Date:
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Name of submitter:
Electricity Networks Association
Industry/area of interest:
Utilities/infrastructure
Contact details
Graeme Peters, Chief Executive
Address:
Level 5, Legal House
101 Lambton Quay
WELLINGTON 6011
Telephone:
64 4 471 1335
Email:
gpeters@electricity.org.nz

Submission on review of distributed generation pricing principles consultation paper

Submission to the Electricity Authority

From the Electricity Networks Association

Contents

1. Introduction

1. The Electricity Networks Association (ENA) appreciates the opportunity to make a submission to the Electricity Authority in respect of the review of **Distributed Generation Pricing Principles (DGPP).**

2. The ENA represents all of New Zealand's 26 electricity distribution businesses (EDBs) or lines companies, who provide critical infrastructure to NZ residential and business customers. Apart from a small number of major industrial users connected directly to the national grid and embedded networks (which are themselves connected to an EDB network), electricity consumers are connected to a distribution network operated by an ENA member, distributing power to consumers through regional networks of overhead wires and underground cables. Together, EDB networks total 150,000 km of lines. Some of the largest distribution network companies are at least partially publicly listed or privately owned, or owned by local government, but most are owned by consumer or community trusts.

2. Submission summary

The ENA submits that:

3. ENA members remain of the view that ACOT payments to local generators are neither cost reflective nor service related and are simply a cost burden on consumers.

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.

5. Careful consideration is given to the contractual arrangements that exist currently between DG and EDBs so that removal of DGPP does not leave EDBs with material costs that could not be recovered through the Input Methodologies.

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.

7. The Authority adjusts the existing TPM in a principled manner to better meet network pricing objectives.[1] This will have a flow on effect of providing better signals and outcomes for local generation. The ENA has submitted on this point previously.

8. The Authority reassesses whether removing the DGPP under the proposed TPM restructure will deliver efficiency enhancing outcomes for DG. Because Transpower's revenue recovery has no real economic cost signals, and is to be allocated on a fixed basis to grid users, it appears that under the combined proposals the economics of DG as a substitute for transmission investments will be determined by negotiation ability, rather than on the basis of economic costs.

[1] We describe our preferred approach to better organizing transmission pricing in submission 'ENA submission on 2016 TPM issues paper' 28 July 2016.

9. Good regulatory practice on DG is as important as the Authority's approach to the proposed TPM. 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.[2]

10. The transaction costs and practicality of changing the DGPP in the manner proposed by the Authority should not be underestimated. There will be a need to renegotiate numerous existing contracts and for EDBs, DG and Transpower to review their approaches to pricing and connection policies.

11. While the proposal does create additional work/costs for Transpower in identifying the avoided transmission costs and then contracting with DG, Transpower is likely to be the best party to do this. Aggregators already exist and are likely to further emerge to reduce the negotiation costs for small-scale DG to provide genuine grid support.

3. A proposal to change DG pricing

12. The Electricity Authority (Authority) proposes to remove the pricing principles (DGPP) from Part 6 of the Electricity Participation Code. Avoided costs of transmission (ACOT) payments such as they currently exist would no longer be required and be replaced with negotiated payments that are assessed by Transpower and paid to DG.

13. The first impact of this change would see Transpower determine whether payments to distributed generation (DG) are deserved, as a result of reduced costs of transmission rather than the avoided costs of transmission that the distributor faces. In principle, this could be seen as an efficient process but detailed consideration of the Authority proposal reveals a number of issues that need to be resolved before the proposal can be finalised.

14. The outcomes are therefore not clear at this time. However, the Authority believes that this change will result in greater efficiency.

15. The second impact from removal of the DGPP would be to change the prices that EDBs could charge DG to connect to their distribution networks. It is intended that the current cap of incremental cost for connection charges in schedule 6.4 of the Code would be replaced with connection charges based on the pricing principles that guide EDBs other pricing arrangements.

