Electricity Authority Review of Distributed Generation Pricing Principles

Incentives Report

Report for **Trustpower**

by Allan Carvell; 24 July 2016

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PURPOSE

The EA is consulting on a proposal to remove the the distributed generation pricing principles (“DGPP”) in schedule 6.4 from Part 6 of the Electricity Industry Participation Code 2010 (“the Code”). Instead, services to and from distributed generation (“DG”) would be priced with reference to the current voluntary distribution pricing principles. The EA also proposes that where there are transmission benefits, compensation for these benefits must be negotiated by the DG owner directly with Transpower, rather than being sought via the distributor (“EDB”).

Trustpower has asked for my opinion on how the operation of the price-quality control regime administered by the Commerce Commission would impact on the incentives for the parties to negotiate, in accordance with the applicable processes laid out in Part 6 of the Code as revised, if the EA’s proposal was implemented.

Qualifications

I provide this **Incentives Report** as an expert practitioner in the field of network operation and regulation in New Zealand. I have been involved in designing, managing and implementing regulatory arrangements in the distribution and transmission network sectors for over 23 years and have 15 years experience operating at executive management level in these network businesses. I hold membership in professional bodies in New Zealand for accountants and for directors and have a graduate qualification in accounting and post graduate qualifications in economics and corporate management.

In preparing my Report I have read and complied with the Code of Conduct for Expert Witnesses as set out in Schedule 4 of the High Court Rules.

Summary

In the context of the EA’s proposal, the price-quality control regime administered by the Commerce Commission is likely to give rise to incentives for:

- EDBs to opportunistically price DG connection services to maximise revenues, given that revenues from connecting DG to the distribution network falls outside the ambit of the price-quality control regime; and

- EDBs to continue to prefer investing in assets in their own network, rather than acquiring services from DG owners for network support benefits.

As a result of these incentives negotiations between EDBs and DG owners are likely to be difficult (if not fruitless), noting that the tightly prescriptive approach in Part 6 of the Code (including in respect of pricing) reflects concerns previously held about the imbalance of negotiating power between the parties.

The removal of schedule 6.4, containing the DGPP, will result in these incentives on EDBs being reflected through the price offered by EDBs to provide connection services to DG, as the voluntary distribution pricing principles provide considerable latitude for EDBs to price above incremental cost.

The EA’s objective of spreading some portion of EDB common cost to DG owners will likely be unsuccessful where the EDB is permitted to apply the ACAM cost allocation methodology.[1] There is, therefore, a reasonable likelihood that consumers will not benefit from a reduction in line charges as a result of EDBs pricing connection services to DG owners under the voluntary distribution pricing principles rather than under the DGPP. Instead of the expected transfer of wealth from DG owners to consumers there is likely to be a transfer of wealth from DG owners to EDBs.

Removal of schedule 6.4 from the Code renders ACOT payments from EDBs to DG owners unsustainable. ACOT payments will cease to meet the definition of 'recoverable costs' under the price-quality control regime meaning that EDBs will be actively discouraged from continuing to make such payments.

While Transpower may have some incentives to negotiate for the procurement of transmission alternative services in relation to new DG investment proposals, there may be much weaker incentives to fully value the benefit of transmission savings in relation to historical DG investments.

BACKGROUND

Current Arrangements

The current arrangements for connecting distributed generation ("DG") to a distribution network are set out in Part 6 of the Code.

Part 6 of the Code prescribes processes for applying to have DG connected to the distribution network.[2] Two separate processes are prescribed in respect of DG with a capacity of up to 10kW (depending on inverter and protection capability) and another distinct process is prescribed in respect of DG with a capacity over 10kW.

Each prescribed process provides for entry by negotiation into a connection agreement between the EDB and the owner of the DG. Regulated terms are prescribed in the event that a connection agreement is not established between the parties.[3] Of particular relevance, in light of the EA's proposal, is that the regulated terms provide that:

> *"Charges that are payable by the **distributed generator** or the **distributor** must be determined in accordance with the pricing principles set out in Schedule 6.4."*

Accordingly, the DGPP must be used if regulated terms are relied upon and <u>may</u> be used (through negotiation) if a connection contract is agreed between the parties.

