Ministry of Business, Innovation & Employment Hikina Whakatutuki

NZ BATTERY PROJECT

OTHER TECHNOLOGIES FEASIBILITY STUDY

Options Analysis Report

23 MAY 2022

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Options Analysis Report

Ministry of Business, Innovation & Employment Hīkina Whakatutuki

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Prepared by:	WSP Team	09-Feb-2022	Privacy of natural persons
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This report ('Report') has been prepared by WSP exclusively for Ministry of Business, Innovation and Employment NZ ('Client') in relation to the NZ Battery Other Technologies Feasibility Study ('Purpose') and in accordance with the Consultancy Services Order Contract Number 17647 dated 6th December 2021. The findings in this Report are based on, and are subject to, the assumptions specified in the Report and the Contract. WSP accepts no liability whatsoever for any reliance on, or use of, this Report, in whole or in part, for any use or purpose other than the Purpose, or any use or reliance on the Report by any third party.

Approved by:	WSP Project Director	09-Feb-2022	Privacy of natural persons	

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NZ Battery Other Technologies Feasibility Study

6-P0264-RPT-1001 Rev 1.2 Options Analysis Report

Please see attached the updated Options Analysis Report, incorporating updates as per feedback comments received on the Executive Summary, noting these updates have also been applied throughout the body of the document.

We look forward to working with the MBIE NZ Battery team further on next steps of the project.

Yours sincerely

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Executive Summary

INTRODUCTION

The Ministry of Business Innovation and Employment (MBIE) is investigating options to manage or mitigate New Zealand's 'dry year problem.' A feature of New Zealand's highly renewable electricity system has been that our reliance on inflows into our hydroelectric dam reservoirs make us susceptible to potential shortages in 'dry years.' In the future, with more of our electricity supply coming from wind and solar generation, the problem may become a 'dry, calm or cloudy year problem.' The NZ Battery Project has been tasked with finding a solution to this problem in a way that supports NZ's commitment to climate change mitigation and a 100 percent renewable electricity future. The Project has several workstreams investigating the various parts of the problem. Globally, interest in energy storage to unlock greater renewables penetration is on the rise, although not generally at the scale and duration Aotearoa NZ seeks, in this regard the large-scale nature of the NZ Battery Project is unique.

SCOPE OF WORKS

WSP was engaged by MBIE to review several alternative, non-hydro technologies that could potentially help to manage, or mitigate, the dry year problem by storing 1 – 5 TWh of electricity or equivalent schedulable generation (meaning it can be released as and when required) from 2030. These alternative technologies are Bioenergy, Geothermal Energy, Hydrogen, Air Storage and Flow Batteries and were generated by MBIE's NZ Battery team following an initial screening process. These Other Technologies may be considered as stand-alone options for NZ Battery or as building blocks for a full solution. The lower storage requirement in the range considered of 1 TWh reflects their potential for their inclusion in a hybrid solution.

The ultimate outcome of the Other Technologies Feasibility Study is to determine which, if any, alternative technology option, or combination of options, should be taken through for further investigation as part of a detailed business case, when considered alongside a pumped hydro solution.

The scope of works is split into three tasks:

Task 1: Preliminary feasibility and applicability assessment (Options Analysis), focused on the review of non-hydro renewable technologies, to recommend two to three Prospective Options for further study.

Task 2: A technical and commercial feasibility assessment of the Prospective Options, including the viability of integration and deployment by 2030, in the New Zealand Battery context.

Task 3: Evaluation of the Prospective Options against evaluation criteria, to assess the options and inform the determination as to whether any should be developed further.

This report presents the results of the Task 1 Preliminary feasibility and applicability assessment (Options Analysis).

APPROACH

Over the course of the Options Analysis review, WSP 's NZ and international team members, together with MBIE's NZ Battery Project team (including support from other subject matter specialists) applied a structured process to evaluate each of the Primary Options. This included sharing drafts of findings for discussion, reviews and feedback, assessment workshops, technical and evaluation challenge sessions to arrive at the recommendations.

The key steps in the analysis methodology included pathway assessments (the various energy transfer routes within each option, from source to electricity generation), Red-Amber-Green (RAG) assessment of a wide range of criteria, SWOT assessments, commercial analysis (based on pre-feasibility level estimates of costs, using a common 1 TWh energy storage scenario across the technologies) and engineering judgement.

Cross checking and challenge used a multi-criteria analysis and the WSP Technical Overview Group (team members acting independently to the main technical team) provided continuous challenge and review to ensure appropriate levels of rigour were applied.

RECOMMENDATIONS FOR PROSPECTIVE OPTIONS

WSP, based on our investigations, together with input and collaboration from MBIE, recommends the following three options be considered for further study as part of the feasibility assessment of Task 2.

RECOMMENDED PROSPECTIVE OPTION	DESCRIPTION
Bioenergy	Biomass Production & Storage (Including investigation into conversion to biofuel, and potential to supplement with import/export)
Geothermal Energy	Controlled Schedulable Geothermal (Combining Long-term and Flexible)
Hydrogen	Hydrogen Production with (Liquid Ammonia) Carrier Storage (Combining NZ production and imported/exported green ammonia)
Air Storage and Flow Batteries are not recommended Prospective Options	

BIOENERGY OVERVIEW

We recommend that the option of Biomass production and storage, using trees from New Zealand's exotic forests, be carried forward to Task 2.

BIOMASS

NZ currently has a primary supply of biomass through its long-rotation exotic forestry that is able to meet the large-scale requirements of this project, allowing for large quantities of harvest and considerable flexibility in the timing of extraction. Other sources of woody biomass (short-rotation and residues) are considered less optimal – requiring more regular harvest (short-rotation crop) or having challenges in collection (residues).

This current woody biomass resource is commercially contracted and so access to this resource would require a negotiated basis. Significant quantities (representing close to the 5 TWh generation requirement) are currently exported for which NZ Battery could be considered a better usage. Should this resource be accessible, the option of using long rotation softwood enables the creation of an NZ Battery solution that is self-reliant with a high level of independence from international forces.

Mature technology options exist to burn biomass and generate the dry year energy needs and is proven across several reference projects. Mature technology is also available to achieve both harvest and processing of fuel and good practices for minimisation of forest residues are known. The use of solid biomass from pine logs as a combustion fuel within a Rankine cycle power generation technology therefore offers a high level of technological maturity across the full technology pathway.

A requirement to harvest large quantities of woody biomass within a short timeframe has implications for logistics. Storage options are considered available, but feasible storage lengths will vary based on form (logs, chips, torrefied) and could require storage release and replenishment. The optimum harvest, storage and pre-processing times would need to be further considered

NZ's sustainably managed exotic forests are considered to offer a GHG-neutral and fully renewable energy source. For example, the volume required could be sustainably produced (without competing with existing high value agricultural land) from an area less than half that of the Kaingaroa forest (provided here purely for illustration). A sustainably managed forest ensures that new plantings occur at the same rate as mature trees are harvested, and so the total carbon in the forest remains unchanged in the long term. If used as an NZ Battery, it is noted that there may be a potential short-term effect of bringing net carbon release forward due to trees being harvested early to meet dry year requirement. This aspect will need further consideration.

BIOGAS

Biogas relies on the bio-chemical reaction from organic wastes (municipal solids, food wastes and landfill). Based on available NZ Bioenergy Association information, the biogas from landfills is considered the largest source, but their total energy generation is insufficient to meet the scale of the NZ Battery project. A landfill serving 1.5 million people will only generate up to 20 MW (approximately 0.04 TWh of energy over 3 months). Other biogas sources are considered lower than from landfills. Biogas is better suited to offsetting local energy demands than as a significant storage solution.

LIQUID BIOFUEL

Liquid Biofuel, specifically ethanol, can be made from the same supply as described for Biomass above, that is, New Zealand's plantation forestry. This option is therefore also considered to offer a NZ Battery solution that meets the large-scale requirements, based on the assumed accessibility of this biomass. It is also assumed to be a sustainable and CO_2-neutral fuel source (as with biomass, further investigation and assurance of this will be included in the feasibility assessment task).

Power generation using ethanol as a fuel for either a Rankine cycle plant or a CCGT plant is considered mature technology. The technology to produce ethanol from biomass however has the lowest technological maturity of the bioenergy pathways, resulting in higher technical risk and less well-known economics. While it is a judgement call, it is considered possible that the conversion process may meet the required technology maturity levels by 2030. This is supported by knowledge that the wider global industry is developing similar processes and NZ has a significant body of science and expertise (Scion, NZ Crown Research Institute) related to this field, including a recently prepared biofuels roadmap document that sets out future practical options.

Should the technology sufficiently mature in the timeframes required for NZ Battery, the conversion of biomass to ethanol will bring several benefits. Firstly, when compared to biomass, ethanol can be used in a wider range of generation plant, offering lower capital costs and higher efficiencies. Such generation plant if implemented would also be more flexible in the choice of fuels. Secondly, the relative ease of storing liquid fuels for extended periods (when compared to solid woody biomass) should allow for a more economical scaling of ethanol production capacity and allow a more continuous, lower rate forest harvest.

RECOMMENDATION

RECOMMENDED PROSPECTIVE OPTION	DESCRIPTION
Bioenergy	Biomass Production & Storage (Including investigation into conversion to biofuel, and potential to supplement with import/export)

With the availability of biomass in the form of NZ's sustainably managed exotic forests assessed able to meet the volume and generation requirements, as well as technical maturity requirements of the NZ Battery project, it is recommended that this Primary Option is taken forward for further feasibility assessment as a Prospective Option. Utilising a domestic supply reduces risks associated with fluctuations and volatility in international supply and makes use of our existing NZ resource as well as achieving NZ's renewable energy goals. The form of the woody biomass used in the generation plant is still considered open at this stage and could include chips, pellets or torrefied biomass.

Through Task 2, further assessment would be carried out in several areas to explore in greater depth the suitability of this solution. This would include:

- Biomass supply: A more detailed evaluation of post-2030 options for supplying either white (pellets or compressed) or torrefied biomass suitable for fuelling of Rankine cycle power plant. This includes consideration of geographical options, environmental issues and competing demands on this resource.
- Augmentation sources: While there is high confidence that long rotation biomass offers an adequate supply for the project, a more detailed review of short-rotation biomass and softwood residue supply options as a means of augmenting supply. This review will also confirm the preferred main energy choice of long rotation crop.
- Biomass treatment and storage: A more detailed review of requirements for large-scale drying and/or torrefaction plant, biomass pre-treatment options (hog, chip, dry or pelletise), and the comparative use of forest store, log-store or torrefied and other biomass storage.
- Rankine plant: A review of fluid bed plant and other new/modified Rankine cycle plants which in turn will clarify requirements for a feasible biomass-fuelled Rankine cycle plant. This evaluation would also examine the lessons of other global trials of new/modified plant.
- Operational modes: Evaluation of possible operational modes for both generation plant and biomass treatment/conversion plant to consider fuel demand management, wet-year usage of fuel for stock rotation, preservation options and/or export or alternative usage options.
- Carbon Neutrality: Further consideration of the carbon-neutrality assessment of a biomass solution, considering the full pathway from harvesting, storage, transport and generation and effects of timing of carbon release vs sequestration, to gain further confidence in this assumption being correct.

Whilst not recommended as a Prospective Option, the potential benefits of conversion of biomass into liquid biofuel are considered relatively significant to this project, offering lower cost, more flexible generation and reducing transport and storage challenges. So, while the technology for creating ethanol from biomass is considered less mature and has therefore not been recommended as a Prospective Option, some further investigation into this would allow more clarity on technology maturity levels. It is therefore recommended that while the main focus is kept on the woody biomass option, a high-level evaluation of the practicably of creating a liquid biofuel supply from the main biomass energy supply chain, starting from 2030 is included.

As a standalone option the importation of bioenergy is not recommended, largely due to the security of supply risk from the international markets, especially when faced with an unpredictable demand profile. The option of supplementing domestic production with imports should however continue to be explored. Imports would provide a contingency supply source when extreme dry year demands arise, as well as offering options for early generation capability using existing plant. Use of existing plant also introduces the possibility of Capex deferral for a NZ Battery solution.

COMPARISON ACROSS TECHNOLOGIES

Relative to other primary options across all technologies, the recommended bioenergy prospective option of Biomass Production & Storage:

- Is likely to cost more than geothermal but less that hydrogen.
- Could potentially offer the higher range 5 TWh energy requirement solution from within NZ, also eliminating risk of international markets causing disruptions to fuel supply.
- Is able to utilise technologies that are existing and well proven in New Zealand
- Offers upside potential to reuse existing generation plant
- Has risks of biomass accessibility and supply chain logistics,
- Will require further assurance that it fully equates to a sustainable low carbon solution.

While noting it is not the least cost option, and acknowledging there exist risks to be further addressed, we recommend this Prospective Option based on its ability to offer a predominantly NZ resourced, large-scale solution with strong security of supply and low technology risk.

GEOTHERMAL OVERVIEW

We recommend the option of developing a geothermal NZ Battery by bringing forward about 500MW of geothermal stations that would be likely implemented after 2030 and operating them in a schedulable manner.

Geothermal energy is a familiar and well-established technology in New Zealand, with over 1000 MW of plant across ~20 sites constructed since 1958, generating around 7.5 TWh of electricity per annum. Geothermal electricity generation in New Zealand is typically operated at very high rates of utilisation for reasons including commercial drivers, practical operation and to minimise potential resource disturbance.

The NZ Battery Project seeks to consider geothermal in a different way, by running plant at varying rates of utilisation (e.g. turning off in normal years and only turning on in dry years - and when running, the additional option of operating in a flexible load following manner). Also considered as options are long-term storage of excess electricity as above or below ground thermal energy, as well as emerging geothermal technologies such as thermosiphoning closed loop (e.g. Eavor-Loop™).

The three key criteria of large-scale, long-term and renewable are all sufficiently satisfied by conventional geothermal electricity generation technology options. Desktop research and qualitative assessments indicate that NZ could build an additional 500 MW (more or less) of new geothermal generation by 2030. This would provide at least 1 TWh of energy over a 3 month period, satisfying the minimum energy requirement for the NZ Battery. One of geothermal's key advantages is its inherent energy storage, meaning it does not need to be recharged like other technology options, and can keep running, if required, to provide more energy in a dry year. This 500 MW of geothermal could provide 4 TWh of energy over 12 months. Whilst geothermal may face challenges to providing a 5 TWh solution by 2030, with NZ Battery focused consenting processes, there is potential for up to 1000 MW to be built, doubling the delivered energy figures above.

Four main geothermal power generation technologies were considered for the NZ Battery:

- Condensing flash plants (a conventional geothermal technology in NZ, with typically larger plants using high temperature resources), incorporating additional design features and operating procedures to enable long-term schedulable operation
- Organic Rankine Cycle (ORC) binary plants (also a conventional technology in NZ, with typically smaller plants using lower temperature resources), incorporating additional design features and operating procedures to enable long-term schedulable (or flexible short-term dispatchable) operation
- Geothermal energy storage (subsurface or above ground) and
- Thermosiphoning Closed Loop technologies (such as Eavor-Loop™), an internationally emerging schedulable geothermal plant type.

GEOTHERMAL SCHEDULABLE (LONG-TERM) - Condensing Flash Plants and ORC Binary Cycle Plants

Geothermal can be run long-term schedulable (on/off), with incorporation of additional design and operating procedures (which would be investigated further as part of the feasibility study work). For a NZ Battery application, in dry years the plant would be ramped up and then run as baseload continuously. It would be run for a period of 3 – 6 months (or longer if required), then be ramped down and potentially mothballed until the next dry year period. The new power stations could be built at various sites across NZ's known geothermal regions in increments of 25 MW, 50 MW, and 150 MW plants. These could then be brought on as required for dry years in controlled increments (e.g. in 25 – 50 MW tranches), depending on the extent of the energy gap.

GEOTHERMAL SCHEDULABLE (FLEXIBLE) ORC Binary Cycle Plants

ORC binary cycle plants could be suitable, with further technology developments, to have the additional flexibility to also run in a load following manner. This is because the ORC binary plant power generation process involves the heat being transferred from the geothermal fluid to a secondary working fluid, potentially enabling better flexibility. However, in the NZ Battery context this may not be the most optimal option when considered amongst NZ's potential future generation mix. It may be more optimal, as a dry year response, to switch on the 'geothermal NZ battery' and provide electricity continuously for say 3 - 6 months, and then use other technologies for short term load following (such as hydro generation or Battery Energy Storage Schemes (BESS), if required.)

As ORC binary plants only account for around a third of the expected geothermal development pipeline, to meet the large-scale requirements of the NZ Battery Project, it is expected that a geothermal solution would need to involve development of both condensing flash and ORC binary plants.

SUBSURFACE OR ABOVE GROUND THERMAL ENERGY STORAGE

This option, whether subsurface or above ground is not recommended for further assessment, primarily due to heat decay losses over the long-term storage time periods required for an NZ Battery. The highly active tectonic setting of New Zealand's geology makes it highly unlikely to determine a subsurface with the required long-term energy storage capabilities, and above ground options are only capable of shorter-term energy storage time frames (hours to days).

THERMOSIPHONING CLOSED LOOP (such as Eavor-Loop™)

Conventional flash plant or ORC binary cycle plant geothermal technology options are expected to outperform closed loop thermo-siphoning in the NZ Battery context. This is due to the relatively low technology-readiness level of emerging closed loop geothermal technologies, such as Eavor-Loop™ and the fact that no systems are planned to be constructed in any regions that share NZ's seismic, tectonic highly fractured geology,

RECOMMENDATION

We recommend that the option described above, to build approximately 500 MW (and potentially up to 1000 MW) of new geothermal (as a combination of condensing flash plant and ORC binary cycle plant) by around 2030, proceeds for further investigation.

RECOMMENDED PROSPECTIVE OPTION	DESCRIPTION
Geothermal Energy	Controlled Schedulable Geothermal (Combining Long-term and Flexible)

It would not be run at full capacity in a normal year, instead it would be run at low load (turned down) or maintained in a mothballed long-term preservation mode, reserved for dry years when needed. In other words, it could replace the fossil fuelled long-term schedulable / baseload plant NZ currently has, such as at Huntly and TCC (Taranaki Combined Cycle).

If the forecasted possibility of a dry year energy gap became a high enough risk, the geothermal NZ Battery plant would be brought online in selected increments. Some could be brought on as baseload only (e.g. condensing flash plants) and others (e.g. ORC binary cycle) may present the ability to also provide some load following flexibility.

A geothermal NZ Battery would provide the optionality to be switched in the future to run as a source of cost effective, renewable baseload generation. This potential solution may, therefore, provide a 'no-regrets' option, in that it could defer the need to build a large-scale energy storage scheme, while other less developed technologies develop further. It may also remove the need, or minimise the size, of any future energy storage scheme, due to a critical mass of Variable Renewable Energy (VRE) sources being built in future.

Even if NZ built a large-scale energy storage scheme, we would still need to also build the new generation sources in the long-term, to provide the electricity to re-charge it within an acceptable timeframe. Geothermal would allow the NZ Battery to provide both potential energy generation, as well as cover the requirement for energy storage - as geothermal is inherently stored and does not need to be recharged by other generation sources.

As part of the further feasibility study investigations in Task 2 we recommend including assessing the feasibility of designing and operating new condensing flash plant and ORC binary cycle plant in a long-term schedulable manner, covering aspects such as preservation methods for mothballing plant (or running in long-term turndown mode) and minimising potential impacts on geothermal steamfield / reservoirs. And for the new ORC binary cycle plant portion, we recommend also investigating the feasibility of including additional features to enable flexible short term dispatchable operation and the value of this capability.

The key issues to further address in Task 2 for this option are:

- The feasibility of operating geothermal sub-surface reservoirs in a long-term schedulable manner
- Location specific environmental / regulatory hurdles
- Challenges associated with implementing a geothermal new build programme across multiple sites in the time frames available
- Investigation into the opportunity cost of a Geothermal NZ Battery potentially displacing geothermal developments that would otherwise have been built anyway as a result of normal market forces in the next 30 years.

COMPARISON ACROSS TECHNOLOGIES

Relative to other primary options across all technologies, the recommended geothermal prospective option of Controlled Schedulable Geothermal:

- Offers the most attractive option from a commercial viability perspective due to its comparatively low ongoing Opex costs once built, with relatively moderate upfront development and Capex costs.
- Is an established technology with a history of successful implementation in NZ
- May be limited in its ability to provide the higher range 5 TWh energy solution by 2030 (noting that this could be addressed by running geothermal for longer periods, as it is not energy constrained like other options)
- Can offer a degree of optionality presenting a relatively low-risk, no-regrets solution in the NZ Battery context
- May have an associated opportunity cost of potentially displacing business as usual geothermal developments

While noting geothermal may have potential large-scale limitations and key risks that will need to be further addressed, we recommend this Prospective Option as it offers a low cost, relatively low-risk solution with future 'no-regrets' optionality benefits.

HYDROGEN OVERVIEW

We recommend that the option of hydrogen production and storage as green ammonia with supplementary imports and export opportunities be investigated further in the feasibility study.

Green hydrogen is being pursued globally as a critical enabler to decarbonize hard-to-electrify elements of the energy system. It facilitates the integration of renewably produced energy because hydrogen (or its derivatives) is a chemical energy storage medium that can support resilience and be transported or piped at large-scale to locations required for end use in the future; in this case, large-scale power generation.

Hydrogen production can utilise otherwise "spilled or stranded" renewable energy sources such as under-utilised wind, solar or over capacity hydro reservoirs. It has the potential to assist in optimising the decarbonisation of NZ's overall energy system, as it may allow more Variable Renewable Energy (VRE) generation to be built, with improved plant utilisation.

An added benefit of all NZ produced hydrogen options is that the electrical loads associated with hydrogen (and carrier) production sites can be interrupted to provide large-scale demand response.

HYDROGEN PRODUCTION WITH SUBSURFACE STORAGE

Production of renewable synthetic methane is a viable option for the NZ Battery Project. The primary strength it has as a hydrogen carrier is its similarity to natural gas. This allows it to be stored subsurface in depleted oil and gas reservoirs (for example, Ahuroa) and take advantage of existing facilities and infrastructure (assuming commercial arrangements were made with current owners). It also means that handling and safe working practices are already well established in New Zealand.

In normal hydrological years, NZ is expected to have the surplus renewable energy resources required to locally produce the amount of synthetic methane needed for a 1 TWh supply option. Shorter production periods or higher supply requirements above 1 TWh would push this demand up exceeding surplus renewable energy available and putting additional load requirements on NZ. It is noted that while renewable synthetic methane has the highest round-trip efficiency of all the hydrogen production options the efficiency advantage is partially lost due to synthetic methane requiring a greater initial green hydrogen input. Electricity demand is therefore not materially different. The balance between production rates and electricity demand on the NZ network would need careful consideration.

The technology readiness for the synthetic methane pathway is reasonable with methanation a widely used process. However, there is a concern around the scale required for the NZ Battery project with current reference projects 1/20th the size of a minimum 1 TWh requirement for this project. A further challenge with renewable synthetic methane is the sourcing of the large quantities of renewable CO_2 gas required for the methanation process. A large renewable carbon dioxide gas source (e.g., 45 MW biomass plant) and a plant to recover and purify that carbon dioxide gas is required, combined with transport of that carbon dioxide gas source or a common production site. This brings supply chain complexities, associated costs and more challenging consent requirements

Capture of the carbon emitted by biomass plant is a relatively immature technology, and while it does have potential to be developed globally, there is concern around it reaching the maturity required for NZ Battery by 2030. There may also be some level of public resistance to synthetic methane production in this manner – as the biomass plant is turning feedstock into electricity and CO_2, which is then being converted into an intermediary chemical (synthetic methane), which is then being turned into electricity and CO_2 again .

Transport of methane also carries the risk of losses to the atmosphere. Methane, being a greenhouse gas significantly more damaging than CO_2, has high cost and environmental impact when that occurs.

HYDROGEN PRODUCTION WITH CARRIER STORAGE

Green ammonia is considered a viable potential option for the NZ Battery Project largely due to non-carbon free ammonia's international popularity as an existing energy vector throughout the world. Development of green ammonia is receiving attention due to its ability to directly substitute fossil fuel-based ammonia and some proponents view as the preferred hydrogen carrier for end-uses such as the large-scale generation required for NZ Battery. More than 85% of export-oriented low-carbon hydrogen development projects around the world plan to ship ammonia.

Conventional natural gas fed ammonia synthesis technology (non-carbon free) and ammonia storage, handling and transport infrastructure is very mature, having been at commercial scale for several decades. Small-scale deployments of green ammonia synthesis integrated with renewable energy fed electrolysis exist presently, with synthesis technology vendors focused on offering large-scale solutions going forward. While the technology for ammonia cracking does not currently have high maturity or scale, it is expected to have reached required maturity levels by 2030, especially given the focus amongst the global supply chain on ammonia as an energy vector.

As with Renewable Synthetic Methane, in normal hydrological years, NZ is expected to have the surplus renewable energy resources required to locally produce the amount of ammonia needed for at least a 1 TWh supply option for NZ Battery. Shorter production periods or higher supply requirements above 1 TWh would push this demand up exceeding the surplus renewable energy available putting additional load requirements on NZ. Again, the balance between production rates and load on the NZ network would need careful consideration. With green ammonia having a lower round trip efficiency than renewable synthetic methane, the network load is slightly higher but not considered material.

Regarding storage, a 1 TWh supply option is estimated to require 391,000 m^3 of ammonia and a 5 TWh supply option, 1,955,000 m^3. The largest existing ammonia storage site globally (in Qatar) has a capacity of 146,000 m^3, approximately 1/3 of the storage required for a 1 TWh solution. Large, specially designed above-ground storage tanks (full containment, double-walled, refrigerated tanks with integrated recovery of ammonia boil-off gas, similar to LNG tanks commonly used) are required to store liquid ammonia, which is highly toxic in both gaseous and aqueous forms. Storage tank technologies are mature, but would require careful consideration of suitable geographic locations in NZ to ensure safety, environmental, seismic and logistical risks can be appropriately managed. It is noted that large scale facilities used for LNG applications with similar storage tank design requirements exist globally. For example, the KOGAS facility in Korea with a total LNG storage capacity of approximately 4,600,000 m^3.

Given the global focus on ammonia and the potential for global trade, there could be an opportunity to be a net exporter of certified green ammonia once NZ Battery storage levels are reached . There are also domestic non-energy uses for green ammonia which will need an increased supply of carbon-free options in the near future.

HYDROGEN CARRIER IMPORTS WITH BUFFER STORAGE

Of these, our view is that Green Ammonia is the only carrier likely to be developed sufficiently to meet the requirements of NZ Battery.

The importing of certified green ammonia from Australia or similar neighbouring large green energy exporting nations is a potential solution for the NZ Battery Project. As stated above, more than 85% of export-oriented low-carbon hydrogen development projects around the world plan to ship ammonia. The seaborne trade in ammonia is currently around 20,000,000 tonnes per annum (roughly 80 TWh equivalent) and so well above the requirements of the NZ Battery project. While at present, that does not include any certified green ammonia it is expected that seaborne trade of green ammonia will emerge shortly and have grown significantly prior to 2030.

Conversely, we believe that any other carrier option is highly unlikely to be sufficiently developed for imports by 2030.. While there is interest in renewable synthetic methane from shipping companies, enabling transport as a hydrogen carrier over large distances would also require the additional step of liquefaction to increase density, with associated losses and decreases in round trip efficiency. Other Liquid Organic Hydrogen Carriers (LOHCs) such as toluene or methylcyclohexane, or Liquid Hydrogen, while expected to potentially develop in future, are not expected to reach a supply chain scale that would meet the NZ Battery time frames for an import opportunity relative to green ammonia. Consequently, we suggest focusing on Green Ammonia as a potential import solution.

NZ has a number of deep-water port locations which may be suited for ammonia's bulk importation requirements. These facilities would require specialised bulk liquid handling and large bulk storage facilities that would need to be developed, however these are mature technologies.

Importing ammonia presents a number of strategic benefits for NZ over local production – chiefly the risk and cost of developing a local green ammonia industry is borne elsewhere. This option however represents a shifting of NZ's current dry year energy supply problem to one of energy security, as although ammonia import with local storage and ammonia or hydrogen fired CCGT's may be very capable of "keeping the lights on" - doing so makes NZ reliant on other countries and transport infrastructure for this backup energy supply.

The import only option also foregoes the use of the NZ's periods of excess electricity. The NZ Battery problem is framed around storing electricity when plentiful to use in dry years. Importing ammonia does not use this potential advantage.

Even with the uncertainty around the scale and liquidity of the green ammonia market by 2030, we expect an import only option could provide a partial solution to the dry year problem, but carries risk as a stand-alone long-term solution. This would especially be high risk for peak ammonia requirements, for example during consecutive or extreme dry years. Managing this risk to acceptable levels can be achieved by sizing the storage based on the combination of dry year and international market risk. While the potential benefits of green hydrogen import as a supplementary solution are recommended to be further considered, depending on imports as a stand-alone option presents too much uncertainty to be considered a complete solution to the NZ Battery problem.

RECOMMENDATION

RECOMMENDED PROSPECTIVE OPTION	DESCRIPTION
Hydrogen	Hydrogen Production with (Liquid Ammonia) Carrier Storage (Combining NZ production and imported/exported green ammonia)

WSP considers the most viable prospective deployment of the hydrogen option is to produce a lower level of green ammonia in NZ (around the 1 TWh range) and supplement this production with overseas import. This is effectively a hybrid of two of the Primary Options described above.

Synthetic methane and ammonia produced locally are economically extremely similar. However, the overall economic benefits of each carrier option will need further assessment to confirm any differences. While it is a close call, there are a number of factors which make ammonia the more favourable of the two. Development of energy storage in the form of synthetic methane is arguably more complex than ammonia due to the added complexities of the supply chain from the CO_2 requirement. The limited technology maturity of both renewable carbon capture and synthetic methane also represent a risk to the project with uncertainty around them reaching technical maturity at the scale required by 2030. It is anticipated that while green ammonia cracking is also not mature at scale that due to the global focus on ammonia as an energy carrier this technology will advance to scale more rapidly. Furthermore, the public perception of synthetic methane in terms of carbon emissions is anticipated to be substantial compared with ammonia – primarily due to the deliberate re-release of CO_2 into the atmosphere during synthetic methane's combustion.

Whilst a 1 TWh local production and storage facility of either green ammonia or synthetic methane is considered viable through the use of available surplus renewable energy, production facilities beyond this scale would become increasingly more challenging. The additional load on the NZ electricity supply would become significant driving up the need for additional variable wind and solar, (or further baseload) generation. This could be mitigated by supplementing local production with imports, allowing the scale of plant to be optimised to maximise capture of excess off-peak electricity and minimise any additional load on the network. Conversely, relying solely on just-in-time imports from other producers' swaps energy costs for long-term energy security, thereby creating another problem entirely. A hybrid of local production and imports mitigates the risk of reliance on an uncertain import market, allowing the split between local production / storage and import capability to be optimised to best match future energy demand and supply scenarios.

With the hybrid option of local production with import being beneficial to allow risks to be balanced, this also points to the use of green ammonia as the recommended carrier, with it expected to have the most global focus as a tradable green hydrogen carrier from 2030.

As part of the further feasibility study investigations in Task 2 we recommend further investigating:

- The hybrid option of local green hydrogen (as ammonia) production with supplementary imports
- Explore and optimise the local hydrogen and ammonia plant sizes, variable off-peak production schedules, storage volumes, port facilities at specific locations, imports, electricity generation and potential export aspects.
- Consider the energy security and supply risks in relation to the size, access to and economics of global green ammonia markets
- Ensure that other hydrogen carrier options are further considered to revalidate that green ammonia is the most feasible hydrogen pathway in the context of addressing the NZ Battery storage duration requirements. The technology and market maturity projections of all hydrogen carrier options should be updated with latest international information and expected developments.
- Locations of grid connections for both production facilities and electricity generation
- Further consider the considerable potential for actual, as well as perceived, environmental and safety risks of large-scale ammonia storage options
- The potential capacity of demand response through shutting down hydrogen production to gain more understanding of its potential benefits to NZ
- Associated costs of the above.

COMPARISON ACROSS TECHNOLOGIES

Relative to other primary options across all technologies, the recommended hydrogen prospective option of Hydrogen Production with (Liquid Ammonia) Carrier Storage is:

- The only true 'excess energy capture and storage' solution being recommended using low value electricity when hydro lakes would spill or there is excess wind or solar generation available.
- An enabler of the development of new intermittent renewable energy.
- The third most attractive option from a commercial viability perspective behind geothermal and bioenergy
- The highest demand on the electricity system
- Less mature than geothermal and bioenergy, however there is significant international research being undertaken, expecting to improve equipment efficiency and lower costs by 2030
- Potentially able to provide options to export and/or to use in domestic non-energy end uses, any excess green hydrogen carrier and provide a revenue source
- Logistically advantageous over geothermal and bioenergy in that it does not have to be located in any specific regions of NZ.
- Able to provide a significant interruptible load with potential demand response benefits to NZ's electricity system (if electricity demand exceeds renewable surplus)

Despite its higher capital costs and electricity demand, we recommend that hydrogen is taken forward as a Prospective Option due to its battery-like nature, which can take advantage of surplus energy and enable the development of further renewable energy. It also provides a possible revenue stream through the export of any excess green hydrogen produced, allowing the commercials to become more attractive. The attention that hydrogen is receiving globally will also likely bring improvements to the technology

OTHER OPTIONS NOT RECOMMENDED AS PROSPECTIVE OPTIONS

The above 3 recommended Prospective Options encompass the technologies of Bioenergy, Geothermal Energy and Hydrogen. The technologies of Air Storage and Flow Batteries have not ranked as highly and therefore have not been recommended to proceed as Prospective Options, as summarised below

Air Storage systems use electricity to compress (or liquify) air and store for later release through an expander, rotating a generator to create electricity. We do not recommend that any Air Storage technologies proceed for further feasibility assessments. This is due to no pathway being available that is both technically feasible and cost effective. One technically feasible option could be to find an existing hard rock cavern in New Zealand, however the exploration would require significant expense with a relatively low likelihood of finding an appropriate cavern. Another technically feasible option could be to construct a new human-made cavern, however this would cost well in excess of $20B and also be highly dependent on finding an area with the right geology. The option of using a depleted oil and gas reservoir has the considerable risk of explosion due to mixing remaining hydrocarbons with compressed air, which despite international research is not expected to be solved in the NZ Battery Project timeframes. In addition to the storage challenges, there are logistical challenges including the need for a large-scale, local, renewable source of heat for the re-expansion and power discharge steps.

Flow Batteries are a type of rechargeable battery architecture, in which electrochemical energy is stored in one or more soluble electrolytes and pumped into cells to produce electrochemical reactions. While flow batteries provide many strengths (such as high round trip efficiency, scalability) and benefits to the NZ Battery Project (including the ability to capture excess renewable energy), they are not recommended as a Prospective Option due to the relatively high Whole of Life costs currently expected when compared to other technologies in this assessment.

However, this is a technology that is attracting significant commercialisation and, consequently, is expected to have a relatively active cost improvement and control system progress. It is unlikely that flow batteries will become commercially viable by the NZ Battery Project's 2030 timeframe, particularly given the large storage requirements. However redox flow battery technologies appear to have the potential for rapid rates of advancement in storage capability and the consequent reductions in cost and size. Redox flow batteries could present a viable energy storage opportunity beyond the 2030s. This is one example of the potential benefits of the aforementioned geothermal option, in that it could 'buy time' for other technologies to develop.

RECOMMENDED NEXT STEPS

Following review of the recommendations of this report and confirmation by the MBIE NZ Battery Team of their decision with regards to the Prospective Options, the next steps recommended would be to develop a detailed workplan to proceed with further feasibility assessments and evaluations. These would be anticipated to include further technical and commercial feasibility assessment of the Prospective Options, and their viability of integration and deployment by 2030, to inform the determination as to whether any should be developed further (as an Advised Option). The next steps can be further discussed and refined as required, and we look forward to working with the MBIE NZ Battery team further on this project.

Glossary

Discontinued Pathways	Pathways not able to meet Key Criteria, so not considered further.
Dispatchable	Power plant that can ramp up/down electrical output in short-term timeframes (nominally half hour)
Evaluation Criteria	The assessment criteria used to assess the Primary Options as part of this study that have been defined as set out in Appendix A.
Levelised Cost of Energy ($/MWh)	This is the average present value of costs related to the present value of the electricity produced from the given system[1].
Load Following	The power plant load governor (controller) is set to automatically adjust to match the load as demanded by the grid within the constraints of safe plant operation
Low energy periods	Prolonged dry, calm and cloudy periods, known as 'dry years'
NZ Battery Project	MBIE's project to identify physical options for managing, or mitigating, the dry year security-of-supply risk in New Zealand in a 100% renewable system.
Other Pathways	Pathways less viable than the Preferred Pathways. These offer no significant advantage over any of the other pathways and are materially disadvantageous in at least one criterion.
Preferred Pathway	The technology pathway under a Primary Option that is assumed to be the most optimal to use in this evaluation, based on the level of detail assessed at this stage of the Feasibility Study.
Primary Options	Technologies and their sub-options that are shortlisted for this Options Analysis study
Prospective Options	The shortlisted options that may be taken through to subsequent phases of the NZ Battery Project.
Schedulable	Power plant that can turn on/off or ramp up/down electrical output, in longer term timeframes (nominally days to weeks)
Technologies	The five main technology areas that were shortlisted for the NZ Battery Other Technologies Feasibility Study, consisting of Bioenergy, Geothermal Energy, Hydrogen, Air Storage and Flow Batteries.
Technical Overview Group	Team members acting independently to the main technical team providing overview, guidance, challenge and quality reviews.

1 The LCOE "represents the average revenue per unit of electricity generated that would be required to recover the costs of building and operating a generating plant during an assumed financial life and duty cycle", and is calculated as the ratio between all the discounted costs over the lifetime of an electricity generating plant divided by a discounted sum of the actual energy amounts delivered. (source: Lai, Chun Sing; McCulloch, Malcolm D. (March 2017). "Levelized cost of electricity for solar photovoltaic and electrical energy storage". Applied Energy. 190: 191–203.)

Technical Reference Group	An advisory group established by MBIE to inform the NZ Battery Project to provide technical expertise and sector knowledge relating to quantitative analysis. Team members acting independently to the main technical team providing overview, guidance, challenge and quality reviews.

Abbreviations

AD	Anaerobic Digestion
AL	Alkaline (electrolyser)
ASU	Air Separation Units (Cryogenic)
BAU	Business As Usual
BMS	Battery Management System
Capex	Capital expenditure
CAPM	Capital Asset Pricing Model
CCS	Carbon capture and storage
CCGT	Combined cycle gas turbine
CFB	Circulating Fluid Bed (boiler)
CO_2	Carbon dioxide
CAES	Compressed air energy storage
CH_4	Methane
CSP	Concentrating Solar Power (plant)
CV	Calorific Value
DME	Dimethyl ether
EPC	Engineering, procurement, and construction
GW	Gigawatt
GWh	Gigawatt-hour
GHG	Greenhouse gas
GT	Gas Turbine
H_2	Hydrogen
HOGV	Hydrogen or other green energy vectors (hydrogen carriers)
ICE	Internal Combustion Engine
IP	Intellectual property
kW	Kilowatt
kWh	Kilowatt-hour
LCOE	Levelised cost of energy
LCOS	Levelised cost of storage (also see Whole of Life cost)
LH_2	Liquified Hydrogen
Li-ion	Lithium-ion

LAES	Liquid air energy storage
LNG	Liquified natural gas
LOHC	Liquid organic hydrogen carriers
LPP	Lean, Premixed, Prevaporised
MCDM	Multi Criteria Decision Making
MBIE	Ministry of Business, Innovation and Employment
Mtpa	Mega tonnes per annum
MW	Megawatt
MWh	Megawatt-hour
NH_3	Ammonia
NZ	New Zealand
NZ Battery	NZ Battery
NZBOTFS	NZ Battery Other Technologies Feasibility Study
NOx & SOx	Nitrous oxides and Sulfur oxides (pollutant emissions)
OCGT	Open cycle gas turbine
ORC	Organic Rankine cycle
O&M	Operation and maintenance
Opex	Operating expenditure
PJ	PetaJoule (10^{15}) Joules
PEM	Proton Exchange Membrane (electrolyser)
PV	Present Value
RAG	Red-Amber-Green
RE	Renewable energy
RNG	Renewable natural gas
RFB	Redox flow battery
R&D	Research and development
RMA	Resource Management Act
RTE	Round-trip efficiency
SNG / Syngas	Synthetic Methane
SWOT	Strengths, weaknesses, opportunities and threats
TES	Thermal energy storage
TW	Terawatt
TWh	Terawatt-hour
WACC	Weighted Average Cost of Capital

WOL	Whole of Life (Cost)
VRE	Variable Renewable Energy
VRFB	Vanadium Redox Flow Battery
ZBFB	Zinc Bromine Flow Battery

1 INTRODUCTION

1.1 BACKGROUND

MBIE is investigating options to manage or mitigate New Zealand's 'dry year problem,' which is a feature of New Zealand's highly renewable electricity system. The dry year problem arises when hydro inflows, and hence generation, become scarce, and a source of back-up generation is needed. In the future, with greater development of variable renewable generation, this may become a dry, calm or cloudy problem. Aotearoa's back-up generation is currently provided by fossil fuels, but the NZ Battery Project is looking to determine the feasibility of renewable energy storage and flexible generation options that can provide this instead. This would enable a transition away from fossil fuels, to achieve the ambition of a 100% renewable electricity system in New Zealand by 2030.

The NZ Battery Project is intended to identify physical options for managing or mitigating supply risk in a 100% renewable system and includes hydro and non-hydro options. The project is a multi-stage, multi-year process and is currently in Phase 1, the Feasibility Study. This phase will end with advice to New Zealand Cabinet in 2022 on which option, or combination of options, should be progressed to Phase 2. This would involve detailed engineering design of the preferred option(s), leading eventually to a final investment decision.

1.2 PURPOSE OF THE OTHER TECHNOLOGIES FEASIBILITY STUDY

The purpose of the Other Technologies Feasibility Study is to investigate the technical, commercial and environmental feasibility of non-hydro solutions to the dry-year problem and help understand their social and cultural effects. These technologies could be complementary to, or a substitute for, a pumped hydro solution such as Lake Onslow Pumped Storage that is being investigated as part of a separate feasibility study.

Five broad alternative technologies are under investigation:

- Bioenergy
- Geothermal Energy
- Hydrogen and other green energy vectors
- Air Storage
- Flow Batteries

These non-hydro solution technologies were generated by the NZ Battery Project team from a long list of alternative approaches, which have been screened against criteria and through targeted external engagement for feedback, in consultation with the Technical Reference Group.

The ultimate outcome of the Other Technologies Feasibility Study is to determine which alternative technology option, or combination of options, should be taken through for further investigation as part of a detailed business case, when considered alongside a pumped hydro solution.

1.3 PURPOSE OF THIS OPTIONS ANALYSIS REPORT

The Other Technologies Feasibility Study is comprised of three tasks:

Task 1: Options Analysis Report: A pre-feasibility assessment of Primary Options (shortlisted sub options against each of the five broad technology areas) to develop a list of Prospective Options.

Task 2: Technical and Commercial Feasibility Assessment: A two stage assessment of the Prospective Options, to assess the technical and commercial feasibility, and viability of integration and deployment by 2030 in the New Zealand context.

Task 3: Evaluation: A final evaluation of the Prospective Options against evaluation criteria, to assess the options and inform the determination as to whether any should be developed further.

This report forms the first task in the overall Other Technologies Feasibility Study – the Options Analysis Report. It takes the list of Primary Options, provides a pre-feasibility review of each, as well as a technical evaluation against a set of Task 1 Preliminary Feasibility Evaluation Criteria, and provides a recommendation on the Prospective Options (shortlisted options that could be taken through to subsequent phases of the Feasibility Study).

2 APPROACH

To undertake the Options Analysis review, WSP applied a four-step process to evaluate each of the Primary Options as reflected in Figure 2-1. These steps are described in more detail in the following sections.

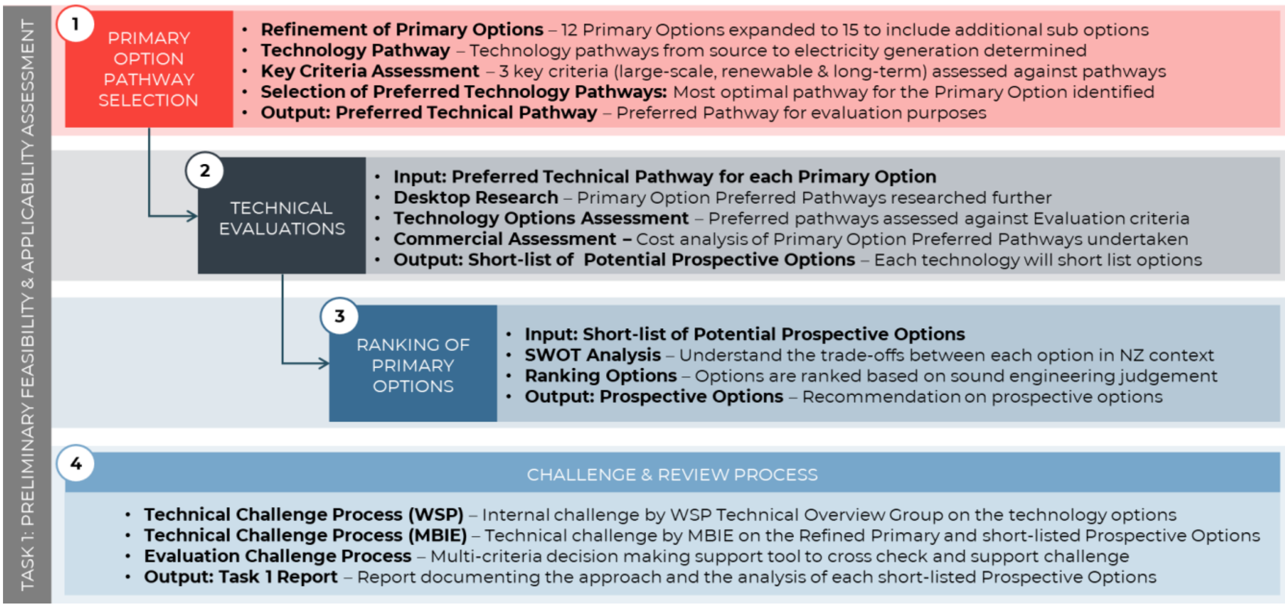

Figure 2-1: An Overview of our Evaluation Approach

Source: WSP

2.1 PRIMARY OPTION PATHWAY SELECTION

2.1.1 REFINEMENT OF PRIMARY OPTIONS

MBIE provided an initial list of 12 Primary Options drawn from the five broad technologies. In discussion with MBIE, the initial Primary Options were refined to include additional sub options within the 5 main technologies that could add value to the NZ Battery Project to create a list of 15 Primary Options. These Primary Options are set out in Section 3 and form the basis of this assessment.

2.1.2 DETERMINING TECHNOLOGY PATHWAYS

The Primary Options were expanded out for each of the five technologies to cover the possible technology pathways, from source to generation, by considering:

- Energy Source: the source of origin of the energy for the technology
- Energy Vector / Conversion: (only where applicable): the medium in which energy is transferred from the original source to the storage facilities or the process by which the energy source is converted to a medium suitable for electricity generation
- Storage: The form in which the energy is stored for the technology
- Generation: The methods of generation to electricity for the technology

2.1.3 KEY CRITERIA ASSESSMENT

Once expanded, the technology pathways for each of the Primary Options were assessed against the three key criteria that are essential for the NZ Battery Project:

- Long-term: capable of storing or remaining ready to discharge energy (in the case of options such as bioenergy or geothermal that do not store energy in the conventional sense) for at least two years.
- Large-scale: capable of delivering nominally 1 TWh of electricity supply over a period of three months and potentially up to 5 TWh. To ensure that options are not discounted that can achieve close to 1 TWh, a threshold of 0.9 TWh has been used.
- Renewable: deploys a fuel or energy vector that is renewable, i.e. one that is able to replenish itself indefinitely. In the New Zealand context, renewable electricity is defined as coming from the following energy sources:

  - Hydro
  - Geothermal
  - Solar
  - Wind
  - Liquid Biofuels
  - Biogas
  - Solid Biofuels

2.1.4 SELECTION OF PREFERRED TECHNOLOGY PATHWAYS

The pathways were then assessed at a high level to determine those most viable for use in this assessment. The following were determined for each Primary Option:

Preferred Pathways: the technology pathway that is assumed to be the most optimal to use for the relevant Primary Option, based on the level of detail assessed at this stage. The justification for the selection of the Preferred Pathway is described within each technology section of this report. These Pathways form the basis of the evaluation against the applicable Primary Option.

Other Pathways: Pathways that are considered less optimal at this stage of assessment than the Preferred Pathways. These offer no significant advantage over any of the other Pathways and are disadvantageous under at least one criterion.

Discontinued Pathways: Pathways that do not meet the Key Criteria or are considered to have a significant flaw, so are not further considered.

2.2 ASSESSMENT OF TECHNOLOGIES

2.2.1 OPTIONS ASSESSMENT

The Primary Options for each technology were assessed against the Evaluation Criteria that were agreed with MBIE during the study. This assessment was carried out by our technology specialist teams, using desktop research of available reference material and reference projects as well as engineering judgement. Details of how the Evaluation Criteria were defined and applied to ensure a fair basis of assessment of the Primary Options are provided in Appendix A.

The assessment was based on the Preferred Pathway for each of the Primary Options. In some cases, the assessment resulted in a reconsideration of the Preferred Pathway for the Primary Option and prompted further research to reconfirm the most optimal solution for assessment.

The Primary Options were scored using a Red Amber Green (RAG) assessment of how they performed against the Evaluation Criteria. The scoring is presented in a Primary Option Assessment table within each technology section of this report, with detailed notes and assumptions related to the scoring.

The following summarises the Evaluation Criteria that were used.

- Long-term
- Large-scale
- Renewable
- Option is practical and deliverable – specifically in terms of:
    - Being likely to have a Technology Readiness Level of 8/9 by 2030 (refer Appendix B for definition)
    - Geographical constraints, subsurface requirements, transportation, or logistics requirements – i.e. land and space requirements for 1 TWh deployment of the option, including but not limited to subsurface storage space if applicable
    - Commercial viability – Considering global use cases and whether the technology has been commercially viable internationally:
    - Indicative Capital expenditure (Capex), operating expenditure (Opex), Whole of Life Cost of storage, levelised cost of electricity (LCOE) ranges ($/MWh) by 2030 (defined below)
    - Round trip efficiencies – both current and expected by 2030
    - Whether environmental / regulatory hurdles are within normal project bounds, and do not present an unacceptable risk
    - Safety hazards and risks (after mitigation)
    - Reference projects of the largest scale projects employing the technology, and projects in the pipeline during the study
- Technology Implementation – key uncertainties, challenges, and opportunities for
    - Global market trends & context – Identifying global key players and market trends, any specific licensor requirements, and Freedom to Operate in New Zealand
    - Commitment and mobility of potential OEMs (original equipment manufacturers), suppliers, supply chain risks
    - Available international market volume to import required resources
    - Potential implementation bottlenecks – barriers and opportunities for technology to be implemented in the NZ Battery context, including construction and engineering requirements

2.2.2 SWOT ASSESSMENT

To provide an alternative assessment of each of the Primary Options, a Strengths, Weaknesses, Opportunities and Threats (SWOT) assessment was also carried out. This again was based on the Preferred Pathway for each Primary Option.

2.2.3 COMMERCIAL ASSESSMENT

WSP built a cost analysis model to perform an initial assessment of the relative costs of the Primary Options. Target accuracy of costs at this stage of option development is Level 1: -50% to +100% (AACE International Recommended Practice No. 18R-97). Within this level of accuracy, we emphasised consistency to allow comparison between options starting with a common scenario applied across all options.

This scenario, while simplistic and not reflective of the best implementation of any particular technology, is indicative of what a dry year operation may look like and is essential to allow a like-for-like comparison. The features of this scenario were:

- The system can store, or be ready to provide, 1 TWh of electricity to the grid over a three-month period in the middle of a dry year
- Capex is completed and all plant fully commissioned by the end of 2029 so that the system is ready to operate (begin storage) at the beginning of 2030
- Two years allowed to store initial energy or recover from a dry year
- 6 weeks' warning will be available for any preparation required for the system to provide electricity
- First dry year is 2032, then every five years

Electricity prices are Commercial Information The off-peak electricity price has been assumed to apply to periods of recharging the NZ Battery, with the peak electricity price applying to periods of discharge.

The model calculates the present value (in 2022 dollars) of:

- Capital Cost
- Operating Expenses
- Whole of Life cost
- Levelised cost of Energy (LCOE).

Capital Cost (Capex) is shown as the total required to be spent to have the plant ready at the start of 2030. Some options have shorter build times so can be started later.

Operating Expenses includes the maintenance costs, any mothballing and un-mothballing, fuel costs and the offset of the electricity sold during the dry years.

Whole of Life cost is the present value of the Capex and operating expenses. The model runs to 2050, then has a terminal value, assuming the system keeps operating indefinitely (so that plants with longer lives can be effectively compared to those with shorter lives). Later costs will be discounted more, recognising this advantage. The PV of capital also includes the ongoing refurbishment requirements for the system to continue operating under the intended conditions.

Levelised Cost of Energy (LCOE) is defined as the average net present cost of electricity generated over the lifetime of the plant. Consistent with this definition, we have calculated it as the whole of life cost (on a real basis) divided by the electricity produced also discounted on a real basis. As the costing scenario is for the system to only produce electricity over three months in dry years, the amount of electricity is very low, resulting in very high LCOE for all options.

The model uses a discounted cashflows approach, so a key assumption is the discount rate. At this point in the process, where the ownership and operation of the solution are not yet defined, there could be valid arguments for the discount rate to be anything between the risk-free rate (currently

Commercial Information to a commercial pre-tax nominal WACC (estimated using CAPM) of Commercial Information We have chosen to assess the different options using a discount rate of 5% nominal and 2.9% real (consistent with Treasury recommendations for government investments).

2.3 RANKING OF PRIMARY OPTIONS

WSP assessed and compared the RAG scoring of each of the Primary Options, the SWOT tables, multi-criteria analysis (MCA), as well as applying qualitative engineering judgement and made a preliminary recommendation for a shortlist of Prospective Options. This shortlisting process involved structured assessment workshops with the NZ Battery Project team at MBIE and our technology specialist lead team, with a challenge process to ensure appropriate levels of rigour were applied and tested. In this report we provide the preliminary ranking of shortlisted Prospective Options and recommendations, for MBIE's review and consideration.

