MINISTRY OF BUSINESS, INNOVATION & EMPLOYMENT
HĪKINA WHAKATUTUKI

COVERSHEET

Minister	Hon Dr Megan Woods	**Portfolio**	Energy and Resources
Title of briefing	Proactive release of market integration/economic modelling reports to inform the NZ Battery Project Indicative Business Case	**Date to be published**	27 October 2023

List of documents to be proactively released		
Date	**Title**	**Author**
10 May 2023	*NZ Battery Project – Update on the three Portfolio component technologies (2223-3270)*	Hidde Mebus Senior Policy Advisor
1 June 2023	*NZ Battery Project – Further advice on the Portfolio option (2223-3271)*	David Stimpson Principal Policy Advisor

Information redacted **YES** / **NO** *[select one]*

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MINISTRY OF BUSINESS, INNOVATION & EMPLOYMENT
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BRIEFING

NZ Battery Project – Update on the three Portfolio component technologies

Date:	10 May 2023	**Priority:**	Medium
Security classification:	In Confidence	**Tracking number:**	2223-3270

Action sought

	Action sought	Deadline
Hon Dr Megan Woods **Minister of Energy and Resources**	**Note** our assessment of the key merits, risks and technical suitability of the three components (geothermal, biomass and hydrogen) of the portfolio solution to the dry year problem	19 May 2023

Contact for telephone discussion (if required)

Name	Position	Telephone	1st contact
Susan Hall	Policy Director, ERM	Privacy of	✓
Hidde Mebus	Senior Policy Advisor		

The following departments/agencies have been consulted

Minister's office to complete:

- ☐ Approved
- ☐ Declined
- ☐ Noted
- ☐ Needs change
- ☐ Seen
- ☐ Overtaken by Events
- ☐ See Minister's Notes
- ☐ Withdrawn

Comments

MINISTRY OF BUSINESS, INNOVATION & EMPLOYMENT
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BRIEFING

NZ Battery Project – Outline of the Portfolio option technologies

Date:	10 May 2023	**Priority:**	Medium
Security classification:	In Confidence	**Tracking number:**	2223-3270

Purpose

To provide you with:

- Further information on the merits and risks of the three Portfolio technologies as a solution to the dry year problem
- MBIE's advice on whether a large-scale hydrogen option could realistically form part of a Crown funded Portfolio solution
- An update on our next steps, ahead of your July 2023 report back to Cabinet.

Executive summary

In February 2023, Cabinet considered the Indicative Business Case (IBC) for the NZ Battery Project and invited you to report back in July 2023 with more information on the merits, risks and trade-offs of the Portfolio option and the potential Upper Moawhango pumped hydro scheme.

The Portfolio option, which contains geothermal, biomass and hydrogen components, described in the IBC was largely based on initial concept designs contained in an MBIE commissioned WSP *NZ Battery Project – Other Technologies Feasibility Study*. This report highlighted some merits, risks and opportunities associated with the three portfolio components which were subsequently reflected in the IBC and the accompanying Cabinet paper.

Since then, we have conducted more work on the risks, merits and strategic interlinkages associated with the three technologies and this work is reflected in the current briefing which also provides a technical overview of the technologies.

Based on this work, we have concluded that a very large scale, Crown-owned interruptible hydrogen electrolysis option as conceptualised by WSP, is not a viable component of a Portfolio solution to the dry year problem. The concept, which has an (interruptible) ammonia synthesis component to it, relies on a suitable market for green ammonia which does not currently exist at scale and the development prospect and timing of it remains uncertain.

Hydrogen could still play an important role in Aotearoa in the future: its production could offer some benefits for covering short term variability in energy supply from renewable sources (e.g. wind and solar). It also has a potential role to play in decarbonising emissions-intensive activities in New Zealand such as heavy transport and hard to abate industries (e.g. fertiliser and steel production). Further advice on this will be provided as part of the Hydrogen Roadmap work that is underway.

In terms of the remaining Portfolio technologies, geothermal and biomass, we have gained a better understanding of their key merits and the associated risks, and these are set out in this paper. Based on this analysis, from a technical perspective, we consider both remain viable options noting that remaining uncertainties can only be resolved through further work in subsequent stages of the project.

To inform your report back to Cabinet in July 2023, in the coming weeks, we will provide you with a further briefing setting out our developing understanding of potential Portfolio procurement and delivery options; and our preliminary findings on how a revised portfolio option excluding hydrogen compares as a dry year solution.

Recommended action

The Ministry of Business, Innovation and Employment recommends that you:

a **Note** that Cabinet considered the Indicative Business Case (IBC) for the NZ Battery Project in February 2023 and invited you to report back in July 2023 with more information on the merits, risks and trade-offs of the Portfolio option and the potential Upper Moawhango pumped hydro scheme

Noted

b **Note** that the Portfolio option assessed through the IBC consisted of the following components:

i. geothermal plant operated flexibly

i. combustion of processed woody biomass

ii. interruptible hydrogen electrolysis and storage as green ammonia.

Noted

c **Note** that this briefing provides an explanation of these components ahead of your July 2023 report back to Cabinet and specifically covers the following points:

i. opportunities, risks, mitigations, and uncertainty management

ii. strategic alignment and potential opportunity costs.

Noted

d **Note** that content of this briefing is based on concept designs (assuming Crown ownership) contained in a Ministry of Business, Innovation and Employment commissioned WSP feasibility assessment report that was used as a key input into the description/assessment of the Portfolio option in the IBC

Noted

Geothermal plant operated flexibly

e **Note** that the geothermal component of the Portfolio option would involve operating geothermal electricity generation in a novel flexible manner by running it at 25 per cent capacity during normal years and running it at full capacity in dry years producing an additional 0.6 TWh of energy over a three-month period

Noted

f **Note** that geothermal energy is inherently stored and renewable and can be reliably called on to provide energy during a dry year event

Noted

g **Note** we consider geothermal remains a viable component of a portfolio battery solution noting that technical and environmental concerns remain especially around the long-term operation of the wellfield in a schedulable manner at short notice and the reinjection of CO_2 into geothermal reservoirs, but these concerns may be managed once a field/location is identified and drilled

Noted

h **Note** that to avoid interfering with the normal operation of the electricity market, providers would need guaranties/assurances that the geothermal battery would only operate during a dry year and will be shut down as soon as circumstances allow

Noted

Combustion of processed woody biomass

i **Note** that this is a proven technology and a form of thermal power generation in which sustainably produced biomass from plantation forestry would be used to fire generation plants rather than fossil fuels such as coal or gas

Noted

j **Note** that the WSP concept design would have a generation capacity of approximately 500 MW, providing an additional (dry-year) generation capacity of 1 TWh over three months and that it could be scaled up to 4 TWh by replicating the system at other sites

Noted

k **Note** that there is a potential to re-use/re-purpose existing generation plant if a decision were taken to use torrefied biomass as the energy source

Noted

l **Note** that we consider woody biomass remains a viable component of a portfolio battery solution noting that some concerns remain:

i. the ability of the biomass solution to cover concurrent dry years due to potential supply constraints

i. the extent to which the public will, or will continue to, perceive the burning of biomass, to be carbon neutral.

