Department for Energy Security & Net Zero

ROCKWOOL

Marubeni Europower

MOTT MACDONALD

IHA Stream 2A

Feasibility Report

Project Reference:	IHA-2A-ROC
Project Name:	Investigating the use of Hydrogen in stone wool insulation manufacturing
Organisation Name:	ROCKWOOL Ltd

Submission Date:	28/02/2023	Submitted By:	K James

Contents

Figures

Tables

Authors

This project has been developed as part of a collaborative partnership:

- ROCKWOOL Ltd. (Lead Partner). Contact: Kathryn James, Public Affairs and Sustainability Advisor. Email: kathryn.james@rockwool.com Telephone: +44 (0)1656 868311
- Marubeni Europower Ltd. Contact: George Dodd, Senior Vice President. email: george-dodd@jpn.marubeni.com Telephone: +44 (0) 207 826 8867
- Mott MacDonald Ltd. Contact: Nick Roberts, Hydrogen Account Lead. email: Nick.Roberts@mottmac.com Telephone: +44 (0)20 8774 2000

Disclaimer

This document is issued for the party which commissioned it and for specific purposes connected with the above-captioned project only. It should not be relied upon by any other party or used for any other purpose.

We accept no responsibility for the consequences of this document being relied upon by any other party, or being used for any other purpose, or containing any error or omission which is due to an error or omission in data supplied to us by other parties.

Units

Unit	Description
barg	Bar gauge pressure
°C	Degrees Centigrade
gCO_2e / tCO_2e	Grams of carbon dioxide (equivalent) / tonnes of carbon dioxide (equivalent)
GWh	GigaWatt hour
kg	kilogram
kV	KiloVolt
mm / km	Millimetres / kilometres
MVA	Megavolt Ampere
MW / MWh/ MWp	MegaWatt / MegaWatt hour/ MegaWatt peak
Nm^3	Normal cubic metre

Abbreviations

Abbreviation / Acronym	Description
AACE	Association for the Advancement of Cost Engineering
AC	Alternating current
Al	Aluminium
ASTM	ASTM International
B	Boron
BAU	Business As Usual

Abbreviation / Acronym	Description
BCBC	Bridgend Country Borough Council
BMV	Best and Most Versatile
BOP	Balance Of Plant
BSP	Bulk Supply Point
CAPEX	Capital Expenditure
CO	Carbon Monoxide
CO_2	Carbon Dioxide
COMAH	Control of Major Accident Hazards
Cr	Chromium
Cu	Copper
DC	Direct Current
DCF	Discounted Cash Flow
DESNZ	Department for Energy Security and Net Zero
DNS	Development of National Significance
DNV	Det Norske Veritas
EIA	Environmental Impact Assessment
EOL	End Of Life
EPC	Engineering, Procurement, and Construction
FAST	Flexible, Appropriate, Structured, Transparent
Fe	Iron
FEED	Front End Engineering Design
FID	Final Investment Decision
GAAP	Generally Accepted Accounting Principles
GET	Guidance for Emerging Technologies
H_2	Hydrogen
H(P)BM	Hydrogen (Production) Business Model
HGV	Heavy Good Vehicle
HHV	Higher Heating Value
HSC	Hazardous Substances Consent
HSE	Health and Safety Executive
HV	High Voltage
IBC	Intermediate Bulk Containers
IFRS	International Financial Reporting Standards
IHA S2A / S2B	Industrial Hydrogen Accelerator Stream 2A / Stream 2B
IRR	Internal Rate of Return
L1 / L2 / L3	Production Line 1 / Line 2 / Line 3
LHV	Lower Heating Value
LCoA	Levelised Cost of Abatement
LCoH	Levelised Cost of Hydrogen (LCoH in this report does not include equity return)
LHV	Lower Heating Value
LPA	Local Planning Authority

Abbreviation / Acronym	Description
LV	Low voltage
MAPP	Major Accident Prevention Policy
MOIC	Multiple Of Invested Capital
NGED	National Grid Electricity Distribution
NOx	Nitrous Oxides
NPV	Net Present Value
NRW	Natural Resources Wales
NTP	Notice To Proceed
NZHF	Net Zero Hydrogen Fund
NZIW	Net Zero Industry Wales
O&M	Operations and Maintenance
O_2	Oxygen
Odorant NB	78% 2-methyl-propanethiol, 22% dimethyl Sulphide
OPEX	Operational Expenditure
PAC	Pre-Application Consultation
PEM	Proton Exchange membrane
PM	Particulate Matter
PV	PhotoVoltaic
QRA	Quantitative Risk Assessment
RAM	Reliability, Availability and Maintenance
REPEX	Replacement Expenditure
RFP	Request For Proposal
RO	Reverse Osmosis
Si	Silicon
SOL	Start of Life
SOx	Sulphurous Oxides
SR	Standard Rules
SWIC	South Wales Industrial Cluster
TBC	To Be Confirmed
TBD	To Be Determined
TR	Transformer Rectifier
TSA	Temperature Swing Absorption
UK	United Kingdom
UPS	Uninterruptible Power Supply
UV / IR	UltraViolet / InfraRed
VAT	Value Added Tax
VCE	Vapour Cloud Explosion

1. Executive Summary

The Industrial Hydrogen Accelerator (IHA) is an innovation funding programme to support the demonstration of end-to-end industrial fuel switching to hydrogen, through funding provided by the Department for Energy Security and Net Zero (DESNZ, previously BEIS). This feasibility study was delivered as part of the stream 2A of IHA.

The current process for the manufacture of ROCKWOOL's stone wool insulation uses natural gas in the combustion systems and curing ovens. This feasibility study has investigated the viability of converting natural gas usage to on-site produced green hydrogen.

The ROCKWOOL factory in Bridgend opened in 1979, the site currently consists of three production lines. Line 3, a state-of-the-art production line was added in 2008, this line doubled the potential production capacity to over 200,000 tonnes a year.

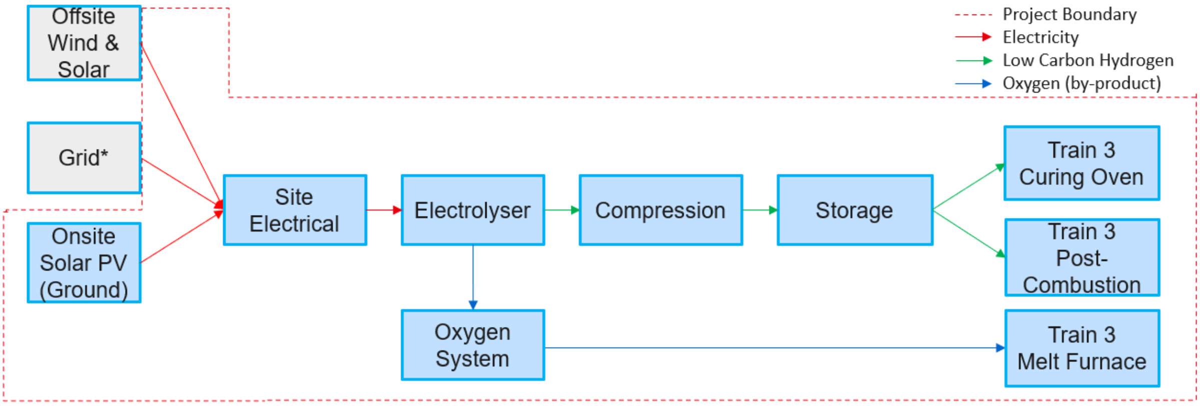
Raw materials are charged into the cupola furnace and melted using coke combustion. The melt flows onto spinners which forms the fibres and adds binder for structural stability and oil for water repellence. The fibres formed by the spinners are collected in the spinning chamber and layered onto conveyor belts. Density and thickness are controlled by the conveyor speed. The product is then passed through a curing oven to set the binder. Two circulation burners fuelled by natural gas provide heat to the oven. Another natural gas fired afterburner transforms the off gases from the curing process and waste heat from this process goes to supporting the circulation burners.

The key aspects of the hydrogen fuel switching study which were investigated were:

- Technical: Renewable Power Supply and Electrical Connections, Hydrogen Production and Facility Re-configuration,
- Regulatory,
- Planning & Environmental,
- Financial and Commercialisation.

It was agreed with ROCKWOOL that a stagewise conversion of the factory was desirable. Therefore, this feasibility study focused on the changeover of line 3 from natural gas to hydrogen (Figure 2.1.1). For **Phase 1** a 14.03 MW Start of life (SOL) / 15.38 MW End of life (EOL) (average production 2,317 kg/day) green hydrogen facility with three days onsite storage would be required to provide hydrogen to production line 3 of the ROCKWOOL factory. The hydrogen will replace 3.8 MW (average) of natural gas consumption, and also include use of by-product oxygen needed for melt furnace operations. For **Phase 2** the hydrogen production facility will be expanded to 35.5 MW (average production 5,782 kg/day) to provide hydrogen for the whole factory.

Figure 2.1.1 Major Project Components



*as partial backup for periods of sustained low renewable supply

Source: Marubeni

This feasibility study concluded that:

Renewable Power Supply and Electrical Connections

- **Phase 1**: Renewable power supply and electrical connections have been determined to be highly feasible by drawing from local renewable power development for up to 15 MW of direct 33kV private wire connection and fully sized 15 MW electrical grid connection as required through these generators.
  Phase 2: Renewable power supply was assessed to be highly feasible; however, 35 MW electrical connections presented difficulty due to the weak local electrical grid requiring 66/132kV connection. Further development of the area is expected by 2030 which would increase feasibility for the 35MW power supply.

Hydrogen Production and Facility Re-configuration

- **Phase 1**: The changeover of the existing ROCKWOOL production line 3 from natural gas to hydrogen would be highly feasible. The major components of the new hydrogen production facility are shown in the figure below. Production line 3 will require burner upgrades to allow the use of 100% hydrogen fuel, while the cupola will use the oxygen enriched air to improve thermal efficiency.
  Phase 2: since adequate space exists for the expansion of the Hydrogen Production Facility the changeover of lines 1 &2 would also be highly feasible.

Planning & Environmental

- **Phase 1**: Planning & Environmental background has been assessed to be highly feasible with a clear process outlined, with expectations that the scheme will be acceptable for Planning and that it would not be considered to require Environmental Impact Assessment due to the low environmental impact. The assessment concluded that onsite wind could present onerous planning requirements and therefore onsite wind was excluded from the base case.
  Phase 2: Planning & Environmental background were assessed to be highly feasible and have similar requirements to phase 1. A particular difference would be dependent on the development of additional renewable power supplies where a

longer process would be expected if classified as a Development of National Significance, which would be more likely given the greater amounts of power required.

Financial and Commercialisation

- **Phase 1**: Financial and Commercialisation aspects for the 15 MW Base Case were assessed to demonstrate a quantified case for the levelised cost of hydrogen (LCoH) of £10.47/kg subsidised, and £11.60 unsubsidised. The levelised cost of abatement (LCoA) of carbon emissions was found to be £1173/teCO2 subsidised and £1326/teCO2 unsubsidised for this hard-to-decarbonise application, strengthening the understanding of how further support mechanisms could be leveraged to enhance deliverability.
- **Phase 2**: The financial and commercialisation aspects were assessed and quantified for a 35MW Current case, showing very similar economics to the 15 MW base case based on LCoH and LCoA which was predominantly due to the weak local electrical grid; despite economies of scale reducing other costs. A 35 MW commercialised case was considered which demonstrated significant reductions in the long term, following Phase 1 and maturation of the hydrogen market beyond 2030, with LCoH of £6.87/kg, and LCoA of £564/teCO2.

By including electrolytic hydrogen production at 15 MW from local wind (12.8MW) and local solar (15 MW) renewable power in Bridgend, the project has demonstrated the technical feasibility of green hydrogen as an end-to-end fuel solution in industrial processes. A phased expanded 35 MW facility was demonstrated to be technically feasible with an associated 30 MW local wind and 35 MW local solar supply; however, the associated grid electrical connections were shown to be potentially cost prohibitive.

This combination of research into green hydrogen use and a viable on-site production solution, has demonstrated real opportunities and delivered ‘proof of concept’ for this approach, not only for other ROCKWOOL production sites but also for other industrial sectors across the United Kingdom.

2. Introduction

2.1. Background

Industry is considered a hard to decarbonise sector due to the volume and intensity of energy consumption required to fuel typical industrial processes along with specific requirements of the fuel and how these interact with various industrial processes.

This project has developed a highly replicable and scalable end-to-end hydrogen fuel switching solution that is directly applicable to stone wool manufacturing sites and has high applicability to further hard-to-decarbonise industrial processes requiring high-grade heat including cement and steel production.

The ROCKWOOL factory in Bridgend Wales opened in 1979, the site currently consists of three production lines. Line 3, a state-of-the-art production line was added in 2008, this line doubled the potential production capacity to over 200,000 tonnes a year. Raw materials are charged into the cupola furnace and melted using coke combustion. The production process required large amounts of energy to melt basalt and other minerals at temperatures up to 1500 °C. The melt flows onto spinners which forms the fibres and adds binder for structural stability and oil for water repellence. The fibres formed by the spinners are collected in the spinning chamber and layered onto conveyor belts. Density and thickness are controlled by the conveyor speed. The product is then passed through a curing oven to set the binder. The curing of the mineral wool fleeces occurs at over 200 °C. Two circulation burners fuelled by natural gas provide heat to the oven. Another natural gas fired afterburner transforms the off gases from the curing process and waste heat from this process goes to supporting the circulation burners.

Due to the concentration of energy required and the nature of the mechanical and chemical processes, these processes are difficult to decarbonise for example, by electrification. For hydrogen fuelling in the furnace process gas combustion and curing ovens, it is expected that comparable efficiency, lifetime, and product characteristics will be achievable with burner configuration modification without further mitigation. The best way to decarbonise the Cupola furnace at Bridgend has not yet been decided. ROCKWOOL already have a mixed fuel furnace which can run off coke, natural gas or biogas. These are installed in Denmark. There is also a similar system using only natural gas in the USA which is less carbon intensive than coke. To fully decarbonise there is also the option of using electric melters. ROCKWOOL already have EAF melters at a number of locations such as Norway, Russia and Canada. The melter in Norway reduced operational carbon emission by 80% and allowed them to increase use of recycled materials.

It was agreed with ROCKWOOL that a stagewise conversion of the factory was desirable. Therefore, this feasibility study, **Phase 1** has focused on the changeover of line 3 from natural gas to hydrogen. **Phase 2** which involves expanding the hydrogen production facility to provide hydrogen for the whole factory and the changeover of lines 1 & 2 to hydrogen will occur at a later date.

2.2. Project Objectives

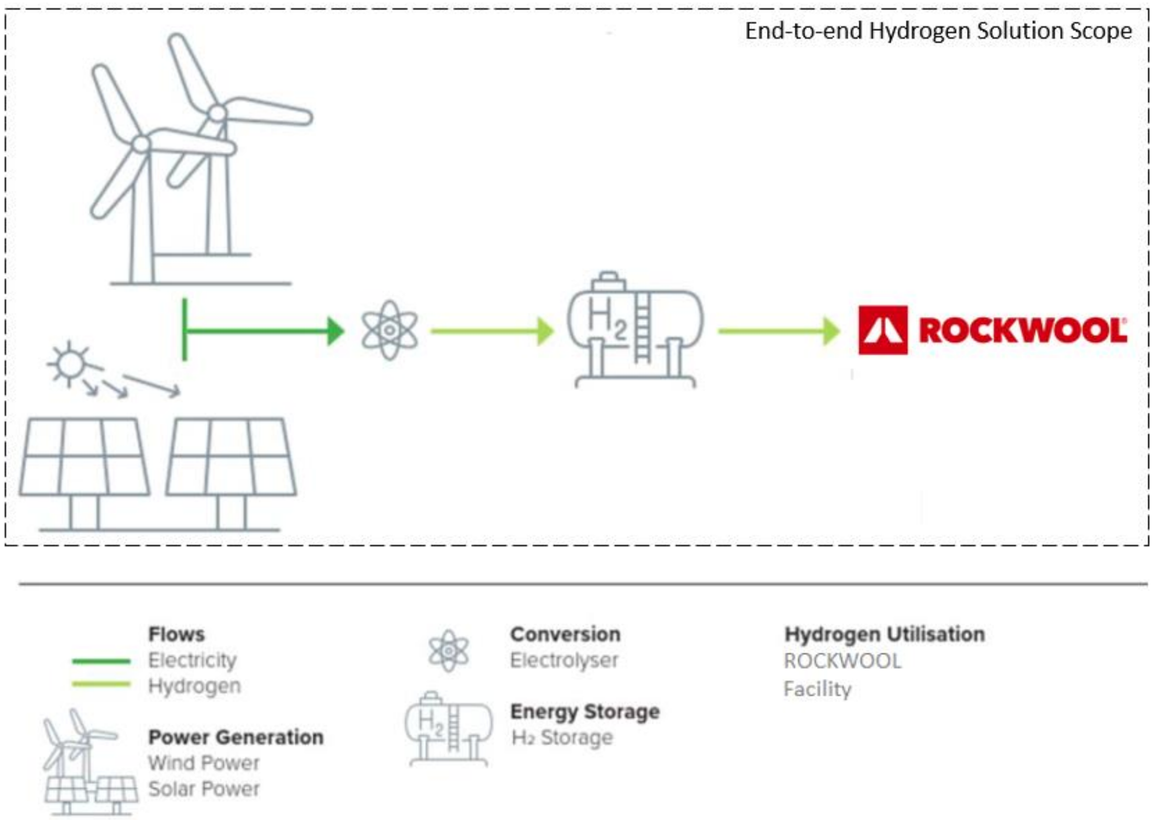
The key project objective was to assess and develop a feasible an end-to-end industrial fuel switching solution for the ROCKWOOL site in Wales. The feasibility study evaluated technical, economic, and regulatory requirements. There was specific focus on; hydrogen burners, facility re-configuration, hydrogen production, renewable power generation, electrical connection, and planning/environmental aspects which will:

(1) Allow evaluation of options for each of these areas,
(2) select suitable technologies to develop a feasible full system configuration concept including market engagement,
(3) develop a feasibility proposal and design ready for demonstration phase including major equipment functional specifications and planning considerations and,
(4) develop financial and commercial analysis including cost of hydrogen.

2.3. Technologies

Within the focal areas, technology options were identified, assessed, selected, and developed. Some of the key technology selections for this end-to-end industrial fuel switch solution are outlined in sections 3.3.1-3.3.4 and a high-level schematic for green hydrogen production is shown in Figure 2.3.1.