The EA proposal

The EA's concerns and proposed solutions are summarised below:

The EA has identified two key problems with the DGPPs:

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[1] ACAM is a cost allocation methodology that is able to be applied by a number of non-exempt EDBs in accordance with clause 2.1.4 of Electricity Distribution Services Input Methodologies Determination 2012

[2] Electricity Industry Participation Code; Schedule 6.1 of Part 6

[3] *ibid.*; Schedule 6.2 of Part 6

a) The ‘connection services issue’

“The DGPPs require distributors to charge owners of distributed generation no more than the incremental cost for connection and distribution services.”[4]

The EA argues that, because the DGPPs *“prevent EDBs from setting prices for DG that include a share of common costs, the DGPPs do not promote efficiency.”*[5]

b) The ‘avoided cost of transmission’ (ACOT) issue.

“The provisions in the DGPPs relating to transmission do not promote efficient decisions about investing in, and operating, distributed generation.”[6]

The DGPP *“require distributors to* [pass onto] *distributed generation owners the avoided/additional transmission charges the distributor would otherwise pay in the absence of distributed generation. These avoided/additional charges do not necessarily reflect the avoided/additional transmission costs* [but may simply reflect a reallocation of transmission costs between transmission grid users]*. As a result, there can be over- or under-signalling of transmission costs and benefits. This in turn will encourage inefficient distributed generation investment and/or operation. It could also create inefficiencies with respect to evolving technologies (for example the development of micro grids).”*[7]

The EA is concerned that *“these problems* [with the DGPP] *are likely to encourage distributed generation owners to operate their distributed generation, or to build new distributed generation, when that is not the lowest cost way to provide electricity”*.[8]

Accordingly, the EA proposes *“ … to amend the Code to address both the connection services issue and the ACOT issue. The proposal is to remove the DGPPs from Part 6 of the Code. The Authority’s voluntary distribution pricing principles guide development of distributors’ pricing methodologies for distribution pricing generally.”*[9]

Application of the voluntary distribution pricing principles (rather than the DGPP) would prevent EDB’s from charging less than incremental cost to DG owners for connection and distribution services. Accordingly, an EDB could, if it chose, include an allocation of common costs in the charges to DG owners/operators.

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[4] Review of distributed generation pricing principles - Consultation Paper; Electricity Authority; 17 May 2016; Page B

[5] *ibid.*; Page C

[6] *ibid.*; Page B

[7] *ibid.*; Page D

[8] Consumer Guide: Have your say on pricing guidelines and methodologies; Electricity Authority; 17 May 2016; para 10.2

[9] Review of distributed generation pricing principles - Consultation Paper; Electricity Authority; 17 May 2016; Page G

Removing the DGPP "*would leave Transpower solely responsible for obtaining and paying for transmission-substitute services that distributed generation provides*".[10]

INCENTIVES IN THE PRICE-QUALITY REGIME

The price-quality control regime administered by the Commerce Commission will impact on the incentives for the parties to negotiate reasonable terms, including price, if the EA's proposal is implemented.

Direct incentives under the price-quality regime

Before assessing the specific incentives arising from the price-quality regime it is worth considering how the price control element of the price-quality regime will operate in light of the EA's proposal.

The following example is intended to demonstrate the considerations that might be relevant for an EDB and/or Transpower assessing a DG proposal for which the DG owner is seeking to negotiate compensation for network benefits. Under the EA's proposal the DG owner will need to engage both with the EDB and with Transpower in order to secure compensation for network and transmission benefits respectively. The DG owner will seek avoided cost of distribution (ACOD) payments from the EDB and transmission alternative operating costs (TAOC) from Transpower.[11]

In the example:

- the DG owner wishes to connect DG to EDB network;
- the DG will have ability to reduce peak load at the nearest GXP. The DG plant has a 20 year operating life. This has the effect of deferring the need for network reinforcement and grid reinforcement for 20 years (i.e. until assumed continued load growth would result in the need for further investment and/or the DG plant comes to the end of its operating life);
- the regulatory period for both the EDB and Transpower is about to commence and the respective price paths have been set by the Commerce Commission;
- both the EDB and Transpower included reinforcement expenditure in the first year of their asset management plans in relation to supply at the GXP. The Commerce Commission set starting prices for the EDB and Transpower assuming these expenditures will take place.

Both the EDB and Transpower must decide whether to invest in network/grid assets or whether to contract for support services from DG to postpone the need to invest. There are incentives in the regulatory regimes for each that should favour saving capex and incurring the additional operating expenditure (in the form of ACOD or TAOC, respectively).

