26 July 2016

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Consultation Paper – Review of distributed generation pricing principles

King Country Energy Limited (KCE) is a publicly owned renewable electricity generation company, with its two largest shareholders being Trustpower Limited (65.1%) and King Country Electric Power Trust (19.9%). The remainder of its shareholding is divided between approximately 4,700 smaller shareholders many of whom are from the King Country.

KCE has its head office in Taumarunui. It owns and operates five hydroelectric power generation schemes, four are considered to be 'small-scale' and one 'medium-scale'. These schemes include Kuratau (6MW), Mokauiti (1.7MW), Piriaka (1.3MW), Wairere (4.6MW) and the Mangahao Scheme (36MW). Figure 1 below shows the location of KCE's Schemes.

All these schemes are embedded in the local network and are considered Distributed Generation (DG). The Schemes generate approximately 80 percent of the Company's current electricity sales. The balance is purchased from the electricity market.

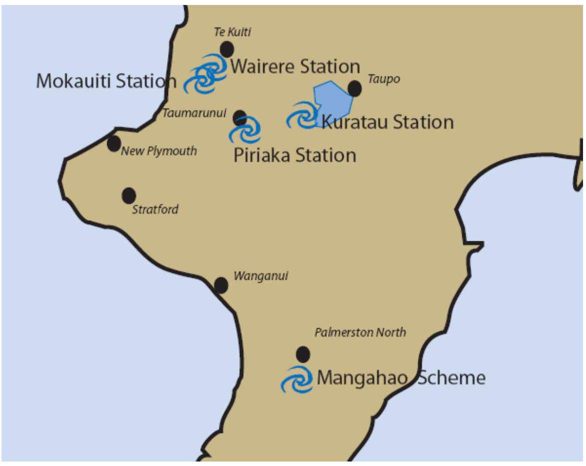

Figure 1: Location of KCE's Hydroelectric Power Generation Schemes

KCE is a member of Independent Electricity Generators Association (IEGA), and KCE supports the IEGA, Pioneer and Trustpower submissions.

KCE has considered the proposal and where relevant comments how it fails to meet the EA's statutory objective

> *To promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers*

KCE's submission will demonstrate that:

- The current system provides a competitive environment between DG and grid connected generation, and the proposals create an imbalance in favour of grid connected generation
- Reliability will be affected as the current system provide a single pricing signal that Transpower can rely on for the whole DG sector. The proposals will make DG intermittent.
- Moving from the current process with simplified efficient methodologies to a number of technically complicated agreements is not an efficient way of addressing benefit payments. It will only add to the overall cost that will be paid for by consumers.

KCE opposes the proposed changes to Part 6 of the Electricity Code.

Background

The Electricity Authority (EA) released a Consultation Paper on the *Review of the distributed generation pricing principles* (DGPP) on the 17 May. King Country Energy (KCE) being significantly impacted by this proposal has prepared this submission in response. KCE engaged Andrew Shelley Economic Consultants to review the DGPP and his report is included in Appendix 1.

The proposed DGPP is backward step for the good work and history that led to the introduction of the Distributed Generation Regulations (DG regulations). Following years of DG investment and a series market change and reform the DG regulations were enacted in 2007 to ensure that DG, which is recognised as nationally significant, is provided access to the electricity market.

Individually each DG scheme cannot influence the market, however combined DG can be seen as the SME's of generation and provide a valuable contribution to the electricity sector. Combined DG represents about 1000MW if installed capacity in New Zealand. They make use of renewable resources that otherwise would not be used by grid scale generation and in many cases provide niche solutions.

KCE has submitted on previous discussion documents that relate to DG and the principles of ACOT (Avoided Cost of Transmission). In many cases the issues raised by the KCE and the wider DG sector has largely been ignored or no adequate answers provided. In the latest consultation paper the EA has raised the connection services issue. This concept is new and has not been subject to any rigorous debate, despite having the potential have as much of an impact as ACOT.

KCE believes that the issue is around how DG is valued to the industry and that the EA is fundamentally opposed to the methods adopted by the industry and is proposing alternatives that disaggregate the current mechanism to a series of more complicated processes. This will effectively create barriers for DG, particularly smaller players, to receive compensation for the benefits they provide.

KCE is fundamentally opposed to the changes proposed in the EA review and has structured its submission as a series of issues, with corresponding proposals to address KCE's concerns.

The first issue relates to EA exceeding its mandate and not being the appropriate authority to conduct this review. KCE's proposal is that the EA steps back and acknowledges this issue allowing for the review to be conducted in a similar environment to which the DG regulations were developed in the first place.

Structure of Submission

KCE's submission to the DGPP is built around a series of issues as listed below. Aspects of this submission relate to the *Transmission pricing methodology: issues and proposal- second issues paper* which is due for submission on the same date and relates to similar issues.

Contents

Financial impact to the DG sector and KCE generation schemes

The financial impact of the removal of the DGPP is significant to KCE, both from the loss of ACOT and the introduction of common charges from Network companies.

Through much of the EA discussion their paper is a general assumption that DG are operating to similar terms of the DGPP. In all of KCE's schemes we have separate terms agreed that are outside the DGPP. Some of these are ongoing arrangements from original contracts, and others are new, reflecting the relationship between DG and Network companies.

Current ACOT payments on average are worth $16/MWh to KCE generation ranging from $12/MWh to $20/MWh between our schemes. The loss of this revenue stream would have resulted in a 34% loss in earnings for our latest results, and highlights the impact of this proposal to our business.

Further to this, the possibility of common charges being added to our existing network charges could a cost of $6/MWh overall, ranging from $3/MWh where the site can be grid connected as an alternative to $12/MWh on other schemes. This would drop our earnings by another 12%.

For two of our schemes it is quite certain there would be negative earnings and a third would be at significant risk.

Impact on the DG sector

The IEGA (Independent Electricity Generators Association) conducted an anonymous review of their members and the impact of ACOT and common costs to their schemes. Price Waterhouse Coopers (PWC) was engaged to conduct the review and their report is attached in Appendix 2 and also forms part of the IEGA submission.

The analysis clearly shows the impact on a sector with an estimate of $240m to $374m of enterprise value being wiped off just from the sample of 10 schemes that volunteered for the analysis. For half of the samples the reduction in earnings is over 100%, ie they become a loss, in a number of the scenarios, and for the remaining most are at least looking at over half their earnings lost.

The EA has assumed that existing DG would continue to operate as it has a small SRMC (short run marginal cost), however these assets are at various stages of life and require significant capital investment to maintain operating. These are costs over and above those indicated in the PWC report.

The impact of the removal of the DGPP would significantly erode investor confidence in investing in existing and new DG. This outcome is in complete contrast to the May 2016 statement from the Minister of Energy and Resources:

> *"The Government is very supportive of distributed generation and its contribution to our renewable electricity advantage. Distributed generation comprises a significant portion of New Zealand's generation and plays an important role in helping deliver New Zealand's energy objectives …"*

Creating pricing mechanisms that will force the closing down of existing *efficient* plant is in contrast to the EA's statutory objective.

Issue 1: EA exceeding its mandate and not acting as a responsible authority

The current Part 6 of the Electricity Code was developed as separate regulation outside the original Electricity Governance Rules back in 2007. This was due to DG having wider benefits than those prescribed in the mandate of the Electricity Commission the pre-cursor to the EA. These benefits are shown in the table below with the EA mandated review limited to those circled.

At the time it was identified that the key barrier to entry was access to the network at a rate comparable to grid connected generation. In addition it was acknowledged that the benefits of DG being connected to the network should be compensated for. This developed into the **pricing principles.**

When the DG regulations were moved into the Code in 2012, it was not perceived that such a radical reform to Part 6 would take place. At that time it was not considered that there was anything fundamentally wrong with the regulations, but had KCE known that such a radical reform was imminent it would have opposed the change.

Had the DG regulations stayed as they were in separate regulation, the EA would have been only one of many submitters on any review.

Now the EA has found itself the sole authority responsible for considering the benefits of DG and within its narrow mandate has concluded it is inefficient for the purposes of effective grid management.

No evidence of any issues or wrong doing.

The code as written allows DG and networks to take disputes to the EA under Part 6 schedule 6.3. KCE is not aware of any disputes being raised with the EA by network companies for the pricing arrangements. The EA has failed to provide any evidence there is a problem with the current pricing principles.

Part 6, as it was originally drafted in the DG regulations is supposed to be an enabler of DG.

The EA itself has admitted there are wider benefits outside its statutory objective. It has even attempted to consider some of these benefits in section 4.2.14 of its paper. The quality and content of this section of the review clearly highlights the limitations of the EA's mandate and abilities to make sound assessments in this area.

One of the most important benefits not considered is the efficient use of renewable resources. This is reinforced in the National Policy Statement for Renewable Electricity Generation that reinforces – Renewable Electricity Generation, no matter what size, is **nationally significant**. With the DGPP proposal as presented there is a clear bias towards large generation and transmission over smaller DG connected to distribution.

It appears the Authority is at odds with wider government policy.

KCE proposal 1: The EA acknowledges that its statutory mandate limits its ability to assess the overall intent of Part 6, and that it recommends that Part 6 is reviewed in a different process to ensure all aspects are considered. For example an Advisory Group.

Issue 2: The EA has failed to identify the 'problem'

The EA has identified that the current process DGPP does not promote efficiency as DG is not paying its share of common charges.

The current model market model works on GXP market prices for clearing the energy settlements to generators and load. This price specifically excludes transportation costs through the grid and this is recovered through the TPM. All grid connected generators have to do is pay their marginal cost of being a new GXP on the grid through connection charges for dedicated assets.

This approach is reflected for DG through the DGPP where networks can only charge for the marginal cost of connecting DG.

This is consistent and fair and creates a level playing field for all aspects of generation to compete in the market. The current system is in line with the statutory objective.

Impact of the proposed TPM

The proposed TPM changes are introducing an Area of Benefit (AOB) charge, which will be charging generators for using the grid, over and above the connection charges.

The proposal includes the ability for these charges to be applied to DG as well as grid connected generation. ***What the EA is asking for out of the combined package of DGPP and TPM reviews is that DG contributes to grid and network costs, while grid connected generation only contributes to grid costs.***

Are the current benefits unfair?

The payments received by DG represent a fair value against other price signals proved by Network companies. The EA's CBA estimates that the current payment system costs consumers \$6 to \$9/MWh for the 800MW of reduced demand to the network.

A study of the network tariffs shows that the price difference between controlled and uncontrolled load for hot water control is \$34/MWh on average for approximately 1000MW of ripple control. This difference in prices is necessary to compensate consumers for the costs of the inconvenience of having controlled hot water, and the cost of this is recovered by increasing the charges to all uncontrolled customers.

It costs network companies $34/MWh to purchase controlled load for hot water, but only $6 to $9/MWh for DG. This price differential demonstrates that consumers have been getting better value for money through DG than ripple control.

KCE proposal: The EA halts the current DGPP review process until after the TPM is introduced and sets up an advisory group to investigate if any changes need to be made to the DGPP as opposed to removing them all together.

Issue 3: Cost Benefit Analysis review and modelling assumptions

The EA has used Oakley Greenwood (OGW) to develop an independent Cost Benefit Analysis model for the TPM review and Concept Consulting for the DGPP review. KCE contests that while independent companies have developed models used in both TPM review and DGPP review, it is the EA that is determining outcomes by specifying the inputs and selecting the outputs to demonstrate its purposes.

Key assumptions that need review or need to be included are

a) *Marginal cost of new DG is diesel generation at $1000/MWh*

The DGPP CBA model shows that 80% of the positive value of the proposal is gained from new DG. The model goes further to assume that any new DG will be built at over $1000/MWh and only diesel peakers will be built in the future. This raises two issues

- Not all new DG will be built at the $1000/MWh price. There have been a number of new windfarms and small hydro that have built at a lot less than this. Energy News lists 98MW of small renewable schemes consented, with a further 80MW under-investigation or on hold.
- Existing DG is efficient. This supports the case for a *grandfathering* process without which this existing DG will not get the appropriate re-investment. OGW in its report within the TPM issues paper comments in footnote 52 that existing distributed generation “is actually contributing slightly positive economic benefits in the future even with the RCPD charge”.

b) *Change in behaviour when removing a peak demand signal*

The modelling completely fails to take into account the change in behaviour that will occur when there is no peak pricing signal to DG. KCE frequently re-schedules or postpones maintenance outages when there is a possibility of RCPD, and this is not unique to KCE.

