INDEPENDENT ELECTRICITY GENERATORS ASSOCIATION

DGPP PROPOSALS

QUESTIONS AND ANSWERS

September 2016

Contents

1. What is the Electricity Authority proposing?

The EA is proposing to remove schedule 6.4 of the Electricity Code, which contains the 'Distributed Generation Pricing Principles (DGPPs)'. These pricing principles lay out how distributors and distributed generators (DGs) must set the prices of the services that they provide to one another if they can't) negotiate a mutually acceptable connection contract. They're the 'default', or 'fall-back' pricing terms. Importantly, the DGPPs require distributors to pay DGs for any transmission or distribution costs that are avoided as a result of the connection.

If the DGPPs are removed, DGs would instead have to negotiate with distributors and Transpower to receive such payments without this default safety net The EA proposes this change would apply from 1 April 2017 for DGs located in the lower North and South Island regions; and 1 April 2018 for DGs located in the upper North and South Island regions.

2. What are the DGPPs?

The DGPPs are the 'default' pricing arrangements for distributors and DGs. They set out what a DG has to pay to a distributor when it connects to the distribution network, if the two parties cannot agree to terms. The DGPPs require (amongst other things) that:

- the connection charges for the DG must not exceed the 'incremental' (additional) costs of providing it with connection services, i.e. a DG is not required to contribute to the 'common costs' of the distribution network that the distributor would be incurring anyway regardless of the presence of the DG;
- the incremental cost must be net of any transmission and distribution costs that the distributor avoids by connecting DG, i.e. the distributor must compensate the DG for any 'avoided network costs'; and
- if the incremental costs are negative, the DG is deemed to be providing 'network support services' to the distributor, and the distributor may *pay the DG* to connect – not the other way around.

The vast majority of distributors have implemented the DGPPs by 'netting off' the transmission charges that they avoid as a result of the DG connecting, i.e. they make an 'avoided costs of transmission' (ACOT) payment. This approach is generally a proxy or 'rule of thumb' for payment for the range of services provided by DGs.

3. What problems are the DGPPs designed to fix?

The DGPPs are designed to address the natural bias distributors might have against non-network solutions – and smaller-scale DGs in particular.

The reasons why distributors might favour network solutions over non-network solutions, like distributed generation; for example, distributors are likely to:

- be more familiar with network solutions and may consequently be reluctant to engage with something less familiar;
- have more transaction costs involved with contracting with DGs – so connecting and contracting DG can be more of a hassle than an 'off-the-shelf' network solution; and
- favour network investment that goes into the regulated asset base (RAB) and earns the weighted average cost of capital (WACC) for a long time.

When there were no rules specifying the way in which payments to DG should be set, there were numerous cases of distributors refusing to contract with DGs, or refusing to pay them a fair price. The purpose of the DGPPs was to address these fundamental problems. The objective was to provide an environment that harnessed the many potential benefits of distributed generation by encouraging DG investment and fair negotiation with distributors. This was achieved by compelling distributors to connect DGs and requiring them to pass on any network cost savings, i.e. to set fair prices.

4. Where did the DGPPs come from, and what process was followed to implement them?

The genesis of the DGPPs was the Caygill Inquiry into the electricity industry, conducted in 2000. The inquiry concluded that:

- DGs – particularly smaller DGs – faced difficulties negotiating with distributors in the absence of binding pricing principles and an effective dispute resolution framework; and
- the lack of any obligation on the part of the distributor to pass on any reduction in its transmission bill was acting as an impediment to investment in distributed generation.

The Government's response was to invite the industry to develop rules: "to ensure that the use of new electricity technologies and renewables, and distributed generation is facilitated". The Electricity Act 1992 was also amended to allow regulations to be made if the industry failed to deliver a satisfactory outcome voluntarily.

Subsequent improvements in DG contracting were limited, and in 2003 the government issued a discussion paper that proposed standard connection contracts, pricing principles and arbitration processes to remove impediments to the establishment of distributed generation. After a few more steps, this culminated in the *Electricity Governance (Connection of Distributed Generation) Regulations 2007* – including the DGPPs.

Importantly, the *Electricity Act* in place at the time generally required electricity governance regulations to be made by the Minister upon the recommendation of the Electricity Commission (the EA's predecessor). However, when it came to distributed generation, the Act gave the Minister power to act on his own without such a recommendation. This highlights the importance the government placed on this legislative initiative.

5. Were ACOT payments made before the DG Regulations came into force?

Yes, they are nothing new. The electricity grid in New Zealand has generally been sized to meet peak demand (i.e. the primary service provided by the grid has been MW of peak capacity), and the costs of the grid have been recovered from consumers on the basis of their shares of peak demand since at least the 1930s. Payments for peak demand reduction were made for decades prior to the industry reforms in 1998, and also in the subsequent period leading up to the introduction of the regulations.

