Better together.

Trustpower Limited

Head Office
108 Durham Street
Tauranga

Postal Address:
Private Bag 12023
Tauranga Mail Centre
Tauranga 3143

F 0800 32 93 02

Offices in
Auckland
Wellington
Christchurch
Oamaru

Freephone
0800 87 87 87

trustpower.co.nz

9 June 2020

Energy Markets Policy
Ministry of Business, Innovation and Employment
WELLINGTON

By email: energymarkets@mbie.govt.nz

TRUSTPOWER SUBMISSION: ACCELERATING RENEWABLE ENERGY AND ENERGY EFFICIENCY

Introduction

Trustpower welcomes the opportunity to contribute to the discussion about how the Government can accelerate the development of renewable energy and energy efficiency.

The Ministry for Business, Innovation and Employment (**MBIE's**) Accelerating Renewable Energy and Energy Efficiency Discussion Document (**the Discussion Document**) explores the policy and regulatory settings which would best support New Zealand's journey towards becoming a net zero carbon economy by 2050, through accelerating renewable electricity and lowering emissions from process heat.

We understand the policy options presented in the Discussion Document are intended to complement the New Zealand Emissions Trading Scheme (**NZ-ETS**) and work alongside other initiatives in the Government's Renewable Energy Strategy.

Trustpower agrees with MBIE that the NZ-ETS should be the key mechanism for reducing emissions. The Government is currently progressing legislative reforms to restructure the NZ-ETS, along with changes to the settings of the scheme (including unit supply and price controls). These changes will better align the price signal from the NZ-ETS with emissions targets and provide greater forward price certainty for investors. We support this work as it aligns with our view that during the transition to a low emissions economy there should be "*as much market as possible*".

We acknowledge that meeting the Government's decarbonisation objective will require a significant programme of change. It is however possible that market or regulatory failures may mean that:

a) emissions pricing is not sufficient to drive the changes that are sought within the required timeframes; or

b) abrupt change could lead to distributional concerns and/or system security issues.

As a result, we also agree that supplementary policy/regulatory measures may be needed to promote a fair and efficient transition[1]. These measures will also mitigate against the risk that delays in market responses mean New Zealand either misses its decarbonisation goals or achieves them at excessive cost.

[1] We also note that this aligns with the advice of the Interim Climate Change Committee.

We strongly support the Government seeking to ensure the policy/regulatory measures intended to guide the energy transition achieve an appropriate energy trilemma balance.

Our background

Since 1994, Trustpower has evolved from a regional vertically integrated electricity business operating in the Tauranga district to a leading nationwide multi-product retailer with a strong history of making significant investments in renewable generation in both New Zealand and Australia.

Currently Trustpower owns and operates 19 hydroelectric generation schemes (comprising 38 hydro power stations) in New Zealand. Previously, it has owned other renewable generation assets in New Zealand (wind farms Tararua Stage I, II , and III, Mahinerangi Stage I schemes) as well as Australia (Snowtown Wind Farm Stages I and II, Blayney and Crookwell wind farms; and the Hume, Burrinjuck and Keepit hydrogeneration assets).

We look forward to continuing to invest in the sector during the energy transition.

Summary of our views

The Discussion Document contains a clear statement of the problems which are sought to be addressed. Therefore, our focus in responding to the Discussion Document has been on the options which we think will best achieve the Government's overarching objectives.

The areas that will have the biggest impact on emissions reduction are process heat conversion, increased energy productivity and uptake of renewable fuels in industrial processes. The Government should prioritise reform in these areas.

More specifically, we support early action on:

a) publication of energy transition plans from the largest energy users in a standardised format to reduce compliance costs;

b) information packages re-electrifying process heat;

c) targeted financial support via Energy Efficiency and Conservation Authority (**EECA**) grants for nascent low emission technologies;

d) co-funding heating feasibility studies;

e) benchmarking information for food processing industries; and

f) the introduction of a levy on coal use to align with electricity and gas levies.

This would leave open the opportunity for further action on matters such as ban on new low and medium temperature heat coal fired process heat equipment (**PHE**) if no change in behaviour is observable over the next 2-3 years. This could be signalled now in the form of draft regulations.

We note that the electricity sector has an established track record of delivering new generation under the current market platform: 14,000 GWh of generation investment (enough energy to power ~2 million residential ICPs) has been commissioned since 2000.

This suggests major reform to the market structures is not required to increase the uptake of new technologies or facilitate capital deployment. In fact, major reform would likely deter investment.

However, we consider that new renewable generation investment and network investment would benefit from more robust Resource Management Act (**RMA**) reform, strengthening of the National Policy Statement (**NPS**): Renewable Electricity Generation (**NPS:REG**) and more clarity about network access and cost allocation. These matters would also assist with ensuring the continued availability of existing renewable generation.

Likewise, we agree that New Zealand is yet to fully realise the potential of demand side participation, and consider that there would be value in a multi-agency work programme being established to further explore options for encouraging greater levels of demand side participation and demand response.

Finally, we support initiatives to facilitate Power Purchase Agreements (**PPAs**) and assist community organisations and Small-Medium Enterprises (**SMEs**) participate in the electrification journey provided these are facilitated in a way that ensures net benefits arise and that private sector investment at scale is not crowded out.

We have set out our more detailed responses to the Discussion Document in the Appendix to this letter.

However, for convenience a comprehensive list of the policy options we support the Government progressing are set out in the following table.

Trustpower supports the Government:

Recommendation 1:	Introducing a requirement for large energy users to prepare and publish Corporate Energy Transition Plans, in a standardised format to reduce compliance costs, and conduct energy audits which should be considered by Boards.
Recommendation 2:	Developing an electrification information package for businesses looking to electrify process heat, co-fund electrification feasibility studies.
Recommendation 3:	Providing benchmarking information for food processing industries.
Recommendation 4:	Facilitating development of bioenergy markets and industry clusters on a regional basis within Industry Transformation Plans, including through identifying clusters of existing process heat customers using coal boilers and considering the introduction of a model long term contract.
Recommendation 5:	Developing a users' guide on application of the National Environmental Standards for Air Quality to wood energy.
Recommendation 6:	Providing targeted financial assistance via EECA grants for nascent low emissions technologies.
Recommendation 7:	Collaborating with EIHI industries to foster knowledge sharing, develop sectoral low-cabon roadmaps and build capability for the future using a Just Transitions approach.
Recommendation 8:	Requiring existing coal-fired process heat equipment supplying end-use temperature requirements below 100°C to be phased out by 2030, and putting in place regulatory backstop arrangements to ban new low to medium temperature equipment if there is no discernable behavioural change within the next 2 years.
Recommendation 9:	Introducing a levy on consumers of coal to fund EECA's process heat activities.
Recommendation 10:	Strenghtening the NPS:REG to ensure local authorities give sufficient weight to the role of renewable electricty generation in the energy transition.
Recommendation 11:	Ensuring the NPS:IB and the NPS: FM support new resource consents for renewable generation and allow existing generation to retain its current operational output and flexibility.
Recommendation 12:	Scoping National Environment Standards or National Planning Standards specific to renewable energy.
Recommendation 13:	Developing a process to ensure that where new RMA instruments are created these are reviewed against existing RMA instruments to ensure consistency and to minimise provisions in conflict (for example, a Board of Inquiry could be established).
Recommendation 14:	Considering allowing renewable energy generators to apply for Requiring Authority status under the RMA, albeit with some carve outs and minor changes.
Recommendation 15:	Considering other potential improvements to streamline the resource consenting processes for renewable generation including:. o Introducing into the RMA a new section 6 matter covering the need to reduce the foreseeable impacts of climate change and recognising the important role of renewable energy infrastructure in achieving this; and o Enabling a Panel of External Planning experts to be established which would provide an audit function across plans to ensure a consistent implementation of national direction

instruments.

Recommendation 16: Exploring a simple, low cost enhanced facilitation arrangement that enables new small renewable generation and loads to self-match, along with the provision of information resources and training, and a standardised PPA contract.

Recommendation 17: Establishing a multi-agency work programme, led by the Electricity Authority, to explore the opportunities for encouraging greater demand side participation and demand response.

Recommendation 18: Working with EECA to ensure that on a long term basis its approach to deploying any energy efficient solutions and accelerating the replacement of inefficient products aligns with other work underway to support energy efficiency improvements.

Recommendation 19: Considering introducing additional discloure requirements about long-term hedge positions into the exisiting stress testing regime..

Recommendation 20: Introducing a new regulatory requirement for advanced provision of information on a thermal generators retirement plans.

Recommendation 21: Developing a clear and consistent Government position on community energy issues, aligned across different policies and work programmes.

Recommendation 22: Providing financial assistance for community energy pilot programmes using nascent technologies; where a key requirement for such projects is that any learnings are shared more broadly.

Recommendation 23: Working with the Commerce Commission to amend the input methodologies to enable the Commission to take into account the economic benefits of climate change mitigation in its capex approval processes.

Recommendation 24: Introducing rules providing that subsequent access-seekers must contribute to the capital costs of connection on a similar basis to that required for existing connection assets.

Recommendation 25: Developing a user guide on the current regulations and approval processes relating to getting an upgraded or new connection to the grid to assist new entrants.

Recommendation 26: Developing a Government Policy Statement that sets out how the Electricity Authority should interpret its statutory objective in the context of network pricing and how distributed generation can best be accommodated during the energy transition, as a short-term initiative.

Recommendation 27: Transferring the regulatory responsibility for TPM to the Commerce Commission, as a long-term initiative.

Recommendation 28: Considering improvements to the existing accountability frameworks as part of the recently announced review of institutional arrangements.

Guiding themes

In developing our response to the Discussion Document, we have been guided by two themes. These are the need to:

1) provide adequate regulatory certainty; and
2) ensure an aligned policy response across all Government and regulatory agencies.

We think these two themes need to be front of mind when decision makers are determining the policy/regulatory arrangements to best achieve the Government's decarbonisation objectives at the lowest possible cost to individuals and society as a whole. These themes are relevant to all the workstreams of the Renewable Energy Strategy and other interrelated priorities of the Government, including freshwater reform, overhaul of the RMA, and the electrification of the transport industry.

1. Ensuring regulatory certainty

To ensure that the necessary global capital is made available for the forthcoming energy transition, New Zealand must strive to have the best regulatory/policy settings to promote scale investment in renewable generation and the uptake of new energy technologies and least-cost abatement opportunities.

This will require a clear recognition that regulatory certainty is vital for investors making substantial, irreversible investments. Likewise, regulatory certainty is important for ensuring that consumers are provided with confidence that services will be provided reliably and that the prices they pay are reasonable.

We accept that some flexibility within the regulatory/policy settings will be required to enable adjustments as technological developments occur, new markets emerge, new business models develop, and behavioural changes take place.

We also note that achieving balance between the dimensions of the energy trilemma during the transition will likely require ongoing monitoring and potential adjustments as the sector evolves. In some cases, direct Government subsidies may be required to address affordability concerns.

The key will be ensuring any adjustments to the policy settings do not undermine long-term investment decisions. This important consideration was highlighted by the Productivity Commission in the final report for its low emissions economy inquiry[2]:

> *".. an important theme in this inquiry is that the long-term perspective must be introduced into politics and policymaking, domestically and internationally. Added to the long horizon is deep uncertainty about many aspects of the future. The combination of these two features requires political commitments and durability that spans many generations. Without durable and ambitious policies now, the signals for firms and households to move their production and consumption towards less emissions-intensive options will be weak, at best. The challenge is therefore how best to design the political and governance architecture in a way that effectively signals future policy intentions and provides a commitment to such intentions."*

2. Ensuring an aligned policy response

It is equally critical that there is alignment in the policy intent which underpins decision making by institutions (including at both a national and local Government level) on matters that impact on the delivery of the Government's decarbonisation objectives, including its Renewable Energy Strategy.

This important theme was also identified by the Productivity Commission's low emissions economy inquiry[3]:

> *"Developing the government response to the Climate Commission's recommendations to meet emissions budgets and targets will be a substantive and challenging policy process and will present major coordination issues. This will require a high level of coherence between overall policy and regulatory frameworks and low emissions goals. A key obstacle to the effectiveness and acceptability of core climate policies is the number of regulatory and policy frameworks outside the climate policy portfolio that are not aligned with the low emissions objectives. Identifying and addressing these misalignments systematically will enhance the responsiveness to the climate-change agenda. Ongoing leadership from the centre of government is critical, but it will need to be more than this. Achieving policy alignment across fragmented government machinery really means that every aspect of government policy will need to be framed with the low-emissions goal in sight."* .

