Submission by

WORLD ENERGY COUNCIL | BusinessNZ Energy Council

to the

Ministry of Business, Innovation and Employment

on the following consultation documents:

Measures for transition to an expanded and highly renewable electricity system discussion document

Developing a framework for offshore renewable energy discussion document

Gas Transition Plan Issues Paper

Interim Hydrogen Roadmap

Implementing a ban on new fossil-fuel baseload electricity generation discussion document

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Introduction

1. BusinessNZ Energy Council (BEC) is pleased to have the opportunity to provide feedback on several documents released by Ministry of Business, Innovation and Employment (MBIE) to advance New Zealand’s energy transition.

2. The BEC is a group of organisations across New Zealand’s energy sector, taking a leading role in creating a sustainable, affordable, and secure energy future for all New Zealanders. Together we seek to shape the energy agenda for New Zealand. BEC is a division of BusinessNZ, New Zealand's largest business advocacy body and the member committee of the World Energy Council (WEC).

3. This submission includes BEC’s response to each paper released by MBIE. Its structure is divided into five sections. Within each section, there are overarching comments on several actions we believe should be prioritised, followed by more detailed explanations based on the questions raised within the papers.

Measures for transition to an expanded and highly renewable electricity system discussion document

Overarching comments

1. This paper outlines numerous challenges and obstacles, along with potential measures to expand and ensure a more sustainable, affordable, and reliable electricity system. The key priorities, based on issues raised, should include:

   a) Alleviate uncertainties stemming from policies by concluding the NZ Battery Project and abandoning the 100% aspirational renewable electricity target.
   b) Avoid duplicating existing work programmes by adhering to recommendations on market changes, if deemed necessary, by MDAG.
   c) Concerning the safeguarding of competitive markets, once again, adhere to the guidance provided by MDAG. Entrust the assessment and potential measures to the Authority and Commerce Commission, allowing them to evaluate and implement the necessary actions.
   d) Streamline the consenting process for new generation, transmission, and distribution, ensuring the timely and cost-effective delivery of infrastructure.
   e) Ensure regulatory frameworks facilitate proactive and forward-thinking investments in transmission and distribution infrastructure.
   f) Form industry consensus on the model and measures necessary to ensure new peaking generation is delivered.
   g) Ensure settings adequately balance trilemma considerations. Despite the importance of price signals, this must follow through with new supply. Prolonged high prices are unsustainable and detrimental to operating businesses, while providing a barrier to the same businesses undertaking electrification.
   h) As more renewables enter the system and peak demand grows, it is vital demand response is sufficiently incentivisied, ensuring businesses and networks face the right signals and are compensated adequately.

Accelerating supply of new renewable electricity

2. We agree that the task of increasing renewable electricity generation in New Zealand constitutes a significant undertaking. Looking ahead to 2030 and further out to 2050, New Zealand will require a considerable upsurge in new capacity and the corresponding level of investment to meet escalating demand. In other words, we need to build the capacity equivalent of about six Manapōuri is a hydro power stations including all transmission and distribution network upgrades just over a period of seven years.

3. Yet, we need to make sure electricity prices for business and household are affordable to support a shift to electrification. This is by no means an easy task, as such infrastructure requires huge investment which will come with a price tag for consumers, not to mention other challenges such as the skill shortage in the energy sector and access to equipment.

4. New Zealand's abundant renewable resources, which yield comparably high-capacity factors, send a compelling signal to invest further. The incentive for utilizing renewable resources extends to solar and geothermal. The latter, for example, has significant potential to expand further, providing a valuable source of baseload energy. These

opportunities provides a potent incentive and serves as a deterrent to building, and continuing to operate, thermal generation by effectively displacing older, more carbon intensive and expensive plant (despite creating challenges for adequate firming along the way to net-zero)

5. As identified by the EA, the long-run marginal cost of new supply, influenced by cheaper renewables, is relatively low and stable out to the forecasted period of 2025, but remain below the ASX contract prices, indicating constraints or barriers.[1]

6. Given the comparatively lower cost of renewables, no electricity generator is currently planning to build new thermal baseload capacity. The pipeline of upcoming renewables is set to be extensive. The pipeline for 2023 to 2025 and beyond reveals a large volume.

Figure 1: Pipeline of new investment by committed, actively pursed and other**.**

GWh/year	2023	2024	2025	2026+	Total
Committed	1,822	762	6	19	2,609
Actively pursued	3,073	2,639	2,402	14,521	22,634
Other	526	451	165	30,351	31,492
Total	5,421	3,852	2,572	44,890	56,735

Source: Concept Consulting (2022)

7. Therefore, it appears **the large problem facing participants does not stem from the lack of incentives including price signals for renewables** but rather numerous obstacles including current regulatory settings that provide possible barriers for why new renewables may encounter challenges. Put simply, the demand is coming from mass electrification, and now the supply must keep pace. These obstacles include:

    a) *Resource Management Regime:* New Zealand's resource planning regime is not fit-for-purpose. Obtaining consent for a new project often takes far longer than building a new development. The replacement legislation, while intended to strike a better balance between the environment and development, has introduced further doubts regarding the timely and cost-effective approval of renewable projects.

       BusinessNZ submitted on both replacement bills, highlighting provisions that are likely to impede the consent process, including the inadequate acknowledgment of a cost and benefit test, and the inherent trade-offs involved in every project, not matter if it is renewable or not.

    b) *Regulatory and political uncertainty:* The presence of the NZ Battery project is eroding investor confidence required for new renewables. The Government, in its capacity as regulator, plays a pivotal role in reduce regulatory uncertainty to encourage

[1] *Promoting competition in the wholesale electricity market in the transition towards 100% renewable electricity*, Electricity Authority (EA), October 2022

investment. The negative impacts of political and regulatory uncertainty on risk, and therefore investment, is extensively demonstrated in the economic literature.[2]

c) *Overseas Investment Act:* This legislation has imposed barriers that hinder the inflow of capital into New Zealand for investments in new generation energy projects. Although this predominantly affects smaller market entrants rather than larger generators, it remains a barrier to new players in the sector accessing capital.

d) *Labour, skills, and supply chain issues:* Challenges encompass the search for suitably skilled personnel to construct, maintain, and operate equipment. There is also a tangible risk and vulnerability within the supply chain, shown as bottlenecks and shortages that are driving up costs. For example, the availability of wind turbine supplies in New Zealand remains constrained.

e) *Network constraints*: Establishing grid connections can often require more time than the construction of the generation infrastructure. The prevailing resource management framework and current Input Methodologies present obstacles to forward-looking investment in construction of essential transmission and distribution infrastructure. At the same time, Transpower requires adequate and flexible resources to respond to the increase in new connection enquiries.

High prices placing pressure on business

8. Despite the current (and futures) market price sending strong signals to invest in new supply, and therefore a strong incentive, there are concerns generation will not be delivered at the sufficient scale required, and at pace, to deliver downward pressure on high wholesale prices.

9. These concerns are valid. They are reflected in elevated and volatile wholesale prices over the past five years. Futures also remain high, close to $150-$160. This has provided significant strain on commercial and industrial users, and as a result, this has weakened the attraction and viability of operating in New Zealand.

10. Energy inputs are a sizeable segment of businesses operating costs. The availability and affordability of energy is consequential in determining the profitability of many firms across New Zealand's economy, especially large energy intensive firms. Europe's energy supply shock demonstrates an extreme but salient example of the broad implications of energy scarcity and the impact high energy costs have on a country's industrial base, the people they employ, the goods they produce and export, and the living standards enjoyed by the wider population.

11. Over the period of high prices, production has been curtailed at several sites and opportunities to expand production have been weakened. The prospect of prolonged elevated wholesale prices, due to inadequate supply, is likely to be unsustainable for many businesses. Unsurprisingly, this limits production potential, and the subsequent living standards resulting from this activity.

[2] *Regulatory uncertainty and long-term harm to consumers,* Part of the response to the Electricity Market Monitoring Review, Kieran Murray and Veronica Jacobsen, Sapere, (2021)

12. This does not bode well for many objectives. Addressing several barriers to new supply, and their causes, will be vital in delivering affordable electricity and addressing these wider objectives encompassing cost-of-living concerns, economic growth considerations and emissions reductions.

13. For example, the same businesses who face high wholesale prices, are planning, or preparing to, decarbonise their processes. Many possible and viable solutions require electrification. In many cases, the operating costs of electricity will be a large determent for whether electrifying a certain process is viable and implemented.

14. Unaffordable electricity will slow the uptake of these new technologies and processes, reducing the speed of which electrification can occur, while limiting its corresponding emission reductions across the economy.

Subsidies

15. In this chapter of the paper, MBIE has asked whether additional incentives, like subsidies, are needed to accelerate new electricity generation coming onstream. **We do not believe subsidies are needed to incentivise new renewable electricity generation.**

16. In the New Zealand context, addressing these constraints would provide significantly greater improvements than introducing subsidies that fail to tackle these fundamental limitations, while possibly introducing distortions in investment choices.

17. The paper discussed measures, like Feed-in-Tariffs and other direct subsidies, which have effectively promoted the uptake of renewable electricity in other jurisdictions. However, these countries had different supply profiles, market structures and resource availability compared to New Zealand. Feed-in-Tariffs are often used for early deployment, at a stage where technology is not yet economically viable. Feed-in-tariffs often add an additional surcharge component to the price of electricity, increasing costs for consumers.

18. Feed-in-Tariffs have helped other countries transition away from a higher proportion of thermal generation, as seen in Australia and Germany, they come with expensive risks. This includes the risk of stranded assets once subsidies cease, an oversupply of electricity, leading to negative prices, underutilized assets and technology being placed in areas with lower than optimal capacity factors.

19. In New Zealand's context, other tools could possibly be suitable for accelerating new renewable energy projects without potentially placing costs on taxpayers. Power Purchase Agreements are one such approach.

20. PPAs play a vital role in providing stable and predictable revenue to developers while mitigating risks for investors through long-term offtake agreements. New Zealand's PPA market is not particularly mature compared to other countries. On the flipside, this is likely because of New Zealand’s small size and relatively few large industrial participants.

21. **We <u>recommend</u> exploring possible measures to enhance the role of PPAs in the future.** This could involve investigating the merits of PPAs for public sector entities by consolidating offtakes from institutions like hospitals and school or investigating the merits

of introducing measures that aggregates and matches supply and demand for new projects, which could stimulate investment.

22. The Government has significant influence through its all-of-government (AOG) tendering of supply contracts. It could accelerate more renewable generation by stipulating in their commercial arrangements that suppliers must develop new renewable generation for the purpose of meeting the public sector's supply contract. They could determine their willingness to pay for the premium associated with the specification.

23. However, the demand from public sector offtake agreements is relatively low and may not provide enough demand for larger generation projects. The potential for PPA's might also be limited for sizable projects.

Ensuring sufficient firm capacity during the transition and managing slow-start fossil fuel capacity during the transition

24. New Zealand's electricity profile is projected to surpass 96% renewables by 2030, as indicated by TIMES-NZ and various models from industry stakeholders. This represents a significant milestone, benefiting the environment and New Zealand's reputation as a sustainable destination for electricity users.

25. Despite achieving this impressive renewable milestone, thermal generation will maintain a pivotal role in stabilising New Zealand's increasingly intermittent energy system. This will persist until cost-effective and technologically advanced alternatives emerge to provide intra-day flexibility during high-demand periods or when wind and solar generation is limited.

The case for gas peaking

26. The role of thermal generation as baseload is evolving to a flexible position. As slow-start thermal generation phases out, which aligns with New Zealand's climate goals, the pressing challenge of ensuring resource adequacy becomes increasingly apparent.

27. **Concerns run deep across the sector regarding New Zealand's current flexible capacity, or lack thereof, to accommodate the growth in electrification and surges in peak demand periods. We agree with this concern**. The last two winters have seen the top ten largest peaks in demand despite record warmth, and El Nino weather conditions may further exacerbate the strain on the electricity system.

28. The situation becomes critical during cold snaps when wind power is limited, hydro capacity is maxed out, or when New Zealand faces a dry year. In such scenarios, the risk of outages becomes very real. This poses a substantial threat to the business community in New Zealand. Modern economies depend on a reliable and uninterrupted energy supply.

29. Increased resource scarcity and outages would lead to severe economic repercussions for businesses, affecting both their operations and the workforce they employ. The energy sector's success in transitioning is heavily contingent on energy affordability, particularly the cost of electricity. Inadequate resources, and insufficient fuel diversity, will jeopardise the reliability of the electricity system. We believe this risk should not be downplayed.