Trustpower provided a number of examples in its submissions to the EA:

- the Tauranga Electric Power Board (which became Trustpower in 1994) had received an *implicit* ACOT payment since the development of the Kaimai hydro power scheme in the 1970s, as a result of being able to reduce its net off-take from the transmission network in peak periods

- Following the sale of its lines business to United Networks in 1999, Trustpower began receiving *explicit* ACOT payments for reducing its peak off-take.

- The same applied to many other stations which Trustpower purchased from other network companies around New Zealand in that period, and to other distributed generation stations it developed subsequently. The revenue from ACOT payments was accounted for in the purchase prices for these stations, i.e., there was an expectation that they would continue. ACOT payments therefore had an indisputable 'air of permanence'.

6. If the DGPPs used to be government regulations, how did they end up in the Code?

When the government reviewed the performance of the electricity market in 2009 – an Inquiry headed by the current Chair of the EA, Dr Brent Layton and the review team concluded that:

> *"it appears that the regulations have helped to resolve the problem of establishing a negotiated connection process for DG and therefore this report has no recommendations to make on DG connections."*

In other words, the DGPPs were thought to be working well.

The *Electricity Industry Act 2010* was enacted following the conclusion of this Ministerial Inquiry, and this specifically mandated that the *Electricity Governance (Connection of Distributed Generation) Regulations 2007* be included in the initial Code. A simple 'cut and paste' was all that was needed because there weren't seen to be any problems with the regulations – including the DGPPs.

7. Why is the EA proposing to remove the DGPPs?

The EA has recently concluded that the DGPPs are problematic and must be removed from the Code completely. This quite unusual and sudden step by the EA has been proposed to address two perceived problems:

- that the DGPPs do not promote efficiency because they prevent distributors from setting prices for the connection of distributed generation that include a share of common network costs – the 'connection services issue'; and
- that the DGPPs result in DGs receiving ACOT payments from distributors when there has been no reduction in transmission network costs, i.e., avoided transmission *charges* are not synonymous with transmission *costs* – the 'ACOT issue'.

The EA believes that these problems have led to customers paying higher prices.

It appears the EA is trying to deal with the following scenario:

- a DG enables a distributor to reduce its contribution to regional coincident peak demand (RCPD) and, therefore the 'interconnection' component of its transmission charge; but
- there's no reduction in Transpower's forward-looking network costs, e.g., because there's plenty of spare transmission capacity (RCPD is much less than system capacity); and
- the DG receives an ACOT payment – the cost of which is passed-on to the end customer – but there's no actual cost saving, and so consumers end up 'paying twice'.

The EA proposes that getting rid of the DGPPs would stop this from happening, i.e. there'd be no more *inefficient investment* in distributed generation. It also assumes that this wouldn't lead to any reduction in *efficient investment* in distributed generation. The EA assumes that networks would be willing to negotiate with DGs to buy network support services when they deliver cost savings, and to pay a fair price for them, and there are no *costs* associated with its proposal. This view is somewhat contrary to prior findings that gave rise to the DGPP regulations in the first place.

In other words, the EA would have us believe that removing the DGPPs would be a 'perfect' regulatory intervention - resulting in exactly the right amount of investment in distributed generation – i.e. no inefficient investment, and every last bit of potentially efficient investment – and absolutely no off-setting costs.

8. Won't removal of the DGPPs destroy the intent of the whole of Part 6?

Yes. The full benefits from distributed generation weren't thought to be achievable if DGs were left simply to negotiate with powerful monopsony buyers (the distributors) that are likely to have a strong preference for network solutions.

It is logical to assume that if the DGPPs are removed, there will be less investment in distributed generation – probably much less. The issue is that, based on current market experience, most DG investment has been *efficient*, delivering network cost savings and a range of other benefits. The EA's advisors Oakley Greenwood found as much in their assessment of the costs and benefits of the EA's concurrent transmission pricing proposal.

Removing the DGPPs eliminates one of the overarching aims of Part 6: to provide *certainty* to prospective investors in distributed generation. A recurring theme throughout the development of Part 6 was the need to provide clear rules and certainty to investors in DG. The EA's proposal would destroy that certainty, and cast a large shadow of doubt over the sanctity of *all* of the regulations the EA oversees. Any rational investor will naturally ponder: "what other regulations can I not rely upon?"

9. Are the issues identified by the EA actually problems with the DGPPs themselves, or the underlying pricing methodologies?