By removing this signal there is the increased probability that DG will not be operating during system peaks. The result being higher load flows through the grid, increasing losses and calling on more expensive peaking plant to be dispatched.

The EA acknowledged in their briefing forum in Wellington that this aspect had not been considered.

c) Transmission Allocation to Load

The modelling assumes that future costs of transmission allocation to load is 60%, but SPD analysis shows that it is should be around 80%. Changing this assumption reduces the EA benefits. There is a contradiction in the assumptions between OGW and Concept in the cost benefit modelling in the TPM and DGPP. OGW in their analysis of the TPM have used a distribution between load and generation of 92%/8%.

However in the DGPP modelling carried out by Concept they have assumed a load/generation split of 60%/40%. Changing this assumption in the DGPP modelling will change the outcome in favour of DG.

The four scenarios they then model all assume existing DG is inefficient and then use the results to calculate the benefits of removing the ACOT payments. There are no counterfactual scenarios modelled, or even a base case to refer against.

d) Additional ongoing costs

If individual contracts are to be maintained with each generator, there will be considerable transaction costs associated with this process. The EA has not adequately assessed these through this process.

As shown later in the submission, there will be little incentive for networks and Transpower to negotiate with DG so this process will be costly and time consuming. As Transpower has no budget for this process, it is likely only short term contracts will be given, requiring recurring costs on a regular basis.

This will be particularly onerous on ACOD (Avoided Cost of Distribution) payments if the contracts are linked to AOB payments in the proposed TPM guidelines and these are reassessed.

KCE proposal: The EA reviews the cost benefit modelling, and is more transparent on the assumptions used and the benefits gained. This would achieved through an Advisory Group.

Issue 4: Proposed benefit assessment methodology is inefficient

The EA has misinterpreted the definition of ACOT payments as literally being the avoided transmission charges. Practically the payment structures agreed by Network companies and DG are a simplified, enduring methods for compensating for **all** benefits that DG provides without the complicated and expensive process of regular reassessment.

The benefits to an electrical system include delayed large generation and large grid upgrades, reduced grid and network losses, voltage support in remote areas, network support in managing maintenance outages for both GXP and network lines, black start, reactive power control.

The EA proposal is to disaggregate this approach and require each generator to prove its benefits to Transpower and Networks. This could be an expensive and laborious process, and rather like applying for resource consents there is no guaranteed outcome or whether the outcome will be economic. This will effectively act as a barrier for many applications and will lead to scenarios where DG is providing genuine benefits but not receiving compensation, particularly amongst the smaller generators.

In order to make the process efficient, simple and fair a postage stamp process is required to ensure all DG receives benefits. Whether this is through a prescribed methodology that Network companies pay DG directly, or whether Transpower takes responsibility and compensates DG directly.

How will Transpower fund ACOT payments?

The EA has also been silent on the process of recovering any payments Transpower makes to DG. Under the current TPM the only available recovery process is through the interconnection charges. This will see the ICR (inter-connection rate) increase and effectively create the same net outcome as the current arrangements.

This effectively transfers wealth between network companies, with those with DG paying significantly less charges to those without. While DG represents 10% of New Zealand's energy supply it is not distributed evenly across each network which will lead to significant price discrepancies between neighbouring networks.

This would be addressed if the proposed TPM guidelines are progressed. However if the TPM is then modified or does not progress, this will create an enduring imbalance.

KCE proposal (i): The EA halt the current process until the new TPM guidelines are released.

KCE proposal (ii): If Transpower is to assess ACOT then a periodic review process is setup and the benefits distributed through a postage stamp methodology.

Issue 5: Alternative methodology for determining the value of ACOT and the distribution of benefits

The current DGPP allows the modelling of DG to occur on a consistent basis as they are all relying on the same pricing signal through RCPD. Current system modelling takes DG for granted and uses the net energy flows at GXPs for forecasting. The grid has effectively been built around DG.

As transmission upgrades and new large generation is 'lumpy' in nature then the system goes from periods of being tight in supply prior to any upgrades to a period of over-supply immediately after the upgrade. Assuming the investment decisions have been made soundly then these upgrades will consider DG's contribution.

However immediately after the upgrade, the DG may appear redundant due to spare capacity.

This is the situation the system current faces, and the time at which the EA has chosen to address the 'problem'. This is taking advantage of the sunk cost of DG and does not reflect the long term benefits DG provides.

The EA is arguing that DG is currently not required as there is surplus capacity but they are receiving too high a benefit under the current avoid charges basis. KCE argues that when there was a shortfall of capacity and DG was required, the ICR rates were too low and DG was not receiving enough compensation.

In order to address this an LRMC calculation could be developed and smoothed over a long period. The Commerce Commission has a price path model that could adequately calculate this. A periodic reassessment of this LRMC value would address any long term imbalance issues.

This approach would provide a simplified reliable method for determining the value of DG and allow budgeting to be more predictable. This also removes the need for complicated negotiations between small DG and large monopolies.

The distribution of this payment can be applied on postage stamp method allow all DG to receive an appropriate share. The methodology of distribution can then be set to provide the appropriate signal as required by System Operator, Transpower, etc. For example the current RCPD system could be used to manage peaks.

KCE proposal: The overall value of all DG is assessed using a standardised model and distribution methodology determines its pricing signal. In unbalanced relationships like DG and monopolies, it is preferable to assume the benefit is given and to put the onus of proof to the counter on the monopolies.

Issue 6: Price discrimination against DG regarding common charges

The EA has raised a new issue called the “connection services issue” and has proposed to tackle it by removing the pricing principles completely. If the new TPM proceeds this results in DG then being charged for transmission components *and* network components, when grid connected generation will only pay for transmission components.

This does not meet the statutory objective regarding *competition*.

Currently distributors are only allowed to charge DG for the marginal cost of the DG connection, but with the proposed changes distributors will be able to charge DG a share of common costs. KCE has contacted the network companies it contracts with and the indication is that the additional common charges could be about $12/MWh to access the network. On one site where DG can connect to the grid as an alternative the additional charge is about $6/MWh.

To further exacerbate the situation DG will find its paying its share of asset charges on both the network and the grid if the proposed TPM is implemented.

The EA presented to the IEGA on the 26 May 2016. During the presentation the EA was asked if they had considered the issue that network common costs were not allocated to grid connected generation. They confirmed it had not been considered.

The current method is efficient and reliable. It means that regardless of whether the DG is connected or not the customer pays for their fair share of costs.

By taking a simple example of any existing network, if a new DG scheme is connected they will pay the marginal connection cost as per the current rules, and then will be allocated a share of the common costs reducing the charges to consumers. There is no equivalent wealth transfer mechanism for new grid connected generation.

KCE proposal: The allocation of common charges to DG should be excluded and the current wording remain in Part 6, and DG only pay for the marginal cost of connecting to the network as currently in the Code.

Issue 7: Removal of the disputes process and inability to negotiate

The EA expects that Transpower and network companies will be incentivised to agree ACOT and ACOD payments, terms used by the EA throughout its proposal. However there is no definition of these terms so what is being negotiated for is still practically unknown.

Even common charges are have no standard definition. This is reflected by the EA's response to a request for IEGA to investigate the impacts of common charges even further when they said,

"Information at the level of detail that your members would require to assess the impact of the DGPP proposals on their businesses will not be available for some years."

This clearly highlights the EA does not understand the impacts of these changes and is expecting large monopolies and small DG to negotiate an agreement.

Inability to negotiate with Transpower

The EA has indicated that DG can negotiate with Transpower to recover benefits of existing DG. There is no incentive on Transpower to go through this process. The challenges it will face is that it has no budget to deal with the applications and no ability to derive an overall expected cost.

This implies that for every DG application, Transpower will have to get an exemption from the Commerce Commission to adjust its recover rates, which will then be reflected in a variations to residual pricing model.

As Transpower has no incentive to make this payment then any negotiation by DG will be complicated an arduous, it will look to alternatives that are an easier process to resolve like demand response.

The current DGPP allows for a disputes process through the EA, but with the proposed system there is no ability for DG to raise disputes with Transpower.

Inability to negotiate with Network companies

The original purpose of the DG regulations was to create a standardised methodology that DG could rely on to develop new opportunities. Prior to the regulations the inconsistent and low priority nature applied to DG meant that many projects were delayed. There is no reason why we would not return to this environment.

Under the current terms KCE has experience of slow negotiating processes with network companies. Without a framework or guideline this will become worse. However KCE will still prefer to have a mutually agreed contract than rely on regulated terms.

The negotiating challenges will be further exacerbated by the proposal to remove the ability for Network companies to recover DG payments through to their customers. This would mean that a complex methodology for allocating service based payments and ACOD would have to be built in to part of its overall expenses before recovery could be made from customers.

Disputes process

The disputes process in Part 6 provides a safety net to ensure that both distributors and DG focus on achieving an outcome. The EGCC has said that disputes between DG and Network companies are not within their jurisdiction.

Removing the disputes clause particularly if the pricing principles are to remain, will remove any incentive for networks to resolve connection disputes. As the monopoly provider they know they can depend on DG operating as that is their primary source of revenue, and any benefits they receive during operation could effectively be taken for granted.

If the charging of common costs is allowed to prevail then DG could be the easy target for price allocations by networks where increases to consumers could be unpalatable. It is clear that in an environment where power price increases are generally not received well by consumers then DG could be seen as a soft target for allocations, particularly if there is no dispute process.

The EA has left a vacuum where there is no framework for common cost allocation. It is quite clear from the interest in the TPM process that clear allocation methodologies are important, and yet through the removal of the DGPP there is no standard methodology to apply to DG for network assets. With network assets being worth almost twice as much as grid assets then the value at risk is significant.

KCE proposal: Section 6.3(4) is reinstated allowing disputes on pricing principles to addressed by either party, and then expanded to include a disputes process with

Transpower. An additional section is required providing a framework for addressing ACOD and ACOT.

KCE's response to EA's specific questions

Q1

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.

The status quo is preferable to the proposed amendments. The submission shows that each aspect of the statutory objective is affected:

- The current system provides a **competitive** environment between DG and grid connected generation, and the proposals create an imbalance in favour of grid connected generation
- **Reliability** will be affected as the current system provide a single pricing signal that Transpower can rely on for the whole DG sector. The proposals will make DG intermittent.
- Moving from the current process with simplified **efficient** methodologies to a number of technically complicated agreements is not an efficient way of addressing benefit payments. It will only add to the overall cost that will be paid for by consumers.
- OGW have identified existing DG as **efficient** even with the RCPD payments in place, and a number of these **efficient** plants are at risk of closure with the proposals.

If the status quo has to change, KCE believes there are better alternatives, as described in issue 5 of the main submission.

Q2

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?

No, the amendments do not comply with the Act.

- Competition to transmission is removed,
- Competition to large scale grid generation becomes unbalanced
- The CBA fails to value the disruption and leaves a number of outcomes to chance.

Q3

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.)

KCE is completely opposed to the Part 6 amendments as presented. KCE's issues 2-7 of the main submission highlight these reasons.

The amendments to Part 17 appear to generally align with RCPD boundaries.

Q4

Do you consider that the proposed Code amendment should come into force at a single date, or should it be phased in?

KCE's preference is that the changes do not proceed, but if they are going to then a single date.

Q5

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?

The amendments should not come into effect until a system for modelling and compensating DG has been developed.

