Chairman: Warren McNabb,
[redacted]
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INDEPENDENT ELECTRICITY GENERATORS ASSOCIATION

3 April 2025

Submissions
Electricity Authority
P O Box 10041
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By email: distribution.pricing@ea.govt.nz

Dear team,

Re: Issues paper – Distributed generation pricing principles

The Independent Electricity Generators Association Inc. (IEGA) appreciates the opportunity to make this submission on the Electricity Authority's (Authority) proposed options to revise the incremental cost rule in the Distributed Generation Pricing Principles (DGPP) in Schedule 6.4 of the Code.[1]

A membership criterion for the IEGA is that the generation must be distribution network connected. The detail in Part 6 of the Code, including the DGPPs, is therefore of significant importance.

Investors in generation plant have a choice of connecting to a local distribution network or the high voltage transmission grid. Factors such as location of fuel and the investor's desired scale of the generation plant will influence this location decision. However, the IEGA submits the regulatory regime for connection of generation plant should not influence this location decision. A level playing field ensuring competitive neutrality is essential.

Members generation output competes with transmission grid connected generation when it is sold in the wholesale market, but the majority of IEGA members are price takers – they don't have the resources to operate 24/7 dispatch functions. We have no influence over the level of spot prices. To be financially successful the LCOE of distributed generation must be comparable with the LCOE of transmission grid connected generation.

In summary, our key conclusions are:

- all generators compete to supply electricity - a level playing field and competitive neutrality across the generation sector is essential

[1] The Committee has signed off this submission on behalf of members.

- the methodology for recovering the cost of connecting to the transmission grid or distribution network should not influence the connection location decision
- distributed generation investors are currently, and prepared to continue, paying upfront the **full** incremental cost of specific assets required for connection to distribution networks (as transmission grid connected generators do to connect to the transmission grid)
- removal of the incremental cost rule in the DGPPs will result in a different methodology for distribution network connected generation relative to transmission grid connected generation
- any charge to distribution connected generation that is above the incremental cost of connection will be a charge that is not being paid by transmission grid connected generators. Distributors do not invoice transmission grid connected generators for any costs associated with delivering 88% of the electricity consumed at ICPs
- if the Authority has determined that it is economically efficient to recover the majority of transmission 'common costs' from load customers only (the Residual Charge) the same economic efficiency argument must apply to recovering distribution network common costs.

This letter focuses on two key topics:

A. ensuring a level playing field and competitive neutrality in the regulatory regime for distributed generation. There are several reasons why the Authority's proposals are not competitively neutral.
B. addressing the ability of distributors to recover investment in Anticipatory Capacity. This problem appears to be an underlying motivator for amending the incremental cost rule in the DGPPs.

We have provided answers to the Authority's questions in Appendix B. This Appendix should be read in conjunction with our following key points:

A. Competitive neutrality

The essence of a workably / economically efficient market is competitive neutrality between all players – a level playing field. The OECD states[2]:

> **Competitive neutrality in competition policy**
>
> Competitive neutrality fosters competition by eliminating or reducing undue competitive advantages that some players may enjoy over their competitors, such as support granted by the state or regulations that favour incumbents. **Governments should ensure a level playing field between** state-owned and privately-owned enterprises, **between different privately-owned enterprises** and between domestic and foreign enterprises.
>
> Ensuring a level playing field is key to enabling competition to work properly and deliver benefits to consumers and the wider economy. [emphasis added]

[2] Source

The IEGA submits a change to the DGPPs will tilt the playing field and create a competitive advantage for generation connected to the transmission grid. Removing the incremental cost rule will mean:

i. distributors can allocate some of their common costs distributed generation. The Authority defines common costs as 'things distributors have to do that don't relate to a particular project'.
ii. the definition and treatment of 'connection asset' will be different for transmission and distribution network connections
iii. the methodology for recovering the cost of 'network' infrastructure will be different.

These three significant consequences from removing the incremental cost rule are discussed below.

1. Ability to allocate 'common costs' to distributed generation

Transmission grid connected generators use distribution network infrastructure so that their electricity is delivered 'the last mile' to the end consumer (after travelling over the transmission grid). This fact applies to both incumbent vertically integrated generators and independent generators.

Using the FY2023 EDB Information Disclosure database the total volume of electricity delivered by EDBs to ICPs was 49,853GWh (after losses). The electricity supplied by distributed generation was 5,887GWh. Grid connected generation therefore supplied 43,965GWh or 88.2% of the total electricity delivered by EDBs to ICPs.

Distributors do not invoice transmission grid connected generators for any costs associated with delivering this electricity.

Any charge to distribution connected generation that is above the incremental cost of connection will be a charge that is not being paid by transmission grid connected generators. This is NOT competitively neutral.

