Net Zero Technology Centre

Alternative Fuel Study

Study Summary Report

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EXECUTIVE SUMMARY

Operator A's Asset A platform has been chosen for an alt-fuels case study as part of NZTC's Alternative Fuel Gas Turbines Project. Asset A was considered for fuel conversion to either renewable methanol or a biofuel. The scope of the study was to take a holistic view of the challenges and opportunities associated with alt-fuel adaptation – this included technical, technology, regulatory, supply chain, economic and operational aspects.

Alt-fuels are an attractive prospect for Asset A as they provide a pathway to emissions reduction. Operator A's Emissions Reduction Action Plan (ERAP) has been developed to provide a pathway to a 50% emissions reduction by 2030, it includes the following projects:

1. Temporary H.V Power Project (temporary TAR power generation for much lower emissions/ lower diesel consumption in TARs)
2. MP & Export Compression Revamp Project (new compressors with expected installation 2025)
3. LPBC Compression Revamp and Electrification Project (started Define / FEED, Execute in 2026)
4. Flare Gas Recovery Project (phased approach to achieve Zero Routine Flaring, Pre-FEED commencing 4Q23)
5. Power Generation Strategy (Up-scale based on feasibility of MPX electrification or down-size to more thermally efficient units)
6. Low-Carbon Power – Alternative Fuel Study
7. Electrification (full electrification from the grid has been assessed and partial electrification from offshore wind power generation is currently being studied, more detail below)

The NSTA's emissions reduction plan (OGA Plan) has a focus upon platform electrification and low carbon power to meet the emissions reduction goals. Specifically for Asset A, an existing asset, there is the expectation that financial investments must be made to electrify all assets where it is reasonable to do so weighting the total remaining value of reserves and resources that will or may be developed through that asset and the expected emissions reductions from electrification against the expected cost of electrification. Operator A have completed offshore electrification screening considering full electrification (from the grid) for the Asset A platform and found it to not be a reasonable balance between maximising economic recovery and net zero. Study work assessing the feasibility of partial electrification from offshore wind is ongoing. Implementation of alternative fuel usage was considered for 2027 with CoP assumed to be 2035.

The equipment considered for alternative fuelling was the main combustion equipment on the platform as well as the temporary diesel generators used for TAR power generation. This equipment is as follows:

- Power Generation Gas Turbines (2-off GT-A & GT-B): Turbine OEM A Model A – Rated Thermal Output 25.4MW ea.
- MP & Export Gas Compression Turbine: Turbine OEM A Model A Rated Thermal Output 25.4MW
- MP & Export Gas Compression Turbine: Turbine OEM A Model B Rated Thermal Output 27.3MW
- TAR Power Generators 3 off: Diesel Generator OEM A Model A Rated Thermal Output 1.1MW

To allow selection of the most appropriate biofuel, Xodus conducted a screening assessment and selection process. The assessment involved researching each fuel option to understand it's feedstocks, production methods and supply chain as well as it's physical properties. HVO was selected as the preferred biofuel option.

For the purposes of this alternative fuel study, renewable methanol (consisting of bio-methanol and e-methanol) and HVO were considered as the alternative fuel options. These were assessed against the current platform fuel options of platform fuel gas and diesel.

A total of 5 power load scenarios were considered for the scope of this study for alt-fuel usage:

SCENARIO	DESCRIPTION	FUEL USERS	TOTAL POWER
1A	TAR Shutdown: GTG	GTGs GT-A/B – 1.5 MW	1.5 MW
1B	TAR Shutdown: Temporary HV Power	Temporary HV Generators – 1.5 MW	1.5 MW
2A	Power Generation: GTG	GTGs GT-A/B – 6.0 MW	6.0 MW
2B	Power Generation: GTG post-LPBC revamp & electrification	GTGs GT-A/B – 10.4 MW	10.4 MW
3	Full: GTG + MPX Compression	GTGs GT-A/B – 10.4 MW MPX Compressor CTG-A/C – 16.8 MW	27.2 MW

Concepts have been split into TAR Shutdown Concepts and Continuous Operation Concepts.

Each concept has developed a feasible design with considerations of brownfield modifications and equipment requirements.

Asset A's existing topsides liquid fuel storage capacity was assessed alongside available space on the platform, and it was concluded that for power load scenarios 2A, 2B & 3 that topsides fuel storage is not viable. Scenarios 1A & 1B however, have reduced fuel storage volumes and importantly are temporary arrangements during TAR shutdown periods. This suggests that during these TAR shutdown of 21 days, more frequent fuel supply may be possible allowing for reduced storage volumes. The TAR shutdown concepts feature platform storage and focus upon a single 21-day TAR shutdown period in 2027.

The TAR Shutdown Concepts are as follows:

DESCRIPTION		POWER LOAD SCENARIO	FUEL STORAGE METHOD	NOTES
Concept 1A	TAR Shutdown with GTG	1A	Platform Storage	OPEX assessment versus continued diesel usage
Concept 1B	TAR Shutdown with Temp HV Power	1B	Platform Storage	OPEX assessment versus continued diesel usage

Continuous operation concepts utilise off-platform storage and consider continuous operation from 2027 to CoP in 2035. Two off-platform storage options were identified – subsea storage and FSO storage. There concepts do require development as they are new concepts for the UKCS.

The Continuous Operation Concepts are as follows:

DESCRIPTION		POWER LOAD SCENARIO	FUEL STORAGE METHOD	NOTES
Concept 2A	Subsea Storage Tanks, 6 MW Power Generation GTG	2A	Subsea Storage	Full cost estimate
Concept 2B	Subsea Storage Tanks, 10.4 MW Power Generation GTG	2B	Subsea Storage	Full cost estimate
Concept 3A	Subsea Storage Tanks, 27.2 MW Power Generation GTG	3	Subsea Storage	Full cost estimate
Concept 3B	Single FSO Comparison	3	Single FSO	Full cost estimate
Concept 3C	Dual FSO Comparison	3	2 off. FSO vessels operating back-to-back	Full cost estimate

Turbine OEM A were engaged to review the required turbine package modifications for e-methanol and HVO fuel options. The Turbine OEM A Model A power generation turbines currently accept both liquid and gaseous fuels. The Turbine OEM A Model A MP / Export compression turbines require dual fuel modifications to accept liquid fuels as they are currently gas fired only. For HVO, the dual fuel modifications would be standard – as per a dual fuel modification for diesel. For renewable methanol, a liquid fuel system with increased capacity, larger diameter fuel injections and fire and gas system upgrades would be an additional requirement. Both renewable methanol and HVO are viewed by Turbine OEM A to be viable fuel options for combustion in gas turbines. Renewable methanol has some benefits related to low flame temperatures, slightly increased thermal efficiency, reduced NOx, and cleaner combustion when compared to other fuel options.

