26 March 2025

Electricity Authority
PO Box 10041
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By E- Mail: taskforce@ea.govt.nz

Re: Submission on Energy Competition Task Force Initiatives 2A, 2B, and 2C

Counties Energy Limited (**CEL**) welcomes the opportunity to comment on the Electricity Authority's (**EA's**) consultation on the Energy Competition Task Force initiatives to provide consumers with more options.

We understand the EA's Energy Competition Task Force (**Task Force**) is proposing to:

- Require electricity distribution businesses (**EDBs**) to pay a rebate when 'mass market' consumers supply electricity at peak times (Task Force Initiative 2A) [1]; and
- Require retailers to fairly reward consumers with power generation systems for the electricity they supply at peak times (Task Force Initiative 2C).

This submission covers aspects of Task Force Initiative 2A only although we have noted the EA's separate consultations on Task Force Initiative 2B and 2C, including its proposal for retailers to pass-through rebates to end-consumers through retailer buy-back pricing plans.

CEL supports the principle of using injection price signals to defer capital expenditure through managing network load

CEL is committed to improving the efficiency of its electricity distribution network. CEL considers that with the step-reduction in battery costs, combined with distributed generation (**DG**) increasing in New Zealand, an opportunity exists for EDBs to use this resource as an additional tool to assist with the management of network constraints, and ultimately, to support the reduction of costs.

CEL supports the EA's proposal in principle, agreeing there should be a distribution price signal for injection by mass market customers, to signal both future network constraints driven by load, and

[1] The EA has defined 'mass market' as consumers that are on 'standard contracts' which includes households, small and medium businesses, farms, and other, but excludes large industry.

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to maximise network capacity utilisation. However, the EA should note that EDBs do not operate a network where load is greater than capacity because this would result in an overload of the thermal rating of the network equipment and/or a voltage drop below regulated levels.[2]

This means that technically, EDBs very seldom operate a constrained network, but rather invest in additional network capacity before an identified constraint occurs. Our submission, therefore, focuses on the practical aspects of the EA's proposal that require further work and/or consideration before implementing.

Using non-network solutions is challenging

While CEL supports the use of suitable non-network solutions, including mass-market DG, as tools to support the management and improve the utilisation of distribution networks, it considers it will be challenging to translate price signals into effective changes in customer behaviour that also gives EDBs confidence to defer capital expenditure, which is the only material network benefit.

The significant challenge of using any DG injection as a non-network solution is the real risk an EDB faces if injection doesn't occur as expected (e.g. a generation outage occurs), with the impact being outages, as feeders trip before thermal overload causes damage to the network, or alternatively, under- or over-voltage causes power quality issues to customers that needs to be resolved.

If simply priced as a negative tariff (i.e. payment by EDBs) to mass-market customers, CEL considers that the network benefits are unlikely to be significant. This makes it challenging for the EA's proposal to be effective at influencing customer behaviour in practice. Furthermore, the downside risk of the EA's proposal is the potential for cross-subsidies (or wealth transfers) between customers on the same electricity distribution network, where customers without DG (e.g. solar) subsidise customers who own DG.

As highlighted by the EA, some EDBs are already trialling (or planning to trial) the use of flexibility, aggregation and/or injection price signals to manage their network constraints, including CEL which is undertaking a trial in Karaka Harbourside (in Auckland) to demonstrate the use of dynamic operating envelopes to coordinate two-way energy flows.[3] These projects, as they progress, will provide valuable insights and findings to inform the EA's work on this initiative should it choose to implement.

[2] Note that the Ministry of Business, Innovation & Employment (MBIE) are proposing to expand permitted (upper and lower) voltage ranges for electricity supply. This would help to partially address voltage issues relating to uptake of solar PV, and other technologies, on distribution networks. Refer to https://www.mbie.govt.nz/have-your-say/proposals-to-expand-the-permitted-voltage-range-for-electrical-supply

[3] Other examples include Orion, Powerco, and Aurora Energy. All have investigated the use of injection price signals to achieve network benefits from DG connected to their networks.

CEL agrees with a targeted approach, but notes that injection price signals should also be used to discourage injection on constrained parts of a network

While CEL supports the approach proposed by the EA, we recommend that the principles should be broadened to also enable EDBs to use pricing signals to fairly manage generation export constraints caused by too much injection (e.g. over voltage issues), at certain times of the day and/or certain areas of the network.

