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Announcement to ASX
ASX: PGY

28 March 2022

Completion of Renewable Energy and Hydrogen Technology Feasibility Studies - confirms Mid West region viability to produce globally competitive clean hydrogen together with multi-staged development pathway

Highlights

- Mid West Integrated Renewables and Hydrogen Project Feasibility Studies completed
- Positive Feasibility Study results has Pilot in a strong position to develop clean energy projects to produce hydrogen and renewable energy on a globally competitive basis, leveraging existing operations in Mid West region
- Feasibility Studies also highlight the Mid West region can produce clean ammonia on a globally competitive /basis for export into emerging Asian clean energy markets
- Next steps for Pilot are to progress into the permitting and approvals process and front-end engineering and design (FEED) for a staged development of commercialising CCS and blue hydrogen leveraging 8 Rivers technology

Pilot Energy Limited (ASX: PGY) ("**Pilot**" or "**The Company**") is pleased to provide an update on its recently completed Mid West region Feasibility Studies.

Completion of Key Clean Energy Feasibility Studies

As outlined in the ASX release of 12 August 2021, Pilot announced the commencement of key studies to assess the feasibility and economics of, and to recommend the pathway for development for a large-scale clean hydrogen production project utilizing the Company's existing oil and gas production operations.

The transition to the production of clean hydrogen requires carbon capture and storage (CCS) and renewable power generation. Pilot is well positioned to play a significant role in the energy transition through harnessing the world-class CCS and Renewable resources of the Mid West region of Western Australia.

The Feasibility Studies for the Mid West Integrated Renewable Energy Project included the Mid West Blue Hydrogen and Carbon Capture and Storage study (**CCS and Blue H_2 Study**) focused on the Cliff Head Oil field, the Mid West Renewable Energy Study (**Renewables Study**), the 8 Rivers Blue Hydrogen Technology Study (**8 Rivers Study**) and the WA 481P CCS Study (**WA 481P CCS Study**) collectively the "Feasibility Studies").

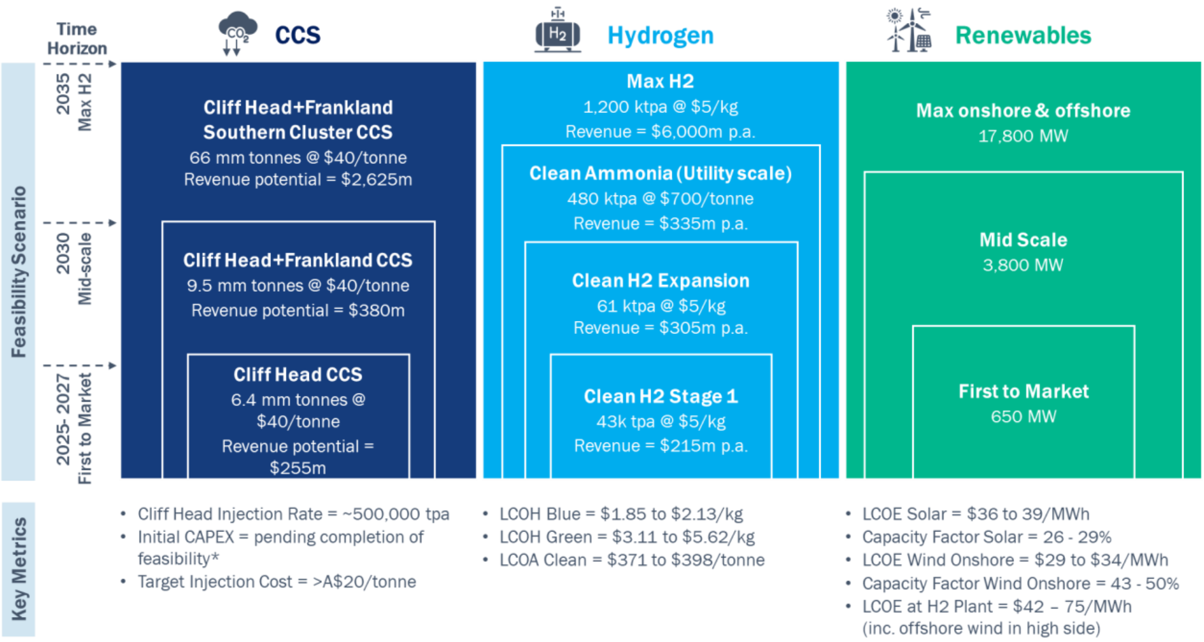
The Renewables Study and the 8 Rivers Study have been completed. The first stage of the WA 481P CCS Study has also completed providing an assessment of the CO_2 storage potential of Pilot's 100% owned WA-481P exploration permit with estimates of both the Contingent and Prospective CO_2 storage resource capacity within the permit. These estimates have been prepared in accordance with the SPE CO_2 Storage Resources Management System (SPE SRMS) Guidelines.

The Company is nearing completion of the CCS and Blue H_2 Study which is assessing the implementation of a CCS and Blue H_2 project centred on the Cliff Head Oil Field which is expected to be completed within the next several weeks. Pilot holds a 21.25% interest in the Cliff Head Oil Field through its 50% ownership of Triangle Energy (Operations) Pty Ltd, the operator of the Cliff Head Oil Field. This CCS and Blue H_2 Feasibility study is being jointly funded and contributed to by Pilot, APA Group (ASX: APA) and Warrego Energy (ASX: WGO).

Feasibility Study Results confirm viability of Mid West Clean Energy Projects

Each of these feasibility studies have confirmed the significant opportunity to develop a large-scale clean hydrogen production project integrating CCS and renewable energy generation to produce hydrogen and electricity for both domestic and export markets. Figure 1 provides a summary of the Feasibility Study results.

Figure 1 Feasibility Study Results Summary



*Refer to Annexure A for further details on the CCS and Blue H_2 Study. Gross (100%) CCS Resource

Pilot Energy Chairman Brad Lingo said: "Pilot is very excited about the results emanating from the feasibility studies. The results not only show how competitive an integrated clean energy project can be in Mid West Western Australia, but also outline a clear multi-stage development path starting with carbon capture and storage and building off this platform to produce clean power and hydrogen for the domestic market and ultimately moves into production of low-cost clean ammonia for export as the new clean fuel for Asian energy markets."

Mr. Lingo continued: "This staged development path is very much in the reach of the Company in terms of financial capacity and technical delivery taking advantage of the existing Cliff Head Oil Field infrastructure and operations. The Company is very focussed on delivering a First-to-Market CCS Project in the Mid West to anchor the further development of a Clean Hydrogen/ Ammonia and Renewable Energy Project."

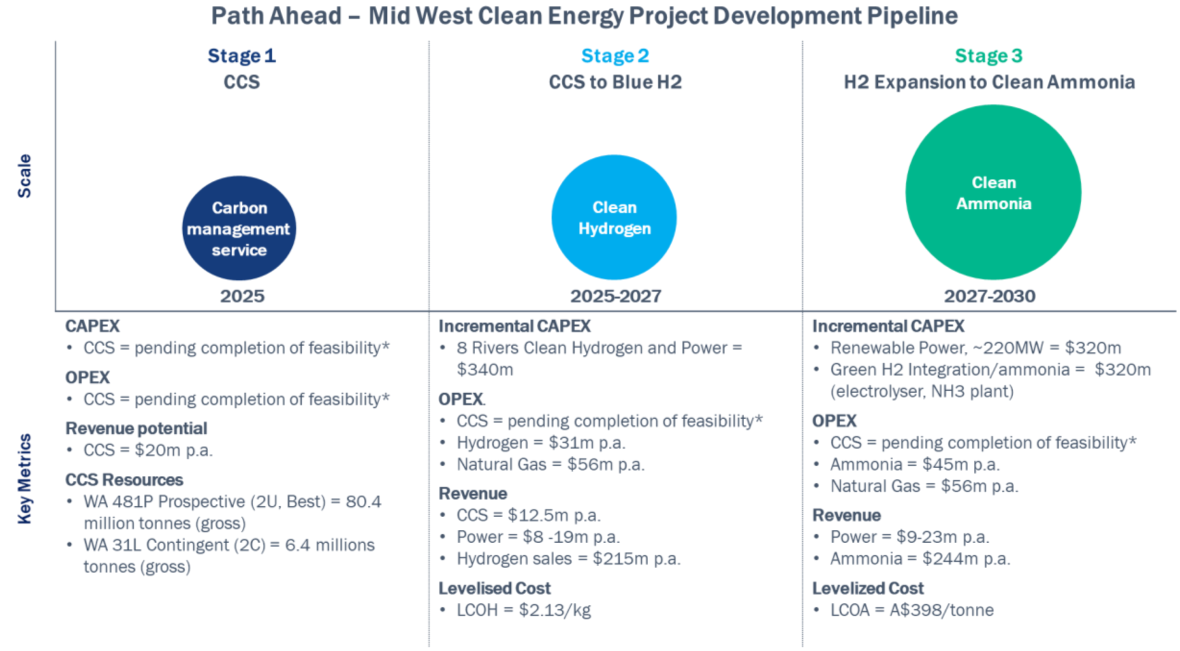
Mr. Lingo added: "We are very much focussed on engaging with NOPTA and the other relevant regulators to secure the necessary approvals to implement this project with an aim of having the first stage of the development pathway operational by 2025 and generating positive cash flow from these operations as well as delivering a material impact on carbon emissions in the Mid West."

Today's announcement of the completion of the Mid West region Feasibility Studies does not commit Pilot to proceeding beyond the feasibility stage of the Mid West Clean Energy Projects and any final decisions with respect to pursuing the recommended development path outlined below will be made at the relevant time, subject to commercial and financial considerations and following consultation with ASX.

Recommended Development Pathway - Mid West Clean Energy Projects

Based on the completed studies, a recommended development pathway for the projects under consideration is outlined in Figure 2 based on phased development over three stages:

Figure 2 Path ahead – Mid West Clean Energy Project Staged Development[1]



*Refer to Annexure A for further details on the CCS and Blue H_2 Study

[1] Analysis assumes $6.5/GJ Natural gas cost price; $40/tonne CO_2 revenue; $55 – 150MWh electricity revenue; $5/kg Hydrogen revenue; $700/tonne ammonia revenue

- **Stage 1 - Carbon Capture & Storage** - development of a carbon capture and storage operation to provide CCS services to third parties and to support the subsequent production of blue hydrogen and clean gas-fired power;

- **Stage 2 - Hydrogen Production –** development of a blue hydrogen generation project utilizing the 8 Rivers clean hydrogen technology ($^8RH_2$) and clean power technology to produce ~43,000 tpa of blue hydrogen with near zero emissions; and

- **Stage 3 - Renewables* and Green Hydrogen Project –** integration into the Mid West Blue Hydrogen Project of approximately 220 MW of renewable power generation from both wind and solar to produce a further 18,000 tpa of green hydrogen.

*Subject to re-compliance conditions imposed by ASX

Upon completion of the 3-stage development, the Studies confirm (with feasibility-stage level confidence) that the Company will be able to produce approximately 61,000 tpa of clean hydrogen to produce approximately 350,000 tpa of clean ammonia to supply into Asian clean ammonia export markets.

Next Steps

Following the completion of the WA-31L CCS Feasibility Study, the Company expects that the WA-31L Joint Venture will progress the regulatory process with the National Offshore Petroleum Titles Administrator (NOPTA) seeking the required approval to have the Cliff Head Oil Field reservoir declared a Greenhouse Gas Storage Formation.

Pilot and Triangle Energy (Global) Limited (ASX: TEG) (Triangle) have entered discussions with the objective of alignment on the future utilisation of the Cliff Head Facilities which would entail the Cliff Head Oil Field reservoir being declared an approved Greenhouse Gas Storage Formation. Subsequent to a declaration, the Company anticipates making an application to NOPTA for the grant of a Greenhouse Gas Injection Licence for the injection of approximately 500,000 tonnes per annum of CO_2 into the Cliff Head Oil Field reservoir for permanent sequestration. Receipt of this injection licence would enable the Company to commence the implementation of the CCS Project with the project anticipated to be operational by 2025. We are pleased to advise that Pilot and Triangle are in constructive and cooperative discussions regarding this development.

In progressing this development path, the Company will be focused on the following activities over the next 12-months for the Stage 1 CCS Project:

- **Permitting** - Engaging with regulators to secure the necessary regulatory approvals;
- **Site Acquisition** - Completing project site selection and commencing site acquisition;
- **Commercial Offtake** - Engaging with prospective parties for commercial off-take;
- **EPCM Contractor –** Commence engagement with potential EPC contractors; and
- **Pre-FEED** - Commencing detailed preliminary Front-End Engineering & Design (pre-FEED) and detailed costings for the CCS and Clean Power and Hydrogen Projects

Completion of the development path over the next 12-months is aimed at securing all necessary regulatory approvals, securing commercial off-take arrangements and completing a full bankable feasibility study and FEED package to enable the Company to take a final investment decision (FID) for the Stage 1 Project.

Feasibility Study Results

Pilot has prepared summaries of the Feasibility Study results set out in the following Annexures to this announcement:

- Annexure A: Mid West CCS Resource Potential
- Annexure B: Mid West Renewable Energy Feasibility Study
- Annexure C: Mid West Hydrogen Potential
- Annexure D: 8 Rivers Blue Hydrogen and CO_2 Technology Study
- Annexure E: Hydrogen & Ammonia market updates

The summaries are structured to provide an overview of the studies with information presented on a summary and aggregate basis, where necessary, to protect the intellectual property and commercially sensitive nature of certain aspects of the studies.

ENDS

This announcement has been authorised for release to ASX by the Chairman Brad Lingo and Managing Director Tony Strasser.

Enquiries
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About Pilot: Pilot is currently a junior oil and gas exploration and production company that is aggressively pursuing the diversification and transition to the development of integrated renewable energy, hydrogen, and carbon management projects by leveraging its existing oil and gas tenements and infrastructure to cornerstone these developments.

Pilot holds a 50% interest in the Operator of the Cliff Head Oil field and Cliff Head Infrastructure, (effectively a net 21.25% interest), 100% interests in WA-481-P and EP416/480 exploration permits, located offshore and onshore Western Australia, which form foundation assets for the potential development of clean energy projects in Western Australia.

Competent Person Statement:

This announcement contains information on CCS resources which is based on and fairly represents information and supporting documentation reviewed by Dr Xingjin Wang, a Petroleum Engineer with over 30 years' experience and a Master in Petroleum Engineering from the University of New South Wales and a PhD in applied Geology from the University of New South Wales. Dr Wang is an active member of the SPE and PESA and is qualified in accordance with ASX listing rule 5.1. He is a former Director of Pilot Energy Ltd and has consented to the inclusion of this information in the form and context to which it appears.

Annexure A: Mid West CCS resource and WA 481P CO_2 Storage resource study

Mid West CCS Resource Potential

Highlights

- The Cliff Head Oil Field production license (WA 31L) area has carbon capture and storage potential of 6.4 million tonnes of CO_2 (2C contingent resource, Gross) at a CO2 injection rate of 500,000 tonnes of CO_2 per annum

- The Cliff Head Oil Field production license area has an upside CO_2 storage capacity of approximately 15.8 million tonnes of CO_2 (3C contingent resource, Gross)

- The existing Cliff Head Oil Field offshore facilities, existing wells and pipelines are suitable for the implementation of a carbon sequestration operation

- The Greater Cliff Head Area extending into WA-481-P has approximately an additional 4.4 million tonnes (2C Contingent Resource, Gross) and 80.4 million tonnes of CO_2 storage capacity (Prospective Resource Best estimate, Gross).

