Fonterra submission on Measures for Transition to an Expanded and Highly Renewable Electricity System

November 2023

Fonterra welcomes the opportunity to comment on the discussion document 'Measures for Transition to an Expanded and Highly Renewable Electricity System' that forms part of the engagement on the New Zealand Energy Strategy.

As a major electricity user, we trust that the commentary we put forward in this submission is a constructive contribution to help ensure New Zealand's electricity system can continue to provide affordable and secure energy as the country transitions to a low emissions economy.

Fonterra is a dairy co-operative owned by around 8,300 New Zealand farming families with 28 manufacturing sites across the country, making us the country's largest exporter and a major supplier of dairy products to the domestic market. The ultimate strength of the NZ dairy sector is the ability of our farmers to innovate and adapt to change. Our farmers lead the world by producing the highest quality milk, quickly adopting technological advances, and increasingly enhancing and protecting the environment and land. A healthy environment is the foundation for a strong economy and a sustainable dairy industry.

We strongly value the fact that, due to our pastoral production model and efficient manufacturing and supply chain, we can deliver dairy products to the market with a world leading low-carbon footprint. Fonterra is committed to achieve net-zero emissions by 2050 for our operations.

We recently announced that we are lifting our scope one and two emissions reduction targets and accelerating our industrial decarbonisation plans, from a 30 percent absolute reduction by 2030 to a 50 percent absolute reduction (compared to FY18 levels). This means we are bringing forward several significant coal decarbonisation projects and we remain committed to ending the use of coal by 2037, in line with the Climate Change Commissions' recommended pathway.

Fonterra believes that the electricity market is generally functioning well, but as the transition to a low emissions economy accelerates, we believe change will be necessary to ensure a continued supply of reliable and affordable electricity.

Primary amongst the measures we recommend is a robust framework for incentivising Demand Response. Large industrial energy users, including Fonterra, are accelerating the adoption of low emissions technologies for process heat, including an increasing move towards electrification. There is a window of opportunity in the coming years to make investment decisions that will both enable businesses to invest in technologies that support their own energy security, and support the wider security of supply for New Zealand's electricity market, through Demand Response.

We believe that putting in place a framework that includes incentives for major industrial users to receive fair compensation for providing Demand Response into the price stack of the wholesale electricity market would be a significant influencer on upcoming investment decisions and help future proof New Zealand's electricity

market. Demand Response could also form a key component of a package of measures to respond to New Zealand's dry year problem.

Other issues in the electricity market also warrant consideration:

- Lowering existing resource consent hurdles for new generation and looking closer at consent sitting of existing consents;
- Addressing first mover disadvantage on transmission upgrades;
- The transparency of pricing within major gentailers;
- Better visibility for the System Operator of factors influencing supply and demand.

We discuss these issues and others in more detail below and are happy to provide further information or engage in discussion with officials if requested.

	Question	Fonterra's comment
1	Are any extra measures needed to support new renewable generation during the transition? Please keep in mind existing investment incentives through the energy-only market and the ETS, and also available risk management products. Any new measures should add to (and not undermine or distort) investment that could occur without the measures.	Fonterra believes there is sufficient interest in new renewable generation projects. Our experience in our engagements and via the Major Electricity Users' Group (MEUG) Power Purchase Agreements (PPAs) project is that this interest will enable PPAs to be concluded and thereby underwrite developments. However, resource consent hurdles need to be lowered, including the ability to install larger equipment due to changes in technology. We also believe there is merit in considering the risk of consent sitting by large generators, particularly in favourable development locations that might otherwise be pursued by new entrants in the market. The concept of consent sitting has been dismissed by several incumbent market participants, but there is evidence suggesting it remains an issue. In particular, the length of some existing consents, coupled with elevated spot market prices, point to a market dynamic where incumbents are preferring to receive higher revenues for their existing plant, rather than invest in sufficient new generation ahead of expected demand.
2	If you think extra measures are needed to support renewable generation, which ones should the government prioritise developing and where and when should they be used? What are the issues and risks that should be considered in relation to such measures?	We believe the Government should prioritise measures to reduce consent barriers and disincentivise consent sitting.
3	If you don't think further measures are needed now to support new renewable generation, are there any situations which might change your mind? When and why might this be?	There is merit in considering what the societal wide benefits might be generated from developing offshore wind capacity in comparison with the costs, and whether policy or other invention is warranted.