16. This second change may lead to connection charges for DG that are higher than incremental cost less avoided costs, as distributors could include some component to pay for the common costs of the network.

3.1 Existing contracts matter

17. The DG pricing principles have been in place for a number of years, and many distributors have interpreted the requirement to pass on avoided transmission costs that they pay to Transpower to be based on the TPM mechanism for determining transmission costs. In many cases, due to DG

[2] The ENA submission on the TPM includes further discussion on regulatory practice.

customers' requirements for certainty about these payments for avoided transmission, distributors have entered into long term contracts with distributed generators, where there is a requirement to base ACOT payments on costs. The proposed change to Part 6 pricing principles will have no impact on many of these contracts, which were entered into in reliance on the DG pricing principles. The only impact on these contracts will be through changes in the TPM.

18. The drafting of the Commerce Commission Input Methodologies (IMs) is clear that only ACOT payments made under Part 6 can be recoverable costs. Therefore, any contracts between EDBs and DG owners that would require continued payments based on RCPD, even if Part 6 pricing principles are removed, will cause a material cost recovery issue for affected EDBs. The ENA is not sure how many EDBs are impacted in this way. However one option might be for the regulation to override such contractual terms. Another option is to grandfather the new arrangements, as we discuss in this submission.

19. Similarly, if the DGPP changes take effect before the TPM changes (as the Authority proposes) such a move could also cause some problems for EDBs whose contracts may refer to avoided costs/charges under the TPM (which still exist) but the recoverable cost would no longer apply as the DGPPs would have been removed.

It is also worth noting that removing ACOT payments is a factor that makes the proposed TPM changes affordable for some EDBs, where they wouldn't be otherwise. That is, these EDB's would make savings from not having to make ACOT payments but would face higher charges under the proposed TPM.

3.2 Policy intent behind DG pricing

20. The original policy intent, developed in 2003 after two consultations, was to encourage smaller scale renewable generation within the distribution networks, when it was economic to invest at a local level. It seems that the DG pricing policy was based on the cost difference between a distribution network with DG connected, and a distribution network without DG. This approach was expressed at the time as avoidable costs objectives.

21. This policy position was re-examined in 2009 as part of the electricity market review that gave rise to a Government policy statement.[3] The relevant parts of the statement are:

> ***Distributed generation***
>
> *Distributed generation … is expected to play an increasingly important role in meeting electricity demand as the cost of smaller-scale and new renewable technologies continues to decline. Distributed generation can improve security of supply by creating diversity of fuel types, locations and technologies, and, where appropriately sited, helps reduce the need for transmission and distribution upgrades. Accordingly, it is important that there are no unnecessary barriers to its development.*
>
> ***Access to lines***
>
> *The Government proposes to introduce regulations prescribing reasonable terms and conditions on which line owners and electricity distributors must*

[3] Reference the GPS 2009 from MBIE site, recently revoked.

> *enable generators to be connected to distribution lines. The objective is to facilitate the use of distributed generation by ensuring that it does not face undue barriers in connecting to lines.*

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. While this was and remains the agreed policy approach, it seems that what are now regarded as inefficiencies may have crept into the application of the Part 6 pricing principles. An example is where DG has been paid the transmission costs that the EDB avoids when DG is present. These avoided costs are recovered from consumers in regulated revenue, so consumers served by a particular EDB face full transmission costs regardless, and because the transmission costs faced by EDBs are not reflective of avoidable costs, this simply results in the overall costs of transmission (including ACOT) increasing.
24. The Authority is now concerned that relevant payments to DG should reflect the reduction in actual costs that the transmission grid experiences as a result of the presence of DG. The Authority interpretation is that any payments to DG should be assessed by Transpower as avoidable costs within the grid in the same way that DG should receive the benefits of the costs that are avoided within the distribution network.
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.