Achieving alignment will require ongoing coordination between a number of institutions and active consideration of the alignment within and between the interrelated elements of each work programme comprising the Renewable Energy Strategy and other interconnected Government priorities including freshwater management reform, RMA reform, electrification of transport, along with the work of the Climate Change Commission (**CCC**).

We are pleased that MBIE has recognised the importance of ensuring policy coherence and appreciate the significant work that has been undertaken to ensure that this can be achieved via the current work

---

[2] Page 3
[3] Page 6

programme to accelerate investment in renewable electricity generation. This includes the release of Discussion Document in parallel with those changes being considered by the Ministry for Environment (**MfE**) to reform the NZ-ETS, thereby enabling submitters to form a comprehensive view on the package of reforms.

We encourage MBIE to:

a) continue working with other institutions (MfE, Electricity Authority (**the Authority**), Commerce Commission, EECA etc) that have interrelated workstreams to ensure that alignment can be achieved in practice. This should also include ongoing engagement with the newly established ICCC as they work to develop the first three emissions budgets; and

b) further consider how it can best ensure that the Government intentions are made clear and remain consistent with respect to accelerating renewable generation and energy efficiency – thereby providing much needed investor certainty.

At this time, we have identified risks of policy discordance arising in two specific areas which we wish to draw to MBIEs attention: network pricing reform and the water-energy-environment nexus. We note that the appropriate tools and arrangements for addressing these risks vary depending on the institutions involved.

Network pricing reform

In our response to the Government's recent Electricity Price Review (**EPR**), we outlined the risk that the Authority's proposed network pricing reforms adversely impact broader Government policy objectives including objectives around energy affordability, regional development and reducing carbon emissions. We continue to consider that the Authority's proposed transmission pricing reforms will put at risk the Government's decarbonisation objectives and explore this issue further in section 13 of this submission.

To achieve alignment between the Government's Renewable Energy Strategy objectives and the work underway by the Authority, we strongly support the Government, via a Government Policy Statement (**GPS**), clarifying how the Authority should interpret is statutory objective in the context of transmission pricing. We see this as an interim step while institutional changes are considered. Longer term we think it will be necessary to co-locate the regulatory functions of:

a) approving transmission investment (including investments required to facilitate decarbonisation objectives) with

b) the allocation of the costs of those investments.

Guidance from the Government would also be valuable around how it considers Distributed Generation (**DG**) can best be accommodated in the transition to a low emissions economy. The previous DG reforms by the Authority have impacted investor certainty, and the currently slated changes to remove the peak demand charge will have further impacts. This needs to be resolved in order to support ongoing investment in distributed renewable generation and other forms of distributed energy resources.

The water-energy-environment nexus

The Discussion Document recognises the importance of addressing the barriers to entry for new generation created by the current RMA and refers to the current reforms being considered by the MfE. However, more broadly we continue to observe misalignment between the various work programmes that are underway that impact on water use and hydro-generation. This includes the proposed reforms to the RMA and recent consultation on the National Policy Statement: Freshwater Management (**NPS:FM**). In its proposed form the NPS:FM has the ability to undermine the Government's decarbonisation ambitions.

We understand the focus of the Discussion Document is on new renewable generation assets, but consider it is also important to ensure that regulatory arrangements also seek to optimise the use of New Zealand's existing low-emissions generation assets.

Currently more than 70% of electricity in New Zealand is generated by renewable sources (hydroelectric generation, geothermal, wind, biosolids and solar), with hydro-generation providing a critical contribution of more than 60% of our total electricity supply.

Hydro-generation is the backbone to the New Zealand electricity generation, providing highly responsive, flexible generation that has the added benefit of being geographically dispersed. During the energy transition it will become increasing important that these existing investments can be used to their fullest extent as the electricity system has a critical role to play in decarbonising the wider energy system.

All hydro-generation schemes contribute to maintaining the security and reliability of the electricity system. Likewise, the efficient utilisation of existing low emissions generation assets will assist in ensuring the Government's energy affordability goals can be achieved.

To ensure that New Zealand can meet its carbon emissions objectives, the broader regulatory/policy settings will need to encourage both:

a) new investment in renewable electricity generation; and
b) the optimisation of the output from existing renewable electricity generation, including through preventing unnecessary limitations or requirements that reduce output.

Further information

For any questions relating to the material in this submission, please contact me on 021 953 104 or alternatively contact Fiona Wiseman, Senior Advisor – Strategy and Regulation on 027 549 9330.

Best regards,

Peter Calderwood

General Manager, Strategy and Growth

APPENDIX A: TRUSTPOWER'S RESPONSE TO THE DISCUSSION DOCUMENT

Part A: Encouraging energy efficiency and the uptake of renewable fuels in industry

1. Introduction

1.1.1. Trustpower agrees with MBIE that changing how the industrial sector uses energy will be a crucial component of our energy transition and that early action in this sector will help provide certainty for investment.

1.1.2. Our response to Part A is structured as follows:

a) In section 2 we discuss our views on how to address information failures between the industry and other stakeholders (MBIE s1);

b) In section 3 we outline our view that developing clusters for wood processing and heat plant may need pro-active, coordinated approach (MBIE s2);

c) In section 4 we present our view that there could be value in expanding EECA grants for technology diffusion and capability building (MBIE s3);

d) In section 5 we outline our views on the phase out of fossil fuels in process heat (MBIE s4);

e) In section 6 we discuss whether additional financial incentives beyond those created by the NZ-ETS is required to accelerate investment in energy efficiency and renewable energy technologies (MBIE s5); and

f) In section 7 we discuss whether a levy on consumers of coal should be introduced (MBIE s6).

1.1.3. A summary of our recommendations for Part A is provided in section 8.

2. Addressing information failures (MBIE s1)

2.1. Corporate energy transition plans

2.1.1. The size of the transformation task ahead, namely emission reductions of approximately 13 Mt CO_2e above what is currently forecast with existing policy measures[4], is massive (particularly taking into account timescales). This suggests there is a real need for individual businesses to focus immediately on their greenhouse gas emissions (**GHG**) emissions, and the options available to them to reduce emissions. Requiring large energy users to prepare and publish Corporate Energy Transition Plans (**CETP**) will assist in this process and will be an important step towards addressing New Zealand's emission reduction challenge.

[4] This assumes the Government confirms the provisional budget of 354 Mt CO_2e over 2021-2025. This budget will require New Zealand to stabilise and then reduce net emissions over this period in straight line towards the Zero Carbon Act targets. Ministry for the Environment, 2019, *Reforming the NZ Emission Trading Scheme: Proposed Settings - Consultation Document*, section 2.

Disclosure content

2.1.2. The Discussion Document proposes that large energy users report emissions and energy use annually and conduct energy audits every four years. To reduce compliance costs, we think the proposed CETP reporting should be consistent with other emission reporting requirements being considered as part of the Government's broader climate change strategy.

2.1.3. While the consultation observes that CETP and proposed mandatory ('comply or explain') Task Force on Climate-related Financial Disclosures (**TCFD**) are largely targeted at different types of business organisations with the only overlap being NZX listed issuers, we consider there may be more. Many of New Zealand's larger electricity users and GHG emitters (e.g. Pacific Aluminium, NZ Steel, Norske Skog Tasman) are subsidiaries of multinational companies and are likely to be subject to related company reporting requirements internationally.

2.1.4. This suggests New Zealand should support standardisation of reporting across jurisdictions, as well as within a sector. Standardisation will also enable benchmarking. This was acknowledged in the Discussion Document as well as in MfE and MBIE's 2019 *Climate Related financial disclosures - Understanding your business risks and opportunities related to climate change: discussion document.*

> *"Mandating reporting, using a single high-quality climate reporting framework will promote reporting that is clear, comparable and consistent and promote business certainty[5]."*

2.1.5. It was also acknowledged that mandating disclosure would encourage slow moving firms to measure emissions earlier than perhaps otherwise might be the case.

> *"A new mandatory disclosure requirement is likely to encourage the routine consideration in business and investment decisions of the effects of climate change much sooner than retaining the status quo would. Slow-moving companies will have to start preparing sooner than they would otherwise[6]."*

2.1.6. From a practical perspective, we agree the areas of overlap between disclosures which comply with the TCFD requirements and CETP are likely to relate to:

a) scope 1 (direct emissions, e.g. emissions from boilers, own transport);

b) scope 2 (indirect emissions, e.g. emissions from electricity at sources not owned);

c) scope 3 (other indirect emissions e.g. business travel by means not owned, waste disposal, purchased materials); and

d) any targets used by the organisation to manage climate related risks and opportunities, and performance against those targets.

2.1.7. Scope for conflict may arise in two areas – the level of assurance and the degree of disaggregation.

2.1.8. In relation to the degree of disaggregation required, Fonterra's 2019 Sustainability Report[7] provided data on:

a) aggregate manufacturing GHG emissions basis across 4 categories - process heat (coal, gas, steam), site power (electricity), transport, non-energy (see below Figure 1);

---

[5] ibid. paragraph 95.3.
[6] Ibid. paragraph 95.4.
[7] Fonterra, *2019 Sustainability Report*. Available from https://view.publitas.com/fonterra/sustainability-report-2019

b) overall energy and emissions intensity, which reflected their operations across seven countries, 7.32GJ/tonne of finished goods and 0.53 tCO2e per tonne of finished goods respectively[8]; and

c) performance change in manufacturing energy intensity and absolute manufacturing emissions (see below Figure 2).

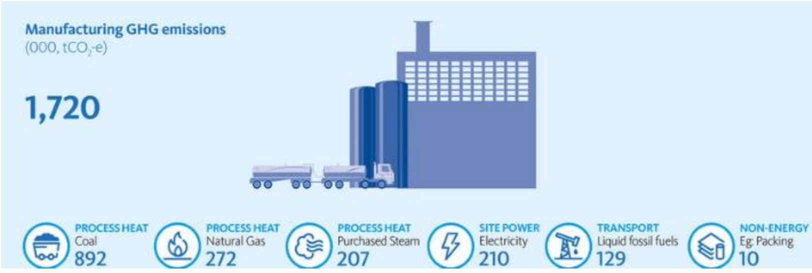

Figure 1: Extract from Fonterra's 2019 Sustainability Report: Climate Change - NZ GHG Emissions

Climate targets					
Indicator	**Target**	**Performance** (cumulative change) FY17	FY18	FY19	**Commentary**
Reduction in manufacturing energy intensity (energy per tonne of production)	**20% reduction by 2020 from FY03 baseline (NZ)**	17.8% reduction	19.3% reduction	19.5% reduction	There was a further improvement in FY19 and we remain on track to deliver this target.
Reduction in absolute manufacturing emissions [1]	**30% reduction by 2030 from FY15 baseline (Global)**	4.6% reduction	2.5% reduction	3.5% reduction	We have reduced absolute emissions by 3.5% from baseline and our overall manufacturing emissions intensity improved slightly compared to FY18. We have a roadmap to deliver the target and capital investment will be staged.
Net change in GHG emissions from dairy farming since 14/15 (NZ) (Pre-farm gate tCO$_2$-e)[2]	**Neutral to 2030**	397,000 reduction on 14/15	1,174,000 reduction on 14/15	864,000 reduction on 14/15	Our estimated absolute GHG emissions continues to be well below the baseline season. There was an increase compared to FY18 due to increased milk production without improved emissions intensity. Underlying emissions intensity on farm is 2.0% higher than 14/15 baseline (1.0% higher excluding land use change component).

Figure 2: Extract from Fonterra's 2019 Sustainability Report: Climate Change – Climate Targets

2.1.9. This suggests that further information on the level of disaggregation will be required.

2.1.10. A further area for conflict could be in the level of assurance expected. Sustainability reports often use Global Reporting Initiative (**GRI**) standards[9]; GRI is considered global best practice for reporting on a range of economic, environmental and social impacts. This was the basis of the Fonterra's Sustainability Report. It seems appropriate for these purposes.

2.1.11. Given organisations will be reporting transport energy and emissions within scope 1 and 3, we also support including transport within the CETPs.

2.1.12. We consider that Boards should be asked to verify that they have considered a relevant energy audit, as opposed to report subsequent compliance with a particular energy audit proposal. This would be analogous to 13.236F of the Electricity Industry Participation Code which requires Boards to consider spot price risk disclosure statements.

2.1.13. We also consider that it would be useful to understand the level of detail that is considered desirable by the statement "energy efficiency actions taken that year" and "plans to reduce emissions by 2030".