Figure 2.3.1 High Level Schematic for Green Hydrogen Production



Source: Marubeni

2.3.1. Power Supply

The main technologies options considered for renewable power supply were onshore solar and onshore wind and renewables sleeved options (via electrical grid). The offsite wind and solar were either pre-existing renewable projects (see section 3.1.1), planned off-site solar and wind projects (see section 3.1.2) or wind and solar projects to be potentially developed on ROCKWOOL land. Given the weak electrical grid in the area studied (see section 3.1.5 for a detailed discussion), the strongest technologies were onshore solar and wind; a mix of these technologies were selected in the 15MW base case solution as 4.1MWp onsite solar ground-mount array, 10.9MW local offsite solar and 12.8MW local offsite wind, with offsite options supplied via a direct private wire connection.

2.3.2. Water Electrolysis

Renewable power by the electrolysers would be generated by a combination of solar and wind power. Both Alkaline and Proton Exchange Membrane (PEM) were evaluated for this project. PEM electrolysers have a better dynamic response, better turn down and faster start up time from cold than Alkaline electrolysers. Consequentially PEM electrolysers have been selected for this project, although it is felt that potentially either pressurised alkaline or PEM electrolysers could be used. It should be noted that alkaline electrolysers would be expected to be significantly cheaper than PEM electrolysers so would result in a cost saving for the project. Since the overall flowsheet will be very similar for either 30 barg pressurised alkaline or 30 barg PEM electrolysers, it will be feasible to change technology with minimal impact if this was commercially desirable. Final technology selection will be made during the FEED phase of the project in conjunction with the technology suppliers.

2.3.3. Hydrogen Storage

Since the project will only use wind turbines and solar electricity generation, hydrogen production will be variable. There will also be fluctuations in demand and planned/unplanned shutdowns and maintenance of the hydrogen facility. Therefore, hydrogen storage will be required for these periods to balance supply and demand. Storage would typically be in the range of 1 to 5 days, and 3 days hydrogen storage was used at this stage; which was confirmed as suitable based on the hydrogen demands and historical wind and solar generation profiles.. For Line 3 three days storage is equivalent to 6,951 kg of hydrogen (3 x 2317 kg/day average demand for line 3 in 2022), while for the whole site would be 17,346 kg of hydrogen.

The Control of Major Accident Hazards (COMAH) Regulations 2015 implemented the majority of the Seveso III Directive (2012/18/EU) in Great Britain. The purpose of the COMAH Regulations is to prevent major accidents involving dangerous substances and limit the consequences to people and the environment of any accidents which do occur. The competent authority for the COMAH Regulations is the Health and Safety Executive (HSE), together with the Environment Agency in England.

An establishment having any specified dangerous substance present at or above the qualifying quantity is subject to the COMAH Regulations, this includes hydrogen.

Establishments that fall within the scope of the COMAH Regulations are defined by two thresholds, known as lower tier and upper tier. For each tier, thresholds are set by the COMAH regulations, and the duties and responsibilities placed on operators of each type of site are different for each tier. The lower and upper tier thresholds are 5-tonnes and 50 tonnes of hydrogen respectively, so after the installation of the hydrogen production facility the ROCKWOOL site will become a lower tier COMAH site. The responsibilities and duties of a lower tier COMAH site are summarised in section 3.

Based on the storage volumes required, the following storage options best fit the project requirements:

- Conventional ground storage - 30-80 Barg horizontal or vertical carbon steel storage vessels
- Containerised Tubular 500 barg storage

A preliminary Capital Expenditure (CAPEX) analysis indicates that the overall storage cost for the 500 barg containerised storage and compression for Line 3 would be £2.4 million less than the 30 barg storage option. However, it is appreciated that there would be a high operational expenditure (OPEX) due to the additional compression requirements.

The standard containerised hydrogen storage would also be very easy to transport to the Bridgend site by standard HGV. In addition, the space required, and the civil work would be significantly reduced.

Based on this preliminary analysis containerised 500 barg containerised storage has been selected for this project.

2.3.4. Gas Burners

Five natural gas burners were considered within the scope of this study:

- Two burners are installed in a single combustion chamber as afterburners for gases released from the cupola furnace
- Two separate circulation burners provide the heat for the curing process of the material
- One burner is used as an afterburner from the curing oven

The burner assessment concluded that the difference in properties between natural gas and hydrogen will require full replacement of the burners and the associated piping.

Although the dimensions of the burners and gas feeds of the hydrogen burners are similar to the existing natural gas burners, the flame diameters will differ. The expected flame diameters have been modelled to check compatibility with the existing gas combustion chambers and were found to be suitable, reducing the overall work required to ready the process to accept hydrogen as a fuel.

3. Main Outputs and Findings

The main outputs and findings are presented in the following section.

3.1. Renewable Power Supply & Electrical Connections

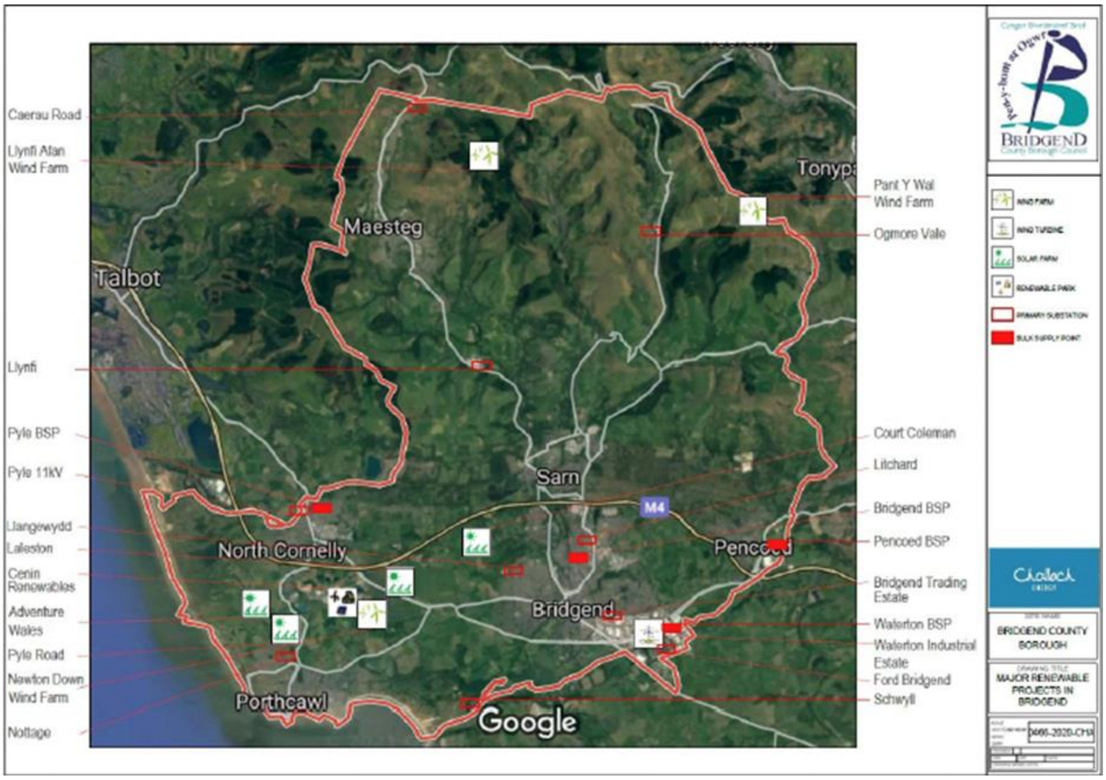
The main outputs and findings are presented in the following subsections. A summary of the findings is:

- the onsite renewable power generation that is considered 'optimal' for first phase (solar PV ground mounted 4.1MWp with an annual output of 4.69GWh)
- the offsite renewable power supplies considered viable are from Cenin 2, which is in planning for 50MWp solar and 30MW of wind west of ROCKWOOL site, and existing RCT Wind Farms and Pant-y-Wal Wind Farms to the east and north of the ROCKWOOL site respectively.
- the NGED grid in the area is rural 11kV network, with no higher voltages nearby. In discussion with NGED the current grid could not support a further 15MW load at the ROCKWOOL location without significant upgrade, limiting sleeved power supply options.

3.1.1. Existing Local Renewable Generators

There are a number of existing renewable generators within a 15km radius of the ROCKWOOL site. Figure 3.1.1 Renewable projects in Bridgend area (ROCKWOOL is marked with a blue dot) shows the renewables in Bridgend County Borough and in Rhondda Cynon Taf County Borough. The closest, and therefore more likely to be feasible options are discussed below.

Figure 3.1.1 Renewable projects in Bridgend area (ROCKWOOL is marked with a blue dot)



Source: Challoch Energy

3.1.1.1. Pant-y-Wal Wind Farm

Of the Bridgend projects, Pant-y-Wal to the north of the ROCKWOOL site is close enough to consider but is still 7.5km distant. The internal wind farm voltage is 33kV and a private wire to ROCKWOOL would be considered at 33kV.

An assessment was made of the route, the landscape factors, numbers of landholdings and any major barriers (rivers, railways, trunk roads). The distance to Pant-y-Wal is 7.5km in a straight-line, once routing has been designed this is likely to increase by 1 to 2km. The route is very hilly and in places forested; any routes across their forestry land is expected to be undergrounded, adding to complexity and cost. There are multiple landowners on all potential routes. However, there are no major barriers to cross such as railway lines.

3.1.1.2. RCT Wind Farms

The RCT wind power projects of Taff Ely and Mynnydd Portref and its extension are at a distance of 3.8km to the east of the ROCKWOOL site. They are all connected to the NGED distribution network at 33kV – it may be feasible to extend one of the 33kV lines westwards to ROCKWOOL. To enable sufficient electricity supply to the ROCKWOOL site at least two of these wind power projects need to be combined on to a single private wire which would require a substation near the wind farms.

3.1.2. Planned Local Renewable Generators

The following is a list of local renewable generators under various stages of development:

- Cenin 2 – Cenin Renewables
    - 50MWp Solar and 30MW Wind
    - Status uncertain – yet to go for planning, target COD 2026/2027
- RCT (Rhondda Cynon Taf) farm
    - 5MWp – early stage
    - Solar farm set up by Rhondda Cynon Taf Council; name and location are kept anonymous at this stage for commercial reasons
- Craig Y Geifr Wind – Belltown Power
    - 4km North-East of Ogmore Vale
    - 8 turbines @ 3MW = 24MW
    - Status uncertain – yet to go for planning, start of construction expected 2026
- Upper Ogmore Wind Farm - Renewable Energy Systems ltd
    - 25MW wind and battery project at Nant-y-Moel
    - Planning and grid approval obtained. COD 2025.

The most viable option in these planned developments is likely to be Cenin 2, as the other development projects suffer from issues such as distance from site and voltage levels.

3.1.2.1. Cenin 2 Wind & Solar Farm

Ongoing discussions with renewable developers are positive to date. Cenin 2 is geographically close to ROCKWOOL and is a combined wind and solar park. This improves the load factor of the hydrogen facility. Wind in this area has a load factor of around 35% and solar has a load factor of around 12%. The Cenin 2 site with 50MWp of solar and 30MW of wind when combined would yield a load factor for the electrolyser of around 40%. Cenin

2 could supply electricity for the first phase of a 15MW electrolyser or a full build out of lines 1, 2 and 3 of 35MW electrolysis.

3.1.3. On-Site Renewable Projects

The ROCKWOOL site has been assessed for both onsite wind and solar PV opportunities. Wind power has been discounted due to the proximity of local homes and manufacturing logistics on site, and complexity associated with securing planning permissions for onshore wind in the Bridgend area.

Solar has been assessed for both rooftop PV and ground-mount PV. Ground-mount solar is viable for supplying the hydrogen production facility with part of its electricity as an efficient, low-cost component. The sizing of the solar is expected to be approximately 4.1MWp with an expected annual generation of 4,690 MWh. The location is shown with the blue box in Figure 3.1.2 below and is part of ROCKWOOL’s land.

Figure 3.1.2 Indicative area for Onsite Ground-Mount Solar at ROCKWOOL site

Source: Challoch Energy

Rooftop PV is viable, with a capacity of around 1MWp. However, this is spread across a number of roofs and electrical interfaces are likely to complex. Thus rooftop PV has been ruled out of scope to supply the hydrogen facility (although the PV would be helpful for ROCKWOOL's own use and may be developed separately, it is not practical to make this power available to the hydrogen project).

3.1.4. Site Electrical Infrastructure

The ROCKWOOL site has three 11kV incomers from the distribution network of National Grid Electricity Distribution (NGED). The incomers arrive on site in a substation that is a joint asset of ROCKWOOL and NGED. The three incomers feed a High Voltage (HV) switchboard with four 11kV circuits feeding the site local substations. These four circuits are interlinked to ensure security of supply on site.

An assessment of the substation has identified that there is space to add further switches at each end of the HV switchboard to allow for expansion. This allows the integration of the hydrogen production facility to the site systems for back-up supplies for essential services.

The site incoming capacity is around 14MVA, additional checks with NGED to ascertain whether this capacity can be augmented have proved that very little extra capacity is available (in the order of 1-2MVA). The site’s current maximum demand (basis for billing) is 10.7MVA. Thus, the headroom at times of maximum demand is only 3MVA. However, site load is not flat and there are times when an additional 2-3MVA could be available. The times of this additional headroom are process related and thus cannot be relied up on.

Nevertheless, the existing site electrical infrastructure is insufficient to supply an electrolyser of any suitable scale as a normal power supply and could only be considered as a partial backup.

3.1.5. NGED Network Infrastructure

The area of the site is on a weak rural network supplied at 11kV. There are no higher voltage layers available in the local vicinity, with the ROCKWOOL site in a ‘gap’ of the HV networks in the area (see Figure 3.1.3).

The Pencoed Bulk Supply Point (BSP) is a 132kV to 11kV substation and there is very little spare capacity at this site and no short to medium term plans to upgrade the BSP. There is a 33kV network to the east of the Rockwool site at a distance of 3.8km. There is also a 66kV network in the hills to the north of site connect the windfarms of Ogmore Vale and Llynfi Afan to Margam BSP and Pyle BSP respectively. However, these networks are at least 7.5km from site. Both of these networks are located relatively far from the ROCKWOOL site.

Figure 3.1.3 High Voltage Network around Rockwool (green is 33kV; orange is 66kV; purple is 123kV)

Source: National Grid Electricity Distribution

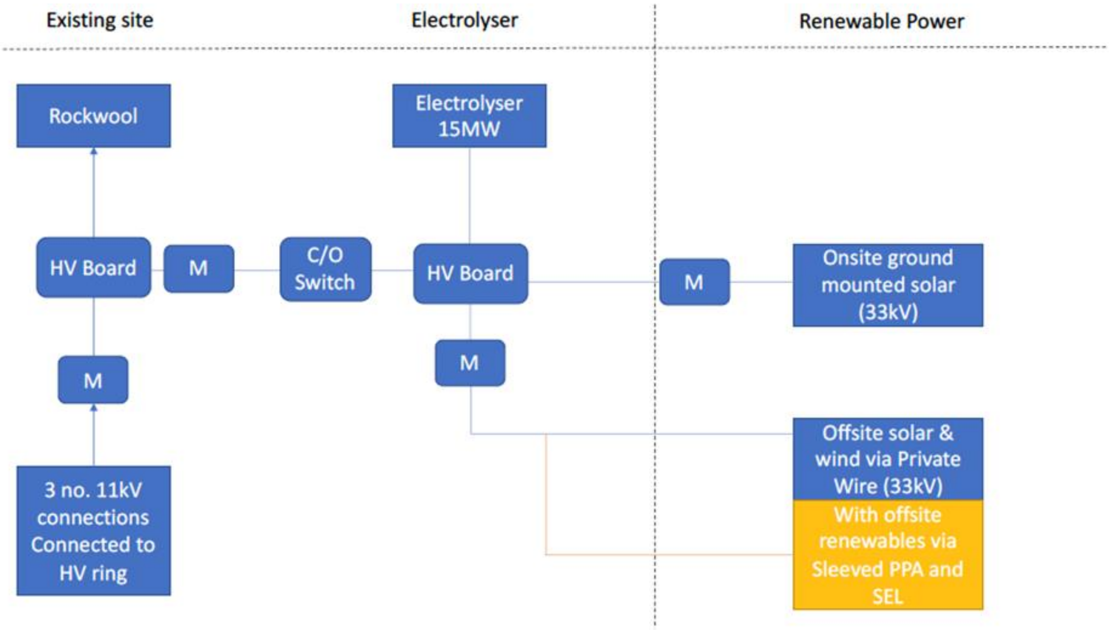
The key findings of the evaluation of the NGED grid in the area around ROCKWOOL, is that it is unlikely to be able to supply the electricity for the electrolyser facility, beyond a small back up supply for essential supplies. A new HV grid connection is therefore expected to have a high cost if built out in the current market.

3.1.6. Electrical System Preliminary Design

The overall concept of electrical supply is presented in Figure 3.1.4. The electrolyser site will be supplied by an HV Board with three incoming supplies:

1. On-site ground mounted solar plant at 33kV
2. Off-site solar and wind power at 33kV
3. Backup supply from Rockwool substation at 11kV connected via a changeover switch

Figure 3.1.4 Conceptual Functional Electrical Design



Source: Challoch Energy

3.1.7. Onsite Ground-mount Solar PV

The PV system initial design has been completed for the blue area shown on Figure 3.1.2 . This area has been evaluated using both PVGIS and Helioscope solar design databases. The results are very similar and the Helioscope is presented here. Figure 3.1.5 presents the high-level layout with the panel arrangement and the location of the substation.

