International Hydrogen Ramp-up Programme – H2Uppp

Feasibility Study Report: Development of an 820 TPD Green Methanol Project

Malkangiri, Odisha, India

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H2Uppp

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List of Abbreviations

ACF	Activated Carbon Filter
AEM	Anion Exchange Membrane
AWE	Alkaline Water Electrolysis
BESS	Battery energy storage system
CO_2	Carbon Dioxide
CTE	Consent to Establish
DAC	Direct Air Capture
DM	Demineralised
DMF	Dual Media Filter
EPC	Engineering, Procurement, and Construction
GH	Green Hydrogen
GHG	Greenhouse gas
GHP	Green Hydrogen Generation Plant
GW	Gigawatt
GW	Gigawatt
H_2	Hydrogen
ISBL	Inside Battery Limit
KOH	potassium hydroxide
LCOM	Levelised Cost of Methanol
LLI	Long Lead item
LOHC	Liquid Organic Hydrogen Carrier
MMT	Million metric tons
MMTPA	Million metric tons per annum
MTJ	Methanol to Jet
MW	Megawatt
NaOH	Sodium hydroxide
OSBL	Outside Battery Limit
PEM	Proton Exchange Membrane
PPP	Public-Private Partnership

PSA	Pressure Swing Adsorption
RE	Renewable Energy
RED	Renewable Energy Directive
SAF	Sustainable Aviation Fuel
SOEC	Solid oxide electrolysis
SPCB	State Pollution Control Board
TPD	Tons Per Day
TRL	Technology Readiness Level
ZLD	Zero Liquid Discharge

Executive Summary

Methanol is a highly versatile molecule with a wide range of commercial and industrial applications. It is widely used as a transportation fuel, a chemical feedstock for producing intermediate chemicals such as formaldehyde and acetic acid, and as a precursor for various final products including wood adhesives, paper, paints, and other industrial materials. In addition, methanol serves as a cleaner-burning fuel for power generation, with rapidly growing adoption in marine applications due to its lower emission profile compared to conventional fossil fuels.

Given the global transition toward cleaner energy systems, the substitution of grey methanol with green methanol is an essential step in reducing lifecycle greenhouse gas emissions and supporting sustainable industrial development. Green methanol produced using renewable based hydrogen and biogenic CO_2 offers significant decarbonisation potential across multiple sectors, including chemicals, mobility and power.

This feasibility report assesses the viability of producing green methanol using green hydrogen generated through renewable-powered electrolysis, combined with biogenic CO_2 captured from sustainable sources. The study evaluates:

- Technical readiness and maturity of available process technologies
- Resource requirements for large scale, continuous operation
- Cost economics, including capital and operating expenditures
- Emission reduction benefits relative to conventional methanol pathways

The project objective is to assess the feasibility of green methanol as a competitive, low-carbon alternative for reducing lifecycle greenhouse gas emissions across multiple downstream industries.

For the proposed plant configuration, the following feedstock quantities will be required:

- Hydrogen: 6,780 kg/h produced via electrolysers operating on renewable energy
- Carbon dioxide: 48.76 TPH captured from biogenic CO_2 sources

These feedstock streams are tailored to support continuous green methanol synthesis at the designed plant capacity.

1 Introduction

ReNew E-Fuels Private Limited (hereinafter referred to as ReNew), established in 2011, is one of India's leading renewable energy companies in terms of total energy generation capacity. Since commencing operations with a 25.2 MW wind project in Jasdan, Gujarat, the company has grown exponentially, and has a current renewable asset base of over 20.2 GW, including projects under development and in the pipeline.

ReNew is planning for setting up a green methanol plant. It is proposed that green methanol (referred to as "PRODUCT") produced shall be exported or utilised indigenously to cater to the energy demand. The proposed facility shall be using green hydrogen produced from water electrolysis using water and renewable energy (RE) as input / feed for electrolyser. RE would be fed from ReNew power plant (hybrid - solar & wind) through open access to meet its power input requirement. The proposed facility will utilise 100% of the hydrogen produced in the project to manufacture green methanol.

2 Project Background

The vision for India's Green Hydrogen Economy was set on 15 August 2021 (75th Independence Day) with the launch of the National Hydrogen Mission by the Prime Minister of India. In January 2023, the Indian National Green Hydrogen Mission was approved by the Government of India with an outlay of EUR 2.25 billion until 2030. The mission aims at making India a global hub for green H_2 production, utilisation and export. Due to its low prices for RE-based electricity production, India has the potential to produce green H_2 and its derivatives on a competitive basis.

A key challenge lies in scaling up the production and utilisation of green methanol, which is expected to play a critical role in the global energy transition and is needed in many industrial processes (e.g., formaldehyde production, production of gasoline, methanol-to-olefins, Methyl Tert-Butyl Ether (MTBE), solvent applications, etc.). In addition to green methanol projects for the local market, projects for the export market, where higher offtake prices are expected, can also support the general market ramp-up of green methanol projects in India as a first step.

To overcome initial market and finance barriers, the International Hydrogen Ramp-up Program (H2Uppp), initiated by the German Federal Ministry for Economic Affairs and Energy (BMWE), supports bankable Power-to-X (PtX) projects and facilitates access to guaranteed offtake. In this context, the Deutsche Gesellschaft für Internationale Zusammenarbeit (GIZ), as the executing organisation of H2Uppp, has formed a public-private partnership (PPP) with 3E and ReNew to develop a green methanol project aimed at export to Europe. 3E is a Belgium-based technology and technical advisory company providing digital solutions and expert services to optimise renewable energy assets, including storage and GH_2.

To further explore how green methanol projects can be set up in India and how they can be aligned with European regulations such as RED II, this PPP project has conducted a comprehensive pre-feasibility study of a green methanol project suitable for domestic consumption as well as for export. The green methanol will be produced using hydrogen through the water electrolysis process and CO_2 sourced from a biogenic source.

2.1 Objective of H2Uppp PPP Measure

The objective of the H2Uppp PPP measure is to enable the development of a bankable green methanol export project from India to the EU by building capacities and enabling an optimised design and configuration of the project in line with EU RED regulations.

2.2 Document Scope

This document covers the feasibility study report for the production of an 820 TPD green methanol project. This project is considered in the state of Odisha, India.

2.3 Green Methanol Uses

Green methanol can serve as a direct, drop-in substitute for conventional fossil-based methanol across a wide range of applications. These include use as a transportation fuel, a chemical feedstock and an energy carrier for power and heat generation.

Methanol demand in transportation fuels is growing. In road transportation, methanol used directly or blending with gasoline (e.g., M15, M85) in internal combustion engines reduces lifecycle GHG emissions. The maritime sector has emerged as a key area of adoption for methanol-based fuels. International shipping currently accounts for roughly 3% of global GHG emissions and approximately 9% of emissions from the transport sector, while handling 80-90% of global trade by volume. Methanol's efficient combustion characteristics, lower pollutant emissions and compatibility with emerging dual-fuel engine technologies make it an attractive alternative for reducing the carbon intensity of maritime operations.

Another critical application of methanol is in decarbonisation of aviation industry by the replacement of fossil jet fuel with sustainable aviation fuel (SAF) through MTJ (Methanol to Jet) pathway. Methanol is also a foundational industrial chemical primarily used to produce formaldehyde, acetic acid, and plastics, with growing applications in olefins (ethylene/propylene) and fuel additives.

A key advantage of green methanol is its compatibility with existing storage, handling and distribution infrastructure, including tanks, pipelines and marine bunkering systems. This reduces the need for large-scale capital investment and enables faster deployment compared with alternative low-carbon fuels.

Table 1 Application of Methanol

Applications	Chemical / Fuel	End Uses
Chemical Applications	Formaldehyde	Primarily used as feedstock for formaldehyde which is an intermediate used for manufacturing of wood adhesive for plywood and particle board. Formaldehyde resins are also used as raw material for a variety of building and automotive products.
	Acetic Acid	Used to produce a wide variety of products including adhesives, paper, paint, plastics, resins, solvents, pharmaceuticals and textiles
Energy Applications	Methanol-To-Olefins (MTO)	Used as an alternative feedstock to produce light olefins (ethylene and propylene) to produce various everyday products used in packaging, textiles, plastic parts/containers and auto components.
	Methyl Tert-Butyl Ether (MTBE)	Used as a gasoline additive to increase octane and reduce emissions.
	Fuel applications	Used as an alternative clean-burning fuel for transportation, industrial boilers, kilns and for cooking stoves.
	Dimethyl Ether (DME)	A clean-burning fuel with growing importance in both household and transportation energy applications.
	Aviation Fuel	The methanol is the feedstock for the production of sustainable aviation fuel through MTJ pathway.

3 Project Description

The project has been designed as a 100% export-oriented green methanol production plant and would cater to the demand of green methanol for the shipping sector, primarily for the EU market. The project is expected to be completed in total duration of 45 months from Zero Date.

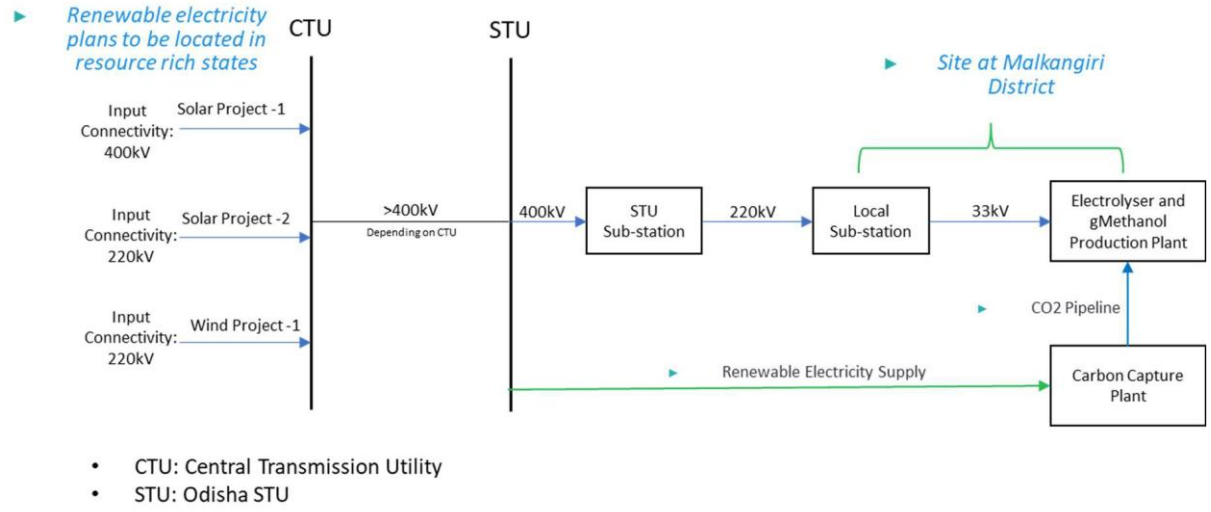


Figure 1: Simplified Project Set-Up

The project is designed as a greenfield project with new green hydrogen and green methanol production units and new renewable energy (RE) plants (solar and wind). The location of the green hydrogen and methanol projects is fixed i.e in Malkangiri district, while the identification of the location of the new RE plants is also the part of the project. Several RE projects are currently under development, and the final selection of RE sites is yet to be determined. Site selection will be based on achieving a higher Capacity Utilisation Factor (CUF) and/or the availability of round-the-clock (RTC) green power, with a focus on RE-rich states.

The green hydrogen and methanol production facilities are planned to be co-located, ensuring optimal integration with the selected renewable energy sources. Electricity will be supplied to the methanol plant through the public grid. The potential CO_2 source(s) close to the location of the methanol plant that use biomass for heating purposes as allowed under Delegated Act (EU) 2023/1185 have been identified. A carbon capture system will be co-located at methanol production facility. The basic set-up of the project is outlined in the following figure.[1]

For export, the port of dispatch has been identified as Kakinada Port and new methanol storage facilities will be constructed at the port. Methanol will be transported by pipeline from the production unit to the storage tanks at the port. Methanol will be loaded from the storage tanks onto the ship for delivery.

Broadly this Project shall comprise of the following units:

- Green Hydrogen Unit & Hydrogen Storage
- CO_2 Capture Unit and Transfer
- Green Methanol Synthesis Unit
- Methanol Storage & Transfer
- Utilities & Offsites

The final product (green methanol) shall be transported from the site to the end users.

[1] *The voltage level and connectivity are subject to the approval from competent authority*

3.1 Renewable Energy

As part of this PPP project, the most suitable locations of new wind and solar farms fitting the expected capacity of 1.5 GW to 1.75 GW are studied across the country. A brief of the approach considered for the analysis is narrated below:

To define the suitable locations, the methodology divides the country into project opportunity areas (POA) which are each given a preference score. This allows to rank the best area in the country for development of wind or solar farms. The following steps were taken:

- Country-wide GIS data representing site suitability factors such as land use, orography, etc. was collected, processed and presented onto a uniform geographical projection and spatial resolution
- A typical wind turbine and PV plant configuration was selected as most suitable on a country level
- A POA size was defined that fits the targeted installed renewable energy capacity for the project
- Attributes to be evaluated per POA were identified. These attributes are meant to allow evaluating each POA with respect to one another
- An analytical hierarchical process matrix was elaborated for renewable sources, to give preference weights to the attributes in order to rank the different POA
- A constraint layer was created to mask the unavailable area out of the POA

The outcomes of this analysis indicates that high-score areas for wind plants are more localised geographically than for solar plants. The wind resource is relatively low even in favourably identified zones while the solar resource has a higher potential for electricity generation, lowering its levelised cost of energy (LCOE). In both cases, the most favourable regions are the north-western states (Gujarat, Maharashtra and Rajasthan) with resource and land availability being the main drivers in terms of LCOE. This regional cross technology overlap of high-scoring POAs provides a good opportunity to combine both technologies in those regions.

These locations are situated on the opposite side of the country relative to the selected methanol production site, planned in the state of Odisha. Nevertheless, although this is yet to be ascertained as of July 2026, they might remain eligible under the European regulatory framework for renewable fuels of non-biological origin (RFNBOs), as India is operated as a single, nationally integrated electricity grid and EU legislation does not require a physical electricity flow between renewable generation assets and hydrogen (or derivative) production facilities, provided that the applicable conditions on temporal and geographical correlation are met. The results are to be used for comparative rather than quantitative basis pertaining to the uncertainties inherent to the datasets used and assumptions made.

For details of the analysis, as mentioned above, please refer to "Site Scoping for renewables for green hydrogen production in India" report produced and launched along with this report. The study can also be accessed via the QR code below:

4 Design Basis

4.1 Plant Specifications

Plant Capacity

The Methanol Unit shall be capable of producing 820 TPD of green methanol. The Hydrogen Unit and the CO_2 capture unit shall be designed in terms of capacity to meet the CO_2 and H_2 requirements for producing 820 TPD of green methanol. The plant shall be designed for 30% turndown.

Design Life

The plant facility shall be designed considering design life of 25 years.

