Format for submissions Initiative 2A

Submitter	Lodestone Energy

Questions	Comments
Problem definition	
Q1. Do you agree with the problem definition above? Why, why not?	Yes, Lodestone Energy completely endorse the initiative to “unlock the benefits” of embedded Distributed Generation (DG) and, in particular, solar and battery storage. Distributed generation is very important to New Zealand’s energy future, including driving the price down for consumers, enabling greater network efficiency, and improving energy security. Getting the policy settings right is now critical. We applaud the Task Force, Commerce Commission and EA for these recommendations, and appreciate the opportunity to help bring them to fruition. We believe that consumers investing in rooftop solar and battery storage, consumers signing solar-sleeving PPAs and Lodestone’s solar contracts are entitled to the full economic value for the electricity delivered during the peak period and for the value of reducing or delaying future capital investments in the network. We also believe that if the full economic value of embedded DG was allocated to those who invest in, or contract for it, there would be no reason to subsidise solar. It has been proven in other countries who have chosen to provide subsidies that this has resulted in many unintended consequences. We fully support a market-based solution where the network side of the market encourages DG through specific standardized and targeted rules. It is our observation that the only reason consumers are unable to realise the full economic value of solar, storage and solar PPAs is the absence of a set of specifically structured rules for distribution companies and energy retailers. Where we may disagree is on the level of complexity. Lodestone’s collective experience in energy retailing, generation development and signing solar PPAs, has taught us that seeking the simplest solution will likely produce the best outcome. Our submission encourages the Task Force to embrace a specific solution (described later in the submission) as we believe it can be more easily implemented by distribution and retail companies and will be more easily understood by consumers. We are also cognisant of the importance of maintaining the delineation between lines and retail for all the historic reasons. Our proposal works completely within the regulatory separations that exist today.

Proposed solution: principles-based rebates	
Q2. Do you agree with these principles? Why, why not?	Rebates versus Consumption Charge Modification The idea of a distribution company rebate for energy injected on-peak is workable. However, we worry about the complexity, the oversight requirements required, and the effect on current regulatory separation and believe that it fails to accomplish other objectives beyond valuing peak power production. To that end, it is our considered opinion that it is more effective to link the set of rules to two elements: a) the distribution consumption charges and b) the rules for retailers for energy pricing. We do not share the view that linking to consumption charges will over stimulate the deployment of solar and batteries. This is naturally constrained by the physical limitations of suitable sites. We also believe that connection charges, that require incremental investment to be paid by a DG participant, will provide natural limits to the tendency to over build. (We will cover this point in more detail in our submission on DGPPs – due 3 April.) We also hold the view that embedded generation, such as solar farms with battery storage, will also be a major part of the long-term solution. However, due to the scale of these investments the need to be able to be built outside of distribution consumption charges and we propose a simple solution for these forms of energy as a separate matter in this submission. A consumption charge solution, based on time of use (TOU), will provide more benefits than just providing value to peak power production. We believe the total list of the signals needed are: 1) Distribution companies should include both demand side and supply side measures that offset escalating demand and increasing pressure to build more capacity within the network and upstream within Transpower; 2) Consumers should have access to a distribution price signal that rewards demand side reductions during peak periods. The solution should reward demand side equally to supply side; 3) EV owners do not have a strong disincentive that penalises discretionary charging during peak periods; 4) Long-term symmetry in pricing is important: exported peak energy production/generation should always receive the same value as the cost of peak consumption; and 5) Transpower should be part of the solution. They need to know that distribution companies are doing everything reasonably possible to control the growth in capacity in the transmission system and should pass through similar TOU pricing incentives in their pricing model. A simple solution is available that addresses all five of these concerns that can easily fit within the current billing systems, distribution charge structures and retail offers.

International experience shows that electricity users with consumption-based TOU pricing will all benefit, with most of the savings coming from pure reductions in volume as well as reductions during the peak period. Generally speaking, fixed and repeated rate differentiation is more successful than ever-changing dynamic pricing. This is presumably because consumers have learned behaviours, invest in timers and other equipment to optimise usage patterns, and they need to be very predictable to make the effort worthwhile.