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[10] *ibid.*; page H

[11] The process for transmission alternatives is provided in clause 35 of the TPM (schedule 12.4 of the Code)

First Regulatory Period

In the first regulatory period regulated entities will be able to earn revenue based on regulated starting prices that reflect the expected expenditure on network/grid reinforcement. The regulatory price setting methodology assumes the expected capital expenditure is rolled into the RAB in the first year (in this case) of the regulatory period. Revenues for the regulatory period reflect the return of and return on the expected capital expenditure ('base capex' in the case of Transpower). The regulated entities are permitted to earn this revenue even though, if the DG solution is adopted, they will not have to make those investments (i.e. will not incur the funding costs or the depreciation expense). Of itself, this should represent a reasonable incentive to save the capital expenditure. The regulated entities must also have regard to the delivery of specified levels of service quality over the regulatory period, so the ability to maintain quality, without the expected investment or with an alternative solution (such as DG), is a countervailing consideration and incentive.

The quality incentive is strong as failure to meet quality standards not only brings potential financial penalties but may also impact the reputation of the regulated entity with end consumers, bring unwanted adverse media activity and can result in political attention. This can lead to EDBs and/or Transpower requiring unreasonably high technical requirements for connecting parties.[12]

If the regulated entities successfully negotiate for DG to provide services that will defer the need for reinforcement investment, the EDB and Transpower will incur ACOD/TAOC payments (essentially reflecting the time value of the deferral of the reinforcement expenditure). In this first regulatory period these ACOD/ACOT payments will not have been included in the assumptions underpinning the regulated starting prices for each regulated entity.

Subject to regulatory approvals for TAOC payments, Transpower will be able to increase its charges (to benefiting consumers) and account for the TAOC payments as a recoverable cost in its price control compliance statement.

However, for the EDB, ACOD payments are not a recoverable cost, and will not be reflected in starting 'allowed' revenues, so the incentive for the EDB is significantly less than that for Transpower. The EDB's incentive is limited to the excess of the value of revenue 'allowed' as a result of the expected capital investment being avoided over the additional (and unbudgeted) ACOD expenditure. This should be a positive financial incentive but will be considerably weaker than that faced by Transpower.

Subsequent regulatory periods

In subsequent regulatory periods the regulatory allowed revenue of the EDB should reflect the ACOD payments the EDB has contracted for. The ACOD cost will form part of the expected operating expenditure of the EDB. However, the regulatory allowed revenue will no longer reflect the recovery of items related to the capital expenditure that was expected

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[12] For example, EDBs are known to have been reluctant to acquire embedded networks due to concerns that the 'network' design differs (may be less robust) than their design standards. However the difference in design standards may be expected to little impact on network performance and be more reflective of the natural conservatism in network design.

in the first regulatory period (and deferred due to the DG arrangement) as this will not form part of the opening RAB for the second (or subsequent) regulatory period(s).[13]

Recovery of the ACOD payments in subsequent regulatory periods is dependent on the Commerce Commission including these costs at each reset. There is, therefore, a degree of regulatory risk attached to recovery by the EDB of ongoing ACOD payments. This risk would be much diminished if the EDB had made the capital investment and the lines assets were in the RAB.

Transpower, having obtained the necessary approvals at the outset of the DG arrangement, will have greater certainty that the TAOC payments are either recoverable costs or operating costs for inclusion in subsequent price resets. However, as is the case for the EDB, the regulatory allowed revenue will no longer reflect the recovery of items related to the capital expenditure that was expected in the first regulatory period (and deferred due to the DG arrangement) as this will not form part of the opening RAB for the second (or subsequent) regulatory period(s).

Wider incentives under the price-control regime

In addition to the economic incentives under the price-quality control regime there are a number of other incentives that relate to, or are derived from, the regime. The impacts are likely to be different in respect of the proposed solution to the connection services issue from those in respect of the proposed solution to the ACOT issue.

The connection services issue

The voluntary distribution pricing principles require that prices *"signal the economic cost of service provision"*, by *inter alia* being subsidy free. The principles identify the 'subsidy free' range as being *"equal to or greater than incremental costs, and less than or equal to stand alone costs"*.[14] By contrast, the DGPP limit the price for connection services to no more than the incremental cost of providing the connection service.