The April 2017 date must be delayed:

a) It is practically impossible for Transpower to develop the model, get approval for extra funding for the Commerce Commission and then negotiate contracts for the majority of DG before 1 Apr 2017.
b) Until the amendments are known DG is currently operating as if the existing DGPP were in place. The implication being that DG would only realise the benefits of 2016 operation in 1 Apr 2017 up until 31 March 2018. By implication the earliest amendment date should be 1 April 2018.

An amendment date needs to be linked to Transpower's ability to develop an appropriate system.

The EA needs to provide a guideline for the framework of ACOD as described in their proposal.

Q6

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.

Issue 7 of KCE's submission clearly highlights KCE's view of the barriers to negotiation. For existing assets, there is no incentive at all for Transpower or Networks to negotiate. The only opportunity for encouraging either monopoly around the table is if alternative uses of the scheme can be found that will effectively change the existing operating regime of the schemes. Eg irrigation.

Changing use like this is inefficient use of existing assets.

An alternative is to assume the benefits are given and leave the onus on the monopolies to prove otherwise. This facility is available through the current DGPP dispute resolution clause.

Q7

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.

a) If the proposal proceeds, then Network companies will not be able to recover the payments to DG through their regulated pricing schedules. This is anti-competitive as they are able to do so for their grid charges. This will naturally encourage Networks to prefer grid connection over DG unless there is a significant financial advantage.
b) For existing sites there is no incentive for DG to compensate, and with the removal of the disputes process will potentially allow them to gouge DG.
c) While Network companies do publish Asset Management Plans, there is no equivalent to a “Statement of Opportunities”, so it will be difficult for DG access points of need to make an efficient decision.

Q8

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?

KCE believes that it is probable for those contracts that have review clauses linked to changes in government policy will want to discuss the implications of the change. Network companies that cannot recover the cost of ACOT payments will look to cease making such payments as soon as possible. There may well be a round of litigation/arbitration as distributors look to exit existing contracts.

Appendix 1: Response to Consultation on Distributed Generation Pricing Principles – ASEC

Report is included as a separate PDF attachment.

Appendix 2: Independent review of the potential impact of proposed regulatory changes on distributed (electricity) generators – PWC

This report is included as a separate PDF attachment.

ASEC
Andrew Shelley
Economic Consulting

Response to Consultation on Distributed Generation Pricing Principles

FINAL REPORT

22 JULY 2016

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EXECUTIVE SUMMARY

This report has been prepared by Andrew Shelley Economic Consulting Ltd on behalf of King Country Energy Ltd in response to the Electricity Authority's proposals to remove the Distributed Generation Pricing Principles (DGPP) Part 6 of the Electricity Industry Participation Code (the Code).

The DGPP require that prices charged by a distribution network to distributed generation (DG) do not exceed the incremental cost of connection and distribution services. The Electricity Authority (the Authority) claims that this requirement does not promote efficiency because DG does not pay for any part of shared network costs. The Authority calls this the "connection services issue".

The DGPP are used as the basis for the payment of the Avoided Cost of Transmission (ACOT). The Authority alleges that ACOT payments result in inefficient decisions about investment in, and operation of, distributed generation because those decisions are made with a focus on obtaining ACOT rather than short-run electricity price signals. The Authority calls this the "ACOT issue".

The Authority has engaged in an extensive consultation programme since 2012, as it has sought to justify its proposed transmission pricing reforms to an industry that widely opposes those reforms. This consultation programme has addressed the ACOT issue on multiple occasions.

It is only now, at the time that the final transmission pricing proposals are released, that the Authority has raised the connection services issue outlined above and proposes for the first time to eliminate the DGPP.

The Authority's proposal to remove the DGPP will allow distributors to act in an opportunistic and rent-seeking manner, but the potential for this has been completely ignored in the Authority's analysis. No arrangements are provided which provide an adequate basis for the DG provider to engage meaningfully with distribution networks on pricing.

DG will be required to pay an allocation of shared network costs for distribution networks, but grid-connected generation will not be required to pay a residual charge for the transmission network. The Authority has not explained how this difference in treatment is justified.

Furthermore, transmission capacity will be guaranteed a payment equal to the average cost of that capacity, but DG which has the effect of substituting for transmission capacity will receive a payment that is highly uncertain. Such DG might be able to negotiate with Transpower to receive a payment for transmission investment deferral, but there is no framework advanced for those negotiations, and many small DG providers have insufficient resources to be able to meaningfully engage in any analysis. Alternatively, under the Transmission Pricing Methodology (TPM) proposals Transpower might develop a so-called LRMC charge, but in dropping to zero when transmission capacity is unconstrained that charge does not behave at all like Long Run Marginal Cost. In either case, the potential payments from Transpower are highly speculative and the relevant frameworks might not be developed at all.

Relevant economics literature shows that reliance on spot contracts (i.e. the energy-only market) is inferior to contracting when parties can behave opportunistically, and that a succession of short-term contracts is inferior to long-term contracts under conditions that are likely to prevail in the real world. The Authority fails to address how short term contracts with an LRMC-based price will provide efficient outcomes. The Authority also fails to address how a succession of short-term contracts for connection (particularly for connection prices) will provide efficient outcomes.

The equivalent distribution pricing methodology in the United Kingdom provides distributed generation with a credit equal to the cost that a demand user would pay at the same location, and thus generally includes a credit equal to a portion of shared network cost. The DGPP as applied in New Zealand provide a much more restrictive set of circumstances in which a credit is provided for a reduction in distribution costs, generally requiring the identification of specific costs or investments that have been avoided.

It would be premature to remove the DGPP from Part 6 of the Code until the issues raised above have been adequately addressed.

ABBREVIATIONS

ACOT	Avoided Cost of Transmission
ASEC	Andrew Shelley Economic Consulting Ltd
Authority	Electricity Authority
Code	Electricity Industry Participation Code
DCUSA	Distribution Connection and Use of System Agreement (in the United Kingdom)
DG	Distributed Generation
DGPP	Distributed Generation Pricing Principles
LUFC	Low-User Fixed Charge
TPM	Transmission Pricing Methodology
UK	United Kingdom

1. INTRODUCTION

1.1. BACKGROUND

The Distributed Generation Pricing Principles (DGPP) are contained in Part 6 of the Electricity Industry Participation Code (the Code). The first of the pricing principles is:

> *subject to paragraph (i), **connection** charges in respect of **distributed generation** must not exceed the **incremental costs** of providing **connection** services to the **distributed generation**. To avoid doubt, incremental cost is net of transmission and distribution costs that an efficient **distributor** would be able to avoid as a result of the **connection** of the **distributed generation.***

The DGPP require that prices charged by a distribution network to distributed generation (DG) do not exceed the incremental cost of connection and distribution services. The Electricity Authority (the Authority) claims that this requirement does not promote efficiency because DG does not pay for any part of shared network costs. The Authority calls this the "connection services issue".

The DGPP are used as the basis for the payment of the Avoided Cost of Transmission (ACOT). The reduction in transmission charges as a result of generation by DG is a reduction in the costs of the distribution network and are payable to the DG on the basis that they are transmission costs that the distributor can avoid as a result of the connection of the generation. The Authority alleges that this results in inefficient decisions about investment in, and operation of, distributed generation because those decisions are made with a focus on obtaining ACOT rather than short-run electricity price signals. The Authority calls this the "ACOT issue".

The Authority proposes to repeal the DGPP. The effect of this would be:

1. Distributors could propose prices for distributed generation that include a contribution towards common costs, and the distributed generator would have little or no ability to appeal these prices.
2. The basis for the pass-through of ACOT to distributed generators would be removed, whether or not the Transmission Pricing Methodology (TPM) is changed.

The Authority also proposes that DG would contract directly with Transpower in the event that the DG does have the effect of reducing transmission investment.

1.2. THIS REPORT

King Country Energy Ltd commissioned Andrew Shelley Economic Consulting Ltd (ASEC) to prepare this report in response to the Authority's proposal to remove the DGPP.

This report is structured as follows:

- Section 2 summarises the prior relevant submissions that have not been addressed by the Authority;
- Section 3 provides an evaluation of the Authority's proposal to remove the DGPP; and
- Section 4 summarises the main conclusions.

Of necessity, this report is not exclusively focussed on the DGPP. Properly responding to the Authority's proposals requires consideration of the alternative arrangements that might be in place if the DGPP are removed, and that necessarily requires some issues related to the TPM to be addressed.

2. HISTORICAL SUBMISSIONS RELATED TO DG

ASEC has prepared the following reports in response to Authority proposals and working papers in relation to Distributed Generation (DG):

- *Avoided Cost of Transmission (ACOT) payments for Distributed Generation*, Final Report, prepared for Independent Electricity Generators Association, Andrew Shelley Economic Consulting, 31 January 2014;
- *TPM Problem Definition: Interconnection and HVDC*, Final Report, prepared for Independent Electricity Generators Association, Andrew Shelley Economic Consulting, 22 October 2014;
- *Submission on TPM Options Paper for the IEGA*, Final Report, prepared for Independent Electricity Generators Association, Andrew Shelley Economic Consulting, 11 August 2015;
- *Review of Proposed TPM Options for Electra and KCE*, Final Report, prepared for Electra Ltd and King Country Energy Ltd, Andrew Shelley Economic Consulting, 11 August 2015.

In relation to the two issues raised by the Authority about the DGPP, these submissions have primarily been focussed on the "ACOT issue". All of the submissions made in response to the ACOT issue as it arises in the context of the TPM are also relevant to the current consultation.

The "connection services issue" has not previously been substantively raised by the Authority. However, a relevant point was made in the *TPM Problem Definition* (October 2010) report. The Authority argued that the fact that generators do not pay for interconnection resulted in a cross-subsidy because those generators were not paying for the shared costs of the transmission network. The ASEC October 2010 report noted that the Authority was using the term cross-subsidy in a pejorative manner, and not in its technical economic sense. A cross-subsidy only occurs if price is less than incremental cost. The Authority no longer makes the assertion of cross-subsidy, either in relation to generation transmission charges or DG connection charges.

3. EVALUATION OF THE AUTHORITY'S PROPOSAL

In reaching its conclusion that the DGPP should be removed, the Authority has narrowly interpreted the concept of efficiency, to the extent that the outcome is not likely to be efficient. The following issues each suggest that the Authority's analysis has been too narrowly focussed:

- Increased uncertainty in returns will reduce distributed generation investment;
- A succession of short-run contracts is unlikely to deliver efficient outcomes;
- Prices for generation capacity are increasingly important in electricity markets, but are completely ignored by the Authority;
- If an LRMC charge were implemented to reward net load reduction, the charge as currently conceived cannot be efficient because (a) the charge is zero when transmission capacity is not constrained, and (b) LRMC does not suddenly drop to zero;
- The Authority proposes replacement arrangements that are poorly specified and will allow distributors to engage in opportunistic pricing behaviour; and
- A number of issues that the Authority considers to be outside its scope will alter what is the true efficient price.

Finally, the equivalent distribution pricing methodology from the United Kingdom (UK) is also briefly addressed. That methodology has the effect of allocating DG a credit for shared distribution network assets, whereas the application of the DGPP means that in New Zealand DG will only receive a credit if there are specific investments avoided.

3.1. Increased Uncertainty in Returns

It is well known that uncertain returns will not necessarily deliver efficient long-run outcomes. For example, a risk-averse investor will require a higher rate of return when facing an uncertain outcome than when facing a certainty equal to the expected value of those outcomes. This will be manifest as reduced investment (only those projects delivering the higher rate of return will proceed) and a willingness to purchase insurance (hedges) to reduce uncertainty. Reducing uncertainty therefore allows movement to a higher production-possibilities frontier. Increasing uncertainty implies movement to a lower production-possibilities frontier and a reduction in efficiency.

The removal of the DGPP will create two sources of uncertainty. First, even if the TPM remains, removal of the DGPP will eliminate the basis under which ACOT is paid to DG. DG will then only earn some form of ACOT if either (a) an agreement can be reached directly with Transpower under poorly-specified arrangements (see section 3.5 below); or (b) Transpower decides to implement some form of "LRMC pricing", albeit on a basis that provides sources of net load reduction with a price less than the value of capacity (see section 3.4 below). Whether either of these options is developed is uncertain, and if one of them is developed the final form of that option is also uncertain.