If there is to be an allocation of network common costs (say an 'injection charge') this rate must be paid by both transmission grid connected and distribution connected generation to ensure competitive neutrality.

2. Transmission connection charges

The Code definition of 'connection asset' is the same whether a generating plant is connected to the distribution network or the transmission network. The definition is integral to the basis of charging for connection assets.

The Code defines connection assets: "for the purposes of subparts 2, 6 and 7 of Part 12, has the meaning set out in the transmission pricing methodology".

Transpower's information sheet on Connection Charges[3] is clear that new connections are charged the incremental costs of their connection:

[3] See TPM Information Sheet Connection charges v2 February 2023

Connection charges for a particular connection asset are paid by the customer or customers connected to it.

Connection assets are grid assets that exist specifically to connect a customer to the grid, even if the customer's assets are not directly physically connected to those assets.

The key distinguishing feature of connection assets is that they are configured such that there are no 'loop flow' effects on the assets, making it possible to identify the specific customer(s) without whom the assets would not exist.

Transpower's methodology for connection assets and connection charges is the 'incremental' impact of a new generation connection.[4]

This clarity about connection assets and charges may create an advantage to being transmission grid connected.

To ensure competitive neutrality, and be Code compliant[5], Transpower's description of 'connection asset' should apply to generation connecting to distribution networks as well as charging for any connection asset being based on incremental costs.

3. Transpower's Residual Charge covers the majority of transmission 'common costs' and the Residual Charge is allocated to load customers

Transpower's Residual costs/charges are described as transmission costs that can not be specifically identified with a particular project, that is 'common costs'.[6] The Authority has made a policy decision that it is economically efficient to have the majority of these 'common costs' paid by Transpower's LOAD customers only (based on 'gross' load so that load customers pay based on the electricity they use, not only the electricity they take from the transmission grid).[7]

The Authority must be clear about why a different economic efficiency position applies when recovering the cost of distribution assets compared to transmission assets.

Any allocation of distributor common costs to distributed generation activity is a charge not being paid by transmission grid connected generation and places distributed generation at a competitive disadvantage.

4. Distributed generation is modelled in the allocation of benefit-based transmission costs

The Issues Paper includes a section titled "Distributed generators pay for fewer costs than grid-connected generators" (paragraphs 2.12 – 2.18). This section argues that "*The incremental cost limit*

[4] In a few cases the connection charge includes an allocation to new generation for shared transmission connection assets

[5] Given the Code relies on the transmission pricing methodology to define connection assets on the transmission and distribution networks

[6] Transpower's description is: "Residual charges recover the part of Transpower's recoverable revenue not recovered through other transmission charges (residual revenue)". Source: Transpower's Information Sheet on Residual Charges

[7] While grid connected generators pay Residual Charges for the 'load' at generating stations – this is estimated at a marginal ~1.25% of Transpower's total Residual Charge for FY26 (based on analysis of Transpower's customer prices spreadsheet). This is ~0.8% of Transpower's Maximum Allowable Revenue for FY24/25 of $828m. The total regulatory income of all distributors was $2,532.297 million in FY22/23

creates an artificial advantage for DG, compared to the allocation of transmission costs for grid-connected generators."

By definition. Distributed generation is not connected to the transmission grid and distributed generators are not Transpower customers. But the discussion in the Issues Paper **fails** to acknowledge that distributed generation is modelled to calculate transmission charges where the Authority has agreed with Transpower this is appropriate – that is, the distributed generation is deemed to benefit from / use the transmission grid.[8] The TPM Assumptions Book[9] lists 30 embedded generation stations that are modelled for the allocation of Benefit-Based Charges to transmission customers, including as new distributed generation is connected. Benefit-Based Charges for 2025/26 include 5 new embedded generation stations. Transmission customers (distributors) have information from Transpower about the impact of this embedded generation on their transmission charges, and as an incremental cost, could pass this cost on to the distributed generator, if inclined to.[10]

5. Distributed generation connection applications

Costs incurred in processing a connection application are separate from the cost of physically connecting generation plant to the distribution network (for example, some applications do not proceed to an actual connection). **The IEGA supports connection application processing costs being charged as an incremental cost by distributors**.

B. First Mover Disadvantage

Most of the reasons given by the Authority to revise the incremental cost rule in the DGPPs arise because of the 'first mover disadvantage'. There are two types of first mover disadvantage (FMD) – referred to as Type 1 and Type 2 in the Transmission Pricing Methodology (TPM).

Type 1 FMD

Since 2007 the DGPPs have included a rule whereby new connections within 36 months of commissioning the connection asset by the 'first mover' are allocated a portion of the cost of this connection asset. The period of 36 months impacts the amount the 'next mover' distributed generation investor pays. However, this type of first mover disadvantage has no consequence for the distributor – they have been paid for the connection asset.