Figure 3.1.5 Initial Solar PV Design, panel rows in blue, electrical substation in white

Source: Marubeni

The details of the design are:

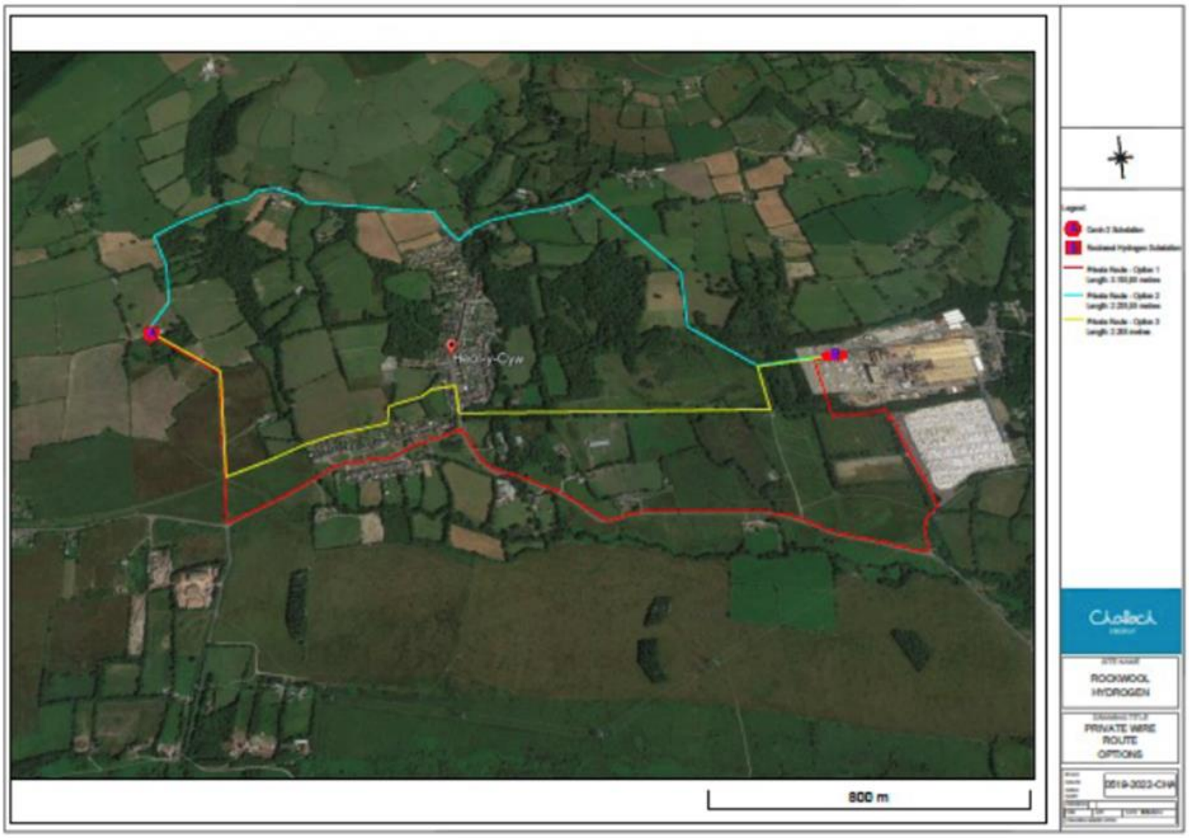
- Capacity of solar panels (DC nameplate capacity) is 4.10MWp
- Inverter AC nameplate capacity is 3.80MW
- Annual production is 4,690MWh
- Performance ratio is 85.1%
- Output is 1,145.3 kWh/kWp
- Peak output is 3.25MW
- The substation will comprise an LV switchboard for the PV, a step-up transformer 415V/33kV and an HV switchboard
- The transformer will have a capacity of 5MVA and all 33kV cabling shall be rated at a minimum of 5MVA

3.1.8. Private Wire Design

The private wire options were explored to the nearest renewable power generator, shown in Figure 3.1.6. The generator's solar PV plant at 50MWp and 30MW wind farm is expected to be connected at a 33kV substation.

To allow for the private wire to the ROCKWOOL site, the renewable power generator substation needs to include a single circuit breaker for Phase 1 hydrogen of 16MVA and a space for an additional circuit breaker for Phase 2 of 20MVA.

Figure 3.1.6 Options for the Private Route



Source: Challoch Energy

Route 1 (in red) is 3,155m in length and is laid in the highway (except the last 500m which is soft dig and across the HPF site in a trench). This route is preferred as it does not require wayleaves or easements.

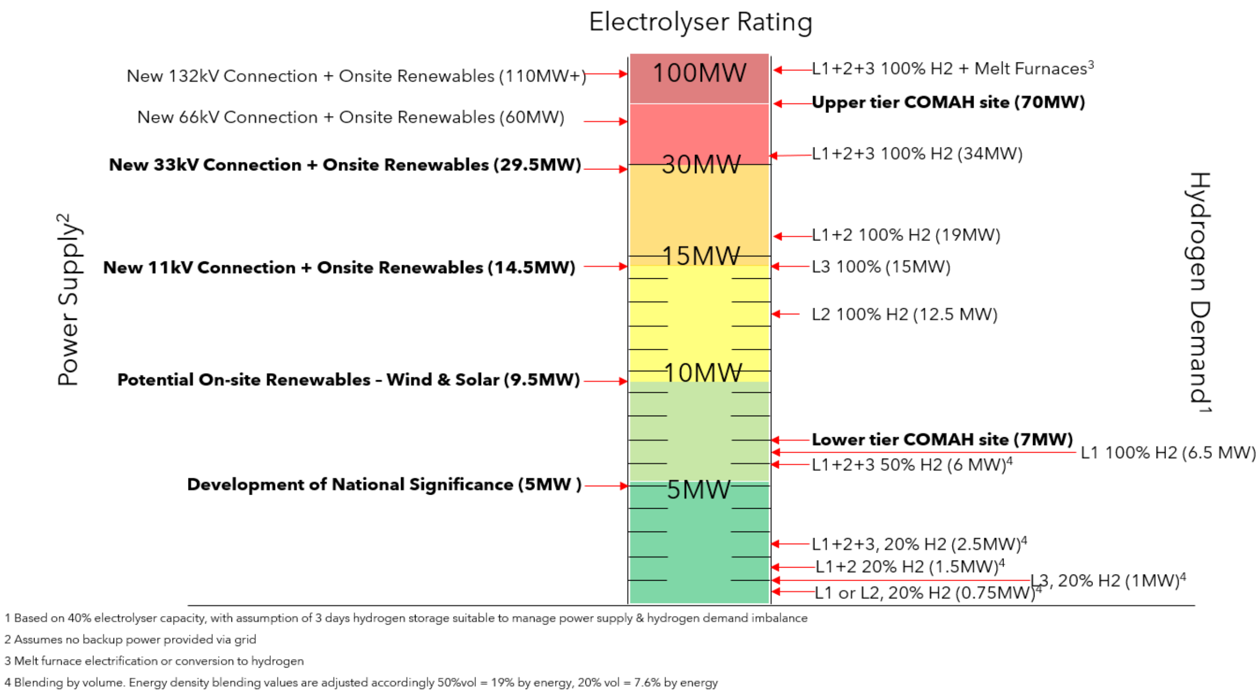
Route 2 (in blue) is 2,225m in length and is a mixture of roads and private landholdings. Ideally this route would be pole-mounted, but there is a significant area of interface with NGED 11kV overhead infrastructure. The route also across private land and thus will require wayleaves. Therefore, this route is not preferred.

Route 3 (in yellow) is 2,305m in length and in part follows the line of a disused railway. There are a number of private landholdings & it would need to cross Heol-y-Cyw village. Ideally a reasonable part of the route could be pole-mounted. The route also across private land and thus will require wayleaves. Therefore, this route is not preferred.

3.1.9. Power Supply and Hydrogen Demand Interface

Based on the power supply points available along with the hydrogen demands of the site, the scales of hydrogen electrolyser facility were considered from natural gas replacement for a single component (Line 1, 2, or 3) conversion, through to multiple combinations of Production Line conversion and also Melt Furnace coke fuel replacement. The natural gas replacement included consideration of 20%, 50%, and 100% H2 fuelling (balance with natural gas). Figure 3.1.7 shows the scales that were considered, along with the key points at which the project scale is should be considered substantially differently.

Figure 3.1.7 Project Scale Infographic Showing Key Considerations



Source: Marubeni

The main findings of this analysis were that a small-scale electrolyser would be highly feasible on the ROCKWOOL site, including 100% fuelling of the smaller production lines (L1 and L2), as well as partial fuelling (up to 50%) of the full site. However, the project would have limited decarbonisation potential, and partial hydrogen fuelling via blends would potentially be more difficult to phase up capacity for later (as burner heads would need to be modified for a different fuel blend).

The next level at which there is a significant difference is the 15MW level, which corresponds closely to the L3 capacity at 100% Hydrogen fuelling, and this is limited by the power that could be transported via an 11kV electrical connection. The facility would need to consider the manageable permitting requirements according to classification as a lower tier COMAH (Control of Major Accident Hazards) site as well as consideration of electrical supplies as a Development of National Significance (DNS) for planning which both add complexity to the development and delivery of the solution.

Higher than this, is the 30MW scale, which corresponds closely to a full facility conversion to 100% hydrogen fuelling, and this is limited by the power that could be transported via a 33kV electrical connection. Given the weak electrical grid in the local area that does not include 33kV as a supply voltage, the requirement of a 33kV connection is a significant obstacle to delivery of a solution at this scale.

The highest range for full fossil fuel switching of the industrial stone wool facility includes the Line 1, 2, and 3 natural gas replacement along with coke replacement with 100% hydrogen e.g. by using gas-based melt technology. At this scale, the electrical connection could require 66kV or even 132kV connection dependent on the amount of switchover of melt furnace fuelling which would be cost prohibitive. The regulatory environment would also require the site to be classified as an upper tier COMAH site which could have a substantial impact on existing site operations.

3.2. Hydrogen Production Facility

The ROCKWOOL factory in Bridgend Wales opened in 1979. The site currently consists of three production lines. Line 3, a state-of-the-art production line, was added in 2008 - this line doubled the potential production capacity to over 200,000 tonnes a year.

It was agreed with ROCKWOOL that a stagewise conversion of the factory was desirable. Therefore, this feasibility study, **Phase 1** has focused on the changeover of line 3 from natural gas to hydrogen. **Phase 2** which involves expanding the hydrogen production facility to provide hydrogen for the whole factory and the changeover of lines 1 & 2 to hydrogen will occur later.

A 14.03 MW Start of life (SOL) / 15.38 MW End of life (EOL) green hydrogen facility would be capable of supplying the hydrogen requirements for Line 3.

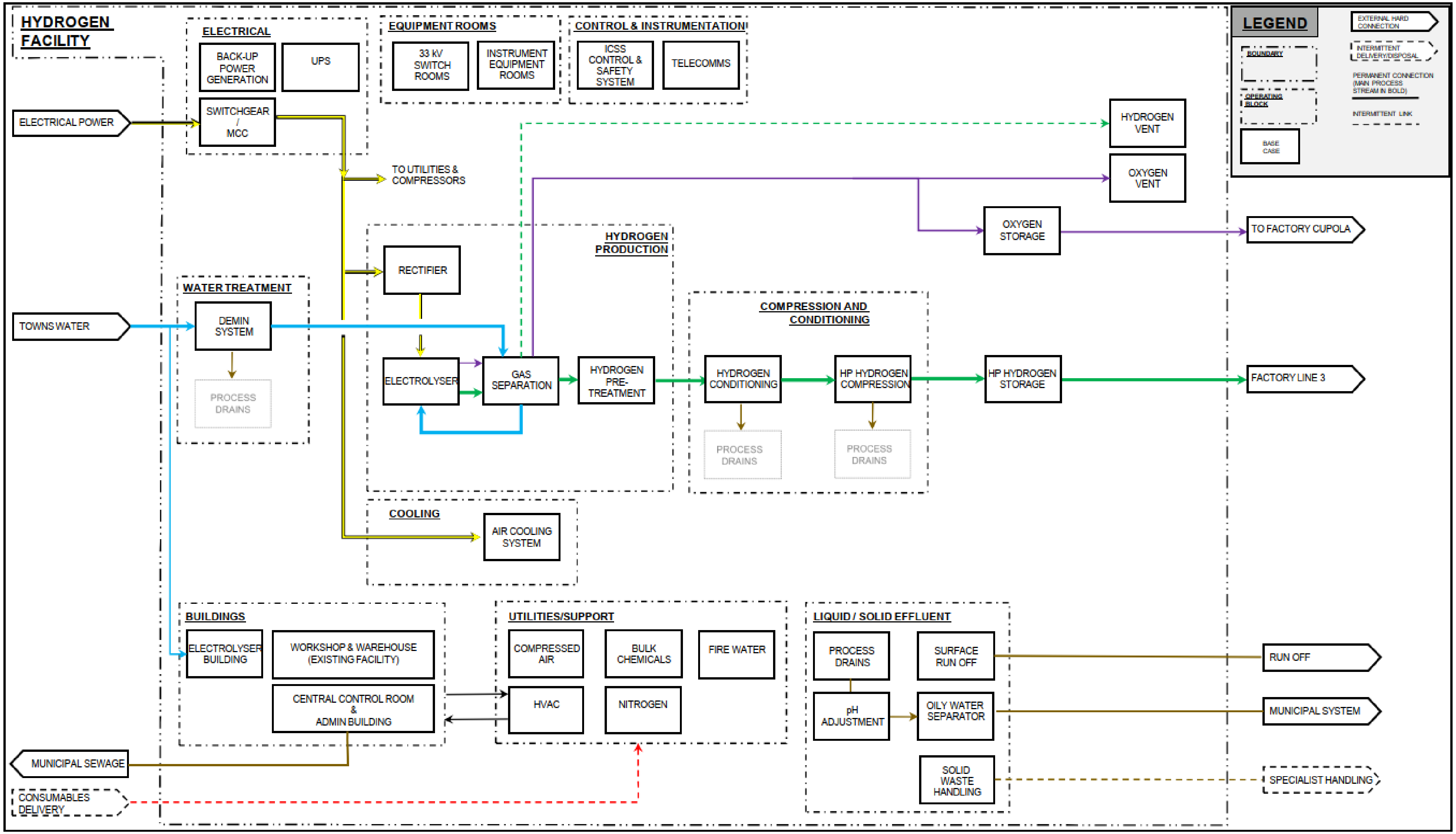
The hydrogen production facility will consist of the following key components:

- Power systems (Transformer and Rectifier)
- Electrolyser stacks
- Gas conditioning (phase separation, drying, deoxidiser)
- Water circulation

To support the operation of the electrolyser and to supply hydrogen to the consumers, the hydrogen production facility (Figure 3.2.1) will also require:

- Feed water treatment and storage
- Cooling systems for the electrolysers, compressors and power systems
- Hydrogen compression
- Hydrogen buffer storage
- Hydrogen pipeline
- Oxygen buffer storage
- Oxygen pipeline
- O_2 and H_2 vents
- Fire and gas detectors at appropriate locations
- Electrolyser house
- Control room
- Utilities including plant/instrument air, nitrogen
- Wastewater treatment
- Fire water network & firefighting facilities
- Maintenance workshop and parts warehouse (existing factory facilities will be utilised/expanded as required)
- Underground drains: This includes stormwater and wastewater drains

Figure 3.2.1 Overall Block Flow Diagram



Source: Mott MacDonald

3.2.1. Transformer/Rectifier Sets

Electrolyser stacks operate at low voltage and use direct current (DC) therefore transformer-rectifiers will be required to provide the correct voltage and current. For a facility of this size a 33kV supply will be required to the electrolyser buildings. The 33kV voltage busbars connect to the transformer-rectifier units to supply them with power. The transformer-rectifier units are composed of a transformer for stepping down the voltage to low voltage alternating current (LV AC) and the rectifier for converting the AC current to DC current. The rectifier will be located adjacent to the electrolyser because it is not feasible to transmit the low voltage high current output of the transformers and rectifiers over long distances. The rectifier will be located inside a rectifier room which will be pressurized to avoid the ingress of any H2 gas.

3.2.2. Process Water Supply

The existing factory water supply will be used to supply feed water to the hydrogen production facility. The ROCKWOOL water supply comes from a soft water area. Based on a peak hydrogen production capacity of 241 kg/h and a consumption of 9 litres/kg H_2, the peak water requirement will be 2.24 m^3/hr allowing for the assumed Ion exchange demineralisation package losses of 4%.

Rainwater from the factory area is collected in concrete water pits for use at the site, as well as in 3 swales located to the east of the main storage and logistics area. These swales have a total storage capacity of 12,500 m^3. This water was considered for use as electrolyser feedwater with appropriate water treatment. However, the water treatment supplier has indicated that it would probably not be cost effective at this scale.

3.2.3. Feed Water Treatment

PEM (and Alkaline) electrolysers require a high purity water feed (Table 3.2.1), since many of the electrolyser components can be adversely affected by water impurities such as iron (Fe), chromium (Cr), copper (Cu), silicon (Si), aluminium (Al) and boron (B). Scale deposits will significantly reduce the life of the electrolyser stacks.

Table 3.2.1 Recommended Water Purity

Type	Water Purity
Alkaline	Conductivity < 5 µS/cm
PEM	ASTM Type II Deionized Water required, < 1 micro Siemen/cm (> 1 Meg Ohm-cm)
	ASTM Type I Deionized Water recommended, < 0.1 micro Siemen/cm (> 10 Meg Ohm-cm)

Source: Nel

A water purity, measured in terms of water conductivity of <0.1 µS/cm has been specified for this project, however this must be confirmed with the selected electrolyser supplier.

There are two main configurations available for the feed water treatment system:

- Feed filtration, Reverse Osmosis (RO) unit, Polishing unit
- Feed filtration, Ion exchange package, Polishing unit

The selection is dependent on the capacity required, water hardness, chemicals usage and environmental requirement (wastewater treatment) and energy consumption:

- Both RO and Ion exchange are well established reliable technologies with a good track of performance worldwide
- Both processes require pre-treatment to remove suspended solids to a low level to avoid fouling. However, Ion exchange is more tolerant of suspended solids and RO requires additional pre-treatment by microfiltration. Membranes are also subject to scaling by hardness present in the feed water and require either a softening plant as part of the feed water pre-treatment or the addition of anti-scaling chemicals
- Ion exchange plants tend to be more flexible than RO, for example in terms of performance over a wider range of temperature variations and the ability to recover from high suspended solids in the feed
- Both RO membranes and Ion exchange resins can be fouled by organics present in the feed water. Ion exchange resins are much more easily cleaned than RO membranes without long plant shut down and use cheap cleaning chemicals, salt and sodium hydroxide.
- The capital cost of an RO plant is generally higher than that of an Ion exchange plant at this scale
- Operating costs represent 70 to 80% of the total cost of both cases. Chemical costs for Ion exchange and power costs for RO are the most significant contributors to operating costs.
- On average, Ion exchange produces as little as 2-4% wastewater, while RO rejects as much as 10-50% of the volume of treated water.

3.2.4. Electrolysers

For **Phase 1** a 14.03 MW SOL / 15.38 MW EOL green hydrogen facility with an average hydrogen production rate of 2,317 kg/day) will be required to supply production line 3.