30. Building new peaking power plants is considered the most compelling safeguard against this risk. Grid-scale batteries also provide assistance; however, they still have limited charge and discharge capabilities spanning a few hours. Demand-side solutions encouraging load shifting are beneficial too. However, these fast-start peakers offer a proven, reliable, and swift responses to abrupt demand surges, serving as dependable backups during supply shortages, thus ensuring a more secure and stable electricity delivery for consumers. They are also relatively modest in terms of emissions, particularly in an increasingly highly renewable electricity sector.

31. Recent incidents, such as the damaged gas turbine peaking units in Stratford and the malfunction of Huntly's Unit 5, underscore the system's susceptibility to unexpected breakdowns in assets that are increasingly old and costly to maintain. Prior to these failures, there was already a shortage of firming capacity in the sector. These failures have intensified these concerns. Despite high lake levels, the country has encountered moments of constrained supply and limited flexibility this winter. The upcoming Winter Capacity Margins for next year are anticipated to be narrow, if not critical. Another failure would mean severe repercussions.

32. Transpower's Security of Supply Assessment report called for urgent investment in grid-scale batteries or flexible peaking plant.[3] The energy sector's TIMES-NZ model also illustrates the importance thermal still plays and is likely to play out to into the future.

33. According to the TIMES-NZ modelling, New Zealand's electricity system is likely to need natural gas, with gas peakers playing a role beyond 2030, both in Kea and Tūī, as shown in Figure 1 and 2 below, ensuring a backup to intermittent sources. Kea needs an additional 200MW of new thermal plant by 2030, and Tūī requires 400MW by 2030.

Figure 2: Kea electricity generation

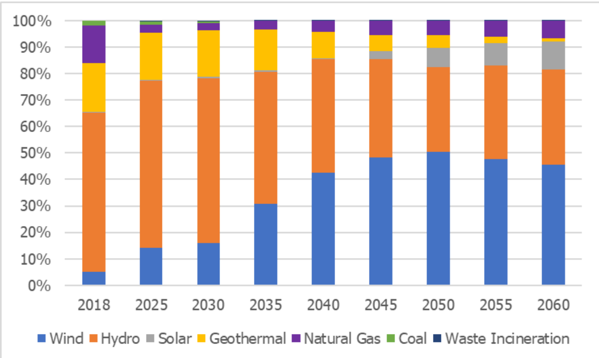
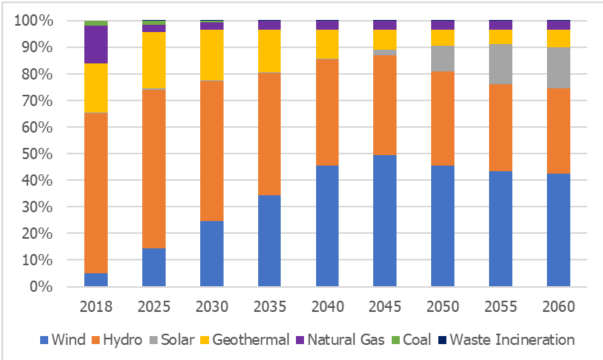


Figure 3: Tūī electricity generation



Note in purple and green, the ongoing role thermal plays in firming out to 2060.

34. BEC commissioned sensitive analysis in TIMES-NZ[4] which revealed that in a scenario with extremely high gas prices, reaching $39NZD/GJ, the model found the utilization of gas for thermal generation to be economically viable in Tūī and Kea. Even in the more climate ambitious Kea, gas remained in operation until 2055.

[3] Security of Supply Assessment, Transpower, June (2023)
[4] Energy Strategy Deep Dive using TIMES-NZ, BusinessNZ Energy Council and Sapere (2023)

35. Assuming that additional hydro options are maxed out, thermal is usually the most-effective choice for firming and TIMES-NZ places significant value on this firming source. This suggests that eliminating thermal generation, prematurely or haphazardly retiring it, would come with substantial system-wide costs. Had it been economically feasible, the model would have identified a pathway to eliminate thermal generation.

The problems facing thermal generation

36. Building new capacity is financially challenging in country with more renewables since they operate infrequently and for short durations, making it difficult to cover their operational expenses. In fact, the investment incentives for building new thermal capacity as backup are currently feeble. This situation is concerning as the necessity for additional capacity from a system security standpoint is clear. In addition to several economic barriers, thermal projects face a deteriorating social license to operate, while financing thermal projects have become increasingly difficult due to ESG requirements.

37. Participants that have the necessary consents to build new peaking capacity also do not want to proceed due to significant regulatory uncertainties that overshadow any final investment decision. Gas peaker options such as Todd Generation's Waikato Power Plant have been considered but not yet built, which may be because of an uncertain regulatory climate.

38. **We highlight that security of supply and resilient infrastructure should be a key focus over the next years, while delivering a strong sustainable backbone of generation. A symphony of solutions is needed.**

39. **We recommend abandoning the aspirational goal of achieving 100% renewable electricity**. This target is arbitrary and overlooks the broader energy landscape where the potential benefits are much greater. There are no associated mechanisms to support the achievement of this target, and, as highlighted above, none are necessary. Realistically, no investments in a peaking plant can be considered, and financial decisions cannot be justified, with an end date of 2030.

40. Further, eliminating the remaining 4% of fossil fuels from electricity generation in a 96%+ renewable electricity scenario, presents significant challenges and costs. There has been no assessment that has had a favourable conclusion. The Commission agrees that pursuing 100% renewable electricity would lead to market intervention and unwarranted uncertainty without commensurate benefits, as marginal cost of each abated unit of carbon rises significantly. For example, transitioning from 99% to 100% renewable electricity reduces emissions by a mere 0.3Mt CO_2e at an emissions cost of $1,200 per tonne, resulting in higher prices, reduced electrification, and diminished system-wide emission reductions.

41. **We recommend closing the chapter on the NZ Battery Project.** This project has added further uncertainty to the sector. This has posed a deterrent for investment in flexible generation and storage. **We strongly believe modular and decentralised solutions spread across the country should favoured over a centralised solution.** Recent extreme weather events have highlighted the vulnerabilities associated with relying solely on a single fuel source. The large-scale Lake Onslow project is situated on the wrong island, has significant environmental impacts, and will incur substantial costs,

and requires large HVDC upgrades (and risks of failure during a natural disaster), and falls short of meeting the system's immediate flexibility needs.

42. **We recommend forming industry consensus on the model and measures necessary to ensure gas peaking generation and/or peak demand response is delivered**. This should be achieved while upholding market fundamentals and avoiding distortions. Coordination among industry stakeholders, policymakers, and regulators to determine the scope and specifics of these measures would be beneficial.

43. **We are open to investigating the merits of a minimum notice period for thermal plant closures.** Requiring this information would offer greater transparency for market participants and the market operator to handle its closure. From a system security perspective, this speaks to delivering ensuring orderly transition, bolstering reliability, while being relatively straightforward to reverse.

44. Conversely, mandating a notice period risks being arbitrary, while imposing additional costs on the asset owner (passed to consumers). A notice period could require a closure beyond its optimal timeframe, slowing down the development of more sustainable or flexible capacity alternatives provided by the market.

45. The issue of generators prematurely shutting down plant without allowing for replacement capacity or providing the market with insufficient time to react is yet to be seen. Contact Energy notified the market well in advance about the Taranaki Combined Cycle closure and replacing it with capacity without a regulated requirement to do so.

46. **We agree that requiring a minimum notice period should be explored further if the closure risk becomes more pronounced**. We are aware the EA is looking at this option closely.

47. **We note that if thermal plant is required in the system, then there must also be sufficient upstream gas supply and flexibility to fuel electricity generation** Ensuring adequate gas supply requires incremental and persistent levels of investment. However, current policy settings are hostile to the economics of incremental drilling. The gas sector is complex and complicated, a more joint-up approach between the EA, MBIE, MPI and the GIC ensures each is not viewed in silos.

The role of DSF and increasing industrial DSF

Demand-side flexibility

48. The benefits of demand response are evident across the entire energy system, encompassing the partially reduction of peak demand, balancing supply, and demand, diminishing the need for additional poles and transmission lines.

49. Aggregators are now rapidly emerging, offering DSF services that empower consumers to extract value from their electric vehicles charging and hot-water management, lowering prices but also exerting pressure on the wholesale market, all without requiring end-consumers to directly manage or respond to price signals. This shift is also reflected in the introduction of more time-of-use tariffs by retailers, supported by more time-based, cost-reflective pricing by distributors.

50. However, these flexible resources must adequately fit within host distribution networks, and policy efforts must accommodate for this. These networks must manage emergencies and DER operational issues, but they face challenges due to network constraints beyond the Grid Exit Point (GXP). Initiatives like Dynamic Operating Envelopes (DOEs) and the development of flexible connections, as witnessed for e-bus charging in Auckland, have shown significant value in managing DER and ensuring efficient network use while minimising costs for consumers.

51. Despite the myriad of potential benefits, participants highlight several barriers impeding the widespread adoption of DSF. These obstacles include existing energy tariffs that dampen the prospects of DSF, the limited provision due to the lack of customer engagement responding to price signal, compliance costs, and information or coordination challenges.

52. From a system's perspective, it's imperative that the incentives for participants to engage in more demand response improves, reducing the possible occurrence of loss of load. The risk of blackouts is underscored by rapidly increasing prevalence of peakier spikes in demand and more intermittent forms of generation entering the system.

53. This trend has become apparent over the past few years and is likely to continue. Putting aside its problems and pitfalls, the RCPD incentivised demand response. Its removal has weakened the incentives to undertake demand response. In Auckland, there was a 7% increase in peak demand after RCPD was removed.[5] This highlights the need for swift solutions to encourage demand response. Winter 2023, and Winter 2024, show the system's balance between demand and supply is tight. The absence of measures to control load by encouraging demand response is of concern.

54. The paper and MDAG's comprehensive assessment underscore numerous avenues for expanding DER. We believe these matters are better housed with the market regulator and **we recommend adhering to MDAG's recommendations aimed at overcoming these challenges**, aiming for early successes while minimising the risk of unintended consequences in the emerging and evolving field that could stifle innovation and limit consumer benefits.

55. For these recommendations to be effectively implemented, the Authority must be adequately equipped with resources to thoroughly assess MDAG's suggestions and carry out its tasks. We acknowledge that the Authority had applied for extra funding specifically to review and implement MDAG's recommendations in the 2023 Budget. Regrettably, part of this funding request was denied. **We recommend that the Authority be sufficiently resourced to fulfil this work programme.**

Industrial demand response

56. The paper explores r potential ways that could improve the prospect for industrial demand response. Bilateral agreements are providing opportunities to deliver more demand-side response, with some agreements containing mechanisms that provide a steady revenue

[5] TeslaForecast (2023)

stream, as well as reward for delivered demand response and compensatory measures for production losses.

57. Nonetheless, there looms some concerns in the sector regarding the future limitations of demand-side response, particularly with industrial flexibility, if there is a sole reliance on bilateral arrangements as the primary mechanism.

58. Industrial users require bespoke arrangements, customised software, and specific rules on when DSF will be invoked, alongside requisite compensation. This requires setting up bespoke agreements, which limits the economics of flexibility. Conversely, initiatives aimed at standardisation, might stifle innovation in this early developing field.

59. Nevertheless, currently, the economic viability of demand response at scale is challenging, especially for sizeable industrial players contemplating participation in the demand response component of Real Time Pricing. Participation in demand response at a large scale requires significant investment in capital and operating expenditure for plant and process modifications.

60. Presently, there are concerns in the sector that the financial gains from participation fail to justify the considerable investments and efforts required. This disincentive becomes evident when production curtailment would occur without adequate compensation. Without remuneration for demand response, the prospect of demand response losses its attractiveness, as businesses understandably would be reluctant to reduce production.

61. This could be problematic if there is insufficient demand response at the volumes required to mitigate against loss of load, especially if new firming capacity is not onstream in short to medium term. The significance of demand response gains importance through assessments conducted by MDAG, underscoring the pressing need for substantial demand response, especially in a system edging closer to a higher portion of intermittent electricity.

62. Introducing a market-based solution that rewards demand response, channeling these benefits back to the affected consumers offering demand-side flexibility, emerges as a possible solution for improving the economics of industrial demand response. However, implementing such a system might have some challenges and might not deliver the intended outcomes of incentivizing demand response. A possible mechanism or reward would have to balance implementation costs against expected benefits.

Workably competitive electricity market

63. We agree that competition is paramount for the underpinnings of a dynamic and efficient electricity system. Competition replaces less effective and pricier methods with more efficient and cost-effective approaches to meet consumer demand.

