Public Knowledge Sharing Report

H2Kwinana

BP Australia Pty Ltd and Macquarie Corporate Holdings Pty Ltd

03 May 2023

→ **The Power of Commitment**

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Executive Summary

bp Australia and Macquarie are working together to co-develop an integrated hydrogen hub, H2Kwinana. It is anticipated that H2Kwinana will encourage the sustainable transition of existing carbon intensive industries and create new green industries in the area.

H2Kwinana is intended to produce hydrogen for use by bp, other local industrial customers, and for on-site tube trailer loading and vehicle refuelling.

GHD has completed a Concept Development phase study to define two potential base case scenarios (44 tpd or 143 tpd of hydrogen production) and the ultimate target potential growth phase scenario (429 tpd of hydrogen production) to a level of definition suitable to enable Class 5 cost estimates for H2Kwinana to be developed.

This report details the analysis performed and the findings of the Concept Development study. Key findings are summarised below.

Production-level options

- Three hydrogen production rates were considered in the study:
  - 44 tpd (Base Case 1), the estimated maximum that can be delivered by the existing 132 kV power infrastructure using PEM electrolysers at the efficiencies assumed in this report. The maximum power that could theoretically be delivered is estimated at 128.5 MW, limited by the 50 MVA generator step up transformers. Western Power has advised the capability of their local 132 kV infrastructure and its required modifications to deliver this power requirement;
  - 143 tpd (Base Case 2), the maximum initial target to fulfill all potential 2026 offtaker demand identified by bp and Macquarie. This would require installation of an expanded 330 kV grid network at additional project cost, which would increase the maximum power available to approximately 900 MW per 330 kV circuit, noting that three 330kV circuits would be required if the system needs to be capable of experiencing an outage of a single transmission line, cable, transformer, or generator without causing losses in the electricity supply. Western Power has advised the SWIS network modifications to provide the capability of the 330 kV grid to deliver this power requirement; and
  - 429 tpd (Growth Case), the potential growth scenario identified for the site by bp and Macquarie for 2035. This would require no new 330 kV circuits beyond those installed for Base Case 2 but the capability of the balance of the SWIS to provide the 1GW is yet to be determined.

Electrolyser technology

- Both alkaline and PEM electrolyser technologies are recommended for further consideration, with a detailed techno-economic assessment required to confirm the most appropriate technology, taking account of:
  - Electrolyser CAPEX
  - Electrolyser OPEX
  - Potential power purchase savings and revenue from Ancillary System Services
  - Storage costs and increased overall plant CAPEX to support reduced production rates for periods each day without reducing daily offtake, which may be required if PEM electrolysers were selected to support more frequent drops in production;
  - Larger electrolyser size required for equivalent hydrogen production with PEM electrolysers due to lower efficiency;

- Impact of rate of efficiency degradation from electrolyser beginning of life (BOL) to end of life (EOL) before requiring overhaul; and
- Impact to production of slower ramp-up time and higher minimum turndown for alkaline electrolysers.

Water and cooling requirements

- The electrolyser plant will demand a large water supply rate for feedwater and cooling systems, therefore minimising water consumption and wastewater discharge rates are key considerations for the Project. Water is proposed to be sourced from the Kwinana Water Reclamation Plant (KWRP).
- A hybrid or adiabatic cooling system is envisaged, incorporating a closed loop cooling water circuit with a combination of direct air cooling and evaporative cooling to achieve the process temperatures required in the electrolyser process, whilst minimising water loss. A cooling system optimisation study is recommended in the next phase of the Project once electrolyser vendor data is available, taking account of the various drivers including CAPEX, water use, power use, footprint, safety, operability, maintenance etc.
- For Base Case 2 and the Growth Case, a centralised cooling system will require very large volumes of water to be circulated, which may result in some practical challenges due to the size and number of pumps, headers and air coolers required. Alternatives such as smaller stand-alone systems may be worth investigating.

On-site hydrogen storage

- To manage an assumed fixed offtake rate, H2Kwinana may require a significant quantity of hydrogen to be stored either at site or within the offtaker battery limits.
- The most suitable storage technology is believed to be above ground pressure vessels, given that the alternatives available are either not market ready (underground shaft storage) or have safety / maintenance concerns due to large numbers of small vessels (e.g., Manifolded Cylinder Packs or ASME tube racks). Increasing vessel size results in lower cost per tonne of hydrogen stored, and based on preliminary safety reviews, bp has proposed a maximum of 2 tonnes per vessel.
- Installation of a Battery Energy Storage System (BESS) was also considered as an alternative to hydrogen storage.

Hydrogen Compression

- Both reciprocating and diaphragm types of compressors are technically viable for hydrogen compression. It is recommended that the selection is based on technical and economic vendor bid evaluations.

Land and site location

- bp has already identified plot space at the site for the H2Kwinana Project. This includes space vacated by equipment from the now closed refinery at the site, that has been, or is in the process of being, decommissioned. The space available at site is confirmed to be adequate for the largest plant design anticipated with 429 tpd hydrogen throughput.
- A conceptual plant layout has been proposed, taking account of inherently safer design principles, along with constructability and sequencing of equipment. A driving factor is the calculated blast radius in the event of an ignited leak from the hydrogen storage. As such, the storage system has been placed as far as possible from manned buildings.

Power costs

- The cost of power delivered to site will be dependent on establishing the pricing mechanism such as a power purchase agreement with a suitable power provider(s) and negotiating an acceptable connection agreement with Western Power. This report does not address the former but does consider the options for the latter with respect to firm and non-firm network access.
- While firm network access is likely to be more expensive, this option provides surety of power supply from the grid to support continuous production that maximises use of electrolysers.
- As the Project objective is to produce certified green hydrogen, the power sourced is required to be from a green PPA or matched with Large Scale Generation Credits (LGCs) (until 1 January 2031), which will be informed by requirements to be developed for Guarantee of Origin for green hydrogen. The feasibility of accessing the required amount of power through a green PPA or sufficient quantity of LGCs has not been assessed in this study.

Potential power market revenue sources

- Potential revenue opportunities from ESS (currently known as Ancillary Services) should be investigated for Load Following Ancillary Service Down (LFAS Up) [1] and Spinning Reserve Ancillary Service (SRAS) equivalent services, both which would require the electrolyser load to be reduced when called on as required in return for a market or contract-based fee, respectively.
- Similarly, revenue opportunities should be further investigated for participation in the Reserve Capacity Mechanism as a demand-side facility, which would require a reduction in load if called upon.
- These further investigations of the reverse capacity payments, LFAS Up and SRAS equivalent services should consider the cost of additional storage and flexibility of offtakers required to provide these services compared to the potential revenues.

Environmental permitting

- An initial assessment of the Project identified the potential for environmental impacts associated with dust from construction activities, disturbance of existing contaminated soil during construction and noise impacts associated with operation of cooling equipment (depending on cooling technology).
- Given the limited number and expected severity of the anticipated environmental impacts an assessment under part IV of the *Environmental Protection Act 1986* (EP Act) is unlikely to be warranted. The construction and operation of equipment to support the Project is expected to be readily manageable under Part V of the EP Act.
- A Development Approval (DA) may be required by the City of Kwinana, which would need to be supported by a noise assessment (which would also be required under a Part V Licence) and potentially a Bushfire Management Plan.
- Where there are commercial agreements with utility providers (i.e., Water Corporation for the operation of the SDOOL), that require modification of environmental approvals, these changes are expected to be the responsibility of the third party.

[1] For clarity, LFAS Down caters for over frequency and requires an increase in generation or a decrease in load response. Whereas LFAS Up caters for under frequency and requires a decrease in generation or an increase in load response.

Project risk & execution

- An initial project risk workshop was facilitated by bp with representatives from bp, Macquarie and GHD from which a project risk register was developed and key risks identified.
- Several key risks identified related to delays in the development of the new 330 kV power supply lines. Risk causes included delays in the required EPA and community approvals, unable to agree required Western Power scope of work to deliver the required power supply and network augmentation by Western Power to support the Project cannot be delivered within the current project timeline.
- Additional key risks identified included failure to secure a Power Purchase Agreement sufficient for the plant capacity and failure to secure sufficient Large Scale Generation Credits.
- Risk responses have been developed for key risks and further risk reviews are recommended to monitor identified risks and risk responses, and to identify new and emerging risks.
- A contracting and procurement strategy is to be developed in the next project phase. For the purpose of this study, a contracting and procurement strategy based on an EPCM model has been assumed.
- A construction strategy has been developed and is dependent on the contracting and procurement strategy. The construction strategy is to be reviewed and updated based on the contracting strategy to be developed in the next project phase.

Class 5 CAPEX and OPEX

- The AACE Class 5 CAPEX and OPEX estimates were developed in accordance with the outcomes of the Basis of Class 5 Estimate Workshop, which was attended by personnel from GHD, bp and Macquarie.
- The Class 5 CAPEX estimates for Base Case 1, Base Case 2 and the Growth Case assumed use of PEM electrolyser stack technology and are summarised in the table below.

Case	CAPEX (AUD M)
Base Case 1 (44 tpd)	399
Base Case 2 (143 tpd)	1,498
Growth Case (429 tpd)	1,424

  - The direct cost of the electrolyser packages is the highest contributor to the CAPEX. Optimisation of the electrolysis design to reduce the total direct cost of hydrogen production is recommended in subsequent stages of this project. This requires engagement with electrolyser package vendors and system integration engineering.
  - Better definition of high CAPEX items, for example, foundations, is also recommended in subsequent phases of the Project to improve the accuracy of the CAPEX estimate.
- The Class 5 annual OPEX estimates for the three cases assumed use of PEM electrolyser stack technology and based on End of Life conditions, are summarised in the table below.

Case	OPEX (AUD M / yr)
Base Case 1 (44 tpd)	82
Base Case 2 (143 tpd)	268
Growth Case (429 tpd)	693

  - The OPEX figures include a nominal assumption on power costs, which is the highest contributor to the OPEX. Early engagement with the power utility supplier on network charges is recommended to determine the actual tariffs and network usage charges that are likely to be applied for the Project.
  - Key drivers contributing to increased OPEX for the PEM technology are the lower efficiency of the stacks (higher power requirement) and higher stack overhaul costs, which are both somewhat more frequent and more expensive.

- Better definition of the other high OPEX items, such as asset management and plant maintenance, is recommended in subsequent phases of the Project to improve the accuracy of the OPEX.

Job creation and economic impact

- A job creation and economic impact assessment has been conducted based on the Class 5 CAPEX estimates for Base Case 1, Base Case 2 and Growth Case for the PEM electrolyser technology. According to the estimates from the analysis, each of the Cases delivers economic and employment benefits for Kwinana and Western Australia.
- The economic analysis is based on expected capital expenditure during the construction phase of the Project. REMPLAN, an economic modelling software tool, was used for the analysis. It is used to generate estimates of the direct investment impacts on supply-chain and consumption spending, as well as employment, wages and overall value-add to the economy.
- The estimated jobs created and potential economic impacts are summarised in the table below.

Case	FTE Jobs (WA)	Wages ($M AUD)	Value added ($M AUD)	Economic Output ($M AUD)
Base Case 1 (44 tpd)	365	81	147	343
Base Case 2 (143 tpd)	1252	275	504	1185
Growth Case (429 tpd)	1617	354	648	1528

- The economic sectors that are expected to benefit from the construction phase are construction, professional services, manufacturing, and transport.
- A significant opportunity exists to leverage this substantial expenditure and bring benefit to the local community and economy.

Summary

The Study has met the following objectives:

- Advanced project design for Phase 1 of the project incorporating both industrial and transport end use cases;
- Demonstrated viable energy and water solution at bp's Kwinana site;
- Understanding ability to re-use or repurpose existing infrastructure at bp’s Kwinana site;
- Requirements for new hydrogen infrastructure to connect to end users;
- Pathways to scale-up the facility over time to potentially accommodate a gigawatt scale electrolyser;
- Understanding of key project risks; and
- Understanding of social, economic and environmental benefits of H2Kwinana to Kwinana, Perth and WA.

The Study finds that an integrated hydrogen hub at bp's Kwinana site(H2Kwinana) with the existing infrastructure and connections to surrounding industry is feasible. With the right policy support this could see bp's existing Kwinana refinery facility repurposed for green hydrogen production.

Acknowledgement of Country

GHD acknowledges Aboriginal and Torres Strait Islander peoples as the Traditional Custodians of the land, water and sky throughout Australia on which we do business. We recognise their strength, diversity, resilience and deep connections to Country. We pay our respects to Elders of the past, present and future, as they hold the memories, knowledges and spirit of Australia. GHD is committed to learning from Aboriginal and Torres Strait Islander peoples in the work we do.

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Acknowledgement of Grant Funding

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GOVERNMENT OF WESTERN AUSTRALIA

The feasibility study (Study) received grant funding from the Western Australian Government’s Renewable Hydrogen Fund, which is administered by the Department of Jobs, Tourism, Science, and Innovation (the Department).

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1. Introduction

bp Australia Pty Ltd is investigating options to repurpose its vacant industrial land located within the Kwinana Refinery precinct, with ambitions to harness existing and emerging technologies to develop a decarbonisation hub, namely the Kwinana Energy Park. bp Australia Pty Ltd and Macquarie Corporate Holdings Pty Ltd (bp and Macquarie) are working together to co-develop an integrated hydrogen hub, H2Kwinana, which will become a key component of the Kwinana Energy Park development.

H2Kwinana is intended to produce hydrogen for use by bp, other industrial customers, tube trailer loading and vehicle refuelling. Future local industrial demand within Kwinana may include nickel refining, ammonia and chemicals production, gas networks and other high energy users. bp and Macquarie also anticipate that H2Kwinana will encourage the sustainable transition of existing carbon intensive industries and create new green industries.

1.1 Project Phasing

The H2Kwinana Project will be developed in project phases. GHD's study scope included analysis of three plant sizes. During the study, the three cases that were agreed with bp and Macquarie are shown in Table 1.1

Table 1.1 Plant Sizes Considered in Concept Development Study

Scenario		Base 1	Base 2	Growth
Hydrogen Production	tpd	44	143	429

Two potential alternative initial base case plant sizes of 44 tpd and 143 tpd were considered. The 44 tpd case was estimated as the maximum that could be achieved using the existing power infrastructure facilities and PEM electrolysers (see Section 2.6). The 44tpd case is also sufficient to cater for the initial 2025 and 2026 demand, excluding the bp Project. The 143 tpd case is the initial demand including the bp Project. The potential growth target of 429 tpd was selected as the third and final case to assess the maximum anticipated plant size that may be required.

1.2 Study Objective

The Project is currently in the Concept Development phase. The objective of this study is to frame and select an initial development option that can be taken forward to the next project phase and to develop a growth phase roadmap for the plant to be scaled up over time.

This phase has investigated the following key areas of interest for the plant sizes listed in Table 1.1 to a level of definition that is suitable to enable Class 5 cost estimates to be developed:

- Hydrogen production capacity and storage capacity;
- Water consumption;
- Site layout;
- Site brownfield utilisation; and
- Electrical infrastructure.