The second source of uncertainty from the removal of the DGPP is the magnitude of future connection charges. The Authority assumes that distributors will dispassionately undertake an efficient pricing calculation. However, the removal of the DGPP allows distributors to act opportunistically to increase prices to DG. Allocation methodologies are extremely easy to manipulate to achieve a desired outcome, and some distributors may be able to increase charges to DG to keep prices at a more palatable level for consumers. As a result, the future connection prices that will be faced by the DG are uncertain.

3.2. Short-Run Contracts are Unlikely to Deliver Efficient Outcomes

Crawford (1988) shows that in an idealised model where parties have perfect information and the contract is complete, short-term contracting leads to under-investment when investment is irreversible.[1] This is a relevant conclusion for DG, where investment is indeed irreversible. The effects will be exacerbated when the parties have less than perfect information and the contract is incomplete.

Furthermore, Rey and Salanie (1996) show that spot contracting is inferior to contracts, i.e. even if the conditions are met for short-term contracts to deliver efficient outcomes, an even more restrictive set of assumptions are required for spot markets to deliver efficient outcomes.[2] When information is symmetric, contracts result in more efficient outcomes than spot contracting due to inter-temporal smoothing of rents. When information is asymmetric, efficiency of spot contracting also requires the contracting agent to receive the same rents in each period ("rent consistency"), and for opportunistic behaviour to be limited ("reverse incentive compatibility").

The lesson for electricity markets is very clear: a succession of spot contracts will lead to under-investment in generation, and while longer term hedge contracts will improve the situation, by being significantly shorter than the investment they will still lead to under-investment. Vertical integration provides an implicit contract that internalises information asymmetries and any issues of incompleteness. This means that investment is more likely to occur by a vertically-integrated gentailer or by an end-consumer.

There are two specific areas where this is relevant to the DGPP. First, even where vertical integration is possible, the succession of short-run contracts for connection between the DG and the local network may lead to under-investment in generation. The DGPP limit the ability for distribution networks to exhibit opportunistic behaviour when setting connection prices, thereby providing conditions in which efficient outcomes are more likely. Second, where the contribution of the DG to aggregate economic welfare includes an element of local capacity provision, and the contract for that capacity is a short-term contract renegotiated over time (and sometimes having a zero price), there will be under-investment in generation. The DGPP as currently interpreted provides a return for the provision of capacity at peak periods and thereby avoids the under-investment.

1 Crawford, V.P. (1988) "Long-Term Relationships Governed by Short-Term Contracts", *American Economic Review*, 78(3):485-499. Retrieved from http://www.jstor.org/stable/1809147

2 Rey, P. and Salanie, B. (1996) "On the Value of Commitment with Asymmetric Information", *Econometrica*, 64(6): 1395-1414. Retrieved from http://www.jstor.org/stable/2171836

3.3. Prices for Generation Capacity

The essence of the conceptual model of long-term investment provided in the ASEC August 2015 report was that: (i) local generation provides a service that remote generation cannot, namely capacity; (ii) the local generation capacity competes with network capacity over the longer term; and (iii) the role of the local distribution company is to enter into contracts with providers of capacity to ensure that there is sufficient capacity to meet consumers demands, subject to consumers' willingness to pay for quality.

The Authority acknowledges that some DG provides capacity, and also acknowledges that at times of constrained transmission DG may substitute for increased transmission capacity. The Authority does not, however, address the question of why there should be different pricing rules for capacity provided by DG and capacity provided by transmission.

It would be trite to answer that New Zealand has an energy-only market and therefore there are no prices for generation capacity. While this is a true statement, it ignores the fact that local generation (capacity + energy) competes against remote generation (energy) plus transmission (capacity). It also ignores the fact that energy-only prices increase volatility and essentially require market participants, including consumers, to divine what portion of the energy-only price actually relates to capacity. As discussed in the previous section, this uncertainty will lead to lower overall levels of investment.

In 1996 the energy-only market framework was the state-of-the-art, but twenty years later that is no longer true. Over the period 2010 to 2014 the United Kingdom electricity market underwent a period of major reform, introducing two new market mechanisms that provide increased certainty to investors in generation:

- Feed-in tariffs and Contracts for Differences (CfDs) providing revenue certainty to investors in low-carbon generation (energy); and
- A capacity market, providing increased revenue certainty for investors in generation capacity.

In introduce a capacity market the UK became one of many markets around the world that have adopted this structure. The capacity market was introduced over concerns that with the retirement of existing generation capacity, the energy-only market was providing insufficient certainty for investors in new generation plant.

Capacity market arrangements necessarily apply at the market-wide level, and do not address whether there is sufficient capacity in a given location (noting that such capacity can be provided by either generation or transmission capacity). A different mechanism is required at the interface between the transmission and distribution networks, one which provides a long-term relatively stable price to both sources of local capacity.

Through the optimisation of dispatch, an energy-only spot market will achieve productive efficiency given existing capacity. But, as discussed in the previous section, a succession of spot contracts or short-term contracts is unlikely to deliver efficient outcomes. Over longer time periods when capacity investment decisions are made, a specific price signal for capacity is likely to produce more efficient outcomes, not least because there is reduced uncertainty about returns earned by that capacity.

3.4. LRMC Does Not Suddenly Drop to Zero

An element of capacity pricing is provided by the Authority's suggestions that ACOT should be replaced by DG negotiating directly with Transpower to receive a payment that is equal to the value of deferred transmission investment. Alternatively, as an area becomes constrained, Transpower could calculate an LRMC price to be paid to (potentially) all sources of load reduction, including DG.

The problem with both of these proposals is that as soon as transmission has been built and commissioned the price paid to the source of the load reduction is zero, but true LRMC does not drop to zero just because an investment has been built and commissioned. If a source of capacity (or net load reduction) is paid the LRMC of transmission capacity for only a period of a few years while capacity is constrained, but is paid nothing the rest of the time, then the average price over the life of a long-life investment will be considerably less than the LRMC of capacity.

In addition, the Authority proposes an entirely different pricing approach for transmission capacity. Transmission capacity receives a price that is effectively based on average cost, and continues to receive that price regardless of how much net load reduction occurs. The Authority has not explained why different forms of capacity are treated differently.

3.5. Replacement Arrangements are Poorly-Specified

The Authority's proposal is incomplete at best. It suggests an approach whereby distributed generators might be able to negotiate with Transpower, but no formal regulatory framework is provided. It also provides absolutely no framework for DG to negotiate with distribution networks, exposing them to hold-up.

There is no particular reason for Transpower to enter negotiations. There is no framework for properly assessing the benefits from DG over an appropriately long time frame. Furthermore, over that appropriately long time frame transmission capacity and DG capacity are competitors, so Transpower's incentives are aligned against such an approach.

Even if Transpower does enter negotiations, no thought has been given to the practicality of DG providers negotiating on a meaningful basis with Transpower. Most DG providers are small, some are very small, and will effectively be price-takers. The brief proposals put forward by the Authority provide no reason to assume that the resulting arrangements and prices will deliver efficient outcomes.

One of the reasons for the original development of the pricing principles in the DG Regulations was that some distribution networks acted in a monopolistic manner towards DG. Once DG has been built it can be very expensive to relocate it to another network, and in the case of hydro stations it is essentially impossible. The distribution network therefore has the opportunity to act opportunistically and raise prices. Nothing in the Authority's proposals protects against this, and no consideration is even given to the issue. Commercial arbitration over the reasonableness of the allocations and assumptions underpinning prices would be possible, but this is likely to be too expensive for a small DG provider, and in all cases still enables the distributor to engage in rent-seeking behaviour.

3.6. Issues Outside the Authority's Scope

If all of the above issues are set aside, so-called first-best prices only achieve efficient outcomes if there are no distortions elsewhere in the economic system. In the presence of distortions, including missing markets, a different set of second-best prices may provide a more efficient (welfare-maximising) outcome.

The Authority specifically acknowledges that the following issues fall outside the scope of its analysis:

- Reducing greenhouse gas emissions;
- Providing renewable energy;
- Other environmental effects, which are claimed to be addressed by the consenting process.

In effect, the Authority's statutory terms of reference are not adequate to address Part 6. An example of the Authority having too narrow a focus to adequately address some matters is the Low-User Fixed Charge (LUFC). The LUFC would be dropped if assessed under the Authority's objectives, and the Authority has already stated that it supports a move to greater fixed charges. Such an approach completely ignores the broader economic considerations of energy poverty, health, and bounded rationality. An overly simplistic focus on optimising the short run use of a network produces prices with no room for low-user support. It is therefore appropriate that the LUFC is specified in regulation, and under the purview of a Ministry with scope to consider the broader economic objectives, than being under the narrow focus of the Authority.

The DGPP were originally specified in the *Electricity Governance (Connection of Distributed Generation) Regulations 2007* (the "DG Regulations"). The DG Regulations were developed in recognition that providers of DG had little negotiating power against a distribution network, and that a clear framework was required to allow for the more efficient provision of DG. The DG Regulations were incorporated, with minimal amendment, into Part 6 of the Code.

There is a reasonable argument that, like the LUFC, the DG Regulations should have been kept as regulations administered by the Ministry of Business, Innovation & Employment (MBIE) rather than being incorporated into the Code. Efficient pricing for DG likewise requires consideration of prices beyond those derived from a focus on optimising the short run use of a network.

3.7. Price Discrimination Against DG

Under the existing Pricing Principles, DG pays only the incremental cost of connection and none of the shared costs of the distribution network. DG will similarly pay no contribution towards transmission costs, unless the DG somehow causes increased transmission costs.

The Authority adopts the contradictory position that it is unfair that DG should not pay any shared network costs, and yet grid-connected generation does not pay costs of the shared network under the Authority's TPM proposals. There are, of course, exceptions for each form of generation. Grid connected generation will pay Area of Benefit charges, but it will not contribute to the cost of the shared network by way of residual charges. A beneficiary-pays methodology is too complex to apply to the distribution system, so the more straightforward causer-pays approach is adopted instead. If DG causes additional costs to be incurred in the shared distribution network then the existing DGPP require the DG to pay those costs.

This causer-pays principles embedded in the existing DGPP are entirely consistent with the property rights in the existing network being vested in consumers, and the DG negotiating a Coasian bargain to pay for costs it imposes on others. The result is efficient. The Authority's proposals will move away from the existing efficient position.

A larger-sized DG might be able to connect to either the transmission system or the distribution system, paying connection costs in both cases. When connected to the transmission system it might not pay for any shared assets under the proposed TPM, whereas when connected to the distribution system the DG will be required to pay for shared assets. Price discrimination of this nature might help the Authority negotiate deals with market participants, but it does not achieve the Authority's statutory objective.

3.8. Distribution Pricing in the United Kingdom

Recent reforms in the UK electricity market were discussed above. Another reform that is directly relevant to the DGPP was the establishment in 2006 of a single multi-party Distribution Connection and Use of System Agreement (the DCUSA). The DCUSA covers all distribution networks, and includes the distribution pricing methodology that must be applied by those networks.

The DCUSA pricing methodology provides that pricing for distributed generation "*relate[s] to the notional assets whose construction or expansion might be avoided due to the generator's offsetting of demand on the network*."[3] This principle is operationalised by "*tak[ing] the same values as for a demand user at the same network level of supply*." In other words, if a load faces a charge of $X/kW, it will save $X for each kW reduction in demand in the relevant period, and the same benefit is available to generation at that location. The same principle applies if the charges to the demand user are energy-based (i.e. c/kWh tariffs). The UK has chosen not to discriminate between different forms of load reduction.

For a given transmission pricing methodology, the UK approach could result in higher payments to distributed generation than occurs in New Zealand with the DGPP. Distribution tariffs recover the shared costs of the distribution network, and under the DCUSA methodology distributed generation will receive a credit for these shared costs. The New Zealand approach typically only provides a credit for avoided distribution costs if it can be demonstrated that specific costs have or will be avoided. The Authority's own criteria would suggest that the DGPP is relatively efficient compared to the DCUSA methodology.