The main operating parameters (Table 3.2.2) and key factors affecting the selection of Alkaline, or PEM electrolysers for this project have been listed below):

- **Commercialisation**: PEM and Alkaline electrolysers are both commercialised electrolyser technologies. Between 1927 and 1977 Alkaline electrolysers were used for large scale production of hydrogen (up to 115MW in size). The first commercial scale PEM electrolyser was installed in 1987 at Stellram SA, a metallurgical specialty company, in Nyon, Switzerland.

- **Stack Cost**: Currently PEM Electrolysers are significantly more expensive than Alkaline electrolysers since they employ noble metals such as Pt, Ir and Ru. Cost information provided by IRENA[2][4] indicates that PEM Electrolysers are currently 50% more expensive than an equivalent alkaline electrolyser (270 $/KW compared to 400 $/KW). However, the cost of both types of electrolyser are expected to drop as the market develops. System costs (includes power supply and installation costs) are expected to be in the range (750 $/KW compared to 1200 $/KW).

- **Hydrogen Purity**: Alkaline electrolysers typically have a slightly lower hydrogen purity than PEM. (Alkaline 99.5% – 99.9998%, PEM 99.9% – 99.9999%). In Alkaline electrolysers contamination with oxygen is a function of diffusion across the membrane particularly at high turndown. Due to the solid structure of the polymer electrolyte membrane, the PEM electrolyser exhibits a low gas crossover rate resulting in a very high hydrogen gas purity. If ultra-pure hydrogen is required, any trace amounts of oxygen would be removed by catalytic reaction in a deoxidiser.
- **Operating Pressure**: Due to their design PEM electrolyser can deliver hydrogen at up to 30 bar, and if required can operate with a differential pressure across the stack. Alkaline Electrolysers come in two forms, those which operated at near atmospheric pressure (hence required gas compression) and pressurised Alkaline electrolysers that can deliver hydrogen at up to 30 bar. Both types of Alkaline electrolysers must operate in balanced pressure mode to avoid crossover of the gases.
- **Efficiency**: Electrolyser efficiency varies from supplier to supplier, however Alkaline electrolysers have a slightly higher efficiency than PEM electrolysers. Electrolyser stack performance is also commonly presented in term of energy consumption in kWh/kg of hydrogen or kWh/Nm^3 of hydrogen. Typical alkaline electrolyser stack energy consumption is in the range 4.4-4.8 kWh/Nm^3 while PEM is in the range 4.7-5.0 kWh/Nm^3. The Gigawatt green hydrogen plant State-of-the-art design [(1)] used the following efficiencies: for Alkaline technology 4.4 kWh/Nm^3 hydrogen as nominal electricity consumption and 4.9 kWh/Nm^3 for PEM technology.
- **Dynamic operation**: PEM electrolysers typically have a better dynamic response than Alkaline electrolysers and faster start up time from cold[(5)]. Refer to table 3.2.1. However, the flexibility of both alkaline and PEM stacks is adequate to follow fluctuations in wind and solar[(2)]. In addition, stack management and control strategies can be employed to ensure that the system is operating efficiently and can manage changes in electrical generation.
- **Operating range:** PEM electrolysers also have a wider operating range than Alkaline electrolysers 9-100% compared to 30-100%[(5)]. Particularly during high turndown diffusion of the gases across the porous separator in an alkaline electrolyser can result in hazardous mixing of oxygen and hydrogen so must be avoid.
- **Stack Lifetime**: Currently PEM Electrolyser have a shorter operational lifetime (40,000 - 60,000 hr) than for alkaline electrolysers (60,000 - 90,000 hr). Stack replacement costs are typically between 40% and 50% of the original electrolyser costs.

Table 3.2.2 Summary Table for Alkaline and PEM Electrolysers.

	Alkaline Electrolysis	PEM Electrolysis
Cell temperature	60-80 C	50-80 C
Stack pressure	Up to 30 bar	Up to 80 bar
Hydrogen Purity	99.5% – 99.9998%	99.9% – 99.9999%
Energy consumption stack	4.4-4.8 kWh/Nm3	4.7-5.0 kWh/Nm3
Energy consumption system	5 to 5.4 kWh/Nm3	5.3 to 5.6 kWh/Nm3
Operating Range (%)	30-100%	9-100%
System Response (ramp up)	7% (full load)/second	40% (full load)/second
(Ramp down)	10% (full load)/second	40% (full load)/second
Cold Start Time	20 minutes +	5 minutes
Lifetime stack	60,000-90,000 h	40,000-60,000 h
Maturity	Mature	Commercial (small and medium size)

Source: Various Publications.

The green electricity for the electrolysers will be generated by a combination of solar and wind generation. The electrolyser system must have a dynamic response which can match the electrical generation. PEM electrolysers have a faster dynamic response, lower turn down and faster start up time from cold than Alkaline electrolysers.

Oxygen must be supplied to the copula at a pressure of 4-6 barg (at the distribution panel just before the cupola). Atmospheric alkaline electrolysers would require pure oxygen compression, which is both expensive and difficult to perform, therefore, atmospheric alkaline electrolysers are not considered appropriate for this project. Both pressurised alkaline or PEM electrolysers would however be able to provide oxygen at this pressure without compression.

Currently PEM Electrolysers are significantly more expensive and have a shorter operational lifetime than Alkaline electrolysers. Alkaline electrolysers typically have a slightly higher efficiency than PEM electrolysers. Currently alkaline electrolysers have a stack life of between 60,000 - 90,000 hrs. While for PEM electrolysers have a stack life of between 40,000-60,000 hrs. The typical electrolyser project life would be between 20-25 years, consequentially the electrolyser stacks would need to be replaced at least once during this period. The cost of stack replacement will typically be in the range of 40% and 50% of the initial electrolyser CAPEX. The higher costs and lower efficiency of PEM will impact the economics of the project.

PEM electrolysers have been selected for this project based on their operational benefits. However, it is anticipated that the overall flowsheet for this project would be very similar for either pressurised alkaline or PEM electrolysers, so it would be feasible to change technology with minimal impact at a later date if this was commercially desirable. The final selection will be made during the FEED phase.

In total fourteen (14) 1 MW stacks will be required, this should provide adequate operational flexibility. In addition, stack management and control strategies can be employed to ensure that the system is operating efficiently and can manage changes in electrical generation.

The electrolyser performance will degrade over time (approximately 1% per year) and the electricity consumption increases hence there is a start of life (SOL) performance and an end of life (EOL) performance. A SOL stack efficiency of 72% and the overall system efficiency taking into account all parasitic loads will be 68%. While the EOL stack efficiency of 66% and the overall system efficiency taking into account all parasitic loads will be 62%

Heat is generated in the electrolyser stacks, so air cooling has been provided to keep the stack within their normal operating limits. The energy lost as heat is in the region of 25% of the energy to the electrolyser. Electrolyser waste heat integration with the site would normally be considered, however there is already an excess of low grade heat available at the site, so electrolyser waste heat integration was excluded from the study scope.

After leaving the electrolyser separator any trace amounts of oxygen in the hydrogen are removed by catalytic reaction in a deoxidiser. This is followed by water removal in a dryer package to achieve the required fuel gas specifications. A Temperature Swing Adsorption (TSA) system based on silica gel absorbent should be adequate for this hydrogen production facility since Silica Gel which can achieve a residual water content in the range of 5 to 10 ppm.

The oxygen produced as a by-product of the electrolyser process, will be supplied to the copula. The oxygen is saturated with water so must also be dried. Excess oxygen produced from the electrolyser will be released to atmosphere through the single oxygen vent located on the electrolyser building.

A single hydrogen vent will be provided. Hydrogen venting occurs only during emergency scenarios or for example during nitrogen purging operations as part of start-up, shutdown or maintenance. During normal operation no hydrogen will be vented.

3.2.5. Compression

After the gas conditioning HP compression is provided to increase the pressure to the storage pressure of 500 barg. To compress the hydrogen from 30 barg to 500 barg the energy consumption will be approximately 2.70 kWh/kg H_2. Reciprocating compressors are commonly used for hydrogen applications. To avoid contamination of the hydrogen gas a non-lubricated (dry piston) compressor would be used.

3.2.6. Hydrogen Storage

Since the project will only use wind turbines and solar electricity generation, hydrogen production will be variable, so hydrogen storage will be required for periods when hydrogen production is lower than demand.

Storage would typically be in the range of 1 to 5 days, and 3 days hydrogen storage was used at this stage; which was confirmed as suitable based on the hydrogen demands and historical wind and solar generation profiles. For Line 3 three days storage is equivalent to

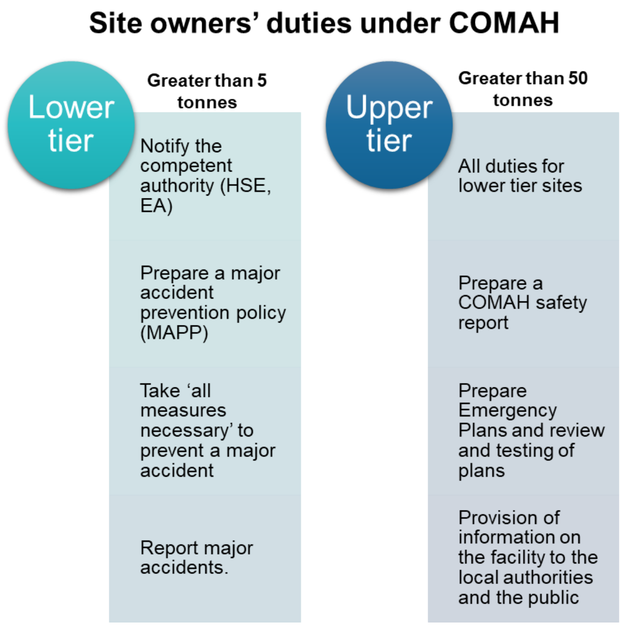
6,951 kg of hydrogen (3 x 2317 kg/day average demand for line 3 in 2022), while for the whole site would be 17,346 kg of hydrogen.

The Control of Major Accident Hazards (COMAH) Regulations 2015 implemented the majority of the Seveso III Directive (2012/18/EU) in Great Britain. The purpose of the COMAH Regulations is to prevent major accidents involving dangerous substances and limit the consequences to people and the environment of any accidents which do occur. The competent authority for the COMAH Regulations is the Health and Safety Executive (HSE), together with the Environment Agency in England.

An establishment having any specified dangerous substance present at or above the qualifying quantity is subject to the COMAH Regulations, this includes hydrogen.

Establishments that fall within the scope of the COMAH Regulations are defined by two thresholds, known as lower tier and upper tier. For each tier, thresholds are set by the COMAH regulations, and the duties and responsibilities placed on operators of each type of site are different for each tier. The lower and upper tier thresholds are 5-tonnes and 50 tonnes of hydrogen respectively, so after the installation of the hydrogen production facility the ROCKWOOL site will become a lower tier COMAH site. The responsibilities and duties of a lower tier COMAH site are summarised in Figure 3.2.2.

Figure 3.2.2 Site Owners Duties Under COMAH



Source: Mott MacDonald

The MAPP is a statement of general intent that should set out the project policy on the prevention of major accidents. The MAPP should give sufficient detail to show that systems are in place to cover the following aspects:

- organisation and personnel;
- identification and evaluation of major hazards;
- operational control;
- planning for emergencies;

- monitoring, audit and review.

The MAPP must:

- deal specifically with major accident hazards; and
- include measures to protect the environment.

The following storage options best fit the project requirements based on storage capacity, cost, and availability:

- Conventional ground storage - 30-80 Barg horizontal or vertical carbon steel storage vessels
- Containerised Tubular 500 barg storage

A preliminary Capital Expenditure (CAPEX) analysis indicates that the overall storage cost for the 500 barg containerised storage and compression for Line 3 would be £2.4 million less than the 30 barg storage option. However, it is appreciated that there would be a high operational expenditure (OPEX) due to the additional compression requirements.

The standard containerised hydrogen storage would also be very easy to transport to the Bridgend site by standard HGV. In addition, the space required, and the civil work would be significantly reduced.

Based on this preliminary analysis containerised 500 barg containerised storage have been selected for this project.

3.2.7. Oxygen Storage

Oxygen produced by the electrolyser will be used to improve the copula combustion efficiency and reduce coke consumption. The Cupola will consume 6692 kg of oxygen per day (200 Nm^3/hr).

Since the project will employ wind turbines and solar electricity generation, hydrogen and oxygen production will be variable, so oxygen storage will be required for periods when oxygen production is lower than demand. Oxygen storage will consist of two 30 barg horizontal carbon steel storage vessels.

3.2.8. Fire and gas detection

The hydrogen production facility will be provided with fire and gas detection systems suitable for hydrogen. Gas detection will be provided in buildings and other enclosed spaces. Smoke, UV/IR Fire detection and ultrasonic leak detection will be provided near the following:

- Electrolysers
- Compressors
- Storage
- Transformer/rectifiers
  Pressure reduction skid

3.2.9. Hydrogen Pipeline

A new 200 mm diameter hydrogen pipeline will connect the hydrogen production facility to the new burners in production line 3. The pipeline will include a pressure reduction station to reduce the header pressure from 30 barg to the 3-5 barg required by the burners.

3.2.10. Oxygen Pipeline

Oxygen will be used to enrich the blast air, however it cannot replace it entirely due to the risk of explosion and the impact on the wool chemistry. The maximum proportion of oxygen in the air is 25%.

A new 50 mm diameter oxygen pipeline will connect the hydrogen production facility to the existing cupola air supply. The pipeline will include a pressure reduction station to reduce the header pressure from 30 barg to the 4-6 barg required. The oxygen supply will be mixed with existing air supply to produce enriched air at the distribution panel just before the cupola.

3.2.11. Utilities, chemical storage, and infrastructure

The following utilities, chemicals and infrastructure will be required for the hydrogen production facility:

- **Potable water**: Potable water will be supplied directly from the existing site towns water supply to the staff welfare facilities as required
- **Nitrogen**: A nitrogen system for system purging will be provided, this will consist of either nitrogen cylinders (bottles) with pressure regulation and distribution, or a small Nitrogen Generation Package.
- **Instrument and Plant Air**: A compressed air package will be provided consisting of air compressor, drier package, filters, and receivers.
- **Chemicals**: Bulk chemicals (sulfuric acid and sodium hydroxide) will be required for the regeneration of the ion exchange beds. Chemicals will be delivered in Intermediate Bulk Containers (IBC) which will be stored and used within a bunded area within the facility
- **Backup Power / Uninterruptible Power Supply (UPS)**: UPS for critical systems will consist of a battery pack. Backup power for key systems will be provided from the existing 11kV site supply.
- **Wastewater Treatment and Stormwater**: All process wastes will be routed to an effluent collection sump with monitoring and pH adjustment prior to release to the existing site drainage system, and will be subject to the existing permit requirements. Storm water and surface run-off will be considered separately and is expected to be integrated with the existing site system.
- **Control room**: A main office building containing the control room/security/permitting office/staff facilities will be provided
- **Electrolyser building**: A building will be provided to protect the electrolyser systems from the environment
- **Maintenance and recycling**: The existing site facilities will be used for waste collection and storage, storage of maintenance spares and consumables

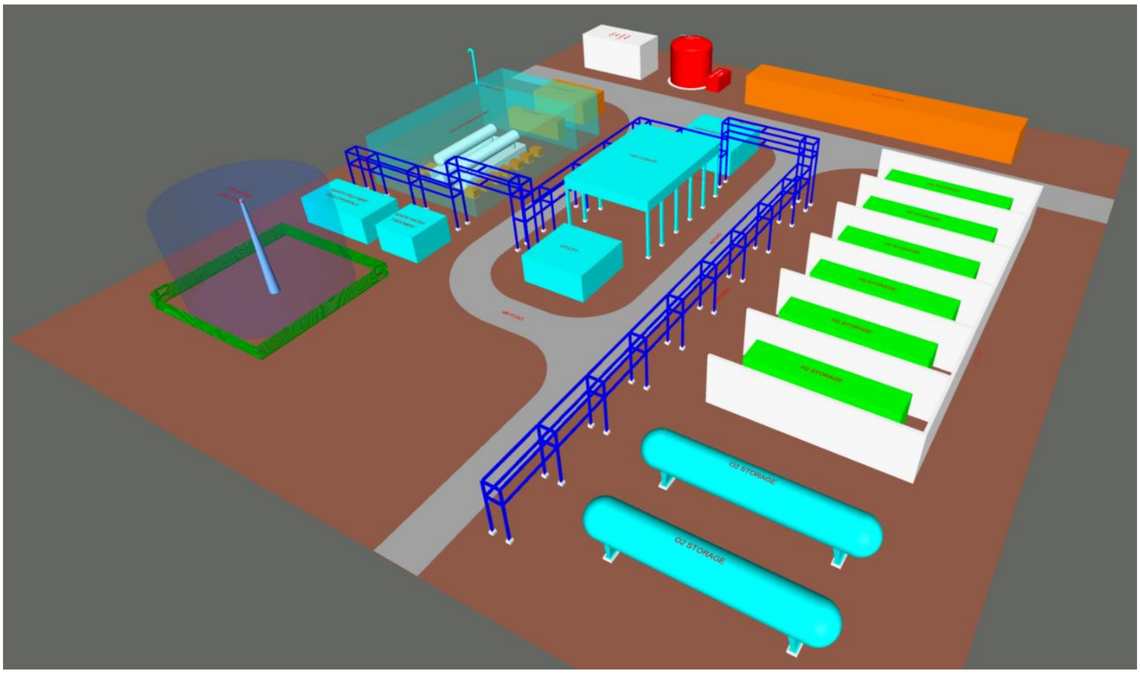
3.2.12. Availability

The availability of the facility will be a function of both scheduled and unscheduled maintenance. Feedback from electrolyser suppliers indicates many require one shutdown per year for periodic maintenance. The annual availability of the hydrogen production facility is expected to be in the range 95% to 98% [(3)(5)].

3.2.13. Plant location and Layout

The new hydrogen production facility will be located on an existing storage and logistics area on the west of the site. This area is covered in concrete hard standing and has an area of 30,000m^2. A conceptual plot plan and a 3D rendering (Figure 3.2.3) has been developed for the new hydrogen production facility. The plot plan study has confirmed that there is adequate space on the West logistics area for the 14.03MW hydrogen production facility and the future expansion to 35.5MW.

Figure 3.2.3 3D rendering of the Hydrogen Production Facility



Source: Mott MacDonald

3.3. Facility Re-Configuration

3.3.1. Interfaces

The following interfaces will exist between the new Hydrogen Production Facility and the existing Rockwool site:

- A new 200 mm diameter hydrogen pipeline will connect the hydrogen production facility to production line 3. The Hydrogen pipeline tie-in will be located on production line 3 at the burners. The existing natural gas pipeline to production line 3 will be isolated and decommissioned.
- A new 50 mm diameter oxygen pipeline will connect the hydrogen production facility to the existing cupola. An Oxygen pipeline tie-in will be located at the existing air pipeline at the Cupola.