1.3 Purpose of This Report

This report summarises the analysis performed and outcomes of GHD's Concept Development study for the H2Kwinana Project, including the following:

1. Case definition for the Concept Development phase;
2. Review of the available technologies for:
   a. Electrolyser stacks
   b. Cooling systems

c. Hydrogen storage and compression
d. Facilities for delivery of hydrogen to mobility users
3. Review of re-use of the existing hydrogen and natural gas pipelines for delivery of hydrogen to customers;
4. Consideration of water supply and discharge options;
5. Assessment of various existing safety and utility systems for potential re-use;
6. High level sizing of new utility systems where required;
7. Utilisation of the existing power infrastructure;
8. Utilisation of the required future power infrastructure; and
9. Initial site layout development.

1.4 Assumptions and limitations

This Report assumes the following in relation to the material received and reviewed:

- All documents and records examined by GHD are genuine, complete and up to date and contained no material errors or omissions;
- All factual matters stated in any document are true and correct at the time of publication; and
- There are no defaults or contraventions under any agreement or instrument other than those set out in the material provided by bp and Macquarie and reviewed by GHD.

This report has been prepared subject to bp and Macquarie's acknowledgement that GHD is not qualified and/or accredited to give advice in relation to legal issues, contractual issues, accounting issues, currency issues, human resources, industrial relations, native title or tax issues or to make financial forecasts that would require any of these areas of expertise. As such, nothing in GHD's report shall amount to advice in relation to these areas of expertise, or any other area of expertise.

General disclaimer

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If this report is required to be accessible in any other format, this can be provided by GHD upon request and at an additional cost if necessary.

Abbreviations

Abbreviation	Description
AACE	American Association of Cost Estimating
ABS	Australian Bureau of Statistics
AGC	Automatic Generation Control
ALARP	As Low as Reasonably Practicable
ASME	American Society of Mechanical Engineers
AUD	Australian Dollars
BESS	Battery Energy Storage System
BOL	Beginning of Life
BOP	Balance of Plant
CAPEX	Capital Expenditure
CS	Carbon Steel
EDI	Electric Deionisation
EOL	End of Life
ESP	Engineering Service Provider
FCAS	Frequency Control Ancillary Services
FTE	Full time equivalent
GIS	Geographic Information System
GSUT	Generator Step-Up Transformer
H_2	Hydrogen
HHV	Higher Heating Value
IA	Instrument Air
IO	Input Output modelling method
KOH	Potassium Hydroxide
KWRP	Kwinana Water Reclamation Plant
LFAS	Load Following Ancillary Service
LCOH	Levelised Cost of Hydrogen
LPG	Liquified Petroleum Gas
LRR	Load Rejection Reserve
M or MM	Million
MCP	Manifolded Cylinder Pack
MEGC	Multi-Element Gas Container
MF	Microfiltration
MSR	Mason Road
MW	Megawatt
NEM	National Electricity Market
NG	Natural Gas
NPI	Non-Process Infrastructure
O_2	Oxygen

Abbreviation	Description
OPEX	Operating Expenditure
PEM	Polymer Electrolyte Membrane
PFSA	Perfluorosulphonic Acid
PPA	Purchase Power Agreement
RFSU	Ready For Start Up
RO	Reverse Osmosis
SAF	Sustainable Aviation Fuel
SDOOL	Sepia Depression Ocean Outlet Landline
SWIS	South West Interconnected System
SRAS	Spinning Reserve Ancillary Service
SWIS	South West Interconnected System
TDS	Total Dissolved Solids
tpd	Tonnes per day
VIE	Vacuum Insulated Evaporator
WA	Western Australia
WEM	Wholesale Energy Market
WWTP	Wastewater Treatment Plant

1 Vision and Commercial Context

After 65 years of fuel operations in Kwinana, bp is planning to reshape its Kwinana refinery site into an integrated energy hub. With the development of a world class import terminal, production of renewable fuels, and a green hydrogen hub, it will support decarbonisation of the Kwinana Industrial Area, as well as the heavy transport and aviation sectors, and provide access to green energy export markets.

bp's Kwinana site has the following benefits as an integrated energy hub:

- **operational infrastructure**, that can be expanded or repurposed, run by a skilled workforce with decades of hydrogen experience.
- **connectivity to domestic and export customers**, with established transmission and pipeline networks, and rail, road, and sea links.
- **existing shared infrastructure** and product exchanges between Kwinana industrial businesses.
- **significant local industrial demand** across sectors including chemicals, minerals processing and heavy transport.

Central to this opportunity is the green hydrogen hub, H2Kwinana, which is being jointly developed by bp and Macquarie. H2Kwinana would provide a source of green hydrogen to transition existing carbon-intensive sectors in both domestic and export markets and support the creation of new green industries as shown in Figure 1.1.

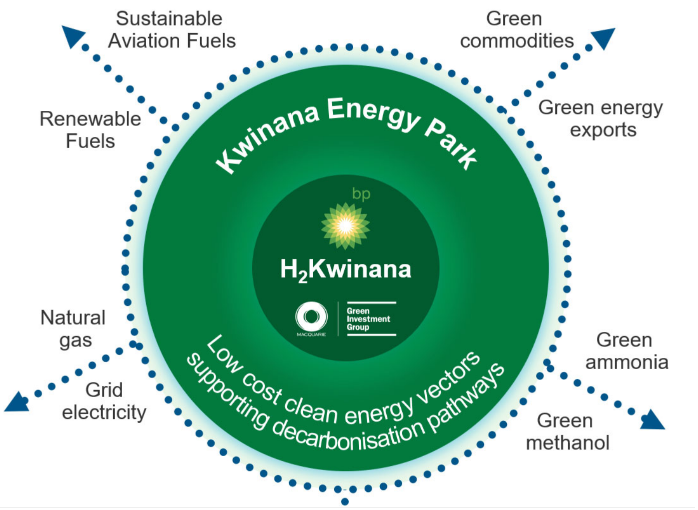


Figure 1.1 Potential markets for H2Kwinana

In the near term, H2Kwinana aims to help facilitate the decarbonisation of existing carbon-intensive industries in the Kwinana Industrial Area and establish a mobility trial in South West Western Australia. Opportunity also exists to support the Western Australian Government's Renewable Hydrogen Target by providing hydrogen for electricity generation in the region.

In the medium to long term, bp and Macquarie's vision for H2Kwinana includes supporting the creation of new green industries in Southwest Western Australia, underpinning a large-scale hydrogen mobility network within Western Australia and the opportunity to establish new green hydrogen export markets, helping to cement Western Australia's position within the global green hydrogen economy.

The vision for H2Kwinana, however, is broader than the significant potential impact on local and global industrial decarbonisation. H2Kwinana is uniquely placed to support the transition and decarbonisation of the South West Interconnected System both as a large variable load supporting the build out of new renewable generation assets and as a supplier of green hydrogen for use in electricity generation and pipeline blending.

bp and Macquarie are currently evaluating the feasibility of H2Kwinana, including engaging with offtake partners, utility and network providers, and evaluating technical feasibility. bp and Macquarie have engaged GHD to undertake a technical feasibility assessment and a preliminary cost estimate for the development to help inform the next phase of more detailed development work.

2. Basis of Design and Key Assumptions

2.1 Site Location

H2Kwinana is intended to be located on the site of the original bp Refinery, located in the Kwinana Refinery precinct (Figure 2.1).

Most of the existing refinery infrastructure has been, or is in the process of being, demolished and removed, although systems such as the bulk power supply system, pipelines, flare, drains, nitrogen, firewater, wastewater treatment and potable water may be repurposed for the new H2Kwinana facility. The office building (blast resistant) and workshops are intended to be retained.

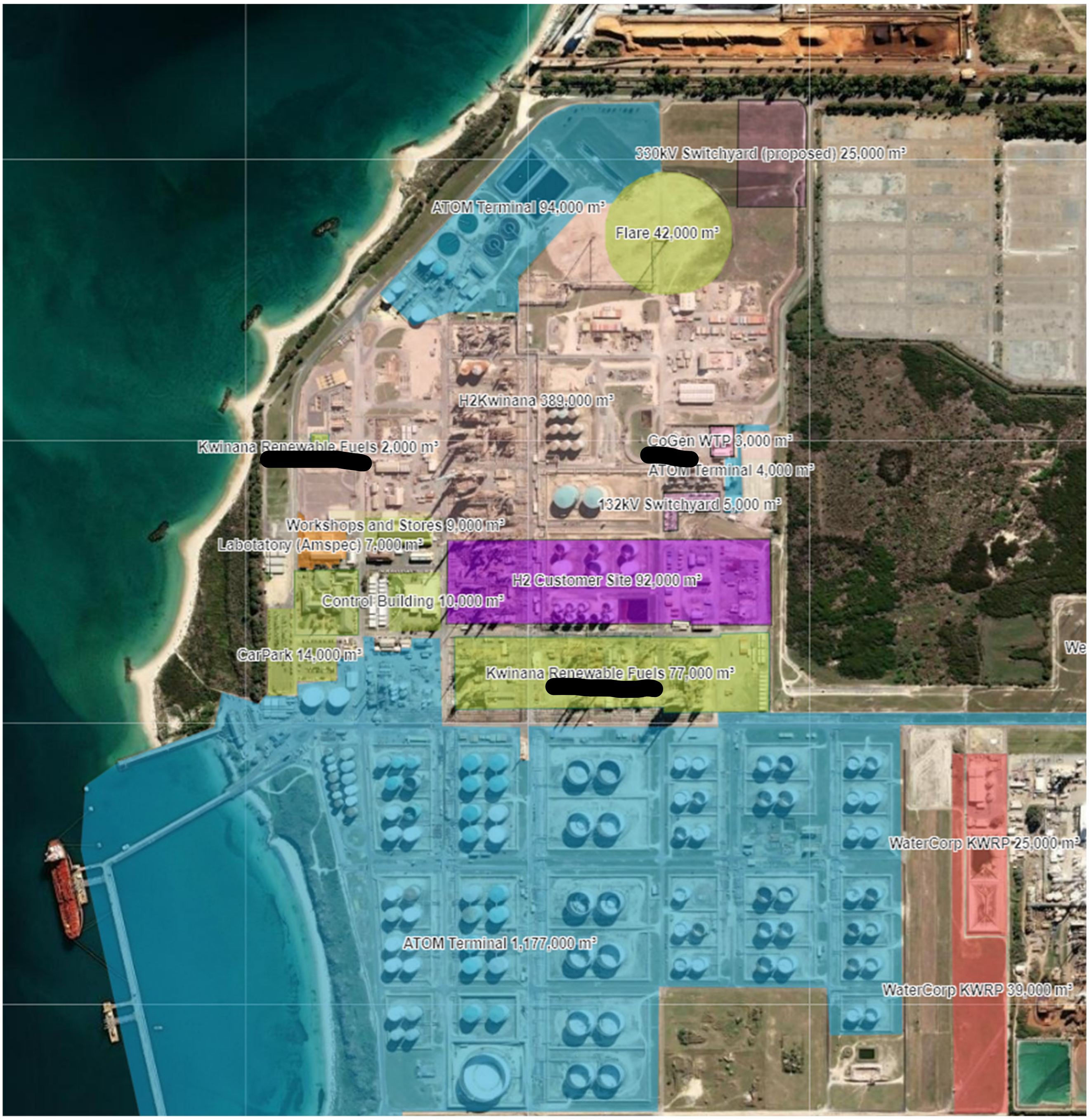


Figure 2.1 bp Kwinana Refinery Precinct

2.2 Site Conditions

The ambient air conditions at Kwinana are shown in Table 2.1.

Table 2.1 Kwinana Ambient Air Conditions

Parameter	Unit	Value
Mean highest ambient temperature[1]	°C	40
Yearly average maximum temperature[2]	°C	23.6
Mean lowest ambient temperature[1]	°C	0
Nominal relative humidity[1]	%	60
Maximum relative humidity[1]	%	86

Parameter	Unit	Value
[1] bp Basic Engineering Design Data Guideline (PRD-RD-01)		
[2] Bureau of Meteorology http://www.bom.gov.au/climate/averages/tables/cw_009064.shtml		

2.3 Power Supply

The following power supply options for the Project have been considered in the Concept Development phase:

1. A power supply drawn from the existing 132 kV infrastructure for the proposed initial hydrogen customers. This will be highly dependent on the Western Power 132 kV network being able to support the associated power requirements.
2. A new power supply drawn from the higher capacity Western Power 330 kV network to provide for the Project's foreseeable production requirements. Similarly, this will be highly dependent on the Western Power 330 kV network being able to support the associated power requirements.

2.4 Water Supply

For the Concept Development phase, bp and Macquarie have assumed that the primary source of water shall be the Kwinana Water Reclamation Plant (KWRP), in line with reducing overall environmental impact of the Project, particularly on the water supply in the local area. Use of KWRP water is considered a 'net positive' water use case, as it reuses treated wastewater that would otherwise be discharged to the environment. Alternatives to using the fully treated KWRP water are investigated in Section 3.3.2, but given that upgrades are already planned to KWRP, and the benefits of the alternative options appear limited. The study has assumed that water is provided from the KWRP outlet with full processing through KWRP. Alternative water sources that may be considered if the KWRP and/or scheme water are not deemed suitable to supply the required quantity and quality of water for H2Kwinana include ground water and seawater.

2.5 Block Flow Diagram

A block flow diagram of the proposed green hydrogen production facility is presented in Figure 2.2.

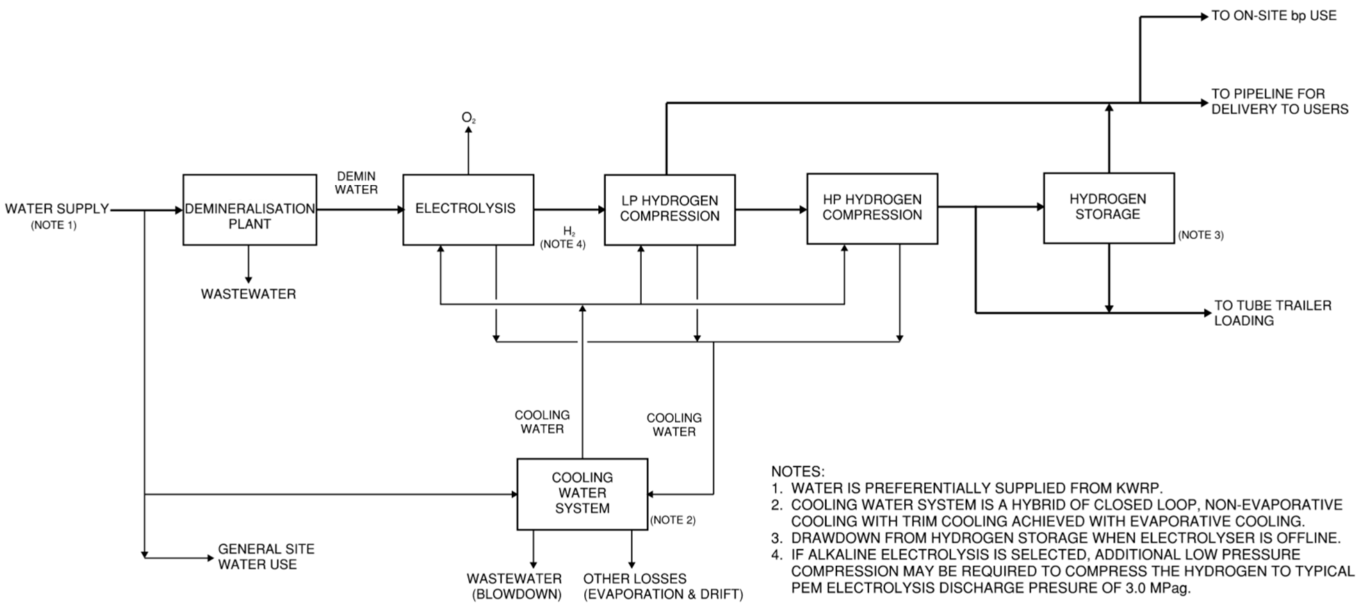


Figure 2.2 Block Flow Diagram of the Hydrogen Production Facility

2.6 Design Capacity

The electrolyser capacities for the three cases in this study are presented in Table 2.2.