A regulatory assessment has been performed for both alternative fuel options with regards to safety, environmental risk, and the UK ETS scheme. Both alternative fuels are acceptable for use on the platform from a safety perspective, modifications to the Safety Case will be required but these can be accommodated.

The e-methanol, bio-methanol and HVO production routes have been evaluated within a review of the current and future supply chains. The supply chain constraints on the availability of both renewable methanol and HVO would provide a major challenge for implementation by 2027. For Power Load Scenario 3, Asset A's renewable methanol consumption would represent almost 2% of expected annual worldwide production. Those figures are based on a projected renewable methanol production capacity increasing greatly from today's figures and all announced renewable methanol production projects being completed. HVO is more readily available - Asset A's consumption would represent ~0.3% of worldwide HVO consumption is 2023. However, it would be ~19% of current UK HVO consumption. Wholesalers of HVO and renewable methanol have indicated that the required HVO supply volumes are likely to be feasible by 2027. The outcomes of discussions with Methanol Vendor, a methanol fuel distributor, have been included.

It is demonstrated that the emissions benefits of alt-fuels are dependent on the supply of fuels which have the lowest environmental impact. If supply chain restrictions mean that alternatives to the greenest alt-fuel options are sourced (such as bio-methanol or crop-based HVO), then there can even be a negative environmental impact over fuel gas combustion. Crop-based HVO also brings food vs. fuel ethics challenges. The lifecycle for these less sustainable fuel options should be fully analysed before any temporary change is made.

The environmental impacts of each alternative fuel have been assessed. The lifecycle emissions of each fuel were determined for use within emissions calculations. Currently, Asset A power generation is via either diesel or fuel gas; TAR Shutdown Concepts conventional use diesel while for Continuous Operation Concepts platform fuel gas is used to power the turbines. Concept emissions estimates have been developed to quantify the CO_2 emissions savings. Figure 1-1 presents an overview of the lifecycle emissions of the fuel options for Concept 3A, compared with platform fuel gas.

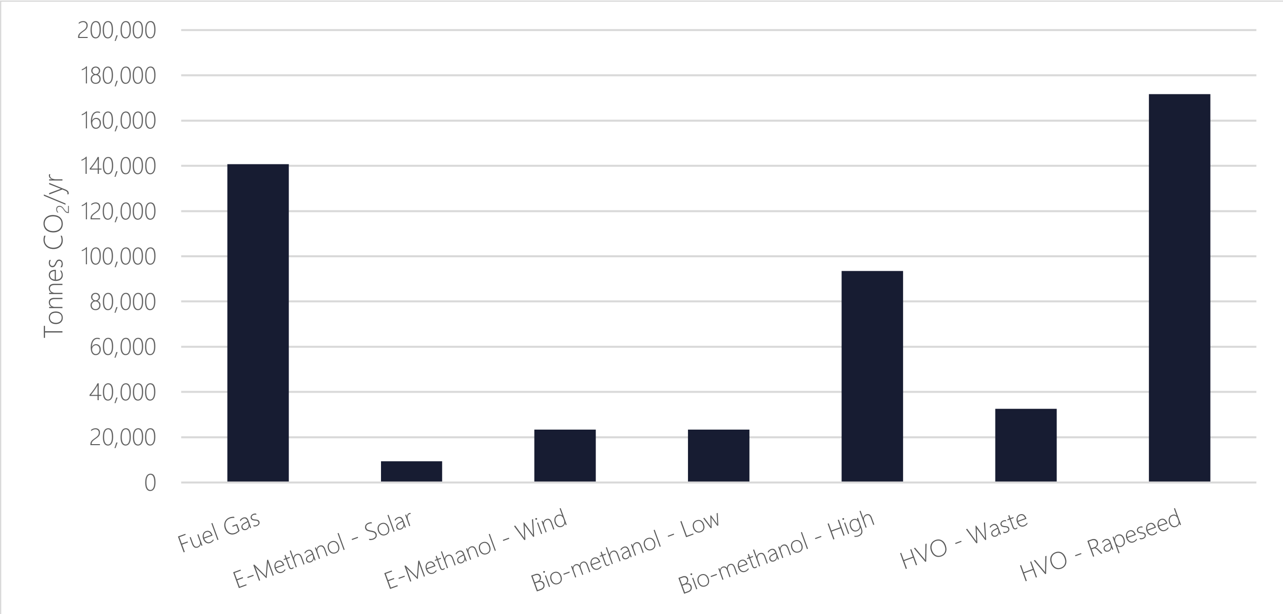

Figure 1-1 - Asset A Lifecycle CO_2 Equivalent Emissions vs Fuel (Concept 3A)

The supply of fuel to the platform would be via ship. Asset A's alt-fuel consumption would be significant in terms of shipping capacity. While Concept 1A and 1B have their storage capacities restricted to the size of the fuel storage tanks on the platform, the subsea and FSO concepts (2A, 2B, 3A, 3B & 3C) require large storage volumes. Although a large platform supply vessel would result in a sub optimal bunkering frequency, this has been considered the viable shipping option at this stage and costs for a platform supply vessel are used in the economic analysis. A platform supply vessel also has the advantage of being able to transport other platform consumables for Asset A and offload these adjacent to the platform.

The Methanol Institute's wide range of fuel cost estimates demonstrate that the cost of renewable methanol is highly dependent on the feedstock costs which are complex to forecast. This study has used a fuel cost of £1,076/te in 2027, based on an Xodus in house cost model for e-methanol. Additional economic sensitivities have been performed utilising input from a methanol supplier, to demonstrate the economic impact of selecting low lifecycle emissions renewable methanol fuels. From discussions with a UK fuel distributor, the HVO price used excludes VAT and is £2207/te in 2027 (this is the fuel distributor price from 2023 with 2 % annual inflation assumed to arrive at a 2027 price).

A review of OPEX concluded that there are earnings attributed to reduced diesel usage, increased sales gas revenue & emissions allowance savings via ETS. There are increased ongoing costs related to fuel costs, shipping costs and FSO charter costs (depending on concept option).

Concepts 1A and 1B economics are based on an OPEX assessment versus continued diesel usage. The remaining concepts have had Class 5 CAPEX estimates developed for each alternative fuel. The CAPEX estimates consider topsides brownfield, turbine modifications and subsea scopes.

