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SUMMARY OF SUBMISSIONS ON DGPP PROPOSALS

IEGA has reviewed all the submissions on the DGPP proposal. A number of members of IEGA submitted on the Authority's DGPP proposals, however, we have not included their comments in this document despite these submissions including important information that was not in the IEGA submission. Our summary of the submissions from organisations excluding IEGA members and Trustpower follows.

Retain the DGPPs in the Code

Of the 54 submissions only three organisations[1], Contact, MEUG and Meridian, supported the Authority's recommendation to remove the DGPPs (Part 6.4) from the Code. Notably MEUG and Meridian suggested the Authority may have to consider modifying the regime or introduce a default agreement at a later date if the proposal for DG to negotiate with Transpower provided too difficult[2]. Further, Contact Energy recommends steps to ensure that distributed generators do not pay a disproportionate share of network common costs.

All other submitters recommended retaining the DGPPs. This is despite some of these submitters commenting that they agreed the current level of payment to DG, or the practice of using the interconnection charge as a proxy for the avoided transmission charge and avoidable cost of transmission and distribution, may be inefficient.

IEGA notes that the support for retaining the DGPPs comes from across the sector – and is not limited to those that some might conclude have a vested interest. The range of reasons for retaining the DGPPs varies.

Reasons given for retaining the DGPPs in the Code include:

Buller Electricity "*does not support the changes proposed in the Electricity Authority's review of the distributed generation pricing principles in their current form. While Buller Electricity agrees that the existing regulations require modification, particularly with respect to the Avoided Cost of Transmission payments to Distributed Generators, further consideration needs to be given to a number of key areas.*" (pg 1)

"The current DGPPs were introduced to encourage the development of Distributed Generation (DG), and this remains the primary mechanism for delivering a secure and diverse DG outcome. The impact of removing the DGPPs needs to be considered in the context of wider DG policy and strategy. It is unclear if removing the DGPPs will deliver on policy intent and/or result in a policy vacuum. While this is an area which may lie outside the EA's jurisdiction, it is perhaps worth considering whether alternative, and perhaps more appropriate mechanisms, need to be considered." (pg 2)

BusinessNZ said that there are *"some implementation details that despite the prospect of lower prices, the EA should give greater consideration to before proceeding." (pg 1)*

[1] We have not included Winstone Pulp International as while it supports the proposal they appear to argue for a change in definition of RCPD to acknowledge the benefits of distributed generation.
[2] In response to question 6

ENA submits that:

"4.The proposal to remove the pricing principles from Part 6 of the Code is reconsidered in light of submissions on both this DGPP and the TPM proposals and a more suitable set of pricing principles be developed. ...

6. Removing the DG pricing principles will remove an important mechanism for delivering a secure and diverse local generation outcome, which remains the policy intent of Part 6 of the Electricity Participation Code. Distribution pricing guidelines may not deliver on this policy intent."

Energy Trusts of New Zealand:

"... we disagree with the Authority's conclusion that its proposal to remove the DGPP would "support the efficiency limb by better allowing distributors to adopt service-based pricing structures across all users of distribution networks." (pg 1)

Genesis suggests improving the existing DG pricing principles.

Hydroworks is a member of IEGA but provides the perspective of a service provider to generation businesses and highlighted the impact of changes to electricity sector regulation on the wider economy:

"The uncertainty that the process and proposal has introduced has a major bearing on the profitability and livelihoods of a whole range of businesses including HydroWorks." (pg 2)

Mercury state[3]:

" …removing the DGPPs in their entirety is neither necessary nor appropriate as it has other ramifications." (pg 1)

"The rationale for a codified framework for connection and charges for distributed generation has not changed and are more so required in the context of emerging technologies;" (pg 2)

Network Waitaki:

"…we are of the opinion that instead of removing the DGPPs it can be amended to include costs which will signal the economic cost of service provision. The DGPPs provide the "rules of the game" which gives market participants some certainty and remove barriers to entry." (para 7c))

Orion:

"We urge the Authority to take a more measured approach to a review of the pricing, commercial and economic aspects of Part 6 with a view to having such a review complete by, say, 1 April 2019. By "more measured" we mean taking the time to consider the wider rationale for Part 6 and the role that DG plays in the New Zealand electricity system. Failing that, and very much as a second best, the proposed changes could apply to new DG only from the proposed dates, leaving significantly longer (say until April 2019 at the earliest) to sort out the arrangements with existing DG." (para 14)