4	Do you think measures could be needed to support new firming/dispatchable capacity (resources reliably available when called on to generate)? If yes, which kind of measures? What needs do you think those measures could meet and why?	The role of Demand Response and potential to incentivise electricity users to participate as firming capacity could be considered. This should be considered as part of a package that could be an alternative to the Lake Onslow project to address the dry year risk, as part of the New Zealand Battery Project. We do not believe a capacity market would be a viable or beneficial alternative as this would spread costs across all market participants for an asset with low utilisation that is unlikely to support overall economic returns to New Zealand.
5	Are any measures needed to support storage (such as battery energy storage systems or BESS) during the transition? If yes, what types of measures do you think should be considered and why?	We believe consideration should be given to a new ultra-fast reserves class for participants that can respond within a cycle. In overseas jurisdictions, the deployment of utility scale batteries has been shown to successfully catch disturbances in the grid by both injecting and removing energy as the frequency bounces.
6	If you answered yes to question 4 or 5 above, should the support be limited to renewable generation and renewable storage technologies only or made available across a range of other technologies? Keep in mind that fossil fuels are generally the cheapest option for firming, though this may change over time as renewable options (particularly batteries) become more efficient and affordable.	N/A
7	If you answered yes to question 6 above, what are the issues and risks with this approach? How could these risks and issues be addressed?	N/A
8	Are any measure(s) needed to support existing or new fossil gas fired peaking generation, so as to help keep consumer prices affordable and support new renewable investment?	We do not recommend any measures as there is sufficient revenue generation opportunity for these market participants.
9	If you answered yes to question 8 above, what measures should be considered and why? What are the possible risks and issues with these measures?	N/A
10	If you answered yes to question 8 above, what rules would be needed so that fossil gas generation remains in the electricity market only as long as needed for the transition, as part of phase down of fossil gas?	N/A
11	Are there any issues or potential issues relating to gas supply availability during electricity system transition that you would like to comment on?	There appears to be limited gas availability, apart from bilateral swaps, out to 2030. This means there is unlikely to be new gas peaking plant built.

12	Do you agree that specific measures could be needed to support the managed phasedown of existing fossil fuel plants, for security of supply during the transition?	Yes. History has shown that as thermal generation leaves the market, the remaining marginal thermal generation is concentrated to set the price which also flows through to the water value for hydro generation.
13	If you answered yes to question 12 above, what measures do you think could be appropriate and why? What conditions do think you should be placed on plant operation? For example, do you have any views on whether there should be a minimum notice period for reductions in plant capacity, and/or for placing older fossil fuel plant in a strategic reserve?	Just as the Electricity Authority requires information on thermal fuel risks, we believe the Electricity Authority should require the declaration of planned thermal retirement dates.
14	If you answered yes to question 12 above, what are the issues and risks with these measures and how do you think these could be addressed?	The market has been informed of Rankine retirement dates previously which have come and gone with the units still in operation.
15	What types of commercial arrangements for demand response are you aware of that are working well to support industrial demand response?	It appears that there are only limited bilateral agreements occurring between end users and retailers that incorporate Demand Response. The issue with this arrangement is it removes all visibility of the demand response to the system operator and therefore introduces increased volatility to the price stack on the demand side. We believe there are more effective ways to incentivise Demand Response.
16	What new measures could be developed to encourage large industrial users, distributors and/or retailers to support large-scale flexibility?	As a starting point, participants that bid Demand Response into the market should be paid the final price for that trading period on the volume of Demand Response dispatched. Taking this approach will mean major electricity users can justify investments that will enable Demand Response participation. This is a major lever that could be pulled for maintaining security of supply and stability of pricing as New Zealand transitions to a low emissions future. Investments will not be made by major electricity users to enable meaningful participation in Demand Response unless there is a sufficient commercial justification for doing so. Fonterra is currently making major investment decisions about the future energy needs and associated plant at sites across New Zealand. In some cases, there may be justification for investing in multiple boiler types of varying capacity, such as biomass and electrode, that could then enable meaningful participant in Demand Response in the future. But without clear incentives in place, there is no justification for investing beyond the specified requirements at the site. Having a properly functioning Demand Response market in place, whereby participants are paid the final price for the trading period on the volume of Demand Response