Any potential efficiency problem the EA sees with the DGPPs is in fact an issue with the underlying pricing methodologies. The 'ACOT issue' has nothing to do with the DGPPs. If there's a problem, it's with the transmission pricing methodology (TPM), which the EA is reviewing in parallel to the DGPPs. The Authority is effectively concerned that distributors are paying DGs ACOT payments when they experience a reduction in their transmission charges. However, under the current TPM, the transmission charges that distributors pay don't always reflect their impact upon Transpower's forward-looking costs – they're 'not cost reflective'. The solution therefore is not to get rid of the DGPPs – it's to *fix the TPM*. If transmission charges were modified so as to better reflect the underlying transmission costs, then any 'ACOT issue' would simply fall away.

10. Won't these problems disappear with any changes to the TPM and DPMs?

Yes. This is confirmed by the EA's own cost-benefit analysis. It examines a scenario in which its proposed changes to the TPM are implemented and transmission charges are assumed to become 'more cost-reflective'. Under that scenario, the only time that the proposed DG reform is estimated to give rise to any benefits at all is in *the first two years*.

This is because the EA assumes that it would not be until *year three* that its TPM reforms would take effect. From that point forward, the benefits from its proposed DG reforms are non-existent. This shows clearly that any problem that the EA has identified is *with the TPM*, not the DGPPs.

The sum of net benefits is small relative to any reasonable measure of the costs – which the EA has specifically ignored. More fundamentally, it has been considered as very poor regulatory practice. As Creative Energy Consulting notes:

> *".. this argument reflects very badly on the EA. It is proposing major changes to existing arrangements for some miniscule and transitory gains in "efficiency", even by the EA's own submission. It really is not sensible to be proposing regulatory changes that may only have a shelf-life of two years."*

The implication of an accelerated reform timeframe to achieve a positive cost-benefit analysis risks doing great damage to the credibility of both the EA and the broader regulatory framework.

11. But doesn't the EA's cost-benefit analysis show that its proposal is a good idea?

No. The CBA comprises a series of largely unsubstantiated numbers multiplied together to give some estimates of benefits. There is little evidence-based analysis nor any inclusion of implementation costs, which is illogical. The transition would give rise to substantial costs, including the direct costs associated with entering into new contracts much earlier than would otherwise be the case (if at all) – as well as the broader costs associated with the damage that would be done to investor confidence.

If its proposal was subjected to a robust CBA that accounted for the many costs that would be involved, there's no question that it would <u>not</u> yield a net benefit and therefore would not meet the EA's statutory objective.

12. Shouldn't investors in DG have known that the DGPPs wouldn't last if they were delivering 'windfall gains', rather than 'efficiency gains'?

Firstly – it has not been proven that the DGPPs are delivering 'windfall gains'. The EA has not demonstrated that the DGPPs *haven't* delivered efficiency gains. Investors in DG are simply responding to the prospect of earning the greatest return and are responding to price signals.

Secondly, investors are entitled to take the regulations at face value – particularly given that they'd been in place for ages and reviewed many times, including by a Ministerial Inquiry presided over by the current Chair of the EA.

The EA claims investors 'should have known better' and that the EA 'is duty bound to fulfil our statutory obligation and, given that, investors should have foreseen we'd do this'. This is nonsensical. Even if an investor was aware that the arrangements might lead to what another party might label as 'windfall gains', it might still have thought that an ACOT payment was justified in its own case. It could have believed it was deferring transmission costs even if others weren't. It might also have figured that potential flaws could be identified in *any* regulatory charging methodology – and so that was no reason to distrust the status quo.

13. What is the difference between someone with solar panels avoiding paying for network charges by reacting to the pricing methodology, and network companies with large DG avoiding paying transmission charges?

Nothing – both are responding to a price signal. However, the EA's reaction to any inefficiency it perceives in these actions is completely different.

The EA has made its views about investments in solar panels quite clear recently: it believes that they can sometimes be inefficient. It has pointed out that a household might reduce its energy bill by using power generated from its solar panels to off-set its consumption (since charges are based mostly on the volume it takes from the grid) but that this may not be desirable, because this:

- may not avoid any distribution network costs, since the amount of network capacity that is needed for houses with and without solar is usually the same. This is because in New Zealand, demand usually 'peaks' in the winter when the sun isn't out; and
- could then cause prices to increase for households *without* solar panels, since the same level of network costs would still need to be recovered - making it more likely that others will also invest in solar, compounding any problem.

There are obvious parallels here with the issue that the EA claims to have identified with the DGPPs. In both cases, customers might benefit from avoided *charges* when there may have been no avoided *costs*. Despite the issues being more or less identical in nature, the EA has called upon distributors to address any such 'solar issue' through more 'cost-reflective' *distribution prices*, i.e. by moving away from volumetric tariffs. In other words, the EA has – quite appropriately – proposed to deal with the *underlying cause,* and in a non-intrusive way.