CONCEPT	FUEL	TOPSIDES BROWNFIELD CAPEX	TURBINE CAPEX	SUBSEA CAPEX	TOTAL CAPEX
2A	Renewable Methanol	£14.55M	£2.89M	£38.96M	**£56.41M**
	HVO	£19.87M	£1.61M	£31.59M	**£53.07M**
2B	Renewable Methanol	£14.55M	£2.89M	£42.83M	**£60.26M**
	HVO	£19.87M	£1.61M	£34.31M	**£55.80M**
3A	Renewable Methanol	£15.22M	£13.93M	£55.32M	**£84.47M**
	HVO	£20.57M	£9.51M	£43.14M	**£73.23M**
3B & 3C	Renewable Methanol	£3.10M	£13.93M	£14.97M	**£32.01M**
	HVO	£10.55M	£9.51M	£14.97M	**£35.04M**

For the TAR shutdown concepts, the economics are presented as profit / loss values for the single 21-day TAR duration in 2027. For continuous operation concepts, NPV estimates have been developed. Economic results shown for renewable methanol and HVO are relative to the do-nothing case of continued usage of either diesel or fuel gas.

TAR Shutdown Concepts Profit / Loss Summary

CONCEPT	FUEL	LOW PRICING CASE DELTA PROFIT / LOSS (£M)	HIGH HIGH PRICING CASE DELTA PROFIT / LOSS (£M)
1A	Renewable Methanol	-£0.82M	-£0.44M
	HVO	-£0.54M	-£0.18M
1B	Renewable Methanol	-£0.39M	-£0.28M
	HVO	-£0.25M	-£0.15M

Continuous Operation Concepts NPV Summary

CONCEPT	FUEL	LOW PRICING CASE DELTA NPV (£M)	HIGH HIGH PRICING CASE DELTA NPV (£M)
2A	Renewable Methanol	-£220M	-£103M
	HVO	-£231M	-£118M
2B	Renewable Methanol	-£289M	-£126M
	HVO	-£302M	-£146M
3A	Renewable Methanol	-£593M	-£235M
	HVO	-£625M	-£279M
3B	Renewable Methanol	-£568M	-£211M
	HVO	-£614M	-£268M
3C	Renewable Methanol	-£563M	-£205M
	HVO	-£624M	-£278M

To determine the impact upon the economic estimates when gas price, caron price and fuel costs varied, tornado charts have been developed to visually quantify the range of profit / loss and NPV values along with the required breakeven points. With renewable methanol fuels, there is a trade-off between the carbon intensities of the chosen fuel and its price. The economics of Concept 1B and Concept 3B have been developed considering a variety of renewable methanol fuel options. The above tables are pre-tax estimated, the report also presents post tax estimates and fuel break even costs based on the post-tax CAPEX estimates.

The use of alt-fuels is commercially challenging from an OPEX perspective. The cost of the fuels looks to be prohibitive without government incentives – even when assuming the greenest of fuel supply chain options.

If the study is progressed to the next phase, the following should be developed:

- Concept select for fuel storage and topsides fuel distribution;
- Further investigation into charter rates for FSOs/tankers for fuel storage;

- Engage with the alt-fuel supply chain for both e-methanol and HVO to understand security of supply for 2027 and the availability of a suitable supply vessel / tanker to deliver the fuel;
- It has been assumed that the life cycle emissions of alternative fuels will apply to the ETS. It is recommended that Operator A's engagement with OPRED is continued to confirm if alternative energy fuels will be treated in the scheme; and

1 INTRODUCTION

As part of the Net Zero Technology Centre (NZTC) Technology Transition Programme, NZTC are committed to accelerating the development of gas turbines capable of running on clean fuels to provide a means of clean, remote power generation. This is being developed under the Scottish Government's Energy Transition Fund.

Under this Alternative Fuel Gas Turbines Project, case studies are required to appraise alternative fuel feasibility. This case study looks at the feasibility of conversion of a fixed offshore oil and gas asset to a low carbon alternative fuel. The purpose of this study is to understand the technical, regulatory and technology challenges associated with enabling the use of alternative fuels as opposed to gas or diesel on an existing fixed oil and gas asset.

The asset considered for this scope is Operator A's Asset A asset which was considered for fuel conversion to either renewable methanol or a biofuel. Operator A and the Asset A platform are an oil and gas asset Operator partner in the Alternative Fuel Gas Turbines Project. Blends of alt-fuels or a combination of alt-fuels and conventional fuels are not considered as part of this study.

Operator A's Emissions Reduction Action Plan (ERAP) has been developed to provide a pathway to a 50% emissions reduction by 2030, it includes the following projects [Ref. 44]:

1. Temporary H.V Power Project (temporary TAR power generation for much lower emissions/ lower diesel consumption in TARs)
2. MP & Export Compression Revamp Project (new compressors with expected installation 2025)
3. LPBC Compression Revamp and Electrification Project (started Define / FEED, Execute in 2026)
4. Flare Gas Recovery Project (phased approach to achieve Zero Routine Flaring, Pre-FEED commencing 4Q23)
5. Power Generation Strategy (Up-scale based on feasibility of MPX electrification or down-size to more thermally efficient units)
6. Low-Carbon Power – Alternative Fuel Study
7. Electrification (full electrification from the grid has been assessed and partial electrification from offshore wind power generation is currently being studied, more detail below)

The NSTA's emissions reduction plan (OGA Plan) [Ref. 45] has a focus upon platform electrification and low carbon power to meet the emissions reduction goals. Specifically for Asset A, an existing asset, there is the expectation that financial investments must be made to electrify all assets where it is reasonable to do so weighting the total remaining value of reserves and resources that will or may be developed through that asset and the expected emissions reductions from electrification against the expected cost of electrification. The same applies for the investigation of low carbon power options, such as alternative fuels. Operator A have completed offshore electrification screening considering full electrification (from the grid) for the Asset A platform and found it to not be a reasonable balance between maximising economic recovery and net zero. Study work assessing the feasibility of partial electrification from offshore wind is ongoing.