3 Distribution and Connection Use of System Agreement, version 8.3, 30 June 2016. See particularly clause 31 or Schedule 16 – Common Distribution Charging Methodology. Retrieved from https://www.dcusa.co.uk/SitePages/Documents/DCUSA-Document.aspx

4. CONCLUSION

The Authority’s case for the removal of the DGPP rests on two assumptions:

- First, even if there is no change to the Transmission Pricing Methodology (TPM), removing the DGPP removes the basis for ACOT to be paid to Distributed Generation; and
- Second, removing the DGPP allows local distribution networks to increase connection charges to DG to include an element of shared network costs.

The analysis that the Authority has advanced to support these assumptions has not included a sufficiently broad consideration of efficiency, nor of relevant literature, and it encompasses logical contradictions which have not been adequately explained.

The Authority’s proposal to remove the DGPP will allow distributors to act in an opportunistic and rent-seeking manner, but the potential for this has been completely ignored in the Authority’s analysis. No arrangements are provided which provide an adequate basis for the DG provider to engage meaningfully with distribution networks on pricing.

DG will be required to pay an allocation of shared network costs for distribution networks, but grid-connected generation will not be required to pay a residual charge for the transmission network. The Authority has not explained how this difference in treatment is justified.

Transmission capacity will be guaranteed a payment equal to the average cost of that capacity, but DG which has the effect of substituting for transmission capacity will receive a payment that is highly uncertain. Such DG might be able to negotiate with Transpower to receive a payment for transmission investment deferral, but there is no framework advanced for those negotiations, and many small DG providers have insufficient resources to be able to meaningfully engage in any analysis. Alternatively, under the TPM proposals Transpower might develop a so-called LRMC charge, but in dropping to zero when transmission capacity is unconstrained that charge does not behave at all like Long Run Marginal Cost.

Relevant economics literature shows that reliance on spot contracts (i.e. the energy-only market) is inferior to contracting when parties can behave opportunistically, and that a succession of short-term contracts is inferior to long-term contracts under conditions that are likely to prevail in the real world. The Authority fails to address how short term contracts with an LRMC-based price will provide efficient outcomes. The Authority also fails to address how a succession of short-term contracts for connection (particularly for connection prices) will provide efficient outcomes.

Finally, the equivalent distribution pricing methodology in the United Kingdom provides distributed generation with a credit equal to the cost that a demand user would pay at the same location, and thus generally includes a credit equal to a portion of shared network cost. The DGPP as applied in New Zealand provide a much more restrictive set of circumstances in which a credit is provided for a reduction in distribution costs, generally requiring the identification of specific costs or investments that have been avoided.

Each of these issues should be properly considered and addressed before it is possible to conclude that the DGPP should be removed. The current consultation does not adequately address the full range of relevant issues. Removal of the DGPP as proposed is likely to create a significant risk of unanticipated consequences.

Pioneer Energy

Independent review of the potential impact of proposed regulatory changes on distributed (electricity) generators

Strictly private and confidential

20 July 2016

pwc

Important notice

Any person other than our client for this report (Pioneer Energy Limited) or who has not signed and returned to us a Release Letter or Hold Harmless Letter accepts and agrees to the following terms:

- The reader of this report understands that our work was performed in accordance with instructions provided by our client and was performed exclusively for our client's sole benefit and use.
- The reader of this report acknowledges that we owe a duty of care to our client only and that this report was prepared at the direction of our client and may not include all procedures deemed necessary for the purposes of the reader.
- The reader agrees that PricewaterhouseCoopers, its partners, principals, employees and agents neither owe nor accept any duty or responsibility or care to it, whether in contract or in tort (including without limitation, negligence and breach of statutory duty), and shall not be liable for any loss, damage or expense of whatsoever nature that is caused by any use the reader may choose to make of this report, or which is otherwise consequent upon the gaining of access to the report by the reader.
- The reader agrees that this report is not to be referred to or quoted, in whole or in part, in any prospectus, registration statement, offering circular, public filing, loan, other agreement or document and not to distribute the report without our prior written consent.

This report has been prepared solely for the purposes stated herein and should not be relied upon for any other purpose.

This report is strictly confidential and (save to the extent required by applicable law and/or regulation) must not be released to any third party without our express written consent which is at our sole discretion.

We have not independently verified the accuracy of information provided to us, and have not conducted any form of audit in respect of the distributed generators for the purpose of this report. Accordingly, we express no opinion on the reliability, accuracy, or completeness of the information provided to us and upon which we have relied.

The statements and opinions expressed herein have been made in good faith, and on the basis that all information relied upon is true and accurate in all material respects, and not misleading by reason of omission or otherwise.

The statements and opinions expressed in this report are based on information available as at the date of the report.

We reserve the right, but will be under no obligation, to review or amend our report, if any additional information, which was in existence on the date of this report was not brought to our attention, or subsequently comes to light.

This report is issued pursuant to the terms and conditions set out in our engagement letter with Pioneer Energy Limited and the Terms of Business attached thereto.

Contents

Introduction

Introduction

Background

- There is a large number of small scale electricity power schemes throughout New Zealand. These are commonly referred to as distributed generators (DGs). The schemes:
  - Are generally connected to an electricity distribution network.
  - Are primarily commercially focussed, selling output through some form of power purchase agreement and on the spot market as price takers.
  - Have fuel sources that are predominately renewable, such as water, wind, biogas and wood waste.
- An important component of the DGs annual revenue is Avoided Cost of Transmission (ACOT) payments that they receive from electricity network companies. Total ACOT payments received by all DGs in 2015 was approximately $52 million.
- The Independent Electricity Generators Association (the IEGA) represents approximately 35 owners/operators of DGs. The IEGA is not a constituted organisation or entity in its own right.
- The Electricity Authority (the Authority) is considering making changes to the methodology for setting transmission prices under Part 12 of the Electricity Industry Participation Code 2010 (Code). The Authority is also considering making changes to distributed generation pricing principles in Schedule 6.4 of the Code.
- The Authority has signalled that the consequences of its proposed changes will include:
  - A significant reduction and/or elimination in the annual ACOT payments to the DGs.
  - DGs potentially having to pay “common costs’ to electricity network companies.
- The IEGA has signalled that the Authority’s proposed changes could result in closure of plants and reduce security of supply.
- The IEGA and/or its members are making a submission on the Authority’s proposed changes to Part 12 and Schedule 6.4. Pioneer Energy Ltd (Pioneer Energy) is managing the development of the submission to the Authority on behalf of the IEGA.

Introduction

Scope

- We have been engaged by Pioneer Energy on behalf of a group of IEGA members to prepare a brief report on the financial impacts on DGs of the potential elimination of ACOT revenue and the potential payment of "common costs" to electricity network companies.
- The scope of our work and the associated terms and conditions are set out in our engagement letter with Pioneer Energy dated 30 May 2016 and our scope extension letter dated 13 July 2016.
- Our analysis, which is presented in this report, is to be included with the IEGA's submission to the Electricity Authority, which is due on the 26 July 2016.
- The first section of this report sets out the methodology and assumptions used to analyse the impact on DGs of the elimination of ACOT revenue and the payment of common costs. The second section sets out the analysis of the impact of the elimination of ACOT revenue. The third section sets out the combined impact of the elimination of ACOT revenue and the payment of common costs by DGs. The final section summarises our findings.
- The sources of information we have used to undertake our analysis include:
  - DG annual financial statements and/or specific financial information for the last three financial years.
  - Pioneer Energy's analysis of Commerce Commission electricity distribution business information disclosures.
  - Our internal analysis of industry benchmarks.
- Ten DGs have participated in the analysis. However, some DGs are not included in certain sections of the analysis because of information limitations.
- DG information has been anonymised. The averages and totals in the figures that follow are the average of three years of historical data.

Methodology and assumptions

Methodology and assumptions

Methodology – ACOT

- We have undertaken the following procedures to analyse the impact of eliminating ACOT revenue:
  - Compiled the DG's financial statements for the last three financial years (where available).
  - Obtained data on annual ACOT revenue received and other information from each DG for the last three financial years.
  - Calculated financial measures to demonstrate the impact on revenue, profitability, gearing, interest cover, liquidity and value of the elimination of ACOT revenue.

Methodology – ACOT and common costs

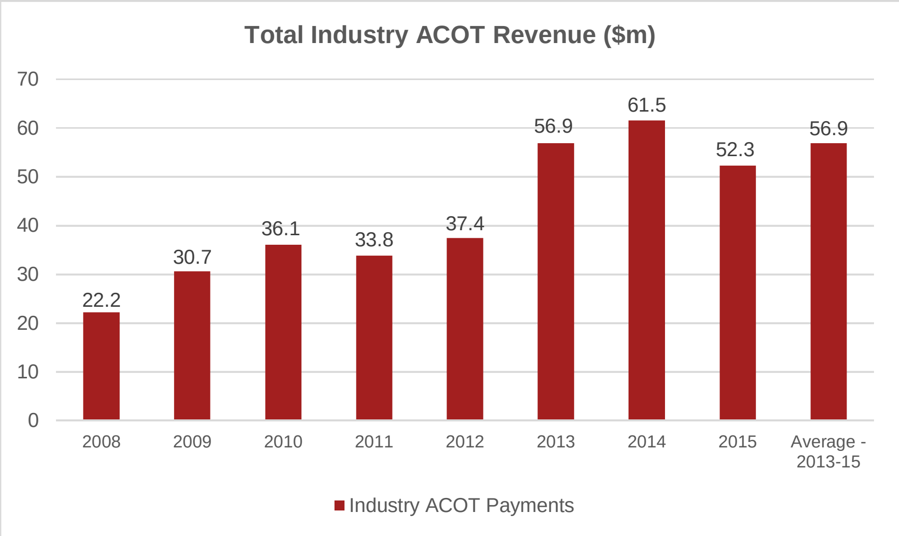
- Our analysis of the combined impact of eliminating ACOT revenue and DGs paying common costs has involved taking the information from step 3 above (including estimated payments for common costs) and then calculating financial measures before and after the elimination of ACOT revenue and the payment of common costs to demonstrate the impact on operating expenses, profitability, gearing, interest cover, liquidity and value.

Assumptions

- We have made the following assumptions to facilitate our analysis:
  - Elimination of ACOT revenue and payment of common costs are the only adjustments that need to be made to the historical financial statements information. Elimination of ACOT revenue and payment of common costs will not have an impact on, and so not require adjustments to other revenue or operating and financing costs.
  - All ACOT revenue will be eliminated. There will not be any re-negotiation of ACOT payments subsequent to any proposals being implemented.
  - Common cost payments will be in the range of $20 and $40 per MWh. The common costs are a range of indicative costs provided to IEGA members on an informal basis due to the restricted timeframes. We understand that these costs are similar to standard commercial tariffs as suggested by the EA proposal for standard consumers.
  - Where a DG has multiple revenue streams (e.g. retail), it is appropriate to undertake the analysis on the profit and loss and balance sheet of the DG's generation assets only. In some cases this has involved making simplifying assumptions to separate generation assets from the rest of the business, for example pro-rating the level of total debt allocated to generation assets.
  - The analysis has been conducted on a cumulative basis (e.g. the impact of the elimination of ACOT revenue on the balance sheet accumulates over time).