64. Competition between participants motivates producers to innovate, striving to outperform their competitors. Innovation drives technological advancements, resulting in enhanced performance across the energy trilemma. At the same time, the fundamentals of competition, and the perception of legitimate competition, or the lack thereof, have profound implications on the durability of the wholesale market structure.

65. Conduct measures encompassing the proactive monitoring and enforcement of trade conduct at the disposal of the Authority and Commerce Commission must ensure that incumbents remain competitive without inadvertently distorting investment decisions, yielding inefficiencies, or harming the long-term interests of consumers.

66. From a whole-of-economy perspective, the long-term interests of consumers are fundamental to securing a favorable environment for New Zealand's businesses to operate, manufacture and export. The interests of consumers extend to ensuring the supply of affordable and secure energy to enable more electrification, and its related objective of reducing emissions. Possible roadblocks to competition will undermine both affordable energy and emission reductions. This highlights the important role of the market regulator.

67. The responsibility for exploring potential interventions to enhance competition should reside within the purview of the Electricity Authority and the Commerce Commission. MDAG, advising the Authority, with its members' comprehensive expertise across the sector, have conducted extensive research and assessments regarding the benefits and potential drawbacks of market interventions aimed at significantly altering the market structure.

68. **We recommend adopting MDAG's recommendations after their final assessments has been made.** The group's evaluation has included comparative analysis of practices and market structures, all aimed at advancing New Zealand's electricity market and achieving a substantial increase in renewable electricity penetration.

69. Globally, electricity systems, be they energy-only markets, capacity-mechanism incorporated structures, or those with emergency reserves, or few market players or many, each grapple with inherent trade-offs and varying benefits. MDAG acknowledges these trade-offs and explains why deviating excessively from the present market structure might not necessarily improve consumer welfare in the long-term.

70. Broadly speaking, we align with MDAG's recommendations that several conduct measures recommended can be effective means to counteract market power, while mitigating against the unintended consequences and time-consuming nature inherent in large-scale structural changes.

71. MDAG has highlighted a potential concern about competition in a future characterized by increased intermittent renewables. Specifically, there's the prospect of incumbent hydro owners accruing more market power. However, this scenario hinges on multiple factors and will evolve depending on market dynamics and influx of new participants.

72. This remains largely unknown. The emergence of competition issues in the wholesale market in the future is uncertain. Should such issues arise, the Authority and Commerce Commission possess the legislative powers to address them.

73. Any argument in favour of vertical and horizontal separation, along with physical disaggregation, must start with a robust problem definition which justifies intervention. A tangible problem supported by evidence is required. The importance of a well-defined

problem cannot be overstated. Implementing a solution that doesn't address a clear problem runs the risk of aggravating other parts of the system instead of solving any issue.

74. In the absence of a definitive problem, ad hoc and significant structural changes, could compound existing market uncertainty. Such changes could be long and costly, potentially deterring, and deferring investment in new generation — posing an obstacle to achieving New Zealand's climate objectives.

75. **We <u>do not support</u> a single buyer model and question the problem it aims to address.** The paper does not adequately assess why a single buyer model is needed and how it could improve any outcomes across the trilemma. Implementing this proposal would represent a significant intervention and a comprehensive undertaking that is not justifiable. We believe that this proposal is largely a diversion from more pressing and pertinent barriers, like the ones addressed on page 4 and 5.

<u>A transmission system and distribution network for growth</u>

The right regulatory settings to ensure proactive investment

76. The large surge in electricity generation outlined in the paper requires significant expansion and investment to New Zealand's transmission and distribution infrastructure. It is evident that additional lines, substations, and transformers will be built to increase the grid's capacity to handle this increase in generation. The need for investment extends to fortifying the network's resilience in the face of extreme weather events.

77. Electricity Distribution Businesses (EDBs) and transmission investment will be responsible for supporting a significant shift towards electrification, such as the adoption of electric vehicles (EVs). The extent of investment is significant. According to the BCG report titled, the Future is Electric, New Zealand could require close to $22 billion in distribution infrastructure (capex + opex) by 2030 to support this transition, about 30% more than existing investment levels.

78. Despite electrification being clear, the challenge lies in synchronising these investments through regulatory frameworks. To support new infrastructure, Electricity Distribution Businesses (EDBs) and transmission investment must be ahead of the curve, ensuring capacity is available to meet consumers' decisions. This relies on an approach that ensures investments are sensibly timed and where the case of need is robust.

79. However, the existing input methodologies (IMs) were designed during a more stable and predictable environment. In an era where electrification is anticipated to grow predictably but not in a linear fashion, it is essential the IMs and TPM take into account a wide array of uncertainties and enable flexibility to adapt to unforeseen changes in demand

80. As the sector transforms, the required infrastructure will have a cost impact on consumers. EDBs must possess the capabilities and resources to meet this demand. However, given varying capabilities of different EDBs, the Commission must ensure that the regulatory settings align with financeability, including sufficient flexibility to manage cashflows within the regulatory periods.

81. A steady state or incremental approach could possibly slow and increase the cost of electrification, and thus jeopardise the country's energy transition. Insufficient allowances for EDBs and insufficient ability for Transpower to invest proactively would likely result in a slower and impeded transition, making it more challenging for the country to meet its international commitments to achieve net-zero emissions.

82. Especially for transmission infrastructure, delaying investment can incur higher costs than investing prematurely. When constructing a line, a connection or interconnection, it's important to plan for future need, as it is often prohibitively expensive to construct an alternative line. It is also unlikely that a community would accept another line in proximity, making planning essential. This demonstrates the importance of regulation that enables investment in projects not only focused on immediate need.

83. **We <u>support</u> changes to the regulatory settings and processes overseen by the Commerce Commissions to enable more investment in transmission and distribution infrastructure.** This should include providing sufficient flexibility mechanisms for reconsideration of capital expenditure allowances during the regulatory control periods. While we support enabling proactive investment, we acknowledge the delicate balance between affordability and covering the necessary expenses in vital transmission and distribution infrastructure.

Consenting constraints

84. We also highlight that a new project can take up to seven to ten years to obtain consent for transmission infrastructure, primarily due to the consenting regime and land use issues raised during this process. This is too prolonged and hampers New Zealand's ability to meet its climate targets.

85. In our early submission on the newly proposed National Policy Statement on Renewable Electricity Generation (NPS-REG) and Electricity Transmission (NPS-ET), we stressed the importance of truly streamlining the resource management regime but recommended amendments to enhance the robustness of the NPS-REG/ET.

86. While the new NPS-REG represents some promising improvements, certain aspects of the statements' wording, or lack thereof, show a step in the wrong direction, particularly concerning existing generation and new transmission infrastructure.

87. Existing renewable generation faces the same challenges as new generation with the resource management regime, particularly when reconsenting existing hydro-electricity generation. This forms the backbone of New Zealand's renewable electricity system. It needs to be afforded protection in the resource management regime through certainty of access to the renewable resource and long-term consent durations. **We recommend this direction is included in the revised NPS-REG.**

88. Mitigating, remedying, and avoiding the impacts on amenity values remains a large challenge in erecting essential transmission infrastructure. The assumption that it is possible to avoid all impacts on sensitive environments, while meeting our targets, is excessively optimistic. Infrastructure has an impact on amenity values. This makes visual effects a common reason for opposition against transmission. This is problematic.

89. New Zealand’s efforts to decarbonise will have some impact the environmental visually. Certain effects can be mitigated and remedied. But in many respects, a transmission line comes with unavoidable trade-offs. The existing legislation does not provide flexibility to acknowledge these inherent trade-offs. This is reflected in an effects management hierarchy in the NPS-ET that as unpractical. While compensation, as outlined in section 3.8, appears to be fair, it runs into problems.

90. However, how Transpower is going to offset the visual impact of its long-linear infrastructure, and how redress will be provided, and who would receive this compensation for visual amenity losses remains unanswered and uncertain. Even if these questions could be answered (which is unlikely), any costs are likely to be significant, and ultimately borne by the electricity consumer. **We <u>recommend</u> that the NPS-ET must account for these problems and ensure consenting is delivered in a reasonable time.**

91. Resource consenting constraints also extend to distributors. Long waiting times and heightened costs associated with obtaining consent act as a barrier to realising the essential investment in distribution infrastructure. **We <u>recommend</u> extending a provision for electricity distribution within the NPS-ET**. This inclusion will aide guidance to Councils, providing greater consistency and potentially reducing time constraints.

Developing a framework for offshore renewable energy discussion document

Overarching comments

1. **We support the Government's commitment to establishing a regulatory framework for the feasibility, construction, and operation of offshore renewable energy**. It provides assurance and the requisite framework to enable the commercial potential of harnessing New Zealand's abundant offshore renewable resources.

2. The main priorities underlying the Government's approach on the offshore renewable energy regulatory framework should include:

    a) Fast implementation of a permit regime with a straightforward criterion to ensure feasibility studies can begin.
    b) Streamline the commercial permit stage by simplifying it to a pass or fail test based on a simpler capability criterion.
    c) Simplify the consenting process by extending current policy guidance in the NPS-REG to the EEZ Act, so both Acts have the benefit of guidance.
    d) Ensure coherence and avoid duplication in decision-making by appointing an authority for the EEZ and RMA components.
    e) Clarify roles and taking necessary action for local port infrastructure, including investigations into required upgrades and funding mechanisms.
    f) Develop a proactive workforce and supply chain strategy in tandem with the feasibility studies process, while being integrated into a sector-wide plan.

3. The implementation of the regulatory framework must occur promptly and efficiently. Offshore wind resources are in high demand globally and delays in implementing a permitting system could lead to investors and developers diverting their investments elsewhere.

4. Certainty is paramount. Ambiguity and the absence of defined exclusive rights pose substantial obstacles, if not one of the most significant, to the development of offshore wind projects. This framework must align seamlessly with the consenting process, ensuring compatibility without adding unnecessary layers that might unduly impede progress.

5. Several crucial actions are pivotal in unlocking offshore development opportunities and should be prioritized and planned alongside the regulatory framework. Given the large-scale nature of offshore projects, infrastructure planning is necessary. Upgrades to ports are imperative to support the assembly and installation processes. Funding and delivery mechanisms for these upgrades, however, remain uncertain and should be clarified.

6. Achieving the task of delivering offshore wind resources requires robust, resilient, and adaptable supply chains, as well as an accessible and skilled workforce capable of delivering the required infrastructure. Proactive workforce and supply chain development

strategies are essential to mitigate risks associated with large-scale offshore projects while generating cascading benefits. This should fit into a wider strategy across the sector.

Further detail on feasibility permitting

7. **We support the adoption of option 2 as it offers greater flexibility to the developers in selecting the project's scope and size, allowing them to evaluate an applicant's capability within the assessment criteria.** This approach also enables a more judicious examination of the reasonableness of the project's scale.

8. We believe that imposing a stringent area could pose challenges in determining an appropriately sized dimension. The paper mentions that within the context of New Zealand, the area is likely to be about 1 gigawatt (GW), equivalent to a range of 150 to 250sqkm. The paper further suggests that this range can serve as guidance.

9. Providing guidance on the project's size, with the flexibility for projects to exceed this guidance, is preferable to establishing a rigid cap. The latter approach appears somewhat arbitrary, as imposing a 1 GW cap may unjustly exclude larger projects. This could jeopardize the economic viability of the proposed projects while limiting the potential benefits of economies of scale associated with larger developments.

10. **Supporting guidance for regulators and developers to consider a 1 GW threshold for fixed-bottom acreage and a 2 GW threshold for floating acreage is recommended**. Regulators should assess the pros and cons of accepting applications that surpass these thresholds. The absence of such guidance may lead to a single developer securing a large area, particularly in the territorial sea, strategically "land banking" most of it, and blocking opportunities for other developers, thereby stifling competition. Yet 'use-it-or-loss-it' provisions should reduce this likelihood.

11. Guidance in the territorial sea is essential, especially when compared to areas within the Economic Exclusion Zone (EEZ) where available space is more abundant. The territorial sea harbours limited locations for development. It's worth noting that a 1 GW guidance for projects could potentially accommodate approximately four projects generously in the territorial sea off the coast of Taranaki. Setting the guidance lower than 1 GW risks adversely affecting the economic feasibility of these projects.

12. **We highlight that a new factor has been recently introduced into the feasibility criteria, which evaluates the electricity system impacts of a project. We oppose the inclusion of this consideration before a feasibility permit is granted because it is too early to gauge the impacts accurately.** The assessment of electricity system impacts heavily relies on assumptions about future demand growth and other developments in power generation.