1.1 Abbreviations

Acronym	Definition
AC	Alternating Current
AI	Analogue Input
AO	Analogue Output
ATM	Atmospheric Pressure
BEIS	Department for Business, Energy and Industrial Strategy
CAPEX	Capital Expenditure
CLIP	Classification, Labelling and Packaging of Chemicals Regulations 2015
CMS	Control and Monitoring System
COP	Cessation of Production
DAC	Direct Air Capture
DI	Digital Input
DME	Dimethyl Ether
DO	Digital Output
DP	Dynamic Positioning
DWT	Deadweight Tonnage
EEMS	Environmental and Emissions Monitoring System
EPU	Electrical Power Unit
ERAP	Emissions Reduction Action Plan
ESD	Emergency Shutdown
ESDV	Emergency Shutdown Valve
ETBE	Ethyl Tert-Butyl Ether
ETS	Emissions Trading Scheme
EU	European Union
F&G	Fire and Gas System
FAME	Fatty Acid Methyl Ester
FSO	Floating Storage & Offloading Vessel
GBP	Great British Pounds
GHG	Greenhouse Gas
GT	Gas Turbine

Acronym	Definition
GTG	Gas Turbine Generator
HP	High Pressure
HV	High Voltage
HVAC	Heating, Ventilation and Cooling
HVO	Hydrogenated Vegetable Oil
ICSS	Integrated Control & Safety System
IEA	International Energy Agency
IMS	Industrial Methylated Spirit
IRENA	International Renewable Energy Agency
ISCC	International Sustainability & Carbon Certification
ISO	International Organisation for Standardisation
LAT	Lowest Astronomical Tide
LER	Local Equipment Room
LHV	Lower Heating Value
LP	Low Pressure
LPBC	Low Pressure Booster Compression
LPG	Liquified Petroleum Gas
MAH	Major Accident Hazard
MCC	Motor Control Centre
MCS	Master Control Station
MJ	Mega-joule
MMBTU	Million British Thermal Units
MOV	Motor Operated Valve
MP	Medium Pressure
MPX	Medium Pressure & Export Compression
MSW	Municipal Solid Waste
MW	Mega-watt
NB	Nominal Bore
NNS	Northern North Sea
NPV	Net Present Value

Acronym	Definition
NSTA	North Sea Transition Authority
NZTC	Net Zero Technology Centre
O&M	Operations & Maintenance
OEL	Occupational Exposure Limit
OEM	Original Equipment Manufacturer
OGA	Oil and Gas Authority
OOM	Order of Magnitude
OPEX	Operating Expenditure
OPRED	Offshore Petroleum Regulator for Environment and Decommissioning
OSPAR	The Oslo and Paris Commissions
P&L	Profit and Loss
PCV	Process Control Valve
PFD	Process Flow Diagram
PLONOR	Poses Little or No Risk to the Environment
PSD	Process Shutdown
PSR	Pipeline Safety Regulations
PUQ	Process, Utilities & Quarters
PWRI	Produced Water Re-injection
RCF	Recycled Carbon Fuels
RESDV	Riser Emergency Shutdown Valve
RFNBO	Renewable Fuels of Non-Biological Origin
RTU	Remote Terminal Unit
SAL	Single Anchor Loading
SDV	Shutdown Valve
SECE	Safety & Environmental Critical Elements
SIMOPs	Simultaneous Operations
SSIV	Subsea Isolation Valve
SSU	Subsea Storage Unit
STOT	Specified Target Organ Toxicity
SVO	Straight Vegetable Oil

Acronym	Definition
TAR	Turnaround
TRL	Technology Readiness Level
TUTU	Topside Umbilical Termination Unit
UKCS	United Kingdom Continental Shelf
UPS	Uninterruptible Power Supply
VAT	Value Added Tax

2 STUDY SCOPE

2.1 Scope Overview

The purpose of this study was to understand the technical, regulatory and technology challenges associated with enabling the use of alternative fuels as opposed to gas or diesel on an existing fixed oil and gas asset.

The alternative fuels considered were:

- Renewable methanol;
  - Bio-methanol
  - E-methanol
- Hydrogen;
- Ammonia; and
- A biofuel.

During the study kick-off meeting, it was agreed to utilise Xodus' and NZTC's previous experience on similar projects, to discount hydrogen and ammonia as fuel options.

Hydrogen was discounted as a fuel option for the following reasons. Hydrogen has a very low volumetric energy density unless it is compressed or liquified. As such the material handling and transport of hydrogen poses obstacles. Hydrogen is not currently handled on offshore oil and gas assets. The introduction of hydrogen to an existing asset would bring several safety challenges related to hydrogen's properties – its low ignition energy, buoyancy, and an increased likelihood of loss of containment (due to small molecule size). Additionally, material compatibility is an issue due to potential for hydrogen embrittlement.

Ammonia was discounted as a fuel option for the following reasons. Ammonia combustion can be challenging in common combustion equipment due to its high ignition delay, low burning velocities and narrow flammability range. The combustion reaction is also susceptible to producing high levels of NOx. It is preferential to store ammonia as a liquid. This requires temperatures below -33.6°C at atmospheric pressure or pressurised to above 6 bara if stored at 10°C. Therefore, storage tanks are required to be either be pressurised or cryogenically insulated or a combination of both. Ammonia is combusted as a gas so the phase change from liquid to gas must be managed upstream of combustion equipment. Ammonia isn't currently handled on oil and gas platforms and therefore there would be adaptation challenges related to handling and toxicity.

Renewable methanol (encompassing bio-methanol and e-methanol) and an alternate biofuel were chosen for the scope of this study. A full assessment of biofuels was conducted to allow for screening and selection of the most promising alternative biofuel option to be carried into the study.

For the two chosen fuel options, the scope was structured to provide a holistic view of the challenges and opportunities associated with changeover to those fuels. The scope overview was as follows:

Technical Workstream:

- Required modifications to convert the platform's energy source to an alt-fuel;
- asset capacity for modifications;
- material compatibility for selected alt fuels and existing systems;
- required alt-fuel volumes;
- limits of the existing fuel storage on site;
- options for alt-fuel storage;
- fuel transportation to site; and
- fuel delivery requirements.

Technology Workstream:

- Technology issues for power generation unit operations for Asset A for the selected fuel options; and
- technology gaps that exist and understand key technologies that could be exploited.

Regulatory Workstream:

- Impact on the offshore asset Safety Case;
- potential issues with toxicity of fuel to humans and flammability of fuel, plus any requirements associated with that in terms of hazardous areas, fire and gas protection, personnel protection, etc.;
- potential barriers in regulations;
- impacts on Safety & Environmental Critical Elements (SECE);
- potential for the fuel to be toxic to the surrounding environment;
- ecological impact from potential leaks and spills;
- potential corrosion risks; and
- lifecycle GHG impact for the chosen fuels,

Supply Chain Workstream:

- Understand the quantities of fuel required relative to supply chain constraints; and
- review how the fuel could be sourced and transported to site.

Economic Workstream:

- OOM costs for modifications;
- high-level lifecycle costs; and
- savings related to emission reduction.

Operations Workstream:

- Impact on operations and maintenance activities; and
- Impact on operator scenarios such as TARs/outages and shutdowns.

The sections of this report reflect this scope and these completed workstreams.

