Submission on *Developing a Regulatory Framework for Offshore Renewable Energy*

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Release of information

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Responses to questions

	Chapter 4: Further detail on feasibility permit
1	**Following an initial feasibility permit application round, should there be both an open-door policy and the ability for government to run subsequent rounds? If not, why not?**
	We believe only set-application rounds should be run for the following reasons: • Greater certainty for developers: In order to prepare a feasibility permit application, it is important for developers to make sure that such applications shall fully comply with the Government's development plan. The set-application rounds will give reasonable certainty to developers since such rounds will be led by the government in accordance with its development plan, and therefore the developers can well organise the schedule for its application. In the meantime, the open-door approach would increase uncertainty, and it would make it difficult for the developers to plan and prepare the application. • Equal opportunity and transparency for developers: A policy of set-application rounds will give equal opportunities and transparency to all developers since they are required to prepare the feasibility permit application based upon a single timeline and a single set of rules and guidelines. In the meantime, an 'open-door' policy may deliver 'an uneven playing field' with less transparency and consistency and produce "first-in, first-served." • Increase in the regulator's administrative works and costs in case of 'open door': Under an 'open door' policy the Government/regulator may likely have to deal with various feasibility permit applications, compliant and non-compliant, at any time. This may escalate the Government's/regulator's workloads and planning, slow its assessments and decision-making on project applications. We believe that your concern mentioned in the discussion document, "developers having to wait for application rounds and reduce the administrative burden on the government, particularly at times when interest might be limited," could be resolved if the government announces the schedule of the application rounds well in advance. The developers can then prepare the feasibility permit application based upon the timeline given by the government, and there will be no idling time for the developers.
2	**What size of offshore renewable energy projects do you think are appropriate for a New Zealand context?**
	We basically agree that projects of between 500MW and 1GW are appropriate considering New Zealand's current total installed generation capacity, grid capacity, and electricity demand. However, such project scales might be further increased subject to increases in future electricity demand and grid capacities.

From another aspect, we believe it is important to ensure a certain size of offshore renewable energy (ideally 1GW, and at least 500MW) so that the project is both feasible for developers and cost-competitive for consumers, especially considering current plant supply chain constraints.

Do you think the maximum area of a project should be put forward by developers and set out in guidance material, rather than prescribed in legislation? If not, why not?

3

We believe that no fixed, maximum limit on the area of a feasibility permit is necessary to be legislatively prescribed because 1) offshore wind turbine is evolving quickly, and the area required for a certain capacity will be accordingly varied and 2) the required area for any offshore windfarm depends on the geographical conditions of a particular area. The developers shall be responsible to optimise the area of a feasibility permit based upon the proposed project capacity, which the regulator shall finally assess in the course of evaluation of the application.

In the meantime, we believe it makes sense that the Government announces the maximum capacity of each project which the developers can propose and also the maximum capacity of the projects for which the feasibility permit will be issued since the development plan for whole electric power (including offshore renewable energy) will be planned by the Government, not by the developers. Such guidance would also give confidence to the developers to submit their feasibility permit applications knowing clearly what size of project shall be developed.

Chapter 5: Commercial permits

Should there be a mechanism for government to be able to compare projects at the commercial stage in certain circumstances? If yes, would the approach outlined in Option 2 be appropriate or would there be other ways to achieve this same effect?

4

- **We agree that there should be a comparison mechanism for assessing commercial permit applications**.
- In the meantime, we also believe it is subject to whether the Government shall introduce a support scheme such as FIT, FIP, or CfD. If this occurs, there should definitely be a competitive process to select the developer(s) who can obtain the commercial permit(s) with such a support mechanism. Hence, we believe it should be a Government-initiated competitive process for the commercial permit award (similar to the set-application rounds to be applied for feasibility permit application). Otherwise, it will likely become a "first-in, first-served" result in case we take the developer-initiated options (even if we take option-2 (i.e., developer-initiated with an option to compare), it is unclear how long it would be required for developers to contest the application which was made by other developers in advance).
- We also believe a developer should be able to continue holding any granted feasibility permit even if the developer fails to obtain the commercial permit (with the support mechanism) as a result of the competitive process in any round. The developer then may