Distributed generation investors are fully aware of the cost and consequence of this rule. It is not clear if any distributed generation investors have been complaining about it.[11]

This approach is the same as the TPM Type 1 FMD Funded Asset Component for transmission connection assets: "*It works by collecting, via connection charges, a financial contribution from*

[8] The modelling assumes DG realises the same benefits from a transmission grid investment as grid connected generation - by using the same approach to output from DG as from transmission grid connected generation in calculating net expected private benefits - even though DG is not using / benefiting from the transmission grid 100% of the time
[9] See Section 2.3.3.1 of Assumptions Book v2. Embedded generators are any generator >10 MW not connected to the transmission grid
[10] Some distributors have said they are not going to pass on these transmission charges because it is too complicated.
[11] We understand the Authority has spoken only to EDBs and not generation investors in preparation of this Issues Paper.

subsequent movers to the capital cost of a connection asset and paying a rebate to the first mover."[12] However, there is no time limit on when a second (or subsequent) connection is obligated to start paying a contribution.

Type 2 FMD

It is the IEGA's view that pressure from distributors to change the incremental cost rule arises because distributors are struggling to know how to recover the cost of Anticipatory Investment – investment in capacity ahead of need or in excess of the requirements for a new connecting generator.

This is described in the relation to recovering transmission infrastructure investment as:

> "Type 2 first mover disadvantage (FMD) arises if early connected or connecting customer(s) (first movers) carry the cost of connection assets in excess of their own requirements until later customers and load arrive.
>
> … result in the first movers being charged for an anticipatory connection asset they do not need or use, and do not necessarily know how long they will continue to be charged for it."
>
> "The TPM addresses Type 2 FMD by spreading the capital cost of an anticipatory investment over a larger set of customers than just the first movers." [13]

In the TPM, the "larger set of customers than just the first movers" are:

- all other connection assets, and
- for injection related anticipatory investment, offtake customers

with the cost of anticipatory investment recovered 50/50 from these two groups.

In the distribution network context, if it not possible to allocate the cost of an Anticipatory Investment to all other connection assets, applying the TPM approach would allocate this cost to all offtake customers as the Anticipatory Investment is injection related.

In summary, under the TPM, Transpower recovers connection costs using the incremental cost of the assets used/required by the connecting party and has clear rules about how to recover Anticipatory Investment.

Competitive neutrality requires the same charging structure for generation connected to distribution networks. **The IEGA submits the Authority focus urgently on a mechanism for distributors to recover Anticipatory Capacity Investment.**

[12] Source: Section 1, TPM Information Sheet Connection charges: the funded asset component mechanism to address Type 1 FMD. V2 March 2023

[13] Source: TPM Information Sheet Connection charges: Anticipatory investment and Type 2 FMD mechanism v2 March 2023

C. Other comments

In this section we comment on other aspects of the Issues Paper.

DGPPs can apply to all distributed generation connections

The Issues Paper states[14]. "The charges distributed generators pay distributors for use of the distribution network are regulated (for those on regulated terms) by the DGPPs in Schedule 6.4 of the Code". While the DGPPs apply automatically for connections on regulated terms, bilateral contracts can (and do) include connection charges based on the DGPPs.

Part 4 of the paper on 'DG price signals are appropriate with respect to transmission costs'

This section of the Issues Paper is beyond the scope of whether or not to change the incremental cost rule in the DGPPs. We are not engaging in response to the Authority's review but include comments on this section in our response to Q12 in Appendix B.

D. Concluding remarks

Much of the Authority's work programme is focused on encouraging more and faster investment in new electricity generation, boosting competition and putting downward pressure on prices. However, the uncertainty created by this Issues Paper could have a chilling impact on near term new distributed generation investment. We urge the Authority to understand this potential by engaging with generation investors.

Charges based on incremental cost are economically efficient, consistent with connection charges for transmission grid connected generation and consistent with the Authority's Distribution Pricing Principles[15] The only changes that are urgently needed are:

- a clear understanding and consistent approach across distributors of what constitutes an incremental cost for a new generation connection to a distribution network, and
- a separate mechanism to recover distributor's investment in Anticipatory Capacity.

Distributed generation will be at a competitive disadvantage to transmission grid connected generation if charged any amount more than the incremental cost for connection. Therefore, the IEGA supports the Authority's proposed Option 1 or retaining the status quo.

We request the opportunity to discuss this submission with you.

Yours sincerely

[redacted]

Warren McNabb
Chair

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[14] Paragraph 2.3

[15] These Principles refer to 'avoidable costs' and the Authority states it uses this term interchangeably with 'incremental costs'.