2.2 Basis & Key Assumptions

The following basis and key assumptions have been used in the study:

- Fuel blending (of fuel options or of fuel options and conventional fuels) has not been considered.
- Fuel consumption data for the Turbine OEM A Model A & B Gas Turbines is based on a 'new and clean' engine operating at ISO conditions (15°C, 101kPa, 60% humidity) with no installation losses.
- See Section 5.1 for basis and key assumptions related to the thermal efficiency calculations performed for each power scenario.
- For economic analysis and measurement of commercial metrics, implementation of an alt-fuel is targeted for 2027 with an asset cessation of production (CoP) of 2035.
- Any modifications made must ensure that the capability to use fuel gas as a fuel must be retained.
- An assumed 85% uptime has been assumed for Asset A (7446 hours per year).
- For OPEX cost estimating, inflation is assumed to be 2% per year from 2027 to CoP.
- CAPEX estimates have been carried out based on 2026 cost, assuming that all required equipment and work is to be purchased the year before operation commences.
- A nominal discount rate of 10 % has been used in NPV calculations.
- TAR duration has been assumed to be 21 days.
- It is assumed that the life cycle emissions of alternative fuels will apply to the ETS. It is recommended that Operator A's engagement with OPRED is continued to confirm if alternative energy fuels will be treated in the scheme.

3 ASSET DESCRIPTION

3.1 Background

Operator A is the owner and operator of the Asset A (98%), Asset B (100%) and Asset C (50%) assets. The Asset A complex, which comprises of three bridge-linked platforms, is located in the North Sea.

Asset A relies on native fuel gas from its own production to provide fuel to its export gas compression and main power generation facilities. This equipment is detailed below in Table 3-1.

EQUIPMENT NAME AND MODEL	TAG NO.	FUEL TYPE	EQUIPMENT PRIMARY PURPOSE	MAXIMUM RATED THERMAL OUTPUT (MW)
Gas Turbine A (Turbine OEM A Model A)	GT-A	Gas / Diesel	Power Generation	25.4
Gas Turbine B (Turbine OEM A Model A)	GT-B	Gas / Diesel	Power Generation	25.4
Compressor A (Turbine OEM A Model A)	CTG-A	Gas	MP & Export Gas Compression	25.4
Compressor B (Turbine OEM A Model B)	CTG-B	Gas	MP & Export Gas Compression	27.3
Diesel Generator	3 x temporary units	Diesel	TAR Power Generation	1.1

Table 3-1 - Asset A's Main Combustion Equipment

Additionally, the following combustion equipment is installed at the facilities:

TAG NO.	FUEL TYPE	EQUIPMENT PRIMARY PURPOSE
CTG-C	Gas / Diesel	LP Booster Compression (CR Platform)
CTG-D	Gas / Diesel	LP Booster Compression (CR Platform)
L-A	Diesel	Platform Crane (PUQ)
L-B	Diesel	Platform Crane (PUQ)
GD-A	Diesel	Emergency Power Generation (PUQ)

TAG NO.	FUEL TYPE	EQUIPMENT PRIMARY PURPOSE
GD-B	Diesel	Emergency Power Generation (PUQ)
P-A	Diesel	Firewater Pump (PUQ)
P-B	Diesel	Firewater Pump (PUQ)
P-C	Diesel	Firewater Pump (D Platform)
P-D	Diesel	Cementer Injection Pump (D Platform)
GD-C	Diesel	Temporary Emergency Power Generation (D Platform)

Table 3-2 - Combustion Equipment Not Included in Scope

The adaptation of alternative fuels to the combustion equipment within Table 3-2 is not considered under the scope of this study – only the main, primarily gas fired, combustion equipment is considered at this stage.

The main power generation facilities are dual fuel capable and are therefore capable of running on diesel fuel when fuel gas is not available. Asset A has no waste heat recovery systems.

Fuel gas is routed from Asset A's gas production system before being superheated and distributed to fuel gas users. Diesel is bunkered to the facility from platform supply vessels and stored in diesel storage tanks (total storage of 505 m^3) and crane pedestal tanks (total storage of 110 m^3).

To reduce emissions associated with this combustion equipment, Operator A have completed offshore electrification screening for the Asset A platform and found it to not be a reasonable balance between maximising economic recovery and achieving net zero.

3.2 Main Combustion Equipment Locations

The locations of the power generation units are summarised within the following three figures.

The main power generation GT's (GT-A/B) are located on PUQ Level 4 (Elevation +51850).

REDACTED

Figure 3-1 - Main Power Generation Location [Ref. 5]

MP / Export Compressor Drivers (CTG-A/B/C) are located on PUQ Level 5 Weather Deck (Elevation +60500).

REDACTED

Figure 3-2 - MP / Export Compression Drivers Location [Ref. 6]

Temporary HV Power Generators (K1400CFG Rigsafe Diesel Generator x 3) have previously been located on the Drilling Platform Weather Deck. Operator A operations team have indicated that the Drill Rig will be skidded to the east side during the TAR to accommodate SIMOPS. The support grillage has been located in the South-East corner of the pipe deck tees, this has been done to ensure the generators can be installed if the Drill Rig is located over the Southern slots at the time of installation/removal [Ref. 6].

REDACTED

Figure 3-3 - Temporary HV Power Generation Expected Location

4 ALTERNATIVE FUELS

4.1 Renewable Methanol

Renewable methanol constitutes both e-methanol and bio-methanol. These two fuels are chemically identical but differ in their feedstocks and manufacturing processes.

E-methanol is a low carbon, renewable alternative to fossil-sourced methanol which utilises green hydrogen and captured CO_2 for production. E-methanol is a liquid fuel with approximately half of volumetric energy density of diesel. E-methanol synthesis methods are shown in Figure 4-1 below.