- A connection to the existing wastewater system will be provided for the hydrogen production facility effluent discharge
- A connection will be provided from the existing potable water main for the hydrogen production facility potable and process water
- An interconnection will be provided between the new and exist fire water systems to give additional flexibility
- A 11kV supply from the existing substation connected through a changeover switch will be provided to supply emergency power.
- Control and Safety System interconnections will be provided between the hydrogen production facility and the existing production line 3 control centre

The routing options shall consider interfaces with existing utilities including requirements for crossings and rerouting and impacts on ongoing operations.

3.3.2. General Modification to Production Line 3

The Production Line 3 building will be provided with Smoke, UV/IR Fire detection and ultrasonic leak detection is expected at key locations along the production line near burners and the hydrogen pipeline.

It is anticipated that a new burner management system for the safe start-up and shutdown of line 3 burners will be required as part of the changeover to hydrogen. These systems will be specified in conjunction with the burner supplier.

The existing production line 3 building ventilation systems must also be assessed to ensure that it is in line with the recommendations set for hydrogen.

The Line 3 modifications will be developed during the FEED phase of the project.

3.3.2.1. Burner Assessment

Once the project scope was narrowed to the largest production line in the Bridgend factory, known as WER3 or Line 3, a burner assessment report was commissioned to investigate the 5 natural gas burners that collectively represent the main natural gas consumers in the production process. Below is a brief overview of the process steps under consideration including the function of the burners.

Raw materials are charged into the cupola furnace and melted using coke combustion. The melt flows onto spinners which forms the fibres and adds binder for structural stability and oil for water repellence. The flue gas from the cupola contains components that require transformation in a combustion chamber to ensure compliance with ROCKWOOL’s environmental permit. This combustion chamber is heated with natural gas prior to and during operation to support the combustion process. There are two burners at this process stage, a larger one (start-up burner) and a smaller one (pilot burner).

The fibres formed by the spinners are collected in the spinning chamber and layered onto conveyor belts. Density and thickness are controlled by the conveyor speed. The product is then passed through a curing oven to set the binder. Two circulation burners fuelled by natural gas provide heat to the oven. Another natural gas fired afterburner transforms the off gases from the curing process and waste heat from this process goes to supporting the circulation burners.

The minimum, maximum and average flow rates of natural gas in each of the burners is summarised in Table 3.3.1 to show the potential level of variability. The ‘Total gas flow’ column is the total over a typical 2-week cupola campaign and the ‘Theory’ column shows the potential extremes of operation.

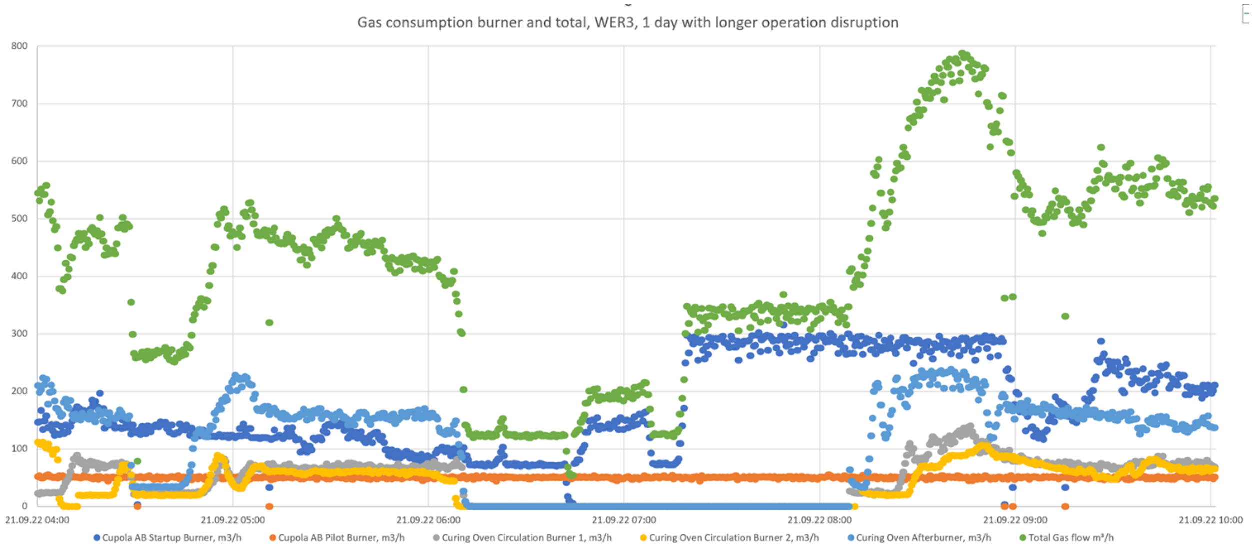
Table 3.3.1 Summary of Burner Capacities

	Cupola AB Startup Burner, m3/h	Cupola AB Pilot Burner, m3/h	Curing Oven Circulation Burner 1, m3/h	Curing Oven Circulation Burner 2, m3/h	Curing Oven Afterburner, m3/h	Total Gas flow m^3/h	Total Gas flow m^3/h, Theory
Minimum	0	0	0	0	0	53	0
High fire	316	58	177	129	243	788	922
Average	73	45	66	43	127	355	355
Low fire	70	25	18	18	34	165	165
Turn down	4,5	2,3	9,8	7,2	7,1	4,8	5,6

Source: Würz GMBH

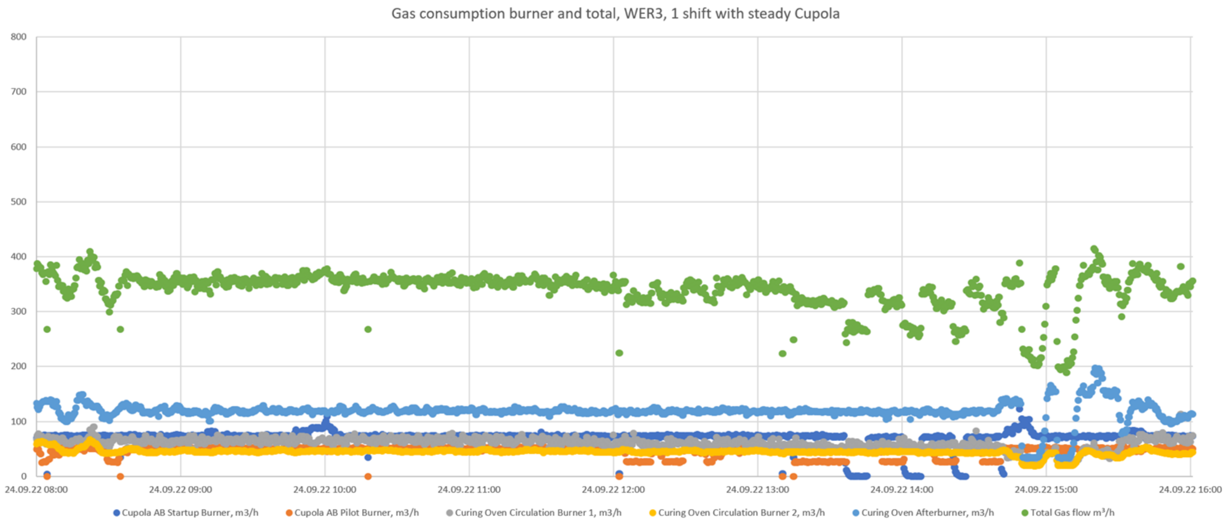
Burner capacity can be impacted by start-up/ shut-down, operation interruptions, product changeovers and process control adjustments The variability of burner capacity was modelled using real life process data from a period of operational disruption (Figure 3.3.1) vs a steady period of production (Figure 3.3.2) to illustrate this. A typical 2-day period of operation was also modelled (Figure 3.3.3) and was used to develop the specification of hydrogen storage capacity needed.

Figure 3.3.1 NG consumption during operational disruption



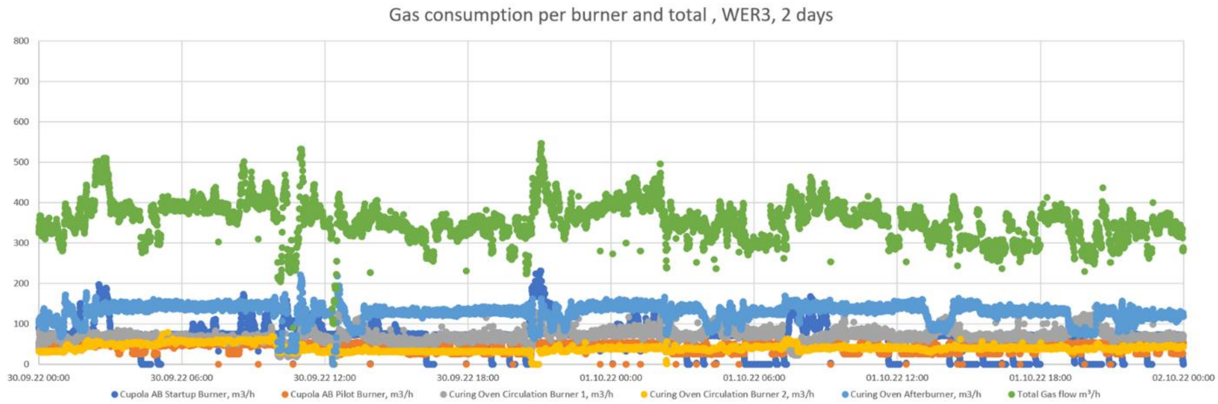
Source: ROCKWOOL/Würz GMBH

Figure 3.3.2 NG consumption during steady state production



Source: ROCKWOOL/Würz GMBH

Figure 3.3.3 NG consumption over typical 2-day operation



Source: ROCKWOOL/Würz GMBH

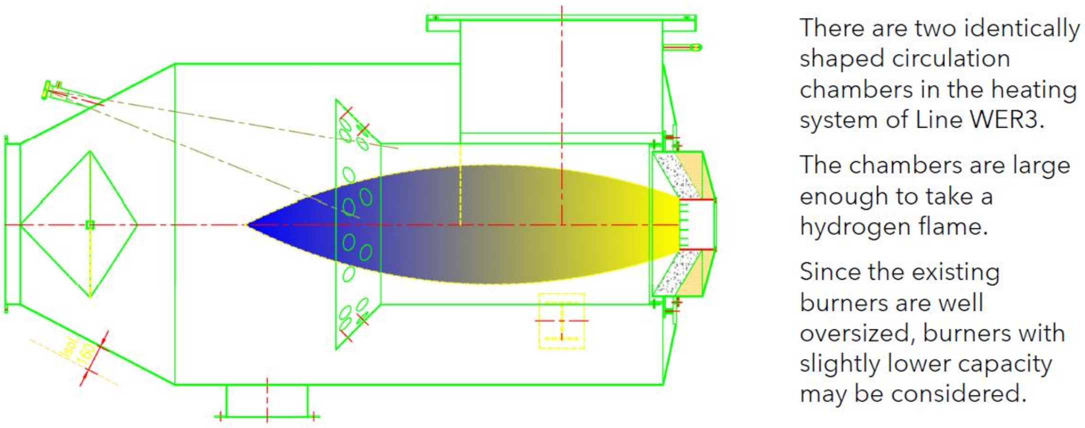
The project plan included work to assess the facility upgrades necessary to enable switchover to 100% hydrogen fuelling for the burners in scope alongside a hybrid hydrogen-natural gas scenario with a minimum of 20% hydrogen. On investigation the maximum concentration of hydrogen possible in a hybrid scenario without burner replacements was only 5% which would not make any meaningful step towards decarbonisation and has therefore been excluded from further study.

Under the 100% switch to hydrogen from natural gas scenario, analysis was undertaken of the impacts of additional water generated from hydrogen burners, dew point of the flue gas, impacts of hydrogen on the materials currently in use for piping and gaskets and control instrumentation. Burner replacements (including piping) would be required due to the different properties of the fuels and the burner specialist concluded that this was possible for all 5 burners in the scope along with the associated pipework, gaskets and control instrumentation. Furthermore, hydrogen burners were available on the market, albeit they are not yet considered standard items.

3.3.2.2. Equipment Burner Upgrades

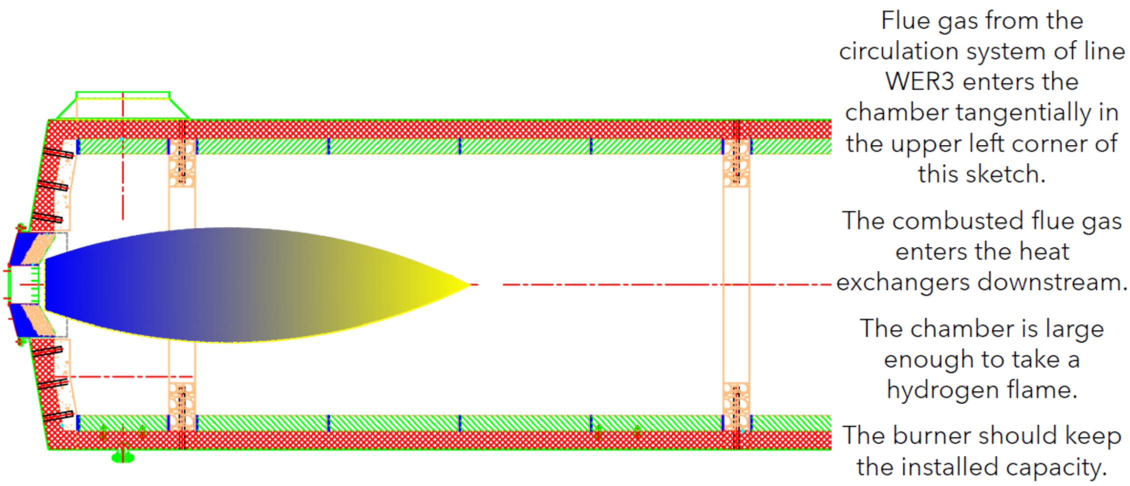
The combustion chambers hosting the burners detailed in 3.3.2.1 were supplied by Würz GMBH and were comfortably sized for natural gas. Burners using hydrogen typically have a flame about 10-15% larger in diameter and length. Flame sizes were sketched into the existing combustion chamber dimensions to assess compatibility (Figure 3.3.4 to Figure 3.3.6).

Figure 3.3.4 Circulation chambers Line 3



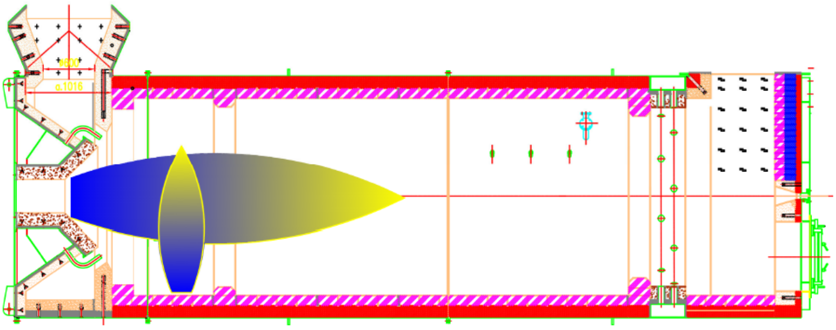
Source: ROCKWOOL/Würz GMBH

Figure 3.3.5 Curing Oven Afterburner Line 3



Source: ROCKWOOL/Würz GMBH

Figure 3.3.6 Cupola Afterburner Line 3



Filtered flue gas containing combustibles from the Cupola system of line WER3 enters the chamber tangentially in the upper left corner of this sketch.

Combustion air is added in a flue gas burner.

The main burner is needed for start-up and support and often is off. The smaller burner is always on and may go to minimum capacity. Both burners are shown in full capacity

Source: ROCKWOOL/Würz GMBH

All burners and associated piping require full replacement to use hydrogen as a fuel. The existing combustion chambers are large enough to accommodate the larger flame size and will not require replacement. Chamber pressure presents a challenge in terms of process control but no more so than for natural gas burners. The burner dimensions and gas trains will be equivalent to natural gas burners and so have not been considered.

3.3.3. Hydrogen Safety

3.3.3.1. HAZID

A HAZID (Hazard Identification) has been completed for the ROCKWOOL hydrogen production facility. The objective of a HAZID study is to identify potential hazards and to reduce the probability and consequences of an incident on site that would have a detrimental impact to the personnel, plant, properties and or environment. The HAZID identified a total of 106 hazard items of which 40 were classified as medium risk and 66 were classified as low risk. Preventive and mitigation measures were included in the HAZID report. The findings have been incorporated into the proposed hydrogen production facility.

3.3.3.2. Site Vent Dispersion Analysis

Dispersion and consequence modelling of the stacks to determine height and location was undertaken using DNV Phast. Based on the results of the modelling, the following recommendations have been made:

- **Recommendation 1**: The oxygen vent should release at a minimum height of 3 m above the electrolyser building in accordance with EIGA 154/16 guidance.
- **Recommendation 2**: The hydrogen vent should be located at a minimum distance of 10 m from the oxygen stack / electrolyser building.
- **Recommendation 3**: The hydrogen vent should release at a height of 1.5 m above the electrolyser building in accordance with NFPA 2 guidance.
- **Recommendation 4**: A fenced isolation zone of 7 m should be placed around the hydrogen vent to prevent potential sources of ignition, noting that given hydrogen is

buoyant, it is not expected that the plume would travel below the release height upon release as confirmed by the dispersion modelling.

The above recommendations have been incorporated into the Plot Plan.

4. Quantitative Risk Assessment (QRA)

A Quantitative Risk Assessment (QRA) is a formal and systematic risk analysis approach to quantifying the risks associated with the operation of an engineering process. A QRA has been undertaken to determine risks to the general public and personnel on-site to support the application for Hazardous Substances Consent (HSC). To achieve this, the QRA had the following objectives:

- Determine suitable scenarios that represent worst-case major accidents hazards (MAH);
- Perform consequence analysis on the scenarios identified above;
- Undertake QRA based on appropriate failure data.

Receptor sites were identified where persons may be located and at risk of fatality both on-site and off-site. Consequence modelling of the above scenarios was undertaken using Det Norske Veritas (DNV) Phast v8, considering jet fire and Vapour Cloud Explosion (VCE) accidents.

An overall release frequency for the MAHs identified was determined to be approx. $5x10^{-4}$, which is equivalent to one release every 2000 years of site operations. Additionally, an overall frequency for an ignited release was determined to be approx. $1x10^{-5}$, which is equivalent to one ignited release every 10,000 years of site operations.