APPENDIX A: Background on the IEGA

IEGA members are small, entrepreneurial businesses, essentially the SMEs of the electricity generation sector, who have made significant economic investments in renewable generation plant and equipment. Combining the capacity of member's plant makes the IEGA the sixth largest generator in New Zealand. We are price takers and have no influence over the level of spot prices in the electricity market – the majority of our members do not have the financial or human capacity to operate 24/7 dispatching into the wholesale market. We. To be financially successful the LCOE of distributed generation must be comparable with the LCOE of grid connected generation.

The IEGA's portfolio of generation is 100% renewable with members' owning and operating the full range of renewable generation technologies: hydro, wind, geothermal, solar and biomass and energy storage.

Our members are innovative, entrepreneurial and passionate about New Zealand's renewable advantage and potential who have made significant economic investments in generation plant and equipment throughout the country. They have a portfolio of new economic renewable generation projects consented or under investigation which have a smaller environmental footprint than grid-connected generation and provide an incremental, rather than a step change, increase in supply more aligned to increasing local demand for electricity. This scale of generation can also be built faster than grid / utility scale generation.

These generation investments can defer or avoid capacity expansion of distribution and transmission networks – lowering overall system cost to NZ consumers. Further, commercial scale distributed generation can be financially incentivised to supply network support services to distributors to assist manage peak demand and network power quality – an increasingly important service as industry and transport demand more renewable energy.

APPENDIX B: IEGA'S RESPONSE TO THE AUTHORITY'S QUESTIONS

Q1.Do you have a view on the definition of incremental cost that is contained in the Code? Should it be more tightly defined to include only network costs and to exclude consequential costs relating to factors such as frequency keeping and voltage support? Would this lead to more timely generation build and lower energy costs?
The Code definition of incremental cost is clear. The issue is that the definition is interpreted differently by distributors. We suggest the first step should be the Authority survey distributors and distributed generation investors to understand the different approaches. The Authority should also be ensuring the definition of incremental cost and connection asset is consistent across transmission and distribution network connections. Competitive neutrality for generators connected to either the transmission grid or distribution network is essential for workably competitive markets for investigation of new generation projects as well as the wholesale market. The Issues Paper does not ask for feedback on the Authority's views that "the incremental cost limit leads to poor outcomes for consumers"[16] We disagree with the Authority's analysis. We address each of the points in paragraph 2.1: • (a)(i): the incremental cost rule does not "favour" DG over transmission grid connected generation – discussed on our cover letter • (a)(ii): passing network common costs on to DG will place DG at a competitive disadvantage to transmission grid connected generation who are not charged for using the distribution network to deliver 88% of the total electricity distributors deliver to ICPs • (b)(i): funding efficient sized investments – in excess of the capacity required by the DG is the issue of funding Anticipatory Capacity which is separate from charging the incremental cost of the assets actually needed • (b)(ii): this is the same 'issue' as (a)(ii) and our response is the same • (c)(i): this is the same issue as (a)(ii) and (b)(ii) and our response is the same • (c)(ii): it's unclear any DG investor has disagreed with paying up front the full cost of the specific assets required to achieve connection to a distribution network The DGPPs already address first mover disadvantage – a methodology is included whereby the cost of connection assets can be shared. Distributors should be indifferent about how this sharing occurs as they have already been paid for the connection. Incremental cost is an economically efficient charging methodology and is consistent with the Authority's guidance in the Distribution Pricing Principles.[17]
Q2. Do you agree with the problems with the incremental cost limit identified in this section? Why or why not? Do you have a view on the relative importance of the problems identified?

[16] Paragraphs 2.1 to 2.11

[17] These Principles use the word 'avoidable' but the Authority states the words 'incremental' and avoidable' are interchangeable

The IEGA does not agree with the problems the Authority identifies with the incremental cost limit. We address each of the topics in this section with our feedback:

Distributed generators pay for fewer costs than grid-connected generators (paras 2.12 – 2.18)

The IEGA strongly disagrees the incremental cost limit creates an artificial advantage for DG compared to the allocation of transmission costs for grid-connected generators.

Please refer to our cover letter.

In addition, if a new DG connection to a distribution network requires any new dedicated assets at the transmission GXP distributors pass these incremental costs on to the DG that required this investment (including a share of Transpower's operations and maintenance charges).

The IEGA also strongly disagrees with the risks identified by the Authority that the incremental cost approach – "*that electricity supply costs increase because investors favour DG projects that have a higher economic cost than grid connected alternatives, whether in terms of scale or technology*". DG is economically efficient and has the same LCOE as transmission grid connected generation. To be financially viable the DG investor must be able to sell their electricity on the wholesale market or in bi-lateral contracts – this will be difficult if the investment has a higher electricity supply cost than its competitors!