	continue their project planning and try to bid for any future rounds as long as the feasibility permit is valid.
	Are the proposed criteria appropriate and complete? If not, what are we missing?
5	**We agree that the proposed criteria are appropriate**. It will be especially necessary to properly set the criteria to assess the technical and financial capability of the developer, such as relevant track records and financial capability, to ensure the project will be promptly delivered by the developer. As you rightly describe, it is important to require the developers to demonstrate their relevant experiences in the construction of similar projects. For your reference, the following evaluation criteria are used for offshore wind power tenders in Japan: • Delivery speed of the project plan (timing up to start of commercial operation) • Completeness of the project plan (project implementation, organisational structure and experience, finance, and income/expenditure plan) • Execution of the project plan (project plan up to commercial operation and after commercial operation) • Technical certainty of electricity supply • Coordination ability with stakeholders, including the heads of relevant administrative agencies • Cooperation and symbiosis with existing shipping and fishery parties • The economic benefits to the local community/stakeholders • The economic benefits to the domestic national economy In addition to the proposed criteria, we believe the evaluation for the support mechanism, i.e., CfD/FIT/FIP price, should also be assessed if the Government proposes to introduce such support mechanisms.
	Should there be mechanisms to ensure developers deliver on the commitments of their application over the life of the project? If yes, what should these mechanisms be?
6	We accept in principle to implement such mechanisms to ensure developers deliver on the commitments of their application over the life of the project. Also, we propose the mechanisms should be based on the VADE model as proposed in Chapter 11. For operation, we agree that developers must submit a Project Management Plan and revise it annually with review meetings with MBIE and other relevant ministries. However, once the project reaches the operation and maintenance stage, we believe revising the Project Management Plan once every three to five years, subject to risk evaluation of the project, with a review meeting would be sufficient as the project reaches a stable stage. Referring to our experience in Japan, the review frequency is every three years for inspection of the tower and foundation of the wind turbine generator.

	Regarding the cabling inspection, if there are observed external or environmental activities which could cause cable damage or defects, such as continuous sediment movements on the sea floor or busier than expected vessel or fishing activities, then shorter inspection intervals, such as annually, should be considered.
7	**Is 40 years an appropriate maximum commercial permit duration? If not, what would be an appropriate duration?**
	- We agree that a maximum commercial permit duration of 40 years is appropriate subject to clearer definition of the commencement of that commercial permit. - Note that any finance arrangement with external lenders typically takes approximately 1-2 years after commercial permit allocation based upon our previous experience. Hence, in case the starting point will be at the time of financial close of the project, we believe a maximum of 40 years is appropriate considering the construction period (approx. 3 years), operational life (approx. 35 years) and decommissioning period (approx. 1-2 years).
8	**Should a developer that wishes to geographically extend their development be required to lodge new feasibility permit and commercial permit applications? Why or why not?**
	- We generally agree in principle that a developer should require a new feasibility permit and commercial permit application for a geographical extension of an already granted permit. Where that developer wishes to expand its area, the entire development plan for the project has effectively been changed. Therefore, we believe a significant geographical extension should require a new feasibility permit. This would prevent a situation whereby a developer uses a shortcut or 'back-door' tactic for the geographical extension, such as increasing a 100MW granted project to 1,000MW. This might be disadvantage of a good-faith developer who applies from the start for a 1000MW feasibility permit. - Nevertheless, to make project development flexible as well as fair, the following circumstances should be considered as minor changes which should NOT require a new feasibility permit. • Minor geographical expansion that does not change the generation capacity and/or number of turbines • Minor modification of transportation routes
9	**Would the structure of the feasibility and commercial permit process as described enable research and development and demonstration projects to go ahead? If not, why not?**
	- We believe that both feasibility and commercial permit process would be necessary to enable research and development and demonstration projects to go ahead. Also, the evaluation criteria for such demonstration projects should be solely considered because the projects' purpose would differ between the commercial and demonstration projects. For example, the Ministry of Economy, Trade, and Industry in Japan evaluates a demonstration project in terms of whether it can contribute to reducing electricity prices and/or introducing cutting-edge technology etc. in the future. However, speedy business

planning, which is one criterion for commercial project assessment in Japan, is excluded in the criteria for demonstration projects.