Table 2.2 Electrolyser Capacity Case Summary

Parameter	Unit	Base 1	Base 2	Growth
Target Daily Hydrogen Production	tpd	44	143	429
Hours Online	h	24	20.7	22.9
Peak Production	tpd	44	166	449
PEM				
Electrolyser Size[1]	MW	111	418	1,133
Total Plant Power[2]	MW	128	483	1,311
Alkaline				
Electrolyser Size[1]	MW	101	380	1,030
Total Plant Power[2]	MW	122	459	1,245

[1] Using EOL electrolyser power consumption of 60.5 kWh/kg for PEM and 55.0 kWh/kg for alkaline electrolyser.
[2] Using EOL facility power consumption of 70.0 kWh/kg for PEM and 66.5 kWh/kg for alkaline electrolyser.

3. Technology Options Review

3.1 Electrolyser Technologies

3.1.1 Objective

The commercially dominant technologies for industrial-scale production of green hydrogen are currently alkaline electrolysers and polymer electrolyte membrane (PEM) electrolysers.

The objective of this review is to present the features of alkaline and PEM electrolyser stacks in order to inform decisions on selection of electrolyser technology.

3.1.2 Technology Description

Hydrogen is produced by electrolysers by an electrochemical process whereby an electrical current is passed through cells containing high purity water causing the water molecules to split into hydrogen molecules at the cathode electrode and into oxygen molecules at the anode electrode.

For an alkaline electrolyser, the electrodes are immersed in an alkaline liquid electrolyte (lye). A diaphragm is placed between the electrodes to separate the two reactions and prevent the hydrogen and oxygen product gases from mixing. For a PEM electrolyser, the electrodes are adjacent to a solid electrolyte membrane. This is depicted in Figure 3.1 (Schmidt et al, 2017).

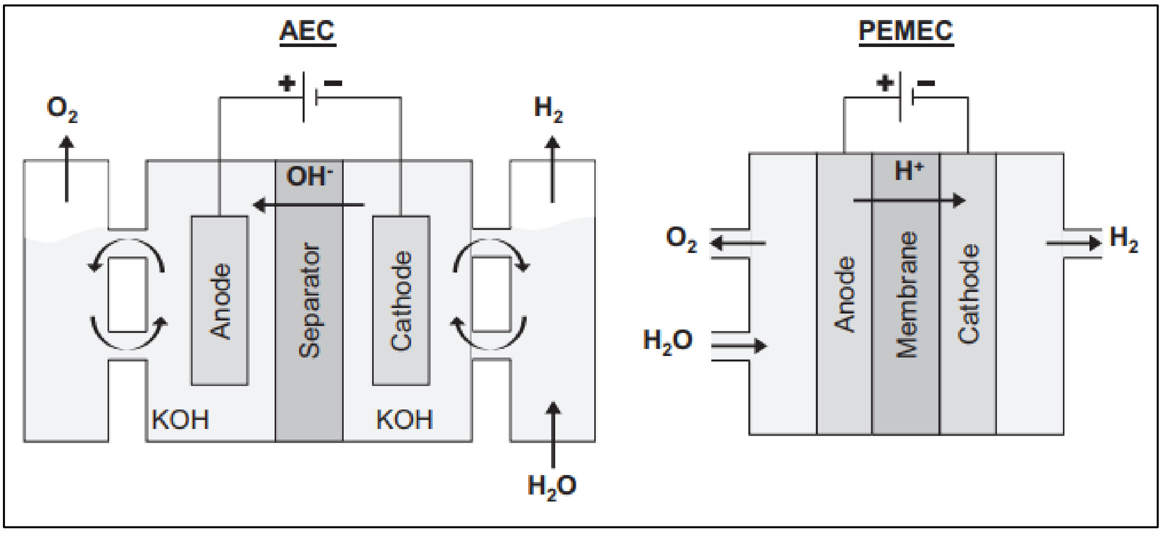


Figure 3.1 Alkaline Electrolysis Cell (AEC) and Polymer Electrolyte Membrane Electrolysis Cell (PEMEC)

The cells are contained within one or more electrolyser stacks. Each stack comprises of multiple cells connected in series with spacers, seals, frames and end plates. The number of cells and stacks required depends on the required hydrogen production rate.

For green hydrogen, the electrical power required for the electrochemical process and the remainder of the hydrogen production facility ("balance of plant") is derived from renewable energy sources or energy that can be greened via Renewable Electricity Certificates (RECs).

The balance of plant (BOP) comprises of:

- The other components of the electrolyser package, such as water treatment, lye make-up and circulation for alkaline electrolysers only, oxygen/water separation and hydrogen purification systems;
- Hydrogen compression (where required), storage and transfer; and
- Utilities systems and non-process infrastructure.

Vendors typically present their electrolysers as modules which are often supplied containerised. A footprint of approximately 600 m^2 is seen for a 10 MW PEM electrolyser containerised module, whereas a 10 MW alkaline electrolyser module has a footprint of approximately 1200 m^2. A study from the Institute for Sustainable Process Technology proposed potential space savings for 1 GW facilities, with compact designs of alkaline electrolysers requiring 62 m^2/MW. For the purposes of this study, 10 MW modules have been assumed for plot area and costing.

Typical inclusions in an electrolyser package are:

- Electrolyser stacks;
- Demineralised water pump and circulating system;
- Hydrogen purification, typically gas/liquid separator, chiller and dryer;
- Oxygen vent;
- Hydrogen vent;
- Power supply system, including rectifier and transformer;
- If alkaline: Lye system, including lye tanks and lye pumps (first fill of Potassium Hydroxide is typically in vendor scope);
- If alkaline: Low pressure compressor and cooler; and
- Optional: Demineralised water treatment, typically reverse osmosis (RO) and electric deionisation (EDI).

3.1.3 Accuracy of References

The information presented in Sections 3.1.1 and 3.1.2 is obtained from publicly available references published between 2017 and 2022. GHD has vendor information on various sizes of alkaline and PEM electrolyser packages, and this supports the information presented above. This was acquired over recent years for the purposes of technology selection and cost estimation for several concept and feasibility studies.

Commercial-scale electrolyser stack technology continues to advance over time. In the near term (2 to 5 years), the market can expect improvements including pressurised alkaline electrolysers, improved stack efficiencies, improved stack lifetimes and lower stack costs. PEM electrolysers stacks are becoming more prevalent and the gaps in stack costs and lifetimes between alkaline and PEM technology are narrowing quickly. Therefore, it is recommended that the information presented herein is revalidated over time.

3.2 Cooling System

3.2.1 Objective

High purity demineralised water will be required as feedwater for the electrolyser. Water will also be required for cooling and for ancillaries. Depending on the cooling technology selected, a large proportion of the overall facility water demand may be attributed to cooling water make-up. The systems that will require cooling in the H2Kwinana facility are listed in Table 3.1, with cooling for the electrolyser package having the highest demand. Although some electrolyser vendors can incorporate direct air cooling to an extent in their designs, it is envisaged that at least some, if not all, of the cooling demand will still need some of form of a water and/or refrigerant based cooling system due to ambient air temperatures at the site exceeding the supply temperature that is typically required by electrolyser vendors for stack cooling.

Table 3.1 Facility Cooling Users

System	Cooling Users	Typical Process Temperature	Typical Coolants
Electrolyser Package	Transformer and rectifier	< 40 °C	Fans
	Buildings	< 40 °C	Fans
	Electrolyser stacks	55 – 80 °C	Cooling water Glycol coolant Chilled water
	Hydrogen purification system (which may include deoxo unit and cooler)	< 45 °C	
	Oxygen separation system	< 40 °C	
Hydrogen Compression Package	Interstage coolers	< 50 °C	Cooling water Direct air coolers
	After coolers	< 50 °C	
Hydrogen Refuelling Station	Dispenser pre-chiller	~ -40 °C	Refrigerant
Utilities	Lube oil coolers (if any)	~ 40 °C	Cooling water Direct air coolers

An important feature of the electrolysers is the stack degradation over their lifetime (approximately 10 years) resulting in the decrease of efficiency and hence an increased heat load. Hence, the cooling duty required by the stacks increases over their life. It is important to ensure the cooling system is capable of handling the required cooling duty at the end of the electrolyser life prior to the stack overhaul to ensure operation of the electrolyser.

3.2.2 Technology Description

Typical process cooling technologies include:

1. Open-loop evaporative cooling;
2. Closed-loop cooling, which can be either
   a. Closed-loop with evaporative cooling, or
   b. Closed-loop with air cooling
3. Direct air cooling;
4. Sea water liquid-liquid cooling;
5. Chiller system; and
6. Adiabatic cooling.

Natural draft cooling towers have historically been used for very large scale cooling duties such as nuclear power stations. This cooling technology was not considered in detail here since the scale of cooling required is not expected to justify the CAPEX of a natural draft tower, particularly given the proposed phasing of the project, and more suitable technology options are believed to be available. In addition, other options considered in this section are more modular in their nature, likely to be provided in multiple smaller units, and therefore offer more flexibility in plant layout, e.g., smaller banks of coolers could be located around the plant, adjacent to banks of electrolyser stacks. Natural draft cooling towers are less suited to this kind of arrangement.

1. Open-loop evaporative cooling

A common process cooling option is the evaporative cooling tower. Cooling water enters the top of the cooling tower and flows down, contacting the up flowing air, collecting at the base of the tower to be used for the facility cooling. The cooling tower utilises the latent heat transfer of evaporating water to cool the circulating water and can be operated via natural draft (chimney effect) or forced draft (using fans). The water loss from evaporation causes salts present in the water to be concentrated, requiring control via a blowdown stream. This results in a high water demand via a make-up stream to maintain the circulating cooling water rate. Additionally, as the cooling tower is open to the environment, airborne contaminants, oxygen, and other gases are introduced to the system, which can cause fouling and erosion within the system. Chemical additives are commonly used to treat the water, and regular maintenance is required to control fouling.

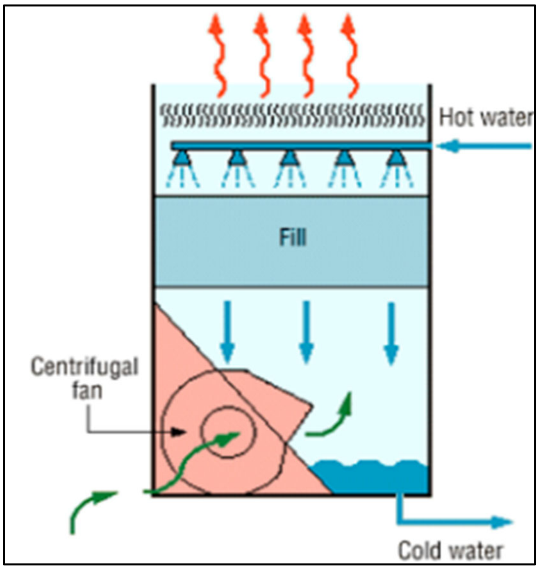


Figure 3.2 Schematic of Evaporative Cooling Tower

2a. Closed-loop evaporative cooling

An evaporative closed-loop system also utilises a cooling tower, however the cooling fluid (which may be a glycol-water mixture, depending on the facility and ambient conditions) is circulated through the cooling tower in coiled tubes. The tubes are sprayed in the cooling tower with water and cooled via the latent heat of evaporation, allowing for increased heat transfer compared to air cooling. Although there is water loss from the evaporation of the water in the cooling tower, this will be minor compared to the previous option. As the closed-loop cooling fluid is not exposed to the local environment, this option requires less maintenance and chemicals due to the reduced risk of fouling within the system compared to an open loop system.

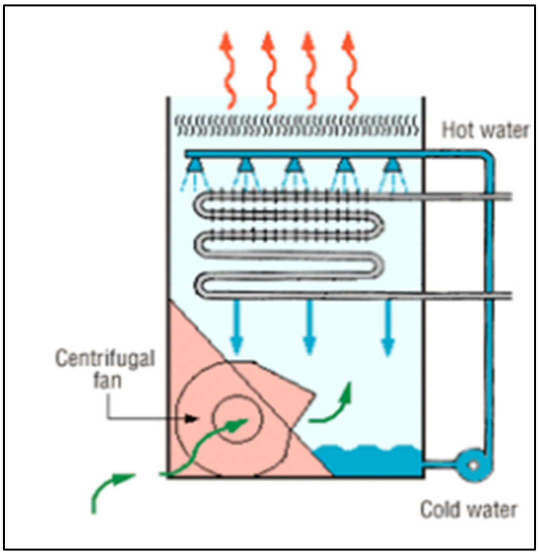


Figure 3.3 Schematic of Closed-Loop Evaporative Cooling Tower

2b. Closed-loop air cooling

Fin fan coolers are used to transfer heat from the cooling water for closed-loop air cooling systems. The cooling water flows through finned tubes, over which ambient air is directed via fans. The cooling water dissipates heat to the ambient air via sensible cooling. This option further reduces the water consumption, as the only make-up required will be for the minor loses through the closed loop. However, the cooling duty possible is limited by the ambient air temperatures, and so may not be feasible for all the plant cooling requirements.

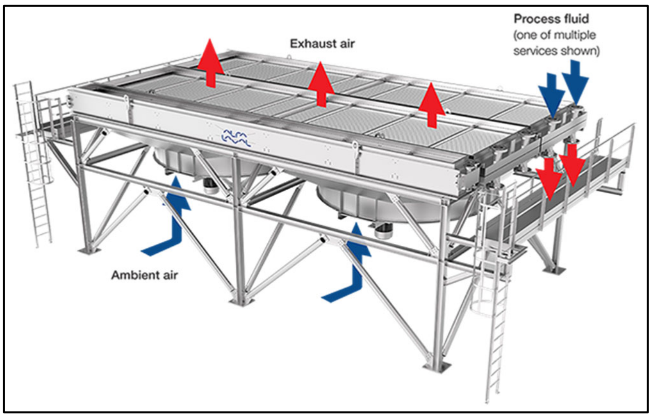


Figure 3.4 Schematic of Fin Fan Cooling

3. Direct air cooling

Also known as dry coolers, direct air cooling utilises fin fan coolers to directly cool the process fluid. The process fluid flows through finned tubes, over which ambient air is directed via fans. The process fluid dissipates heat to the ambient air via sensible cooling. This option negates the need for cooling water; however, it is limited by the ambient air temperatures to achieve cooling and so may not be feasible for the plant cooling requirements.