Investors in new assets are discouraged from accommodating future demand (para 2.19 to 2.23)

This discussion is confusing – is the "investor" the distributor?

The Code already includes a mechanism for refunding the first generator connector that paid for the specific connection assets. The 36-month limit on cost-sharing could be reviewed. We note the TPM does not include any time limit for FMD Type 1.

The IEGA agrees it would be useful to have a mechanism to fund Anticipatory Capacity. This cost is difficult to socialise across a distributor's (small) customer base. The IEGA (and the ENA) has been advocating for a fund (like the Crown fibre rollout) that distributors can use.

Funding Anticipatory Capacity is a separate issue to payment for the cost of specific connection assets at the size needed by DG. We strongly suggest it would be more useful for the Authority to focus on solving FMD and funding Anticipatory Capacity than removing the incremental cost rule.

Current incremental cost limit stands in the way of efficient arrangements (para 2.24 – 2.28)

This is also a confusing discussion.

It is not clear, yet, what the connection charge methodology for load customers will be. However, under the Authority's proposals there may be a limit of 47% on the amount a new load customer pays upfront to connect (with the balance recovered by the distributor over the life of the connection assets).[18]

[18] In our view this reflects that revenue from some load connections builds up over time.

The DGPPs mean DG investors pay 100% of the upfront incremental cost of the specific connection assets. Is it clear to the Authority that this is impacting generation investment decisions?

In our view, paragraphs 2.26 to 2.28 is another description of the issue of funding Anticipatory Capacity.

The one-size-fits-all cost-sharing formula may discourage efficiency (para 2.29 – 2.30)

The IEGA agrees an additional clause could be added to the Code that says "or any other cost-sharing method that is agreed between the first connected generator and subsequent connections". Any cost sharing approach does not have to involve the distributor as they have already been paid for the connection assets.[19]

The incremental cost limit yields weak incentives to dedicate resources to DG (para 2.31 – 2.34)

Distributors should be able to recover the cost of processing applications for connection on an incremental cost basis. This is distinctly different from recovering the cost of assets dedicated to the physical connection.

We suggest the Authority talks to Northpower and Counties about the incremental costs they are recovering from their 'Congestion Charge' on DG.

As stated in our cover letter, any common costs attributed to DG as a class of customer for the use of the distribution network must also be levied on transmission grid connected generators who supply 88% of the electricity distributors transport across their network to ICPs.

The incremental cost limit creates other impediments to efficient pricing (para 2.35 – 2.39)

As stated in our cover letter, any network common costs attributed to DG as a class of customer for the use of the network must also be levied on transmission grid connected generators who have to use the distribution network to deliver electricity to the end user.

Being clear about the quantum of charges to DG – based on incremental costs – means there is less of total network revenue that has to be based on 'approximations'.

We note distributors have the discretion to impose their "Connection and Operation Standards" on DG as well as any other technical specifications in the Connection Agreement that can be used to limit impacts on the network that create costs for the distributor.

Q3 Do you agree circumstances have changed significantly since the DGPPs were introduced, including that there are now far fewer impediments to distributed generation than in the early 2000s?

No, the IEGA does not agree there are far fewer impediments to DG than when the regulations were first introduced in 2007. The incremental cost rule is not a 'leg up' for distributed generation but an

[19] This differs from load connections where the distributor recovers the connection costs over a period of years.

economically efficient charging methodology that is consistent with the Authority's Distribution Pricing Principles and consistent with connection charges for transmission grid connected generation. There remains an imbalance of power between DG investors and distributors that would likely impact connection charges if unregulated. Further, DG investors need surety that a distributor is using the same methodology for charging connection of its own generation as it charges third parties. The DGPPs have not "helped eliminate barriers to investment in DG", nor do these rules create "inefficient subsidies or reduction in costs for some types of DG".[20] The IEGA does not agree with the Authority's assertion that the DGPPs raise the *"risk of incentivising excessive investment in DG which would raise consumers' costs of electricity supply".[21]* It would be useful if the options / issues discussed by the Authority distinguish between those that relate to household versus commercial scale DG. It seems contradictory to consider having no rules relating to the cost of connecting new generation to distribution networks when the Authority is attempting to impose rules for charging connection of new load.
Q4 Do you agree with the assessment of the current situation and implications of incremental cost pricing? If not, why not? What if any other significant factors should the Authority be considering?
No. See details in answer to Q2. The Authority has not provided any clear rationale for changing incremental cost pricing. Further, • making any change tilts the current level playing field placing DG at a competitive disadvantage to transmission grid connected generation in relation to connection charges • transmission grid connected generators also use the distribution network to get their electricity the last mile to electricity users and pay NO distribution charges.
Q5. Do you agree these are the appropriate options to consider?
The IEGA does not agree with the Authority's "*tentative view that there is a good case to overhaul the DGPPs comprehensively augmented by specific guidance for injection prices*" (para 3.3) The following is our feedback on each of the Authority's options: **Option 1: Retaining the existing DGPPs (the status quo) (paras 3.4 – 3.5)** The Authority's main argument <u>against</u> retaining the existing DGPPs appears to be that "*the DGPPs may be preventing distributors from efficiently planning for future connections*" and "*Left unaddressed, these problems could negatively impact on security of supply and lead to higher charges for consumers*."