Location Specific Individual Risk (LSIR) was calculated for each of the receptor sites for persons located both indoors and outdoors. The Health and Safety Executive's (HSE's) Land Use Planning (LUP) methodology (HSE, n.d.) was used in reverse to determine if the risk at receptor sites was tolerable based on the receptor sensitivity level and the planning zone in which they would lie in relative to the proposed HPF.

The calculated risk at each of the receptors is well within the HSE LUP guidance. Therefore, it was not considered necessary at this stage of the project to determine the Individual Risk Per Annum (IRPA) noting that if an operator were to spend 100% of their time in the worst-case location (HPF Control Room), the risk of fatality would be $2.73x10^{-6}$ per year.

Whilst the risk to both on-site and off-site persons has been determined to be tolerable / broadly acceptable, it is worth noting that the QRA is considered to be overly conservative given that it was assumed that the electrolysers were operating continuously, and no consideration was given to probability of a specific wind direction. In reality, the risk is expected to be lower than that calculated if these factors are taken into consideration.

4.1.1.1. Further Safety Studies

During the FEED phase the following additional studies will be performed:

- A HAZOP (Hazard and Operability) study will be required to identify if deviations from the design or operational intent can result in safety issues. This study will be performed once the P&IDs have been developed.
- A Layers of Protection Analysis (LOPA) / Safety integrity level (SIL) analysis will be performed once the definition of the control and safety systems becomes available.

The initial Quantitative Risk Assessment (QRA) will be reviewed and updated as further design information becomes available.

4.2. Planning & Environmental

4.2.1. Planning Consenting Regime (Wales)

Based on our current comprehension of the project components as of writing, all on-site infrastructure, namely hydrogen production and storage and the ground mounted solar array fall under the Town and Country Planning Act[11] and will therefore be consented via a planning application to Bridgend County Borough Council (BCBC) as the Local Planning Authority (LPA). The application will be informed by pre-application advice, EIA Screening and the outcome of informal and formal consultation pre-submission.

It is understood that connections to off-site renewable power generating stations may be required as part of the project.

Any overhead private wire connection up to and including 132kV to the site from an off-site wind generating station would be considered a Development of National Significance (DNS) and would need to be consented via a separate application process to the Welsh Ministers via Planning Environment Decisions Wales (formerly the Planning Inspectorate Wales).

The process of assessing the likely planning and consenting parameters for the proposal involved a number of steps, namely:

- A site visit/tour of the facility.
- A review of the planning consenting regime/pathway.
- A review of the policy context.
- Planning history review of recent, relevant planning applications at the site.
- A formal pre-application advice request of BCBC.

4.2.2. Pre-application Advice and Environmental Impact Assessment Requests

On the basis that the planning consenting regime pathway is clearly established as set out above, requests for pre-application advice and Environmental Impact Assessment (EIA) Screening have been made to BCBC. These were submitted on 25th January 2023 and 10th February 2023 respectively. Responses to both are awaited at the time of writing.

4.2.2.1. Pre-application Advice

In planning terms, "pre-application" refers to the stage in the planning process where a developer or applicant engages with the relevant planning authority before submitting a formal planning application. The purpose of pre-application is to allow the developer or applicant to seek advice, guidance and feedback from the planning authority regarding their proposed development.

Whilst the formal pre-application response is awaited, the key planning considerations and a view on the likely acceptability of the proposal in planning terms are set below:

- Planning Policy Context
- Future Wales – the National Plan 2040 (February 2021)
- Planning Policy Wales, Edition 11 February 2021
- Development Plan
- Local Development Plan Proposals Map
- Replacement BCBC Local Development Plan
- Planning History

The findings are based on professional planning judgement and the benefit of experience of renewable energy, infrastructure and other developments in Bridgend over many years. It has also informed by a site visit and a review of the planning history of the site and the relevant planning policy context.

In summary and subject to the BCBC response, it is considered that, in policy terms the proposal should be welcomed and considered acceptable.

4.2.2.2. EIA Screening

An Environmental Impact Assessment (EIA) is a systematic process that is used to identify, assess and evaluate the potential environmental impacts of a proposed development or project before it is approved.

As with pre-application consultation advice, obtaining clarity as to whether a proposal is EIA development or not is fundamental for reasons of timeframe and cost. A Screening Decision will enable an applicant to know from the outset what the timeframe will be (it will usually be extended by 6 months or more if EIA in terms of preparation time to prepare and report on relevant technical assessments and will also be extended in terms of the determination period of any application. Secondly, it will define the cost envelope of any application, as the level of input to an EIA will be considerably more than for a non-EIA application.

The Screening Request describes and appraises the characteristics of the potential impacts for the following topic areas:

- Traffic and Transport
- Air Quality
- Noise and Vibration
- Landscape and Visual
- Cultural Heritage
- Land Use, Agriculture and Recreation
- Population and Human Health
- Geology, Hydrogeology and Ground Conditions
- Climate Change
- Decommissioning
- Inter-related effects

- Cumulative effects.

In considering the potential for likely significant effects to arise, the following aspects will be taken into account:

- size and design of the whole development;
- cumulation with other existing development and/or approved development;
- use of natural resources in particular land, soil, water and biodiversity;
- production of waste;
- pollution and nuisances;
- risk of major accidents and/or disasters relevant to the project concerned, including those caused by climate change, in accordance with scientific knowledge; and
- risks to human health (for example due to water contamination, noise, or air pollution).

In the Screening Opinion request, the location of the development and its environmental sensitivity, and the types and characteristics of potential impacts, will be considered in respect of each potential impact pathway and with regard to the inter-relationship and cumulation of impacts.

In appraising the proposal under the above topics, the Screening Request establishes that:

- The proposal does not fall within Schedule 1 of the EIA Regulations.
- The total site area for the proposed works is above 5 hectares. As such, the scheme falls under

Schedule 2 of the EIA Regulations. However, it is the case that a Schedule 2 development does not always require EIA to be undertaken. The development in question must be considered against the criteria provided in Schedule 3 of the Regulations to determine whether significant effects on the environment are likely. Schedule 3 includes the characteristics and location of the development and the characteristics of the potential impact.

When the effects and their significance have been assessed against Schedule 3 of the EIA Regulations, despite the proposal falling under Schedule 2, the opinion is that the proposal is not EIA development.

In reaching a conclusion that the proposal is not considered to be EIA development, that opinion is in line with the precedent of over 20 Screening decisions made by planning authorities for other hydrogen production facilities in the UK. It is also in line with the formal opinion for a hydrogen production development in Bridgend (<5km from the Rockwool site) which was also screened as not requiring EIA. That proposal also contained a solar array which was screened on its own and cumulatively alongside the hydrogen production and storage.

4.2.3. Permits and Consents

4.2.3.1. Environmental Permit

The production of hydrogen falls under Schedule 1 Part 2, Section 4.2 a(i) of the Environmental Permitting Regulations. This type of activity has no lower threshold specified within the Regulations below which a permit from the Natural Resource Wales (NRW) is not triggered.

However, NRW would potentially consider production of hydrogen from electrolysis as a low impact installation dependant on installation capacity and location. Early contact with the local NRW office is recommended.

In the event that there is a discharge direct to surface water this release would be covered by the environmental permit. If the discharge was to sewer, see the Trade Effluent Consent section below.

The UK Regulators are currently in the process of developing Guidance for Emerging Techniques (GET) for hydrogen production from electrolysis of water, once issued it would be expected that this guidance will apply to NRW regulated hydrogen production facilities in Wales. Given work is already in progress on the guidance it is likely that it will be available within the timeline of this project and the facility will need to be designed to meet GET requirements as set out in the guidance.

4.2.3.2. Trade Effluent Consent

Trade effluent consents are required to discharge process waters into the public sewer. The consent is applied for from Welsh Water (Dŵr Cymru).

A trade effluent consent will contain a number of conditions related to the volume, flow rate and nature of the effluent that are set to protect the environment and water company assets – the sewerage network, the sewage treatment processes and personnel (employees and general public), for example. Differing conditions and range of substances to be controlled may be set considering the industry type of the effluent and the receiving sewer and sewage treatment works.

There may also be conditions that require the discharger to provide apparatus that will measure and record trade effluent flows, pH and temperature etc. An automatic sampling machine may also be necessary.

If a discharge to sewer is proposed at an early stage you should submit a pre-planning enquiry to establish whether sufficient capacity to accept the proposed discharge exists within the sewerage network and local treatment wastewater treatment works.

4.2.3.3. Hazardous Substances Consent

A hazardous substances consent is triggered where the storage and use of hazardous substances is at or above the controlled quantity set within the Planning (Hazardous Substances) Regulations 2015(13). For hydrogen facilities a hazardous substances consent would be triggered by 2 or more tonnes of hydrogen or 200 or more tonnes of oxygen.

4.2.3.4. COMAH
Adherence to Control of Major Accident Hazard (COMAH) Regulations[14] applies to facilities that store hazardous substances above specified thresholds. Two tiers of facility are identified, Lower and Upper Tier, with Upper Tier sites being considered higher risk and are subject to a higher degree of regulation.

For hydrogen the storage thresholds for COMAH are:

1. Lower Tier – 5 tonnes
2. Upper Tier – 50 tonnes

Oxygen a by-product of the hydrogen generation process is also regulated under COMAH, with the following storage thresholds applied:

1. Lower Tier – 200 tonnes
2. Upper Tier – 2,000 tonnes

In the event that COMAH is triggered, the facility owner will need to notify the competent authority (HSE/NRW) 3-6 months before construction of the facility begins.

4.2.3.5. Electrical Connections
The project is currently developing the plan for electrical connections which includes current discussions with the applicable Distribution Network Operator (National Grid Electricity Distribution).

The timelines and electrical grid connection approvals requirements are well understood from the feasibility study work, and would include for formal application, quotation, and acceptance of an offer from NGED, followed by engineering design and notice to proceed for implementation for the new electrical connection.

The electrical connections approach is expected to include supply and sale of electrical power from renewable power suppliers by interfacing directly with the local renewable generator electrical grid connection.

4.2.4. Environmental Performance
The environmental performance of the hydrogen fuel switching solution provides strong benefits in terms of greenhouse gas emissions with minimal impact to liquid and solid environmental impacts e.g. feed water consumption & effluents.

This expectation of strong environmental performance is reflected in the expectation of the development to be screened out of a formal Environmental Impact Assessment (see section 4.2.2.2), and the specific environmental focal areas are discussed below.

4.2.4.1. Carbon Emissions Savings Potential
The carbon emissions savings potential is assessed based on the difference between the carbon emissions of the solution i.e. with hydrogen fuelling replacing natural gas, and with oxygen supplementation in the melt furnaces, compared to the carbon emissions without the solution.

The hydrogen production is to be considered Low Carbon Hydrogen, which although includes low carbon intensity (<20 gCO2e/MJLHV H2), it is still quantified and compared against the existing emissions of carbon from natural gas combustion and coke fuelling in the melt furnace.

The determination is based on the key factors below

1. Amount of CO_2 abated i.e. the difference between:
    - Amount of CO_2 produced under a counterfactual case
    - Amount of CO_2 produced under the project
2. Cost of the abatement i.e. the difference between:
    - Cost of the counterfactual case
    - Cost of the project

The selection of a counterfactual case is important to understand how well the project performs as well, since other technologies could provide cost-effective decarbonisation routes. For this project, the CO_2 abatement could be attributable to:

1. Natural gas replacement in the curing oven and post-combustion systems which removes the CO_2 generated from natural gas combustion
2. Reduced coke consumption due to melt furnace oxygen supplementation (oxygen enrichment increases the efficiency of the melt furnace but is expensive and only used for startup/ramping of melt furnace)

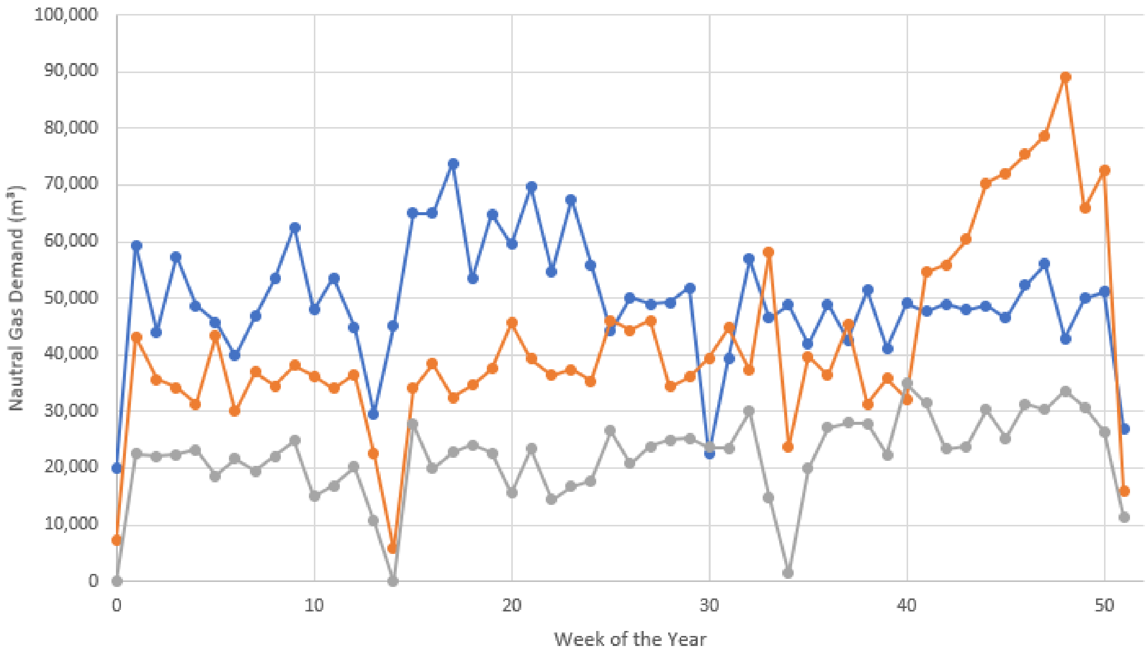
For the natural gas replacement in the curing oven and post-combustion systems, there are no alternative options than a low-carbon gas replacement due to the configuration of the equipment itself and electrification would not provide suitable operating conditions for the production processes; therefore the counterfactual case for consideration will be a 'business-as-usual' (BAU) case where natural gas fuelling continues.

For the melt furnace oxygen supplementation, electrification of the furnace would lead to significantly reduced coke consumption requirements, therefore the carbon emissions savings related to oxygen supplementation were excluded for the analysis.

4.2.5. Amount of CO_2 Abated

The amount of CO_2 produced under a counterfactual case i.e. the BAU consumption of natural gas can be based on the existing demand case for the proposed fuel switch areas. The data were used for the determination of hydrogen demands as shown in Figure 4.2.1.

Figure 4.2.1 2021 Natural Gas Consumption Profile for Line 1, 2, and 3 areas identified for fuel switching



Source: Marubeni/ROCKWOOL

A 10% future growth capacity factor was also considered for the total natural gas consumption forecast for the facility natural gas consumptions, with the total BAU annual natural gas consumptions and related CO_2 emissions shown in Table 4.2.1, with breakdown showing the full point of production to point of use natural gas carbon emissions.

Table 4.2.1 Total Carbon Emissions related to Natural Gas Fuelling of Production Lines 1, 2, and 3

Production Line	Existing Natural Gas Consumption, m^3	BAU Natural Gas Consumption m^3	Point of Use Emissions	Well-to-Tank Emissions, $teCO_2e$	Total Emissions $teCO_2e$/year
Line 1	1,137,768	1,251,545	2,523	430	2,953
Line 2	2,182,692	2,400,961	4,840	824	5,664
Line 3	2,610,870	2,871,957	5,789	986	6,775
Total	**5,931,330**	**6,524,463**	**13,152**	**2,241**	**15,392**

*2.016 $kgCO_2e/m^3$ NG emissions, 0.343 $kgCO_2e/m^3$ WTT emissions = total 2.359 $kgCO_2e/m^3$ natural gas emissions from Green Book 2022 (9).

The amount of CO_2 produced under the project can be determined from the CO_2 intensity of the project which has been determined through the BEIS Hydrogen Emissions Calculator which is informs the required methodology for reporting of emissions related to Low Carbon Hydrogen for the purposes of public funding consideration. The output of the calculation showed the carbon emissions intensity of hydrogen produced for the 15 MW Base Case as 5.4 gCO2e/MJ(LHV) hydrogen, and for the 35 MW Current Case (and Commercialised Case), 4.4 gCO2e/MJ(LHV) hydrogen. The lower value for the scaled-up project is due to lower fluctuations in the hydrogen demand profile requiring less import of power from the grid.

The low carbon hydrogen calculation of carbon emissions includes for emissions to point of production and since hydrogen production and consumption are to be co-located, the emissions related to transport and distribution are zero. The carbon emissions developed from the project are shown in Table 4.2.2.

Table 4.2.2 Carbon Emissions related to hydrogen production for fuel switch.

Production Line	BAU Natural Gas Consumption m^3/y	Associated Hydrogen Demand, kg/y	Associated Hydrogen Demand, MJ(LHV)/y	Total Emissions $teCO_2e/year$
15 MW Base Case (Line 3 conversion)	1,251,545	847,903	101,917,941	540
35 MW Current Case (Line 1, 2, 3 conversion)	6,524,463	1,926,252	231,535,442	1,019
35 MW Commercialised Case (Line 1, 2, 3 conversion)	6,524,463	1,926,252	231,535,442	1,019

*Conversion factor of 120.2 MJ(LHV)/kg hydrogen

Therefore, the total CO_2 abated for each of the project cases is presented is 6,775 – 540 = **6,235 $teCO_2$/year** for the 15 MW Base Case, or 15,392 – 1,019 = **14,373 $teCO_2$/year** for the potential phased scale up through the 35 MW Current Case or 35 MW Commercialised Case. In terms of CO_2 abated per MJ_{H2LHV}, this is 61.1 gCO_2e/MJLHV H_2 for the 15 MW Base Case, and 62.1 gCO_2e/MJLHV H_2 for the 35 MW cases; both present a significant contribution towards the UK's 2050 Net Zero targets and international targets for decarbonisation.

Similar levels of de-carbonisation could be replicated and scaled across ROCKWOOL manufacturing sites, the wider stonewool industry, and across other UK industrial applications including e.g., cement and steelmaking where high-grade process heat is required and difficult to decarbonise.