Unlike demand load, excess generation capacity is managed through the timing of the amount of generation that can connect to the electricity distribution network. This is complicated by network export capacity nearly always being constrained on a voltage basis rather than the thermal rating of the network assets.

As distribution networks were traditionally designed for load, many EDBs are now facing the challenge of managing their networks to support increasing levels of two-way energy flows and increasing injection.[4] As a consequence, CEL has no feeders constrained for demand load (i.e. energy flow to the customer) but has two feeders constrained for generation export (i.e. energy flow into the electricity distribution network). With a significant amount of additional DG capacity planned, that will further constrain generation exported power across large parts of CEL's network.[5]

Our proposal is also consistent with the Australian Energy Regulator's (AER's) approach where the application of a distribution cost charge to customers (instead of a rebate) signals when exported energy is driving the need for future network investment to build additional generation export capacity. The export price (used with TOU prices) signals when it is better for customers to use their own rooftop generated (or stored) solar electricity within their own premises, instead of injecting into the electricity distribution network.[6]

Distribution price signals should be viewed as just one option, among a range of options, to support management of network constraints

CEL supports the use of suitable non-network solutions to manage network constraints for the benefit of consumers. However, the reality of the benefits and costs of providing an injection rebate will vary between individual networks, depending on:

- extent of forecast network constrained areas;
- underlying cause of the constraint (e.g. voltage or capacity issue); and

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[4] Saxena, V et al., Navigating the complexities of distribution generation: Integration, challenges, and solutions. Energy Reports, Volume 12. December 2024. Retrieved from https://www.sciencedirect.com/science/article/pii/S2352484724005948

[5] We note that, if DG is evenly dispersed (e.g. locationally, with diversity of generation types), DG may not cause additional costs to augment/reinforce an electricity distribution network.

[6] Australian Energy Regulator (AER), Export Tariff Guidelines, May 2022. Retrieved from https://www.aer.gov.au/system/files/AER%20-%20Export%20Tariff%20Guidelines%20-%20May%202022_0.pdf

- type of DG technology used by customers, including ability to 'flex' (e.g. solar, solar plus battery).

Additionally, the extent to which EDBs have confidence in using a rebate to defer network investment costs would depend on:

- effectiveness of using price signals as a tool to change customer behaviour (noting that this will rely partly on how retailers pass-through an EDB's pricing structure to the customer);
- persistence of changes to network use behaviour (e.g. how long, and how consistently, a customer injects energy into a network). For example, if a customer's injection is persistent and consistent over a reasonable length of time, this provides EDBs with greater confidence to commit to the deferral of a capacity upgrade; and
- type of customer growth in the constrained areas. This is because new industrial customers have a wide range of power requirements so being unable to accurately forecast and being able to 'swamp' any flex service with one large connection increases the risk of using the EA's proposal as a tool to manage an EDB's network constraints.

There will also be some costs incurred by EDBs to implement an injection rebate. For example, some EDB's billing systems may require system upgrades to accommodate the rebate. Distribution prices are also typically allocated at broad customer segments, which balances the trade-off between simplicity (less targeted) and complexity (more targeted). This makes it challenging to target certain customers that should benefit from injection in practice, without introducing additional complexity in distribution charges.

In short, while injection price signals may be of some benefit to some EDBs, they will not necessarily be practical or the optimal solution for others.

CEL considers that EDBs are best placed to understand their networks. The EA's proposed principles should allow for sufficient flexibility for EDBs to consider these benefits and costs in the context of their network and decide on the best option for them to use DER to manage their network constraints. This could include the use of TOU price signals, contracted flexibility with a third-party provider or aggregator, flexible connections, or a combination thereof.

In the future, we consider that the largest potential opportunity for flexible services may be from batteries in residential EVs being able to provide vehicle to grid (V2G) power.[7] This is being driven by a combination of increasing EVs, as a percentage of vehicle fleet, and improving battery technology, with battery life becoming longer than the vehicle itself and uptake of V2G technology.

As EDB peaks occur less than 5% of the time, provision of flexibility services from residential EV batteries will have minimal impact on EV owners, especially if managed by an aggregator that can

[7] Already the largest battery capacity is in New Zealand's EV fleet. A (rough) estimate places this at ~4GW (assuming 50kW battery and a fleet of around 81,000 excluding plug-in EVs). However, currently, most EVs lack V2G capability.

maximise the export value through 'value stacking' (i.e. a combination of energy arbitrage, flexibility services, and bidding supply into the interruptible reserves market).