3.3 A more efficient outcome?

26. The ENA also has difficulty with the Authority argument that removing the principles is likely to lead to more efficient outcomes (excluding the issue with ACOT payments). The Authority describes costs as being the costs of the grid *in the absence* of DG versus the costs that are avoided *in the presence* of DG. Given that the bulk of Transpower costs are sunk and do not change in the presence of DG, it appears that the Authority thinks that only a small amount of grid cost would be avoided compared to the grid charges that go forward to the EDB. The remaining grid costs are reallocated to all grid users including the EDB that has DG embedded in

its network and makes less contribution to covering the costs of the transmission grid. The Authority considers that this reallocation is inefficient because there is no transmission cost saving, only a reallocation of costs to other connected parties.

27. If local generation is embedded in the distribution network then, under the current TPM, because the EDB is taking less power from the grid, they will face lower transmission charges. That is, the EDB faces lower grid charges which are passed onto the DG as cost savings.

28. Local consumers are largely indifferent because they face the costs of transmission regardless of whether DG is present in the local network or not. The displaced transmission charges are then reallocated to other grid users.

29. The Authority also wants to change the TPM so that Transpower can look into the distribution network and charge the EDB on a gross basis as if the DG operator was not off-setting local demand. If there is a transmission capacity issue where there is an avoided transmission cost (e.g., avoiding transmission capacity upgrades) then Transpower would contract for demand response or local generation.

30. In aggregate consumers will be better off because there will only be costs incurred by Transpower or distributors to cover the actual avoided costs of transmission capacity, rather than inflated transmission costs as connected parties enter into a zero-sum game of seeking to shift transmission costs to other connected parties.

3.4 Unintended outcomes

31. There is potential for outcomes that the Authority does not appear to have considered;

32. ENA members are especially concerned about the absence of economic signals with transmission charges that flow through to DG. The Authority plans to replace the quasi-locational peak demand driven interconnection charge (RCPD) with a charge for use of a small set of transmission assets (termed Area of Benefit) and a residual charge on all load. This lack of real economic pricing signals renders the existing and the proposed TPM as unfit for easily determining whether DG is an economic substitute for grid investment. Many things can therefore get in the way, delivering outcomes that the Authority might not have intended.

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.

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. The fact that distribution pricing is principle driven means that the negotiation situation between DG and EDBs would be slightly better, but it's also hard to identify likely outcomes here.

36. In the same way as with TPM, ENA members have concerns with the overall approach the Authority is taking to changing the way local generation is compensated. They are both administered, regulated solutions that require good regulatory practice to be credible and durable. 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.

37. Another parallel with the proposed TPM is the ENA concern with the Authority handing the perceived problem of economic inefficiency over to Transpower with what appears to be minimal guidance. The potential exists for the pricing development process to take some years to complete and possibly end with a solution that is materially worse than existing TPM and DG arrangements.

3.5 Change management

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.

39. Transaction costs for this change will likely be significant, creating barriers to entry for DG. The Authority proposal does not acknowledge this cost, which will have a material impact on the cost-benefit analysis (CBA). Other aspects of the proposal suggest that any transition will need to be carefully managed. These include:

    - Negotiation power is with the larger entities, not smaller DG;
    - Some DG installations will cease to be viable;
    - The relative competitiveness between DG and grid generation will change, generally for the better.

3.6 Cost benefit analysis

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.

42. Consumer benefits dominate in the CBA, suggesting that the problem may be more to do with the ACOT payments being sent forward to consumers, than the issue of payments for avoided costs. If this is correct, then this seems to be a Part 4 issue or a problem with pricing principles. Regardless, the benefits attributed to lowering the price of electricity to consumers by removing the DGPP are overstated in the CBA. The price change to end consumers is not material enough to credibly make the assumption that they would notice the change. It is unlikely to generate the response that is valued in the CBA.

4. Conclusion

43. ENA members believe that the Authority needs to reconsider their proposal in light of the following three issues:

44. The first is 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.

46. It is difficult to envisage a situation where loads become so elastic that it becomes necessary to charge generators common costs. If that did occur then it would be important to have a policy debate about that at the appropriate time rather than remove the principle now.