For completeness, below is the summary of our proposed solution as follows:

Mandated Rules for Distribution Companies

1) For all consumers, distribution companies and Transpower must substitute fixed charges with variable distribution charges based on time of use (TOU);

   Specifically, provide variable on-peak (6 to 10 pm) charge (Peak) to all consumers (ICPs) by splitting charges into Day, Night, and Peak periods, which means a removal of fixed charges for everything except metering. In round numbers, Day and Night distribution charges should be in the order of 75% and 50% of the Peak value, respectively. This would send a clear signal indicating the value of avoiding the utilisation of peak assets. We estimate that a Peak charge that is twice as costly as a night charge will give the desired signaling to EV owners, particularly if energy has a similar differential;

2) For consumers with behind-the-meter DG, they must continue to register as a DG ICP and, to the extent they induce added cost to the distribution company, they must pay for the incremental connection cost. The distribution company will remain responsible for recovering the cost of maintaining the level of service as a 'common good' cost recovery as DG implementation grows. The value of DG is therefore deemed to be greater than the cost of adapting to DG in the network. Consumers will gain a distribution cost and nodal price benefit over time;

3) For solar DG generators (with or without batteries) that are network connected, they would pay lines charges for all periods they draw from the network, in exactly the same way a large commercial or industrial load does. For batteries, this could be a substantial cost as off-peak lines charges could be quite material. Clearly, filling a battery on peak would be highly discouraged if they were to face the peak period charge. Similarly, they would pay for all incremental connection assets and pay a connection charge in the same way a large commercial or industrial customer would. Also, in line with behind-the-meter DG, the value of network connected DG and batteries is deemed to be greater than the cost of adapting to DG in the network. Consumers will obtain immediate savings in lower network costs and receive nodal price benefits over time.

Mandated Rules for Retail Energy Companies

1) Mandate that all consumers are entitled to receive separated billing disclosure (volume and price) for each of the day, peak, and night periods;

2) Mandate a rule to 'flow through' lines charges to consumers without a markup;

	3) Allow a fixed daily charge for retail services and metering services only (in keeping with flow through of lines charges); 4) For designated DG ICPs, retailers must transparently provide time-of-use energy charges and guarantee that the export value of energy fed into the grid is perfectly symmetrical with the price of consumed energy in the period of exporting (day exports receive the day price, and so on); 5) The competitive market will ensure that DG ICPs choose a retailer that prices the best outcome. This consumption-based model is recommended over a rebate regime because: 1) It keeps a clear separation between retail and lines and remains in synch with historical accountabilities and billing relationships. Distribution companies do not need to be involved in the energy settlement activity in the market; 2) Allows non-DG consumers to carry on with their existing retailer without any disruption. However, it will likely trigger a comprehensive re-assessment of which retailers will provide the most attractive offers for DG consumers, leading to a positive churn event; 3) It allows competition between retailers to continue but forces them to provide symmetry with exported power; 4) Consumers can save money if they shift peak demand; 5) Provides the DG ICP a path to full economic value without changing the market mechanisms and dynamics. It enables competition between retailers to specialise in DG ICPs and forces large gentailers to compete with the best alternative; 6) Revenue requirements for network companies will be managed by adjusting weighting between periods and will receive positive offsets from new loads off-peak such as EVs.
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?	We think the principles should be applied to every type of consumer and both behind-the-meter DG and network connected DG. Large network connected generators, such as a large solar farm, already must pay for their incremental connection assets; or, if a network chooses, be subject to an additional charge for the amortisation of those assets. Any special negotiations around battery capacity, such as handing over dispatch rights, would be above and beyond the general rules. For network connected generators who wish to be retailers and sell solar PPAs, they should be exempt from following the billing structure stipulated for mass market consumers as the form and substance of such a contract is more like a PPA and likely to be over a long term. It is expected that fundamentals, such as flowing through lines charges, would be included in the PPA.

	The general theme of this proposal is equality and non-discrimination. All generation that delivers energy on-peak will be encouraged and costs to connect any network participant, whether a load or a generator, will receive equal treatment and cost. As long as behind-the-meter DG or embedded DG generators pay for incremental connection costs, then consumers will be receiving a positive gain from all forms of DG. The risk of over-building is limited by the limits to viable sites, the overall retail price competition in the market, and incremental costs to connect. These natural governors, along with the incentive to put in battery storage, will avoid over-cooking the solar provision that has occurred in jurisdictions with government subsidies.
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)?	YES. To the extent that a solar installation without batteries exports energy during the peak period, there should be no difference as the metered values tell the story. This will mean a system without batteries will unlikely obtain much benefit from avoiding a peak charge or exporting during high priced periods.
Q5. Do you agree with the direction of the guidance that would likely accompany the principles? Why, why not?	Mandating these rules is necessary as lines companies and retailers will, as history has shown, not responded voluntarily. It is also important to note that it is unlikely that any participant will be economically harmed by these actions.
Q6. Are there any additional issues with the principles where guidance would be particularly helpful?	We fully support the steps the EA is taking on the Level Playing Field measures, specifically option 1, where generators sell to retailers on the same terms as they sell to themselves, as it will leave the integrity of the market intact and improve transparency and fairness. This will allow DG operators a fertile market where customers are not biased towards choosing a gentailer. It will also eliminate predatory pricing which may stop a DG from competing directly. With respect to the suggestions we have made on connection charges, these measures should be superior in rank to other pricing methodologies that already exist, including discretionary pricing rules and TPM. This should become a specific carve out that does not get confused with Part 6 or any methodologies that effect historic generators on the Transpower system. We have quite serious concerns with the TPM in relation to promoting DG in the Transpower network and potentially distribution networks to the extent that the TPM allocation flows through. We think the current TPM is not encouraging DG; on the contrary, it is currently discouraging the notion of responding to location signals. The benefits allocation most likely negates any location signaling from nodal pricing.