- Australian Commonwealth Government has announced an express policy "prioritising carbon capture and storage"

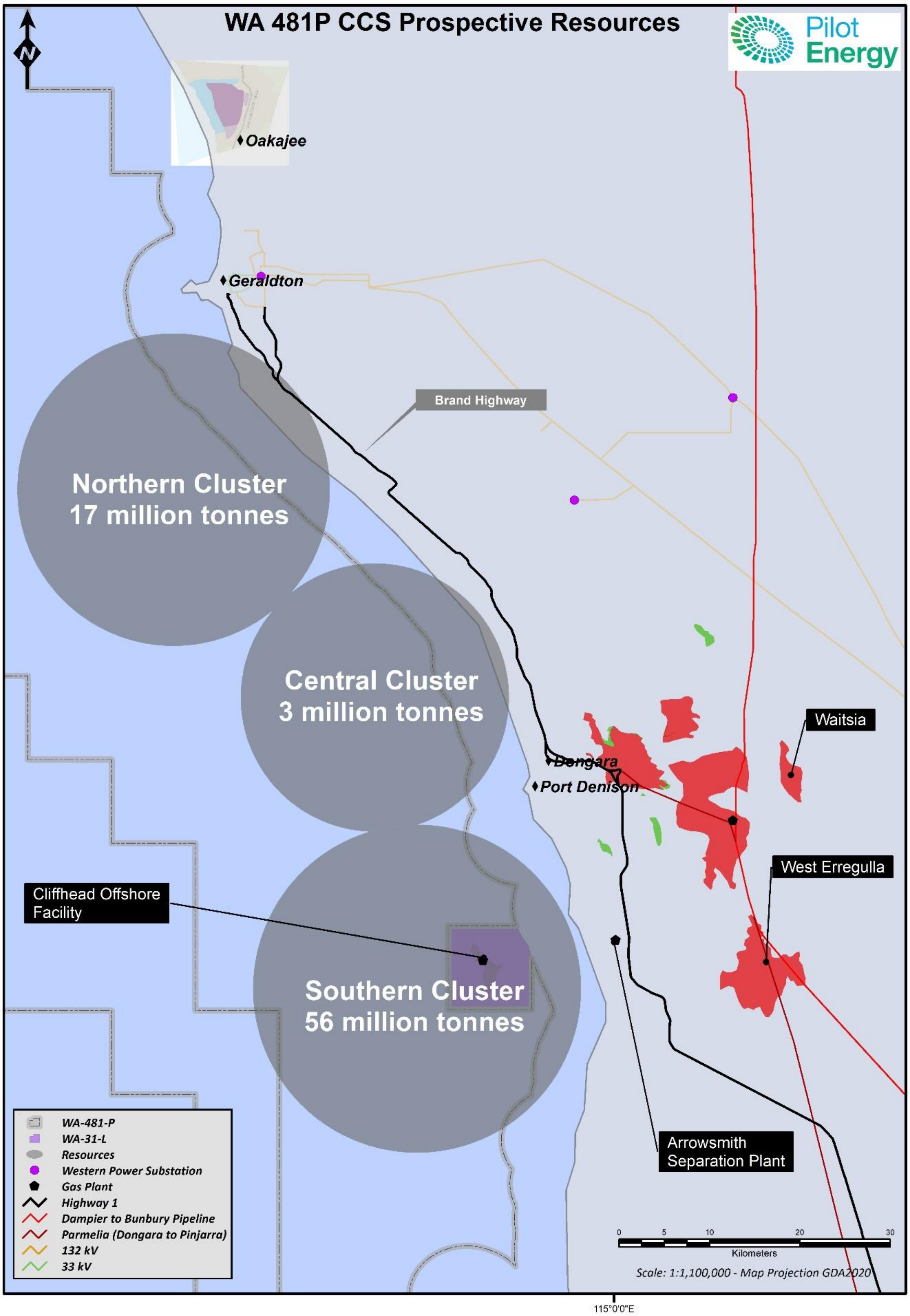
- Price of Australian Carbon Credit Units (ACCU) forecast to increase to over $40/tonne by 2026

The Company has undertaken a feasibility study of the carbon capture and storage potential of both the Cliff Head Oil Field production license (WA 31L) and the surrounding WA-481-P exploration license areas.

The feasibility study for the WA-481-P exploration license area has been completed and the study covering the Cliff Head Oil Field production license area is nearing completion. So far, the studies have confirmed the significant carbon capture and storage potential of both the Cliff Head production license and the WA-481-P exploration license areas (refer to Figure 3 and Table 1below) with a total 10.8 million tonnes 2C Contingent resources and best estimate Prospective resources of 80.4 million tonnes.

Subject to further assessment, these resources represent a potentially significant resource base for Pilot to develop its Carbon Management business providing CCS services to third parties and Pilot's own blue hydrogen plants.

Figure 3 WA-481-P CCS Storage Prospective Resources[2]



[2] Determined in accordance with SPE SRMS Guidelines for estimating CO_2 storage

Table 1- Greater Cliff Head & WA 481P CCS Storage Contingent & Prospective Resources

Contingent Storage Resource (million tonnes)	1C	2C	3C
WA 481P (Pilot share, 100% basis)	2.8	4.4	7.2
WA 31L (100 % basis)	1.0	6.4	15.8
WA 31L (Pilot share, 21.25 % basis)	0.2	1.4	3.4
Prospective Storage Resource (million tonnes)	1U	2U	3U
WA 481P (Pilot share, 100% basis)	46.2	80.4	144.2

Notes

1. Determined in accordance with the SPE SRMS Guidelines for estimating CO_2 storage resources

Subject to the completion of the CCS and Blue H_2 Study, to date the study has also confirmed that the Cliff Head Oil Field reservoir can accommodate the injection of CO_2 at a rate of approximately 500,000 tonnes per annum utilizing the existing Cliff Head Oil Field offshore and onshore production facilities, wells and pipelines. A detailed review of the offshore and onshore production facilities, existing production and injection wells and the oil production and water injection pipeline is also being conducted. This review has confirmed that these production facilities are suitable for the implementation of a carbon sequestration operation. Further analysis in the next stage of the project will examine the specific actions required to repurpose the equipment for CCS operations.

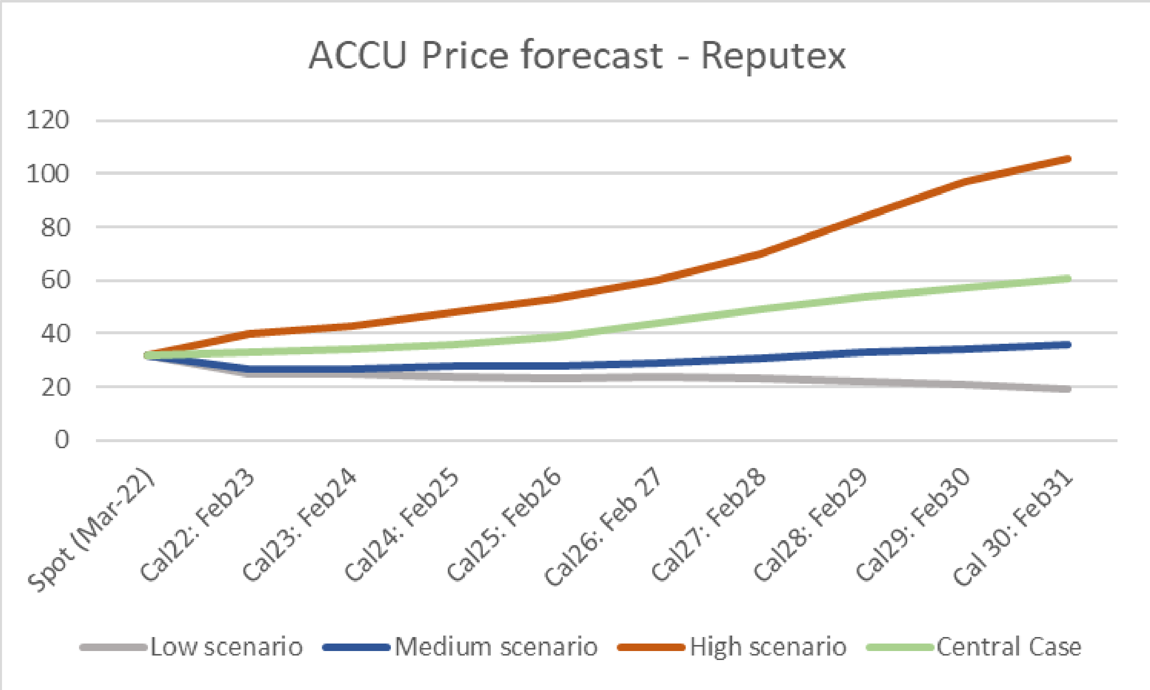
The Australian Commonwealth Government has announced a policy "prioritising carbon capture and storage technology and has identified carbon capture and storage as a priority low emissions technology under the Technology Investment Roadmap."[3]

To this end, the Australian Government is investing in enabling infrastructure for large-scale deployment of the technologies. "***CO_2 compression, transport and storage under $20 per tonne is a stretch goal of the roadmap***. ***CCS can also be used to produce clean hydrogen, another priority technology.*** [emphasis added]"[3]

In terms of the forward market outlook for long-term carbon price and supply and demand for carbon credits in Australia, the Company is utilizing the Reputex ACCU Forward Price Forecast set out in Figure 4.

[3] https://www.industry.gov.au/policies-and-initiatives/australias-climate-change-strategies/reducing-emissions-through-carbon-capture-use-and-storage#:~:text=Carbon%20capture%20and%20storage%20(CCS,scale%20deployment%20of%20the%20technologies.

Figure 4 Reputex ACCU Price Forecast



WA 481P CO_2 Storage resource study

Pilot engaged the consulting arm of CO2CRC[4], CO2Tech to undertake a regional assessment of the CO_2 storage capacity within Pilot Energy's exploration permit (EP) WA-481-P, which is located in the Abrolhos Sub-basin, offshore Perth Basin, Western Australia.

This initial study assessed the CO_2 storage potential at the Dongara Sandstone and Irwin River Coal Measures levels within Pilot Energy's audited 2017 portfolio of 23 leads and discoveries. This approached leverage existing data sets and internal knowledge across WA 481P based on historical oil and gas focused exploration efforts. However further potential exists beyond the known structures and at this stage the review has not accounted for the CO_2 storage potential in the shallower Cadda, Cattamarra, Eneabba, & Leseur aquifers, the deeper High Cliff Sandstone, and the (likely very large) storage capacity of deep, basin-centred sands. These targets are planned to be assessed in future studies which are expected to be progressed in parallel with progressing regulatory applications for the CCS resources identified in the current study.

[4] https://co2crc.com.au/

Figure 5 Composite seismic section: WA 481P CCS mechanisms

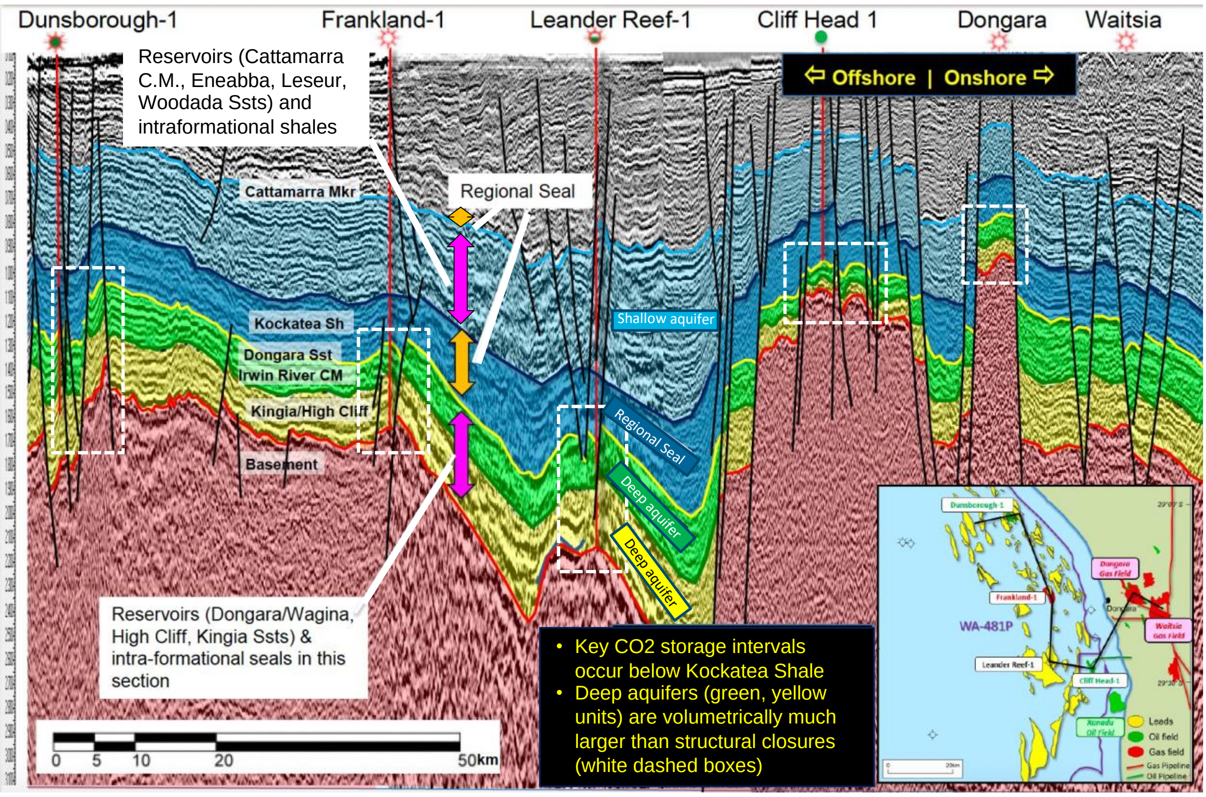


Figure 5 is a composite seismic section through selected wells in the northern Perth Basin, Western Australia. The prospective CO_2 storage intervals considered in this study occur in structural closures (white dashed boxes) in the Dongara Sst, Irwin River Coal Measures, and Kingia-High Cliff Sst (green and yellow stratigraphic units) beneath the Kockatea Shale (dark blue stratigraphic unit), a proven regional seal. Additional unquantified storage potential exists in deep, saline aquifers where the Dongara Sst, Irwin River Coal Measures, and Kingia-High Cliff Sst is not in structural closure.

The analysis assumed the structures associated with the leads and discoveries were hydrocarbon filled. Fault seal integrity was highlighted by the study as a risk relevant to the development of the initial CCS reservoirs identified in the study. Further assessment of the faults, trap validity and trap size will be assessed in the up-coming WA 481P 3D seismic campaign planned for 2023 and further studies will probabilistically model the portfolio outcomes, in order to further develop risked estimates of the storage potential.

Further assessment of the potential for large-scale storage within deep basinal settings, where aquifer trapping predominates and uncertainties in regard to fault seal integrity are ancillary was recommended by CO2Tech. Repurposing existing basin-scale migration models may provide the foundation for this further assessment.

These leads and discoveries contain an indicative storage capacity of approximately 85 million tonnes of CO_2, on a most likely (ML) basis. The low-to-high case range is 43-151 million tonnes of CO_2. The calculated storage potential for the 23 assessed leads and discoveries within WA-481-P are summarised in Table 2.

Table 2 WA 481P CCS Storage Contingent & Prospective Resources (100% Gross)

Contingent Storage Resource (million tonnes)	1C	2C	3C
WA 481P	2.8	4.4	7.2
Prospective Storage Resource (million tonnes)	1U	2U	3U
WA 481P	43.4	80.4	144.2

Notes

1. Determined in accordance with the SPE SRMS Guidelines for estimating CO_2 storage
2. Pilot holds a 100% interest in WA 481P

The storage leads and discoveries can be loosely grouped almost entirely (21 of 23) into three geographic clusters (from NNW to SSE), namely the Northern, Central and Southern Clusters (**Figure 6**).