13. These assumptions are subject to change over the period of approximately seven years between feasibility permit application and the commencement of construction. At the same time, permit holders will be concurrently navigating Transpower's new connection process, potentially leading to a duplication of efforts in assessing energy system impacts. Assessing the wider system impacts should be a co-ordinated effort between the regulator,

Transpower and the developer throughout the feasibility, and a fixed deadline for system impacts would not be appropriate.

<u>Commercial permitting</u>

14. **We <u>agree</u> that a developer-initiated approach when applying for commercial permit is preferrable**. This minimizes the disruption to project schedules caused by an abrupt time limit imposed by the regulator. Timelines may change for many reasons. It would be unreasonable for the regulator to enforce a restrictive timetable.

15. The paper mentions that ongoing communication between the regulator and permit holder will be a regular occurrence, with the regulator periodically evaluating the permit holder's capability, including their financial and technical capability, among other factors**. We <u>believe</u> it is more fitting to accommodate unforeseen changes in the feasibility plan during this process**. Offering flexibility is crucial, as developers may unexpectedly need to alter their course of action.

16. The consultation paper highlights that failure to adhere to the feasibility plan could jeopardize the developer's feasibility permit and potentially result in the release of the allocated space.

17. The regulator should require substantial justification for revoking a permit. As currently stated, a feasibility permit holder could lose their permit if the feasibility plan deviates from the original intent.

18. There should be a high threshold for initiating an assessment and making any decision to revoke a permit. As mentioned, there is a significant likelihood of deviations from the initial plans, possibly due to delays caused by unforeseen factors beyond the developer's control.

19. This situation may arise due to the extensive and inherent complexity of such projects. The existence of a low threshold for deviating from a feasibility plan introduces substantial uncertainty, potentially leading to unwarranted permit revocations due to unforeseeable circumstances.

20. We broadly <u>support</u> the proposed commercial permitting assessment criteria. We perceive this criterion at the commercial stage as a checkpoint to measure whether applicants remain capable of fulfilling the project's requirements. However, **we <u>advise</u> several changes should be made to make the commercial stage simpler.**

21. The evaluation of a developer's capacity is shown in New Zealand's oil and gas sector. Under the CMA, section 29A(2)(b), the Minister must consider an applicant's technical and financial capability before granting a permit. This ensures that the Minister has confidence in the applicant's ability to execute the proposed work program effectively.

22. **We <u>agree</u> that the regulator responsible for granting permits should scrutinise whether an applicant can operate day-to-day in alignment with established industry best practices**, demonstrate their financial robustness, risk management strategies, a well-defined management plan, a deep understanding of complexity and technical expertise, and other relevant factors like health and safety.

23. Operating offshore poses inherent hazards, particularly in New Zealand, where weather conditions can be unpredictable. Consequently, it is imperative to evaluate an applicant's credentials in health, safety, and environmental management alongside their technical and financial competence.

24. As previously stated in our earlier submission, we advocate for transparent criteria in assessing feasibility permit eligibility. This involves establishing a minimum compliance threshold and assigning a 'score' to each applicant. Developers should earn higher scores for demonstrating greater adherence to technical and financial criteria. In cases of score equality among overlapping applications, applicants should attempt to resolve the matter among themselves, with a lottery system as a fallback option.

25. At the commercial permitting stage however, applications should undergo a simple pass-or-fail assessment based on predefined criteria. Again, this serves as a checkpoint to validate ongoing capacity.

26. **We <u>oppose</u> any mechanism that compares and awards commercial permits to different parties during this phase**. A competitive assessment between two or more projects should be confined to the feasibility stage.

27. When multiple parties applying for commercial permits face connection constraints in allocated areas, projects should be determined by developers' ability to secure offtake agreements, obtain consents, and establish grid connections. Intervention driven by a preference or perceived lack of market demand, would be an overreach.

28. If multiple separate projects are likely to secure consents, offtake arrangements, and transmission connections, the regulator or Minister should refrain from favouring one project over another. At this commercial permitting stage, evaluation should focus solely on assessing whether the developer remains capable, as mentioned through a pass-or-fail assessment.

29. **We <u>support</u> developers' ability to start the process of obtaining consents before receiving a commercial permit**, acknowledging their exclusive right to apply for a commercial permit based on their granted feasibility permit status. Allowing developers to start the consenting process during the feasibility stage ensures a more time efficient development timeline. As noted earlier, it is important that projects can move at pace,

30. **We <u>oppose</u> public consultation during the commercial permit application process,** as it is not the appropriate forum for discussing project merits or drawbacks. Public engagement will occur during the consenting process. This will avoid unnecessary delays in offshore development.

31. As suggested in BEC's previous submission, aligning the national interest test with the Overseas Investment Act 2005 is recommended to ease administrative burdens on developers. Expanding the criteria to include broader national interest considerations, such as alignment with New Zealand values and economic interests, may introduce complexity. We note that national interest tests do not occur for onshore developments. They should

not occur for offshore developments. Any national interest test is best suited for overseas capital under the Overseas Investment Act.

32. **We also believe any mention of competition test considerations during the commercial permitting stage is questionable**, given that projects' area is addressed during the feasibility stage.

33. The paper mentions the possibility of giving the decision maker flexibility to consider any other matter they consider relevant as part of this criterion. **We question the wording of 'any other matter**.' The criteria should be clear and objective from the outset, avoiding surprises in the process.

The economics of the regime

Lack of large enough offtake agreements

34. Offshore wind developers interested in New Zealand face some barriers when it comes to making the commercial feasibility of building and operating these developments a reality. New Zealand's economy is marked by a scarcity of industrial users willing to enter creditworthy and extended Power Purchase Agreements (PPAs) of this size spanning a duration of fifteen years or longer. These long-term PPAs serve as a linchpin for rendering large scale renewable development viable.

35. The lack of creditworthy offtake agreements impedes the fulfilment of lending requirements, thereby increasing project costs and slowing the rate of development for these projects. Due to the sheer size of these offshore projects and the lack of one large user to fill the demand, developers will likely have to secure multiple PPAs concurrently. This is likely to be a difficult task for multiple offshore developers. This creates challenges for securing finance without the assured offtake and certain return.

36. However, the outlook and likelihood of securing large offtake agreements may undergo change in the future, driven by the emergence of new technologies, a more fluid customer base and increasing grid demand, demonstrated by electrification across the economy shown in TIMES-NZ.

37. This aspect of technology change assumes particular significance contingent upon the pace of hydrogen development, which holds the potential to scale up significantly and fulfil supply requirements. Assuming the favourable economics of production at scale, including the price of electricity and technologies for storage and transport, hydrogen produced in New Zealand could meet demand for aviation, heavy vehicles, and other functions, requiring up to 88TWh of electricity according to MBIE's hydrogen scenarios.[6]

38. If a similar scenario eventuates in the long-term, out to the 2040s and beyond, offshore developments become more favourable. Yet the degree to which demand materialises for these offtake agreements remains largely uncertain. The paper outlines a few possible mechanisms to encourage its development, including Contracts for Difference (CfDs).

[6] New Zealand Hydrogen Scenarios (2022), Castalia

39. However, CfD's, like all mechanisms have trade-offs. We outline the trade-offs and considerations policymakers must grapple with below:

a) Contracts for Difference CfD's can significantly improve the certainty of a project's return through an assured strike price, improving its ability to obtain finance to construct a project. This would encourage large projects offshore that do not broadly have competing uses or face local opposition compared to onshore projects.

b) New Zealand is expected to witness an unprecedented surge in electricity demand over the coming two decades and beyond, as industrial processes electrify, and modes of transport electrify. CfD's could incentivise larger projects to be built to meet this significant increase in demand, both from the grid and other sources including hydrogen production. This could be beneficial in incentivising electrification and accelerating emission reductions.

c) On the other hand, the role of support mechanisms providing financial incentives and thereby stimulating development would deviate from technology neutrality, which could introduce distortions in relation to other energy sources, diverting resources away from their most efficient and lowest cost means of delivering energy precisely where and when it is needed.

d) In the UK, CfDs have been used since 2014 to facilitate large-scale renewable projects, like onshore and offshore wind, reducing reliance on gas and coal generation. New Zealand's current abundant renewable resources, primarily hydro and geothermal, have positioned the country uniquely with a strong renewable energy foundation, reducing the need for additional economic support to increase renewable deployment.

e) It is well understood that entities or individuals engaging in a certain activity, in this case building new generation, are better able to assess, manage and hedge against the risks inherent in every project. CfD's externalise some of the internalised risks to other parties. This includes market participants, competitors and or the Government.

f) Shifting this risk from a developer to the Government (all taxpayers), through financial stabilisation mechanisms, could heighten the risk of inefficient over-build and stranded assets once support is relinquished. This is because participants who do not face the true cost increases the risk of an over-supply of resources.

g) CfD's may also impact existing assets and the risk of those assets becoming stranded. This is especially the case if new electrons are brought to market by a CfD that do not have an offtake (supressing spot prices due to the Government holding the risk and substituting the role of private capital). This would result in the transfer of the risk (cost) from energy producers, and as a result also users, to the general taxpayer, diminishing scarce funds available for other wider societal objectives.

h) CfDs could also discourage investment in new generation that is needed in the short to medium term out to 2030. Developers could hold off on new investment on non-CfD forms of generation if there is a large CfD project expected on the horizon that would bring significant supply to market (Similar to the effect of uncertainty created by the NZ Battery Project on investment).

i) It also could risk displacing and putting non-CfD renewable sources at a disadvantage, creating perverse incentives of seeking supported generation over non-subsidised forms of energy, potentially skewing the pipeline of investment.

Revenue gathering mechanisms

40. We <u>oppose</u> the introduction of a revenue gathering mechanism in the form of royalties or payment of allocated rights.

41. We understand the rationale behind implementing a revenue collection mechanism, which is to appropriate a portion of the gain derived from offshore development. While parallels can be drawn with Crown minerals domain and, by extension, the Crown Minerals Act of 1991, it is important to note that there exist disparities in terms of ownership rights.

42. Crown Minerals represent a category of resources that are vested under national ownership and are extracted in the pursuit of the national interest. This arrangement is underpinned by a well-defined rationale that justifies the Crown's entitlement to royalties, considering the inherent value and relative scarcity.

43. This differs when it comes to offshore renewable energy. While wind resources are not inherently scarce, the regions that offer the optimal wind conditions necessary for energy generation are indeed limited in number. In such instances, the regulatory framework is primarily focused on the identification and allocation of areas within the commons located in marine and coastal regions under the purview of the Crown.

44. Granting a commercial permit that allows for the construction and operation of an offshore development creates a scarce property right, one that is likely to preclude or significantly restrict other activities within the designated area. This allocation invariably excludes other developers from pursuing similar developments within the same space.

45. In the event multiple stakeholder's express interest in securing this limited property right for the same area, the most efficient approach would be to allocate it through a competitive tendering process with the highest bidder receiving the right, wherein interested parties compete for its acquisition. This would more accurately mirror their willingness to pay and their eagerness to secure the exclusive property right.

46. At first glance, this approach appears reasonable. However, it would potentially stifle early interest and involvement in offshore wind development. Experiences with tendering in Germany have demonstrated that they can curb competition, and not necessarily led to developments.

47. This limitation on participation becomes pronounced when developers are confronted with the necessity of making a substantial upfront capital outlay merely to secure a permit for a specific area. Setting aside capital before any feasibility assessment has been conducted, places developers at significant risk and serves as a disincentive to invest as future

assessments could illustrate the project's lack of commercial viability. In this case, the payment is a sucken cost.

48. The capacity to secure funding typically becomes evident only when a project has demonstrated its commercial viability after a comprehensive feasibility assessment has taken place, environmental information has been gathered and offtake agreements have been agreed.

49. Introducing a royalty structure would increase the levelized cost of providing energy, resulting in higher costs for consumers if the projects were to materialise. This runs counter to the objective of fostering investment in renewable energy generation. It would also introduce an imbalance between offshore and onshore renewable generation, which is not subject to royalty payments.

50. It would be ideal if any royalty obligations exist. This is also shown in overseas jurisdictions. This would serve to ensure that the barriers to entry are not disproportionately onerous compared to the opportunity to invest in offshore renewables. It is however reasonable to require compensatory payments when a project encroaches upon existing rights.

51. If an offshore project disrupts or diminishes the activities of existing fishing operations or quotas, compensation payments should be given for the loss of value. This should extend to additional externalities on other parties. This practice of compensation is commonplace in international jurisdictions when pre-existing rights are affected.