- In addition, we emphasise that any revenue support mechanism (such as CfD) is crucial for establishing the feasibility of new power techniques. For example, in the UK, the AR5 CfD Administrative Strike Price for power generation from wave energy was set at GBP 245/MWh which is much higher than other mature renewable energy options.

Chapter 6: Economics of the regime

Is there an interdependency between the case for revenue support mechanisms and the decision as to whether to gather revenue from the regime? What is the nature of this interdependency?

10

We believe there is no strong or obvious interdependency between the case for the revenue support mechanisms and the decision as to whether to gather revenue from the regime especially when the country/region introduces the very first project for offshore wind power.

Offshore wind power projects typically face much larger project costs compared to other renewable energy projects due to the massive size of plant, the complexity of their development, and particularly the nature of offshore construction works. Hence, before the market matures, revenue support mechanisms are required. Otherwise, the project shall not be economically feasible.

Even in Europe, when offshore wind power was first introduced, the government led the arrangement for off-take (together with the grid operator) and the support mechanism (such as FIT) since no plant supply chain had yet been established and the market was immature. After the number of developers/projects had increased and the supply chain was developed in the region, a new type of subsidy scheme was introduced (i.e., CfD), which resulted in reducing the Government subsidy. Recently, in some (not all) European countries where the supply chain and the market are now mature, the combination of the revenue gathering scheme and the revenue support scheme (for example, in the UK, the seabed option fee will be collected from the developers while the CfD scheme is introduced) the subsidy free scheme, or negative bidding scheme (like Germany) are being introduced. Thus, as the market matures, there may be some nominal appearance of interdependency between the revenue support mechanisms and the revenue gathering mechanisms. However, it is still debatable whether these projects could be financially and economically viable under no support mechanism considering the current challenges in the plant supply chain and international inflation.

Although offshore wind power has become more established in some regions like Europe, for new countries/regions, we believe it is critical to build up the supply chain (considering the physical distance from Europe) to attract and assure international lenders so that the project may be realised. Hence, in the early stage of the market, there is NOT necessarily an interdependency between the revenue support mechanisms and the revenue gathering mechanisms.

11 **Is there a risk in offering support mechanisms for offshore renewables without offering equivalent support to onshore renewables? Are there any characteristics of offshore renewables which mean they require support that onshore renewables do not?**

- **We believe there is no risk in offering support mechanisms for offshore renewables without offering equivalent support to onshore renewables** since such a policy is commonly adopted in Europe (i.e., support mechanisms for offshore renewable energy while limited support mechanisms for onshore renewable energy). As described in our response in item 10, the project costs of offshore renewable energy are incomparably higher than that of onshore renewable while offshore renewable energy has many unique merits compared to onshore renewable energy (such as a higher capacity factor, a higher volume of generated electricity, and fewer visual impacts etc.).
- However, we believe adopting the CfD scheme with proper CfD price for ALL renewable energy would also benefit New Zealand in accelerating all renewable energy installation. The regulator may set a lower CfD price for several matured renewable technologies in New Zealand.

12 **Should there be a revenue flow back to government? And if yes, do you have views on how this should be structured? For comments on potential flows to iwi and hapū please refer to Questions 14 and 15.**

As described in Q.10, we believe that only the revenue support mechanism should be adopted until the market matures and the supply chain is established. The introduction of a revenue flow-back mechanism should only be discussed once the market reaches appropriate maturity.

13 **Do you agree with the proposed approach to cost recovery? If not, why not?**

As discussed in the 1st discussion document, we believe that it is preferable that such costs should NOT be charged to the developers to motivate the development of offshore renewable energy in the feasibility phase (please refer to our response to item 26 in 1st discussion document). Please also refer to our responses to items 10 and 12 of this 2nd discussion document. However, we agree that a commercial fee should be higher than the feasibility fee and that the amount should vary depending on the size of the occupied area of the seabed surface if a cost recovery approach is introduced.