Figure 6 Southern, Central and Northern Clusters of leads and the CCS storage potential associated with each cluster

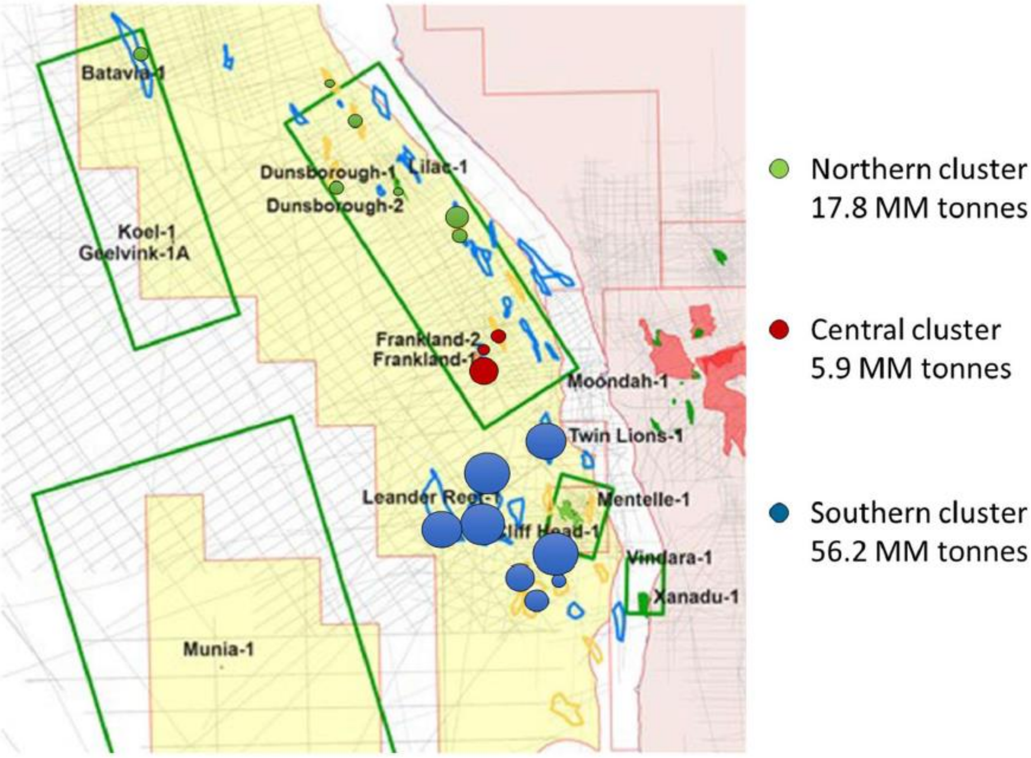


Figure 6 shows how the leads and structures within each of the clusters are situated in relation to a hypothetical series of three CCS project developments, with a development radius of 15 km from three central development locations.

21 of the 23 structures investigated fall logically into three geographic clusters, namely the Northern, Central and Southern Clusters. Of these clusters, the Southern Cluster is by far the most attractive, based upon the current limited study. It contains the largest (ML case) aggregate volume of 56.2 million tonnes of CO_2, the greatest number of leads (10) which are also often the largest of those investigated and occurs closest to the Cliff Head Field.

In the development of these volumetric capacities for CCS storage, the SPE-SRMS classification has been applied.

<u>Southern Cluster</u>

The Southern Cluster contains ten leads, all of which are in relatively close proximity to the Cliff Head Field. The aggregate estimated storage volume of these leads is 56.2 million tonnes CO_2. Moreover, six of the leads have an individual ML storage capacity of >5 million tonnes; two have an individual ML storage capacity of 2.5-5 million tonnes and two have an individual ML storage capacity of <2.5 million tonnes.

In summary, the Southern Cluster has easily the greatest calculated storage capacity (more than three times that of the next closest cluster, the Northern Cluster), the highest number of leads and it is situated near the Cliff Head Field producing asset. It is also considered likely, by analogy, that the effective Kockatea Shale-Dongara/IRCM storage pair is viable in this immediate region.

The Southern Cluster is easily the most attractive of the three clusters for a potential development hub for CO_2 storage, given current knowledge. It is favoured because of several factors, including the comparatively large CO_2 storage volumes of key leads (easily the largest of the three clusters), its close proximity to existing petroleum infrastructure at the Cliff Head Field, and importantly, the potential synergies between a potential future CO_2 development and the ongoing petroleum technical assessments and data acquisition programmes around the Cliff Head field.

<u>Central Cluster</u>

The Central Cluster consists of only three leads, with an aggregate estimated storage volume of 5.9 million tonnes CO_2. One has an individual ML storage capacity of 2.5-5 million tonnes and two have an individual ML storage capacity of <2.5 million tonnes. However, there are several unnamed leads shown on the map for which EURs were not provided, and so the storage capacity within this cluster may increase on completion of further assessment. Overall, however, the small number of audited leads, combined with the limited aggregate volume, makes this cluster the least attractive cluster for a CCS development.

<u>Northern Cluster</u>

Northern Cluster is centred near the sub-economic Dunsborough oil discovery and contains seven additional leads which have an ML aggregate estimated storage volume of 17.8 million tonnes CO_2. Three of the leads have individual ML storage capacity of 2.5-5 million tonnes; the other five leads have individual ML storage capacity of <2.5 million tonnes. No lead has an individual ML storage capacity of >5 million tonnes.

In summary, the Southern Cluster appears to represent a viable future development hub for CO_2 storage within WA-481-P, given current knowledge. It is favoured because of the comparatively large CO_2 storage volumes in its key leads (easily the largest of the three clusters), its close proximity to existing petroleum infrastructure at the Cliff Head Field, and importantly, the possible synergies between a potential future CO_2 development and the ongoing petroleum technical assessments and data acquisition programmes around the Cliff Head Field.

Annexure B: Mid West Renewable Energy Feasibility Study

Highlights

- Confirmed that the Greater Mid West region contains 18.7 GW of total technical renewables energy resource – onshore and offshore wind and solar – potential in three core development areas

- 15 large scale potential development sites identified across onshore and offshore renewable generation development areas. Solar LCOE from $36 - 39/MWh; Onshore Wind LCOE $29 – 34/MWh and Offshore wind of $199 – 214/MWh

- Identified renewable energy development strategies which can provide renewable power at an LCOE of $42 - 75/MWh with a combined capacity factor of 64 – 73% delivered to hydrogen production facilities at Arrowsmith or Oakajee. Deploying energy storage technologies is expected to improve these results

1. Overview of Renewable Energy Feasibility Study

Pilot engaged a team of internationally recognised consultants to assess the viability of developing the Mid West regions significant renewable resources and commercialising the resource initially through the production of hydrogen. The Consulting team and their respective focus areas are summarised out in Table 3.

Table 3 Renewables Study consultants and focus areas

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Offshore and Onshore Wind, electricity transmission and port assessments	LAUTEC
Onshore Solar	GREEN FUEL DEVELOPMENT
Hydrogen Production and Feasibility Reporting	T.EN TECHNIP ENERGIES; GENESIS

The feasibility study consultants conducted an initial resource assessment of the renewable energy resources across the Mid West region. This review confirmed the pre-study assessment of the regions potential to host utility scale renewable energy projects.

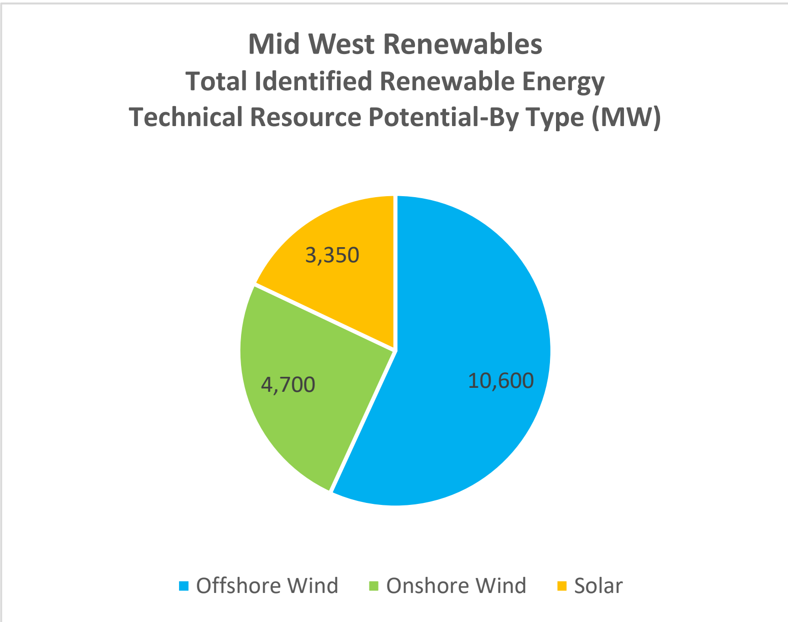
The onshore/offshore wind resource assessment confirmed the region as relatively free of constraints and offered conditions favourable for wind energy developments. Sophistic GIS mapping was deployed in the resource assessment to provide resource estimates which accounted for the following constraints (not an exhaustive list):

- Physical: marine traffic, water depths, onshore infrastructure, competing projects/resource developments, areas of small land holdings;
- Environmental: Marine and other onshore protection zones, contaminate sites, forest/bushland, existing land use and rainfed cropping; and
- Cultural heritage: Aboriginal heritage and communities, tourism

The next stage of any project will involve a further, more detailed assessment of the above constraints.

The feasibility study assessed the Renewable Energy resource potential across the Mid West region – in terms of onshore and offshore wind and onshore solar. The overall technical renewable energy resource potential identified was approximately 18.7 GW across all three resources (see Figure 7 below).

Figure 7 Mid West Renewable Resources by Type



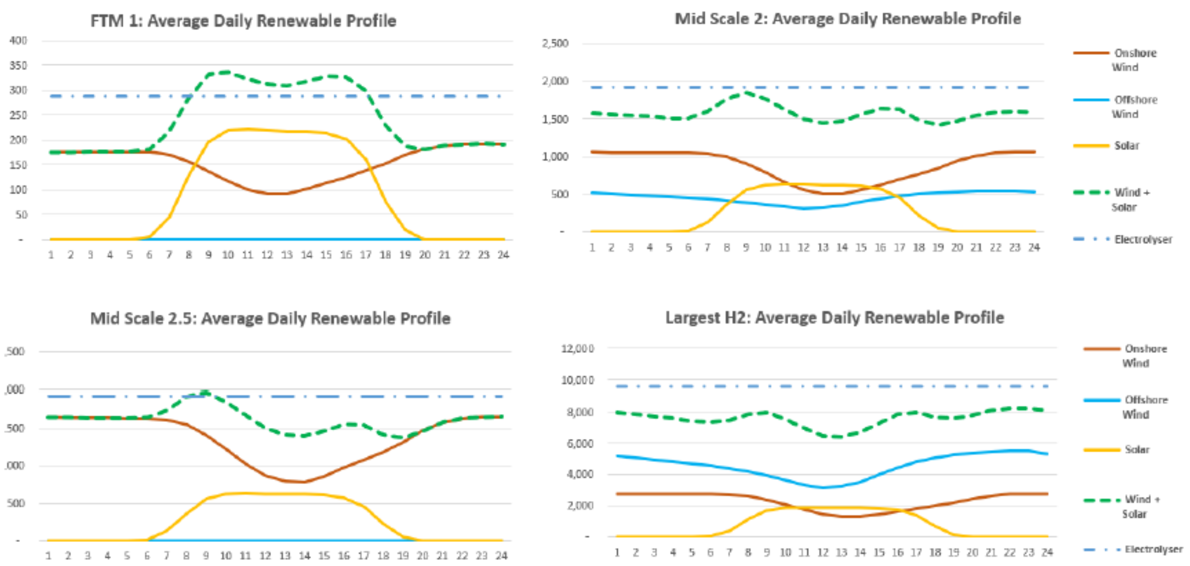
A key outcome of the study is the benefit of developing a portfolio of renewable energy resources which is clearly demonstrated by reviewing the capacity factors of resources. Portfolio capacity factors available across the identified renewable energy sites provides the ideal setting for the production of green hydrogen. High-capacity factor renewable energy delivered to a hydrogen plant maximises the hours per day an electrolyser can produce hydrogen. Further enhancement is possible through the integration of long and short duration energy storage systems.

Table 4 Renewable Energy capacity factors

Capacity factors (%)	First-to-Market scenario	Mid-Scale combined	Mid-Scale onshore	Maximum Generation
Solar	26	29	29	29
Onshore Wind	43	50	47	45
Offshore Wind	-	48	-	48
Portfolio Capacity Factor @ electrolyser	64	73	72	70

In addition to capacity factors, it is also of interest to compare the average diurnal energy profiles between wind and solar. The climate conditions prevalent within the region provide a complimentary daily balance between the wind and solar profiles. This is clearly shown in Figure 8 below which illustrates the average renewable power throughout the day as well as the nominal electrolyser capacity.

Figure 8 Renewable Energy average daily energy profiles



Pilot's study assessed the development of renewable energy projects across three strategies: First-to-market, Mid-Scale and Maximum Generation strategies. The assessment of these strategies assumed the renewable energy resources were commercialised through the production of hydrogen. During the study a 4th scenario was included as a sensitivity to assess the LCOH of a mid-scale project powered by onshore renewables. This scenario is presented throughout the Renewables Study and Hydrogen Potential Annexures and utilised the technical analysis prepared for the other strategies. A summary of the development scenarios is set out in Table 5 below.

Table 5 Feasibility Study Development Strategies

Strategy	H_2 Plant location	Project start	H_2 End use	Onshore Wind (MW)	Offshore Wind (MW)	Onshore Solar (MW)	H_2 capacity & volume
First to market	Arrowsmith	~2025/6	Mobility and industrial	300	-	350	290 MW 30 ktpa
Mid-Scale: Onshore	Oakajee	2035	Industrial	2,800	-	1,000	1900 MW 250 ktpa
Mid-Scale: Off/ Onshore	Oakajee	2035	Industrial	1,800	1,000	1,000	1,900 MW 260 ktpa
Max generation	Oakajee	2035	Industrial	4,700	10,100	3,000	9.5 GW 1,200 ktpa

2. Offshore and Onshore Wind Resource Assessment

The wind energy resources were assessed initially on the basis of the Maximum Technical Potential, which was further constrained through detailed assessments of the main sites ability to host wind turbines and transmission infrastructure. The following table summarises the breakdown of the total Maximum Technical potential wind resource of **15,100 MW.**

Table 6 Wind Energy Maximum Technical Potential resource estimate

	Offshore (limited to WA 481 P area)	**Onshore (located within reasonable transmission distance to Cliff Head and Oakajee**
Wind Resource	10,600 MW across 3 sites	4,700 MW across 4 sites

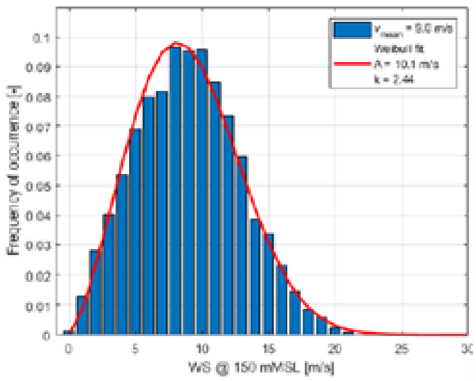
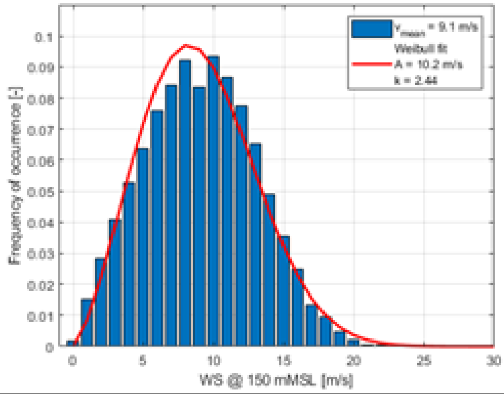
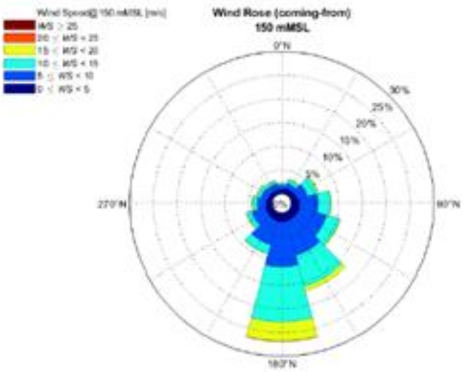
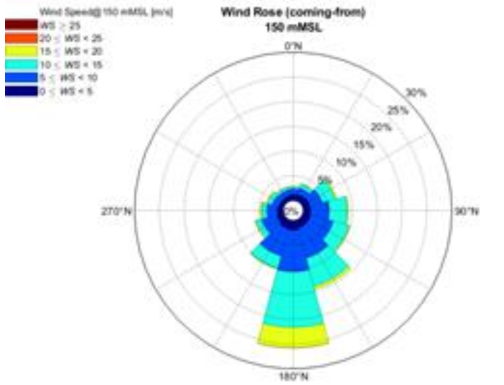
Across the onshore and offshore sites Lautec identified 13 potential development areas (accounting for the wind resource constraints).