PwC for 14 network companies, "*acknowledge the problems the DGPP paper has identified with the DGPPs, but to fully remove them creates other problems and may go too far."* (para 22)

Powerco"

"We share ENA's view that restructuring the TPM and ACOT payments to better meet network pricing objectives, including providing efficient economic signals, may provide a better solution than the proposed removal of the pricing principles." (pg 1)

[3] Using the new company name for Mighty River Power

Solarcity:

"The EA needs to:

- *Retain the disputes process. The lines companies have shown little appetite to move towards the new paradigm and are likely to put in place policies to slow the adoption of new technology as Unison has demonstrated with its solar tax. The disputes process is essential for ensuring lines company charging policy encourage competition and have long term benefits for consumers rather than meeting short term objectives of incumbent monopolies."* (pg 2)

Transpower:

"We are not yet convinced that removing the DGPPs is the best remedy available. For example, the proposal appears to create new problems while our proposed changes to the TPM appear to obviate the need for major change to the DGPPs." (pg 1)

"…we were surprised by the proposal to remove the DGPPs from the Code." (pg 2)

Axiom in its report for Transpower stated *"… the problems arising under the status quo are overstated because, in many cases, they relate to the transmission pricing arrangements rather than the principles in schedule 6.4."* (pg 11)

Top Energy:

"7. … Top Energy does not support the proposed new TPM guidelines or the proposed removal of the distributed generation pricing principles (DGPPs). We support the retention of the current TPM and DG pricing principles including the recently introduced changes by Transpower which focused on improving operational aspects of the existing TPM (100 highest peaks)."

"28. … We consider that if the DGPPs are removed (which we do not support) they should be removed only as fast as Transpower can develop, negotiate and implement alternative arrangements in good faith."

Unison:

"Unison disagrees that the Authority's proposal to remove the DGPPs in their entirety is the most effective way of addressing the problem around ACOT payments in particular. Unison is concerned that there will be unintended consequences of this regulatory change…." (pg 3)

*"The original intent of the DGPPs seems to have been overlooked – that the connection of DG (especially SSDG) should be simple, predictable and provide regulatory stability. The purpose of Part 6 of the Code is "…**<u>to enable</u> connection and continued connection of distributed generation if connection is consistent with connection and operation standards**". Unison questions how the current proposal fits with this Code purpose. We also query whether the purpose of Part 6 may also need to be reviewed to consider efficient connection as well as simply to enable the connection and continued connection of DG."* (pg 3)

*"Unison submits that the Authority needs to do a more thorough examination of the purpose of Part 6 and therefore the function that the DGPPs currently fulfil. Specifically, what aspects do the DGPPs have that the distribution pricing principles do not? For example, consideration of avoided or avoidable costs. These aspects may be important to retain, or incorporate into the distribution pricing principles. To remove the DGPPs in their entirety without consideration or discussion of their function or the purpose of Part 6 generally seems hasty. It may be that the purpose of Part 6 has now shifted, but this should be further explored **before** removing Schedule 6.4."* (pg 3)

Allocation of Network Common Costs not consistent with promoting competition

IEGA members made strong representations that the allocation of network common costs to distributed generation places DG at a competitive disadvantage to grid connected generation. This view is supported by network companies who clearly described this disadvantage. For example:

Eastland Generation:

"While the recovery of interconnected costs within the transmission system is still being debated under the TPM, Eastland notes that none of the approaches that are under consideration require a grid connected generator to pay interconnected charges based on its generation output or name plate rating. Grid connected Generators do pay the present interconnection charge when they consume electricity to provide local services to their site or when generators are providing reserves while running in synchronous condenser mode. Importantly, that interconnection charge is as a result of acting as a purchaser not as a generator.

Bringing that parallel of interconnected cost recovery to the DG environment then yes, DG should be required to pay for the common costs of the network to the extent that they cause them, not as a generator nor based on their generation output as those costs are recovered via the connection fee. It is DG's use of the network via it's consumption of electricity that should drive the recovery of common cost." (pg 4)

ENA:

"22. The pricing principles clearly exist for what were valid policy objectives, amongst these was a desire to maintain parity between large-scale grid generation and distributed generators. Grid generators (with the exception of South Island generators payments for the HVDC) were not required to pay for the common costs of the transmission interconnections assets or for use of the distributors networks to transport grid electricity to end-consumers. The concern was that distributed generation could, in the absence of pricing rules, be made to pay part of the common cost burden of connection, transmission and distribution charges, which would distort competition between grid generation and local generation.

23. Therefore the desire seems to have been for DG to face only the avoidable costs of being connected to the local network, rather than any share of common network costs."