Noted

Interruptible hydrogen electrolysis

m **Note** that this technology would, under WSP's concept design, involve the building of a large scale, 350 MW electrolyser plant to produce hydrogen which would then be converted into ammonia at a green ammonia synthesis plant and collected in bulk storage tanks and exported at a rate of 22,000 m^3 per month

Noted

n **Note** that interruptible hydrogen electrolysis would contribute to a dry year solution through:

ii. electricity load demand response, via switching off the hydrogen production plant in dry years and halting green ammonia production and exports: the demand response over a three-month dry period would be 0.50TWh

iii. combusting hydrogen for electricity generation generating 0.29TWh over three months (this would involve converting ammonia back to hydrogen at a 'cracking' plant).

Noted

o **Note** that the hydrogen solution offers the following key merits:

i. it is a renewable energy resource with minimal carbon emissions that, by introducing a new source of flexible demand, provides a use for renewable energy that may otherwise be wasted

ii. it offers flexibility in that both the demand response and generation elements of this solution can be deployed rapidly which means the plant could potentially help manage shorter term energy balancing in the market.

Noted

p **Note** that based on the following risks and uncertainties we do not believe interruptible hydrogen electrolysis, as presented in WSP's concept design, forms a viable component of a Crown-owned and operated Portfolio solution to the dry year problem:

i. the concept relies on a suitable renewable ammonia market that does not exist at scale either in New Zealand or internationally and its development prospects and timing are uncertain

ii. the concept relies on emerging technologies which are unproven at the proposed scale and questions remain around whether equipment could be delivered on time

iii. there are health and safety risks associated with this concept, and very large-scale ammonia storage in particular, which may prove hard to resolve

iv. the availability of a suitable location that adheres to specific location requirements.

Noted

Next steps

q **Note** that you will receive a further briefing in late May on the Portfolio option which will provide:

i. our developing understanding of potential Portfolio procurement and delivery options

ii. preliminary findings on how a revised portfolio option excluding hydrogen compares as a dry year solution.

Noted

Susan Hall
Policy Director
Energy Resource Markets, MBIE

10 / 05 / 2023

Hon Dr Megan Woods
Minister of Energy and Resources

..... / ...... / ......

Background

1. The NZ Battery Project is investigating large-scale, long-term renewable energy storage options that could address New Zealand's 'dry year problem'. The first stage of this work has been completed resulting in an Indicative Business Case (IBC) which was reviewed by the Treasury's Gateway Review Panel in October 2022.

2. The IBC considered two main options:

   a. A pumped hydro scheme at Lake Onslow

   b. A Portfolio option which includes the following components:

      - new geothermal plant operated flexibly
      - combustion of processed woody biomass
      - interruptible hydrogen electrolysis and storage as green ammonia.

3. The Portfolio option showed promise in the IBC; it outperformed the Lake Onslow option in a multi-criteria analysis that was used to identify a preferred Battery option albeit at a slightly higher financial cost. However, it was acknowledged that significant uncertainties remain around the deliverability and technical and economic feasibility of each of the elements of the Portfolio option that would need to be investigated further.

4. Cabinet considered the project and associated IBC in February 2023 and agreed to progress the project to the next phase of work which at a high level would involve:

   a. Phase 2a on the option of a pumped hydro scheme at Lake Onslow which would include further technical design and development and policy work. The purpose of the next phase of the project will be to prepare detailed designs and undertake policy work to further inform the potential operating models of such a scheme and its impact on the market.

   b. Further work on two other options that could address the dry year problem: a Portfolio of other technologies option; and, subject to iwi engagement, further preliminary investigations into a potential North Island pumped hydro location at Upper Moawhango.

5. You were invited to report back to the Cabinet Economic Development Committee in July 2023 with more information on the merits, risks and trade-offs of the Portfolio option and the potential Upper Moawhango pumped hydro scheme.

6. On 24 March 2023, we provided you with a briefing that outlined our workplan to support your July 2023 report back to Cabinet on the NZ Battery Project [Briefing 2223-3099 refers]. The next steps in this briefing indicated delivery of further advice on the following:

   a. Explanation of Portfolio components (this briefing).

   b. Explanation of Portfolio procurement and delivery options (briefing expected to be delivered by late-May).

7. The current briefing provides further information on the different components of the Portfolio option and specifically covers the following points:

   a. Opportunities, risks, mitigations and uncertainty management.

   b. Strategic alignment and potential opportunity costs.

8. The IBC identified three delivery models for the Portfolio option. This briefing contemplates a model based on **Option 1** where the Crown would procure and own the storage and generation assets associated with each of the technology components.

9. The next briefing - *Explanation of Portfolio procurement and delivery options* - will specifically provide further advice on the other potential Portfolio delivery options which, in addition to Crown-ownership, will consider the following (technology agnostic) options:

   a. **Option 2. The Crown procures contracts for reserve capacity** involving long term contracts with private suppliers to hold generation capacity available for use in dry year emergencies.

   b. **Option 3. Development of a Reserve Capacity Market:** Procurement of dry year reserve energy through an open and actively traded market.

10. The analyses contained in the current briefing informs that briefing as any delivery option is likely to include (some) of the technologies discussed here.

11. The content of this briefing draws on analyses contained in a Ministry of Business, Innovation and Employment (MBIE) commissioned WSP feasibility assessment report: *NZ Battery Project – Other Technologies Feasibility Study.* This report, and more specifically the initial concept designs it provided for each of the technologies, was used as a key input into the description and assessment of the Portfolio option in the IBC. The WSP report was peer reviewed by independent technology experts.

12. This briefing also draws on economic modelling undertaken on the Portfolio option and its components, discussions with stakeholders and other agencies, and our broader analysis and consideration of the Portfolio option within the wider project and energy and resources policy context. We are currently engaged in further analysis and economic modelling work that has been progressing following Cabinet consideration of the IBC. The results of this work, which will include a comparison between the Portfolio and Lake Onslow options, will be incorporated in the next briefing mentioned in paragraph 9.

New geothermal plant operated flexibly

13. This section on geothermal generation and the following sections of this briefing on biomass and hydrogen describe concept designs contained in the WSP feasibility assessment report, which were the basis of the Portfolio option put forward in the IBC. They are a starting point that would very likely change following more detailed engineering work if the Portfolio option is taken further in future.

Summary of flexible geothermal

14. Geothermal electricity generation involves drawing hot geothermal fluid from subsurface reservoirs through production wells. The high-pressure hot water is separated into steam and water, and the steam is used to spin turbines which generate electricity. It is a renewable energy source that can be relied on to generate electricity when needed regardless of weather conditions. It is a well-established technology, with over 60 years of operating history in New Zealand. Currently, there is 1000 MW of plant across 20 sites, generating around 7.5 TWh of electricity annually. Traditionally and economically, geothermal operates as baseload, meaning that it invariably runs at maximum capacity, except during periods of maintenance and faults.

15. In the NZ Battery context, the geothermal plant would work on a long-term "controllable schedulable" basis which would allow plants to ramp up electricity generation in dry years as needed. Traditional geothermal power generation technologies would be used, with the inclusion of some additional engineering design, operating and maintenance features. These additional features would allow the below-ground geothermal reservoir to be run at a low load

(turned down) condition, while allowing several of the above-ground power plants to be switched off (mothballed) during normal years, in readiness to be ramped up to run at full load in dry years.