The EA's preferred solution to any 'solar issues' is *distribution* pricing reform driven by *distributors.* This could be replicated for DG by solving any 'ACOT issues' using *transmission* pricing reform driven by *Transpower*. The EA is recommending a sensible, light-handed approach in respect of the former, but an ill-conceived, hasty and heavy-handed reform for the latter. This difference in approach is striking and difficult to reconcile.

14. Haven't ACOT payments (and the increases in ACOT payments over the past few years) been factored into DG investors' business cases?

Yes. ACOT payments have been a source of revenue for investments in distributed generation for many years – both new developments, purchase of existing assets and upgrades. There is a legitimate expectation that this source of revenue would continue to flow as they reflect a competitive locational benefit.

The existence and stability of the DGPPs and associated ACOT payments has meant that DG investors have not pursued other potential options that were available when investments were made – like approaching Transpower directly to contract for network support. Most of those alternatives would be 'off the table' now. For example, why would Transpower or distributors contract with a DG for network support if they can get the local benefits without having to pay anything?

15. Isn't forcing DG owners to renegotiate their ACOT payments and network charges, after their investments have been made, the very definition of a hold-up problem?

Yes. Hold-up occurs when one party to an agreement incurs costs that cannot be recouped, only for another party to exploit that fact. The EA's proposal risks giving rise to several textbook cases of this phenomenon. A hypothetical example of hold-up is provided below. This example is an easier situation to understand but essentially replicates the situation DG currently faces.

A considerable amount of investment in DG has taken place on the understanding that investors would receive an ongoing stream of ACOT payments.

Those ACOT payments have been only 'loosely' linked to the value of the services that DGs have provided over time. Prior to Transpower's recent upgrades, the payments were probably *much lower* than the network cost savings that some DGs were providing. But now that those upgrades have taken place, they will often exceed the network cost savings. .

The EA has decided to act opportunistically by proposing to scrap the DGPPs and, by extension, ACOT payments. Its rationale is essentially 'there's spare grid capacity now and a lot of these DGs probably aren't allowing network costs to be avoided – so why are we paying them for that?' This gives rise to 'hold-up'; namely:

- DGs that are no longer delivering network cost savings, but which did so in the past and haven't been compensated fully for those benefits through the ACOT payments that they've received to date would get nothing and be held-up;
- DGs that *are* delivering network costs savings today, but which wouldn't change their generation profiles in any meaningful way if they were no longer paid for those benefits would get nothing either – so they'll be held-up too; and
- DGs that *are* delivering network costs savings today, and which *could* change their generation profiles in a meaningful way won't need to be paid very much by networks to prevent those changes of behaviour – so they'll get very little and be held-up as well.

It's important to note that networks would have no choice but to 'hold-up' DGs in these ways if the proposed reform went ahead – even if they didn't want to. For example, it would be impossible for a network to work out what would happen to its costs if a DG was 'not there'. Should it hypothetically 'remove' just that DG – in which case the impact might be very small? Or should it notionally remove a 'group' of DGs? There's no answer to these questions – it would be like trying to unscramble an egg.

If the reforms went ahead, the only question that a network could feasible ask itself is: "if I don't give this DG a network support payment, would my costs go up?" The answer to this question would often be 'no', even if a distributed generator was delivering network cost savings, or had done so in the past. Or the answer might be 'yes – but I won't have to pay much to stop it'. In other words, the reform is *designed* to give rise to hold-up – whether the networks want to do it or not. This is atrocious regulatory practice.

The removal of the requirement limiting DGs' connection charges to incremental costs could spell even more bad news. Without that restriction, there'd be nothing to stop distributors from increasing existing DGs' connection charges right up to the level at which they were only *marginally* better off staying in business rather than shutting down. This price might be well above what those DGs would have been willing to pay *before* they'd invested, when they had the option of going somewhere else, or not investing at all.

But of course, now that those DGs have invested, their power stations aren't going anywhere – and everyone knows it. Distributors would therefore be in a position to charge existing DGs as much as they like for connection charges. This would serve to compound the already substantial 'hold-up' problems described above. Not only would existing DGs see their ACOT payments plummet or vanish completely – their connection charges could sky-rocket as well; a 'double-whammy'.