The effective difference between the DGPP and the voluntary distribution pricing principles is the potential, under the latter, for EDBs to allocate a portion of their common costs to DG owners by pricing somewhere in the subsidy free range, i.e. above the incremental cost (but not exceeding the stand alone price). The EA identifies that *"it may be efficient for owners of distributed generation not to pay common costs in some situations,* [however] *it is unclear why this would be efficient in all cases"*.[15] The voluntary distribution pricing principles enable EDBs to include recovery of common costs in charges for providing network connection services to DG by pricing above incremental cost while the DGPP effectively prohibit this. Pricing at incremental cost is possible under both sets of principles.

In the event DGPPs are removed, the EA believes that EDBs will apply the voluntary distribution pricing principles when negotiating prices for the provision of connection services for distributed generation. However, EDBs generally 'set' prices rather than

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[13] There is some carry-over of the benefit into the second period under the Incremental Rolling Incentive Scheme (IRIS). However, IRIS is intended to remove incentives in respect of the timing of savings within the regulatory period and its effect is not material to this analysis.

[14] Voluntary Distribution Pricing Principles; principle (a) (i)

[15] Review of distributed generation pricing principles - Consultation Paper; Electricity Authority; 17 May 2016; para 3.2.9

‘negotiate’ prices and the purpose of Part 6 in the first instance was to provide a mechanism where the imbalance in negotiating power between the EDB and a DG owner could be moderated. Part 6 of the Code is tightly prescriptive as to technical and commercial terms (including price) and timeframes for negotiation. Reliance on the voluntary distribution pricing principles is a material relaxation of that level of prescription.

Without constraints, an EDB may set prices for connection services to DG that sit higher in the subsidy free range than is economically efficient. At the extreme, price may be constrained under the voluntary distribution pricing principles as high as the stand alone cost. For DG that is injecting into a distribution network to provide energy to consumers within the EDB footprint, the stand alone costs may be the cost of replicating, in large part, the extant network.[16] Prices at or near the stand alone cost level likely will deter what might otherwise be economic investment in DG.

How far above the incremental cost an EDB might set prices for connection services to distributed generation will be impacted by the incentives faced by the EDB. The price-quality control regime introduces several incentives that may encourage EDBs to allocate common costs to DG at inefficient levels, potentially at or above the DG owner’s ability or willingness to pay. In short, EDB’s cannot be relied upon to price DG connection services efficiently (hence the existence of schedule 6.4 of the Code), just as they cannot be relied upon to avoid exploiting their monopoly position when pricing electricity lines services (and hence the existence of Part 4 of the Commerce Act 1986).

Incentive based regulation

The Commerce Commission makes the point that the revenue path for those EDBs subject to price control is largely predetermined at the beginning of the regulatory period.[17] Within the regulatory period the price-quality control regime incentivises EDBs to maximise profits in ways other than increasing regulated revenue. *“The price limit is fixed in advance, and means profitability depends on the extent to which costs are controlled. Actual costs may differ from forecasts for a variety of reasons. But the incentive to increase profits helps to put pressure in the right direction.”*[18] However, the incentive to increase profit for the EDB is not just in terms of minimising costs in the regulated business but also to seek unregulated revenues by leveraging off the regulated cost-base wherever possible.

While the profit maximising incentive might work favourably in respect of those costs of undertaking the regulated activity that the EDB can control, it also promotes behaviours in respect of unregulated activities that are beyond the Commerce Commission’s ambit under Part 4. The EA’s proposal will strengthen these incentives to the detriment of consumers by loosening the constraints imposed by schedule 6.4 of the Code.

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[16] As the EA notes in Review of distributed generation pricing principles - Consultation Paper; Electricity Authority; 17 May 2016; para 4.2.25
[17] The drivers of change in regulated revenues over during the regulatory period are factors largely outside the control of the EDB, e.g. inflation, energy volume growth.
[18] Default price-quality paths for electricity distributors from 1 April 2015 to 31 March 2020 Main policy paper; Commerce Commission; 28 November 2014; Para 3.6

Scope of price-quality control regime

Prices or revenues for connection and distribution services an EDB provides to DG fall outside of the regulatory ambit of the price-quality control regime in Part 4 of the Commerce Act. The regulated service, *electricity lines services,* is defined in Part 4 as the conveyance of electricity by line but <u>not including</u> *"conveying electricity only from a generator to the national grid … [or] conveying electricity (other than via the national grid) only from a generator to a local distribution network or from a local distribution network to a generator"*.[19,20]

Accordingly, there is no constraint under the price-control regime on how or where EDBs set the price of network connection and distribution services for DG.