[8] Ibid. Page 65.
[9] Global Reporting, *GRI Standards*. Available from https://www.globalreporting.org/standards

Obligation to disclose

2.1.14. The Discussion Document suggests that a large energy user is defined as a user with energy spend of more than $2m per annum. We support the $2m quantum but note there will be a need to clarify what this will encompass (expenditure on electricity, gas, petrol, diesel, coal, biomass etc), and further consider the measurement basis.

2.1.15. Certain large electricity users are direct purchasers under the Electricity Industry Participation Code and receive invoices from the Clearing Manager. However, this will not reflect any financial contracts they may have entered into and the final electricity expenditure may be higher or lower. Further, electricity retailers purchase on behalf of customers and then on-sell to end use customers. On this basis Trustpower would be included within the definition, yet our annual energy spend for our own purposes amounts to less than ~$1.5m, and we simply do not have the complete information required to make disclosures on behalf of our customers entire energy consumption and emissions.

2.1.16. Our energy spend can also be highly variable depending on a number of factors outside our control, including hydrological conditions and demand. This is also likely the case for other large electricity users. To avoid issues with large users being captured periodically by the threshold level, we suggest determining the threshold based on an average over a 3-year period may be appropriate.

2.1.17. In summary, Trustpower supports requiring CETPs to be published, and energy audits to be considered by Boards. This will lift emission reduction and energy efficiency opportunity awareness but risks being resource intensive (if not aligned with other reporting).

2.1.18. We note we are at an early stage ourselves with respect to improving our disclosures but have a programme of work underway which will determine our commitments within the short term.

2.2. Electrification information package and feasibility studies

2.2.1. The Discussion Document observes that the information in Appendix 5 is a snapshot at a relatively high level of the process heat electrification opportunities. In our view, businesses considering electrification options want to understand:

a) current levels of electrical reliability of the local network or national grid, and the relevant site given current levels of demand;

b) mechanisms to increase the level of reliability, via installation of equipment within the local network/grid or within the relevant site, at varying levels of demand;

c) the cost of increasing reliability, whether via customer specific new investment contracts with a specific network owners/Transpower or via distribution/interconnection charges (ie. allocated across a broader set of users) at varying levels of demand; and

d) the timeframe and process for any investment approvals required to improve reliability at varying levels of demand.

2.2.2. We consider it may be prudent for Transpower to pro-actively undertake particular grid studies to provide more detailed information to parties considering electrification.

2.2.3. Arguably this is analogous to work being undertaken over Summer 2019-2020 whereby Transpower is undertaking work associated with an approved major capital expenditure project

(Clutha Upper Waitaki Line Upgrade Project[10]), which will proceed to construction subject to certain triggers. We recognise that this may require certain changes to rules under Part 4 of the Commerce Act 1986 around what constitutes pre-feasibility capital expenditure.

2.2.4. Co-funding heating feasibility studies will ensure greater specificity is available to support the necessary grid studies.

2.3. Benchmarking in food processing

2.3.1. We support benchmarking information for food processing industries.

2.3.2. Trustpower is not in the food processing business but considers that benchmarking information would likely assist smaller businesses to understand the potential to reduce emissions and improve energy productivity.

3. Developing markets for bioenergy and direct geothermal use (MBIE s2)

3.1. Facilitating the development of bioenergy markets and industry clusters on a regional basis

3.1.1. Trustpower appreciates that further work is going on across Government to grow the bioeconomy, and that feedback is sought to inform the development of options.

3.1.2. We agree that developing clusters for wood processing and heat plant may need pro-active, coordinated approach to their development. As part of MBIE's Industry Transformation Plans (**ITPs**), we suggest the best approach may be to identify groups of businesses that currently have onsite coal boilers to supply heat and are located in close proximity. We are aware of the Washdyke Energy Centre which provides heat to DB Mainland Ltd, Juice Products NZ and NZ Light Leathers Ltd via a $20MW_{th}$ coal fired boiler with the option to burn wood chip[11]. The original coal boiler investment was likely able to occur as a result of leveraging the economies of scale offered by the customer cluster. We note that NZ Light Leathers have commented "not having boilers on-site was a major benefit". This example suggests designing clusters around existing heat customers rather than creating a heat plant and expecting customers to arrive.

3.1.3. Another form of support the Government could consider is drafting a model long term contract to assist with reducing transaction costs associated with the multiple partners.

3.2. Guidance on RMA consenting for wood energy plants

3.2.1. We support the development of a user guide on application of National Environmental Standards (**NES**) for air quality associated with wood energy plants.

3.2.2. Addressing unintended regulatory barriers posed by council air quality planning rules is an important step towards enabling the necessary transformation in the process heat sector. We believe a user guide of the sort proposed will assist Council staff throughout the country, as well as project developers, and help to avoid anomalous regional differences.

---

[10] Transpower, *Work to recommence on Transpower's Clutha Upper Waitaki Lines Project*. Available from: https://www.transpower.co.nz/news/work-recommence-transpower's-clutha-upper-waitaki-lines-project

[11] Pioneer Energy, *Industrial Energy Partnership*. Available from: https://pioneerenergy.co.nz/assets/PE-Case-Study-Washdyke-Industrial-Energy-Partnership-FINAL-2018.pdf

4. Innovating and building capability (MBIE s3)

4.1.1. A step change is required across organisations to enable New Zealand to achieve the emissions reductions required. Implicit in the proposed provisional budget is that 50% of the identified energy efficiency opportunities in the process heat for food processing are taken up by 2025. A further 25% of process heat plant have switched to biofuels or electricity (see Figure 3).

		Proposed budget (13 Mt CO2-e additional abatement required)		More ambitious budget (18 Mt CO2-e additional abatement required)		Less ambitious budget (6 Mt CO2-e additional abatement required)	
	Potential change	Change	Kt CO_2-e	Change	Kt CO_2-e	Change	Kt CO_2-e
Electricity	The percentage of electricity efficiency potential identified by EECA that is implemented	33%	450	40%	550	15%	200
	The year that the additional wind and geothermal renewable stations are built to displace the remaining baseload gas-fired power station are implemented	2024	1,100	2023	1,100	Yet to occur	0
Process heat for food processing	The percentage of identified energy efficiency opportunities that are of net benefit that have been adopted	50%	450	90%	800	25%	250
	The percentage of process heat that currently uses coal or gas that has switched to biofuels or electricity	25%	700	45%	1250	10%	300
Sum of estimated emissions abatement achieved in 2025			2700		3,700		750

Figure 3: Provisional emissions budget comparisons 2021-2025

Source: Ministry for the Environment, 2019, "Reforming the New Zealand Emissions Trading Scheme: Proposed Settings"

4.1.2. In general, our preference is to rely on market solutions (ie. NZ-ETS as the primary driver) but if additional financial assistance from Government is available, we think it would be best directed to supporting development of markets for bioenergy and direct use geothermal.

4.1.3. This reflects:

a) the 8% of total emissions from process heat[12];

b) the proposed provisional budget of 354 $MtCO_2$-e for the period 2021-2025[13]; and

c) opportunities to reduce emissions that are likely to be available to assist process heat conversion.

4.2. Technology diffusion and capability building, industrial innovation and transitioning to a low carbon future

4.2.1. We support expanding EECA grants for technology diffusion and capability building and knowledge sharing.

[12] ICCC, 2019, "Accelerated Electrification: Evidence, Analysis and Recommendations", page 13.
[13] Ministry for the Environment, 2019, "Reforming the New Zealand Emissions Trading Scheme: Proposed Settings"

4.2.2. Trustpower recalls support to wind development in early 2000s where Tararua Stage 2 and 3 wind farm, and other projects were allocated funds that bridged the, then, economic gap in light of their positive contribution to reducing emissions ("additionality" grounds[14]). Wind at this time would have been described as "nascent technology'. Expanding EECA grants to accelerate diffusion of, and transform the market, for low emission nascent technology would appear similarly appropriate.

4.2.3. We are aware that a requirement of funding for various Australian grant schemes, including from the Australian Renewable Energy Agency (**ARENA**) is knowledge sharing. Indeed, under the Australian Renewable Energy Agency Act 2011 (Cth), ARENA is required to promote the sharing of information and knowledge about renewable energy technologies where appropriate. Knowledge Sharing Plans identify the data, information and knowledge that will be generated and shared, along with how it will be shared, with an agreed timetable. In relation to data, methodologies that will be used to capture, store, assess and report this data are established at the time funding is agreed.

4.2.4. Knowledge sharing with grants will facilitate identifying feasible technological pathways for decarbonisation. As such industry roadmaps are likely to assist, and the proposed collaborative process is analogous to the Smart Grid Forum established by the Government in the mid 2010s.

5. Phasing out fossil fuels in process heat (MBIE s4)

5.1.1. Trustpower understands that PHE is classified as low, medium or high:

a) low, less than 100°C which is typically used for water and space heating;

b) medium, between 100°C and 300°C, for drying wood products or milk powder; and

c) high, greater than 300°C for making steel.

5.1.2. Imposing a ban on specific technologies is a blunt regulatory instrument. In counterbalance, Trustpower acknowledges there is a "cost of inaction" both in terms of:

a) efficiency gains and emission reductions made in existing plants have the potential to be outweighed by the building of new fossil fuel heat plant; and

b) potential for an extended "grandfather axe" effect with the new coal boilers, which have not been deterred, remaining in the boiler fleet for an extended period as owners choose repairs rather than spending further capital on an alternative plant.

5.2. Low temperature PHE

5.2.1. In light of this, we support signalling that existing low temperature (<100°C) coal fired process heat equipment should be phased out from 2030. This extended notice period will provide owners with almost a decade long notice period that refurbishing and maintaining existing plant is timebound. During this period, we expect carbon prices under the NZ-ETS will also increase providing an increasing economic incentive to switch technologies. Depending on the price the proposed phase out may indeed be more of a "backstop" regulatory instrument.

[14] This was under the MfE Projects to Reduce Emissions Scheme (PRE) which pre-dated the Emission Trading Scheme.

5.2.2. With respect to new low to medium temperature equipment, Trustpower would support a future ban if there is no discernible behaviour change observable over the next 2 years. Trustpower suggests draft regulations are drafted and actively shared with the community. These will act to encourage users to investigate alternatives, including co-funding under an expanded EECA grant scheme, and potential industrial clusters being established. For larger energy users with energy spend in excess of $2m the CETPs would also provide a vehicle for investigating alternatives.

5.3. Medium temperature PHE

5.3.1. With respect to medium temperature heat coal fired process heat equipment used for milk powder, we understand:

a) Fonterra has made a commitment to not invest in any new coal boilers or increase in capacity as of 2019, this had previously been Fonterra's 2030 target but has been brought forward[15];

b) Synlait has also made a commitment to never build another coal boiler[16]; and

c) Westland Milk installed LPG fired units during recent expansions[17].

5.3.2. While this does not address medium temperature heat used for wood drying or meat processing purposes it is possible that commitments by major dairy industry players are such that taking steps to ban *new coal fired medium temperature for dairy plant* would simply serve as a regulatory backstop.

Sector/process	Number of boiler plant in New Zealand
Dairy processing Milk powder / other	~80 ~50 / 30
Meat processing	86
Other food	44
Wood processing	75

Figure 4: Estimated number of boiler plants by industry sector/process

Source: Table 2, Ministry for the Environment, 2020 "Marginal Abatement Cost Curves Analysis for New Zealand: Potential Greenhouse Gas Mitigation Options and their costs."

6. Boosting investment in energy efficiency and renewable energy (MBIE s5)

6.1.1. As outlined above, Trustpower considers the NZ-ETS should be the primary driver of reducing emissions in New Zealand. Poorly targeted initiatives could serve to depress the carbon price through reduced demand for NZ-ETS units.

---

[15] Fonterra, media release: *No new coal boilers for Fonterra*, July 2019. Available from: and statements by Fonterra during oral submissions to Electricity Commission in relation to transmission pricing.
[16] Synlait as advised in https://www.synlait.com/sustainability/
[17] Evans, Gavin (Newsroom), *Why electricity will replace coal in dairy plants,* July 2018. Available from: https://www.newsroom.co.nz/2018/07/11/149629/why-electricity-will-replace-coal-in-dairy-plants

6.1.2. Beyond the limited set of initiatives above (EECA grants for technology diffusion purposes) which could inject funding in to stimulate process heat conversion, Trustpower does not support additional financial incentives beyond those created by the NZ-ETS. This reflects the risk that there could be overlapping and conflicting regulatory intervention measures.