2.4 CHALLENGE AND REVIEW PROCESS

2.4.1 TECHNICAL CHALLENGE PROCESS

During each of the WSP working team progress and review meetings, held regularly during the Task 1 delivery, members of the project Technical Overview Group provided theoretical and technical challenges across the key criteria. These were then researched further by the respective Technology teams and incorporated as appropriate.

Both formal and iterative technical review challenge sessions were held as part of the Draft Task 1 deliverable hold point, via formal meetings and communication with the Technical Overview Group and each technology workstream lead. These were documented in WSP's records and quality management system.

Each of the assessments of the Primary Options against the Evaluation Criteria and this Options Analysis Report have been peer reviewed internally by WSP.

2.4.2 EVALUATION CHALLENGE PROCESS

The evaluation process that has produced the preliminary rankings and recommendations for Prospective Options has undergone an internal challenge and review via WSP's Technical Overview Group, as well as cross checks from each of the workstream leads.

We used a multi-criteria analysis (MCA) approach as a cross check and validation of the RAG. We used a subset of the Red – Amber – Green (RAG) criteria and standardised these to ensure no overlaps or inherent biases.

The MCA was performed in the 1000minds[2] MCA tool and was supervised by the developer, an authority in the use of MCA. The tool provides structure to an MCA as well as providing state of the art analysis support features. This structure has been overlaid on the analysis as follows:

- The three Key Criteria (non-negotiable) were entered separately – this allows any alternatives ('Other Pathways') that do not meet these criteria to be 'switched off' and excluded from the

[2] 1000minds (1000minds.com) is an MCA tool that implements a robust Multi Criteria Decision Making approach along with state of the art features, including their unique conjoint analysis methodology (PAPRIKA) for assessing weights

assessment of trade-offs between various criteria. This also means that non-negotiable criteria are not given weights that are traded off against other criteria.

- The other criteria and scoring from the RAG mechanisms were simplified and refined in conjunction with MBIE.
- Overlaps and correlations in the other RAG criteria were identified. Overlaps and correlations in criteria are where two criteria have "common ground" or are both affected by another factor in the same way. In an MCA, this results in the common ground being "double counted". These were removed by combining criteria and adding criteria that represented the differential aspect between the criteria.
- The scores for the options were taken from the RAG scores and a survey of the WSP technology specialists.
- The conjoint analysis survey was developed to assess the weights. This survey was tested on the WSP project team, MBIE project leaders then given to the wider MBIE project team and TRG. The results of this final survey were compared to the earlier surveys and proved consistent (indicating low levels of ambiguity). These weights were used in the MCA.

This analysis was intended to be used in conjunction with the other evaluation approaches to provide challenge and rigour. The results of the analysis show a strong correlation with the other evaluation approaches, indicating that the conclusions we have reached are reasonably robust. Weights and alternatives were scored on each criterion using a survey across the MBIE NZ Battery team and reviewed as part of the decision recommendation process.

Alternatives ranked by 1000minds were then compared with the Rankings of Primary Options.

2.5 GENERAL NOTES AND ASSUMPTIONS

The general notes and assumptions relevant to our evaluation of the Primary Options are:

- All expenditure values are stated in terms of 2022 NZ dollars. Any currency conversion applied to available data is based on a 3-year average conversion[3] rate from 1 February 2019 to 31 January 2022 (NZD = 0.67 USD = 0.94 AUD = 0.51 GBP = 0.59 EUR)
- For storage options that source electricity from the national grid (e.g. hydrogen and other green energy vectors, air storage and flow batteries), we have assumed that all electricity supplied to the grid in 2030 is from a renewable energy source, so those storage options are considered renewable.
- The primary scope and focus of this project is to solve the long-term, large-scale, dry year issues in New Zealand. The evaluation is based on the Criteria set out in section 2.2.1 and further defined in Appendix A. Any additional benefit brought by the technology or the specific option that does not fit against these criteria has been noted but has not formed part of our recommendation process. An example of this secondary benefit is the ability to dispatch in a short-term load-following manner.
- For the purposes of investigation, we have assumed that all options, in particular those that involve international supply chains, utilise inputs that are sourced using ethical, non-corrupt, transparent, and sustainable practices with green financing, while meeting anti-slavery, human rights and other moral and ethical requirements.

[3] Conversion rates from Yahoo Finance

- This study has not considered specific locations for plant or issues of logistically aggregating/distributing resources. These aspects will be covered for the Prospective Options in the subsequent feasibility study.
- Technology options in this assessment may face significant implementation challenges affecting the feasibility of them being procured, fabricated, delivered and constructed by 2030. We have been cautious to not eliminate options based on an inability to be implemented by 2030. We have assumed that costs related to supply chain logistics, shipping, transportation are based on a 2019 business as usual scenario (i.e. pre COVID conditions and constraints).
- Note that this report has been prepared with contributions from multiple authors involving different technical, commercial, environmental and advisory team inputs and, as such, is presented as a compilation of various technical and assessment sections.
- The options assessment has covered only practical application aspects of technology options. It has not included the financial / ownership structures through which these options could be implemented.

3 PRIMARY OPTIONS

This section sets out the Primary Options for each of the five broad alternative technologies assessed as part of this Options Analysis Report. MBIE originally short-listed 12 Primary Options for this study. Through the first step of our approach, including discussions with MBIE, this was expanded and refined to include 15 Primary Options.

Table 3-1: The original Primary Options and refined Primary Options.

TECHNOLOGY	PRIMARY OPTIONS	REFINED PRIMARY OPTIONS
Bioenergy	Biomass production and storage Biogas production and storage Liquid biofuel production and storage Bioenergy import with storage (including biomass, biofuel and/or biogas)	Biomass production and storage Biogas production and storage Liquid biofuel production and storage Bioenergy import with storage (including biomass, biofuel and/or biogas)
Geothermal Energy	Geothermal energy storage Controlled schedulable geothermal	Geothermal energy storage Controlled schedulable geothermal (long-term) Controlled schedulable geothermal (flexible) Controlled schedulable geothermal (via closed loop thermo-siphoning)
Hydrogen (or other green energy vector)	Hydrogen production with subsurface storage Hydrogen production with carrier storage Hydrogen carrier imports with buffer storage	Hydrogen production with subsurface storage Hydrogen production with carrier storage Hydrogen carrier imports with buffer storage
Air Storage	Compressed air energy storage Liquid air energy storage	Compressed air energy storage Liquid air energy storage
Flow Batteries	Flow batteries	Redox Flow Batteries Hybrid Flow Batteries

Source: WSP & MBIE (Discussed on 13-Dec-2021)

4 TECHNOLOGY PATHWAYS

The Technology Pathways for each alternative technology are set out at a high level in Table 4-1 (noting that this tabular format is limited in the ability to clearly show the actual combinations of Technology Pathways). More detail of the technology pathways for each of the Primary Options is set out in sub-sections of each technology chapter (Sections 5 to 9). These Technology Pathways were passed through an initial refinement / selection process, as described in our methodology in Section 2.1.4 before proceeding to the preliminary evaluation.

Table 4-1: Technology Pathways

TECHNOLOGY	BIOENERGY	HYDROGEN	GEOTHERMAL	AIR STORAGE	FLOW BATTERY
Fuel Source	*Energy Crops *Biomass Crops *Oily Wastes *Algae *General Waste	*Renewable Energy *Raw Water	*Earth's subsurface heat (Renewable Energy)	*Renewable Energy *Air	*Renewable Energy
Energy Vectors	*Ethanol / Methanol *Biodiesel *Methane *Biogas *Chipped Biomass *Torrefied Biomass Pellets	*Hydrogen Gas (electrolysis) *Ammonia *Synthetic Methane *LOHC *Liquified Hydrogen	*Steam *Binary Fluid	*Compressed Air *Liquefied Air	*Vanadium Redox *Iron based *Zinc based *Lithium-based Organic
Storage	*In-forest/log *Tank Storage *Stockpile *Compressed Storage	*Subsurface *Surface Tank Storage *Vessel (pressure)	*Inherent storage *TES Under-ground *TES Above ground heat storage mediu m (molten salt, gravels)	*Depleted subsurface oil and gas reservoirs *Saline Aquifers *Subsurface Caverns *Surface Tank Storage	*Tank Storage of electrolyte
Transportation	*Logging-truck / chip liner *Road-tanker *Rail *Pipelines *Coastal Shipping	*Pipelines *Road-Tanker *Truck Tube Trailer *Rail Tanker *Coastal Shipping *International Shipping	Not Applicable	Not Applicable	Not Applicable
Generation	*Rankine cycle *CCGT *ICE	*Turbine (OCGT / CCGT) *Fuel Cell *Reciprocating engines	*Condensing Steam Turbine (long-term schedulable)	*Air Expander /Turbine *Natural Gas Turbine	*Direct Grid Connection

TECHNOLOGY	BIOENERGY	HYDROGEN	GEOTHERMAL	AIR STORAGE	FLOW BATTERY
		*Steam boilers	*ORC (binary) cycle (short term dispatch or long-term schedulable) *Closed Loop thermo-siphoning		

Source: WSP

5 BIOENERGY

Within this section we consider and assess the potential to manage dry year risk using bioenergy in the NZ Battery Project context.

5.1 BIOMASS PRODUCTION AND STORAGE

5.1.1 PRIMARY OPTION INTRODUCTION

Biomass is produced from renewable sources (wood, plants), which is then resized (for example by chipping). Some of the options for biomass sources in New Zealand are:

- Forestry - Long rotation softwood (logs)
- Residues – softwood tree portions other than sawlogs
- Biomass crops - for example fast growing coppice crops
- Agricultural wastes – for example stover or straw

The biomass is converted into electricity using one of several methods:

- Direct combustion - the biomass is burnt to produce steam which is then run through a generation Rankine Cycle.
- Gasification - the biomass is heated under a controlled amount of oxygen and under pressure to produce a low-CV combustible gas, syngas (a mixture of hydrogen and carbon monoxide). This Syngas is then fired directly into a Rankine cycle plant or internal combustion engine, or the gas can be compressed and fired in a gas turbine.
- Pyrolysis – the biomass is heated in the absence of oxygen to create pyrolysis oil which can be burned like petroleum to generate electricity.

This option is illustrated in Figure 5-1 below.

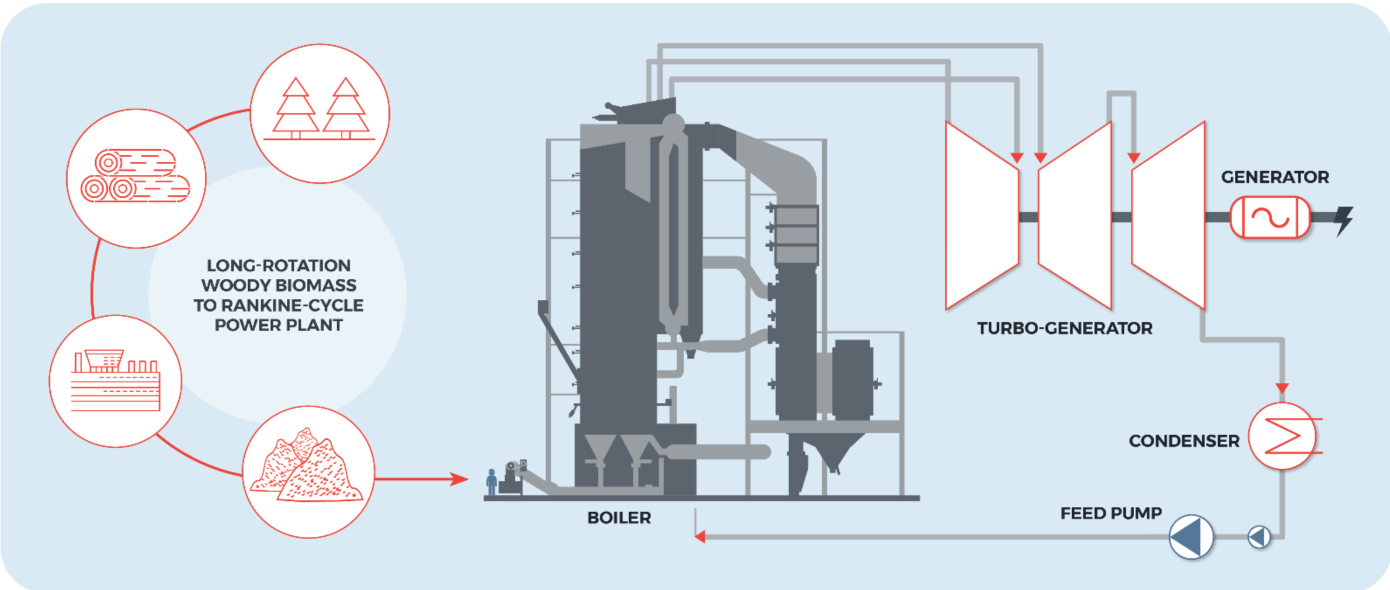

Figure 5-1: Biomass production and storage schematic

5.1.2 TECHNOLOGY PATHWAYS

Table 5-1 presents a broad categorisation of the pathway options to use bioenergy for the generation of electricity via biomass production and storage. In the table, **Bold text** represents the Preferred Pathway, Normal text represents Other Pathways, and Red text represents Discontinued Pathways.

Table 5-1: Bioenergy Technology Pathways

PRIMARY OPTION	BIOMASS PRODUCTION AND STORAGE
Energy Source	**Softwood:** Short Rotation Crop Long Rotation Crop Residues Agricultural Wastes
Energy Vectors / Conversion	Thermal conversion: Combustion of biomass Pyrolysis of Biomass Gasification of Biomass
Storage	**Forest/log** Chipped / Hogged / Torrefied Pelletised Natural carbohydrates (sugars/starches)
Generation	**Rankine Cycle**

Source: WSP

5.1.2.1 PREFERRED PATHWAYS

Long Rotation Crop Softwood (Woody Biomass): New Zealand has an existing, large and well-known plantation forestry resource (long-rotation biomass) that can be sustainably managed. Significant quantities of log biomass can be harvested from this resource, with considerable flexibility in the timing of the extraction. Currently, extraction is partially driven by maturation rates and local demand, but also by offshore markets for minimally processed logs. The long-rotation biomass (pine logs) could be harvested close to time of need, then debarked, chipped or hogged (reduced to a uniform small size) and dried, torrefied ("roasted") or even converted to biocoal/biochar for storage.

Data from the NZ Bioenergy Association of NZ (5-19) and also data from Scion assesses that commercially and technically accessible biomass resources are at least double the quantity required for 5 TWh generation. For context, although actual source locations will only be considered in Task 2, this volume is likely to be able to be sustainably produced from an area less than half of the area of Kaingaroa forest[1]. Access to the biomass resource would be at a market price and within commercial constraints. However, it is noted that large quantities of minimally processed logs (representing energy close to the 5 TWh generation requirement) are currently exported and so offer a source of significant biomass that could be made available to NZ Battery Project. Other sources of logs could also become available, for example in response to changing markets for fibre.

Harvest and transport capabilities to support biomass supplies equivalent to 5 TWh generation exist, and they are currently used for log export. These current exports are transported to different ports depending on the initial source location, which is comparable to the multiple generation units that are likely to be required for this project (locations yet to be investigated). The *prima facie*

[1] Kaingaroa Forest covers approximately 2900 km^2

De-barked logs: Major difficulties in biomass projects worldwide have related to inconsistencies in fuel specifications or changes from an original specification. The use of debarked logs as the source material for the Preferred Pathway ensures a good uniformity of fuel specification is possible and would make it possible to specify plant with confidence.

Chipped / Hogged / Torrefied: Wood chips can be readily dried to about 25% moisture content but can only be stored for a limited time before fungal and other degradation becomes significant. It is however possible to "torrefy" chips or pellets, using a relatively modest (200°C – 300°C) temperature process that drives off most volatiles, to leave a brown/black material. Torrefaction processes (which include steam-exploded pellet processes) and levels of torrefaction vary somewhat in both inputs and product properties. The limits to torrefied fuel life are not well-known, and the mechanisms/rate of degradation are also not well-known. Limited information suggests that torrefied biomass is able to be stored for periods of one or more years, however storage limits will need further review in the feasibility study task. Optimal approaches to the use of forest storage or torrefied storage have been kept open at this stage.

Rankine Cycle: For solid biomass, Rankine cycle plant (boiler, steam turbine, generator) is the only generation option practically available. The Rankine cycle option could burn chips, crushed pellets or torrefied biomass. A satisfactory dual-fuel combustor and fuel chain for coal/biomass is considered challenging. Rankine cycle plant of this type commonly have a poor turndown ratio (to around 40% of Maximum Continuous Rating MCR. New combustors would likely be Circulating Fluid Bed types. Options would be evaluated at the feasibility study stage.

Between dry years such plant would require well-designed preservation and recommissioning plans which are possible, but not simple, and the intermittent operation would have implications for staffing continuity also. At a later stage, the operational cycle would need careful consideration.

The possibility of converting existing Rankine-cycle units needs careful consideration. Such conversion would offer a low-Capex pathway by taking advantage of, not only boilers, but also steam and generation plant, cooling water and grid connection infrastructure, however, would involve plant with limited remaining life. The extent of modifications required and the effect upon performance is likely to be quite specific to a particular, existing plant.

New or modified-existing Rankine cycle power plants, use mature technology to convert an energy source to power. therefore, this has been taken as the Preferred Pathway for the purposes of assessment.

5.1.2.2 OTHER PATHWAYS

Short Rotation Crop Softwood: Limited-scope trials show that the use of short rotation biomass crops (fast-growing coppice crops) is possible within some NZ regions. The fast growth needs regular harvest, and the low bulk density of the material presents some challenges for the specific requirements of this project. It seems likely that it would be possible to use short-rotation biomass, harvested, dried and torrefied then combusted in new or modified Rankine cycle plant. However, the need for regular harvest and large-scale storage currently makes the use of this source a less-preferred pathway for the purposes of this assessment.

Softwood Crop Residues: Tree portions other than sawlogs are additionally produced during log extraction and are potentially recoverable for biomass. Scion data indicates that these represent up to 40% of total tree mass and so represent a significant source. This material is however more difficult to collect and tends to incorporate contaminants (mud, alkali salts) that affect combustion, and results in higher costs and carbon emissions than the harvesting of biomass logs (e.g. due to the additional use of heavy mobile equipment to gather residues). This is therefore, considered a less-preferred pathway.

Pelletised or briquetted Woody Biomass for Combustion: Pellet production is possible and well-proven. Pellet specifications are standardised, which facilitates acquisition/aggregation from many smaller suppliers, but this advantage is reduced when a few suppliers generate fuel for a specific large user. The simpler handling requirements of pellets make these attractive for smaller-scale use, however the advantage decreases at larger scales. Pellets are comparatively expensive to produce and their propensity to disintegrate if they become wet presents a challenge and, therefore, this is not a preferred pathway.

Pyrolysis: Direct use of pyrolysis oil derived from woody biomass is possible, but quality issues and the difficulties of standardisation mean that it is unlikely to be technically acceptable in gas turbines. It offers no advantage over biomass-derived liquid fuels and incurs risks of long-term degradation in storage. This is, therefore, less attractive than the preferred pathways.

5.1.2.3 DISCONTINUED PATHWAYS

Agricultural wastes: (straw, etc) that arise within short seasons could be assembled and burned, but there are significant difficulties in assembling from a diffuse source and storing for the periods required. Industrial wood waste can be converted into a good-quality fuel, however, the source is irregular and diffuse. Pathways from this source are not considered to meet the large-scale, practical option requirements of this project.

Gasification (Syngas): Biomass can be gasified to produce a low-CV combustible gas (Syngas) that can be either fired directly into a Rankine cycle plant or internal combustion engine, or the gas can be compressed and fired in a gas turbine. The gas requires significant clean-up to be acceptable as a fuel and poses significant challenges for storage. We consider that direct combustion of biomass syngas is not practically able to meet the large-scale key criteria, or practical and deliverable criteria, of this project.

5.1.3 PRIMARY OPTION ASSESSMENT

Following the initial screening assessment, the Primary Option of biomass production and storage on the Preferred Pathway of woody biomass direct usage has been considered for further analysis. Table 5-2 provides an indication of the degree to which this option meets the evaluation criteria.

Each bioenergy technology option is scored based on a qualitative rating and quantitative evidence against the established RAG criteria defined in Appendix A. Our assessment against the Evaluation Criteria is explained further below.

Table 5-2: Bioenergy Options

CATEGORY	CRITERIA	BIOMASS PRODUCTION AND STORAGE
Preferred Pathway		Woody Biomass Direct usage
Long-term	Between Dry Years Energy Storage	🟢 In-forest/torrefy
	Storage Recovery	🟢 Chip/hog, possibly torrefy
	Asset Life	🟡 > 40 years
Large-scale	Min. 1 TWh	🟢 Yes [1]
	Up to 5 TWh	🟢 Yes [1]
	3 to 6 Months Output	🟢 Yes
Renewable	Renewables	🟢 Yes
	Operational carbon emission intensity	🟢 Low [2]
	Built carbon emission intensity	🟡
	Sustainable Resources Risk	🟢 Yes
Technology Readiness	Technology Readiness Level (2030)	🟢 (TRL 9)
	Technology Ready for Commissioning (2030)	🟢 Yes
Geographical and Logistical Constraints	Geographical Constraints	🟡 Well-known
	Subsurface Constraints	N/A
	Transportation or Logistic Requirements	🟢 Well-known
Commercial Viability	Whole of Life Cost ($)	$6.4B [3]
Efficiency Measures	Round Trip Efficiencies (2021)	N/A
	Round Trip Efficiencies (2030)	N/A
	Annual Storage Decay Factor	🟢 Negligible
Environment and Safety	Environmental or Regulatory Hurdles (Ability to obtain a consent)	🟡 Large industrial plant
	Environmental Risks	🟡 Assume dry condenser
	Safety Hazards Risks	🟢

CATEGORY	CRITERIA	BIOMASS PRODUCTION AND STORAGE
Reference Projects	Reference Projects	●
Technology Implementation	Global Market Trends & Context	● No issues expected
	Commitment of OEM Suppliers	● Adequate
	Available International Market to Import Resources	● Based on supplementary imports supporting NZ production
	Potential Implementation Bottlenecks	● Scale is large

Source: WSP

Notes on the option assessed

[1] NZ bioenergy association have estimated 60 PJ/yr is exported from NZ in logs. In Scion's Pathways Analysis (5-16), Figure 3, page 180, quotes the availability of 14 PJ residual biomass in central North Island (with as much again spread over other NI regions. In Table 2, page 4 of Peter Hall's 2013 (more recent) study "Bioenergy options for New Zealand: Key findings from five studies", he quotes projected further 34 PJ / year available from forest harvest residues. Current logwood is subject to commercial contracts and access to the resource would require a negotiated basis - which is likely to be feasible.

[2] Supply chain emissions are not known with any level of precision. These are expected to be low for Rankine Cycle biomass use, approximately 60-300 gCO_2e/kWh, and are offset by the carbon absorbed during the regrowth phase of the bioenergy cycle.

[3] Based on Whole of Life calculation methodology applying consistent scenarios across all technologies.

5.1.3.1 LONG-TERM

Woody biomass (debarked logs) from long-rotation forests offers an inherently sustainable and long-term bioenergy storage option. Resource economics are inherently insensitive to year-of-harvest. Although pine forest has a recycle time of about 25 years, this is not a fixed term, and harvest over a wide window (20 years to 35 years) is possible.

The irregular nature of the "dry year" energy need is relatively easily accommodated by using a long-rotation forest as the primary energy storage approach - additional years of growth require minimal incremental effort.

Processing capacity would need to match a dry-year demand pattern. Provided this is available, processing times can be relatively short but would certainly need some level of stockpiling. Optimum levels and locations have not been assessed at this stage of the project.

Woody biomass will need size reduction and drying for practical transport and combustion/processing. In large plant, low-grade heat may offer options for drying. Torrefaction would reduce storage challenges and may allow optimisation of storage between stockpiles close to generation plant, and forest stocks. This will be investigated further if this option proceeds.

Biocoal (biochar) is yet closer to coal in properties but is a by-product of pyrolysis and, so, is not considered as a fuel source.

5.1.3.2 LARGE-SCALE

NZ already has pine forests that are extensive and well-known (in terms of regional scope, access options, level of maturity and likely growth rate). NZ also currently exports a significant volume of minimally processed logs, for which NZ Battery may present a more attractive usage. The amount of current bulk log exports from NZ represent energy very close to the 5 TWh generation requirement. The scale of log movement that would be associated with dry year generation would be very large, but less than that currently associated with log transport.

The current resource is commercially contracted and so access to the resource would require a negotiated basis. The current usages of the resource may add limited value to NZ through its exports but should be weighed up against whether dry year security is a better use of this resource. A more detailed evaluation of specific options for commercial and temporal management of fuel stocks will be carried out in Task 2.

The emphasis on logs, rather than use of slash (debris resulting from the felling of trees), arisings (waste products of industrial recovery operations) or whole tree, allows significant improvement in consistency of fuel properties - essential for large-scale, long-term use.

5.1.3.3 RENEWABLE

Pine forest usage in NZ is considered renewable.

Since forest biomass is synthesized from atmospheric CO_2, the combustion of biomass generates no net increase in atmospheric CO_2. Biomass can essentially be seen as a natural way of capturing and storing solar energy. A sustainably managed forest ensures that new plantings occur at the same rate as mature trees are harvested, and so the total carbon in the forest remains unchanged. NZ's sustainably managed exotic forests, therefore, are considered to offer a GHG-neutral and fully renewable energy source. This assumption will be further refined in Task 2 to consider CO_2 across the full technology pathway, also taking into account timing of harvesting and transportation of the biomass.

5.1.3.4 TECHNOLOGY READINESS

Woody biomass harvesting and pre-processing technology is mature.

Woody biomass drying and torrefaction (if used) technology is considered mature.

Rankine cycle plant and CCGT plant are mature technology: Circulating Fluid Bed boilers would likely be used for large-scale biomass combustion; however, this would be confirmed as part of further study.

It is likely that existing Rankine cycle plant designed for coal would require modifications before being able to burn woody (torrefied) biomass, and further study of this option would be required. It is reasonable to expect that viable modifications could be completed before 2030, and thus offer a limited lifetime opportunity pending commissioning of new plant.

Torrefied biomass has been substituted for coal in smaller boilers. New boilers could be designed for torrefied biomass. Although the properties of torrefied biomass approach those of coal, it is still considered that required modifications would be likely to be significant for a larger plant designed for specific coal-specifications; the extent of these modifications and of any derating needs further investigation. Torrefied biomass cannot automatically be considered a drop-in fuel option for boilers designed for coal.

5.1.3.5 GEOGRAPHICAL AND LOGISTICAL CONSTRAINTS

Detailed information on long-rotation biomass availability is available via the industry, who also hold information on maturity of stock and on extraction options. Long rotation biomass plantations are widespread - optimum logistics for post-harvest processing have not been assessed.

The transport of large volumes of logs at the approach to a dry-season generation (i.e. if the forest is treated as the primacy stockpile) will require significant logistics resources and careful planning.

Limited experience has indicated the possibility of storing torrefied biomass, but aspects such as practical durations and rate of degradation will require further study. While a regime of continuous harvest and torrefaction could build up a store of enough torrefied biomass to fuel a dry year scenario, this would only be practical if torrefied storage for several years were practical and would require stockpile rotation (probably by low-load operation of Rankine cycle plant) and refreshment of the stockpile.

Location for generation plant has not been considered in detail. Existing power station locations are attractive because they have cooling water, grid connection and possible opportunities for expansion. New plant options would require careful evaluation of cooling options, grid connection, storage areas and many other factors.

5.1.3.6 EFFICIENCY MEASURES

Round trip efficiency is not relevant for any of the bioenergy options, as they do not require significant offtake of grid power for the purposes of storage.

The processing of biomass includes initial felling, debarking, log-transport/storage and chipping. These are not considered to require major energy input compared to the energy value of the preferred source-category of biomass (export logs).

Biomass drying (which for the purposes of this study may extend to torrefaction) consumes low-grade energy. Particularly for torrefaction, this is likely to be available from the biomass source (expelled volatiles), however hybrid options (such as geothermal heat) are also possible.

5.1.3.7 ENVIRONMENT AND SAFETY

No major environmental or safety issues are envisaged beyond those arising in any large forestry operation or industrial site: Well-established practices need to be applied.

We assume that the plant would be sufficiently large to be considered a proposal of national significance under part 6AA of the Resource Management Act 1991. It is anticipated that there is a strong likelihood of residual environmental effects (i.e. those which cannot be mitigated) after detailed design. Submissions from stakeholders, which would prolong the decision-making process, are also considered likely.

5.1.3.8 REFERENCE PROJECTS

- *Drax power station* "...The station has a design capacity of 3,906 Megawatts (MW)..." "...The site near Selby in North Yorkshire provides the most renewable power of any single location in the UK, some 14 terawatt-hours (TWh) or enough electricity to power the equivalent of four million homes. Drax Power Station has evolved considerably since construction began in the 1960s..." (5-9). This station does not use precisely the same fuel specification as is envisaged. This project is quoted as evidence of technology readiness, and without any assertions regarding economics or other factors.

- *The Alholmens Kraft power plant* in Finland was constructed in 1999 and commissioned in 2001. The Alholmens Kraft power plant has a capacity of 240 megawatts (MWe), producing around 1300 gigawatt-hour (GWh) of electricity per year (OPET Finland, 2001). The plant is powered by a combination of wood-based fuels (30-35%), forest residues (5-15%), peat (45-55%) and coal (10%). The total cost invested on this project was approximately 170 million Euro (285 million NZD) (OPET Finland, 2001).
- *Ontario Power Company converted the single-200MW unit at Atitokan* from coal to biomass in 2018, at a quoted cost of about CAD200million. Arbaflame (5-1) report the conversion of Ontario Power's other (peaker) station at Thunder Bay, to black pellets (torrefied).
- *The Seinajoki biomass power plant located in southern Ostrobothnia, Finland* has a specified total capacity of 120 megawatts (MWe). The power plant is owned by Vaskiluodon Voima and was commissioned in the 1990s. The Seinajoki power plant can produce 400-800 gigawatt-hour (GWh) of electricity annually, with fuel that primarily uses wood residues and forest chips as its feedstock. The plant was designed to use circulating fluidised bed boiler and condensing turbine to achieve high combustion efficiency while minimising the formation of nitrogen oxides due to its low combustion temperatures (5-28).

5.1.3.9 TECHNOLOGY IMPLEMENTATION

A significant number of international firms can offer woody biomass processing equipment, for example Babcock, Foster Wheeler (FW), Mitsubishi Heavy Industries (MHI) and General Electric (GE).

A significant number of international firms can offer Rankine cycle power generation systems, from boilers to turbogenerators.

5.1.4 COMMERCIAL VIABILITY

5.1.4.1 INTRODUCTION

A woody biomass solution is based on storing energy as trees in situ, stored logs, and torrefied biomass (the mix of these would be determined under Task 2). In a dry year this woody biomass would fuel a Rankine Cycle generation plant.

5.1.4.2 COSTING SCENARIO

As with the other technologies, the woody biomass costing scenario targets meeting 1 TWh of demand over a three-month period identified as a dry year. Dry years occur in 2032 and every five years subsequently. To achieve these dry year requirements, logs designated for export would be diverted for electricity production. A wood processing plant and a Rankine cycle generation plant with capacity of 500 MW would be built, which is sufficient to generate 1 TWh over three months.

The station remains mothballed until required to meet a dry year energy shortfall. When a dry year occurs, the station is de-mothballed, run as base load for three months, delivering 1 TWh to the electricity grid, then mothballed until the next dry year occurs. The plant operates in this manner in perpetuity from 2030.

5.1.4.3 KEY ASSUMPTIONS:

- A wood preparation plant Commercial Information – taking in logs and processing ready for burning.
- A 500MW Rankine Cycle Generation plant Commercial Information with a 32% efficiency rating.
- Cost of wood including processing Commercial Information. This is based on diverting export logs.

5.1.4.4 ANALYSIS RESULTS

ITEM	COST	NOTES
Capex Total ($)	Commercial Information	Wood plant and Generation.
Capex ($/kW)		
Opex (per year)		Average over life
Whole of Life Cost ($)		
LCOE ($/MWh)		

5.1.4.5 ALTERNATIVE IMPLEMENTATIONS

There is existing Rankine cycle plant that could be supplied with this woody biomass and could provide capacity close to 1 TWh over a 3-month period. Some conversion costs may be expected, nevertheless a significant avoidance of Capex would be possible by this conversion of existing plant. A more detailed analysis would be required to establish whether a lower overall cost is obtained by purchase/operation of a wood processing plant and lesser modifications to power generation plant – or the converse. Some of this plant is approaching the end of its useful life so it is not clear to what extent this would provide a short- or long-term solution.

There are other operating approaches, including providing peaking capacity on a short or long-term basis. These alternatives could lower the effective cost significantly by providing a higher return on the asset. However, the design and cost of plant for these alternative operating scenarios may be significantly different and would need separate analysis.

In a dry year, other sources of logs could include diversion from uses such as pulp and paper. This would provide a demand response aspect as well as generation.

5.1.4.6 DISCUSSION

Our analysis suggests that woody biomass is commercially viable as a NZ Battery option. In addition, there are a number of alternatives to consider that might provide significant upside.

Currently, our analysis suggests that woody biomass would be preferred to a liquid fuel alternative but the benefits of a liquid fuel (more efficient generation plant, ability to supplement production with imports) may change during further feasibility study investigations. The capacity and cost of the fuel supply approach will be heavily influenced by the operational mode selected for the plant.

5.1.5 SWOT ASSESSMENT

The Biomass Production and Storage Primary Option is based on the Preferred Pathway of chip/hogged/torrefied fuel derived from long-rotation woody biomass as discussed earlier.

Table 5-3: Biomass Production and Storage SWOT

	Helpful to achieving the objective	Harmful to achieving the objective
Technology (source to grid)	STRENGTHS	WEAKNESSES
	• The forest source (long-rotation crop) allows significant flexibility in time-of-harvest. The basic principle of a renewably sourced raw material that can be obtained at times of convenience is a strength. • Very long-term storage of processed biomass is not practical. The use of torrefaction and the use of the forest as the store mitigates this. • Technologies for biomass harvest and recovery, and for power generation using biomass, are mature. • There are likely options for conversion of existing generation plant.	• A purpose-built Rankine cycle plant for the NZ Battery duty would be large, expensive and complex. The nature of the project implies a low utilization factor. • The level of modification required to allow existing plant to burn biomass fuel requires further study. This may not prove to be a significant weakness in the context of eliminating of dependency on coal. In addition, existing plant will have finite remaining life • The concept of harvesting and pre-processing close to the time of need requires harvest and pre-process capability that may not be well-utilized. Large harvest within a short-term results in higher environmental effects. This requires further study and optimization • Although storage of torrefied biomass is possible, durations and effects on physical and thermal properties need confirmation.
Operating Environment (external)	OPPORTUNITIES	THREATS
	• Making use of a highly visible NZ renewable resource is an opportunity to demonstrate national commitment to use of natural resources as well as addressing climate change issues.	• Public concern at logistics of biomass (log) recovery. • Public concern at scale of any proposed new Rankine cycle plant. • The assumption that long-rotation biomass crops are commercially available close to dry-year periods of need. • A choice to use logs increases fuel consistency but leaves waste in forest

		• Potential future additional bioenergy demand side-step change increases (competition for the same bioenergy resources in NZ)

5.1.6 DISCUSSION

NZ currently has a primary supply of biomass through its plantation forestry that we assess as able to meet the large-scale requirements of this project. The main source would be from long-rotation exotic forestry which allows for large quantities of harvest and considerable flexibility in the timing of extraction.

This woody biomass resource is current commercially contracted and so access to this resource would require a negotiated basis. However, significant quantities (sufficient to generate nearly 5 TWh of electricity per annum) are currently exported for which NZ Battery could be considered a higher value use in dry years. A more detailed evaluation of specific options for commercial and temporal management of fuel stocks can be carried out in Task 2. This would include tapping into substantial work that has already been done in NZ by organisations such as Scion and the Bioenergy Association of NZ to refine knowledge of biomass resources for NZ. Should this resource be accessible, the option of using long rotation softwood enables the creation of an NZ Battery solution that is self-reliant with a high level of independence from international forces.

Short rotation crop is still considered possible in some regions but needs more regular harvest and has a lower bulk density that requires larger scale storage. Similarly, softwood crop residues can also represent a significant source, but is more difficult to collect resulting in higher collection costs and carbon emissions. Both of these options are considered worth some further exploration as an augmentation for the main long-rotation supply. Other biomass sources, such as agricultural wastes are not considered suitable for the large-scale requirement of the project with these sources irregular and diffuse.

Mature technology options exist to burn biomass and generate the dry year energy needs as demonstrated across several reference projects. A range of initiatives are also known to be in progress globally, including planned trials of various types/formats of biomass combustion within existing Rankine cycle plants. The use of a well-defined fuel source will offer consistency of fuel specification to improve plant reliability. Mature technology is also available to achieve both harvest and processing of fuel and good practices for minimisation of forest residues are known. The use of solid biomass from pine logs as a combustion fuel within a Rankine cycle power generation technology, therefore, offers a high level of technological maturity across the full technology pathway.

Since forest biomass is synthesized from atmospheric CO_2, the combustion of biomass generates no net increase in atmospheric CO_2. Biomass can essentially be seen as a natural way of capturing and storing solar energy. A sustainably managed forest ensures that new plantings occur at the same rate as mature trees are harvested, and so the total carbon in the forest remains unchanged. NZ's sustainably managed exotic forests, therefore, are considered to offer a GHG-neutral and fully renewable energy source. This assumption can be further considered in Task 2 to consider CO_2 across the full technology pathway, also taking into account harvesting and transportation of the biomass.

Flexible scheduling of harvest is possible, but a requirement to harvest large quantities within a short timeframe has implications for logistics, bringing both transportation and storage challenges. Storage options that are adequate to buffer between harvest and generation are considered to be available but possible storage timeframes will vary based on the stored form of the biomass (such as logs, chips and torrefied biomass). The optimum harvest, storage and pre-processing times would need to be further considered, as if left to close to the time of need, it could lead to pre-process capability that is not well utilised and result in higher environmental effects. This is an optimization recommended for further investigation in the subsequent feasibility study.

5.2 BIOGAS (INCLUDING BIOMETHANE) PRODUCTION AND STORAGE

5.2.1 PRIMARY OPTION INTRODUCTION

Biogas is produced via bio-chemical reactions from organic waste, including:

- Food waste
- Municipal waste
- Industrial waste
- Sewage

The organic waste is broken down using micro-organisms in a biogas reactor, commonly using anaerobic digesters, that result in the production of biogas. Alternatively, the biogas can be created naturally by anaerobic bacteria in covered municipal solid waste landfills. Biogas is distinguished from Syngas (created from biomass) as it is largely methane based. Biogas has a low energy density.

The biogas is converted into electricity through either a Rankine cycle or CCGT.

5.2.2 TECHNOLOGY PATHWAYS

Table 5-4 presents a broad categorisation of the pathway options to use bioenergy for the generation of electricity via biogas production and storage. In the table, **Bold text** represents the Preferred Pathway, Normal text represents Other Pathways, and Red text represents Discontinued Pathways.

Table 5-4: Bioenergy Technology Pathways

PRIMARY OPTION	BIOGAS (BIOMETHANE) PRODUCTION AND STORAGE
Energy Source	Waste Products: Municipal solid waste Food Waste Sewage Industrial / Agricultural
Energy Vectors / Conversion	Fermentation to Biogas
Storage	Tank Storage
Generation	Rankine Cycle CCGT Plants

Source: WSP

All Biogas pathways are not considered viable for the purposes of the NZ Battery project.

5.2.2.1 DISCONTINUED PATHWAYS.

NZ's bioenergy association has compiled data on biogas plants (5-4). Extrapolating from the capacity of generation from landfills that service known populations, it is unlikely that a landfill serving 1.5 million people could generate more than 20 MW. According to Bioenergy Association biogas data, biogas from waste treatment plants servicing similar populations is lower than that from landfills. There are some industrial biogas plants, but these are linked closely to industrial energy usages and cannot be considered to offer a significant contribution to NZ Battery requirements.

Based on available information, while Biogas generation from the organic waste sites are useful, their total energy generation is insufficient to meet the dry year demand and are better used to offset local demand. Thus, this Primary Option is not considered to meet the long-scale key criteria of this project.

5.2.3 PRIMARY OPTION ASSESSMENT

As no biogas pathways are considered to meet basic project criteria, further evaluation has not been carried out.

5.2.4 SWOT ASSESSMENT

As no biogas pathways are considered to meet basic project criteria, further evaluation has not been carried out.

5.3 LIQUID BIOFUEL PRODUCTION AND STORAGE

5.3.1 PRIMARY OPTION INTRODUCTION

Biofuels can be created from a range of sources and processes, such as:

- Softwood, long / short rotation and residues (woody biomass) can be converted into ethanol by thermal / enzymatic treatment followed by fermentation.
- Woody biomass can also go through a gasification process, followed by a water-gas-shift reaction and catalytic synthesis/conversion to create methanol.
- Sugars, whether naturally available (sugar-cane) or generated by breakdown of starches or other biomass materials, can be fermented to produce ethanol.
- Oils pressed from algae or seed crops (rapeseed, sunflower etc.) or taken from waste oily materials (tallows, waste oils) can go through a transesterification or other processes to create biodiesel.

These liquid biofuels are then stored in tanks and can be combusted to generate electricity.

Liquid fuels have a relatively high energy density and above ground tank storage is practical.

This option is illustrated in Figure 5-2.

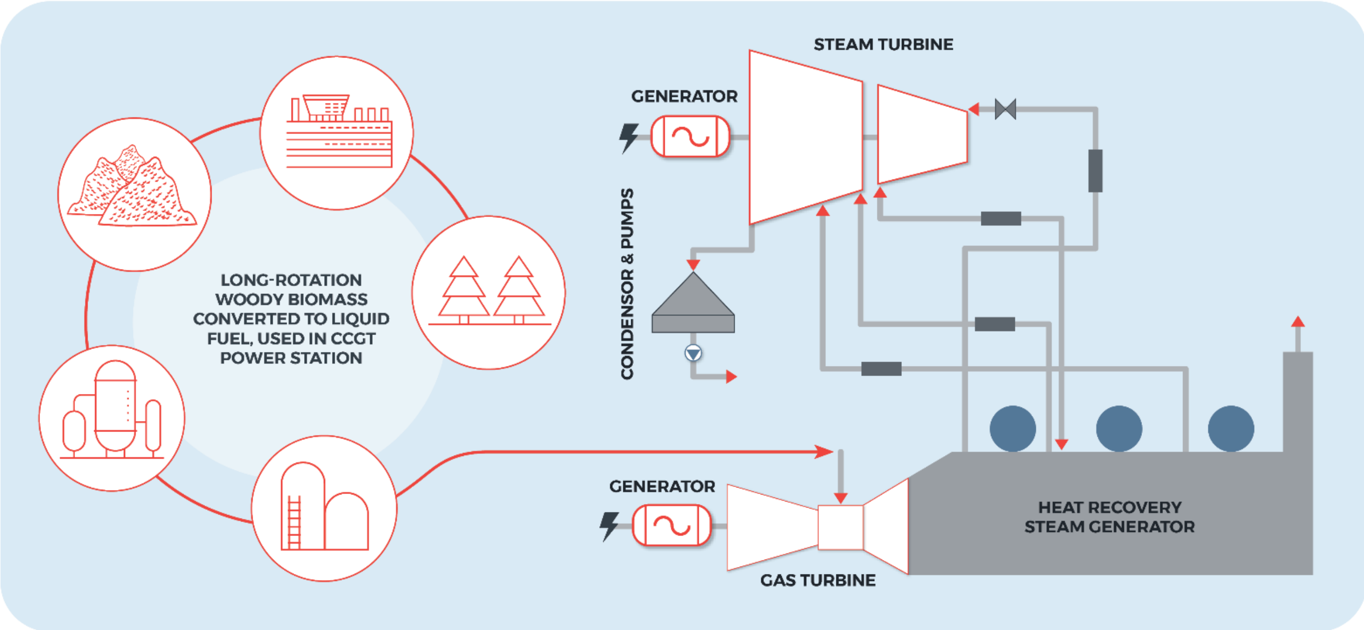

Figure 5-2: Liquid biofuel production and storage schematic

5.3.2 TECHNOLOGY PATHWAYS

Table 5-5 presents a broad categorisation of the pathway options to use bioenergy for the generation of electricity via liquid biofuel production and storage. In the table, **Bold text** represents the Preferred Pathway, Normal text represents Other Pathways, and Red text represents Discontinued Pathways.

Table 5-5: Bioenergy Technology Pathways

PRIMARY OPTION	LIQUID BIOFUEL PRODUCTION AND STORAGE
Energy Source	**Softwood:** Short Rotation Crop Long Rotation Crop Residues Other Energy Sources: Oily Seeds Algae Oil Waste Tallow Maize
Energy Vectors / Conversion	**Ethanol by thermal or enzymatic treatment** Methanol by Syngas Biodiesel by Transesterification
Storage	**Tank Storage**
Generation	**Rankine Cycle** **CCGT Plants**

Source: WSP

Liquid biofuels offer good energy density and storage options. Liquid biofuels can be burned in either Rankine cycle plant, internal combustion engines or gas turbines. It is likely that only modest levels of modification would allow existing generation plant to burn liquid biofuels. Provision would be needed for generation plant preservation between dry years. Options may exist for continuous operation at low load and dry-year operation at high load.

5.3.2.1 PREFERRED PATHWAY

Long-rotation biomass (Woody Biomass) to Ethanol: Long-rotation biomass meets the key criteria for a bioenergy source (refer to section 5.1.2 above).

Ethanol by thermal or enzymatic treatment: Ethanol meets key criteria for a generation fuel. The technology for generating ethanol from woody biomass through thermal/enzymatic treatment is developing and although carrying risk, a stepwise review of the uncertainties and the experience with each process step, has concluded that this approach is likely to achieve the project criteria for technological maturity within the specified timeframe. This pathway is therefore, identified as the Preferred Pathway for this assessment.

5.3.2.2 OTHER PATHWAYS

Short Rotation Softwood: Short rotation softwood and softwood residues offer possible/supplemental sources but are considered less preferred due to need for regular harvest and large-scale storage (refer to section 5.1.2 above).

Softwood Crop Residues: This material is more difficult to collect, has higher recovery cost and tends to incorporate contaminants (mud, alkali salts) that affect combustion and, therefore, is a less-preferred pathway.

Food crops / Oily Seeds: The technology to use oil-seed crops and maize to create, and use biodiesel is mature, however the large diversion of land area from food crops for the scale required for the NZ Battery Project makes this a less-preferred option. The use of arable land to grow crops, that are to be converted into liquid fuels, has been studied previously (5-27). Of relevance to NZ Battery criteria, Scion concluded (Page 29 2.8 Alternatives to liquid fossil fuels) "...It is likely that New Zealand would follow overseas trends and be unwilling to allow arable land to be used for growing biofuel feedstocks ..". Scion's study also concludes (Page 79. 9 Way Forward. "... Large-scale biofuel use in New Zealand will require consumers to be convinced they are being produced in a 'sustainable' way before they buy them. Given the long-term nature of investments in large-scale biofuel production, it would be prudent to reduce future market risk by avoiding food crops or using land capable of growing food crops (this would also exclude most of the land currently being used for dairying) ....". For these reasons biofuels from crops grown on NZ arable land are not a preferred pathway.

Syngas-derived liquid fuels (e.g. Methanol): The biomass to Syngas to liquid fuel pathway probably meets project criteria but with multiple process steps and a more complex technology (operating at higher temperatures and pressures) than the preferred approach for conversion of biomass to ethanol. NZ does have a backup source of methanol, but that backup material is produced from fossil fuel. While international sources of ethanol are available, the opportunities for sourcing renewable Methanol are unknown. Biomass-syngas-derived liquid fuels are, therefore, less preferred than other options.

5.3.2.3 DISCONTINUED PATHWAYS

Tallow and waste cooking oil: These can both be used to produce Biodiesel which can be fired in either gas turbines or in Rankine cycle plant. The technology for conversion is mature. Edible tallow is commercially contracted elsewhere, and waste cooking oil will not meet the large-scale criteria for this project.

Algae energy source: Biodiesel can be produced from algae produced in either high-rate ponds or photo-bioreactors. Biodiesel could be fired in gas turbines or in Rankine cycle plant. Algae selection is a developing field, the fuel conversion technology is less than mature, but current algae/pond systems are reported (5-21) to produce about 6 t/ha of material suitable for creation of biodiesel at significant cost. For the volumes of biodiesel that would be required for NZ Battery Project, this translates to an area that is quite impractical and so this source is not considered to meet the large-scale criteria for this project.

5.3.3 PRIMARY OPTION ASSESSMENT

Following the initial screening assessment, the Primary Option of liquid biofuel production and storage on the Preferred Pathway of liquid biofuel from woody biomass has been considered for further analysis. Table 5-6 provides an indication of the degree to which this option meets the evaluation criteria.

Each bioenergy technology option is scored, based on a qualitative rating and quantitative evidence against the established RAG criteria defined in Appendix A. Our assessment against the Evaluation Criteria is explained further below.

Table 5-6: Bioenergy Options

CATEGORY	CRITERIA	LIQUID BIOFUEL PRODUCTION AND STORAGE
Preferred Pathway		Liquid biofuels from woody biomass
Long-term	Between Dry Years Energy Storage	In-forest and tank
	Storage Recovery	Liquid fuel to Rankine or CCGT
	Asset Life	> 40 years
Large-scale	Min. 1 TWh	Yes [1]
	Up to 5 TWh	Probable [1]
	3 to 6 Months Output	Yes
Renewable	Renewables	Yes
	Operational carbon emission intensity	Medium [2]
	Built carbon emission intensity	
	Sustainable Resources Risk	Yes
Technology Readiness	Technology Readiness Level (2030)	(TRL 7)
	Technology Ready for Commissioning (2030)	Yes
	Geographical Constraints	Well-known

CATEGORY	CRITERIA	LIQUID BIOFUEL PRODUCTION AND STORAGE
Geographical and Logistical Constraints	Subsurface Constraints	N/A
	Transportation or Logistic Requirements	Well-known
Commercial Viability	Whole of Life Cost ($)	Commercial Information
Efficiency Measures	Round Trip Efficiencies (2021)	N/A
	Round Trip Efficiencies (2030)	N/A
	Annual Storage Decay Factor	Minimal
Environment and Safety	Environmental or Regulatory Hurdles (Ability to obtain a consent)	Medium/large industrial plant, storage
	Environmental Risks	Assume dry condenser -
	Safety Hazards Risks	Fire/explosion risk
Reference Projects	Reference Projects	
Technology Implementation	Global Market Trends & Context	Minor issues with development are possible
	Commitment of OEM Suppliers	Unknown
	Available International Market to Import Resources	Based on supplementary imports supporting NZ production
	Potential Implementation Bottlenecks	Large-scale technology

Source: WSP

Notes on the option assessed

[1] NZ bioenergy association have estimated 60 PJ/yr is exported from NZ in logs. In Scion's Pathways Analysis (5-16), Figure 3, page 180, quotes the availability of 14 PJ residual biomass in central North Island (with as much again spread over other NI regions. In Table 2, page 4 of Peter Hall's 2013 (more recent) study "Bioenergy options for New Zealand: Key findings from five studies", he quotes projected further 34 PJ /year available from forest harvest residues. Current log-wood is subject to commercial contracts and access to the resource would require a negotiated basis - which is likely to be feasible.

[2] Supply chain emissions are not known with any level of precision. These are expected to be low for Rankine Cycle biomass use, approximately 60-300 gCO_2e/kWh, and are offset by the carbon absorbed during the regrowth phase of the bioenergy cycle. Moderate emissions will occur, while converting biomass to liquid biofuels, but these emissions will effectively be from the renewable source.

[3] This option lacks a large Capex data base.

[4] Based on Whole of Life calculation methodology applying consistent scenarios across all technologies.

5.3.3.1 LONG-TERM

Long-term biomass storage is as described in the previous option. While the forest allows insensitivity to harvest time, this option holds the possibility of continuous harvest at a lower and more continuous rate to give an improved utilisation factor for ethanol conversion plant while accumulating ethanol. Optimisation of forest storage/processing capacity/liquid fuel storage has not been carried out.

Storage of ethanol is possible in above-ground tanks. At this stage, no optimisation has been carried out to determine the best basic biomass processing rate, liquid fuel processing rate or storage capacity. The option of ethanol storage below ground has not been considered.

5.3.3.2 LARGE-SCALE

NZ already has pine forests that are extensive and well-known (in terms of regional scope, access options, level of maturity and likely growth rate). Long-rotation forestry is already well-accepted as a carbon sink. The long rotation time, and the relative insensitivity of harvest timing, make these well-suited to the specific demand profile of the NZ Battery.

NZ biomass is subject to commercial contract, and a negotiated basis for access would be required. NZ currently exports a very significant volume of minimally processed logs, for which NZ Battery may present a more attractive usage.

Generating liquid biofuel from this resource does place another potential failure node between source and generation, however a backup option utilising importation of ethanol is possible.

Generating liquid fuel allows the possibility of firing either existing Rankine cycle plant up to plant capacity or new or existing peaking plant (CCGT/OCGT or new ICE). The use of existing plant would allow an early start option, pending the construction of new plant dedicated to biofuel combustion.

Limited modifications/additions would be required to fuel-chains within existing dual-fuel plant (gas/coal) for biofuels.

Generation plant will require careful preservation between dry years – or planning for continuous operation at low load. Stockpile (ethanol) rotation may require operation of generation plant during non-dry years. This issue will require further study in Task 2.

5.3.3.3 RENEWABLE

The energy sources are renewable.

Assuming process heat and power for conversion are sourced from the NZ Battery, the complete process can be considered renewable.

5.3.3.4 TECHNOLOGY READINESS

Biomass pre-processing (harvest, debarking, transport, sizing, drying) technology is mature.

Ethanol from cellulosic biomass is a developing technology, however there are currently no direct reference plants. The closest reference plants that do exist (e.g., BTG bioliquids BV and Red Rock Biofuels, Utah, USA) use different feedstocks, and softwoods such as radiata pine are known to have specific requirements.

The conversion of woody biomass to liquid fuel is not currently at TRL 8, however may meet the criterion of “likely to achieve TRL 8 or 9 by 2030”. While this is a judgement call, it is supported by knowledge that industry is developing similar processes and NZ has a significant body of science and expertise (Scion) related to this field. For many bioenergy technologies, barriers are commercial and market-originated rather than primarily technology related. We note that it would be possible to consider importing renewably produced ethanol as a backup for a biomass-sourced NZ option.