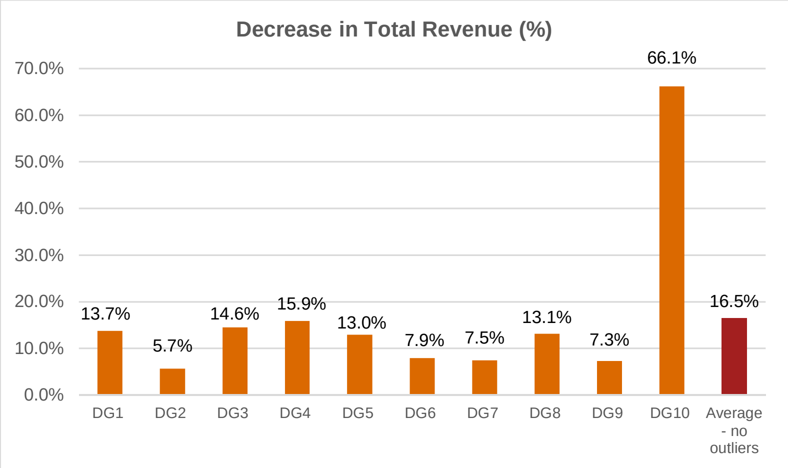
ACOT revenue analysis

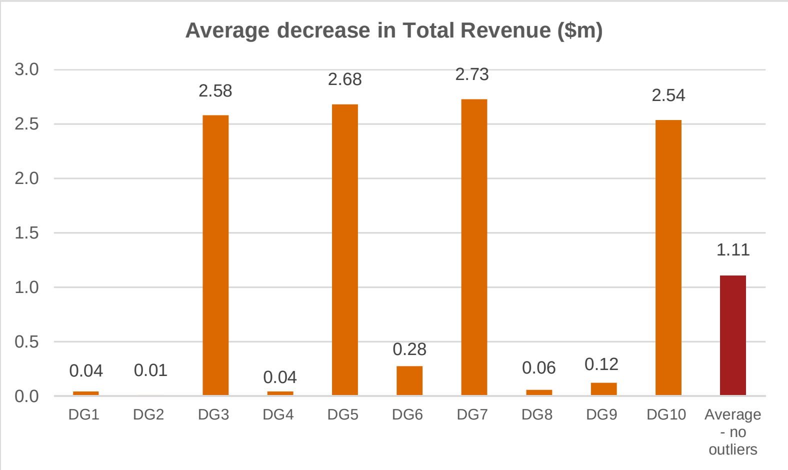
Total industry impact



- Total industry ACOT revenue (the total of all ACOT payments made by the electricity network companies to the DGs) is presented in the figure opposite.
- Total industry ACOT revenue has:
  - Ranged from a low of $22.2 million in 2008 to $61.5m in 2014.
  - Averaged $41.4 million over the period 2008 to 2015.
- The average annual ACOT payments in the last three financial years made to DGs included in the analysis in this report is $11.1m. This is approximately 20% of the annual average total industry ACOT payments from 2013 to 2015 of $56.9m.
- The indicative total industry value impact of DGs losing ACOT revenue is approximately $540 million assuming an industry WACC of 7.6%. This impact has been calculated using the average of total industry ACOT revenue (after tax) made over the last 3 years.

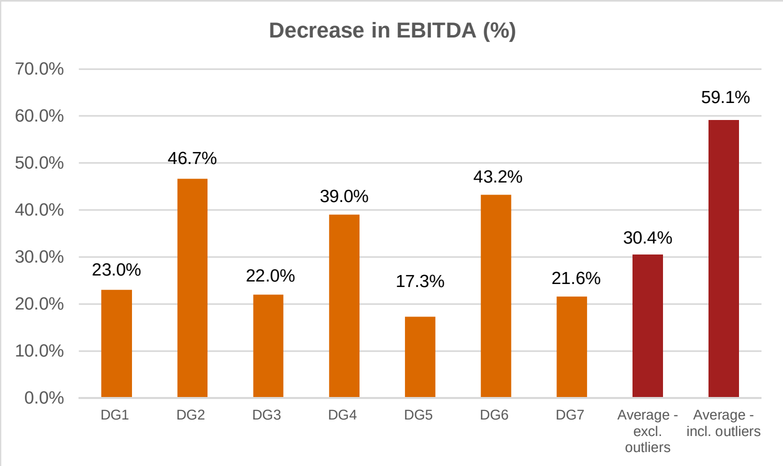
Revenue

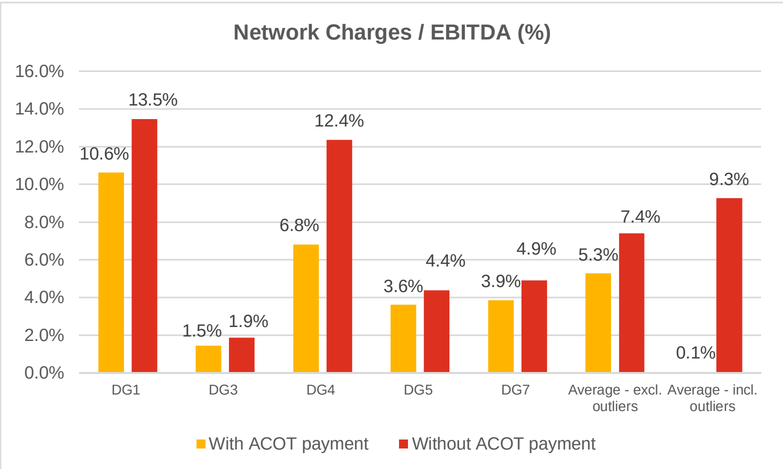




- The loss of ACOT revenue results in an average 16.5%, or a $1.1 million, decrease per annum in total revenue for the ten DGs included in our analysis.
- For one DG (DG10) the loss of ACOT revenue could potentially result in an average loss per annum of up to 66.1% of total revenue. DG10 is an outlier in terms of the percentage decrease in total revenue.
- In subsequent figures we have excluded individual outliers to make the figures more meaningful. For example, only DGs with positive EBITDA in all scenarios are included in the Net Debt / EBITDA figure on page 22. However, we have included averages with and without outliers in the figures and commentary to provide readers with a balanced view of the results.
- The average decrease in total revenue demonstrates that there is a wide range in the level of ACOT revenue received by the ten DGs who provided information for our analysis. This partially reflects considerable differences in the size of the DGs. For example, revenue varies from approximately $0.2 to $36.1 million per annum and generation volume varies from 2,135 to 224,168 in MWh per annum.

Profitability





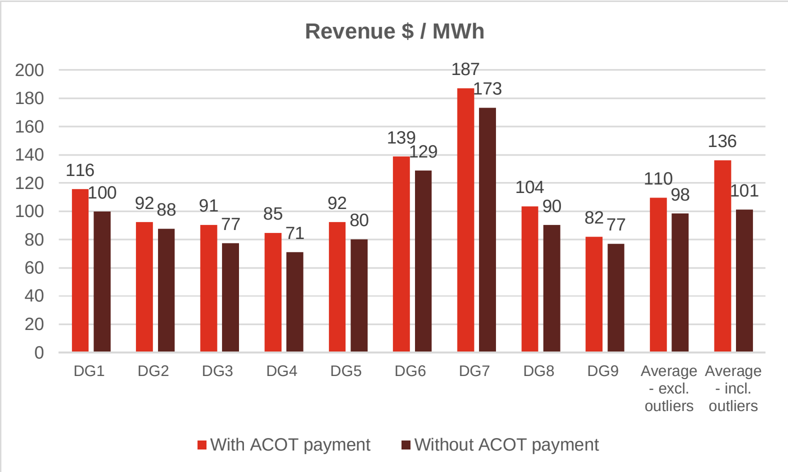
Decrease in EBITDA (%)

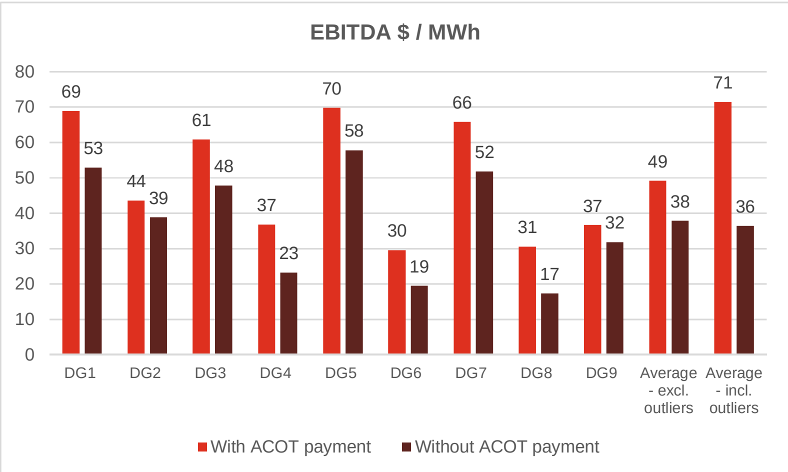
- The percentage decrease in EBITDA demonstrates the impact on profitability of the elimination of ACOT revenue. There are no costs associated with ACOT revenue and so the elimination of ACOT falls straight to EBITDA.
- We have not analysed the percentage change in EBIT due to the DGs' differing depreciation policies.
- The elimination of ACOT revenue results in a significant decrease in profitability for DGs. The average decrease in EBITDA is 30.4% excluding outliers and 59.1% including outliers.
- For some DGs, the elimination of ACOT revenue changes average annual EBITDA from positive to negative. This emphasises the significance of DGs losing ACOT revenue.

Network Charges / EBITDA (%)

- Network charges are negotiated bi-laterally between electricity network companies and individual DGs. This means there are significant differences in network charges between the DGs, reflecting their individual circumstances such as geographical location.
- Network charges measured as a percentage of EBITDA increases for all DGs after the elimination of ACOT revenue (excluding DGs with negative EBITDA where the measure is not meaningful).
- The average network charges / EBITDA ratio:
  - Excluding outliers increases from 5.3% to 7.4%.
  - Including outliers increases from (0.1%) to 9.3%.

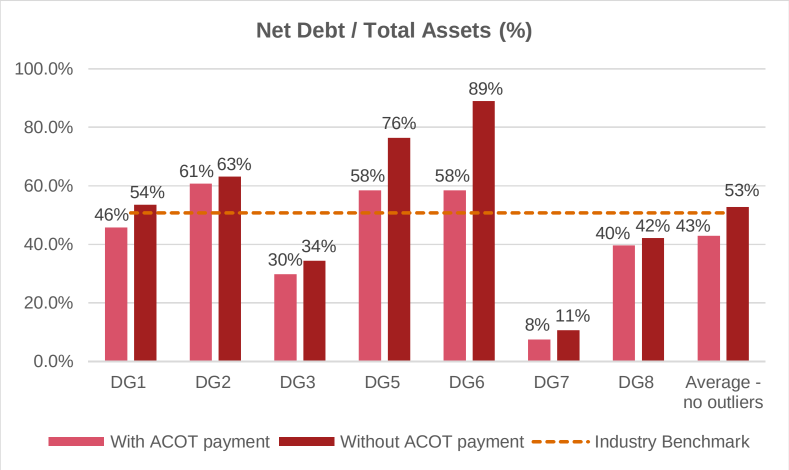
$/MWh metrics

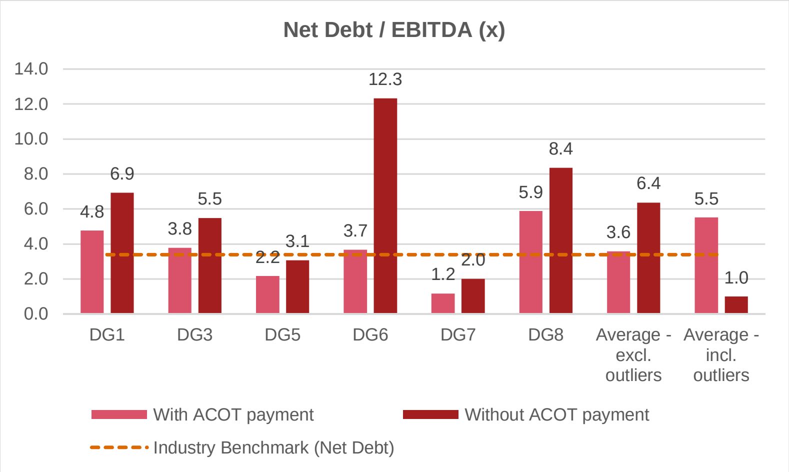




- Revenue and profitability per unit of output will decrease with the elimination of ACOT revenue. On average DGs will lose approximately:
  - $12 of revenue and EBITDA per MWh generated excluding outliers.
  - $35 of revenue and EBITDA per MWh generated including outliers.