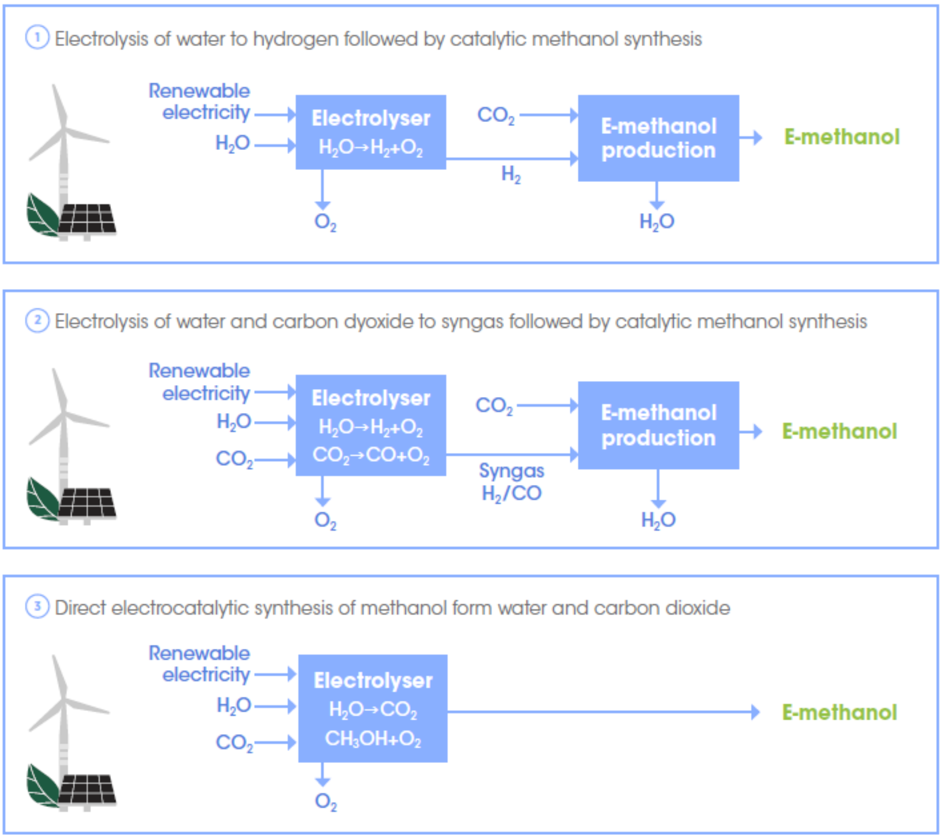

Figure 4-1 - E-methanol Production Process [Ref. 1]

Bio-methanol is produced through the gasification of biomass followed by catalysed synthesis. The biomass feedstocks include forestry & agricultural waste, biogas from landfill, sewage, municipal solid waste, and black liquor.

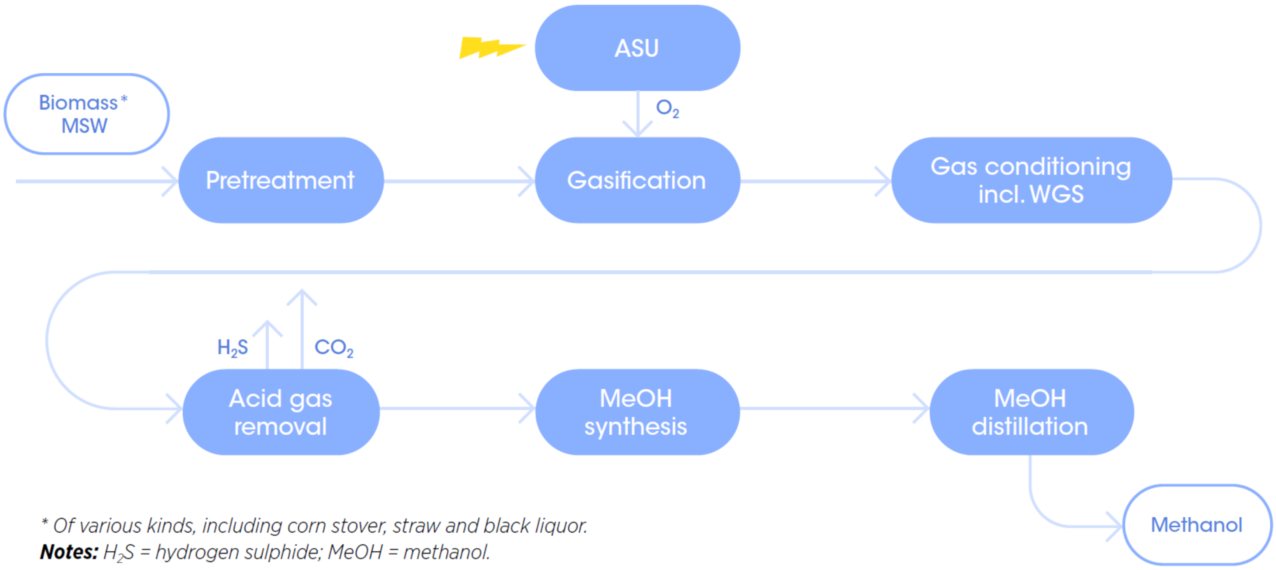

Figure 4-2 - Bio-methanol Production Process [Ref. 1]

Methanol is a commonly used chemical in the oil and gas industry, mainly in offshore applications. It is injected continuously or intermittently, depending on the process, to prevent hydrate formation. Therefore, the use of methanol is not a new concept for offshore oil and gas production facilities. However, if the methanol is to be used as alternative fuels, the quantity of methanol needs to be transported and stored in the facility at a much larger scale.

The challenges and advantages of adapting combustion equipment to methanol fuel is summarised by Table 4-1.

ADVANTAGES	CHALLENGES
Liquid fuel – material handling	Low energy density
High lower flammability limit – storage safety	Low flash point
Biodegradable	Material compatibility
Already widely shipped	Low lubricity

Table 4-1 - Renewable Methanol Advantages and Challenges

4.2 Biofuels Assessment

All parties involved at the initial kick-off meeting agreed that to allow a comprehensive assessment of fuel options, a wide range of biofuels should be considered. Xodus have performed a biofuels assessment, to allow selection of the most appropriate biofuel to be carried forward within this study, as detailed in the following section.

The assessment involved researching each fuel option to understand it's feedstocks, production methods and supply chain as well as it's physical properties. This research has been collated in a table and is presented in Appendix A.1. A screening of the fuels was then performed to allow for selection of the most appropriate biofuel. The results of the screening were shared with Operator A who agreed with the outcome, a full summary slide pack of the selection process is found in Appendix A.3.

The following two sections detail the screening process and results, before providing a summary of the selected biofuel.

4.2.1 Screening

A literature and technology review were conducted and identified 15 biofuels to be included in the screening process. These were:

- Straight vegetable oils (SVO)
- Biodiesel
- Hydrogenated vegetable oils (HVO)
- Biobutanol
- Bioethanol
- Ethyl tert-butyl ether (ETBE)
- Cellulosic ethanol
- Bio-oil
- Bio-DME
- F-T diesel
- Bioelectricity
- Biohydrogen
- Algal biofuels
- BioSNG
- Biogas

The feedstocks and production process for each of these is displayed with Figure 4-3.