52. **We <u>support</u> recovering the administrative costs of the regulatory framework from participants,** as this is a standard practice that ensures those who benefit from the permitting system shoulder the associated costs. The proposal for an application fee and annual fee is fair in this context.

<u>Maori Rights and interests and enabling Iwi and hapū involvement</u>

53. **We <u>support</u> developers engaging with iwi and hapu throughout the commercial permitting process,** as well as during the feasibility stage. This approach ensures that cultural and environmental impacts are assessed and effectively mitigated. Engagement extends to delivering broader benefits to local communities, including employment opportunities.

54. Developers express their support for this engagement, recognising the significance of comprehensively understanding the repercussions of their actions and work programs on iwi environmental plans.

55. It is important that iwi and hapu are given ample information and afforded adequate time to formulate their perspectives. Equally vital is the commitment of decision-makers to act in good faith and genuinely consider these viewpoints.

56. The extent to which iwi and hapu will be involved in this process remains uncertain, and the demarcation of responsibilities between the developer and the Crown is somewhat unknown.

57. In its role as a Treaty partner, the Crown (the regulator) should assume the responsibility of evaluating the potential consequences of offshore wind development on pre-existing rights before authorising a permit for any prospective applicant.

58. **We <u>prefer</u> the use of requirements akin to those set out in the Petroleum Programme 2013.** We propose to use sections 2.2, 2.4 and 2.5 of the Programme, stipulating that the Minister and agency tasked with permit allocation engage in consultations with affected iwi and hapu, incorporation with the perspective applicant. The consultations would encompass various impacts, such as permit specifications and work programs.

59. It is important that the Crown's obligation aligns more closely with its role as a treaty partner, avoiding the undue shift of responsibility onto industry stakeholders and iwi. This issue is particularly acute considering the time and financial limitations faced by iwi and hapu. In cases where iwi and hapu are expected to play a more proactive role, the Crown must ensure that the relevant iwi and hapu are adequately equipped with the necessary resources to enable their meaningful participation.

60. **We <u>do not support</u>** any mechanism that grants veto rights, enabling the rejection of application solely on the grounds of one iwi or hapu deeming the engagement to be insufficient. Instead, the adequacy of engagement should be assessed by the decision-maker, considering a range of considerations within the established criteria.

61. To ascertain the appropriateness of engagement, an impartial iwi advisory group could be established to evaluate whether the engagement process was satisfactory and whether both the Crown and developers engaged in participation. As previously mentioned, this should be factored into a broader points system in the approval process for both feasibility and commercial permits.

62. However, determining adequate engagement is difficult and hard to quantify. Outlining prescriptive engagement actions runs the risk of becoming a rigid checkbox exercise. This should be avoided.

<u>Environmental consents</u>

63. **We <u>support</u> the permits not replacing or removing the need for environmental consents.** This is consistent with the regulatory regime for petroleum and minerals. We agree that the permitting regime should not consider an environmental assessment on the development’s effects on the environment to avoid duplication as this will be dealt with through the consenting process.

64. We are aware that the National Policy Statement for Renewable Electricity Generation (NPS-REG) encompasses guidance for offshore renewables within the territorial sea. However, there is no guidance in the Economic Exclusion Zone (EEZ). This is problematic because offshore projects are also likely to occur in the EEZ. **We <u>recommend</u> extending**

the policy guidance in the NPS-REG to encompass offshore generation within the EEZ Act, without impacting existing rights.

65. This will provide more clear guidance and directives to Councils during the consenting process and potentially speed up approvals. Presently a calling-in process exists for nationally significant projects, merging the RMA and EEZ aspects referring them to the EPA. Consolidating these under a single decision-making authority would simplify this complicated process and avoid duplication.

<u>Enabling Transmission and other infrastructure</u>

66. **We <u>support</u> a developer hybrid model and a Transpower owned and operate position once this infrastructure has been built.** This model mirrors oversea jurisdictions, including the United Kingdom.

67. Offshore wind projects must factor in investments for onshore grid capacity. However, existing regulatory frameworks hinder proactive investment by Transpower in new transmission infrastructure. This lack of proactive approach creates a dilemma for new projects, as final investment decisions are elusive without assured grid access. Conversely, Transpower cannot ensure infrastructure without confirmed connections, exacerbating the challenge. This creates a chicken-and-egg problem.

68. This approach has been effective in recent decades. However, in the next two decades and beyond, projects must move at pace to ensure New Zealand achieves its decarbonisation targets, demanding swift expansions in electricity generation. Regulatory frameworks overseen by the Commerce Commission can enable sufficient flexibility and proactive investment, while carefully balancing affordability. This relates to both offshore and onshore generation.

69. Although we support the developer-led model, offshore wind transmission is not mutually exclusive compared to onshore transmission. **We <u>support</u> Transpower's onshore responsibilities extending to offshore assets.** While Transpower does not need to initially finance offshore assets, its role to ensure integration with onshore assets is critical. This alignment ensures a stable and reliable grid, while optimising planning. Grid connection is vital for power quality and the ability to withstand disruptions, preventing subpar transmission infrastructure that might compromise quality.

70. **We therefore <u>support</u> Transpower having a clear and decisive role in designing and planning the offshore transmission grid**, ensuring smooth coordination, optimisation with onshore infrastructure and appropriate connections standards.

71. Nevertheless, coordination between the regulator, Transpower and the developer will be important to ensure integration. This includes joint concept studies and regional system impacts, and wider energy system impacts.

<u>Decommissioning requirements</u>

Perpetual liabilities

72. Decommissioning is undoubtedly an important component of an offshore development's life cycle. However, we provide caution against its stringency as currently proposed. As written, the permit holders would be liable for meeting the costs of decommissioning even if they transfer out of a permit and the new permit holder fails to carry out and fund decommissioning. **We strongly <u>oppose</u> the proposal and implementation of perpetual liabilities.**

73. Imposing obligations on former permit and license holders, in the event of a transfer, would interfere with commercial arrangements and undermine the established property right. Perpetual liabilities create further work for those seeking to transfer permits or licences, creating a barrier for transfers to occur.

74. Transferors and transferees would need to factor any ongoing liabilities into any divestment or investment decisions, likely slowing any future transfer of interests. Transferors are unfairly burdened as they are likely to have to accept a lower offer for assets to offset the potentially higher decommissioning costs imposed and may still be liable to meet decommissioning costs in future.

75. Creating such barriers to transferring interests and the associated liabilities means property rights are no longer divestible. Clearly defined and divestible property rights are a fundamental part of any market economy. Where rights are restricted, the incentive to invest is severely weakened. This contradicts the aim of creating a regulatory environment that encourages investment in offshore renewable energy developments.

76. It is also largely not proportionate to the environmental risks associated with the relevant infrastructure being abandoned. The potential damage to the environment is low, as illustrated in the consultation document. This is especially true compared to the extraction of offshore hydrocarbons infrastructure.

Financial security

77. The paper notes the prospect of a financial security that affirms the cost of decommissioning. **Any financial security amount should increase gradually over time, reflecting the NPV decommissioning costs in the future**. If the security is not reflected in NPV, the upfront cost at the commercial permitting stage would be large. Developers would have to set aside a large amount of capital before the development is built and operational. Tens of millions of dollars would be allocated for decommissioning, a process not slated to happen for another four decades. This is difficult to justify and would severely undermine the projects' economics unnecessarily.

78. **In the event of sale and a permit transfer, we <u>support</u> a capability assessment to determine whether the transferee can undertake the relevant decommissioning, with the new permit holder lodging a financial security to guarantee funding in the event of decommissioning**. Again, this is more appropriate than placing liability on the original permit holder in perpetuity.

79. As proposed, the developer would be required to meet a defined criteria for decommissioning, both at the feasibility and commercial stages. **We question the need for assessing an applicant's decommissioning capability during the feasibility process.**

80. A project's specifics, including its size and potential, is largely not solidified and highly uncertain during the feasibility stage. The assessments and monitoring undertaken to test the feasibility of a development will conclude whether a project is viable and can be built, and thus decommissioned at some point. Assessing a developer's decommissioning capabilities years before these comprehensive assessments take place is premature.

81. If any testing during the feasibility stage does occur, it should remain a simple plan indicating how decommissioning could possibly happen with a cost estimate subject to change. The commercial permitting stage is best suited to outline the procedures and costs associated with decommissioning.

82. **We support adequate procedures to protect against the abandonment of infrastructure and ensure it will be dismantled with minimal effect on the surrounding environment.** This is particularly important for hazardous material that could have negative impacts on the environment. On the other hand, not all pieces of infrastructure are created equal, and impact the environment differently.

Decommissioning flexibility

83. The underlying assumption that "leaving the seabed and environment as you found it" reduces the negative impact on the marine environment is disputed and largely depends on a case-by-case basis. Offshore platforms have shown to support ecosystems by acting as artificial reefs, harbouring threatened species[7] and increasing fish biomass.[8] Similar environmental benefits have been demonstrated in and around offshore hydrocarbon infrastructure, with marine fauna inhabiting steel substructures[9] and pipelines that degrade over time with minimal impact.[10]

84. The decommissioning criteria should reflect the varying positive and negative impacts certain offshore equipment have on the environment. A flexible approach that allows options for partial or complete removal of offshore installations is preferable. The determination should be decided based on a net environmental benefit test. A compulsory full removal option could bring undue to cost without any corresponding gain to the environment.

85. Globally, there have been few instances of offshore wind project decommissioning, primarily because the projects are relative age in their life cycle. This has limited determining the best practise.[11] The scarcity of decommissioned offshore renewable projects underscores the likelihood of continued learning and improvements in the efficient

[7] Coolen JWP (2017). North Sea reefs: benthic biodiversity of artificial and rocky reefs in the southern North Sea
[8] Claisse JT, Pondella DJ, Love M, et al. (2014). Oil platforms off California are among the most productive marine fish habitats globally
[9] Fowler, Ashley M (2018) Environmental benefits of leaving offshore infrastructure in the ocean,
[10] European Commission, (2022), study on decommissioning of offshore oil and gas installations: a technical, legal and political analysis.
[11] Smyth K, Christie N, Burdon D, et al. (2015). Renewables-to-reefs? Decommissioning options for the offshore wind power industry.

and environmentally friendly dismantling of offshore wind infrastructure. Flexibility is essential to accommodate the evolving knowledge and best practices in this field.

Appealing decision-making

86. Providing a route to appeal permitting decisions is fair and reasonable. Applicants who consider a permit has been declined or revoked unjustly should have the ability to appeal the decision. This is particularly important in the revocation of a permit, both at feasibility and commercial stages.

87. A permit is an established property right. Developers must be assured that this right cannot be revoked arbitrarily at the whims of changing criteria or political preferences without redress. The decision to undertake an offshore development requires billion-dollar investment. If a property right is not durable over time and can be revoked freely without an elevated threshold, no investment will occur.

Gas Transition Plan Issues Paper

Our overarching comments:

1. Overall, **we support this issues paper and its contents.** It has shown awareness of the issues and opportunities faced by the sector, and the wider interdependencies between the producers and users of natural gas. The paper demonstrates the importance of gas in smoothing the transition to a more sustainable energy system.

2. **Priorities** underlying the GTP should include:

   a) An enduring and bipartisan understanding about the important role of gas throughout the transition and the right policy settings to reflect this role.
   b) Restore enough confidence to ensure investment in deliverability by ruling out further heavy-handed interventions and replacing existing decommissioning requirements that lock away capital needed for incremental drilling.
   c) Investigate routes on how CCS technology could be deployed sooner, while developing regulatory settings that enable and incentivise the use of CCS technology.
   d) Keep all options open. Regulatory interventions aimed at reducing emissions may limit optionality, i.e., a ban on new residential gas connections limits biogas and hydrogen, destroying option value.
   e) A joint-up approach is needed in the formulation of policy. The direction of ETS policy could determine a firms' presence in New Zealand and its demand for gas.
   f) Clarify the role of renewable gases, including the actions required to enable biogas or hydrogen blending.
   g) Clarify the role, responsibilities and costs involved in the decommissioning of some existing gas infrastructure.

Industry, Commercial and Residential Sector

3. The trend for natural gas in New Zealand's energy system is clear. It will play a lesser role as demand decreases due to increasing carbon prices, technological developments in a range of substitutes and decreasing electricity costs, rebalancing the scale towards switching to other sources.