Wind farm layouts were developed for four sites (assessed as being representative of the other sites) enabling levelized cost analysis based on wind resource simulations, level 5 capital and operating cost forecasts.

The following sections provide an overview of the key aspects of the offshore and onshore assessment.

Figure 9 provides an overview of the data from two of the key offshore sites identified in the study in the Northern and Central parts of the offshore area of interest.

Figure 9 Mid West Offshore wind energy resource overview

Site	Northern development site #1	Central development site #1
Wind Speed	Average: 9.0m/s	Average: 9.1m/s
P50 Long term distribution		
Wind Rose		

The offshore wind farm sites were analysed assuming the Vestas V236 15 MW turbine. When analysing the wind farm layout, the following constraints were applied:

- Buffer to site boundary*:* A 250 meter buffer to the site boundary has been implemented to ensure no blade flyover, as well as to allow reasonable space for installation vessels.
- Inter-turbine distance*:* Minimum 5x turbine diameter (5D) to minimize the turbulence and wake losses.

Several conceptual layouts *were* analysed and compared in order to assess the maximum capacity for the site and optimize the capacity factor.

For each scenario, an energy generation time-series was calculated for the period of one full year. Long term average wind conditions were determined based on 10 years of a high-fidelity mesoscale time series from Vortex and a single year, representative of the long-term average was selected for each site.

The gross capacity factors were determined based on the Vestas V236 15 MW turbine, correcting for hourly variations in air density.

Wake losses were modelled for various layout configurations, using the N.O Jensen model in a standard configuration. The long-term wind speed and direction distribution were extrapolated to individual Wind Turbine Generators (WTG) positions using the Global Wind Atlas data.

The additional energy losses (WTG availability, performance, temperature curtailment and electrical losses) were defined based on LAUTEC's and C2Wind's experience and knowledge of standard industry values. C2Wind were engaged by Lautec, within its arrangements with Pilot, to assist with the analysis.

The uncertainty of the preliminary energy production estimates can be reduced in the next stages of the project by incorporating onsite or near-site wind measurements in order to:

- refine the knowledge of site-specific WTG performance characteristics
- further optimize the wind turbine layout and wake loss modelling

The following table provides the spacing specifications and net capacity factors for the Northern Development site based on a 1GW and 2.5GW offshore wind farm configurations.

Table 7 Offshore Wind farm spacing and capacity factors

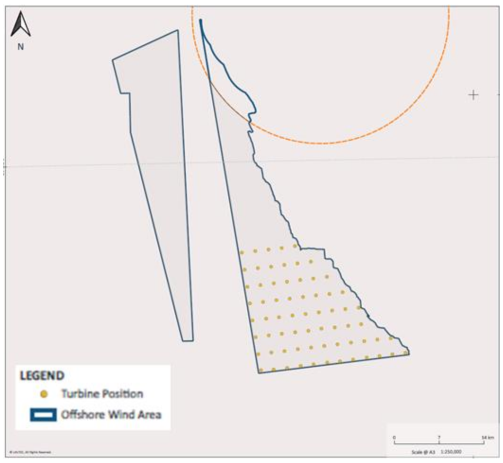
Layout	Northern Development site: 1GW	Northern Development site: 2.5GW
Turbine Spacing	2.7km x 2.1km	2.2km x 2.1km
Net Capacity factor (adjusted for losses)	45.2%	44.4%

Turbine spacing of 2.7 km x 2.1 km prioritizes the areas closest to the prospective connection point, as well as the highest wind speeds and results in a layout with the highest gross and net energy yield. Refer to

Figure 10 and Figure 11 for further details on the wind farm layouts assumed in the analysis.

Figure 10 Northern Development site: 1GW wind farm layouts options

2.7km x 2.1km Spacing – layout



3.7km x 3.3km Spacing – Alternative layout

Figure 11 Northern Development site: 2.5GW wind farm layout

2.7 km x 2.1 km spacing

The following table provides a summary of the basis for the development of the capital and operating forecast for a 1 GW wind farm site which is located ~18km offshore. The values are primarily based on data from a large offshore wind farm of approximately 1 GW, which holds monopile foundations at 30-meter depths. Furthermore, the expenditure specified in the table below excludes connection cost to either grid or H_2 production facilities.

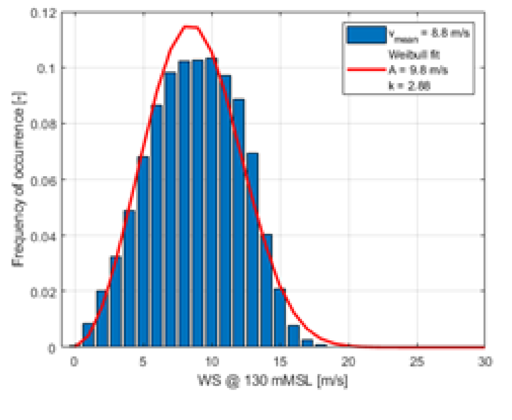
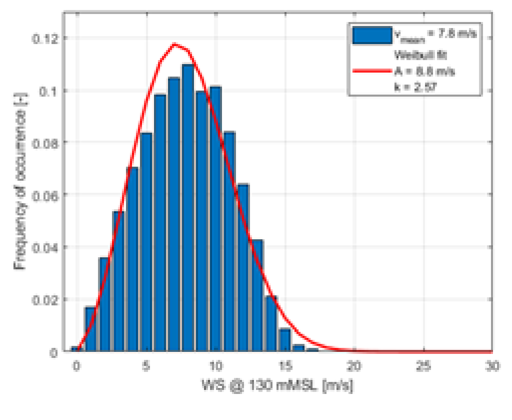
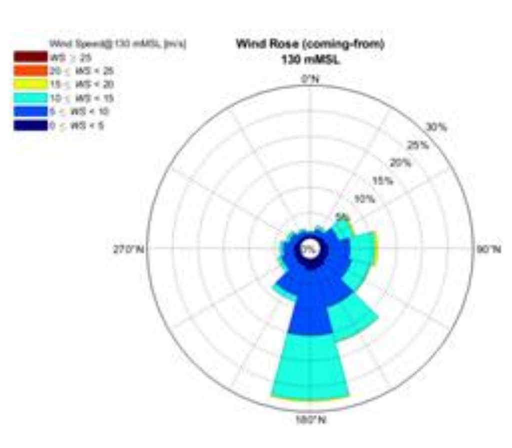
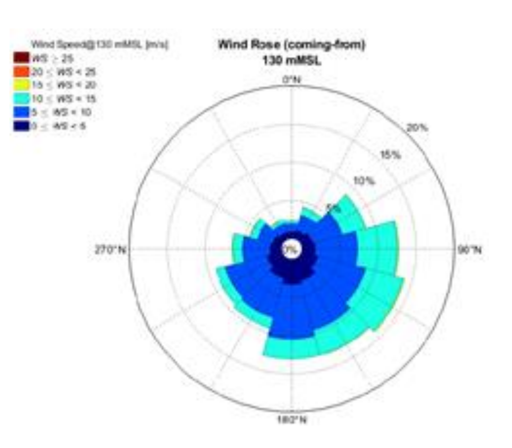
Table 8 Northern Development site: 1GW offshore wind project expenditures excluding H_2 connection costs

Total Capex	5,200,000	AUD/MW
Total Opex	180,000	AUD/MW/annum

Figure 12 provides an overview of the data from two onshore sites identified in the study in the Northern and Central parts of the area of interest.

Figure 12 Mid West Onshore Wind Energy Resource overview

Site	Northern development site #1	Central development site #1
Wind Speed	Average: 8.8m/s	Average: 7.8m/s

<table>
<tr><td>P50 Long term distribution</td><td>
</td><td>
</td></tr>
<tr><td>Wind Rose</td><td>
</td><td>
</td></tr>
</table>

The onshore wind farm sites were analysed assuming the Vestas V150 6 MW turbine. When analysing the wind farm layout, the following constraints were applied:

- An offset of 250 meters from existing roads, power line infrastructure and a minimum distance of 2km between the turbine and landowners.
- Inter-turbine distance: 5 rotor diameters abreast and 8 rotor diameters downwind
- Site specific considerations: existing land use and farming practices, visual impacts, turbine/substation access

Several conceptual layouts were analysed and compared in order to assess the maximum capacity for the site and optimize the capacity factor.

For each scenario, an energy generation time-series was calculated for the period of a full year. Long - term average wind conditions were determined based on 10 years of a high-fidelity mesoscale time series from Vortex and a single year, representative of the long-term average was selected for each site.

The gross capacity factors were determined based on the Vestas V150 6 MW turbine, correcting for hourly variations in air density.

Wake losses were not modelled at his stage due to the complexity of such analysis for onshore sites (unlike offshore sites, the onshore wake modelling needs to account for land cover and terrain topography). Rather, the wake loss was estimated based on wind power industry knowledge and assuming that wind turbine placement to optimize the wake loss will be possible during project development.

The additional energy losses (WTG availability, performance, temperature curtailment, and electrical losses) were defined based on experience and knowledge of standard industry values. The uncertainty of the preliminary energy production estimates shall be reduced in the next stages of the project by:

- wake loss modelling and further optimization of the wind turbine layout
- incorporating onsite or near-site wind measurements in order to refine the knowledge of site- specific WTG performance characteristics.

The sites were divided in WTGs clusters. An initial cluster size of 350 MW was utilized. The cluster size is indicative at this stage and will need to be refined in the next stage of analysis. Equal clusters are preferred to minimize the number of spare transformers to be carried.

Indicative locations of the collector substations were selected to minimize the reticulation system total lengths. Existing roads, property boundaries, vegetation dwellings and operation and maintenance activity also informed the locations.

A collector substation footprint is assumed to be 200 x 200 meters, while HV transmission requires a permanent corridor width between 30 to 65 meters depending on the voltage and technology selected (overhead or underground). Indicative locations of the main substations were selected to minimize the HV transmission total lengths.

The following table provides technical specifications and net capacity factors for a Northern development site of 1.8GW and a Central Development site of 1.3GW.

Table 9 Onshore Wind farm key technical specifications

Layout	Northern Development site: 1.8GW	Central Development site: 1.3GW
Number of turbines	300	217
Substations	2-3 x 33/330kV at Wind farm	1-2 x 33/330kV at Wind farm
Net Capacity factor	50.7%	44.6%

Refer to
Figure 13 for an example 300MW wind farm layout assumed in the analysis.

Figure 13 Central Development site: 300MW wind farm example layout

The following table provides a summary of the basis for the development of the capital and operating forecast for a wind farm site which is located within the area of interest. Furthermore, the expenditure specified in the table below excludes connection cost to either grid or H_2 production facilities.

Table 10 Northern Development site: 1GW onshore wind project expenditures excluding H_2 connection costs

Total Capex	1,700,000	AUD/MW
Total Opex	25,000	AUD/MW/annum

Lautec also completed an assessment of the project infrastructure requirements to deliver large scale energy projects and transmit energy to central locations for integration into hydrogen production facilities. This assessment considered existing grid infrastructure, new build transmission, local ports and the Australian supply chain.

The transmission infrastructure assessment considered the existing Mid West transmission network/SWIS and new build options. At this stage, the study has assumed the development of an independent/dedicated new build transmission infrastructure to aggregate the produced energy for each of the development scenarios. Although providing a potentially conservative basis for the study, the study recommends collaborating with Western Power to explore the possible synergy of a private network development which accounts for Western Powers long term transmission planning. A further opportunity to reduce the overall transmission costs includes the potential to develop the transmission infrastructure set up to enable third party access arrangements.

For the first to market scenario (300MW wind and 350MW solar) the study highlights some potential to connect to the existing infrastructure and possible network augmentations to expand the existing capacity. For the larger development scenarios, the SWIS may be able to provide some essential services to the isolated grid in the form of black start, minimum power required to feed all critical loads of the processing facility, and/or back up auxiliary power.

The Port and Harbors assessment considered the different requirements during the manufacturing and fabrication, constructure, assembly and operational phases of future projects. The port and harbor assessment identified 5 existing suitable port sites with different capabilities and hence different potential uses.

Furthermore, there are several proposed port facilities in the region under development. The most relevant being Oakajee Port – part of the Oakajee Strategic Industrial Area. The proposed facilities would be suitable for all aspects of the project, and since the location is ideal, it is recommended that the progress of the development of Oakajee Port is followed closely.

Each of the 5 existing ports are evaluated with respect to its features and proximity to the proposed sites. Smaller ports such as Geraldton can act to facilitate the day-to-day activities of operations and maintenance, while larger ports including Freemantle could host larger components, material laydown (staging) areas and potentially participate in assembly and fabrication of components for the farms. All other sites are included but are over 400 km's from the sites, however, often include large rural space with large potential for all activities involved with the construction and operations of an offshore wind farm. Furthermore, each port has the potential to act as the import harbor for components sourced from abroad (likely Asia, Europe and the United States) for both the onshore and offshore wind farms.

Table 11 Overview of existing ports

Port	Berths	Depths (m)	Approx. distance to WA 481P	Attributes
Geraldton	7	7.9-12.3	70	Proximity catering for O&M, material laydown area, and boutique operations.
Fremantle	19	6-14.7	352	General cargo port and 4th largest container port in Australia
Ashburton	1	7.8-7.9	1,400	Material Loadout facility, laydown area
Dampier	7	6.7-10	1,550	Iron ore export, heavy load out facility with large open space for utilization
Hedland	19	13.4-14.7	1,840	World largest bulk exporter, hence large size and capability.

To assist with understanding the timeframes and execution of large-scale renewable energy projects, Lautec undertook a supply chain assessment to identify the key onshore and offshore wind supply chain elements in Western Australia. The onshore wind industry is quite mature in Australia and will require less innovation as the methodology of execution is proven due to substantial experience in Australia. Hence, the assessment focused on the potential for local supply and the potential capability of Australian companies' capacity to enter the market in the short term and long term to service an offshore wind industry. The assessment also included an investigation into existing offshore oil and gas infrastructure and companies for the repurposing and/or employment in an offshore wind industry.

The main identified work packages required for offshore wind power that were assessed include project development, wind turbines, foundations, Balance of Plant, installation and commissioning and operations & maintenance. Refer to Table 12 through to

Table 15 for a summary of the assessment.