Chapter 7: Māori Rights and Interests and Enabling Iwi and Hapū involvement

14 **Is there anything you would like us to consider as we engage with iwi and hapū on Māori involvement in the permitting regime?**

We fully agree to involve iwi and hapū in the permitting regime. It would be appreciated if the Government could give feedback to the developers in relation to the discussions with iwi and hapū on Māori from time to time so that the developers can make a proper consideration in the course of the project planning/development.

We believe it is also essential for developers to directly communicate with iwi and hapū even prior to and during the application process since coordination with the local community is one of the most important factors in the development of offshore renewable energy.

15 **Have we identified the key design opportunities to work collaboratively with iwi and hapū alongside consultation? Is there anything we have missed?**

We agree with the opportunities listed by MBIE and believe involvement in decision-making and economic contribution should be key opportunities. Nevertheless, we believe it shall be always subject to how iwi and hapū themselves wish to be involved in offshore renewable energy.

In the meantime, we believe the revenue flows option should be studied and considered in a later stage after the market matures and the supply chain is well established as per our responses to items 10, 12, and 13.

16 **Are there any Māori groups we should engage with (who may not have already engaged)?**

We believe only Māori groups who may be directly influenced by the development of offshore renewable energy should be engaged. For example, we understand Taranaki region is known as the potential site for the development of offshore wind power and therefore all the 8 iwi groups in Taranaki region should be engaged (while we understand the engagement with these 8 iwi groups has been already coordinated by the government).

Chapter 8: Interaction with the environmental consenting processes

17 **For each individual development, should a single consent authority be responsible for environmental consents under the Resource Management Act 1991 and the and Exclusive Economic Zone and Continental Shelf (Environmental Effects) Act 2012? Why or why not?**

We agree that a single consent authority should be responsible for all environmental consents under the RMA and the EEZ Act because of the reasons mentioned in the discussion document.

18 **Do environmental consenting processes adequately consider environmental effects such that it is not necessary to duplicate an assessment of environmental effects in the offshore renewables permitting regime?**

We believe that the environmental consenting process does adequately consider environmental impacts. However, there is likely to be a need for refinement to those processes and further guidance to enable adequate consideration of effects associated with offshore wind applications. For example, we acknowledge that there have been legal controversies around seabed mining applications due to differences in perception regarding scientific uncertainty or the amount of information required. Therefore, we agree that all environmental effect assessments are concluded in the environmental consenting process, and the offshore renewables permitting regime does not include any of it, while we do consider that further guidance is required to adequately assess the specific effects of offshore wind.

	Should the offshore permitting regime assess the capability of a developer to obtain the necessary environmental consents? If not, why not?
19	**We think assessing the developer's capability to obtain necessary environmental consent is reasonable**. To assess those capabilities, we agree that the regulator should ask developers to submit their clear plan for obtaining necessary environmental consents with explanations of 1) their understanding of the environmental consenting process(es) in New Zealand, 2) the type of survey(s) the developer has already conducted before the permit application and the type of surveys to be conducted after the issuance of permit, and 3) the progress of early engagement with related stakeholders like consent authorities and iwi.
	What is the optimum sequencing between obtaining feasibility permits, commercial permits and relevant environmental consent(s)?
20	**We believe that Option 1 would be the best solution** on the premise that the preparatory work, such as submission of application for commercial permits, is not hindered by this option. As it is unlikely that discussions with financial lenders will be significantly progressed before relevant environmental consents are granted, we consider that adopting Option 1 does not cause significant delay for a project.
21	**Are there are any other matters about the environmental consent regimes that you think need to be considered in the context of the offshore renewable energy permitting regime?**
	We do not have any other matters to be considered. As there are some EEZ regulations related to oil & gas activities, we believe that same kinds of regulations related to offshore renewable energy should also be considered. Also, it would be useful to develop the EEZ Policy Statement and/or other guidance to enable EPA to adequately assess marine consent applications.
22	**How should the factors outlined influence decisions to pursue offshore renewable energy developments in the Exclusive Economic Zone or the Territorial Sea? Are there other factors that may drive development in the Exclusive Economic Zone versus the Territorial Sea?**
	Our considerations for each outlined factor are as follows. - **Project economics:** We agree that the project located further into the EEZ has higher transmission cable costs. However, many factors affect project economics, such as • natural conditions (wind-speed, water depth, geological features, current wind velocity etc.), • turbine design (considering the impact on landscape, the turbine size tends to be smaller if the projects are closer to shore), and • type of foundation (which would depend on the natural conditions). Hence it is difficult to conclude the projects closer to shore in the Territorial Sea are economically better than that of further out into the EEZ. For example, the wind resource is generally greater further out into the EEZ area.