Feed and Product Specifications

The unit shall be designed considering the feed specifications as given below. Hydrogen shall be generated from the electrolyser using DM water. Carbon dioxide shall be sourced from a biogenic source and captured from flue gases as per the composition given below.

A. Flue Gas Parameter

Table 2 Flue Gas

Description	Unit	Value
Total CO_2 required	Ton/day	1171
Flue Gas temperature	°C	140 - 180
Flue Gas pressure	mmwc	4-8
Flue gas Composition (V/V)		
CO_2	%	12 - 20
Total CO_2 required	Ton/day	1171
Flue Gas temperature	°C	140 - 180
Flue Gas pressure	mmwc	4-8

B. **DM Water**

DM water will be used in electrolyser for producing hydrogen. Water storage and treatment units will be incorporated within the site to meet the necessary process requirements.

Table 3 DM Water Quality

S. No	Quality	Unit	Value
1	pH	--	7-8
2	Conductivity (25°c)	µS/cm	< 1

C. **Product Quality**

The plant shall be designed to meet following product specifications:

Table 4 Product Quality

S. No	Product / Feedstock	Specification
1	Methanol	Purity: 99.50 % Methanol (w/w) / Water: 0.5 % w/w
2	Hydrogen	Purity: 99.999 mole %, O2< 2ppm v/v, H_2O <5 ppm v/v
3	CO_2	Purity: 99.3 mole % (Dry Basis) / 96.0 (Wet Basis)

The plant will utilise 100% of the hydrogen produced in the project to manufacture green methanol.

The optimal capacity of different unit is given in following table.

Table 5 Project Optimal Capacity

Unit	Optimal Capacity
Solar	750 MW
Wind	1080 MW
BESS	205 MWh
Electrolyser	705 MW
Hydrogen Production and storage	158 TPD
CCU	1214 TPD
Methanol Production & Storage	820 TPD

A block flow diagram of the process is given in Appendix-A.

4.2 Site Details

Source of CO_2

The capacity and round the year operation pulp and paper mill is selected as sustainable source of CO_2 for methanol plants. For target capacity of 820 TPD of methanol production, the required CO_2 is 48.76 TPH and will be met from CO_2 emitting source preferably located near the methanol plant.

Site Location

The project will be located in Malkangiri district, Odisha, in India, with an available area of 140 acres. Hydrogen and methanol production facilities are preliminarily located adjacent to each other at project site. The carbon capture unit will be co-located at the methanol production facilities.

Export port

For export, the port of dispatch has been identified as Kakinada Port and new methanol storage facilities will be constructed at an area near to the port.

4.3 Energy and Water Resources

Power Supply

The production facilities and carbon capture unit will be powered by electricity from the Indian grid from nearest substation. Total 1190 MW of RE power will be required for the production and transportation of methanol.

The port will utilise its own electricity for logistics operations. It is important to highlight that the amount of electricity consumed for logistics purposes is significantly lower than the amount required for the molecule production plants.

Source of Raw Water

Raw water supply will be from perennial Sabari River which is a tributary of Godavari River. Water allocation from the competent authority as the project progresses. The water will be drawn by dedicated intake infrastructure and transported by a dedicated water pipeline to the project location. Sufficient storage will be kept at plant location to continue uninterrupted operations during lean season. Preliminary raw water quality considered for this study is given in the following table.

Table 6 Raw Water Analysis

S. No	Parameter	Unit	Acceptable Range
1	pH	--	6.5-8.5
2	Total Dissolved Salts	mg/l	300-350
3	Calcium (as CaCO3)	mg/l	75-180
4	Magnesium (as CaCO3)	mg/l	30-80
5	Ph. Alkalinity - (as CaCO3)	mg/l	100-120
6	M. Alkalinity - (as CaCO3)	mg/l	100-120
7	Sulphate (as SO4)	mg/l	40-50
8	Chlorides (as Cl)	mg/l	80-100

The preliminary raw water composition provided herein shall be verified during the project execution phase.

5 Technology Evaluation - Methanol Production Plant

The proposed production facility is a key step toward the green economy, with the objective of producing green methanol using renewable energy, green hydrogen and captured biogenic CO_2. The plant is designed to operate entirely on renewable power and to utilise 100% green hydrogen generated within the project boundary.

Hydrogen will be produced via water electrolysis using renewable electricity supplied from a hybrid solar–wind power plant. Carbon dioxide will be captured from industrial flue gas and combined with green hydrogen to synthesise methanol through a catalytic methanol synthesis process.

A simplified block flow diagram of the process plant is given below.

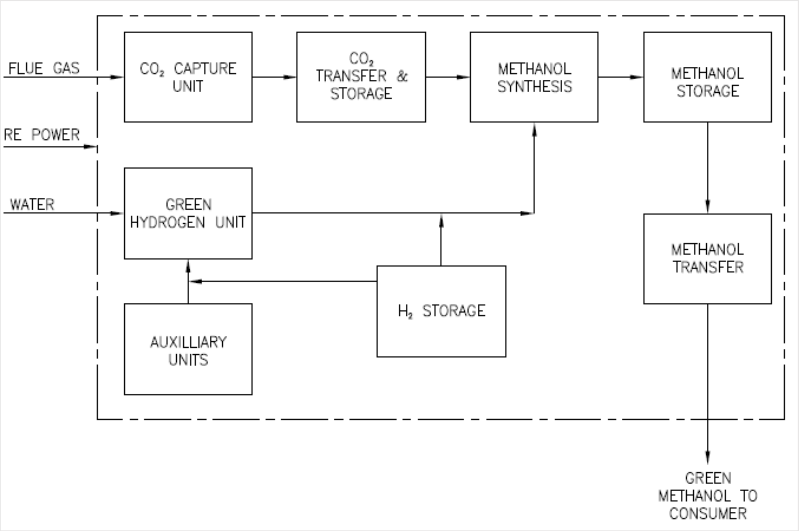


Figure 2 Simplified block flow diagram

5.1 Green Hydrogen Production Process By Electrolysis

Electrolysis is an electrochemical process that occurs due to the application of an electrical potential (voltage gradient) across two electrodes immersed in an electrolyte. The applied voltage drives oxidation and reduction reactions of chemical species, resulting in the decomposition of water into hydrogen and oxygen.There are 4 technologies for hydrogen production through water electrolysis with different operating temperature and maturity levels.

Low Temperature Electrolysis

Low temperature electrolysis (LTE) technologies operate at near-ambient temperature (NAT) conditions, typically in the range of 60°C to 80°C. Based on the nature of the electrolyte and charge carrier, low-temperature electrolysers can be broadly classified into the following three technologies:

1. Alkaline Water Electrolysers (AEL)
2. Proton Exchange Membrane (PEM) Electrolysers
3. Anion Exchange Membrane (AEM) Electrolysers

High Temperature Electrolysis

High temperature electrolysis (HTE) is an advanced water-splitting technology that operates at elevated temperatures, typically in the range of 650°C to 850°C. At these temperatures, part of the energy required for splitting water is supplied as thermal energy, which reduces the electrical energy demand and can result in higher overall conversion efficiency compared to low temperature electrolysis. High temperature electrolysis is commonly implemented using Solid Oxide Electrolysis Cells (SOECs).

5.1.1 Low Temperature Electrolysis

Alkaline Water Electrolysers (AEL)

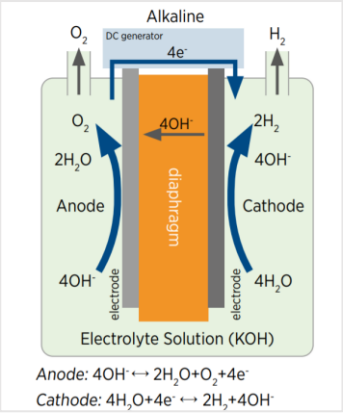


Figure 3: Alkaline water electrolysis

It is the most mature electrolysis technology for production at industrial scale.
In alkaline water electrolysis, hydroxide (OH^-) ions generated during the electrolysis reaction are transported through the electrolyte from the cathode to the anode. This ionic transport occurs across a permeable diaphragm that physically separates the two electrodes while allowing the passage of ions.

The anode and cathode compartments are separated by a diaphragm that is permeable to the alkaline electrolyte. This diaphragm prevents the mixing of hydrogen and oxygen gases while enabling the migration of OH^- anions from the cathode side to the anode side, thereby completing the internal ionic circuit of the cell.

Alkaline electrolysis requires the use of a concentrated alkaline electrolyte, typically a 20–30% aqueous solution of potassium hydroxide (KOH) or sodium hydroxide (NaOH). The electrolyte provides high ionic conductivity and supports sustained electrochemical reactions over long operating periods.

Proton Exchange Membrane (PEM) Electrolysers

In proton exchange membrane electrolysis, hydrogen ions (protons, H^+) generated by the electrolysis reaction at the anode are transported through a solid polymer electrolyte membrane to the cathode. The membrane acts both as the electrolyte and as a physical separator between the electrodes, allowing only protons to pass while preventing the mixing of hydrogen and oxygen gases.

Electrons released during the anodic oxidation reaction are conducted through an external electrical circuit to the cathode, where they combine with protons to form hydrogen gas. The solid electrolyte membrane thus enables efficient ionic transport while maintaining high gas purity and system compactness.

PEM electrolysis is a commercially mature technology with a Technology Readiness Level (TRL) of 9, and large-scale PEM electrolyser plants are currently being deployed worldwide. The technology is particularly well suited for integration with renewable energy systems due to its fast start-up times and excellent load-following capabilities.

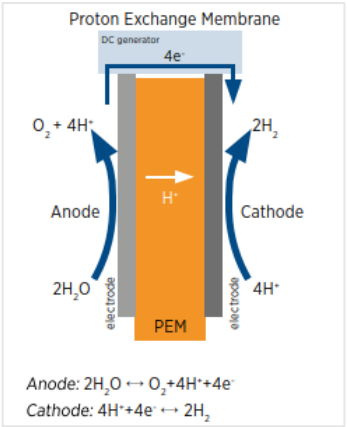


Figure 4: Proton Exchange Membrane

A key advantage of PEM electrolysers is their ability to operate at high current densities, which results in a reduced cell area and a more compact system design. Additionally, PEM stacks can tolerate differential pressure operation between the anode and cathode compartments. This characteristic enables operation at elevated pressures, with current typical operating pressures of approximately 30 bar, thereby reducing or eliminating the need for downstream hydrogen compression.

Due to these features, PEM electrolysis is considered especially suitable for applications requiring pressurised, high-purity hydrogen and dynamic operation under fluctuating power supply conditions.

Anion Exchange Membrane (AEM) Electrolysers

In anion exchange membrane (AEM) electrolysis, hydroxide ions (OH^-) generated during the electrochemical reaction are transported from the cathode to the anode through a solid anion-conducting electrolyte membrane. The membrane serves as both the electrolyte and the separator, allowing selective ion transport while preventing the intermixing of hydrogen and oxygen gases.

Electrons released at the cathode are transferred through the external electrical circuit to the anode, where the oxidation reaction occurs. The solid electrolyte design eliminates the need for concentrated liquid alkaline solutions, thereby simplifying system architecture and improving operational safety compared to conventional alkaline systems.

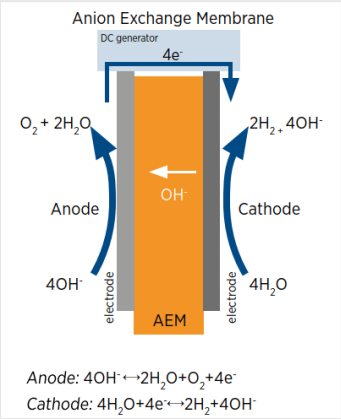


Figure 5: Anion Exchange Membrane

AEM electrolysis is a developing technology, currently assessed at a Technology Readiness Level (TRL) of approximately 4-7. One of the principal advantages of AEM electrolysis is its ability to combine benefits of both PEM and alkaline electrolyser technologies. AEM systems utilise a solid electrolyte membrane similar to PEM electrolysers, enabling compact stack designs and high current densities. At the same time, they operate under alkaline chemistry, which allows the use of non-noble metal catalysts, significantly reducing potential capital costs compared to PEM systems.

Current AEM electrolyser designs are capable of operating at pressures up to approximately 30 bar, enabling elimination of downstream hydrogen compression. As membrane durability and long-term performance improve, AEM electrolysis is expected to become a competitive, cost-effective solution for green hydrogen production.

5.1.2 High Temperature Electrolysis

Solid oxide electrolysis (SOEC)

In high-temperature electrolysis using Solid Oxide Electrolysis Cells (SOECs), oxide ions (O^{2-}) generated during the electrochemical reaction are transported through a solid ceramic electrolyte from the cathode to the anode. The solid electrolyte acts simultaneously as the ionic conductor and the separator between the electrodes, ensuring controlled ion transport while preventing gas mixing.

SOEC technology is currently under active development, with an estimated Technology Readiness Level (TRL) of 5–7. Prototype systems and pilot plants are being developed and the technology has not yet reached full commercial maturity.

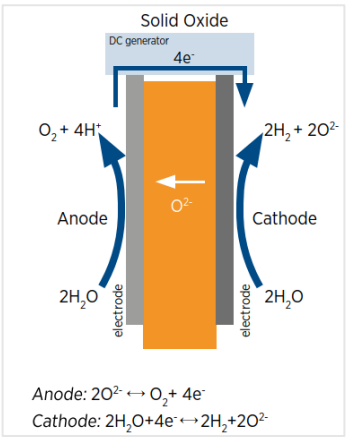


Figure 6: Solid oxide electrolysis

5.1.3 Technology Comparisons and Recommendation

As the AEM and SOEC are in development phase, for commercial scale deployment Alkaline and PEM electrolyser are preferred.

Alkaline electrolyser These systems are well suited for base-load operation where power supply conditions remain largely stable. In contrast, Proton Exchange Membrane (PEM) electrolysers exhibit fast start-up and ramp-up characteristics, making them more suitable for variable or fluctuating operating conditions. Owing to their superior dynamic response, PEM electrolysers are generally preferred for applications where hydrogen production needs to closely follow variations in renewable power output.

Alkaline electrolysers, however, have a high minimum load requirement, which limits their ability to operate efficiently under part-load conditions. This characteristic represents a disadvantage when integrating alkaline electrolysers with intermittent renewable energy sources such as solar and wind, where power availability varies continuously.

Additionally, alkaline electrolysers have longer ramp-up and ramp-down times compared to PEM systems. As a result, they are less flexible in responding to rapid changes in power input and are therefore more suitable for stable, fixed-operating conditions rather than dynamic renewable energy-driven applications.

For constant-capacity hydrogen production units, alkaline electrolyser is preferred due to their relatively lower capital expenditure (CAPEX) and proven long-term operating reliability.

5.2 Green Hydrogen Generation Unit

In the Green Hydrogen Production Unit, hydrogen is produced through the electrolysis of water using an alkaline water electrolyser. The electrolysis process is powered exclusively by renewable energy, ensuring that the hydrogen generated qualifies as green hydrogen.