16. A geothermal NZ Battery solution would involve bringing forward geothermal stations that would otherwise not likely be implemented until after 2030. This would involve developing several new geothermal fields/sites most likely in the Taupo Volcanic Zone. To avoid displacement of business-as-usual geothermal developments best used for baseload generation, the NZ Battery project would select potentially feasible sites that appear to be available from the later part of the generation stack[1] and are physically located away from established developments.

17. The base case contained in the WSP report assumed for purposes of analysis 400 MW of new geothermal plant at five currently undeveloped sites with (nominally) four generating units at each site. In normal years, each site's plant would run turned down, by modulating wellhead valves to a constant 25 per cent open and running one unit of four geothermal power station units at full load, with other units mothballed. In normal years, each plant would run at 25 per cent capacity. The electricity thus generated (i.e. 100 MW) would be baseload. In dry years, the plant could be ramped up, over approximately two weeks, to 100 per cent capacity (or a chosen increment to best match the dry year energy requirement) to bring online an additional 300 MW of dry year back-up generation equating to 0.6 TWh of energy over a three-month period.

18. There are technical reasons for running plant continuously in a low load mode (i.e. 25 per cent) rather than shutting it down altogether. Traditionally, most geothermal systems operate on a continuous basis for both economic (zero marginal cost to operate) and technical reasons. Shutting down or turning down the system may cause issues such as: degradation of the well; accumulation of potentially hazardous gases around surface facilities; and difficulties starting flow again.

19. To minimise CO_2 emissions, WSP's geothermal base case includes non-condensable gasses (NCG) extraction and reinjection technology with the assumed capacity to extract 50 per cent of emissions produced during operation and reinjecting these back into the geothermal reservoir.

Cost

20. The Class 4 capital cost estimate provided by WSP for its proposed geothermal solution is in the table below.[2]

		Estimated financial cost ($'m, nominal)
Construction CAPEX	Base estimate	Commercial Information
	Contingency Comme	
	Escalation	
Total construction CAPEX (P50)		

Contribution to total Portfolio capex (Commercial)	
Contribution to 3-month dry year capability (Commercia)	25%

[1] The Generation Stack refers to a list of geothermal development locations and includes information on their generation capacity and the earliest date plant is expected to be constructed in a BAU scenario.
[2] Note that minor adjustments were made to these costs in the IBC to incorporate advice from Transpower.

21. A geothermal solution would have ongoing operational costs primarily reflecting carbon costs, and administrative and maintenance costs.

Timing

22. WSP has produced a preliminary implementation schedule for the geothermal base case which would allow for staggered start dates for the five sites proposed to account for differing rates of progress with landowners and other stakeholders. The risk adjusted schedule[3] would see the first site completed by the second quarter of 2031 and the fifth and final site by the first quarter of 2033.

Key merits of a geothermal NZ Battery solution

Renewable stored energy resource

23. Geothermal is inherently stored and renewable and does not need to be "recharged" like the other proposed portfolio technology options. It can be reliably called on to provide energy during a dry year event and can do so continuously (i.e. it is not limited to providing 0.6TWH over a three-month period but can do so almost indefinitely).

Attractive option value

24. If in future we find better dispatchable electricity generation to provide dry year cover, the (proposed) flexible geothermal plant could be switched to permanent baseload. From a technical perspective this would be a relatively straightforward adjustment – it is in effect no different to the dry year operation use of this plant when 100 per cent of the generation capacity is utilised.

Allows for staged development

25. The geothermal base case in the WSP report assumes multiple geothermal sites, with multiple power stations. Having more than one site and associated power station allows for a staged development of the battery option, with expenditure committed over time. This could provide a more attractive approach for the Government, relative to a large one-off investment.

Solution relies on existing technologies

26. The proposed solution would rely on the use of mature technology (specifically for the surface equipment) to generate electricity in a novel interruptible manner. The technological risk[4] of providing electricity in this way is not considered high. Furthermore, NZ could develop new technology or geothermal plant operating techniques that would enhance New Zealand's status as a global leader in this industry - with related knowledge export benefits.

North Island location close to demand centres and transmission

27. The known geothermal fields in New Zealand are (mainly) in the Taupo Volcanic Zone, therefore any development will be close to existing transmission infrastructure and close to upper North Island demand centres.

Potential benefits for Māori

28. Māori have an interest in geothermal projects in several different ways (which at times can have conflicting objectives): as kaitiaki of the resource, as mana whenua (land overlying

[3] The risk adjusted schedule allows additional time for reaching the decision for notice to proceed, and the pre-procurement, procurement and construction stages, resulting in an additional 3 years.
[4] This means that the technology used can viably generate electricity in an interruptible manner – this is quite separate to the technical risk of running geothermal wellfields in this manner (see under *Key challenges and risks*).

many of our geothermal resources belongs to Māori trusts), and as claimants to be owners or users of the resource.

29. Under the Geothermal Energy Act (1953), it was stated clearly that: *"The sole right to tap, take, use, and apply geothermal energy on or under the land shall vest in the Crown."* Ownership of some resources has however been challenged with several Waitangi Treaty claims, some of which are unresolved, and some of which have been brought by wider parties than the specific landowners.

30. While in no case has actual ownership of the resource been transferred to Māori as part of a Waitangi Tribunal settlement, the Crown has in cases recognised access to the resource and ownership of assets such as wells.

31. Māori have taken a lead role in several geothermal developments. The Tuaropaki Trust took the lead and was initially the sole owner of the Mokai power scheme. Mercury operates five geothermal stations in the central North Island, two of which, Rotokawa and Nga Awa Purua, are joint venture partnerships with Tauhara North No.2 Trust (representing about 800 owners affiliated to Ngati Tahu).

32. Engagement with Māori is critical to the success of the NZ Battery project. This option could create opportunities for iwi/Māori. If the Crown were to invest in geothermal as part of the dry year solution, it would be advisable to engage with current geothermal providers such as Mercury to learn what engagement processes they have followed, and how Māori might benefit either as active partners or in a more passive way from a geothermal scheme.

Key challenges and risks

Electricity Market Risks

33. The proposed geothermal battery operation would require the development/construction of infrastructure and plant at high cost. Operating costs are very low – primarily associated with carbon costs - and do not vary much between running the plant at 25 per cent or at full output. There is therefore an economic incentive to run the plant at full capacity all the time (unlike the biomass or Lake Onslow solutions which have a fuel cost, and hence a natural incentive to stop use when it is not economic).

34. Using geothermal in a flexible manner therefore comes with potential energy market consequences that need to be carefully managed. To avoid interfering with investment incentives in the electricity market, market participants would need certainty about how a geothermal battery would operate. This could include guarantees/assurances that the battery would only operate during a dry year and would be turned down as soon as circumstances allow. Firm rules would need to be established to ensure this. These issues will be addressed in more detail in the subsequent briefing scheduled for late May 2023.

Technical risks associated with running a geothermal plant flexibly

35. For the NZ Battery, geothermal plant would work on a long-term flexible basis to meet the changing output requirements from dry years to non-dry years.

36. There is a very limited track record of this type of operation for geothermal wellfields and there is a risk that long-term operation of a particular wellfield in a schedulable manner is not feasible due to subsurface issues (e.g. mineral precipitation, changing boiling point in the well could pick at fresh rock faces bringing fine material to the surface to foul steam field equipment).