"44. … whether there is real fault with the pricing principle that DG should be charged incremental costs less avoidable costs. This principle, with the exception of ACOT payments, ensures that there is competitive neutrality between grid and local generation, given that grid generation does not pay common costs, at least under the current TPM.

45. While generation under the proposed TPM will pay some common costs, this will only be for assets where there is a benefit to the generator. The proposed TPM also provides a mechanism where this share of common costs could reduce over time. Such circumstances are unlikely to exist on distribution networks where EDB's build to connect loads. If there are network investments needed to reduce constraints to allow more embedded generation to export (e.g., if there are localised concentrations of PV generation) then this could be accommodated under the incremental less avoided cost principle. "

Unison:

"… Unison does not agree … that there is an inefficiency associated with DG owners not being required to pay a share of the common costs of providing distribution services. The current arrangements (of DG owners not paying for common costs) is consistent with what is in place for generators connected to the national transmission grid. For example, under the current TPM, the interconnection charge is paid only by load customers. Under the proposed TPM that the Authority is currently consulting on, the residual charge is also only to be paid for by load customers, not generation. To change the payment arrangements for DG and not generation in general would create inequalities in the industry and competitive neutrality would be removed. This may also distort dispatch decisions and simply increase the costs of generation which would ultimately be passed on to consumers." (pg 2)

Other submitters provided different insights into why allocation of network common costs to DG should not be implemented.

Mercury rightfully points out networks are built and operated to meet the service / reliability requirements of load customers. The Authority estimates load values outages at up to $20,000/MWh VOLL. The value for a distributed generator of losing connection to a local network is the loss of revenue from selling its generation output, of say $80/MWh.

Mercury state:

"*In our view, working out the appropriate share of serviced-based common costs to distributed generators is likely to be problematic in absence of any framework or pricing methodology. If there is thought around establishing any framework then we suggest that this exercise wait until the EA's consultation on distribution pricing responding to emerging technologies is finalised."*

In any event, many common costs are likely to relate to ensuring reliable supply to load customers. Distributed generation can in fact aid reliability on some networks and also defer investment within some networks. As the main beneficiaries of many network investments are non-distributed generators, allocation of common network costs to distributed generators should be considered carefully. The costs of working these out could outweigh the benefits.

For these reasons we do not consider that the common costs issue should be a reason to remove the entire DGPP regime." (pg2)

Solarcity:

"The EA needs to:

- *Retain the rule that distributed generation can only be charged the incremental cost of providing for distributed generation. Clear rules are needed to encourage competition at the distribution level and ensure that long term benefits are delivered to consumers rather than the monopoly lines companies."* (pg 2)

BusinessNZ:

"While we would agree that there seems to be potential for efficiency losses to arise by precluding any common cost recovery from distributed generation owners, in light of the negotiating asymmetries in play removing the code would not seem to be a proportionate response (especially in light of the CBA)." (pg 5)

Timing of any change to the DGPPs should be aligned with the TPM

IEGA noted that DG owners, network companies and Transpower will not understand the value of the services provided by DG until the TPM is finalised. Further, the proposed TPM creates transmission charges that are more cost reflective so that the current perceived inefficiency is eliminated (as shown in the DGPP CBA). At a minimum there is a considerable amount of work for Transpower to complete before they can engage in good faith negotiations.

Other submitters provided different reasons for aligning any change to the DGPPs with the TPM:

Buller Electricity:

"The changes currently proposed for the DGPPs and the TPM are not independent, as changes in one have implications for the other. BEL is of the view that the changes to the DGPPs & TPM should be developed/finalised as a package, and preferably implemented at the same time. Should DGPP changes be finalised and ready for implementation in advance of TPM changes (the most likely scenario), then a transition to the new ACOT payment system can be phased in. However, this should not be begun until a new TPM is finalised (though not yet necessarily implemented)." (pg 2-3)

BusinessNZ describes a transition path in a number of steps, including:

- *"undertake work to develop the generic approach that would be used by Transpower as a broad framework in its contracting arrangements between distributed generation providers and Transpower. This work should be undertaken in an open and transparent manner in order to ensure that all relevant issues are considered; and*
- *apply the new approach once the new TPM and Distributed Pricing Principles are finalised."* (pg 6)

Castalia for Genesis:

"We recommend a transition to the new regime that ties in with transition arrangements for the wider TPM changes …. This appears the simplest approach, is consistent with the changes made to the High Voltage Direct Current charges, minimises the potential for detrimental impacts on consumers, and would give time for participants to manage their individual impacts. This would involve a longer transition than proposed and is necessary to ensure contracting mechanisms are developed appropriately and works with other changes to the TPM." (pg 4)

Genesis:

"... any decision to remove the current D-G pricing principles is not reached until ***after*** *Transpower's new TPM is approved. This will provide D-G owners and operators more clarity on what a future Area of Benefit charge looks like and the potential opportunities for their individual assets to offer value to transmission customers."* (pg 5)

"We support the concept of Transpower having a direct relationship with distributed generators who provide grid support services. However, we suggest Transpower will require much more time to develop an appropriate mechanism for identifying and incentivising the provision of these services. In this regard, we consider there is potential alignment with Transpower's thinking on the future use of a Long Run Margin Cost ("LMRC"), or similar type, investment signal." (pg 1)

Mercury supports aligning the implementation timeframe with the new TPM:

"Proceeding with a phased implementation for 1 April 2017 … is not likely to be achievable in our view. We support aligning the implementation timeframe with the new TPM." (pg 1)

Network Waitaki:

"The DGPPs review states on page G that the scenario used by the EA is one where the TPM does not change, However, the EA is proposing changes to the TPM. The two processes do not align and we would recommend that they be considered in the same review as they impact one another." (para 7a))

Orion:

"Given the wider changes being proposed to the TPM it is not clear to us why the dates are not aligned (that is, on 1 April 2019). It seems to us that the proposed TPM changes are likely to lessen or remove ACOT payments by distributors even under the current Part 6." (pg 6)

Transpower:

"We consider, for example, that providing more targeted price signals through the TPM could substantially address the Authority's primary concern. This would allow efficient signals for the operation of load control and distributed generation, and this may obviate the need for major change the DGPPs." (pg 2)

"We consider that proceeding with the proposal changes to the suggested timetable would be high risk and may prove counter-productive." (pg 2)

"For example, Transpower could not establish the planning, economic, commercial or legal frameworks to support the new regime before 1 April 2017." (pg 1)

Unison:

"However, this timeframe is likely to be challenging for Transpower to implement, as they will need to assess all DG against the Commerce Commission's criteria (to provide transmission services at the lowest possible cost) and negotiate contracts and ACOT payment schedules with key DG owners. Unison suggests that the implementation schedule is discussed and agreed with Transpower to ensure that the proposal will be workable for them to implement." (pg 5)

Quality of the cost benefit analysis

IEGA was very critical of the CBA in the DGPP proposal. A small number of submitters commented on the CBA but those that did:

BusinessNZ states the *"cost-benefit analysis (CBA) is problematic"* for a number of reasons including:

i. the range of net benefits is extremely broad essentially ranging from zero to just under $22 million in net-present value (NPV) terms. This huge variability should, if nothing else, ring alarm bells for the Electricity Authority and the extent to which it can justify an unequivocal course of action based upon it. …

ii. the highly assumption-driven nature of the CBA. The CBA is based on educated guesswork at best. Virtually all of the inputs into the CBA are estimated average values (for example, "a rough approximation to the mean wholesale spot price in regional peak periods") and likely to be highly sensitive; and

iii. the Electricity Authority seems comfortable drawing regulatory conclusions in the absence of information. For example the Electricity Authority itself notes that:

> *"It is not possible to assess the benefits of addressing the connection services issue in a quantitative way, because there is not enough information available. Instead the EA has made a qualitative assessment."*

As noted in our submission on the transmission pricing methodology second issues paper, the Courts have recognised the importance of quantified CBA as part of the operation of regulatory bodies' decision-making processes;" (pg 3-4)

ENA:

"40. Given these uncertainties about outcomes, the ENA believes that it is too speculative to attempt to develop a CBA to assess the proposal. The very small net present value (NPV) of benefits in the Authority CBA is noted. However we suggest that only small changes to assumptions could easily give rise to a different CBA result. At best, the current CBA result is marginal.

41. There will be material transaction costs for all parties involved in the process, if this proposal is implemented. These are not factored into the Authority CBA. If they were included it is reasonably easy to envision a negative NPV outcome. However, even without these transaction costs, the CBA of the proposed change is unconvincing."