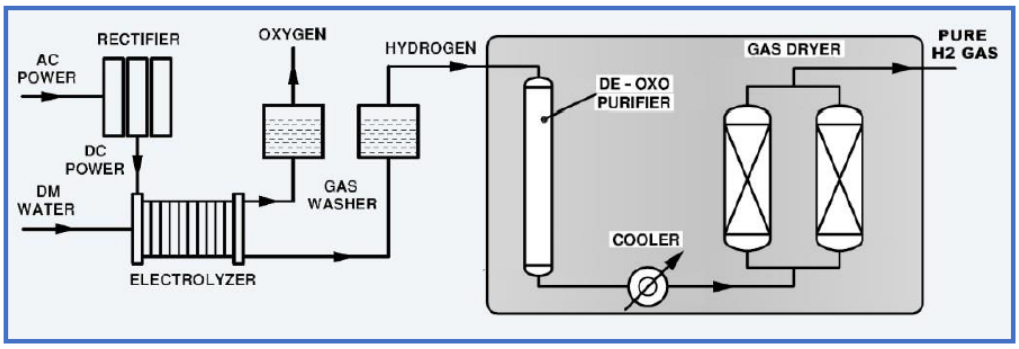


Figure 7: Block flow diagram - Green hydrogen

During electrolysis, water molecules are dissociated into hydrogen and oxygen. The oxygen generated as a by-product is presently proposed to be safely vented to the atmosphere. However, suitable provisions may be considered for the recovery and utilisation of oxygen for value-added applications, subject to economic viability and the availability of nearby consumers. Potential utilisation pathways include supply to adjacent industrial facilities, conversion to medical-grade oxygen after appropriate purification, or sale for other commercial purposes.

The hydrogen produced from the electrolyser contains trace quantities of oxygen and moisture. To meet downstream process specifications, the hydrogen gas is first routed through a De-Oxo purification unit, where residual oxygen is catalytically reacted with hydrogen to form water, thereby removing oxygen impurities from the gas stream.

Following the De-Oxo purification step, the hydrogen gas remains saturated with water vapor. The gas is therefore passed through a drying system, typically consisting of multiple beds of desiccant dryers, to reduce the moisture content to the required specification. This dehydration step is critical to prevent corrosion, avoid catalyst degradation, and ensure reliable operation of subsequent processing units.

After drying, the purified and dry hydrogen gas is suitable for further use within the facility, including its use as feedstock for the methanol synthesis unit or other downstream applications as envisaged in the project design.

TECHNOLOGY PROVIDERS

Major Technology providers:

- **Alkaline Water Electrolyser (AEL)**
  1. Thyssenkrupp Nucera
  2. John Cockerill
  3. Nel ASA
  4. HydrogenPro
  5. Longi
  6. Shuangliang
  7. Peric
- **Proton Exchange Membrane (PEM)**
  1. Cummins
  2. Plug Power
  3. ITM Power
  4. Ohmium International
  5. Siemens Energy
- **Anion Exchange Membrane (AEM)**
  1. Enapter
  2. Alchemr
- **Solid Oxide Electrolysis Cells (SOEC)**
  1. Bloom Energy
  2. Sunfire
  3. Elcogen

5.2.1 Challenges in Electrolyser technology

Operation at partial load range

Turndown in electrolyser capacity is inevitable due to variable nature of RE power supply. At partial load there are chances of the cross-diffusion of H2 and O2. Operation at partial ranges is limited by the ability of the membrane to prevent crossover.

Stack Degradation

Due to intermittent supply of renewable energy and generation operation, the electrolysers are claimed to have a yearly degradation of 1-1.5% in stack efficiency, resulting in increased electricity consumption for the same hydrogen production.

Stack Refurbishment & Replacement

After a period of 8-10 years, the stack is refurbished or replaced to reset the degradation of the system to the original performance. To compensate the yearly degradation of the electrolyser, an additional electricity will be required. The decision of stack refurbishment or replacement will be made based on the techno-economical evaluation of cost directly affecting LCOM.

Technology development

To make green fuels competitive with conventional fuels, with technology advancement costs of electrolysis processes are expected to fall, driven by lower power consumption and CAPEX, as well as increased stack lifetime.

5.3 Carbon Dioxide Recovery Process

Carbon dioxide (CO_2) is a feed for the Green Methanol Unit. For this project CO_2 shall be captured from a biogenic CO_2 source.

5.3.1 The Carbon Capture Technology

The concept of carbon capture has evolved over the years, with the basic process of amine scrubbing technology being patented in the 1930s. Initially used in refineries for oil hydrodesulfurisation (H2S) and sweetening of natural gas by removing H2S and CO_2, this technology relied on Monoethanolamine (MEA) as an absorber. It was later extended to the power sector to capture CO_2 from flue gas generated by natural gas- and coal-fired power plants. There are four main carbon capture approaches being developed.

1. Pre-combustion

The pre-combustion approach involves converting fuel into syngas and removing CO_2 before combustion in turbines. This approach is typically applied to coal gasification and natural gas reforming processes, where the CO_2 content in the syngas is usually above 40%.

2. Post Combustion

Post-combustion focuses on treating flue gas after combustion. The CO_2 content in the flue gas is typically less than 30%, and this approach offers an easier retrofit option, making it suitable for various industries, including paper mills.

3. Oxyfuel combustion

Oxyfuel combustion involves burning fuel in an atmosphere saturated with oxygen to increase the concentration of CO_2 in the flue gas. This approach can be combined with pre- or post-combustion carbon capture methods but requires a new combustor unit, making it more suitable for new construction projects rather than retrofitting existing plants.

4. Direct air capture

Direct air capture is capable of capturing CO_2 directly from the atmosphere. However, the concentration of CO_2 in ambient air is extremely low (around 0.04% vol), leading to energy-intensive processing steps to extract it. Direct air capture is still an area of ongoing development.

For each approach to carbon capture, several technologies have been developed. A summary of these technologies is provided below. Based on the source of CO_2, its concentration and the maturity levels of the technologies, Liquid amine-based chemical absorption is the most mature and versatile technology available and is most adequate to capture CO_2.

1. Chemical Absorption
   a. Amine
   b. Calcium Looping
2. Physical Adsorption
   a. Pressure Swing adsorption
3. Oxy-fuel combustion
4. Cryogenic separation
5. Membrane separation
6. Direct Air Capture (DAC)
   a. Liquid DAC
   b. Solid DAC

5.3.2 Process Description

An amine absorption-based CO_2 capture plant is generally divided into several functional sections, each designed to perform a specific role in the capture, purification, and delivery of CO_2 for downstream utilisation. Main section of plant are:

- Pre-treatment section
- Absorber Section
- Stripper Section
- Absorbent Purification Section

- CO_2 Conditioning section
- CO_2 compression Section (to transfer CO_2 to Green methanol Unit)

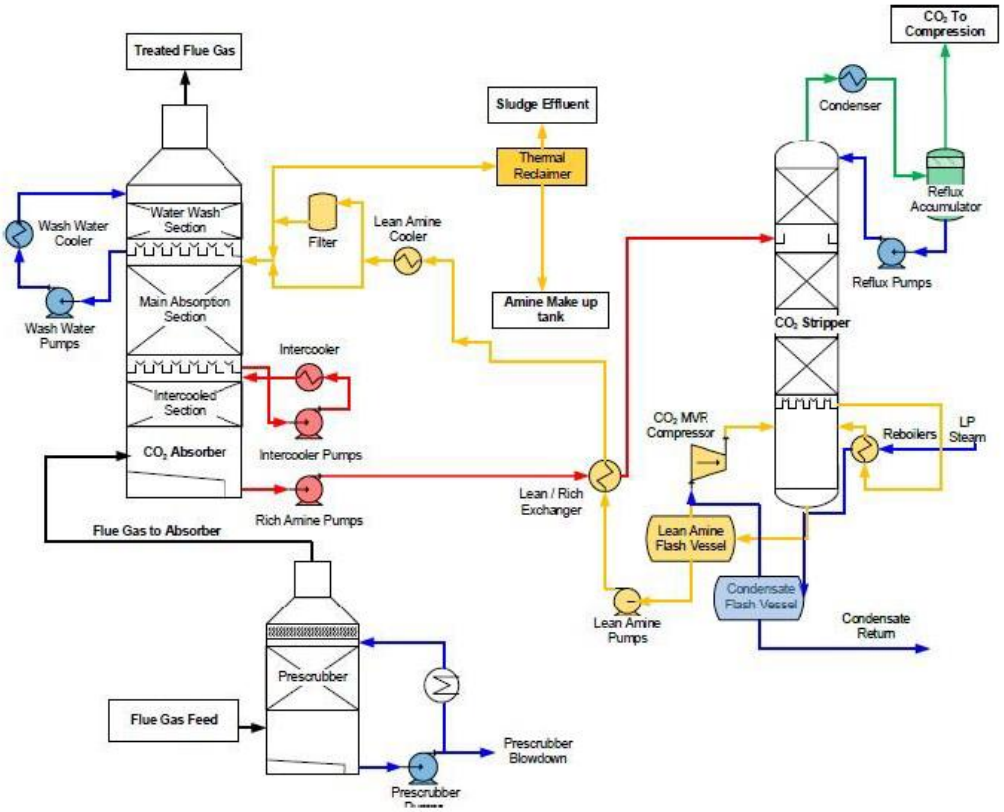


Figure 8: Simplified block flow diagram - CO_2 Capture Unit

Pre-Treatment Section

Flue gas typically contains impurities such as sulphur oxides (SO_x) and nitrogen oxides (NO_x) and is discharged at a relatively high temperature. The presence of these impurities and elevated temperatures can adversely affect the performance and longevity of the amine solvent used in the absorption process.

To address these challenges, a pre-scrubber unit is installed upstream of the main CO_2 absorber column for removal of SO_x and NO_x, Quenching and Cooling of Flue Gas and and remove residual particulates, creating stable and predictable inlet conditions for the absorber. In case the acid gas and other contaminants is in high concentration, then caustic wash is done in the pre-scrubber unit.

Absorber Section

Carbon dioxide is captured from the cooled and conditioned flue gas exiting the pre-scrubber through interaction with an aqueous lean amine absorbent in the CO_2 absorber column. The absorber is typically designed as a vertical packed column, in which flue gas flows upward counter-currently to the downward-flowing amine solution. Multiple structured or random packed beds are employed within the absorber to enhance gas–liquid mass transfer while maintaining a low pressure drop across the column. The extensive contact area provided by the packing enables efficient chemical absorption of CO_2 into the amine solvent.

The absorption of CO_2 in amine solvents is a highly exothermic process, resulting in a temperature rise within the absorber column. To manage this thermal effect, an intercooling system is incorporated.

The upper section of the absorber is equipped with a water wash system to reduce solvent losses and minimise the emission of amine vapors, aerosols, and degradation products to the atmosphere. The water wash captures entrained solvent droplets from the treated flue gas before it exits the column.

Stripper Section

The CO_2-rich amine absorbent from the absorber is regenerated in a stripper column equipped with structured packing and reboilers that generate stripping steam using low-pressure steam. Prior to regeneration, the rich absorbent is preheated in a lean-rich heat exchanger using hot lean amine from the stripper, improving energy efficiency. The regenerated lean absorbent is subsequently cooled and recycled to the absorber. Overhead vapors from the stripper are condensed to recover high-purity CO_2 for further conditioning and compression. Overall energy consumption can be reduced by incorporating a mechanical vapor recompression (MVR) system, subject to the availability and cost of electrical power and low-pressure steam.

Absorbent Purification System

The absorbent purification section maintains amine solvent quality by controlling the build up of contaminants and degradation products, thereby ensuring reliable and efficient operation of the CO_2 capture unit. This is achieved through cartridge filtration, including carbon and pre/post filters, to remove solids and foam-promoting organics, and a thermal reclaimer that treats a slipstream of the solvent to remove degradation products via vacuum distillation. The overall process produces high-purity CO_2 (about 99.9% mol on a dry basis), which is subsequently dried to meet the feed parameter of green methanol unit.

5.3.3 Major Licensor

1. Fluor

Fluor Econamine FG PlusSM is a propriety carbon capture solution with more than 30 licensed plants and more than 30 years of operation. This technology uses a solvent to capture CO_2 from post-combustion sources. The process is well suited to capture CO_2 from large, single-point emission sources such as power plants or refineries, including large facilities with CO_2 capture capacities greater than 10,000 tons per day.

2. Honeywell UOP

Honeywell UOP has a broad portfolio of carbon capture technologies with decades of experience. UOP offer different solvents including Advanced Solvent Carbon Capture (ASCC), Amine GuardTM Processes and Benfield. Selection of solvent is based on range of concentrations, removal efficiency rates, and CO_2 product specs.

3. Carbon Clean

Carbon Clean offers patented formulation of Amine-Promoted Buffer Salts for fast-acting, high-capacity carbon capture. It is built with modular components, allowing for flexible and scalable solutions to fit different industrial needs.

4. Shell CANSOLV

The CANSOLV CO_2 Capture System employs a regenerable solvent. A proprietary amine technology captures the CO_2 from the flue gas and releases it as a pure stream. Shell Catalysts & Technologies has used its experience to develop a patented CO_2 capture technology that offers cutting-edge performance, including low parasitic energy consumption, fast kinetics and extremely low volatility.

5. Mitsubhishi Heavy Industries (MHI)

MHI has developed KM CDR ProcessTM, with proprietary amine solvent KS-1TM in collaboration with Kansai Electric Power Co., Inc. (KEPCO). As per MHI, proprietary solvent KS-1 has highly efficient with the lowest energy consumption and the least degradation. Further and Advanced KM CDR Process KS-1 is also developed with KEPCO.

Summary

There are multiple technology licensors available globally for CO_2 capture units. The main differentiating technological factor is applicability and consumption of proprietary lean amine solution for CO_2 capturing. Finalisation of the licensor should be based on CAPEX and OPEX and proven references and should be fairly compared with other licensors on the same basis.

5.3.4 Challenges in CO_2 capture technology

Some of the major challenges which are faced in CO_2 capture by amine absorption are:

High Energy Requirement

Regeneration of CO_2-rich amine requires substantial thermal energy in the stripper/reboiler. Typically accounts for 60–75% of total operating cost.

Temperature Management in the Absorber

CO_2 absorption in amines is highly exothermic. Temperature rise in the absorber leads to reduced CO_2 solubility, lowers capture efficiency and increases solvent degradation and amine loss. If temperature is not controlled, it can lead to amine loss and deviation from the final CO_2 specifications.

Corrosion Issues

Rich amine solutions are highly corrosive. Higher-grade metallurgy is required to handing highly corrosive rich amine solution resulting in high initial capital cost and increases risk of unplanned shutdowns.

Sensitivity to Flue Gas Impurities (SOx and NOx)

The low concentration SOx and NOx is required for methanol feed. The process requires extensive upstream flue-gas pre-treatment.

Solvent Handling, Disposal, and Environmental Concerns

Degraded amine and reclaiming waste are classified as hazardous waste due to the presence of degradation products and corrosive constituents. Such waste streams require careful handling, appropriate neutralisation, and environmentally compliant disposal in accordance with applicable environmental regulations and waste management guidelines.