37. These issues may lead to increased maintenance costs, damage to infrastructure and equipment and long-term wellfield productivity reductions that mean schedulable operation of a geothermal site is not feasible from both a technical and cost perspective.

38. Running the plant continuously at low load (i.e. 25 per cent) is intended to materially mitigate this risk, as these impacts are most strongly associated with shutting the production well down altogether. Most notably, it will keep plants running hot which prevents corrosion and scaling issues and limits potential damage to plant equipment caused by temperature fluctuations.

39. Free and frank opinions

Carbon emissions

40. There are CO_2 emissions associated with both the construction and operation of the geothermal battery solution. While operational CO_2 emissions vary by site, they are generally around one fifth of the emissions of an efficient gas generator. Even so, our work so far indicates that these emissions may be material enough to impact market-led development of geothermal generation as carbon prices rise.

41. It is possible to minimise CO_2 emissions from a flexible geothermal battery through CO_2 extraction and reinjection into the reservoir.

42. Gas reinjection technology has been used overseas since the late 1990s to reduce CO_2 emissions from gas fields and other point sources. Currently, the International Energy Authority estimates there are around 35 sites internationally capturing around 45Mt of carbon per annum, including geothermal sites. In New Zealand, reinjection implementation at geothermal sites is in the very early stages. Both Mercury and Contact have invested in trials of the technology, with Mercury successfully reinjecting CO_2 back to the subsurface at Ngatamariki Power Station in the Waikato region. Contact Energy is in the process of installing equipment at Te Huka Power Station in Taupō, to trial CO_2 reinjection.

43. The success rate of CO_2 reinjection will be linked to local conditions, including the gas content of the geothermal fluid, the volume of fluid as well as the structure of the reservoir.

44. The degree of success of gas reinjection technology in New Zealand for geothermal applications cannot be taken for granted and will require continued research and development by the geothermal industry. We will not be able to resolve the uncertainty around this for the NZ Battery project (at least until a wellfield is identified and drilled). Our work to date nominally assumes 50 per cent of CO_2 emissions could be successfully reinjected, reflecting a potential range of success of between 0 per cent and 100 per cent with an expectation that the benefit for reinjection will be positive.

Strategic interlinkages and opportunity costs

Non-electrical uses of geothermal energy

45. There is a wide range of direct uses of geothermal energy in New Zealand, which involves using geothermal heat directly, without a heat pump or power plant. Other existing applications include high temperature process heat for kilns for drying timber and milk drying, and low temperature heat for horticulture, aquaculture and other space and water heating.

46. It may be possible for a geothermal battery solution to support other prospective heat users, creating broader economic benefits and opportunities. However, this is entirely speculative at this stage.

Funding and financing

47. Further consideration on how this, and other technologies in the Portfolio option might be funded will be provided in the next briefing which you will receive in late May 2023. This briefing will include consideration of whether New Zealand Sovereign Green Bonds could be utilised to fund this or other portfolio technologies.

Displacement of business-as-usual geothermal development

48. New Zealand's geothermal resources are finite, and this constrains how much electricity generation it can support. If part of the resource is used as a battery solution, it will reduce the resource that is available for others to develop and may hence impact business-as-usual geothermal development.

49. Geothermal plant traditionally provides reliable baseload generation. Renewable technologies that can provide firm baseload supply are scarce. As fossil fuelled thermal plant retires, and the intermittency of wind and solar generation becomes an increasing feature of our grid, that baseload generation is likely to be highly valued, particularly if the emissions impacts can be managed through reinjection. It may (therefore) be that a battery solution does not represent the best use of our limited geothermal resource. We expect to be able to provide some insight on this during subsequent stages of the project.

Conclusion

50. On balance, geothermal plant operated flexibly may provide a viable component of a Portfolio battery solution. However, some technical and environmental concerns remain especially around the long-term operation of the wellfield in a schedulable manner and the ability to mitigate emission impacts through reinjection of CO_2 into geothermal reservoirs.

51. A staged development approach would allow us to gain experience and develop techniques/technologies to operate hydrothermal plant in a schedulable manner which may help avoid undue subsurface issues and manage effects.

52. A complicating factor is that every geothermal site is different which precludes a one size fits all approach/solution to running a geothermal plant in a schedulable way and to CO_2 reinjection. More would be known about potential subsurface issues only when a field/location is identified and drilled. Any issues arising may well be unique to the specific site requiring bespoke technical solutions.

53. The risk surrounding using geothermal as a battery solution comes with potential energy market consequences that need to be carefully managed.

54. Our initial thinking is that market participants would need certainty around how any battery solution would operate in the market and operating rules would be required to provide this certainty. However, given the strong baseload proving capabilities of geothermal, it must be acknowledged that there may be strong incentives to change those rules in future, should baseload use of the resource become increasingly desirable.

55. This is a core point for discussion in our following briefing that you will receive in late May.

56. It is important to note that a progressive development approach for flexible geothermal that aims to resolve risks and uncertainties before extending the approach to multiple sites would push the risk adjusted completion date identified by WSP of the first quarter of 2033 out even further. Alternative means may be necessary to fill the dry year electricity generation gap if a choice is made to proceed with this kind of staged development approach.

Combustion of processed biomass

Summary of processed biomass

57. This technology is a form of thermal power generation in which sustainably produced biomass is used to fire electricity generation plants rather than fossil fuels such as coal or gas. Biomass refers to renewable solid-state organic material derived from (once living) plants or animals and, within the context of the NZ Battery project, specifically refers to woody material from production forestry.

58. The WSP base case assumes/identifies the construction of a single generation facility using Rankine plant. The use of this plant would provide some flexibility in terms of the biomass fuel medium used, with individual generation plant units having shaft power up to 250 MW. This targets a total installed generation capacity of approximately 500 MW, providing an additional (dry year) generation capacity of 1 TWh over three months.

59. The boilers would be fired using low-grade, de-barked pine logs harvested from sustainably managed existing New Zealand forests which would be processed at an on-site chipping and processing plant prior to combustion. These logs would be sourced from exotic forest plantations within a 70 km radius from the facility, to limit logging truck movements and associated carbon emissions.

60. The base case envisages the use of low-grade pine logs[5] that would otherwise be destined for the export market. Some 560,000 tonnes of logs would be required for a 1 TWh storage solution. This equates to approximately 4 per cent of the total annual exotic log export quantity of 14,000,000 tonnes (or 1.5 per cent of the total annual New Zealand exotic log harvest of approximately 36,000,000 tonnes).

61. To allow for a 70km supply radius, the generation plant would need to be situated in a region that has significantly large volumes of sustainably managed forests. These areas are in the Central North Island, East Cape, top of the South Island and the Otago Region. For each region, there are existing biomass transport and logistical capabilities to support the volumes being considered.

62. The onsite stockpile of logs (volume) needed to ensure 1 TWh of generation over three months in a dry year would be approximately 1.1 million tonnes which would require a log yard and storage area of some 60 hectares. By comparison, Wellington's CentrePort has an area of 46 hectares.

63. In the base case, pine logs are assumed to have a useful life of three years before they can no longer be used as biofuel. This means that the stockpile would need to be replenished at a rate of approximately 33 per cent per year. The stockpile that has reached the end of its usable life could be used to generate additional power or drive other revenue generating activity (e.g. pulp/paper manufacturers). The value of generation from retired stockpile material, or sales to other markets, can be expected to substantially off-set the cost of purchase of the biomass required for stockpile turnover.[6]

64. The biomass plant would have a warm-up time of approximately two days, which would make it unsuitable for short-term daily peaking.