Table 12 Project Development supply chain

Element	EU Leading Companies	Possible Australian based suppliers/contractors
Wind resource assessment – Meteorological sensors	FT Technologies NRG Systems Riso Thies & Vector Instruments	Australian Radio Towers Vaisala
Oceanographic Assessment – sensors	Nortek Planet Ocean	GEOMACS AIMS CSIRO Horizon
Geophysical and geotechnical surveys	Nasco G-tec GEOxyz	Australia Government department of Geoscience Fugro Benthic Tek-Ocean Horizon Windpal Bhagwan
Consenting and planning	ERM Natural Power NIRAS Royal Haskoning	360 Environment AECOM Emerge Associates GHD Preston Consulting Bennelongia BMT Dalcon Environmental MBS Environmental Stantec Australia Strategen-JBS&G Talis Consultants

		Tecsol Australia ARUP
Design and engineering	Arup Atkins COWI DNV GL LIC energy Mott MacDonald OWEC Worley Ramboll	WSP AECOM GHD Worley

Table 13 Wind turbine supply chain

Element	EU Leading Companies	Possible Australian based suppliers/contractors
Wind turbines	Siemens Vestas GE Goldwind Ming Yang	Suzlon Goldwind Siemens Gamesa Vestas GE Ming Yang
Blades for offshore wind turbines	LM blades Euros SSP	Suzlon
Generators	ABB	Marand Precision Engineering
Towers	Ambau Welcon CS Wind	Keppel Prince Crisp Bros. & Haywards

Table 14 Foundation supply chain

Element	EU Leading Companies	Possible Australian based suppliers/contractors
Monopile foundations	Bladt EEW Steelwind Bilfinger SIF Smulders	Bluescope

Table 15 Balance of Plant supply chain

Element	EU Leading Companies	Possible Australian based suppliers/contractors
HVAC cables	Nexans Prysmian JDR cable NKT	Prysmian NKT
Offshore substation	Main suppliers of electrical equipment: Siemens ABB Alstom CG Power The support structure: Heerema Bladt Bilfinger Harland and Wolff Semco Maritime EU and Global Companies	Main suppliers of electrical equipment: Alstom Siemens the market

The supply chain assessment also considered the Installation, commissioning and operations & maintenance phases and identified the following resources may be available to support a future offshore wind industry:

- Turbine Installation Vessels: A2Sea's Sea Challenger and Sea Installer, Van Oord's Aeolus, Seajacks's Scylla and Swire Blue Ocean's Pacific Orca, Seaway 7 (2022).
- Foundation Installation Vessels: Existing vessels from Australia's extensive oil and gas industries could be transferred, while other vessels are also widely available in Asia and the Middle East. Three different types of vessels have been used to install foundations and they include:
    - Wind turbine installation vessels
    - Floating heavy lift vessels with advanced position holding capability (e.g. Seaway Heavy Lifting's Oleg Strashnov and Stanislav Yudin, Van Oord and several others with hold potential including Saipem 3000, and OSA's Samson & Goliath)
    - Sheer leg crane vessels (e.g. Taklift 7)
- Cable Installation Vessels: A range of vessels and barges have been utilized for offshore cable installation. Furthermore, the oil and gas and telecommunications cable installation experience in Australia can be easily transferred for the export and inter-array cable installation for offshore wind power.
- Offshore Substation Installation Vessels: Specialist heavy lift crane vessels are used due to the size and mass of offshore topsides. Oil and gas topsides installation experience in Australia can almost be directly transferred to offshore wind power.

- Crew Transfer Vessels: Leading European and Global Companies: Alnmaritec, Alicat, CWind and Damen. In Australia, existing yards and boat builders should be able to easily transition to build or retrofit existing vessels to convert them to Service Operation Vessels (SOVs) and Crew Transfer Vessels (CTV's) easily.
- Ports: Geraldton port is in proximity and is the likely choice for O&M port for the offshore wind farms.

3. *Solar Energy resource assessment*

Green Fuel Development (GFD) completed solar assessments focussed on two potential project sites in the Mid West region. The study also considered the grid connection requirements and a review of energy storage options.

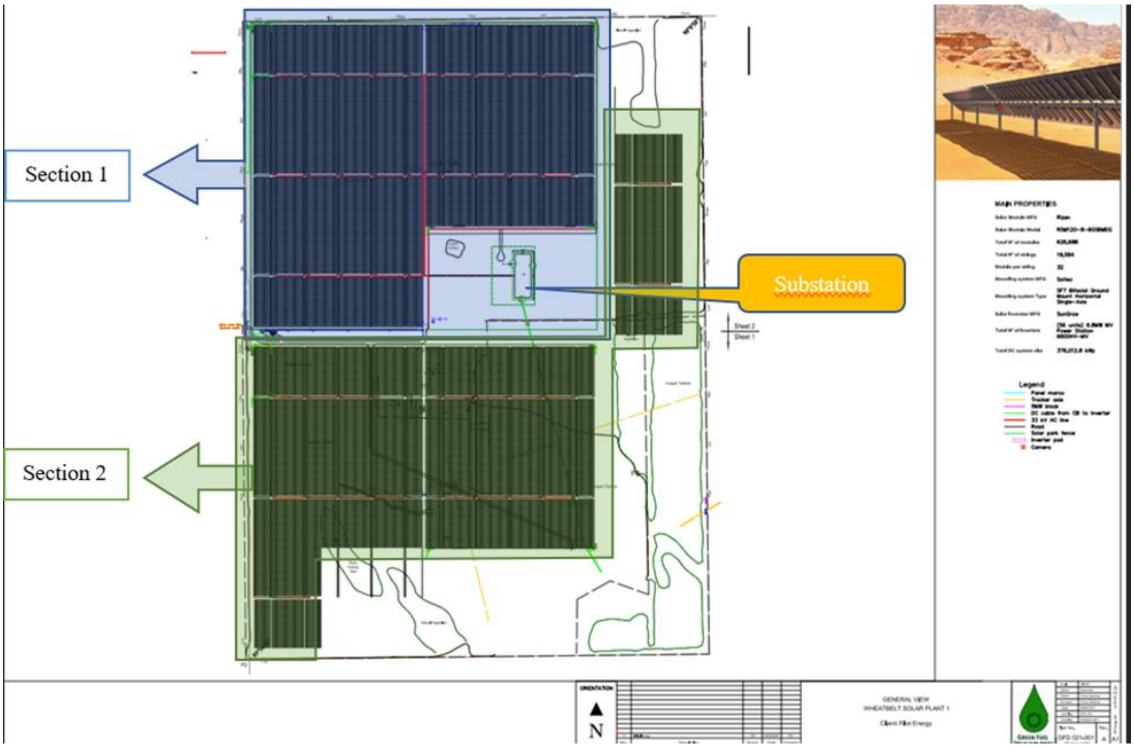
The historical predevelopment studies completed for one of the sites provided a basis for progressing the feasibility assessment with an aggregate potential solar resource of 3350MW. Due to its advanced nature, the study of site #1 (up to 350MW) included the following assessments

- Aboriginal Heritage studies
- Environmental studies
- Geotechnical assessment (ongoing)
- Solar resource yield assessments (PVsyst simulations)
- Land constraints
- Project design and plant layouts

Plant layouts were developed for the two sites enabling levelized cost analysis based on solar resource simulations, level 5 capital and operating cost forecasts. Refer to

Figure 14 for an overview of the proposed layout for site #1.

Figure 14 *Site #1* solar *farm* project layout



The Geotechnical assessment across the Site #1 area highlights a requirement to utilise different installation techniques across section 1 and section 2. The proposed configuration is based on a single axis tracking solution oriented North South to optimally track the sun. The relatively flat terrain across site #1 allows the design to utilise blocks of panels and trackers to be connected to a centralised string inventor and a mid voltage step-up transformer.

The following provides an overview of the key solar farm components and potential suppliers:

- Solar Panel from a Tier one manufacturer: for example Risen's bi-facial dual glass mono PERC module named Titan on 600Wp.
- Single-axis tracking system: Soltec SF7 bifacial ground mount horizontal tracker.

Centralized string inverter with mid-station transformer: SunGrow 6800HV-MV Power Station. All mid-station transformers are interconnected to each other in mid-voltage rings going to the substation.

The proposed solar farm design was based on 32 modules (0.6kWp) per string, 2 strings per tracker (two panels in portrait on each side of the tracker), 1 block design is composed of 192 tracker tables, 384 strings and 12,288 panels.

The proposed block layout is relatively simple, where the inverter station stands in the middle of the block, on the North of the inverter station with 16 columns composed of 6 trackers per column. The South part of the block is a mirror image of the Northern part.

Every 12 strings are interconnected into a DC combiner box before heading to the inverter station. There are 32 DC combiner boxes per central inverter station and a total of 51 central inverters and a mid-voltage step-up transformer. Offering a total install capacity of 376 MWp install capacity on-site and 346.8MVA capacity.Refer to Figure 15 and

Figure 16 for example single line drawing of the String and DC Box and DC combiner boxes for mid-voltage configurations.

Figure 15 Site #1 String and DC Box SLD

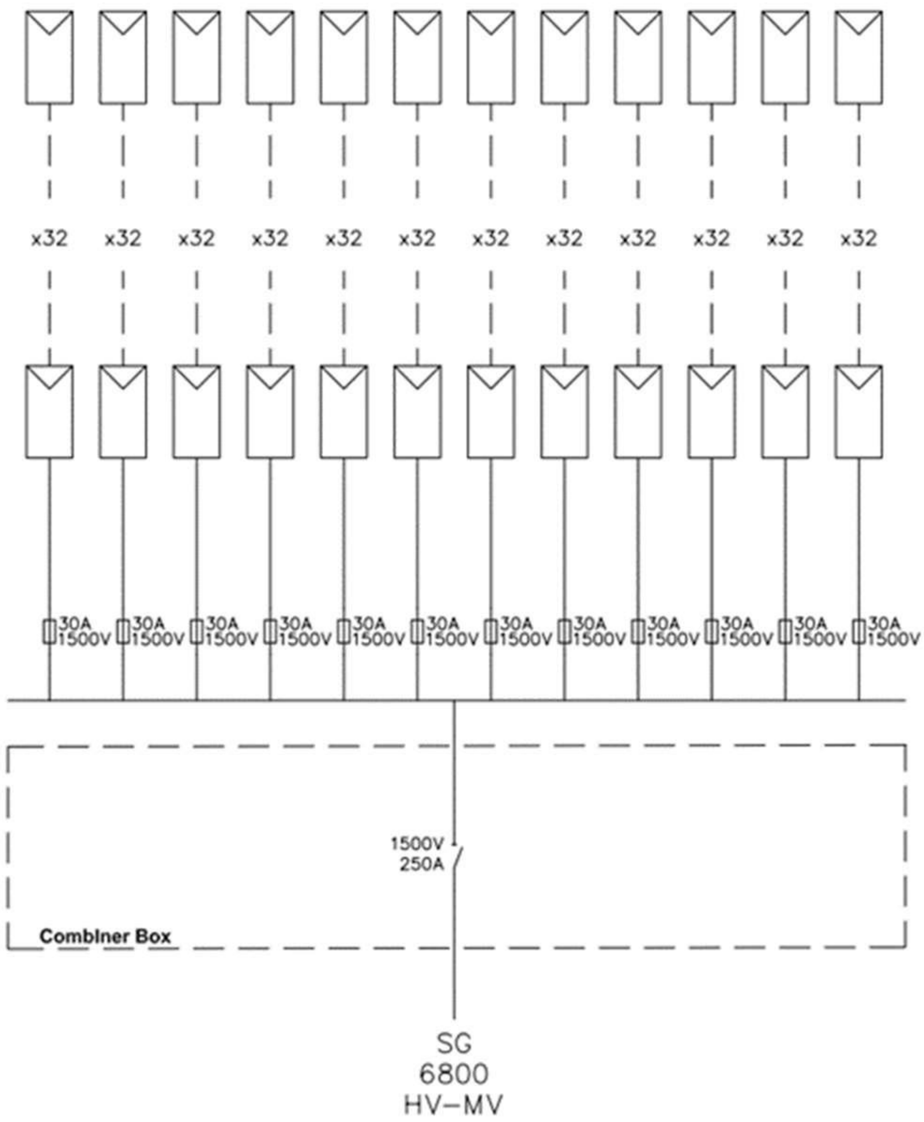
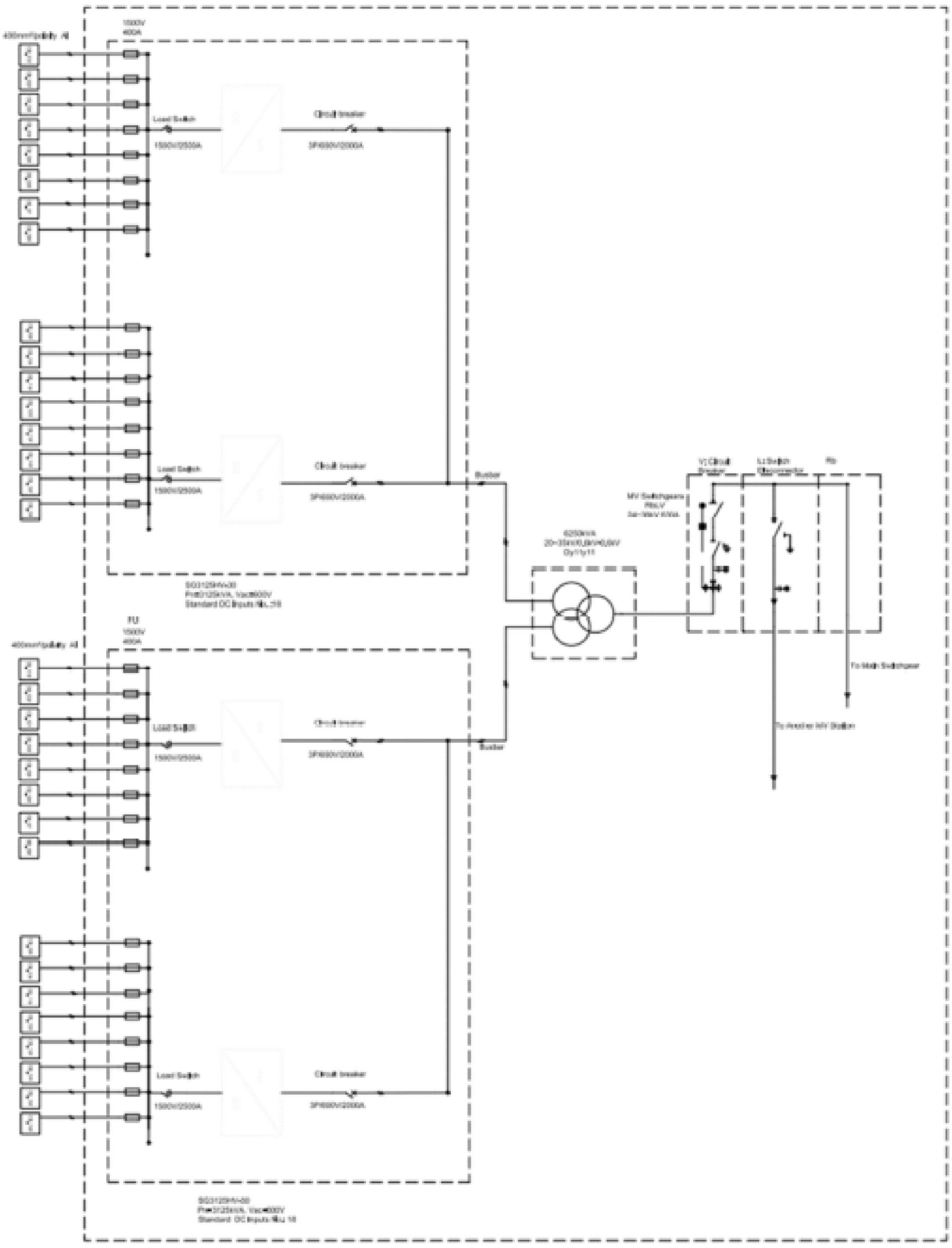


Figure 16 DC combiner boxes to mid-voltage SLD



The yield assessment of this site was conducted using PvSyst a world-class simulation tool to evaluate the yield of a solar field. The dataset is Meteonorm 7.1 using a Mid West location for the initial simulation, with the purchased specific data set from SolarGis for every year between 2006 and 2016 for the site location. There is also an on-site weather station which includes a pyranometer, a wind speed and humidity sensors.