Contracted flexibility with an aggregator may provide more meaningful benefits at lower risk

As discussed above, the use of injection price signals (or 'price-based flexibility') to achieve material network benefits introduces a level of uncertainty and risk for EDBs. This is because, for mass-market injection to achieve meaningful network benefits, it would need to be coordinated across multiple connections to inject at similar times, of a sufficient scale to achieve material network benefits, and be able to provide sufficient 'firm' capacity for EDBs to defer its capital investment (i.e. results in a consistent and reliable change in network behaviour that persists over a reasonable length of time).

Given these requirements, CEL considers that 'contracted flexibility' would provide greater network benefits, at a lower risk, for many EDBs. For example, assume that a rebate is being paid to a group of customers connected to a substation forecast to be constrained within the next 5-years. The rebate is expected to incentivise connected customers to inject during 'peak' times to defer the need to upgrade the substation.[8]

If, after the pricing year has ended, the EDB determines that total customer injection during the peak times isn't material enough to justify the deferral of the new substation (e.g. peak demand is still steadily approaching its N-1 capacity limit), the EDB will need to invest in a new substation, regardless.[9] The project may now be at a higher cost due to cost escalations, compared to the counterfactual of building the substation as originally planned. Furthermore, the lead time to address the network constraint has now shortened, increasing the pressures on delivery.

In this example, paying an aggregator for contracted flexibility (e.g. coordinated injection across multiple customer connections during peak times) would provide a higher level of certainty and assurance for an EDB to factor in when considering whether to defer network investment. This is because commercial terms can be clearly set out between the aggregator and EDB, and these might require an aggregator to provide 'firm capacity' to the EDB for a specified period (daily) to commit to deferring capital expenditure.

This could be akin to an energy supply agreement where the aggregator injects (across multiple mass-market customers) a specified minimum amount of energy, at a certain time, with penalties applied if injection doesn't occur as contracted. Under this scenario, the EDB would have greater confidence to redistribute its funding for other projects on its network, underwritten by the firm capacity that the contracted flexibility provides.

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[8] We use the term 'peak' here to refer to times and areas of a network where there are constraints caused by too much demand/load. However, we note that the 'peak' for one EDB may not necessarily be the same for another. Furthermore, constraints can also be caused by export generation constraints, such as voltage issues.

[9] For example, if only 5 customers injected on average during peak times, when 100 customers were forecast to inject.

While CEL supports the overall principles of the EA's proposal, we consider there are several key issues that need to be explored before implementing. CEL would be happy to discuss any aspect of this submission further.

Yours sincerely

[redacted]

Marcus Sin
Senior Regulatory Manager

Annex – Response to questions

Questions	CEL comments
Problem definition	
Q1. Do you agree with the problem definition above? Why, why not?	CEL agrees in principle with the EA's problem definition that there is merit in a distribution price signal for injection by mass market customers. However, CEL considers this should be used to signal both the value of mass-market injection to address network constraints driven by load (as a rebate), and to discourage generation export where there is limited injection capacity available on a network (as a charge). This is because, as distribution networks were traditionally designed for load, many EDBs are now facing the challenge of managing their networks to support increasing levels of distributed generation where a first mover advantage means that feeders are reaching their export capacity with just one generation connection. While CEL supports the use of suitable non-network solutions as a tool to help support this task, including mass-market DG, we consider that the challenge will be in determining the best approach to implement efficient price signals that: • are effective in influencing customer behaviour; • are reliable in managing network constraints to achieve network benefits (e.g. the deferral of capital expenditure); • maintains a EDB's ability to recover reasonable network costs; and • treats all customers fairly.
Proposed solution: Principles-based rebates	
Q2. Do you agree with these principles? Why, why not?	CEL supports the targeted approach as proposed by the EA to incentivise injection that benefits the network. However, we recommend the principles should also enable EDBs to include 'cost' pricing signals to manage network constraints caused by too much injection, at certain times of the day, or certain areas of the network. As distribution network lines were traditionally designed for load (one-way) power flows, EDBs are facing the challenge of adapting their networks to support two-way flows of power. With technology