Gearing





- Gearing is a measure of financial leverage, demonstrating the degree to which a business' activities are funded by debt.
- We have calculated two gearing measures – net debt to total assets and net debt to EBITDA. Net debt is total debt less cash and cash equivalents.

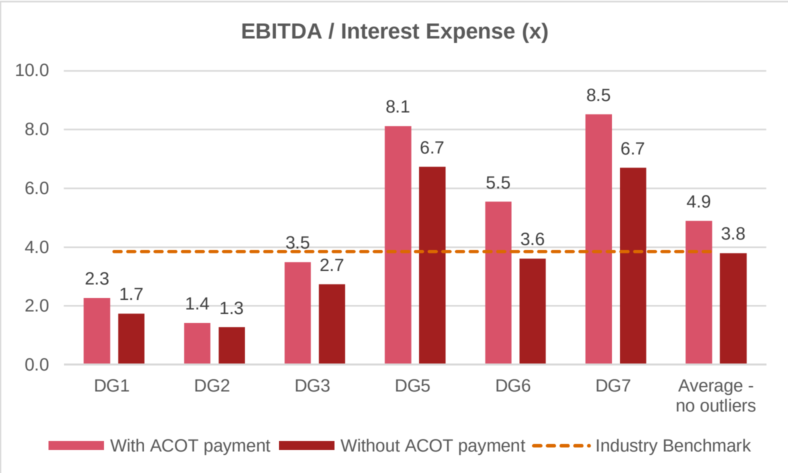
Net Debt / Total Assets (%)

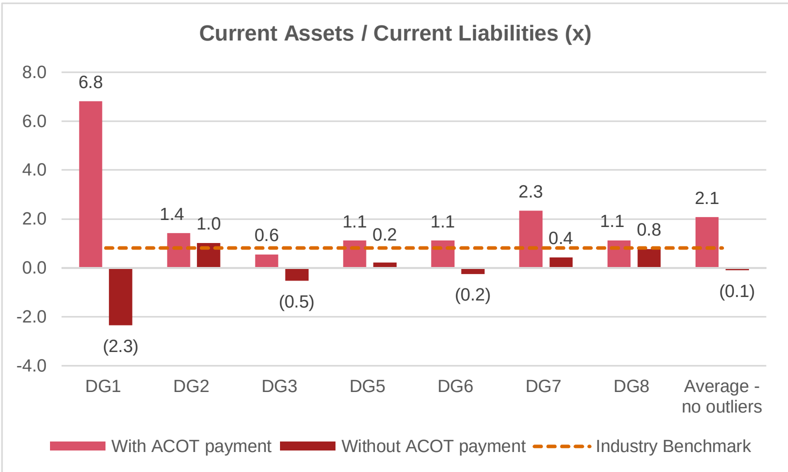
- Elimination of ACOT revenue reduces DG's free cash flow. Assuming no change in distributions to shareholders, lower free cash flow will reduce retained earnings and therefore increase the proportion of debt in a DG's capital structure. Consequently, elimination of ACOT increases the average net debt / total assets ratio from 43% to 53% for the participating DGs.
- The estimated average percentage total debt/assets ratio for eleven New Zealand energy companies was 50.8% in 2015. This industry benchmark includes large energy companies with higher credit ratings and more diversified businesses compared to the DGs.

Net Debt / EBITDA (x)

- Lower EBITDA also increases the ratio of net debt / EBITDA for all DGs (excluding DGs with negative EBITDA where the measure is not meaningful).
- The elimination of ACOT revenue increases the net debt / EBITDA ratio from 3.6x to 6.4x excluding outliers. The average including outliers decreased from 5.5x to 1.0x due to one DG incurring a particularly large EBITDA loss in one of the years included.
- The estimated average net debt to EBITDA ratio for the eleven New Zealand energy companies was 3.4x in 2015.

Interest cover & liquidity





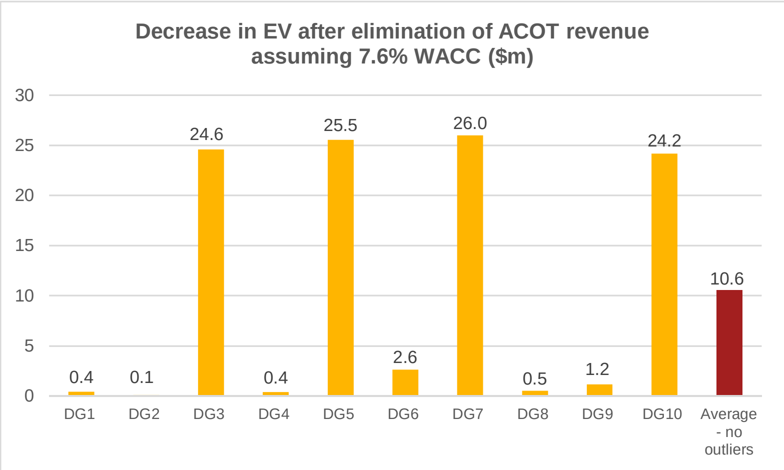
EBITDA / Interest Expense (x)

- The EBITDA / interest expense ratio measures interest cover. It provides an indication of a business' ability to meet its interest commitments. If ACOT is eliminated DGs will suffer a reduction in EBITDA and a decrease in interest cover. In calculating this ratio we have assumed no change in interest expense.
- The average EBITDA / interest expense ratio decreases from 4.9x with ACOT revenue to 3.8x without ACOT revenue.
- The estimated average EBITDA / interest expense ratio for the eleven New Zealand energy companies was 3.9x in 2015.

Current Assets / Current Liabilities (x)

- The current assets / current liability ratio (current ratio) is a measure of a business' ability to meet short-term obligations.
- To calculate this ratio, we have assumed the elimination of ACOT revenue reduces cash in the DGs' balance sheets. This in turn reduces current assets, and consequently the current ratio.
- The average current assets / current liabilities ratio decreases from 2.1x with ACOT revenue to (0.1x) without ACOT revenue. This means DGs are noticeably less liquid without ACOT revenue and a number have negative ratios.
- The estimated average current assets / current liabilities ratio for eleven New Zealand energy companies was 0.8x in 2015.

Indicative value impact



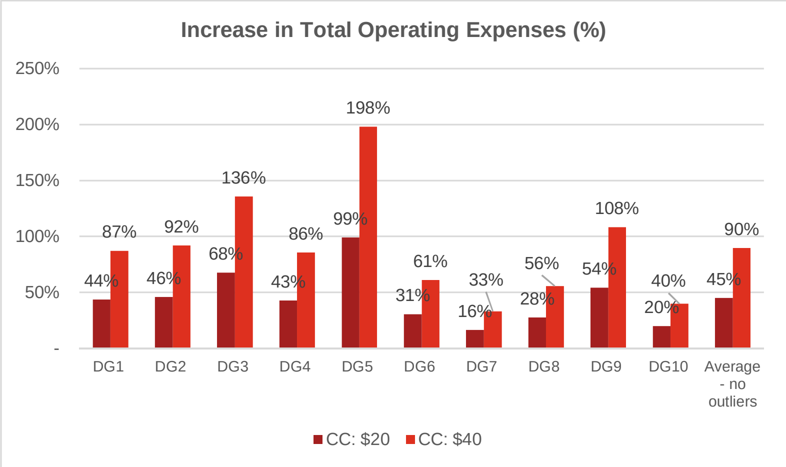
- The indicative enterprise value (EV) impact of the elimination of ACOT has been calculated for each DG. The calculation is high level and has involved estimating the present value of after tax ACOT revenue using an industry weighted average cost of capital (WACC) of 7.6%.
- The average reduction in EV assuming the loss of ACOT revenue across the DGs is $10.6 million.
- The total indicative value impact on all DGs who participated in the analysis is $106 million. This is approximately 20% of the estimated total industry value impact of $540 million referred to earlier.
- The variance in the estimated loss in EV across the DGs largely reflects differences in size.

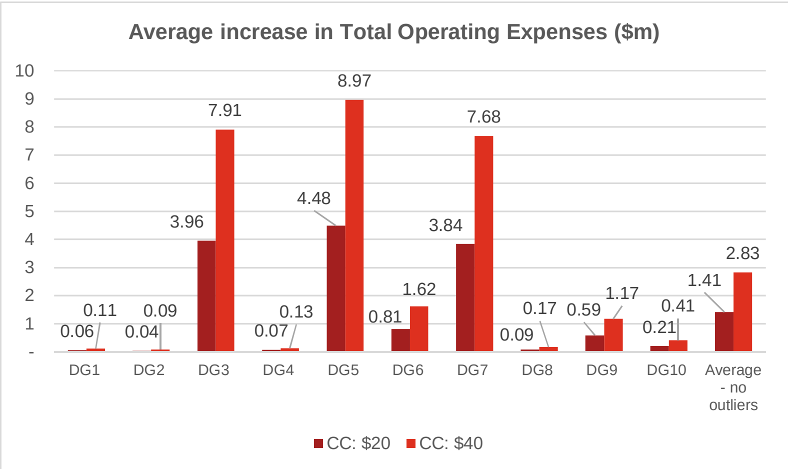
Common costs analysis

Introduction

- This section contains analysis of the combined impact of eliminating ACOT revenue and DGs paying common costs across a range of measures including operating expenses, profitability, gearing and value.
- The common costs analysis uses the same measures as the ACOT revenue analysis to enable a comparison between the two analyses (where possible). In some figures we have also included the ACOT revenue analysis to show the impact of DGs also having to pay common costs.
- We have used two estimates of potential common costs payment assumptions provided to us by Pioneer Energy: $20 and $40 per MWh. Pioneer Energy requested that we undertake our analysis of the impact of the potential payment of common costs in combination with the elimination of ACOT revenue, rather than analysing the impact on DGs of just paying common costs and assuming that ACOT revenue remains.
- We understand further work is required to better understand the potential quantum of common costs for DGs. Consequently, the analysis in this report is indicative only

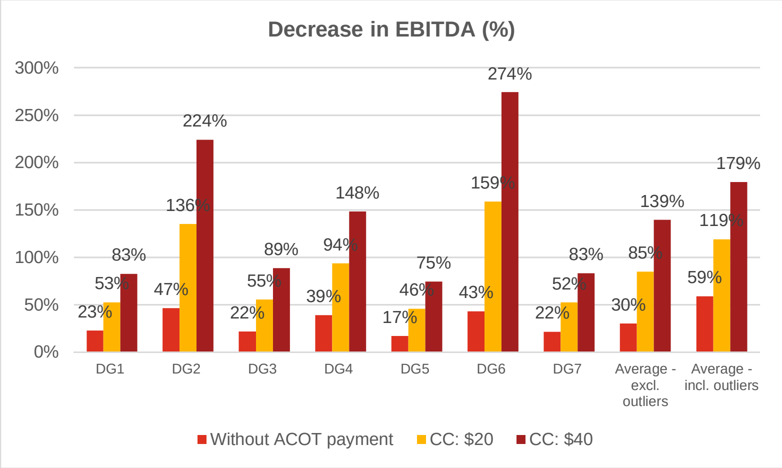
Operating expenses

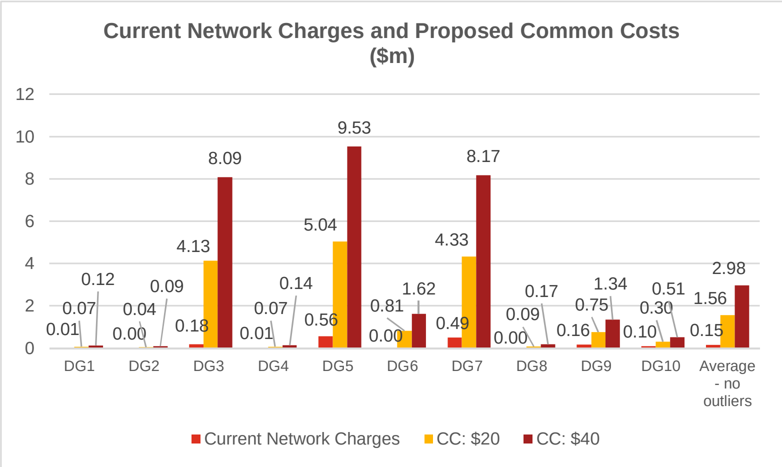




- Changes in operating expenses are used to demonstrate the percentage and absolute impacts of DGs paying common costs to electricity network companies.
- The payment of common costs results in significant increases in average total operating expenses of 45% and 90%, or $1.4 million and $2.8 million, assuming common cost payments of $20 and $40 MWh respectively.
- The average increase shows the wide range of potential costs payable by the ten DGs who participated in this analysis.