A hybrid closed-loop system is also possible with both evaporative and air cooling. The system operates in dry mode (i.e., via air-cooling only) until it can no longer provide the cooling duty required. The system then operates in wet mode using evaporative cooling as described above. The hybrid solution can maximise energy efficiency and also reduce the water consumption required.

4. Seawater liquid-liquid cooling

For seawater liquid-liquid cooling, sea water is pumped to the plant and passes through liquid-liquid heat exchanger within the closed loop cooling water system. Due to the lower temperature of seawater, this system would be able to provide increased cooling duty compared to a closed loop air cooling system. However, use of direct seawater introduces scaling and fouling issues and risk of entrainment of aquatic organisms. Additionally, the local environmental impact of discharging increased temperature water back into the sea must be considered.

5. Chiller system

In cases where the cooling duty cannot be achieved due to high ambient temperatures or low required cooled temperatures, a chiller system may be used. A refrigeration cycle is used, which comprises of a refrigerant loop through an evaporator, compressor, condenser and expansion valve. The chilled water passes through the evaporator, where it is cooled via the refrigerant. Heat from the refrigerant is dispelled through the condenser through an air system or through another cooling water system. Use of chiller systems is often confined to low process temperature duty requirements due to the relatively higher power consumption, complexity, and CAPEX.

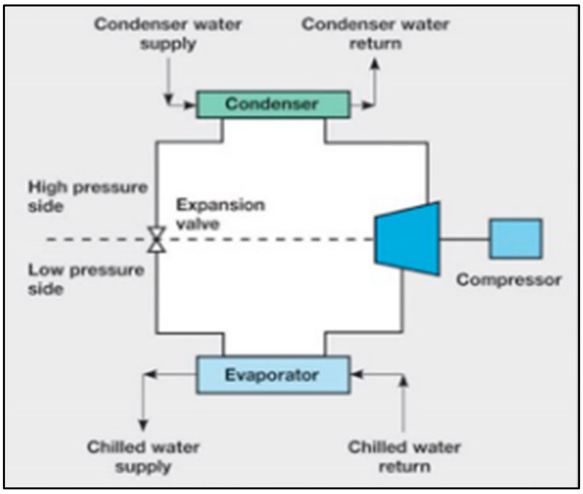


Figure 3.5 Schematic of Chiller System

6. Adiabatic Cooling

Adiabatic coolers are fin-fan coolers with addition of air humidification systems and an adiabatic chamber to enable increased cooling duty. Inlet air is pre-cooled via spray of water droplets. The humidified air then flows through specialised adiabatic chambers which consist of cooling pads that are equipped with misting nozzles. This further cools the air via isoenthalpic cooling. This system is able to run in dry mode when the ambient air is able to provide the required cooling duty, or in spray and/or adiabatic modes to provide further cooling as required when ambient air temperatures increase.

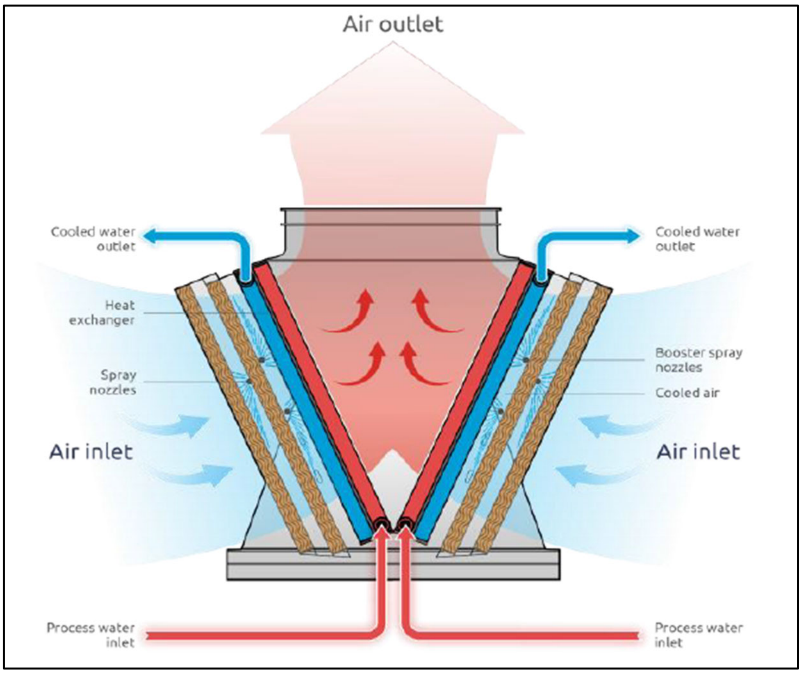


Figure 3.6 Schematic of Adiabatic Cooler

3.3 Water

3.3.1 Objective

Electrolysis requires high purity demineralised water for the electrochemical process, typically to ASTM D1193 Type I or Type II water quality criteria. Additionally, the facility will require water for other uses, including cooling water, fire water, wash water and potable water. Sources of water supply to the facility and the quality of water produced is investigated, as a means to reduce the CAPEX of water treatment for H2Kwinana.

3.3.2 Water Supply

For the Concept Development phase, bp and Macquarie have assumed that the primary source of water shall be the Kwinana Water Reclamation Plant (KWRP), in line with reducing overall environmental impact of the Project, particularly on the water supply in the local area. Desalination water is also assumed to not be viable in light of sufficient and timely KWRP supply. This is a wastewater treatment plant located close to the proposed project site, which sources its water from the Woodman Point Wastewater Treatment Plant, and includes microfiltration (MF) and reverse osmosis (RO) to treat the water to a quality suitable for site use.

Given that the current KWRP capacity is potentially insufficient for the ultimate Growth Case, and some of the major water users for the Project (e.g., cooling system) do not require water at KWRP outlet quality, alternative supply options have been considered including taking water directly from the Woodman Point Treatment Plant discharge, or taking water mid-treatment at KWRP (upstream of the RO plant). It's noted that supply lines do not currently exist at these locations. A schematic for these possible alternative water supply options is shown in Figure 3.7.

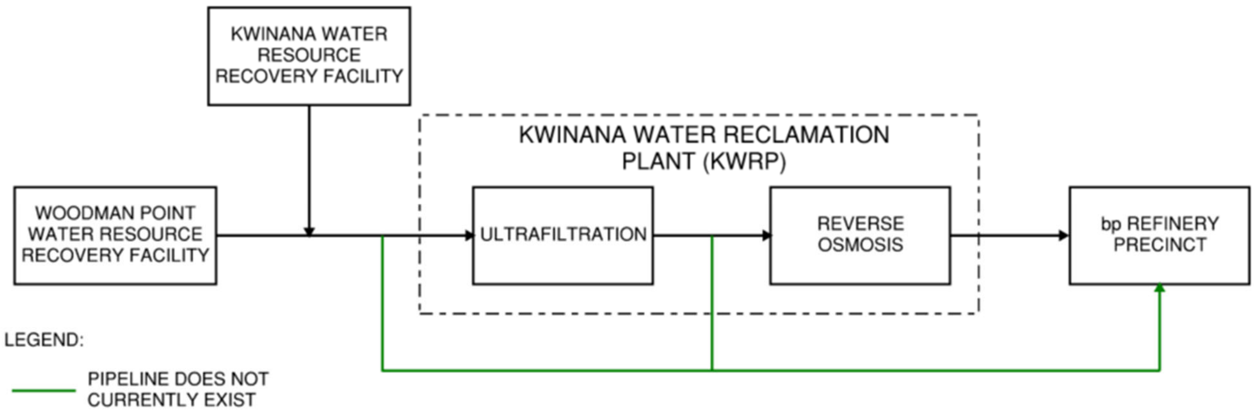


Figure 3.7 Possible Alternative Cooling Water Supply Options

If capacity limitations on KWRP dictate, consideration may later be given to the use of Water Corporation scheme water. However, this is expected to come at a relatively high cost, and would not allow the Project to achieve its goal of being a 'net positive' water user.

Alternative water sources that may be considered if the KWRP and/or scheme water are not deemed suitable to supply the required quantity and quality of water for H2Kwinana include ground water and seawater.

An estimate of total water demand for each of the scenarios considered is provided in Table 3.3. The total demand is highly dependent on the cooling solution selected (see Section 3.2).

Table 3.2 Water Supply Options

Water Supply	Use
Woodman Point Treatment Plant discharge	Cooling water supply
KWRP post-microfiltration	Cooling water supply
Kwinana Water Reclamation Plant (KWRP)	All H2Kwinana use
Scheme water	Potable water supply
Bore water	Fire water supply

Table 3.3 Demineralised Water and CoGen Demineralisation Plant Requirements

Parameter	Unit	Base 1	Base 2	Growth
Hydrogen Production (daily)	tpd	44	143	429
Hydrogen Production (peak)	tpd	44	166	449
Demin Water Required	m^3/h	18.4	69.1	187.4
Feed to Demin Water Plant	m^3/h	20.4	76.8	208
Cooling System Demand – Low Water Solution (EOL)	m^3/h	2.1	8.0	21.7
Cooling System Demand – High Water Solution (EOL)	m^3/h	55.5	209	565
Other General Site Water Use	m^3/h	2.1	2.1	2.1
Total Water Demand	m^3/h	24.6 – 78.0	86.9 - 288	232 - 775
	m^3/d	591 – 1,872	1,799 – 5,952	5,313 – 17,756

3.4 Hydrogen Compression

3.4.1 Objective

Hydrogen is typically discharged from PEM electrolyser packages at a pressure of 3.0 MPag. Compression to approximately 4.0 MPag is required prior to export to compensate for the following:

- Pressure losses in the piping between the electrolyser package and storage;
- Pressure losses in the hydrogen pipeline and metering systems between the storage;
- Storage pressure drawdown due to offtake during periods of no hydrogen production.

Hydrogen is also planned to be used for mobility refuelling or stored to enable continuous hydrogen supply to users. Mobility refuelling of tube trailers onsite will occur at a minimum of 20 MPag, while hydrogen is typically stored at higher pressures, due the very low density of the gas. As discussed in Section 1.1, this study will assume storage of hydrogen at 20 MPag. Once all hydrogen has been compressed to the low pressure compression discharge pressure of 4.0 MPag.

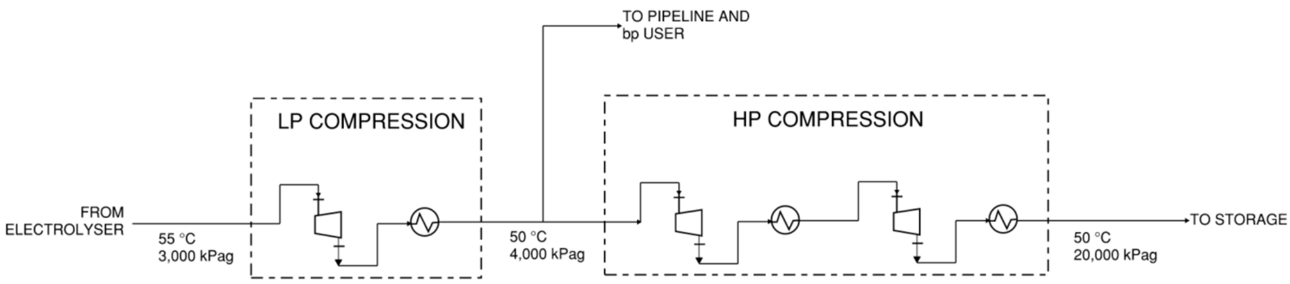


Figure 3.8 H2Kwinana Hydrogen Compression

3.4.2 Technology Description

Depending on the required storage pressure, multiple stages of compression, with interstage and after cooling, may be required. For example, three stages of compression would be required to compress hydrogen from 3.0 MPag to 30 MPag.

The compressor technologies typically used for hydrogen are diaphragm and reciprocating compressors. Reciprocating compressors compress the gas via the positive displacement caused by the reciprocating pistons, moving via the crankshaft (Figure 3.9), whereas diaphragm compressors utilise the flexing of a flexible disc via a crankshaft to create positive displacement within the compression chamber (Figure 3.10). Non-lubricated compressors are typically preferred, in order to avoid contamination of the product stream and meet product quality requirements.

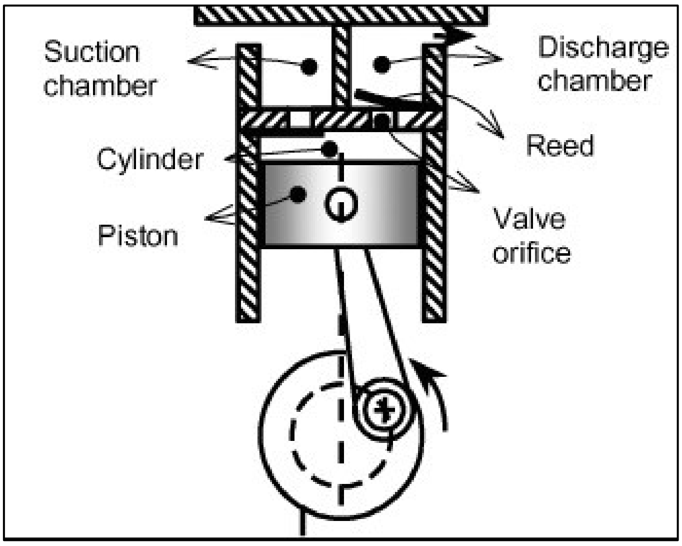


Figure 3.9 *Schematic of Reciprocating Compressor*

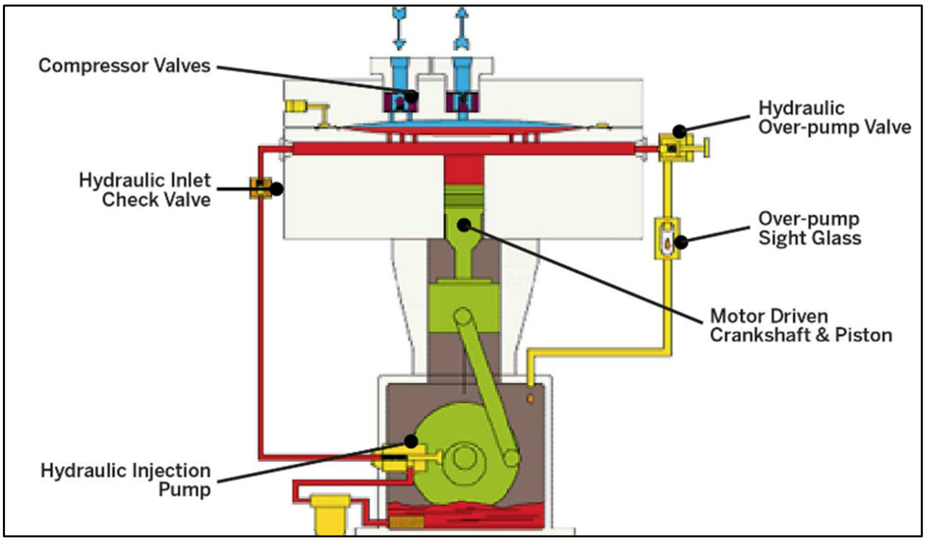


Figure 3.10 *Schematic of Diaphragm Compressor*

Whilst centrifugal compressor technology has been successfully used for hydrogen compression in the past, in GHD's experience, compression vendors tend not to recommend it for hydrogen due to issues with high impeller tip speeds.