	improving, DG is increasingly being deployed. This could mean charging a cost for injection (instead of paying a rebate) where voltage or injection-related capacity issues might occur.
Q3. Do you agree that the principles should only apply to mass-market consumers, or should they apply to larger consumers and generators also? Why, why not?	CEL agrees with the EA that the principles should only apply to mass-market consumers, and not non-standard customers. Larger DG can be better targeted through non-standard contract arrangements with EDBs, regulated by the DGPPs. This is because larger customers/DGs are often better equipped to respond to network signals. For example, larger DGs can respond more efficiently (from a single ICP) to a network congestion event, whereas mass-market DG requires the coordination across multiple ICPs to achieve similar benefits to a network (and possibly also paying an aggregator an additional service fee or margin to manage this). By applying the rebate to mass-market consumers only, this limits any potential cross-subsidies for larger customers/DGs connected on the same network.
Q4. Do you agree the principles should apply to all mass-market DG, including inflexible generation (noting that the amount of rebate provided will still be based on the benefit the DG provides)?	CEL agrees with the EA that the principles should apply to all mass-market DG, including inflexible generators. However, inflexible generators are likely to be rewarded at a lower amount (reflecting lower value) compared to flexible generators, due to the lower reliability in using an inflexible resource to manage network constraints. We consider that the EA's proposed principles should be designed in a way that enables EDBs to reflect this in their pricing methodologies.[10] There is also likely to be a requirement for DG to provide more than one flexibility product, depending on the ability of the DG to guarantee flexible supply. This is where a Distribution System Operator (DSO) model, that enables EDBs to create a 'flexibility market' and orchestrate multiple DERs to manage its network constraints, can provide benefits to consumers. However, further

[10] Note that, all things equal, 'flexible generators' should inject more often during peak times when compared to 'inflexible generators'. If paid the same $/kWh rate, this means 'flexible generators' will generally receive a higher total rebate amount when compared to 'inflexible generators'.

	work is needed to clarify the emerging role of the DSO within the distribution sector.
Q5. Do you agree with the direction of the guidance that would likely accompany the principles? Why, why not?	CEL agrees in principle with the general direction of the EA's draft guidance but considers that the guidance should allow EDBs to determine the best intervention available to them to manage network congestion and investment costs. This is because providing a rebate is only one intervention to potentially defer investment costs. We consider that EDBs should have the flexibility to consider an injection rebate against other interventions that may achieve similar outcomes, such as contracted flexibility, controlled load, TOU pricing, or flexible connections. CEL considers that a rebate may not necessarily be the best solution for all EDBs. We suggest that the pricing methodology would be the ideal place to detail the rationale behind whether a rebate may or may not be the preferred option for an EDB to manage its network constraints
Q6. Are there any additional issues with the principles where guidance would be particularly helpful?	CEL considers that it would also be helpful if the EA provided more detailed guidance and/or clarity on how it envisages EDBs will implement an injection price signal, including: • how to determine the value of the rebate – i.e. whether this should be consumption-linked (and if so, at what discount), or based on avoided network costs (e.g. the present value of deferred transformer/feeder/substation build costs); • whether the injection rate should be based on forecast or historical volumes. If based on forecast injection volumes, what elasticity estimate should be assumed to calculate injection; and • at what minimum amount would an injection price signal considered to be 'effective' in changing customer behaviour and achieving network benefits for an EDB.
Q7. Do you agree the principles should be incorporated within the Code, rather than being voluntary principles	Given the likely issues with implementation, CEL recommends for the proposed principles to be guidance only, at this stage, instead of incorporating directly into the Code. This would allow the EA to work closely with EDBs, and to leverage some of the lessons learned from previous trials using injection price signals, to develop a better understanding of likely network benefits and different use cases, and to develop a more well-informed approach.

outside the Code? Why, why not?	
Q8. Do you agree with the proposed implementation timeline for this proposal? If not, please set out your preferred timeline and explain why that is preferable.	CEL agrees in principle with the EA's proposal for the change to take effect from the start of the pricing year. However, we note that EDBs may not be able to implement in time, as many are contractually required (under the Default Distributor Agreement) to consult with retailers on any tariff structure changes several months before the start of the pricing year. Other EDBs may also require changes to their billing systems and/or require other system upgrades. As a result of this, CEL considers that 1 April 2027 would be a more appropriate timeframe to implement this change.
Q9. Do you agree the proposal strikes the right balance between encouraging price-based flexibility and contracted flexibility? Why, why not?	CEL agrees that the EA's proposal is balanced between encouraging price-based flexibility and contracted flexibility. However, as noted above, CEL considers that contracted flexibility is likely to provide an EDB with greater certainty of network benefits from which to make (or adjust) network planning investment decisions.
Q10. Do you agree the proposal will lead to relatively minor wealth transfers in the short term, and will lead to cost savings for all consumers in the longer term?	CEL supports the use of injection price signals to manage future network constraints. However, we consider that the potential for cross-subsidies is a significant risk and could result in wealth transfers, if price signalling is not effective in reducing network costs. In practice, different EDBs may experience different results. CEL considers network benefits will vary depending on individual network characteristics, such as: • network constraints and characteristics; • type of constraint (e.g. voltage issue, capacity issue); • type of DG technology used and ability to flex (e.g. solar, solar plus battery, EV battery vehicle to grid); • effectiveness of price signals to change customer behaviour (e.g. depends how retailers pass-through EDBs price structure); and • reliability of changes to network use, that in turn, changes network planning and investment.