4. This is particularly evident for residential, commercial, low-temperature industrial users. Such an outcome is necessary and beneficial for New Zealand's climate goals (in that it emits less emissions compared to other thermal fuels) and simply a matter of favorable economics in many cases, ensuring that supply is reliable and affordable during the energy transition.

5. However, until widespread improvements occur in the economics of substitute fuel sources, it appears natural gas will remain the lowest cost and most reliable option for some sectors and industrial users that do not have commercially viable alternatives. For some users, it remains the only option for the foreseeable future. Some need specific properties of flame; others cannot tolerate micro-outages or the flickers in electricity supply; others need the very high temperatures provided by gas.

6. Without sufficient gas supply, these industrial users will have to curtail production or shut completely. The effects of a supply squeeze were well demonstrated in 2020. A significant

decline in production at the Pohokura gas field coinciding with a dry year saw higher prices with significant costs and disruption for energy users. Some businesses shut entirely.

7. Looking forward, if demand is uncertain, investment in well developments will not take place. On the demand side, industrial users have deep concerns that gas will not be available to be contracted. These concerns have deferred investment in plant and raise serious questions about the practicality of operating in New Zealand.

8. The prospect of departing users, combined with an accelerated decline in gas production, provides a real risk of a disorderly exit from natural gas. **We believe the risk is far more material than illustrated in the paper.**

9. A disorderly exit of natural gas would have significant economic and social consequences across the country, increasing the cost of firming renewable generation and energy inputs for many businesses. A disorderly exit of natural gas could undermine the objective of decarbonization, the social license of the transition itself, the living standards of entire communities, and the risk that New Zealand may need coal or imported LNG to fill the supply gap.

10. Shifting demand dynamics and reduced activity in some cases is not necessarily a suboptimal outcome. There will be significant efficiency gains from a whole-of-energy-sector perspective. However, it is crucial that the decline in natural consumption happens in a coordinated way that protects against widespread negative consequences across the energy system.

11. As the Gas Transition Plan (GTP) unfolds more clearly, its ultimate outcome will be pivotal in meeting our emissions targets, protecting security of supply, mitigating consumer costs and delineating roles across the sector, which will hopefully clarify the boundaries and scope of each role in this intricate sector as gas consumption decreases. This undertaking is complex with many dynamic elements set against the backdrop of uncertainty.

12. **We are pleased to see the emphasis placed on the important role of industrial users in the discourse of gas supply and the transition.** Their presence will not only uphold economic value through exports, employment, and goods for the country but also plays a crucial role in ensuring security of supply across the system. The trajectory of industrial gas demand will impact the phase down in gas production.

13. The demand for gas from Methanex significantly underpins the development of gas fields to fulfill its supply contracts. Without essential consumers like Methanex, minimal investment would take place. As highlighted in the paper, methanol production emits considerably less CO_2e than the gas it consumes, with 60-65% of the gas consumed is used as a feedstock embedded in the product.

14. Overseas, numerous shipping companies are reducing their fleets' emissions with Methanol. Maersk has recently ordered six more methanol dual fuel containerships to add to their outstanding order of twelve ships. The six vessels will save about 800,000 tons of CO_2 emissions annually[12], according to the company. Rather than exporting methanol

[12] A.P. Moller – Maersk continues green transformation with six additional large container vessels.

overseas, there's an opportunity and possibility for it to remain in New Zealand as part of the transition, optimizing the process.

15. Whether this occurs remains uncertain and will be influenced by various commercial factors. However, policymakers must recognise these possibilities and avoid dismissing or ruling-out options that could prove viable in the future. Businesses should be able to explore and purse these options (if they bear the true carbon cost). This perspective extends beyond methanol to other users. Ensuring the deliverability of existing natural gas demand will offer greater certainty for users like Methanex while keeping possibilities open.

16. Restricting fuel options by constricting natural gas supply further through regulatory intervention outside the ETS heightens the risk of carbon leakage. Industrial users require large quantities of energy. Escalating prices due to fuel scarcity make it challenging for businesses to remain in New Zealand, potentially leading them to move to other jurisdiction using more carbon intensive fuels and processes, while damaging local activity, employment, and exports.

17. This likelihood is compounded by uncertainties surrounding the Emissions Trading Scheme and its potential impact on carbon leakage. **We <u>assert</u> that the ETS should not be viewed in isolation from the Gas Transition Plan.**

18. **We <u>recommend</u> a more integrated approach between MfE and MBIE concerning energy policy and the ETS.** The future settings of the ETS will significantly affect gas demand and supply. Recognising the intricate connection between gas demand and carbon prices will provide clarity regarding the role of gas in the future and its gradual decline.

<u>Restoring investor confidence</u>

19. Reaffirming the role of gas, the role of alternatives like biogas and hydrogen, including what the Government will do, and not do, and when this will happen, will be useful in clarifying the emission reductions needed, while improving certainty in a sector where the direction of travel is blurred by uncertainties. In particular, the role of Government policy over time.

20. Outlining future policy settings and actions that are either excluded or scheduled will instill greater assurance and clarity about prospective investment decisions in the sector. While many factors, including future technology costs, the pace of innovation, supply-demand dynamics, and unexpected events, all remain outside the purview of policy planning, this approach can mitigate the risk of ad hoc and sudden policy shifts that undermine investment confidence throughout the sector. This includes a clear set and sequencing of priorities spanning years ahead. Yet the plan should be flexible to better adapt to technology advancements in the future.

21. As mentioned, gas consumption is declining. Production at New Zealand's gas fields are well and truly entering the decline phase. Nevertheless, ongoing investment is needed to smooth the transition to a more sustainable system by realizing sufficient supply,

maintaining deliverability, and avoiding a disorderly thermal exit. This figure is estimated to be close to $300-500 million every three to five years to maintain production levels.[13]

22. New Zealand's energy system model, TIMES-NZ, shows the need for investment out to 2050. The model shows around 50PJ of natural gas is consumed in 2050 in both scenarios. Even in the more climate focused Kea, gas remains as a back-up fuel to support increasing levels of intermittent sources.

Figure 1: Kea – Fuel Consumption for all subsectors, all end use, all technology (PJ)

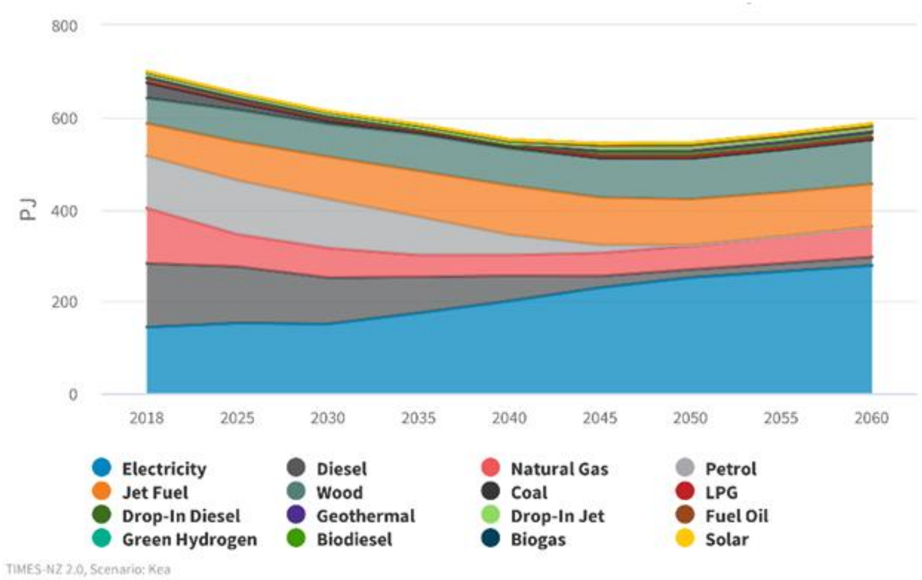
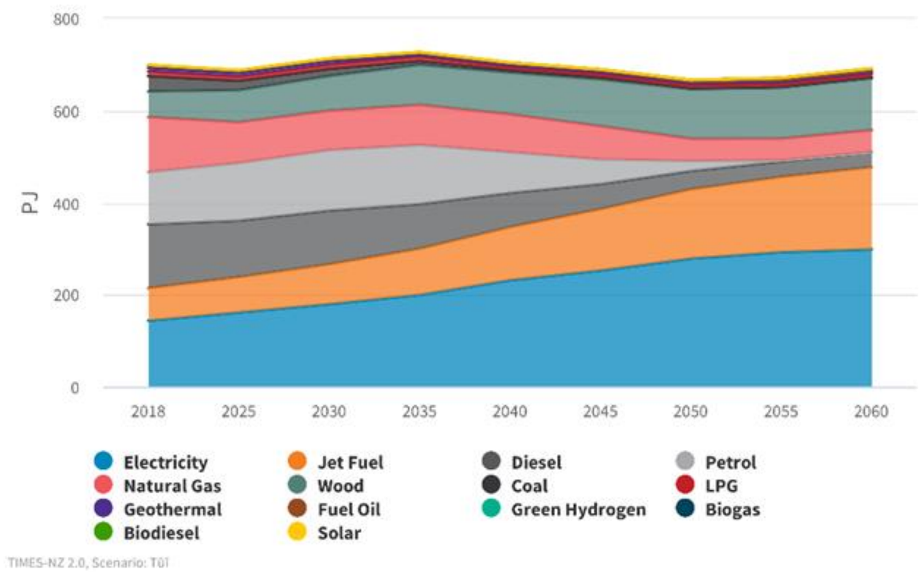


Figure 2: Tui – Fuel Consumption for all subsectors, all end use, all technology (PJ)



23. Investments are usually 'lumpy,' requiring very large upfront costs. These investments incur significant risks. They operate in the backdrop of inherent engineering and economic

[13] Gas Industry Go, Briefing to the Incoming Minister, October 2020, p4.

uncertainty. Millions of dollars are often spent before any gas had left the ground. This requires sufficient rewards to justify this risky venture. If the rewards are far less, or the risks are too high, capital with will be divested elsewhere to find sufficient return at the corresponding risk.

24. Further risks can be caused by uncertain future policy settings, complicated through signals conveyed by decision-makers that hint to further costs in the future that risk future return on present day investments. This disincentivizes upfront investment. Present-day policy settings can do the same.

25. Policy changes, reflected in the offshore oil and gas exploration ban and changes to decommissioning liability requirements, are two examples that have culminated in sending a clear signal that has repelled investment in this naturally high-risk sector. Unsurprisingly, needed investment has been low.

26. **Both international and domestic investors have come to denote New Zealand as a country with a high sovereign risk profile**. Several companies have diverted resources and invested elsewhere. For New Zealand, as a comparatively small market, this is problematic. The 'size of the prize' is lower due to our scale. Recent interventions, and uncertainty about future policy settings, have reduce the prize further.

27. The lack of adequate investment has been reflected in New Zealand's trilemma ranking. The energy trilemma framework helps benchmark the performance of our energy system globally. Despite meaningful improvements in our sustainability score over the past decade, our security score has declined due to worsening import dependency and declining energy storage.

28. It is also reflected in MBIE's 2023 gas reserves data has shown a 17% decrease in Proven plus Probable (2P) reserves. Estimated gas reserves have now dropped below ten years of remaining use for the first time. Gas supply remains tight, despite last year being the wettest and warmest winter on record, with more electricity supplied from hydro.

29. This year has provided enough rainfall to push hydro-lakes well above historic averages this winter too. This illustrates that an unexpected dry year in the coming years ahead could have significant and widespread implications on security of supply, while threatening existing supply contracts that could be undermined to keep the lights on.

30. The concern of a lack of investment is reflected in the GIC's analysis, using modelling by Concept Consulting, found that production could come largely from existing reserves until 2027, but beyond 2027 it is likely to require development of contingent resources. This will require even more investment.

31. Investment that does not occur due to uncertainty and lack of confidence may lead to severe shortfalls. This will impact the affordability of energy. Major users exposed to the wholesale electricity and gas prices have expressed concern this winter over affordability and access to gas. Gas plays an important firming role in the electricity market during dry years, so this issue flows through to electricity affordability by pushing up the spot price. This will undermine efforts to electrify.