5.4 Methanol Production Process

5.4.1 Methanol Synthesis Unit

Methanol synthesis involves the reaction of hydrogen and carbon dioxide to form methanol. Industrially, methanol is produced using either high-pressure or low-pressure synthesis routes, with low-pressure methanol synthesis being the most widely adopted today. This process operates at moderate temperatures of approximately 200–350 °C and pressures of 50–100 bar using a catalyst.

The reactions during the synthesis are:

- The hydration of carbon dioxide, and
  $CO2+3H2 \leftrightarrow CH3OH+H2O$
- The reverse water gas shift
  $CO2 + H2 \leftrightarrow CO+H2O$
- The hydration of carbon monoxide,
  $CO + 2H2 \leftrightarrow CH3OH$

Which added and simplified results in:

$CO2+3H2 \leftrightarrow CH3OH + H2O$

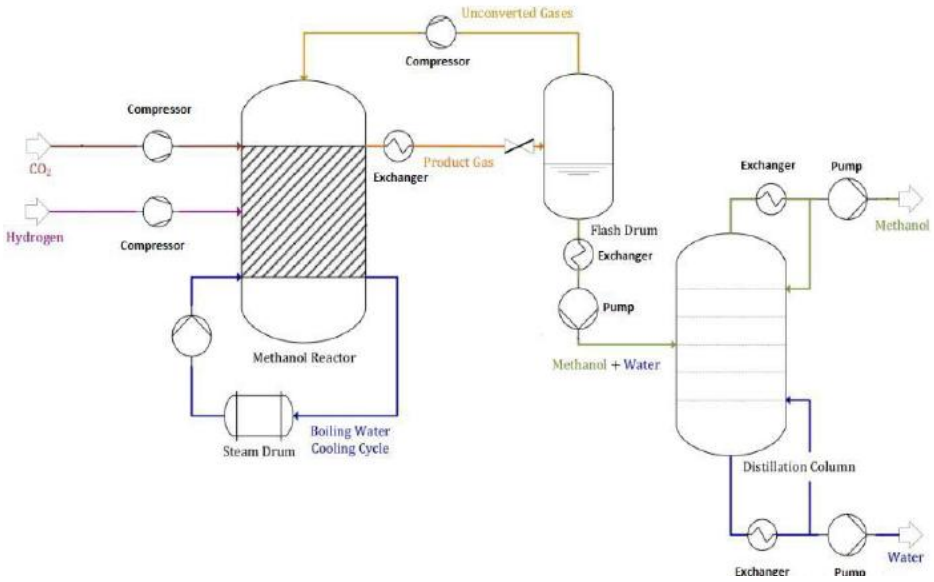


Figure 9: Simplified block flow diagram - Methanol synthesis

The methanol process is structured into three main sections based on functional objectives:

1. Methanol Synthesis
2. Methanol Purification by Distillation
3. Methanol Storage tank

Methanol Synthesis

In the proposed facility, green hydrogen produced via electrolysis and CO_2 captured from flue gas are combined as synthesis gas (syngas) to produce green methanol. Methanol synthesis also generates water and purge gas as by-products, both of which can be safely treated, recycled, or disposed of using established industrial practices. The methanol synthesis section utilises green hydrogen (99.9% purity) and CO_2-rich feed gas (>97% purity), mixed in a required stoichiometric ratio, to produce methanol. The syngas is treated to remove oxygen and contaminants, adjusted for stoichiometry, and compressed using syngas compressor before entering the synthesis loop. Methanol is produced in a water-cooled tubular reactor using a Cu/Zn/Al based catalyst at moderate temperatures, where the exothermic heat of reaction is efficiently removed by water to generate useful steam. Unreacted gases are recycled to achieve overall conversion efficiencies of >98%, with a small purge to prevent inert build-up. Energy integration, recycle compression, optional hydrogen recovery from purge gas, and start-up heating systems ensure high efficiency, flexibility, and reliable operation of the methanol synthesis process. It is envisaged to run methanol synthesis unit continuously utilising stored green hydrogen when renewable power is not available.

Methanol Purification by Distillation

Methanol purification removes water and impurities to achieve the required product quality at minimum loss of methanol. The distillation section purifies crude methanol by removing dissolved gases and low- and high-boiling impurities with minimal methanol loss. The process includes degassing by flashing crude methanol to release dissolved gases, removal of low-boiling by-products such as DME, acetone and methyl formate in the prerun column, and removal of high-boiling by-products like water and higher alcohols in the pure methanol column. Heat is supplied using low-pressure steam, and purified methanol is condensed, partly refluxed, and then sent to storage, while off-gases and heavy residues are routed to the fuel system or battery limits for safe handling.

Methanol Storage tank

Methanol is stored in both Crude Methanol Tanks and Pure Methanol Storage Tanks. The crude methanol tank provides interim storage between the methanol synthesis and distillation sections, enabling limited independent operation of these units and serving as a collection point for off-specification methanol produced from synthesis. After purification in the distillation

unit, the on-specification pure methanol is stored in dedicated pure methanol storage tanks and periodically transferred to bulk storage facilities, from where the final methanol product is dispatched to end consumers.

5.4.2 Green Methanol Technology Provider

There are several technology licensors provided for green methanol:

1. Haldor Topsoe

To produce sustainable methanol, Topsoe uses its eSMR™ technology. Synthesis gas (syngas), a crucial component in the creation of polymers (plastics) and chemicals, is produced using the ground -breaking technique. By using green power for heating and biogas as a feedstock, the eSMR™ technology is CO_2- neutral. To produce grid-quality biogas, it even uses half the CO_2, which generally costs money to separate and vent and accounts for around 40% of biogas. In the synthesis of a variety of fuels, chemicals, and polymers, methanol serves as clean fuel or a crucial intermediary (plastics).

- Variable capacity of 1,00,000 – 17,00,000 tons annually.
- Produces CO_2 and H2 from water electrolysis.

2. Lurgi

Air Liquide E&C has built, designed, or engineered more than 60 methanol plants worldwide. Over the decades, the technology has been optimised and further developed to suit all client and market requirements. The experience and the lessons learned from recently completed and on-going methanol projects are continuously introduced to each new methanol project.

Air Liquide's Lurgi LP Methanol™ process is based on the Lurgi LP Methanol™ process, an advanced technology for converting syngas to methanol at low cost in large quantities. The main feature of the Air Liquide Methanol Synthesis is the well-proven Water-cooled Reactor design. Air Liquide uses a tubular reactor, whose concept has been well-proven for more than 40 years and has been continually further improved since then.

3. Thyssenkrupp

Thyssenkrupp uses its own Uhde Methanol technology for large-scale operations. The patented and highly effective alkaline water electrolysis (AWE) technique, based on the tested chlor-alkali electrode technology created by thyssenkrupp nucera, is used to produce the hydrogen. The carbon dioxide is extracted from waste gas, flue gas, or biogas plants, among other fermentation facilities. The procedure significantly contributes to climate protection by keeping or removing this greenhouse gas from the atmosphere.

Green energy sources including wind, geothermal, and hydropower provide the electric power needed to produce green methanol. In other words, countries with a legal system that supports the use of renewable energy and the conversion of that energy into chemicals will benefit most from this green methanol technology. Thyssenkrupp provide their technology in Norway and Germany e-methanol production plant.

- Total installed capacity is 90,000 – 1,60,000 tons/year.
- Use CO_2 produced from ferrosilicon plant and H2 from water electrolysis.

Ecological and economic benefits

- Sustainable, climate-protecting technology
- Customised, cost-effective solution for every operator
- One-stop solution from a single source: EPC, plant operation, staff training, service, and spare parts from a single source – thyssenkrupp

4. Toyo Engineering

g-Methanol® is a form of renewable methanol. By combining CO_2, which is obtained from a variety of exhaust sources and used as a feedstock to produce methanol, and H_2, which is produced by water electrolysis while using renewable power. The overall process is known as "Toyo Methanol Process".

- Total installed capacity is 2,00,000 – 2,50,000 tons/year.
- CO_2 sourced from coal-fired power plant and H2 from renewable energy source/product stream valorised.

Features:

- Shell-side catalyst/wide range single train capacity.
- Steam raising methanol reactor/best use of surplus heat.
- Cross f low to cooling tubes/ maximum heat transfer.
- Radial gas flow/low pressure drop.
- Bayonet boiler tubes/no thermal stress.
- Single responsibility from process licensing to EPC including water electrolysis.
- Propose supply chain.

5. Carbon Recycling International (CRI)

The Emission-To-Liquids (ETL) technology was developed by Carbon Recycling International (CRI) and enables small-scale, economically viable conversion of renewable energy to liquid fuel. Any renewable energy source, such as geothermal, hydro, solar, and wind, can be used to produce energy. ETL is a technique of electrolytic cracking and catalytic synthesis that results in an electrochemical production process at low pressure and temperature.

- Total installed/planned capacity is 4,00,000 - 5,10,000 tons/year.
- Largest e-methanol plant announced in Finnfjord, Europe.
- CO_2 sourced from coke production facility/ethylene oxide production facility/production of ferrosilicon/ geothermal powerplant and H2 by product stream valorised/electrolysis using local hydropower.

6. Mitsubishi Gas Chemical (MGC)

MGC developed methanol production technology which converts captured CO_2 and H_2 to green methanol. This technology is known as "CO_2 based methanol synthesis technology".

- Total installed/planned capacity is 150,000 – 2,20,000 tons/year.
- MGC provide their technology in first commercial green methanol plant of Japan.
- CO_2 sourced from coke production facility/ Japan commercial plant and H_2 by product stream valorised.

The major difference between different licensors lies in Reactor Design. Licensor selection is based on CAPEX and OPEX evaluation as all the mentioned licensors have proven technology with operationl references.

5.4.3 Challenges in Green Methanol technology

Some of the major challenges which are faced in Green Methanol unit are:

1. Reactor configuration and Conversion Optimisation

Selection of reactor type and operating condition plays and important role in OPEX optimisation. Different licensors offer varied reactor designs, which significantly impact CAPEX and OPEX.

2. Heat Management in the Synthesis Loop

Methanol synthesis is highly exothermic. Effective removal and utilisation of reaction heat are required to Maintain catalyst activity, Avoid hotspots and Improve energy integration. Poor heat management can result in Catalyst deactivation, Loss of conversion and Increased purge requirements.

3. Purge Gas Management

A purge stream is necessary to prevent accumulation of inerts in the synthesis loop. However, purge gas contains valuable reactants (H_2, CO). In green methanol plants, purge minimisation is critical to reduce carbon losses.

4. Steam and Utility Optimisation

Large steam demand can require oversized boilers and OSBL infrastructure. Reducing steam import through Improved heat integration, Advanced distillation configurations (e.g., three-column purification schemes) and Electrification of reboilers is a key optimisation challenge. As an alternate option, the steam can be generated using the electrical boiler using Green power.

5. Catalyst Life and Sensitivity

Methanol synthesis catalysts are sensitive to sulfur compounds, chlorides , oxygenates and metals. Catalyst poisoning significantly impacts plant availability and operating expenditure hence, strict control of feed-gas quality is a key design and operational requirement.

6 Catalyst and Chemicals

6.1 Methanol Synthesis Catalyst

Methanol synthesis primarily use $Cu/ZnO/Al_2O_3$ catalysts to convert synthesis gas into methanol. The type of catalyst depend on the feed parameter, operating condition, end product and reactor design selected by the licensor.

6.2 Electrolyser Unit

Catalysts and chemical in alkaline water electrolysis are required for hydrogen generation, dexo and purification unit.
The other catalyst and chemical required for methanol plant are summarised in the following table.

Table 7 Catalyst and Chemicals Summary

S. No.	Type	Equipment/Unit	Unit	Quantity	Cycle Life
1	Methanol Synthesis Catalyst	Methanol synthesis Reactor	m3	55-60	4-5 years
2	De-Oxygenation Catalyst (Palladium)	Electrolyser Hydrogen Purification System	kg	41000	3 years
3	Desiccant (Molecular Sieve)	Electrolyser Hydrogen Drying System	kg	108000	3 years
4	Desiccant (Molecular Sieve)	Instrument Air Dryer	kg	1.5	3 years
5	Potassium Hydroxide (100% wt KOH)	Electrolyser (for system fill-up)	kg	1100000	5 years
6	Vanadium pentoxide (V2O5)	Electrolyser	kg	6800	2 years
7	Caustic Soda	Methanol Distillation	kg/annum	7800 (As per requirement)	
8	Amine Solvent (100 wt% basis)	CCU plant	tons/annum	100- 120	
9	NaOH Make-up(100 wt% basis)	CCU plant	tons/annum	450 - 500	
10	Coordinate phosphate / PH treatment	CCU plant	tons/annum	3 (As per requirement)	
11	Cooling Tower	Antiscalant	tons/annum	96	
		Biocide	tons/annum	212	
		Corrosion inhibitor	tons/annum	96	
		H2so4	tons/annum	694	
		Chlorine Gas	tons/annum	694	
12	Water Treatment Plant	Ferric Chloride	tons/annum	301	
		Gas chlorination	tons/annum	17	
		Antiscalant	tons/annum	7	
		Sodium Meta Bisulfite	tons/annum	6	

		Caustic	tons/annum	42	
		HCL	tons/annum	90	
		Dewatering Polymer	tons/annum	7	
13	Effluent Treatment Plant	Ferric Chloride	tons/annum	56	
		Sodium hypochlorite	tons/annum	39	
		HCl	tons/annum	597	
		Antiscalant	tons/annum	6	
		Sodium Meta Bisulfite	tons/annum	6	
		Dewatering Polymer	tons/annum	40	

7 Effluent and Emissions Summary

Effluents and emissions are by-products of various utility and processes within plant. Hazardous or flammable gases will be safely disposed through flare. Non-hazardous gases like oxygen or air will be vented to atmosphere at safe location.

Flare is provided to safely burn the relief gases during venting operation at start- up, trip or other upset operating conditions of electrolyser and process plant. Effluent generated will be collected and treated in effluent treatment plant. The list of major effluent and emissions is given in below table.