- **Landscape, character, and amenity value:** We agree with your expectations that developments further from shore are generally less visible and therefore less of a disturbance to the natural coastline.
- **Environmental impacts:** We agree with your expectations. We believe developers should judge which area should be feasible for the offshore renewable project by careful environmental impact assessment.
- **Existing and future uses and interests:** We acknowledge that there are Statutory Acknowledgement Area, Coastal Management Area and some protection area stipulated under Regional Coastal Plan, and some places used for surfing in Territorial Sea. Therefore, from our viewpoint, it would be more complicated and difficult for developers to acquire relevant environment consents for Territorial Sea.

Chapter 9: Enabling transmission and other infrastructure

23 **Are the trade-offs between a developer-led and a TSO-led approach, set out above, correct? Is there anything missing? What could we learn from international models?**

We believe that the trade-offs as outlined above are correct.

24 **Which party do you think should build offshore connection assets? Can existing processes already provide the flexibility for this to be carried out by the developer?**

- **We agree with the approach you propose in the 2nd discussion document that developers themselves fund and build the offshore transmission infrastructure and onshore connection, and once operational, developers sell part of them to Transpower, and Transpower owns and operates them.**
- In practical terms, we propose the following role sharing so that the developer shall provide offshore transmission infrastructure and onshore connection quicker, and Transpower could own and operate transmission infrastructure. Inter-array cables connect directly to the wind farms, and we believe they should be owned and operated by developers.
- We propose the development and installation cost shall be compensated within a reasonable time, e.g., within one or two years after the grid connection of the OWF. We believe clear rules are needed, stipulating how that shall be documented, what shall be reimbursed, and when the costs will be compensated.

<table>
<tr><th></th><th>inter-array cables</th><th>offshore substation</th><th>export cables</th><th>onshore connection</th></tr>
<tr><td>fund and build</td><td colspan="4">Developers</td></tr>
<tr><td>own and operate</td><td>Developers</td><td colspan="3">Transpower</td></tr>
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25 **What are the potential benefits and opportunities for joint connection infrastructure? Do you agree with the barriers set out and how could these be addressed?**

- Joint connection infrastructure can minimise the cost and optimise land use of the new transmission infrastructure by multiple projects sharing the transmission infrastructure.
- We agree with the barriers for developers mentioned in the 2nd discussion document, For example, our UK project is considering an option to install a joint connection infrastructure with the neighbouring project since the majority shareholders for these projects are same. However, we still see barriers/difficulties in proceeding with it as listed in the discussion document (especially as it is too risky to take a delivery risk of another project).
- Therefore, in the likely scenario that the projects shall be developed by different developers), it is very difficult to consider joint connection infrastructure. If the Government does pursue the joint connection infrastructure principle, we recommend TSO will take a lead to fund and build the offshore transmission infrastructure so that the developers will be freed from the delivery risk of another project.

26 **Do you agree with the representation of the timeline challenge for onshore interconnection assets? What opportunities might there be to front load planning work for interconnection upgrades? What role do you see for the developer in this?**

We agree with the representation of the timeline challenge for onshore interconnection assets. However, we think that upgrades to the existing onshore interconnection assets are required for New Zealand, which aims to generate 100% renewable electricity by 2030. As described in the 2nd discussion document, initial developer’s interest in offshore renewable energy projects in New Zealand is currently concentrated only in a few locations, and the Government and Transpower can easily identify the most likely areas where upgrading onshore interconnection assets will be necessary.