Power generation using ethanol as fuel for either a Rankine cycle plant or a CCGT plant is considered mature technology. Gas turbines are generally capable (albeit with combustion chamber/injector modifications) of operating with most liquid fuels. For Rankine cycle plant, solid-fuel chains are high-cost components that are commonly designed for tight fuel specifications, but by contrast liquid and gas fuel chains are less difficult/expensive to modify, and such modifications are common - this option is therefore, considered feasible. Although not the topic of this study, it is likely that conversion of generation plant to ethanol firing could be economically reversed, or even modified for dual-fuel operation.

5.3.3.5 GEOGRAPHICAL AND LOGISTICAL CONSTRAINTS

A future evaluation would need to consider the possible location(s) of biomass sources, conversion plant and generation plant. A future evaluation would also need to consider the relative merits of multiple plant resulting in lower biomass transport vs higher Capex for multiple smaller plants and ethanol transport issues.

5.3.3.6 EFFICIENCY MEASURES

Round trip efficiency is not relevant for any of the bioenergy options, as they do not require significant offtake of grid power for the purposes of energy storage

Rankine cycle efficiency is assumed to be 32%. CGGT efficiencies of over 60% on LCV (lower calorific value) have been achieved.

5.3.3.7 ENVIRONMENT AND SAFETY

Conversion of biomass to ethanol is not considered to generate significant environmental or safety issues. Any by-products of the conversion process would be treated by good industry practice.

Ethanol is inflammable and potentially explosive, and catastrophic discharge of stored ethanol would create a safety and environmental hazard. However safe practices for storage and handling of such materials are well-established.

5.3.3.8 REFERENCE PROJECTS

Very large numbers of liquid fuelled CCGT, Rankine cycle and ICE power generation plant are installed worldwide.

Specific reference to use of ethanol in GT plant is found in Ignacio Carvajal-Mariscal, Florencio Sanchez-Silva, Rodrigo Jaramillo-Martínez & Georgiy Polupan (2013) Evaluation of Ethanol as a Fuel for Gas Turbines.

Trials of ethanol in standard GT plant is referenced in Bryan Sims (2008). (5-25)

Use of ethanol in power plant is referenced in "...Ethanol Power Plant, Minas Gerais...""... On 19 January 2010, Brazil's state-owned company Petrobras launched the world's first ethanol-fired power plant. Situated in the city of Juiz de Fora, in the state of Minas Gerais, approximately 180 km north of Rio de Janeiro, the plant generates electricity on a commercial scale using sugar cane-derived ethanol. The plant's technology, engineering and field support was provided by General Electric (GE). (5-10)

5.3.3.9 TECHNOLOGY IMPLEMENTATION

Significant numbers of international firms offer biomass pre-processing equipment.

Several firms (noted elsewhere) have acquired some experience of converting biomass to ethanol. The NZ Forest Research Institute (trading as Scion) has acquired a large body of relevant scientific material, and significant experience at pilot plant level with the processes. This is, however, a step that carries technology risk, and has lower technological maturity than other approaches

Significant numbers of international firms offer large capacity liquid fuelled CCGT plant

Significant numbers of international firms offer liquid fuel-fired Rankine cycle generation plant.

5.3.4 COMMERCIAL VIABILITY

5.3.4.1 INTRODUCTION

A liquid bioenergy solution is based on converting trees into ethanol and storing. In a dry year this ethanol would fuel a Combined Cycle Gas Turbine (CCGT) generation plant. This liquid-fuel option allows the use of plant with higher thermal efficiency than is available for solid-biomass, however the (imperfectly known) conversion efficiency of cellulose to liquid fuel detracts from this advantage.

5.3.4.2 COSTING SCENARIO

As with the other technologies, the liquid bioenergy costing scenario targets meeting 1 TWh of demand over a three-month period identified as a dry year. Dry years occur in 2032 and every five years subsequently. To achieve these dry year requirements, logs designated for export would be diverted for ethanol storage and electricity production. An ethanol plant and a CCGT generation plant with capacity of 500 MW would be built, which is sufficient to generate 1 TWh over three months.

The ethanol would be produced over a two-year period stored ready for use. The generation station remains mothballed until required to meet a dry year energy shortfall. When a dry year occurs, the station is de-mothballed, run as base load for three months, delivering 1 TWh to the electricity grid, then mothballed until the next dry year occurs. The plant operates in this manner in perpetuity from 2030.

5.3.4.3 KEY ASSUMPTIONS

- An ethanol plant Commercial Information – taking in logs and outputting and storing ethanol with a 50% efficiency rating
- A 500 MW Combined Cycle Generation plant Commercial Information with a 65% efficiency rating.
- Cost of wood including processing at Commercial Information This is based on diverting export logs.

5.3.4.4 ANALYSIS RESULTS

ITEM	COST	NOTES
Capex Total ($)	Commercial Information	Ethanol and Generation plants
Capex ($/kW)		
Opex (per year)		Average over life
Whole of Life Cost ($)		
LCOE ($/MWh)		

5.3.4.5 ALTERNATIVE IMPLEMENTATIONS

There is existing combined cycle plant in NZ that could be supplied with this ethanol and could provide capacity close to 1 TWh over a 3-month period. Some of this plant is approaching the end of its useful life so it is not clear to what extent this would provide a short- or long-term solution.

There are other operating approaches, including providing peaking capacity on a short or long-term basis. These alternatives could lower the effective cost significantly by providing a higher return on the asset. However, the design and cost of plant for these alternative operating scenarios could be significantly different and would need separate analysis.

While NZ is unlikely to have sufficient advantage in the production of ethanol to support exporting, other local uses may justify extra ethanol production. Also, ethanol imports could be used to support or even replace local production (see next option).

5.3.4.6 DISCUSSION

Our analysis suggests that liquid bioenergy is commercially viable as a NZ Battery alternative. In addition, there are a few options to consider that might provide significant upside.

Currently, our analysis suggests that woody biomass would be preferred to a liquid fuel alternative but the benefits of a liquid fuel (more efficient generation plant, ability to supplement production with imports) may change on closer inspection as part of the next feasibility study steps.

5.3.5 SWOT ASSESSMENT

The Liquid Biofuel Production and Storage Primary Option is based on the Preferred Pathway of creating liquid biofuels (ethanol or methanol) from woody biomass as discussed in Section 5.3.3.

Table 5-7: Liquid Biofuel Production and Storage SWOT

	Helpful to achieving the objective	Harmful to achieving the objective
Technology (source to grid)	STRENGTHS	WEAKNESSES
	• The forest source (long rotation crop) is large and accessible. • Liquid biofuel can feasibly be stored, allowing more economic sizing of biomass conversion plant, however no studies of optimal capacity/storage have been made. • Harvesting technology is mature. • Technology for generating power using ethanol (in either Rankine-cycle or more-efficient CCGT plant) is considered mature and can be expected to have lower Capex than similar plant designed for biomass. • It is likely to be possible to convert plant back from biofuels to other liquid/gas fuels, and it may even be possible to design for multi-fuel operation.	• The maturity of the technology to produce ethanol from biomass is the lowest of the three preferred bioenergy pathways and represents a technical risk. • Ethanol storage volumes are large, so both fire and short-term contamination hazards need to be managed. • Stockpile rotation is likely to require plant operation in non-dry years. • Substances used and generated in the conversion process may require careful management. • The NZ Battery project implies a low equipment utilisation factor and need for storage regimes. • A choice to use logs allows an increase in fuel consistency but leaves waste in forest.

	Helpful to achieving the objective	Harmful to achieving the objective
Operating Environment (external)	OPPORTUNITIES	THREATS
	• Development of this approach could offer NZ significant IP opportunities. • Development of this approach would offer options for displacement of transport fuels. • Liquid fuel offers more flexibility in selection of generation plant and options for modifying existing generation equipment. • Liquid fuel allows the possibility of using efficient CCGT plant. • Options may exist for modifying existing generation equipment and even possibly for dual-fuelling. • Biofuel exports creating an additional value stream. • Backup ethanol sources exist.	• Unforeseen difficulties of generation (considered unlikely). • The assumption that long-rotation biomass crops are commercially available. • Public concern at logistics of biomass (log) recovery. • Public concern at scale of any proposed new plant. • Unforeseen difficulties of generation (considered unlikely). • The assumption that long-rotation biomass crops are commercially available. • Public concern at logistics of biomass (log) recovery. • Public concern at scale of any proposed new plant. • A choice to use logs increases fuel consistency but leaves waste in forest.

5.3.6 DISCUSSION

Liquid Biofuel, specifically ethanol, can be made from the same available biomass supply as described in the previous Primary Option, that is New Zealand's plantation forestry. This option is therefore, also considered to offer a NZ Battery solution that meets the large-scale requirements, based on the assumed accessibility of the biomass. It is also assumed to be a sustainable and CO_2-neutral fuel source that can be further explored in Task 2.

Power generation using ethanol as a fuel for either a Rankine cycle plant or a CCGT plant is considered mature technology. The technology to produce ethanol from biomass however has the lowest technological maturity of the bioenergy pathways, resulting in higher technical risk and less well-known economics. While it is a judgement call, it is considered possible that the conversion process may meet the required technology maturity levels by 2030. This is supported by knowledge that the wider global industry is developing similar processes and NZ has a significant body of science and expertise (Scion) related to this field. This includes a recently prepared biofuels roadmap document that sets out future practical options.

Should the technology sufficiently mature in the timeframes required for NZ Battery, the conversion of biomass to ethanol will bring several benefits. Firstly, when compared to biomass, ethanol can be used in a wider range of generation plant - Rankine, CCGT or OCGT. The best generation technology for use with ethanol has a lower capital cost than Rankine cycle plant used for direct combustion of solid biomass and has much higher generation efficiency. Such generation plant if implemented would also be more flexible in the choice of fuels, for example hydrogen. The fact that ethanol can be used in a wider range of plant also opens possibilities of using a wider range of already existing and operational plant in New Zealand.

Secondly, the relative ease of storing liquid fuels for extended periods (when compared to solid woody biomass) should allow for a more economical scaling of ethanol production capacity and allow a more continuous forest harvest at a lower and more continuous rate. Depending on timeframes between dry years, the biomass (de-barked, torrefied or other) could require a portion of stored resource to be released and replaced due to limitations on storage timeframes, whereas ethanol can be stored for a lot longer and would not have this requirement.

From a safety and environmental perspective, whilst the large volumes of ethanol would require careful management of fire and environmental hazards, this is considered manageable with safe practices of storage and handling well established.

5.4 IMPORTING BIOENERGY WITH BUFFER STORAGE

5.4.1 PRIMARY OPTION INTRODUCTION

Bioenergy can be imported in the form of either raw materials (crops, wood) or the final product for electricity generation (biomass, biogas or biofuel). The possibilities for import for the NZ Battery project could include:

- Importation of sustainably produced ethanol
- Importation of sugar-products from which ethanol would be produced in New Zealand
- Importation of biomass, possibly in the form of either pellets or torrefied pellets

This Primary Option considers the full import of all bioenergy required for the NZ Battery project.

5.4.2 TECHNOLOGY PATHWAYS

Table 5-8 presents a broad categorisation of the pathway options to use bioenergy for the generation of electricity via bioenergy import with storage. In the table, **Bold text** represents the Preferred Pathway, Normal text represents Other Pathways, and Red text represents Discontinued Pathways.

Table 5-8: Bioenergy Technology Pathways

PRIMARY OPTION	BIOENERGY IMPORT WITH STORAGE
Energy Source	Partially processed precursors: Non-refined Sugar Softwood: Biomass pellets **Imported Liquid Biofuel:** Ethanol Liquid Methane Import Biodiesel import
Energy Vectors / Conversion	Methanol by Syngas: • Imported Partially Processed Precursors Combustion / Pyrolysis / Gasification: Imported Biomass Pellets Imported Liquid Biofuel: No further conversion

PRIMARY OPTION	BIOENERGY IMPORT WITH STORAGE
Storage	Pelletised Storage: Biomass pellets Other bulk Storage Sugar or Starch Tank Storage: Liquid biofuels (Methane, Biodiesel) Biogas
Generation	Rankine Cycle CCGT Plants

Source: WSP

5.4.2.1 PREFERRED PATHWAY

Ethanol import: Ethanol from renewable sources is traded internationally and it is considered possible to be directly imported, although access to this ethanol source is unknown at this stage. Ethanol import would meet the project criteria and offer a technically simple solution making use of well-known and existing liquid fuel handling approaches and capabilities to achieving a large store of renewable liquid fuel in NZ. It should be noted that significant effort would however be required to ensure that any imported ethanol was produced and transported in a truly sustainable manner and to assess the risk to security of supply.

Use of ethanol as fuel for generation plant (Rankine cycle, CCGT or ICE) is considered an option with low technical risk and has been identified as the Preferred Energy Pathway for this Primary Option. The Preferred Pathway would involve sourcing liquid biofuels from biomass products such as sugar (unrefined, possibly molasses) or corn-starch, and importing ethanol. This option is considered because other countries' land and climate conditions allow large-scale sugar cultivation. NZ's environment is highly favourable to the growth of exotic forest biomass, and while large-scale importation of pellets or other biomass is technically possible, there appears to be less basis for any significant importation advantage.

5.4.2.2 OTHER PATHWAYS

Biomass Pellet Import: In the Northern hemisphere, there is substantial international trade in biomass pellets., and a somewhat lesser trade in torrefied pellets. Importation of pellets must therefore, be considered possible, although the ability to access these pellets in New Zealand is at this stage unknown. Using a standardised specification of pellets allows multiple sources to be used to supply a pathway to generation.

As described in section 5.1, pellets (and all solid biomass) can only be used directly in a Rankine cycle generator and offer less flexibility in generation plant selection than is available for liquid biofuels. NZ also does not currently have bulk material handling facilities that would be appropriate for the importation of the large quantities of pellets that would be required for the scale of this project. The volume of pellets would represent the same volume as proposed log export diversions. This would likely require new and specific handling facilities. For these reasons Biomass imports are not considered the Preferred Pathway for this Primary Option of full imports. It should be noted that on a smaller scale or if being used to supplement an already established domestic biomass NZ Battery Option, importation of biomass products could be an attractive option.

Partially Processed Precursors (e.g. non-refined sugar): Sugar is produced in many countries at large-scale and is an internationally traded commodity. NZ has several deep-water ports that would allow import, but (unlike liquid fuel) would likely require new and specific handling facilities. Conversion of sugar to ethanol is widely practised at large-scale and therefore, considered a mature technology. Conversion plant and associated import and storage facilities would need to be acquired for NZ.

A pathway that imports sugar and produces ethanol within NZ for storage, for use as a power generation fuel is considered to meet all the criteria of this project but has not been considered the preferred pathway option. This is because it would require port facilities, sugar storage and plant development in NZ to be functional whereas ethanol import requires minimal new plant / facilities prior to operation. This option would transport a raw material to NZ and process it here; for this to be optimal, NZs processing efficiency would need to be high enough to counter the inefficiency of transporting the lower energy density raw material. Further study may revise this judgement.

Biodiesel Import: At least one country is believed to export biodiesel. The market risk has not been assessed, and unconfirmed doubts exist regarding the long-term sustainability of the raw material source from the exporter. This option has therefore not been considered a preferred pathway.

5.4.2.3 DISCONTINUED PATHWAYS

Liquid Methane import: Internationally traded liquified methane (LNG) is derived from fossil-fuel sources. Although it would be technically possible to liquify biogas offshore and ship this, biogas generation (from sewage or landfills) is commonly closely coupled to local power generation. Data for New Zealand biogas supports the observation that the quantities produced can easily be absorbed to offset local demands without leaving excess to encourage the additional costs of export. It is considered highly unlikely that the option will prove to be practical or meet either the scale, or the long-term criteria of this project.

5.4.3 PRIMARY OPTION ASSESSMENT

Following the initial screening assessment, the Primary Option of bioenergy import with storage, on the Preferred Pathway of importing renewable biofuel has been considered for further analysis. Table 5-9 provides an indication of the degree to which this option meets the evaluation criteria.

Each bioenergy technology option is scored, based on a qualitative rating and quantitative evidence against the established RAG criteria defined in Appendix A. Our assessment against the Evaluation Criteria is explained further below.

Table 5-9: Bioenergy Options

CATEGORY	CRITERIA	BIOENERGY IMPORT WITH STORAGE
Preferred Pathway		Renewable \ Biofuel Imports
Long-term	Between Dry Years Energy Storage	Bulk and tank
	Storage Recovery	Liquid fuel to Rankine or CCGT
	Asset Life	> 40 years
Large-scale	Min. 1 TWh	Yes
	Up to 5 TWh	Probable

CATEGORY	CRITERIA	BIOENERGY IMPORT WITH STORAGE
	3 to 6 Months Output	Yes
Renewable	Renewables	Yes
	Operational carbon emission intensity	Medium [1]
	Built carbon emission intensity	
	Sustainable Resources Risk	Probable
Technology Readiness	Technology Readiness Level (2030)	(TRL 9)
	Technology Ready for Commissioning (2030)	Yes
Geographical and Logistical Constraints	Geographical Constraints	Multiple import sources
	Subsurface Constraints	N/A
	Transportation or Logistic Requirements	Hazardous goods transport, port handling
Commercial Viability [2]	Whole of Life Cost ($)	Commercial Information
Efficiency Measures	Round Trip Efficiencies (2021)	N/A
	Round Trip Efficiencies (2030)	N/A
	Annual Storage Decay Factor	Minimal
Environment and Safety	Environmental or Regulatory Hurdles (Ability to obtain a consent)	Medium/large industrial plant, storage
	Environmental Risks	Assume dry condenser
	Safety Hazards Risks	Fire/explosion risk
Reference Projects	Reference Projects	
Technology Implementation	Global Market Trends & Context	Unknown
	Commitment of OEM Suppliers	Adequate
	Available International Market to Import Resources	[3]
	Potential Implementation Bottlenecks	

Source: WSP

Notes on the option assessed

[1] Supply chain emissions are not known with any level of precision. These are expected to be low for Rankine Cycle biomass use, approximately 60-300 g CO_2e/kWh and are offset by the carbon absorbed during the regrowth phase of the bioenergy cycle.

[2] Based on Whole of Life calculation methodology applying consistent scenarios across all technologies.

[3] Market issues related to the import of these bioenergy products, or their precursors, have only been reviewed at high level for security and price.

5.4.3.1 LONG-TERM

Ethanol and sugar are traded internationally. While this option incurs an exposure to international trade and supply lines, it may offer large-scale acquisition of renewable fuel on demand.

5.4.3.2 LARGE-SCALE

Sugar ethanol is available from multiple sources.

This option exposes NZ to international markets, and to the vagaries of international supply lines. However multiple sources and options to stockpile between dry years reduce this risk.

5.4.3.3 RENEWABLE

Sugar crops probably do not compete with other food crops for arable land in the countries where sugar is grown, and sugar is considered an inherently renewable resource.

The fermentation process for creation of ethanol is considered to be essentially renewable.

Significant effort would be required to ensure that any imported material was produced in a truly sustainable manner.

5.4.3.4 TECHNOLOGY READINESS

Ethanol already provides a significant percentage of the transport fuel needs of Brazil (5-22).

Ethanol from sugar is a technologically mature process that has operated at large-scale for an extended period (e.g., South America).

Breakdown of starches (e.g. corn) to sugars for fermentation is also considered mature technology.

Ethanol storage is considered mature technology.

This option offers a low-Capex, high-technology maturity option.

Power generation using ethanol, via either Rankine cycle or CCGT plant is mature technology. Provision will be needed for preservation of plant between dry years, or continuous operation at low loads.

5.4.3.5 GEOGRAPHICAL AND LOGISTICAL CONSTRAINTS

If ethanol is to be imported, this option is subject to the market availability of ethanol, over the inter-dry-year periods. The risk of non-availability exists but is difficult to assess.

Significant port facilities would be needed.

5.4.3.6 EFFICIENCY MEASURES

Round trip efficiency is not relevant for any of the bioenergy options, as they do not require significant offtake of grid power for the purposes of storage.

Efficiency of generation from CCGT plant can go up to almost 60% (on LCV).

Efficiency of generation from Rankine cycle plant would be similar to that achieved with coal.

5.4.3.7 ENVIRONMENT AND SAFETY

The environmental and other issues related to ethanol are noted elsewhere: A more detailed review of these issues will be undertaken as required in Task 2

No significant environmental issues related to storage of ethanol (beyond normal industrial good practice) are expected.

Depending on scale and location, these may be considered more readily acceptable from a planning perspective than the woody biomass option.

5.4.3.8 REFERENCE PROJECTS

"Biofuels in Brazil: Lean, green and not mean." "The Economist". The Americas. Jun 28th, 2008, edition. (5-22)

CCGT and power station references as for ethanol derived from biomass (see 5.1.3)

5.4.3.9 TECHNOLOGY IMPLEMENTATION

Significant numbers of international firms are likely to be able to supply material.

Liquid fuel shipping is mature technology.

5.4.4 COMMERCIAL VIABILITY

5.4.4.1 INTRODUCTION

An alternative liquid bioenergy solution would be to bypass local production and just import ethanol. In a dry year ethanol would be imported and fuel a Combined Cycle generation plant. Some local storage might be required to cover the delivery time from international sources.

5.4.4.2 COSTING SCENARIO

As with the other technologies, the imported ethanol costing scenario targets meeting 1 TWh of demand over a three-month period identified as a dry year. Dry years occur in 2032 and every five years subsequently. To achieve these dry year requirements, ethanol would be imported to fuel a new Combined cycle generation plant with capacity of 500 MW, which is sufficient to generate 1 TWh over three months.

The ethanol would be imported when required, with some local storage as required to cover delivery periods. The generation station remains mothballed until required to meet a dry year energy shortfall. When a dry year occurs, the station is de-mothballed, run as base load for three months, delivering 1 TWh to the electricity grid, then mothballed until the next dry year occurs. The plant operates in this manner in perpetuity from 2030.

5.4.4.3 KEY ASSUMPTIONS

- A 500MW Combined Cycle Generation plant Commercial Information - 60% efficient
- Port upgrades at Commercial Information
- Cost of ethanol at Commercial Information

5.4.4.4 ANALYSIS RESULTS

ITEM	COST	NOTES
Capex Total ($)	Commercial Information	Generation station, port upgrades including storage.
Capex ($/kW)		
Opex (per year)		Average per year of life.
Whole of Life Cost ($)		
LCOE ($/MWh)		

5.4.4.5 ALTERNATIVE IMPLEMENTATIONS

There is existing combined cycle plant in NZ that could be supplied with this ethanol and could provide capacity close to 1 TWh over a 3-month period. Some of this plant is approaching the end of its useful life so it is not clear to what extent this would provide a short- or long-term solution.

There are other operating approaches, including providing peaking capacity on a short or long-term basis. However, relative to local energy production, the import options have lower capital cost and higher fuel costs. This means their bid price in the market would be relatively higher.

5.4.4.6 DISCUSSION

Our analysis suggests that import of ethanol is commercially viable as a NZ Battery alternative. As a comparative example, ttransport fuel usage in Brazil indicates commercial maturity. While it has been argued that the viability of this model is peculiar to Brazil's particular circumstances, it nevertheless suggests the possibility of moderate commercial viability.

The main disadvantage is the dependence on international markets, however, this is similar to the risk we face in importing coal. The low capital cost is a significant advantage and if combined with use of existing plant this option could provide an option to delay commitment (with potentially high option value).

5.4.5 SWOT ASSESSMENT

The Bioenergy importation and Storage Primary Option is based on the Preferred Pathway of importing liquid biofuels as discussed in Section 5.3.

Table 5-10: Bioenergy Import with Storage SWOT

	Helpful to achieving the objective	Harmful to achieving the objective
Technology (source to grid)	STRENGTHS	WEAKNESSES
	• Liquid biofuel can feasibly be stored. • Acquisition and storing of biofuel is expected to be feasible.	• Ethanol storage volumes are large, so both fire and short-term contamination hazards need to be managed. • Stock rotation is likely to require plant operation in non-dry years. • The NZ Battery project implies a low equipment utilisation factor. • Dependent on the practicalities of unloading imported biofuel within NZ. • Dependent upon setup and management of facility(s) for storage/distribution of ethanol.
Operating Environment (external)	OPPORTUNITIES	THREATS
	• Liquid fuel offers more flexibility in selection of generation plant and options for modifying existing generation equipment. • Liquid fuel allows the possibility of using efficient CCGT plant.	• Unforeseen difficulties of generation (considered unlikely). • Supply chain risk. • Political/public concern at concept of reliance upon importation of crop-derived materials.

	Helpful to achieving the objective	Harmful to achieving the objective
	• Options may exist for modifying existing generation equipment and even possibly for dual-fuelling. • Options may exist for dual-fuelling.	• Political/public concern for the sustainability of offshore sugar plantations and/or difficulties of ensuring only sustainable sources are used.

5.4.6 DISCUSSION

This option extends the import alternative to the NZ ethanol production option by having no national production and just importing ethanol.

Internationally, ethanol is produced (from sugar for example) and consumed in volume using technology that is mature and uses renewable processes. Production figures are growing due to the continued focus on decarbonisation. Market purchase of such products would require care to ensure that any imported material was produced in a sustainable manner. For this project, we assume that these hurdles can be overcome and that certified green ethanol will be available on international markets for importation to NZ.

As described in section 5.3, technology for electricity generation from ethanol is mature and available. The port handling and storage facilities are considered low risk given the comparison to already imported liquid fuels. Importation of ethanol was therefore, considered the most practical complete import solution at this stage of the assessment. While biomass imports (pellets) are also a viable option, the added challenges of port handling facilities and storage requirements for the volumes needed for the NZ Battery solution, coupled with a limitation to only Rankine based (lower efficiency) generation plant, make this a less attractive option.

Importation of bioenergy (renewably produced ethanol or biomass pellets) does offer some additional decision options for the NZ Battery project. One possibility is to use imported energy in existing CCGT or Rankine cycle plant. This assumes that required plant modifications would be able to be completed prior to 2030. Existing plants are mostly nearing the end of their useful life and this solution may not be long lived; however, this could be used to delay commitment to other technologies providing option value such as 'buying time' for other technologies to become more mature.

Imports could also be used to supplement any biomass or biofuel production in New Zealand, for example providing a back-up supply for periods of consecutive dry years or allowing the bioenergy production and processing plant to be 'right-sized' to get the most economical solution to the dry year problem. In this scenario the imports would need to match the bioenergy form created in New Zealand – whether woody biomass or ethanol.

Reliance on imports will inevitably create a critical point of exposure for the supply line, resulting in higher levels of risk. Mitigations such as forward purchase will be required, but the irregular/ unpredictable nature of the dry-year demand will create a difficult market demand profile. With security of supply being a high priority for the NZ Battery Project, this risk is undesirable, and we do not expect an import only solution to be suitable. We suggest continuing to evaluate bioenergy imports as a backup to NZ production.

5.5 BIOENERGY SUMMARY AND RECOMMENDATION

With the availability of biomass in the form of NZ's sustainably managed exotic forests being perceived to meet the volume and generation requirements, as well as technical maturity requirements of the NZ Battery project, it is recommended that the Biomass production and storage Primary Option is taken forward to Task 2 as a key Prospective Option. Utilising a domestic supply reduces risks associated with fluctuations and volatility in international supply and makes use of our existing NZ resource as well as achieving the renewable energy goals we have set ourselves.

This Prospective Option would predominantly focus on the use of long rotation crop which allows for large quantities of harvest and considerable flexibility in the timing of extraction. Other suitable sources of woody biomass (short-rotation and residues) will also continue to be explored but are considered to be less optimal – requiring more regular harvest (short-rotation crop) or having challenges in collection (residues). These are considered more as a potential augmentation of a long rotation crop supply. The form of the woody biomass used in the generation plant is still considered open at this stage and could include chips, pellets or torrefied biomass.

Through Task 2, further assessment would be carried out in several areas to explore in greater depth the suitability of this solution. This would include:

- Biomass supply: A more detailed evaluation of post-2030 options for supplying either white (pellets or compressed) or torrefied biomass suitable for fuelling of Rankine-cycle power plant. This includes consideration of geographical options, environmental issues and competing demands on this resource.
- Augmentation sources: While there is high confidence that long rotation biomass offers an adequate supply for the project, a more detailed review of short-rotation biomass and softwood residue supply options as a means of augmenting supply. This review will also confirm the preferred main fuel choice of long rotation crop.
- Biomass treatment and storage: A more detailed review of requirements for large-scale drying and/or torrefaction plant, biomass pre-treatment options (hog, chip, dry, pelletise), and the comparative use of forest store, log-store or torrefied and other biomass storage.
- Rankine plant: A review of fluid bed plant and other new/modified Rankine cycle plants which in turn will clarify requirements for a feasible biomass-fuelled Rankine cycle plant. This evaluation would also examine the lessons of other global trials of new/modified plant.
- Operational modes: Evaluation of possible operational modes for both generation plant and biomass treatment/conversion plant to consider fuel demand management, wet-year usage of fuel for stock rotation, preservation options and/or export or alternative usage options.
- Carbon Neutrality: Further consideration of the carbon-neutrality assessment of a biomass solution, considering the full pathway from harvesting, storage, transport and generation to gain further confidence in this assumption being correct. The potential effect of bringing net carbon release forward in time will also be included in the further carbon neutrality assessment.

Whilst not recommended as a Prospective Option, the benefits of conversion of biomass into liquid biofuel are considered relatively significant to this project, potentially offering lower cost, more flexible generation and reducing transport and storage challenges. So, while the technology for creating ethanol from biomass is considered less mature and has therefore, not been recommended as a Prospective Option, some further investigation into this would allow more clarity on technology maturity levels. It is therefore, recommended that while the main focus of further assessments is kept on the woody biomass option, a simple high-level evaluation of practicably creating a liquid biofuel supply from the main biomass energy supply chain, starting from 2030 is also carried out. This would also include a high level review of methanol vs ethanol.

As a stand along option the importation of bioenergy is not recommended, largely due to the security of supply risk from the international markets, especially when using an unpredictable demand profile. The option of supplementing domestic production with imports should however continue to be explored. Imports would provide a contingency supply source where extreme dry year demands arise, as well as offering options for early generation capability using existing plant. Use of existing plant also introduces the possibility of Capex deferral for an NZ Battery solution. Although our main recommendation for the Prospective Option is centred around woody biomass, import investigations could include both import of pellets and of renewable ethanol as both are considered viable as a supplementary supply.

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6 GEOTHERMAL ENERGY

Within this section we consider and assess the potential to manage dry year risk using geothermal energy in the NZ Battery Project context.

6.1 GEOTHERMAL ENERGY STORAGE

6.1.1 PRIMARY OPTION INTRODUCTION

This Primary Option involves storing thermal energy from renewable electricity in either an above ground Thermal Energy Storage (TES), or subsurface feature (known as geologic TES or GeoTES). The thermal energy is then delivered to an ORC binary cycle plant to generate electricity (as described below in section 6.3.1) when needed.

6.1.1.1 ABOVE GROUND THERMAL ENERGY STORAGE

Above ground TES systems include storage of thermal energy in surface tanks containing high thermal inertia materials such as molten salts, gravels, water or specialised Phase Change Materials (PCMs). Internationally, molten-salt storage currently accounts for the majority of installed TES capacity in the power sector due to its advanced technological readiness and common applications in concentrating solar power (CSP) plants worldwide. By 2030 between 491 GWh and 631 GWh[6-8] of installed molten salt capacity is expected to come online globally. In the near-term, other TES technologies are likely to become commercially viable, including solid-state and liquid air variants that store surplus energy from CSP, solar photovoltaics (PV) and wind. Typical eutectic molten salt tank systems installed at concentrating solar power plants tend to be suitable for short term energy storage (hours or days).

6.1.1.2 SUBSURFACE THERMAL ENERGY STORAGE (GEOTES)

GeoTES systems involve the storage of thermal energy underground. For the scale of NZ Battery requirements this would typically require geologies that encompass sedimentary basins confined by caprock and base rock, and with permeabilities that are significantly lower than the thermal reservoir's permeability. Consequently, movement of fluid is confined to the reservoir zone. GeoTES systems worldwide tend to be in geologic regions that do not have a naturally high fracture network.

6.1.2 TECHNOLOGY PATHWAYS

Geothermal energy includes various options for storage and subsequent generation of energy. Table 6-1 presents a broad categorisation of the options for these pathways. In the table, **Bold text** represents the Preferred Pathway, Normal text represents Other Pathways, and Red text represents Discontinued Pathways.

Table 6-1: Geothermal Technology Pathways

	GEOTHERMAL ENERGY STORAGE (SUBSURFACE OR ABOVE GROUND TES) **STORAGE**
Energy Source	Renewable energy
Storage	Subsurface Geothermal Energy Storage (GeoTES) Above Ground Thermal Energy Storage (TES)
Generation	Condensing flash plant Organic Rankine Cycle (ORC) binary

Source: WSP

There are not considered to be any viable pathways for this Primary Option, explained further as follows.

6.1.2.1 DISCONTINUED PATHWAYS

Subsurface Geothermal Energy Storage (GeoTES): Does not sufficiently satisfy the key criteria of long-term storage.

This is primarily due to heat decay (the losses of useful heat over time to surroundings) and limits to the practicable ability to achieve long-term storage at the temperatures required for large-scale power generation. For example, using broad numbers and even assuming a very low fracture network could be found in NZ, heat decay losses would be approximately 0.5% per day (this would be much higher for a typical NZ high fracture network that allowed for colder fluids to interact). Over the course of one year more than 80% of the originally stored energy would have been lost, or in other words at least 80% of the originally stored energy would need to be provided to keep the system topped up. Whilst potentially useful for applications such as ground source heat pumps for building heating purposes, the lower temperature ranges that might be considered feasible for long-term storage would be too low for thermal power generation.

GeoTES systems typically require sedimentary basins confined by caprock and base rock with permeabilities that are significantly lower than the thermal reservoir's permeability. This allows for a higher permeability horizontally versus vertically. Consequently, movement of fluid is confined to the reservoir zone (i.e. the hot fluids are contained and have limited ability to escape vertically upwards through the earth's surface). therefore, GeoTES systems need to be located in areas that do not naturally have a high fracture network.

The highly active tectonic setting of New Zealand's geology makes determining a location that has a low permeability caprock and base rock to confine the GeoTES system without heat decay and reduced pressures extremely challenging. This is due to the naturally produced subvertical fracture networks generated in our highly faulted landscape. Subvertical fracture networks are the reason that NZ has naturally occurring, high temperature geothermal systems that are used for electricity generation. There is no engineering logic to storing excess electricity as thermal energy in NZ where we already have abundant inherent thermal energy available.

Above Ground Thermal Energy Storage (TES): Does not sufficiently satisfy the key criteria of long-term storage.

This is primarily due to heat decay (the losses of useful heat over time to surroundings) and limits to the practicable ability to achieve long-term storage at the temperatures required for large-scale power generation. Above ground TES systems have heat decay rates in the order of 1% per day when storing energy at the temperatures required for large-scale power generation. This technology can be suitable for short term (days, weeks and potentially months) storage applications, if energy is available from other sources for short term recharging. However, this option is not deemed feasible for the long-term storage periods required for NZ Battery. For example, using broad numbers and the 1% decay assumption above, over the course of one year more additional energy than that originally stored would need to be provided to keep the system topped up.

Table 6-2 illustrates the order of magnitude difference between the large-scale and long-term requirements (i.e. the Storage Period columns) of the NZ Battery Project and the limits of current (and expected by 2030) global TES technologies.

Table 6-2: Key technical attributes of selected TES technologies

TES TYPE	TES TECHNOLOGY	CAPACITY RANGE	POWER RANGE	OPERATING TEMPERATURE	ROUND TRIP EFFICIENCY	STORAGE PERIOD	LIFETIME (YEARS OF NO. OF CYCLES)
Sensible	Water Tank Thermal Energy Storage	kWh to 1 GWh	kW to 10 MW	10 to 90°C	50 to 90%	Hours to months	15-40 years
	Underground Thermal Energy Storage	MWh to GWh	MW to 100 MW	5 to 95°C	Up to 90%	Weeks to months	50 years
	Solid state	10kWh to GWh	KW to 100 MW	-160 to 1300°C	>90%	Hours to months	> 5000 cycles
	Molten salts	MWh to 5 GWh	100 kW to 300 MW	-265 to 565°C	>98%	Hours to days	> 20 years
Latent	Ice thermal energy storage	kWh to 100 MWh	KW to 10 kW	-3 to 3°C	>95%	Hours to days	> 20 years

TES TYPE	TES TECHNOLOGY	CAPACITY RANGE	POWER RANGE	OPERATING TEMPERATURE	ROUND TRIP EFFICIENCY	STORAGE PERIOD	LIFETIME (YEARS OF NO. OF CYCLES)
	Sub-zero temperature Phase Change Material (PCM)	kWh to 100 kWh	kW to 10 kW	Down to -114°C	>90%	Hours	> 20 years
	Low-temperature PCM	kWh to 100 kWh	kW to 10 kW	Up to 120°C	>90%	Hours	300-3000 cycles
	High-temperature PCM	10 kWh to GWh	10 kW to 100 kW	Up to 100°C	>90%	Hours to days	>5000 cycles
Thermo-chemical	Chemical looping (calcium looping)	MWh to 100 MWh	10 kW to 1 MW	500 to 90°C	45-63%	Months	> 30 years
	Salt hydration	10 kWh to 100 kWh	N/A	30 to 200°C	50 – 60%	Months	20 years
	Absorption systems	10 kWh to 100 kWh	10 kW to 1 MW	5 to 165°C	C.O.P. 07-1.7	Hours to days	50 years

Source: IRENA Innovation Outlook TES (2020) (6-7)

6.1.3 PRIMARY OPTION ASSESSMENT

As no Geothermal Energy Storage pathways are considered to meet the key project criteria, further evaluation has not been carried out. Refer section 6.2.1.

6.1.4 SWOT ASSESSMENT

As no Geothermal Energy Storage pathways are considered to meet the key project criteria, further evaluation has not been carried out. Refer section 6.2.1.

6.1.5 DISCUSSION

The main drawback of geothermal energy not being able to be effectively and efficiently stored over a multi-year period as required by NZ Battery means it is not recommended for further assessment. Nevertheless. This type of energy storage system could be useful for say building heating via ground source heat pumps, however the NZ Battery project's need is ultimately for electricity generation.

6.2 CONTROLLED SCHEDULABLE GEOTHERMAL (LONG-TERM)

The NZ Battery project primarily seeks to assess energy storage technologies that can be dispatched over the long-term (schedulable). Conventional geothermal generation technologies may be able to sustainably operate in this manner, with some adjustments to their traditional baseload operations, i.e. allowing to operate in this way by running at low load or mothballing plant during normal periods, and then ramping up during prolonged 'dry, calm, and cloudy' periods. This section primarily considers flash steam power plants, whereas the next section covers ORC binary plants. Both technologies may be able to provide long-term schedulable operation. ORC binary plant, in addition, may be able to provide flexible short-term load following operation, which will be covered separately in the subsequent section. To meet the large-scale requirements of the NZ Battery Project, it is expected that a geothermal solution is likely to involve development of both flash steam and ORC binary.

6.2.1 PRIMARY OPTION INTRODUCTION

This Primary Option involves deploying traditional geothermal power generation technologies to generate electricity from NZ's geothermal resources, with incorporation of additional design and operating procedures to allow the plant to be run at low load (turned down) or mothballed into long-term preservation mode during normal years, and then ramping up and running in dry years.

The following sections provide an overview of the geothermal power generation plants that are considered most suitable for this type of application.

6.2.1.1 DIRECT DRY STEAM PLANTS

In this case, the conversion device is a steam turbine designed to directly use the low-pressure, high-volume fluid produced in the geothermal reservoir. Dry steam plants commonly use condensing turbines. The condensate is re-injected (closed cycle) or partially evaporated in wet cooling towers. This type of geothermal power plant typically uses dry steam of 150°C or higher, and generally the steam entering the turbine needs to be at least 99.995% dry to avoid scaling and/or erosion of the turbine or piping components. Direct dry steam plants tend to range in size from 8 MW to 140 MW. The vast majority of NZ's geothermal resources are 'wet' (2-phase) therefore, Direct Dry Steam Plants are not typically used in NZ.

6.2.1.2 FLASH PLANTS (CONDENSING STEAM TURBINE)

These are the most common type of geothermal electricity plants in operation globally, as well as in New Zealand. They are similar to dry steam plants, however, as the fluid arrives from the reservoir as 'wet'(2-phase) fluid, the steam is obtained from a separation process called "flashing" within a separator (flash), typically located in the steam field. Figure 6-1 illustrates this process.

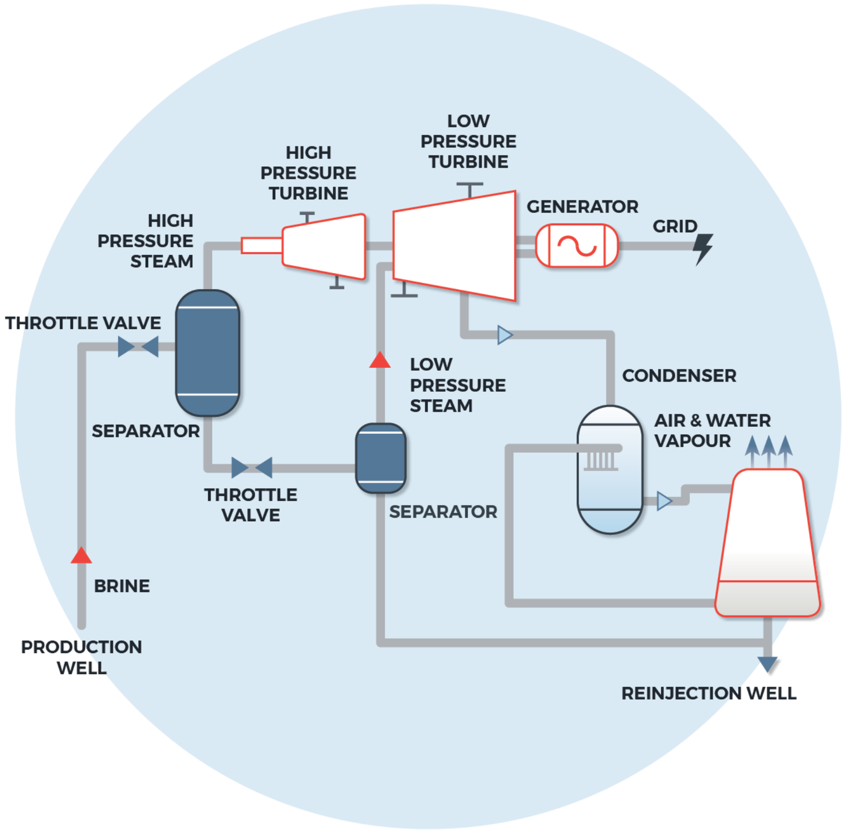

Figure 6-1: Flash Plant (Condensing Steam Turbine) Process

Source: IRENA 2017

The steam is then directed to the turbine(s), and the resulting condensate is sent for reinjection or further flashing at lower pressure. The temperature of the fluid drops as the pressure is lowered, so flash plants work best with well temperatures greater than 180°C.

The fluid fraction exiting the separators, as well as the steam condensate (except for condensate evaporated in a wet cooling system) is reinjected. Flash plants vary in size depending on whether they are single (0.2-80 MW), double (2-110 MW) or triple-flash (60-150 MW) plants.

6.2.2 TECHNOLOGY PATHWAYS

Table 6-3 presents a broad categorisation of the pathway options to use geothermal energy for the generation of electricity in a controlled schedulable (long-term) manner. In the table, Bold text represents the Preferred Pathway, Normal text represents Other Pathways, and Red text represents Discontinued Pathways.

Table 6-3: Geothermal Technology Pathways

	CONTROLLED SCHEDULABLE GEOTHERMAL (LONG-TERM)
Energy Source	Earth's subsurface heat (renewable energy)
Storage	Inherent storage
Generation	Condensing Steam Turbine (flash plant) Organic Rankine Cycle (ORC) binary

Source: WSP

6.2.2.1 PREFERRED PATHWAY

This pathway involves building new geothermal generation (as a combination of condensing flash plant and ORC binary cycle plant) incorporating additional design and operating procedures to optimise for running at low load (turned down) or mothballing and running in a long-term schedulable manner. The new geothermal NZ Battery plant would be turned down or mothballed into long-term preservation mode for normal years. It would then be ramped up in dry years and left to run as baseload continuously for 3 - 6 months (or longer if required), before ramping down the plant and potentially mothballing again until the next dry year period.

6.2.3 PRIMARY OPTION ASSESSMENT

Following the initial screening assessment, the Primary Option of Controlled Schedulable Geothermal (Long-term) with the Preferred Pathway of building a combination of condensing flash and ORC binary plant has been considered for further analysis. Table 6-4 provides an indication of the degree to which this option meets the evaluation criteria.

Each geothermal technology option is scored based on a qualitative rating and quantitative evidence against the established RAG criteria defined in Appendix A. Our assessment against the Evaluation Criteria is explained further below.

Table 6-4: Geothermal Energy Options Assessment

CATEGORY	CRITERIA	CONTROLLED SCHEDULABLE GEOTHERMAL (LONG-TERM)
Preferred pathway		BUILD COMBINATION OF CONDENSING FLASH AND ORC BINARY PLANT
Long-term	Between Dry Years Energy Storage	● inherently stored energy
	Storage Recovery	● inherently stored energy
	Asset Life	● > 50 years
Large-scale	Min. 1 TWh	● 1 TWh [500 MW] [1]
	Up to 5 TWh	● 4 TWh [up to 1000 MW] [2]
	3 to 6 Months Output	●
Renewable	Renewables	●
	Operational carbon emission intensity	● 76 g CO_2eq/kWh [3] [4]
	Built carbon emission intensity	●
	Sustainable Resources Risk	●
Technology Readiness	Technology Readiness Level (2030)	● 9
	Technology Ready for Commissioning (2030)	●
Geographical and Logistical Constraints	Geographical constraints	●
	Subsurface Constraints	●

CATEGORY	CRITERIA	CONTROLLED SCHEDULABLE GEOTHERMAL (LONG-TERM)
	Transportation or Logistic Requirements	
Commercial Viability	Whole of Life Cost ($)	Commercial Information
Efficiency Measures	Round Trip Efficiencies (2021)	N/A
	Round Trip Efficiencies (2030)	N/A
	Annual Storage Decay Factor	
Environment and Safety	Environmental or Regulatory Hurdles (Ability to obtain a consent)	~500 MW [6] up to ~1000 MW
	Environmental Risks	~500 MW up to ~1000 MW
	Safety Hazards Risks	
Reference Projects	Reference Projects	
Technology Implementation	Global Market Trends & Context	
	Commitment of OEM Suppliers	
	Available International Market to Import Resources	N/A
	Potential Implementation Bottlenecks	labour and equipment supply constraints (multiple sites)

Source: WSP

Notes on the option assessed

[1] Based on energy generated over 3 month period at 90% capacity factor

[2] Based on energy generated over 6 month period at 90% capacity factor

[3] Lawless et al, 2019 Future Geothermal Generation Stack

[4] Geothermal generators in NZ are piloting processes for geothermal carbon capture and reinjection, these carbon emissions values have potential to reduce in future if these trials prove to be technically and commercially successful.

[5] Based on Whole of Life calculation methodology applying consistent scenarios across all technologies.

[6] Assumes that this option can be located within the areas identified within the Taupō District Plan as having potential for further geothermal energy production. Consentability would depend upon the design, scale, and geographical context of the particular site progressed. A location outside of areas with policy preference may incur delays and/or risk of the application being refused.

6.2.3.1 LONG-TERM

Geothermal power plant has been proven to be a highly reliable means of supplying electrical energy in NZ. It has demonstrated good longevity, with many plants having seen more than 40 years of operational life (with appropriate maintenance).

Due to its inherent energy storage (or in other words being a renewable resource with thermal energy continuously replenishing the reservoir), geothermal does not need to be recharged like other technology options - one of its key relative advantages. Once constructed, and as long as the geothermal reservoir fluids are extracted at the long-term sustainable rate, the key criteria of long-term energy storage can be met.

6.2.3.2 LARGE-SCALE

Desktop research and qualitative assessments indicate that NZ could build approximately 500 MW of new geothermal generation by 2030. This would provide the equivalent of around 1 TWh over 3 months (assuming at least a 90% capacity factor, an historically achievable figure), satisfying the 1 TWh energy over 3 months requirement.

It could be more difficult for geothermal to meet the higher 5 TWh energy storage figure; however, with NZ Battery focused consenting (similar to the RMA 'call in') processes it may be possible for around 1000 MW to be built by 2030. This would provide the equivalent of around 2 TWh over 3 months, or 4 TWh over 6 months, using the same 90% capacity factor

The amount of energy generated will depend on the length of the discharge period. The quantum of energy is certainly available, the constraint lies in the practically achievable rate of generation in MWs. Using the example of 1000 MWs referenced above, the 4 TWh over 6 months could extend to say 8 TWh of energy over 12 months if required. This would be achieved by simply running the geothermal plant for longer a duration, a feature that does not apply to other 'energy constrained' options.

6.2.3.3 RENEWABLE

The geothermal resources considered for NZ Battery are all renewable. This is on the basis that the heat is extracted at the geothermal field's long-term sustainable rate, and extracted fluids are reinjected back into the reservoir via reinjection wells.

Using geothermal fluid causes greenhouse gas emissions from the release of non-condensable gases in the fluid. This takes place either after separation of steam from fluid, or in the direct use of two-phase geothermal fluid. Geothermal fluid users, along with other stationary energy participants, are required to monitor and report on their greenhouse gas emissions as part of the New Zealand Emissions Trading Scheme (NZ ETS). The NZ ETS requires these geothermal fluid (and other stationary energy participants, to acquire and surrender New Zealand Units (NZUs) each year to the amount of emissions they reported for the previous year. The Government sets an overall limit, known as a 'cap', on NZUs supplied to the ETS market. This limit and price controls are geared to meet an emissions budget that has been developed to align Aotearoa New Zealand's emissions with its international climate commitments and targets. As geothermal generators in NZ are piloting processes for geothermal carbon capture and reinjection, there is potential to reduce geothermal emissions in future if these trials prove to be technically and commercially successful.

6.2.3.4 TECHNOLOGY READINESS

Traditionally, geothermal power plants have supplied power at full or near full load capability. Geothermal operated in this manner for long-term continuous power generation is a well proven technology. This operating profile has been driven by O&M and asset management reasons as well as economic drivers, as geothermal plant, once installed, is relatively low cost to operate owing to low 'fuel' costs. This has incentivised operating geothermal plants at high-capacity factors.

Running at low load or mothballing of geothermal steamfield and power generation plant for long-term storage and intermittent use would be a new approach both internationally and in NZ and may create additional challenges for start-up and operation. These would need to be investigated further as part of the Task 2 technical feasibility, however for the purposes of this Task 1 evaluation we have assumed that appropriate measures and solutions will be able to be suitably developed to counter any associated challenges (see discussion provided in key challenges section below).

Manufacturing capacity for geothermal technology is well developed and, subject to project approvals, no issues have been identified which would prevent deployment of this technology at a level consistent with a 1 TWh electrical capacity by the year 2030. Options which provide increased energy output (or increased install capacity) are also likely possible.

6.2.3.5 GEOGRAPHICAL AND LOGISTICAL CONSTRAINTS

The MW generation size and number of new build geothermal plants are based on those that are considered at a pre-feasibility study level to be reasonable. Table 6-5 summarises NZ's potential new build geothermal resources.

In this study, the Whole of Life costing has allowed for normal generation builds out to the year 2030 and has only allowed for the NZ Battery to include the 500 MW of plant, that is currently expected to come online after 2030. It is this plant that is being brought forward: This is a novel concept and raises a number of issues around market implications, however for the purposes of understanding the cost implications of doing so such an approach is deemed robust.

Table 6-5: Potential new build geothermal plants.

	Name	MW	Power Plant
	Tauhara 2a[1]	*150*	*Condensing Flash*
1	Tauhara 2b	125	Condensing Flash
2	Ngawha 4	25	ORC Binary
3	Mangakino	25	ORC Binary
4	Mokai-4	25	ORC Binary
5	Ngatamariki-2	50	ORC Binary
6	Rotokawa-3	50	Condensing Flash
7	Kawerau-2	50	Condensing Flash
8	Rotoma-1	25	ORC Binary
9	Tokaanu-1	20	ORC Binary
10	Tikitere-1	50	Condensing Flash
11	Taheke-1	25	ORC Binary
12	Reporoa-1	25	ORC Binary
13	Tauhara-3	30	ORC Binary
14	Horohoro	5	ORC Binary
15	Atiamuri	5	ORC Binary
16	Rotokawa-4	50	Condensing Flash
17	Tokaanu-2	100	Condensing Flash
18	Tikitere-2	50	Condensing Flash

	Name	MW	Power Plant
19	Taheke-2	25	ORC Binary
20	Reporoa-2	25	ORC Binary
21	Ngawha-5	25	ORC Binary
22	Taheke-3	25	ORC Binary
23	Reporoa-3	25	ORC Binary
24	Ngawha-6	25	ORC Binary
	Total all BAU scenario	1035	

Source: Estimate of NZ future geothermal generation out to 2051 [Extract from Lawless et al 2020]

Notes: [1] Assumes that as part of any NZ Battery scale program additional resource can be developed similar to Tauhara 2a

6.2.3.6 EFFICIENCY MEASURES

Due to the inherently stored nature of geothermal resources, the round-trip efficiency of other 'charge and discharge' energy storage technologies does not apply. An advantage of geothermal is that it does not need to be recharged like other technology options (in the context of NZ Battery recharge periods, and assuming reinjection of fluids).

6.2.3.7 ENVIRONMENT AND SAFETY

The National Policy Statement for Renewable Electricity Generation 2011 requires objectives, policies and rules to be included within local and regional policy documents, to provide for the development of new geothermal electricity generation (where relevant to the region or district). The Waikato Regional Policy Statement classifies geothermal resources at the regional level; with some areas identified as (Limited) Development Geothermal Systems and others for research and/or protection. The majority of geothermal systems within the Taupō area are classed as Development Geothermal Systems providing some scope for further generation scheme development. Anticipated Environmental Outcomes within the Taupō District Plan include that the "land use effect associated with the use of geothermal resources are avoided, remedied, or mitigated".

Proposed geothermal electricity schemes must also be consistent with the requirements of the Resource Management Act 1991 (notably sections 6 and 7). The RMA is in the process of being replaced and the criteria under the new legislation have the potential to be more onerous. Either way, the likelihood of consent being granted will depend heavily upon the specific location and potential for avoiding more than minor environmental effects. This includes the potential for effect upon cultural, scenic, recreational, and spiritual values; all of which are noted in the Taupō District Plan. therefore, the specific location will influence the likelihood of gaining consent and would require investigation in further detail (i.e. in Task 2).