Hypothetical example of Hold-up

- *a regulator sees that there's a big wave of expensive new transmission grid investment that's going to be needed in Auckland if peak demand kept climbing;*
- *it estimates that the upgrades could be pushed back by several years if enough Auckland households invested in solar PV and battery storage;*

- *it works out that the costs saved by pushing back the network investment would be much bigger than the costs of the investment in PV and batteries;*

- *it consequently instructs the local distributor to pay households that invest in PV and batteries a 'negative tariff' that reflects their contribution to the avoided network costs;*

- *but rather than pay out that sum all in one go the regulator decides to spread it out over twenty years, i.e., the deferral value divided by twenty; and*

- *new suppliers flood into the market, thousands of households spend thousands of dollars installing PV and batteries, and the grid investment is duly deferred by five years.*

Now fast-forward to year six. The grid has now been upgraded – but five years later than it would otherwise have been without the investment in PV and batteries. Now just think what would happen if the regulator turned around at that point and said:

'The distributor's paying out these sums to Auckland households – and, in turn, PV and battery suppliers – but they're not actually deferring any transmission costs because there's now heaps of spare capacity. I know, I'll scrap the regulation requiring distributors to pay that negative tariff and it'll cut costs".

There'd be an absolute uproar. Those households invested with the legitimate expectation of receiving a stream of revenue for twenty years – not five. Some might have been depending on that revenue to justify outlaying those many thousands of dollars – it might threaten their ongoing financial wellbeing. The regulator would essentially be tearing up that 'regulatory contract' without warning. It would be no answer for it to say: "fear not – those households that are delivering actual network cost savings are still free to go and negotiate a new price with the distributor." That logic is flawed for two reasons.

First, the vast majority of those households probably wouldn't be delivering network cost savings following the upgrade. But that doesn't mean they're not entitled to anything. They would still justifiably feel entitled to the share of the network cost savings that they delivered prior to the upgrade for which they had not yet been paid – the remaining fifteen years' worth of negative tariffs which they had been promised. The regulator's actions would mean they'd get none of that – textbook hold-up.

Second, even if some households were still delivering network cost savings, that doesn't mean that the distributor would have to pay them anything to receive those benefits. What would the households do if the distributor refused to pay a cent? Remove the panels and batteries? Not likely. What would they do with them? The fact is, those investments are 'sunk' – and the distributor would know it. So, most of the time, the distributor won't have to pay anything to continue receiving the same advantages.

And on those rare occasions that a household might be able to do something to alter the level of network support it offered – e.g. change its consumption patterns – the distributor won't have to pay very much to stop it from doing so. All it would have to do is pay a sum that is slightly above the marginal cost the household would incur to change its behaviour. That payment probably wouldn't be very much – and could be considerably lower than the benefit that the distributor consequently reaped in terms of network support.

Now, if you change 'solar PV and battery storage' to 'distributed generation'; 'Auckland households' to 'DGs'; and 'negative tariff' to 'ACOT payment' in the above example, you get more or less exactly the same scenario that would arise under the EA's proposal.

16. Is it fair to force renegotiation of ACOT payments for DG which may have provided a benefit when it was built, but which now provides less of a benefit due to increases in transmission build?

No, it would be manifestly inequitable and could do potentially enormous damage to the credibility of the regime and ongoing investor confidence.

Existing DG assets have not lead to any oversupply in transmission or energy delivery infrastructure. Therefore the amount paid to DG for the services it has been providing since it was commissioned should continue unchanged. Instead, investment by Transpower in transmission assets has created the current excess transmission capacity. The difference for Transpower is that it is guaranteed to get paid for this additional capacity.

The issue of cyclical over-capacity of networks is commonly termed an "economic sizing" issue, whereby the long term economic benefits of scale are recognised ahead of short-term, cyclical inefficiencies. DG capacity is an incremental alternative to networks and in most jurisdictions is treated on a long-term economic basis in the same fashion as networks.

Asking an investor to negotiate with Transpower *now*, after the investor has sunk its costs and $2b of grid investment has created ample spare capacity, would be grossly unfair. The situation wouldn't be remotely comparable to the scenario that would have played-out ten-years' earlier, when the DG had something valuable to offer and the option of not investing. The DG would have none of that bargaining power now and would find itself completely at the mercy of Transpower. The inevitable result is hold-up.

The EA's proposals do not take into account:

- that DGs has provided substantial network support benefits *in the past*, e.g., if it wasn't for those investments in distributed generation, Transpower might have had to spend $2b much sooner than it did, imposing much greater costs on consumers; or
- whether DGs have been compensated adequately for any network support benefits that they have provided, e.g., the ACOT payments that they have received to date may be many magnitudes less than the deferral benefits that they've delivered.

The timing of the EA's proposal would make these effects especially punitive. If a prospective investor in distributed generation had been negotiating directly with Transpower, say, ten years' ago – before if had started its $2b build – it might have been in a position to get a very large network support payment; probably much larger than any ACOT payments on offer at that time. Put simply, the DG would've had something valuable to sell.