Alternatives to base case

65. A torrefied fuel usage alternative to the base case described above has been considered by WSP. With this type of fuel usage, torrefied biomass replaces chipped logs as the fuel source

[5] Low-grade means they have inferior characteristics and are unsuitable to be used for structural applications.
[6] A minimum purchase price of $120 per tonne and a sale price of $74 has been assumed.

for the generation plant. Torrefied biomass is produced through a process called torrefaction whereby woody material is heat-treated in a temperature range of approximately 200 to 300 degrees Celsius to create pellets with lower moisture and higher energy content than the raw biomass. With this option a torrefaction plant would need to be built to create the torrefied pellets and the torrefaction plant would be located on the same site as the generation plant.

66. This option was considered worth further investigation and could still be inserted into the biomass solution within existing development timeframes (see below).

Solution requires a staged development and decision approach

67. A base case has been selected where generation plant, fuel storage and associated infrastructure are co-located and with a log supply within 70 km radius from the facility as the basis for more detailed scope and cost evaluation. The base case assumes that logs/chips (with a useful life of three years) would be used in the electricity generation process. However, uncertainty remains around the durability of logs as an energy storage option.

68. In addition, an alternative (torrefaction) solution exists that may prove to be a more attractive alternative fuel option for the following reasons:

    a. It may provide a more durable, higher energy fuel source for the generation plant.

    b. It may more readily be used as a fuel source in existing power generation plant.

69. The implementation timeframe allows for time to arrive at the preferred fuel source without affecting the delivery schedule of the overall biomass solution and with minimal effect on the feasibility level cost estimates, and no effect on the total assessed project risk.

70. An early decision will need to be taken on the implementation of a trial to test the durability of logs as an energy storage option. The trial would require Pinus radiata logs to be harvested and stored alongside torrefied pellets in controlled conditions and regularly tested for quality and durability. The results of this trial could demonstrate that a torrefaction plant may not need to be incorporated in the biomass battery solution, as proposed.

71. Alternatively, there are external influences that may prompt a decision to use torrefied pellets. New Zealand has existing plant that can likely be modified to use biomass (either torrefied or similarly modified). The remnant life of that plant is not fully known, but even if the remnant life were relatively short compared to the proposed life of new plant, a capex deferral option would be attractive.

72. Recently, Genesis has successfully completed a burn trial of torrefied biomass pellets at Huntly Power Station, to prove the technical viability of operating a Rankine unit solely on biomass. With some minor adaptation, the existing plant can utilise (torrefied) biomass.

73. A choice on whether to use torrefied pellets represents a trade-off between an existing plant that will reach the end of its life between 2035 and, with appropriate maintenance, 2040 (according to Genesis' public statement) and a new bespoke plant that is likely to be more efficient in terms of cost and associated emissions in the longer term.

74. Given the scale of the biomass solution, we would also need to allow time to commence the biomass procurement process for long term supply agreements and to conclude biomass supply negotiations.

Cost

75. The Class 4 cost estimate provided by WSP for its proposed biomass solution is in the table below.[7]

		Estimated financial cost ($'m, nominal)
Construction CAPEX	Base estimate	Commercial Information
	Contingency Comme	
	Escalation	
Total construction CAPEX (P50)		

Contribution to total Portfolio capex Commercial	
Contribution to 3-month dry year capability Commercial	41%

76. A biomass solution would have ongoing operational costs dependent on use and log prices, as well as administrative and maintenance costs.

Timing

77. WSP has produced a preliminary implementation schedule for the biomass solution which assumes a start date of April 2023 and a target end-date (handover of commissioned plant) in the third quarter of 2030. The risk adjusted base case completion date would be in the third quarter of 2032.[8]

78. The assumed start date of April 2023 (which would involve the commencement of a fuel storage trial) has passed. This means that the target end date in the third quarter of 2030 cannot be met and that the risk adjusted completion date would also need to be moved back.

Key merits and opportunities of a combustion of processed biomass solution

Mature technology

79. Mature technology options exist to combust biomass and generate electricity during dry years. Mature technology is also available to achieve both harvest and processing of fuel and good practices for minimisation of forest residues exist.

Sustainable greenhouse gas (GHG) neutral energy resource

80. The logs used for this portfolio option would be harvested from sustainability managed New Zealand forests providing a potentially constant supply of renewable energy.

81. Within a sustainably managed forest, harvesting comes with replanting obligations meaning the total inventory is maintained. Therefore, the total inventory of the forest remains unchanged from year to year. The CO_2 emissions are eventually reabsorbed by the forest, they are not included in New Zealand carbon accounting rules and IPCC guidelines as net emissions over time are considered to be zero in the energy sector.

82. However, there is some controversy around whether the biomass option could be considered carbon neutral. Most of the CO_2 sequestered by a tree as it grows is stored in the trunk. Logs are less energy dense than fossil fuels such as natural gas, so when it is combusted, they can emit more CO_2 emissions per unit of energy than fossil fuels. Net emissions from

[7] Note that minor adjustments were made to these costs in the IBC to incorporate advice from Transpower.
[8] The risk adjusted timing would allow for extra time for the pre-construction, procurement and construction phases of the program.

the use of logs are lower than fossil fuels if the feedstock is replanted, however the net emissions impact depends on the timeframe over which it is measured.[9]

83. Overseas, and Europe in particular, there appears to be a growing consensus among scientists and environmental groups that plans to convert significant numbers of coal-fired power plants to biomass (particularly wood pellets) would, on balance, have negative effects for the climate and environment. They argue that large-scale forest removal to supply biomass plants will drive the climate crisis, not avert it. However, this refers to the European context where they do not have large scale plantation forestry like New Zealand does and where native forests are harvested for biomass.

Scalability

84. A biomass solution offers the potential advantage of being able to scale up from 1 TWh to 4 TWh (requiring up to 2,240,000 tonnes of logs per annum representing 16 per cent of total exotic log exports). This could be achieved by replicating the system with several separate generation plants and biomass supply chains across New Zealand. There are several locations with concentrations of smaller sustainably managed exotic forest that could support a smaller scale generation plant. This would come at a significant cost though and more work will need to be conducted to better understand these costs as well as local economic, social and environmental impacts.

Relatively flexible in location – could be close to demand centres

85. Unlike hydro power, biomass plant is relatively flexible in terms of its possible location provided it is close to large forestry assets and associated logistics links. The largest forest assets are in the Central North Island relatively close to demand centres which is advantageous from a transmission perspective.

Potential re-use/re-purposing existing generation plant

86. As highlighted in paragraphs 71-73, there is potential to re-use/re-purpose existing generation plant if a decision is taken to use torrefied biomass as the energy source[10].

87. New Zealand has existing plant, in Genesis Energy's 250MW coal/gas Rankine units at Huntly, that can likely be modified to use biomass (albeit in thermally treated (torrefied) form). The remnant life of such plant is not certain, but even if the remnant life were relatively short compared to the proposed life of new plant, a capex deferral option could be attractive (i.e. we could use existing generation plant, such as Huntly, in the short to medium term rather than investing in new plant).