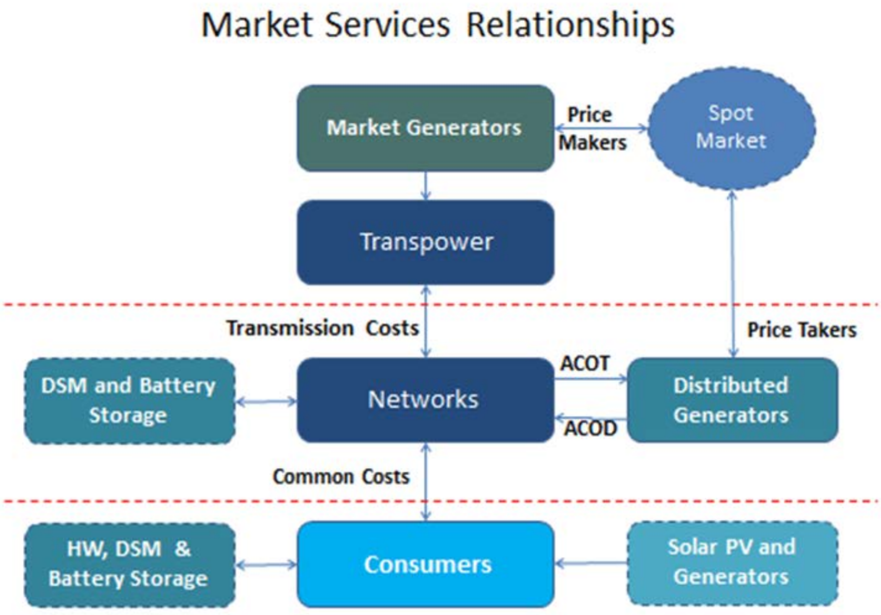
Transpower:

"The Authority's proposal is for Transpower to create a new role and capability. Based on costs published by the Authority, this could entail tens of millions per annum in new costs. It will be important for the Authority to resolve with the Commission how Transpower will be compensated for the costs before reaching a decision." (pg 1)

"…we consider it important that any changes to the regulation of network services are well justified and supported by quantified cost benefit analysis. We do not consider that the Authority's proposals have yet met this test." (pg 2)

Impact on competition

IEGA provided a clear description of the relationship distributed generation other parts of electricity supply chain – summarised in this diagram:



In our view distributed generation competes with transmission to deliver energy to consumers and also competes with demand side management and battery storage to manage peak volumes demanded by consumers. The DGPPs were promulgated specifically to account for this unique locational position in the electricity market supply chain. Payments for the avoided and avoidable costs of transmission and distribution (ACOT/ACOD) are payments for these locational benefits.

Consumers and networks also earn revenue for providing similar benefits if they invest in load control, storage or smaller scale generation located behind the load meters. These payments are estimated in the following table:

A number of other submitters commented on the impact of removing the DGPPs on the Authority's statutory objective to promote competition:

Bryan Leyland:

"There appears to be a general acceptance that demand side management is good and there are inducements available to those who provide demand-side management. Distributed generators provide exactly the same service yet, it seems, will be deprived of a very large portion of the benefit that they confer. This defies common sense and sound economics." (pg 3)

ENA:

"33. If there were effective economic pricing signals based on long-run marginal costs at each grid exit point then these, combined with locational wholesale market prices, would provide the right sorts of signals to DG investors. Grid generation would see the same signals. In the absence of these pricing signals, it is hard to envision how DG will respond to this proposal."

"25. In the absence of economic price signals in the TPM, or pricing principles in part 6, it seems that DG investors will face considerable uncertainty regarding the amount of avoidable costs that Transpower would be willing to agree to pay to them. There is also a conflict of interest for Transpower regarding making payments in this proposal which we discuss below. However from a policy viewpoint, removing the pricing principles could do away with an important mechanism to realising government aims for a more diverse local generation supply. "

Energy Trusts of New Zealand:

"The Authority's proposal to give Transpower the responsibility for obtaining/paying for transmission-substitution services that it deems necessary reflects the top-down approach that evolved for the benefit of established transmission and generation providers, and is out of step with the trend towards demand-side options that we are beginning to see. Emerging technologies such as solar power and battery storage are giving consumers and EDBs increasing scope to compete with those established providers, and any proposal that has the effect of weakening that competition should only be considered if there is a very strong case for change, and – in particular – if an alternative that either has no impact on upstream/downstream competition or else strengthens that competition cannot be found.