Table 8 Emission Summary

S. No	Type	Frequency	Quantity	Remarks
1	Process Gaseous Waste Streams	Continuous	500-550 Nm3/hr H2: 55-65 mol% CO + CO2: 15-25 mol% Others : 10-30 mol%	To Flare (there is no direct release of any gases to the atmosphere)
2	Off-Spec Methanol Tank Vent	Intermittent	300-350 Nm3/hr (Nitrogen containing traces of Methanol)	Vent to atmosphere at safe location
3	Product Methanol Shift Tanks Vent	Intermittent	260-300 Nm3/hr (Nitrogen containing traces of Methanol)	Vent to atmosphere at safe location
4	HP Flare Package (Peak Emergency flowrate)	Emergency Scenario	350-400 ton/hr H2: 75 mol% CO_2: 25 mol%	
5	Oxygen from Electrolyser	Continuous vent to atm	1,01,780 kg/hr O2 > 98.5 mol%	Vent to atmosphere at safe location
6	Treated gas from CCU Absorber	Continuous vent to atmosphere	250-300 ton/hr consisting of mostly nitrogen	Vent to atmosphere at safe location
7	Hydrogen	Intermittent & Emergency Scenario	12.6 ton/hr consisting of mostly hydrogen	Vent to atmosphere at safe location

Table 9 Effluent Summary

S. No	Type	Frequency	Quantity	Remarks
1	Water Treatment Plant including DM Plant and Cooling Tower Package	RO Reject, CT Blowdown etc.	205 m3/hr	To ETP (after treatment in ETP, water is reused within the system, resulting in zero discharge from plant)
2	Waste Water from Methanol Unit	Distillation water and compressor condensate	29 m3/hr	
3	Liquid effluent from CCU Plant	Effluent liquid from thermal reclamation system	51 m3/hr	

8 Storage and Transportation Solutions

8.1 Hydrogen Storage

One of the primary challenges associated with hydrogen utilisation is the development of safe, efficient, and scalable storage solutions. Several hydrogen storage technologies have been developed, each characterised by distinct technical trade-offs in terms of energy density, cost, efficiency, safety, and system complexity.

8.1.1 Physical Storage

8.1.1.1 Gaseous Storage

A. Salt Caverns

Salt caverns are a proven large-scale storage option for hydrogen, particularly well suited for bulk, long-duration, and seasonal energy storage

B. Depleted Gas Fields

Depleted natural gas reservoirs represent a potential option for large-scale underground hydrogen storage, particularly for long-duration and seasonal energy balancing. It present greater technical uncertainty compared with salt caverns.

C. Pressurised Storage

One widely adopted hydrogen storage approach involves maintaining hydrogen in its gaseous state under high pressure. Compressed gaseous hydrogen storage is a mature and commonly deployed technology, offering relatively low operating expenditure compared with alternative storage options. The storage tanks are divided into type I to type V depending on the material and operating pressure.

8.1.1.2 Liquid Storage

Cryogenic hydrogen storage involves storing hydrogen in its liquid state at extremely low temperatures, typically around −253 °C (20 K). At these conditions, hydrogen liquefies, enabling significantly higher volumetric energy density compared with compressed gaseous storage at ambient temperature and pressure. As a result, liquid hydrogen storage is commonly considered for applications requiring large storage volumes or high transport efficiency.

This approach offers a higher volumetric energy density than compressed gaseous hydrogen storage; however, it requires specialised cryogenic tanks, insulation systems, and handling equipment to maintain the extremely low storage temperatures. These infrastructure and operational requirements significantly increase both capital and operating costs, making cryogenic hydrogen storage considerably more expensive and complex than high-pressure gaseous hydrogen storage.

8.1.1.3 Key Challenges

Key challenges in hydrogen storage and transportation arise from several degradation mechanisms that can lead to failure of storage vessels, pipelines, and associated equipment. These mechanisms are associated with hydrogen–material interactions and include:

- Hydrogen Embrittlement (HE):
- Hydrogen Induced Cracking (HIC):
- High Temperature Hydrogen Attack (HTHA):
- Hydride Embrittlement:.

These degradation processes primarily affect low carbon and low alloy steels commonly used in pipelines, pressure vessels, and tubing. As a result, material selection, operating condition control, and adherence to hydrogen specific design and inspection standards are critical for ensuring the safety and reliability of hydrogen infrastructure.

8.1.2 Chemical Storage

Chemical hydrogen storage involves the binding or adsorption of hydrogen within liquid or solid carrier materials.
Chemical storage methods are

1. Ammonia
2. Liquid Organic Hydrogen Carrier (LOHC)
3. Metal Hydrides

Hydrogen is stored through physico-chemical interactions or chemical bonding and is released on demand via controlled processes such as catalytic cracking, dehydrogenation, or by applying changes in temperature and/or pressure. These systems typically operate near ambient conditions, offering higher volumetric storage density and enhanced safety compared with high-pressure or cryogenic storage. Current practices for hydrogen storage and transportation are summarised in the table below.

Table 10 Practices for hydrogen storage and transportation

S. No.	Storage Type	Applicability	Distance	Transportation
1	Gaseous storage	Small amount of hydrogen	Short distance	Transport either in pressure vessels or in a pipeline
2	Liquid Storage	Larger amount of hydrogen	Longer distance	Transport in an LH2 tank either on a truck or on a ship
3	Chemical Storage	Very large amount of hydrogen	Long storage duration and very long distance	Transport depending on the storage technology

Recommendation
This project will consider spherical or cylindrical gaseous storage system at 25 barg pressure and Ambient temperature.

8.2 Methanol Storage

The methanol storage system at the process plant and bulk storage typically comprises multiple designated tanks based on product quality, operating requirements, and logistics. The main storage categories are as follows:

- Crude methanol – An interim storage vessel placed in between the methanol synthesis unit and distillation unit.
- Pure Methanol Tank (5000 MT storage capacity) – Final product will be stored in pure methanol storage tanks. Methanol loading pumps are provided for transferring methanol to bulk storage tank.
- Methanol Bulk Storage tank/ jetty Storage (1 x 25000 MT storage capacity)

Methanol is stored under near-ambient conditions, typically at approximately 40 °C and atmospheric pressure, in atmospheric storage tanks designed in accordance with applicable codes and standards. Storage tanks shall be constructed using compatible materials, including killed carbon steel, mild steel, or stainless steel, in accordance with API 650 material specifications. In addition, tanks shall be equipped with an inert gas blanketing system (typically nitrogen padding) to maintain a non-flammable vapor space, prevent air ingress, and control oxygen concentration. Storage tanks shall be located within secondary containment (dikes or bunds) designed to contain potential releases. Tanks shall be protected by a fixed fire-protection system supported by supplementary fire protection.

Recommendation
The proposed material of construction for pure methanol storage tanks is killed carbon steel (KCS), provided with an internal protective lining to enhance corrosion resistance and ensure long-term integrity under methanol service conditions.

8.3 Methanol Transportation

For transportation of methanol of nearest port, three transport options are analysed. The analysis considers the transport of methanol by a nearby railway, though a greenfield pipeline or using fuel products trucks. The main assumptions and results of this analysis can be found in Table 11.

Table 11 Transport Options for green methanol from nearest port [2]

Mode	Rail	Road	Pipeline
Specific Transport Cost [INR/t-km]	1.6	3.6	2
CO2 Emissions [g CO2/t-km]	11.5	101	0

The lowest cost option results in transporting the methanol in rail wagons. In this case, a loading terminal is required at the nearby railway line together with a pipeline that connects the methanol production facility to the rail terminal. Each Bogie Tank wagon for Petroleum product with Air-brake system (BTPN) rail wagon can carry up to 70 m3 of methanol, requiring 16 daily wagons to transport the methanol to the destination port. The second option to be considered is road transport with class 25 KL trucks. This option has the highest emission intensity and would require about 46 daily trucks for the transport of methanol depending on the availability and capacity of the trucks available.

For rail transport, a railway sliding and supporting infrastructure is required. A railway siding is a short stretch of railway track that branches off from the main line to provide access to a particular facility. The cost of building a railway siding can depend on various factors such as the length of the siding, the type of track required (e.g., broad gauge, meter gauge, narrow gauge), the signalling and communication systems required, and any related infrastructure such as bridges, culverts, or embankments. The construction of a railway siding may also require approvals and permits from various regulatory bodies, including the Indian Railways, local government authorities, and other relevant agencies. These approvals can add to the overall cost and time required to complete the project. Overall, building a railway siding can be a significant investment
.
In conclusion, if there are enough capacities on the railway system to transport the methanol trough rail and the feasibility to create a rail terminal, railway is recommended.

The pipeline has the higher cost of transportation as compared to railways but has no carbon emissions because it is powered by renewable energy. The pipeline is a one-time capital investment with lower operating cost. For this project, the pipeline option of 200 km total length, 8" diameter, constructed from Stainless Steel is considered.

The transfer system utilises canned motor pumps at 48 m^3/hr (37.5 tons/hr) in a 1W+1S configuration at two primary locations: the main plant and a booster station at the 120 km mark. Required Sluice valve stations & booster station Infrastructure shall be provided. The pipeline shall be constantly monitored by instrumentation & telecom system consisting of field instruments, SCADA connectivity for remote monitoring, CCTV surveillance, and a PA/GA system.

8.4 CO_2 Transportation

Carbon dioxide is sourced from a biogenic CO_2 stream using a carbon capture process. After CO_2 recovery and dehydration, the captured CO_2 is transported via pipeline to the green methanol production unit. CO_2 can be transported in either the gaseous phase or the supercritical phase. The major technical and operational differences between gaseous and supercritical CO_2 transportation are summarised in the table below.

[2] Note: Ref NITI AAYOG, RMI, AND RMI INDIA, 2021

Table 12 Technical and Operational Differences Between Gaseous and Supercritical CO_2 Transportation

Parameter	Gaseous CO_2 Transport	Dense / Supercritical CO_2 Transport
CO_2 Phase	Gas	Dense phase or supercritical fluid
Typical Operating Pressure	10–30 barg	≥ 74 barg (typically 80–150 barg)
Typical Operating Temperature	Ambient (~20–40 °C)	Above CO_2 critical temperature (≥ 31 °C); temperature tightly controlled
Density	Low (~15–30 kg/m³)	High (~600–800 kg/m³)
Pipeline Diameter	Large diameter required for given flowrate	Significantly smaller diameter for same mass flow
Compression Power Requirement	Lower initial compression power	Higher compression power required to reach and maintain supercritical pressure
Booster / Recompression Stations	Often required at shorter intervals due to pressure drop	Fewer recompression stations due to high density and lower frictional losses
CAPEX – Pipeline	Higher (due to larger diameter and right-of-way requirements)	Lower per unit throughput due to smaller diameter, despite higher pressure rating
CAPEX – Compression	Lower	Higher (multi-stage compression and cooling required)
OPEX – Energy	Moderate; dominated by recompression	Higher; dominated by compression, temperature control, and pressure maintenance
Risk of Two-Phase Flow	Low	High if pressure drops below critical, leading to flow instability
Materials Requirement	Carbon steel	Carbon steel
Leak Consequences	Wider dispersion due to large volumetric flow	Dense cloud formation possible; localised asphyxiation risk
Suitability for Long-Distance Transport	Less suitable due to large diameter and pressure losses	Highly suitable; industry-preferred option for long-distance, high-capacity CO_2 pipelines
Overall Assessment	Economical for short distances and small flow rates	Preferred for large-scale, long-distance CO_2 transport despite higher compression cost

Recommendation

CO_2 transport in gaseous phase is recommended.

8.5 CO_2 Storage

Carbon dioxide may be stored either in the gaseous or liquid state. Gaseous CO_2 storage typically requires lower initial capital investment; however, due to its low density, it occupies significantly larger volumes, resulting in a higher storage footprint. In contrast, liquid CO_2 storage offers substantially higher volumetric density, enabling a more compact storage configuration and reduced land requirements.

In the proposed configuration, carbon dioxide will be stored in the liquid phase at operating conditions of approximately 20 bar and −20 °C. Storage of liquid CO_2 will be maintained in insulated cylindrical pressure vessels. The storage system will be

equipped with an integrated refrigeration and boil-off gas (BOG) re-liquefaction system to manage heat ingress, minimise CO_2 losses, and maintain stable storage conditions.

9 Port Logistics

Kakinada port in Andhra Pradesh is selected for exporting methanol to international consumers. Methanol will be transferred from plant via pipeline and stored in bulk storage tank of 25,000 Ton near port area. Methanol will be transferred to vessels/ships using methanol Transfer/loading Pump of capacity 1566 TPH.

At present stage it is envisaged that a common fuel-handling infrastructure will be developed by the port authority for transferring fuel from pipe to ship via marine loading arm.

Kakinada is Deep Water Port (KDWP) is an all-weather port and can handle vessels up to 50,000–70,000 DWT (deadweight tonnage). The storage capacity of 25000 ton can be supplied in a single shipment using medium size chemical handling vessels. The capacity and frequency of ship depends of the location and consumer requirement.

10 Electrical System

The design concept of the electrical system is based on the requirements for the safe and reliable electrical system with provision for easy maintenance and overhauling. The design principles and standards delineated herein are generally in compliance with the latest IEC/IS Standards, and Code of Practice and Electricity Rules already established in the state. Design ambient temperature for the electrical equipment is considered as 50°C.

10.1 Electrical System Description

Power Supply for the proposed green methanol production project will be from nearest Pooling substation at 400kV to the plant. A 400kV switchyard/substation will be constructed to receive the power. Based on the distribution of power to electrolyser, 400KV/33kV power transformers shall be installed in switchyard.

Power will be fed from power transformer to 33kV switchgears which will have a double incomer with a bus-coupler arrangement and receive power from 2 x 100% rated 400/33kV power transformers.

The auxiliary transformers will feed the balance of plant loads. The two incomer one bus coupler arrangement provides 100% redundancy and ensures power supply to the BoP auxiliaries even when one of the power transformers fails.

Each 33kV switchgear will be provided with a harmonic filter to mitigate the harmonic distortions caused by the rectifier circuits. One 11kV switchgear is envisaged for the plant Medium Voltage (MV) auxiliaries i.e., motors/loads rated 160kW and above.

The 33 kV voltage level is further stepped down to 415 V level through 2x100% rated 33/0.415kV transformer. Low Voltage drives (motors/loads rated less than 160 kW) and all lighting loads shall be connected to 415 V switchgear panel. The number of switchgears at each level shall be decided during the execution stage. The motor load up to 160KW shall be shall be fed at 415V however motor above 160KW shall be fed at 11KV.

Lightning transformer is envisaged for feeding lighting load for normal lights and emergency load. 220V DC control supply be used for protection, control and monitoring of electrical switchgear.

10.2 Equipment for Hazardous Areas

Cables will be segregated to reduce fire risk, damage, and shutdown. Electrical equipment located in hazardous areas such as hydrogen compressor/storage, shall be explosion proof, flame proof, intrinsically safe or otherwise designed to be suitable

for the location zone. Electrical equipment required for safety critical operation and continued operation upon gas detection shall be rated for Zone 1.

The fire protection / detection system shall be in accordance with NFPA requirements. Automatic water spray deluge protection for all oil filled transformers and cable floors. Gas extinguishing fire protection system shall be provided for Electrical rooms, MCC rooms, switchgear rooms, panels rooms, instrument rooms, control rooms, raised flooring cellars (NFPA 2001 Clean Agent System).

10.3 Uninterruptible Power Supply

The uninterruptible power supply (UPS) furnishes a reliable and interruption free source of required voltage, single phase power to equipment/instrument vital for plant control and emergency operation.

UPS units (2x100%) shall be furnished to feed essential AC loads like DCS and other C&I equipment. The DC supply for the UPS system shall be sourced from an independent DC system. The UPS system shall be provided with two (2) Nos. 100% capacity inverters.

