Some examples are:

> PowerNet 2016/17 pricing methodology: "*This is because the most significant cost driver that influences investment requirements in the network is the combined peak demand of all consumers in an area. PowerNet designs and constructs its network to meet this peak load.*

This ensures that prices signal the impact of additional demand on future investment costs." (pg 8)

Alpine 2016/17 pricing methodology: "*Allocating costs in this manner reflects that future costs to upgrade and or replace assets are driven by consumer use of the asset at peak times.*" (pg 17)

Vector 2016/17 pricing methodology: "*Vector aims to allocate asset-related costs on the basis of a consumer group's usage of the assets during peak periods as this usage drives the need for, and the size of, the assets.*" (pg 13)

Unison 2016/17 pricing methodology: "*In particular, it is essential that consumers face relative price signals that reflect the benefits of consuming outside of network peaks, as it is peak demand (not total volumes consumed) that drives Unison's long-term cost structure.*" (pg 14)

Wellington Electricity 2016/17 pricing methodology: "*This will provide consumers with the ability to reduce electricity charges by reducing usage during peak demand periods and may allow WELL to reduce or defer investment in the network."* (pg 12)

We have tried to discuss with our network companies how they might approach making service based payments to existing DG but have had limited engagement. Network companies are faced with considering and making submissions on changes to the Commerce Commission's Input Methodologies and transmission charges at the same time as the DGPP proposals – which are probably a lower priority. We requested an extension to the submission timeframes to enable our advisors to consult with Networks on behalf of all members. Our request was turned down by the Authority, despite their own acknowledgement that wealth transfers from DG are likely to be more than PV300m. This response shows a callous disregard for long term small business owners in this market.

IEGA anticipates the issues that many of us experienced prior to promulgation of Electricity Governance (Connection of Distributed Generation) Regulations will reappear. The incentives on network companies (and Transpower) are no different now than they were in the early 2000's. In fact relaxation of the ability for network companies to own DG can be expected to make them even more difficult to negotiate given that third party owned DG will compete with their ambitions to own and operate generation.

We understand this 'free-for-all' unregulated approach to reaching agreement with network companies for connection costs and service based payments is in sharp contrast to the Authority's approach to the relationship between retailers and network companies. The Authority is arguing for a mandated agreement claiming major benefits from lower transaction costs and reduced potential for disputes.

We note that the Australian Energy Market Commission is considering a rule change proposal prepared by Oakley Greenwood on behalf of its clients for a 'Local Generation Network Credit'. There have been positive submissions on this proposal and a decision is expected in the near term. This will create a regulated service based payment by network companies to distributed generation. The AEMC has a very similar statutory objective to the Electricity Authority. We submit the Authority must seriously consider the route the AEMC is taking to recognise the benefits of DG and provide consistency and investor certainty for DG owners.

7. Proposed solution

In our view the 'efficiency' impact of DG that the Authority is trying to address is the quantum of payments resulting from using the Interconnection Rate to calculate ACOT payments. We acknowledge that there has been recent investment in the transmission grid that has resulted in an increase in the Interconnection Rate, and an increase in transmission capacity. Our DG has not caused the overcapacity in the system used to deliver electricity to consumers. It is economically efficient to continue making payments to DG even if there is excess capacity to deliver electricity – see the submission by Pioneer supported by advisors Morrison Low.

The Authority has recognised that Transpower is a beneficiary of the existence of current DG. The TPM CBA states that existing DG is efficient and the Authority expects DG to contract with Transpower for the service DG provides.

The IEGA submits that Transpower has no incentive to negotiate with DG owners as it is a monopoly, its expertise is in building and managing lumpy transmission assets as well as more recently developing expertise in arranging demand response by load customers. While Transpower has been required for many years to consider non-transmission solutions as part of developing any grid upgrade project it has not, to our knowledge, contracted with distributed generation to defer or avoid transmission investment. Further Transpower has no budget to pay DG for the services it provides.

The current transmission grid incorporates existing DG. Transmission planning has been undertaken taking into account existing DG (see Transpower's Transmission Planning Reports).

We recommend that consideration be given to the Commerce Commission being responsible for establishing a price path to be paid to DG for the current and future services offered by DG as an LRMC derived component part of the Commission's determination of the Price Quality Path for Transpower.

The Commission already approves transmission investment, has an understanding of the competitive long run marginal cost of new transmission and is responsible for determining the maximum allowable revenue that Transpower can collect from customers.