Revenue from the sale of retired stockpile material

88. As previously mentioned, (paragraph 63), biomass that has reached the end of its useful life could be sold to other markets and this could substantially off-set the cost of purchase of the biomass required for stockpile turnover.

Employment and commercial opportunities

89. The supply chain requirements for the biomass solution may well result in long-term, local employment benefits due to the job creation opportunities associated with the relatively

[9] CO_2 is released on combustion, and recaptured over the growth life of a tree, typically 25-28 years for Pinus Radiata

[10] Torrefied wood produces less CO_2 emissions than raw biomass. However, torrefaction is an energy intensive process requiring high energy inputs (that could be sourced from non-renewable sources or burning of biomass).

labour-intensive biomass harvesting and supply chain logistics that would be permanently required, as well as seasonal dry year work gains.

90. Māori have a considerable interest in forestry as owners of forests, participants in joint ventures or through forestry leases on Māori land[11]. As such, Māori are likely to benefit from a potential increase in demand for forestry products (biomass) and the associated job opportunities.

Key challenges and risks

Technical risks – log life (durability)

91. There is a risk that logs deteriorate faster than assumed and handling becomes more challenging. If log life proves to be shorter than assumed, stockpile turnover would need to increase. We may also find that the logs will have less power output than anticipated which would mean that more logs would need to be burned to generate the same amount of electricity.

92. As highlighted earlier, to mitigate against this risk, a trial would need to be conducted relatively early in the development of the biomass solution to better understand the storage life of logs, chips and torrefied pellets, their energy potential, and how they deteriorate.

Fuel shortage risk following consecutive dry years

93. Consecutive dry years, depending on the severity, may cause biomass fuel shortages (deplete the biomass stockpile)[12]. This is further exacerbated by the relatively slow recharge rate (biomass is expected to take ~ 2 years to replenish 1TWh of storage). This risk could be managed through the development of supply contracts with contingency plans. Upwards adjustments in stockpile size may also be considered.

94. Significant uncertainties remain around the mitigation of this risk:

    a. Upwards adjustment in stockpile size will come at a cost. Moreover, uncertainties remain around the durability of logs (or torrefied pellets) further adding uncertainty.

    b. Contingency plans notwithstanding, additional biomass, although possible to purchase, will be subject to commercial availability and market prices (there might be some scope to have contracts that negotiate and pay for the right to call for more supply at agreed prices).

    c. The market price impacts, and opportunity costs associated with procuring more logs that would otherwise be destined for the export market.

95. Related to the above-mentioned point, biosecurity threats, fire and other hazards may impact on the availability of sufficient amounts of biomass (as well as the price of the logs).

Public perception that the burning of biomass is not carbon neutral

96. The public may not perceive the proposed biomass solution, and particularly the burning of biomass, to be carbon neutral for the reasons set out in paragraphs 82 and 83. To counter this perception, assurances would need to be provided that large-scale biomass generation is carbon neutral (or better) over the full operating lifecycle by referencing carbon accounting standards. However, the transport of logs to the generation facility cannot be considered carbon neutral (unless transport trucks will run on non-fossil fuels/are electrified in future).

[11] According to Crown Forestry, there are currently 29 forests planted on Māori land, with a total planted area of 20,500 hectares.
[12] A fuel shortage risk following consecutive dry years is an inherent risk for all dry year solutions that rely on 'fuel' storage (including Lake Onslow).

Risk of securing a generation plant site

97. The base case does not propose a specific location for the generation plant and associated facilities other than a general recommendation that it should be near large forestry assets and associated logistics links.

98. The physical footprint of the biomass solution proposed under the base case would be inevitably large – it would need to accommodate not only a generation plant but also a wood chipping facility, potentially a torrefaction plant, and a large log storage area of some 60 hectares. Moreover, it would need to be located close to a large water source (i.e. to feed the boilers).

99. These requirements, in addition to having to be located close to existing infrastructure (roads, transmission lines), impose constraints on where the facility could potentially be located. Selecting a potential site would require a substantial amount of (engagement, modelling and consenting) work.

100. Although there is a significant amount of work required to find and secure a site for a generation plant, we consider that this is achievable provided appropriate planning steps are undertaken.

Strategic interlinkages and opportunity costs

Forestry and Wood Processing Industry Transformation Plan

101. The Forestry and Wood Processing Industry Transformation Plan (the Plan) sets out a vision and actions that drive growth, create jobs, and underpin a low-carbon future, further building New Zealand’s forestry and wood processing sector.

102. The plan acknowledges that biofuels provide a pathway for transitioning away from fossil fuels as the most immediate and available means to reduce emissions in some of our most hard-to-abate sectors, such as transport and process heat.

103. Biomass presents an opportunity for transitioning industrial heat away from coal and other fossil fuels, for example, in milk processing. It is unclear how much biomass those industrial customers will demand, and what the impact will be on the forestry industry. Using substantial volumes of biomass for electricity generation may present an opportunity cost for transitioning process heat. This is something that would need to be better understood through further work (this work is outside the scope of the NZ Battery Project).

104. Some of the industrial consumers may use wood milling residues (e.g. saw dust, wood shavings) rather than logs to create heat. This may limit the impact the biomass solution would have on industry moving away from fossil fuels.

105. The plan notes that approximately 3.5 million tonnes of harvest residues, not to be confused with the milling residues mentioned above, remain in production forests each year and that as demand for biofuels and bioproducts increases demand for residues from wood processing will also increase.

106. It remains to be seen whether residues can be used as a biofuel for the biomass solution. Low grade residues, such as bark, are not suitable for combustion - it contains minerals that are not good for boilers. However, Ministry of Primary Industries (MPI) officials have advised that logs may be present in harvest residues, and these may be suitable for combustion. The key question is whether these residues can be extracted at an acceptable cost.

107. Indeed, the Plan acknowledges that lowering the extraction and transport costs of recovering and distributing forest residues will be key to increasing their use.

MPI advice on log availability

108. We expect to see a 2025 peak in harvested logs followed by a period of decrease which will bottom out around 2033. Harvest levels are not expected to return to current levels until the mid-2030s. WSP's risk adjusted delivery date for the biomass portfolio component is scheduled to be around mid-2032. This date coincides with a decrease in availability of harvested logs, and this would likely have an impact both in terms of log availability and the price point at which logs are purchased. Further consideration would need to be given to these possible impacts if/when the biomass solution is considered in further detail.

Genesis and Fonterra considering plans for a torrefied wood pellet production facility

109. Related to the recent burn trial of torrefied biomass pellets at Huntly Power Station (see paragraph 72), Genesis has teamed up with Fonterra to investigate the possibility of building a torrefied pellet production facility, including the potential for a local supply chain, to power Huntly Power Station as well as for milk-drying purposes. MPI has contributed $25,000 towards the Stage 0 (fatal flaw analysis) of the feasibility study for this project.

110. MPI officials have also advised us that as part of the feasibility study, wood availability work is being conducted. The outcome of this work could well inform further work on the biomass Portfolio option, and we have requested a copy of the outcome of this study when it becomes available.

Conclusion

111. Biomass appears a viable component of a Portfolio battery solution. The technology is mature and securing a site is likely feasible. Some uncertainties/risks remain however, most significantly around:

  a. The ability of the biomass solution to cover concurrent dry years due to potential biomass supply constraints and to relatively slow stockpile replenishment rates. Additional feedstock (logs) could be found on the spot market, however this may come at a significant financial cost because of rapid increase in demand.

  b. CO_2 emissions - the public may not perceive the proposed biomass solution, and particularly the burning of biomass, to be carbon neutral (even though the biomass solution may in the long-term be considered largely carbon neutral, provided all harvested trees are replaced).