32. Below are several recommendations on the Government's role that we believe could help restore confidence and improve the incentive to ensure sufficient indigenous supply is extracted.

a) **We <u>recommend</u> that the plan must <u>rule out</u> any further regulatory restrictions on the prospecting and drilling of natural gas that would damage investment confidence.**

b) **We <u>recommend</u> that the ETS should remain the main policy tool in impacting investment decisions and the extent of such investment in the sector**. As mentioned, industrial and commercial customers will switch to other economic alternatives as the carbon price continues to rise. For some this will mean electric low-temperature space heating. For others, this will mean biomass alternatives. The ETS will guide these decisions.

c) **We <u>believe</u> the GTP should aim to achieve consensus across both, the sector and the political spectrum.** The transition itself, and the role gas will inevitably play, transcends the three-year parliamentary term. Investments have long time horizons. And constant course corrections damages confidence. Emulating the Zero Carbon Act, bipartisan agreement on the important role of gas, the opportunities of biogas, hydrogen, and CCS to reduce the sector's emissions further is incredibly important.

d) **We <u>recommend</u> a more proactive approach when engaging with the industry, exploring avenues to enhance investment viability by being responsive to the need of ongoing investment to ensure security of supply**. These businesses harbour many solutions and should not be viewed merely as the problem.

e) **We <u>recommend</u> policymakers should leave as many options as possible open to reduce emissions in the gas sector.** For example, **we <u>strongly oppose</u>** proposals to ban new residential gas connections, when the uptake of renewable gas is a significant opportunity to reduce emissions and stranded asset risks. **New Zealand's energy mix must remain diverse by not ruling out options**. Fuel neutrality, and no overt picking of winners will help balance the trilemma.

   Producers require confidence that there will be a sustainable market demand to recover their upfront development costs. A ban would deter confidence in biogas deployment and undercut this opportunity to reduce the sector's emissions and mean the incurred costs related to the decommissioning of the gas network may not be mitigated.

f) **We <u>recommend</u> replacing the current financial security requirement faced by licence holders for decommissioning activities, as introduced in the Crown Minerals (Decommissioning and Other Matters) Amendment Bill in 2021.** While we support license holders' bearing the financial cost, rather than taxpayers in the event of abandonment, but the current requirement is flawed and overly restrictive.

The current legislation requires capital to be set aside for decommissioning activities slated for years or decades in advance. This inefficiently ties up valuable capital that could be utilised for incremental drilling. Producers emphasise this cost disincentive in hindering incremental drilling and deliverability.

Policymakers should consider the merits of other measures including insurance models that are in place in other jurisdictions. Insurance products ensure decommissioning occurs and is paid for when required, whilst not locking away large quantum of upfront capital that have more productive uses. Insurance products would also better reflect the corresponding risk associated with decommissioning compared to a financial security stipulating an amount which risks being overtly disproportionate to the level of risk.

Importing LNG is far from a true climate-friendly solution

33. The lack of investment would likely mean imported LNG would substitute indigenous supply. We are aware that building new import terminals can be done swiftly, and analysis conducted by the GIC demonstrate that imported LNG is not as costly as initially perceived.

34. This should not downplay the fact that LNG is substantially more expensive than indigenous supply. Displacing indigenous gas with imported LNG due to impeding local production, defies economic logic for the country's business community that are vulnerable to energy input costs, jeopardizes supply security, harms the climate, and weakens our resilience against global shocks. As stated by the Government, decarbonisation should not mean deindustrialisation.

35. However, impediments to sufficient natural gas supply during the transition heightens the risk of deindustrialisation and carbon leakage, with firms leaving to other jurisdictions with far cheaper and more dirty forms of energy. We believe this is not an exaggeration. Energy inputs are a large determinant to whether a business is inevitably profitable, especially large energy users. Prolonged energy scarcity would likely lead firms to move offshore.

36. The energy crisis faced in Europe is a stark reminder of the vast economic and social consequences of an energy shortage and the heavy reliance on imported natural gas, affecting both the stability of the continent's industrial base and the living standards of communities.[14]

37. **It is worth repeating that we do not endorse business-as-usual**. Demand and supply will continue to decline. This is needed to achieve necessary emission reductions. But investment confidence must be restored to ensure deliverability to the smaller base of critical consumers over time.

The role of gas in electricity is small but significant

[14] '*Crippling' Energy Bills Force Europe's Factories to Go Dark:* The New York Times, (2022)

38. We agree with the stances taken surrounding the role of gas in electricity generation. Until alternative fuels become cost-competitive, natural gas will be needed for peaking capacity to protect security of supply. Our stance on the questions provided in this section can be found on page 6 – 7.

Don't limit opportunities: renewable gas and pipeline infrastructure

39. **We agree that biogas holds many promising and viable opportunities to reduce the gas sector's emissions, coupled with providing many co-benefits in waste utilisation**. Biogas also has the potential to reduce the liability of decommissioning network infrastructure.

40. The complete cessation and decommissioning of gas pipelines would come at a substantial cost. Instead, by utilising existing gas infrastructure, the costs linked to stranding and replacing infrastructure can be minimised, ensuring the efficient allocation of resources and averting unnecessary expenses. This approach safeguards and maximises the utility of the current gas infrastructure, delivering tangible value and long-term benefits to the energy system.

41. There exists genuine uncertainty surrounding the transition's impact on existing gas pipeline infrastructure, especially regarding long-term assets and the risk of stranded investments. Biogas, mirroring natural gas in its chemical composition, can be seamlessly blended with natural gas within pipelines. Embracing biogas in the residential and commercial gas sector could expedite the decarbonization process substantially.

42. The process of decarbonizing gas fuels offers the advantage of obviating the necessity for extensive replacement or displacement of current gas infrastructure, as well as household plumbing and appliances. This kind of overhaul can incur substantial costs on a large scale. For instance, in the Esperance Energy Transition Plan, which entailed disconnecting fewer than 400 homes in a Western Australian township, the expenditure reached approximately A$12 million, translating to $30,000 per home.[15]

43. The argument for biogas is reinforced when viewed from a systemic perspective. By reducing emissions in the sector, it can postpone necessary upgrades to the grid and distribution networks, simultaneously diminishing the need for new generation. Such an approach yields wide-ranging benefits in terms of cost efficiency and affordability across the entire system.

44. As indicated in the paper, there is a possibility that pipelines may operate at significantly reduced pressure in the future. Nevertheless, there are situations where the network might contract, leading to the decommissioning or lack of upgrades in infrastructure. The allocation of responsibilities and costs in these scenarios remains unclear, including how any consumers dependent on those pipelines will be supported through the transition. Currently, there is an assumption that the expenses will be distributed and borne by other consumers. The plan must confront the issue of decommissioning directly and address how infrastructure repurposing will take place.

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[15] Horizon Power, Esperance Energy Transition Plan, (2023)

a) **We recommend that policymakers should clarify Government support for the principle of financial capital maintenance (FCM) for the owners of and investors in gas pipeline infrastructure.** This will ensure these pipelines are not decommissioned in an unmanaged way, and options to convert industrial and domestic users to renewable gases will remain on the table. Maintaining FCM will ensure confidence is maintained for investors in other regulated infrastructure assets, including electricity networks.

b) **We <u>recommend</u> a thorough review of Part 4 of the Commerce Act 1986, focusing on price quality regulations for FirstGas, GasNet, Powerco, and Vector**. Part 4 was primarily designed for a world where gas pipeline infrastructure was stable or expanding without competition, a paradigm that worked effectively. However, it may no longer be suitable given the current circumstances. The existing regulations outlining revenue allowances lack the necessary flexibility to cover decommissioning costs. A review of these regulations would be advantageous in devising a more appropriate regulatory framework.

c) **We <u>recommend</u> that the final plan must define the role of blending biogas and outline the prerequisites for its adoption.** This approach would enhance certainty regarding pipeline infrastructure in the future. Present uncertainties have raised concerns, evidenced by the Commerce Commission's adoption of accelerated depreciation for pipeline infrastructure to address this uncertainty. If these uncertainties are reduced and the associated risks are minimised due to better conceptualising the future of biogas, accelerated depreciation may become unnecessary.

d) **We <u>recommend</u> investigating possible changes to landfill fees over time and its corresponding impact on increasing the economic viability of biogas**. Landfill chargers have increased from $10 per ton to $40 per ton over the past few years and will increase further to $50 per ton. This has improved the financial incentive of diverting waste away from landfill to alternative users.

   New Zealand's relatively modest landfill chargers may not be suboptimal considering the ample availability of potential landfill sites in comparison to other countries with higher population densities and limited land availability. However, establishing certainty regarding the trajectory of landfill fees and their long-term implications, coupled with clear guidelines, would offer a more definitive understanding of the economic prospects of biogas.

e) **We <u>recommend</u> a more integrated approach involving local Councils, MBIE, and MfE.** The successful blending of biogas demands a concerted and comprehensive coordination across the entire supply chain, engaging multiple Councils. Currently, the involved parties operate in relative silos, lacking effective coordination. A collaborative effort among these entities is important for the seamless adoption of blended biogas.

f) **We <u>agree</u> with the paper's focus on renewable gas certificates and <u>recommend</u> for its prompt implementation**. The potential for biogas and hydrogen becomes significantly more robust in regions with an established framework for trading renewable gas certificates, alleviating the necessity for buyers to actual molecules directly from biogas producers. Such a system would stimulate increased demand from organizations interested in mitigating their emissions.

Carbon Capture Utilization and Storage

45. By substituting gas consumption with electricity and biomass, enhancing industrial process efficiency, and incorporating residential and commercial biogas blending, emissions will significantly decrease. However, further emission reduction opportunities exist through CCUS.

46. Globally viable and economically feasible, CCUS technology shows significant potential in specific New Zealand sites. This was shown in past applications at the Kapuni gas field two decades ago and current uses in geothermal. Under the Climate Change Response Act, CCUS technology qualifies as a removal activity, yet entities currently can't receive NZUs for CO2 removal.

47. The Government must establish a comprehensive CCUS regulatory framework, enabling entities to earn units. This approach would better allow the removal of CO2 in the gas sector emissions, allowing gas-dependent firms to operate in New Zealand, minimising climate impact and overall system costs.

48. This was demonstrated in recent modeling undertaken by Castalia showing CCUS as the most effective, cost-efficient emissions reduction pathway among six studied. We **recommend** that the Government must investigate routes on how CCS technology could be deployed sooner and ensure a framework is developed effectively and swiftly.

Interim Hydrogen Roadmap

Our overarching comments:

1. Overall, **we support this interim hydrogen roadmap.** The paper adeptly recognizes the potential opportunities in hydrogen and how they can be effectively leveraged during the transition, integrating into an energy system with high renewables penetration.

2. **We judge the main priorities underlying the hydrogen roadmap should include:**

    a) The roadmap should aim to enhance the investability of hydrogen. The first few pages should attract this investment by telling a positive story. It should provide a lucid understanding of hydrogen's role in New Zealand. Once this clarity is achieved, it will attract investments and international attention. Given the capital-intensive nature of the transition, New Zealand must be open to foreign investments to capitalize on these opportunities, especially in the absence of robust domestic capital markets.
    b) Conduct a comprehensive assessment outlining the distinctive characteristics of New Zealand's possible hydrogen market, aligning the imperative to decarbonise. This assessment should be grounded in our unique energy system, geographical nuances, economic landscape, and demand profile, prioritizing local considerations over global trends that may not be pertinent to New Zealand's future demands. Modeling for the final roadmap must incorporate these specific contextual factors.
    c) Perform analysis encompassing the uncertainties and risks associated with hydrogen utilization. This analysis should also explore alternative applications, ensuring that the evaluation of hydrogen is not isolated from other potential uses.
    d) Ensure ongoing monitoring of international and domestic developments that could significantly influence the economic and technological viability of hydrogen adoption in New Zealand.
    e) Promptly implement the recommendations in PwC's New Zealand's hydrogen regulatory pathway report submitted to MBIE in July 2022. This will help reduce the roadblocks hindering hydrogen's deployment in New Zealand.

Context and hydrogen's role

Domestic and International Context

3. The issue paper adeptly delves into the global landscape of hydrogen usage, spotlighting its applications in countries such as the United States and Japan, showcasing the developments over recent years. While this international perspective offers valuable insights, it must be carefully integrated and contextualised within the subsequent section of the roadmap, specifically focusing on hydrogen's role within New Zealand.

4. The evolution of hydrogen technologies is intricately linked with the unique characteristics of each country's energy systems, a factor that will continue to shape its trajectory.

5. Market dynamics for hydrogen vary significantly between countries discussed such as Japan and Germany, and the United States due to distinct needs, applications, and energy system attributes. For example, in some countries, like Japan, they grapple with constraints in renewable electricity supplies, leading to a higher reliance on imported clean fuels for their decarbonisation, especially for their transportation needs. Geographical isolation, such as that faced by New Zealand has ample generation potential, but comparatively has a greater requirement for clean fuels for air travel and international shipping, thereby shaping unique demands.