4.2.5.1. NOx Emissions

NOx gases are serious environmental pollutants contributing to photochemical smog formation, acid rain and climate change. They are also detrimental to human health, particularly contributing to respiratory problems. As such, the release is controlled through environmental permitting and ROCKWOOL uses continuous emissions monitoring to measure emissions from the existing process to maintain compliance with emission value limits set by the regulator Natural Resources Wales.

Although most NOx emissions are caused by fossil fuel combustion, hydrogen use can increase NOx production. Abatement strategies and technologies include burner temperature control, catalytic reduction, excess air control and flue gas recirculation.

Site development to include green hydrogen production and use would trigger the need for a permit variation in which maximum emission levels of NOx would be mandated. NOx modelling and an appropriate abatement strategy will therefore form a core part of future burner design

4.2.5.2. Other Environmental Factors

Other environmental factors were assessed from the project including consideration within the HAZID (hazard identification) review:

- Other air quality e.g. PM, SOx: the hydrogen production only requires the continuous release of oxygen to the atmosphere which is not considered to have a negative impact on air quality. The fuel switch to hydrogen may impact the burner emissions; however, PM/SOx are not expected to be worse than using natural gas. Potential NOx increases are considered in section 4.2.5.1 above.
- Liquid wastes: the main volumes of liquid effluent from the project shall be from purification of the water; the water treatment waste stream contains elevated levels of minerals as a result of the purification process, but would otherwise be low impact, pH neutral streams.
- Solid wastes: No major sources of solid wastes are expected to be produced under normal operation; typical solid wastes (e.g. packaging plastic/paper) will be generated as part of maintenance activities. Since the equipment are expected to be relatively high value, major componentry are expected to be recycled where possible e.g. electrolyser parts.

4.2.5.3. Noise

A preliminary noise impact assessment was prepared based on the hydrogen production facility feasibility design.

A desktop review of baseline noise conditions has been undertaken which identifies the nearest noise sensitive receptors to the proposed site and considers typical background sound levels based on existing measurement data.

Noise modelling has been completed to predict noise levels at the nearest sensitive receptor locations. Modelling results have been used to inform a preliminary noise impact assessment in accordance with BS 4142:2014+A1:2019. Assessment results indicate noise impacts are likely to be low during the daytime period, however may result in small adverse impacts during the night-time period. Assessment shows that compressor enclosures assist to minimise adverse noise impacts at the nearest receptors.

Good acoustic design will be adopted, and mitigation measures included where necessary subject to final plant equipment selection during detailed design. Measures discussed within the preliminary assessment include:

- The selection of low-noise equipment
- Enclose or internalise noise sources
- Use of control measures including attenuation/silencers to reduce noise emissions
- Provision of screening features (noise barriers or bunds)
- Site layout arrangement to maximise the distance from noise sources to sensitive receptors and use intervening buildings/structures as screening features
- Orientation of noise generating equipment with directional component away from noise sensitive receptors

Further study is required during the subsequent phases of the project to finalise, noise impacts, to establish background sound levels at the nearest noise sensitive receptors, undertake consultation with the local planning authority, and where necessary assess the requirement for additional noise mitigation measures.

4.3. Financial & Commercial Analysis

4.3.1. Financial Model Methodology

A Financial Model (“Model”) has been developed to assist in evaluating the economic viability of the project. The model methodology follows industry guidelines and practices as discussed below.

4.3.1.1. Modelling Approach

The model was built in-house specifically for this project. This approach was taken to ensure the production of a simple, streamline, and easy to understand model whilst taking account of all the unique complexities of this project. The approach to developing the model incorporated the following:

- The Model was developed and optimised following “FAST” principals (Flexible, Appropriate, Structured, Transparent). This enables the model to be easily understood and adjusted by non-financial professionals, whilst also providing a high level of reliability and assurance.
- The Model follows a Discounted Cash Flow (DCF) approach.
- Calculations are predominantly monthly; however hourly calculations are utilised as appropriate.
- Tax and accounting calculations (including but not limited to; working capital, depreciation, capital allowances, tax losses, Value Added Tax VAT, and dividend policy) have been carefully considered and modelled in line with UK law as well as International Financial Reporting Standards (IFRS) & UK Generally Accepted Accounting Principles (GAAP).

The process of developing the financial model was highly iterative and broadly as followed:

1) Input initial technical assumptions
2) Develop hourly technical calculations
3) Input commercial data
4) Develop monthly calculations
5) Combine all calculations
6) output financial analysis,
7) refine technical design, assumptions, and structure of outputs as required
8) repeat financial analysis with new technical & commercial data

4.3.1.2. Financial Model outputs

The Financial model outputs include, but are not limited to:

- The 3 Financial Statements (Income Statement, Cash Flow Statement, and Statement of Financial Position).
- Levelized Cost of Hydrogen (LCoH), expressed in £/ kg and £ / MWh.
- Hydrogen Pricing, Investor return metrics; Internal Rate of Return (“IRR”), Net Present Value (NPV), Payback Period, and Multiple of Invested Capital (MOIC).

4.3.1.3. Key Assumptions

- The project has a useful economic life of 15 years.

- No residual value, or decommissioning costs are assumed. This is a prudent assumption as in reality the project may be extended beyond 15 years.
- Electrolyser stack Replacement Costs (REPEX) are assumed during the 8th year of operation.
- Wholesale power prices are assumed to be constant year-on-year based on forecasted average prices, however intra-year seasonality (based on the actual renewable generation at the site) is considered on an hourly basis.
- The model is considered in real terms (no indexation applied).
- Gearing ratio of 0% (no debt funding is utilised). There may be potential to ultilise debt funding at a later stage.
- Capital Expenditure (CAPEX): costs assumed for onsite solar PV, electrical connections, private wire to offsite renewables, hydrogen production and storage facilities, and facilities configuration.
- Operational Expenditure (OPEX): costs assumed for Operations and Maintenance (O&M), power supply costs, and other OPEX costs.
- Replacement Expenditure (REPEX): costs assumed for major maintenance and replacement costs.

4.3.1.4. Modelling limitations

- The model represents the best view of forecasted future costs and macro-economic conditions, however an inherent margin of error in the assumptions should be expected due to the long passage of time, and rapidly changing market conditions. The risk of assumption error has been partially mitigated through engaging expert advisors, carrying out sensitivity analysis, and applying additional contingency to cost assumptions.
- Inflation is not considered in the base case (however, it is considered in sensitivity analysis).

4.3.2. Expected Costs of the Solution

The expected costs of the solution are developed as part of the Feasibility Study Cost Estimate for CAPEX and OPEX, and these were incorporated in the Financial Modelling inputs alongside various commercial inputs to produce an output of estimated Levelised Cost of Hydrogen as well as consideration of Hydrogen Price as a basis for the project.

4.3.2.1. Capital Costs and Operational Costs (CAPEX & OPEX)

The Cost Estimate has been developed for both the 15MW base case (Table 4.3.1) and the 35MW sensitivity case as an Association for the Advancement of Cost Engineering (AACE) Class 5 estimate[(10)], which is typically developed from information that include: capacity factoring, parametric modelling, judgment, or analogy.

The information inputs have included hydrogen and renewable power cost data for similar projects as part of in-house data sets held by Mott MacDonald and Marubeni. The estimate accuracy at this level is expected to be -20% to 50% on the low end, and +30% to 100% on the high end. The total cost of the 15MW base case is estimated to be £84.8m CAPEX, with £74.2m OPEX costs, and £5.9 REPEX costs, subject to the estimate accuracy ranges commensurate with this feasibility stage of project definition.

Table 4.3.1 Base Case – 15MW Cost Estimate

CAPEX	£'000
Hydrogen Production	21,517
Power Supply & Electrical	39,825
Storage, Distribution, and End-Use	15,718
Contingency	7,706
Total CAPEX	**84,766**
OPEX	**£'000**
Power Supply Costs	58,802
O&M – Hydrogen Production	14,160
O&M – Power Supply	1,230
Total OPEX	**74,192**
REPEX	**£'000**
Electrolyser Stack Membrane Replacement	5,907
Total REPEX	**5,907**

4.3.2.2. Levelised Cost of Hydrogen

The main intention of a levelised cost metric is to provide a simple “rule of thumb” comparison between different types of hydrogen production technologies and projects.

The Levelised Cost of Hydrogen (LCoH) is an output from the financial model based on the approach detailed in the BEIS Hydrogen Production Costs 2021 documentation(6). According to this approach, the levelised cost of hydrogen is the, “discounted lifetime cost of building and operating a production asset, expressed as a cost per energy unit of hydrogen produced (£/MWh). It covers all relevant costs faced by the producer, including capital, operating, fuel and financing costs.”

Importantly, **LCoH is a production cost metric** and does not include any costs associated with delivery or storage of the produced hydrogen, nor costs of end-use adaptation.

Therefore, for this feasibility study, the below elements have been included in the LCoH determination in alignment with the definition, and the results are shown in Figure 4.2.1 and Table 4.3.2.

- CAPEX:
  - Electrolyser system (the stack)
  - Necessary balance of plant (compressor, drier, cooling, de-oxo & water de-ionisation equipment)
  - Civil works (building and foundations)
  - Electricity grid connection (inc. private wire, substations, transformers, and rectifiers)
  - Public Funding e.g. Net Zero Hydrogen Fund (as sensitivity)
- OPEX
  - Annual Operations & Maintenance for CAPEX items listed immediately above
  - Power Supplies to the Hydrogen Production (renewable and grid import)
- REPEX
  - Major Maintenance (i.e. electrolyser stack membrane replacement)

The following were specifically excluded for LCoH calculations as they are not included within the standardised LCoH approach (which is a production metric). However, these costs are considered within the financial model and analysis of the Total Cost of Hydrogen:

- CAPEX:
    - Hydrogen Storage
    - Hydrogen Distribution i.e. pipeline
    - Facility Re-configuration (inc. pipework & end-use equipment upgrades)
    - Oxygen Equipment/Distribution
- OPEX
    - Annual Operations & Maintenance for CAPEX components above
- Equity return

Figure 4.3.1 Summary Chart of Levelised Cost of Hydrogen (Unsubsidised)

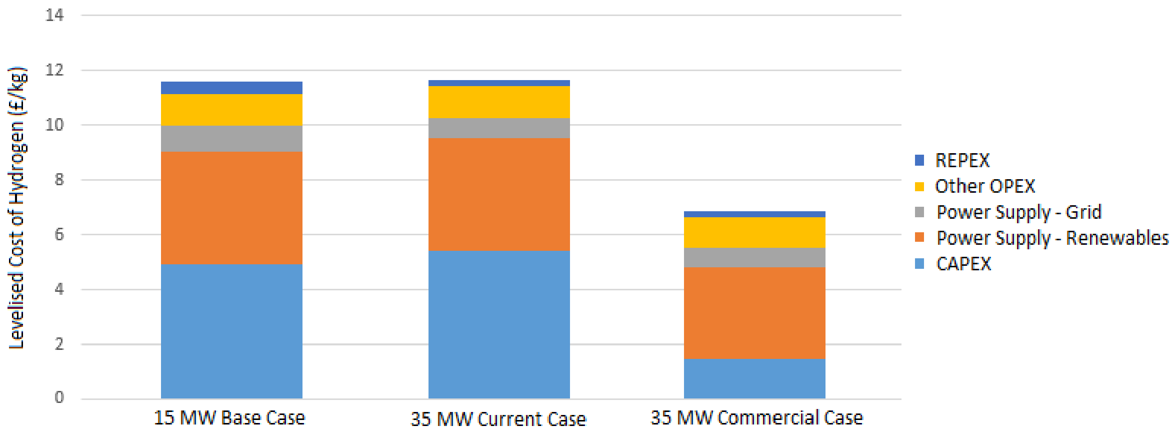


Table 4.3.2 Detailed Breakdown of Levelised Cost of Hydrogen

Component	**LCoH (£/kg* H₂)**			**LCoH (£/MWhLHVH₂*)**		
	15 MW Base Case	**35 MW Current Case**	**35 MW Commercial Case**	**15 MW Base Case**	**35 MW Current Case**	**35 MW Commercial Case**
CAPEX	4.95	5.45	1.49	148.51	163.52	44.70
Power Supply – Renewables	4.10	4.07	3.36	123.01	122.11	100.81
Power Supply - Grid	0.95	0.75	0.68	28.50	22.50	20.40
Other OPEX	1.14	1.17	1.13	34.20	35.10	33.90
REPEX	0.46	0.20	0.21	13.80	6.00	6.30
Unsubsidised LCOH	11.60	11.63	**6.87**	348.03	348.93	**206.12**
20% CAPEX Grant	-1.13	-1.16	N/A	-33.90	-34.80	N/A
Subsidised LCOH	**10.47**	**10.47**	N/A	314.13	314.13	N/A

4.3.2.3. Levelised Cost of Hydrogen Sensitivity Analysis

35 MW Current Case LCoH

The 35 MW Base Case LCoH is determined as £11.63/kg hydrogen or £348.93/MWhLHV hydrogen. Potential available funding for this 35MW Current Case project includes the Net Zero Hydrogen Fund which could provide 20% of the CAPEX costs of the project. The effect of this funding on the overall LCoH is -£1.16/kg hydrogen or -£34.80/MWhLHV hydrogen leading to a subsidised LCoH of £10.47/kg hydrogen or £314.13/MWhLHV. Additional potential funding sources include the Hydrogen Business Model (HBM) for OPEX which considers difference against a total hydrogen price – see section 5.3 for Total Cost of Hydrogen and related HBM funding considerations.

The major components of the LCoH are the CAPEX at 47% of the LCoH, and the power supply costs making up 41% of the costs – the remaining 12% of costs are for other OPEX costs including fixed O&M and major maintenance costs.

Broadly, the 35 MW Current Case has a very similar LCoH profile to the 15 MW Base Case despite the economies of scale reducing CAPEX of most components as well as a smoother demand profile requiring less wholesale grid power to be purchased which is expensive. The largest item offsetting these reductions is the very high cost of installing a 33kV/132kV primary for grid connection due to the weak grid connection options in the area in the current market. The CAPEX reductions associated with grid connection/grid reinforcement works to support the power supplies to the project as well as fully sized grid connection CAPEX in addition to the private wire in order to provide a 100% import/export backup to the electrolyser are considered in the 35 commercialised Case scenario – see section 5.2.3 for details.

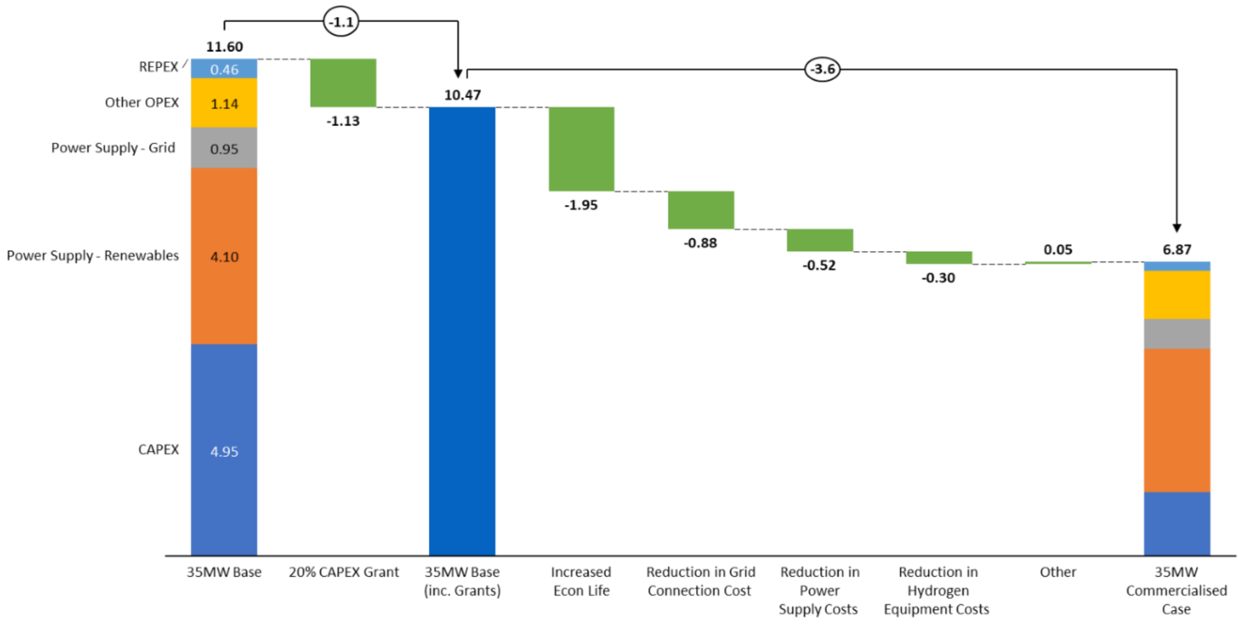
Overall, the 35 MW Current Case subsidised LCoH of £10.47/kg hydrogen represents the production costs of a real UK project in the hydrogen market space that is at an early stage of maturity and reflects the challenges of the power supply and electrical grid connection requirements that impact scalability of projects in the current market. The LCoH should be taken in context and considered against overall end-to-end project requirements and benefits, as well as the ability to decarbonise a hard-to-abate application.

35 MW Commercialised Case LCoH

The 35 MW Commercialised Case LCoH was determined as £6.87/kg hydrogen or £206.12/MWh,LHV hydrogen which is a 40% reduction in unsubsidized LCoH compared to the 15MW Base Case and 35 MW Current Case.

The dominant component of the LCoH is the power supply costs making up 59% of the costs – the remaining costs include CAPEX at 21% of the LCoH and OPEX costs including fixed O&M and major maintenance costs at 20%. This reflects the balance of costs moving towards OPEX with higher volumes of hydrogen produced in the longer useful economic lifetime, as well as significant reductions in the CAPEX in a commercialised market as demonstrated in Figure 4.3.2.

Figure 4.3.2 LCoH Waterfall Chart showing Commercialisation Cost Reductions



Source: Marubeni

The key differences in the 35MW Commercialised Case that results in the LCoH reductions include:

1. Increased useful economic lifetime (-21% impact):
   The Commercialised case considers a 30-year useful economic life of the project based on typical process plant and machinery compared to 15-year useful economic life based on current market conditions that reflect the maturity of the market. in particular, the HBM revenue support aims to provide OPEX support at the 15-year economic life(7), whereas greater confidence in hydrogen technology would allow projects to be invested into longer term. This difference equates to a 21% LCoH reduction.