Practically, we understand that the lines between 1) Stratford – Huntly and 2) Stratford – Brunswick-Bunnythorpe-Whakamaru do not currently have sufficient grid capacity to deliver electricity generated from offshore wind farms in Taranaki. All Taranaki offshore wind projects shall use them to deliver electricity to major electricity consumption areas in North Island. Their capacity upgrade is critical for whichever offshore wind projects in Taranaki are implemented. Thus, we believe the Government should lead and commence upgrading these grid capacities as soon as possible in parallel with the new regulatory regime.

27 **What changes might be needed in order to deliver the types of port infrastructure upgrades needed to support offshore renewables?**

In general, we think that upgrades of the port’s laydown area, bearing capacity, number and length of wharves, its water depth, and cargo handling equipment should be considered based upon the size of planned projects. Also, the seabed's geographical condition immediately around the port must be assessed to determine whether delivery and installation vessels can be jacked up at the port.

Firstly, we suggest that potential developers and the government conduct a collaborative survey on the types of required what kinds of upgrades are required based upon the currently proposed project sizes and the expected timeframes and costs. Secondly, based upon the survey results, we suggest the port owner and/or the Government clearly announce that they shall upgrade the port, which will provide developers greater certainty and enable their investment.

Furthermore, if there are other physical restrictions which may be obstacles for vessels or facilities, these obstacles need to be removed. For example, there may be overhead lines crossing, which may limit the height of installation vessels with regard to the height of cranes and vessel feet.

Chapter 10: Decommissioning

28 **Should developers be required to submit a decommissioning plan, cost estimate and provide a financial security for the cost estimate? If not, why not?**

We agree that developers must submit a decommissioning plan and cost estimate and provide financial security for the cost estimate. For your kind reference, developers have the same obligations proposed in this question in Japan.

29 **Should the permit decommissioning plan, cost estimate and financial security be based on the assumption of full removal? If not, why not?**

- We believe Option 2 – full removal with the option to present alternatives- is preferred.
- Even in Europe, the decommissioning of offshore wind power plants has rarely yet commenced. It might be more efficient to prolong the project life by rehabilitating or re-powering the plant rather than simply decommissioning it. While it is important to impose an obligation on the developers in relation to their decommissioning activity, we believe it is also important to set flexible rules so that the Government and developers may select the best choice for the project and the country nearer the decommissioning period.

  For your kind reference, in the UK, developers may extend the project life by getting approval for an amended decommissioning plan with the repowering of the wind power plants before environmental assessment for decommissioning which has to be commenced 3 years before the commencement of decommissioning activities in the original decommissioning plan.
- Also, there may be cases where alternative plans to keep some of the structures in place have environmental or health and safety benefits rather than full removal of the offshore renewable energy infrastructure.

  We believe that most structures shall eventually be fully removed, but considering environmental or health and safety benefits, developers probably should leave certain structures, such as foundation piles buried in the seabed.

  In terms of this issue, the Japanese regulator stipulates the criteria to approve developers to keep structures in place as follows;

  - There is no residual oil or other potentially floating materials left in the offshore facility to be disposed of,

- There is no possibility that the offshore facility being disposed of itself nor will break-off or move from the weight of the offshore facility in the water, and
- Any remaining structure does not interfere with the safety of vessel navigation.

30 **What are your views on the considerations set out in relation to the calculation of the cost estimate and financial security value or suggested approach for financial security vehicle?**

- We believe that any full financial security should be prepared before starting commercial operation. However, it should NOT be required upon submission of the commercial permit application since developers shall provide the equivalent performance guarantee to the government, which is the effective financial security during the construction phase.
- Regarding the calculation of the cost estimates and financial security value, we believe that it is challenging for any party to estimate the current detailed decommissioning costs since there are so few examples of offshore windfarms being decommissioned anywhere in the world.