112. More information on how biomass may be included in a possible battery solution will be provided in our next briefing to you in late May 2023.

Interruptible hydrogen electrolysis

Summary of interruptible hydrogen electrolysis

113. Green hydrogen[13] is being pursued globally as a critical enabler to decarbonise hard-to-electrify elements of the energy system. It facilitates the use of renewably produced energy because hydrogen and its derivatives offer a chemical energy storage medium that can be transported or piped at large-scale to locations such as electricity generation facilities at a future date.

114. Hydrogen is obtained through an energy intensive electrolysis process which involves chemically splitting fresh water into its component parts of oxygen and hydrogen, using electricity.

115. The base case proposed in the WSP report would involve the building of a large scale, 350 MW electrolyser plant that could vary its electricity demand to utilise what might otherwise be

[13] Green hydrogen is obtained by electrolysis of water using renewable energy (e.g., wind, solar energy)

spilled or stranded renewable energy sources (e.g. overcapacity hydro reservoirs, or under-utilised wind and solar energy) to produce green hydrogen.

116. Gaseous hydrogen is very difficult to store at volume and is highly flammable but can be further chemically processed into other substances for easier storage or onwards use. For this reason, the hydrogen produced through electrolysis would be moved through a small hydrogen buffer storage tank and converted into ammonia at a green ammonia synthesis plant and collected in bulk storage tanks (4 x 50,000m^3).

117. It would take approximately 9 months to fill the storage tanks and once full, the green ammonia produced could be exported at a rate of approximately 22,000 m^3 (a small ocean-going ammonia tanker) per month. Green ammonia has a number of uses; among other things it can be used in the production of fertilisers or chemically cracked to retrieve the hydrogen (as an energy source).

118. In a dry year, the green ammonia stored on site would be cracked back to hydrogen and combusted for electricity generation through a 100 per cent hydrogen-fuelled 150 MW combined cycle gas turbine (CCGT).

119. These combined operations would likely require an energy hub at a port with access to a large fresh water source.

120. Interruptible hydrogen electrolysis would contribute to a dry year solution in the following manner:

    a. Electricity load demand response, via switching off the hydrogen production plant in dry years and halting the associated green ammonia production and exports. The demand response over a three-month dry period would be 0.50TWh.

    b. Converting (cracking) stored green ammonia back to hydrogen for dry year hydrogen-fuelled CCGT electricity generation. This would generate 0.29 TWh of electricity over a three-month dry period.

121. In summary, the interruptible hydrogen electrolysis solution would have the capacity to contribute 0.79TWh over a three-month dry period.

Cost

122. The Class 4 cost estimate provided by WSP for its proposed hydrogen solution is in the table below.[14]

		Estimated cost ($'m, nominal)
Construction CAPEX	Base estimate	Commercial Information
	Contingency Commercial Information	
	Escalation	
Total construction CAPEX (P50)		
Contribution to total Portfolio capex Commercial		
Contribution to 3-month dry year capability Commercial		33%

[14] Note that minor adjustments were made to these costs in the IBC to incorporate advice from Transpower.

123. A Hydrogen solution would have ongoing operational costs dependent on use, and the price of electricity that is paid to produce hydrogen, as well as administrative and maintenance costs.

124. The high contingency (54 per cent) in the hydrogen capex cost estimate is influenced by:

    a. A relatively low confidence in cost data used to inform estimates, due to the lack of a track record of implementing this technology[15], both in New Zealand and internationally.

    b. The potential high variance in cost between the potential locations for the project and associated infrastructure requirements.

    c. The relatively high level of risk associated with the technology, consenting, availability of equipment, electricity purchase prices and ammonia sale prices.

Timing

125. The hydrogen base case and risk adjusted schedules assume a start date of April 2023. The base case assumes a completion date in the first quarter of 2030 and a risk adjusted completion date in the first quarter of 2034.

Key merits and opportunities of interruptible hydrogen electrolysis

Renewable energy resource

126. Green hydrogen constitutes a potential long-term dry year solution with minimal carbon emissions. Unlike biomass and geothermal, it has a demand response component which could utilise ‘spilled’ renewable energy (e.g. wind and solar energy overproduction).

Quick plant response times means it could also support a calm, cloudy solution

127. Short response times for both the demand response and generation could help manage shorter term peak electricity demand in the market.

Key challenges and risks

The concept relies on a suitable market for renewable ammonia that does not yet exist

128. The plant would need to sell its surplus green ammonia during times of electricity abundance to a domestic or international market. During dry years, or other times of electricity scarcity, those supply contracts would need to be interrupted as the electrolysis plant would be turned off/down. When this interruption might occur cannot be foreseen in advance and may happen in some years and not others and could potentially last for several weeks or months. This makes it a different proposition from the type of flexibility hydrogen production is commonly associated with, which relates to operating the plant around short-term and/or predictable seasonal variation in wind and solar generation.

129. Green ammonia markets are in their infancy. They do not yet exist in New Zealand or internationally at a scale or level of liquidity that would provide confidence that interrupting ammonia production and sales is a mechanism that could provide a reliable, long-term solution to a dry year risk.

130. This would be most assured in a highly liquid market with many buyers and many sellers allowing sales without making long term supply commitments and withdrawal of supply at short notice. It is unlikely that the market reaches that kind of maturity within the timeframes for the NZ Battery project dry year solution. In the nearer term, supply contracts would likely

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[15] This includes uncertainty around the manufacture of (for example) large electrolysers at scale, and the assumed prices for these items

be negotiated directly with targeted counterparties. It is possible that there could be a contractual counterparty willing and able to accommodate an interruption to ammonia supply in a dry year – for example, through temporarily switching back to an alternative fuel source.

131. It is difficult to predict with any confidence and accuracy how any future international green ammonia market will develop, and the timing of that development. It is uncertain whether New Zealand would be internationally competitive in producing green ammonia, what the end-use and hence value of that product would be, and what the commercial implications of interrupting ammonia production and sales for prolonged periods would be. It is highly likely that these factors could change materially during the course of the market's development. An arrangement agreed in the near-term to secure a dry-year response may not be repeated through future sales arrangements as market conditions change.

132. Given that the hydrogen solution relies on demand response in an uncertain and changing market, officials consider this a key risk to its long-term viability as part of a dry year solution.

133. We note that our consideration of this risk does not reflect hydrogen's potential value to the electricity system or New Zealand more generally – only its ability to contribute as a large scale, Crown owned and operated solution to long-term electricity supply security during dry years (as described in WSP's base case).

The concept relies on emerging technology which is unproven at the proposed scale

134. The hydrogen concept proposed by WSP relies on technology that has not reached maturity and is yet to be deployed at scale. This relative lack of maturity applies to multiple components of the system including: the hydrogen electrolyser, ammonia synthesis process plant that can tolerate variable operation, and the ammonia cracking plant.

135. The last two technologies in particular are considered to have the highest level of uncertainty around reaching a suitable maturity level by a target date of 2030. Moreover, a hydrogen electrolyser at the required scale for the solution does not exist at present, nor does large scale production of electrolysers.