Also, compared with other technology options geothermal would require deployment across a relatively large number of sites and locations (i.e. with over 50 potentially impacted Hapu each requiring Cultural Impact Assessments). This significant number of cultural and other impact assessments relative to alternative options is another risk to be further investigated. The separate sites may require separate applications for resource consents, depending upon the proximity between proposed sites. Each would be assessed on its own merits with a separate decision-making process and therefore, there is a risk that different applications could result in different outcomes i.e. approved or refused. Ensuring that the design responded to site-specific environmental baselines and outcomes and feedback from stakeholder engagement may reduce the risk of refusal and/or challenge.

6.2.3.8 REFERENCE PROJECTS

Condensing flash steam and ORC binary geothermal plants are a familiar and well-established technology in New Zealand, with our first plant Wairakei having commenced operation in 1958 and over 1000 MW of geothermal generation across ~20 sites constructed and operating since then including Poihipi (which notably was originally run in a dispatchable manner), Kawerau, Rotokawa, Nga Awa Purua, Ngatamariki, Te Mihi and Te Ahi O Maui.

6.2.3.9 TECHNOLOGY IMPLEMENTATION

There is an established history of key OEM participation and a proven supply chain for the specialised power generation and balance of plant (BOP) equipment such as turbines, generators, cooling towers and bespoke large-scale pressure equipment.

Conventional condensing flash plants (and ORC binary cycle plants) can be run in a long-term schedulable manner however, traditionally they pay a penalty in efficiency loss, subsurface resource degradation and plant life by doing so. Particularly in the case of condensing flash plants, to operate in a schedulable mode sustainably (i.e., by continuously modulating the wellhead valves as opposed to local steam venting) can decrease the expected life of the geothermal resource, due to thermal cycling and creation of mineral deposits such as silica or calcite scaling - blocking the wells and rapidly decreasing their production rate and life. Mitigations are expected to be possible through additional design and operational features to suitably address any uncertainties and challenges with regards to operating geothermal subsurface reservoirs in a long-term on/off schedulable manner. Mitigations are also possible for the surface power generation plant, such as building new process equipment, piping and plant with greater use of corrosion resistant materials (e.g. 316 stainless steel or Duplex) to improve their resilience to on/off cycling or load following generation, with an associated additional Capex requirement. (See discussion in following section).

There may be some challenges associated with the ability of current NZ construction contractor resources to deliver the implementation of a large-scale geothermal generation new build programme across multiple sites.

Other key challenges include: -

- The opportunity cost of developing geothermal for long-term storage and removing from the generation stack optionality to build as baseload plant in a 'business as usual' scenario.
- Whether market participants have development rights to certain fields.

6.2.3.10 KEY UNCERTAINTIES, CHALLENGES, AND OPPORTUNITIES TO IMPLEMENT

The items presented in Table 6-6 have been identified as requiring specialised attention to detail if proceeding to Task 2. These items provide for safe and optimal long-term mothballing of plant, and better response to bringing the plant on / off, or for load changes, if required.

While the items listed below may present a risk, they are generally considered to have manageable solutions, implementable at low to moderate cost to a project. The items below are also considered technologically available. Some of these have been trialled at individual existing plants but are not universally applied to all projects.

Table 6-6: Technology Challenges and Solutions

CONSIDERATION	DISCUSSION
Reservoir lifetime: steamfield design to enable long-term storage and resistance to fouling, blockage and early degradation while in standstill mode	Over time, steam and hot fluid supply and reinjection wells have the potential to change characteristics and, in some cases, become less productive. Operating a conventional condensing flash plant as long-term schedulable, with the reservoir wellhead valves fully shut-in for long periods of time, has the potential to exacerbate this risk. However, mitigations and optimisation of a geothermal reservoir to operate in long-term schedulable manner are possible and will be investigated further as part of the Task 2 Feasibility Study. With further research, appropriate upfront design, and additional maintenance and operation practises, there appears to be potential to suitably manage these risks Potential mitigations include designing a system that permits selection of the supply source from multiple wells across a combination of operating and mothballed plant - in that if one well reduces, it only affects a portion of the overall reservoir supply. Or developing hybrid systems where in normal years the geothermal fluid provides process heat to other green production plant such as biomass or other (milk drying) - thus providing a steady load for the geothermal bores. This issue is also controllable via monitoring of the well condition over time. Other mitigations include chemical additives such as anti-scalants, anti-calcite or acid dosing. Maintaining operational staff capacity and knowledge is also an important mitigation step.
Design to avoid standstill corrosion and degradation	Severe standstill corrosion has been observed in some geothermal steam plants. This has affected the longevity of steam lines, vessels, and the power generation equipment, and in some cases can render equipment unsafe and inoperable. Experience suggests that this issue may be solved by application of any of the following: • Design of equipment with materials that are not susceptible to the environment during storage conditions • Back purging of equipment with a noble gas to promote a less aggressive environment • Flexing of plant control elements at timed intervals using control system, ensuring mechanical equipment moves as anticipated on a regular frequency; and also to minimise potential for corrosion on terminals, contacts, relays, sensor heads etc as these can present critical points of risk/failure. • Eliminate this risk by allowing some steam to run through plant at part load while mothballed then ramping up in dry years.

CONSIDERATION	DISCUSSION
Design to permit rapid cleaning of steam lines	Prolonged storage can promote oxide and scale forming layers on steam supply equipment (piping and vessels). Traditionally this has been removed by way of 'steam-blowing'. This process can be time-consuming, noisy and create disturbance to the local community supporting the power plant. This issue can be mitigated by either: • Selection of appropriate construction materials (which limit oxide and scale formation) • Provision of blowing or other (e.g. mechanical) cleaning methods which are more amenable to the environment.
Improved responsiveness of plants	As previously mentioned, geothermal plant has tended to be run at fixed high load capacities owing largely to project economics. However, there are examples where geothermal plant has also provided a level of load response. This type of operation can be successful provided that appropriate design, controls, and automation are implemented. Areas for consideration include: • Design of steam field operations which permit rapid flow response • Advanced coordination between power plant and steam field operation • Advanced controls on chemical additives (where required) for condensate return and reinjection wells • More sophisticated controls and automation within the plant to automate responses
OEM Warranties	OEM Warranties do not typically allow for mothballing, and may require additional contractual requirements for suitable processes and procedures (potentially with associated evidence or participation of OEMs)
Plant design to optimise mothballing	Designing the system to optimise mothballing, such as dosing points, materials selection, easy removal (double block and bleed) of sensitive instruments or sensors, bleed/evacuation and inert gas quick connect points.
Advance warning of need to start plant	A potential mitigation is that where a plant has been inactive for longer than 6 months, the system operator may be able to provide e.g. 1-2 months prior notice of the need for a plant to supply power (it is likely that with further investigation this may be reduced). We believe that with modern weather, hydro resource monitoring and renewable generation prediction that this advance warning of an impending need would be achievable. Where a plant has been out of service for a shorter duration, a shorter period of notice may be acceptable.

Source: WSP

6.2.3.11 OPPORTUNITIES

Building new long-term schedulable geothermal generation as a NZ Battery could provide a 'no-regrets' option, in that it could defer the need to build a large-scale energy storage scheme, while other less-developed technologies develop further. It may also remove the need, or minimise the size, of any future energy storage scheme, due to a critical mass of VRE sources being built in future (noting more VRE generation is expected to be built regardless of any future pathway). It thus provides optionality with regards to future choices for NZ.

A geothermal NZ Battery also provides further optionality by being capable of being switched, in the future, to run instead as a source of cost effective, renewable baseload generation. as the generation mix changes and risk profiles alter.

6.2.4 COMMERCIAL VIABILITY

6.2.4.1 INTRODUCTION

Controlled, long-term schedulable geothermal generation is based on building a combination of Condensing Flash and ORC Binary Plant. The plant is built with additional design and operational considerations to optimise for long-term schedulable operation but no extra features, to allow short term flexibility, are included. All plant will be run as baseload during dry years and mothballed when not required.

The total impact to the electricity system includes the removal from normal generation expansion of the plant allocated to NZ Battery. This may remove from the generation expansion 'stack' some geothermal plant that would be lower cost options and can be expected to result in the construction of more expensive options. Estimation of this wider economic cost is outside the scope of this part of the study but is likely to be the subject of analysis by the wider NZ Battery modelling team in future stages of the project.

The geothermal NZ battery build whether it is 500 MW or up to 1000 MW would include a mixture of condensing flash plants and ORC binary cycle plant, and site locations, all of which have varying costs. For the purposes of costing this option we have assumed a consistent mix of plant and mix of site locations.

Long-term geothermal power generation in NZ is a well-developed and cost-effective technology option. The commercial risk is very low and there are options for any plant to be transferred out of the NZ Battery programme to regular market operation.

6.2.4.2 COSTING SCENARIO

As with the other technologies, the geothermal costing scenario targets meeting 1 TWh of demand over a three-month period identified as a dry year. Dry years occur in 2032 and every five years subsequently. To achieve these dry year requirements, currently identified geothermal [refer table 6.5] that is not planned to be built by 2030 is "brought forward" and built by 2030. Capacity of 500 MW is built, which is sufficient to generate 1 TWh over three months.

The stations built are loosely those from the back of the stack but note that actual capacity does not match any particular set of stations.

The stations remain mothballed until required to meet a dry year energy shortfall. When a dry year occurs, the stations are de-mothballed, run as base load for three months, delivering 1 TWh to the electricity grid, then mothballed until the next dry year occurs. These stations operate in this manner in perpetuity from 2030.

6.2.4.3 KEY ASSUMPTIONS

- 500 MW of plant, that is currently expected to come online after 2030, is brought forward to be available from 2030.
- Mothballing and de-mothballing each cost of Commercial Information
- No estimation of the impact of removing the opportunity to include these generation options to meet regular market demand increases after 2030 has been included.

6.2.4.4 ANALYSIS RESULTS

ITEM	COST	NOTES
Capex Total ($)	Commercial Information	Total build costs of the stations making up 500 MW
Capex ($/kW)		
Opex (per year)		Sale of electricity in dry years exceeds operating costs
Whole of Life Cost ($)		
LCOE ($/MWh)		

6.2.4.5 ALTERNATIVE IMPLEMENTATIONS

An alternative implementation that could provide additional benefits would be the use of incremental de-mothballing. As the geothermal plant is a set of smaller plant sized from 5 to 150 MW, the plant can be de mothballed in a staged manner as the level of certainty around the dry year requirement increases. Similarly, the plants can be re-mothballed as the requirement decreases.

Another alternative with associated potential benefits relates to the future optionality to return new plant to market operation. Should circumstances change the geothermal plant designated for NZ Battery purposes can be returned to a normal commercial operation. All currently identified stations were expected to be in operation by [2060] so they could be used to delay commitment to other technologies.

6.2.4.6 COMMERCIAL VIABILITY DISCUSSION

Our analysis suggests that building geothermal stations, with additional design and operational considerations to optimise for long-term schedulable operation to address the dry year problem is the most cost effective of all options.

There is an economic cost to the electricity system from removing these options from the expected market driven generation expansion that has not been included in the cost analysis.

There is an economic benefit to being able to reverse the decision to include any or all NZ Battery geothermal stations by returning them to normal electricity market operation.

Our view of the balancing these effects is that geothermal remains the most cost effective of the options we have considered.

6.2.5 SWOT ASSESSMENT

Table 6-7: Controlled Schedulable Geothermal (Long-term) SWOT

	Helpful to achieving the objective	Harmful to achieving the objective
Technology (source to grid)	STRENGTHS	WEAKNESSES
	• Mature technology, already well established and proven • 'No regrets' by building new geothermal, optionality to switch in future from dry year cover to full time baseload. • Highly dependable plant • Operates with high capacity factors 90%+ • Full control over schedulability (long-term) unlike other Renewables such as solar and wind.	• May have limits to ability to achieve 5 TWh • Limited ability to also provide short term flexible generation.
Operating Environment (external)	OPPORTUNITIES	THREATS
	• NZ can develop geothermal industry skills, exportable to rest of world. • Opportunity for NZ to develop long-term flexible geothermal design & operation knowledge and skills • Flexible solution in terms of future optionality	• Supply chain of construction contractors and international OEM equipment to provide quantum of plant in time scales required. • Potential consenting / planning barriers across the relatively large number of separate developments required. • Opportunity cost of developing geothermal for long-term storage and removing from the generation stack optionality to build as baseload plant in a 'business as usual' scenario. • Whether market participants have development rights to certain fields.

6.2.6 DISCUSSION

The NZ Battery project primarily seeks to assess energy storage technologies that can be dispatched over the long-term (schedulable). Conventional geothermal generation technologies may be able to sustainably operate in this manner, with some adjustments to their traditional baseload operations, i.e. allowing to operate in this way by running at low load or mothballing plant during normal periods, and then ramping up during prolonged 'dry, calm, and cloudy' periods. The ability to design and operate new geothermal reservoirs, steamfield equipment and power generation plant in this manner is a key risk for further assessment in Task 2.

A newly built geothermal NZ Battery could supply around 1 TWh of electrical energy over at least a three-month period. This would consist of a combination of conventional flash steam and ORC binary geothermal power plants developed and constructed according to the suitability of the steam field supply conditions (I.e., reservoir enthalpy, a measure of the pressure and temperature of the underground heat resource).

While geothermal power plants have traditionally been run as continuous baseload generation in NZ, if new plants were designed from the outset to be operated as long-term schedulable (i.e. running at low load or mothballed in normal years and only run in dry years) then geothermal appears to present a viable option for the NZ Battery. In particular the above ground power generation plant (including both condensing flash plants and ORC binary plants) appears to be able, with further research, to include additional design and operating features to allow long-term schedulable operation. There is however a higher level of risk associated with the ability of the subsurface geothermal reservoirs and reinjection wells to be operated in a schedulable manner. While also not expected to be insurmountable, it is these subsurface aspects that are anticipated to be critical to determining geothermal's overall ability to be used for dry year energy back-up in the NZ Battery context.

There are limits to the expected amount of new geothermal plant that could be dedicated to a NZ Battery, however while this constrains the total amount of power in MWs available, because of the inherently stored nature of geothermal energy, the same constraints would not apply to the amount of available energy in TWhs. In other words, to provide more energy to NZ in dry years, the geothermal battery could simply be run for a longer time period. The inherently stored nature of geothermal energy means it does not need to be recharged like other technology options - one of its key relative advantages.

Geothermal is a renewable energy source. This option does release carbon emissions during electricity production, however through a combination of site and plant type selections, as well as developments in geothermal carbon capture technology, these are expected to be able to be minimised to an acceptable level.

Relative to other options, the geothermal energy battery would need to be spread across more sites and locations (for example across over 20+ sites each ranging from 5 MW to 150 MWs. There are some benefits to this including the ability to bring on the dry year reserve in increments of energy capacity. However, on the downside is that more locations would in turn require more consenting efforts and potential complexity.

From an estimated costs viewpoint, geothermal is a relatively low cost option, even when considering the expected additional costs to modify designs and operation to make long-term schedulable.

Of all the primary options considered, geothermal is closely connected to the currently available electricity generation market. A key consideration for further investigation is the potential market implications (and economic benefits and costs to NZ as a country) of bringing forward and building new geothermal plants as a NZ Battery, that may otherwise have been built through normal market forces. The "flipside" of this risk is that it would be relatively straightforward to remove a plant from the NZ Battery system and add to standard market operation – even matching the timing to when the market forces would have seen it built. This "no regrets" opportunity could allow delay to commitment in technology providing the option value of allowing further development of other technologies.

6.3 CONTROLLED SCHEDULABLE GEOTHERMAL (FLEXIBLE)

The NZ Battery project primarily seeks to assess energy storage technologies that can be dispatched over the long-term (i.e. schedulable over months, years). Conventional geothermal generation technologies are well suited to this, with some adjustments to the traditional baseload operations. The NZ Battery project will also consider, as an additional secondary benefit, the potential of a technology also being able to dispatch in the short term (i.e. hours) in a load following manner. This applies particularly to the Organic Rankine Cycle (ORC) binary plant technology option (as described further in this section).

ORC binary plants are investigated here as they would be needed to provide the large-scale electricity generation required for a NZ Battery, and are suited to NZ's lower enthalpy geothermal resources, i.e. those with lower temperature fluids. They are well-suited for long-term dispatch (schedulable), and also considered to be the most suited geothermal generation option to provide flexibility if required, for shorter-term dispatch or load following operation.

6.3.1 PRIMARY OPTION INTRODUCTION

Organic Rankine cycle (ORC) binary plants are typically applied to geothermal fields with low or medium enthalpy (a measure of the system's internal energy). The resource fluid is used, via heat exchangers, to heat a process fluid in a separate (binary) cycle loop. Figure 6-2 illustrates this process.

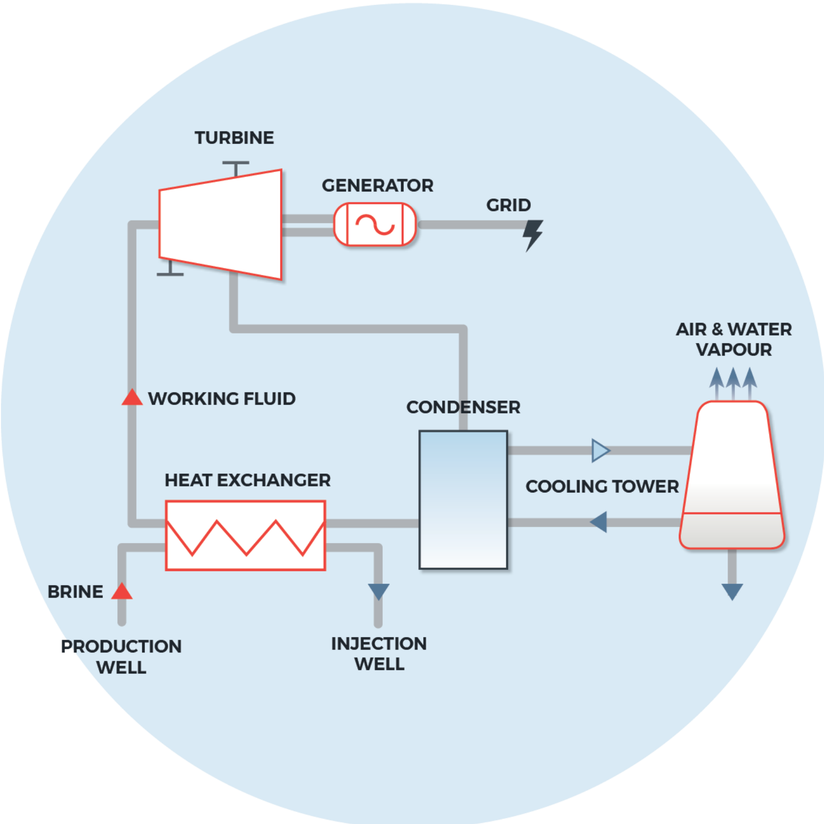

Figure 6-2: Binary Plant (ORC) Process

Source: IRENA 2017

The secondary process fluids (usually n-pentane or isopentane in NZ) have boiling and condensation points that better match the geothermal resource temperature. These secondary fluids operate in a closed loop and no secondary fluids are combusted or consumed in the process.

Typically, binary plants are used for resource temperatures between 100°C and 170°C. Although it is possible to work with temperatures lower than 100°C, the efficiency of the electricity output decreases. In NZ, ORC binary plants typically range in size from 5 MW to 50 MW.

6.3.1.1 COMBINED CYCLE OR HYBRID PLANTS

Some geothermal plants use a combined cycle, which adds a traditional Rankine cycle to produce electricity from energy that in a binary cycle, would become waste heat. Figure 6-3 illustrates this process.

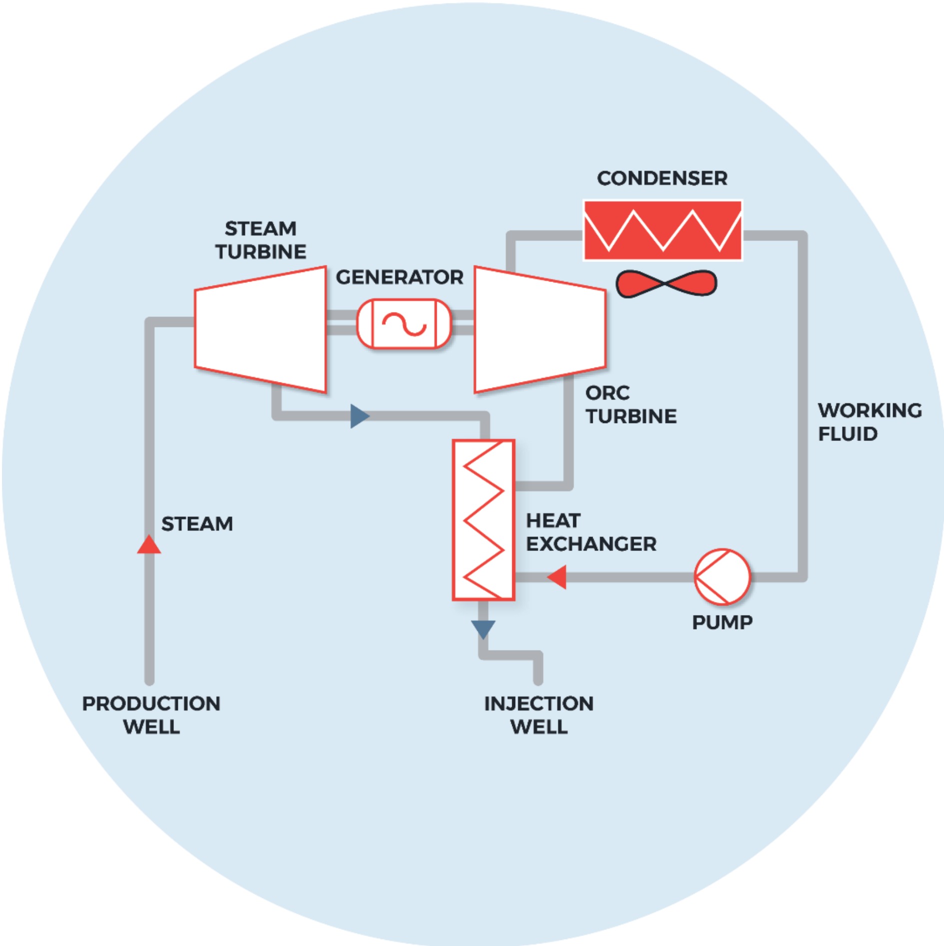

Figure 6-3: Geothermal Combined-cycle Plant

Source: WSP adapted from Ormat, 2017

Using two cycles provides relatively high electric efficiency. The typical size of a combined cycle plant ranges from a few MW to 10 MW.

Hybrid geothermal power plants use the same basics as a stand-alone geothermal power plant but combine a different heat source into the process, e.g. heat from a concentrating solar power (CSP) plant. The heat is added to the geothermal brine (increasing the temperature and power output, or directly to the working fluid of the binary cycle (superheating it, bringing associated additional complexity and challenges). The Stillwater project in the USA, operated by ENEL Global Renewable Energies, has developed such a hybrid system, combining CSP and solar photovoltaics with a binary system.

Another hybrid system being studied by ENEL is a hybrid plant with biomass in Italy, which increases the brine temperature, similar to the above CSP system.

6.3.2 TECHNOLOGY PATHWAYS

Table 6-8 presents a broad categorisation of the pathway options to use geothermal energy for the generation of electricity in a controlled schedulable (flexible) manner. In the table, **Bold text** represents the Preferred Pathway, Normal text represents Other Pathways, and Red text represents Discontinued Pathways.

Table 6-8: Geothermal Technology Pathways

	CONTROLLED SCHEDULABLE GEOTHERMAL ORC BINARY (FLEXIBLE)
Energy Source	**Earth's subsurface heat (renewable energy)**
Storage	**Inherent storage** Above ground Thermal Energy Storage (TES)
Generation	**ORC binary**

Source: WSP

6.3.2.1 PREFERRED PATHWAY

This pathway involves building new ORC binary cycle geothermal generation with additional research, development, and implementation of supplementary technologies, design and operating procedures to optimise for low load operation or mothballing. It would then run at full load during dry years, in a flexible schedulable manner. The new ORC binary plant would form part (approximately a third) of a new geothermal NZ Battery plant which would be turned down or mothballed into long-term preservation mode for normal years. It would be ramped up in dry years and left to run for 3 - 6 months (or longer if required), before ramping down the plant and potentially mothballing again until the next dry year period.

6.3.3 PRIMARY OPTION ASSESSMENT

Following the initial screening assessment, the Primary Option of Controlled Schedulable Geothermal (Flexible) on the Preferred Pathway of building new ORC binary plant has been considered for further analysis. Table 6-9 provides an indication of the degree to which this option meets the evaluation criteria.

Each geothermal technology option is scored based on a qualitative rating and quantitative evidence against the established RAG criteria defined in Appendix A. Our assessment against the Evaluation Criteria is explained further below.

Table 6-9: Geothermal Energy Options Assessment

CATEGORY	CRITERIA	CONTROLLED SCHEDULABLE GEOTHERMAL (FLEXIBLE)
Preferred pathway		Build new ORC binary plant for flexible operation
Long-term	Between Dry Years Energy Storage	Inherently stored energy
	Storage Recovery	Inherently stored energy
	Asset Life	> 30 years
Large-scale	Min. 1 TWh	0.4 TWh [200 MW] [1]
	Up to 5 TWh	1.4 TWh [350 MW] [2]
	3 to 6 Months Output	
Renewable	Renewables	
	Operational carbon emission intensity	50 g CO_2eq/kWh [3] [4]
	Built carbon emission intensity	
	Sustainable Resources Risk	
Technology Readiness	Technology Readiness Level (2030)	Short term dispatchable
	Technology Ready for Commissioning (2030)	Short term dispatchable
Geographical and Logistical Constraints	Geographical constraints	
	Subsurface Constraints	
	Transportation or Logistic Requirements	
Commercial Viability	Whole of Life Cost ($)	Commercial Information
Efficiency Measures	Round Trip Efficiencies (2021)	N/A
	Round Trip Efficiencies (2030)	N/A
	Annual Storage Decay Factor	
Environment and Safety	Environmental or Regulatory Hurdles (Ability to obtain a consent)	~200 MW [6] up to ~350 MW
	Environmental Risks	~200 MW up to ~350 MW
	Safety Hazards Risks	With some additional requirements (with NZ precedents)
Reference Projects	Reference Projects	Short term dispatchable
Technology Implementation	Global Market Trends & Context	
	Commitment of OEM Suppliers	

CATEGORY	CRITERIA	CONTROLLED SCHEDULABLE GEOTHERMAL (FLEXIBLE)
	Available International Market to Import Resources	N/A
	Potential Implementation Bottlenecks	Labour and equipment supply constraints (multiple sites)

Source: WSP

Notes on the option assessed

[1] Based on energy generated over 3 month period at 90% capacity factor

[2] Based on energy generated over 6 month period at 90% capacity factor

[3] Geothermal generators in NZ are piloting processes for geothermal carbon capture and reinjection, these carbon emissions values have potential to reduce in future if these trials prove to be technically and commercially successful.

[4] Lawless et al, 2019 Future Geothermal Generation Stack, and WSP judgement of expected binary cycle vs condensing flash plant builds and their resource locations.

[5] Based on Whole of Life calculation methodology applying consistent scenarios across all technologies.

[6] Assumes that this option can be located within the areas identified within the Taupō District Plan as having potential for further geothermal energy production. Consentability would depend upon the design, scale, and geographical context of the particular site progressed. A location outside of areas with policy preference may incur delays and/or risk of the application being refused.

6.3.3.1 LONG-TERM

As stated above, geothermal power plants of all types have been proven to be a highly reliable means of supplying electrical energy in NZ. This includes both condensing flash plants and ORC binary plants. ORC binary plants have demonstrated good longevity, with many having seen in excess of 20 years of operational life (with appropriate maintenance). For example; Ngawha ORC binary cycle was built in 1998, and Wairakei binary plant in 2005, both with successful operation since then.

Geothermal energy is inherently stored (or in other words is a renewable resource with thermal energy continuously replenishing the reservoir). therefore, once constructed as long as the geothermal reservoir fluids are extracted at the long-term sustainable rate, the long-term energy storage criteria is easily met. Due to this inherent energy storage geothermal does not need to be recharged like other technology options - one of its key relative advantages.

6.3.3.2 LARGE-SCALE

Desktop research and qualitative assessments indicate that NZ could build approximately 200 MW of new ORC Binary cycle generation as a NZ Geothermal Battery by 2030. These ORC binary cycle plants, on their own, would provide around 0.4 TWh energy over 3 months (assuming at least a 90% capacity factor, an historically achievable figure). In other words, ORC binary plants on their own would not be expected to achieve the large-scale requirement of 1 TWh or more over 3 months. A combination of condensing flash plants and ORC binary cycle plants would need to be built to achieve this. This option would require bringing forward and constructing ORC binary plant from the current generation stack that would otherwise not be expected to be built until after 2030.

It may be possible with NZ Battery-focussed consenting (similar to the RMA 'call in' processes) to allow up to around 350 MW new ORC Binary cycle plants to be built by 2030. This would provide the equivalent of 0.7 TWh over 3 months, or 1.4 TWh over 6 months, using the same 90% capacity factor assumption.

If any ORC binary plants built for the NZ Battery purposes, were to, in addition to their normal on/off 'baseload' operation, be run in a short-term dispatch, load following manner (whilst there may result in some inefficiencies of plant output and shortening of asset life), it would not be expected to present insurmountable challenges to their ability to contribute to the large-scale, long-term energy key criteria.

6.3.3.3 RENEWABLE

The geothermal resources considered in the NZ Battery Project context are all renewable. This is on the basis of the fact that the heat is extracted at the geothermal field's long-term sustainable rate, and extracted fluids are reinjected back into the reservoir via reinjection wells.

Using geothermal fluid causes greenhouse gas emissions from the release of non-condensable gases in the fluid. This takes place either after separation of steam from fluid, or in the direct use of two-phase geothermal fluid. Geothermal fluid users, along with other stationary energy participants, are required to monitor and report on their greenhouse gas emissions as part of the New Zealand Emissions Trading Scheme (NZ ETS). The NZ ETS requires these geothermal fluid (and other stationary energy participants, to acquire and surrender New Zealand Units (NZUs) each year to the amount of emissions they reported for the previous year. The Government sets an overall limit, known as a 'cap', on NZUs supplied to the ETS market. This limit and price controls are geared to meet an emissions budget that has been developed to align Aotearoa New Zealand's emissions with its international climate commitments and targets. As geothermal generators in NZ are piloting processes for geothermal carbon capture and reinjection, there is potential to reduce geothermal emissions in future if these trials prove to be technically and commercially successful.

6.3.3.4 TECHNOLOGY READINESS

Traditionally, geothermal power plants have supplied power at full or near full load capability. Geothermal operated in this manner for long-term continuous power generation is a well proven technology. The technology readiness of operating geothermal in a flexible schedulable or load following manner is less well proven.

The manufacturing capacity for geothermal technology is well developed and, subject to project approvals, no issues have been identified which would prevent deployment of ORC binary cycle technology to be developed, in conjunction with condensing flash plants to deliver the MWs needed to provide at least 1 TWh of electrical energy capacity by the year 2030.

The primary advantage of a geothermal resource is its reliability in providing energy at a constant rate, independent of external factors like weather. Hence the widespread use of geothermal to supply base load. This section discusses the practicality of also utilising geothermal energy for short-term dispatch or load following operation.

A desktop study has been carried out to investigate the ramp rate of ORC binary geothermal plant, and existing technologies that have succeeded in either implementing load-following geothermal generation or that negate the need to increase fluid flow rate sharply to meet short-term demand changes.

6.3.3.5 INVESTIGATION – ORC BINARY CYCLES

Organic Rankine Cycle (ORC) turbines were considered for further investigation into their ability to operate in a load following manner as they tend to be smaller plants and have a greater ability to ramp down heat extraction (and power generation) from the primary geothermal fluid, without causing undesirable disturbances to the production and reinjection wells' flow rates or wasting heat energy in the process.

Table 6-10 below summarises the key technological advantages and disadvantages of ORC turbines.

Table 6-10: Advantages and disadvantages of ORC turbines.

ADVANTAGES	DISADVANTAGES
Better suited for lower enthalpy, lower temperature geothermal resources	Lower thermodynamic efficiency
Small and modular	Higher capital cost
Closed loop in that geothermal fluids are completely reinjected back into the ground. Hence, minimising reservoir depletion	-

By way of an example, the Ngatamariki 82 MW ORC Binary Plant in Taupō is referred to here to provide an indication of possible ORC turbine ramp rates. The plant has four Ormat 20.5 MW binary cycle units, utilising geothermal fluids (steam and brine) at temperatures of around 193°C. The fluid is supplied from three production wells and reinjected entirely through 4 reinjection wells.

The normal ramp rate of a geothermal ORC turbine is approximately 15% of its nominal power per minute, via the heat source valve (6-4). Hence, each Ngatamariki 20.5 MW unit would take up to 7 minutes to ramp up to its nameplate capacity. We note that although potentially possible to ramp up / down, the Ngatamariki plant (as with most geothermal) is operated continuously for commercial reasons.

It is also possible to increase the ramp rate of an ORC turbine by increasing the geothermal primary fluid flow rate. However, this is not ideal operation, as doing so tends to shorten the lifespan of the geothermal resource and power generation plant. Unlike long-term schedulable operation, short-term dispatch will require further technology development and trials to allow successful adaption for geothermal resources to be utilised without compromising the life of the asset.

6.3.3.6 GEOGRAPHICAL AND LOGISTICAL CONSTRAINTS

NZ could build approximately 200 MW of new geothermal ORC Binary cycle generation across approximately 8 sites in NZs geothermal regions by 2030. It may be possible with NZ Battery-focussed consenting (similar to the RMA 'call in' processes) to allow up to around 350 MW new ORC Binary cycle plants to be built by 2030.

6.3.3.7 EFFICIENCY MEASURES

Due to the inherently stored nature of geothermal resources, the round-trip efficiency of other 'charge and discharge' energy storage technologies does not apply. One of the relative advantages of geothermal is that it does not need to be recharged like other technology options, as the energy is inherently stored (in the context of NZ Battery project recharge periods and assuming reinjection of fluids).

6.3.3.8 ENVIRONMENT AND SAFETY

Similar to the long-term schedulable technology option (Condensing flash plants and ORC binary cycle plants) the specific locations will influence the likelihood of gaining consent and, until investigated in further detail (I.e., in Task 2), all geothermal options have been considered Red or Amber.

6.3.3.9 REFERENCE PROJECTS

Ormat Puna, Hawaii Trial Flexible ORC / TES Plant: To improve the response time of geothermal power, Ormat has embarked on an investigation of integrating thermal energy storage with geothermal power generation (Thermal Energy for Dispatchable Geothermal Power Paper).

The concept involves utilising above-ground Thermal Energy Storage (TES) stored heat to provide a "buffer" for geothermal resources to respond more slowly and avoid flow instability issues, allowing more flexible load following operation These initiatives are currently in the early technology development stages, for example, a trial plant has been installed in Puna, Hawaii with limited results to date.

As discussed in section 6.1 above, New Zealand's geology tends to greatly reduce the apparent feasibility of utilising geologic (subsurface) thermal energy storage (GeoTES).

The Future Geothermal Generation Stack Paper lists two instances of technically successful implementations of geothermal resources to follow load:

- Tongonan I Plant: This plant in the Philippines is a 700 MW binary-cycle plant. However, it achieved load-following by discharging surplus steam into the atmosphere. This method pollutes the environment and depletes the geothermal resource. Hence, it is unlikely to be accepted in New Zealand.
- Poihipi Plant: This 55 MW plant in New Zealand, when first constructed, was bounded by Resource Consent constraints to limit its daily output. Hence generation was staggered by running at full capacity in the day (when spot prices were highest) and reducing generation in the night. However, this method of limiting generation at certain times of the day is economically inefficient, and the plant has since been purchased by Contact Energy, integrated into the Wairakei-Te Mihi steamfield, and operates at full capacity.

6.3.3.10 TECHNOLOGY IMPLEMENTATION

Challenges include:

- Traditional ORC binary cycle plants can be run in load following manner; however, in so doing, they pay a penalty in efficiency loss, resource degradation and plant life. To operate in a load-following manner sustainably (i.e., by continuously modulating the wellhead valves as opposed to local steam venting) would tend to decrease the expected life of the geothermal resource, due to thermal cycling and creation of mineral deposits, such as silica or calcite scaling - blocking the wells and rapidly decreasing their production rate and life.

- Potential mitigations are possible, such as building new process equipment, piping and plant with greater use of corrosion resistant materials (e.g. 316 stainless steel or Duplex) to improve their resilience to on/off cycling or load following generation, with an associated additional Capex requirement. Above ground TES may be an option (recommended for further investigation in Task 2), to optimise an ORC binary cycle's adaption to run in a load following manner.
- A geothermal plant undergoes many complex processes. To maximise both the resource and asset life, processes such as the fluid flow rate are carefully set to work efficiently with all parts of the plant. Controlled short-term (hourly) dispatch would require geothermal resources to ramp up generation frequently within a short space of time. The related sharp increases and decreases in fluid flow rate would tend to shorten the lifespan of the plant and geothermal wells.
- The opportunity cost of developing geothermal for long-term storage and removing from the generation stack optionality to build as baseload plant in a 'business as usual' scenario.
- Whether market participants have development rights to certain fields.

Opportunities include:

- Short-term dispatch using geothermal resources is deemed possible and worth further feasibility assessments if proceeding for further consideration as a technology option. It is proposed that geothermal energy (whether condensing flash plant or ORC binary cycle) as a NZ Battery option, is best utilised to be started up as required in a dry year to supply base load generation in a long-term schedulable operating mode.
- As explained in the long-term schedulable geothermal option above, building new flexible geothermal generation as a NZ Battery could, as a minimum, provide a 'no-regrets' option, in that it could defer the need to build a large-scale energy storage scheme, while other less developed technologies develop further.

6.3.4 COMMERCIAL VIABILITY

6.3.4.1 INTRODUCTION

Controlled, short term dispatchable geothermal generation is based on building only ORC Binary Plant as we expect that only ORC plant can be set up for flexible operation in a load following manner. This would be built to current standards with design and operational features, to allow short term load following flexibility.

Like other geothermal options, the total impact to the electricity system may include the removal from future generation expansion of the plant allocated to NZ Battery. Estimation of this wider economic cost is outside the scope of this part of the study but is likely to be the subject of analysis by the wider NZ Battery modelling team in future stages of the project.

Long-term geothermal power generation in NZ is a well-developed and cost-effective technology option. The commercial risk is relatively low and there are options for any plant to be transferred out of the NZ Battery programme to regular market operation.

6.3.4.2 COSTING SCENARIO

As with the other technologies, the geothermal costing scenario targets meeting 1 TWh of demand over a three-month period identified as a dry year. Dry years occur in 2032 and every five years subsequently.

Based on currently identified geothermal plant option, about 350 MW of ORC binary plant could be implemented by 2030. For the purposes of providing a consistent Whole of Life Costing basis, we have used a basis of 500 MW, which assumes that an additional 150 MW of new ORC binary cycle plant could be explored, found, and developed if geothermal energy were to be deployed as a NZ Battery solution.

The stations remain mothballed until required to meet a dry year energy shortfall. When a dry year occurs, the stations are de-mothballed, run flexibly (e.g. to optimise water use by the hydro stations) for three months, delivering 1 TWh to the electricity grid, then mothballed until the next dry year occurs. These stations operate in this manner in perpetuity from 2030.

6.3.4.3 KEY ASSUMPTIONS:

- 500 MW of ORC Binary plant with additional features for flexible schedulable operation is built to be available from 2030.
- Mothballing and de-mothballing each cost of Commercial Information
- No estimation of the impact of removing the opportunity to include these generation options to meet regular market demand increases after 2030 has been included.

6.3.4.4 ANALYSIS RESULTS

ITEM	COST	NOTES
Capex Total ($)	Commercial Information	Total build costs of the stations making up 500 MW
Capex ($/kW)		
Opex (per year)		sale of electricity in dry years exceeds operating costs
Whole of Life Cost ($)		
LCOE ($/MWh)		

6.3.4.5 ALTERNATIVE IMPLEMENTATIONS

Incremental de-mothballing. As the geothermal plant is a set of smaller plant sized from 5 to 150 MW, the plant can be de mothballed in a staged manner as the level of certainty around the dry year requirement increases. Similarly, the plants can be re-mothballed as the requirement decreases.

Hybrid geothermal stations with a mix of short and long-term schedulable stations may allow flexible dispatch without requiring all stations to be ORC Binary and set up for short term dispatch.

Return to market operation. Should circumstances change the geothermal plant designated for NZ Battery purposes can be returned to a normal commercial operation. All currently identified stations were expected to be in operation by [2060] so they could be used to delay commitment to other technologies.

6.3.4.6 COMMERCIAL VIABILITY DISCUSSION

Our analysis suggests that building long-term geothermal stations to address the dry year problem is the most cost effective of all options. However, building at least some short term dispatchable stations would also be commercially viable. The optimal mix would need to be determined by analysis that includes market operation.

Unlike the other options, once the plant is built and operating, there is no economic incentive to shut the station down in non-dry years. A NZ Battery "rule" would be required to signal that the plant should shut down until next required.

There is an economic cost to the electricity system from removing these options from the expected market driven generation expansion that has not been included in the cost analysis.

There is an economic benefit to being able to reverse the decision to include any or all NZ Battery geothermal stations by returning them to normal electricity market operation.

On a commercial viability basis only, it is not clear that any stations should be implemented as short term dispatchable, but this would be assessed further in next Tasks.

6.3.5 SWOT ASSESSMENT

Table 6-11: Controlled Dispatchable Geothermal ORC Binary (Flexible) SWOT

	Helpful to achieving the objective	Harmful to achieving the objective
Technology (source to grid)	STRENGTHS	WEAKNESSES
	• Mature technology, already well established and proven for baseload operation, with strong opportunity to develop additional flexible dispatch. • 'No regrets' by building new geothermal, optionality to switch in future from dry year cover to full time baseload. • Highly dependable plant • Operates with high capacity factors 90%+ • Full control over schedulability (long-term) unlike other Renewables such as solar and wind.	• Limited to ability to achieve 5 TWh (needs to be deployed in combination with relatively inflexible condensing flash plant to achieve this).
Operating Environment (external)	**OPPORTUNITIES**	**THREATS**
	• NZ can develop geothermal industry skills, exportable to rest of world. • Opportunity for NZ to develop flexible geothermal design & operation knowledge and skills. • Optionality to run as either long-term schedulable, flexible dispatchable, or as future baseload	• Supply chain of construction contractors and international OEM equipment to provide quantum of plant in time scales required. • Potential consenting / planning barriers across the relatively large number of separate developments required. • Opportunity cost of developing geothermal for long-term storage and removing from the generation stack optionality to build as baseload plant in a 'business as usual' scenario. • Whether market participants have development rights to certain fields.

6.3.6 DISCUSSION

Organic Rankine Cycle (ORC) Binary plants are considered to be the most suitable geothermal technology to provide flexible dispatchable (load following) generation. This would be an additional capability to providing long-term schedulable (on/off) operation. However due to the limits to the available pipeline of new ORC binary plant in NZ, using this plant type on its own would not be able to provide enough energy to satisfy the large-scale requirement for an NZ Battery (i.e. be capable of providing at least 1 TWh over 3 months). To meet the large-scale requirement, a combination of ORC Binary plants (designed with additional features to allow flexible and/or long-term schedulable operation) and condensing flash plants (designed with additional features to allow long-term schedulable operation) would need to be deployed.

While ORC binary geothermal power plants have traditionally been run as continuous baseload generation in NZ, if new ORC plants were designed from the outset to be operated as flexible schedulable (i.e. running at low load or mothballed in normal years and only run at full load in dry years, and then with the ability to also run in a short-term load following manner) then ORC geothermal appears to present a viable option. In particular, the above ground ORC binary power generation plant appears to be able, with further research, to be able to include additional design and operating features to allow operation in a load following dispatchable manner. There is, however, a higher level of risk associated with the ability of the subsurface geothermal reservoirs and reinjection wells to be operated in a flexible schedulable manner. While also not expected to be insurmountable, it is these subsurface aspects that are anticipated to be critical to determining geothermal's overall ability to be used for dry year energy back-up in the NZ Battery context.

Geothermal is a renewable energy source. The ORC option does release carbon emissions during electricity production, and more so than condensing flash plants due to its lower cycle efficiency (corresponding to the lower resource temperatures associated with ORC binary plants) However through a combination of site selections, as well as developments in geothermal carbon capture technology, these are expected to be able to be minimised to an acceptable level.

Relative to other options, the geothermal energy battery would need to be spread across more sites and locations (for example the ORC binary plants would be spread across over 10+ sites each ranging from 5 MW to 50 MWs in increments of capacity). There are some benefits to this including the ability to bring on the dry year reserve in 'chunks' of energy capacity. However, on the downside is that more locations requires more consenting efforts and potential complexity.

From an estimate costs viewpoint, short term flexible geothermal is a relatively low cost option, (albeit more expensive than condensing flash plants) even when considering the expected additional costs to modify designs and operation to make flexible schedulable. Of all the primary options considered, geothermal is closely connected to the currently available electricity generation market. A key consideration for further investigation is the potential market implications (and economic benefits and costs to NZ as a country) of bringing forward and building new ORC binary geothermal plants as a NZ Battery, that may otherwise have been built through normal market forces. The "flipside" of this risk is that it would be relatively straightforward to remove a plant from the NZ Battery system and add to standard market operation – even matching the timing to when the market forces would have seen it built. This "no regrets" opportunity could allow delay to commitment in technology providing the option value of allowing further development of other technologies.

6.4 CONTROLLED SCHEDULABLE GEOTHERMAL (VIA CLOSED LOOP)

6.4.1 PRIMARY OPTION INTRODUCTION

Closed loop geothermal technologies such as Eavor-Loop™ have also been considered. This emerging technology option is based on a closed-loop geothermal system within which a working fluid is contained, and is naturally circulated, via the thermosiphon effect of a hot fluid rising in the outlet well and a cool fluid falling in the inlet well. Figure 6-4 illustrates this process.

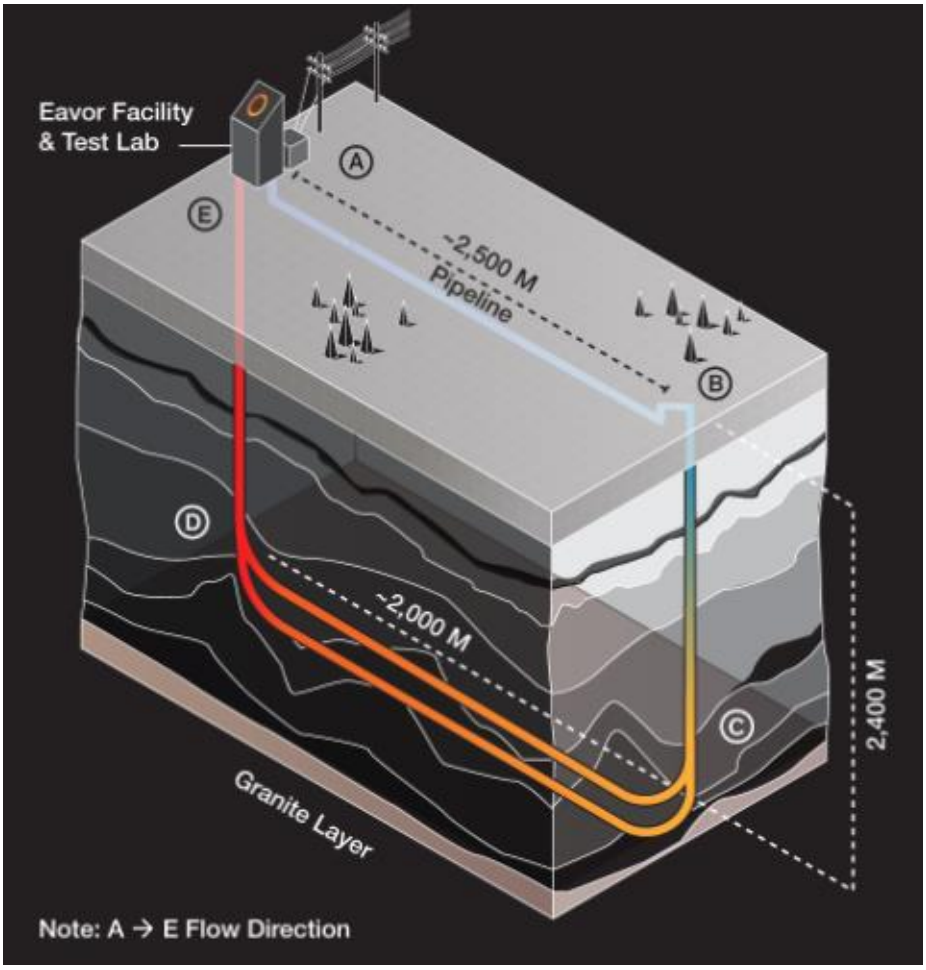

Figure 6-4: Schematic of the Derek Riddell Eavor-Lite Demonstration Facility at Rocky Mountain House, Canada

Source: Eavor, 2021

The concept involves connecting two vertical wells, several kilometres deep, with multiple horizontal multilateral wellbores several kilometres long, using Eavor-Loop™'s self-sealing rock pipe fluid (patent pending).

The concept for these types of system is a large heat exchanger, using a working fluid that is added to the system. As such, they do not rely on flow in a reservoir to bring the heat from the deep subsurface to ground level. The thermosiphon effect created by the closed-loop system means that there is no requirement for an external pump to circulate the working fluid – hot fluid naturally rises in the outlet well and thermal energy is harvested at the surface, and at the same time cold fluid falls in the inlet well.

Eavor states the following advantages of this emerging technology option:

- Simple – acts like a heat exchanger using a "working fluid"
- Schedulable – can charge during low demand periods and discharge during high-demand periods. Due to heat exchange type system, 'recharge' is faster than conventional geothermal which relies on reservoir fluid flow
- Highly scalable, as a permeable aquifer is not required

As well as using the extracted heat for electricity generation, other applications could include direct use such as district heating and cooling networks, particularly where population density is high, or heating and cooling for agriculture or industry. In non-permeable strata the typical resource temperatures at several kilometre's depth would tend towards being more suitable for direct use.

Other closed loop thermosiphoning geothermal power technologies are being explored globally (such as GreenLoop™, by GreenFire Energy Ltd). Eavor-Loop™ has been assessed as this is the most advanced.

6.4.2 TECHNOLOGY PATHWAYS

Table 6-12 presents a broad categorisation of the pathway options to use geothermal energy for the generation of electricity in a thermosiphoning closed loop system. In the table, **Bold text** represents the Preferred Pathway, Normal text represents Other Pathways, and Red text represents Discontinued Pathways.

Table 6-12: Geothermal Technology Pathways

	CONTROLLED SCHEDULABLE GEOTHERMAL (VIA THERMOSIPHONING CLOSED LOOP)
Energy Source	**Earth's subsurface heat (renewable energy)**
Storage	**Inherent storage**
Generation	**ORC binary using subsurface rock pipes (e.g. Eavor Loop™)**

Source: WSP

6.4.2.1 PREFERRED PATHWAY

This involves building new (thermosiphoning) closed loop geothermal generation, such as Eavor-Loop™ technology. With this pathway, the new geothermal NZ Battery plant would be turned down or mothballed into long-term preservation mode for normal years. It would then be ramped up in dry years and left to run as baseload continuously for 3 - 6 months (or longer if required), before ramping down the plant and potentially mothballing again until the next dry year period. This technology option, if it were to achieve technological advancement and the ability to operate successfully in NZ geologic conditions, may also provide an additional secondary benefit of the ability to provide flexibility for load following or shorter term dispatch if desired.

6.4.3 PRIMARY OPTION ASSESSMENT

Following the initial screening assessment, the Primary Option of Controlled Schedulable Geothermal (via Closed Loop) on the Preferred Pathway of building new thermosiphoning closed loop (e.g. Eavor-Loop™) plant has been considered for further analysis. Table 6-13 provides an indication of the degree to which this option meets the evaluation criteria.

Each geothermal technology option is scored based on a qualitative rating and quantitative evidence against the established RAG criteria defined in Appendix A. Our assessment against the Evaluation Criteria is explained further below.

Table 6-13: Geothermal Energy Options Assessment

CATEGORY	CRITERIA	CONTROLLED SCHEDULABLE GEOTHERMAL (VIA CLOSED LOOP)
Preferred pathway		Build new thermosiphoning closed loop (e.g. Eavor-Loop™)
Long-term	Between Dry Years Energy Storage	Inherently stored energy
	Storage Recovery	Unproven, in terms of heat extraction rate and impact on reservoir enthalpy
	Asset Life	Unproven
Large-scale	Min. 1 TWh	Unproven
	Up to 5 TWh	Unproven
	3 to 6 Months Output	Unproven
Renewable	Renewables	
	Operational carbon emission intensity	11.6 g CO_2eq/kWh[1] unproven
	Built carbon emission intensity	
	Sustainable Resources Risk	
Technology Readiness	Technology Readiness Level (2030)	5 Canadian geology 2 NZ geology
	Technology Ready for Commissioning (2030)	
Geographical and Logistical Constraints	Geographical constraints	Likely to apply to 'new' deep geothermal locations in NZ
	Subsurface Constraints	Unproven
	Transportation or Logistic Requirements	Unproven
Commercial Viability [2]	Whole of Life Cost ($)	High[3]
Efficiency Measures	Round Trip Efficiencies (2021)	N/A
	Round Trip Efficiencies (2030)	N/A
	Annual Storage Decay Factor	Unproven
Environment and Safety	Environmental or Regulatory Hurdles (Ability to obtain a consent)	[4]
	Environmental Risks	Unproven in NZ geology
	Safety Hazards Risks	

CATEGORY	CRITERIA	CONTROLLED SCHEDULABLE GEOTHERMAL (VIA CLOSED LOOP)
Reference Projects	Reference Projects	● One small scale pilot plant in non-NZ geology and no power generation
Technology Implementation	Global Market Trends & Context	●
	Commitment of OEM Suppliers	● Needs technology and international petroleum expertise for drilling, not currently licensed to operate in NZ
	Available International Market to Import Resources	● N/A
	Potential Implementation Bottlenecks	● Labour and equipment supply constraints (multiple sites) & IP for self sealing rock pipe system

Source: WSP

Notes on the option assessed

[1] Boundless Impact Research and Analytics Climate Impact Profile, June 2021. Eavor Technologies Inc. Geothermal Energy Industry (estimate based on Geretsried, Germany Eavor-Loop™ system, expected to be commissioned 2022)

[2] Based on Whole of Life calculation methodology applying consistent scenarios across all technologies.