		dispatched, would enable investment decisions that can support the wider security of supply for the electricity market.
17	Do you have any views on additional mechanisms that could be developed to provide more information and certainty to industry participants?	There should be a way that bilateral Demand Response agreements can be cleared through the spot market to ensure price visibility to the System Operator.
18	Do you agree that the key competition issue in the electricity market is the prospect of increased market concentration in flexible generation, as the role of fossil fuel generation reduces over time?	Yes.
19	Aside from increased market concentration of flexible generation, what other competition issues should be considered and why?	There should be consideration of increased market monitoring of thermal service removal. The Electricity Authority and System Operator also need increased visibility on negotiations of thermal fuel contracts.
20	What extra measures should or could be used to know whether the wholesale electricity market reflects workable competition, and if necessary, to identify solutions?	Monitoring by the Electricity Authority for unusual offer practices needs to be increased. It appears that all risk is being priced into the market with no risk being held by the four main generators. This is illustrated by the long-dated hedges that do not show any alignment to Long Run Marginal Cost (LRMC), even though hydrology is not known three years out.
21	Should structural changes be looked at now to address competition issues, in case they are needed with urgency if conduct measures prove inadequate?	The persistent gap between the LRMC and the ASX prices since 2018 shows that the generators are pricing all risk into the market and this should be looked at. The internal reporting by some generators themselves shows transfers occurring at a fair value but the reporting should also add the requirement to report on retail profitability i.e. revenue from sales minus cost to purchase electricity at the internal transfer price. This would then require the vertically integrated retailers to financially report in a similar manner as non vertically integrated retailers.
22	Is there a case for either vertical separation measures (generation from retail) or horizontal market separation measures (amending the geographic footprint of any gentailer) and, if so, what is this?	There is a case for considering further vertical separation measures. Several large gentailers are showing revenue from retail operations and associated supply costs that result in their retail businesses losing significant money, but they are still very profitable when their generation revenues are taken into account (e.g. generating at LRMC which can be as low as $15/MWh and selling to retail sector at $100/MWh). This is in comparison to the independent retailers that must pass all electricity procurement costs on to their customers via their tariffs and do not have the ability to offset losses with profits from generation. There is not a case for any horizontal separation.
23	Are measures needed to improve liquidity in contract markets and/or to	N/A

	limit generator market power being used in retail markets? If yes, what measures do you have in mind, and what would be the costs and benefits?	
24	Should an access pricing regime be looked at more closely to improve retail competition (beyond the flexibility access code proposed by the Market Development Advisory Group or MDAG)?	N/A
25	What extra measures around electricity market competition, if any, do you think the government should explore or develop?	The Electricity Authority could consider requiring a metric on the volume of retail electricity purchases from generation not owned by the parent company.
26	Do you think a single buyer model for the wholesale electricity market should be looked at further? If so, why? If not, why not?	No.
27	Do you consider that the balance of risks between investing too late and too early in electricity transmission may have changed, compared to historically? If so, why?	Yes. Transpower should take on more risk, starting with conducting upfront design when first approached, then matching consenting when new generation is consented but not constructed, then constructing once contracted. There still needs to be further work to eliminate first mover disadvantage. We still have situations where the EDB is not going to trigger a Transpower spend as they know another party might trigger the spend and therefore fund it. There needs to be a way that no matter who triggers the spend any future load will then cover the capital recovery proportionally.
28	Are there any additional actions needed to ensure enough focus and investment on maintaining a resilient national grid?	As we increase dependency on electrification, the need for resilience increases. For example, two circuits on two separate transmissions lines running side by side might technically be N-1, but if they are both exposed to the same natural hazard potential then they are not fully N-1.
29	Do you agree we have identified the biggest issues with existing regulation of electricity distribution networks?	EDBs should be required to show non-distribution solutions have been considered to defer or avoid investments in new assets, just as Transpower is required.
30	Are there pressing issues related to the electricity distribution system where you think new measures should be looked at, aside from those highlighted in this document? How would you prioritise resolving these issues to best enable the energy transition?	Some EDBs are still not driving towards the best solution for all stakeholders. In some cases, they are delaying distribution upgrades/spend knowing that another party might trigger the upgrade and therefore fund fully it, allowing the EDB to avoid spending themselves.
31	Are the issues raised by electricity distributors in terms of how they are regulated real barriers to efficient network investment? Please give reasons for your answer. Is there enough scope to address these issues with the current ways distributors are	Yes. The issues raised are barriers to efficient network investment and unfortunately the work underway as laid out in the paper does not have clear linkage to the issues. For example, there needs to be clarity as to whether regulatory incentives to encourage non-capital solutions