7. Cost recovery mechanisms (MBIE s6)

7.1.1. Trustpower supports the creation of a levy on coal to fund EECA's process heat activities. It is both pragmatic and consistent with the Petroleum or Engine Fuel Monitoring Levy, the Electricity Industry Levy and the Gas Safety, Monitoring and Energy Efficiency Levy.

8. Our recommendations for Part A

To encourage energy efficiency and the uptake of renewable fuels in industry, Trustpower supports the Government:

- Introducing a requirement for large energy users to:
  - prepare and publish Corporate Energy Transition Plans in a standardised format to reduce compliance costs; and
  - conduct energy audits which should be considered by their Boards;
- Developing an electrification information package for businesses looking to electrify process heat, co-fund electrification feasibility studies;
- Providing benchmarking information for food processing industries;
- Facilitating development of bioenergy markets and industry clusters on a regional basis within Industry Transformation Plans, including through:
  - identifying clusters of existing process heat customers using coal boilers; and
  - considering the introduction of a model long term contract;
- Developing a users' guide on application of the National Environmental Standards for Air Quality to wood energy;
- Providing targeted financial assistance via EECA grants for nascent low emissions technologies;
- Collaborating with EIHI industries to:
  - foster knowledge sharing,
  - develop sectoral low-cabon roadmaps; and
  - build capability for the future using a Just Transitions approach; and
- Requiring existing coal-fired process heat equipment supplying end-use temperature requirements below 100^{o}c to be phased out by 2030, and putting in place regulatory backstop arrangements to ban new low to medium temperature equipment, if there is no discernable behavioural change within the next 2 years; and
- Introducing a levy on consumers of coal to fund ECCA's process heat activities.

Part B: Accelerating renewable electricity generation and infrastructure

9. Introduction

9.1.1. Trustpower agrees with MBIE that it is important to consider if the current regulatory settings will support the required *new* investment in low emissions generation, transmission and distribution lines as putting in place the right settings early will reduce the long-term costs of the transition.

9.1.2. We think it is also important to cross-check if our regulatory settings will continue to support *current* investment such as existing renewable generation and the continued availability of load management to manage congestion on networks as this will also be needed to achieve our electrification goals.

9.1.3. Our response to Part B is structured as follows:

a) In section 10 we discuss our concerns about the current RMA instruments and the risks associated with the resource consent process for new, consented but unbuilt, and existing generators (MBIE s7);

b) In section 11 we discuss the opportunities to improve participation in the energy transition (including from demand side management without disrupting current wholesale market settings in a manner that would deter investors in large scale projects (MBIE s8);

c) In section 12 we outline our views around facilitating community engagement (MBIE s9);

d) In section 13 we discuss the potential impact of proposed new grid pricing on the transition to the low emissions economy (MBIE s10); and

e) In section 14 we outline our experience with recent changes to the pricing principles which apply to distributed generation and how that is likely to affect future investors in similar technologies (MBIE s11).

9.1.4. A summary of recommendations is provided at the end of each section.

10. Enabling renewables uptake under the Resource Management Act 1991 (MBIE s7)

10.1.1. Trustpower is pleased that the Discussion Document recognises the importance of the resource consenting processes under the RMA for new renewable generation, consented but unbuilt renewable generation (which might need amended consents to accommodate the latest technology) and existing generation which needs to be re-consented.

10.1.2. We agree that the NPS:REG is most relevant to renewable generation but note that the proposed NPS:FM and the proposed NPS on Indigenous Biodiversity (**NPS:IB**) create significant risk to renewable generation being supported under the RMA.

10.1.3. This is because enabling policy, as demonstrated by the language used in the NPS:REG, will not be able to compete with avoidance policy, as demonstrated by the language proposed in the NPS:IB.

10.1.4. For hydro electricity generators, the cumulative effects of the currently proposed NPS:FM and NPS:IB policies is very significant. In our view, neither NPS sufficiently values nor recognises the importance of the hydro-generation to the electricity market, both in terms of output and flexibility. If the NPS:FM and NPS:IB proceed in their proposed forms, despite extensive feedback from industry, then the output from hydro-electric generation will simply diminish.

10.1.5. We think it is imperative that the broad definition of 'environment' under the RMA remains – that is, the definition includes all ecosystems (including people and communities) as well as the social and economic conditions of these ecosystems. Section 5 of the RMA carries the concept of 'sustainable management', capturing the wide range of environmental management decisions about the protection, use and development of natural and physical resources. Unfortunately, the recent NPS proposals appear to have shifted from this integrated approach.

10.1.6. Rebalancing of the NPS:FM, the NPS:IB, and the NPS:REG is essential. Both the Productivity Commission and the ICCC recognised the policy tension and uncertainty between the NPS:REG and the NPS:FM, along with the need to strengthen the NPS:REG.

10.1.7. The ICCC especially acknowledged the value of existing hydro generation to meeting New Zealand's climate change objectives, and the Productivity Commission noted the investment uncertainty arising from water allocation decisions is yet to be addressed.

10.1.8. We strongly support the options for a greater national direction under the RMA on the importance of renewable energy put forward in the Discussion Document, including the recommendations of the ICCC that:

> *4 The Committee recommends that the Government ensures the value of existing hydro generation to New Zealand's climate change objectives is given sufficient weight when decisions about freshwater are made, including by:*
>
> *a. Strengthening and clarifying national direction on making trade-offs between hydro generation and freshwater objectives across National Policy Statements…*
>
> *5 The Committee recommends that the Government provides for the development of wind generation and its associated transmission and distribution infrastructure at scale by:*
>
> *a. Revising the National Policy Statement for Renewable Electricity Generation to resolve issues relating to lapsing and varying consents, and re-powering existing wind farms.*
>
> *b. Developing National Environmental Standards to enable timely consenting of wind generation, both large and small, and transmission and distribution infrastructure. This should include proactively identifying which types of landscapes are likely to be particularly suitable for wind infrastructure.*

10.1.9. These matters must be addressed in order to support investments in generation (both new generation and upgrades to existing generation) and ensure that existing hydro generation assets are maintained.

10.1.10. However, we consider changes to the RMA consenting process should go further. In particular, we would like to see the inclusion of a new section 6 matter in the RMA covering the need to reduce the foreseeable impacts of climate change and the recognition of the role of renewable energy infrastructure to achieve this.

10.1.11. That is, climate change response ought to become a matter of national importance under the RMA and should play an important mitigation role which supports the signals for reductions in emissions sent by the NZ-ETS.

10.1.12. We encourage MBIE to work closely with MfE to ensure policy cohesion is achieved across the energy sector with respect to implications and consequences. Otherwise the ability for New Zealand to become a low emissions economy will be substantively impacted.

10.1.13. Trustpower has provided a submission to MfE on the current review of the resource management system. We refer MBIE to our more detailed views on the proposed RMA reforms (provided in our response to the MfE) when considering this issue.

Impact of Essential Freshwater package and proposals to amend NPS:FM

10.1.14. Trustpower considers that New Zealand's broad network of existing hydro-electric power schemes have a critical role to play in transitioning to a low emissions economy. For these existing assets, both their operational flexibility and level of output must be protected, and any regulatory or legislative change ought to state this as a necessary policy output.

10.1.15. The Discussion Document contains a footnote[47] which suggests that uncertainty for hydro generators could potentially be reduced by the Essential Freshwater package, which includes proposals to amend the NPS:FM. Whilst Trustpower agrees this *could* be the case, we do not believe the NPS:FM, in its publicly notified form, would actually reduce uncertainty in effect. Submissions from all generators highlighted similar concerns around impacts of the proposed NPS:FM on existing operational output and flexibility, plus ongoing uncertainty that is likely to arise during consenting processes. These issues remain real and outstanding.

10.1.16. Independent experts at Sapere [18]reported that the proposed NPS:FM would undermine New Zealand's ability to meet its climate change targets. In its publicly notified form, the freshwater reform will restrict the operation of New Zealand's existing hydro-generation fleet, both with respect to flexibility to meet peak requirements and contribution to overall volume of electricity. This will act to increase New Zealand's carbon emissions and create loss of future opportunities.

10.1.17. Sapere estimated that the potential impacts of the draft NPS:FM on hydro-electricity generation could increase total emissions by 629 kt CO2-e per annum. There is also a potential for these proposals to create an anti-competitive environment that increases the cost for consumers.

10.1.18. The unprincipled approach within the proposed NPS:FM to allow exceptions for some hydro-electric power schemes and not others, is not only inconsistent with the principles of natural justice, but it is also inconsistent with the NPS:REG, which does not make such a distinction.

10.1.19. Trustpower's recent submission on the NPS:FM suggested solutions to these issues and offered an alternative consistent and principled approach that would recognise the benefits of all renewable electricity within the NPS:FM.

NPS: REG

10.1.20. We note that all generators have also made suggestions in the past around ways to strengthen the NPS:REG by making the language more directive and being more explicit around how renewable generation should be recognised in RMA planning instruments.

10.1.21. We consider that the issue currently encountered around the diminishing value of the NPS:REG can be corrected without extensive regulatory change (i.e it is within the power of officials to fix now).

10.1.22. As an immediate priority, Trustpower supports:

a) officials strengthening the NPS:REG; and

b) the Government resolving the current imbalance between the NPS:FM and NPS:REG and NPS:IB;

---

[18] Sapere (October 2019), *Review of proposed NPS:FM and associated RIA :potential hydroelectricity generation impacts*.

Scoping NES or National Planning Standards specific to renewable energy

10.1.23. We support the development of NES or National Planning Standard specific to renewable energy, provided it follows a fair approach which is accessible to all renewable generation activities.

10.1.24. We consider that:

a) there are opportunities to gain greater consistency through the implementation of National Planning Standards; and

b) for certain types of infrastructure a National Planning Standard could also be useful to attain region to region consistency.

10.1.25. Trustpower considers that any National Planning Standard should cover all renewable generation options (not only windfarms), along with transmission and distribution infrastructure. This is because issues relating to lapsing and varying of consents and providing for technological advancements and enhancements of existing schemes, are not unique to windfarms alone. An inequitable or selective approach within a National Planning Standard would potentially impact on competition and investment and could limit technological initiatives.

10.1.26. We also note that a flaw in the current process for developing National Planning Standards is that new instruments are created but there is no parallel review process of the existing instruments to ensure consistency and to minimise provisions in conflict. We recommend a Board of Inquiry could be established to look into issues of imbalance.

10.1.27. We agree with MBIE that there is a potential role for better strategic planning through the use of spatial planning approaches, particularly for infrastructure development and management.

Additional opportunities for improvements to the consenting process

10.1.28. Better consenting processes are required to accommodate the long lead times associated with some infrastructure, such as electricity generation and transmission projects. This will help to enhance certainty surrounding investment and long-term planning for nationally significant infrastructure.

10.1.29. Currently the Councils, communities, and infrastructure providers expend unnecessary resources on re-consenting permits for infrastructure. This could be streamlined considerably via improvements to the designation processes, or a similar pathway to allow for initial concept approval, planning and investment certainty.

10.1.30. Other opportunities for improvement include:

a) enabling electricity generators to have Requiring Authority status and allowing land to be designated for renewable energy purposes. To pursue this option, the current priority of NES over designations would need to be rectified. We would expect other tweaks may also be necessary, such as removing the right to compulsorily acquire land;

b) including electricity generation within the definition of network utility operators (correcting a current gap); and

c) permitting substantially longer consent durations (in excess of 35 years) for nationally significant renewable energy infrastructure such as hydro with permanent riverbed structures.

10.1.31. We note that the Productivity Commission also made a number of recommendations to improve consenting processes for renewables (both existing and new) which we consider should be progressed as a matter of priority by the Government.

10.1.32. Finally, we consider there is an opportunity for Government to ensure better policy cohesion by putting in place an oversight function via the Environmental Protection Agency or the Climate Change Commission appointing a panel of external planning experts to provide an audit function across plans to ensure consistent implementation of national direction instruments.