2. Reduction in Grid Connection Cost (-12% impact):
   The Commercialised case considers a grid connection cost where reinforcement works are owned by the DNO and the costs of grid connection reflect the benefits that flexible operation of electrolysers can bring to the wider grid. In addition, operation of the electrolyser should demonstrate that the maximum 40% electrolyser capacity as import should be sufficient to manage prolonged periods of low renewable generation, reducing the capacity of the grid connection from 35MW to 14 MW which could be delivered with 11kV infrastructure instead of 33kV. This reduces the potential cost of a 35MW connection from ~£50m to the range of £1-10m, with £5m taken as a reasonable mid-point in this range. This difference equates to a 12% LCoH reduction.

3. Reduction in Power Supply Costs (-8% impact):
   The Commercialised case considers increased efficiencies in the electrolysers leading to reduced power supply costs, as well as reductions in renewable power costs from

generators. Efficiency improvements of up to 10% could be expected for the PEM electrolysers considered, which would result in 10% less power to be supplied to the electrolysis with related cost reductions in associated electrical equipment, and forecasts of renewable energy costs which follow baseload wholesale electrical power pricing, show a reduction of approximately 20% in 30+ year horizon due to increases renewables due to politically driven shift away from gas, resulting in cheaper imports into the UK i.e. 10% average power pricing reduction for the duration of a 30 year project(8). This difference equates to an 8% LCoH reduction.

4. Reduction in Hydrogen Equipment Costs (-5% impact):
   The Commercialised case considers hydrogen equipment cost reductions as the market matures (including electrolysers, compressors, storage, and control equipment). The range of cost reductions with could be expected as up to 30% on electrolysers and associated balance of plant, with lesser reductions up to 10% on related control equipment. This difference equates to a 5% LCoH reduction.

5. Other:
   Other impacts have a minimal impact on the LCoH of the commercialised case and are the result of slight interdependencies between assumptions.

Overall, the 35 MW Commercialised Case LCoH of £6.87/kg hydrogen represents an estimate of the production costs of a real project in a mature UK market, which shows the power supply costs dominating. The LCoH should be taken in context and considered against overall end-to-end project requirements and benefits, as well as the ability to decarbonise a hard-to-abate application.

4.3.2.4. Total Cost of Hydrogen & Hydrogen Business Model

The LCoH allows a ‘rule-of-thumb’ comparison to be made for a hydrogen technology route against other hydrogen technologies up to the point of production. To set the project in context, the full end-to-end consideration for total cost of hydrogen needs to be taken into account which includes elements downstream of hydrogen production e.g. storage, distribution, facility re-configuration and end-use, as well as equity return requirements.

The total cost of hydrogen production for this project considers the additional CAPEX, OPEX, and equity return impacts for the project components downstream of the hydrogen production for the 15 MW Base Case, 35 MW Current Case, and the 35 MW Commercialised Case. For this analysis, the project lifetimes were assumed to be 30 years in all cases reflecting typical process plant and machinery lifetimes; this is due to the likelihood of equipment being able to generate revenues beyond an initial 15 year support period which could be taken into account for consideration of equity return and HBM support discussions. The results are tabulated in Table 4.3.3.

In order to calculated the TCoH an Equity IRR hurdle rate of 10.5%(12) is assumed which is based on an industrial reference for illustrative purposes.

Table 4.3.3 Total Cost of Hydrogen

Component	Total Cost of Hydrogen (£/kg H_2*)			Total Cost of Hydrogen (£/MWhLHVH_2*)		
	15 MW Base Case	35 MW Current Case	35 MW Commercial Case	15 MW Base Case	35 MW Current Case	35 MW Commercial Case
Hydrogen Production	11.60	11.63	6.87	348.03	348.93	206.12
Hydrogen Storage, Distribution, Facility Re-configuration and end-use	1.36	1.26	0.55	40.80	37.80	16.50
Minimum market return expectation**	6.93	7.08	1.32	207.92	212.42	39.60
Total Cost of Hydrogen	19.89	19.97	**8.74**	596.76	599.16	**262.23**
20% CAPEX Grant***	-2.44	-2.52	N/A	-73.21	-75.61	N/A
Subsidised LCOH	**17.45**	**17.45**	N/A	**523.55**	**523.55**	N/A

*conversion factor of 0.033 MWhLHV/kg hydrogen
**10.5% IRR assumed Base case & Current Case, 5% IRR for Commercialised Case
***the effect of funding includes knock-on impacts to downstream components & financial costs

4.3.3. Hydrogen Business Model

The Hydrogen Production Business Model (HBM or HPBM) is a support mechanism in development by the UK Government intended to provide revenue support as a ‘contracts for difference’ style model between the total cost of hydrogen compared to a reference price based on the cost of natural gas[7].

The feasibility study investigated the level of support that would be required to support the 15 MW Base Case project by determining the expected natural gas costs and comparing the gap to the total cost of hydrogen.

The forecast natural gas prices are based on historical natural gas pricing data from the ROCKWOOL facility with a forecast based on market trends including cost of carbon, based on the high bound forecast data[8]. The forecast pricing averaged over 30 years was determined to be approximately £76/MWh on a HHV-basis, or £84/MWh on a LHV-basis for natural gas[8].

The pricing of £84/MWhLHV can be used as a close comparison of the total cost of natural gas against the total cost of hydrogen, given that the downstream CAPEX elements (storage, distribution, facility reconfiguration) are a small proportion of the overall total cost of hydrogen. The comparison is therefore against the £597/MWhLHV hydrogen for the 15 MW Base Case (and £262/MWhLHV for the commercialised case). Compared to a “kg/hydrogen” measurement, the natural gas price would be equivalent to £2.80/kg hydrogen; this

£2.80/kg hydrogen is the average price that the hydrogen offtaker could be expected to pay for the hydrogen supply.

Based on this preliminary analysis, the indicative support required from the HBM for the 15 MW Base Case would be £14.65/kg hydrogen (which includes effect of NZHF 20% CAPEX funding).

The analysis demonstrates that for this hard-to-abate application, the driver of decarbonisation is unlikely to be for cost reasons against the business-as-usual use of natural gas, based on current forecasts for natural gas and carbon pricing. However, the market is quickly changing and significant changes in policy and market conditions could be expected including considerations around security of energy supply and net zero, leading to stronger commercial reasons to implement this industrial fuel switch.

4.3.3.1. Levelised Cost of Abatement

The determination of levelised cost of abatement is based on the key factors below

1. Amount of CO_2 abated i.e. the difference between:
    - Amount of CO_2 produced under a counterfactual case
    - Amount of CO_2 produced under the project
2. Cost of the abatement i.e. the difference between:
    - Cost of the counterfactual case
    - Cost of the project

For determination of the amount of CO_2 abated, see Section 4.2.4.1. The Costs of abatement for the counterfactual case and for the project were determined (excluding market return component) and compared with historical natural gas system installation and fuel pricing data from the ROCKWOOL site. The results of the levelised cost of abatement considerations are shown in Table 4.3.4.

Table 4.3.4 Levelised Cost of Abatement Calculation

	Units	15 MW Base Case	15 MW with NZHF Funding	35 MW Current Case	35 MW with NZHF Funding	35 MW Commercial Case (30 year)
Hydrogen Demand	kg	12,718,539	12,718,539	29,160,495	29,160,495	58,320,990
LCoH plus downstream components	£/kg	12.96	11.83	12.89	11.73	7.42
Total Hydrogen Costs for hydrogen demand excl. market return	£m	164.8	150.5	375.9	342.1	432.7
Total Natural Gas BAU Cost	£m	40.7	40.7	94.7	94.7	189.5

	Units	15 MW Base Case	15 MW with NZHF Funding	35 MW Current Case	35 MW with NZHF Funding	35 MW Commercial Case (30 year)
Total Cost of Abatement	£m	124.0	109.7	281.1	247.3	243.3
CO_2 Abated	teCO_2	93,525	93,525	215,595	215,595	431,190
Levelised Cost of Abatement	**£/teCO_2**	**1,326**	**1,1723**	**1,304**	**1,147**	**564**

4.3.4. Benefits and Challenges of the Solution

The project has developed a tremendous amount of knowledge and understanding of the key technical, economic, and regulatory aspects of end-to-end industrial fuel switching project.

4.3.4.1. Benefits of the Solution

There are many benefits of the solution discussed within this report including:

- Decarbonisation and fossil fuel use reduction: Green hydrogen can help reduce the carbon emissions associated with industrial processes and energy production by replacing fossil fuels.
- Use of oxygen as a by-product: Oxygen is typically vented in electrolytic hydrogen production however the project has determined a potential use case to boost cupola performance.
- Potential heat source for offsite applications: Waste heat is recaptured and reused across the process for example to generate electricity, provide hot water and heating as well as preheating of input streams. The heat generated by the electrolyser is therefore not required and is potentially available for offsite applications such as digital farming or district heating
- Decarbonising the built environment: Embodied carbon is fast becoming an area of focus in the building stock as ever rising building standards drive buildings towards net zero operational carbon. There is therefore growing demand for reduced carbon building materials.
- Sustainability: Green hydrogen is produced using renewable energy sources and is therefore a sustainable fuel option.
- Energy security: green hydrogen can help improve energy security by reducing dependence on fossil fuels and increasing reliance on renewable energy sources.
- Innovation and patentable technology: The development of green hydrogen technologies can drive innovation and lead to the creation of patentable technologies e.g., burner designs.
- Collaboration: The development of green hydrogen technologies requires collaboration across various industries and stakeholders, promoting cooperation and partnerships.

- Job security and creation: Attracting inward investment from our parent company secures the future of the site and the jobs based here. Supply chain development can lead to job creation.
- Skills and training: The development of green hydrogen technologies requires skilled labour, providing opportunities for training and upskilling the workforce.
- Reputation: Development of green hydrogen can enhance the reputation for the project team partners as thought leaders advancing understanding of new and emerging technologies.
- Inward investment: The development of a green hydrogen industry can attract inward investment to Wales, promoting economic growth and development.

4.3.4.2. Challenges of the solution

The project has considered the technical, economic, and regulatory challenges amongst others. Some of the key challenges include:

- High cost: The production of green hydrogen is currently more expensive than producing hydrogen from fossil fuels, making it less competitive in some markets.
- Infrastructure development: A significant investment in infrastructure is needed to support the production, transport, and storage of green hydrogen, including the development of electrolysers and hydrogen refuelling stations.
- Energy efficiency: The process of producing green hydrogen requires significant amounts of energy and improving the efficiency of the production process will be critical to reducing costs.
- Scale-up: While there are several demonstration projects in operation, scaling up the production of green hydrogen to meet the needs of industrial and energy applications will be challenging.
- Regulation: There is a need for clear regulatory frameworks to support the development of a green hydrogen industry, including standards for safety and quality.
- Supply chain: The development of a green hydrogen industry requires the establishment of a supply chain, including the sourcing of equipment and the transportation of hydrogen to end-users.
- Competition with other low-carbon technologies: There are other low-carbon technologies, such as battery storage, that can compete with green hydrogen in some applications, and the relative competitiveness of these technologies will depend on the specific use case.
- Education and awareness: There is a need to educate the public, policymakers, and businesses about the potential benefits of green hydrogen and how it can be integrated into the energy system.
- Skills and training: The development of new training frameworks to upskill existing engineers and attract new talent to design, install, maintain and operate green hydrogen systems.

- Timelines: The rapid turnaround required for this study meant some opportunities for meaningful engagement with equipment suppliers was lost.

4.3.5. Commercialisation Potential

The feasibility study has demonstrated a strong, technically feasible end-to-end industrial hydrogen fuel switching solution that is widely applicable, adaptable, and scalable across UK sectors, particularly other industries requiring high-grade process heat.

The focus of this project has been on conversion of the largest of three stone wool production lines to hydrogen fuelling (15MW Base Case), designed to facilitate roll-out to all of the facility's three production lines natural gas consumption (35MW Current Case) as well as consideration of how the technology and financial considerations may develop beyond 2030 (35MW Commercialised Case).

These uses for post-combustion and curing ovens are difficult to decarbonise and there were no feasible alternatives to the business-as-usual use of fossil fuels (natural gas) for these applications.

The feasibility study Financial Analysis determined that the current early maturity of hydrogen technology leads to total costs of hydrogen to be above a natural gas 'business-as-usual' counterfactual case based on the current trajectory and forecast of natural gas pricing in the UK. Although there it was assessed that economics are currently not expected to drive the development of real end-to-end hydrogen fuel switching projects in the current market, it was shown that the gap between green hydrogen in the 35MW commercialised case is quickly closing the gap between the natural gas counterfactual and that the political and market landscape could very quickly change this balance as energy security and net-zero policy becomes increasingly important. Funding plays a key role in bridging this gap and public funding streams such as the Net Zero Hydrogen Fund and Hydrogen Business Model shall improve the route towards commercialisation of this technology.

The knowledge of fuel switching to hydrogen could potentially be applied to further decarbonise a further 22MW of coke consumption on the Rockwool site through gas-based melt technology; however, this specific approach has found limited feasibility at this time due to much larger scale and furnace technical development for the melt furnaces, including alternatives for electrification.

Within the UK, there are multiple manufacturing sites for insulation products that this technology is highly applicable for and could be replicated and scaled up, including another insulation products manufacturer in Wales.

Globally, ROCKWOOL has 51 stone wool manufacturing sites that could directly utilise the solution and knowledge from this project which would align with the ROCKWOOL Group's decarbonisation strategy. The findings of this IHA Stream 2A project have been in active dissemination to wider ROCKWOOL sites and has led to follow-on industrial hydrogen fuel switching projects now being explored in ROCKWOOL's sites in Germany and Spain.

The hydrogen fuel switching solution is highly applicable, adaptable and scalable across UK industry where industrial plants typically require high amounts of process heat from directfiring applications e.g., cement-making, and is particularly applicable in these related sectors where electrification alone is insufficient to decarbonise significant emission sources e.g. off-gas post-combustion. In the UK there are 2 major stone wool manufacturing plants, 47 major paper and board mills, and 12 cements plants, as well as potential applications in glass, ceramics and steel industries, that could utilise the end-to-end hydrogen solution and knowledge. The majority of UK industrial sites utilising a high amount of process heat could use aspects of the hydrogen fuel switch solution, particularly the local, decentralised power supply and hydrogen generation aspects for industrial sites not located in industrial clusters.

To this end, the project has engaged with the South Wales Industrial Cluster (SWIC) and Net Zero Industry Wales (NZIW) groups that facilitate knowledge sharing and push towards more sustainable industrial practice in Wales by 2050. The regional collaboration could further low carbon hydrogen fuel switching opportunities in other industrial settings, as well as within a future hydrogen economy with opportunities to further decarbonise industry through the supply chain including heavy transport, given the large volumes of heavy materials currently transported to support industrial facilities that include stone wool insulation production.

5. Value, Future plans, and Dissemination

5.1. Social Value

Social value benefits would be derived through a deployment project, including reduced emissions and environmental impacts, skills and employment opportunities, commercial collaborations and improving the evidence base for hydrogen as a tool for industrial decarbonisation.

5.2. Benefits Management

Stream 2A projects are limited in their ability to contribute significantly to the NZIP programme benefits. Nonetheless the strength of the working relationship between the project partners and the level of domestic and international interest in the project has been considerable and so an outline description of the benefits is provided in Table 5.2.1.

Table 5.2.1 Benefits Management

Benefit name	Description	Timeframe	Measure
Increased knowledge stimulating further innovation	Domestic and international interest in the study	At project close and over 1 year	Qualitative
	Publication of project reports	At project close	1
	Publication of project reports	End 2025	3
	Media coverage including announcement of projects	At project end	14
	Media coverage including announcement of projects	Over 1 year	+2
Domestic and international collaborations	Collaboration formed through Stream 2A process	At project close	3
	Collaboration formed post-project	End 2025	4

5.3. Dissemination

Dissemination activities from the project have been summarised in Table 5.3.1.

Table 5.3.1 Dissemination

Title of Activity	Category of Activity	Description of Activity	Stakeholders Engaged	Date
Press release	Media	Press release announcing the project achieved good traction	Published in industry and sustainability specific publications	31/10/2022
Interview	Media	Interview conducted between the project lead and Hydrogen Industry Leaders and published.	Industry	14/12/2022

Title of Activity	Category of Activity	Description of Activity	Stakeholders Engaged	Date
Case study and presentation	Industry	Request made to submit a case study into the South Wales Industrial Cluster project report for 'Cluster Plan 2' which will set out a roadmap to decarbonisation for South Wales industry. Alongside publication, there could be an opportunity to present the case study at the launch event.	Industry and policy audiences	13/03/2023
Presentation	Industry	The Danish UK Association, a Danish embassy led business association of which ROCKWOOL is a member, will host an Industrial Decarbonisation event at the embassy later this year. ROCKWOOL are topic sponsors for the event and will provide an overview of this study.	Industry	Date TBC
Presentation	DESNZ event	DESNZ online event allowing Stream 2A participants the opportunity to present their studies.	Industry and policymakers	27/03/2023

6. References

(1) Gigawatt green hydrogen plant State-of-the-art design and total installed capital costs

(2) IRENA, Green Hydrogen Cost Reduction Scaling Up Electrolysers to Meet The 1.5°C Climate Goal report

(3) FCH, The Study on Early Business Cases for H2 In Energy Storage and More Broadly Power to H2 Applications Final Report, 2017

(4) IRENA, Hydrogen From Renewable Power Technology Outlook For The Energy Transition report

(5) E4tech, Development of water electrolysis in the EU Final Report 2014

(6) BEIS, Hydrogen Production Costs 2021, August 2021

(7) BEIS, Agreement For The Low Carbon Hydrogen Production Business Model: Heads Of Terms, December 2022

(8) Aurora Energy Research, GB Power Market Forecast, October 2022

(9) UK Government BEIS & DEFRA, Conversion factors 2022: full set (for advanced users), Sept 2022

(10) AACE International, Cost Estimate Classification System – As Applied In Engineering, Procurement, And Construction For The Process Industries

(11) Town and Country Planning Association, Town and Country Planning Act 1990, Available From: https://www.legislation.gov.uk/ukpga/1990/8/contents, Last Accessed Feb 2023

(12) Trinomics, Rate of Return for Renewable Energy Investors, February 2020, Available from: https://trinomics.eu/wp-content/uploads/2020/12/Trinomics-2020-IRR-studie-voor-VEA.pdf Last accessed: Feb 2023

(13) The National Archives, The Planning (Hazardous Substances) Regulations, Available from: https://www.legislation.gov.uk/uksi/2015/627/contents/made, Last accessed: Feb 2023

(14) Health and Safety Executive, Control Of Major Accident Hazards Regulations 2015, Available From: https://www.hse.gov.uk/comah/background/comah15.htm Last Accessed: Feb 2023