Cost allocation rules

An EDB may generate revenue from the provision of network connection and distribution services to DG at prices above the incremental cost of providing that service without there being any reduction in the EDB's regulated revenue. This is possible because, within certain constraints, the EDB can allocate costs between regulated and unregulated activities using the Avoidable Cost Allocation Methodology (ACAM).

ACAM based allocations would not require the allocation of common costs away from the regulated activity and towards the unregulated activity (i.e. connection and distribution services to DG). These common costs, by definition, would not be avoided if the unregulated activity was not entered into or was discontinued.

As a result of the allocation rules under the price-quality control regime there is a clear potential gain to the EDB, with no reduction in the prices levied on consumers through regulated line charges. This means that there will be a wealth transfer from the DG owner to the EDB, rather than a wealth transfer from the DG owner to consumers (as anticipated by the EA).

This incentive may be somewhat muted if the EDB is required to allocate costs under the Accounting-Based Allocation Approach (ABAA), although the EDB still has a large degree of discretion as to the choice of cost-drivers to be used as the basis for the cost allocation. However, to the extent that there is an allocation of common costs between regulated activities and the unregulated DG connection activity then consumers may see some benefit through lower regulated line charges.

Preference to invest in assets

In addition to the potential impact of the profit incentive on EDB price setting, the choice between investment in assets or the acquisition of services is also important. Notwithstanding some measures within the price-quality control regime to provide balanced incentives between operating expenditure and capital expenditure, EDB's continue to favour capital expenditure over operating expenditure. At a recent industry

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[19] Commerce Act 1986; s 54C(2)(b) and (c); Part 4

[20] For some small scale generation, e.g. domestic scale solar PV, it may be arguable that the connection service also provides 'normal' electricity supply to the residence and therefore the charges do not meet the exclusion in 54C. This is unlikely to be the case for DG in the over 10kW category.

workshop an EDB spokesperson, discussing the choice between purchasing a service (i.e. incurring an operating cost) or building network assets (i.e. incurring capital expenditure), described this bias:

> *"The thing about a service in the current regulatory environment is we're on a five year price reset and anything we put into a service which becomes opex, it's just a cost, it disappears, ,,, If we can put it on our RAB … we actually at least get that money back …"*[21,22]

This bias means that EDBs may prefer to build assets to reinforce and grow their networks rather than rely on DG connecting and providing network support services to achieve similar outcomes. There is an incentive therefore for EDBs to price (and negotiate generally) in a manner that would discourage (otherwise potentially economically efficient) DG from connecting.

The capital expenditure bias arises from a number of drivers:

- the desire to increase RAB, and therefore revenue and profit. Like most business, for EDBs a key measure of the success of management and governance is 'growth' measured, for example in asset or revenue terms;

- the desire to control the performance of the network. Assets that are owned and in the RAB represent easily controlled assets, of the kind EDBs are accustomed to managing, with a known reliability and performance;

- a view that a solution involving generation is inherently less reliable than a solution based on 'lines';

- generation has a higher risk profile than 'lines' and therefore a higher cost of capital, it is therefore inherently lower cost to invest in 'lines' than in generation. The lower cost is assumed to benefit consumers;

- the avoidable cost of distribution ("ACOD") is not a recoverable cost and would, therefore be regarded as an ordinary element of operating costs to be recovered within regulated revenue. The incentive weightings in the IRIS rules between capital expenditure savings and operating expenditures overspend are unlikely to offset the short term impact on profit and the ability to pay dividends to owners/beneficial owners;

- as expressed in the industry participant comments quoted above, once an asset is in the RAB, it delivers a (near) certain regulated income stream that recovers its capital costs (return of and return on the capital invested) plus associated maintenance and operating costs. EDBs are wary of additional operating costs that might arise during the regulatory period as these may be in excess of the forecast cost level used to establish their regulated revenue path.