10.4 Control of Electrical System

400 kV switchyard will be controlled from the dedicated SCADA in the switchyard control room that provides an interface to control the system through mimic screens. An additional screen shall be provided in the main plant control room also. All the I/Os will be terminated in a marshalling panel / remote I/O panel located in the switchyard control room. Sequence event recording / status of breakers & fault reporting shall be indicated in the SCADA system.

The complete MV and LV electrical system of the power plant shall be controlled and monitored from the plant DCS system. The controls for the following shall be through mimic screens in the VDU. A backup control panel is also envisaged.

Critical signals, Analog signals, Status alarms and controls of all switchgears shall be extended to DCS. All the I/Os of plant auxiliary systems shall be terminated in a marshalling / remote I/O panel. Sequence event recording / status of breakers & fault reporting of 33 kV, 11 KV, 415 V distribution system, 220 V D.C system, 230 V UPS etc. shall be indicated in the Plant DCS. Separate mimic screens shall be provided for 33 KV, 11 KV and 415 V system. Control of all motors shall be from DCS only. Energy monitoring system shall also be installed at each of the voltage level as part of EMS system.

10.5 Protection Philosophy

For protection of equipment against abnormal system conditions, adequate protective devices will be installed in the respective switchgear and/or control and relay panels. Proper discrimination and selectivity shall be provided to isolate only the faulty elements, keeping the healthy part of the system in service.

All protection relays will be numerical microprocessor based with IEC 61850 Communication Protocol with Ethernet port except Anti pumping, Trip circuit supervision, Master trip Lock out and fuse failure and synchronous check relays.

10.6 Power and Control Cables

33/11kV cables will be of stranded aluminium/copper conductor with heavy duty XLPE insulated, each core screened on conductor as well as on insulation, colour coded, extruded bedding, extruded PVC inner sheathed, armoured, and overall FRLS PVC sheathed. The cables will be suitable for unearthed systems.

LV power cables will be 1100 V grade with stranded aluminium/copper conductor, XLPE/PVC insulated, extruded PVC inner sheathed, armoured, and overall FRLS PVC sheathed. Control cables will be multicore 1100 V grade, PVC insulated, PVC inner sheathed armoured and overall FRLS PVC sheathed with 2.5 mm stranded copper conductors. The cables will

conform to the relevant Indian/IEC standards in general with the following special, FRLS properties for the outer sheath. Cables used in hazardous locations will comply with IEC 60332.

10.7 Illumination System

The plant lighting system includes the –

- Normal AC lighting (70% of total lighting)
- Emergency AC lighting (30% of the total AC lighting fed from emergency UPS).
- Escape system (lighting fittings with integral batteries or DC/UPS supply)

Lighting feeders shall be provided with lighting transformers of voltage ratio 1:1 to reduce the fault level. For general illumination, LED fixtures are taken into consideration. This lighting shall be energised from 3-phase, 4-wire, 415 V main lighting distribution boards fed from suitably rated lighting transformers.

These MLDBs shall feed lighting panels for each individual area/room. The average illumination levels for the lighting system design shall follow OISD guidelines.

10.8 Grounding and Lightning Protection

The plant grounding system will be designed as per the requirements of IEEE-80/IEEE 142/IS-3043/IEC:62305. The earth mat of the station shall be designed such that the total ground impedance does not exceed 1.0 ohm.

The plant and switchyard shall be equipped with lightning protection. Lightning Protection Level LPL 1 of IEC62305 will be provided. Lightning protection conductors located on the top of the structures shall be connected to the ground loop surrounding the structure with down conductor as per provision contained in the latest issued Indian electricity rules and IS 2309. Insulating mats/flooring shall be provided for all electrical switchgear to protect operators from electrical shock. Each of the switchgear room to have PPE and SLD displayed for safe O & M practices.

11 Instrumentation and Control System

- The plant shall be operated, controlled, and protected through an Integrated Control and Safety System (ICSS), comprising a Safety PLC–based Emergency Shutdown System (ESD) and A Distributed Control System (DCS) for safe, reliable, and efficient operation of the proposed plant.
- A Machine Monitoring System (MMS) shall be provided for condition monitoring and protection of compressors.
- A SCADA (Supervisory Control and Data Acquisition) system shall be implemented for centralised supervision, monitoring, and data acquisition.
- All field instruments, including transmitters, control valves, on–off valves, motor operated valves (MOVs), safety valves, and other associated instrumentation, shall be provided as part of the I&C system.
- A Fire and Gas Detection System (FGS) shall be provided to ensure early detection, alarm, and protective actions.
- A Telecommunication System shall be provided, including CCTV, Access Control System (ACS), EPABX, LAN, and Public Address & General Alarm (PAGA) systems.
- All instrumentation and control systems and equipment shall be of modern, compact design, incorporating proven technologies and current industrial best practices.
- The design of all control and safety systems shall conform to the "Fail Safe" philosophy wherever personnel safety or plant equipment protection is involved. Fail safe operation shall ensure that loss of signal, loss of power, or failure of any component does not result in a hazardous condition.

Requirements of DCS

- The plant control system shall be based on a Distributed Control System (DCS) to ensure safe, reliable, and efficient operation of the proposed plant,The control system (DCS) shall be of the latest version (software & Hardware) available in the market at the time of supply, preferably on the same hardware and software platform.
- The overall operational control and supervision of CCU(Carbon capture unit), Hydrogen plant with storage ,Green methanol synthesis unit, Methanol storage and tranfer system, utilities, offsites and associated electrical system shall be executed through the proposed plant DCS.
- Two Large Video Screens (LVS) of size 80" Inch shall be provided at Central control room. This monitor shall be connected to the operator station. Space provisions shall also be considered for the future. Large video screens, complete with projectors, screens, control units (graphical generators) & associated accessories shall be supplied as per standard specifications. LVS as a backup for control & operation, in case all OWS are blackout. The control unit of LVS shall be the same as the operator workstation without the TFT monitor. Facility of projecting a particular display on a selectable area of the screen upon activation of a predefined event shall be provided.
- Processor modules, power supply modules, communication modules & network interface cards and serial interface to other control systems shall be redundant. The individual measurements (dual or triple) shall be wired to separate input modules.
- The system will be designed in such a manner that in the event of failure of the primary controller, the entire configuration of the failed controller will be instantaneously and automatically transferred to the back-up controller without operator's intervention. Mode changeover in either direction will bump less and procedure less.
- The communication sub system will be a real time reliable communication network between control processors, operator stations, printers, and engineering stations.

ESD System

- The ESD shall be a system with a very high degree of reliability, Min. SIL-2, TUV category V certified. Owner prefers that the ESD system shall be microprocessor based two out of three programmable logic control (PLC) with fault tolerant redundant processors and operate totally independent of the DCS and shall be able to override the DCS or any other regulatory control system

- The emergency Shut Down System shall perform any of the following functions for safety of the plant from central control room.
  - Total Shut Down
  - Unit Shut Down
  - System Draining and Depressurisation
- ESD system shall be a standalone fail-safe system independent of other areas of the plant. ESD system instruments, junction boxes and marshalling cabinets shall be independent of other systems.
- Sequence of event (SOE) shall be implemented in ESD.

Machine Monitoring System

- The condition monitoring system (Bentley Nevada series 3500 or equivalent) shall be supplied for all the critical and essential services as required by the process. This system shall be interfaced with DCS for continuous monitoring, logging, and alarm purposes. The equipment shall be classified and complied with application design below.
- CRITICAL
  - CO_2 Compressors
  - Hydrogen compressors
  - Synthesis Gas compressor
  - Recycled compressors

SCADA system for Methanol Pipeline

- The methanol pipelines shall be monitored and controlled through a SCADA (Supervisory Control and Data Acquisition) system dedicated to CO_2 and methanol pipeline operations.
- It consists of One Engineering workstations, Five Operator workstations (dual monitors), One Historian PC and One Electrical system PC with Two numbers of A3/A4 LaserJet printers. These workstations shall be provided with 24" LED monitors with dedicated operators keyboard and trackball.
- Each Sectionalising Valve (SV) station shall be provided with RTUs interfaced with all relevant field instruments and equipment, including Sectionalising valves, Pressure and temperature transmitters, Fire and gas detectors. RTUs shall support Modbus connectivity for integration with Electrical systems, Fire alarm system, Custody transfer meter etc.

Clock System

- Redundant Master and Slave Clock System shall be provided to synchronise all the systems with GPS clock.

Other Control System's Communication

- Vendor Packaged PLC and other plant's control systems/devices shall be interfaced to this proposed plant ICSS system. The interfacing between the various control systems with plant ICSS system will be achieved through redundant Optical Fiber Cable (OFC) through appropriate communication protocols by analysing the individual plant's control system's available protocols.
- Packaged equipment like Electrolysers and carbon capture units shall have its own microprocessor-based PLC for its control & operation. However, it shall be interfaced with the plant ICSS with redundant FO network to monitor the operations as well shall have facility to control the packaged items from main ICSS (only critical functions like Start/Stop from DCS, all other permissive and interlocks to be implemented in local control systems)
- Fire and gas detection and protection system will be a separate independent control system but interfaced with plant ICSS through redundant ethernet network.

Asset Management System

- The Asset Management System shall be provided for collecting and archiving data from the self-diagnostic functions of field instruments using adequate protocol. The AMS will be fully integrated with the DCS, and the user can run the AMS application from the dedicated workstation.

- The AMS will read HART information from field devices. The system will be provided with read-write password protection to download parameter settings into the devices. Failure of the AMS system will not inhibit the functionality of the DCS.
- The AMS will be capable of interrogating all HART devices and providing similar notification upon abnormal conditions defined during detailed design.
- Alarms generated by the AMS will be displayed on the operator console on HMI graphics. The AMS can be accessed from maintenance and engineering workstations.

Remote Communication

- Since the methanol storage terminal at the port area is approximately 200 km from the proposed Methanol plant location, so methanol will be transfered through the cross country pipeline.
- The Pipeline sections should be provided with enroute sectionalising valve Station (SVS), pressure relieve valve station, Cathodic protection systems, OFC telecommunication system along with associated station facilities. Automation, Control and monitoring mechanisms for pipeline operations should be provided with PLC based logics and Instrumentation at various stations and with SCADA and appropriate Application software (APPS) for Leak detection, Pipeline Intrusion Detection system (PIDS), etc
- This control system will be interfaced with the main plant DCS through wireless satellite communications like OPC.

Field Instrument Specification/ Requirements

- All Instrument devices shall utilise "smart" type electronics using HART Protocol such as smart transmitters, smart positioners for Control Valves, smart gas detectors and analysers, etc. The standardised instruments shall be provided and utilised for the measurements of process variables (Pressure, Temperature, Level and Flow).
- All field instruments shall be suitable for installation in the hazardous area and climatic conditions as specified. All parts subject to moisture, fungus growth, or insect attack shall be treated with suitable coating to inhibit such attack. Suitable weather protection, IP65 (as minimum) shall be provided. Sunshades shall be provided.
- All field instruments shall be certified Zone-2, Gas Group IIC, and Temperature class T3, as a minimum.
- Capable of calibrating & configuring on-line locally & remotely by using a HART handheld communicator or Asset Management System (AMS) software, including write protection feature.
- Electronic devices shall be selected and installed such that the electromagnetic interference (EMI), including radiofrequency interference (RFI), shall not interfere with their function.
- All transmitters shall be complete with integral indicators and shall be installed so that these can be readable from grade or platform. Local indicators shall be provided where transmitter indication is not available locally.

Signal Transmission

- Conventional Hardwire interface for all field instruments to the plant DCS shall be implemented. All field transmitters shall be compatible with HART protocol.
- Instrument analog signals except for special signals shall be as follows:
  - The electronic transmitters connected to the DCS, and process control application shall be preferably based on 4-20mA HART protocol.
  - All transmitters shall be indicating type.
  - In case of HART instrumentation, electronic signals used for process measurement will be analog 4-20mA (2 wires).
  - All control signals like digital inputs shall be 24VDC and digital outputs shall have interposing relays and shall be potential free with contact rating of 5A/240V. The voltage rating of wetted digital outputs shall be according to the field instruments ratings.

Critical Measurements

- For critical measurements, 2oo3 voting logics are envisaged to accomplish Main Check philosophy. Some of the critical process variables like Hydrogen flow, C02 flow, Methanol flow, Methanol storage tank level etc. shall be measured in this philosophy. Some critical measurements are-

- Level instruments
  a. The level measurement for special type application like Liquid Methanol in Cryogenic tanks will be of Radar / displacer type instruments with high accuracy (2oo3 voting). Radar type of non-contact type is envisaged. It shall be easy for maintenance and replacement.
  b. Level switches will generally be 'displacer' type with external cage type.
  c. All level gauges / transmitters will be provided with drain connection at ground level. Gauge glasses will normally be reflex or transparent type depending upon service, with overall length not exceeding 1500 mm. All gauge glasses will be provided with graduated suitable scale. Wherever necessary, standpipes or float chambers will be provided.
- Flow instruments
  a. Flow measurement will be carried out using Mass flowmeter / Magnetic flowmeter / Ultrasonic flowmeter. Flow transmitter's displaying unit shall be integral / separate mounted with signal type isolated 4-20 mA with HART protocol. Coriolis type mass flowmeter will be preferred for liquid methanol & Hydrogen flow. 2oo3 voting shall be considered for this measurement.
- Gas Detectors
  a. Gas detectors will be of standard make and have a voltage level of 24 VDC with isolated 4-20 mA output. The detectors will be wall/frame mounted and display gas concentration, alarm, fault and status information via backlit LCD and LEDs. This can be locally tested and calibrated periodically.
  b. Ultrasonic acoustic type leak detectors are envisaged for detecting hydrogen leakage.
- Methanol Leak Detection System
  a. A standalone leak detection system with dedicated PLC will be provided for detection of leaks in the Methanol transfer pipeline from plant to offsite storage terminal at the port. The objective is to enable real-time, continuous monitoring for early detection of leaks, intrusions, and third-party interference (TPI), ensuring safe and reliable operation of the pipeline.
  b. Leak detection system shall be interfaced with SCADA system through a redundant communication link.
- Custody transfer metering system:
  a. The metering system shall ensure accurate, reliable, and safe measurement of Methanol, in compliance with recognised international standards viz. API MPMS, AGA
  b. The metering system will be designed for continuous, unattended operation, with appropriate diagnostic and alarm capabilities.
  c. Metering system will include but not limited to:
  o Coriolis mass flow meters
  o Pressure and temperature transmitters.
  o Flow computers and control panels.
  o Isolation valves, strainers, filters, and safety accessories

12 Offsite Facilities and Utilities

To support the operation of the process units, a range of offsite facilities and utility systems is required. The utility consumption summary for the green methanol plant is presented below.

12.1 Green Methanol Plant

At this site, green hydrogen, green methanol, hydrogen storage & methanol storage units are installed. To support these process units, the various offsite facilities required are:

- Instrument Air and Plant Air
- Nitrogen
- Cooling Water
- Steam
- Water Treatment Plant
- De-Mineralised Water
- Potable water
- Fire water
- Flare Package
- Chiller

Instrument Air & Plant Air

Instrument air in a methanol plant is clean, dry, oil-free compressed air used to operate control valves, pneumatic instruments, analysers, and safety-critical systems to ensure safe and reliable plant operation.