10.2. Our recommendations for MBIE s7

To enable renewable energy development under the RMA, Trustpower supports the Government:

- Strenghtening the NPS:REG to ensure local authorities give sufficient weight to the role of renewable electricty generation in the energy transition;
- Addressing the imbalance between the NPS:REG and NPS:FM and proposed NPS:IB;
- Ensuring the NPS:IB and the NPS: FM support new resource consents for renewable generation and allow existing generation to retain its current operational output and flexibility;
- Scoping National Environment Standards or National Planning Standards specific to renewable energy;
- Developing a process to ensure that where new RMA instruments are created these are reviewed against existing RMA instruments to ensure consistency and to minimise provisions in conflict (for example, a Board of Inquiry could be established);
- Considering allowing renewable energy generators to apply for Requiring Authority status under the RMA, albeit with some carve outs and minor changes; and
- Considering other potential improvements to streamline the resource consenting processes for renewable generation including:
    - Introducing into the RMA a new section 6 matter covering the need to reduce the foreseeable impacts of climate change and recognising the important role of renewable energy infrastructure in achieving this; and
    - Enabling a Panel of External Planning experts to be established which would provide an audit function across plans to ensure a consistent implementation of national direction instruments.

11. Supporting renewable electricity generation investment (MBIE s8)

11.1.1. As outlined earlier, Trustpower supports the NZ-ETS being the centrepiece of the policy package to support New Zealand's energy transition.

11.1.2. A credible and robust NZ-ETS that provides certainty to the market will be vital for ensuring that effective emissions pricing occurs. Likewise, it is important that the settings of the scheme provide the right signals to encourage businesses to reduce emissions, innovate and invest in solutions.

11.1.3. We support the settings for the NZ-ETS enabling a stronger price signal than currently proposed by MfE. Our internal research suggests that the cost containment reserve should be lifted to approximately \$75/t CO_2e to provide a carbon price that will drive the necessary behavioural changes and investment decisions to meet New Zealand's climate change objectives.

11.1.4. At a carbon price of around $75/t CO_2e, a change in the generation merit order would likely occur which would result in thermal baseload generation moving up the order, operating at a higher cost, and importantly baseload gas generation running before baseload coal.

11.1.5. We also refer MBIE to our more detailed views on the proposed NZ-ETS settings (provided separately in our response to MfE) when considering this issue.

11.1.6. However, we consider that a major reform in the existing market structures is not required to increase the uptake of new technologies or facilitate capital deployment. The existing market structures have been highly effective at incentivising the commissioning of approximately 14TWh of generation investment since 2000 and so we should seek to build off this strong foundation in our energy transition.

11.1.7. In addition, as we note in our covering letter, investors in scale projects need regulatory certainty. Major reform to the wholesale market will simply deter investment until any new arrangements are fully understood.

11.2. PPA Platform

11.2.1. The current PPA market is relatively informal. Renewable energy developers (and energy buyers) leverage existing relations and are assisted by existing brokers to find other parties that may wish to enter into a PPA with them (for example: OM Financial Limited, Simply Energy and EnergyLink.) Likewise, some legal firms and engineering firms can also assist project developers and energy buyers in this regard. Our experience has been that these informal arrangements have worked reasonably effectively over many years and are low cost.

11.2.2. However, we recognise the ICCC's view that it might be challenging for owners or would-be investors in small to medium size distributed generation to access suitable buyers in the electricity market and that this problem may grow overtime as electrification occurs.

11.2.3. This suggests there may be some scope for further facilitation of PPAs in this segment of the electricity market[19] along with ensuring that the existing hedge market arrangements continue to function well, which we note is the ongoing focus of the Authority's hedge market enhancements work programme[20].

11.2.4. While we do not consider there is a need to introduce a match-matching arrangement (Option A), we support MBIE exploring the opportunities for providing more information resources and exploring simple, low cost enhanced facilitation arrangements to further assist parties to self-match. Potential enhanced facilitation options include:

a) improving transparency of opportunities (for example, through the publication of a list of potential electrification opportunities and generation projects, along with contact details for the relevant entities); and

b) making information around existing consultancy services more readily available (for example, a list of brokers could be published or held by the Authority)

---

[19] Enhanced facilitation arrangement should be focussed on projects similar to the previously proposed, but now cancelled, Blueskin Bay turbine (~1x3MW turbine). Or the often muted Paekakariki project (3x900kW).

[20] Trustpower's recent submission to the Authority (2 December 2019) outlined that we consider the Authority should pursue the following measures in order of sequence and priority: 1) Improve transparency of existing market making; 2) Improve market understanding; and 3) Investigate an incentives-based scheme. Mandatory market making arrangements should only be considered once these options have been exhausted.

11.2.5. We consider that better enabling self-matching between new generation projects and load will act to support other market led solutions emerging, while not directly undermining the existing business models of those brokers that are currently active in this area.

11.2.6. It is possible that this simple arrangement could be further developed at a later date in response to evolving industry needs (if required). Potential incremental developments that could be considered include:

a) expanding any transparency arrangements to incorporate existing small loads, small electricity retailers and existing small-scale generation projects; and

b) actively encouraging state sector entities to be proactive in presenting opportunities for electrification via any published list (a variant on Option B).

11.2.7. We also agree with MBIE that:

a) some inexpensive information resources and training could be beneficial; and

b) there could be some value in developing a standardised PPA contract to reduce the need for energy buyers and project developers to have legal and contracting experience. This would not, however, completely remove the need for both parties to engage with lawyers to assist with the negotiations and tailor the final contract to suit both parties. As a result, it is unclear that a standardised arrangement would significantly reduce costs.

11.2.8. Currently, there is no strong case for the Government taking a more direct role in facilitating PPAs via assuming financial risks (Options C and D). As a stronger NZ-ETS signal begins to take effect and we begin to see more large energy buyers look to electrify, this will likely further develop. The proposed CETPs will also assist here.

11.2.9. Establishing the right settings and ensuring regulatory/policy certainty more broadly, should result in private sector finance being made available to projects that are commercially viable. As a result, we do not consider there is a need for direct Government involvement in facilitating PPAs; in fact, it could crowd out private sector investment.

11.2.10. We also note that the NZ Green Investment Finance (**NZGIF**), which has been recently established with initial capital of $100m from the Government, will be in a position to deploy capital on a commercial basis to companies and projects that accelerate emissions reductions. The initial focus for NZGIF will be transport, process heat, energy efficiency, agriculture and DER and so should capture small to medium sized projects. While large scale generation projects will not be within their remit, we note that commercially viable large-scale projects are more likely to be progressed by larger companies, with access to private capital, and in our view are unlikely to require any additional assistance with respect to matching with counterparties.

11.3. Encouraging greater demand-side participation and develop the demand response market

11.3.1. We consider that building on the existing work to encourage greater participation from the demand-side of the market should be a priority, as it will help to ensure that New Zealand is fully realising the potential of demand-side participation.

11.3.2. Demand side participation options are becoming increasingly sophisticated as technology improves. The flexibility that demand-side response can potentially offer to the market will become increasing important as the underlying generation mix adjusts to reflect greater levels of variable renewable generation.

11.3.3. A reasonable effort has been made to increase the level of demand-side response within the New Zealand electricity market to date. This includes Transpower's development of its demand response pilot programme and the upcoming introduction of a dispatch-lite facility type to allow qualifying consumers to bid their controllable demand into the spot market. There are also a number of larger industrial companies that have developed sophisticated responses to spot market signals.

11.3.4. The level of general uptake of demand-side response opportunities has however been relatively limited when compared to the experience in other jurisdictions.

11.3.5. The one exception to this relates to the level of ripple control currently used by many distributors. This load control provides a stable means for reducing transmission network peaks by constraining demand to constraints and minimises transmission investments.

11.3.6. As Orion New Zealand Ltd outlined in its recent submission to the Authority on its proposed transmission pricing reform:

> *"…within that peak demand there will always be some uses of energy that are not so immediately valuable and which can be deferred at least for a while. The standard example is storage water heating. Where these uses can be managed in a coordinated way at peak times it allows for a lower level of peak capacity to be built - we can do even better than diversity – and so the same amount of energy can be delivered over a smaller capacity network – a straightforward productive efficiency benefit that translates into dynamic efficiency when considered over time and across the supply chain (there being a related reduction in the need for peak generation capacity). This approach has been a feature of distribution network design, build and operation in New Zealand for decades. Generally, end-consumers choosing to contribute to this coordination partnership are rewarded by some form of price discount. RCPD, whatever its other limitations, is consistent with this longstanding arrangement. "*[21]

11.3.7. The historic trigger for investment in ripple control systems was peak demand charges and more recently transmission charges based on regional coincident peak demand (**RCPD**). The Authority's plan to remove peak demand charges is expected to result in the loss of significant levels of demand response therefore we think that an immediate priority for the Government is to address this issue. We return to this topic in section 13.

11.3.8. As technology continues to evolve and internet-enabled energy producing and consuming assets become more mainstream the opportunities for additional demand response to provide a meaningful service at times of peak demand will further evolve and enhance. This is already becoming evident in other jurisdictions.

11.3.9. However, we do not consider there is a need for direct Government involvement in setting up a demand response market at this time.

11.3.10. Private sector solutions are emerging in other jurisdictions and provided the policy/regulatory settings within New Zealand are enabling we see no reason why similar private sector led initiatives would not emerge here as well once the scale of the opportunity is sufficient[22]. For example, a decentralised energy exchange (deX) developed by Green Sync, and partially funded by the Australian Government via ARENA grant, has recently been launched in Australia[23] and

[21] Orion submission on Electricity Authority *Transmission Pricing Review – 2019 Issues Paper* (1 October 2019).

[22] We note that given New Zealand's small size and the limited potential number of larger loads that might participate initially, there may not be sufficient justification for a platform until such time as households are in a position to be more active in this area.

[23] The deX is a digital marketplace designed to help electricity networks better utilize the increasing penetration of distributed energy resources and virtual power plants and allow consumer energy assets to be registered and visible to the grid.

provides an opportunity for integrating distributed generation resource into the grid and facilitating demand side response at a localised level.

11.3.11. The immediate focus should be on ensuring that sensible and certain pricing signals act to incentivise consumers to change their electricity consumption patterns and fully realise the benefits of investing in technologies that enable consumers collectively to flatten their demand profiles.

11.3.12. The introduction of new forms of distribution pricing and the removal of the low fixed charge sooner rather than later will be important for enabling these adjusted pricing mechanisms. Policy stability is also essential in order for consumers to make decisions to invest in solar PV systems, batteries, smart home systems etc. which assist them in being more price responsive.

11.3.13. We support a multi-agency work programme, led by the Authority,[24] being established to further explore options for encouraging greater levels of demand-side participation and demand response, including:

a) considering how to maximise the value of the existing arrangements that we have already put in place. For example, to ensure the uptake of the new dispatch-lite arrangements is maximised we suggest that the Authority/Transpower should consider running a targeted education programme to ensure large industrials are aware of the opportunity and understand the associated value to them of being involved;

b) identifying opportunities to distributors to be more enabling of demand response within the existing regulatory arrangements and ensure that they continue to take advantage of existing load control opportunities such as the control of hot water cylinders;

c) identifying whether the existing regulatory/policy settings will enable private, technology agnostic platforms that operate decentralised markets to emerge in the future, and if not, what changes are required[25]; and

d) considering the potential implications of other electrification related initiatives on the opportunities for demand side response. For example, a greater level of electric vehicles within the system may provide an opportunity for distributors to use the capacity from their batteries to manage distribution constraints provided the right technology is put in place and the broader policy/regulatory settings are designed to enable this[26].

11.3.14. To be successful the work programme would need to ensure:

a) ongoing prioritisation of initiatives to ensure quick wins can be achieved. We anticipate the largest opportunities for improvement currently sit with encouraging increased engagement by large industrials. Gaining significant value from high levels of household interaction may still be a number of years away (dependent on the level of uptake of smart appliances, development of the internet of things etc); and

---

[24] Other agencies that should be involved in the work programme include MBIE, the Commerce Commission, Transpower and EECA. There may be some overlap with existing work programmes of the Authority, including the open access workstream.

[25] We note that reliability and resilience services are different from transmission and distribution services. The regulatory/policy settings to enable supporting markets to emerge (DER, etc.) should account for this difference.

[26] We understand that deX is currently working with Wellington Electricity on its EV Connect project which is looking at the opportunities to charge EVs at scale, while managing the extra electricity demand this places on the network without the need for augmentation of the network: https://dex.energy/case_study/case-study-wellington-electricity/

b) alignment with interrelated work programmes such as the current joint emerging technology workstream that the Authority and Commerce Commission are exploring and EECA's current ripple control investigation.

11.3.15. Likewise, the work programme will need to ensure ongoing engagement with a range of potentially interested stakeholders including demand response aggregators, technology providers, retailers, distributors, consumer representatives etc.