Based on the site conditions the plant yields 2290 kWh/kwp before it reaches the substation. The overall performance ratio of the plant is 85% before the substation. The system was simulated using the backtracking option and detailed string positioning

The capital cost estimate for site #1 and site #2 are summarised in Table 16 covering the solar fields, mid-voltage substation and high voltage substation. The transmission requirements were captured in the Lautec report. Site #2 was assessed in a similar manner to site #1 and provides over 5000 hectares which has been identified as marginal agricultural land and well suited for the development of a large scale solar farm with a potential solar resource of ~ 3000MW.

Table 16 Site #1 and Site #2 Project Capex summary

Location	**Cost (000'AUD)**
Site #1	375,000
Site #2	3,000,000

4. Renewable Hydrogen production and project integration assessment 25 March

Genesis and Technip Energies were engaged to complete an assessment of the hydrogen market and study the production of hydrogen as a means to commercialise the regions significant renewable energy resources. In addition, Genesis managed the process to integrate the various feasibility study outputs into an assessment of each development strategies levelized cost of electricity and hydrogen.

The renewable hydrogen assessment considered the equipment directly associated with the production, purification and compression of green hydrogen and auxiliary/utilities, such as water purification, cooling systems and nitrogen generation.

The electrolysis process is simply the separation of hydrogen and oxygen atoms from a water molecule. The primary equipment required for a water electrolysis plant is a power transformer and rectifier, an electrolyser stack and a gas/liquid separation skid. This skid typically contains equipment such as circulation pumps, vessels, tanks and heat exchangers. Depending on the hydrogen quality, further purification may be required.

This project has been based on pressurised alkaline electrolyser technology, specifically equipment designed and constructed in China and the following 20MW configuration:

- 4 x 5MW transformers
- 4 x 5MW rectifiers
- 4 x 5MW electrolysers
- 1 x separation package (including liquid/gas separators, pump, heat exchangers, etc), sized for a 20MW of electrolysers.

The study noted that the electrolyser industry is developing and changing at a fast pace. Through the future stages of this project, technology selection should be considered based on current technology readiness anticipated for the development timeline.

The assessment considered a number of end users, the likely hydrogen quality specified in hydrogen purchase arrangements and hydrogen storage requirements. Hydrogen leaving the gas/lye separation skid is saturated with water and of a quality around 99% purity. For users that require specific purification requirements and/or dehydration, the hydrogen is passed through a purification skid. The hydrogen leaving the purification skid has a purity of >99.999% and a dewpoint of minus 70 C°. At this purity the hydrogen is suitable for liquefaction. For hydrogen fuels cells, a purity of 99.97% is required. Hydrogen use for industrial processes or pipeline blending will require a purity of ~98%. As the purification skid is capable of producing higher purity hydrogen than required for fuel cells, the purified hydrogen can be blended with dehydrated hydrogen to increase the fuel cell quality product.

Hydrogen storage is highlighted in the study as a key opportunity and an area for further assessment. Due to its low density, any significant hydrogen storage can produce very large storage requirements that will comprise a significant proportion of the total overall plant costs. Storage is required to provide a buffer for supply, owing to the intermittency of the hydrogen generation from renewables, and due to the periodic offtake of some supply chains. The preliminary storage capacities are given in Table 17.

Table 17 Hydrogen Storage Capacity

End use	Storage Capacity (tonnes)	
	First to Market strategy	Mid Scale
Industrial Hydrogen	100	600
Fuel Cell hydrogen	100	n/a

The fuel cell storage capacity is larger as the offtake is periodic whereas the industrial hydrogen is assumed to be a continuous supply. The storage basis should be reviewed when export routes and target markets are more defined. Storage assumptions assumed:

- Weekly offtakes for fuel cell grade hydrogen
- Fuel cell grade storage sized for 10 days production
- Continuous offtake for industrial grade hydrogen
- Industrial grade hydrogen storage sized for typical daily production

The hydrogen production assessment and capital cost estimates are summarised in Table 18, Table 19 and Table 20. The table's present the analysis on the basis of the development strategies identified during the feasibility study.

The hydrogen production assessment incorporates results from the renewable energy resource assessments with Table 18 illustrating how the energy is transformed and utilised by the selected hydrogen plant. This analysis highlights that the majority of the power is utilised directly by the electrolyser stacks in the electrolysis of water to produce hydrogen at the stack outlet. The remaining energy powers utilities and/or is assumed to be spilled energy.

Table 18 Renewable energy production and electrolyser utilisation

Category	First to Market	Mid-scale offshore/onshore	Mid-scale Onshore only	Maximum Generation
Solar (MW)	350	1,000	1,000	3,000
Offshore wind (MW)	-	1,800	-	10,100
Onshore Wind (MW)	300	1,000	2,800	4,700
Total Generation (MW)	650	3,800	3,800	17,800
Total production (GWh)	2,000	13,500	13,000	66,500

Table 19 summarises the hydrogen production results for each development strategy. It is worth noting that:

- The Electrolyser operates at between 68-70% on average for all strategies. This is not surprising given the oversizing of the nominal renewable sizing to nominal plant capacity is approximately 180%-200% in most cases.
- Hydrogen production per MW installed capacity is relatively consistent across the strategies at between 107 Te/MW and 111 Te/MW installed capacity. This metric cannot be currently validated against reference projects due to the stage of market development, but is consistent with first principals estimation.

Table 19 Hydrogen production estimates

Category	First to Market	Mid-scale offshore/ onshore	Mid-scale Onshore only	Maximum' Generation
Renewables Production (GWh)	2,000	13,500	13,000	66,500
Electrolyser Actual Plant Size (MW)	288	1,920	1,920	9,600
Hydrogen Annual Output (ktpa)	30	260	250	1,200
Hydrogen Plant Average Utilisation	65%	75%	70%	70%

The Study introduced the Mid-scale onshore only scenario to assess the potential cost base of a mid-scale hydrogen project supplied exclusively by onshore renewables. The results indicate the benefits of a slightly more regular annual power production profile with less of a higher peak energy output in summer compared to winter. The LCOH analysis details further the benefit of incorporating the lower cost onshore wind resources assuming current technologies and costs.

Table 20 Hydrogen plant summary

(kAUD)	First to Market	Mid-scale	Maximum Generation
Total installed cost	935,000	4,000,000	11,000,000
Nominal H_2 production (ktpa)	30	260	1,200

The final aspect of the study involved an assessment of the levelized costs of electricity (LCOE) (based on the underlying Lautec and GFD reports) and the levelized cost of hydrogen (LCOH). The levelized cost analysis was based on the following formula and key assumptions (in addition to the consultant's forecasts of capital costs, operation costs and energy/hydrogen production).

- LCOE equation

$$\mathbf{LCOE}\left({}^{\mathbf{AUD}}/_{\mathbf{MWh}}\right) = \frac{\mathbf{NPV\ of\ (CAPEX+OPEX)}}{\mathbf{NPV\ of\ MWh}}$$

- LCOH equation

$$\mathbf{LCOH}\left({}^{\mathbf{AUD}}/_{\mathbf{kg\ H_2}}\right) = \frac{\mathbf{NPV\ of\ (CAPEX+OPEX)}}{\mathbf{NPV\ of\ kg\ H_2}}$$

- Key assumptions
    - Cost of Capital: real 4% (equivalent to 6% nominal)
    - Real ($2022) capital and operating cost forecast
    - To assist with comparing the LCOH across the development strategies with materially different delivery timeframe and allow comparison against current market commentary regarding hydrogen price expectations the LCOH and LCOE analysis is present on a real basis ($2022)
    - Technology learning rates, economies of scale, plant degradation & replacement (e.g Electrolyser stacks and invertors replaced every 10 years) have been incorporated into the analysis

Project levelized cost of electricity

The real levelized cost of electricity has been developed at a number of relevant points within the energy flow path for the study and these are presented in Table 21. The values identified are compared against representative ranges provided within CSIRO 2021 GenCost report.

The results indicate:

- Overall LCOE for the onshore solar and wind farms is very competitive and is at or below the lower bound CSIRO costs

- Strategies with offshore wind farms had the highest Hydrogen Plant "Farm Gate" delivery costs. This is attributable to the increased transmission costs and the early stage nature of the Australian offshore wind industry which has resulted in relatively high capital cost forecasts for offshore wind developments.

Lautec noted that although the LCOE at this early stage are on the high side of industry expectations, the following are forecast to assist with improving the project economics of offshore wind developments in Australian waters:

- Further development on an industry in Australia, which will drive cost significantly down due to greater interest from supply chain and resource availability locally;
- Further wind measurements to drive down the uncertainty on the mesoscale model, which generation profiles are based on;
- Development of concept transmission design and further wake modelling, which will help understand and optimize the losses on the system;
- Optimizing the transmission assets in relation to the final stages of the projects

Table 21 LCOE Summary of the Development strategies

	Units	CSIRO Gen Cost 21/22[5]	First to Market	Mid-Scale Offshore/ Onshore	Mid-Scale Onshore	Max Generation
Solar	AUD/MWh	44 - 65 (2021) 28 - 60 (2030)	39	36	36	36
Onshore Wind	AUD/MWh	44 - 57 (2021) 39 - 55 (2030)	34	29	29	31
Offshore Wind	AUD/MWh	N/A	N/A	214	N/A	199
Combined LCOE at H_2 plant	AUD/MWh	N/A	57	56	42	75

Project levelized cost of hydrogen

The real levelized cost of hydrogen is presented in Table 22

Table 22 LCOH summary

	Units	First to market	Mid-Scale Offshore/onshore	Mid-Scale Onshore	Maximum Generation
H_2 plant size	MW	288	1920	1920	9600
Total Generation	MW	650	3,800	3,800	17,800
Total LCOH	AUD/ H_2 kg	5.62	3.94	3.11	4.73

The results indicate:

- The lowest LCOH was determined for the 2 Mid-scale onshore scenario and is within the expected range of pricing for an optimal project.
- The current global estimate for the early 2030's is approximately USD 2 per kg which equates to approximately AUD 2.95. The global estimates typically exclude the cost of compression and storage (which are approximately 13% of the CAPEX for this case) and also exclude transmission aspects.
- Transmission costs are a significant aspect of the LCOH.

[5] Graham, Paul; Hayward, Jenny; Foster, James; Havas, Lisa. GenCost 2021-22: Consultation draft. CSIRO publications repository: CSIRO; 2021. https://doi.org/10.25919/k4xp-7n26

- The LCOH results indicate that the LCOH in 2025 will be significantly higher than the LCOH in 2035, due to expected increases in efficiency and lowering costs in future years as global production and technological advancements are available.

Annexure C Mid West Hydrogen potential

Highlights

- Renewables and 8 Rivers studies demonstrate the significant clean hydrogen opportunity in the Mid West

- 8 Rivers Study estimates 43,000 tpa of globally competitive blue hydrogen can be produced at a levelized $2.13 per kg at plant gate utilising the Industrial scale $^8RH_2$ hydrogen technology

- Renewables Study estimates the levelized cost of delivering green hydrogen to key demand centres across the Mid West from $3.11 per kg on a stand-alone basis utilizing only renewable power

- Low-cost blue hydrogen production can be used to produce approximately 240,000 tpa of globally competitive clean ammonia at a levelized cost of product of A$398 per tonne and potentially as low as ~A$371 per tonne by increasing facility size to approximately 480,000 tpa. Integrating renewables energy into the Industrial Scale $^8RH_2$ facility can increase ammonia production to at least approximately 345,000 tpa

- Clean ammonia produced from blue and green hydrogen is seen as an emerging low carbon energy source for use in key Asian energy markets capable of playing a key role in decarbonizing power generation, maritime shipping and heavy industry

- Extending the scope of the Studies, the Company will commence activities to pursue the production and the development of an integrated ammonia export project capable of initially supplying 240,000 to 345,000 tpa of clean ammonia into international markets

The Renewables Study and 8 Rivers study separately assessed the production of hydrogen leveraging the Mid West regions globally significant renewable energy and CCS resource. The results to date indicated that blue hydrogen can be supplied at key demand centres in the near term to stimulate the important transition to a hydrogen-based economy with green hydrogen production providing expansion over the medium to long term.

One of the key outcomes of the studies is the integration of renewable energy into the 8 Rivers technology potentially enabling near term production of green hydrogen with competitive economics. The 8 Rivers technologies require oxygen as a key process input and are typically designed with air separation units to deliver the required oxygen. 8 Rivers and Pilot have studied supplementing the energy intensive air separation equipment with electrolysis powered by renewable energy. Introducing electrolysis provides an amount of the required oxygen stream at the same time as producing green hydrogen depending on deployed capacity. This exciting outcome is discussed as a key component of Pilot's near term development plans.

The 8 Rivers Study indicates that the Company can produce clean hydrogen on a globally competitive basis. The development of an Industrial scale $^8RH_2$ Hydrogen Plant can produce clean hydrogen with capture of 98% CO_2 for $2.13/kg or USD1.50/kg. Further the 8 Rivers study indicates that an integrated ammonia development project (industrial scale) can deliver clean ammonia with near zero carbon emission ready for export at $398/tonne.

The results of the Renewables Study which includes the integration of the projects significant renewable energy resources into green hydrogen projects are summarised in Table 23.

Table 23 Renewables Study Summary of development strategies and levelized cost of hydrogen

Strategy	**Project start**	**H_2 Plant location**	**Onshore Wind (MW)**	**Offshore Wind (MW)**	**Onshore Solar (MW)**	**H_2 plant capacity, volume**	**LCOH ($/Kg – real $2022)**
First to market	~2025/6	Arrowsmith	300	-	350	288 MW 30ktpa	5.62
Mid-Scale – Onshore	2035	Oakajee	2,805	-	1,000	1,900 MW 250ktpa	3.11
Mid-Scale – Off/Onshore	2035	Oakajee	1,800	1,000	1,000	1,900 MW 260 ktpa	3.94
Max Generation	2035	Oakajee	4,700	10,000	3,000	9,600 MW 1,200 ktpa	4.73
Note: Levelized Cost of Hydrogen is presented on a $2022 basis and calculated on the basis of forecasts prepared by feasibility consultants assuming real cash flows ($2022) and a real cost of capital of 4% (equivalent to a 6% nominal cost of capital).							

The results of the feasibility studies provide further evidence in support of the WA Governments plans to locate a hydrogen hub in the Mid West region. The McGowan Government has committed to invest up to $117.5 million to attract Federal funding for renewable hydrogen hubs in the Pilbara and Mid West to drive Western Australia as a global clean energy powerhouse. Pilot was pleased to provide a letter of support to the WA Governments recent application for Federal funding under the Clean Hydrogen Industrial Hubs program[6].