[21] Transcript; Emerging Technologies Workshop; Commerce Commission; 14 December, 2015 Page 89, lines 3-5, 7-8 & 10

[22] RAB means Regulated Asset Base

Non-exempt EDBs do not face the same incentives and regulatory regime as Transpower

As noted above, relying on distribution pricing principles that are voluntary implies a significant degree of faith in EDB behaviour and incentives in a more relaxed regulatory framework. The EA base their proposal on an assumption that EDBs *"would contract with distributed generators to develop and/or operate distributed generation that avoids distribution network costs … and make appropriate ACOD payments to the distributed generators".*[23] Given the functioning of the regulatory regime and the incentives acting on EDBs there seems little basis for confidence that removing the constraints that exist in Part 6 of the Code, in particular the binding nature of the pricing requirements in schedule 6.4, will result in economically efficient outcomes. Rather the difficulty in negotiating and contracting with EDBs that Part 6 of the Code was intended to resolve will re-manifest.

Many elements of the incentives and arrangements that are in place for Transpower are clearly absent for EDBs. In particular, the EA notes that Transpower has incentives to contract with DG, including:[24]

- Transpower is required to appropriately consider, and consult on, non-transmission solutions – such as contracting for distributed generation – as alternatives to major capex investment;

- The Commerce Commission regime gives Transpower an incentive to contract for distributed generation to defer base capex. Transpower has a fixed base capex allowance in each regulatory control period, irrespective of its actual expenditure. Therefore, to the extent that Transpower can reduce or defer base capex expenditure – either through distributed generation or by any other means – it has an incentive to do so;

- Transpower has demonstrated willingness to contract for distributed generation in the course of its demand response trials.

These incentives, assuming that these are effective for Transpower, generally do not exist for EDBs. For a start, 10 EDBs are exempt from the price-quality control regime. EDB investment decisions are not subject to oversight and review by the Commerce Commission in the same way as Transpower's are. The distribution pricing principles are voluntary and, where incentives are not aligned, can be ignored.[25] And the regulatory regime applying to EDBs cannot constrain charges for connecting DG nor ensure that common costs are allocated away from the regulated activity and to the unregulated activity.

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[23] Review of distributed generation pricing principles - Consultation Paper; Electricity Authority; 17 May 2016; Para 4.2.16(b)

[24] Review of distributed generation pricing principles - Consultation Paper; Electricity Authority; 17 May 2016; Para 4.2.24

[25] Review of Electricity Distribution Businesses' 2013 Pricing Methodologies - Report to the Electricity Authority; November 2013: Castalia reports relatively poor compliance with the voluntary distribution pricing principle in respect of pricing between incremental and stand alone cost, with only 2 out 29 EDBs satisfying the criteria for total compliance and a further 9 partially complying, leaving 17 EDBs not complying.

Exempt EDBs

Non-exempt EDBs are regulated (in respect of the provision of lines services) under Part 4 of the Commerce Act, but only in respect of information disclosure and not in respect of price or quality.

The primary constraints on the behaviour of EDBs that are exempt from price-quality regulation are the threat of losing their exempt status and, as with non-exempt EDBs, pressure from their owners/beneficial owners. Despite the need to operate as 'successful businesses', some exempt EDBs focus on providing the benefits of (beneficial) ownership to their consumers through low prices (rather than through repatriation of profits).

However, any largess on the part of exempt EDBs is unlikely to extend to DG owners because DG owners do not qualify as 'consumers' for the purpose s 54D or for s 54H of the Commerce Act, So DG are not relevant to the exempt status criteria, nor are they able to threaten an EDB with loss of its exempt status.[26]

Under the EA's proposal, exempt EDBs will be expected to price services to DG using the voluntary distribution pricing principles. As for non-exempt EDBs, these principles provide considerable latitude for exempt EDBs to price above incremental cost. Exempt EDBs are also bound by the cost allocation input methodology but this is only relevant for information disclosure purposes as non-exempt EDBs are free to price the regulated service as they see fit (subject to the constraints noted above). In other words, the choice of cost allocation method does not necessarily have any relation to how or where an exempt EDB pitches its prices.

Overall, the incentive on exempt EDBs is for them to price aggressively where they can, i.e. towards DG owners, and to continue to price leniently towards electricity consumers as they currently do.