Due to the variability in power supply and storage pressure drawdown, it is recommended to install a buffer vessel between the electrolyser package and the compressor suction to ensure stable process control, even though pulsation dampers are typically fitted to each compression stage. Buffer sizing of 1-2 minutes of operation is typical.

If intermittent operation of the hydrogen production system is selected, consideration should be given to the potential impact of this on the hydrogen compressors, in consultation with the compressor vendor. This can potentially be managed by running the compressors continuously in recycle during periods of low/no hydrogen production.

3.4.3 Options Assessment

A summary of the two compressor technologies is shown in Table 3.4.

Table 3.4 *Comparison of Compression Technologies for Hydrogen*

Parameter	Reciprocating Compressor	Diaphragm Compressors
Volumetric efficiency	Approximately 75 to 80%	Approximately 87 to 94%
Compression ratio	1:6 (limited by maximum discharge temperature)	1:20 (limited by maximum discharge temperature)
Speed	Lower than diaphragm type	Higher than reciprocating type
Risk of process fluid contamination by lubricant/oil	Lubricated piston compressor: potential for contamination Non-lubricated piston compressor: no risk	None (lubricant does not enter compression chamber
Risk of process fluid leakage	Potential for leakage for non-lubricated reciprocating piston compressors due to the large piston rod seal	Considered very low (compression chamber is hermetically sealed)

3.4.4 Options Review Outcome

Both reciprocating and diaphragm compressors are technically viable. Therefore, it is recommended that both technologies are carried forward, and compression selection is based on technical and economic vendor bid evaluations. It is noted that there is no known difference in capability of each technology option for intermittent operation. It is expected that the compressors will operate continuously in recycle or turndown during periods of low/no production.

Reciprocating compressors have been assumed as the basis for the cost estimate for both the low and high pressure compression stages, at 2 x 100% compressors.

In future phases, optimisation options may be considered, such as including an initial low pressure stage of centrifugal compression upstream of the reciprocating compressor.

3.5 Hydrogen Storage

3.5.1 Technology Description

Due to the very low density of hydrogen, high storage pressures can be advantageous for storing larger capacities due to the reduction in overall storage volume and footprint. However, this needs to be traded off with the impact on storage vessel material, wall thickness and hence cost, along with higher compressor CAPEX and OPEX.

Hydrogen pressure vessel designs are generally classified by material type, as shown in Figure 3.11 (Barthélémy, H. Air Liquide)

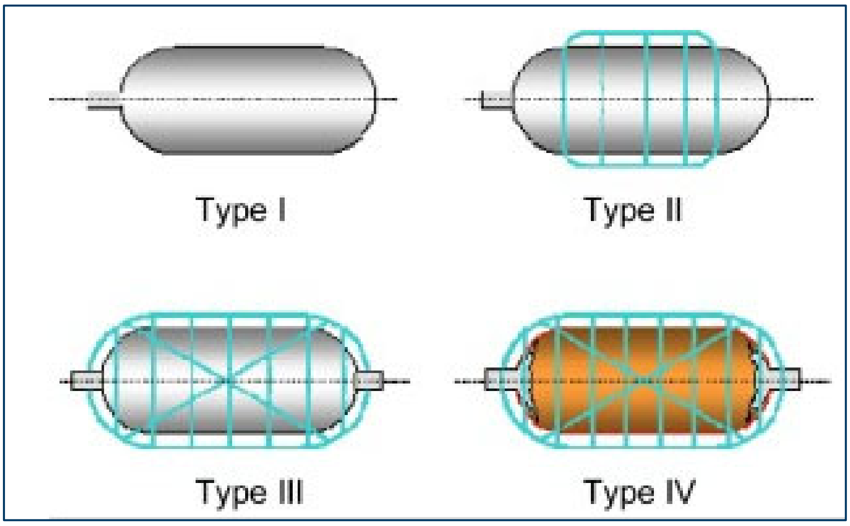


Figure 3.11 *Types of Hydrogen Storage Vessels*

Pressure Vessels

Pressure vessels generally fall under Type I or Type II for stationary storage. The size of these vessels is limited by manufacturing limitations and transportability to site. As storage volume and pressure increase, the complexity of the pressure vessels also increases due hydrogen embrittlement and wall thickness issues, particularly where daily pressure cycling is required (as would likely be the case for H2 Kwinana). For example, for a previous study conducted by GHD, the maximum capacity for a hydrogen pressure vessel was considered as approximately 1 tonne. Recently, Spain based company Iberdrola have custom built hydrogen storage vessels with 0.52 tonnes capacity at 6 MPa. These vessels are 23 meters high, 2.8 meters in diameter and weigh 77 tonnes empty[2].

Manifolded Cylinder Packs

A common pressurised storage option for hydrogen are manifolded cylinder packs (MCPs), also known as multi-element gas containers (MEGCs). These consist of a number of pressurised cylinders contained within a steel frame, with the gas routed to common inlets and outlets. The cylinders are typically Type I or Type IV, dependent vendor design. MCPs are available in various sized shipping container (or equivalent) capacities. These can be vertically stacked to reduce the storage footprint required. Additionally, some MCP designs are also able to be used for transport. Additionally, racks of three tiers of 20 ft or 40 ft long pressure vessels, known as tube racks, are common for hydrogen storage because of their ease of transportability and site installation.

Figure 3.12 ASME Tubes

[2] Iberdrola. (2021). The first 5 Green Hydrogen storage tanks arrive in Puertollano. **https://www.iberdrola.com/press-room/news/detail/-/d/storage-tanks-green-hydrogen-puertollano**

Figure 3.13 Type I MCP

Figure 3.14 Type IV MCPs

Pipeline

Pipelines may also be able to be used for hydrogen storage. Constructing new pipelines within the existing pipeline corridors around the Kwinana site is an option to achieve desired storage pressure and capacity.

Underground Storage

Underground caverns have been used for hydrogen storage but are unlikely to be feasible for the Kwinana area.

Underground bores comprising of a vertical shaft with a steel liner could be considered. For example, an Australian company can provide hydrogen storage capacities of 50 to 500 tonnes. A diagram of the storage can be seen in Figure 3.15 (Ardent Underground). Multiple shafts may be used to increase the overall storage capacity.

Shaft storage removes the requirement for pressure containment materials, such as composites or thick vessel walls by utilising the rock itself to contain the pressure of the gas. The footprint of shafts is smaller than that of typical pressure vessels. A geotechnical investigation would be required to assess the suitability of this technology for H2Kwinana.

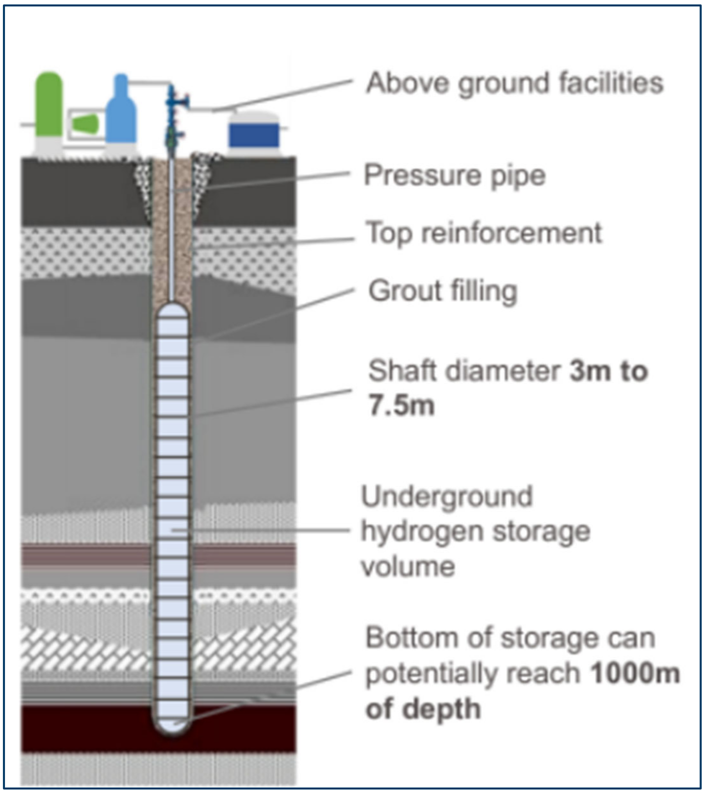


Figure 3.15 Vertical Shaft Hydrogen Storage

Battery Energy Storage System (BESS)

An alternative to providing storage for the produced hydrogen, a BESS would store electricity to be used when power use from the grid needs to be reduced. The BESS would supplement the power drawn from the grid, to ensure a constant power supply to the electrolyser, and hence constant hydrogen production and supply to users. A benefit to this system would be hydrogen plant would not need to be oversized to produce enough hydrogen to supplement the produced hydrogen when the plant is ramped down. However, batteries currently have a high CAPEX. BESS is considered to be a relatively safe technology, although thermal runaway events can occur, which may result in fire.

3.6 Mobility Refuelling

3.6.1 Objective

The hydrogen compression, precooling and storage system design required for hydrogen refuelling is typically handled as part of the vendor supplied refuelling package. The hydrogen pressure required for hydrogen refuelling is typically 70 MPag for light vehicles and 35 MPag for heavy vehicles. Typical hydrogen pressures for tube trailer loading are in the range of 20 to 50 MPag. Given that the delivery pressure required is higher than the proposed main hydrogen storage pressure of 20 MPag, a high pressure buffer storage unit has been included in the layout and cost estimate, with an assumed storage capacity of 600 kg, based on the approximate capacity required to fill a single tube trailer. This is assumed to be provided in a MCP stored at around 50 MPag.

Base Case 1 and 2 of the project will displace up to 3,456L/day of diesel (1261.5ML/year) by replacing heavy vehicle diesel use with green hydrogen, the equivalent of fuelling 33 heavy vehicles per day. There will be a direct carbon emissions reduction of up to 3.38 million kg CO_2 per year. This is the equivalent of 55,933 trees being planted and grown over a 10-year period. The Growth Case in 2035 will see that number increase to 120,956L/day with a carbon emissions reduction of up to 118.38 million kg of CO_2.

3.6.2 Technology Description

Fixed Tube Trailer

Currently in Australia, typical tube trailers consist of multiple steel construction vertical vessels fixed to the back of a truck. The hydrogen is stored typically at 20 MPag and can hold approximately 0.4 tonnes hydrogen. The market is currently investing in Type IV composite vessels, which would enable storage at higher pressure and increased capacity of hydrogen up to approximately 1 tonne.

Figure 3.16 Tube Trailer

Mobile Storage Packs

An alternate tube trailer technology is the ‘drop and go’ configuration. Manifolded cylinder packs that are in typical isotainer sizing store hydrogen at around 30 MPag due to the Type IV composite cylinders. The containers are loaded with approximately 0.7 tonnes of hydrogen and are stored on-site, to be picked up by trucks when required.

Figure 3.17 Mobile Storage Pack Loaded onto a Truck

Vehicle Refuelling

Hydrogen vehicle refuelling skids typically have a capacity of 450 kg hydrogen dispensed per day. Options are available to dispense at both 35 and 70 MPag. The refuelling package includes compression up to high pressures, along with chillers to ensure reasonable temperature for loading. Some vendors offer inclusion of additional buffer storage, typically in cascade configuration.

Figure 3.18 Vehicle Hydrogen Refuelling Skid

4. Balance of Plant and Interfaces

4.1 Wastewater

Wastewater from the H2Kwinana facility can be discharged through the Sepia Depression Ocean Outlet Landline (SDOOL). The current wastewater volume and key quality limits for discharge through the SDOOL are shown in Table 4.1.

Table 4.1 SDOOL Environmental Licence Thresholds – Key Process Wastewater Limits

Parameter	Unit	Limit	Compliance Period
Volume	m^3	7,930	Daily
pH	pH units	6.0 – 9.5	All discharge
Total Nitrogen	kg/d	200	Daily
Total Suspended Solids (TSS)	mg/L	60	Monthly average
Chemical Oxygen Demand	mg/L	100	Monthly average
Biological Oxygen Demand	mg/L	25	Monthly average

The wastewater produced from the H2Kwinana facility includes the Demineralisation Plant waste, and the cooling water blowdown, as shown in Table 4.2. The Growth Case will require an estimated discharge rate of 3,036 m^3/d to the SDOOL, which is assumed to be feasible based on previous refinery discharge limits.

Verification of the wastewater quality from the facility should be performed on the key wastewater quality parameters listed in the table above for all three cases, although there are no issues anticipated for the wastewater quality for Base Case 1. Another consideration is the TSS of the wastewater, which can be managed via filtration prior to discharge, with the produced retentate discharge to a pond at site. Note that the current cases conservatively assume that all general site use water is sent to wastewater, although in practice a portion of this site use water may be able to be recovered for use in the cooling water system.

Table 4.2 Wastewater Discharge Peak Rates

Parameter	Unit	Base 1	Base 2	Growth
Hydrogen Production (Daily)	tpd	44	143	429
Hydrogen Production (Peak)	tpd	44	166	449
Wastewater Rate (Peak)	m^3/h	15.1	51.0	134.6
	m^3/d	363	1,225	3,232
Wastewater Rate (Daily Peak)	**m^3/d**	363	1,056	3,084

The current infrastructure for wastewater at the bp Refinery Precinct includes oily water sewer lines to area sumps, and onward to the onsite water treatment plant. There are numerous oily water headers that may be used, with the two largest being sized DN250 and DN450.

A calculation was completed to assess the velocity experienced in these headers with the above wastewater flowrates, which found that the DN250 header is likely sufficient for H2Kwinana Base Case 1 and Base Case 2, based on an assumed velocity limit of 3 m/s, however the DN450 header would likely be required for the Growth Case.

A review of the sump system layout with the H2Kwinana plant layout is required to ascertain which headers can be re-used; some of the oily water sewer headers are only DN100 which are likely to be too small for all cases. An integrity review should also be undertaken to confirm the remaining life of the existing system and any repair works required.

4.2 Flare / Vent

Flaring or venting of hydrogen will be required from H2Kwinana in various circumstances including:

- During cold start-up of electrolysers until hydrogen is on spec;
- Relief scenarios;
- Emergency depressurisation (blowdown), e.g., in the event of fire or gas detection; and
- Equipment depressurisation for maintenance.

The most significant of these is expected to be blowdown of the hydrogen storage system, which could potentially require discharge of up to 25 tonnes of hydrogen in a short space of time. This may be required in the event of fire and/or gas detection in the storage area.

From a safety perspective, flaring of the high pressure hydrogen allows for controlled burning of the gas. Venting of the hydrogen on the other hand poses a potential hazard through the dispersion of flammable gas. Given the location of H2Kwinana in a built up area, it is unclear whether venting of large volumes of hydrogen will be acceptable, particularly given that a flare system already exists at the site. As such, flaring is proposed as the base option for dealing with gas releases.