This possible solution places the responsible for determining the value of DG services to a regulator. This value is likely to be more efficient than that developed by a monopoly who benefits from the service but has no incentive to offer a fair price.

The same approach could also be applied to the avoided cost of distribution – consistent with the regulated approach in Australia promoted by Oakley Greenwood.

Under this solution Part 6.4 of the Code remains highly relevant, only requiring a review by the Commerce Commission as part of its Part 4 Price Quality Path determination. This mechanism could also be a precursor for future evolving technologies.

Further, under any solution the DGPPs must be retained to ensure that the monopoly transmission and distribution networks pay for the services they benefit from provided by DG. The services based payments, developed by the Commerce Commission under our suggestion, will be an efficient 'beneficiaries pay' charge.

Yours sincerely

Warren McNabb
Chairman

Appendix 1- **IEGA response to Authority's questions**

Q1	**Do you consider that the proposed Code amendment described in section 4.1 is preferable to the status quo and the alternatives described in section 4.6?** **If not, please explain your preferred option(s) in terms consistent with the Authority's statutory objective.**

IEGA does not agree that the proposal to remove Part 6.4 from the Code, and the subsequent amendments, better meets the Authority's statutory objectives than the status quo.

Our view is that the status quo is more consistent with the Authority's statutory objective than any of the proposals in the consultation paper – in section 4.1 and 4.6.

Our cover letter clearly outlines all our reasons why IEGA does not agree that the proposal to remove Part 6.4 from the Code better meets the Authority's statutory objective than the status quo.

Q2	**Do you consider that the proposed Code amendment described in section 4.1 is preferable to the status quo and the alternatives described in section 4.6?** **If not, please explain your preferred option(s) in terms consistent with the Authority's statutory objective.**

As noted above IEGA does not consider the proposed Code amendment in section 4.1 is preferable to the status quo. One option has not been discussed in the consultation paper – although it is a counterfactual in the CBA analysis. That is, make no change to Part 6 of the Code and rely on the new TPM to achieve efficient investment in distributed generation.

We note that the TPM CBA assumes all existing DG continues to operate as in the past and investment in DG contributes to meeting annual growth in demand for electricity. Some of the assumptions relating to DG in the TPM appear to be very spurious. The cost of investing in DG fuelled from renewable resources, as opposed to that assumed for diesel fired DG, makes new investment in DG significantly more attractive in the TPM CBA relative to new transmission investment, or grid connected generation.

In summary, IEGA does not consider the proposed Code amendment in section 4.1 or the alternatives described in section 4.6 to be preferable to the status quo.

The status quo also achieves the benefits the Authority are seeking as the proposed TPM eliminates any service payments to DG based on transmission charges based on peak demand volumes. The Authority cannot say implementation of a new TPM is uncertain when it is completely under the Authority's control. While Transpower might be responsible for writing the transmission pricing *methodology* based on the *guidelines* approved by the Authority, the Authority is responsible for approving the methodology proposed by Transpower.

Q3	**Do you consider that the proposed Code amendment described in section 4.1 complies with section 32(1) of the Act, and with the Code amendment principles, and should therefore proceed?**

Compliance with section 32(1) of the Act:

IEGA do not consider the proposal meets Section 32(1) of the Act. The removal of DGPP rules lessen competition for transmission and network alternatives and the allocation of network common costs introduce new charges that are not also allocated to competing Market Generators supplying energy to consumers from the transmission grid. The proposed Code changes do not acknowledge or recognise the original objectives of including DGPP in the regulations. IEGA cross-references Pioneer Energy's DGPP submission detailing the history and reasons leading to those regulations.

Compliance with the Code amendment principles:

IEGA submits that the analysis of the application of Principle 4 is mysterious. The paper states that the change is NOT small-scale 'trial and error'. However, the EA has placed no more weight on this principle than the other principles that the Authority concludes the proposal is consistent with. There is no explanation of how the other principles provide a greater benefit than implementing a proposal that is so clearly NOT consistent with the principle and the Authority's preference for "options that are initially small-scale, and flexible, scalable and relatively easily reversible with relatively low value transfers associated with doing so".

Further, there is no attempt to value the cost of this disruption in the CBA. Transaction costs are dismissed as being assumed to be "minimal". This demonstrates a clear lack of understanding of the practicalities of staying in business.

As discussed in para 42 - 45 in our cover letter, this approach by the Authority is strongly contradictory to the EA's analysis of the reasons why there should be a default use of system agreement.