Profitability





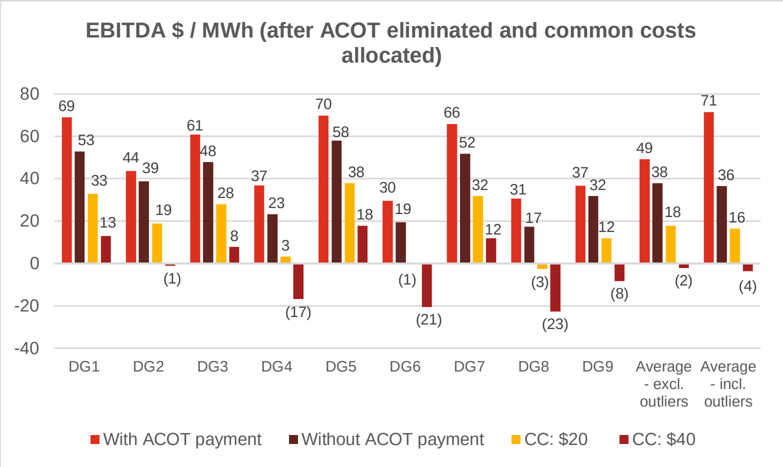
Decrease in EBITDA (%)

- The combined impact of losing ACOT revenue and paying common costs results in a very significant decrease in profitability for DGs.
- The average decrease in EBITDA is:
  - 85% and 139% assuming common costs of $20 and $40 per MWh and excluding outliers.
  - 119% and 179% assuming common costs of $20 and $40 per MWh and including outliers.

Current Network Charges and Proposed Common Costs ($m)

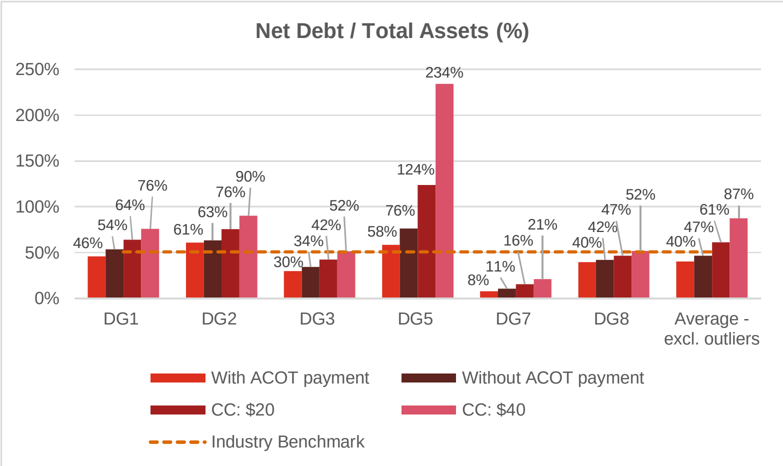
- DGs' total network costs increase significantly if the common cost payments of $20 per MWh and $40 per MWh are assumed to be in addition to existing network charges.

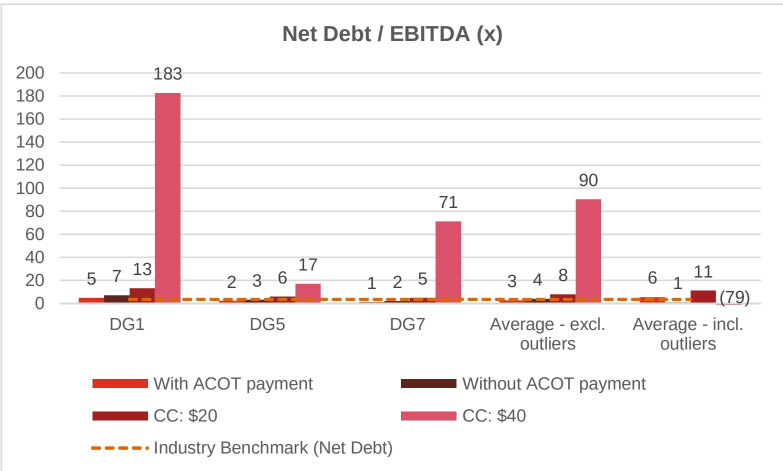
$ MWh metrics



- The figure opposite presents the cumulative impact on EBITDA / MWh of losing ACOT revenue and paying common costs of $20 and $40 per MWh.
- For some DGs, the EBITDA / MWh ratio goes from positive to negative. This demonstrates the significance of DGs having to pay common costs in addition to losing ACOT revenue.

Gearing





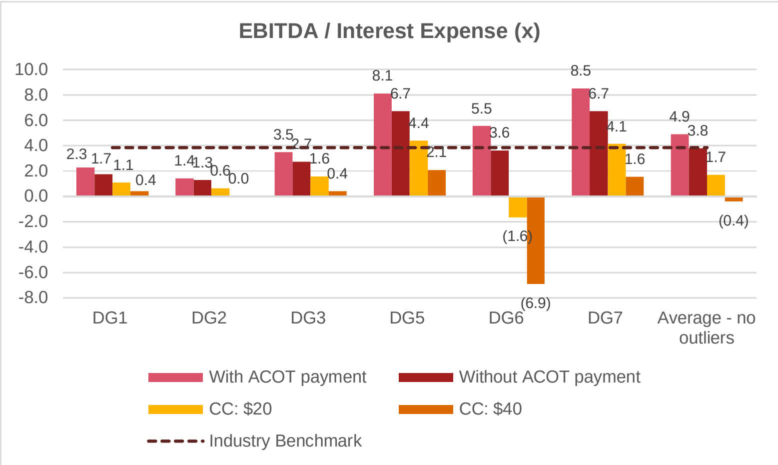
Net Debt / Total Assets (%)

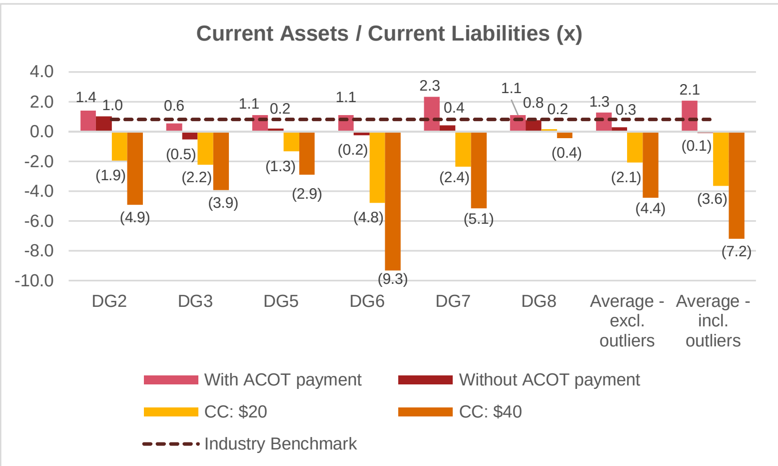
- The combined impact of eliminating ACOT revenue and DGs paying common costs increases the average net debt / total assets ratio to 61% and 87% excluding outliers and assuming common costs of $20 and $40 per MWh respectively.
- This will result in gearing levels for a number of the DGs that will be difficult to sustain.

Net Debt / EBITDA (x)

- The combined impact of eliminating ACOT revenue and DGs paying common costs increases the net debt / EBITDA ratio to 8x and 90x excluding outliers and assuming common costs of $20 and $40 per MWh respectively. This ratio also demonstrate the significance of DGs having to pay common costs in addition to losing ACOT revenue.

Interest cover & liquidity





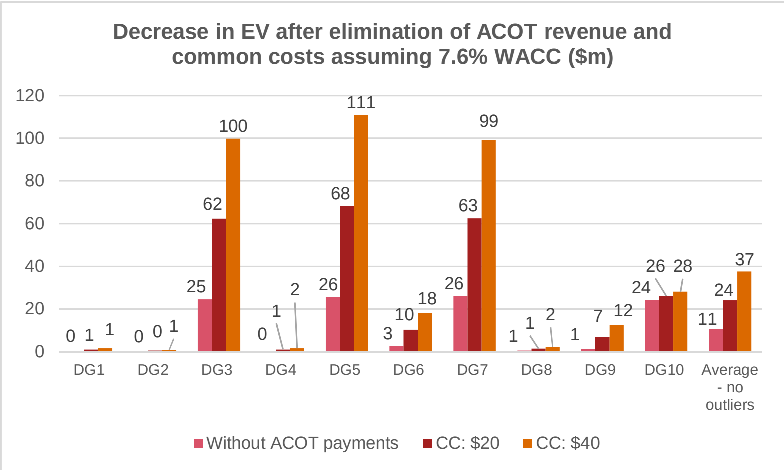
EBITDA / Interest Expense (x)

- DGs' interest cover deteriorates significantly as a result of having to pay common costs in addition to losing ACOT revenue. The average EBITDA / interest expense ratio decreases to 1.7x and (0.4x) without ACOT revenue and assuming common costs of $20 and $40 per MWh respectively.

Current Assets / Current Liabilities (x)

- The average current assets / current liabilities ratio including outliers decreases to (3.6x) and (7.2x) without ACOT revenue and assuming common costs of $20 and $40 per MWh respectively. This means that for many DGs current liabilities will exceed current assets.

Indicative value impact



- The average indicative loss in EV for each DG is:
  - $24 million after elimination of ACOT revenue and assuming $20 per MWh of common costs.
  - $37 million after elimination of ACOT revenue and assuming $40 per MWh of common costs.
- The total indicative value impact for all DGs (who participated in this analysis) is:
  - $240 million after elimination of ACOT revenue and assuming $20 per MWh of common costs.
  - $374 million after elimination of ACOT revenue and assuming $40 per MWh of common costs.

Summary

Summary

- The average annual ACOT payments in the last three financial years made to DGs included in the analysis in this report is $11.1 million. This is approximately 20% of the annual average total industry ACOT payments from 2013 to 2015 of $56.9 million.
- The financial information provided to us by the DGs included in our analysis suggests that most operate profitably and have prudent levels of financial gearing compared to wider industry benchmarks.
- Eliminating ACOT revenue from the DGs financial statements for the 2013 -2015 financial years results in an average reduction in EBITDA of 30.4% and an average increase in net debt / EBITDA ratio from 3.6x to 6.4x (excluding outliers).
- If ACOT revenue is eliminated and DGs are also required to pay network common costs at a level of $20 per MWh then the EBITDA of the DGs in our analysis reduces on average by 85% and net debt/EBITDA increases on average to 8x. If network common costs are assumed to be $40 per MWh then the average decrease in EBITDA and increase in net debt /EBITDA is considerably larger.
- The elimination of ACOT revenue could result in a reduction in enterprise value for the DGs in our analysis of approximately $106 million. The value reduction could be up to approximately $374 million if the DGs in the analysis lose ACOT revenue and are also required to pay network common costs at $40 per MWh.

The revenue of the DGs in our analysis is approximately 20% of total DG sector revenues. If the impact on value of eliminating ACOT revenue and paying network common costs on the DGs in our analysis is representative of these changes on the sector as a whole, then the total sector value impacts could be between $0.5 billion and $1.5 billion or possibly more.