6. These differences underscore the diverse fuel requirements of each country's unique attributes, influencing electricity systems and resource allocation in distinct ways. Conducting a rigorous assessments of New Zealand's needs for hydrogen, and its alternatives, relating to the country's characteristics is imperative.

7. However, we are aware that the transport component of the roadmap was largely based on international trends from data originating from the International Energy Agency (IEA), while it did not adequately consider domestic trends and wider factors, including rebates for project capex and opex introduced over the past few years.

8. Relying only on megatrends is not helpful for providing a clear pathway for investment. Such rigorous analysis into New Zealand's use case will offer insights into hydrogen's role and alternative fuels that could prove more economically advantageous from a whole-energy-systems perspective. **We recommend that any modelling must encompass domestic contextual factors.**

9. This approach ensures that efforts and regulatory measures are channeled into the most suitable use cases tailored to New Zealand's specific context. Currently, as mentioned the paper, the Government has invested $88 million. It is clear that scarce funds must not be invested in areas where alternatives are more certain to be economic. This is no easy endeavor and is naturally fraught with uncertainty.

10. Robust analysis of economic cases of hydrogen will be vital, both for the successful application of hydrogen in New Zealand and its palatability for regulatory intervention. Systematic analysis of hydrogen and its alternative fuels, including its source of demand, available feedstocks, that could meet demand must underpin the completed roadmap.

The future role of hydrogen

11. This section outlines hydrogen's role in the future, prompting response on its likely role. **We agree with the diverse applications of hydrogen discussed in the document**. These applications are many and will be contingent on numerous factors, underscoring the challenges associated with electrifying certain processes or substituting them with alternative sources.

12. The imperative for clean fuels, such as hydrogen, becomes apparent when considering the Climate Change Commission's recommendations in the 2023 draft advice to inform the strategic direction of the Government's second emissions reduction plan. It showed

the need for significant emission reductions in emissions budget's 2 and 3, both in the transport and energy sectors.

13. At this stage, hydrogen predominantly shows significant potential to decarbonising hard-to-abate sources, such as heavy-duty transport, short-haul aviation, maritime transport, or potentially energy for export.[16] However, its application faces hurdles in in energy intensive activities that rely heavily on large quantities of natural gas.

14. The specific roles of hydrogen, within the context of New Zealand, remain uncertain. Producing green hydrogen at the necessary scale needed to curtail emissions presents challenging. However, the economics of green hydrogen is expected to improve as the price for electrolysis and fuel cells falls. Key challenges lie in the in establishing compelling business cases and achieving scalability, both of which hinge on finding solutions to overcoming the additional costs of producing green.

15. New Zealand, being a technology-taker, cannot ignore overseas developments in hydrogen technology. Hydrogen's role will evolve alongside changes in the global economy and technological advancements.

16. Larger economies have made substantial investments, allocating billions for research and development, tax incentives, and subsidies on a significant scale. These investments are likely to have profound implications for the progress of clean fuel technology, including hydrogen. The extent to which global innovation will unfold and the competition for limited technology resources during the early to medium stages remain uncertain.

17. These key uncertainties and risks associated with hydrogen, and its alternatives, will influence its inevitable application. **We <u>recommend</u> that the roadmap must outline these risks, uncertainties surrounding hydrogen, and its alternatives more clearly, enabling these risks to be managed and making sure policymakers are well-informed about the uncertainties before implementing interventions.**

18. It is crucial to monitor breakthroughs, both internationally and domestically, particularly in potential step change developments that could significantly enhance cost-efficiency, potentially altering the trajectory outlined in the roadmap. These considerations should encompass the evolving costs associated with hydrogen production, transportation, and utilization over time.

19. We note that there have been various scenarios explored by many entities within the sector, with numerous assumptions and conclusions that have been drawn. We anticipate that the final roadmap will present scenarios that are transparent, outlining assumptions and detailing the prerequisites for each scenario to materialise, along with the corresponding likelihood of these events occurring.

20. This approach should encompass factors such as demand probability, competition from alternative sources, and input costs. By offering a clear and transparent set scenarios

[16] GIC Hydrogen Scenarios Castalia final report 070922.pdf

of hydrogen's potential roles, this approach will provide clarity to all stakeholders in the energy sector. It will illuminate the path forward, justifying the actions taken by government policies.

The Government's role

Providing investment certainty

21. **We believe that the roadmap's clarity and envisioned trajectory for hydrogen are vital in fostering investment in the sector.** International investors demand assurance regarding government policies and the regulatory framework that will influence the economic feasibility of operating in New Zealand. A well-defined roadmap delineating both the government's and the private sector's roles instills confidence and fosters investment.

22. Prioritising "investability" should underpin the roadmap's objectives. The government's responsibilities include streamlining consenting processes, not just for hydrogen, thereby reducing the cost, effort, and time required for private sector initiatives to proceed, ensuring the successful implementation of these projects.

Accountability of the roadmap's delivery.

23. The paper mentions the merits of a sector co-ordination body responsible for assembling expertise and engaging a diverse group of stakeholders regularly. Their objective would be to collaboratively discern the next steps to facilitate the deployment of hydrogen. **We support this proposal or a comparable task force to spearhead and oversee the implementation of the roadmap**. This group should be responsible and accountable for executing specific actions, reporting directly to the Minister.

Implementing pre-existing recommendations

24. We **support** the swift implementation of recommendations in PwC's New Zealand's hydrogen regulatory pathway report submitted to MBIE in July 2022. This report outlined the clear regulatory hurdles acting as impediments to hydrogen technology deployment in New Zealand. The prescribed actions taken in the report are imperative for developing an effective roadmap.

Green credentials for exported hydrogen.

25. The paper maintains a balanced perspective, considering both domestic demand and export prospects, avoiding favoring one option over the other. The viability of hydrogen export from New Zealand is uncertain due to various factors that might not materialise. Hydrogen as a gas has a very low density and takes up space. A lot of the discussion is therefore around transporting it in its liquid form.

26. New Zealand's green hydrogen will also have to compete with countries where green hydrogen might be produced more cheaply, such as Australia and those closer to markets. Despite challenges, countries such as Germany have shown interest in procuring green hydrogen from New Zealand. Potential customers from Japan and

South Korea have also signaled interest, given their domestic renewable energy limitations. Assurance of certification is crucial for these potential buyers.

27. The Government has indicated upcoming actions, including mechanisms assuring its quality to importing jurisdictions. Government-to-Government assurance could enhance credibility in trade. **We <u>recommend</u> the government provide clarity on the mechanisms, such as certificates or other standards for exported product, although this may not be an immediate priority compared to other initiatives.**

Implementing a ban on new fossil-fuel baseload electricity generation discussion document

<u>No adequate problem definition</u>

1. The consultation package includes a proposal to ban new thermal baseload generation capacity. **We believe this proposal is a solution looking for a problem**. Currently the probability of new thermal baseload development remains low due to a confluence of factors, including gas supply uncertainties, high uncertain investment paybacks, limited access to financing, and challenges associated with securing all relevant consents due to recent changes to the RMA in 2020.

2. There is no developer exploring, nor planning to, construct new thermal baseload generation. This trend is highly likely to persist due to advancing renewable technology, which promises even lower Levelised Cost of Energy (LCOE), in addition to higher carbon prices and concerns regarding future scarcity of thermal fuel supplies.

3. As stated in the paper, the prevailing outlook is unequivocally oriented towards a greater renewables base, with thermal generation shifting its role from serving as baseload to addressing peak demand surges, highlighting the need for new thermal peaking capacity. This context underscores that the proposal seems to be driven by factors not grounded in evidence.

4. Renewable electricity generation is already superior in the sense of offering lower costs for each kilowatt hour produced. Participants are facing the right incentives due to the foundational principles of the wholesale market; they are following the lowest costs options to meet demand. A ban on a more expensive and more inferior option, which is not chosen by developers, is wasted effort.

5. Current forces guide participants, making it extremely unlikely that there will be a situation where a large investment can be justified to a board of directors and shareholders based on a preference for a more expensive and less efficient technology.

6. Despite the low probability of new thermal baseload construction, we acknowledge that there are certain scenarios that could justify new plant, as detailed in the paper. Firstly, in cases where renewables, for unspecified reasons, fail to deliver sufficient baseload generation, thereby compromising security of supply, thus warranting new baseload.

7. Secondly, new plants might be necessary to replace aging ones that could still play a role in the system for unspecified and unknown reasons. While existing baseload is not as useful for meeting capacity peaks, they are currently necessary for energy security, especially during dry years. Replacing existing plant with modern and more energy efficient units capable of operating as baseload if necessary during dry years could be beneficial.

8. Lastly, participants may identify opportunities for new co-generation to enhance the efficiency of their industrial processes.

9. The paper raises the question as to whether a prohibition should incorporate provisions to address various scenarios**. We agree that any ban ought to include provisions that permit these various scenarios to ensure that compromises do not jeopardise future security of security and potential efficiency gains, particularly in the context of co-generation and replacement plant.**

10. It is worth emphasising that a ban, even with these exemptions, ultimately yields the same outcome as the counterfactual where no ban exists. In the former, exemptions are incorporated, and the construction of new thermal baseload facilities is deterred due to their already higher LCOE, unless the market necessitates them to ensure security of supply security, capitalize on co-generation opportunities, or replace inefficient plants, factoring in elements such as payback and the ETS.

11. In the latter, there is no ban in place, yet again new thermal baseload construction is discouraged due to its higher LCOE, unless the market necessitates it to maintain

supply security, explore co-generation possibilities, or replace inefficient plant, factoring in elements like payback and the ETS.

12. The distinction between these two scenarios lies only in the presence of regulatory restrictions in one and their absence in the other. Such an impediment is unnecessary within a system that is already capped under the Emissions Trading Scheme. The ETS presents a large hurdle for any form of carbon-intensive generation, without the direct intervention of regulatory bans and ministerial interference.

13. The prevailing price dynamics of the ETS serve as a pivotal factor in deciding whether new plant will be built. In a scenario where the economic feasibility of additional thermal baseload improves markedly and no superior alternatives are viable, and if the system necessitates this generation to fulfill demand despite the elevated carbon price, it merely signifies that this plant and its emissions hold a higher value relative to other emissions.

14. This, in turn, underscores the existence of more cost-effective and valued abatement options elsewhere in the economy. Banning the prospect of these projects, frees units to less valued ends, while having implications on energy affordability and security of supply considerations.

Appendix One - Background information on BusinessNZ Energy Council

About the BusinessNZ Energy Council

The BusinessNZ Energy Council (BEC) is a group of New Zealand energy organisations taking on a leading role in creating an affordable, reliable, and sustainable energy system for New Zealand. The BEC is a division of BusinessNZ, New Zealand's largest business advocacy group and the New Zealand Member Committee of the World Energy Council (WEC). The BEC offers a unique opportunity to shape the New Zealand's energy-system with business leaders, government, and research as well as access to global thinking on energy issues via our involvement with WEC.

About the World Energy Council

The World Energy Council is an independent global organisation that promotes an affordable, reliable and sustainable energy system for all. It is comprised of over 100 member countries. The Council provides impartial information on critical issues that affect society's well-being such as climate change mitigation strategies; energy efficiency; renewable energies; nuclear power; clean coal technologies; rural electrification; energy access; regional integration; urbanisation; geopolitics; innovation; finance; human capital; governance; resilience; hydrogen; storage; digitalisation; mobility; cooling; heating; behaviour change; scenarios; and transition leadership.

About the BusinessNZ

BusinessNZ is New Zealand's largest business advocacy body, representing:

- BusinessNZ Energy Council of enterprises leading sustainable energy production and use
- Buy NZ Made representing producers, retailers and consumers of New Zealand-made goods
- Regional business groups EMA, Business Central, Canterbury Employers' Chamber of Commerce, and Employers Otago Southland
- Major Companies Group of New Zealand's largest businesses
- Gold Group of medium sized businesses
- Affiliated Industries Group of national industry associations
- ExportNZ representing New Zealand exporting enterprises
- ManufacturingNZ representing New Zealand manufacturing enterprises
- Sustainable Business Council of enterprises leading sustainable business practice

BusinessNZ is able to tap into the views of over 76,000 employers and businesses, ranging from the smallest to the largest and reflecting the make-up of the New Zealand economy. In addition to advocacy and services for enterprise, BusinessNZ contributes to Government, tripartite working parties and international bodies including the International Labour Organisation (ILO), the International Organisation of Employers (IOE) and the Business and Industry Advisory Council (BIAC) to the Organisation for Economic Cooperation and Development (OECD).

www.businessnz.org.nz