Our proposal that 'avoided costs' be transferred to transmission-reliant generators rather than to downstream parties would be a satisfactory alternative." (pg 2-3)

Mercury is *"… not convinced that the EA has justified reason for change to the extent that it involves the entire removal of the DGPPs, especially in light of distributors potentially moving into more competitive markets and the need for on-going consumer protection."* (pg 2)

"Emerging technologies, like distributed solar and battery storage, are blurring the boundaries between the competitive and regulated elements of the supply chain. We consider the current DGPP provisions provide useful consumer and competition protections against monopolies potentially implementing discriminatory pricing to advantage their own commercial offerings. The potential for discriminatory pricing would in our view be greatly increased by the proposal to shift away from incremental cost pricing." (pg 1)

Network Waitaki:

"… the consultation paper states that the competition limb will be supported with this removal of the DGPPs as the scope for DG to be artificially advantaged relative to grid-connected generation is reduced. A DG will need to contract with Transpower directly if it wants to receive ACOT. We believe that making Transpower judge and jury over its competition in the market does not reflect a level playing field and will lead to unintended consequences, such as DGs becoming unviable, reduced investor confidence with potential consequences on security of supply." (Para 7d))

Unison:

"Competitive neutrality potentially would be removed if some distributors moved towards recovering common costs from distributed generation. Having different charging methodology for grid-connected generators as opposed to distributed generators will unfairly disadvantage distributed generators …)." (pg 3)

Balance of negotiating power

IEGA is concerned about the asymmetry of information and balance of negotiating power for its small 40-odd members negotiating with both Transpower and their local network company. One member likened this negotiation with Transpower as 'like a farmer with two cows negotiating with Fonterra'. Other submitters highlighted their concerns:

Buller Electricity is of the view that *"barriers might prevent agreements being reached between Transpower and distributed generation owners. Agreement must be reached on the value of the service being provided by distributed generation."* (pg 4)

BusinessNZ:

"While we would agree that there seems to be potential for efficiency losses to arise by precluding any common cost recovery from distributed generation owners, in light of the negotiating asymmetries in play removing the code would not seem to be a proportionate response (especially in light of the CBA)" (pg 5)

"...while we agree that Transpower is likely to be the most appropriate counterparty to these contracts, we are unclear if the incentive structure outlined in Appendix C will play out as clearly (or as smoothly)

as implied. While we understand that Transpower faces incentives that are aligned with the outcomes anticipated by the Electricity Authority, we note that:

i. *there is likely to be bias (even if unintended) towards solutions that involve transmission solutions, especially in areas where there is load growth, as distributed generation in such areas would only defer investment temporarily;*
ii. *devoting resources to the implementation of the new arrangements by Transpower is likely to be seen as a distraction from its core business;*
iii. *there is a real risk of 'hold-up' especially in the case of existing distributed generation assets. We note in this context that the Electricity Authority has clearly signalled its expectation by stating that the LSI and LNI are likely to have the least avoided transmission benefit; and*
iv. *The Electricity Authority is pursuing this proposal at the same time as it looks to introduce a default use of systems agreement for retailers – for reasons presumably associated with the difficulty associated with negotiating commercial contracts with natural monopoly providers;*
v. *we think that the transaction costs associated with the proposal – especially for the small providers of distributed generation - are likely to be larger than anticipated by the Electricity Authority." (pg 4)*

ENA:

"34. Another concern is the difficulty that will likely arise in a negotiation process between DG and Transpower, and DG and EDBs, in the absence of appropriate pricing principles. It's unclear what approach each party will bring to these negotiations when they have quite different incentives and information. Given that its revenue recovery is guaranteed, and changes in allocations to one GXP mean charges are reallocated to other locations, Transpower will likely have little incentive to pay for DG investments that are sunk.

35. Transpower can also use its significant information base and resources to its own advantage when negotiating pricing arrangements with DG parties who don't have access to these capabilities. There would be no pricing principles to guide this process, making outcomes even less certain."

Mercury:

"The DGPPs provide some certainty to distributed generators for charges payable which would otherwise be at the discretion of a monopoly service. We are concerned that their complete removal would have adverse consequences for distributed generators who have limited negotiating power." (pg 1)

"We agree that Avoided Cost of Distribution (ACOD) payments are an appropriate recognition for distributed generators that provide a local reliability benefit. However, the proposal which removes the DGPPs means these payments follow no regulatory framework. Keeping the preservation of ACOD payments in the DGPPs via the wording around "negative incremental costs" and "network support services" payments is preferred and provides more certainty." (pg 1)

"We have seen in other situations lack of 7 standardisation and limited bargaining power an issue (e.g. the Authority's proposal for the Default Distribution Agreement earlier this year). Further, the DGPPs provide some protection for distributed generators and ultimately consumers where distributors are investing in competitive emerging technologies." (pg 6-7)

Network Waitaki:

"(i) A DG will have to negotiate with Transpower for provision of DG. It is questionable whether a big monopoly such as Transpower will always be open to negotiate with small DGs.