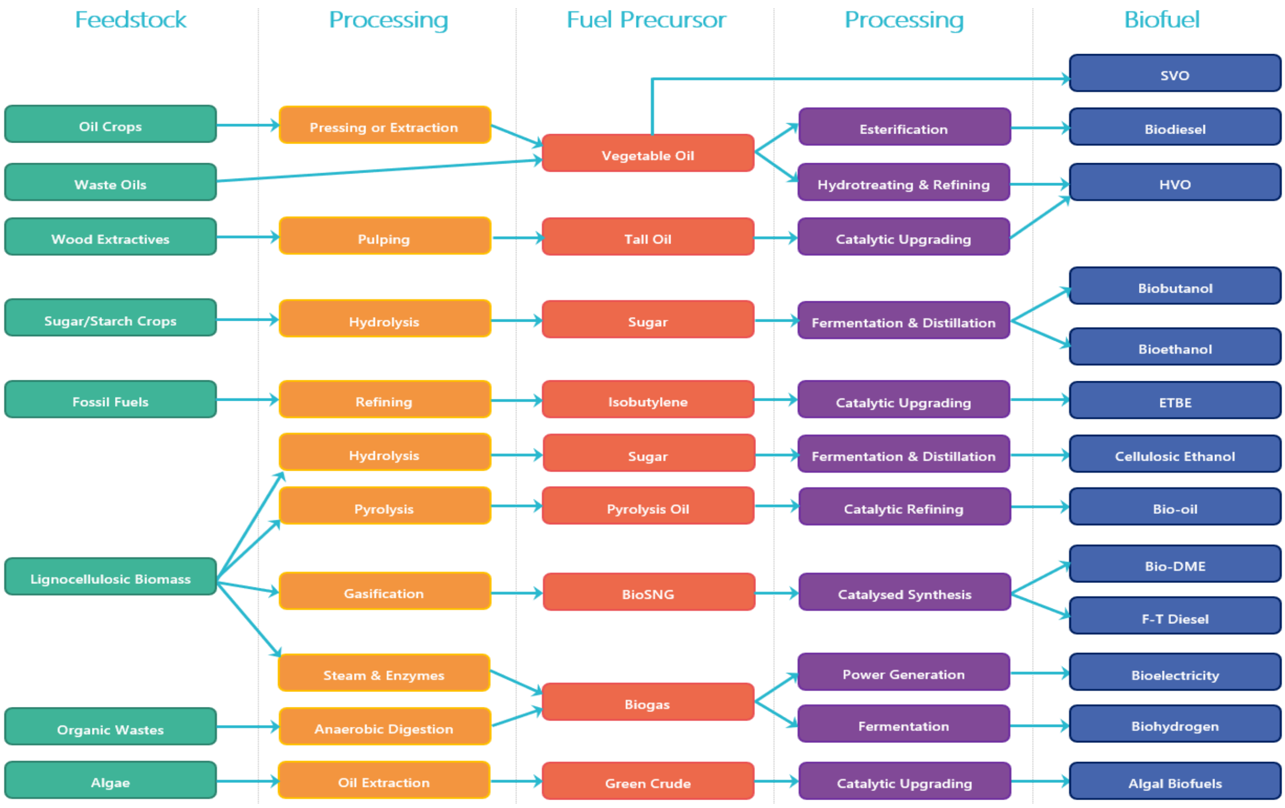

Figure 4-3 - Biofuel Feedstock & Production Processes

An initial screening was performed to remove options which were clearly unfeasible due to operational or sustainability issues. The initial screening results can be seen within Appendix A.1 which shows fuels that were not considered for implementation based on initial screening.

A summary of the biofuels research conducted, along with associated reference, can be found within Appendix A.2.

The initial screening left five biofuels, with the remaining options to be assessed with regards to their Technology Readiness Levels (TRLs) [Ref. 37] and supply chains.

F-T Diesel

Feedstock	Lignocellulosic biomass
Production Method	Gasification of biomass followed by conversion to liquid biofuels via Fischer Tropsch
Pros	• Good viscosity, density, and calorific energy properties

	• Each stage of production process is well developed
Cons	• Not currently beyond the development stage • Very little F-T diesel currently produced globally • Current and announced commercial F-T installations indicate nearly 300 million litres of F-T liquid production by 2025 (Asset A demand is potentially > 24% of production)
TRL	6
Supply Chain	Undeveloped

Table 4-2 - F-T Diesel Profile

Algal Biofuels

Feedstock	Algae
Production Method	Oil extraction followed by catalytic upgrading
Pros	• Low cost and no competition for food resources, algae grow in large concentrations on ponds • Algal formations can remove GHG from the atmosphere
Cons	• Development towards commercialisation has stalled due to struggles developing algal species with high enough oil production per m^3 • Global research investment has dried up suggesting commercialisation is multiple decades away
TRL	5
Supply Chain	Undeveloped

Table 4-3 - Algal Biofuels Profile

Bio-DME

Feedstock	Lignocellulosic biomass
Production Method	Gasification followed by gas shift, synthesis, and distillation
Pros	• Capable of using waste from industries • Each stage of process is developed

	• Similar properties to LPG
Cons	• Technology is currently at demonstration scale • Historically conventional DME is used as a fuel additive rather than a standalone fuel
TRL	6
Supply Chain	Undeveloped

Table 4-4 - Bio-DME Profile

Cellulosic Ethanol

Earlier bioethanol was discounted based on sustainability concerns however a combination of bioethanol and cellulosic ethanol supplies may be worth considering as biofuels suppliers are working to address sustainability concerns, and bioethanol makes up > 10 % of biofuel production:

"Biofuel producers are also seeking feedstocks produced on degraded land or from crops planted during what were previously fallow periods to increase acreage without appropriating land that would otherwise be used for food and feed production. In Brazil, for instance, 75% of corn ethanol production comes from second-crop production in existing fields. In Europe, some biofuel producers are sourcing oilseeds grown on degraded terrain to meet RED II sustainability criteria, and bio-based diesel feedstock producers globally are establishing new supply chains for bio-oils such as tall oil and fish oil and expanding those for animal fats and used cooking oil." – [Ref. 2].

Estimates suggest potentially 6,196 -7,068 million litres of bioethanol per year in EU 2027 (may be an option to support the supply of cellulosic ethanol).

Feedstock	Lignocellulosic biomass (e.g., forestry residues, energy crops)
Production Method	Cellulose hydrolysis of agricultural residues
Pros	• Utilises more sustainable feedstock than conventional bioethanol • Feasibility has been proven • Ambitious estimates suggest 3,800 million litres could be produced in EU by 2030. Asset A demand is 3 % of this prediction. Note: The forecast assumes a favourable policy environment extending beyond 2030 exists for cellulosic ethanol, which would make the ramp up to 2030 viable.
Cons	• World's largest Cellulosic Ethanol producer, Raízen, guarantees only 280 million litres by 2024

	• Turbine OEM A are not doing any development work on ethanol e.g., they don't have ethanol fuel injectors or any data using ethanol in any of their turbines. • EU production in 2017 at 31 million litres • Low mass and energy density
TRL	9
Supply Chain	EU production in 2017 at 31 million litres. Ambitious estimates suggest 3,800 million litres could be produced in EU by 2030.