[3] 'High' in the Whole of Life context equates to costs expected to be generally above $20B or with no commercially viable solution identified.

[4] Due to the high-level of innovation and uncertainty in this option, it is likely to experience high level of challenge and potential delays during consenting.

6.4.3.1 LONG-TERM

The asset life and system design life of emerging thermosiphoning closed loop technologies such as Eavor-Loop™ are unproven, particularly in NZ's seismic subsurface conditions. The asset system lifecycle would depend mainly on the subsurface components as they are less accessible and present higher challenges to maintain compared to the surface facility components.

Geothermal energy is inherently stored (or in other words is a renewable resource with thermal energy continuously replenishing the reservoir). therefore, once constructed as long as the geothermal reservoir fluids are extracted at the long-term sustainable rate, the long-term energy storage criteria is easily met. Due to this inherent energy storage, geothermal does not need to be recharged like other technology options, one of its key relative advantages.

6.4.3.2 LARGE-SCALE

Thermosiphoning closed loop geothermal generation, if it were to become sufficiently technologically advanced and ready for commercial scale deployment in NZ, may have the potential to be used to generate the large-scale energy needed for the NZ Battery project.

6.4.3.3 RENEWABLE

The geothermal resources considered in the NZ Battery Project context are all renewable, this is on the basis that the heat is extracted at the geothermal field's long-term sustainable rate, and any extracted fluids are reinjected, which is the case for a closed loop thermosiphon.

Eavor states that their technology has relatively low carbon emissions: "lifecycle emissions for Eavor's German Eavor-Loop system are estimated as 11.6 kg CO_2e/MWh energy produced".

6.4.3.4 TECHNOLOGY READINESS

A key factor in this criterion is that an example of a full Eavor-Loop system has not yet been constructed. This is likely to take place in Germany in 2022. Until now, only an Eavor-Lite demonstration pilot plant has been constructed in Canada, which has been in operation since 2019. This 'Lite' version plant has focused on establishing the thermo-siphon effect, and no power generation has been included in this plant. The fact that a full Eavor-Loop system has not yet been constructed (and not planned to be constructed in any regions sharing NZ's seismic, tectonic geology) highlights additional potential risks/challenges.

We believe that this option is outperformed by other, significantly more advanced and readily available, geothermal technology options. We already have enough conventional permeable volcanic zone reservoirs available that can, with relative ease, be utilised for geothermal electricity generation, using the conventional and well-established technologies of condensing flash plants and ORC binary.

6.4.3.5 GEOGRAPHICAL AND LOGISTICAL CONSTRAINTS

High risks are associated with the subsurface constraints of using this technology option in NZ geologic conditions. The Eavor Lite demonstration pilot plant has been constructed in a massive wedge of sedimentary rocks that is bound by the Rocky Mountains. This region has been home to a vast oil and gas industry since the 1940s. This site was selected because it has an ideal depth, geological formation, existing surface locations, conductive sediments with low porosity and permeability. These geological conditions allow for a site with controllable drilling parameters and uniform geology. There are expected to be significant constraints to locating similar suitable geologic conditions in NZ at the scale required for NZ Battery.

6.4.3.6 EFFICIENCY MEASURES

Due to the inherently stored nature of geothermal resources, the round-trip efficiency of other 'charge and discharge' energy storage technologies does not apply. One of the relative advantages of geothermal is that it does not need to be recharged like other technology options, as the energy is inherently stored (in the context of NZ Battery project recharge periods and assuming reinjection of fluids). While Eavor-Loop™ systems can be used intermittently (in which case the working fluid is 'recharged' by absorbing heat during no-flow conditions), this does not change the rate at which the geothermal resource heat is able to be extracted.

6.4.3.7 REFERENCE PROJECTS

- *Eavor Loop's Derek Riddell Eavor-Lite Demonstration Facility at Alberta, Canada* (Eavor, 2021). Has been in operation since 2019. This 'Lite' version plant has focussed on establishing the thermo-siphon effect and no power generation has been included in this plant
- *GreenFire Energy* successfully demonstrated their GreenLoop technology at Coso, California, USA, in 2019.

6.4.3.8 TECHNOLOGY IMPLEMENTATION

There is a high risk due to the unproven ability to maintain thermosiphon in fractured NZ geologic conditions. The Eavor-Loop concept relies on a completely airtight system to allow the thermosiphon to continue circulating in the long-term. The lateral subsurface passages (in the 'radiator' section) are not metallic pipelines, they are tunnels drilled in the rock and then lined with Eavor's patented self-sealing rock pipe fluid, to create a 100% airtight system. The Eavor-Lite pilot plant has been able to maintain thermosiphon in the local (Alberta, Canada) geology. This is unproven in a NZ context.

A high risk of long-term viability applies to the use of this concept in NZ's highly subvertical fractured subsurface conditions. These conditions may present significant challenges to maintaining an airtight system using a self-sealing rock pipe system, across multiple laterals, where one failure at a weak point between the substrate and the self-sealing rock pipe will break the thermosiphon.

Eavor is not currently registered to operate in New Zealand.

This technology has relatively low favourability because, in a NZ context, we already have enough conventional permeable volcanic zone reservoirs available that can, with relative ease, be utilised for geothermal electricity generation (and also due to the relatively low technology readiness level). Conventional flash plant or ORC binary cycle plants are expected to outperform thermosiphoning closed loop technologies in the NZ Battery context, in terms of costs, technology risk, and the practical ability to deliver large-scale, long-term energy storage.

6.4.4 COMMERCIAL VIABILITY

In our view, the cost of emerging thermosiphoning closed loop technologies is too high in comparison with other traditional geothermal options. Our view is based on the high costs related to drilling (particularly in a NZ context) and the quantum of drilling required (approximately 70-80 km of lateral rock pipe tunnels required per 10 MW of plant). On this basis we have assessed this option as not commercially viable.

6.4.5 SWOT ASSESSMENT

Table 6-14: Controlled Schedulable Geothermal ORC Binary (Flexible) SWOT

	Helpful to achieving the objective	Harmful to achieving the objective
Technology (source to grid)	STRENGTHS	WEAKNESSES
	• Full control over schedulability (long-term) unlike other renewables such as solar and wind. • Relatively small above ground footprint	• Low technology readiness: a full Eavor-Loop system has not yet been constructed. • High risk / uncertainty of technology being able to maintain thermosiphon in NZ's highly fractured seismic geologic conditions. • High relative cost due to significant drilling required
Operating Environment (external)	**OPPORTUNITIES**	**THREATS**
	• NZ can be an early adopter of a newly emerging technology, with related industry and deep drilling skills, exportable to rest of world. • Opportunity for NZ to develop flexible geothermal design & operation knowledge and skills.	• Supply chain of construction contractors and international OEM equipment to provide quantum of plant in time scales required. • Potential consenting / planning barriers across the relatively large number of separate developments required, in areas of NZ that have not traditionally been associated with power generation.

6.4.6 DISCUSSION

Thermosiphoning closed loop geothermal technologies such as Eavor-Loop™ have the potential to provide a new source of renewable energy, possibly at a scale globally comparable with wind and solar. However, the likelihood of this technology being suitable for NZ conditions, to cost-effectively satisfy the requirements of the NZ Battery project by 2030 is expected to be very low.

We believe that this option is outperformed by other lower risk, lower cost and more readily available geothermal power generation options in NZ. In the event that the thermosiphoning closed loop options such as Eavor-Loop™ succeed in achieving an advanced level of technology readiness, it is still likely to be only suited to the benign geologic conditions more readily found in countries that do not share NZs high levels of seismic activity. We already have enough conventional permeable volcanic zone reservoirs available that can, with relative ease and significantly less cost, be utilised for geothermal electricity generation, using the conventional and well-established technologies of condensing flash plants and ORC binary.

6.5 GEOTHERMAL SUMMARY AND RECOMMENDATION

The three key criteria of large-scale, long-term and renewable are all sufficiently satisfied by conventional geothermal electricity generation technology options. Desktop research and qualitative assessments indicate that NZ could build approximately 500 MW of new geothermal generation by 2030. This would provide at least 1 TWh of energy over 3 month period (assuming at least 90% capacity factor), satisfying the minimum energy requirement for the NZ Battery. One of geothermal's key advantages is its inherent energy storage, meaning it does not need to be recharged like other technology options, and can keep running if required to provide more energy in a dry year. In the above scenario the 500 MWs of geothermal could provide 4 TWhs of energy over 12 months. Whilst geothermal may face challenges to providing a 5 TWh solution by 2030, with NZ Battery focused consenting processes, there is potential for around 1000 MW to be built by 2030, doubling the delivered energy figures above.

6.5.1.1 GEOTHERMAL SCHEDULABLE (LONG-TERM)

Conventional condensing flash plants and ORC binary cycle plants can be run long-term schedulable (on/off), with incorporation of additional design and operating procedures (that would be investigated further if this option proceeds). Ideally the operators would have 1 - 2 months' notice, to ramp up the plant and then run as baseload continuously for 3 - 6 months (or longer if required as outlined above), then ramping down and potentially mothballing plant into a long-term preservation mode until the next dry year period. In this scenario, for example, the 500 MW of newly built power stations would consist of around 12 sites across NZ's known geothermal regions in increments of 25 MW, 50 MW, and 150 MW plants. These could then be brought on as required for dry years in controlled increments (e.g., in 25 – 50 MW tranches), depending on the extent of the energy gap.

6.5.1.2 GEOTHERMAL SCHEDULABLE (FLEXIBLE)

Conventional condensing flash plants and ORC binary cycle plants can both be run in a flexible, load following manner; however, both pay a penalty in efficiency loss, resource degradation and plant life by doing so. This applies particularly in the case of condensing flash plants.

ORC binary cycle plants would be more suitable, with further technology developments, to be run in a load following manner as, due to the heat being transferred to a secondary working fluid, the plant output may be more easily varied without having to vary geothermal fluid flows from the wells. However, in the NZ Battery context this may not be the most optimal option when considered amongst NZ's potential future generation mix. It may be more optimal, as a dry year response, to switch on the 'geothermal NZ battery' to provide the dry year baseload generation, and then use other technologies which are more suited to provide short term load following (such as hydro generation, flow batteries, or Battery Energy Storage Schemes (BESS) if deemed required.)

As ORC binary plants only account for around a third of the expected geothermal development pipeline, to meet the large-scale requirements of the NZ Battery Project, it is expected that a geothermal solution would need to involve development of both flash steam and ORC binary plants.

6.5.1.3 THERMOSIPHONING CLOSED LOOP

Due to the relatively low technology-readiness level of emerging closed loop geothermal technologies, such as Eavor-Loop™ and, with no systems planned to be constructed in any regions sharing NZ's seismic, tectonic highly fractured geology, conventional flash plant or ORC binary cycle plant options are expected to outperform closed loop thermo-siphoning in the NZ battery context.

6.5.1.4 OPPORTUNITY FOR GEOTHERMAL IN NZ BATTERY CONTEXT

The opportunity would be to build approximately 500 MW (and potentially up to 1000 MW) of new geothermal by around 2030. It would not be run at full capacity in a normal year, instead it would be run at low load (turned down) or maintained in a mothballed long-term preservation mode, reserved for dry years when needed. In other words, it would replace the fossil fuelled long-term schedulable / baseload plant NZ currently has, such as at Huntly and TCC.

If the forecasted possibility of a dry year energy gap became a high enough risk, the geothermal NZ Battery plant could be brought online in selected increments. Some could be brought on as baseload only (e.g. condensing flash plants) and others (e.g. ORC binary cycle) with the ability to provide some load following flexibility (noting that it would still be more optimal to also run the ORC binary plant as baseload, for best overall efficiencies, to maximise the resource life and minimise costs as aforementioned).

In this scenario, as NZ builds more Variable Renewable Energy (VRE) sources (such as wind and solar), their variability could be firmed using existing hydro's (which may be dispatched less conservatively, as the geothermal NZ Battery would remain in reserve for any low energy periods). Or the increased VRE could be firmed using new highly flexible short-term energy storage technologies, such as flow batteries (or BESS), hydrogen (if technology developed sufficiently by 2030) or pumped hydro. Noting that in this scenario, any new pumped hydro would not necessarily need to be as long-term or large-scale, because the long-term, large-scale energy back-up (not constrained by the long-term schedulable energy available), would be provided by the geothermal NZ battery.

This potential solution may, therefore, provide a 'no-regrets' option, in that it could defer the need to build a large-scale energy storage scheme, while other less developed technologies) develop further. It may also remove the need, or minimise the size, of any future energy storage scheme, due to a critical mass of VRE sources being built in future (noting more VRE generation is expected to be built regardless of any future pathway). A geothermal NZ Battery would provide the optionality to be switched in the future to run as a source of cost effective, renewable baseload generation.

Even if NZ built a large-scale energy storage scheme, we would still need to also build the new generation sources in the long-term, to provide the electricity to re-charge it within an acceptable timeframe. . Geothermal would allow the NZ Battery to provide both potential energy generation, as well as cover the requirement for energy storage - as geothermal is inherently stored and does not need to be recharged by other generation sources.

6.5.1.5 RECOMMENDATION

WSP recommends that the option described above, to build approximately 500 MW (and potentially up to 1000 MW) of new geothermal (as a combination of condensing flash plant and ORC binary cycle plant) by around 2030, proceeds for further investigation. As part of the further investigations we recommend including assessing the feasibility of designing and operating new condensing flash plant and ORC binary cycle plant in a long-term schedulable manner, covering aspects such as turndown operation, preservation methods for mothballing plant and minimising potential impacts on geothermal steamfield / reservoirs. And for the new ORC binary cycle plant portion, we recommend also investigating the feasibility of including additional features to enable flexible short term dispatchable operation.

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7 HYDROGEN OR OTHER GREEN ENERGY VECTORS

Within this section we consider and assess the potential to manage dry year risk using renewably produced hydrogen or derivatives of hydrogen (other green energy vectors, also known as hydrogen carriers) in the NZ Battery Project context.

7.1 HYDROGEN PRODUCTION WITH SUBSURFACE STORAGE

7.1.1 PRIMARY OPTION INTRODUCTION

Green hydrogen is being targeted globally as a critical enabler to decarbonize the energy system. Hydrogen is an energy carrier or energy vector and not an energy source.

The three Primary Options are described in the following sections and relate to different green energy vectors (also known as hydrogen carriers) that are formed from green hydrogen or that relate to the import of these energy vectors. Each Primary Option starts with the same common processes for green hydrogen production as described below, which is then converted as described in the subsequent section.

7.1.1.1 HYDROGEN PRODUCTION

Green hydrogen production technology internationally is growing and improving rapidly. There is a large amount of R&D and development trials underway across the globe. In the current preferred process, hydrogen molecules are separated from water through electrolysis. The primary plant for this process is an electrolyser unit as shown in Figure 7-1. Through this process electricity is used to break down the water into its elements.

There are three main types of electrolyser used currently:

- proton exchange membrane electrolysis (PEM),
- alkaline electrolysis (AE), and
- solid oxide electrolysers (SOEC).

These different electrolyser types, function in slightly different ways depending on the electrolyte material involved. PEM electrolysis and AE electrolysis are the most dominant electrolysers used in the market today, with the latter having been around for over a century.

The PEM electrolysers are targeted for this project due to their ability to produce high-purity hydrogen and relative ease to cool. They are best suited to match the variability of renewable energy sources and have a compact installation footprint.

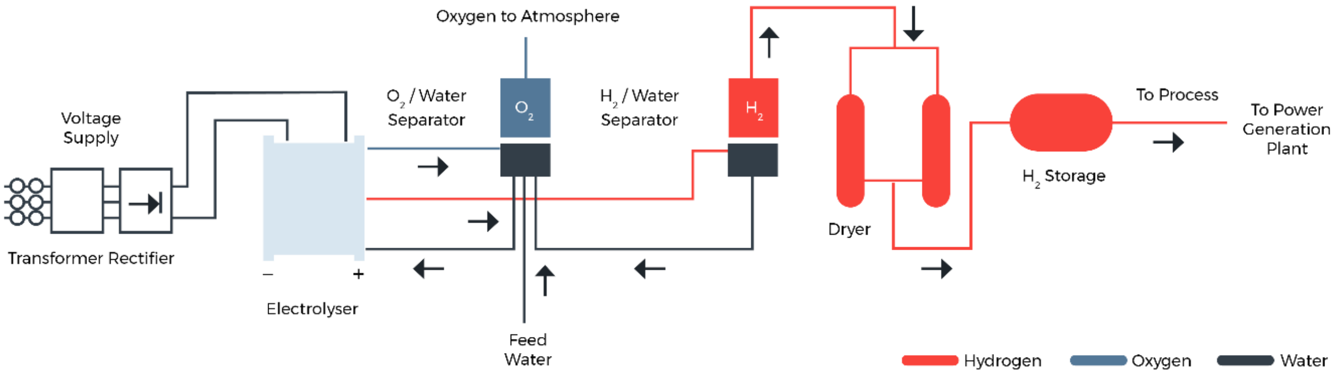

Figure 7-1: PEM Electrolysis process diagram graphic

Large-scale hydrogen electrolyser units (typically made of many stacks) require large quantities of high voltage grid power; the IEA notes that typically approximately 75% of the electrolyser operational costs are made up of the power supply costs. It is therefore, best to optimise the timing and use of the input electricity to be scheduled during periods when power demand and market prices are low. Large volumes of raw water are also required, (9 kg of water to make 1 kg of hydrogen typically), This feedwater must be processed to a high-quality grade (similar to boiler feedwater) via a site water treatment plant, prior to the electrolysers own water-conditioning equipment for each unit.

The output of this electrolysis process is high purity oxygen and hydrogen. The oxygen can be collected for other uses or vented to atmosphere. The hydrogen gas is available to use locally as a gas or for the next part of the production process to produce the required energy carrier product, where it may need pre-treatment to enable it to be supplied at a specific temperature and pressure. It may also need to be stored in pressurised buffer storage tanks, for subsequent process plant operational requirements. For instance, an ammonia synthesis plant generally requires production side operation, which will ideally enable this plant to operate continuously for periods of time. Buffer storage of the compressed green hydrogen allows the two different optional modes of these two plants, to work together.

Figure 7-2: 10 MW PEM electrolyser plant example in foreground

Hydrogen has been available in relatively small volumes in NZ for a long time. Most of it has not been produced from 100% renewable sources (non-carbon free) and is used in industrial sectors, ammonia synthesis plants and petroleum refining plants. Only recently has “Green Hydrogen” begun to be produced in NZ in any large volume. Firstly, by BOC producing hydrogen at Glenbrook from certified green electricity for use in the NZ Steel plant. Then shortly followed by Halcyon Power Limited, a joint venture between Tuaropaki Trust and Obayashi Corporation, who recently officially opened their 1.5 MW green hydrogen production plant adjacent to the Mokai 110 MW geothermal power station, near Taupō. Other small scale NZ green hydrogen developments are in the planning stages; however, these together are not expected to exceed 100 MW capacity for many years.

Green hydrogen blended with fossil fuels has not been considered as an option for this project, as a fully renewable generation solution is required for this study.

7.1.1.2 HYDROGEN SUBSURFACE STORAGE

Storage of hydrogen in a gaseous form can either be as pure hydrogen gas or via conversion to a hydrogen carrier or another gas such as renewable synthetic methane (CH_4). Hydrogen gas has not been commonly stored subsurface due to the high-volume storage requirements and its ‘slippery’ nature (hydrogen has the smallest of all gas molecules so presents extra challenges to long-term containment). 100% hydrogen gas can be used to generate electricity via:

- hydrogen fired steam boilers driving a Rankine cycle turbine
- direct combustion through modified gas turbines, (Combined Cycle Gas Turbine (CCGT) or Open Cycle Gas Turbine (OCGT))
- reciprocating engine driven generation units
- fuel cell generation units

As an alternative, by conversion of green hydrogen to renewable synthetic methane through a process called methanation as shown in Figure 7-3, the volumetric storage requirements can be reduced by approximately three times. The renewable synthetic methane can be directly fed through to gas turbine units, just as they would use natural gas.

The full process for using renewable synthetic methane for fuelling electricity generation plant is complex and involves the following facilities as shown in Figure 7-3:

- Green hydrogen gas production plant
- Hydrogen gas compressor and buffer storage vessels
- Renewable CO_2 capture plant (from renewable sources)
- CO_2 separation and cleaning plant
- Renewable CO_2 compression plant, buffer storage and transportation mechanism,
- Methanation and compressor plant
- Synthetic methane long-term subsurface storage
- Thermal generation plant

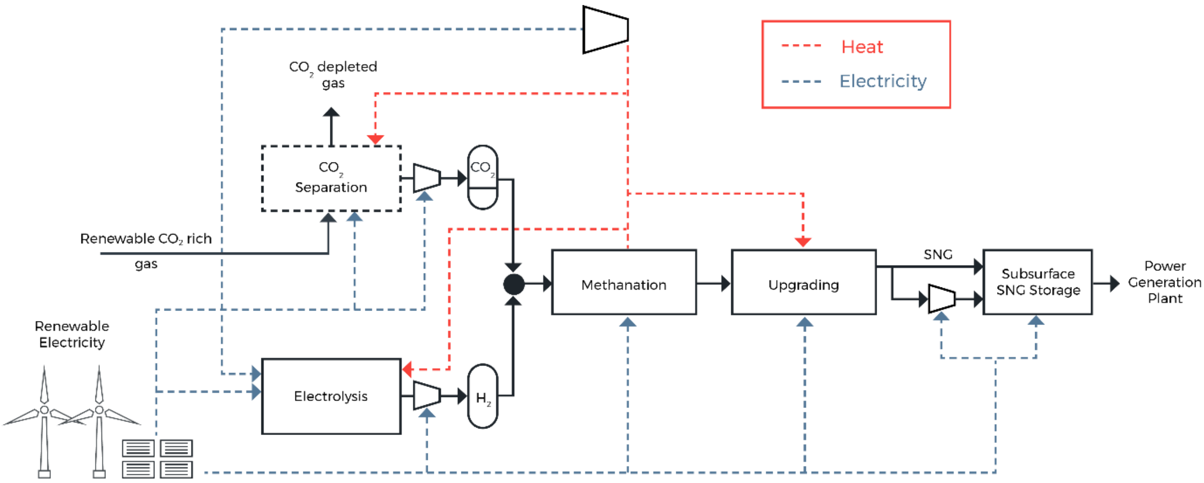

Figure 7-3: Synthetic methane process flow graphic

Methanation involves reacting captured renewable CO_2 with hydrogen over a catalyst and at high temperature. To ensure that the synthetic methane is 'renewable' the CO_2 used in the process needs to be from renewable sources. For example, this could be from a geothermal power plant where CO_2 is emitted in its process or from separation from biogas purification. The produced renewable synthetic methane has similar characteristics to that of conventional natural gas. Due to this similarity, synthetic methane can be stored long-term in storage facilities which are used for natural gas.

Due to its low relative energy density to other liquid organic hydrogen carriers (LOHC), (e.g., ammonia and liquid hydrogen), synthetic renewable methane is only considered suitable for domestic use, not as an import or export hydrogen carrier option.

7.1.2 TECHNOLOGY PATHWAYS

Table 7-1 presents a broad categorisation of the pathway options to use hydrogen technology for the generation of electricity via hydrogen production with subsurface storage. In the table, **Bold text** represents the Preferred Pathway, Normal text represents Other Pathways, and Red text represents Discontinued Pathways.

Table 7-1: Hydrogen Technology Pathways

PRIMARY OPTION	HYDROGEN PRODUCTION WITH SUBSURFACE STORAGE
Energy Source	**Renewable energy** **Raw Water** **Renewable CO_2**
Energy Vectors / Conversion	Hydrogen Gas **Renewable Synthetic Methane**
Storage	Above ground storage tanks/vessels (pressure) **Subsurface storage facilities**
Generation	**Gas Turbines (OCGT or CCGT)** Fuel Cell Reciprocating Engine Steam Boiler

Source: WSP

The initial production of hydrogen is common to all of the technology pathways so will always be considered as a Preferred Pathway for this assessment.

7.1.2.1 PREFERRED PATHWAYS

Renewable Synthetic Methane: Renewable synthetic methane is a hydrogen carrier, and its production technology (methanation) is readily purchased from companies including Johnson Matthey. It can also be transported, like natural gas, in vessels and pipelines. Synthetic methane has a higher density than hydrogen gas.

The CO_2 required for methanation could be sourced from renewable sources, such as geothermal plants, biogas plants, or Rankine cycle biomass plants fitted with amine-based post combustion capture technology. This complexity of requiring a large-scale renewable CO2 source in part contributes to the overall synthetic methane supply chain being at a relatively low scale capacity. Large-scale renewable CO_2 gas capture technology is relatively immature, and the purifying processes will require large amount of process electricity, depending on actual requirements, which will lower the round-trip efficiency of the overall process. It is also not certain exactly where the sources of the large amount of renewable CO_2 capture gas would be located relative to the subsurface gas storage facility location and/or generation power plant. Despite the uncertainties, renewable synthetic methane is considered the Preferred Pathway for this Primary Option as it represents the most feasible option when compared to storing hydrogen gas.

Subsurface storage facilities: Subsurface storage in depleted oil and gas reservoirs, such as the Ahuroa facility in Taranaki (currently approximately 15 PJ storage, but could be expanded to 50+ PJ), is deemed a possibility for large, long-term storage of synthetic methane due to its similarities to natural gas.

Gas Turbines: An advantage synthetic methane has over other hydrogen options is that it can be used to directly fuel existing natural gas fuelled OCGT's, CCGT's and reciprocating engine power generation units. For this study it is recommended that we specifically look at the use of CCGT plant, as they are a larger scale and more efficient than Rankine, OCGT units and reciprocating engine driven power generation plants.

7.1.2.2 OTHER PATHWAYS

Reciprocating Engine: Currently reciprocating engines driving generators tend to be in the smaller size ranges, 200 kW to 10 MW, so are not considered as the Preferred Pathway for the basis of this assessment.

Steam Boilers: Steam boilers, where the hydrogen is combusted to produce heat and then steam, which is used to generate power via a turbine, are not considered appropriate for the scale of NZ Battery. Whilst large units combusting hydrogen for heat exist, they are typically petrochemical operations designed for direct heating rather than steam raising. Utilising hydrogen gas or synthetic methane as simple steam raising could be accommodated at reasonable scale, but efficiency is likely to be low, and the cost per unit of energy would also be significant. The technical maturity of this process is relatively low. For these reasons steam boilers have not been considered as a Preferred Pathway.

7.1.2.3 DISCONTINUED PATHWAYS

Hydrogen Gas: The challenge with storage of hydrogen gas is related to the large-scale volume requirements that are needed due to its relatively low energy density. It is uncertain if pressurised hydrogen gas can be effectively stored long-term in the required volumes in known New Zealand subsurface cavities. The study of hydrogen storage in the context of subsurface formations is ongoing. Global examples of subsurface storage for hydrogen rely on salt cavern formations, such as Teesside, UK and Texas, USA. For these halite formations the cavern wall has a very low permeability for hydrogen. Similar salt caverns are not present in New Zealand. Research is ongoing internationally into the use of depleted oil and gas reservoirs for hydrogen storage. However, their permeability and the subsequent loss of hydrogen is less well understood.

Due to the unproven ability to store hydrogen subsurface in NZ and the larger storage volume requirements compared to synthetic methane, hydrogen gas has not been considered further in this assessment. This NZ subsurface storage constraint is unlikely to be resolved in this project's timeframes.

Above Ground Storage: This is not deemed to be a viable option, as the storage tanks required to store 1 TWh of hydrogen gas (more than 1,000,000 m^3 at high pressure, e.g., 700 bar plus) would be prohibitively large and expensive. For smaller, local end use of hydrogen gas, above ground storage facilities may be viable in the future. Above ground storage of synthetic methane would also not be viable for the same reasons as above, just as natural gas is not commonly stored in large above ground storage tanks. (Although not a subsurface option, this pathway is stated here for completeness as it covers a theoretical hydrogen gas or synthetic methane storage possibility).

Fuel Cell: The fuel cell option is only applicable for the direct use of hydrogen gas, which has not been selected as the Preferred Pathway for this Energy Vector. It is therefore, not continued in our assessment.

7.1.3 PRIMARY OPTION ASSESSMENT

Following the initial screening assessment, the Primary Option of Hydrogen Production with Subsurface Storage on the Preferred Pathway of synthetic methane with gas turbines for power generation has been considered for further analysis. Table 7-2 provides an indication of the degree to which this option meets the evaluation criteria.

Each hydrogen carrier technology option is scored, based on a qualitative rating and quantitative evidence against the established RAG criteria defined in Appendix A. Our assessment against the Evaluation Criteria is explained further below.

Table 7-2: Hydrogen Green Energy Vector Options Assessment

CATEGORY	CRITERIA	HYDROGEN PRODUCTION WITH SUBSURFACE STORAGE
Preferred Pathway Assessed		Synthetic methane, gas turbines for power generation
Long-term Storage	Between Dry Years Energy Storage	
	Storage Recovery	
	Asset Life	80,000 hr electrolyser stack life
Security of Supply	Min. 1 TWh	
	Up to 5 TWh	Large amount of renewable CO_2 required
	3 to 6 Months Output	
Renewable Technology	Renewables	
	Operational Carbon Emission Intensity	
	Built Carbon Emission Intensity	
	Sustainable Resources Risk	
Technology Readiness	Technology Readiness Level (2030)	Large-scale Renewable CO_2 CCS new to NZ
	Technology Ready for Commissioning (2030)	Renewable CO_2 CCS tech may still not be common in NZ
Geographical and Logistical Constraints	Geographical Constraints	May require multi sites, with additional CO_2 piping networks
	Subsurface Constraints	Ahuroa could be upgraded and/or converted
	Transportation or Logistic Requirements	Renewable CO_2 logistics uncertain
Commercial Viability [1]	Whole of Life Cost ($)	Commercial Information

CATEGORY	CRITERIA	HYDROGEN PRODUCTION WITH SUBSURFACE STORAGE
Efficiency Measures	Round Trip Efficiencies (2021)	31%
	Round Trip Efficiencies (2030)	31% & improving
	Annual Storage Decay Factor	
Environment and Safety	Environmental or Regulatory Hurdles (Ability to obtain a consent)	Some concerns
	Environmental Risks	Some concerns
	Safety Hazards Risks	Some concerns
Reference Projects	Reference Projects	
Technology Implementation	Global Market Trends & Context	New to NZ
	Commitment of OEM Suppliers	Plant availability may become constrained
	Available International Market to Import Resources	Green CO_2 availability
	Potential Implementation Bottlenecks	Large, complex construction sites

Source: WSP

Notes on the option assessed

[1] Based on Whole of Life calculation methodology applying consistent scenarios across all technologies.

7.1.3.1 LONG-TERM

A crucial requirement of this project is a large storage capacity combined with high charge/discharge rates. Synthetic methane can fulfil this requirement over long periods.

Synthetic methane is expected to be able to be stored long-term within subsurface gas storage facilities such as the Ahuroa Underground Natural Gas Storage facility in Taranaki. It would require commercial arrangements to be set up with current owners of NZ gas storage facilities.

7.1.3.2 LARGE-SCALE

Synthetic methane is practically the same as natural gas, and as a result the storage and delivery infrastructure is largely in place at the large-scale required.

The largest planned global plant for synthetic methane will be only around 6%of the required size of the 1 TWh scenario plant for this project (mid 2020's commissioning). The scale required for this project is 17 times larger than anything currently planned globally., which would present a key risk. – Reference: MeGa-stoRE and Vantaa Energy projects.

This option has some security of supply concerns due to the availability of purified renewable CO_2 availability and technology-readiness in NZ. With increased green CO_2 capture, storage and transportation opportunities likely in NZ beyond 2030, this concern may be mitigated. More investigation is required. Options for renewable CO_2 capture are discussed further under Technical Readiness.

7.1.3.3 RENEWABLE TECHNOLOGY

This process can be considered a renewable technology assuming renewable CO_2 can be sourced at the volumes required and then cleaned to the required specifications.

7.1.3.4 TECHNOLOGY READINESS

Green hydrogen production via electrolysis is a mature process.

The production of high voltage power from gas turbines fuelled by synthetic methane is also a mature process.

Methanation

The methanation process has been used to create synthetic methane for many decades. Production facilities exist worldwide, but as yet not at the large-scale that would be required for this project. Existing global plant for synthetic methane production is currently only 5% of the required size of the 1 TWh scenario for this project. The technology is available from multiple process technology providers such as Johnson Matthey, Axens, Shell and Thyssenkrupp Industrial Solutions.

CO_2 capture

The technology readiness of the CO_2 capture at geothermal power plants is not proven. The three options that could be considered for sourcing 'renewable' CO_2 are from biogas purification, and geothermal energy plants, or biomass Rankine cycle plants fitted with post combustion capture technology. These are not considered 'regular' carbon capture plants, which would typically be extracting the CO_2 from the exhaust gas stream from a power plant ('post-combustion capture'). or industrial process. The technology for renewable CO_2 is not considered to be mature, however options are:

- For biogas purification, there are a range of technologies that are commercially employed to separate CO_2 from methane, and these include the use of amine solvent-based separation, similar to what is used for post-combustion capture.
- Geothermal sites currently emit the renewable CO_2 from their processes into the atmosphere or reinject it back into their geothermal reservoirs. A developing technology is CO_2 recovery from geothermal energy – essentially producing carbonated water, with the CO_2 produced from the solution after depressurisation at the surface. The process used will depend on the configuration of each geothermal plant. The CO_2 is then compressed and dehydrated ready for transport or use.

It is likely there would be a requirement for significant buffer storage of CO_2 at both ends of the transportation route. However, this would incur significant Capex.

7.1.3.5 GEOGRAPHICAL AND LOGISTICAL CONSIDERATIONS

It is clearly preferable for the supply chain to be in physical proximity, i.e., renewable CO_2 source, electrolysis, methanation, subsurface storage and generation to all be in one location or general area.

If the generation facility was located at a different location to the large-scale subsurface storage facility, additional supply infrastructure for the synthetic methane gas would be required. Existing natural gas pipeline infrastructure could be converted over to synthetic methane if they were not required for natural gas reticulation (blending is not considered appropriate for this project). As with the storage facility this would require commercial arrangement with current owners else new gas pipelines or transport by road, rail or ship would be required to supply fuel to the power plant.

The renewable CO_2 could come from a biomass plant or geothermal station. If there was a need to transport CO_2 between sites, then a pipeline would be the optimal option. There are two options for pipelines - gaseous phase pipeline operating at around 30 bar pressure or a dense phase pipeline at >100 bar operating pressure. While the dense phase requires a smaller pipeline, the perceived safety risks may mean that gaseous phase is preferred. With pipeline transport, hopefully one could avoid the need for significant (or any) buffer storage at either end. The pipeline itself provides a buffer through line pack that can be utilised if there are any short-term process interruptions at either end.

As an alternative to pipeline transport, the CO_2 can be liquefied for transport by road, rail or ship. For non-pipeline transport storage would need to be buffered at both ends of the transport route to facilitate cargo loading/unloading.

Other entities in NZ (such as Southern Green Hydrogen (SGH) and FFI etc.) are investigating both large-scale hydrogen production and export opportunities, which could compete for the same resources, in a similar timeframe as this NZ Battery project. For this option large NZ renewable power supply, water supply, production infrastructure, land and large grid connections could become a “pinch point”.

7.1.3.6 ENVIRONMENT AND SAFETY

Large-scale green hydrogen production sites are developing rigorous environmental and safety processes, which are deemed to manage site risk to an acceptable level. These sites will be considered hazardous sites, just as any gas site would be.

Synthetic methane production sites have similar environmental and safety processes as natural gas production sites, which are deemed to manage site risk to an acceptable level.

The generation site would be comparable to a natural gas fuelled gas turbine generation site. Scientists have warned that hydrogen could be a significant “indirect” contributor to the greenhouse effect when it leaks through infrastructure and interacts with methane in the atmosphere. So, to mitigate this environmental risk, hydrogen plant and infrastructure needs to be designed to minimise or eliminate any leaks or releases to atmosphere as much as practicably possible. There may be risks associated with fugitive methane emissions (which have more than 20 times the impact of CO_2 in terms of global warming)

7.1.3.7 REFERENCE PROJECTS

Green Hydrogen Production:

There are numerous green hydrogen plants proposed for the future. Here are just a few examples:

The Fukushima Hydrogen Energy Research Field in Japan is currently among the world’s largest hydrogen-production facilities and began operation in 2020. Equipped with a 10 MW hydrogen production facility, the plant is producing green hydrogen by utilizing electricity generated from solar panels arrayed around its perimeter.

The world's largest green hydrogen project is currently Air Liquide's 20 MW Bécancour facility in Quebec, Canada, which uses a PEM electrolyser supplied by US-based Cummins and is powered by local hydroelectricity.

Thyssenkrupp Uhde Chlorine Engineers have been awarded a contract to build an 88MW water electrolysis plant for Hydro-Québec, in Varennes, Québec, Canada. This plant is due for commissioning in late 2023.

Methanation to produce synthetic methane: The methanation process has been used to create synthetic methane for many decades. Production facilities exist worldwide, but as yet not at the large-scale that would be required for this project. The technology is available from multiple process technology providers such as Johnson Matthey, Axens, Shell and Thyssenkrupp Industrial Solutions. The following are project references:

- Jupiter 1,000, completed 2018, 1 MW of electrolysis (https://www.jupiter1000.eu/english) – CO_2 is being captured from a "nearby industrial site". Produces 25 m^3/h of methane. Considered a demonstration plant only, no plan to upscale. The NZ Battery project will be approximately 170 times this size.
- Power2Gas Hungary built a 1 MW commercial plant and plans to build a 10 MW upscaled plant but operates with different (proprietary) technology based on a microorganism.
- MeGa-stoRE: planned to scale up to a 10 MW electrolyser in 2035 after successful demonstrations. Scaling up of a smaller scale technology needs to demonstrate its performance before larger scale developments will proceed.
- Vantaa energy: 10 MW plant being built for commissioning in 2025. (http://www.hydrogenfuelnews.com/power-to-gas-plant-finland/8547237/) – 10 MW of fuel output approximates to 40 MW of electrolysis, still not on the same scale. Project is currently an agreement of cooperation only, FID decision unknown. The NZ battery project will be approximately 17 times the size of either of these.

7.1.3.8 TECHNOLOGY IMPLEMENTATION

The captured renewable CO_2 required for methanation can be sourced from renewable sources, such as geothermal plants, biogas plants, or Rankine cycle biomass plants fitted with amine-based post combustion capture technology. The challenges with the capture, cleaning, processing and transportation of the renewable CO_2 will be significant. This complexity of requiring a renewable CO2 source in part contributes to the overall synthetic methane supply chain being at a relatively low technology readiness level.

Large-scale synthetic methane production could become common in NZ and has the potential to increase in the future. Currently it is very small in scale in NZ. Synthetic methane production is currently being looked at to substitute other existing fossil fuel gas use as a blended fuel and in so doing, helping to lower some carbon emissions from the industrial and transport sectors. However, this is a process outside of the scope of this project.

7.1.3.9 EFFICIENCY MEASURES

The Round-Trip Efficiency for synthetic methane is 31.2% which is the highest compared to other green energy vectors: Ammonia (22.8%) LOHC (18.3%) and liquid hydrogen (13.6%).

Overall, it is anticipated that the efficiency of all of the process plant areas will continue to improve in the near future. As more R&D is undertaken and the scale of manufacture increases, suppliers of these plant items need to stay competitive and show that their equipment is as efficient as possible.

The Round-Trip Efficiency is influenced by the different stages in the process, with estimated efficiencies as show in Table 7-3. (The renewable CO_2 capture and cleaning process efficiencies are not known or accounted for).

Table 7-3: Synthetic Methane – Round Trip Efficiencies

Process	SNG
Electrolyser (H_2 production)	65%
Methanation (synthetic methane production)	80%
CCGT (power generation)	60%
Round trip efficiency	**31.2%**

These figures do not currently account for any process at the renewable CO_2 capture facility, which is yet to be confirmed. Significant energy will be needed for CO_2 capture (amine regeneration step) and compression.

The production plant power demand loads can provide large-scale demand response options. The major production load which will be from the PEM electrolyser plant, which can operate extremely flexibly. The rest of the production facility will need to operate more base loaded for periods of time. So, buffer storage of compressed hydrogen will be required downstream of the electrolyser plant.

7.1.4 COMMERCIAL VIABILITY

7.1.4.1 INTRODUCTION

This option involves converting the Hydrogen produced from renewable electricity into Synthetic Methane.

Key advantages for Synthetic Methane are its similarity to Natural Gas (meaning NZ has significant experience in its storage, transportation and use for generation). In particular, a viable option may be to store synthetic methane subsurface in, for example, an exhausted gas reservoir.

Disadvantages mostly relate to the scale required for the NZ Battery project. Existing plant globally are 5% of the size that would be required. In addition, a large volume of “green” CO_2 is required; the CO_2 captured in the synthetic methane process is released when the methane is used so, to be a renewable energy source, the CO_2 used must be renewable. More investigation and cost analysis is required to determine the viability of sourcing, purifying and transporting large volumes of renewable CO_2 from the various renewable plant options, such as bio energy and geothermal plants, to production and/or generation site locations.

7.1.4.2 COSTING SCENARIO

As with the other technologies, the synthetic methane costing scenario targets meeting 1 TWh of demand over a three-month period identified as a dry year. Dry years occur in 2032 and every five years subsequently. To achieve these dry year requirements:

- A 366 MW electrolyser, hydrogen storage & methanation plant is built. This plant runs for two years to produce sufficient methane to produce 1 TWh of electricity in a dry year; Capital cost of Commercial Information and annual operating (excluding fuel) of Commercial Information
- A biomass Rankine cycle power plant is built with post combustion capture co-located with the methanation plant to supply the green CO_2 for methane production. Capital cost Commercial Information annual operating cost Commercial Information
- An existing underground storage facility is converted for storage of methane between dry years. Costs for conversion and operating the facility are included but no allowance is made for purchase or rental of the underground cavern; Capital cost of Commercial Information and annual operating cost Commercial Information
- A new CCGT plant is built ready to convert the methane to electricity. It is run for three months in each dry year. Capital cost Commercial Information and annual operating cost Commercial Information
- The methane production only occurs in non-dry years and only the first two years and for two years following each dry year. A 50% load factor is assumed.

7.1.4.3 ANALYSIS RESULTS

ITEM	COST	NOTES
Capex Total ($)	Commercial Information	Total build costs of equipment delivering 500 MW Generation Capacity
Capex ($/kW)		
Opex (per year)		
Whole of Life Cost ($)		
LCOE ($/MWh)		

7.1.4.4 ALTERNATIVE IMPLEMENTATIONS

There are several implementations that would be more cost effective than the scenario used for cost comparison. These upsides are not included in the modelling to allow the alternatives to be compared on an equal basis.

As synthetic methane has very similar fuel properties to natural gas, it can be used to fuel existing gas turbines without major modifications. Stations currently using fossil fuels could substitute synthetic methane to allow them to extend their expected useful lives.

Synthetic methane could also be used as a pipeline fuel option in NZ. This could gradually or immediately substitute existing natural gas usage.

If production of the synthetic methane were extended for uses other than for meeting dry year demand then the increased utilisation of the plant could lower the effective cost. In this situation there would be an added benefit of providing a demand response. When electricity prices rise, the value of the gas would determine a maximum price at which the conversion to synthetic methane was economic and the electrolyser would stop drawing electricity to produce hydrogen. Operating the plant in this manner would require a number of design changes that would affect costs.

7.1.4.5 COMMERCIAL VIABILITY DISCUSSION

We consider the option to use hydrogen to produce synthetic methane to be commercially viable especially if some of the alternative implementations can be included.

However, considering the hydrogen possibilities as a group, we consider the ammonia option to be preferable. This is mainly due to the higher energy density of Ammonia which enables more efficient import and export possibilities and simplified storage (above ground).

7.1.5 SWOT ASSESSMENT

Table 7-4: Hydrogen Production with Processing and Subsurface Storage (Synthetic Methane) SWOT

	Helpful to achieving the objective	Harmful to achieving the objective
Technology (source to grid)	STRENGTHS	WEAKNESSES
	• Synthetic methane can be used and stored just as natural gas is currently. • Synthetic methane has the highest round-trip efficiency (31.29%) of all the hydrogen production options being looked at. • Synthetic methane can be used to directly fuel gas turbine generation plant. • Plenty of workforce experience with the end product fuel and the infrastructure associated with this gas.	• Large quantities of renewable CO_2 are required for the synthetic methane process plant, which would likely require considerable gas purification at the capture source. • The source of the required renewable CO_2 (biofuels or geothermal plants) is likely to be at a location separate to the subsurface storage and generation facilities. therefore, additional transportation or pipeline infrastructure may be required. • Round-trip efficiency of 31% low when compared to other NZ Battery options • 371 MW of renewable energy over a 2-year production period is needed to produce fuel for a 500MW renewable "dry year" generation output. • High Capex costs for required infrastructure. • Large-scale production is not currently undertaken in NZ and is a maturing process at large-scale. • Existing global plant for synthetic methane production is currently only 1/20th the required size of the 1 TWh scale scenario for this project.
Operating Environment (external)	OPPORTUNITIES	THREATS
	• Renewable CO_2 could be sourced in conjunction with the development of a large-scale bioenergy development (as a part of the NZ Battery Project). • If the CO_2 could be supplied in Taranaki, the whole fuel processing, storage and generation facility could be located at the Ahuroa site. • The hydrogen and synthetic methane production plants can be shut down in periods of constrained power supply as hydro storage declines. This is an effective form of bulk load shedding which the System Operator can utilise. • Synthetic methane is currently being proposed to blend into the First Gas	• There is some public perception that as synthetic methane releases carbon back into the atmosphere during the generation process, that this is not an entirely green, emission free fuel. • The reliable supply of the large volumes of renewable CO_2 will be critical to the synthetic methane production process. • Synthetic methane is also currently being looked at to blend into existing Natural Gas networks and storage facilities (First Gas). This could create supply pressures, especially for the renewable CO_2 supplies. • Some new technology areas for NZ. • Investigation of any risks associated with fugitive methane emissions (which has a 20

	Helpful to achieving the objective	Harmful to achieving the objective
	Natural Gas pipeline network (re EcoGas – Reporoa AD Plant). This blending will reduce overall emissions levels as the blend percentages increase. In time 100% synthetic methane pipeline supplies may be possible. • Any excess gas production via an NZ Battery Project asset, could supply gas pipeline demand and create a revenue stream.	x CO_2 factor) will be required. (Task 2 activity) • Scientists have warned that hydrogen could be a significant "indirect" contributor to the greenhouse effect when it leaks through infrastructure and interacts with methane in the atmosphere. • Other entities in NZ are investigating both large-scale hydrogen production and export opportunities, which could compete for the same resources, in a similar timeframe as this NZ Battery project. For this option large NZ renewable power supply, water supply, production infrastructure, land and large grid connections could become a "pinch point".

7.1.6 DISCUSSION

Production of renewable synthetic methane is a viable option for the NZ Battery project. The primary strength it has as a hydrogen carrier is its similarity to natural gas. This allows it to be stored subsurface in depleted oil and gas reservoirs and take advantage of existing facilities and infrastructure should these be available for the NZ Battery project. The estimated volume of synthetic methane for a 1 TWh supply storage requirement is 1.4 million m^3 which is well within the storage capability of Ahuroa for example (refer section 8 for volumes). It also means that handling and safe working practices are well established in New Zealand.

In normal hydrological years, NZ is expected to have the surplus renewable energy resources required to locally produce the amount of synthetic methane needed for a 1 TWh supply option for NZ Battery. This is estimated at 371 MW for a 2-year production period. Shorter production periods or higher supply requirements above 1 TWh would push this demand up (at an extreme 5 TWh over 2 years would result in a load of 1,855 MW) and this would exceed the surplus renewable energy available putting additional load requirements on NZ. The balance between production rates and load on the NZ network would need careful consideration.

Renewable Synthetic Methane has the highest round-trip efficiency of all the hydrogen production options due to the higher efficiency of the methanation process and the fact that it can be directly fired in the gas turbine plant. This advantage is partially lost due to Synthetic Methane requiring a greater initial Green Hydrogen input to create the required storage volumes, pushing up the electrolyser load, but still results in a lower load that other hydrogen carriers.

The technology readiness for the synthetic methane pathway is reasonable with methanation a widely used process. However, there is a concern around the scale required for the NZ Battery project, with current reference projects 1/20th the size of a minimum 1 TWh requirement for this project. We have not seen evidence of projects moving towards the size needed for this project, representing a risk to the project.

A key challenge with renewable synthetic methane is the sourcing of large quantities of appropriate renewable CO_2 gas required for the methanation process. To produce the synthetic methane for a 1 TWh output option, for instance, a 45 MW biomass power plant would be required to provide the renewable CO_2 source requirement. It is envisaged that this could require multiple process locations for the end-to-end process, requiring a biomass facility for CO_2, a synthesis plant for methanation, and finally a generator to consume the synthetic methane. These would incur additional costs and consent requirement to link all the process locations together.

Capture of the carbon emitted by this biomass plant is a relatively immature technology, and while it does have potential to be developed globally, there is significant political push-back in certain areas (for instance, Germany). Furthermore, many consider carbon capture to be an already redundant technology, as in many cases it decarbonises industries which are already technically redundant (for instance, blue hydrogen). There may also be some level of public resistance to synthetic methane production in this manner – as the biomass plant is turning feedstock into electricity and CO2, which is then being converted into an intermediary chemical (synthetic methane), which is then being turned into electricity and CO2 again.

7.2 HYDROGEN PRODUCTION WITH CARRIER STORAGE

7.2.1 PRIMARY OPTION INTRODUCTION

Refer to section 7.1.1 for the production of green hydrogen. For carrier storage, the hydrogen is converted to another carrier medium more suitable for storage. This includes:

- Renewable synthetic methane (subsurface storage option described above)
- Green ammonia
- LOHC
- Liquified green hydrogen

7.2.1.1 GREEN AMMONIA:

Green ammonia has the benefit of a high hydrogen content by mass (hydrogen constitutes 17.65% of the mass of ammonia) and therefore has high energy density in comparison to gaseous hydrogen. By converting hydrogen to green ammonia volumetric storage requirements can be reduced by approximately three times, like synthetic methane. It can be liquefied at ambient temperature and moderate pressure (typically 10 bar, or by refrigeration at -35°C at atmospheric pressure). Combustion technology with direct use of green ammonia is proven in blended fuels for combustion turbines with major OEM's. These OEM's have stated an intention of confidence to develop the direct use of green ammonia in combustion turbines at a 100%. However, for the purposes of this study, we have assumed the cracking of ammonia back to hydrogen gas.

Ammonia synthesis is an established technology with commercial ammonia plants having been in operation for over 100 years, although this has traditionally used hydrogen from fossil fuels (non-carbon free) rather than from electrolysis using renewable electricity. Apart from the type of hydrogen used to produce the ammonia e.g., non-carbon free ammonia from fossil fuels, or green ammonia from renewable energy, the production processes and the end use of the ammonia is the same. The full process for using green ammonia for electricity generation is complex and involves the following steps as shown in Figure 7-4:

- Green hydrogen gas production plant
- Hydrogen gas compressor and buffer storage

- Green ammonia synthesis process plant, described further below
- Ammonia long-term storage
- Ammonia cracking plant to convert back to Hydrogen
- Combustion turbine generation plant

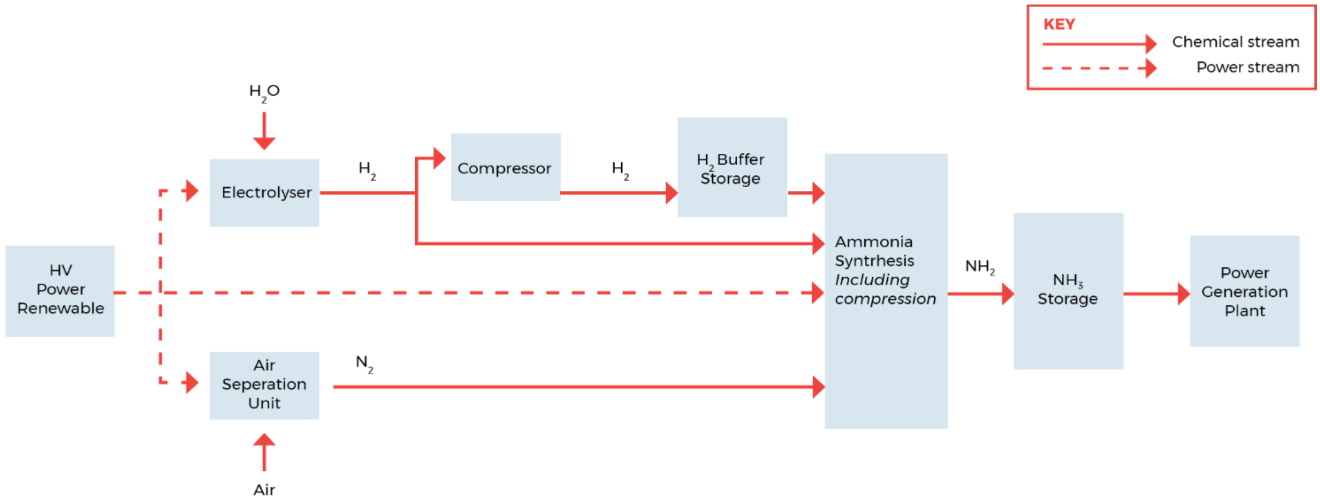

Figure 7-4: Green ammonia synthesis process flow graphic

The ammonia synthesis process, comprises:

- A cryogenic air separation unit for production of high purity nitrogen
- A main synthesis compressor compressing produced hydrogen and nitrogen to ammonia synthesis pressures (in the order of 150 – 200 bar).
- Synthesis typically via an iron catalyst, but some plants use ruthenium-based catalysts, at high pressure and high temperature (specific to each vendor). A significant recycle stream with associated recycle compressor is required to achieve near-complete conversion.
- Several heat exchangers are required to manage process temperatures noting the strong exothermic reaction

Stored ammonia can be decomposed (cracked) over a catalyst to produce hydrogen along with nitrogen a non-toxic, non-greenhouse gas. This high purity hydrogen can then be used to fuel a gas turbine power plant. Direct firing of ammonia in GT's is developing, but currently this technology is not considered mature enough for this project. This option would be the subject of further investigation as part of the next feasibility study steps.

All ammonia has an established distribution system, as it is already widely transported globally. The drawbacks are the energy penalty and capital cost of facilities for converting back to hydrogen, and the known risk factors for handling ammonia, including its highly toxic nature. As well as being converted back to hydrogen gas for generation, there is the possibility of using Ammonia to directly fuel the generation plant, which is a process currently under trials and development.