(ii) Asymmetry of information - Transpower will have all the information to assess potential for avoidance of transmission cost which will leave DGs with very little bargaining power." (para 7e))

NZWEA:

"9. We consider proposed DGPP changes place DG providers at a competitive disadvantage to grid connected generation. NZWEA is concerned that distribution companies, as potential DG providers, can set connection charges for existing and new DG owners with no recourse to a dispute resolution process."

Powerco:

"…we suspect that there will be problems with parties reaching agreement due to asymmetrical negotiation power and availability of information." (pg 3)

Unison:

"… negotiating power of smaller distributed generators may prevent or discourage them from seeking agreements with Transpower. However, experience in other markets indicates that aggregators are likely to emerge that may help to improve negotiating power for these smaller operators." (pg 8)

There must be a transition

IEGA commented that the Authority is proposing treatment of existing assets in the TPM which protect customers from increased charges. That is, the Authority's TPM proposals include the option to apply for a prudent discount, claim a material change in circumstances, or optimisation of transmission assets if transmission charges for existing assets are above customer's willingness to pay. The Authority is not proposing the same type of discretion or flexibility for investors in DG.

Others submitted that the Authority should consider grandfathering or a transition:

Alpine:

"20. … the Authority could consider grandfathering of existing ACOT payments. Grandfathering would also remove the potential issue that will arise if Transpower has little incentive to pay ACOT payments to DG connected to transmission assets with sunk costs.

BusinessNZ is "*concerned about the impact of the proposed treatment of existing (or sunk) distributed generation.* ***...***

ii. the demonstration effect of the proposal on sunk assets for future distributed generation investments. In general we agree with a 'clean' application of any new approach to all new assets (for more on how the new rules could be applied see below) but the fact that the Electricity Authority is proposing to essentially remove ACOT payments immediately for all ACOT recipients signals a willingness by the Electricity Authority to disturb what could be thought of as the legitimate expectations of investors. This is similar to the risk that BusinessNZ sees in the case of businesses who have invested in the ability to avoid transmission charges. This has the potential to raise the risk profile of these (and potentially other) investments going forward and in turn raise the cost of capital for future such investments, with a potentially chilling effect;" (pg 2)

Eastland Generation – while Eastland Generation is a member of the IEGA, they articulate a clear issue with the Authority's proposal very succinctly:

"… *how under the proposed changes is DG able to be rewarded for the reduction in transmission costs that they have and continue to provided?*

It is Eastland's understanding that unless the EA ask the Commerce Commission to consider a 52P determination, there is not a process within Transpower's Commerce Commission input methodology to allow them to recover costs other than their investment costs. This appears to preclude any grandfathering of the benefits of reduced transmission investment cost that DG has provided unless the EA ask for a review. At the time of those investments DG received ACOT payments and there was no expectation within the industry that those payments would change. There was no driver for DG to contract directly with Transpower nor an incentive for Transpower to contract with DG even if the regulatory framework allowed for such contracts to be put in place.

This effectively means that Transpower has captured that benefit as a reduction in its cost against its price path and therefore increased it profit at the determent of DG. Nor has the industry been exposed to the true cost of those transmission investments". (pg 8)

ENA:

“9. ENA members believe that local generation is entitled to consistency and longer term stability in regulatory decision making, in the same manner as for any other market participant.”

"36. Stability and consistency are important, especially when local generators have invested in long lived assets under a government-sponsored policy, and then had pricing rules changed."

“38. Implementation from 2017 seems very hasty. The renegotiation process that needs to take place (DG to Transpower, and DG to EDB) if the Authority goes ahead as proposed, suggests to ENA members that some sort of grandfathering transition for ACOT may need to be devised to avoid undermining the local DG market. “

“48. The Authority needs to do further work to ensure that in the transition there are not unintended consequences whereby peak injections and demand response are lost, creating transmission constraints, until such time as ACOT payments can be reinstated.”

Castalia for Genesis:

“If the Authority did not choose to transition the wider TPM changes, it would still be worth considering wider transition arrangements for ACOT. An extension could be targeted at DG investments made since ACOT was introduced, with signals targeted to ensure bankability of investments made during this period. This would address concerns relating to wider investment certainty in the sector and potential impacts on consumers.” (pg 4)

Genesis:

"We acknowledge that the Authority’s review of current D-G pricing principles was well advertised. However, knowing that a decision will be made is not the same as knowing what the decision will be. In this regard, we also note that the Authority must be careful not to pre-determine its own decisions by suggesting that D-G owners “should have known” that the Authority was likely to change the D-G pricing principles.