  For your reference, in Japan, the regulator has determined a nominal decommissioning cost and financial security value equivalent to 70% of construction costs of foundations, wind turbines, cables, offshore substations, and other offshore construction costs. We believe this 70% nominal benchmark is more than enough to cover actual decommissioning costs. Such a benchmark would also assist your assessment of the financial ability of various developer candidates.

  As another example, the UK's Crown Estate, estimates that decommissioning costs of a 1GW offshore wind farm is around GBP330million (roughly NZD700million) in their Guide to an offshore wind farm issued in April 2019. We believe this amount would be a kind of benchmark to estimate actual decommissioning cost.
- In terms of the suggested approach for financial security vehicles, in our international practical experience, we believe your proposed approach is reasonable. It shall be important for developers to have several options in selecting the most feasible type of securities to deal with the change in the regulatory requirements and commercial banks' requests.

31 **What should the developer be required to provide in relation to decommissioning at the feasibility application stage?**

- **We agree to provide the proposed items in the "WHEN SHOULD DECOMMISSIONING PLANS BE ASSESSED" section.**
- We believe that the developers should submit documents proving their financial capability to bear decommissioning costs, at the feasibility permit application stage. However, it is quite challenging for developers to submit a kind of guarantee issued by third parties at that point of time, since it is too early to be guaranteed by third parties. For your reference, in Japan, the regulator requires developers to submit a Letter of Intent at the time of bidding for tariff, which a designated commercial bank shows intent to issue the

Letter of Credit during the operation stage with the amount equal to the estimated decommissioning cost.

32 **What ongoing monitoring approach do you think is appropriate for the decommissioning plan, cost estimate and financial security?**

- In terms of the decommissioning plan and their cost estimates, we understand the first review shall be made by the developer and the regulator just before the commercial operation when we assume the developer will be obliged to provide the financial security for decommissioning works. Thereafter, we believe it is NOT necessary to have regular assessments/reviews on the decommissioning plan and their cost estimates unless any special requests for update will be made either by the developer or the regulator.
- The developer shall be eligible to update the decommissioning plan and cost estimates based upon the latest method/technology for decommissioning works but subject to the agreement with the regulator. The regulator shall also have the right to request developers to update and revise the decommissioning plan if the regulator expects an extraordinary increase in the decommissioning costs.
- In the meantime, the final decommissioning plan shall be fixed at least one year before the expiration of the commercial permit so that the developer can be prepared for the decommissioning works once the commercial permit expires.

  For your reference, in the guidance from the UK's Department for Business, Energy and Industrial Strategy, it is stated that a developer/owner should start the final and comprehensive review of the decommissioning plan two years ahead of the decommissioning term commencement.
- Regarding financial security, it shall be provided for the entire period after the commercial operation. However, the amount of the security shall be updated from time to time based upon the updates in the decommissioning plan and the cost estimate as described above.

33 **Are there any other ways in which the regulatory regime could encourage the refurbishment of infrastructure or the recycling of materials?**

We believe the regulator can encourage the refurbishment of infrastructure or the recycling of materials by providing some supporting schemes.

For example, if the developer is potentially able to extend the duration of commercial permits to recover the cost of the refurbishment of infrastructure, this would encourage developers to consider refurbishment options. In addition, some specific refurbishment tax incentives such as exemption of corporation tax, GST, or customs duties would encourage developers to develop refurbishment options.

In Japan, there is a possibility that a commercial permit can be extended as per the following conditions are met:

- It is appropriate to continue to designate the area as a promotion zone
- There is no need to re-open the application to the public