47. The second issue is around the current inclusion of transmission charges in "avoided costs". It is clear that because transmission pricing is about recovering sunk costs, ACOT payments have high risk of compensating for avoided charges and not avoided underlying costs. Shifting responsibility to Transpower to identify areas where ACOT payments or demand response is needed is sensible because the TPM is always going to have strong elements of cost allocation not cost signalling. Such a move would assist in ensuring that the party that can distinguish between avoidable costs and avoidable charges is directly involved in the negotiations.

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.

49. The third issue is associated with long-term ACOT related contracts. The Authority needs to recognise that simply by removing the pricing principles not all distributors will be able to cease ACOT payments because these are governed by long-term contracts that link to the TPM. Distributors and DG have entered into those contracts in good faith as a result of the requirement to pay avoided costs. Unless the TPM changes, these contracts will still require ACOT.

EA consultation questions

Q No	Question	Response
1	Do you consider that the proposed Code amendment described in section 4.1 is preferable to the status quo and the alternatives described in section 4.6? If not, please explain your preferred option(s) in terms consistent with the Authority's statutory objective.	• No, ENA members do not consider the change is preferable to the status quo because the outcomes are quite unclear. • There are real risks of efficiency reducing unintended outcomes. • There are alternatives to the proposed amendments that would deliver better outcomes.
2	Do you consider that the proposed Code amendment described in section 4.1 complies with section 32(1) of the Act, and with the Code amendment principles, and should therefore proceed?	ENA members do not believe that the proposed Code amendments should proceed.
3	Do you have any comments on the drafting of the proposed Code amendment described in section 4.1? (The drafting is included in Appendix B.)	Changes as drafted should not go ahead for reasons explained in this submission.
4	Do you consider that the proposed Code amendment should come into force at a single date, or should it be phased in?	Changes as drafted should not go ahead for reasons explained in this submission.
5	Is the proposed phasing for the Code amendment appropriate? (The phasing is discussed in section 4.3.) If not, what alternative phasing or dates would you propose and why?	ENA members consider that the Code should not be amended as proposed, so this question is not relevant.
6	If the proposal were to proceed, do you consider that there would be barriers that might prevent agreements being reached between Transpower and distributed generation owners to efficiently reduce or defer transmission network costs? If so, what are these barriers? Please consider both existing and proposed new distributed generation.	• Yes, there will be problems with parties reaching agreements if this proposal goes ahead. • We describe the barriers and issues in this submission. • The outcomes from the proposed change are quite difficult to envision so it is difficult to be more specific.

7	If the proposal were to proceed, do you consider that there would be barriers that might prevent agreements being reached between distributors and distributed generation owners to efficiently reduce or defer distribution network costs? If so, what are these barriers? Please consider both existing and proposed new distributed generation.	We cannot speculate whether there would be changes to distribution costs from the proposed DGPP change. It is hard to envision that costs would reduce – they are more likely to increase.
8	If the proposal were to proceed, do you consider that those distributors that were no longer able to recover the cost of making ACOT payments would cease making such payments?	This too would be a speculative response. The contractual arrangements between EDB's and DG are relevant here.

5. Appendix

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

1. Alpine Energy
2. Aurora Energy
3. Buller Electricity
4. Counties Power
5. Eastland Network
6. Electra
7. EA Networks
8. Horizon Energy Distribution
9. Mainpower NZ
10. Marlborough Lines
11. Nelson Electricity
12. Network Tasman
13. Network Waitaki
14. Northpower
15. Orion New Zealand
16. Powerco
17. PowerNet
18. Scanpower
19. The Lines Company
20. Top Energy
21. Unison Networks
22. Vector
23. Waipa Networks
24. WEL Networks
25. Wellington Electricity Lines
26. Westpower