4.3 Nitrogen

Nitrogen is currently available to the bp Kwinana Refinery Precinct via pipeline supply.

Nitrogen is required by the electrolyser:

- Upon commissioning;
- In case of repair; and
- In case of cold start after a long period of inactivity.

To meet the nitrogen demand for H2Kwinana, it is proposed to compare the use of nitrogen VIEs brought in from offsite with the option to compress nitrogen from the existing pipeline and store sufficient inventory in a high pressure receiver to enable a volume of nitrogen to be available to allow for efficient start-up of electrolysers after a major outage. In future project phases, the size of the receiver is recommended to be selected based on selected vendor electrolyser requirements.

4.4 Compressed Air

Compressed air is required for H2Kwinana for the following users:

- Electrolyser package and other main equipment packages instrument air;
- Control valve and actuator instrument air;
- Instrument air system leakage; and
- Intermittent compressed air allowance for air driven tools.

The compressed air is proposed to be provided from a new vendor package.

4.5 Firewater

As hydrogen fires are not easily quenched, fire protection is based on:

- Reducing hydrogen inventory (depressurisation and venting);
- Applying separation distances to minimise the risk of ignition of adjacent plant, storage vessels and buildings due to flame or heat exposure from the original fire;

- Cooling adjacent equipment, storage vessels and buildings to minimise risk of ignition and explosion due to heat exposure from the original fire; and
- Applying firewater to buildings and process equipment to extinguish any fires originating within them and to protect them from adjacent fires.

Fixed fire protection systems will be provided to allow for the above needs, which may include a mix of sprinklers, hose reels, extinguishers, monitors, hydrants, and foam systems.

4.6 Chemicals

Multiple different chemicals are expected to be used onsite. The chemical usage is expected to be low. Additionally, although vendors often quote negligible potassium hydroxide top-up required throughout the lifetime of the alkaline electrolyser, the number of electrolyser stacks required for the Base 2 and Growth Cases is so large, that the quantity required at site for top-up may become more significant. It is recommended that top-up requirements are clarified with electrolyser vendors, if alkaline electrolysers are selected.

4.7 Site Preparation and Civil Infrastructure

The plot plan space for the facility was identified at the site for the H2Kwinana Project. This includes space vacated by equipment from the now closed refinery at the site, that has been, or is in the process of being, decommissioned.

Site preparation and civil works are expected to include:

- Trimming of existing surface to required lines and levels;
- Reuse of existing roads which may require resealing, and new local roads provided to new infrastructure;
- Reuse of existing buildings where possible
- Existing drainage systems and oily water systems along existing site roads to be utilised with only local drainage modifications to suit layout of existing infrastructure.

5. Power Supply

5.1 Overview of Existing Electrical Infrastructure

The existing power supply to the bp site is provided by two (2) overhead 132 kV lines from a Western Power 132 kV substation. Both lines are rated at 87 MVA or 83 MW at 0.95 power factor and are connected to different bus sections at MSR. The power factor of 0.95 being what Western Power require all major loads to maintain.

It is proposed that the supply for the future hydrogen production plant be provided via 132/11 kV generator step up transformers (GSUT). The combination of incoming transmission line and transformer capacity provides the installed and contingency capacities as shown in Table 5.1 below.

Table 5.1 Installed and Contingency Capacities

No.	Case	Limiting component	Capacity – intact system (N)	Capacity – single contingency (N-1)
1	Existing line Infrastructure	Thermal capacity	166 MW	83 MW
2	Existing GSU transformers	Rating	142.5MW	95MW

Whilst the above table indicates a firm (i.e., N-1) plant capacity of 83 MW to the bp refinery, Western Power has advised that the 132 kV system supplying the substation does not have the capacity to continuously supply this load. However, as there are other power stations being established in that region, bp and Macquarie requested Western Power to advise what capacity can be supplied in the near future without grid modification. Western Power has advised that grid modifications would be required to enable a 125 MW electrolyser supply plus the 15MW to the bp refinery via the existing 132 kV infrastructure.

The preliminary advice provided is that to enable a 140MW supply to the bp site, various modifications to the existing Western Power infrastructure would be required.

To supply a 44 tpd hydrogen production facility the worst case power requirements (assuming PEM electrolysers) will be in the order of 129 MW_{EOL}. This allows for loss of electrolyser efficiency over time.

5.2 Scale Up Path

5.2.1 Base Case 2 Power Supply

The Base Case 2 hydrogen production target is 143 tpd. This rate will have a total electrolyser power requirement of 418 MW_{EOL} to allow for loss of electrolyser efficiency over time and offline time of 4 hours per day. With ancillaries the required installed capacity will be 484 MW_{EOL}. The determination of this is as shown below in Table 5.2.

Table 5.2 Power Demand for Base Case 2

H_2 Production Rate (T/day)	H_2 Power consumption (MWh/day)	H_2 Power Demand[1] (MW)	Ancillaries Demand (MW)	Total Demand (MW)
143	9130	418	65	484[2]

[1] EOL demand
[2] Does not include KRF and refinery load of 15MW

Previous studies carried out by GHD have determined that this power requirement cannot be supplied from the Western Power 132 kV system and will have to be provided by the 330 kV network.

The combination of incoming transmission line and transformer capacity provides the installed and contingency capacities as shown in Table 5.3.

Table 5.3 Base Case 2 Installed and Contingency Capacities

No	Case	Limiting component	Capacity – intact system (N)	Capacity – single contingency (N-1)
1	Future transformer	Transformers T1 & T2	950 MW[1]	475 MW[1]
2	New double 330 kV circuits	330 kV circuits	2760 MW	1840 MW
1. Assuming transformers rated at 500MVA @ 0.95 power factor				

As can be seen from Table 5.3, full redundancy is not provided with the proposed transformer and line configuration. In the event of loss of one transformer, the plant output will have to be reduced to 98% of full capacity or 475 MW. In the event of the loss of one 330kV line the plant output will not have to be reduced. However, the loss of a transformer is expected to be a rare event with the loss of a line should be expected at least every few years, depending upon its design and route selection.

6. Network Service Charges, Capacity Payments and Ancillary Services

6.1 Network Service Charges

Western Power's network service charges will reflect the cost of the network assets built to accommodate any increase in the demand; and the extent of the network used to transmit power from generation to the load.

Ultimately, GHD expects bp and Macquarie to agree two contracts with Western Power:

- Electricity Transfer Access Contract (ETAC) or Access Contract – This is the standard access contract that Western Power proposes for each reference service. It covers the ongoing use of the network; and
- Individual Connection Works Agreement (ICWA) – This covers connection works, including any possible system enhancements needed as a result of the connection.

Information in Western Power's 'Application and Queuing Policy' and 'Applications & Queuing Policy: Methodology to determine the Preliminary Offer Processing Fee and the Preliminary Acceptance Fee' documents provide more information on the connection process with Western Power including potential costs.

The exact cost of studies and requirements for connection will be determined through the Western Power negotiation process. However, there are two options when it comes to the network services:

- Reference services; and
- Non-Reference services.

Reference services provide the basis from which Western Power may enter negotiations for non-reference services. Hence, GHD discusses these first below and then provides some future detail on non-reference service arrangements.

6.1.1 Reference services

Western Power publishes reference network tariffs with prices approved by the Economic Regulation Authority (ERA) annually. The network access prices are charges for transporting electricity across the existing network and exclude any upgrades that may be needed. These are referred to as "**reference services**" and assume firm transmission capacity is required.

The pricing formulas provided in Western Power's Price List[3] form the starting point for negotiation with Western Power around access that varies from the reference service.

6.1.2 Non-reference services

A '**non-reference service**' connection may allow an increase in demand at the existing connection point without additional connection charges by utilising non-firm transmission capacity. With this approach, the electrolyser may need to rapidly reduce output in response to network contingencies (i.e., appropriate run-back scheme).

Non-reference tariffs are negotiated with Western Power and the negotiated prices are not published. Hence, there is no public information available to inform advice on what may or may not be acceptable to Western Power for bp's connection and ongoing fees.

GHD understands negotiations with Western Power are being undertaken in parallel with the development of this feasibility study report. As part of the connection application process, GHD expects Western Power to set out the range of studies (and steps) needed and indicative costs associated with the process and for the connection agreement terms to become clear.

[3] https://www.westernpower.com.au/about/regulation/network-access-prices/

6.2 Capacity payments

Capacity credits allocated to generators and loads that participate in Demand Side Management (DSM) based on their installed capacity and the ability to provide generation or reduce load when called on. For DSM, capacity payments require the load to be available to be reduced when called on. Failure to be able to decrease load when required (anytime during the year excepting planned outages), can result in penalties and the loss of access to future capacity credit payments.

Capacity payments vary from year to year. DSM are eligible to receive the floating Reserve Capacity Price (and are not eligible to be a Transitional or Fixed Price Facility). For the period 2022-23, the price will be AUD 85,294 per MW and for the 2023-24 period the price will be AUD 105,949.27 per MW.

6.2.1 Reform of the Reserve Capacity Mechanism

The advice above is based on the Reserve Capacity Mechanism as it currently operates. Energy Policy WA released a consultation paper on 29 August 2022 commencing the start of significant reforms to the Mechanism[4]. Of note, the Stage 1 proposed reforms include the removal of the current Availability Classes and replacement of these with revised categories based on the firmness of capacity offered and to allow for participation by hybrid facilities.

The review is being undertaken in three Stages, with the first two stages considering various design aspects of the revised Mechanism and the Rule changes required to implement reforms being the subject of the final stage. At this point, Energy Policy WA expects the final Rule change proposal to be submitted for implementation in June 2023.

6.3 Ancillary services (or essential system services)

Ancillary services (or essential system services)[5] refer to a variety of operations beyond generation and transmission that are required to maintain grid stability and security. Figure 6.1 provides a summary of the current ancillary services in the WEM. The services that can be provided by load include:

- Load following ancillary service (LFAS), which provides frequency regulation. A load that is able to increase and decrease the power consumed in response to control signals issued by the AEMO Automatic Generation Control (AGC) system can provide LFAS;
- Spinning reserves ancillary service (SRAS), which responds to any contingency involving unexpected trip of generation. Loads that can decrease their consumption of electricity rapidly following the local detection of a drop in frequency can provide SRAS; and
- Load rejection reserve (LRR), which responds to contingencies involving the trip of load. Loads that can increase consumption rapidly following the local detection of an increase in frequency can provide LRR.

Ticks and crosses in Figure 6.1 indicate the services that bp and Macquarie **may** consider providing. Of these services, LFAS is provided as a market service where participant bid into the market to provide specified quantities of LFAS raise and lower at self-determined prices. SRAS and LRR are provided as contract services through an annual procurement process run by AEMO.

[4] Refer to the following website for further information: https://www.wa.gov.au/government/document-collections/reserve-capacity-mechanism-review
[5] Ancillary services is the current name for these suite of services. Following market reforms, including changes to a co-optimized energy and essential system service market dispatch, these services will be re-named and collectively known as essential system services. The move to the new essential system service framework is dependent on other market reforms and is expected to be implemented in October 2023.

Market-based service	Load Following Ancillary Service (LFAS)	LFAS allows for supply and demand to be continuously balanced in real-time. It compensates for variations between load and intermittent generation, and forecast, as well as normal generation deviations. Both load and generation can provide this service.	✓	AEMO enables specific Facilities to provide LFAS based on LFAS Market outcomes. A Facility may provide LFAS Upwards, LFAS Downwards, or both. To provide the service, the facility must be online and output in required range.	In 2020/21, approved maximum requirements (updated in September 2020) were: • LFAS up and down, 5.30am to 7.30pm = 105 MW • LFAS up and down, 7.30pm to 5.30am = 80 MW • Currently five certified LFAS providers in the WEM, and three of them actively participated in the LFAS Market in 2020-21.
Contract service	Spinning Reserve Service (SRAS) **(primary frequency response)**	Spinning reserve is generation capacity that is held in reserve but ready to respond quickly if another generator suffers an unexpected outage. The service can also be provided through load shedding.	✓	The SRAS requirement is at least the maximum of: • 70% of the largest generating unit; and • 70% of the largest contingency event that would result in generation loss. AEMO may relax the SRAS requirement by up to 12% where it expects a shortfall will be for a period of less than 30 minutes.	In 2020/21: • Highest minimum requirement = 310 MW • Provided by Balancing Portfolio Facilities and by Interruptible loads under two Ancillary Service Contracts
Contract service	Load Rejection Reserve (LRR)	Load Rejection Services are provided in the event of lost load, such as when a transmission line trips.	✓	AEMO adopted a dynamic LRR for 2020-21 that incorporated physical aspects of the power system, including setting the upper limit of the LRR requirement based on the largest credible contingency in real time. The quantity available from the generator (or load) is determined by its output and it's ability to respond to frequency increases.	In 2020-21: • Approved maximum requirement = 90 MW • Provided by generators in the Balancing Portfolio that were capable (generator must be online and the output is in the current range)
Contract service	Dispatch Support Services (DSS)	Provided by Synergy if needed.	✗	Not currently required. However, AEMO may identify opportunities for early implementation of the WA Market Reforms, including services such as Rate of Change of Frequency (RoCoF) Service.	In 2020-21: • Not required.
Contract service	System Restart Service	Provided by generators capable of starting up on black system conditions and are also able to energise the power system to enable other generators to be started up.	✗	The System Restart Service requirement for 2020-21 was: • Three Facilities with system restart capability, to allow for one Planned Outage and one Forced Outage. • At least two System Restart services must be planned to be available at all times.	In 2020-21: • Three System Restart Ancillary Service Contracts in place during 2020-21 for three Facilities.

Figure 6.1 Summary of current ancillary services in the WEM

6.3.1 Reforms to adopt an 'Essential System Service' framework

The ancillary service markets are being reformed. After the reform, these services will be called 'essential system services'. Following the change, the basic technical requirements will remain the same. However, the services will be re-named, and regulatory barriers that prevent provision of services by certain technology will be removed.

The move to the new essential system service framework is dependent on other market reforms, including a change to a co-optimised energy and essential system service dispatch engine and the adoption of a 5-minute dispatch interval (from a 10-minute interval). These reforms are currently expected to be implemented in October 2023.

7. Overview of Concept Design

7.1 Power Supply Description

The power supply for the three hydrogen production cases considered in this study are:

- 44 tpd (Base Case 1), the estimated maximum that can be delivered by the existing 132 kV power infrastructure, with PEM electrolysers, is estimated at 128.5 MW, limited by the 50 MVA repurposed existing 132/11kV generator step up transformers. Western Power has advised the capability of their local 132 kV infrastructure and the modifications needed to deliver this power requirement. A new 11kV distribution system would be required to supply the electrolysers and balance of power requirements.
- 143 tpd (Base Case 2), this would require installation of an expanded 330 kV grid network, which would increase the maximum power available to approximately 920 MW per 330 kV circuit. Western Power has advised the capability of the 330 kV grid and the modifications needed to it to deliver this power requirement. A new 330/36kV distribution system would be required to supply the electrolysers and balance of power requirements via two (2) 500MVA 3 winding transformers.
- 429 tpd (Growth Case), the potential growth scenario identified by bp and Macquarie would require no new 330 kV circuits beyond those installed for Base Case 2. However, the capability of the SWIS to deliver the power requirements is yet to be determined by Western Power. The Base Case 2 330/36kV distribution system would be required to be extended to supply the additional electrolysers and balance of power requirements via two additional 500MVA 3 winding transformers.