More technology option details are available in the next sections.

7.2.1.2 LIQUID ORGANIC HYDROGEN CARRIERS (LOHC)

LOHCs as a green energy vector are also a solution to the challenge of volumetrically efficient hydrogen storage solutions. In the LOHC process, hydrogen becomes chemically bound in a proprietary fluid, or LOHC, which carries the hydrogen safely. This allows the hydrogen to be stored in more compact, scalable systems at normal ambient temperatures and pressures, facilitating long-distance transport and long-term storage of hydrogen. Once the hydrogen is extracted from the LOHC, the carrier fluid can be recharged and used repeatedly.

Figure 7-5 shows the two-step process involved in the use of LOHC from hydrogen gas:

- Hydrogenation: loading of hydrogen into the LOHC molecule (i.e., hydrogen is covalently bound to the LOHC) through an exothermic reaction.
- Dehydrogenation: unloading of hydrogen form the host LOHC molecule through an endothermic reaction, which requires considerable additional renewable heat.

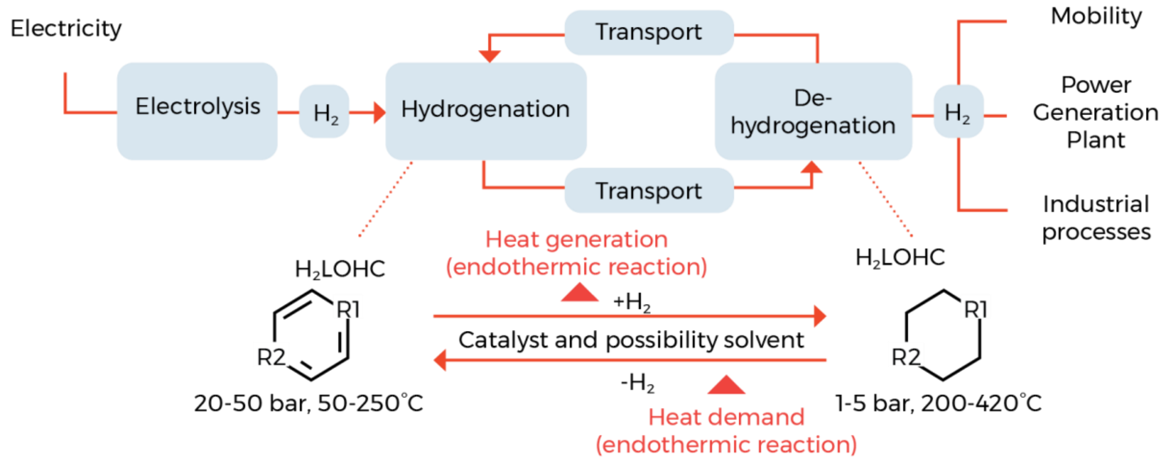

Figure 7-5: LOHC process flow graphic from the Royal Society of Chemistry7

7.2.1.3 LIQUIFIED GREEN HYDROGEN:

Gaseous hydrogen is liquefied by cooling it to below −253°C as shown in Figure 7-6. It can then be stored at a liquefaction plant in large, insulated tanks. It takes significant quantities of energy to liquefy hydrogen. Using today's technology, liquefaction consumes the equivalent of more than 30% of the energy content of the hydrogen and is also expensive.

In addition, some amount of stored hydrogen will be lost through evaporation, or "boil off" of liquefied hydrogen, especially when using small tanks with large surface-to-volume ratios. Research to improve liquefaction technology, as well as improved economies of scale, could help lower the energy required and the cost.

For long-term storage and/or transportation requirements, liquified green hydrogen is placed in large super-insulated, cryogenic tanks. For large-scale developments, this storage is expensive and takes up a large site footprint. Not currently deployed at scale.

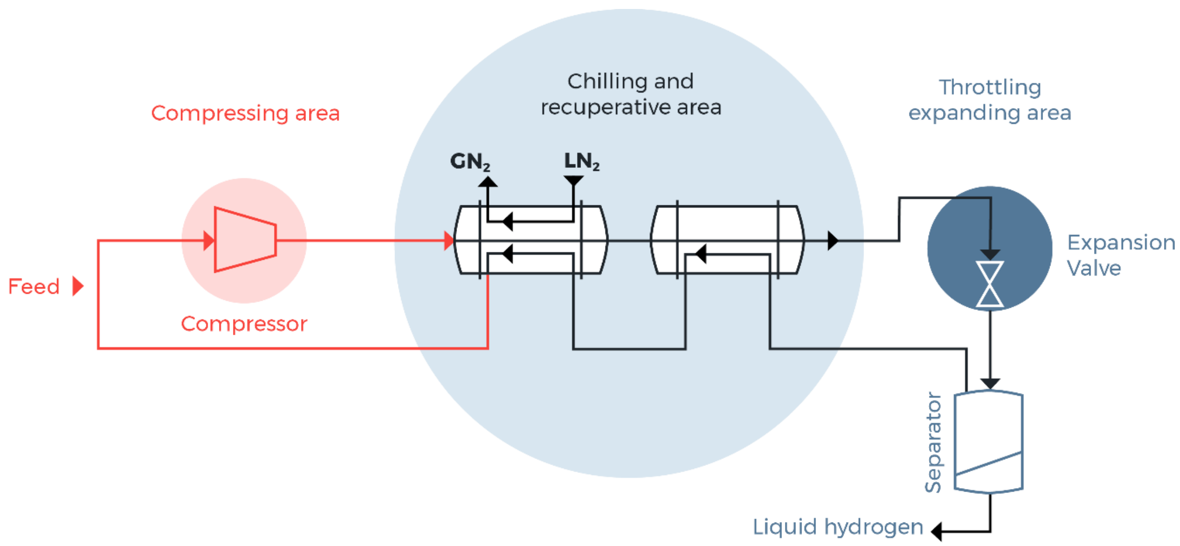

Figure 7-6: Liquified green hydrogen process flow graphic

7.2.2 TECHNOLOGY PATHWAYS

Table 7-5 presents a broad categorisation of the pathway options to use hydrogen technology for the generation of electricity through hydrogen production with carrier storage. In the table, **Bold text** represents the Preferred Pathway, Normal text represents Other Pathways, and Red text represents Discontinued Pathways.

Table 7-5: Hydrogen Technology Pathways

PRIMARY OPTION	HYDROGEN PRODUCTION WITH CARRIER STORAGE
Energy Source	**Renewable energy** **Raw Water**
Energy Vectors / Conversion	**Ammonia** LOHC Liquified Hydrogen
Storage	**Above ground storage tanks**
Generation	**Generation from hydrogen** Generation direct from Ammonia **Gas turbines (OCGT or CCGT)** Fuel Cell Reciprocating Engine Steam Boiler

Source: WSP

7.2.2.1 PREFERRED PATHWAYS

Green ammonia: The process to produce ammonia from green hydrogen is the same as the current common technology for fertiliser production from fossil fuels (non-carbon free), except that the hydrogen used is renewable, instead of being produced by breaking apart hydrocarbons. The hydrogen is reacted with nitrogen in the Haber-Bosch process to produce ammonia.

Stored ammonia can be decomposed (cracked) over a catalyst to turn it back into hydrogen and nitrogen. This process requires significant energy input, as well as a large reactor mass and volume. The high purity hydrogen gas is then able to fuel a combustion turbine driven power generation plant. It is worth noting that the leading OEM suppliers for combustion turbines (prime mover) are considering direct combustion of ammonia and/or hydrogen as the fuel of the near future.

Ammonia is a product which is currently produced, stored and transported in NZ and around the world in large quantities. It therefore, has an established distribution system. The ability to convert green ammonia back to hydrogen gas allows it to be used as a 100% renewable fuel source and this technology is improving rapidly. The drawbacks are the energy penalty and capital cost of facilities for converting back to hydrogen, and the known risk factors for handling ammonia, including its highly toxic nature.

Green ammonia is emerging as the hydrogen carrier of choice by many parties around the world and dominates the current wave of hydrogen export projects. Ammonia is currently preferred for three reasons: its energy density; its proven synthesis technology and existing supply chains. In NZ we need ammonia for fertilizers and will keep making it, so it has to be made without fossil fuels in the future, to help meet NZ's emission reduction targets.

As reported recently by the Wood Mackenzie's Hydrogen Project Tracker, more than 85% of international export-oriented low-carbon hydrogen projects plan to ship ammonia, not hydrogen.

Green ammonia is considered more technically mature than the alternative hydrogen carriers and therefore, able to meet the requirements of the NZ Battery project.

7.2.2.2 OTHER PATHWAYS

Liquid Organic Hydrogen Carrier: LOHC is another solution to the long-standing problem of a lack of volumetrically efficient energy storage solutions. Currently there are many countries looking to use LOHC as a fuel supply for backup power generation, but there are few large-scale production facilities. It is, therefore, unclear if this technology is sufficiently mature and scalable to meet the full requirements of NZ Battery by 2030. For the purposes of this assessment, it has not been considered as the Preferred Pathway at this stage.

Generation direct from Ammonia: Generation directly from ammonia is a possibility and the technology is improving. Some examples include:

- In March 2021, IHI burned a 70% liquid ammonia co-firing on a 2,000-kW turbine – has completed limited trials of 100% - plans to commercialise 100% ammonia fired turbines by 2025. (https://www.ihi.co.jp/en/all_news/2020/resources_energy_environment/1197060_2032.html)
- Mitsubishi Power is planning to develop a 40 MW turbine for commercial use by 2025. (https://www.argusmedia.com/en/news/2191814-japans-mitsubishi-developing-ammoniafired-gas-turbine)

The generation of electricity from ammonia is less favoured by the majority of international OEMs than generation from hydrogen gas. therefore, it has not been taken as the preferred pathway for this assessment. However, this may be considered further in subsequent studies.

7.2.2.3 DISCONTINUED PATHWAYS

Liquified Green Hydrogen: Liquefication of hydrogen consumes significant quantities of energy (the equivalent of more than 30% of the energy content of the hydrogen),is expensive and not appropriate for long-term storage. The Round-Trip Efficiency of liquified hydrogen is 13.6%, which is the lowest compared to other green energy vectors: synthetic ammonia (22.8%), and LOHC (18.3%). In addition, hydrogen is lost through evaporation, or "boil off" during storage.

We consider that production of liquid hydrogen for power generation fuel storage is not practically able to meet the large-scale key criteria, or the practical and deliverable criteria of this project. There may also be too much boil off over a long storage period.

7.2.3 PRIMARY OPTION ASSESSMENT

Following the initial screening assessment, the Primary Option of Hydrogen Production with Carrier Storage using the Preferred Pathway of ammonia storage, and hydrogen gas turbines for power generation has been considered for further analysis. Table 7-6 provides an indication of the degree to which the option meets the evaluation criteria.

Each hydrogen carrier technology option is scored, based on a qualitative rating and quantitative evidence against the established RAG criteria defined in Appendix A. Our assessment against the Evaluation Criteria is explained further below.

Table 7-6: Hydrogen Green Energy Vector Options Assessment

CATEGORY	CRITERIA	HYDROGEN PRODUCTION WITH CARRIER STORAGE
Preferred Pathway Assessed		Ammonia storage, hydrogen gas turbines for power generation
Long-term Storage	Between Dry Years Energy Storage	🟢
	Storage Recovery	🟢
	Asset Life	🟡 80,000 hr electrolyser stack life
Security of Supply	Min. 1 TWh	🟢
	Up to 5 TWh	🟢 Better if supplemented by imported ammonia
	3 to 6 Months Output	🟢
Renewable Technology	Renewables	🟢
	Operational Carbon Emission Intensity	🟢
	Built Carbon Emission Intensity	🟡
	Sustainable Resources Risk	🟢
Technology Readiness	Technology Readiness Level (2030)	🟢
	Technology Ready for Commissioning (2030)	🟢

CATEGORY	CRITERIA	HYDROGEN PRODUCTION WITH CARRIER STORAGE
Geographical and Logistical Constraints	Geographical Constraints	Single Energy Hub site possible
	Subsurface Constraints	NA
	Transportation or Logistic Requirements	
Commercial Viability [1]	Whole of Life Cost ($)	Commercial Information
Efficiency Measures	Round Trip Efficiencies (2021)	23%
	Round Trip Efficiencies (2030)	23% & improving
	Annual Storage Decay Factor	
Environment and Safety	Environmental or Regulatory Hurdles (Ability to obtain a consent)	Hazardous storage and transportation
	Environmental Risks	Hazardous storage and transportation
	Safety Hazards Risks	Hazardous storage and transportation
Reference Projects	Reference Projects	Many
Technology Implementation	Global Market Trends & Context	Known capabilities
	Commitment of OEM Suppliers	Plant availability may become constrained
	Available International Market to Import Resources	
	Potential Implementation Bottlenecks	Large, complex construction sites

Source: WSP

Notes on the options assessed

[1] Based on Whole of Life calculation methodology applying consistent scenarios across all technologies.

7.2.3.1 LONG-TERM

Liquified green ammonia can be stored long-term in large above-ground full containment storage tanks, similar to those used for storage of LNG. These storage facilities will require careful safety design and planning to mitigate effects of this hazardous product.

7.2.3.2 LARGE-SCALE

Ammonia synthesis and cryogenic air separation (ASU) are both conducted at large-scale globally using fossil fuels. What is missing is the integration with green hydrogen from electrolysis to manufacture green ammonia. The conventional fossil route has significant energy export from reforming processes.

A simulation of ammonia synthesis production facility, with green hydrogen inputs, requires electricity inputs of the following:

For a 600 MW total input load facility, the estimated load breakdown is 568 MW electrolysis, 24 MW synthesis plant, 8 MW nitrogen ASU.

Production: In international terms, the plant required for the NZ Battery project requirements is very large.

The largest current planned plant for green ammonia will only be 1/20th the required size of NZ Battery Project requirements (2030 commissioning).

The largest existing (closest large-scale example found) plant for green ammonia is currently only 1/3rd the required size for NZ Battery Project requirements however the expectations are for growth in both production and size of plant.

Global market for green ammonia typically forecast to follow a logarithmic trajectory, from (next to nothing now) and approaching USD10b in 2030.

Storage: The storage of ammonia is well understood and a highly mature technology. Large volumes of locally produced liquified green ammonia can be stored in large above-ground storage tanks. These tanks are similar in design to LPG full containment tanks.

For ambient temperature storage applications, the ammonia is held at pressure, typically 8-12 bar and typically, in pressure vessels or Horton spheres. The other option is for storage at atmospheric pressure, which requires the liquid to be cooled below the boiling point -33.3°C and managed similarly to that of liquified natural gas (LNG), where the fluid is chilled and gas evolving due to ambient temperature is collected and cooled again.

For larger volumes of storage as required for this project, the storage at pressure would require significant numbers of spheres or pressure vessels that would cover a large footprint. Whereas, for liquified green ammonia, refrigerated storage, like LNG, can occur in large, full containment, cylindrical tanks with multiple insulating layers utilising lower footprints and typically lower Capex costs per tonne. So, this is the option we recommend is investigated further for this project.

World-scale LNG storage tanks have capacities of around 200,000 m^3, shown in picture below. Using this size of tank for ammonia should be relatively straight forward, refrigerated liquid ammonia storage tanks have more typically been built up to 50,000 m^3 scale. The best configuration would need to be determined during more detailed studies.

Regarding storage, a 1 TWh supply option is estimated to require 391,000 m^3 of ammonia and a 5 TWh supply option, 1,955,000 m^3. The largest existing ammonia storage site globally (in Qatar) has a capacity of 146,000 m^3, approximately 1/3 of the storage required for a 1 TWh solution. Large, specially designed above-ground storage tanks (full containment, double-walled, refrigerated tanks with integrated recovery of ammonia boil-off gas, similar to LNG tanks commonly used) are required to store liquid ammonia, which is highly toxic in both gaseous and aqueous forms. These are mature technologies, but would require careful consideration of safety, environmental, seismic, geographical and logistical design requirements to mitigate these hazards. It is noted that large scale facilities used for LNG applications with similar storage tank design requirements exist globally. For example, Korea Gas Corporation (KOGAS) with initial 36 LNG storage tanks in Korea has a total LNG storage capacity of approximately 4,600,000 m^3.

World-scale LNG storage tanks typically have capacities of around 200,000 m^3, shown in picture below. Using this size of tank for ammonia should be relatively straight forward, refrigerated liquid ammonia storage tanks have more typically been built up to 50,000 m^3 scale. The best configuration would need to be determined during more detailed studies.

Figure 7-7: Liquid ammonia insulated storage tank example

There are options to supplement local ammonia production and storage with imported green ammonia (internationally certified). Excess/surplus product could also, as an option, be exported on the expected global green ammonia market.

Hydrogen to Ammonia Plant Buffer Storage: We can assume that the ammonia synthesis plant will be sized for the same overall load factor as the electrolysers, albeit with some mismatch in when they operate.

To allow for the reduced flexibility of the ammonia synthesis plant, the site will require a buffer store of compressed hydrogen. Currently we estimate a 12 hour buffer store of compressed hydrogen, to even out the supply to the ammonia synthesis plant during periods of intermittent operation of the electrolysers being supplied from variable off peak power supplies. This plant sizing optimization will be undertaken in Task 2.

7.2.3.3 RENEWABLE

This technology is renewable when produced using renewable electricity supplies

Hydrogen to ammonia and conversion back to hydrogen in large-scale for generation is a maturing green process and the scale of the plants is increasing.

7.2.3.4 TECHNOLOGY READINESS

Green hydrogen production via electrolysis is a mature process.

Ammonia synthesis, liquification and bulk storage is also a mature process. These processes do not change for green ammonia.

Technology to fuel CCGT generation plant on 100% hydrogen gas is maturing and is in operation currently globally.

Direct firing of ammonia in CCGT generation plant is developing currently but is not yet mature at the scale required for this project.

Ammonia cracking

Ammonia can be decomposed (cracked) over a catalyst to produce the desired fuel. Ammonia cracking plant is at pilot/small scale demonstration scale presently, not high maturity, but is expected to mature by 2030.

Recently a larger scale demonstration green ammonia cracker plant, the first of a kind, capable of producing 200 kg/day of hydrogen in a single step has been announced. This plant is anticipated to be able to demonstrate the performance and economics of this larger scale solution.

A viable option may be partial cracking that would improve cycle efficiency and reduce Capex by scaling down the cracking to, say, 70% of the fully cracked scenario.

A blend of 70% ammonia + 30% cracked ammonia can burn well in a conventional natural gas burner with very low ammonia slip and acceptable NOx using a stoichiometric fuel-air mixture. This will be considered further in Task 2. Refer https://www.ammoniaenergy.org/articles/cracking-ammonia-panel-wrap-up-from-the-ammonia-energy-conference/.

Generation from high hydrogen fuel is a rapidly developing technology with OEM's such GE having 100 plus gas turbines in operation around the world running on hydrogen of various blends and ratios. GE's fleet of gas turbines installed for operation on high hydrogen fuels includes more than a dozen Frame 5 gas turbines and more than twenty 6B.03 gas turbines. Many of these turbines operated on fuels with hydrogen concentrations ranging from 50% (by volume) to 80% (by volume). One example of a gas turbine operating on a high hydrogen fuel is a 6B.03 operating at a refinery in South Korea. A second example of a high hydrogen turbine is at Enel's Fusina, Italy facility. This plant, which was inaugurated in 2010, used a GE-10 gas turbine to produce ~11.4 MW of net electrical power operating on a fuel that was ~97.5% (by volume) hydrogen (ref GE's Hydrogen for Power Generation https://www.ge.com/gas-power/future-of-energy).

7.2.3.5 GEOGRAPHICAL AND LOGISTICAL CONSTRAINTS

Large specially designed storage facilities with hazardous materials site precautions would be required, at appropriate locations.

Ammonia conversion back to hydrogen can be performed at the power plant site. Sufficient space needs to be available for the ammonia storage, cracking plant, etc, while making allowance for necessary separation distances to account for ammonia/hydrogen hazards. therefore, for some existing power station sites, there could be an issue regarding space availability.

With the main ammonia storage adjacent to the power plants, ammonia transportation is at a modest rate throughout the 2 year production period (otherwise you would have to transport all the ammonia within the 3 month operating window of the power plant). For transport of ammonia within NZ, then several options exist:

- Pipeline
- Road
- Rail
- Coastal Shipping

With further investigation, an option may be to produce the green ammonia in the South Island (such as Southland where a large grid connection/energy load currently is operating with a possible planned shutdown window), and then use coastal shipping to transport the ammonia to a North Island port. This could be a deep-water port such as the Port of Taranaki or Marsden Point, Northland.

If imports or exports of green ammonia are to be considered, along with NZ production of green ammonia, there will also be benefits in locating plant near a deep-water port with adjacent industrial zoned land areas.

7.2.3.6 ENVIRONMENT AND SAFETY

Ammonia is a toxic chemical, and its production and handling in traditional sectors is regulated. It must be treated carefully as it is corrosive and may ignite / burn with explosive force. Poisonous gases are produced, and containers may explode, if a fire occurs.

The potential for release or spillage must also be managed carefully. Environmental issues can be caused during a containment event, due to its poisonous nature.

Ammonia production, storage and generation sites need specific location selection to ensure environmental and safety mitigations can be put in place (bunding, large buffer zone areas, etc.).

Scientists have warned that hydrogen could be a significant “indirect” contributor to the greenhouse effect when it leaks through infrastructure and interacts with methane in the atmosphere. So, to mitigate this environmental risk, hydrogen plant and infrastructure needs to be designed to be as leak free or release to atmosphere free as is possible.

7.2.3.7 REFERENCE PROJECTS

Green Hydrogen Production:

There are numerous large-scale green hydrogen plants proposed for the future. Refer to section 7.2.3.7.

Ammonia Production:

There are many existing operational and planned green ammonia plants up to a scale of 50 tonnes per day ammonia capacity.

- *The NEOM project* proposed by ACWA in Saudi Arabia intends to deliver a 4 GWe electrolysis-based green ammonia facility producing 1.2 million tonnes per year. Initial production is expected to be in 2025/2026.
- *H2U Eyre Peninsula Gateway Hydrogen Project,* South Australia, is the world’s largest green ammonia plant. This will include the installation of a 75 MW electrolyser, capable of producing enough hydrogen to create 40,000 tonnes of ammonia each year. The plant will also feature two 16 MW open cycle gas turbines operating 100% on hydrogen at the site to provide electricity generation to the grid during periods of low wind or solar output (7-12):
- *Andrew Forrest’s Fortescue Future Industries (FFI)* has proposed a 50,000 tonne a year green hydrogen and ammonia facility near Brisbane, the first of its scale in Australia. FFI’s plans for a green hydrogen revolution are bold: 15 million tonnes of green hydrogen per year by 2030, rising to 50 million tonnes in the decade thereafter – and the new announcements are now starting to put meat on those plans (Renew Economy - October 2021).
- *Skovgaard invest in Denmark (Jutland)* – powered by 62 MW of electricity, producing 2,000 tonnes annually. This was proposed for 2021, pushed back to possibly 2023. There are preliminary plans for of demonstration phases of 10 MW being built first. The NZ Battery Project at the 1 TWh scenario will be approximately 3 times this size.

- *Two green ammonia demonstration plants* went online in 2018 producing between 20 - 30 kg of ammonia per day. One in Oxfordshire, UK, and the other in Fukushima, Japan. The 5 year, 1 TWh scenario demands nearly 40 tonnes of ammonia production per day.

The biggest currently being developed project is the "Duqm" – with 3.5 GW of electrolysis (estimated, power input is 4 GW total), to be commissioned in 2030. Land reservation agreements have been approved by the Oman government. The NZ Battery project will be approximately 1/20th this size. Note: Oman also is talking about a "SuperGiant" project which will be 25 GW, to be 1/3 completed by early 2030's.

The first phase of construction is yet to commence on a 300 tonne per day plant to be operational by 2022. Most recent press around this project is that technology partners have been selected. (7-4) The NZ Battery project will be approximately 1/8th this size.

7.2.3.8 TECHNOLOGY IMPLEMENTATION

Electrolyser equipment availability at large-scale in NZ may be a constraint. Dependent on worldwide installations growing substantially to develop supply chains. Cost of electrolysers forecast to drop significantly by 2030.

Large-scale electrolysis and ammonia synthesis production plant development experienced resources are likely to be scarce in NZ, and overseas Engineer, Procure, Construct (EPC) providers would need to be attracted to these developments.

Major plant items, requiring procurement internationally, are likely to have long lead times. These items will need to be identified, specified, and procured promptly to meet a 2030 operational target.

Other entities in NZ (such as the Southern Green Hydrogen joint venture) are investigating both large-scale green ammonia production and green ammonia export opportunities, which could compete for the same resources, in a similar timeframe as the NZ Battery project. For this option large NZ renewable power supply, water supply, production infrastructure, land and large grid connections could become a "pinch point".

7.2.3.9 EFFICIENCY MEASURES

Ammonia process, round trip efficiency

Process	NH_3
Electrolyser (H_2 production)	65%
Ammonia Synthesis	65%
Ammonia Cracking	90%
CCGT (power generation)	60%
Round trip efficiency	**22.8%**

The Round-Trip Efficiency for ammonia is 22.8% which is the second highest compared to other green energy vectors: synthetic methane (31.2%), LOHC (18.3%) and liquid hydrogen (13.6%).

It is anticipated that the efficiency of all process plant areas will continue to improve in the near future. As more R&D is undertaken and the scale of manufacture increases, suppliers of these plant items need to stay competitive and show that their equipment is as efficient as possible. Green ammonia production plant scale is rapidly increasing, and this in turn allows plant efficiency improvements to be designed, trialled and implemented globally.

7.2.4 COMMERCIAL VIABILITY

7.2.4.1 INTRODUCTION

This option involves converting the hydrogen produced from renewable electricity into ammonia. Ammonia represents a high energy density medium that can be stored and transported relatively efficiently.

Disadvantages are mostly related to the conversion losses and the significant safety and environmental precautions required in dealing with large-scale quantities of a highly toxic chemical.

7.2.4.2 COSTING SCENARIO

As with the other technologies, the green ammonia costing scenario targets meeting 1 TWh of demand over a three-month period identified as a dry year. Dry years occur in 2032 and every five years subsequently. To achieve these dry year requirements:

- 353 MW electrolyser, hydrogen storage & ammonia plant is built. This plant runs for two years to produce sufficient ammonia to produce 1 TWh of electricity in a dry year; Capital cost of Commercial Information and annual operating (excluding fuel) of Commercial Information
- An ammonia storage facility is built. Capital cost of Commercial Information
- An ammonia to hydrogen cracking plant is built at a cost of Commercial Information with operating costs of Commercial Information
- A new CCGT plant is built to run on hydrogen. It is run for three months in each dry year. Capital cost Commercial Information and annual operating cost Commercial Information

The ammonia production only occurs in non-dry years and only the first two years and for two years following each dry year. A 50% load factor is assumed.

7.2.4.3 ANALYSIS RESULTS

ITEM	COST	NOTES
Capex Total ($)	Commercial Information	All plants for ammonia production, storage and Generation.
Capex ($/kW)		
Opex (per year)		Average per year over life.
Whole of Life Cost ($)		
LCOE ($/MWh)		

7.2.4.4 ALTERNATIVE IMPLEMENTATIONS

It is possible that by the time the system is to be constructed that it will be best to run the generation plant directly on ammonia. Our view is that this will not be able to be implemented by 2030. Therefore, we have based the commercial viability scenario on including an ammonia to hydrogen cracking plant, and that there would be a commercial upside if direct ammonia GT firing were able to reach technical maturity in time for NZ Battery Project deployment.

This option also provides the opportunity to both export and import green ammonia to provide revenue and supplement product volumes as required. Adding the ability to import ammonia means that the storage requirements are lower as quantities can be imported during dry years to supplement domestic production.

The cost of producing additional green ammonia is about Commercial Information and this could be exported. While there is no market for green ammonia currently, there are gathering expectations that such a market will soon be formed. Current international cost expectations are for prices up to Commercial Information Even considering transport costs, this would allow a sound return. International costs are mostly based on an electricity price of Commercial Information, about Commercial Information

There is an expectation that market prices will fall significantly by 2030 mainly due to efficiencies in production. These expectations appear highly speculative – so it is not clear to what extent this would affect NZ exports.

If the ammonia production plant was operated for export, then it could be shut down during dry years, this option also provides an aspect of interruptible load for demand response services.

7.2.4.5 COMMERCIAL VIABILITY DISCUSSION

We consider the option to use hydrogen to produce green ammonia to be commercially viable especially if some of the alternative implementations can be included.

Considering the hydrogen possibilities as a group, we consider the ammonia option to be preferable. This is mainly due to the higher energy density of ammonia which enables more efficient import and export possibilities and simplified storage (above ground).

7.2.5 SWOT ASSESSMENT

Table 7-7: Hydrogen Production with Hydrogen Carriers Processing and Above Ground Storage Ammonia) SWOT

	Helpful to achieving the objective	Harmful to achieving the objective
Technology (source to grid)	STRENGTHS	WEAKNESSES
	• Ammonia has benefits as a hydrogen carrier; it has a high hydrogen content by weight (around 17%) and thus high energy density in comparison to gaseous hydrogen. • Ammonia can be liquefied at ambient temperature and moderate pressure, typically 10 bar, or by refrigeration: -35°C at atmospheric pressure. • The use of ammonia as a non-organic hydrogen carrier is considered because the density of ammonia is at least 3 times higher than liquefied hydrogen or high pressure compressed hydrogen. • Comparatively, although hazardous, the ammonia can be considered easier to handle than cryogenic liquid hydrogen or high-pressure compressed gas.	• The drawbacks with ammonia are the energy penalty and capital cost of facilities for converting back to hydrogen. • The known risk factors for handling ammonia, including its highly toxic nature. • Large above ground storage tanks are needed. • A large safety buffer zone will be needed around the ammonia plant and storage areas. • Round-trip efficiency of 23% • 430 MW of renewable energy needed to produce fuel over a 2-year production period, for a 500 MW renewable "dry year" generation output. • High Capex costs for required infrastructure.

	Helpful to achieving the objective	Harmful to achieving the objective
	• Ammonia has an established distribution system as it is already widely transported globally. • An ammonia system allows for export potential to be considered, but also adds the element of security of supply. Should a shortfall occur then more ammonia could be imported.	
Operating Environment (external)	OPPORTUNITIES	THREATS
	• Locally produced green ammonia could be supplemented with imported certified green ammonia. • Locally produced green ammonia could replace ammonia sourced from fossil fuels, for use in other domestic non-energy sectors such as agriculture and industry. • NZ produced green ammonia can be certified "Green" for both NZ and international recognition. Any increase in the cost of imported ammonia could be offset by the prices received for the NZ export product. • In time new CCGT's are expected to be able to be fuelled directly by 100% green ammonia. This will improve costs and the round rip efficiency compared to a process requiring the ammonia to be "cracked" back into a hydrogen gas. Not likely to be viable in large-scale units until 2040. • The hydrogen and ammonia production plants can be shut down in periods of constrained power supply as hydro storage declines. This is an effective form of bulk load shedding which the System Operator can utilise.	• Public perception of ammonia storage facilities • Hazardous and toxic nature of ammonia • Obtaining the required and timely consents may become an issue. • Scientists have warned that hydrogen could be a significant "indirect" contributor to the greenhouse effect when it leaks through infrastructure and interacts with methane in the atmosphere. • Other entities in NZ are investigating both large-scale green ammonia production and green ammonia export opportunities, which could compete for the same resources, in a similar timeframe as this NZ Battery project. For this option large NZ renewable power supply, water supply, production infrastructure, land and large grid connections could become a "pinch point".

7.2.6 DISCUSSION

Green ammonia is considered a viable potential option for the NZ Battery project largely due to its popularity as an existing energy vector throughout the world. Development of green ammonia is receiving attention due to its ability to directly substitute fossil fuel-based ammonia and in the view of some proponents as the preferred hydrogen carrier for end-uses such as the large-scale generation required for NZ Battery. More than 85% of export-oriented low-carbon hydrogen development projects around the world plan to ship ammonia (refer section 7.3).

Conventional natural gas fed ammonia synthesis technology (non-carbon free) and ammonia storage, handling and transport infrastructure is very mature, having been at commercial scale for several decades. Demonstration to small scale deployments of green ammonia synthesis integrated with renewable energy-fed electrolysis exist presently, with all synthesis technology vendors particularly focused on offering large-scale green ammonia synthesis solutions going forward. While the technology for ammonia cracking does not currently have high maturity or scale, it is expected to have reached required maturity levels by 2030. Given the focus amongst the global supply chain on ammonia as an energy vector it is expected it is expected the full pathway to generation at scale will have progressed materially by 2030.

In normal hydrological years, NZ is expected to have the surplus renewable energy resources required to locally produce the amount of ammonia needed for at least a 1 TWh supply option for NZ Battery. Over a 2-year production period this pathway would require a total facility power loading estimated at 390 MW. Shorter production periods or higher supply requirements above 1 TWh would push this demand up (at an extreme 5 TWh over 2 years would result in a load of 1,950 MW) and this would exceed the surplus renewable energy available putting additional load requirements on NZ. The balance between production rates and load on the NZ network would need careful consideration. With green ammonia having a lower round trip efficiency than Renewable Synthetic Methane, the network load is slightly higher, although it is noted that should direct firing of generation plant with green ammonia mature (rather than cracking back to Hydrogen) this would provide some improvement in efficiency.

Regarding storage volumes, a 1 TWh supply option is estimated to require 391,000 m^3 of Ammonia and a 5 TWh supply option, 1,955,000 m^3. Large, specially designed above-ground storage tanks (full containment, double-walled, refrigerated tanks with integrated recovery of ammonia boil-off gas, similar to LNG tanks currently used) are required to store liquid ammonia, which is highly toxic in both gaseous and aqueous forms, but these are mature technologies. Chemical storage sites such as this require careful design to mitigate site environmental and safety hazards. While large LNG storage facilities with total storage capacity of approximately 4,600,00 m^3 exist internationally (e.g., Korea Gas Corporation (KOGAS) with initial 36 LNG storage tanks), an ammonia storage site of this scale presently does not exist anywhere in the world.

Given the global focus on ammonia and the potential for global trade (refer section 7.2.3), there could be an opportunity to be a net exporter of certified green ammonia once NZ Battery storage levels are reached. This would open up a revenue stream to somewhat offset NZ Battery costs.

7.3 HYDROGEN CARRIER IMPORTS WITH BUFFER STORAGE

7.3.1 PRIMARY OPTION INTRODUCTION

Regions such as Australasia, Latin America, South Asia, Middle East and Africa are currently developing large-scale hydrogen carrier production and export facilities. By 2030 it is expected that these developments will be well-established internationally and could provide NZ with a relatively quick turnaround supply timeline and provide offshore bulk storage resilience options. We note however, that currently there is no operational international shipping supply chain for hydrogen carrier products.

The option of importing the green hydrogen carriers described in section 7.2.3 (ammonia, LOHC or liquified hydrogen) is therefore, considered a possibility. These hydrogen carriers could be imported in large quantities and stored in bulk storage, prior to use, in hydrogen-fuelled GTs or Fuel Cells.

The full supply chain to produce electricity from imported hydrogen carrier imports would involve:

- Hydrogen carrier import to NZ deep water port
- Buffer storage tanks
- Conversion back to hydrogen e.g. via ammonia cracking plant
- Generation through Gas Turbine or other generation technology

As mentioned for green ammonia as a carrier option previously, direct fuelling of the generation plant with green ammonia is also expected to develop in the future. Currently this is however considered less likely to develop as a viable option by 2030.

7.3.2 TECHNOLOGY PATHWAYS

Table 7-8 presents a broad categorisation of the pathway options to use hydrogen technology for the generation of electricity through hydrogen carrier imports with buffer storage. In the table, **Bold text** represents the Preferred Pathway, Normal text represents Other Pathways, and Red text represents Discontinued Pathways.

Table 7-8: Hydrogen Technology Pathways

PRIMARY OPTION	HYDROGEN CARRIER IMPORTS WITH BUFFER STORAGE
Energy Source	**Renewable energy** **Raw Water**
Energy Vectors / Conversion	**Ammonia** LOHC Renewable Synthetic Methane Liquified Hydrogen
Storage	**Above ground storage tanks**
Generation	**Generation from hydrogen** Generation direct from Ammonia **Gas Turbines (OCGT or CCGT)** Fuel Cell Reciprocating Engine Steam Boiler

Source: WSP

7.3.2.1 PREFERRED PATHWAY

Imported Green Ammonia: Ammonia the preferred pathway for the green hydrogen carrier imports option, with NZ importing green ammonia from other countries to either fully meet the dry year power generation demand requirements (1 TWh to 5 TWh 3-month demand), or to supplement locally produced green ammonia. Much of the required infrastructure (such as deep-water port infrastructure) could already exist (with some modification requirements) for this green ammonia import opportunity. As described above, ammonia production is also a more technically mature process than LOHC, therefore, it is considered to have a higher availability for import.

7.3.2.2 OTHER PATHWAYS

LOHC: This green hydrogen carrier has potential in the future as an imported product, however this technology needs to mature and looks poor from an energy supply chain efficiency perspective so are likely to have high energy costs. LOHC transport carriers, such as toluene/methylcyclohexane systems for hydrogenation/dehydrogenation processes, have also been piloted, but the technology is still less advanced than for a carrier such as ammonia. With the lack of current large-scale production facilities, this technology would need to significantly grow in scale to meet the requirements for this project by 2030. We consider that any import of a hydrogen carrier product which differed from any local NZ hydrogen carrier produced product would be less optimal.

7.3.2.3 DISCONTINUED PATHWAYS

Liquified Green Hydrogen: As detailed above, we believe that this product faces large challenges to mature and grow to meet the scale for the NZ Battery requirements by 2030. Large-scale shipping infrastructure has only recently started to become operational and will take time to grow. Japanese shipbuilder Kawasaki Heavy Industries recently reported that the world's first liquefied hydrogen (LH_2) carrier had left Japan to pick up its first cargo in Australia.

Liquified Renewable Synthetic Methane: we believe that it is highly unlikely that the option to import renewable synthetic methane will sufficiently develop by 2030, based on current international supplier developments, and noting that to practicably enable transport as a hydrogen carrier over large distances would also require the additional step of liquefaction to increase density, with associated losses and decreases in round trip efficiency. While a future international market for low carbon (e.g. blue hydrogen) derived synthetic methane may grow as a potential low-carbon transitional fuel option, the same is not expected of global production and trade in renewable synthetic methane.

7.3.3 PRIMARY OPTION ASSESSMENT

Following the initial screening assessment, the Primary Option of Hydrogen Carrier Import with Buffer Storage on the Preferred Pathway of green ammonia imports with hydrogen gas turbines for power generation has been considered for further analysis. Table 7-9 provides an indication of the degree to which the option meets the evaluation criteria. This is based on the Preferred Pathway of importing and/or exporting green ammonia. It should be noted that there would also be a hydrogen buffer storage between the cracking plant and the CCGT to accommodate safety zones, demand and specification requirements.

Each green hydrogen carrier technology option is scored, based on a qualitative rating and quantitative evidence against the established RAG criteria defined in Appendix A. Our assessment against the Evaluation Criteria is explained further below.

Table 7-9: Hydrogen Green Energy Vector Options Assessment

CATEGORY	CRITERIA	HYDROGEN CARRIER IMPORT WITH BUFFER STORAGE
Preferred Pathway Assessed		Ammonia imports, hydrogen gas turbines for power generation
Long-term Storage	Between Dry Years Energy Storage	
	Storage Recovery	
	Asset Life	
Security of Supply	Min. 1 TWh	

CATEGORY	CRITERIA	HYDROGEN CARRIER IMPORT WITH BUFFER STORAGE
	Up to 5 TWh	Favourable with robust supply agreements & forward scheduling
	3 to 6 Months Output	
Renewable Technology	Renewables	
	Operational Carbon Emission Intensity	
	Built Carbon Emission Intensity	
	Sustainable Resources Risk	
Technology Readiness	Technology Readiness Level (2030)	
	Technology Ready for Commissioning (2030)	
Geographical and Logistical Constraints	Geographical Constraints	Single port site possible
	Subsurface Constraints	NA
	Transportation or Logistic Requirements	Very hazardous goods transport and port handling
Commercial Viability	Whole of Life Cost ($)	Commercial Information
Efficiency Measures	Round Trip Efficiencies (2021)	23%
	Round Trip Efficiencies (2030)	23% & improving
	Annual Storage Decay Factor	
Environment and Safety	Environmental or Regulatory Hurdles (Ability to obtain a consent)	Deep water port issues
	Environmental Risks	Deep water port issues
	Safety Hazards Risks	Deep water port issues
Reference Projects	Reference Projects	Many
Technology Implementation	Global Market Trends & Context	Known capabilities
	Commitment of OEM Suppliers	Plant availability may become constrained
	Available International Market to Import Resources	Market for international green ammonia supply still evolving.
	Potential Implementation Bottlenecks	Large, complex ports and construction sites.

Source: WSP

Notes on the options assessed

[1] Based on Whole of Life calculation methodology applying consistent scenarios across all technologies.

7.3.3.1 LONG-TERM

This is considered possible as the export market for green ammonia is growing and the ammonia technology is mature.

Bulk onshore full containment storage tanks similar to LNG storage tanks can be installed in NZ.

Offshore bulk storage could be contracted, or supply agreements put in place.

Long-term contractual agreements would be required to ensure overseas production, storage and shipping logistics arrangements were in place to meet NZ's requirements. There is no current international trade in green ammonia, but it is coming shortly.

7.3.3.2 LARGE-SCALE

Imports of hydrogen carrier products could enable NZ to have consignment storage stocks of these products stored in overseas storage facilities and then shipped to NZ as required.

Imports able to add to NZ product storage volumes.

Large overseas hydrogen carrier product export developments are under development now, and it is expected that by 2030 the supply chain will have increased significantly.

7.3.3.3 RENEWABLE TECHNOLOGY

This option is considered to be renewable, if internationally approved green certification can be provided, and transparency maintained.

7.3.3.4 TECHNOLOGY READINESS

Ammonia is currently the most mature hydrogen carrier product with large volumes of ammonia currently transported and shipped around the world.

Ammonia offers proven synthesis technology and existing supply chains. The synthesis, storage and shipping of ammonia is a well-established industry. The existing market for ammonia is around 180 million tonnes per annum (Mtpa), mostly integrated with the production of derivatives, such as urea, or fertilisers such as ammonium nitrate.

The seaborne trade in ammonia is currently around 20 Mtpa and a world-scale ammonia plant is around 2 Mtpa. There is no current international trade in green ammonia, but it is coming shortly.

Ammonia cracking plant is at pilot/small scale demonstration scale presently, not high maturity, but is expected to mature by 2030. Refer to section 7.3.1 for further commentary on ammonia cracking.

7.3.3.5 GEOGRAPHICAL AND LOGISTICAL CONSTRAINTS

Logistical constraints can be managed and achieve cost effective supply arrangements. Securing appropriate international procurement and delivery contracts will be extremely important for this option.

Development of existing deep-water ports and new specialist bulk storage facilities would be required.

The port facilities for ammonia import are however similar to an LNG or LPG import terminal: including equipment such as unloading arms at the jetty head, insulated pipelines to the storage tanks and refrigerated storage tanks. The facilities will be comparable between an ammonia loading terminal and an ammonia unloading terminal. This would then facilitate both import and export of green ammonia.

Figure 7-8: Port facility example, with LNG unloading, storage and power generation through 3 x CCGT units

Other entities in NZ (such as Southern Green Hydrogen (SGH) and FFI etc.) are investigating both large-scale green ammonia production and green ammonia export opportunities, which could compete for the same resources, in a similar timeframe as this NZ Battery project. For this option large NZ ports infrastructure and land could become a “pinch point”.

7.3.3.6 EFFICIENCY MEASURES

The Round-Trip Efficiency for ammonia is 22.8% which is the second highest compared to other green energy vectors: synthetic methane (31.2%), LOHC (18.3%) and liquid hydrogen (13.6%). Refer to section 7.3.2.9 for more information.

7.3.3.7 ENVIRONMENT AND SAFETY

Ammonia is a toxic chemical, and its production and handling in traditional sectors is regulated. It must be treated carefully as it is corrosive and may ignite / burn with explosive force. Poisonous gases are produced, and containers may explode, if a fire occurs.

The potential for release or spillage must also be managed carefully. Environmental issues can be caused during a containment event, due to its poisonous nature. Globally, large full containment storage tanks are used to mitigate against the release and spillage of liquified ammonia. These tanks are similar to those commonly used globally for LNG bulk storage facilities.

Ammonia storage and generation sites need specific location-selection to ensure environmental and safety mitigations can be put in place (such as bunding, large buffer zone areas, etc.). Deep water port off-loading facilities would require careful planning and design to ensure adverse effects are managed appropriately.

7.3.3.8 REFERENCE PROJECTS

Green Hydrogen Production:

There are numerous large-scale green hydrogen plants proposed for the future. Refer to section 7.1.3.7.

Ammonia Import/Export:

Many examples of large-scale overseas Ammonia developments are underway for export, this includes.

- *Southern Chile*: Total Eren will lead development of the H_2 Magallanes project in southern Chile. Up to 10 GW of onshore wind capacity will power 8 GW of electrolysers, a desalination plant, an ammonia production plant and port facilities to export the product to local and global markets. At full capacity, 4.4 million tonnes of renewable ammonia will be produced every year. Although H_2 Magallanes is still in the pre-feasibility stage, its intended launch will be in 2025, to begin hydrogen electrolysis in 2027.
- *Shoreham, West Sussex*: H_2 Green will develop a renewable energy hub at the Port of Shoreham in West Sussex. The initial focus will be the electrification and use of hydrogen fuel in the Port's vehicle fleet (heavy forklifts and trucks), before expanding to accommodate the ~800 heavy goods vehicles that enter the port daily. The second phase will be an ammonia import facility to meet growing demands for hydrogen fuel in the surrounds.
- *Geelong, Australia*: In Australia, the Geelong Hydrogen Hub will be developed by CAC-H2, a developer who is also planning two carbon-negative, waste-to-ammonia projects in Australia. The Geelong Hub includes multiple, new-build infrastructure elements including import/export & cracking facilities. Similar to Shoreham, import of green ammonia to meet growing demand for hydrogen fuel is the second phase of the project.
- *Ain Sokhna, Egypt:* A Fertiglobe-led consortium has selected US-based Plug Power to supply 100 MW of PEM electrolysers for a new green ammonia project adjacent to EBIC's ammonia plant in Ain Sokhna, Egypt. At full capacity, the project will generate enough green hydrogen feedstock to produce 90,000 tonnes of ammonia per year. The consortium partners are targeting a start date of 2024 for operations.

Other reference projects are proposed or are in development at Port Bonython South Australia, Papua New Guinea (led by Fortescue Future Industries), Bell Bay Tasmania, Gladstone Australia.

Different countries attract different forms of renewable generation for the creation of Hydrogen as reflected in Figure 7-9.

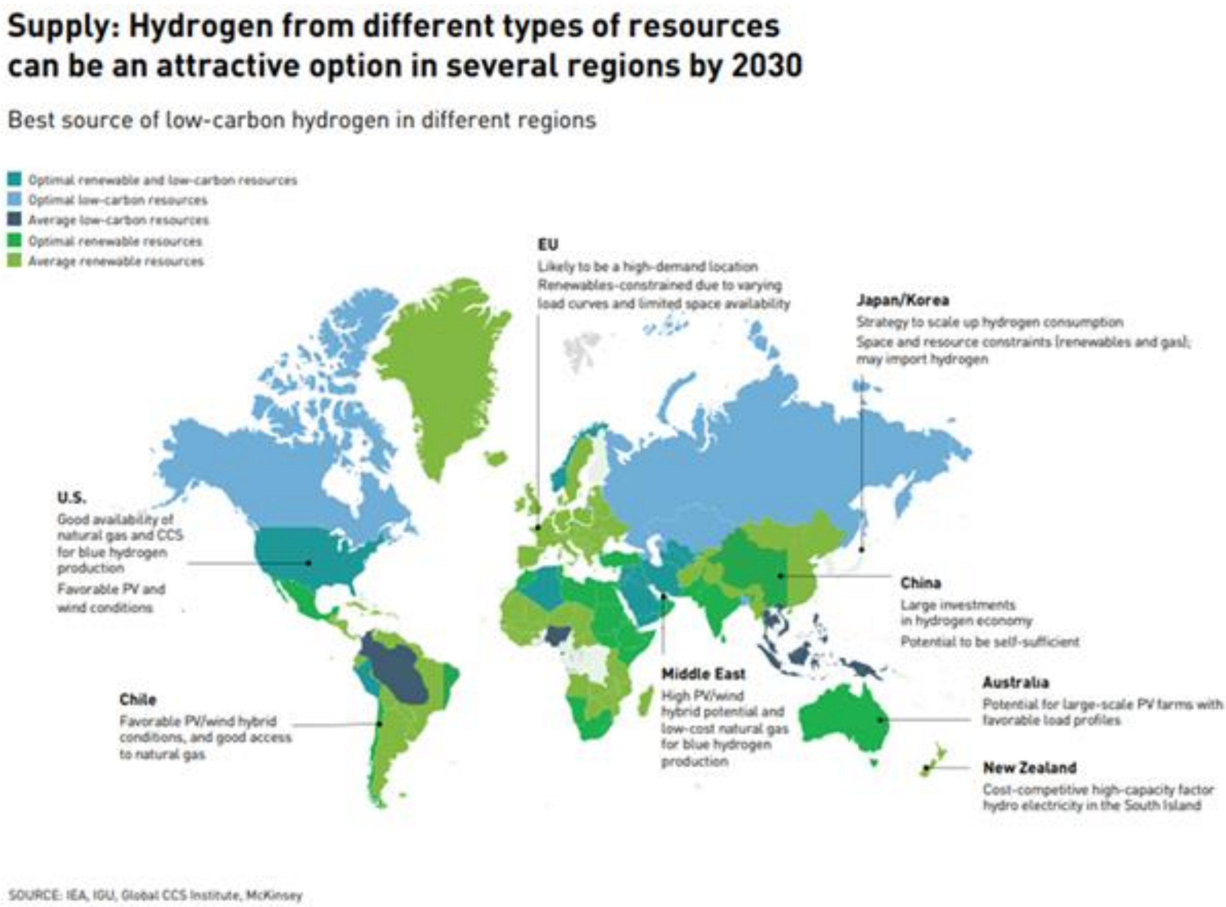

Figure 7-9: Global Hydrogen Supply

7.3.3.9 TECHNOLOGY IMPLEMENTATION

Many examples of large-scale overseas green ammonia export developments are underway as per the project examples previously provided above.

New ammonia floating storage and regasification unit (FSRU) infrastructure is being developed by Mitsubishi Shipbuilding, which could provide an alternative to expensive port upgrades. These are floating facilities for receiving and storing ammonia which is transported in a liquid state from its production area, with the stored ammonia is then heated and degasified onboard for transfer to an onshore pipeline.

More than 85% of export-oriented low-carbon hydrogen (not green hydrogen) development projects around the world plan to ship ammonia. The seaborne trade in ammonia is currently around 20 Mtpa (although that does not include any green ammonia trade currently) and a world-scale ammonia plant is around 2 Mtpa. It is expected that seaborne trade of green ammonia may emerge and grow prior to 2030, though there remains significant uncertainty as the scale of trade this may represent as at 2030.

Global trade in bulk green methane is not expected to develop in the manner that green ammonia trade is, hence limiting the ability to supplement NZ produced methane with imports (or export surplus).

7.3.4 COMMERCIAL VIABILITY

7.3.4.1 INTRODUCTION

An alternative hydrogen solution would be to bypass local production and just import green ammonia. In a dry year ammonia would be imported, cracked into hydrogen and used to fuel a Combined Cycle generation plant. Some local storage would be required to cover the delivery time from international sources and port facilities would need to be developed for ship type and handling requirements.

7.3.4.2 COSTING SCENARIO

As with the other technologies, the imported ammonia costing scenario targets meeting 1 TWh of demand over a three-month period identified as a dry year. Dry years occur in 2032 and every five years subsequently. To achieve these dry year requirements, ammonia would be imported to fuel a new Combined cycle generation plant with capacity of 500 MW, which is sufficient to generate 1 TWh over three months.

The green ammonia would be imported when required, with some local storage Commercial Information as required to cover delivery periods. The generation station Commercial Information and ammonia cracking plant Commercial Information remain mothballed until required to meet a dry year energy shortfall. When a dry year occurs, the plants are de-mothballed, run as base load for three months, delivering 1 TWh to the electricity grid, then mothballed until the next dry year occurs. The plant operates in this manner in perpetuity from 2030.

Key Assumptions:

- A 500 MW Combined Cycle Generation plant, Commercial Information
- Port upgrades at Commercial Information
- Ammonia to Hydrogen Cracking Plant, Commercial Information
- Cost of ammonia at Commercial Information
- Shipping cost of Commercial Information

7.3.4.3 ANALYSIS RESULTS

ITEM	COST	NOTES
Capex Total ($)	Commercial Information	Total build costs of the plant providing capacity of 500 MW
Capex ($/kW)		
Opex (per year)		Average over life.
Whole of Life Cost ($)		
LCOE ($/MWh)		

7.3.4.4 ALTERNATIVE IMPLEMENTATIONS

There is existing combined cycle plant that could be modified and supplied with this green hydrogen and could provide capacity close to 1 TWh over a 3-month period. Some of this plant is approaching end of useful life so it is not clear to what extent this would provide a short- or long-term solution.

While there are other operating approaches, including providing peaking capacity on a short or long-term basis. The cost of imported fuel would their bid price in the market would be very high.

7.3.4.5 COMMERCIAL VIABILITY DISCUSSION

Our analysis suggests that import of ammonia is commercially viable as a NZ Battery alternative. The main disadvantages are the relatively high price of electricity generated from this source and the dependence on international markets. NZ would need to ensure that it could be protected from large cost increases due to global supply market variations and that ammonia was available when required for dry years. The ability to store consignment product stocks offshore would save the cost of large NZ-based buffer storage.

The low capital cost is a significant advantage and if combined with use of existing plant this option could provide an option to delay commitment (with potentially high option value).