To meet requirements, the compressed air is thoroughly dried to remove water vapor and achieve a specified atmospheric dew point of –40 °C. This low dew point prevents condensation, corrosion, freezing, and malfunction of pneumatic equipment under all operating and ambient conditions.

Plant Air (PA) is compressed air that is not required to meet the stringent cleanliness and dryness specifications of instrument air. It is used primarily for general utility, maintenance, and non-critical pneumatic services throughout the methanol plant.

For Plant Air service, wet compressed air is utilised. The compressed air undergoes initial condensate removal in a wet air separator to remove free moisture and bulk liquid formed during compression and cooling. IA shall be about 2000 – 2400 Nm3/hr & PA shall be 300 – 400 Nm3/hr.

Nitrogen Generation

Nitrogen (N_2) shall be used as an inert medium for critical purging and blanketing services, including purging of the electrolyser array, flare header purging, tank blanketing, and other applications where oxygen exclusion and inert atmosphere maintenance are required to ensure safety and process integrity.

The generated nitrogen shall be supplied to the plant through an on-site nitrogen storage system to ensure continuous availability. Nitrogen (N_2) shall be produced either by a Pressure Swing Adsorption (PSA) unit or by a cryogenic air separation plant.
The nitrogen storage facility shall provide operational flexibility and reliability by supporting start-up, shutdown, purge, blanketing, and peak demand requirements, as well as maintaining supply continuity during normal operation or temporary production shortfalls. Nitrogen requirement 2200 - 2800 Nm3/hr.

Cooling Water

Cooling Water (CW) is used to cater to the cooling duty requirements of the process units. A closed-loop cooling water system is employed to supply cooling water to the plant users, while heat rejection from the system is accomplished through a cooling

tower. Cooling water system shall be supported by side stream filtration, controlled blowdown, and a comprehensive chemical treatment program to ensure long-term system integrity and performance.

Make-up water to the circulating cooling water system is supplied from raw water to compensate for losses due to evaporation, drift, and blowdown. Capacity of Cooling Water Package estimated as 40000 - 45000 m3/hr.

Steam Generation

For the Green Methanol Unit, external steam is required during start-up operations as well as for continuous operation, primarily to meet the heating requirements of process reboilers.

The total low-pressure (LP) steam demand for the unit is estimated to be approximately 60–70 t/h. Steam shall be generated at a pressure of 12 barg, after which it shall be superheated to approximately 280 °C using an electric superheater, in line with the green facility philosophy.

To support decarbonised operations, an electric boiler is proposed for steam generation. Demineralised Water (DM Water) supplied from the DM water package shall be used as Boiler Feed Water (BFW) to ensure appropriate water quality and reliable boiler operation.

Water Treatment Plant

The Raw water from the identified source will be stored in the raw water storage tank. The Raw water storage tank shall be considered for 1 day of storage. The Raw water from tank will be fed to cascade aerator through raw water transfer pumps & further to stilling chamber, parshall flume, flash mixer and flocculator. The raw water from flocculator will be fed to Clarifier to remove TSS before entering into the filtration system. This Clarified water is stored in Clarified cum fire water storage tank considering the firefighting water requirement. The holding capacity of clarified storage tank shall be based on 4-6 hour holding time of process water requirements. Dual media filter feed pump shall be used to transfer water from clarified storge tank to dual media filter. The filtration system shall have Dual Media filtration unit designed to ensure proper feed water quality to downstream water treatment equipment. Water from the DMF is treated in order to generate water of required quality suitable for various downstream units like service water, cooling tower makeup, potable water treatment and DM plant. Water treatment for 18.6 MLD is required for Methanol plant.

DM Water Package

Clarified water is pumped from clarified Water Tank using DM Water Pumps to Demineralisation Water Plant. Dual Media Filter (DMF) and Activated Carbon Filter (ACF) will provided before the demineralisation train to remove suspended solids, color and residual chlorine. The DMF and ACF is periodically backwashed with filtered water based on set timing or pressure drop across the bed. Backwash water will be recycled in water treated plant or sent to effluent treatment plant.

Filtered water will be sent to demineralised plant consists of trains of cation exchanger and anion exchanger, followed by a mixed bed polishing unit. Cation exchange resin removes cations from water such as Ca+, Mg+ with H+ ions available in the resin and the water is de-cationised. Anion exchange resin removes anions such as SO4-, Cl-, NO3- with OH- ions available in the resin. A combination of cation and anion exchange resins is provided in a mixed bed. The resins used in DM plant get exhausted and need periodic regeneration.

Diluted hydrochloric acid (HCL) and diluted caustic (NaOH) will be used to for regeneration of resin beds. Regenerated effluent will be collected in neutralisation pit. Based on the pH, Acid or alkali will be used to neutralised the effluent. eutralisation regenerant wastewater is well mixed using the neutralised effluent pump. Neutralised effluent is then transferred to the effluent treatment plant.

Demineralised water is stored in the DM Water Storage Tank. DM water tank is nitrogen blanketed. Demin water is transferred to the consumers by DM Water Transfer Pumps. Capacity of DM water treatment Package shall be 156 - 180 m3/hr.

Potable Water Package

Potable Water Treatment system will be provided to produce potable water suitable for human consumption. The clarified water shall be passed through Activated carbon filer and dosed with Sodium Hypochlorite from the Hypochlorite Dosing system to provide a 0.5-3 mg/l residual chlorine in the water. The product water then stored in Potable Water Tank from which it is pumped to Drinking water distribution network and safety showers. Required purity shall be as per Drinking water specification of IS or WHO latest standard.

Backwash water from potable water system is recycled or discharged to effluent treatment plant. Capacity of Potable water treatment package shall be 2 m^3/hr.

Effluent Treatment Plant

All the process waste water (DM Plant reject, cooling water reject, blowdowns, process condensate) will be collected in Waste Water Collection tank and treated in ETP. ETP Process will include inlet Tank, flash mixer, flocculator, clarifier, filtration and chlorination.

Sewage Treatment Plant (STP) effluent from township and plant area will be sent to common treatment facility of 10 KLD. STP treated water will be used in green belt.

Zero Liquid Discharge (ZLD) will be installed along with Effluent Treatment Plant (ETP) to recycle treated water back to process resulting in zero liquid waste discharge from the plant.

Total effluent generated is about 230 – 250 m^3/hr which will be treated in effluent treatment plant.

Fire water

The firefighting system will be the backbone of the entire fire protection system. There shall be a network of pipe runs in the form of connected rings to cover the entire premises. The proposed system mainly consists of Fire Water Tank, Fire Water Pumps, Pipe & Fittings, isolation valves, external hydrants, fire escape hydrants, hose reels, hose cabinets & hydrant accessories, water cum monitors, water jumbo curtain nozzles.

The number of hydrants will be based on the perimeter of the buildings, on the basis of one hydrant for every 40 meters for tank farm, process plant, storage buildings (Finished goods & Raw material warehouse) and 50 meters for utility block, administration Building. Location that has flammable or combustible fuel storage shall have fire hydrants, sprinkler and spray systems provided in according with NFPA 30 Flammable Liquids Code and IS:15201 Standard for Hydrogen code of Safety.

Flare Package

Flare is provided to safely burn the hydrogen and methanol during venting operation at startup, trip or other upset operating conditions of electrolyser and process plant. Flare pilot flame will be in continuous operation. Hazardous or flammable gases will be safely disposed through 350-400 ton/hr flare.

Chiller

In electrolyser-based hydrogen production, the chiller system is a crucial component for gas conditioning and moisture removal. The hydrogen generated at the electrolyser outlet is typically saturated with water vapor and at elevated temperature. A chiller system is therefore essential to cool the hydrogen stream, remove moisture, and prepare the gas for downstream purification and storage processes. This cooling stage ensures that the hydrogen meets required purity and dryness specifications.

12.2 CO_2 Capture: Offsite Facilities and Utilities

The CO_2 capture unit is co-located at the Green Methanol site. The estimated capacity for various utilities is seen in Table 13.

Table 13 Estimated CO_2 capture capacity for utilities

	Capacity	Unit
Instrument Air	250 – 350	Nm3/h
Nitrogen	100 – 150	Nm3/h
Water Treatment	4.1 – 4.5	MLD
Cooling water	8000 – 10000	m3/hr
Effluent treatment	55- 60	m3/hr

13 Cost Estimate

13.1 Cost Range of Total Capex

The Project capex estimate is calculated based on major components of the project given in the following table

Table 14 Capex Component [3]

Configurations	Optimal Capacity	Cost in Bn USD.
Solar + Wind	750 MW & 1080 MW	1.92
BESS	205 MWh	0.055
Electrolyser	705 MW	0.3
Hydrogen storage	60 Ton	0.2
CCU	1214 TPD	0.15
Methanol Production & Storage	820 TPD	0.6
Engineering & FEED consultant, Project management, land development and EPC	As per requirement	0.1
	Sub Total	3.325
Contingency @ 20%		0.665
	Total Cost	3.99

Key Observations:

1. Renewable generation dominates CAPEX, accounting for the largest share (~58%), making it the primary cost driver.
2. Methanol production & storage is the second biggest component (~18%), highlighting its importance in downstream processing.
3. Electrolyser cost (~9%) is moderate but expected to reduce over time with technology improvements.
4. BESS cost is relatively low (~2%), indicating limited reliance on storage compared to generation capacity. It may vary depending on specific RE configuration.

Overall, the project is heavily weighted toward energy generation and conversion infrastructure, with supporting systems forming a smaller portion of total cost.

[3] Note: The above cost includes Civil, Electrical, piping, instrumentation including Balance of Plant (Water, Cooling, HVAC, Chiller, pumps, etc)

13.2 Levelised Cost of Methanol

Based on the project cost and following assumptions, the Levelised Cost of Methanol (LCOM) is calculated.

Table 15 Levelised cost of methanol (LCOM)

Parameters	Units	Values
Debt: Equity Ratio	-	70% : 30%
Interest on Loan	%	9
Repayment period (Excl. Moratorium)	Years	10
Moratorium Period	Years	1
Design useful life of the plant	Years	25
Useful life of Stack	Years	10
Annual availability of overall system	%	91.32%
Electricity Cost	INR/kWh	4
Green Methanol Aux. Consumption & Electrolyser Continuous Load	MW	70
WACC	%	~10
Maintenance cost (Electrolyser & BoS)	%	2% of Capex
Escalation on O&M (y-o-y)	%	3
Escalation on Manpower Cost (y-o-y)	%	5
Depreciation for Stack	%	10
USD to INR Exchange Rate	-	90
Depreciation for Balance of System	%	4

Based on the above parameters, the Levelised Cost of Methanol (LCOM) is Rs 128 - 130/kg. The estimated LCOM of INR 128-130/kg is indicative in nature and can be further optimised through forward integration, enhanced value chain integration, and strategic pricing improvements, as cost optimisation is a continuous process.

The most impactful levers to optimise LCOM are:

- Lower electricity cost
- CAPEX reduction (especially electrolyser + renewables)
- Improved plant efficiency and utilisation through through reduction in Specific Energy Consumption (SEC)
- Cheaper financing (lower WACC)
- Forward integration & revenue enhancement through long term off-take agreement

14 Area Requirement

14.1 Methanol and CCU Plant

The area requirement for the methanol plant depends on equipment footprint, installation, technological and operational requirements, meeting safety requirements and industrial standards. A total of 140 acres of land is required for green methanol plant, green hydrogen plant, Carbon capture unit, including Offsets and Utilities. Land requirement will change due to the land condition, shape and technology provider.

Layout is attached as Appendix B.

14.2 Port Storage

Approximately 6 acres of land are required at port for storage and balance infrastructure. It is envisaged that the common facility will be developed by the port authority.

15 Project Schedule

The Project Master Schedule is structured into two distinct phases: a Pre-Investment Stage and an Investment (Implementation) Stage, separated by the Final Investment Decision (FID) milestone. Upon completion of all pre-investment workstreams and approval of the Financial Investment Decision, the project transitions into the implementation stage.
An EPC / Multi-EPC contracting strategy is assumed, allowing execution of the project across different locations or discrete project components under separate EPC packages, as appropriate.

The Project Master Schedule has been developed to include all key milestones, studies, engineering activities, and tendering and contract award processes, providing an integrated framework for planning, coordination, and execution of the project.

15.1 Project Milestone

In the following table the main indicative project milestones are listed.

Table 16 Project Milestones

Milestones	Date
Project Start	Zero Date (M)
FEED & Final Investment Decision (FID)	M+18
Commercial Operation Date (COD)	M+45

Project the total duration corresponds to 3 years and 9 months from Zero date. L1 Project Schedule is attached as Appendix C.

15.2 Long Lead Items

Identified Long Lead items (LLI) identified for the project are:

1. Electrolyser
2. CO_2 Compressor
3. Synthesis Gas Compressor
4. Recycle gas Compressor
5. Methanol Synthesis Reactor

15.3 Permits and Approvals

The development of a green methanol production facility and its associated infrastructure requires a series of statutory, environmental, safety, and operational approvals from central, state, and local authorities. Consolidated list of key approvals typically required for such projects are given be table below.

Table 17 Permits and Approvals

S. No	Approval / Clearance	Responsible Authority
1	Project Registration under Green Hydrogen Policy	Renewable Energy Development Agency
2	Import Export Code (IEC) Registration	Directorate General of Foreign Trade (DGFT)
3	Consent to Establish (CTE)	State Pollution Control Board (SPCB)
4	Environmental & Social Impact Assessment (ESIA)	SEIAA / MoEFCC
5	Factory Plan Approval	Directorate of Industrial Safety & Health,
6	Right of Way (RoW) Clearances (multiple agencies)	NHAI / Railways / PWD / Utilities
7	Building Plan Approval & Construction Clearance	Town & Country Planning Dept / Local Bodies
8	Registration under Building & Other Construction Workers Act	Labour Department
9	Temporary Power Connection	State Electricity Distribution Company
10	Temporary Water Connection	State water authority
11	Raw Water Allocation	Irrigation & Water Resources Department
12	Central Transmission Utility (CTU) Connectivity	Power Grid Corporation of India Ltd. (PGCIL)
13	Transformer / Line Energization Certificate	State Electricity Distribution Company
14	Custom Duty Clearance for Import of Equipment	Central Board of Indirect Taxes and Customs (CBIC)
15	Approval for Communication Devices (Walkie-Talkie, etc.)	Department of Telecommunications (DoT)
16	Safe Electrical Installation Clearance	Chief Electrical Inspectorate,
17	Diesel Generator (DG) Set Permission Certificate	Pollution Control Board (PCB)
18	Other Approvals as per State Policy	Fire, Forest, Explosives, etc. (case-specific)
19	Petroleum and Explosives Safety Organisation (PESO) Approval	Petroleum & Explosives Safety Organisation (PESO)

Table 18: Certification

S. No	Approval / Clearance	Responsible Authority
1	EU RED	Renewable Energy Directive certification
2	Regulation (EU) 2025/1189 & 2025/1185	Commission Implementing Regulation (EU)

16 Key Risks and Success Factors

16.1 Key Risks

As with any new technology or industry, there are some risks associated with the production and use of green methanol. Some of the key risk factors include:

1. **Cost Uncertainty**
   The cost of producing green methanol is still uncertain, as the technology is still in its early stages. There is a risk that the production costs could remain high, making it less competitive with traditional fossil fuels and reducing demand.
2. **Market Uncertainty**
   There is also uncertainty around the market demand for green methanol. While there is increasing awareness and demand for cleaner energy sources, it is unclear how quickly the market will adopt green methanol and whether it will be a viable commercial product in the long run.
3. **Dependence on Raw Materials**
   The production of green methanol is dependent on the availability of raw materials, such as biomass or carbon dioxide. Any disruption in the supply chain or fluctuations in the availability of raw materials could impact the production of green methanol.
4. **Infrastructure Challenges**
   Developing the necessary infrastructure, such as pipelines and storage facilities, to support the production of green methanol is a significant challenge. Building this infrastructure will require significant investment and coordination among various stakeholders.
5. **Technology Risks**
   The production of green methanol involves complex technologies, which may be subject to technical failures, operational risks, and cybersecurity threats. Any disruption in the production process could impact the availability and cost of green methanol.
6. **Environmental Risks**
   While green methanol is a cleaner alternative to traditional fossil fuels, there are still environmental risks associated with its production and use, such as land-use change, water usage, and potential air emissions from the production process.