For the level of Code Development, and the acknowledge material wealth transfers, IEGA would have expected a more thorough Market Review Investigation and Advisory Group support to ensure any knowledge gaps were identified and peer reviewed.

Q4	**Do you have any comments on the drafting of the proposed Code amendment described in section 4.1? (The drafting is included in Appendix B.)**

While Transpower uses the same geographic longitudes in its TPM it has been using regions for load forecasts and RCPD calculations by grouping network companies. Grouping of network companies is the only possible approach for implementing this proposal. To be more specific one DG plant within a specific network could be on one side of the line proposed by the Authority and another DG connected to the same network on the other side of the line. This proposal creates serious implementation issues for the negotiations DG owners are expected to have with both Transpower and network companies.

However, the transmission system does not operate exclusively in regions (by longitude or network region) – the transmission system is interconnected. For appropriate rigour to be applied to the analysis of the impact of the existing ~800MW of DG on transmission investment Transpower must model the whole system removing any RCPD signal and then model the system with no DG or network load control before signing any agreement with a DG owner.

Our comments on the drafting relating to the implementation timetable are included in response to Q5 and Q6.

Q5	**Do you consider that the proposed Code amendment should come into force at a single date, or should it be phased in?**

While Q5 and Q6 ask about phasing, and Q7 and Q8 ask for feedback on whether there are any barriers to implementing this proposal – the EA has not directly asked:

Can the proposal be implemented on 1 April 2017?

Can the proposal be implemented on 1 April 2017?

IEGA submits that it is completely unrealistic to assume all the necessary work would be complete by 1 April 2017. We describe our understanding of the steps required to implement the Authority's proposal:

1. Submissions on DGPP received late July – at the same time as the TPM submissions.
2. The Authority must take the appropriate length of time to consider submissions on the DGPP consultation paper before making a decision. A reasons paper should be issued at the same time as announcing the decision.
3. The Authority informs the Commerce Commission under section 54V, as soon as practicable, following any change in the Code that result in increased costs (threshold >1% change) to Transpower or to any distributor or class of distributors.
4. Transpower has to apply to the Commerce Commission for additional funding to cover the cost of developing the mechanism for payment (set up costs) and for funds that are available to pay DG

for its services. Transpower can only start any negotiations with DG owners that could be legally viewed as ‘good faith’ once it has sufficient funds to pay for any agreement reached.

5. Transpower has to develop the economic, commercial and legal framework before commencing any negotiations to ensure a consistent and fair process and approach.
   At the same time the Authority expects that Transpower to be prioritising development of the TPM guidelines. The Commerce Commission is yet to approve any funding for this TPM work.

Further, the Authority has pre-judged the outcome of any negotiations with Transpower by DG owners based in the LSI and LNI by stating that DG located in the LNI and LSI transmission regions are considered least likely to deliver avoided transmission benefits[7]. This is completely inappropriate and is contrary to the universal expectation of good faith bargaining.

Response to Q5

The transmission system does not operate exclusively in regions – it is interconnected. For the appropriate rigour to be applied to the analysis of the impact of the existing 800 MW of DG on transmission investment Transpower must model the whole system removing any RCPD signal and then model the system with no DG or network load control before signing an agreement with the first DG owner.

If phasing is used then the regions must be re-classified to be consistent with network boundaries.

[7] Source: DGPP Consultation Paper page I

Q6	Is the proposed phasing for the Code amendment appropriate? (The phasing is discussed in section 4.3.) If not, what alternative phasing or dates would you propose and why?

The EA states that one of the reasons for the phasing is:

"deliver most of the net benefit of the proposed new ACOT payment regime early in the transition, as distributed generation located in the LNI and LSI transmission regions are considered least likely to deliver avoided transmission benefits"

This is mere assertion. Publicly available information[8] reveals the following ACOT payments per MWh of output by DG into networks by region. The highest payments are made in the Upper North Island and Lower North Island, with the lowest payment per MWh being made in the Lower South Island.

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	

[8] Commerce Commission Information Disclosure analysis updated on 16 October 2015 for the 2014/15 financial year returns from network companies. At http://www.comcom.govt.nz/regulated-industries/electricity/electricity-information-disclosure/electricity-information-disclosure-summary-and-analysis/information-disclosed-march-2013-august-2015/

Q7	If the proposal were to proceed, do you consider that there would be barriers that might prevent agreements being reached between Transpower and distributed generation owners to efficiently reduce or defer transmission network costs? If so, what are these barriers? Please consider both existing and proposed new distributed generation.