[6] https://www.mediastatements.wa.gov.au/Pages/McGowan/2021/11/117-point-5-million-dollars-to-progress-two-renewable-hydrogen-hubs.aspx

Annexure D: 8 Rivers Blue Hydrogen and CO_2 Technology Study

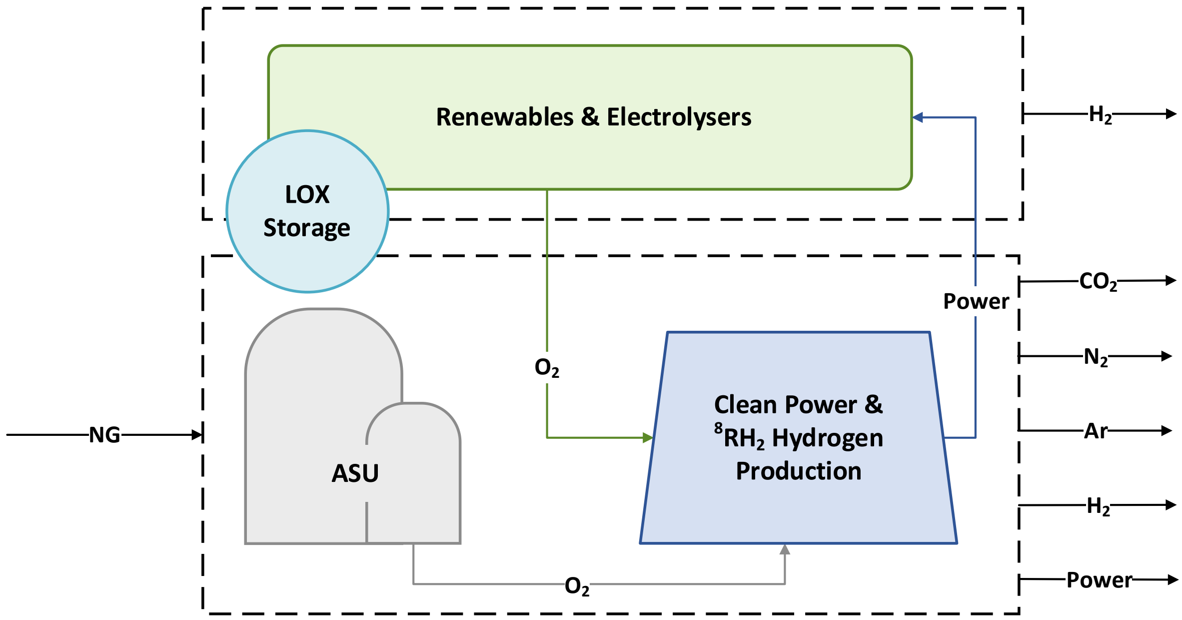
Pilot commissioned 8 Rivers Capital, LLC (8 Rivers) to carry out a Feasibility Study to support the evaluation of clean hydrogen production utilising 8 Rivers Hydrogen ($^8RH_2$) for blue hydrogen production, and as integrated with clean power and additional renewable energy sources and electrolysers, producing green hydrogen, in Western Australia.

Analysis of the renewable energy sources and electrolysers themselves was outside the scope of this study, however the potential benefits of integration with them have been investigated.

1. Technology Overview

8 Rivers' $^8RH_2$ technology emits virtually no CO_2 and generates hydrogen as its primary product. The $^8RH_2$ process is the ideal system for large-scale hydrogen production with CO_2 capture, boosting efficiency above that of steam methane reforming while enabling up to 99% capture rates (refer to Figure 17). The system uses oxygen-blown autothermal reforming to minimise external firing and atmospheric CO_2 venting. Additionally, a heat exchanger reformer is used in tandem to maximise the heat utilisation for hydrogen production. A low-energy, cryogenic CO_2 separation system is included which allows CO_2 capture from the high-pressure syngas loop while maximising H_2 recovery. This hydrogen may then be used as-is or processed further to produce ammonia.

Figure 17 $^8RH_2$ process overview



Using pure oxygen from an ASU or the electrolysers allows the $^8RH_2$ system to be operated at high pressures with a closed-loop configuration between the reforming reactors, increasing efficiency and inherently capturing produced CO_2. An oxy-fuel heater, instead of an air-fired heater, is used such that the flue gas is composed of only CO_2 and steam, which can be easily separated, without pollutants such as NOX. Essentially, having a pure oxygen input stream allows for the full decarbonisation of the hydrogen production process.

2. Project and study Overview

Project case studies considered in the 8 Rivers study looked at a fully integrated $^{8}RH_2$ clean hydrogen plant with clean power and renewables with electrolysers, along with stand-alone cases.

Additional scenarios also considered the integration of additional plant to produce ammonia, taking advantage of the already-existing market and the operational synergies (for example nitrogen production by the ASU).

On top of the basic $^{8}RH_2$ and ammonia production technology matrix, further analysis was conducted to ensure proportional CO_2 source and sink matching as well as to address varying commercial strategies based on unique local attributes. Project configurations are evaluated primarily according to the injection capacities of local sequestration opportunities; utility-scale, “full-size” deployments may be accommodated by large sequestration opportunities (e.g., the Lesueur formation in the South West) while industrial-scale deployments are scaled down to afford deployments in other regions such as the Mid West and to suit supplying hydrogen.

While sacrificing economies of scale, it is observed that, naturally, industrial-scale deployments require lower capital investment up front and may lend themselves, among others, to a fleet-building strategy over time as the emerging clean hydrogen market (and clean ammonia market) is established.

Three potential sites are assessed: Arrowsmith, Oakajee, and Kwinana/Rockingham.

3. Performance Results

Integration between $^{8}RH_2$ & clean power, renewables, and electrolysers has been analysed to assess the integration benefits between gas-fired carbon capture to electrolytic hydrogen production. Table 24 presents the increased hydrogen production capacity for a specific case selected by Pilot as having the highest interest.

Table 24 Hydrogen Production

Required LOX Storage	Electrolytic H_2 from Renewables	Electrolytic H_2 from gas with carbon capture	H_2 from $^{8}RH_2$	Total H_2 Production
tonnes	Tpd	tpd	tpd	tpd
141 (high-end min.)	37.7 (average)	11.6 (average)	116.9 (average)	166.2

4. Financial Results

The feasibility study includes a Class 5 assessment of the CAPEX, OPEX, by-product revenues, and levelized cost of production (LCOP, electricity and/or hydrogen and/or ammonia) for each configuration. The following table summarises the levelized cost of hydrogen/ammonia results for selected cases.

Table 25 LCOP Analysis Results

LCOP (AUD/kg)	100 MMSCFD H_2	50 MMSCFD H_2	1,360 TPD NH_3	680 TPD NH_3	680 TPD NH_3 with Oxygen Storage
H_2/NH_3	H_2	H_2	NH_3	NH_3	NH_3
Total	**1.85**	**2.13**	**0.371**	**0.422**	**0.398**

Key findings from the financial analysis of include:

- Under an industrial-scale [8]RH_2 Project configuration with a bolt-on ammonia train (680 TPD NH_3), the plant could produce clean ammonia at the plant gate at $422/tonne
- Under an industrial-scale configuration with a bolt-on ammonia train, and allowing for 50% of the oxygen required to be provided as a zero-cost by-product of separate electrolyser deployment, the cost of clean ammonia at plant gate reduces to $398/tonne.
- Economies of scale in the technology drive better economic performance. The industrial scale (50 mmscfd H_2 & 680 tpd NH_3) case economics, whilst still positive, are not as strong as those of the utility scale (100 mmscfd H_2 & 1360 tpd NH_3) cases.
- Typical unbated global ammonia costs range from $300 to $450. Whilst the analysis above is at plant gate, it suggests that ammonia produced from the technology could be competitive with unbated ammonia, let alone other sources of clean ammonia.

Annexure E - Hydrogen and Ammonia market update

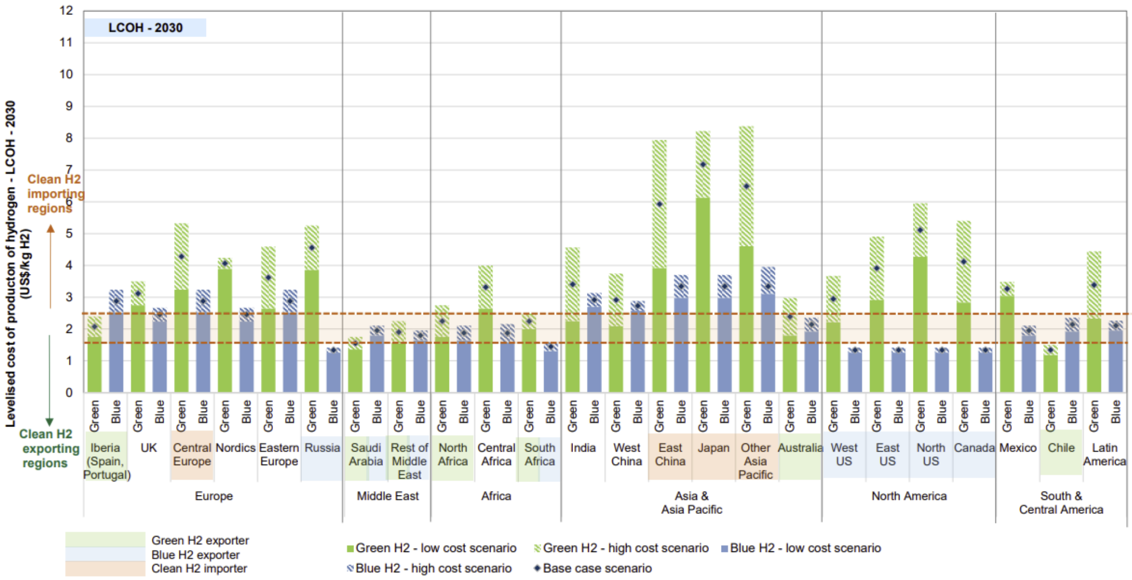
1. Hydrogen market update - Renewables and 8 Rivers Study support further investment in developing Mid West hydrogen projects

Global hydrogen of ~ 70 million tonnes per annum (2020 volume) is predominately met by grey hydrogen manufactured from the natural gas steam reformation process without carbon capture and emits ~ 600 million tonnes per annum of CO_2. The Australian domestic hydrogen market is around 0.65 million tonnes per annum of grey hydrogen. The production cost base on grey hydrogen in the domestic Western Australian market was estimated by Advisian's Australian Hydrogen Market Study[7] (May 2021) at $1.70/kg without accounting for the cost of CO_2 emissions.

Converting from grey to blue hydrogen requires carbon capture technology to be retrofitted to existing infrastructure. The complexity of a retrofit, in addition to the varied sources of emissions (flue gas from balance of plant and CO_2 from reformation process), may result in existing facilities being able to capture 90 - 95% of the associated emissions.

Goldman Sachs Carbonomics: The clean energy revolution report[8] of February 2022, forecast Global LCOH in 2030 with countries producing hydrogen below USD2/kg likely to emerge as clean hydrogen exporting regions.

Figure 18 Carbonomics Global Levelized cost of hydrogen in 2030



[7] https://www.cefc.com.au/media/nhnhwlxu/australian-hydrogen-market-study.pdf
[8] https://www.goldmansachs.com/insights/pages/gs-research/carbonomics-the-clean-hydrogen-revolution/carbonomics-the-clean-hydrogen-revolution.pdf

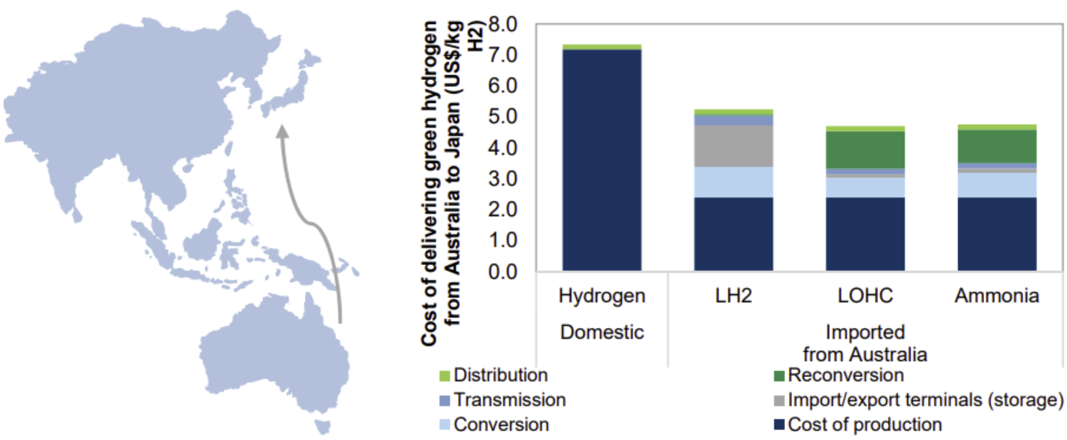
The results of the Feasibility Studies confirm that the CCS and Renewable resources and Hydrogen Potential support cost competitive clean hydrogen being produced from the Mid West region of Western Australia. Comparing the Renewable and 8 Rivers Study's estimated LCOH ($3.11/kg to $1.85/kg (Utility Scale) respectively) to Goldman Sachs' global forecast highlights the near-term opportunity to develop cost competitive hydrogen projects in particular through the deployment of 8 Rivers technology.

2. Ammonia Market Update – 8 Rivers Study Points to Clean Ammonia

The 8 Rivers study indicates that an integrated ammonia development project can deliver ammonia ready for export at $398/tonne (industrial scale). Goldman Sachs estimates Australian ammonia will be competitive on a delivered basis assuming USD2 – 2.5/kg (A$2.9 – 3.6/kg) hydrogen input price with ammonia produced domestically in Japan (refer to Figure 19 used to estimate the Australian domestic H_2 price).

Figure 19 Goldman Sachs – Cost of Australian hydrogen delivered to Japan

Exhibit 102: A summary of all-in costs of Japan importing green hydrogen from Australia under various forms



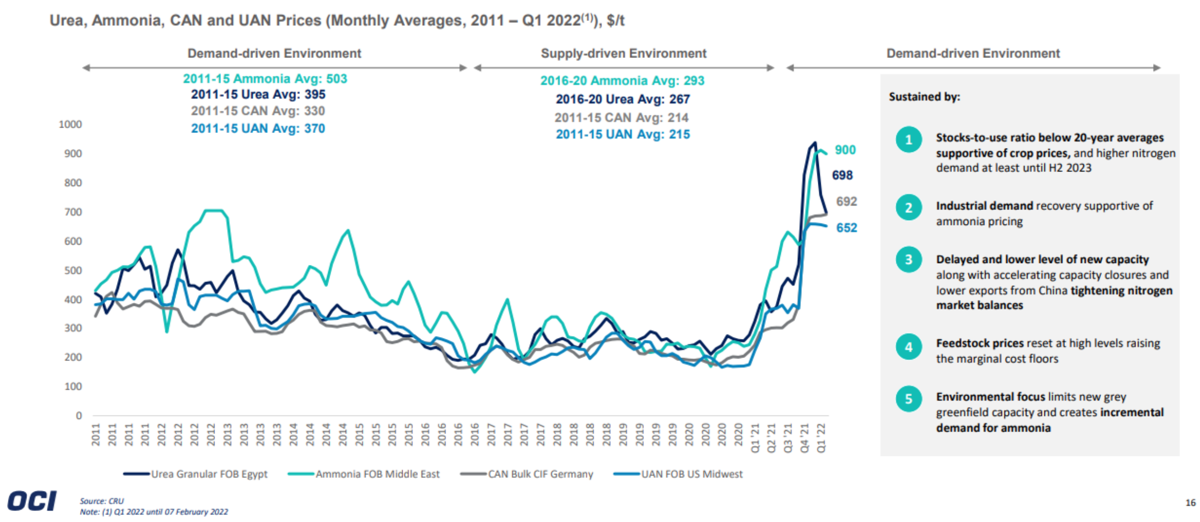
Source: Goldman Sachs Global Investment Research

The [8]RH$_2$ Blue Hydrogen system can produce clean ammonia at the plant gate for as low as $371/tonne at utility scale. This clean ammonia is competitive even against unabated ammonia, whose price fluctuates between $300-$450/tonne on the global market (noting that recently prices have been inflated);[9] in US Dollars, as depicted in

Figure 20 below, this is equivalent to USD210-315/tonne.