7.2 Process Description

Treated water from the KWRP will supply the Demineralisation Plant to produce demineralised water to feed the electrolyser. Hydrogen is produced at pressure ranging 0 to 3.0 MPag, depending on the choice of electrolyser technology, while the co-produced oxygen is vented. The hydrogen is passed through low pressure compression to compress the hydrogen to 4.0 MPag. This will require only one stage of compression if compressing from 3.0 MPag (typical discharge of PEM electrolysers), although at least four stages will be required if the electrolyser discharges hydrogen at close to atmospheric pressure (typical of alkaline electrolyser). Inter-stage cooling will be provided from the closed loop cooling water circuit.

The hydrogen at 4.0 MPag will be exported from site. The remaining hydrogen will go through a two-stage high pressure compression system to 20.0 MPag, with inter-stage and after cooling. The mobility refuelling offtake supplies the required amount to the onsite tube trailer loading system, where it will be compressed to the pressure required for tube trailer loading and/or supply to buffer storage. The rest of the hydrogen is stored in pressure vessels for use when the electrolyser hydrogen production is turned down to ensure consistent hydrogen supply to the users.

A hybrid cooling system will be used to provide cooling for the electrolysers and both the low pressure and high pressure compression. The circulating cooling water will first be cooled through fin fan coolers. Trim cooling is provided by an evaporative cooling tower when the ambient conditions prevent sufficient cooling duty to be provided by the fin fan cooling alone.

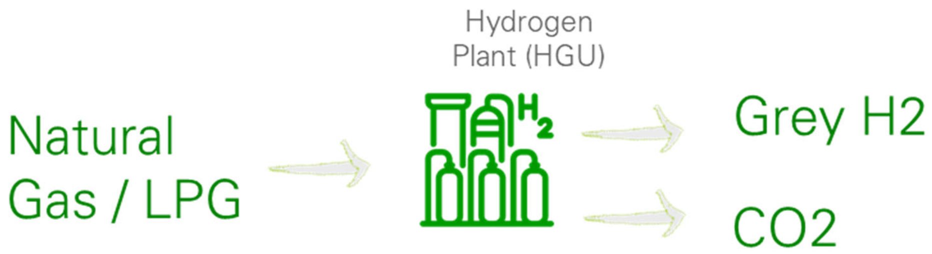
The Block Flow Diagram for each of the three cases can be found in Appendix A.

8. Renewable Fuels and Alternative Renewable Hydrogen Production

While the concept design is based on Green hydrogen production, it is important to note there are alternatives to this. These are outlined below.

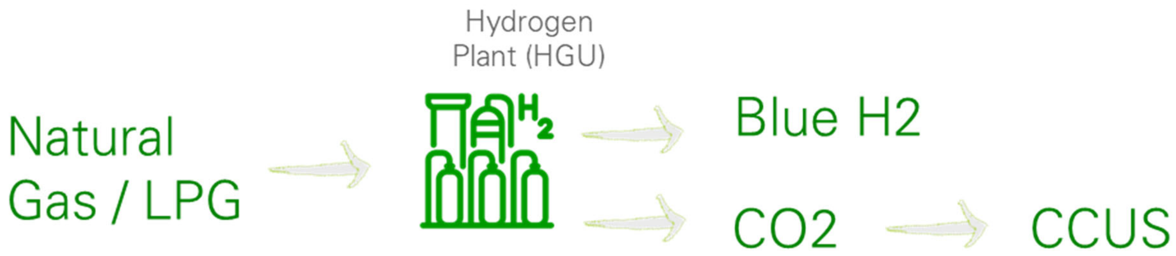
8.1 Grey Hydrogen Production

An alternative method to produce hydrogen is through a hydrogen generation unit (HGU) which generates hydrogen through steam methane reforming and pressure swing adsorption. Inputs into the HGU can be natural gas and/or LPG. Hydrogen produced from fossil based natural gas or LPG is considered to be grey hydrogen as it is fossil based and the HGU releases a stream of CO2 into the atmosphere.



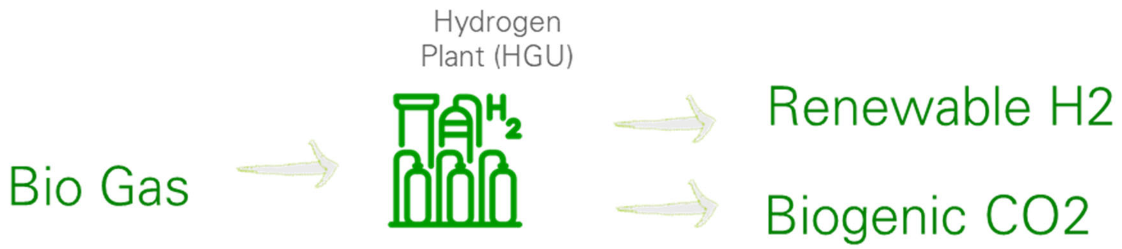
8.2 Blue Hydrogen Production

Hydrogen produced from a HGU is considered blue hydrogen when Carbon Capture, Utilization and Storage (CCUS) is added to the production of grey hydrogen. This redirects the CO2 released from the HGU to storage and eliminates CO2 emissions being released to the atmosphere.



8.3 Renewable Hydrogen

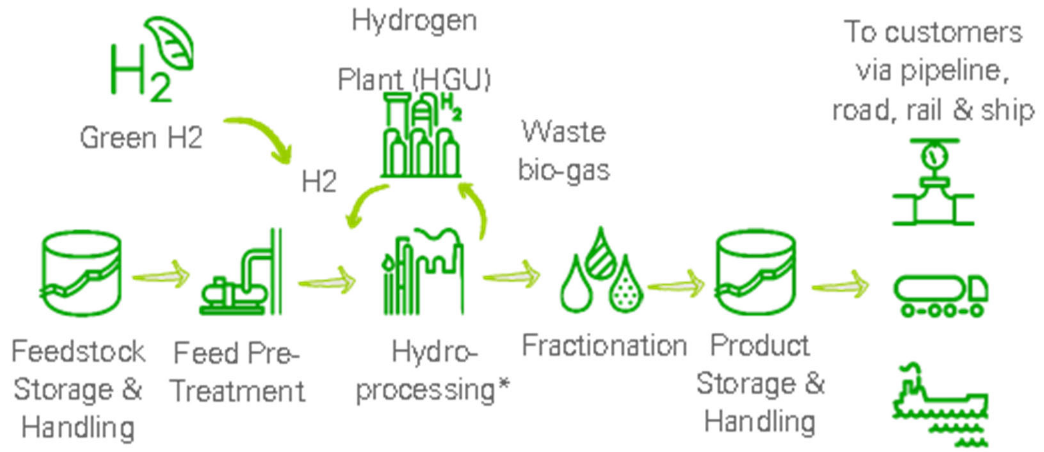
Renewable Hydrogen can also be produced from a HGU if the fossil-based feedstock is replaced with renewable feedstocks. In the case of a renewable fuels project renewable feedstocks are purified and reformed to produce products like renewable diesel and sustainable aviation fuel. As part of this process bio-genic hydrogen rich off gas and bio-genic LPG are produced and can be captured and used as feedstock in the HGU.



8.4 Overview of Renewable Fuels Production

As part of the planned bp Kwinana Energy Hub, bp is progressing the Kwinana Renewable Fuel Project (KRF Project), which could be a key first user of green H2 at industrial scale. The KRF Project is being progressed independently of proposed Hydrogen Hub and is currently in FEED phase. The project is planning to produce Sustainable Aviation Fuel (SAF) and Renewable Diesel (RD) from sustainable feedstocks targeting commencement of operations in 2026. Feedstock will be provided by both domestic and international sources, with products available for domestic consumption as well as exports to international markets with existing biofuel demands.

In the first step of the renewable fuels production process, renewable feedstocks are purified of any contaminants that may cause damage during the production process. The feed is then processed through hydro-processing and fractionation units to produce product such as renewable diesel and sustainable aviation fuel. These are then stored and sold to customers. During the process waste bio-gas is produced which can be feed through a conventional HGU to produce renewable hydrogen which can then be used in the production process or for alternate use. The balance of hydrogen production that is not provided by bio components in feed would be supplied by either natural gas or, by the consumption of green Hydrogen.



8.5 Green Hydrogen usage in Renewable Fuels Production

The benefit of Green hydrogen is renewable fuels production comes from the potential to either eliminate the need for a HGU or eliminate the need for fossil based natural gas or LPG in the HGU feed. This has the benefit of reducing the capital investment required in the renewable fuels plant and/or further reducing the carbon emissions from renewable fuels production. KRF Project would plan to take green hydrogen from the first phase of a hydrogen production facility at the bp Kwinana Energy hub.

9. Environmental Planning

9.1 Preliminary Environmental Impact Assessment

The main environmental legislation applicable in Western Australia to mining, infrastructure and industrial developments is Part IV of the *Environmental Protection Act 1986* (EP Act). The Environmental Protection Authority (EPA) takes into account the environmental significance of potential impacts that may result from the implementation of the scheme or proposal. For assessments under Part IV of the EP Act, the EPA has substantial flexibility in determining how they assess a proposal and the corresponding timelines for doing so. As such, the EP Act assessment is the key driver of approvals timelines.

The permitting requirements of the project (and thus likely timelines) are determined by the environmental aspects likely to be affected by the development of the project. To determine the potential for impacts GHD undertook a three-step process that included:

1. Determining the environmental values that could be affected by reviewing publicly available spatial datasets (largely sourced from the Government of Western Australia (GoWA))
2. Reviewing the project elements that have the capacity to affect the identified environmental features.
3. Undertaking an initial assessment of the potential for impacts from the Project.

Important for determining the environmental approval requirements, the project is expected to use a range of existing infrastructure, such as pipelines, power infrastructure and water treatment and supply infrastructure. The reuse of existing infrastructure, where there are no changes to the rate of polluting emissions, typically does not require approval. The main new project elements are the electrolysers, hydrogen compression, hydrogen storage and associated interface/connections. Other offsite impacts include new transmission line corridor.

There are also expected to be some changes to the throughput rates of infrastructure, such as the increase in wastewater rates from the new facilities. In additional there is the potential for transmission lines and gas pipelines that may be required. However, it is anticipated that the service provider (e.g. Western Power) would be the responsible for obtaining required approval for related infrastructure, such as native vegetation clearing permits.

Based on the initial assessment of the impacts the only anticipated impacts are associated with:

- Dust associated with construction activities;
- Disturbance of existing contaminated soil; and
- Noise impacts associated with cooling (depending on cooling technology.

In addition, the need for connection of infrastructure, such as powerlines, may require some vegetation clearing, which would need to be assessed but may be the responsibility of a third party.

In addition to the primary approval there are a number of secondary approvals that will be required (such as a works approval under Part V of the EP Act). If a Primary approval is required then secondary approvals can be assessed but not approved/issued until the primary approval is granted.

9.2 Carbon Footprint Assessment

A carbon footprint assessment was conducted to estimate the emissions abatement potential of replacing business-as-usual fuel inputs with hydrogen inputs in the following activities, which are considered as potential use cases for hydrogen produced at H2Kwinana:

- Renewable fuel production;
- Ammonia production;
- Heavy vehicles (transportation); and
- Power generation.

Table 9.1 presents a summary of the life cycle emissions intensity for each of the activities and an estimated emission reduction percentage between the business-as-usual (BAU) and hydrogen incorporated approach.

Table 9.1 Comparison of the life cycle emission intensity for some potential use cases

Life Cycle	BAU	H_2 Utilisation	Unit	% Reduction
Renewable Fuel Production	7.5	3.75	g CO_2 / MJ	50%
Ammonia Production	2.6	0.24	t CO_2 / t NH_3	91%
Diesel for heavy vehicles	338	58	g CO2-e/km	83%
Power Generation	420	70	g CO2/kWh	83%

Table 9.2 contains estimated emission abatement per tonne of hydrogen consumed for each of the activities listed. The abatement estimates have been made based on avoided emissions associated with the business-as-usual activities.

Table 9.2 Estimated carbon abatement for each activity

Activity	Carbon abated (t CO_2-e per t H_2)
Renewable Fuel Production	0.7
Ammonia Production	8
Heavy vehicles	12
Power Generation	6.7

Details of specific emissions intensity reductions and estimated emissions abatement are provided in the following activity descriptions.

10. Project Risk

An initial project risk workshop was held on the 26 May 2022 via teleconference (MS Teams). The workshop was facilitated by bp and representatives from bp, Macquarie and GHD provided input to identify potential project risks. The group comprised of representatives from investment, project management, environmental approvals, process engineering and power engineering.

The primary purpose of the risk workshop was to identify potential project risks and opportunities associated with country and regulatory, market and commercial, health, safety and environment, technical, project definition and execution complexity, and operability and production ramp-up. The identified risks and opportunities were also assessed for credible consequence associated with health and safety, environment, and cost and schedule. Furthermore, responses and actions have been identified for each risk and opportunity. These responses and actions have been delegated to an appropriate risk owner.

The number of identified risks and opportunities is summarized in Table 10.1.

Table 10.1 Identified Risks and Opportunities

Risks and Opportunities	Ranking	Number identified
Risks	Very High	5
	High	10
	Medium	13
	Low	13
Risks – Total		**41**
Opportunities	High	1
	Medium	1
Opportunities - Total		**2**
Total		**43**

The key risks identified during the initial project risk workshop are:

- Delays in required EPA and community approvals for the installation of new 330 kV power supply lines. This risk event could be caused by unclear accountability for the required approvals and delays in the approval process resulting in delays to overall project schedule;
- Failure to secure a Power Purchase Agreement sufficient for the plant capacity. This risk event could be caused by competition with other industry for grid power and may result in the Project not being developed as planned;
- Failure to secure sufficient Large Scale Generation Credits (LGCs). This risk event could be caused by a lag in scale up of the renewable generation capacity in Australia to meet LGC demand. This may impact the Project's ability to meet customer product requirements. The project economics may also be impacted if the price of LGCs increases due to upward pressure in the market if demand is greater than supply;
- Unable to agree the required Western Power scope of work to deliver the required power. This risk event could be caused by uncertainties in the network connection studies required by Western Power and the complex negotiation structure. This could result in project delays or re-work due to incorrect assumptions; and
- Network augmentation by Western Power required to support the Project cannot be delivered within current project timeline. This could be due to longer than anticipated timelines for network augmentation, delayed execution of network augmentation, and/or delays in EPA approvals to commence installation. This may result in delays to overall project schedule.

It is recommended to conduct project risk reviews in subsequent project phases to identify new and emerging risks and to continue monitoring identified risks and risk responses.

11. Project Execution

11.1 Construction Strategy

The development of the construction strategy is dependent on the contracting and procurement strategy. This high-level construction strategy assumes the contracting the procurement strategy outlined in Section 1.1 and is to be reviewed and updated during the next project phase.