7.3.5 SWOT ASSESSMENT

Table 7-10: Hydrogen Carrier Imports with Buffer Storage (Ammonia) SWOT

	HELPFUL TO ACHIEVING THE OBJECTIVE	HARMFUL TO ACHIEVING THE OBJECTIVE
Technology (source to grid)	STRENGTHS	WEAKNESSES
	• Imported product can supplement locally produced product, especially during times of abnormally high additional power demand in NZ. • The shipping delivery turnaround times for deliveries from many Australian or other Southeast Asian ports is short. • Large quantities of product is currently in final development stages, so large volumes of product is expected to be available by 2030. • By 2030 it is expected that recognised global green hydrogen product certification processes will be established, which will ensure a transparent green supply chain can be traced.	• These imported products would be subject to global supply chain pricing pressures. Strong supply agreements will be required to manage this risk. • NZ is not likely to be a large client for these product exporters, so our buying power will be small. • International market price of green ammonia could be very volatile. Green ammonia market costs range from Commercial Information per tonne. • Estimated shipping costs range from Commercial Information per tonne. • High Capex costs for required infrastructure.
Operating Environment (external)	OPPORTUNITIES	THREATS
	• A bundled approach option to import additional ammonia to supplement NZ produced ammonia will provide an opportunity for more flexibility and reduce the high Capex for the higher TWh supply range. • Contingency stock of the export product could be stored by the exporter overseas (consignment product), which would reduce the scale of infrastructure required to be built in NZ. This will come with additional costs. • If NZ were to export and important stocks of ammonia, the same ports, storage	• Public perception of ammonia storage facilities • Hazardous and toxic nature of ammonia • Obtaining required and timely consents may become an issue. • Other large product international clients may secure large amounts of the available export supply. • Supply delivery may not meet generation fuel requirements. • Other entities in NZ are investigating both large-scale green ammonia production and green ammonia export opportunities, which could compete for the same resources, in a similar timeframe as this NZ

	HELPFUL TO ACHIEVING THE OBJECTIVE	HARMFUL TO ACHIEVING THE OBJECTIVE
	infrastructure and generation facilities could be utilised. • Opportunity to create a large facility (Energy Hub) in a location which can facilitate a deep-water port, bulk long-term storage, hydrogen and ammonia production and power generation. Constitutional conventions • Could create new infrastructure build and employment opportunities in regional areas such as Taranaki and Northland. These areas will be seeing a downturn due to less fossil fuel related activities heading into 2030. • New ammonia floating storage and regasification unit (FSRU) infrastructure is being developed which could provide an alternative to port upgrades.	Battery project. For this option NZ port infrastructure could become a "pinch point".

7.3.6 DISCUSSION

The importing of certified green ammonia (subject to development/acceptance of such international certification schemes) from Australia or similar neighbouring large green energy exporting nations is a potential solution for the NZ Battery Project. More than 85% of export-oriented low-carbon hydrogen development projects around the world plan to ship ammonia. The seaborne trade in ammonia is currently around 20 Mtpa – roughly 80 TWh equivalent (although at present that does not include any green ammonia trade) and a world-scale ammonia plant is around 2 Mtpa. It is expected that seaborne trade of green ammonia will emerge and grow prior to 2030.

We believe that it is highly unlikely that the option to import renewable synthetic methane will sufficiently develop by 2030, based on current international supplier developments. To practicably enable transport as a hydrogen carrier over large distances would also require the additional step of liquefaction to increase density, with associated losses and decreases in round trip efficiency. While a future international market for low carbon (e.g. blue hydrogen) derived synthetic methane may grow as a potential low-carbon transitional fuel, the same is not expected of global production and trade in renewable synthetic methane. Other Liquid Organic Hydrogen Carriers (LOHCs) such as toluene or methylcyclohexane, or Liquid Hydrogen, while expected to potentially develop in future, are not expected to reach a supply chain scale that would meet the NZ Battery time frames for an import opportunity relative to green ammonia. Consequently, we suggest focusing on Green Ammonia as a potential import solution.

NZ has a number of deep-water port locations which may be suited for ammonia's bulk importation requirements. These facilities would require specialised bulk liquid handling and large bulk storage facilities that would need to be developed, however these are mature technologies.

One option is to also to investigate putting in place overseas based infrastructure to support large-scale importation of certified green ammonia liquid from early-mover producers (e.g., Australia). This would provide a short duration (1 week) delivery supply option, with large consignment stocks of green ammonia being stored overseas at the exporter's location until required by NZ. This would reduce the amount of bulk storage required in NZ and offer potential additional resilience, as any supply issues from the preferred (consigned) source could be circumvented by purchase on the open market.

While there is some additional energy load locally (to manage required port facilities) this is insignificant compared to locally produced ammonia or synthetic methane. Storage scenarios are envisaged to be practically the same as locally produced ammonia at most.

Importing ammonia presents a number of strategic benefits for NZ over local production – chiefly the risk and cost of developing a local green ammonia industry is borne elsewhere. This option however represents a shifting of NZ's current dry year energy supply problem to one of energy security, as while local ammonia storage and ammonia or hydrogen fired CCGT's may be very capable of "keeping the lights on" - doing so makes NZ reliant on other countries and transport infrastructure for this backup energy supply.

Even with the uncertainty around the scale and liquidity of the green ammonia market by 2030, we expect an import only option could provide a partial solution to the dry year problem, but carries risk as a stand-alone long-term solution. This would especially be high risk for peak ammonia requirements, for example during consecutive or extreme dry years. Managing this risk to acceptable levels can be achieved by sizing the storage based on the combination of dry year and international market risk. While the potential benefits of green hydrogen import as a supplementary solution are recommended to be further considered, depending on imports as a stand-alone option presents too much uncertainty to be considered a complete solution to the NZ Battery problem.

7.4 HYDROGEN SUMMARY AND RECOMMENDATION

WSP considers the most viable prospective deployment of the green hydrogen option is to produce a lower level of green ammonia in NZ (around the 1 TWh range) and supplement this production with overseas imports. This is effectively a hybrid of two of the Primary Options described above.

Renewable synthetic methane and green ammonia produced locally are economically extremely similar. However, the overall economic benefits of each carrier option will need further assessment to confirm any differences While it is a close call, there are a number of factors which make ammonia the more favourable of the two. Development of energy storage in the form of synthetic methane is arguably more complex than ammonia due to the added complexities of the supply chain. A large renewable carbon dioxide gas source and a plant to recover and purify that carbon dioxide gas is required, combined with transport of that carbon dioxide gas source to a common production site. The limited technology maturity of both renewable carbon capture and synthetic methane also represent a risk to the project with uncertainty around them reaching technical maturity at the scale required by 2030. It is anticipated that while green ammonia cracking is also not mature at scale that due to the global focus on ammonia as an energy carrier these technologies will advance to scale more rapidly.

Furthermore, the public perception of synthetic methane in terms of carbon emissions is anticipated to be substantial compared with ammonia – primarily due to the deliberate re-release of CO_2 into the atmosphere during synthetic methane's combustion.

Whilst a 1 TWh production and storage facility of either green ammonia or synthetic methane is considered viable through the use of available surplus renewable energy, production facilities beyond this scale would become increasingly more challenging. The additional load on the NZ electricity supply would become significant driving up the need for additional variable wind and solar, (or further baseload) generation. This could be mitigated by supplementing local production with imports, allowing the scale of plant to be optimised to maximise capture of excess off-peak electricity and minimise any additional load on the network. Conversely, relying solely on just-in-time imports from other producer's swaps energy costs for long-term energy security, thereby creating another problem entirely. A hybrid of local production and imports mitigates the risk of reliance on an uncertain import market, allowing the split between local production / storage and import capability to be optimised to best match future energy demand and supply scenarios.

With the hybrid option being beneficial to allow risks to be balanced, this also points to the use of green ammonia as the recommended carrier, with it expected to have the most global focus as a tradable green hydrogen carrier from 2030.

Green ammonia produced in NZ (to at least 1 TWh energy storage): Green hydrogen is produced using off-peak renewable power from the NZ grid and buffer stored prior to injection into an ammonia synthesis plant. The stored hydrogen is then supplied to the ammonia synthesis plant to produce ammonia liquid, which is then stored in large long-term storage tanks until required to fuel dry year CCGT generation units.

This hydrogen and ammonia production will be scheduled over multi-year production periods at variable load factors (all to be further investigated and optimised during Task 2). No production will occur within a period of notified "dry year" energy constraint.

Utilising a domestic surplus renewable power supply as much as possible reduces risks associated with fluctuations and volatility in international supply chains and makes improved use of existing NZ resources as well as achieving the renewable energy goals we have set ourselves.

Import certified Green ammonia (Up to the 5 TWh requirement): When energy forecasts indicate that the level of dry year generation needed exceeds 1 TWh and approaches the 5 TWh range, imported certified green ammonia could be used to supplement the existing NZ produced ammonia. This would ensure sufficient fuel stocks are available to meet the forecast dry year generation demand, whilst avoiding the need to develop further renewable energy to produce ammonia at the volumes required for this higher demand scenario.

In this bundled, hybrid option; a deep-water port, bulk ammonia storage tanks, larger scale ammonia cracking and CCGT generation plant will be required to meet up to the 5 TWh requirement scenario, if this is deemed necessary. This port facility, bulk storage, generation power plant infrastructure size and dispatch period, will be further investigated and optimised during Task 2. At the moment this high end 5 TWh scenario for hydrogen is not considered reasonable.

For the ammonia stream, as part of the further feasibility study, WSP would recommend we further investigate and optimise this hybrid ammonia option, looking at the production, import, export, storage and generation aspects. Risks exist in relation to the size, access to and economics of global green ammonia markets which will need to be further investigated (which could include direct engagement with potential export focused green ammonia project developers). WSP will look to optimise the plant sizes, storage volumes and port facilities at specific locations. A key consideration will be to also optimise the location of the grid connections for both production facilities and CCGT generation units. In this study we would ensure that other hydrogen carrier options are further considered to revalidate that green ammonia is the most feasible hydrogen pathway in the context of addressing the NZ Battery storage duration requirements.

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8 AIR STORAGE

Within this section we consider and assess the potential to manage dry year risk using air storage in the NZ Battery Project context.

8.1 COMPRESSED AIR ENERGY STORAGE

8.1.1 PRIMARY OPTION INTRODUCTION

There are several variations of CAES. Two of the common ones are Diabatic CAES (D-CAES) and Adiabatic CAES (A-CAES) which aims to improve efficiencies of the system. Isothermal CAES is an emerging technology that aims to overcome some of the traditional CAES limitations.

The Diabatic Compressed Air Energy Storage System is an energy storage system based on the compression of air and storage in geological underground voids, typically salt caverns (however other media are under investigation such as aquifers, mined hard rock caverns and depleted gas fields). When air is compressed, it becomes very hot and must be cooled prior to injection into the storage container. This cooling represents a loss of energy in the form of heat being rejected and lost to the atmosphere. Upon withdrawal from storage, the air energy must be supplemented with a heat source to regain the energy lost from cooling after the air was compressed and placed in storage. The two operating D-CAES facilities worldwide use natural gas, which complements the energy derived from the expansion of the compressed air passing through the power turbine.

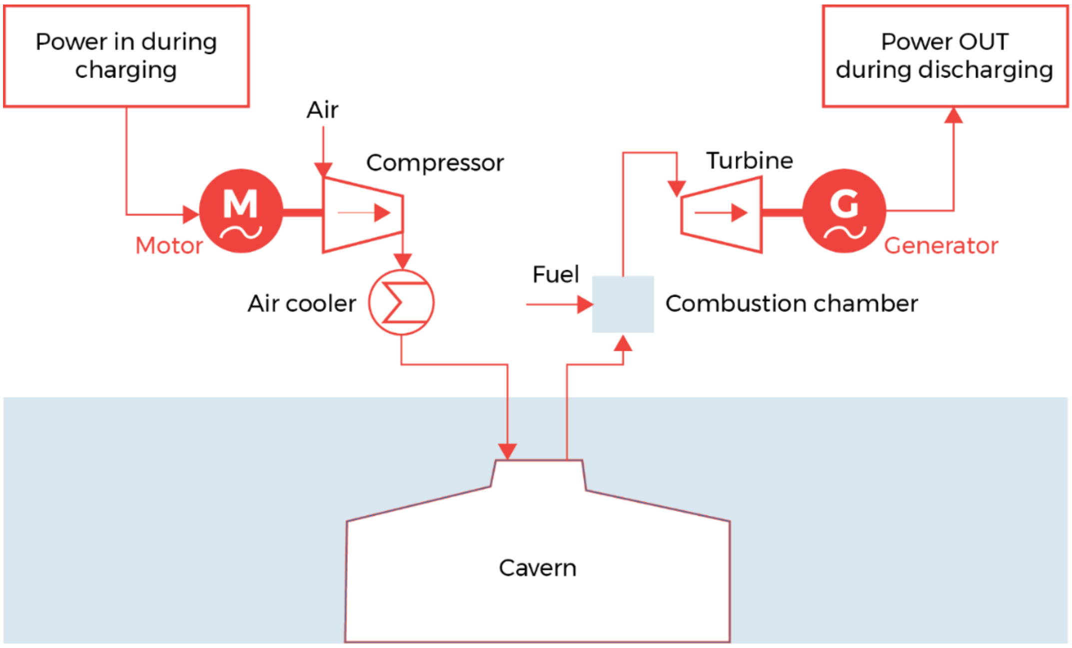

Figure 8-1: Diabatic Compressed Air Energy Storage

Source: European Association for Storage of Energy

The Adiabatic Compressed Air Energy Storage System works in a manner similar to D-CAES; however, the heat produced during the compression cycle is not rejected to the atmosphere but captured and stored using a Thermal Energy Storage (TES) medium. When the air is later withdrawn from storage, it is heated by the TES medium, prior to expansion through the power turbine. Unlike D-CAES, an externally provided source of supplementary heat, e.g. through combustion of natural gas (with associated CO_2 and NOx emissions) is not required.

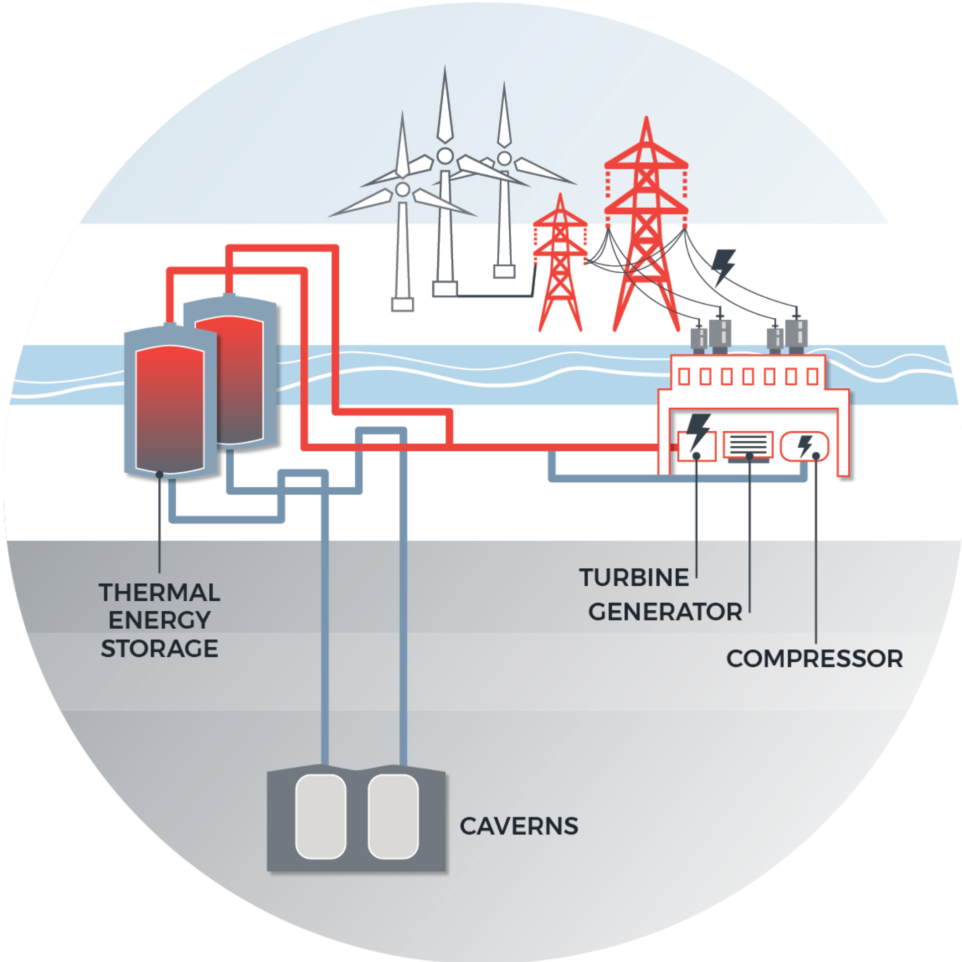

Figure 8-2: Adiabatic Compressed Air Energy Storage

Source: Power AG, 2010

Isothermal CAES cycles have also been proposed by several technology proponents. Isothermal compression offers significant opportunities for industrial energy efficiency more broadly, but has proven technically very difficult, especially for high flow-rate applications.

It relies on creating a large heat transfer surface and using a heat transfer fluid, such as water or foam. Sustain-X (no longer in business) built an isothermal CAES pilot plant based on reciprocating compression technology with direct foam heat exchange within the compressor cylinders. General Compression (later merged with Sustain-X, also no longer in business) developed an approach using a pressurised bank of shallow water trays to create a similarly large heat transfer surface.

Storage of compressed air: To capture and store energy for long periods before discharging in a dry year, CAES (and in the absence of salt caverns) would require a reservoir or cavern developed in a sand/sandstone, hard rock or a human-made cavern. This geological 'trap' must have structural closure to sustain necessary elevated pressures. The storage location needs to be close to a power generation site or transmission network. Commonly considered storage options include depleted oil/gas reservoirs, non-hydrocarbon-charged or non-commercial deep structural traps, saline aquifers, salt domes and mined (human-made) hard rock caverns.

8.1.2 TECHNOLOGY PATHWAYS

Table 8-1 presents a broad categorisation of the pathway options to use air storage for the generation of electricity through compressed air energy storage. In the table, **Bold text** represents the Preferred Pathway, Normal text represents Other Pathways, and Red text represents Discontinued Pathways.

Table 8-1: Compressed Air Energy Storage Technology Pathways

	COMPRESSED AIR ENERGY STORAGE
Energy Source	**Renewable Energy**
Storage	**Subsurface depleted oil & gas reservoir** **Existing subsurface hard rock cavern** **Human made subsurface hard rock cavern** Salt domes and bedded salt Deep Saline Aquifer Formations
Generation	**Diabatic Cycle** Natural gas combustion heat source re-expansion Renewable energy heat source for re-expansion **Adiabatic Cycle:** Using Thermal Energy Storage as heat source for re-expansion **Isothermal Cycle:** Using heat transfer fluid (water / foam) as heat source for re-expansion

Source: WSP

8.1.2.1 PREFERRED PATHWAY

Subsurface Depleted oil & gas reservoir: Depleted oil/gas reservoirs such as Ahuroa would appear to be the most likely option for subsurface compressed air storage in the NZ Battery context. All of NZ's commercial oil/gas fields are in Taranaki, both onshore and offshore. Many are in the final years of commercial production. Ahuroa – an operating natural gas storage facility - would appear to be an ideal option due to its readiness to access. Ahuroa has 4 operating wells Ahuroa-2A, 3, 4, 5ST1. Ahuroa was converted in 2008 to an underground gas storage facility and opened in 2011. It has a nominal storage volume of 456 Mm^3 with an extraction capacity of 1.18 Mm^3/day, upgraded in 2020 to allow increased injection/extraction rates of 1.71 Mm^3/day.

Other fields in Taranaki include Tariki, Waihapa, McKee, Kaimiro & Ngatoro, Kapuni and Mangahewa fields. All these fields still have some form of gas/oil production except Tariki (Nonactive since 2012 and status unknown).

Unfortunately, mixing compressed air with hydrocarbons has safety concerns (explosive risk) that, despite much international research, has not been solved. There is a risk that this problem is not solved in time.

Existing Subsurface Hard Rock Caverns: Hard rock caverns present a viable option for compressed air storage as there is no permeability to contend with in restricting air leakage. However due to New Zealand's geology (fractured and seismically constrained), it is unlikely that a suitable hard rock cavern with the size and structural competence needed to provide the large-scale, long-term energy storage criteria could be found in time creating a high risk option.

Human-made Hard Rock Caverns: Building a cavern in a hard rock location is technically feasible but would be extremely expensive to construct (i.e., well over $20B), and with limited suitable locations in NZ.

Diabatic Cycle (D-CAES) using renewable energy heat source for re-expansion: Overseas the most common option for heating the air during the re-expansion of the compressed air is natural gas. To meet the renewable requirement of the NZ Battery solution, the only viable pathway is to use a renewable energy heat source such as biomass.

8.1.2.2 OTHER PATHWAYS

Porous media: In general, will have a very low likelihood of success in storing compressed air. Formations are not naturally "tight." Even if they have been able to contain e.g., hydrocarbons in the past, those formations will have to be rigorously studied to ensure there are no migration pathways, vertically or horizontally. For example, oil and gas formations internationally have both trapped hydrocarbons at the high point of the formation while simultaneously allowing gas to seep out along the edges of formation.

8.1.2.3 DISCONTINUED PATHWAYS

Salt domes and bedded salt: These are used internationally for gas and liquid storage. Caverns, unlike depleted reservoirs or saline aquifer formations, do not have formation permeability to restrict air flow to the turbines. However, neither salt domes nor salt beds are present in New Zealand.

Deep Saline Aquifer Formations: This pathway is another potential option for storing gas or liquids subsurface. However international efforts to develop this option for gas storage have failed to date; these have been extremely costly and there are no known successful applications currently worldwide. In addition, this option would also require extensive seismic surveys and geologic feasibility studies to first locate and then determine containment, which would be expected to be highly expensive with a low probability of success.

Diabatic Cycle using Natural Gas heat source for re-expansion: This pathway requires the use of non-renewable fuel sources which does not meet project key renewable criteria and therefore, this pathway is not analysed further.

Adiabatic Compressed Air Energy Storage (A-CAES): This technology requires Thermal Energy Storage (TES) to temporarily store the heat emitted during air compression step, then feed the heat back during the expansion step. TES is only feasible for shorter term energy storage (i.e., days, weeks, or at most months). With the long-term time periods of NZ Battery context, using TES to provide heat for compressed air re-expansion is not a viable option.

Isothermal Compressed Air Energy Storage: There are no prospects for isothermal CAES (or isothermal compression more broadly) being of sufficient technical maturity by 2030. The thermal energy storage required for isothermal CAES, like A-CAES is only feasible for shorter term energy storage (i.e., days, weeks, or months at a maximum). This does not satisfy the long time periods of NZ Battery context. Consequently, isothermal CAES options have not been considered further.

8.1.3 PRIMARY OPTION ASSESSMENT

Following the initial screening assessment, the Primary Option of Compressed Air Energy Storage with Subsurface Storage on the Preferred Pathway of D-CAES and storage in an existing or human-made hard rock cavern has been considered for further analysis. Table 8-2 provides an indication of the degree to which the option meets the evaluation criteria.

This technology option is scored based on a qualitative rating and quantitative evidence against the established RAG criteria defined in Appendix A.

Table 8-2: Air Storage Options

CATEGORY	CRITERIA	COMPRESSED AIR ENERGY STORAGE WITH SUBSURFACE STORAGE
Preferred Pathway		D-CAES and storage in subsurface depleted oil & gas reservoir, Existing, or Human Made Hard Rock Cavern
Long-term	Between Dry Years Energy Storage	🟢
	Storage Recovery	🟢
	Asset Life	🟢 > 50 years
Large-scale	Min. 1 TWh	🟢
	Up to 5 TWh	🟡
	3 to 6 Months Output	🟢
Renewable	Renewables	🟢
	Operational carbon emission intensity	🟡
	Built carbon emission intensity	🟡
	Sustainable Resources Risk	🔴
Technology Readiness	Technology Readiness Level (2030)	🟢
	Technology Ready for Commissioning (2030)	🟡
Geographical and Logistical Constraints	Geographical constraints	🟡
	Subsurface Constraints	🟡
	Transportation or Logistic Requirements	🟢
Commercial Viability [1]	Whole of Life Cost ($)	High [2]
Efficiency Measures	Round Trip Efficiencies (2021)	🟡
	Round Trip Efficiencies (2030)	🟡
	Annual Storage Decay Factor	🟡 Depends on geology
Environment and Safety	Environmental or Regulatory Hurdles (Ability to obtain a consent)	🟡
	Environmental Risks	🟡
	Safety Hazards Risks	🔴 (Ahuroa) Significant & unproven 🟢 Existing / Man-made cavern hard rock cavern
Project References	Project References	🟢 Huntorf / McIntosh

CATEGORY	CRITERIA	COMPRESSED AIR ENERGY STORAGE WITH SUBSURFACE STORAGE
Technology Implementation	Global Market Trends & Context	Scale
	Commitment of OEM Suppliers	(Small no of international developers)
	Available International Market to Import Resources	N/A
	Potential Implementation Bottlenecks	Scale of renewable heat Existing hard rock cavern Safety Solution for oil & gas reservoir

Source: WSP

Notes on the option assessed

[1] Based on Whole of Life calculation methodology applying consistent scenarios across all technologies.

[2] 'High' in the Whole of Life context equates to costs expected to be generally above $20B or with no commercially viable solution identified.

8.1.3.1 LONG-TERM

The D-CAES option provides for long-term storage of compressed air, given an appropriate cavern. The Ahuroa depleted gas-field is proven to hold natural gas. It has a vast capacity for gas storage under high pressure. The facility allows for variable and reliable injection/extraction rates. A suitable hard rock cavern, either found or human made, would also hold compressed air for years.

8.1.3.2 LARGE-SCALE

A D-CAES system of the size required to store 1 TWh is significantly larger than anything built or known to be planned. However, there are no known impediments to scaling to this size. Due to Ahuroa's large storage volumes, it is considered that energy storage above 1 TWh could be achieved. At Ahuroa, the storage is 456 Mm^3 at 23 MPa maximum reservoir pressure. This volume is two orders of magnitude more than the operational plants worldwide - McIntosh (US) or Huntorf (Germany) at 0.56 Mm3 and 0.31 Mm^3. A planned plant at Norton Ohio was for 2700 MW, from air compressed to 10 MPa, from a cavern with 120 Mm^3 volume. Refer to Table 8-3 for key comparative size and energy storage data.

Hard rock caverns, built or found, would need to be of a size or strength to allow similar storage volumes.

Table 8-3: Comparison of storage and withdrawal characteristics for potential depleted oil and gas reservoir to existing one and two solution mined caverns

Location	Ahuroa, NZ	McIntosh, US	Huntorf, Germany
Storage type	Depleted gas-bearing reservoir in Oligocene sandstone	One solution-mined salt cavern	Two solution-mined salt caverns
Depth at top of reservoir (m true vertical below ground)	2269	457	650
Storage volume (Mm^3)	456	0.56	0.31
Max reservoir pressure (bar)	234	73	70
Withdrawal rate	65 TJ/day = 1.71 Mm^3/day		417 kg/s = 28 Mm^3/day
Deliverable power (MW)	1000	100	290
Generation period (hours)	1000 (42 days)	26	3
MWh	1000000	2600	870
TWh	1	0.0026	0.00087

Source: Ahuroa: de Bock et al. 1989; NZPAM well completion reports: Taranaki Regional Council 2020; McIntosh: Nakhamkin et al 1992; Huntorf: Crotogino et al 2001;

Using the example of the McIntosh plant and scaling up to compare with the use of Ahuroa for the NZ Battery project, we need to compare the energy in MWh (McIntosh is 2,600 MWh and 0.56 Mm^3. Therefore, to scale up to 1 TWh equates to a scaling factor of approximately 385. Applying this scaling factor to McIntosh (and conservatively not adjusting for the higher allowable reservoir pressure of Ahuroa), the volume needed would be roughly 385 x 0.56 Mm^3 = 216 Mm^3. This is approximately 47% of the volume of Ahuroa for 1 TWh. therefore, the scale of available storage volume within Ahuroa appears to be in the order of magnitude range to support large-scale energy storage for the NZ Battery project.

There are also other depleted fields in Taranaki which could be considered. The Tariki field, for example, ceased production in 2008, but in 2021 its owners carried out a 3-D seismic survey, to both assess its potential as a gas-storage facility and to appraise possible bypassed gas.

Finding a non-hydrocarbon bearing geological structures is also possible. Numerous petroleum exploration wells have been drilled in onshore New Zealand without finding commercial (or, in some cases, any) hydrocarbons. These have been identified by seismic or surface mapping, tested by a single well and then abandoned. There are several such structures in Hawkes Bay, Whanganui-Manawatu and Canterbury. Key uncertainties include reservoir porosity and permeability, competent top-seal, and adequate structural closure. Evaluation for CAES would require review of existing well data; detailed seismic surveys to test structural integrity, one or more wells drilled into optimum parts of the structure, and pressure integrity tests. If none of these is suitable, then other hard rock caverns may exist. Finding one of these is possible but not necessarily likely.

Human-made hard rock caverns are feasible but very expensive.

8.1.3.3 RENEWABLE

D-CAES requires a source of locally available, long-term, large-scale heat to supplement the compressed air as it expands through the power turbine. Internationally this is supplied by natural gas but for the NZ Battery requirements this would need to be sourced from a renewable source.

To put this in perspective, the Huntorf D-CAES plant in Germany needs 1.6 TWh (5.76 PJ) of natural gas to produce 1 TWh of electricity. An eco-biomass facility like Reporoa, with a generation capacity of 0.083 TWh (0.3 PJ), would need to be scaled up about 19 times to meet the required output. These high-level figures are assumed from the similar gas combustion chamber efficiency and LCV (Lower calorific value) of natural gas and biomass.

Use of alternative heat sources, such as natural gas, results in emissions of CO_2 and other pollutants including, oxides of nitrogen (NOx) into the atmosphere so these are not appropriate for the NZ Battery solution.

8.1.3.4 TECHNOLOGY READINESS

D-CAES Technology is widely established around the world. The first CAES facility was commissioned in Huntorf, Germany in 1978. Newer and more efficient CAES technology is rapidly developing.

CAES is a mature technology that is backed up with strong reference plants in operation, albeit on a much smaller scale than that required for NZ Battery.

8.1.3.5 GEOGRAPHICAL AND LOGISTICAL CONSTRAINTS

New Zealand's geology is limiting due to the lack of salt caverns and structural closure in reservoirs needed for the storage of compressed air.

Depleted Oil and Gas Reservoir the Ahuroa depleted gas field is the most favourable location due to its readiness and proven containment of gas under high pressure.

Ahuroa's wells are completed with 4-1/2" production liner hanging inside 7" production casing. These diameters are suited for natural gas and as such are very small compared with the production casings used at the Huntorf project (more info in Section 6.3.2).

Existing hard rock caverns are already used for hydro-power generation facilities (e.g., Manapouri, Rangipo) or underground coal / gold mines (e.g., Huntly, Greymouth) but as explained above, are unlikely to provide a complete seal or will lack a definite highpoint. Due to New Zealand's geology (fractured and seismically constrained), there are expected to be significant limitations in finding a suitable hard rock cavern location with the size and structural competence needed to provide the large-scale, long-term energy storage criteria. Non-hydrocarbon bearing geological structures could also be considered, with the benefits of lower likelihood of producing explosive gas-air mixtures. Numerous petroleum exploration wells have been drilled in onshore New Zealand without finding commercial (or, in some cases, any) hydrocarbons. These have been identified by seismic or surface mapping, tested by a single well and then abandoned. There are several such structures in Hawkes Bay, Whanganui-Manawatu and Canterbury. However, these are highly likely to be infeasible for air storage due to reservoir porosity and permeability, competent top-seal, and adequate structural closure. This option would face additional challenges in terms of the low likelihood of finding an existing cavern in or near location that is suitable to site the power generation plant and grid connection.

Human-made hard rock caverns are likely to be technically feasible, if the right geology could be found, but the real impediment is the cost – likely to be more than $20B.

Heat Requirement. The other logistical issue is the need for a significant amount of heat. As the air decompresses, it cools and needs to be heated to expand sufficiently for generation purposes. Internationally, the heat source is generally natural gas but for NZ Battery, this would need to be renewable. The heat requirement for generation is between 1.2 - 1.6 kWh of heat for each kWh of electricity produced. The mitigating factor for this implementation would be that converting, say, the heat energy of woody biomass to electricity in a Rankine Cycle generation plant requires 3.1 kWh of heat energy for each kWh of electricity. The stored compressed air could be used to effectively double of the output of a biomass plant.

8.1.3.6 EFFICIENCY MEASURES

The round-trip efficiency for D-CAES is about 50%.

8.1.3.7 ENVIRONMENT AND SAFETY

Depleted gas/oil fields such as Ahuroa contain hydrocarbon residuals which can lead to the formation of compounds within the reservoir which are flammable and explosive in nature. The suitability of compressed air storage in such a hydrocarbon environment is yet to be proven effective and safe.

The mixing of compressed air and trace hydrocarbons, i.e., in a depleted oil and gas reservoir, could be a high risk 'critical flaw'. The risk is that the system storage and power generation process will involve potential spark and hotspot heat environments, which may have a high associated potential explosion risk with the working fluid being a hydrocarbon and compressed air mixture at high pressure (further increasing combustibility). We framed this risk in the form of a question: "*have any CAES reference plants in the world to date, stored compressed air in a depleted oil and gas reservoir such as Ahuroa.*" Following research carried out during this Task 1 of the project, there appears to be no known CAES Plants in existence using a depleted gas or oil field.

This risk is therefore significant and with no current prospect of this concern being addressed adequately in time, options using depleted oil and gas reservoirs are deemed infeasible.

Finding an existing cavern or building one does not have significant environmental or safety concerns.

8.1.3.8 REFERENCE PROJECTS

- Carrington, UK This facility is a 50 MW cryogenic energy storage plant with a minimum of 250MWh. The plant is due to be in operation by 2022. The approximate cost is £110/MWh for a 10-hour, 200MW/2GWh system.
- Vermont, USA This is a 50 MW liquid air energy storage facility with a minimum of 8 hours of storage (400MWh). The facility can store energy for weeks at a time. The plant operational date is unknown at this stage. The facility has a lifespan of 30-40 years.
- Huntorf, Germany This plant, commissioned in 1978, is the world's first CAES plant. The Huntorf CAES facility consists of two salt caverns, one of which has a displaced volume of 140,000 m^3; the other, 170,000 m^3. The power generating turbines operate with an air mass

flow rate of 417 kg/s for up to 3 hours, generating 290 (New upgrades – 321) MW and at lower output for a period. The plant uses 0.8 kWh of electricity and 1.6 kWh of gas to produce 1 kWh of electricity. There is a 1160MWh capacity which is 4 hours at 290 MW power output. The round-trip efficiency of this plant is about 42%.

- McIntosh, USA This CAES facility in Alabama, deployed in 1991, consists of a single solution mined salt cavern having a displaced volume of 538,000 m^3. The facility can have a sustained output of 110 MW for 26 hours. The plant uses 0.69 kWh of electricity and 1.17 kWh of gas to produce 1 kWh of electricity. There is a 2860 MWh capacity which is 26 hours at 110 MW power output. The installation cost is $1068/kW in 2020 USD. The round-trip efficiency of this plant is about 54%.
- Broken Hill Energy Storage, Australia This is a 200 MW utility-scale A-CAES facility. It will be located at a local decommissioned mine and is designed to provide up to 8 hours of electricity discharge at a time (i.e., up to 1,600 MWh). This plant is due to be in service by 2025.

8.1.3.9 TECHNOLOGY IMPLEMENTATION

There are few CAES developers internationally therefore, limited information is available in terms of current projects and feasibility study.

However, the technology components are all relatively standard requiring no substantial technological developments for implementation.

8.1.4 COMMERCIAL VIABILITY

8.1.4.1 INTRODUCTION

Using a Compressed Air Electricity Storage system for the NZ Battery problem involves finding a suitable cavern, building the system to compress air into the cavern and the generation plant to use the compressed air.

The key hurdle to a commercially viable implementation of this system in NZ is the need for a suitable cavern. NZ has no salt caverns as used internationally. The use of a depleted oil or gas reservoir, such as Ahuroa, would be ideal, except for the issue of mixing compressed air with the remaining hydrocarbons that has not been solved anywhere in the world. There are no known hard rock caverns in NZ, though there are some geological indications that a suitable hard rock cavern could possibly exist so, with some exploration risk, one might be found. It is also possible to build a suitable cavern, but the cost is extremely high.

8.1.4.2 COSTING SCENARIO

The only feasible option for implementing a CAES system is to build a human made cavern. This would be prohibitively expensive, in excess of $20B. On this basis, this option is not recommended for further assessment.

8.1.4.3 ALTERNATIVE IMPLEMENTATIONS

If a suitable cavern were found near to where a bioenergy plant was suitable, then the combination of bioenergy heat and compressed air storage could be viable. Low cost (off peak) electricity could be used to compress the air. In a dry year, the biomass plant could burn woody biomass and the heat would be used to heat the decompressing air instead of generating electricity in a Rankine Cycle generation plant.

This would effectively be a mechanism for increasing the efficiency of a biomass plant. At the time of generation, the stored compressed air is used to raise the efficiency of electricity conversion from woody biomass (that would be used in a Rankine Cycle plant) from 32% to between 63% and 83%.

8.1.4.4 COMMERCIAL VIABILITY DISCUSSION

Commercial viability of all feasible Air Storage options fail. The only feasible option is a human-made cavern that would cost in excess of $20B.

8.1.5 SWOT ASSESSMENT

Table 8-4: Compressed air energy storage (subsurface) SWOT

	Helpful to achieving the objective	Harmful to achieving the objective
Technology (source to grid)	STRENGTHS	WEAKNESSES
	• Proven Technology • Small surface footprint • Minimal concerns with vandalism or terrorism	• Geology dependent (salt formation preferred, certain amount of reservoir capacity required); geology that will store air at sufficient pressure • Must be located near power infrastructure in order to receive power to operate • Need large-scale renewable heat source that must be nearby
Operating Environment (external)	OPPORTUNITIES	THREATS
	• Make use of surplus available power in order to store energy for peak demand • Long project life span, high durability	• Potential air combustion if using depleted oil and gas reservoir for hydrogen/air storage • Earthquakes

8.1.6 DISCUSSION

Air storage is a battery in the sense that it stores low value electricity and uses it later in the generation of electricity. However, it also requires a significant amount of heat at the time of generation that could be used directly. Mature technology exists to store compressed air and the technology is rapidly developing around the world. However, while CAES plants are well-established overseas they tend to be very much smaller than NZ Battery requires.

The key challenge to the use of CAES for NZ Battery is the requirement for a suitable cavern for air storage.

NZ has several depleted oil/gas reservoirs that would appear to be the most likely option for subsurface compressed air storage, but currently this represents a significant risk due to mixing of compressed air with remaining hydrocarbons. This is yet to be proven as effective and safe anywhere in the world. We conclude that this option has too high a safety risk to be considered feasible.

Another option could be to store air in an existing subsurface hard rock cavern, but it is uncertain whether any suitable caverns exist in NZ. It would require significant investigations to locate a cavern of the scale required and this exploration could result in nothing being found. Non-hydrocarbon bearing geological structures could also be considered, with the benefits of lower likelihood of producing explosive gas-air mixtures, However, these would also be highly likely to be infeasible for air storage due to reservoir porosity and permeability, lack of competent top-seal, and adequate structural closure. We conclude that this option has too high a risk to be considered feasible.

The only feasible alternative is to build a cavern. The cost of this would be in excess of $20B. We conclude that this is too high and that this option should not be taken further.

If a feasible, reasonable cost, cavern was found then it is possible that air storage could be combined with another renewable energy source that used heat as an intermediary energy step (e.g., the burning of biomass). Using this renewable heat in the generation of electricity from CAES results in a very high conversion efficiency of the heat to electricity. However, the chances of the feasible cavern being close to the source of the renewable energy and both being at a suitable location for connection to the grid make this possibility highly unlikely.

We do not recommend any CAES options be taken into Task 2.

8.2 LIQUID AIR ENERGY STORAGE

8.2.1 PRIMARY OPTION INTRODUCTION

The baseline Liquified Air Energy Storage (LAES) system is generally a three-stage system consisting of air liquefaction, liquid air storage, and power generation. Each stage can be operated independently of the other stages. As liquifying gas significantly increases the density of the fluid, it can be stored using smaller storage volumes compared to gas. During the liquefaction phase, air enters the compression process at ambient pressure and temperature and leaves at high pressure and high temperature. The compression process generates heat energy, raising the air temperature significantly. The heat is generally stored for use in the subsequent power generation cycle. The hot, high-pressure gaseous air enters a heat exchanger where it is cooled and condensed to a temperature of approximately -190°C. The resulting high pressure liquid flows through a throttle valve, which both causes the liquid to expand and results in a low pressure (approximately atmospheric), and finally a further temperature reduction to approximately -196 °C.

The liquid is separated from remaining gas and stored. The cooling required for liquefaction is typically supplied from a cold storage system, usually in the form of liquid refrigerants or a solid packed bed. The liquid is then stored in a low-pressure vessel, until power generation is required. To release the energy stored in the liquid air and convert it to electricity, a power cycle is required. Liquid air is taken from the storage vessel and pumped to a high pressure using a cryogenic pump. The liquid air is evaporated and then superheated using the stored heat of compression removed from the air during the liquefaction process. Thus, the liquid air is heated into a gaseous state and the resulting expansion of air is used to drive a turbine to generate electricity.

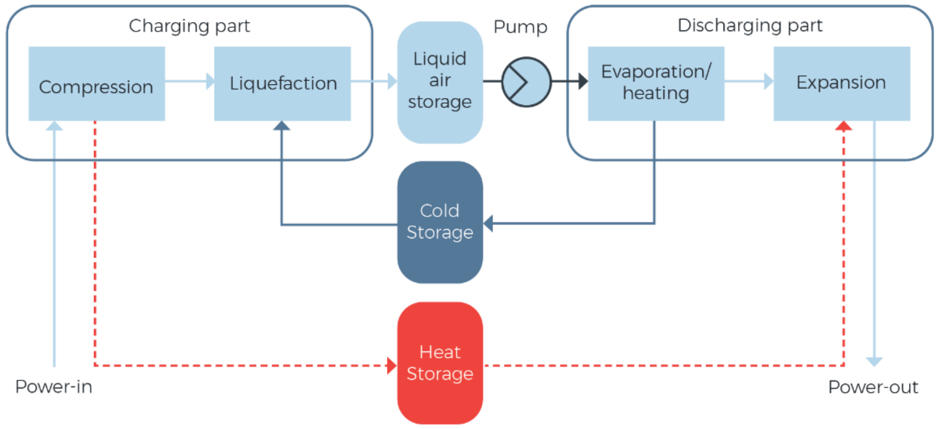

Figure 8-3: LAES Process Schematic

Source: European Associated for Storage of Energy

8.2.2 TECHNOLOGY PATHWAYS

Table 8-5 presents a broad categorisation of the pathway options to use air storage for the storage of electricity through liquid air energy storage. In the table, **Bold text** represents the Preferred Pathway, Normal text represents Other Pathways, and Red text represents Discontinued Pathways.

Table 8-5: Liquid Air Energy Storage Technology Pathways

	LIQUID AIR ENERGY STORAGE
Energy Source	Renewable Energy
Storage	Above ground cryogenic tank storage Subsurface (underwater) cryogenic tank storage Thermal Energy Storage
Generation	Natural gas combustion heat source re-expansion Expansion Turbine Combined Compressed Air & Natural Gas fired gas turbine

Source: WSP

8.2.2.1 PREFERRED PATHWAY

There are no pathways considered to satisfy the three key criteria of the NZ Battery project.

8.2.2.2 DISCONTINUED PATHWAYS

Liquid Air Energy Storage: Liquid Air Energy Storage requires cryogenic storage for the liquid air and Thermal Energy Storage (TES) to temporarily store the heat emitted during air compression step, then feed the heat back during the expansion step. (Allowing the heat to instead dissipate during the compression step would require a prohibitively large amount of additional renewable heat during the expansion step). Cryogenic liquid air storage and TES is only feasible for shorter term energy storage (i.e., days, weeks or months at a maximum). With the long time periods of NZ Battery context, using TES to provide heat for liquid air re-expansion is not a viable option.

8.2.3 DISCUSSION AND SUMMARY

As covered above, cryogenic liquid air storage with TES is only feasible for shorter term energy storage, therefore, for the large-scale, long-term time periods associated with the NZ Battery context, Liquid Air Energy Storage is not a viable option.

8.3 SUMMARY AND RECOMMENDATION

We do not recommend that any Air Storage technologies proceed for further feasibility assessments.

Several options, including Liquid Air Energy Storage, Adiabatic and Isothermal cycle Compressed Air Energy Storage involve Thermal Energy Storage, which does not meet the requirements for long-term storage.

The remaining option, Diabatic Compressed Air Storage, has no pathway that is both feasible and cost effective. The requirement for suitable subsurface storage cannot be met:

- Using a depleted oil and gas reservoir has the considerable risk of explosion due to mixing remaining hydrocarbons with the compressed air. Despite considerable international research, this problem has not been solved. Even with continuing research there remains too high a likelihood that this problem will not be solved in time.
- Finding an existing hard rock cavern is also a high risk option as significant expense would be required with a relatively low likelihood of finding an appropriate cavern.
- A human-made cavern may be feasible, depending on finding an area with the right geology, but would cost well in excess of $20B.

If a feasible subsurface could be found then an investigation into combining a CAES system with biomass would be worthwhile. It would effectively use off peak electricity to make generation from woody biomass twice as efficient.

Other options would require:

- A solution to the safety problem of mixing compressed air with hydrocarbons would need to be found.
- An existing hard rock cavern would need to be found.

We are of the view that the probability of either of these events is too low for any options to warrant further investigation.

8.4 AIR STORAGE REFERENCE LIST

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9 FLOW BATTERIES

Within this section we consider and assess the potential to manage dry year risk using flow batteries in the NZ Battery Project context.

9.1 REDOX FLOW BATTERIES

9.1.1 PRIMARY OPTION INTRODUCTION

A flow battery is an electrochemical energy storage device that has excellent potential for large-scale modular systems. It has a unique type of rechargeable battery architecture, in which electrochemical energy is stored in one or more soluble electrolytes. These electrolytes are pumped through a reaction tank consisting of a positive (anode) and negative electrode (cathode) that are separated by an ion selective membrane. In the reaction tank reduction / oxidation of the electrolytes takes place to create electrical potential (hence the name Redox). Electricity is generated by the ion exchange that then occurs between the two electrodes. A schematic of a flow battery is shown in Figure 9-1. A flow battery is a reservoir for energy and is not a net generator, so it relies on being charged from an external source as reflected in the figure.

Flow batteries consist of three main components:

- The Cell (also called a “stack” or power unit): this is the reaction tank with an anode / cathode and dividing membrane, connected to the electrical output. The anode / cathodes are typically made of graphite plates.
- Positive cell tank holding positive electrolyte
- Negative cell tank holding negative electrolyte

The tanks are linked by pumps and piping which bring a controlled amount of electrolyte from the positive and negative tanks in and out of the power unit. These are controlled by a battery management system (BMS) which monitors operations against demand and performance.

Different oxidation states of dissolved ions in the electrolyte, store or deliver electric energy. The electrolyte is continuously fed from a tank system into the reaction cell. Depending on the current demand, energy is stored in the electrolyte (battery charging) or fed into the grid/network (battery discharging).

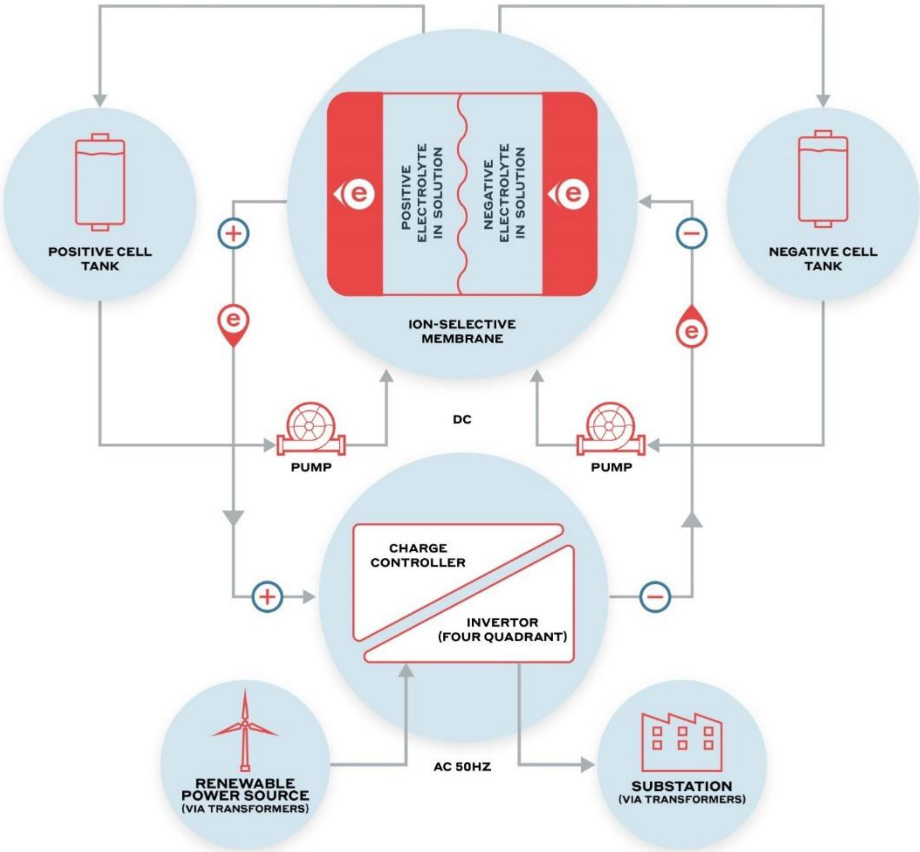

Figure 9-1: Flow Battery Process

Source: WSP

In flow battery systems, the power and energy capacity can be designed separately. The power (kW) of the system is determined by the size of the electrodes and the number of cells in a stack. The energy storage capacity (kWh) is determined by the concentration and volume of the electrolyte. Both energy and power can be easily adjusted for storage from a few weeks to months, depending on the application. This flexibility makes flow batteries an attractive technology for grid-scale applications where both high-power and high-energy services are being provided by the same storage system. Flow batteries are, however, still considered to be in development.

Redox and hybrid flow batteries were investigated as the flow battery Primary Options. Details of each Primary Option are provided below.

9.1.1.1 REDOX FLOW BATTERIES

Redox flow batteries have all active material (i.e. the chemicals that store the energy and release it) in the electrolyte and the electrodes are not involved chemically in the reaction. The batteries charge and discharge via a cell linked to two electrolyte tanks. All active materials are stored in the electrolyte and can be removed from the cell for storage. Little or no changes in volume occur to the electrolyte or electrodes.

9.1.2 TECHNOLOGY PATHWAYS

Flow batteries include a wide range of technologies, using different electrolytes to store energy.

All pathways considered would involve installing a large-scale flow battery, charging it using off-peak renewable electricity from the grid, and discharging it back to the grid when a shortage occurs during dry years.

Table 9-1 presents a broad categorisation of the pathway options to use flow batteries for the storage and generation of electricity through redox flow batteries. In the table, **Bold text** represents the Preferred Pathway, Normal text represents Other Pathways, and Red text represents Discontinued Pathways.

Table 9-1: Flow Batteries Technology Pathways

	REDOX FLOW BATTERIES
Energy Source	Renewable Energy
Import	Not Applicable
Storage	Surface tank storage of: Vanadium Iron Chromium All Organic
Generation Process	Redox Flow

Source: WSP

9.1.2.1 PREFERRED PATHWAYS

Vanadium Redox Flow Batteries: Vanadium redox flow batteries have been selected as the most optimal pathway for this assessment, as they are currently being produced for energy storage and are considered the most technically mature. The batteries are already commercially available (in smaller sizes) and can be scaled in several different manners. (They can be scaled by increasing the size of the electrolyte tank, or the number of cells connected to the tanks.) Several larger scale plants have been installed globally, including the Minami Hayakita Substation in Japan (60 MWh), Fraunhofer ICT in Germany (20 MWh), and Dalian Battery in China (800 MWh). These are however small in the context of the NZ Battery project that aims to store between 1 TWh and 5 TWh.

Vanadium batteries do not suffer from dendritic growth[4], and being a pure redox flow battery, do not suffer from some of the issues that hybrid batteries must deal with, such as loss of active material due to plating or deposition.

VRFB can recharge quickly, will not lose capacity with use, can be totally discharged (i.e., have a 100% depth of discharge), and have a roundtrip efficiency approaching 85%.

[4] **Dendritic growth** is a process where the electrodes grow in an organic manner and can short the cell electrically or interfere with electrolyte flow.

9.1.2.2 OTHER PATHWAYS

Iron Chromium, All Iron and other Flow Batteries: As with Vanadium Redox, the manufacture of all-iron redox flow batteries has been realised at a commercial level. Prototypes are currently 50 kW/400 kWh with a lifespan of 20,000 cycles. This is a similar life to Vanadium redox flow batteries, but at lower energy densities, and hence require more land area or a greater volume. Energy density is still low, and the land area required for TWh scale currently makes this chemistry difficult to implement, however, it is one of the more mature flow battery technologies and WSP recommends that it be monitored for further development.

Zinc flow batteries do not respond well to being discharged below 5% and still require further development.

Vanadium Redox are considered to have advantages over Iron batteries and other available technologies presently available and are therefore, selected as the preferred pathway.

9.1.2.3 DISCONTINUED PATHWAYS

All-Organic Flow Batteries: These batteries were initially considered due to their lower toxicity and potentially attractive chemistry, but WSP have found that their technology readiness is low, and no commercial supplier currently exists. The lack of technical maturity means that this type of battery is not considered able to meet the large-scale required for the NZ Battery project in the project timeframe.

9.1.3 PRIMARY OPTION ASSESSMENT

Following the initial screening assessment, the Primary Option of Redox Flow Batteries on the Preferred Pathway of Vanadium Redox has been considered for further analysis. Table 9-2 provides an indication of the degree to which these batteries meet the evaluation criteria.

The scoring is based on a qualitative rating and quantitative evidence against the established RAG criteria defined in Appendix A. Our assessment against the Evaluation Criteria is explained further below.