- All of the criteria for the commercial permit are met

34	**Should offshore renewable energy projects applying for a consent to decommission be required to provide a detailed decommissioning plan related to environmental effects for approval by consent authorities? If not, why not?**
	We agree that consent authorities should have the ability to review environmental effects arising from the activities in the decommissioning plan subject to the timing of any such review. Although decommissioning is a critical activity for the project, it shall not commence for over 40 years. It is not necessarily effective to conduct the detailed environmental assessment for the initial decommissioning plan since it is likely that such plan will be updated from time to time. Therefore, we believe the detailed environmental assessment for the decommissioning plan should be performed before the final decommissioning plan is fixed. For your kind reference, in the UK, a developer/owner is required to submit an environmental impact assessment for decommissioning three years in advance of the decommissioning term.
Chapter 11: Compliance	
35	**How can the design of the regulatory regime encourage compliance so as to reduce instances of non-compliance?**
	We agree to introduce the VADE model to reduce or minimise instances of non-compliance.
36	**Is the compliance approach and toolbox in Chapter 11 appropriate for dealing with non-compliance within the regulatory regime?**
	We believe the compliance approach and toolbox are appropriate to reduce instances of non-compliance. Regarding the “Enforced” items, the UK and Japan prohibit developers for a certain period from applying for a permit or participating in tender if those developers have made severe breaches in the regime.
Chapter 12: Other regulatory matters	
37	**Should the decision maker within the regime be the regulator but with an option for the Minister to become the decision maker in a specific set of circumstances? If not, why not?**
	We agree that Option 3 (the hybrid option) would be the most appropriate decision-maker option. However, we kindly ask the Government to clearly define under which circumstances the Minister may become the final decision maker so that the final decisions can be timely made by the responsible person (i.e., either the regulator or the Minister).
38	**Should there be an opportunity for public submissions on the commercial permitting decision? What would this capture that the environmental consent decision does not? If not, why not?**
	We agree that Option 1: notification only would be more workable than Option 2.

There will be public hearing processes to obtain environmental permits and can exchange opinions with local stakeholders & the public at that time. Option 1 is more likely to simplify the consenting process and avoid duplication.

For your kind reference, we understand that the UK and Japan do not offer opportunities like public hearings during their permitting process.

39 **Should permitting decisions be able to be appealed and if so which ones? Which body should determine such appeals?**

Assuming that permitting decisions will be made by either the Minister or the regulator based on their deep study/analysis of the applications, we believe the appeals to permitting decisions need NOT be considered.

For your kind reference, we understand that the UK and Japan do NOT allow an appeal rule for developers to permit decisions to be made by Ministers.

40 **What early information would potential participants of the regime need to know about health and safety regulations to inform decisions about whether to enter the market?**

We agree that high safety and standards are significant components of the project, and developers prioritise compliance especially during the construction, O&M, and decommissioning phases.

However, in our understanding, there are limited cases where the developers decide whether to enter the market depending on the information about health and safety obligations, especially in advanced countries, including New Zealand, since similar levels of health and safety rules are commonly adopted.

It would be appreciated to let us know if there are any key components of the health and safety obligations unique to New Zealand and that the developers should take note of.

41 **What are your views on the approach to safety zones including the trade-offs between the different options presented?**

We propose that the United Nations Convention on the Law of the Sea and DNV-ST-N001 Marine operations and marine warranty are the basis for the safety standards for the safety zones. International commercial banks typically require developers to comply with such standards to provide finance, so we believe these are appropriate criteria.

42 **Do you have any views or concerns with the application of these proposals to other offshore renewable energy technologies?**

We believe these proposals may be broadly applied to other offshore renewable energy technologies, while there should be some items to be adjusted for other offshore renewable technologies, such as environmental issues and supporting mechanisms.

For your reference, the UK has already held CfD auctions of other offshore renewable technologies, such as tidal stream and wave energy, under the same framework as the offshore wind.

General comments

- We advocate some type of offtake scheme for offshore windfarms is adopted by the Government. If no offtake mechanism is offered, there is a risk of unstable or unsustainable project cashflows which will undermine efforts arranging project finance and/or establishing a supply chain for the project. Generally, in other international markets, power utilities are appointed as the off-taker under such offtake schemes.
- Additionally, we advocate that the decision regarding any subsidy scheme such as CfD is determined and announced as part of the new regulatory regime or, at latest, before an application for feasibility permit. This shall give certainty to developers considering significant expenditures are required for feasibility activities. Also, especially in case a revenue gathering scheme such as "Option fee" is introduced, we need certainty in advance of the feasibility permit application.