[20] Paragraph 3.10

[21] At the same time the Energy Competition Task Force is consulting on a proposal to incentivise more investment in small-scale distributed generation *because the electricity is generated locally when and where it's needed, and eases pressure on the local distribution network where it's constrained. This avoids the need for distributors to build more infrastructure to cope with higher demand peaks, meaning lower overall costs, and lower prices for consumers in the long run"* Source: ECTF paper 'Proposals to encourage efficient investment in distributed generation' Electricity Authority Advisory Group: subgroup 1 meeting 1. Released under OIA

Efficiently planning for future connections involves planning network capacity in efficient increments that is expected to meet future demand. This is the issue of recovering the cost of Anticipatory Capacity. It is not efficient that the first new connection pays the cost of this larger than needed capacity increment. The Authority has recognised this in the approach to Anticipatory transmission Capacity. Funding Anticipatory Capacity is separate from charging the incremental cost for specific connection assets in the Transmission Pricing Methodology – and should be separately addressed for distribution investment. This is not a reason to get rid of the DGPPs.

The IEGA supports the Authority and/or the ENA developing a mechanism to Anticipatory Capacity. The IEGA has previously submitted that the NZGIF or an entity like the Crown Infrastructure Partners pays for the 'excess capacity' and is repaid as additional load and generation use up this excess.

A DG investor understands the consequences of its location choices. Why should other customers be paying for a DG investor to be located say 30km from existing distribution network. Incremental costs mean DG customers pay for the cost of the assets that are dedicated to that customer.

The IEGA supports retaining the existing DGPPs with urgent attention to ensuring:

- a clear understanding and consistent approach across distributors of what constitutes an incremental cost for a new generation connection to a distribution network, and
- a separate mechanism to recover distributor's investment in Anticipatory Capacity

Option 2: Limited modification of DGPPs to address the identified issues (para 3.6 – 3.18)

The Issues Paper (para 3.6) says targeted amendments could include:

(a) an amendment to clarify the definition of incremental cost (for example, to clarify the treatment of consequential costs related to frequency or voltage) and/or

As discussed in answer to Q1 the IEGA recommend the first step should be the Authority survey distributors and distributed generation investors to understand the different approaches to 'incremental cost'. The Authority should also be ensuring the definition of incremental cost and connection asset is consistent across transmission and distribution network connections.

(*b) adding a clause creating an exception to the incremental cost limit to allow for allocation of attributable costs to DG as a customer class, and/or*

As discussed, any allocation of 'attributable costs to DG as a customer class' would be a cost that is not paid by transmission grid connected generation, placing DG at a competitive disadvantage.

As discussed elsewhere, addressing first mover disadvantage (both Type 1 and Type 2) should be addressed separately – as they are in the Transmission Pricing Methodology (alongside incremental costs for transmission grid connections).

(c) deleting principle 2(m) to remove the time limit on recovery and refunding of connection costs by, and/or

Removing the 36-month limit on recovery and refunding connection costs could be useful. The TPM has no time limit.

(d) replacing the prescriptions for cost-sharing in principles 2(i)(i) and 2(i)(ii) with 'prices should account for differences in network services provided and be responsive to end users' circumstances and requirements' to allow discretion in how costs are recovered.

The IEGA does not support removing the prescriptions for cost-sharing in principles 2(i)(i) and 2(i)(ii). As discussed in response to Q2, the IEGA agrees an additional clause could be added to the Code that says "or any other cost-sharing method that is agreed between the first connected generator and subsequent connections". Any cost sharing approach does not have to involve the distributor as they have already been paid for the connection assets.