11.4. Energy efficiency obligations

11.4.1. We do not support mandatory obligations being put on retailers or distributors to deploy energy efficient technologies across their customer base as this type of obligation is likely to:

a) distort competition if obligations are linked to a specific group of customers (i.e. those in energy hardship), as it will create a deterrent for retailers to acquire those customers. There is also a strong case for restricting the involvement of distributors in contestable activities; and

b) lead to out of date regulations in a fast-paced technology changing environment.

11.4.2. This type of obligation would also be unlikely to result in the desired improvements in energy efficiency at least cost. This is because retailers are not necessarily the only or best person to take advantage of economies of scale required to deliver energy efficient installations at least cost.

11.4.3. We note that the electricity industry has been working together on the Energymate pilot programme which works directly to help households experiencing energy poverty through a package of support, which includes assistance with improving energy efficiency in the home. This trial has come about voluntarily and shows promise that it could be scalable.

11.4.4. On a long-term basis, EECA would be best placed to take on any role in deploying energy efficient solutions and accelerating the replacement of inefficient products such as washers, dryers, lighting etc. This could be achieved by EECA funding community level support for customers in energy hardship to improve their energy efficiency (for example, via an extended Energymate arrangement).

11.5. Developing offshore wind assets

11.5.1. We do not currently consider that the development of an offshore wind market is a priority for the energy sector. This is because offshore wind developments generally are at a scale which is significantly bigger than New Zealand's near-term electricity demand requirements, even with electrification.

11.5.2. While we acknowledge the economic feasibility of smaller offshore wind developments have been improving, there is currently over 1600 MW of consented onshore sites for windfarms in New Zealand which can be progressed.

11.5.3. This suggests there is likely limited value in the short to medium term associated with undertaking further work to explore the necessary regulatory framework, environmental impacts and economic feasibility of offshore wind in New Zealand. We support MBIE prioritising this option accordingly.

11.6. Renewable electricity certificates and portfolio standards

11.6.1. We agree with MBIE's assessment that the introduction of renewable portfolio standard for retailers and/or large users and requirement to produce or procure renewable electricity certificates to meet that standard should not be a preferred option at this time.

11.6.2. While this option may assist in supporting renewable electricity investment, it would achieve this by introducing significant additional complexities and costs into the current arrangements. It would also potentially create distortions to the signal from the NZ-ETS for renewable generation investment, as was reflected in the Discussion Document.

11.6.3. As outlined earlier, we consider the NZ-ETS should be the primary enabler for achieving the Government's decarbonisation objectives. A strong emissions price in combination with stable regulatory/policy settings should result in both a clear signal around the need for investment in renewable generation and the right conditions for private sector equity to be made available to fund the necessary investments. As a result, it is unclear that additional encouragement of renewable generation would be required from the Government via this option.

11.7. Phase down of thermal baseload and place in strategic reserve

11.7.1. As outlined earlier, we consider that a strong price signal from the NZ-ETS will ensure that the negative externalities associated with burning coal and gas are better taken into account within the dispatch merit order. As the signal gets stronger over time, this will have ramifications for the phasedown of thermal baseload generation.

11.7.2. Regulatory/policy changes to remove existing barriers to entry (i.e. changes to the RMA, transmission network connections etc) will also assist in accelerating the closure of thermal baseload generation, as new renewable generation comes online which displaces coal generation and encourages gas generation to be run as mid-merit plant or peaking. As a result, we do not consider there is a need for a formal thermal phasedown arrangement to be put in place and so support MBIE's assessment that this option need not be progressed. We also note that such an arrangement might be viewed poorly by investors.

11.7.3. In our view most retailers are focussed on the need to provide secure supply to their customers. This is, after all, a core part of the service Trustpower offers. This suggests that as security of supply becomes more of an issue, retailers will have increasing incentives to enter into appropriate contracts to maintain supply. This will likely include contracts with gas fired generation to bridge the gap whilst new renewable generation is built and to ensure reliability can be maintained during short term scarcity shocks, until such time as technology advances to the point required (such as daily storage in batteries). These arrangements collectively will provide the desired phased transition.

11.7.4. If there are any concerns about whether this will occur for all retailers, then those concerns could in part be addressed by additional disclosure requirements about long-term hedge positions in the Authority's stress testing regime.

11.7.5. It may also be appropriate to formalise the obligations on thermal plant owners to provide advance notice of their intention to close. For most current thermal plant owners, we suggest that this is unlikely to be more onerous than existing Stock Exchange obligations, but plant ownership can change and not all owners will necessarily be listed companies and therefore subject to these requirements. It is important our energy system is robust to all ownership possibilities.

11.7.6. The introduction of a requirement for advanced provision of information on a thermal generator's retirement plans would:

a) provide market participants with a clearer expectation around future generation capacity and enable them to better identify how to best respond/adapt to changes; and

b) allow market participants to factor this information into their investment, operational and retirement decisions, resulting in more informed and efficient decision making.

11.7.7. To be effective the obligations would need to establish a notice period that would ensure Transpower and other industry participants can appropriately put in place arrangements to manage security of supply, and to allow sufficient time for the broader market to adjust, including bringing new capacity online. We note that a similar obligation has recently been introduced in the National Electricity Market in Australia.[27]

11.8. Our recommendations for MBIE s8

11.8.1. Our primary recommendation to MBIE is that the existing wholesale market structures have been highly successful at delivering the necessary generation investment to date. A major reform to these arrangements is unnecessary and would simply deter investment until any new arrangements are fully understood.

11.8.2. However, some policy options would potentially enhance the existing arrangements and ensure that accelerated investment in supply and demand side renewable electricity investment and energy efficiency is best promoted.

Trustpower supports the Government:

- Exploring a simple, low cost enhanced facilitation arrangement that enables new small renewable generation and loads to self-match, along with the provision of information resources and training, and a standardised PPA contract;
- Establishing a multi-agency work programme, led by the Electricity Authority, to explore the opportunities for encouraging greater demand side participation and demand response;
- Working with EECA to to ensure that on a long term basis its approach to deploying any energy efficient solutions and accelerating the replacement of inefficient products aligns with other work underway to support energy efficiency improvements;
- Introducing additional discloure requirements about long-term hedge positions into the exisitng stress testing regime; and
- Introducing a new regulatory requirement for advanced provision of information on a thermal generators retirement plans.

[27] We note that a similar obligation has been introduced into the National Energy Market by the Australian Energy Market Commission (**AEMC**) based on recent experience that sudden and unexpected retirement of large generators can cause undesirable consequences in the market – including price shocks and system security challenges. In particular, the AEMC's amendments introduced:

a) a requirement for three years advanced notification of generation closures; and

b) an ability for the Australian Energy Regulator to grant an exemption to this notification requirement in extreme circumstances.

The AEMC has recommended to COAG that the relevant provisions be designated as civil penalty provisions.

12. Facilitating local and community engagement in renewable energy and energy efficiency (MBIE s9)

12.1.1. We agree with the analysis in the Discussion Document that:

a) there can be positive local economic and social impacts from community renewable energy and energy efficiency projects but:

b) they will not reach the scale required to decarbonise the economy; and

c) there are risks of cost shifting and distributional impacts.

12.1.2. Nevertheless, interest in community renewable energy and energy efficiency projects is likely to grow, whether from communities of place ("Blueskin Bay-esque") or communities of interest (sports club, kindergartens). Therefore, we need to distinguish between:

a) providing investment for economic projects[28] where there are capital constraints (e.g. options to fund a small scale - 3x900kW - wind farm at Paekakariki include community funded, joint venture or investor owned)[29];

b) opportunities to install uneconomic, but mature technologies in local communities (i.e. wind, geothermal);

c) opportunities which may be economic, although it is too early in the development process to be certain, but there are information barriers (e.g. lack of local capacity and resources to undertake resource management applications, negotiate technical legal contracts);

d) island communities without access to national grid (e.g. Stewart/Rakiura Island[30]);

e) potential opportunities to access co-benefits (e.g. use of low-cost wood fuel enabling process heat conversion);

f) providing seed funding for nascent technology pilot programmes (e.g. hydrogen).

12.1.3. As outlined earlier, Trustpower supports "*as much market as possible*" to ensure the transition to a low emissions economy is not at excessive cost. This suggests interventions should be at the lighter end of the spectrum such as information sharing, pilot programmes using nascent technology, or assistance to island communities.

12.2. Our recommendations for MBIE s9

To facilitate local and community engagement in renewable energy and energy efficiency, Trustpower supports the Government:

- Developing a clear and consistent Government position on community energy issues, aligned across different policies and work programmes; and
- Providing financial assistance for community energy pilot programmes using nascent technologies; where a key requirement for such projects is that any learnings are shared more broadly.

---

[28] Refer to https://www.kapiticoast.govt.nz/media/23347/wind-turbine-project-paekakariki.pdf
[29] Refer to https://www.stuff.co.nz/environment/102618292/power-to-the-people-paekkriki-looks-toward-a-windpowered-future
[30] Refer to https://www.beehive.govt.nz/release/pgf-approves-wind-turbines-funding-stewart-island.

13. Connecting to the national grid (MBIE s10)

13.1. Access to national grid

13.1.1. The Discussion Document notes that we are moving into a period of more customer-driven transmission investment arising from both increased renewable generation and also process heat demand connecting to the grid. To facilitate this, it is important that connection to the grid is available to new entrants and existing grid users on reasonable terms.

13.1.2. The Discussion Document observes that:

a) issues with cost allocation and risk associated with new transmission lines; and

b) co-ordination challenges amongst multiple beneficiaries of new connection assets,

may slow or hold up the deployment of decarbonisation initiatives.

13.1.3. It proposes a set of options to address the risks associated with "first mover disadvantage" for connection costs. These are designed to ensure that appropriate economies of scale are realised whilst mitigating the costs of excessive over-investment.

13.1.4. The paper also seeks feedback on whether more public information sharing would assist transmission investment planning and co-ordination between transmission contract counterparties in relation to their grid access needs. We address these issues in the next section.

13.1.5. However, we think there are other grid access issues which will also need to be addressed if there are to be no speed bumps for investors in the transition to a low emissions economy. These arise from the Authority's proposed reform of the Transmission Pricing Methodology (**TPM**) Guidelines and are of an order of magnitude greater than the issues raised in the Discussion Document around early build and cost-sharing for connection assets.

13.1.6. We also observe the various perceptions of the risks of Transpower under or over-investing in the national grid change when the need for electrification is considered.

13.2. First mover disadvantage in relation to new connection assets

13.2.1. Trustpower agrees that there is an issue to be addressed in relation to the allocation of costs of new connection assets to first movers. From our perspective this has not been a significant issue in the past, but we accept that it may become more important as New Zealand seeks a step change in the level of renewable generation capacity and more industrials need to connect directly to the grid.

13.2.2. Our understanding is that the capital costs of new connection assets are funded by customer investment contracts and that connection assets are currently not able to be built without an identified contract counterparty.

13.2.3. We agree that "user pay" connection arrangements encourage:

a) new generation in locations which do not incur significant first mover costs; and

b) the commissioning of assets right sized for the "first mover" that may not take advantage of the economies of scale associated with an asset build anticipating future users.

13.2.4. Our view is that the Commerce Commission is the entity best placed to judge if particular connection capex is prudent in all circumstances, including in relation to the economic benefits of climate change mitigation.

13.2.5. We therefore support amendments to the input methodologies which will enable the Commission to take into account the economic benefits of climate change mitigation in its capex approval processes.

13.2.6. In a world of increased customer-driven transmission investment there is likely to be more need for multi-party connection contracts. However, contract arrangements between multiple counterparties will only work if each counterparty has similar leverage and is operating to similar timeframes. This suggests that some facilitation will be required.

13.2.7. We are also aware there can be issues with the recovery of costs from parties who seek access after connection assets are built.

13.2.8. We think this could be addressed by rules providing that subsequent access-seekers must contribute to the capital costs of connection on a similar basis to that required for existing connection assets.

13.2.9. We support a user guide on the current regulations and approval processes relating to getting an upgraded or new connection to the grid to assist new entrants.

13.2.10. However, we are wary of increased disclosure obligations of potential generation options (over and above listing rules) because of the potential deterrence effect. It is also important that there is a level playing field in relation to all disclosure obligations, including new entrants domestically and from overseas.

13.3. Proposed reform to TPM Guidelines

13.3.1. From our perspective a much bigger issue for investors in new renewable energy and new energy technologies (particularly new entrants and less established players) is the Authority's proposed reform to the way national grid costs are allocated via the TPM. This reform also has problematic distributional issues as well.