Nevertheless, the prospective investor might have preferred to receive an ongoing stream of ACOT payments from its local distributor rather than contracting directly with Transpower. It might have reasoned – quite sensibly – that:

- getting an ACOT payment was a fairly uncomplicated exercise given the almost ubiquitous practice throughout the industry – whereas negotiating a bespoke payment for network support with Transpower would take more time and effort; and

- although the ACOT payments were less than what it could have got from Transpower in the short-term, at least it would continue to receive them in the long-term – including after the LRMC of transmission dropped (as it duly did when the $2b was spent).

17. What incentives do network companies and Transpower have to negotiate with existing DG owners?

Not much. It's not obvious that networks would bother to talk to *any* existing DGs. Networks always have the option of investing in more network assets, within their regulated RAB and earning their WACC – which may create a disincentive to negotiate with DG parties.

Even if the EA is correct to conclude that distributors would have efficient incentives to procure network support from existing DGs where they would save costs the EA has failed to recognise that, in the absence of any constraining regulatory principles, the distributors would have little or no incentive to pay a fair price for them. This is the very reason that the DGPPs were introduced in the first place.

18. Is it realistic to assume that there won't be any transaction costs or renegotiation costs from implementing the proposal?

No. The EA's assumption that its proposal would entail no transaction costs is misleading. Transpower, in its submission and expert's report (Axiom), describe some of the transaction costs they expect to arise from this proposal.

For exactly the same reasons, DGs would approach their distribution businesses in large numbers, seeking to negotiate avoided cost of distribution (ACOD) payments. The magnitude of those transaction costs depends ultimately on how those businesses respond to the reforms, e.g., whether they seek to implement their own frameworks for paying for network support. However, there's no doubt whatsoever that there'd be additional substantial administration costs.

Moreover, these direct administrative outlays could be dwarfed by the costs associated with the damage done to investor confidence if the reforms are implemented – none of which are considered by the EA. There's a global market for capital and the EA's opportunistic conduct could heighten the perceived level of regulatory risk in the eyes of prospective investors. Their appetite for investment in New Zealand may fall, and they may demand higher returns before they're prepared to wear those risks, with negative flow-on effects for consumers..

19. Are the implementation timeframes realistic?

No. Transpower has made it clear that it couldn't possibly establish the planning, economic, commercial or legal frameworks to support the proposed new regime before 1 April 2017.

This has significant ramifications for the EA's CBA, which has all of the benefits arising in the first two years in the scenario in which the TPM is reformed. It's now clear that any such benefits couldn't arise, since the reforms wouldn't be in place.

20. Does the fact that levels of ACOD payments are low really mean that DGs don't provide benefits to distribution networks?

No. Evidence from other jurisdictions highlights that the benefits of DG accrue to distribution, as well as transmission networks. For example, the AEMC noted recently that if there's an imminent need to invest in new distribution network capacity, and distributed generation of sufficient capacity and reliability is able to defer or down-size that investment and/or reduce operating costs, then there's a clear benefit. So why are ACOD payments the exception to the rule, in New Zealand?

The answer may lie in the imbalance in the negotiating positions between DGs and distributors. The DGPPs require distributors to pay DG the avoided and avoidable costs of distribution, as well as transmission, but the standard practice for the level of payments has come to be just the avoided transmission charges. This practice is simple to administer as there is a rate that is published by another independent party (Transpower's interconnection rate) and does not require detailed analysis of the avoided costs by each distributor. The EA is focused on ACOT payments and has not considered in any detail if current levels of ACOD payments have been 'efficient'.

21. Could investors in batteries experience the same kinds of issues in trying to negotiate with distribution network owners that DG owners faced prior to the introduction of the DG Regulations?

Yes. Unless distributors have an obligation to accommodate investors in batteries, and to provide them with fair and reasonable prices, then exactly the same issues would arise. Distributors would have a clear incentive to try and capture every dollar of potential benefits offered by any battery investment – either through offering very unfavourable prices to third-party providers, or by making those investments themselves.

22. Should Part 6 be expanded to include batteries as well (or should batteries be redefined as generation so that they can be covered by the DGPPs)?

Yes, potentially. Either approach would, ultimately, amount to the same thing (batteries coming within the scope of the DGPPs) and afford investors in batteries the same safeguards that were seen to be vital when the DG regulations were being formulated following the initial Caygill Inquiry. Another approach would be to specify some regulatory pricing principles that can be applied to *all* non-network suppliers perhaps by using Part 6 as a starting point.

23. How could owners of DG and batteries better realise the full network benefits of their assets?

Changes would need to be made to the current Part 4 regime to ensure that it sufficiently encourages network companies to consider non-network solutions (like distributed generation and batteries) and to pay third-party providers fairly for those services. At the moment, there's very little in the IMs compelling Transpower to consider non-network options when weighing up an investment decision (aside from for major capex exceeding $20m) and there's nothing whatsoever forcing distributors to do so.