The current significant uncertainty about the structure of future transmission charges will be a substantial barrier to forming any agreements with Transpower. Transpower is yet to develop how it will allocate its costs. The benefits provided by DG are interrelated to this. Future transmission charges will also impact how existing DG operates and the incentives for additional DG investment.

For example the proposed Gross AMD basis for allocating costs to load has significant flow on effects for DG – not only the service it provides as an alternative to transmission but any charges by distribution companies.

As discussed above, the exceedingly short implementation timeframe is also a significant barrier good faith negotiation and robust agreements.

Transpower is a monopoly regulated competitor to DG. The established approach and process Transpower has for its own version of non-transmission solutions – the Demand Response programme – may influence the amount of DG that is contracted by Transpower.

The scale of transmission investment, reflecting economies of scale, could be a barrier to contracting with DG. By way of example, member Pioneer Energy has already discussed the opportunity for a new hydro project to defer upper South Island transmission investment. Aggregation may provide a solution to this scale issue – but represents a barrier as it involves further costs in organising and signing commitments.

Q8	If the proposal were to proceed, do you consider that there would be barriers that might prevent agreements being reached between distributors and distributed generation owners to efficiently reduce or defer distribution network costs? If so, what are these barriers? Please consider both existing and proposed new distributed generation.

Distribution companies are even more of a competitor to third party DG owners now with relaxation of legislative limits on their investment in generation (and retail) in 2007 compared with when the Government put in place the Electricity Industry (Connection of Distributed Generation) Regulations in 2007.

The barriers discussed when the Government agreed to introduce DGPP regulations were:

1. Lack of transparent, fair and cost-reflective locational pricing mechanisms;
2. Imbalance in negotiating power between independent market providers and two competing monopolies; and
3. No incentive on monopolies to negotiate, thus requiring fall-back default terms and rulings panel escalation rules.

There are no new incentives on a distributor to ‘smoothly’ agree connection charges and service payments compared with 2007. Further, the Authority is planning to be non-prescriptive about all aspects of distribution charges and has stated that, due to asymmetry of information it may not be able to identify if resulting charges are efficient.

Of equal concern is the fact the Authority’s cost benefit analysis assumes transaction costs from implementing this proposal will be minimal. Transaction costs and the lack of a dispute resolution process or backstop agreement are likely to be major barriers to reaching agreement with distributors.

Q9	If the proposal were to proceed, do you consider that those distributors that were no longer able to recover the cost of making ACOT payments would cease making such payments?

There are two topics under this question that the Authority must consider to ensure that the proposal promotes competition and reliable supply:

1. How a distributor treats DG owned by its arms' length associate in a related party transaction? The distributor can decide how to recover this payment from consumers via a different classification of the 'expense'

2. The DGPP apply when a DG investor is constructing and connecting new plant to a distribution network. Once a contract is signed between the DG owner and the distributor, and the plant is operational, the relationship is governed by a bilateral contract.

Appendix 2 – list of members

The Independent Electricity Generators Association makes this submission along with the support of its members, listed below.

1. AD Harwood Limited
2. Aquarius Energy Ltd
3. Brooklyn Hydro
4. Clearwater Hydro
5. Inchbonnie Hydro
6. Drysdale Hydro
7. Eastland Generation
8. Energy 3
9. Electra Generation
10. EnviroNZ
11. EnviroWaste
12. Graham Berry
13. Griffin Creek Hydro Ltd
14. Harihari Hydro Ltd
15. Hydro Works Ltd
16. J.G. Wilson Hire Ltd
17. Kawatiri Energy
18. Karaponga Power
19. King Country Energy
20. Kea Energy
21. Lulworth Wind Farm
22. Mainpower
23. Marakopa
24. Mount Campbell Networks Ltd
25. Northpower
26. Nova Energy
27. NZ Energy
28. NZ Wind Farms
29. Omanawa Falls Hydro
30. Onekaka Energy
31. Opuha Water
32. Palmerston North City Council
33. Pioneer Energy
34. Pupu Hydro
35. Roaring Forties
36. Renewable Power
37. SEL Group
38. Simply Energy
39. Trust House Ltd
40. Tuaropaki Power Company Ltd
41. Valetta Irrigation Scheme
42. Waste Management
43. Weld Cone Wind Farm
44. West Coast Hydro
45. Westpower

Appendix 3 – IEGA letter to Authority requesting extension and Authority response

Appendix 4 – PWC Report: Independent Review of the Potential Impact of Proposed Regulatory Changes on Distributed Generators