13.3.2. Supporting evidence for our views (from a variety of different stakeholders) can be found in the oral submissions on the TPM which have been recently published on the Authority's website. We note submissions on MBIE's "*Process Heat in New Zealand: Opportunities and barriers to lower emissions*" paper also raised this issue.

13.3.3. The Authority believes fundamental change to the TPM is required to improve overall sector efficiency particularly transmission investment efficiency. Its proposed reform to the TPM Guidelines is summarised in Figure 5 below.

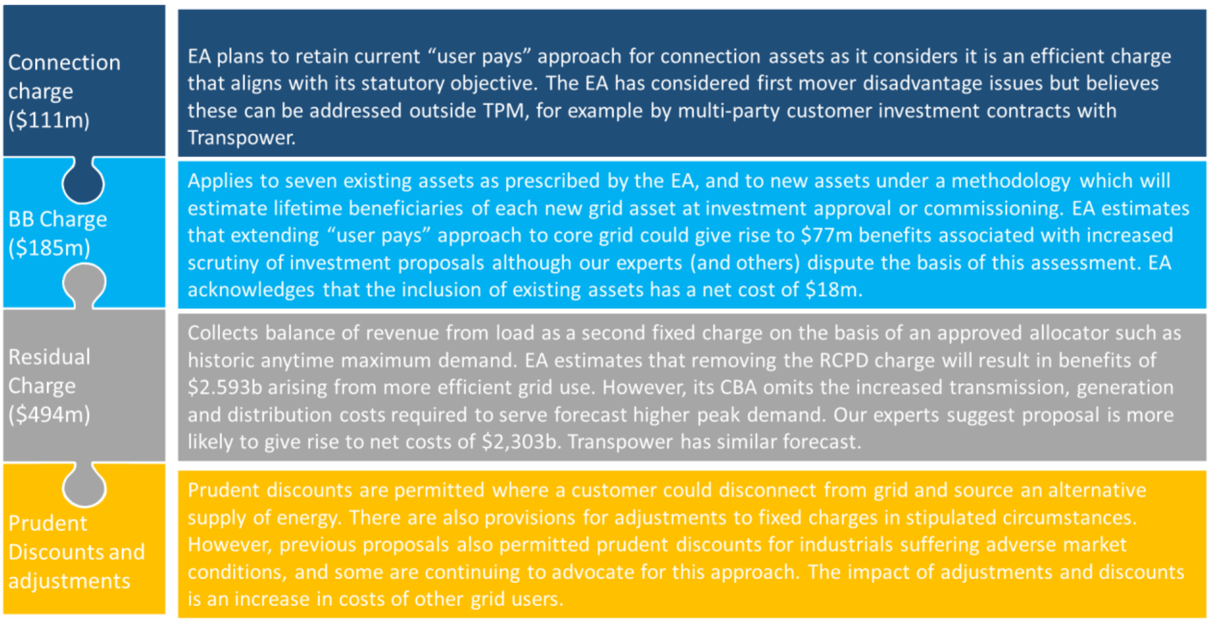

Figure 5: Proposed TPM Guidelines

NB The distribution of revenue for each charge is based on the Electricity Authority's estimate of Transpower's regulated revenue of $845m in 2020/21 year.

13.3.4. This proposal was developed to address the Authority's concerns that the current TPM creates incentives for parties to:

a) advocate for inefficient investment in grid assets because the costs are socialised; and

b) avoid grid use when the grid is not constrained.

13.3.5. At the core of this proposal is the Authority's flagship benefits based (**BB**) charging proposal which, by design, creates a price shock whenever any new transmission investment is required. This price shock is the trigger for the identification of the lifetime beneficiaries (who will be assigned the costs) and the disclosure of information to ensure "just in time" investment.

13.3.6. The Authority considers its reform will facilitate the transition to a low emissions economy by:

a) delivering more efficient prices at different points of the supply chain, particularly in relation to future transmission investment;

b) reducing the level of disputes arising under the current methodology; and

c) reducing the level of cost shifting which it expects would occur if the current RCPD charge for the interconnection assets is retained.

13.3.7. Trustpower, Transpower and a number of other parties do not agree that this is the most likely outcome of the Authority's proposals[31].

13.3.8. Instead there is concern that:

a) the proposed BB charging:

[31] Evidence supporting these views noted above can be found in the oral submissions on the current TPM which are available on the Electricity Authority's website.

i. is opaque and complex and will either deter some investors or cause them to seek additional reward for new risks;

ii. will result in volatile charges both at the initial allocation of a BB charge and over time as the rules permit re-allocations in some circumstances;

iii. will have adverse distributional impacts on some of our poorest regions whose infrastructure is already at a lower standard than other regions;

iv. will either make no difference to grid investment scrutiny or, problematically, result in the deferral of investments needed for electrification;

v. is highly assumption dependent and thus likely to result in increased disputes both initially and over time; and

b) the proposed changes to the interconnection charges (removal of the RCPD charge) will result in the loss of low-cost demand management and a significant rise in peak energy costs (across the supply chain).

13.3.9. These issues are briefly addressed below.

Benefits-based charging

13.3.10. BB charging, as modelled to date by the Authority in its various proposals, and in our own test cases is both complex and highly assumption dependent. BB charging is based on assessed lifetime beneficiaries. This involves making a number of assumptions about the future in relation to long life assets at a single point of time. It is inevitable that these assessments will be inaccurate and thus create winners and losers amongst grid users and within particular industries.

13.3.11. Charges will be more volatile than the current TPM as there will be an increase in costs when new assets are commissioned, or the actions of other parties trigger a re-allocation of costs amongst grid users.

13.3.12. Once a BB charge is allocated to your business you are obliged to pay for that charge even if your plant closes down. The Authority is currently consulting on a proposal to restrict this post-closure payment obligation to ten years. However even this shortened timeframe is problematic for conversion to low emissions technologies.

13.3.13. We think it is inevitable that BB charging will become a fertile ground for disputes both initially and over time as real beneficiaries become known (after allocations have been made to assumed beneficiaries) or costs are reallocated to unsuspecting parties (as businesses exit or are granted discounts under the Authority's proposed new prudent discount regime).

13.3.14. Of particular concern for some stakeholders is the proposed adoption of BB charging for 7 *existing* assets as this has adverse implications for some of our poorest communities in the North and *net costs of $18m* in the Authority's own analysis.

13.3.15. However, we think it is also likely that the allocations for *new* transmission assets will continue to trigger political debates about whether social infrastructure should attract individualised or socialised pricing and who should pay for assets which are over-sized to achieve scale economies or sized to encourage new renewable generation.

13.3.16. Looking forward there is also a risk that the opaqueness and complexity of BB charging will favour larger established players in the generation market over new entrants. This view has been confirmed by expert Dave Smith from Creative Energy Consulting who stated:

"small new entrants are the lifeblood of a competitive market due to their ability to disrupt the incumbents. Under the proposed TPM they could be substantially disadvantaged an, possibly to the extent that they do not enter the market at all[32]*"*

13.3.17. The volatility of BB charges will have a similar effect. This is problematic given the size of the investment challenge associated with electrification and the need to maintain competition in the generation market so as to ensure this transition occurs at the lowest cost possible.

13.3.18. The introduction of this policy at this time is likely to discourage early electrification. The industry and investors have already indicated sensitivity to volatility, wealth transfers and complexity associated with this proposal in TPM submissions and also more recently in feedback on MBIE's "*Process Heat in New Zealand: Opportunities and barriers to lower emissions"* paper.

13.3.19. We are aware that a core driver of the proposal is the Authority's desire in prevent over-investment by Transpower and acknowledge this is an important consideration.

13.3.20. However, we think this benefit has been overstated. The Authority's cost benefit analysis (**CBA**) estimates the benefits associated with increased scrutiny of transmission investment has a net present value of only $77m. Further:

a) this quantification of the benefits relies on a single data point: the level of savings the Commerce Commission achieved in its review of Transpower's proposed enhancement and development capex for its second regulatory control period; and

b) the basis on which the Authority considers that stakeholders would not just replicate the outcome of the Commerce Commission's review processes but improve them is unexplained.

13.3.21. We note that Fonterra in its recent oral submission on the proposed TPM advised the Authority that although it is New Zealand's largest company, it is unlikely to apply scarce resources to complex transmission issues and believes very few other consumers will do so. Nor did Fonterra consider that distributors would engage in this debate - under price-quality regulation, distributors are able to pass costs directly on to their customers. Thus, Fonterra does not believe that that the benefit of increased scrutiny will ever be realised.

13.3.22. This and other factors led our CBA expert to conclude that the Authority's analysis is likely to overstate the benefits as in its view "*any benefits associated with increased scrutiny are likely to be small relative to the Electricity Authority's estimate*"[33].

13.3.23. Setting CBA issues to one side, we understand the intuitive appeal of BB pricing. However, we think BB charging may not in practice change behaviour in the beneficial manner envisaged by the Authority as decisions to invest in transmission, generation and demand side are all made by different parties in very different timescales and the information required to "improve" the scrutiny of transmission investments may not be available at the time it would be required.

13.3.24. In contrast, experts including Hayden Green from Axiom Economics (for Transpower) have noted that BB charging is likely to give parties more incentives to strategically withhold information which might impact on charge allocations resulting in delays in transmission investment needed for decarbonisation.

---

[32] "Review of the Electricity Authority's TPM Third Issues Paper", a report by Creative Energy Consulting Pty Ltd, September 2019 for Trustpower, see Appendix E of its submission. Page 9.

[33] Houston Kemp Cost Benefit Analysis Report, see Appendix D of Trustpower's submission to the Electricity Authority, page v.

13.3.25. For all these reasons we do not think that the Authority's claim BB charging will support the transition to a low emissions economy is well founded.

Design of residual charge

13.3.26. The second fundamental change in the Authority's proposal is the design of the residual charge which (despite its name) recovers the major part of Transpower's regulated revenues.

13.3.27. The Authority is concerned that the recovery of interconnection costs through strong RCPD peak signals under the current TPM sends inefficient signals for the use of the transmission network. Therefore, it proposes to replace the RCPD charge with a fixed charge. This is a significant change as once implemented it will mean nodal prices will be the only signal of the need for new transmission investment.

13.3.28. Trustpower acknowledges that the RCPD charge is not a charge which signals the actual costs of congestion. Instead, it is a long-term price signal of the value in avoiding peak demand on transmission capacity. The sudden removal of this charge will result in an increase in peak demand. This will put pressure of distribution and transmission networks at the very time when the Government is seeking more renewable generation to achieve economy wide emission reductions.

13.3.29. The Authority's primary solution to this risk is to accelerate distribution pricing reforms, however progress to date in this area does not suggest this will be either an easy or complete solution. We do however consider it would be preferable to complete distribution pricing reform first.

13.3.30. We also note that experts believe the removal of the RCPD charge is unwise as:

a) nodal prices are likely to be insufficient to signal the lumpy transmission investments until there is much deeper demand-side participation, real time pricing, and readily available FTRs which may never occur or could be many years away; in the interim

b) removing the RCPD signal is likely to lead to loss of low-cost load control and a rise in cost of peak generation; whereas

c) more modest reform, such as diluting the RCPD signal, is more likely to realise the gains of more efficient grid use without any of the other adverse consequences.

13.3.31. The Authority has claimed that the removal of the RCPD charge will give rise to net <u>benefits</u> of $2,593 million. However, it omits to include in its analysis the extra costs of transmission, distribution and generation which arise from its removal. Correcting for these omissions results in the Authority's grid use model estimating net <u>costs</u> of $2,303 million arising from its proposal rather than the net benefits of $2,593 million it claims. Transpower's expert gets a similar result to our analysis.

13.3.32. Irrespective of whose CBA figures are correct, the risk of the proposal resulting in net costs not net benefits should not be ignored as the size of the swing is significant and not a risk that a corporate entity would consider reasonable.

Sovereign risk

13.3.33. Some parties think that the process of this reform has resulted in a heightened sovereign risk for investors, particularly new entrants.

13.3.34. This was recently quantified by Mike Fuge, on behalf of NZ Refining, as a cost of 200-300 basis points on each investment, primarily because of the complexity of the Authority's TPM proposal. In his recent presentation to the Authority, Mr. Fuge also said he thought the new TPM proposal was inconsistent with the transition to a low emissions economy as:

> *"By encouraging more demand during peak periods [the proposal] would increase the challenge of investing in new energy including in projects like 25 MW solar farm at Marsden Point. [it] may favour incumbents but it actively discourages new investment from outsiders like ourselves and international investors who are fundamentally disturbed by both the change and the complexity of the change".*

13.3.35. Trustpower is not aware of the economics of NZ Refining's solar farm but does share the NZ Refining's view that investors in long-life assets require a stable and understandable regulatory system.