The project site is located at the existing bp Kwinana Refinery at Mason Road, Kwinana. The existing refinery equipment and process plant will be decommissioned and demolished/removed by others prior to the construction phase of H2Kwinana. Some existing cabling, piping and equipment are expected to remain on the site and therefore the project site is considered to be a brownfields site and the contractor will be expected to comply with the bp site requirements.

It is recommended to consider whether there is a potential opportunity to quarantine a portion of the site for the Project such that the site can operate as a greenfield site. This could provide some benefit by allowing the contractor to be responsible for site management and safety, and compliance with all associated legislation for the construction activities. In the event that this is not possible, and the site operates as a brownfields project, bp will be responsible for overseeing these aspects including interfaces between contractors and operations.

The site will be governed by the West Australian Legislation, Work Health and Safety Act 2022. If the site is considered a Major Hazard Facility then the applicable regulations will be the Work Health and Safety (Petroleum and Geothermal Energy Operations) Regulations 2022: Work Health and Safety (Petroleum and Geothermal Energy Operations) Regulations 2022 - [00-a0-00].pdf (legislation.wa.gov.au). If the site is not considered a Major Hazard Facility then the applicable regulations will be the Work Health and Safety (General) Regulations 2022: WALW - Work Health and Safety (General) Regulations 2022 - Home Page (legislation.wa.gov.au).

Designation of the facility as a Major Hazard Facility or otherwise will be the responsibility of the Chief Officer based on an assessment in line with the Dangerous Goods Safety (Major Hazard Facilities) Regulations 2007, since the mass of hydrogen stored and contained at the site is expected to fall above the critical quantity of 5 tonnes, above which an assessment is required, but below the threshold quantity of 50 tonnes, above which a facility is automatically classed as a Major Hazard Facility.

During construction, the project team will potentially utilise the existing office buildings and the existing temporary offices located between the office buildings and control building. There is potential for the contractors to set up temporary construction offices adjacent to the laydown area.

A large laydown area (ca. 200 x 200 m) has been identified at the northeast of the site. Road access to the project site and laydown area is either via the bp gate on Mason Road or James Court.

Equipment may be delivered to Henderson, the Port of Kwinana or the bp jetty. A logistics plan is to be developed in the subsequent project phases to support the delivery of equipment to the project site, particularly the storage pressure vessels which may weigh up to 440 tonne.

The construction of the plant is mostly expected to be a modular build for each case. Equipment has been spaced to allow free movement of construction vehicles between systems. Specifically, electrolysers have been proposed to be installed in a modular arrangement with banks of back-to-back electrolyser stacks.

The construction of the electrical infrastructure varies due to the different requirements for the 44tpd, 143 tpd and the 429tpd cases:

- For the 44tpd case, the switchrooms are the major elements of the electrical infrastructure. The buildings will be constructed off site with the switchboards installed and precommissioned by the switchroom manufacturer and then delivered as a single module. The earthing transformers and 11kV/415 V transformers will be transported to site separately for installation. The switchrooms represent the major electrical lifts for this case.
- For the 143 tpd and 429tpd cases, the 330 kV switchyard equipment typically comes from various overseas suppliers. Consequently, due to this and the fragility of much of the equipment, they will be installed on a piece by piece basis. The major power transformers will be in excess of 200 tonne and as such will either be slid into

place or done as a major lift. The various switchrooms will be as for the 44tpd case and be fabricated off site, including switchgear installation.

- For all cases the question of whether cabling is done below ground in trenches or above ground on cable racks will be decided in the subsequent project phase following discussions with bp on access requirements.

Major lifts are expected during construction for switchrooms (20 tonne), transformers (>200 tonne) and storage pressure vessels (265 tonne to 440 tonne, depending on storage capacity selected). A crawler crane such as the Liebherr LR1400-2 may be suitable for 265 tonne lifts (Daniel Smith Industries, 2011) while a larger crane such as the Liebherr LR1750 may be suitable for 440 tonne lifts (Daniel Smith Industries, 2011). Major lifts are to be further detailed and crane specifications are to be developed during subsequent project phases with a suitable crane contractor.

The construction duration of the base case is assumed to be 2 calendar years. Further construction planning is required to confirm the construction duration and labour hours for both the Base Cases and Growth Case.

11.2 Long Lead Items

Long lead items identified during this study, together with expected lead times based on the 2022 market are tabulated in Table 11.1.

Table 11.1 Identified Long Lead Items

Long Lead Items	Expected Lead Time	Potential Contract Type
Electrolyser (1 x 10 MW)	12-24 months[1]	Supply Contract
Storage pressure vessels	24 months	Supply Contract
Compressors	6-8 months	Supply Contract
330 kV switchyards	14 months	Western Power/Supply Contract[2]
Transformers, 36 kV switchgear	14 months	Supply Contract
High voltage cables	8 months	Supply Contract

Expected lead times are indicative for 2022 and are subject to market conditions. It is recommended that bp and Macquarie monitor changes in market conditions.

Western Power have advised that the lead time to provide the 330kV power supply needed is approximately 57 to 72 months.

Note[1] – lead time for large quantities of electrolyser stacks is unknown and may be impacted by competition from other similar projects and limited number of suppliers. Vendors may request to stage delivery of electrolyser stacks. bp and Macquarie may need to place an order with a cancellation clause for electrolysers prior to FID to meet the project schedule.

Note[2] – contract type for 330 kV switchyards will be dependent on agreed scope and contract with Western Power.

12. Cost Estimate

Class 5 Cost Estimates have been developed for the Concept Development stage. The cost estimates have been developed in accordance with AACE (American Association of Cost Estimating) International Recommended practices. The scope of the estimates comprises of the hydrogen production, pipeline transfer, hydrogen loading and hydrogen refuelling facilities, along with the process utilities, electrical infrastructure and other non-process infrastructure required to support the hydrogen production facility.

Class 5 Cost Estimates are prepared for Base Case 1, Base Case 2 and Growth Case described herein. The estimates are summarised in Table 12.1.

Table 12.1 Concept Development Scenarios for Cost Estimates

Parameter	Unit	Base 1		Base 2		Growth	
RFSU	Year	2026		2026		2035	
Electrical Infrastructure		Existing Western Power 132 kV Supply and bp GSUTs		New Western Power 330 kV Supply		Additional Western Power 330 kV Supply	
Total Hydrogen Target Rate	tpd	44		143		429	
Number of 1.94 tonne Hydrogen Storage Vessels		4		13		13	
Stack Technology		PEM	Alkaline	PEM	Alkaline	PEM	Alkaline
Facility Power Demand (EOL)	MW	128	122	483	459	1,311	1,245

12.1 Capital Cost Estimate

The estimated CAPEX of the two potential base case scenarios and the potential Growth Case scenario are summarised in Table 12.2.

Table 12.2 Estimated Class 5 CAPEX Summary

Case	Estimated Class 5 CAPEX (million AUD)
Base Case 1 – PEM Electrolysis	399
Base Case 2 – PEM Electrolysis	1,498
Growth Case – PEM Electrolysis[1]	1,424
Base Case 1 – Alkaline Electrolysis	334
Base Case 2 – Alkaline Electrolysis	1,253
Growth Case – Alkaline Electrolysis[1]	1,181
[1] The Growth Case CAPEX shown in this table is the incremental CAPEX required above the Base Case 2 CAPEX to achieve the full Growth Case target hydrogen production capacity, as shown in Figure 12.1.	

The CAPEX estimates are given in present day Australian dollars (AUD). The CAPEX estimate for the Growth scenario is built up from the Base 2 scenario cost. Items that are installed in Base Case 2, for example, all the hydrogen storage vessels, are not recounted in the Growth Case CAPEX. Therefore, the overall CAPEX to achieve the Growth Phase target hydrogen production rate is the Base Case 2 CAPEX + Growth Case CAPEX, as shown in Figure 12.1.

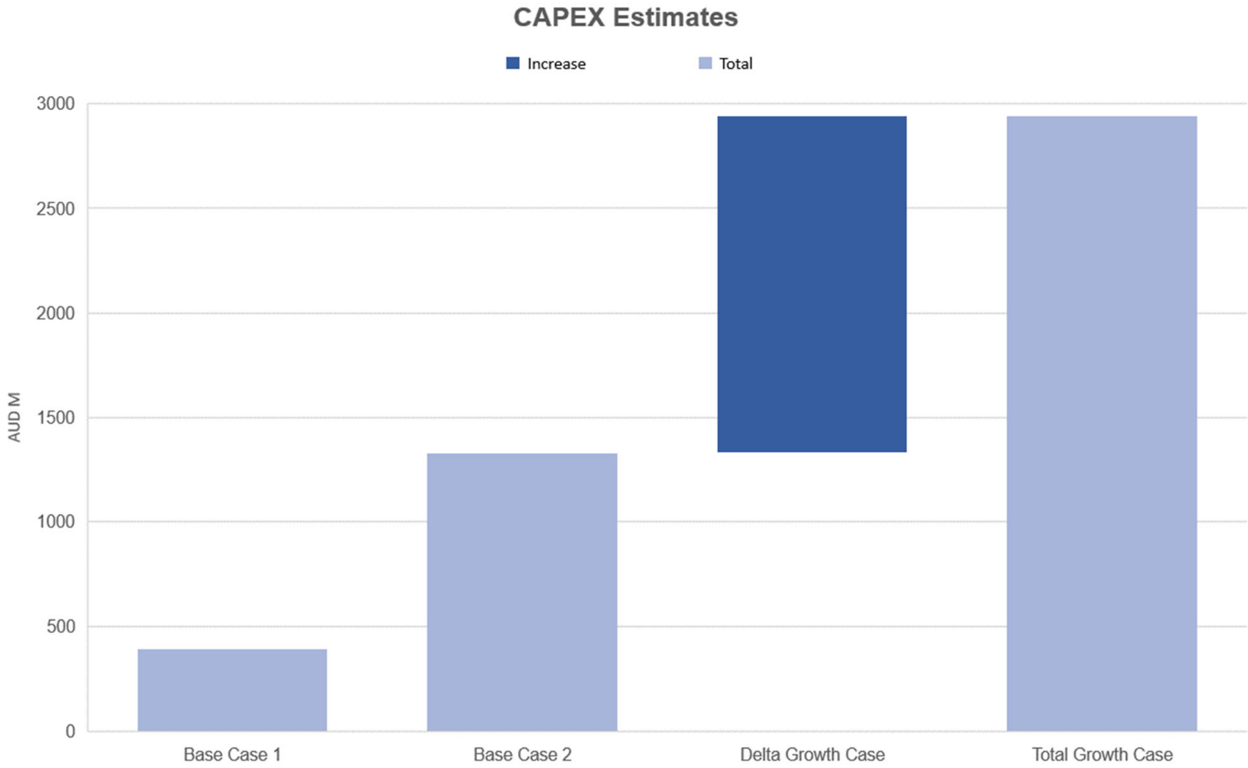


Figure 12.1 H2Kwinana Capital Cost Estimates

The direct costs for the Project for each scenario are dominated by the electrolyser packages, followed by sitewide civils and hydrogen storage (refer Section 1.1). Optimisation of the electrolysis design to reduce the total direct cost of hydrogen production, for example, by using largest available individual stack capacities and fewer, larger hydrogen purification systems, is recommended in subsequent stages of this project. This requires engagement with electrolyser package vendors, along with ESP system integration engineering.

Better definition of high CAPEX items, for example, foundations, is recommended in subsequent phases of the Project to improve the accuracy of the CAPEX estimate.

12.2 Operating & Maintenance Cost Estimate

The estimated OPEX of the two potential base case scenarios and the potential growth case scenario are summarised in Table 12.3. Costs are taken at end of life (EOL) conditions.

The OPEX estimates are presented as an annual cost, based on present day AUD. The OPEX estimate for the Growth Case is the total OPEX for the Growth Case target hydrogen production capacity.

Table 12.3 Estimated Class 5 OPEX Summary

Case	Estimated Class 5 OPEX p.a. (million AUD)	Estimated Class 5 OPEX p.a (million AUD/MW)	Estimated Class 5 OPEX p.a (% of CAPEX)
Base Case 1 – PEM Electrolysis - EOL	82	0.64	20
Base Case 2 – PEM Electrolysis - EOL	268	0.55	18
Growth Case – PEM Electrolysis - EOL	692	0.53	24
Base Case 1 – Alkaline Electrolysis – EOL	71	0.58	21
Base Case 2 – Alkaline Electrolysis – EOL	229	0.50	18
Growth Case – Alkaline Electrolysis - EOL	596	0.48	24

The cost of electrical power supply dominates the OPEX. The assumed power price of AUD 50/MWh is considered optimistic based on GHD's experience; early engagement with the power utility supplier is required to determine the actual tariffs and network usage charges that are likely to be applied for the Project.

Better definition of the other high OPEX items, such as asset management and plant maintenance, is recommended in subsequent phases of the Project to improve the accuracy of the OPEX.

12.3 Levelised Cost of Hydrogen

Levelised cost of hydrogen (LCOH) was estimated for each of the three cases, Base Case 1, Base Case 2 and Growth Case, considering both the PEM and Alkaline electrolysers as described in the above sections. The LCOH for the Growth Case was estimated based on the incremental Capex and incremental Opex, along with the incremental production compared to Base Case 2. Sensitivity cases were considered based on power costs of $50/MWh and $100 MWh to give an approximate LCOH range for the project.

The following table summarises the assumptions used for the LCOH calculations.

Table 12.4 LCOH Model Assumptions

Construction Duration	Base Case 1 / Base Case 2: 2 years Growth Case: 3 years
Project Life	25 years
Inflation	3%
Nominal Discount Rate	8%
Operating Cost Estimate Basis	Averaged between BOL and EOL annual Opex costs.

The following table summarises the LCOH results for PEM Electrolyser.

Table 12.5 LCOH estimates for PEM Electrolyser cases

Power Cost	Power Cost $50/ MWh	Power Cost $100/ MWh
Base Case 1, $/kg	7.1	10.4
Base Case 2, $/kg	7.4	11.3
Growth Case, $/kg	7.1	10.4

The following table summarised the LCOH results for Alkaline Electrolyser.

Table 12.6 LCOH estimates for Alkaline Electrolyser cases

Power Cost	Power Cost $50/ MWh	Power Cost $100/ MWh
Base Case 1, $/kg	6.1	9.3
Base Case 2, $/kg	6.3	10.0
Growth Case, $/kg	5.8	9.0

12.4 Funding

The Australian federal government announced a funding of $70 million for the bp Kwinana Green Hydrogen Hub project in April 2022, which is around 18-21 % of estimated Base Case 1 CAPEX, or around 5-6% estimated Base Case 2 CAPEX, depending on the type of electrolyser selected.

The funding will reduce Base Case 1 LCOH from a range of $6.1 – $10.4 /kg to a range of $5.8 – $10.1 /kg, depending on power costs and electrolyser technology selected.

Similarly, the funding will reduce the Base Case 2 LCOH from a range of $ 6.3 – 11.3 /kg to a range of $6.2 – $11.2 /kg, depending on power costs and electrolyser technology selected.

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Appendices

Appendix A

Block Flow Diagram

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