	TPM specifically states its intention to stimulate DG, but we have not observed a scenario where it does; on the contrary, it is a deterrent. To facilitate distributed generation across the Transpower network, TPM needs to incorporate a similar simple solution with straight forward cost reflective connection charges and incremental costs paid by the generator. New generation that chooses a location in response to nodal price signals will improve the network stability and reduce system losses. Benefit allocation methodologies, that apportion historic transmission expenditure, do not make sense as generation addition is a net positive benefit, and consumers will receive 100% of the benefit of lower line losses and reduced infrastructure spend. With gas shortages looking permanent, eliminating barriers to solar and batteries, both behind-the-meter and from embedded solar farms, is critical. Level Playing Field separation, enabling peak period futures contracts, amending TPM, and adopting TOU pricing at a distribution level will maximise the quantum and speed of delivery for DG.
Q7. Do you agree the principles should be incorporated within the Code, rather than being voluntary principles outside the Code? Why, why not?	Yes, they should be incorporated and be covered by the Code. It should incorporate past and future DG installations and incorporate all DG connected to network assets.
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.	We think it can be immediately. We agree with the Code amendment coming into effect on 1 April 2026 to align with the start of the 2026–2027 pricing year for distributors.
Q9. Do you agree the proposal strikes the right balance between encouraging price-based flexibility and contracted flexibility? Why, why not?	Our proposal would allow for many commercial approaches within the core structure. We do not believe lines companies should be required to participate in the energy side of the market beyond sending a simple variable price signal for day, night, and peak periods. This is all that is needed to give DG peak capacity a value for its investment. The retailer side of the market, if forced to pay full value for the energy exported, will be kept honest and reflect the true value of energy. (Other important level playing field regulations, such as forcing gentailers to transparently provide equal access to internal transfer priced hedges to independent retailers, would make this aspect more competitively derived.)

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?	Whenever a rebate or allocation of TOU costs occurs, there is a wealth transfer of some kind. We think either proposal will have a minor effect in this regard. However, for our proposal, all consumers can avoid the peak period in some way to save money, as all consumers have equal opportunity to shift load and reduce their power bills. We acknowledge that consumers that ignore the price signals are the ones likely to pay more than in the past. A positive outcome is we expect retailers will make it their business to help low-income users save money. We also acknowledge that users that use a lot of peak power may pay a higher average c/kWh, and owners of EVs will likely pay more in absolute volume terms. Lower night-time prices might induce more night-time consumption, in the form of space heating during cold periods, but the health benefits of doing so may outweigh the added costs, particularly in low socio-economic categories where night-time has become a commonly cold experience. We also expect a reduction in consumers' bills purely from EV volumes being added and costs of network expansions reducing over time. On day one, the networks have the opportunity to become revenue neutral with all existing DG including in the allocation to TOU. The general outcome to reduce national peak demand will be a shared economic benefit across all socio-economic categories.
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?	We think our proposal is more workable than a two-way tariff regime. Our proposal is very close to existing mechanisms and could be implemented sooner with less investment in IT and less disruption to lines companies.
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?	No, we recommend a consumption linked tariff, as described. It works within the current separation of lines and retail, is simpler to implement and has additional benefits as we described in this submission.

Q13. If this approach was progressed, do you think: a) injection rebates should perfectly mirror consumption charges? b) there are sufficient safeguards in place that would allow distributors to avoid over-incentivising injection to the extent that it incurs additional network costs?	Our view is: Keep it simple. Let posted distribution prices and retailer compliance and transparency drive the behaviour. A simple variable TOU structure supported with mandating peak energy symmetry, between consumed energy and exported energy, will provide the result expected. Over incentivising is not a concern given the natural limitations described earlier.
Regulatory statement	
Q14. Do you agree with the objective of the proposed amendment? If not, why not?	Yes
Q15. Do you agree the benefits of the proposed amendment outweigh the costs?	Definitely. With a simple approach as we suggest in our submission, we would assess the benefits to far outweigh the costs.
Q16. Do you agree the proposed amendment is 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.	Our submission is based on the basic idea that distribution companies will be mandated to provide TOU pricing structures and retailers will be obliged to transparently pass these through to consumers and provide symmetrical prices between consumption and exporting in day, night, and peak periods. It is our understanding that this would fit with the regulatory statement.
Proposed amendment Code drafting	
Q17. Do you have any comments on the drafting of the proposed amendment?	No.