We consider the proposed changes will have a significant financial impact on some D-G owners. This impact should not be trivialised by the Authority, and we suggest the changes could have adverse impacts on consumers if not carefully managed. For example:

- *In the short term, removing the existing ACOT payments may encourage uneconomic dispatch behaviours from distributed-generators.*

- *In the long term, removing the ACOT payments (without transition to a new mechanism) may affect how future investors see investment in New Zealand. As discussed above, there is the potential for New Zealand’s future grid to be more reliant on D-G or large-scale battery to defer or otherwise avoid transmission investment."* (pg 3-4)

"Finally, a number of D-G owners will be financially affected by the proposed change. We are concerned that the Consultation Paper does not properly consider how to manage the adverse financial impact on current ACOT beneficiaries whilst transitioning to a new (yet undecided) approach to payment. The absence of an appropriate transition timeframe may incentivise uneconomic and undesirable behaviours from D-G owners." (pg 1)

While **Inchbonnie Hydro** is a member of the IEGA, it provided an relevant example of policy change that recognised that long term investment had been made on the basis of an existing policy.

“The British government has recently changed regulations surrounding the electricity industry without affecting existing investors. For example, the Feed-In-Tariff schemes to encourage investment in small wind, solar, and hydro schemes were changed to reduce the rate paid for the electricity generated. But the changes were not retrospective for people who had invested in previous iterations of the scheme. The deal they invested in remains in place.” (pg 4)

Infratil:

"… we do not believe it good regulatory practice to radically change regulatory settings unless the benefits are clear, demonstrable and material (which we do not believe is true here). In essence, the Authority is penalising incumbent investors for having sunk their costs. The fact there is little that affected investors can do in response to the changes (e.g. reduce output) is not a good reason to make the change. In the long run, effecting wealth transfers through regulatory changes hurts consumers." (pg 2)

"We did not anticipate the combination of proposals for the removal of the DGPPs and the removal of peak transmission pricing signals. We certainly would never have expected such a significant policy change to be introduced without a transition which recognised the legitimate expectations of investors. In our experience of regulatory change, the complete lack of consideration for (or examination of) the reasons a policy exists in the first place, and how that policy was introduced, is unique." (pg 2)

"In summary, changes such as those proposed, without sufficient appreciation for the expectations of existing investors, will have a material impact on the cost of capital for future investment. This will flow through directly to investment costs and to the cost of electricity, and must be accounted for by the Authority in its assessment of the long-term benefits to electricity consumers." (pg 3)

NZWEA:

"11. The proposed changes create significant uncertainty and a number of NZWEA members consider the proposed changes will have a significant impact on the viability of existing wind farms. In addition, the uncertainty over future revenue streams and connection costs are material impediments to future investment."

PwC:

"24. Grandfathering arrangements for existing distributed generators should also be considered as a means of retaining investor confidence to make investments within the electricity industry."

"128. Since 2007 a number of parties have made material investments in distributed generation in an environment where ACOT payments and incremental cost charging has been in place. Investors had reasonable expectations that these arrangements would continue at the time their investments were made. To remove the DGPPs without grandfathering arrangements will have an effect on investment across the electricity value chain as investors will now see an increased probability of other ex-post regulatory changes being imposed after investments have been made. A reduced willingness to invest in electricity infrastructure (or to invest only if higher returns are available) is likely to increase costs, reduce competition and affect reliability, with a consequential negative effect on the long-term benefit of consumers.

129. The distributors which support this submission recommend the Authority puts in place a form of grandfathering arrangement to mitigate this substantial risk."

Top Energy:

"11. The proposed TPM and the proposed removal of the DGPPs are likely to have a negative impact on investor confidence and hence investment. This is because they change the rules after investments have been made, which makes investors concerned about similar actions in the future. A stable and predictable set of regulations is desirable as this will make investors more willing to make investments.

12. Distributed generators in particular had a reasonable expectation that the regulatory regime would remain stable (it was only in 2007 when the regulatory environment encouraged distributed generation and there was no reason to assume these regulations would change so quickly)."

"42. If the DGPPs are removed, they should continue to apply (through grandfathering arrangements) to existing distributed generators that are in operation at the time the Code amendments are made. This will avoid the negative investment issues noted above and also mitigate the costs involved with creating higher peak demand."