Contrast this with Australia, where network businesses are *explicitly required* to consider non-network solutions whenever they're looking to invest more than $5m (for distribution) or $6m (for transmission). These 'regulatory investment tests' (the 'RIT-D' and 'RIT-T') were put in place because it was recognised that if businesses weren't *made* to consider non-network solutions they wouldn't. Instead, they'd stick with familiar network solutions, load that expenditure into the RAB and earn the WACC for the next 50-years or so.

It's a 'no-brainer' that similar investment test frameworks should be introduced in New Zealand to ensure that there's an efficient mix of investment in network and non-network solutions, moving forward, and no undue bias towards 'poles and wires'. The question then becomes: how should third-party providers of network support services be compensated? Should they be left simply to negotiate with networks (monopsony buyers) on a 'case-by-case' basis – which is what the EA is proposing for DGs? Or should some 'default pricing principles' (something similar to, say, the current DGPPs) be put in place?

Specifying some regulatory pricing principles that could be applied to *all* non-network suppliers or, alternatively, some well-defined sub-set in need of that 'safety-net' (say, the 'smaller guys') would: a) deal with networks' natural aversion to non-network providers and make them offer fair prices; and b) avoid the time and expense associated with 'case-by-case' negotiations – most of the work would instead be done 'up-front' when the standard principles were defined. The irony is that this is exactly what was done for distributed generation.

This makes the EA's proposal to remove the DGPPs all the more surprising. Given the emergence of these new technologies, surely what's needed is *more* regulatory guidance – not less. For example, shouldn't we be looking to expand Part 6 to encompass other technologies – or, at least, to use it as a starting-point/blueprint for doing so? Given the wide-ranging nature of the issues described above – which have implications for almost every aspect of the regulatory arrangements (planning, investment, pricing) – the best approach would surely be to undertake a methodical market study that looked at *all* of these matters in conjunction.

24. That would certainly be consistent with the approach that has been taken by the AEMC in Australia, which has consulted widely and thought about these things very carefully before making measured recommendations. Shouldn't grid-connected generators have to pay for using the distribution network to deliver their power as well?

As a general concept, the notion of levying additional charges on generators to reflect the 'bits of the grid that they're using' is not a very helpful one – and nigh on impossible to implement, in practice. Having said that, it is important regulations are designed so as not to bias any particular solution. They should instead be framed to encourage efficient, market-like outcomes so that they don't act as a barrier to the use of whatever technology delivers the most cost-effective service – they should be 'technology neutral'. This means that if DGs face additional charges that grid-connected generators don't – e.g., in the form of a contribution to the common costs of the distribution network – then that could create unwelcome distortions.

Most obviously, it might cause an investor who's thinking about connecting to the distribution network to connect to the transmission grid instead – even if that would result in fewer net market benefits. In principle, one way to restore technology neutrality would be to require grid-connected generators to make a contribution to the distribution networks that they 'use'. However, that approach would run into the problem set out above – namely, determining which networks that those grid-connected generators are, in fact, 'using' would be a hugely controversial exercise.

Another option would be to require grid-connected generators to make an equivalent contribution to the common costs of the transmission network. The EA has proposed something along these lines in its parallel review of the TPM (although, its proposal is again deeply flawed). But the best – and simplest – way to achieve technology neutrality would be to charge *all* types of generation the incremental costs of connecting to the distribution or transmission grid, respectively – and no more (with the HVDC charge perhaps being a 'special case'). That's what happens at the moment, and there's no good reason to change it.

25. What could be the impacts on existing and new DG of reductions in ACOT payments and increases in network charges?

Potentially catastrophic. PwC has undertaken some preliminary calculations on behalf of the Independent Electricity Generators Association (which represents 40 small generators) that suggest that the total industry value impact of DGs losing ACOT revenue (i.e., without even taking account of the impact of higher connection charges) would be over $500m (assuming an industry WACC of 7.6%). This negative impact on the value of the sector compares with the EA's estimated net benefits of the proposal of $0.5m-$20m in benefits. Assuming network common costs of $40 per MWh are allocated to all DG output, the value of the DG sector is estimated to decline by $1.5 billion.

PwC's analysis of the more specific impacts on ten particular DGs is even more sobering. Its analysis indicated that the loss of ACOT revenue by those ten DGs would result in an average 16.5% annual reduction in their total revenue. The average reduction in EBITDA across the ten DGs was estimated to be 30.4% and, for some of them, the elimination of ACOT revenue would flip this figure from positive to negative. These are extreme negative financial consequences arising from regulatory change.