136. In addition to the above, questions remain whether equipment could be delivered on time given the likely international demand for hydrogen-related technology in future.

Health and safety risks

137. The proposed ammonia storage facility containing four 50,000m^3 tanks would be larger than any that currently exists in the world. While there is considerable familiarity with handling ammonia, storage at such a scale comes with health and safety risks. Ammonia is a highly toxic and flammable substance. Breach of storage vessels (e.g. through technical failure, earthquake or external impact) could result in the release of ammonia into the atmosphere and the contamination of land and waterways which could lead to harm to health and the environment. Moreover, there is a risk that a toxic flume could affect larger, potentially densely populated, areas.

138. This risk may be managed, by good site selection, appropriate design and response plans, but residual risks remain high.

139. Quite apart from whether the health and safety risks can be mitigated, public tolerance for such a large-scale ammonia storage facility needs to be considered.

Location of facility

140. The proposed hydrogen solution would have a large physical footprint and would have certain geographical requirements which are influenced by the following:

   a. The avoidance of significant transportation of high-risk green ammonia.

b. The safe export of large volumes of liquified green ammonia with the optional ability to also import large volumes in the future.

c. A location for storage and plant that is adequately buffered from neighbours.

d. The requirement for a large capacity high voltage grid connection point to connect large volumes of renewable energy to and from the production facility.

e. Access to a sufficiently large water source.

141. Based on these considerations, WSP recommended that all plant and storage would need to be located at/near a port facility with a deep-water loading berth to allow for the transfer of green hydrogen to specialist refrigerated liquified green ammonia ships (likely to be in the region of 20,000 to 80,000 m^3 capacity).

142. The combination of these characteristics would limit the number of feasible locations for the hydrogen solution. Using existing port sites and facilities would come with opportunity costs (e.g. possible displacement of commercial activities) which are not well understood at present, and which would only be better understood when site specific work is conducted. The likelihood of the facility (with its associated storage tanks containing hazardous ammonia) being near a major population centre would have health and safety implications and RMA consenting ramifications that would need to be worked through.

Strategic interlinkages and opportunity costs

Hydrogen Roadmap

143. In the 2022 Emissions Reduction Plan, the Government committed to developing a Hydrogen Roadmap (the Roadmap) to support the development and uptake of low-emissions fuels and to support industry decarbonisation.

144. An interim Roadmap is currently being developed for your approval and presentation to Cabinet in June 2023. At a high level it will cover:

a. how hydrogen in New Zealand could contribute to core priority objectives, within the context of the broader energy transition and other government work

b. expected priority use cases for hydrogen, and other areas that are less certain or may require further consideration

c. an immediate package of actions, as well as signalling where further thinking is necessary to inform the final Roadmap to be delivered alongside the Energy Strategy.

Hydrogen within the context of the broader energy transition requires greater renewable generation investment

145. Of particular relevance to the NZ Battery project, and the portfolio option, the draft Interim Roadmap acknowledges that as large interruptible loads, hydrogen electrolysers have the potential to contribute through demand response, and the effective storage and later utilisation of spill from renewables to even out electricity demand.

146. The draft interim Roadmap considers that hydrogen, liquid-organic hydrogen carriers (LOHC), and liquid hydrogen carriers such as ammonia, have export potential in the medium to long-term as countries with limited renewable generation capacity are signalling plans to import significant amounts to support the decarbonisation of their economies. This is already being considered by private companies without direct New Zealand government involvement, namely through the Southern Green Hydrogen project. However, at present, it is unclear whether New Zealand would be cost-competitive on the export market, particularly given the heavy subsidisation seen in other countries

147. The draft interim Roadmap also notes that it is not yet clear whether the market for renewable electricity generation could adequately respond to the additional demand created by a large export-oriented hydrogen sector.

148. Potential for hydrogen production in New Zealand remains – apart from export, hydrogen is one of a range of low-emissions technologies available to decarbonise emissions-intensive activities in New Zealand such as heavy transport and hard to abate industries (e.g. fertiliser and steel production) that have few alternative decarbonisation options. Having production facilities in Aotearoa could also offer some benefits for covering short term variability in energy supply from renewable sources (e.g. wind and solar) in future.

149. However, for the reasons set out previously, production of hydrogen at the scale that would be required for the specific purposes of dry year security appears high risk.

[BUDGET SENSITIVE] Regional Hydrogen Transition

150. The Just Transition Partnership team has been developing a mechanism to support the domestic uptake of hydrogen in just transition regions, lowering emissions, creating jobs and helping regions make the most of emerging clean-energy opportunities. The initiative is being designed to align with the outcomes of the Hydrogen Roadmap.

151. The scale of the proposed mechanism ($100m committed through Budget 23) is insufficient to support a large-scale electrolysis plant. The Regional Hydrogen Transition (RHT) subsidises hydrogen consumption, not production, through the use of an indexed hydrogen consumption rebate. Potential participants, particularly in the heavy-transport sector, are likely to rely on smaller-scale, distributed electrolysis plant to support their operations.

152. Given uncertainty over New Zealand's international competitiveness in hydrogen or ammonia export markets, the RHT is focused purely on domestic uptake and decarbonisation in hard-to-abate sectors. The initiative will grow skills and familiarity with the technology in the private sector, while also encouraging the timely development of fit-for-purpose regulations.

153. The RHT will require participants to contribute to New Zealand's energy transition through contracting with new generation or participating in demand response markets. Though these activities will not be at a scale to contribute meaningfully to the dry year response, they will establish a model for how future privately developed large-scale electrolysis plants could contribute to energy system security.

Conclusion

154. Interruptible hydrogen electrolysis has some merits as a potential component of a portfolio solution to the dry year problem. It is a renewable energy resource with minimal carbon emissions that may add to demand in a way that reduces 'spilled' (i.e. otherwise wasted) renewable energy while not exacerbating peak demand. It also offers flexibility in that both the demand response and generation elements of this solution can be deployed rapidly. This means that there is the potential that the plant could also be operated to manage shorter term energy balancing in the market.

155. On the other hand, a significant number of risks and uncertainties remain even after mitigations, namely:

    a. The concept relies on a suitable renewable ammonia market that does not yet exist at adequate scale either in New Zealand or internationally and its development prospects and timing are highly uncertain.

    b. The concept relies on emerging technologies which are unproven at the proposed scale and questions remain around whether equipment could be delivered on time given the likely international demand for hydrogen-related technology in future.

c. There are health and safety matters associated with this solution, and ammonia storage at the scale required in particular, that may prove hard to resolve.

d. The availability of a suitable location for the hydrogen plant that adheres to specific location requirements.

156. In addition to these outstanding risks, we also acknowledge the additional challenges noted as part of the draft interim Hydrogen Roadmap (see paragraph 147) as obstacles to hydrogen being part of a Portfolio solution.

157. Based on these remaining risks and uncertainties, interruptible hydrogen electrolysis, as presented in the WSP base case, is considered unlikely to be a viable component of a Crown owned and operated Portfolio solution to the dry year problem.

Next steps

158. The table below sets out further advice you may expect to receive prior to your July Cabinet report back.

Advice	**Estimated date**
Explanation of Portfolio procurement and delivery options and an update on economic modelling of the Portfolio option	Late May 2023
Draft Cabinet paper for July report back	Mid-June 2023