Table 9-2: Flow Battery Options Assessment

CATEGORY	CRITERIA	REDOX FLOW BATTERIES
Preferred pathway		Vanadium Redox
Long-term	Between Dry Years Energy Storage	🟢
	Storage Recovery	🟢
	Asset Life	🟡
Large-scale	Min. 1 TWh	🟢 [1] [2]
	Up to 5 TWh	🟢 [1] [2]
	3 to 6 Months Output	🟢
Renewable Technology	Renewables	🟢
	Operational carbon emission intensity	🟢
	Built carbon emission intensity	🟡
	Sustainable Resources Risk	🟡
Technology Readiness	Technology Readiness Level (2030)	🟢 9
	Technology Ready for Commissioning (2030)	🟢
Geographical and Logistical Constraints	Geographical constraints	🟢 Land area
	Subsurface Constraints	🟢
	Transportation or Logistic Requirements	🟢
Commercial Viability	Whole of Life Cost ($)	Commercial Information
Efficiency Measures	Round Trip Efficiencies (2021)	🟡 65 to 80% (9-31)
	Round Trip Efficiencies (2030)	🟢 80 to 90% (9-20)
	Annual Storage Decay Factor	🟢 0.4%
Environment and Safety	Environmental or Regulatory Hurdles (Ability to obtain a consent)	🟡
	Environmental Risks	🟡 [3] [4]
	Safety Hazards Risks	🟢 [3]
Reference Projects	Reference Projects	🟡 [2]
Technology Implementation	Global Market Trends & Context	🟢
	Commitment of OEM Suppliers	🟡
	Available International Market to Import Resources	🟡
	Potential Implementation Bottlenecks	🟡

Source: WSP

Notes on the option assessed

[1] Flow batteries are, in theory, fully scalable by increasing electrolyte volume. However, the associated – price increase for capital aspects and the related production challenge are the limiting factors in producing a 1 TWh RFB. For some batteries, the sheer bulk and volume of materials required may be a limiting factor.

[2] The world's largest vanadium RFB has a claimed capacity of 800 MWh (200 MW) (9-13).

[3] Abnormal operation such as electrolyte leaks or primary containment failure are typically protected by secondary and tertiary containment (9-16).

[4] ESS are manufacturing an iron/sodium chloride battery of low energy density but there are no current commercial manufacturers of Iron Chromium flow batteries. During normal operation, RFB's typically do not pose any environmental threats (9-16).

9.1.3.1 LONG-TERM

Vanadium-based storage systems cannot burn and do not lose capacity even after decades of use. Vanadium is stable for a nearly indefinite period, making it more durable than any other battery technology, and the most cost-efficient battery technology (based on a multi-month storage system).

Vanadium does not decompose or degrade, so, with regular maintenance, there is no loss of power and capacity, even after many years of operation. In principle, vanadium redox flow batteries have an unlimited lifecycle. The electrochemical reactions within the battery occur on the surface of graphite electrodes, so that no forces are exerted on the electrodes themselves. The lifecycle of a Vanadium reflow system is only limited by the auxiliary components and, finally, the plastic tanks.

Storage decay can be decreased when the system is in standby mode. Only electrolyte within the cell is active and, once this is discharged, no further reaction occurs and so losses decrease with time. In the electrolytic storage tank, there is no discharge until the electrolyte is pumped back through the cell by the pumps.

9.1.3.2 SCALABILITY

The "front end" of the flow battery is the anode/cathode active component. The storage capacity of a vanadium redox flow battery can be doubled by retaining the front end and doubling the electrolyte tank capacity. Therefore, the costs for the entire system decrease proportionally, as the capacity tank increase of redox flow batteries is relatively inexpensive.

Due to the modularity of the flow batteries, these can be arranged in distributed sections to be close to load centres and reduce the visual impact.

Many components of flow batteries, including the high-power inverters and control systems are common with other industries, such as solar farms.

As demand for storage increases, the number of storage cycles per day also increases. Multiple storage cycles lower the price per stored kilowatt hour. The vanadium battery does not degrade in accordance with the cycles, so no added adaptations are needed.

The electrolyte flow direction does not have to change when loading and unloading, thus the VRFB has a fast response time (less than 20 ms).

It can be switched between charging and discharging whilst under full load.

9.1.3.3 RENEWABLE TECHNOLOGY

This technology is renewable when produced using renewable electricity supplies.

Vanadium can be recycled, making it especially sustainable. It can be reclaimed from the electrolyte solution and then used in another vanadium redox flow battery, as part of the lithium battery electrodes or in the steel industry.

At present the most effective membranes are derived from fossil fuels, as are some of the tank linings. However, these are usually characterised by extended life use.

The redox flow batteries do not consume their electrolytes and hence could be considered a storage bank of the chemicals, a low carbon approach in itself.

9.1.3.4 TECHNOLOGY READINESS

Vanadium redox flow batteries are already commercially available (in smaller sizes) and can be scaled in several different manners.

Technology readiness level is currently assessed at 8 for battery installations in the order of 1000 MW and is expected to be 9 or above by 2030 based on the level of research and commercial application recorded by IRENA/NREL/DOE for larger systems.

The stumbling block currently is the capital cost, see commercial viability below.

9.1.3.5 GEOGRAPHICAL AND LOGISTICAL CONSTRAINTS

Vanadium is a rare element produced in China, Russia, India, South Africa and Brazil (in order of annual production). Although rising, its use in long-term energy storage systems still only represents a fraction of global demand for vanadium. Australia has announced it is developing Vanadium resources (9-2). Availability and cost of vanadium to supply a large energy storage demand will require further attention on sourcing, procurement and logistics, as well as the associated costs as vanadium is used in multiple processes as well as VRFB (9-21).

Electrolyte storage tanks will require a significant storage area. At current energy density (30 – 50 Wh/l) this is 20-33 GJ per TWh. At 30 Wh/l this equates to 1 km^2 to a height of 30 m for 1 TWh (including the cell itself that takes about 15% of that area).

9.1.3.6 EFFICIENCY MEASURES

Round trip efficiency is already approaching 85% and is targeted to reach parity with Lithium-ion batteries (95%) in 2030 but this is speculative at this stage.

Decay rates of Vanadium Flow Batteries are relatively low at 0.25 - 0.31% per cycle.

Vanadium batteries can be totally discharged without limitation. (In comparison, Lead/Zinc/Iron flow batteries currently do not respond well to being discharged below 5%).

9.1.3.7 ENVIRONMENT AND SAFETY

During normal operation, RFBs typically do not pose any environmental threats (9-16).

The electrolyte of a vanadium flow battery is acidic and should be treated as an acid if released. However, abnormal operation such as electrolyte leaks or primary containment failure are typically protected by secondary and tertiary containment (9-16). The tanks are designed with double walls. Leaks can be identified with accuracy and result in the module being shut down

Vanadium is dissolved in a water-based electrolyte solution, which is not combustible, and the technology has little danger of overheating which could result in fires or explosions. Safety Hazard risks are therefore, considered able to be sufficiently mitigated to a low residual risk.

If fire reaches the storage tank, the electrolyte solution itself could be used to extinguish the fire.

9.1.3.8 REFERENCE PROJECTS

The Vanitec website lists 26 companies as producers of Vanadium redox flow batteries (9-27) and several plants have been installed globally (9-28). Among the largest are:

- The Minami Hayakita Substation in Japan, rated 15 MW and 60 MWh and built by Sumitomo Electric Ind. for Hokkaido Electric Power Inc. in 2015.
- The energy storage station at Fraunhofer ICT in Pfinztal, Germany, rated 2 MW and 20 MWh and commissioned in 2019.
- UniEnergy Technologies, US-WA, has installed a number of systems rated 2 MW and 8 MWh.
- The 200 MW 800 MWh Storage Station designed by Rongke Power of China.
- SDG&E and Sumitomo Electric have partnered to install a 2 MW / 8 MWh vanadium redox flow battery in California.

Whilst there are several reference projects, none are at the scale of NZ Battery requirements.

9.1.3.9 TECHNOLOGY IMPLEMENTATION

No major barriers are noted but capital costs are high.

Efforts continue to improve components (i.e., electrolyte composition, membrane and electrode), performance (efficiency and power and current densities).

There are some commercial suppliers of Vanadium redox flow batteries, but only at limited scale.

9.1.4 COMMERCIAL VIABILITY

9.1.4.1 INTRODUCTION

Using a Vanadium redox flow battery for the NZ Battery problem involves building the battery, taking renewable electricity from the grid, storing the electrolyte until a dry year, and then reversing the process to inject electricity back onto the grid.

Flow battery solutions are high capital cost but relatively low running cost. The high capital cost is driven by the quantities of electrolyte needing to be stored. In a NZ Battery context, the need to store large quantities for significant time periods is a hurdle for flow batteries. There is a significant amount of research into increasing the energy density of the stored fluids that could make significant reductions in cost likely in the future.

9.1.4.2 COSTING SCENARIO

As with the other technologies, the flow battery costing scenario targets meeting 1 TWh of demand over a three-month period identified as a dry year. Dry years occur in 2032 and every five years subsequently. To achieve these dry year requirements, electrolyte storage for 1 TWh is required at a cost Commercial Information (including the battery plant itself that is Commercial Information). The battery plant can fill the storage gradually from lowest cost electricity as it is sized to re-inject at the equivalent of 500 MW. Conversion efficiency is assumed to be 90% so 1.1 TWh is required to provide the 1 TWh output.

9.1.4.3 ANALYSIS RESULTS

ITEM	COST	NOTES
Capex Total ($)	Commercial Information	Total build costs of the battery to provide 1 TWh over 3 Months (500MW)
Capex ($/kW)		
Opex (per year)		
Whole of Life Cost ($)		
LCOE ($/MWh)		

9.1.4.4 ALTERNATIVE IMPLEMENTATIONS

Vanadium redox flow batteries are ideal electricity storage systems and often used for continuous operation. They can react within a few seconds and yet can still supply energy for long periods. This makes it possible to not only cover dry year loads but can also be used as a spinning reserve or standby (peaking) plant. This may add some management and equipment cost but could be financially effective especially in systems with high intermittent generation.

9.1.4.5 COMMERCIAL VIABILITY DISCUSSION

Our view is that, despite the forecast cost reductions, the current expected cost at 2030 is still too high for the NZ Battery requirements. This is principally due to the cost of the large electrolyte volume required for large-scale energy storage.

It is unlikely that redox flow batteries will become commercially viable by the NZ Battery Project's 2030 timeframe, particularly given the large storage requirements. However of the options investigated redox flow battery technologies appear to have the potential for rapid rates of advancement in storage capability and the consequent reductions in cost and size and could present a viable energy storage opportunity beyond the 2030s. If there are any changes to commitment timelines then a redox flow battery solution could become commercially viable. This would add to the option value of any solution that allowed delivery of a full NZ Battery solution to be delayed.

9.1.5 SWOT ASSESSMENT

Table 9-3: Vanadium redox flow battery SWOT

	Helpful to achieving the objective	Harmful to achieving the objective
Technology (source to grid)	STRENGTHS	WEAKNESSES
	• Pure electrical storage media and requires no feeder industry to operate. • Flexible design and high scalability. Lending themselves to incremental implementation. • Efficiency at 70 – 80% today and increasing to 90% by 2030 • Low operating cost in proportion to capital costs	• High Capex costs for required infrastructure. • Relatively large land required for the installation. • Low Energy density 30–50 Wh/kg (for Vanadium RFB) • Due to size, competition for key resources (vanadium, chemicals) may drive prices

	Helpful to achieving the objective	Harmful to achieving the objective
	• Response time in milliseconds • Low storage losses • Pollution-free – self-contained, bunded and constrained • Not affected by charge-discharge cycles since electrodes are inert. Life mainly depends on membrane lifespan. • High reliability - standard equipment (pumps, pipes, tanks, inverters etc.) • Flow batteries do not degrade the storage media and hence the media can be on-sold when decommissioned or upgraded to an alternative technology.	upRelies on reliable acquisition and importation of large volumes of chemicals
Operating Environment (external)	STRENGTHS	THREATS
	• On-shore design, manufacture and construction create national employment and develops new skills. • Technology and IP can be exported globally. Ongoing development in both chemistry and lifecycle. Opportunity to develop better membranes • Flexible application - Flow batteries are scalable and can consist of multiple types of battery systems (hedging bets on technology). • Fabrication - Development of a flow battery fabrication factory could facilitate exports • Solar and wind back up, spinning reserve, large-scale utility storage, emergency power.	• Low carbon emissions in operation but uses toxic/acidic chemicals. • Redox flow batteries are developing rapidly, and new chemistries may supersede current equipment, but by its modular nature upgrades may be possible. • Unforeseen difficulties of generation (considered unlikely). • Political/public concern about the land area required (Low energy density leads to large land area requirements)

9.1.6 DISCUSSION

Redox flow batteries are a form of conventional storage option, taking power from the grid and converting it through a chemical process for storage. On demand, this process can be reversed, and the chemical energy released to generate a current which can be fed back into the grid via an inverter. No other ancillary operations are required outside of the footprint of the flow battery.

Redox flow batteries have several strengths as a NZ Battery Project solution. Both power storage and power release can be effected in extremely short periods and provide a great level of flexibility, without an extended start up process. High cycle capability means that the flow batteries can be left online as required and do not need to be disconnected awaiting a dry year, providing a low mothballing and standby cost. The energy decay only occurs in the active cell where electrolyte is in contact across the membrane, and therefore decay is very limited when considered against the volumes held in the electrolyte tanks.

Redox flow batteries lend themselves to incremental implementation, taking advantage of their unique scalability both for power and energy. This could enable a staged approach, by initially constructing the battery with a smaller volume of electrolyte then incrementally increasing this volume over time if required to meet NZs dry year energy needs.

Redox flow batteries do not pose any environmental threats during normal operation. Abnormal operations such as electrolyte leaks or primary containment failure are typically protected by secondary and tertiary equipment. Safety Hazard risks are generally considered low. However, due to the large-scale nature, and land area required (their low energy density leads to large land area requirements) to accommodate high quantities of the toxic / acidic chemicals associated with Redox flow batteries, this option would be expected to create relatively high public concern.

The main challenges to the Redox flow battery as a NZ Battery solution relate to its commercial viability in the timeframes required by this project, with current high capital costs per kW installed. Redox flow batteries are both an existing commercial offering and yet are still in development. This implies they are rapidly approaching full commercial roll out in a cost-effective manner and investors are anticipating that some financial and performance barriers may in future be overcome. The rapid development and deployment (with financial guarantees) of Iron Salt redox flow batteries is an example of this expectation.

Our current expectation is that this technology, despite its rapid technological development trend, will not be commercially viable by 2030. However, if there are any changes to commitment timelines then a redox flow battery solution could become commercially viable. This would add to the option value of any solution that allowed delivery of a full NZ Battery solution to be delayed.

9.2 HYBRID FLOW BATTERIES

9.2.1 PRIMARY OPTION INTRODUCTION

Like standard redox flow batteries, hybrid flow batteries charge and discharge via a cell linked to two electrolyte tanks. However, the active materials are not only stored in the electrolyte, but also in the cell materials, typically the electrodes. This allows for higher current densities to be achieved when compared to pure redox.

Many of the battery chemistries have great future promise (higher energy density and less toxic electrolytes) but are still in development and have a variety of limitations yet to be overcome.

9.2.2 TECHNOLOGY PATHWAYS

Table 9-4 presents a broad categorisation of the hybrid flow battery pathway options, simplified to aid this initial assessment. In the table, **Bold text** represents the Preferred Pathway, Normal text represents Other Pathways, and Red text represents Discontinued Pathways.

Table 9-4: Flow Batteries Technology Pathways

	HYBRID FLOW BATTERIES
Energy Source	Renewable Energy
Import	Not Applicable
Storage	Surface tank storage of: • Zinc Bromine • Lithium Sulphur • Sodium Sulphur • Sodium Nickel Chloride • Copper/Zinc Rechargeable Battery • Planar stacked Na-beta • Membraneless Flow Battery Technology
Generation Process	Hybrid Flow

Source: WSP

The overall lack of technical maturity in the battery chemistries means that hybrid flow batteries are not considered able to meet the large-scale required for the NZ Battery project within the project timeframe. Common challenges for hybrid batteries involve deposition or plating of electrodes which can cause significant volumetric changes in selected parts of the cell. This makes them harder to maintain and results in scalability issues. Specific issues with individual technologies are described further below:

9.2.2.1 DISCONTINUED PATHWAYS

Zinc-Bromine

Zinc Bromine Flow Batteries (ZBFB) have no cycle-life limitations because the electrolytes do not suffer aging effects: lifetimes of 11–14 years are already commercially proposed. ZBFB pilot systems are capable of a performance comparable to commercial VRFBs (i.e. charge/discharge durations up to 10 hours (9-18)) and can operate at current densities of up to 80 mA cm^{2,} with energy efficiencies around 80%.

While the ZBFB is the most investigated and successfully commercialised hybrid battery technology it has not scaled up as expected and has proven to be volatile in some scenarios. While they offer 100% depth of discharge capability, they need to be fully discharged every few days to prevent dendrites growth from short-circuiting (9-22). Dendritic growth is a process where the electrodes grow in an organic manner and can short the cell electrically or interfere with electrolyte flow. Zinc Bromine also has yet to overcome the high discharge rate (decay) of 8 to 33% per day and expected efficiency gains have not yet been realised.

Due to the requirement for regular discharge, they are not suitable for extended, un-used storage modes and are therefore, considered to be currently unsuitable for the NZ Battery criteria.

Lithium Sulphur Flow Batteries

Currently, the Lithium Sulphur battery technology is limited by several factors including, energy losses (discharge and decay) when in standby, capacity loss caused by precipitation, low conductivity of Sulphur, and volumetric expansion during cycling (charging and discharging). Lithium sulphur flow batteries are not considered mature enough to be able to meet the long-term / large-scale criteria within the project timeline.

Sodium Sulphur

Sodium Sulphur batteries are intended for long durations of energy storage, as they have high round-trip efficiency and relatively high energy density, however their costs continue to be high, and they are still in the early stages of development. The high temperatures (300°C) result in a high energy drain with time. Sodium Sulphur flow batteries are not considered mature enough to be able to meet the long-term / large-scale criteria within in the project timeline.

Prototypes of up to 245 MWh (9-26) have been tested in Japan and could be watched for further development, especially if operating temperatures can be reduced.

Sodium Nickel Chloride (NaNiCl)

As with Sodium Sulphur batteries, these currently do not meet the long-term storage requirements of the NZ Battery project as they require high temperatures which have a high energy drain over time.

The Sodium Nickel Chloride battery is a high-temperature battery which can stand limited overcharge and discharge. There are safety concerns regarding the need to protect the Sodium from moisture. Another common problem with the technology is that many chemistries form undesirable Na_2S_2 solids with higher depth-of-discharge operation. This option currently has a relatively low energy density, although theoretically this could reach above 450 Wh/L with a related loss of 20% capacity over 1000 cycles. They have been used in electric vehicles and new research is being done to further develop these batteries, but they are not yet at the scale required.

Copper / Zinc Rechargeable Battery

Copper / Zinc batteries are also high-temperature batteries, with the same related high energy drain issues when in standby mode.

Planar stacked Na-beta (planar Na-β) batteries

These are currently only at laboratory scale and no commercial pilot was found during research. It is therefore, considered that planar stacked Na-beta batteries do not meet the requirement to be commercially viable in the time scale available. Na-β batteries (or NBBs) use a solid β-alumina electrolyte membrane that selectively allows Na ion transport between a positive electrode (e.g. a metal halide) and a negative Na electrode.

Membraneless Flow Battery Technology

Considering the high cost of most commercial ion exchange membranes, membrane-free cell configurations are considered a simpler operation and hence a more cost-effective application. However, the current technology is limited by high self-discharge effects, charging limitations and low voltage efficiencies (9-5). Due to low technical maturity, membraneless batteries do not meet the requirement to be commercially viable in the time scale available.

9.2.3 DISCUSSION

Hybrid flow batteries offer the same strengths and benefits for the NZ Battery project as the Redox flow battery. At present, hybrid flow batteries do not meet the requirements of NZ Battery due to lower technology readiness but are still receiving attention due to the promise of higher energy density. For the timelines proposed for this project, WSP is doubtful that sufficient advances will be made to overcome some of the problems highlighted for large-scale TWh development.

9.3 SUMMARY AND RECOMMENDATION

While flow batteries provide many strengths and benefits as a solution to the NZ Battery project, they are not recommended as a prospective option due to the relatively high Whole of Life costs currently expected when compared to other technologies in this assessment.

Flow batteries are currently highly utilised successfully for smaller scale energy storage systems globally, with new or improved chemistries appearing annually. Estimating Capex of a 1 TWh Vanadium RFB is a complex exercise due to a lack of global development of costing models for a system of such high energy storage capacity. As global interest in high energy-to-power ratio RFB's grows, the accuracy of costing such systems is expected to improve.

The following are some areas that can be expected to improve significantly:

- *Power / Energy density:* Vanadium redox flow batteries are currently achieving energy density values between 23 and 25 Wh/L with research indicating up to 70 Wh/L may be achievable by 2025 (9-1). The Power density is limited by the number of cells stacked in series, and research continues into increasing the voltage per cell to reduce the associated costs and complexity.
- *Round Trip Efficiency:* Round trip efficiency is high for redox flow batteries, but ongoing research is improving this further.

WSP has considered Flow Batteries as a standalone option. However, it should be noted that flow batteries could be incorporated into other technology options to reduce the power system maximum demand and reduce stress on the network at peak times. (Use of flow batteries in this manner could be closer to the 4-hour wholesale operation and could be contracted out to a third party.)

WSP note that flow battery technologies are attracting significant commercialisation and, consequently, are expected to have a relatively steep cost improvement and control system progress. While it is unlikely that flow batteries will become commercially viable by the NZ Battery project's 2030 timeframe, redox flow battery technologies appear to have the highest potential for rapid rates of advancement in storage capability and the consequent reductions in cost and size. If there are changes to commitment timelines then a redox flow battery solution could become viable.

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10 RECOMMENDATION FOR PROSPECTIVE OPTIONS

WSP assessed and compared each of the Primary Options, using the following evaluation approaches:

- Options Assessment - (Red – Amber – Green (RAG) scoring again evaluation criteria
- SWOT Assessment
- 1000minds support tool
- Qualitative engineering judgement,

From the above approaches we have made a preliminary recommendation for a shortlist of Prospective Options. This process involved structured assessment workshops with the NZ Battery team at MBIE (including support from other subject matter specialists) and our technology specialist lead team, with a challenge process to ensure appropriate levels of rigour were applied and tested.

RECOMMENDED PROSPECTIVE OPTION	DESCRIPTION
Bioenergy	Biomass production & storage (Including investigation into conversion to biofuel, and potential to supplement with import/export)
Geothermal Energy	Controlled Schedulable Geothermal (Combining Long-term and Flexible)
Hydrogen	Hydrogen Production with (Liquid Ammonia) Carrier Storage (Combining NZ production and imported/exported green ammonia)
Air Storage and Flow Batteries are not recommended Prospective Options	

This section provides a comparison of what we considered the most feasible options (and associated pathways) for each of the five technologies.

Refer to the summary of the shortlisted Prospective Options across all technologies combined into a summary RAG table.

10.1 COMPARISON OF PRIMARY OPTIONS

Commercial

From a purely commercial viewpoint, Geothermal stands out as being the most attractive solution with a Whole of Life cost of controlled schedulable (long-term) Commercial Information and the flexible option more expensive but still Commercial Information. Flow batteries stand out as having costs that put it out of range of the other shortlisted options for the NZ Battery project, with Whole of Life costs forecast Commercial Information Other Primary Options are all within Commercial Information range so are considered to not be outside the range of uncertainty at this stage and are not able to be rejected / recommended based on cost alone.

Long-term, Large-scale, Renewable

When looking at the RAG table, all Primary Options presented are considered to meet the key long-term, large-scale and renewable requirements of the NZ Battery Project. The only exception to this is for controlled schedulable geothermal (flexible) which has flagged a limitation on the size of the solution available by 2030, with a potential size limitation of 0.4 TWh delivered over 3 months. On its own the flexible geothermal solution does not meet the large-scale requirements of the NZ Battery. This requirement can be met, however, by deploying as a combined solution together with long-term schedulable geothermal. (One of the reasons this has been included as the recommended prospective option).

Technology Maturity

Technology maturity and suitability in terms of readiness for the timeframes of the NZ Battery and the Round-Trip efficiencies, have been key factors informing the discussions around our recommendations. In general, all Primary Options presented in the table are considered able to be ready for commissioning by 2030, however three options are to some degree behind the others – Bioenergy (Liquid Biofuel), Hydrogen stored as Renewable Synthetic Methane and Redox Flow Batteries. Essentially there is believed to be more risk in these technologies meeting the 2030 timelines, and the level of risk needs to be contrasted against the potential benefits that these options bring.

Round Trip Efficiencies

Hydrogen stands out as having significantly lower round trip efficiencies than all other options with an efficiency less than 30%. On its own this does not impact the decision around the most optimal solution, as this low efficiency is brought out in the commercial costs. There may be some negative public perception around the deployment of an energy solution that has comparatively low round trip efficiency. To counter these perceptions, it may be beneficial to reconceptualise hydrogen as an energy vector, that while on its own appears to represent an inefficient use of available energy, is in fact a key enabler to unlock the benefits of a fully renewable energy system. In other words, while hydrogen may have a low round trip efficiency, overall it allows maximisation of renewables and minimisation of net carbon emissions from an integrated electricity and energy storage system. Flow batteries have a relatively high round trip efficiency, although this assessment does not strictly apply in the case of geothermal energy and bioenergy which do not require a charge and re-charge cycle as the energy is inherently stored.

Environmental and Safety

From an environmental perspective, at this stage it is difficult to make a strong distinction between the different Primary Options without a higher level of detail in regard to plant location(s), scale of plant (whether one or multiple) and transport requirements and solutions. They have therefore, all scored comparatively. Each may have its own risk which has been described in the relevant sections.

Geothermal has been given a slightly higher consentability score due to it having enabling provisions in that regional / district plans already have an allowance for geothermal development - whilst noting that compared with other technology options geothermal would require deployment across a relatively large number of sites and locations, requiring a substantial number of cultural and other impact assessments.

Other technologies are less known at this size, with a comparative lack of baseline for consenting purposes. Hydrogen is considered to have higher safety risks due to the hazardous nature of hydrogen gas and its carriers (in particular storing large-scale quantities of ammonia) requiring significant safety mitigations and hazardous substance control measures.

While there are differences in operational carbon emissions between the geothermal technology options considered, geothermal generators in NZ are piloting processes for carbon capture and reinjection so these may be expected to decrease in future across all geothermal plant types.

Technology Implementation

Of the shortlisted prospective options, those that involve the production of the energy storage medium within New Zealand, are considered to have similar constraints in terms of international generation equipment suppliers' commitment and capability. The large-scale nature of all shortlisted options would require significant local (as well as national and possibly international) construction contracting involvement and support. The options that rely solely on importing the energy storage medium (i.e. hydrogen or bioenergy import) are more exposed to international market and supply chain risks and have scored less favourably.

Constitutional conventions

Constitutional conventions

Constitutional conventions

10.2DISCUSSION AND RECOMMENDATION

Bioenergy

We recommend that the option of Bioenergy, using trees from New Zealand's exotic forests, be carried forward to Task 2.

Our analysis suggests that this alternative is commercially viable. Likely to cost more than geothermal but less that hydrogen.

There is sufficient supply from New Zealand's sustainably managed exotic forests to provide a GHG-neutral and fully renewable energy source to provide 5 TWh of electricity in dry years. Trees can easily be stored long-term in the forest, with buffer storage for quicker response.

All technologies used in this system are existing and well proven in New Zealand.

The ability to source all the energy from onshore sources means that there is no risk of international markets causing disruptions to fuel supply.

The key relative risks of this option are:

- the potential public concerns around the accessibility and logistics of the large-scale biomass harvesting, and supply chain logistics required to ramp up in a dry year, and
- the perception that the use of bioenergy does not fully equate to a sustainable solution across the source, processing, generation, and regrowth cycle.

The simplest implementation is to use woody biomass from trees directly in a Rankine Cycle Generation plant. Alternatives include converting the biomass into ethanol allowing it to be burned in a higher efficiency CCGT Generation plant; supplementing supply by importing bioenergy in some form; and using existing power generation plant rather than building new.

The alternative Primary Option of Liquid biofuel, where the biomass is converted into ethanol is not as technically mature and so has a higher risk to being ready for commissioning in 2030. However, the benefits of using ethanol rather than direct use of the biomass may make this option attractive, with the ability to use a wider range of generation equipment, in particular CCGT plant with its higher efficiency. Therefore, it is recommended to dedicate a limited portion of the subsequent study effort to assessing ethanol further.

This option could potentially be initially deployed by retrofitting existing power generation plant in NZ. While the amount of existing plant would not meet the scale required by NZ Battery and much is reaching end of life, this could have several advantages. It could enable deferment of commitment to a technology allowing further technological development, deferment of capital expenditure for a greenfield plant, and possibly offer a 'fast start' to the NZ Battery Project.

Depending on the selection of the storage medium, bioenergy also offers the flexibility to supplement NZ's stored energy with imported material, if required in the event of extreme or consecutive dry years.

The key issues to address in the Task 2 feasibility assessment for this option are the detailed considerations of plant location, supply chain dynamics, optimal renewable fuel sources, existing plant modification options, scale-up and refinement of liquid biofuel options, and review of the benefits of importation.

Our recommendation to proceed with this option is based on it being the second cheapest option, high level of technology readiness and upside potential to use existing generation plant. It also scored relatively highly in the parallel MCA process carried out (see next section). It scored higher than hydrogen but lower than geothermal.

Geothermal

We recommend the option of developing a geothermal NZ Battery by bringing forward geothermal stations that would be likely implemented after 2030 and operating them in a schedulable manner.

Geothermal is the most attractive option from a commercial viability perspective and has an established history of successful implementation in NZ geothermal regions. It can provide a minimum of 1 TWh in a dry year and is a renewable energy source.

The traditional base-load operation of geothermal is well proven both internationally and in NZ conditions, and we consider there is a high level of confidence of being able to develop this technology to meet the long-term schedulable (and to a slightly lesser degree, flexible load following) aspects of the NZ Battery Project.

Geothermal as a NZ Battery solution offers a degree of optionality not provided by other options. Building a geothermal NZ Battery and running only when needed in dry years, presents a relatively low-cost, low-risk, no-regrets solution, as it would allow time for further development of alternative energy storage technologies, while providing optionality for future redeployment as base-load or flexible generation (or a combination of both).

The relative weaknesses compared with other options are: that geothermal may face challenges to provide a 5 TWh solution by 2030. The nominally available 500 MW of new geothermal by 2030 would provide at least 1 TWh of electricity over 3 months. Post 2030 there may be potential to develop a nominal total of 1000 MW of new geothermal, which could provide around 4 TWh over 6 months. While considered unlikely, it may be possible to bring more of this geothermal potential forward if the required NZ Battery energy quantum was deemed to be needed nearer to 5 TWh

- Another key risk that is not faced by other technologies, is that there may be an opportunity cost of the new geothermal plant built for the NZ Battery potentially displacing geothermal developments that would otherwise have been built anyway in the next 30 years.
- Further assessment of the ability to include additional design and operational features to enable the switch practicably and cost-effectively to this mode of operation will be a key investigation of the feasibility study.

Our recommendation to proceed with this option is based on its cost effectiveness, well known technology and the ability to reverse any commitment. The option also scored highest in the MCA carried out as a parallel process (as described in the next section).

Hydrogen

We recommend that the option of green hydrogen production and storage as green ammonia with supplementary imports and export opportunities be investigated further in the feasibility study. This hydrogen option can be scaled to provide 5 TWh of renewable electricity for a dry year.

The green hydrogen option is a true 'excess energy capture and storage' solution so utilises "low value" electricity when hydro lakes would spill or there is excess wind or solar generation available. The variability of the New Zealand hydro-electric storage system that results in the dry year problem also results in times where there is more water than can be used for hydroelectric electricity generation. This "free" electricity generation provides a competitive advantage to New Zealand in hydrogen production. Therefore, based on a 100% renewable electricity grid in NZ, we expect hydrogen would be accepted to be a fully renewable option, with low lifecycle carbon emissions,

Hydrogen production has logistical advantages over geothermal and bioenergy in that it does not have to be located in any specific regions of NZ. It could be deployed across a wide spread of split locations with access to large electricity grid connections (covering production, import, bulk storage, generation) to increase resilience and system flexibility.

While, currently, green hydrogen has a relative lack in maturity relative to geothermal and bioenergy, there is significant international research and development investment currently being undertaken. This technology investment is demonstrated in currently available technology and is expected to increasingly improve equipment efficiency and lower costs between now and 2030. For example, this may include the ability to directly fuel generation units with green ammonia which is currently too uncertain to include in our commercial viability assessment.

This international investment also leads to many options for improving the implementation of New Zealand's green hydrogen system:

- The expected development of an international market in green ammonia provides options to import to meet high demand and export any excess supply
- As green hydrogen production requires significant input electricity, compared with other key primary options it can provide interruptible load with potential demand response benefits to NZ's electricity system
- Through development and implementation of a green hydrogen supply chain for the NZ Battery Project, Aotearoa's engineering knowledge base and construction workforce could become a world leader in this emerging renewable energy vector, including the relatively novel use for long-term storage.

Like bioenergy, there are some possibilities for using green hydrogen in existing generation plant. This could lower the capital commitment and allow staged investment in the hydrogen technology.

Green hydrogen's key relative weaknesses include its high initial capital cost (compared to geothermal and bioenergy), the large electricity and water consumption needs for electrolyser plants, compared with other shortlisted options, and its low round trip efficiency, that the scale required to provide the NZ Battery requirements is large compared to current operational global schemes with a similar concept, and that ammonia is a toxic and explosive substance requiring stringent safety risk mitigations.

The alternative green hydrogen carrier, synthetic methane, is commercially viable but we consider less preferable to ammonia due to global trade in bulk green methane being much less likely than green ammonia. It has a relatively complicated supply chain, requiring that a large amount of renewable carbon dioxide gas be processed and transported to a common production site, and that methane is a GHG with many times the detrimental effect of CO_2, so the impact of any leakage is significant. Synthetic methane does have the advantage that it has the same characteristics as natural gas and New Zealand has significant experience in the logistics around natural gas.

WSP also examined the possibility of not producing green hydrogen locally but importing whatever we need for a dry year. This option has much lower capital costs and so superficially attractive. Relative weaknesses are the reliance purely on global markets for supply of certified green hydrogen carrier products and the likely higher cost of the green ammonia than local production from excess electricity.

Task 2 key issues will include the location selection trade-offs between siting high-power demand production facilities together with generation output grid connections or transport nodes, generation plant options and configurations, likely international green ammonia market characteristics, low-cost electricity quantities, and system flow and storage optimisation.

Our recommendation is based on the option being commercially viable (though less so than geothermal and bioenergy) and green hydrogen's ability to directly capture NZ's excess renewable energy, that the green ammonia is likely to be able to be imported or exported. This option also scored well in the MCA carried out as a parallel process (as described in the next section) though not as high as geothermal or bioenergy.

The optimal mix of these, along with the potential scale of production system demand response, is recommended for further investigation in the next steps feasibility study.

The following paragraphs provide an overview of three Prospective Options we recommend for further study in Task 2. These have been established by WSP, together with input and collaboration from MBIE. We recommend these are considered for further study under Task 2:

10.2.1 RECOMMENDED PROSPECTIVE OPTION 1

Controlled Schedulable Geothermal (combining Long-term and Flexible)

NZ Battery Project builds approximately 500 MW (and up to 1000 MW beyond 2030) of new geothermal power plant, incorporating additional design and operational modifications to optimise for long-term schedulable operation. It would not be run at full capacity in a normal year, instead it would be run at low load (turned down) or kept in a mothballed long-term preservation mode, reserved for dry years when needed. Approximately a third of the above would be ORC binary cycle plant, and through the development phase this technology would be investigated for its ability to also be run in a flexible load following manner.

10.2.2 RECOMMENDED PROSPECTIVE OPTION 2

Biomass production & storage (including investigation into conversion to biofuel, and potential to supplement with import/export) for generation

NZ Battery implements a Biomass solution, primarily using NZ's existing sustainably managed exotic forests, to generate electricity during dry years. Storage can be provided by flexible scheduling of harvest or may include storage of partially or fully processed material. This option is renewable and both generation and carbon sink are preserved in the long-term. Within this option, alternative implementations include the conversion of biomass into liquid biofuel. Liquid biofuel allows greater generation efficiency and has the potential for import or export to provide greater flexibility.

10.2.3 RECOMMENDED PROSPECTIVE OPTION 3

Green Hydrogen and Liquid Ammonia Carrier Production and Storage (combining NZ production and imported green ammonia)

NZ Battery uses renewable off-peak power to produce large amounts of green hydrogen that is converted into green ammonia and long-term stored to later fuel generation plant in a dry year (electrons to molecules and back to electrons at another time and place). In a dry year the ammonia is used either directly or after conversion back to hydrogen to generate electricity.

Within this option, alternative implementations include producing additional green ammonia for export and importing certified green ammonia to supplement the NZ produced ammonia storage stocks and variations of storage capacity. While NZ domestic-only hydrogen production can be scaled to provide a 5TWh solution at a high cost, the best deployment may involve producing a lower level of green ammonia in NZ, supplementing with imports as required, and exporting excess NZ produced product when there is no dry year requirement. This is effectively a hybrid of two of the hydrogen Primary Options. The future international green ammonia market is currently unpredictable so Task 2 will consider how this risk is best accommodated, commercially, geographically, in terms of grid constraints and technically.

While ***renewable synthetic methane*** was considered a strong potential option for the NZ Battery, global trade in green methane is not expected to develop in the way that green ammonia trade is, hence limiting the ability to supplement NZ produced methane with imports (or export surplus). Adding to this the supply chain is arguably more complicated (requiring a renewable CO_2 gas source and a plant to recover/purify that CO_2, and transport that CO_2 source to a common process site) and is currently of limited technology maturity at a large-scale (pilot/demonstration scale only). Another differentiator between the hydrogen as ammonia, or synthetic methane, options was that ammonia scored relatively highly in the MCA carried out as a parallel process (as described in the next section).

The above shortlisted prospective options can all provide a solution that would focus firstly on the long-term. With these options, as NZ builds more Variable Renewable Energy (VRE) sources (such as wind and solar), the increased variability could be firmed using existing hydros (which may be dispatched less conservatively, as the geothermal, hydrogen, or bioenergy NZ Battery would remain in reserve for any low energy periods), highly flexible short-term energy storage technologies, such as flow batteries (or BESS), fast response 'green peakers' or pumped hydro. Noting that in this scenario, any new pumped hydro would not necessarily need to be as long-term or large-scale, because the long-term, large-scale energy back-up would be provided by the NZ battery.

The above 3 recommended Prospective Options encompass the technologies of Bioenergy, Geothermal Energy and Hydrogen.

OPTIONS NOT RECOMMENDED

The technologies of Air Storage and Flow Batteries have not ranked as highly and therefore, have not been recommended to proceed as Prospective Options, as summarised below:

Air Storage We do not recommend that any Air Storage technologies proceed for further feasibility assessments. This is due to no pathway being available that is both technically feasible and cost effective. One technically feasible option could be to find an existing hard rock cavern in New Zealand, however the exploration would require significant expense with a relatively low likelihood of finding an appropriate cavern. Another technically feasible option could be to construct a new human-made cavern, however this would cost well in excess of $20B and also be highly dependent on finding an area with the right geology, The option of using a depleted oil and gas reservoir has the considerable risk of explosion due to mixing remaining hydrocarbons with compressed air, which despite international research is not expected to be solved in the NZ Battery Project timeframes. In addition to the storage challenges, there are logistical challenges including the need for a large scale, local, renewable source of heat for the re-expansion and power discharge steps.

Flow Batteries Vanadium Redox Flow Batteries were assessed as the best flow battery option, however, did not rank highly compared with others due to their high capital cost and scalability challenges. Flow battery technology is relatively recent and has not previously been implemented at the scale required for the NZ Battery context. s. While it is unlikely that flow batteries will become commercially viable by the NZ Battery project's 2030 timeframe, redox flow battery technologies appear to have the highest potential for rapid rates of advancement in storage capability and the consequent reductions in cost and size. If there are changes to implementation timelines then a redox flow battery solution could become viable. This is one example of the potential benefits of the aforementioned geothermal option, in that it could 'buy time' for other technologies develop.

10.3SUMMARY OF MCA RESULTS

To support our analysis, we used a multi-criteria analysis approach as a cross check. We used a subset of the Red – Amber – Green (RAG) criteria and standardised these to ensure no overlaps or inherent biases.

The NZ Battery problem is a complicated multi-criteria decision problem and we believe that the use of a multi-criteria analysis approach is an appropriate check on the decision process being used. A multi-criteria analysis (MCA) methodology includes:

- Alternatives: There are a huge number of alternatives. While these are grouped into the five technologies, the range of options within each technology is vast.
- Criteria: Excluding commercial viability, the criteria are of two distinct natures. There are three criteria that are hurdles – if the alternative does not meet all three of these then it is not a feasible solution. The remaining criteria are complex and overlapping. Commercial viability is a separate criterion.
- Criteria scores for each alternative: Criteria scores are difficult to get consistent as they apply quite differently to the range of alternatives.
- Criteria weights: Criteria weights are always difficult to assess.

The MCA was performed in the 1000minds MCA tool and supervised the developer, an MCA authority.

The main analysis used a pathways analysis to rule out many possible alternatives and select just a few alternatives for analysis. We used just the alternatives identified as best from the pathways analysis. 1000minds could have been used to manage the volume of data but this was not required.

The criteria were simplified and refined from the RAG criteria. Overlaps were eliminated and some criteria eliminated on the basis that they should affect the decision. These could have been included with the expectation that they would have had a low weight, but simplification meant that the trade-offs between criteria were more obvious.

The scores for the options were taken from the RAG scores and a survey of the WSP technology experts.

1000minds has built in functionality to perform an efficient questionnaire to establish appropriate weights. This survey was developed under the guidance of the 1000minds team, tested on the WSP project team, tested and refined with the MBIE project leaders, and then given to the wider MBIE project team and TRG. The results of this final survey were compared to the earlier surveys and proved consistent (indicating low levels of ambiguity).

This analysis is intended to be used in conjunction with the other evaluation approaches to provide challenge and rigour. The results of the analysis show a strong correlation with the other evaluation approaches, indicating that the conclusions we have reached are reasonably robust.

The overall ranking of the Primary Options that passed the hurdle of the three key criteria based on the criteria scores (which excludes cost) was:

Table 10-2: Overall Ranking from MCA Scores (excluding costs)

OPTION	1000MINDS SCORE
Controlled schedulable geothermal (long-term)	92.5
Controlled schedulable geothermal ORC (flexible)	92.5
Biomass production and storage	88.9
Hydrogen production with hydrogen carriers (ammonia & LOHC) processing and above ground storage	87.1
Liquid biofuel production and storage	86.0
Vanadium RFB	84.5
Hydrogen production, synthetic methane processing with subsurface storage	83.2
Controlled schedulable geothermal (via closed loop eavor loop)	76.5
Bioenergy import with storage	74.8
Zinc Bromine FB	73.0
Hydrogen carrier (ammonia & LOHC) import with buffer storage	71.3
Lithium Sulphur RFB	69.0
Iron Chromium RFB	58.7
Compressed air energy storage	50.4

Source: WSP 1000minds analysis

Summarising these options and comparing scores against cost is shown in the following graph.

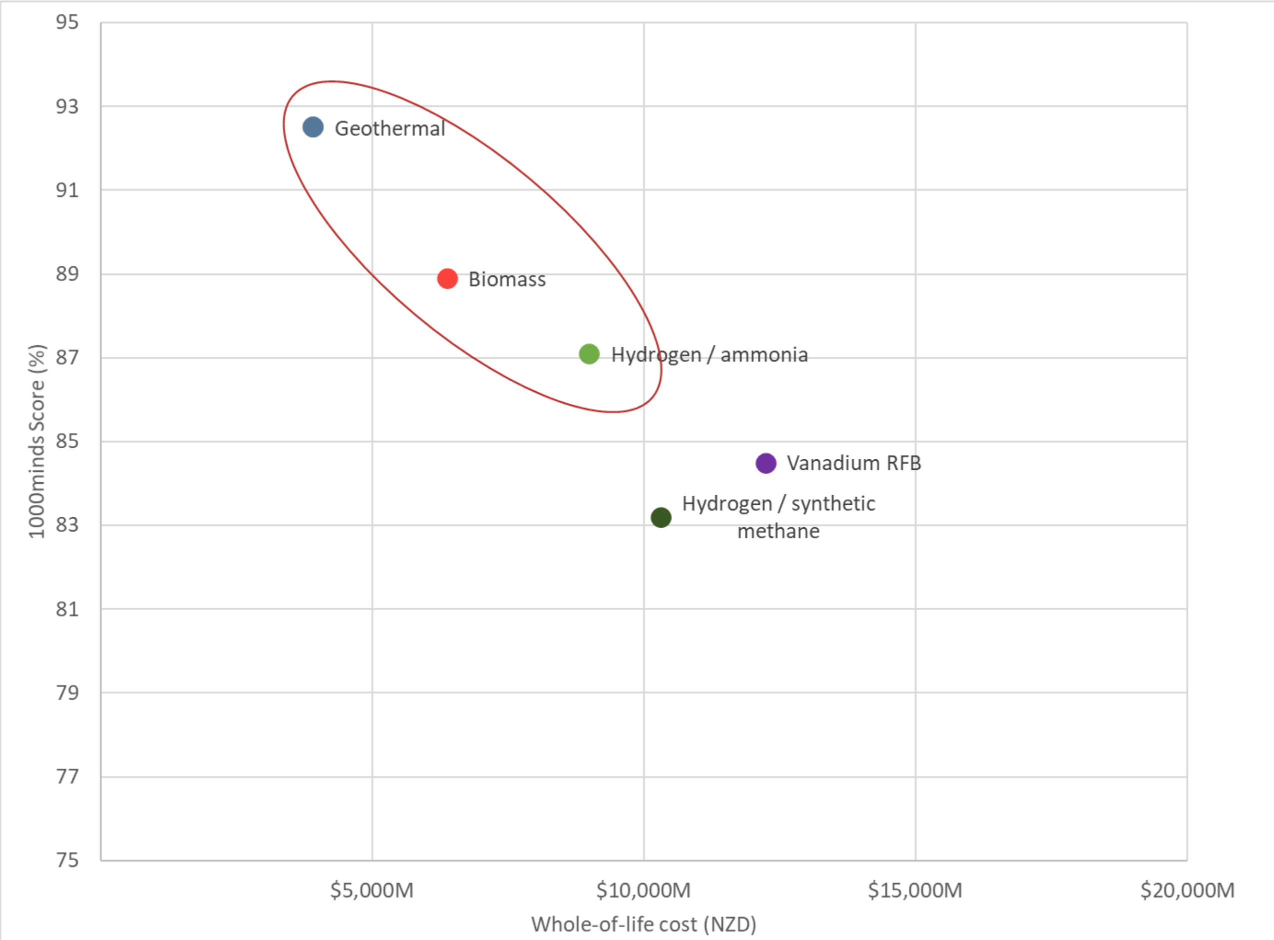

Figure 10-1: Whole of Life Cost vs 1000minds Score Comparison

Source: WSP 1000minds analysis

Not shown on the graph is Air Storage as it was eliminated before this step. Early indications were that it would score below 75 and have a Whole-of-Life cost greater than $20B.

Unusually for a multi-criteria analysis, the highest scoring options were also lowest cost. The three recommended options are circled.

Hydrogen / synthetic methane scores lower than the recommended options and Vanadium is significantly more expensive.

11 LIMITATIONS

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Appendix A
Evaluation Criteria

Each technology option is scored based on a Red Amber Green (RAG) assessment of how that option performs against the established criteria. The scores are based on a qualitative rating and quantitative evidence described throughout the report.

Table 11-1: Evaluation Criteria

Constitutional conventions

[5] Source: [NZ Electricity Emissions (ecotricity.co.nz)]

Constitutional conventions

Constitutional conventions

Constitutional conventions

CRITERIA DEFINITION AND ASSUMPTIONS

[1] The original brief wording was ‘capable of delivering at least 1 TWh of electricity supply over a period of 3 months, and potentially up to 5 TWh, potentially in a distributed manner’. We have assumed a nominal time period of 6 months to represent the distributed manner.

Appendix B
Safety Risk Likelihood and Consequence Matrix

Business Group:	
Section:	
Location:	
Project Name:	
Project Number:	
Project Manager:	
Date reviewed:	
Review team:	
Project Overview:	

Risk Assessment Matrix

Consequence / Severity	Probability / Likelihood				
	Almost Certain	Likely	Possible	Unlikely	Rare
5 Catastrophic	Critical	Critical	High	High	Medium
4 Major	Critical	High	High	Medium	Low
3 Moderate	High	High	Medium	Low	Low
2 Minor	High	Medium	Low	Low	Low
1 Insignificant	Medium	Low	Low	Low	Low

Consequence / Severity

Consequence	Safety	Health	Environment	Program / Quality (meeting customer requirements)
5 Catastrophic	Death of member of the public. Multiple worker deaths.	Death of member of public. Multiple worker deaths e.g. asbestosis, cancers.	Extreme environmental incident, resulting in irreversible or long term or widespread harm.	Extreme product / service non- conformance resulting in catastrophic failure. Critical impact on customer business. Permanent stoppage.
4 Major	Single worker death. Multiple major injuries (worker or third party). Significant irreversible disability.	Single worker death. Life-shortening health effect. Health effect causing significant irreversible disability e.g. lung diseases.	Major environmental incident resulting in significant impact requiring management by external authorities and / or high level of resources for response and remedy. Environmental incident managed by external authorities e.g. contamination of potable water.	Major non-conformance or delay that adversely affects customer interests.
3 Moderate	Single major injury (worker or third party). Worker injury resulting in three days away from work.	Irreversible health effect e.g. loss of hearing, HAVS cases. Serious illness from which there is full recovery e.g. poisoning, legionnaires disease, MRSA.	Moderate environmental impact requiring management response to aid recovery. Reportable to authorities e.g. fuel tank spillage.	Partial delivery or delay to customer requirements.
2 Minor	Minor injury (worker or third party). Injuries resulting in one day away from work. Restricted work Medical treatment beyond first aid.	Reversible health effect, e.g. minor dermatitis, asthma, tinnitus. Minor illness, e.g. chronic poisoning. Restricted work. Medical treatment beyond first aid.	Local impact requiring management response, but from which there is natural recovery e.g. recovery of fly-tip waste, silt into spawning river.	Delayed or inconsistent delivery of customer requirements.
1 Insignificant	First aid case, with no lost time. Negligible safety impact.	Mild health effect for short period, with no lost time e.g. local skin irritation.	Minimal environmental impact e.g. minor oil drips.	Slight deviation from specification, of little customer concern.

Note: Consequence / Severity table extracted from WSP [Global] Standard 103 – Reporting Requirements: Appendix B – Scale of Severity.
For Determination of Environmental Consequence / Severity Definitions, refer to PM-SHEQ-701 Risk and Hazard Management Procedure.

Probability / Likelihood

Almost Certain	Likely	Possible	Unlikely	Rare
Several times a year	Once annually	Once every 2 to 5 years	Once every 5 to 10 years	Less than once every 10 years

WSP Critical Safety Risks

Refer to the organisational risk register

PF-SHEQ-326 Training Guide - Critical Risk

Construction risks	Working at height
	Working around plant and machinery
	Working around electricity
	Working around trenching and excavations
	Working around cranes and lifting operations
	Working in confined spaces
	Managing Traffic
	Working in and around the rail corridor
	Working around or over water
People management	Driving at work
	Lone working
	Mental Health
Occupational health	Working with asbestos
	Handling and storage of hazardous chemicals

Hierarchy of Control

Control	Ref.	Description
Eliminate	E	Remove the hazard or risk entirely.
Substitute	S	Minimise by substituting (wholly or partly) the hazard causing the risk, with something else that gives rise to a lesser risk. E.g. changing a highly hazardous chemical for a less hazardous one.
Isolate	I	Minimise by isolating the hazard to prevent any person coming into contact with it. An example is locking an electrical switchboard.
Engineering Controls	EC	Minimise by establishing engineering controls. Examples include any engineering solution that reduces a hazard (for example, noise, fumes) at the source such as welding fume extraction ventilation.
Administration Controls	AC	If a risk remains it must be minimised, so far as is reasonably practicable, by also implementing administrative controls. Examples include training, procedures, policies, signage and shift design that lessen the risk of a hazard. This includes job rotation, adjusting work schedules, and providing adequate staffing when the work output is increased.
PPE	P	If a risk remains, further minimise the risk through the provision and use of suitable personal protective equipment.

IF THE CONTROL MEASURE ELIMINATES THE HAZARD OR RISK, THEN THE HAZARD OR RISK SHOULD NO LONGER BE PRESENT

Risk Ranking Requirements

Critical	Operation at this level is not acceptable. Implement and/or review controls.
High	Only tolerated if examination proves that the hazard cannot be eliminated and is minimised as far as is reasonably practicable.
Medium	Only tolerated if examination proves that the hazard cannot be eliminated and is minimised as far as is reasonably practicable.
Low	Risk is acceptable. Review at next interval.

Appendix C
Technology Readiness Level Definition

Extract from: Technology Readiness Levels for Renewable Energy Sectors, ARENA, February 2014

Level	Summary
1	Basic principles observed and reported: Transition from scientific research to applied research. Essential characteristics and behaviors of systems and architectures. Descriptive tools are mathematical formulations or algorithms.
2	Technology concept and/or application formulated: Applied research. Theory and scientific principles are focused on a specific application area to define the concept. Characteristics of the application are described. Analytical tools are developed for simulation or analysis of the application.
3	Analytical and experimental critical function and/or characteristic proof of concept: Proof of concept validation. Active research and development is initiated with analytical and laboratory studies. Demonstration of technical feasibility using breadboard or brassboard implementations that are exercised with representative data.
4	Component/subsystem validation in laboratory environment: Standalone prototyping implementation and test. Integration of technology elements. Experiments with full-scale problems or data sets.
5	System/subsystem/component validation in relevant environment: Thorough testing of prototyping in representative environment. Basic technology elements integrated with reasonably realistic supporting elements. Prototyping implementations conform to target environment and interfaces.
6	System/subsystem model or prototyping demonstration in a relevant end-to-end environment: Prototyping implementations on full-scale realistic problems. Partially integrated with existing systems. Limited documentation available. Engineering feasibility fully demonstrated in actual system application.
7	System prototyping demonstration in an operational environment: System prototyping demonstration in operational environment. System is at or near scale of the operational system with most functions available for demonstration and test. Well integrated with collateral and ancillary systems. Limited documentation available.
8	Actual system completed and qualified through test and demonstration in an operational environment: End of system development. Fully integrated with operational hardware and software systems. Most user documentation, training documentation, and maintenance documentation completed. All functionality tested in simulated and operational scenarios. Verification and Validation (V&V) completed.
9	Actual system proven through successful operations: Fully integrated with operational hardware/software systems. Actual system has been thoroughly demonstrated and tested in its operational environment. All documentation completed. Successful operational experience. Sustaining engineering support in place.

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