The following comments are provided on the Authority's reasons given for making limited modifications to the DGPPs (in paragraphs 3.7 to 3.18):

- The imbalance of bargaining power still exists between distributors and DG investors (para 3.8 and 3.13). This is even more so given distributors are likely to be able to invest as much as they want in new generation capacity and must be required to charge themselves on the same basis as a third party. So not sure why the Authority has changed its view of the risk distributors use monopoly power to overcharge DG owners for connection services.
- Under the incremental cost rule, DG investors are paying upfront for the cost of specific assets required for connection to the distribution network. Facing cost reflective pricing is unlikely to create an incentive to over or under invest in DG.
- Distributors have been identifying incremental costs directly attributable to connection on new generation since 2007. The key difference now is issues relating to first mover disadvantage which must be addressed separately.
- The IEGA supports a discussion to create greater consistency across distributors about what are 'incremental costs'.
- Paragraphs 3.16- 3.18 discuss the cost of processing DG applications which is being addressed by the Authority in a different workstream. Recovering the cost of processing an application to connect is completely unrelated to recovering the cost of physically connecting the DG.

Option 3: Remove DGPPs and rely entirely on contracting (para 3.19 – 3.25)

The IEGA does not support this option to rely entirely on contracting. While the discussion of this option appears to relate to contracting for non-network solutions, we understand this option is essentially that there is absolutely no guidance on what distributors can charge for connecting generation plant.

Our response to Q2 addresses the issue of the imbalance of power between monopoly distributors and individual DG investors.

A pricing principle for DG connection is essential – especially as there is likely to be restriction or safeguards for distributors investing in their own generation assets.

The Authority has developed clear pricing principles (a detailed pricing methodology) for charging for connection to and the use of the transmission grid and is in the process of implementing pricing principles / methodology for connection of load to distribution networks.

The case is not proven that connection of DG is different and can be economically efficient without any pricing principles.

Option 4: Comprehensive overhaul of DGPPs (para 3.26 – 3.41)

The following extracts provide an indication of the Authority's thinking with respect to the outcome of undertaking a "comprehensive overhaul of the DGPPs".

Para 3.26: "*Authority would develop pricing guidance for distributors through a new set of pricing principles applicable to DG. The new principles could potentially draw on the pricing guidance for load customers that the Authority has already produced."*

Para 3.28: "*At least initially, the new principles would be less prescriptive than the existing DGPPs: the new principles would not restrict pricing to incremental cost. Distributors would be able to develop their own approach to pricing for DG, guided by the new principles* …"

Para 3.29: "*Depending on the Authority's decision regarding its proposal released in November on connection pricing for load customers, the recommended approach for load customers could also be applicable to connection pricing for DG."*

Para 3.31: "*The Authority has not yet considered in any detail whether the current proposed approach to connection pricing for load customers should also be applicable to connection pricing for DG. It is noted here as a possible option to consider in the future."*

While the current consultation is an "issues paper" the above extracts indicate the Authority probably has a preference to impose their new connection pricing methodology for load customers on generation connections – given the repeated mention of this option.

The IEGA disagrees

- with a comprehensive overhaul of the DGPPs; and
- that the new load connection pricing methodology is appropriate for generation connections

for the following reasons:

- DG investors are prepared to pay upfront the **full** incremental cost of specific assets required for connection
- the Authority's proposed approach for load connections is unnecessary if DG is paying the upfront cost of connection
- the DGPPs are already a 'principles-based' approach – the principle is incremental cost. Consideration of the identified avoided and avoidable costs at the time of connection should already take account of different network characteristics (eg winter or summer peaking[22])
- any change to the incremental cost rule will place DG at a competitive disadvantage to transmission grid connected generation

[22] Paragraph 3.33 and 3.35

- transmission grid connected generation does not pay anything to distributors for transporting 88% of the electricity they deliver to ICPs. DG payment of any more than incremental cost of connection places DG at a competitive disadvantage to transmission grid connected generation
    - the incremental cost rule for distribution connection is the same as the approach for connection to the transmission grid
    - the TPM allocates transmission 'common costs' to load customers only
- the DGPPs are already consistent with the Distribution Pricing Principles
- the DGPPs have no bearing on a decision by a distributor to contract with DG for a Non-Network Solution[23]
- funding for Anticipatory Capacity is a separate issue from the incremental cost rule.

The Authority's preference for a comprehensive overhaul of the DGPPs is based on a poorly developed problem statement – which this submission discusses in answer to Q2 above. In our view the problem statement conflates a number of issues that are distinctly different from and should be considered separately to, the incremental cost rule.

It also appears highly inconsistent that the Authority is proposing to mandate Code for the payment of the avoided cost of distribution specifically for standard consumers but proposing the removal of any requirement for this payment to other generation connections.

Q6. Are there other options the Authority should consider for improving rules about costs that can be recovered from distributed generators?

The IEGA recommends the first step should be the Authority survey distributors and distributed generation investors to understand the different approaches to implementing the incremental cost rule to connection of new generation. The Authority should also be ensuring the definition of incremental cost and connection asset is consistent across transmission and distribution network connections.