Overall, the production and use of green methanol involves some risks and uncertainties, but with careful planning and investment, these risks can be managed and minimised over time.

16.2 Success Factors

1. Regulatory Frameworks and Policies

Governments has been forthcoming in providing production linked incentives for usage of Green hydrogen in Refineries and Green Ammonia in Fertiliser Industry while similar support is required for mandating usage of Green Methanol in Chemicals and Energy Applications including plastics, formaldehyde, marine fuel, e-SAF via MTJ, etc.

An important step is mandating usage of green methanol in sectors such as Chemicals and Energy Applications including plastics, formaldehyde, marine fuel, e-SAF via MTJ, etc.

2. Development of Infrastructure

The development of green methanol as a clean fuel and industrial feedstock requires a coordinated build-out of production, logistics, and end-use infrastructure. A robust infrastructure ecosystem ensures reliable supply, cost efficiency, and market adoption across sectors such as shipping, power generation, mobility, and chemicals.

It includes developing cost-effective solution such as pipeline networks for transfer of CO_2 and Hydrogen with common infrastructure of methanol storage terminals and port facilities.

3. Cost Reduction through Technological

The production cost of green methanol is currently higher than conventional fossil-based methanol due to the cost of renewable hydrogen, CO_2 capture, and the capital intensity of synthesis and storage facilities. However, substantial cost reduction opportunities exist through targeted technological improvements across the value chain. These improvements can significantly reduce the Levelized Cost of Methanol (LCOM), enhance plant efficiency, and improve bankability.

Advances in Electrolyser Technology

a. Increased energy efficiency i.e kWh/kg H_2
   Developing New-generation PEM and alkaline electrolysers with 70–75% efficiency, reducing power demand.
b. Capex reduction through scale & modularisation:
   Developing Gigafactories for electrolyser manufacturing driving down cost curves.
c. High-temperature electrolysis (SOEC):
   Utilises waste heat from methanol synthesis which reduces electricity consumption by 10–15%.
d. Improved durability & stack life:
   Longer life reduces replacement frequency and lowers lifetime cost.

CO_2 Capture Technology Improvements

a. Membrane and adsorption technologies:
   It Reduces heat duty and operating cost for CO_2 sources.
b. Integration with industrial waste heat:
   It Lowers steam requirements for solvent regeneration.

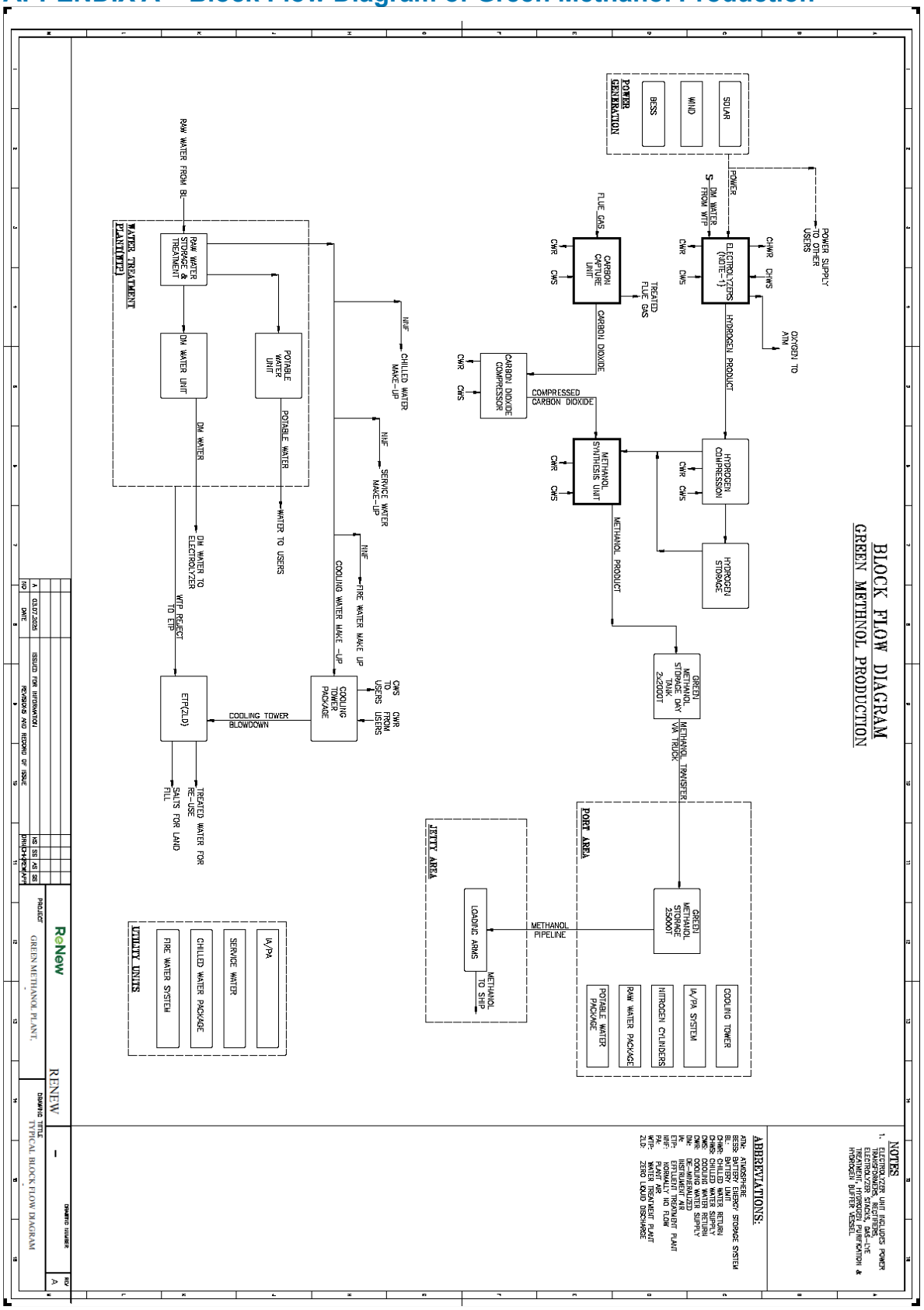
Methanol Synthesis Process

Technological improvements in methanol reactor design and plant configuration which reduce both capex and energy consumption such as developing advance catalyst and waste head reviver

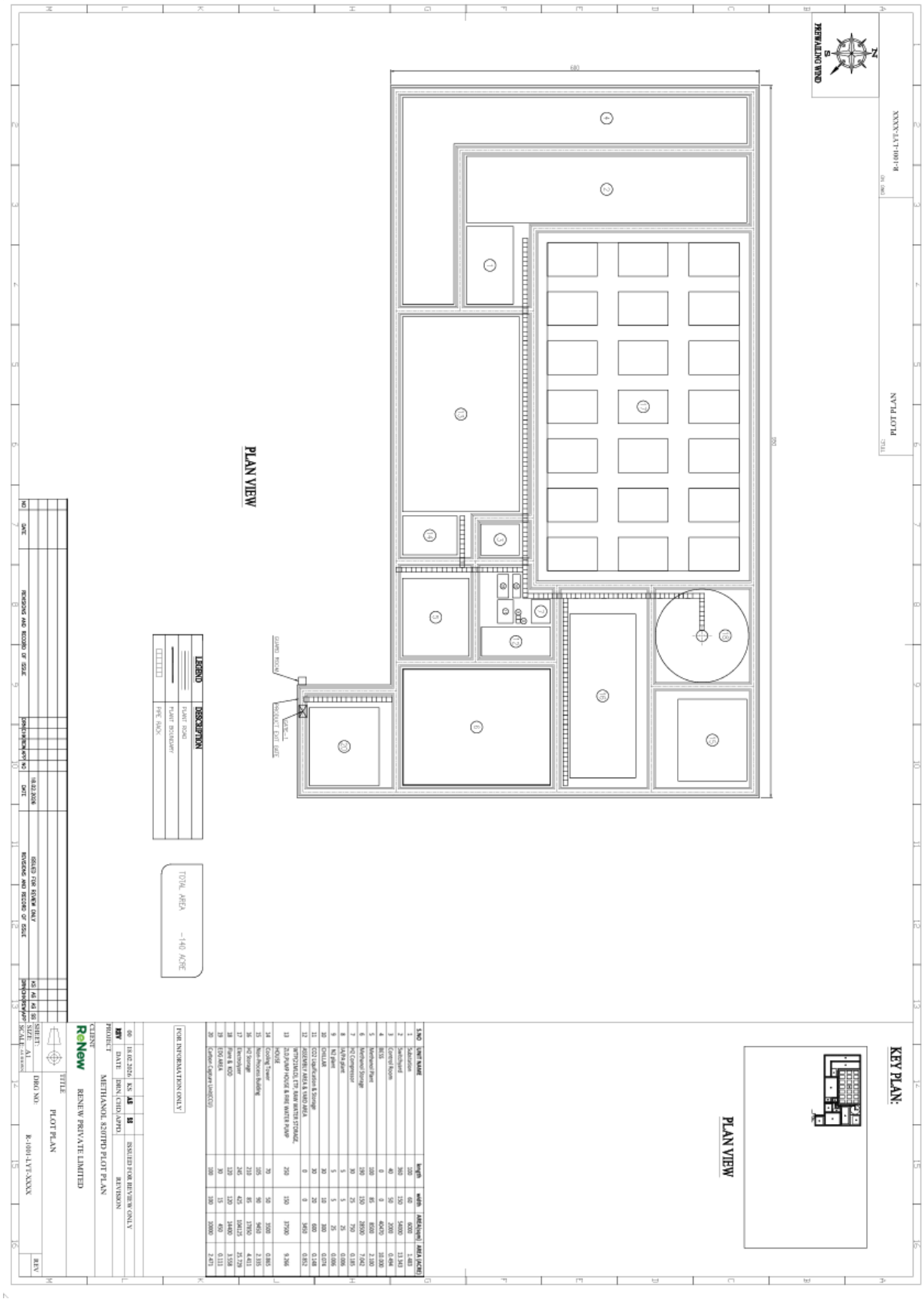
Storage and Logistics Optimisation

Cost optimisation by Creating common infrastructure for green methanol logistics like storage, handling, bunkering.

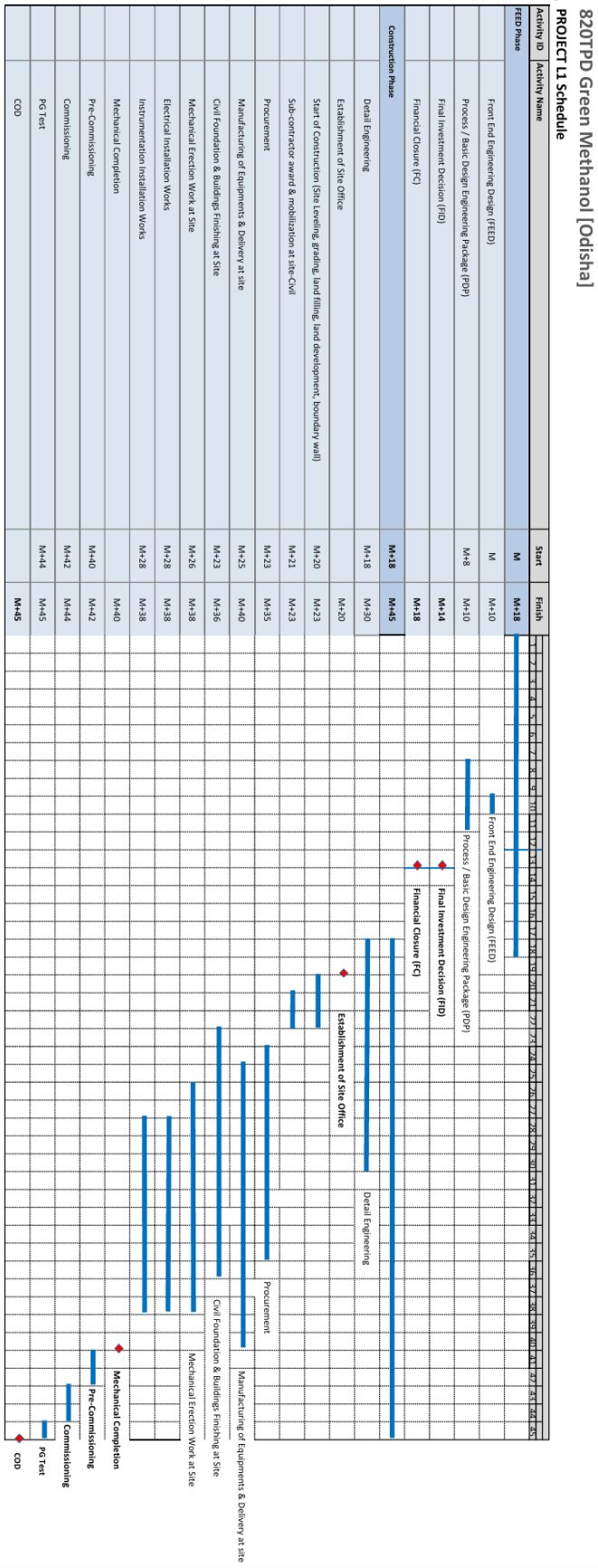
APPENDIX A – Block Flow Diagram of Green Methanol Production



APPENDIX B – Plot Plant with CCU



APPENDIX C - Green Methanol L1 Project Status





The International Hydrogen Ramp-up Programme (H2Uppp) is supporting entrepreneurial engagement in the ramping-up of hydrogen in the Global South and is a funding programme of the:

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