To the extent that an exempt EDB aims to provide the lowest priced lines service it can to is (beneficial owner) consumers (as some but not necessarily all exempt EDBs do), the incentives for selection of price points, for both the regulated lines services and for DG connection, are more likely to result in the transfer to consumers of the benefit of the recovery of some portion of common costs from DG. That is to say, in pricing their services some exempt EDBs are likely favour consumers over DG owners. Other exempt EDBs are likely to extract value from DG owners for the benefit of their shareholders (which does not include DG owners).

The ACOT issue

The EA proposes that Transpower would approve ACOT payments. Transpower would be *"solely responsible for obtaining and paying for transmission-substitute services that*

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[26] s 52D of the Commerce Act provides that **consumer** has the same meaning as s 2(1) of the Electricity Act 1992, i.e. *"consumer—(a) means any person who is supplied, or who applies to be supplied, with electricity; but (b)does not include any electricity generator or any electricity distributor or electricity retailer, except where the electricity generator or, as the case may be, the electricity distributor or electricity retailer is supplied, or applies to be supplied, with electricity for its own consumption and not for the purposes of resupply to any other person*"

distributed generation provides".[27] Currently, DG owners would obtain ACOT payments from the EDB (on the basis that the EDB will benefit from a reduction in charges from Transpower due to the effect operation of the DG has on peak demand, i.e the basis for allocation of interconnection charges under the Transmission Pricing Methodology or TPM).

Currently an EDB is neutral to facing costs of transmission payable to Transpower or the cost of passing the benefit of avoided transmission charges onto a DG owner. The price-quality control regime provides for both transmission charges paid to Transpower and costs of avoided transmission paid to a DG owner to be treated as recoverable costs. In the Specification of Price input methodology the avoided cost of transmission, or 'distributed generation allowance', is defined as payments *"made in accordance with (a) Schedule 6.4 of Part 6 of the Code or (b) the Electricity Industry Act 2010"*.[28]

Under the EA's proposal it is intended that EDBs no longer make payments to DG owners in respect of ACOT. As a result of removing the DGPP from the Code (i.e. removing schedule 6.4) any ACOT payment made by an EDB to a DG owner would no longer be a recoverable cost. Accordingly, non-exempt EDBs would have very little incentive to make ACOT payments to DG owners under the EA proposal.

The EA proposes that DG owners may still receive compensation for benefits or services provided to transmission but the DG owner will have to engage and negotiate directly with Transpower to identify the 'transmission benefits' and have these 'approved' by Transpower. This is intended to alleviate the EA's concern that ACOT may be incurred when there is, or has been, no compensating reduction in transmission costs.

The EA identifies a number of elements of the price-quality control regime applying to Transpower that incentivises Transpower to negotiate for the provision of services where this will enable Transpower to make savings on its base operating and capital expenditure allowances. These incentives are likely to function in relation to new DG which will impact Transpower's operating and capital expenditure relative to the allowances provided for that regulatory period. In addition, Transpower is able to treat payments for 'transmission alternatives' as recoverable costs (although these do require additional approval from regulatory bodies).[29]

It is unclear how effective these arrangements can be expected to be. However, Transpower faces many of the same incentives as EDB's to prefer grid investment solutions to solutions based on market behaviours or other technologies.

The EA also considers that Transpower has demonstrated its capability in contracting for distributed generation in the course of its demand response trials.[30] DG owners that engaged successfully or unsuccessfully, or that had reason not to engage, with the trials might be better placed to comment on the extent to which the EA should put faith in the

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[27] Review of distributed generation pricing principles - Consultation Paper; Electricity Authority; 17 May 2016; Page H

[28] Electricity Distribution Services Input Methodologies Determination 2012 (consolidated as of 15 December 2015); Commerce Commission; clause 1.1.4(2)

[29] Transpower Input Methodologies Determination (consolidated as of 12 February 2016); Commerce Commission; Clauses 3.1.3(1)(c) and 3.1.3(3)

[30] Review of distributed generation pricing principles - Consultation Paper; Electricity Authority; 17 May 2016; para 4.2.23 (b)

progress of those trials. However, it may be unrealistic for the EA to put significant faith in the observations of a small scale trial which Transpower was probably keen to have succeed.

As EDB’s will no longer be incentivised to make ACOT payments to DG owners Transpower’s negotiations will have to relate to existing as well as new DG investments. The process for demonstrating historical transmission benefits may be challenging. As it may be economically impractical for existing DG to withhold its services there may a be an incentive on Transpower to understate those historical benefits and minimise future payments that would take the place of existing ACOT payments.