Q7. Will new aggregator business models emerge to solve the problem?

The IEGA interest is in connecting commercial scale DG. The emerging 'aggregator business model' is irrelevant.

Q 8. Are distribution price signals alternative to, or complementary to contracting?

The Authority's discussion about 'contracting' is about Non-Network Solutions (NNS). In our view this is distinctly different from the topic of charges for connecting new generation plant. The IEGA interest is in connecting commercial scale DG. The imbalance of power between monopoly distributors and DG investors means clear rules about connection costs are required.

[23] Paragraph 3.40

Q9. Which, if any of the above options, do you consider would best support efficient pricing for recovery of distribution costs from DG?
The IEGA supports Option 1 of retaining the status quo. In addition, a new mechanism is required to recover the cost of Anticipatory Capacity
Q10. Do you agree with the Authority's tentative view on a solution? In particular:
• Should efficient price signals be sent through a revised set of pricing principles?
No. The IEGA does not support the Authority's preferred approach of a comprehensive overhaul of the DGPPs, including a likelihood that the outcome of this overhaul will be imposing the connection pricing for load that is currently under development. This is a significant change to the regulatory environment for distributed generation at a time when significant investment is needed, is planned or under consideration. There is a significant risk that all this potential investment will stall if there is uncertainty about how connection charges are to be determined by each different distributor. Currently there is a clear rule – a DG investor knows that he will pay the incremental cost of connecting generation plant at a particular point in the distribution network. The DG investor pays for the consequence of his location choice.
• Would voluntary guidelines or mandating through the Code be the best approach?
No comment – the IEGA does not support a change to the current Code.
• Should we rely on the distribution pricing principles outside the Code or codified new pricing principles for DG? Why?
The IEGA supports the status quo plus a new mechanism to recover the cost of Anticipatory Capacity.
Q11. Are there any unintended consequences from removing the existing DGPPs?
YES – this Issues Paper creates uncertainty about the future cost of connecting DG to distribution networks. This has the potential to chill planned and future investment for the foreseeable future. The Authority has overlooked the consequence of allowing distributors to recover some of their common costs from DG. Transmission grid connected generation does not pay anything to distributors for transporting 88% of the electricity they deliver to ICPs. Any allocation of distribution network common costs to DG will put DG at a competitive disadvantage to transmission grid connected generation.
• Do you agree with the risks we have identified, and our assessment of them?

We have commented above about the analysis throughout the Issues Paper.
• Do you think there are any other risks we should consider associated with the removal of the DGPPs?
The Authority must seriously consider the risk of placing DG at a competitive disadvantage to transmission grid connected generation if the incremental cost limit is removed.
• Do you have any information that would allow the Authority to better assess such risks?
We suggest the Authority talk to individual DG investors to understand the implications of any change to the DGPPs.
Q12. Do you agree market and regulatory settings provide efficient incentives for DG reducing or avoiding transmission costs? What, if any, other significant factors or options should the Authority consider?
This section of the issues paper is beyond the scope of whether or not to change the incremental cost rule in the DGPPs. We are not engaging in response to the Authority's review but have the following comments on this section of the Issues Paper: 1. One of the key points in the discussion about ACOT was that distributed generators received a price signal to increase generation output during peak demand periods and distribution companies received a price signal to manage down peak load. Since the new TPM has been in place peak demand has increased more than overall demand and more than expected. The Authority has, in fact, acknowledged that removal of the RCPD transmission price signal has contributed to the increase in peak demand. This increase in peak demand is placing increasing pressure on the entire power system. Ironically, the Authority is currently consulting on other initiatives to encourage mass market customers to reduce their peak demand and increase injection from their own generation into the distribution network to avoid or defer network investment. 2. IEGA members are constantly monitoring opportunities to contract with Transpower and distribution companies to provide non-traditional solutions that avoid or defer infrastructure investment. It's hoped the Authority's assertions in this section of the paper have not created barriers or influenced other parties' perceptions of the value of distributed generation as a non-traditional solution before seeing any specific proposals. 3. The following paragraph in the consultation is factually incorrect: Para 4.17: "*DG dispatched to supply local consumers is paid this nodal price[37] yet does not incur grid transport costs. This gives DG a cost advantage over grid-supplied generation at the relevant node. It does not suggest the need for any further incentive for efficiency reasons*"

Distributed generation greater than 10MW is likely to be dispatched by the System Operator. 10MW is also the threshold used by Transpower for modelling distributed generation in the allocation of Benefit-Based Investments. That is, transmission customers will have information from Transpower about the impact of this embedded generation on their transmission charges, and as an incremental cost, could pass this cost on to the distributed generator, if inclined to. Distributed generation does not have a cost advantage over grid-supplied generation at any node.