13.3.36. As we explained in our submission to the EPR on "*Fit-for-purpose regulatory frameworks*" paper, sovereign risk in relation to network access and pricing is exacerbated by the Authority's power to change the Code (including the TPM) at any time.

13.3.37. We, our expert advisers, and other stakeholders are also concerned about:

a) the sudden jump of benefits from $213.3m in 2016 to $2,711m in 2019 for a substantially similar TPM proposal;

b) the Authority's use of CBA to confirm its preferred charging mechanism rather than to evaluate alternative options (as many of the claimed benefits could be achieved by less disruptive reform); and

c) the recent proposal to extend the prudent discount scheme beyond situations of technical by pass and allow "other considerations" to be considered in establishing a "fairer" price for some users (with the costs picked up by other users).

13.3.38. These matters impact on the Authority's credibility and increased the prospects of ongoing challenge to this reform both before and after implementation. This is likely to be costly and detract from the real challenge at hand.

Proposed solution

13.3.39. Trustpower notes that the Authority process is not complete, but its recent publications suggest it is still on track for implementation of the proposed new TPM Guidelines in the quarter commencing 1 April 2020. This suggests it is advancing its current proposal, substantially unchanged.

13.3.40. We support the independent regulation of the sector so believe there should be a very high threshold for intervention by Government. However, in the present case, we think this threshold has been met. Our preferred circuit-breaker is the solution we put forward in our "Improving Transmission access" paper for the EPR.

13.3.41. This would involve:

a) the Minister setting the high-level policy guidelines (which could include climate change and Just Transition objectives);

b) the regulator developing a transmission pricing input methodology which sets out the processes which Transpower is to follow in developing a TPM in response to those high-level policy guidelines; and

c) Transpower having the primary responsibility for developing the TPM in accordance with the GPS and TPM input methodology.

13.3.42. We have also recommended that the regulatory responsibility for the TPM be transferred to the Commerce Commission. This is to ensure a close alignment between the assessment of the benefits of new investment and the allocation of its costs. This is particularly important if the decision is made to proceed with BB charging.

13.3.43. We have also suggested that as an interim measure the Government should issue a GPS setting out how it considers the Authority should interpret its statutory objective in the context of transmission pricing. This would signal the 'direction of travel' for all stakeholders.

13.4. Our recommendations for MBIE s10

To address the existing barriers to transmission connections that could impact on renewable generation investment and electrification of load, Trustpower suggests that the Government:

- Works with the Commerce Commission to amend the input methodologies to enable the Commission to take into account the economic benefits of climate change mitigation in its capex approval processes;
- Introduces rules providing that subsequent access-seekers must contribute to the capital costs of connection on a similar basis to that required for existing connection assets;
- Develops a user guide on the current regulations and approval processes relating to getting an upgraded or new connection to the grid to assist new entrants;
- In the short-term, issues a GPS to clarify how the Government's views around how the Electricity Authority should interpret its statutory objective in the context of transmission pricing.
- In the medium to long-term, transfers the regulatory responsibility for TPM to the Commerce Commission.

14. Local network connections and trading arrangements (MBIE s11)

14.1. Role of DER in transition to low emissions economy

14.1.1. Trustpower agrees with MBIE that DG can assist in maintaining system security and reliability and provide a lower cost alternative to investing in transmission or distribution networks directly. It also can provide incremental increases of supply that are aligned to local demand growth. These features mean that DG, and other newer forms of distributed energy resources (**DER**), (such as battery storage and demand response) have an important role in the transition to a low emission economy.

14.1.2. Trustpower supports both the Authority's and the Electricity Networks Association's work to identify and develop ways to provide for the uptake of new technology on distribution networks. We also support the Commerce Commission's recent decisions, that incentivise non-wire alternatives where that is more cost effective, and that allow price paths to be re-opened in the case of unforeseen costs such as costs arising from the electrification of process heat.

14.1.3. We agree that regulatory frameworks need to have sufficient flexibility and adaptability to provide for new technologies and changing patterns. However, it is also important that the regulatory frameworks which govern DER, including those that provide access to distribution networks have the stability and predictability required for investment in long life assets and that any reform to longstanding arrangements is well-justified. Our experience of recent DG reform has raised issues about whether this is currently the case.

14.2. Appropriateness of DG regulatory frameworks

14.2.1. Trustpower is the largest supplier of DG in New Zealand and so has been closely engaged in the efforts of the Government, and more recently the Authority, to regulate this form of generation.

Unfortunately, the regulation from these two entities has pulled in two entirely different directions in the last two decades.

14.2.2. In the 2000's the Government introduced measures to facilitate the DG (partly as a result of the difficulties we and others were experiencing in connecting renewable generation to distribution networks). However, the following decade the Authority amended these measures and has indicated that further changes are on the way. These may include changes to the pricing that DG pays for interconnection.

14.2.3. The Authority's concern is the high levels of RCPD charge in the TPM is encouraging a surge of investment in inefficient DG which is merely resulting in cost-shifting to other transmission counterparties. Furthermore, it considered that the issue was so important that it could not wait for TPM reform but should be addressed in the rules which regulate the supply of services to and from DG. This involved a significant change in the regulatory landscape for affected stakeholders.

14.2.4. The following table provides a brief precis of the history of DG regulation:

Pre 1998	Energy supply businesses were provided incentives to invest in generation close to load from 1930s as wholesale energy was charged on the basis of winter peak demand. This prompted local authorities to invest in load management such as ripple control and to build, or otherwise support, local generation.
1998	Lines energy split meant that new access contracts were required between: • distributors and retailers • distributors and DG Many of the distributor/DG contracts involved a transfer of the right to receive the benefit of lower transmission charges which arose from the operation of DG at times of peak demand (known in the industry as ACOT payments). In some cases, ACOT payments were part of the sale consideration for the relevant businesses.
2000	A Ministerial Inquiry raised the prospect that the incentives on distributors to enter fair and reasonable access contracts with new DG was weak. This led to a the first of many Government Policy Statements which sought rules to "*ensure that the use of new electricity technologies and renewable, and distributed generation is facilitated and that generators using these approaches do not face barriers*"
2003	MED issued a discussion paper "*Facilitating Distributed Generation*" which proposed standard connection contracts, pricing principles and arbitration processes to remove impediments to the establishment of DG. In the foreword to this paper the Minister of Energy said: "*I am very keen to encourage the development of distributed generation….The proposed regulations outlined in this paper have the fundamental objectives of improving investor certainty and clarity about obtaining interconnection, particularly concerning any costs*"
2008	Following an unsuccessful attempt at developing an industry approach to improving the terms for DG access, the Government stepped in and directly regulated access terms. The approach adopted was a legislated default contract which applied if contractual terms were not agreed. The Minister noted that: "*Investment in distributed generation can contribute to security of supply by increasing overall generation capacity, and reducing the amount of power lost during transmission. Most distributed generation exporting to local lines is based on renewable energy sources, which helps us to avoid the greenhouse gas emissions otherwise produced using fossil fuels. The effect of the regulations is that lines companies can only charge distributed generators the additional costs caused by distributed generation. If there's no additional cost there is no charge.*"

2016	The Authority consulted on proposals to remove peak demand charges in its TPM reform and also proposed the removal of the default price terms (known as Distributed Generation Pricing Principles (**DGPPs**)) from the Code. The proposed removal of the DGPPs means that incremental costs would no longer be the upper limit for charges paid by DG for connection services and DG would be required to enter into commercial negotiations with monopoly network companies to receive any network payments for any network benefits they provide without having the backstop of the DGPPs to support those negotiations. Following submission feedback, the Authority decided to implement its reform in two stages; with the first stage restricting the operation of the pricing principle applying to avoided transmission costs and the second stage addressing the costs DG owners had to pay for interconnection. The first stage was to provide that all future DG and existing DG which does not pass an eligibility test overseen by Transpower will no longer be eligible to receive ACOT payments under the regulated default terms (**ACOT amendment**). The ACOT amendment also had a flow on effect to contracts of price-regulated distributors as they were not able to add on to their regulated costs the contract costs of any ineligible DG. This amendment resulted in a patchwork of access terms depending on the extent to which the default or bespoke terms govern existing access arrangements and whether the distributor is price regulated or not. Problematically the ACOT amendment was made without further consultation so there was no opportunity to explain some of these practical issues to the Authority.
2017-20	The ACOT amendment came into effect on a staggered basis for the four transmission pricing regions from 1 April 2018 to 1 October 2019 and is now fully operational. As it has transpired Transpower's assessments have shown that much of the DG which was considered to be inefficient by the Authority when it advanced this reform is in fact required to assist it meet its grid reliability standards. This has impacted on parties' perception of the efficacy of this reform.
2022 ?	Implementation of the new TPM will remove peak demand charges. Consequentially it will also remove any obligation to make payments (contractual or under the default terms) for DG's contribution to the avoidance of peak demand as there will be no peak demand charges. DG owners will still be able to earn revenue in the wholesale market but will lose a supplementary revenue stream.
Unknown	The Authority has indicated that it plans to further review the access terms that apply for DG no later than five years after the new arrangements have commenced in each transmission pricing region**.** This is the second stage of its reform and is likely to involve the removal of the incremental cost cap that was an important feature of the 2008 DG regulations.

14.2.5. This legislative history has had a particular adverse impact on the smaller DG owners who relied on regulated terms for services supplied to, and received from, distribution networks.

14.2.6. The policy uncertainty is also likely to have an impact on much larger investors whose capital will be important for decarbonisation at the lowest possible cost.

14.2.7. Infratil, which has the majority shareholding in Trustpower, made the following submission on the Authority's 2016 Discussion Document:

> *"As a major shareholder in Trustpower, Infratil has supported Trustpower's investment in distributed generation (DG) for over 20 years, particularly for enhancements of existing schemes and new windfarms. The business cases underpinning this investment (covering generation development, acquisition, upgrades and reconfiguration) included long-term expectations of receiving revenue from payments for avoiding the cost of transmission (ACOT) to distributors.*
>
> *We understand that the levels of returns that these investments will earn could change, due to the actions of other market participants. That is a risk we accept. But we do not believe it good regulatory practice to radically change regulatory settings unless the benefits are clear, demonstrable and material (which we do not believe is*

true here). In essence, the Authority is penalising incumbent investors for having sunk their costs. The fact there is little that affected investors can do in response to the changes (e.g. reduce output) is not a good reason to make the change. In the long run, effecting wealth transfers through regulatory changes hurts consumers.

The confidence with which we have invested in DG has been based on the longevity of peak pricing signals in New Zealand and the long-standing regime for payment of ACOT benefit. The practice of network companies paying distributed generators ACOT benefit preceded the introduction of the DGPPs by many years, and was formalised as Government policy in 2007 after a multi-year review."[34]

14.2.8. Infratil's 2016 views are only likely to have been exacerbated by more recent activity including:

a) the reluctance of the court to grant Trustpower's application for extended consultation time on the first proposal under a judicial review application (which also applied to the parallel TPM consultation);

b) the absence of consultation on the ACOT amendment (and the reluctance of the Regulations Review Committee to provide a remedy for that breach of section 39); and

c) the evidence during implementation process that some of the Authority's core assumptions in its original policy analysis promoting this reform were incorrect.

14.2.9. Our conclusion, as we shared in our "*Fit for purpose regulatory framework*" paper for the EPR, is that the current accountability frameworks are weak and that to rebuild the confidence of investors a review of institutional arrangements may be required[35].

14.2.10. However, we appreciate this reform will take time to put in place any legislative changes and implement. We believe a useful interim step might be a GPS which provides (again) guidelines on how DG (and DER) can best be accommodated in the transition to a low emissions economy.

14.3. Our recommendation for MBIE s11

To address the existing barriers to transmission connections that could impact on renewable generation investment and electrification of load, Trustpower suggests that the Government:

- In the short-term, issues a GPS to clarify how the Government's views around how DG (and DER) can best be accommodation in the transition to a low emissions economy.
- Considers improvements to the existing accountability frameworks as part of the recently announced review of institutional arrangements.

[34] Infratil, *July 2016 Letter to the Electricity Authority*. Available from https://www.ea.govt.nz/dmsdocument/21003
[35] We note the Government's recently announced review of institutional arrangements will provide an avenue for considering this matter further.