	regulated? If not, what steps would you suggest to address these issues?	should be for the Commerce Commission or the Electricity Authority to resolve. There also needs to be more clarity on who is driving the EDBs towards the grid of the future at the lowest cost to customers.
32	Are there other regulatory or practical barriers to efficient network investment by electricity distributors that should be thought about for the future?	N/A
33	What are your views on the connection costs electricity distributors charge for accessing their networks? Are connection costs unnecessarily high and not reflective of underlying costs, or not? If they are, why do you think this is occurring?	The costs are high and unclear as there is no regulatory requirement to show cost breakdowns. The EDBs should also be required to provide network load information and asset utilisation in a GIS format that is open to all.
34	If you think there are issues with the cost of connecting to distribution networks, how can government deliver solutions to these issues?	There needs to be regulatory change to allow competition in the supply of EDB upgrade vendors. For example, a customer requesting an upgrade should be able to contract any qualified party to build the upgrade to the EDBs design requirements, if paid by the customer.
35	Would applying the pricing principles in Part 6 of the Code to new load connections help with any connection challenges faced by public EV chargers and process heat customers? Are there other approaches that could be better?	Yes, this would help standardise the process across the country.
36	Are there any challenges with connecting distributed generation (rather than load customers) to distribution networks?	N/A
37	Are there different cost allocation models addressing first mover disadvantage (when connecting to distribution networks) which the Electricity Authority should explore, potentially in conjunction with the Commerce Commission?	Options should be considered for eliminating the first mover disadvantage. Where the size of a connection upgrade is at the request of the end user, who is providing the capital, the EDB should not be able to require it be oversized unless the end user is fully compensated. If future spare capacity is installed, the first mover should have the right to retain that spare capacity for future use or sell it back to the EDB at its relative value and therefore other parties will pay for its cost.
38	Should the Electricity Authority look at more prescriptive regulation of electricity distributors' pricing? What key things would need to be looked at and included in more prescriptive pricing regulation?	Yes, there needs to be standardisation across all EDBs.
39	Do current arrangements support enough co-ordination between the Electricity Authority and the Commerce Commission when regulating electricity distributors? If not, what actions do you think should	No, there is still no clear drivers in the Commerce Commission's regulatory oversight to ensure that EDB pricing is efficient at driving to the grid of the future, specifically around priority on non-capital solutions and fairness to all users across New Zealand.

	be taken to provide appropriate co-ordination?	
40	Will the existing statutory objectives of the Electricity Authority and Commerce Commission adequately support key objectives for the energy transition?	No.
41	Should the Electricity Authority and/or the Commerce Commission have explicit objectives relating to emissions reduction targets and plans set out in law? If so, • should those objectives be required to have equal weight to their existing objectives set in law? Why and how might those objectives affect the regulators' activities?	N/A
42	Should the Electricity Authority and/or the Commerce Commission have other new objectives set out in law and, if so, which and why?	NA
43	Is there a case for central government to direct the Commerce Commission, when dealing with Electricity Distributors and Transpower, to take account of climate change objectives by amending the Commerce Act and/or through a Government Policy Statement (GPS)?	N/A
44	If you answered yes to question 43, please explain why and indicate: • What measures should be used to provide direction to the Commerce Commission and what specific issues should be addressed? • How would investment in electricity networks be impacted by a direction requiring more explicit consideration of climate change objectives? Please provide evidence.	N/A
45	Would government setting out the future structure of a common digital energy infrastructure (to allow trading of distributed flexibility) support co-ordinated action to increase use of distributed flexibility?	Yes, through the System Operator.
46	Should central government see how demonstrations and innovation to help inform how trade of flexibility evolves in the New Zealand context, before providing direction to support trade of distributed flexibility? If yes, how else could government support the sector to collaborate and invest in digitalisation now?	N/A
47	Aside from work already underway, are there other areas where government should support	The Government should support a whole of system approach, including how to get retailers that are contracting Demand Response directly to provide that visibility to the