[9] Prospects, Challenges, and Trends in the Global Ammonia Market. Georgy Eliseev, HIS Markit, September 2019

Figure 20 Global Ammonia Market, OCI Presentation[10]



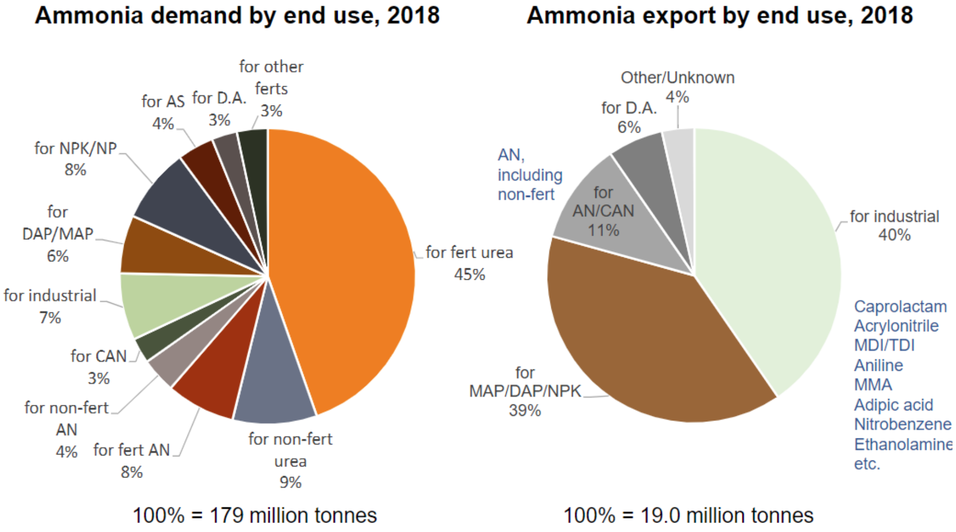
Bloomberg New Energy Finance has projected that ammonia from renewables is on a downward cost curve but still would only reach \$650/tonne in 2030 and <\$400/tonne in 2050.[11] The economic results of the 8 Rivers study show that producing clean ammonia in WA using the $^8RH_2$ system is competitive against the existing ammonia supply chain and that the process has low enough costs for its product to co-exist with ammonia produced from solar and wind, even with the falling cost of renewables and electrolysers. Such a project also produces dispatchable clean electricity which can balance solar and wind generation on the Australian power grid, thus providing electricity that is affordable, clean, and reliable.

Figure 21 Ammonia Demand[12]

[10] *OCI Full Year and Q4 2021 Results Presentation*

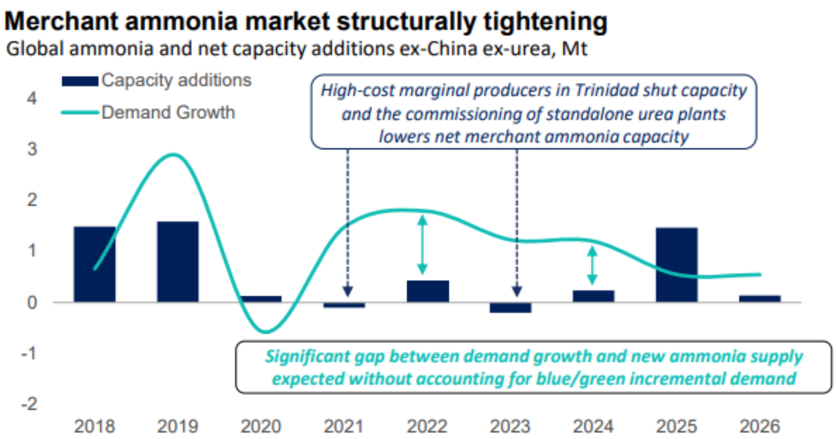
[11] Bloomberg NEF Hydrogen: Making Green Ammonia and Fertilizers. August 2019. (All numbers converted to AUD.)

[12] IHSMarkit GPCA Fertilizer Conference Presentation

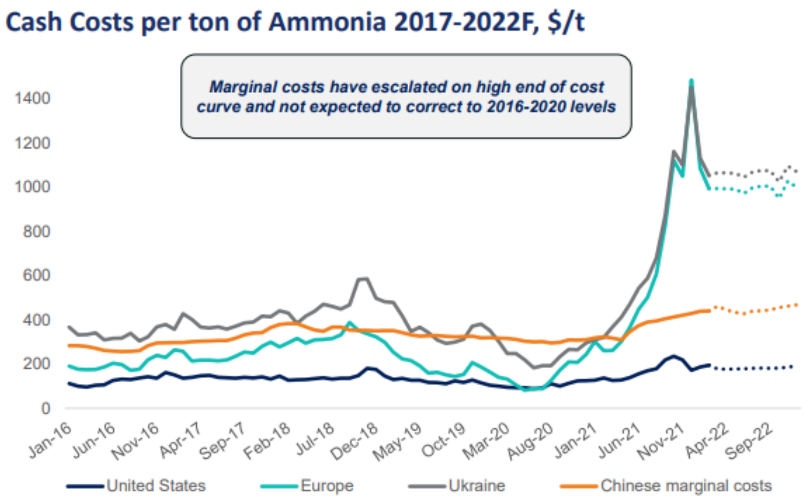


Even outside of decarbonisation, the market outlook for ammonia prices is positive, with continued demand growth and slowing capacity additions, combined with high fuel prices in Europe. Additionally, in 2021 Russia was the largest exporter of ammonia, which with tensions with Ukraine and potential Western sanctions potentially causing further instability or higher prices in the global ammonia market.[13]

Figure 22 Ammonia Market[14]



[13] Ukraine Crisis Highlights Russia Fertilizer Supply Risk - https://www.argusmedia.com/en/news/2304708-ukraine-crisis-highlights-russia-fertilizer-supply-risk
[14] OCI Full Year and Q4 2021 Results Presentation



Australia's ammonia trade flows are nearly net neutral, with current exports around $70 million of ammonia from the Yara Pilbara plant, and imports around $75 million of ammonia from Fremantle and two Eastern Australia ports.[15]

This analysis and the growing demand for ammonia as a clean energy source in Asian markets, evidence by JERA recent tender for an initial tranche of 500,000 tonnes per annum of clean ammonia[16] and its target of 50% co-firing of coal fired power stations by 2030[17], support Pilot's plans to accelerate the integrated ammonia project leveraging Pilots existing operational footprint.

Growing Clean Ammonia Global Market

Energy importers like coastal China, Japan, and Korea do not suddenly become energy self-sufficient by virtue of decarbonising. In fact, many of these countries have realised that the energy transition poses a threat to their energy security. Using Japan as an example, Japan has minimal natural energy resources such as oil, natural gas, and coal.[18] It had historically used a large share of nuclear power, but after Fukushima it reduced its nuclear power from 13% to just 3% of its share of energy in 2019. This has also propelled it to be one of the largest users of fossil resources and because of its lack of natural resources, it relies almost entirely on imports.

In 2019, Japan was the largest importer of LNG in the world, all of which came in through tankers as Japan has no international pipelines. Japan has potential to increase their renewable penetration, particularly when it comes to offshore wind,[19] but they otherwise face an uphill battle due to their mountainous geography, lack of photovoltaic power potential,[20]

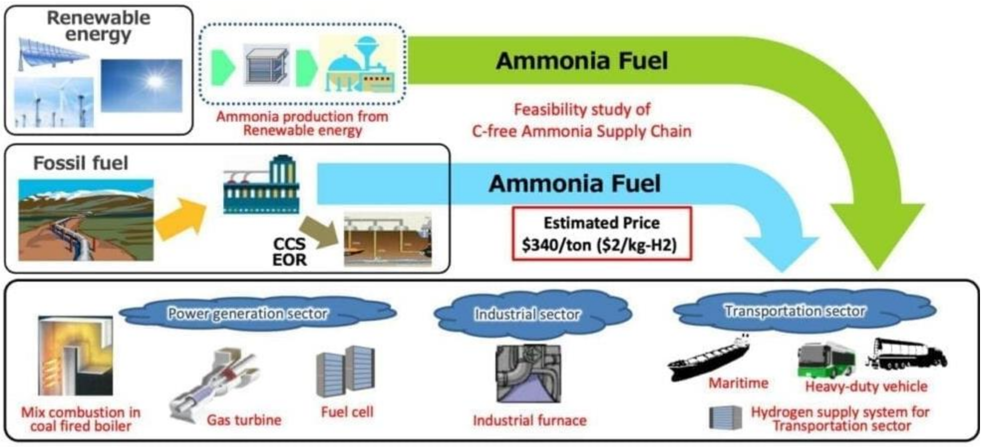
[15] Ammonia in Australia | OEC
[16] https://www.jera.co.jp/english/information/20220218_853
[17] https://www.ammoniaenergy.org/articles/jera-targets-50-ammonia-coal-co-firing-by-2030/
[18] Japan's Energy
[19] Global Offshore Wind Potential
[20] Solar Resource Maps of the World | Solargis

and disparate unstable power transmission network.[21] In addition, the geology in Japan makes local CO_2 storage difficult when compared to other regions.[22]

Countries like Japan, with minimal natural resources that rely heavily on imports, paired with suboptimal renewable potential, are intimately aware that they will have to include imported zero-carbon fuels in their future energy portfolio if they are going to be successful in reducing their emissions through the energy transition.[23] It is expected that they will shift their imports from coal and gas to hydrogen and ammonia.

New energy imports in the form of hydrogen and clean ammonia can still be combusted in existing (following modification) gas power plants (hydrogen) and coal power plants (ammonia) and can be used as fuel for transportation and industrial process heat. As such, Australia can transition from exporting hydrocarbons, to exporting clean hydrogen.

Figure 23 Japan's Green Ammonia Consortium Strategy



Japan is leading the market through demand creation and has been public about their plan to stop importing coal and to transition towards importing blue and green clean ammonia, announcing their first purchase of clean ammonia from gas produced by Saudi Arabia in September of 2020. Japan is targeting 3 million tonnes of clean ammonia import by 2030 and 30 million tonnes by 2050.[24]

JERA, Japan's biggest power company, announced that they will co-fire their coal plants on ammonia, aiming for 20% co-firing by 2035 and ramping up so that by 2050, all of their thermal power plants will run on 100% ammonia. Japan recently announced funding to demonstrate

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[21] Potential of Renewable Energy in Japan
[22] Estimation of CO_2 Aquifer Storage Potential in Japan
[23] Japan Will Have to Tread a Unique Pathway to Net Zero, but It can Get There Through Innovation and Investment | IEA
[24] Japan's Road Map for Fuel Ammonia

50% ammonia-coal co-firing by 2030, as part of a larger ammonia fuel supply chain project with a $500 million budget.[25]

This is a case study for the use of ammonia to replace coal and decarbonise power. Some of the same Japanese coal plants currently importing Australian black coal will soon be on the market searching for clean and affordable ammonia from Australia to supplement and eventually replace those imports.

Ammonia can, similarly, be used directly as a zero-emission marine fuel. With 940 million tons of CO_2 emitted annually by maritime vessels, and with the International Maritime Organisation aiming for 70% carbon reduction by 2050, shipping represents a massive market for the direct use of clean ammonia produced in Australia.

Hydrogen itself is expected to be used directly to help decarbonise refining, industrial process heat, heavy duty trucking, home heating, and existing gas turbines. However, there is a strong case for ammonia to be the dominant transport mechanism for this hydrogen while it is being shipped globally due to its established supply chain and relative ease of handling compared to liquid hydrogen. This is demonstrated in the figures below, showing ammonia shipping costs in various scenarios.

Figure 24 Transportation Cost of Hydrogen and Hydrogen Carriers[26]

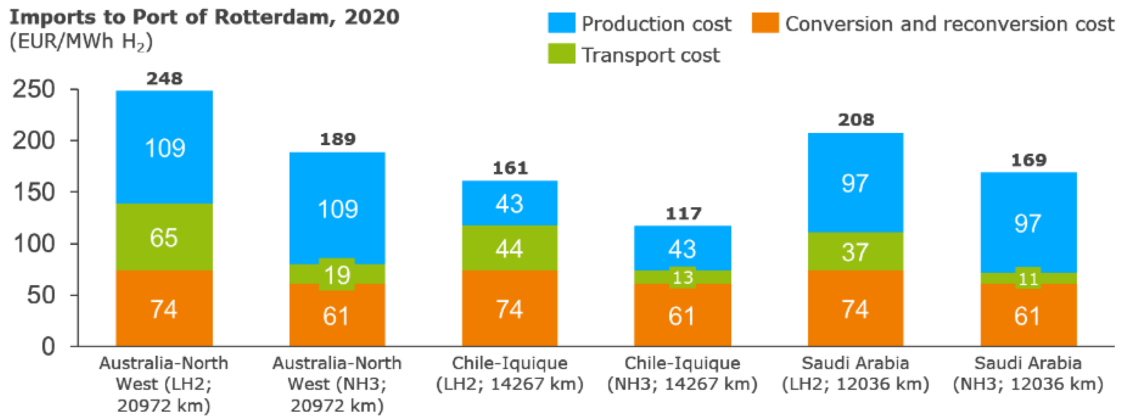
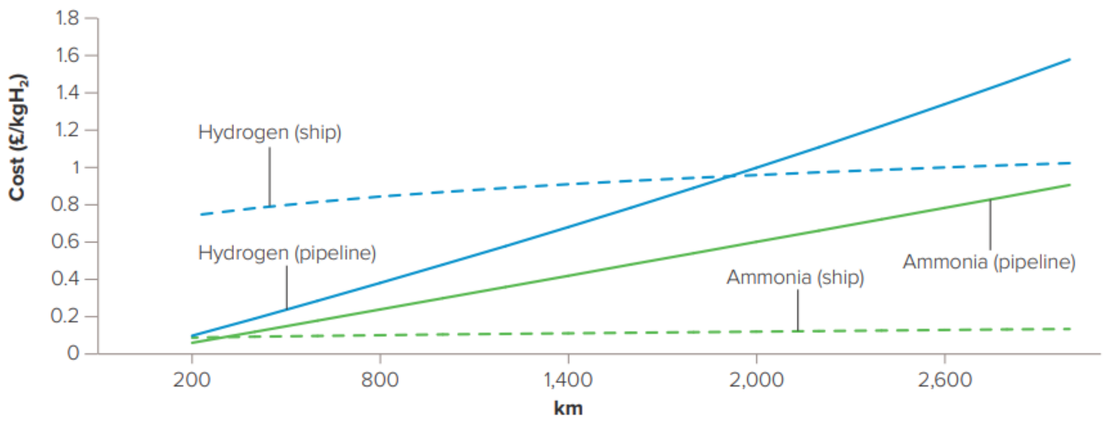


Figure 25 Cost Estimates for Transport of Energy as Hydrogen or Ammonia[27]

[25] Green Innovation Fund Project | NEDO

[26] Hydrogen Generation in Europe – Overview of Costs and Key Benefits

[27] *The Royal Society Green Ammonia Policy Briefing*



Note: Hydrogen transported via pipeline is gaseous and liquefied for shipping. Costs include both the transport and storage required; not the conversion, distribution or reconversion.

The 8 Rivers Study has indicated that given that importing nations like Japan and Korea often have limited fossil fuel reserves, limited renewables capacity, and limited carbon storage availability, ammonia is expected to be one of the most attractive decarbonisation alternatives; it sometimes may be the only pathway.

The global market has been signalling increased interest in ammonia from companies and countries who are including ammonia in their decarbonisation roadmaps through to the development of dedicated fuel ammonia conferences.[28] The IEA projects significant growth and demand for fuel ammonia as countries decarbonise with SE Asia being the critical market making Australia uniquely well situated to deliver this critical decarbonisation vector.[29]

[28] International Conference on Fuel Ammonia 2021

[29] The Role of Low-Carbon Fuels in the Clean Energy Transitions of the Power Sector