	Therefore, CEL considers there is only likely to be long-term cost savings for all consumers over the longer term if the issues discussed in this paper are appropriately addressed.
Alternative option: Prescribed rebates	
Q11. Do you agree that more prescriptive requirements to provide rebates will be less workable than a principles-based approach, and therefore should not be preferred? Why, why not?	CEL considers that a more prescriptive approach would be less workable and more costly to implement given the individual characteristics between networks, and the constraints they face, as discussed above.
Alternative option: Consumption-linked injection tariffs	
Q12. Do you agree that a consumption-linked injection tariff would not be sufficiently targeted, and therefore should not be preferred? Why, why not?	CEL agrees with the EA's view that a consumption-linked injection tariff would not be sufficiently targeted. If this option was to be pursued, this has the risk of driving increased injection even when it does not benefit the network (and indeed may result in increased costs to the network, and consequently to the customers serviced by it). Cross-subsidies would result, and a greater level of network investment would be needed (e.g. to address voltage issues), over and above what is already required. This means that mass-market DG owners would be partially subsidised by existing customers without DG, which creates undesirable wealth transfers.
Q13. If this approach was progressed, do you think: a. injection rebates should perfectly mirror consumption charges?	As already noted above, CEL supports the EA's view that a consumption-linked injection tariff would not be accurately targeted or accurate. However, if this option is pursued, CEL does not agree that injection rebates should perfectly mirror consumption charges, for the reasons the EA has already indicated in its paper. We also do not agree that the proposed safeguards are sufficient (by itself) to allow accurate targeting of injection benefits. This is because the price elasticity of demand response is likely to be lower than injection, as demand during the day is driven by routine or

b. there are sufficient safeguards in place that would allow EDBs to avoid over-incentivising injection to the extent that it incurs additional network costs?	commercial activities, which is less 'shiftable'. Injection on the other hand is driven by excess supply (e.g. by solar) left unused by customers. Therefore, the opportunity cost of shifting demand over time versus injecting excess solar is unlikely to be the same for all customers.
Regulatory statement	
Q14. Do you agree with the objective of the proposed amendment? If not, why not?	CEL agrees in principle with the objective of the EA's proposed amendment.
Q15. Do you agree the benefits of the proposed amendment outweigh the costs?	CEL agrees that the benefits of the proposed amendments would outweigh the costs, under the EA's preferred principle-based option. This is because this option allows EDBs to decide the quantum of network benefit that an injection price signal provides against the practicalities of implementing such an option. However, if a more prescriptive option was pursued, CEL considers that the net benefit test may not be the same for all EDBs, due to: • practical challenges for some EDB to process rebates without requiring system upgrades; • complexity in identifying network constrained areas, • complexity identifying customers associated/connected to constrained areas; and • introduction of new tariffs or changing existing tariff design (e.g. new rates or new customer groups) to accurately target certain consumers that benefit.
Q16. Do you agree the proposed amendment is	CEL agrees that the proposed amendment (a principles-based option) is preferable compared to the EA's other proposed options. However, as discussed above, we recommend for the proposal to be

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preferable to the other options? If you disagree, please explain your preferred option in terms consistent with the Authority's statutory objectives in section 15 of the Electricity Industry Act 2010.	guidance only at this stage while the likely network benefits are further explored, and the implementation issues are resolved.
Proposed amendment Code drafting	
Q17. Do you have any comments on the drafting of the proposed amendment?	CEL does not have any specific comments on the drafting of the EA's proposal. However, as noted above, we consider a guidance-focused approach to be more appropriate at this stage given the complexities in implementation. However, if the EA's proposal is progressed, CEL recommends that the Code drafting considers the points that are discussed above.