	collaboration to help grow and develop flexibility markets and improve outcomes? If yes, what areas and actions are a priority?	system operator to ensure that the market dispatches for the lowest cost.
48	Could co-funding for procurement of non-network services help address barriers to uptake of non-network solutions (NNS) by electricity distributors?	EDBs need to be regulated to consider NNS at all times.
49	Would measures to maximise existing distribution network use and provide system reliability (such as dynamic operating envelopes) help in New Zealand? If yes, what actions should be taken to support this?	Yes, there are significant capital assets that are built for very low maximum utilisation. A metric that should be tracked is 24hr average load versus installed capacity gap and there should be regulatory drive to get that down to 10%. One way is for TOU distribution charging equal to the utilisation if successful in achieving load flattening the costs would approached that of a flat daily charge.
50	What do you think of the approaches to smart device standards and cyber security outlined in this document? Are there other issues or options that should be looked at?	N/A
51	Do you think government should provide innovation funding for automated device registration? If not, what would best ensure smart devices are made visible?	N/A
52	Are extra measures needed to grow use of retail tariffs that reward flexibility, so as to support investment in CER and improved consumer choice and affordability?	By allowing Demand Response participants, including aggregators, to bid into the System Operator market and be compensated at the final trading period price. This will generate the financial return to allow for capital spend either at the large scale or at the small scale but distributed e.g. smart residential load control. There needs to be a way to encourage multiple parties to compete for demand response and eliminate the current monopoly EDBs have via ripple control on hot water without compensating the end consumer.
53	Should the government consider ways to create more investment certainty for local battery storage? If so, what technology should be looked at for this?	Yes, solar and battery technologies deployed at any scale will provide multiple benefits, including distributed solar and battery technologies at a residential level. Encouraging the accelerated adoption of these technologies will provide resilience, potentially add to security of supply and could even be part of an alternative solution to the Lake Onslow project. This likely requires regulated price floors for residential export of electricity that aligns to the long run daytime ASX
54	Should further thought be given to making upfront money accessible to all household types, at all income levels, for household battery storage or other types of CER?	Yes, these technologies could have multiple benefits. There is significant value to the overall market in getting new generation into the market efficiently, by for example demand shifting via charging EV batteries at night to eliminate morning peak demand and then charging off solar and grid during day to eliminate evening peak. This also

		adds resilience as more houses have back up power in outages.
55	Should government think about ways to reduce 'soft costs' (like the cost of regulations, sourcing products, and upskilling supplier staff) for installing local battery storage with solar and other forms of CER/DER storage? If so, what technology should be looked at?	N/A
56	Is a regulatory review of critical data availability needed? If so, what issues should be looked at in the review?	N/A
57	What measures do you consider the government should prioritise to support the transition?	We recommend prioritising these measures: • Demand Response should be prioritised. This can be achieved by treating Demand Response offers similarly as generation offers and paying them at the final price; • Smart technology/appliances that assist with moving demand or being price responsive; • Significant solar and battery installation in residential housing, with default settings that aim to eliminate morning and evening demand; • A mechanism for existing hydro generation owners to be compensated to operate as batteries and minimise solar and wind spill; • The HVDC link that can move electricity between islands at scale and not be the weak link setting reserve prices in the North Island. • The system operator to have full visibility of all generation and demand anticipated responses to ensure the optimised price solution for lowest cost.
58	Are there gaps in terms of information co-ordination or direction for decision-making as we transition towards an expanded and more highly renewable electricity system and meeting our emissions goals? Please provide examples of what you'd like to see in this area.	N/A
59	Are there significant advantages in adopting a REZ model, or a central planning model (like the NSW EnergyCo), to coordinate electricity transmission investment in New Zealand? Would a REZ model for local electricity distribution be an effective means of addressing first mover disadvantage with connecting to electricity distribution networks?	N/A
60	Should MBIE regularly publish opportunities for generation investment to enable informed market decision-making?	N/A

61	How should the government balance the aims of sustainability, reliability and affordability as we transition to a renewable electricity system?	N/A
62	To what extent should wholesale, transmission, distribution or retail electricity pricing be influenced by objectives beyond the (affordability-related) efficiencies achieved by cost reflective pricing, such as sustainability, or equity?	N/A
63	Are the current objectives for the system's regulators set in law (generally focusing on economic efficiency) appropriate, or should these also include more focussed objectives of equity and/or affordability?	N/A