PwC's analysis of the *combined* impact on those businesses of the loss of ACOT revenue *and* the higher network charges arising from their new contribution to common costs is even more compelling. It estimates that the average reduction in EBITA would be between 85% and 139%, assuming network common costs of $20 and $40 per MWh, respectively.

This alone could jeopardise the ongoing survival of many of those businesses, but also impacts these businesses' forward-looking cash-flows which would result in credit rating downgrades and, in turn, increased debt-raising costs. Meanwhile, they would be incurring significantly higher administrative costs re-contracting with networks. All in all, it's not overstating things to say that this is a recipe for potential financial ruin.

26. Aren't transition mechanisms normally used for changes which have these kinds of impacts on investors?

Yes. It is extremely unusual for a regulator to *even be countenancing* a regulatory change that could risk the ongoing financial viability of a significant number of firms. It's even more extraordinary that this proposal has been made without any meaningful consultation with the affected parties – it's come completely out of the blue, with no workshops, no socialisation of ideas, no examination of the financial effects, no serious consideration of less intrusive options and so on. This is highly unorthodox and extremely poor regulatory practice.

Further it is very surprising that that the EA hasn't even raised the possibility of limiting the application of these sweeping reforms to only new DGs. Any party contemplating new development now would be investing with their eyes wide open – as opposed to existing DGs, which would be completely blind-sided. These 'grandfathering' arrangements are a very common and effective way of respecting existing 'regulatory contracts' when significant regulatory reforms are made and have been employed in New Zealand in the past to avoid reducing investor certainty.

The absence of any consideration of 'smoothing' mechanisms is similarly perplexing. When regulatory changes (or even simple periodic price resets) result in price changes of more than 5-10% this is often characterised as a 'price shock'. Regulators are typically reluctant to expose customers or suppliers, as the case may be, to those shocks 'all in one hit'. Instead, the customary approach is to transition to that new price/revenue level more slowly, e.g., a few percentage points at a time, per year.

There are numerous examples across the New Zealand regulatory environment of transition mechanisms such as grandfathering being applied in order to protect investor confidence. The EA has itself proposed such transition mechanisms in the past, e.g., it has raised the possibility of 'smoothing' the adverse financial impacts of proposed changes to the TPM over many years, to 'soften the blow'. PwC's initial analysis indicates that the adverse financial impacts of the DGs reforms would be far worse than those arising from the EA's previous TPM proposal – and well in excess of the 5-10% 'rule of thumb'. Yet, there's no mention whatsoever of transition mechanisms in DGPP paper.

27. Is it fair that locally connected generation gets compensated for network support benefits but grid connected generation does not? If it is not fair, is the right solution to remove the DGPPs?

We suggest that grid-connected generators tend to be much larger and in a stronger position to negotiate terms for the benefits they offer, compared with distributed generators.

For example, if a grid-connected generator is able to deliver significant network cost savings to Transpower, it's conceivable that this might be factored into the new investment contract that it negotiates when it connects, i.e., the price and non-price terms and conditions might be more favourable. In other words, the fact that a separate, explicit payment isn't being made doesn't necessarily mean that a generator isn't being rewarded through other means.

We note that Australia has the RIT-T and RIT-D network investment tests. All of the network support payments that are made (and have been made) to larger generators in Australia have arisen out of the application of those tests – which *compel* networks to consider non-network alternatives before making significant investments. There are no equivalents to the RIT-T and RIT-D in New Zealand, so this might limit the opportunities even for larger grid-connected generators to negotiate contracts for network support.

In Australia, the general perception is that 'larger' generators (whether embedded or grid-connected) don't need any help negotiating acceptable network support payments. Indeed, both the Victorian Essential Services Commission (ESC) and the AEMC are examining this issue at present, and both are focussing on the 'smaller end' of the market. For example, the ESC is looking only at DGs smaller than 5MW – presumably because it believes that larger generators can already receive the 'true value' of any network support benefits they offer by negotiating directly with networks.

If grid-connected generators can't receive adequate compensation for the network support benefits that they offer, the answer isn't to prevent *DGs* from reaping those benefits by removing the DGPPs – two wrongs don't make a right. All that removing the DGPPs would do is replace any bias against grid-connected generation with a bias against *all forms of generation.* The net result would be under-investment in generation and overinvestment in poles and wires – an even worse outcome, conceivably.

28. Why does DG need a set of pricing principles but grid-connected generation does not? Put another way, what protection does grid-connected generation have when connecting to Transpower's network?

Grid connected generation is protected in its negotiations with Transpower by the regulated benchmark agreement, and the prescription for connection, interconnection and HVDC charges in the regulated Transmission Pricing Methodology.