Table 4-5 - Cellulosic Ethanol Profile

HVO

HVO is a biofuel designed as a diesel replacement. HVO is a mixture of straight chain and branched paraffins with typical carbon numbers of C15 to C18. HVO is produced by the hydrotreatment of triglyceride. The hydrotreatment process requires hydrogen to remove oxygen from triglyceride.

HVO is considered a more reliable biofuel than traditional biodiesel which can be known to leave fatty deposits in cold weather and can be varied in quality. No modifications are required to diesel fuelled combustion equipment changing to HVO.

The triglyceride feedstock can be derived from vegetable oils or fatty residues and wastes. If a crop is used to provide a vegetable oil feedstock, there may be environmental impact associated with growing crops specifically for HVO. Additionally, there are food versus fuel ethics issued related to this land use for biofuels. Environmental impact and land use is reduced when a waste stream can be used as the triglyceride source.

The existing diesel facilities on oil and gas assets could readily be adapted to HVO.

Feedstock	Oil crops, tall oil & industrial waste oils (used cooking oil)
Production Method	Hydroprocessing of oils and fats
Pros	• Ease of adaptation • Already produced at scale • Established diesel shipping practices • IEA main case world production 2027 = 26,588 million litres per year (potentially 6,511 - 9,566 million litres per year in Europe 2027 main vs accelerated cases). Asset A demand is < 0.3 % of global production. • Feasible to use as a fuel source for GTs

	• Low freezing point (-25C to -40C) • Low water solubility (non-polar as per fossil diesel) • Good filterability, not prone to precipitation above the cloud point • Stability is similar to fossil diesel so no need for a 'use by' date as there is for biodiesel
Cons	• Emissions vs. e-fuel options • Environmental impact of crop feedstock production • Food versus fuel ethics • Material compatibility typically similar to fossil diesel - In principle, the lack of aromatic compounds may shrink elastomers that have already been swollen due to aromatic or FAME containing fuels, but Neste have experienced no leakage during 12 years field operations. • Slightly lower density than diesel so review of existing re-used pumps, etc. required (HVO density 780 kg/m^3, conventional diesel circa 830 kg/m^3).
TRL	9
Supply Chain	Potentially 9,566 million litres could be produced in the EU by 2027. However, there are expected to be supply constraints related to manufacturing and increased demand.

Table 4-6 - HVO Profile

4.2.2 Biofuel Selection

In addition to studying renewable methanol, HVO and bioethanol / cellulosic ethanol are the best options. Given that Turbine OEM A are not doing any development work on ethanol (e.g., they don't have ethanol fuel injectors or any data using ethanol in any of their turbines), progressing with an ethanol fuel would be higher risk.

Methanol as a fuel type is more comparable to ethanol than HVO. Choosing HVO will allow for a more diverse pairing of alternative fuels for the Asset A fuels study. For the reasons outline through the screening process, HVO is the selected biofuel. More information on the supply chains of renewable methanol and HVO is presented in Section 11.

4.3 Fuel Summary

4.3.1 Selected Alternative Fuels

For the purposes of this alternative fuel study, renewable methanol (consisting of bio-methanol and e-methanol) and HVO were considered as alternative fuels. These were assessed against the current platform fuel options of platform fuel gas and diesel.

4.3.2 Fuel Properties

A summary of the key properties related to the storage and use of each fuel option are presented in the table below.

FUEL	STATE AT ATM. PRESSURE AND AMBIENT TEMPERATURE	DENSITY (KG/M^3)	LHV (MJ/KG)	VOLUMETRIC ENERGY DENSITY (MJ/L)	FLASH POINT (°C)
Platform Fuel Gas	Gas	26.6 (35 barg, 60°C)	42.5	1	Flammable Gas
Diesel	Liquid	830.0	43.1	36	~61°C
Methanol	Liquid	801.5	19.9	16	11°C
HVO	Liquid	780.0	44.4	35	~61°C

Table 4-7 - Fuel Properties [Ref. 1, 3, 4]

5 POWER LOAD SCENARIOS

5.1 Power Load Scenarios

A total of 5 power load scenarios were considered for the scope of this study for alt-fuel usage. The scenarios, provided by Operator A, are as follows:

SCENARIO	DESCRIPTION	FUEL USERS	TOTAL POWER
1A	TAR Shutdown: GTG	GTGs GT-A/B– 1.5 MW	1.5 MW
1B	TAR Shutdown: Temporary HV Power	Temporary HV Generators – 1.5 MW	1.5 MW
2A	Power Generation: GTG	GTGs GT-A/B – 6.0 MW	6.0 MW
2B	Power Generation: GTG post-LPBC revamp & electrification	GTGs GT-A/B – 10.4 MW	10.4 MW
3	Full: GTG + MPX Compression	GTGs GT-A/B – 10.4 MW MPX Compressor CTG-A/C– 16.8 MW	27.2 MW

Table 5-1 - Power Load Scenarios

Scenario 1A – This scenario represents the platform operating during a TAR shutdown period, utilising the main power generation units.

Scenario 1B – This scenario represents the platform operating during a TAR shutdown period, utilising temporary HV power units. Please note, 3 x units operating at a duty of 0.5 MW each has been considered as the basis.

Scenario 2A – This scenario represents the normal base power load, provided by the main power generation units.

Scenario 2B – This scenario represents the normal base power load with an additional load relating to the electrification of the Low-Pressure Booster Compressors, provided by the main power generation units.

Scenario 3 – This scenario represents the normal base power load with an additional load relating to the electrification of the Low-Pressure Booster Compressors, provided by the main power generation units. The MP/Export compression drivers are also considered to be powered by alternative fuel, giving the full platform power load.

5.2 Thermal Efficiencies

As per Section 5.1, there are five fuel consumption cases reviewed as part of this study. To allow for calculation of required fuel flowrates for alternative fuels, and current conventional fuels (i.e., fuel gas & diesel), thermal efficiency data for each case at the specific operating points was required. The thermal efficiency values utilised are summarised in Table 5-2.

POWER LOAD SCENARIO	EQUIPMENT PURPOSE AND TAGS	POWER CONSUMPTION (MW)	THERMAL EFFICIENCY AT OPERATING POINT (%)
1A	Power Generator GT-A/B	1.5	10.0
1B	Rigsafe Diesel Generator	1.5	34.9
2A	Power Generator GT-A/B	6.0	21.0
2B	Power Generator GT-A/B	10.4	26.5
3	Power Generator GT-A/B	10.4	26.5
	MP Export Compression CTG-A/C	16.8	35.0

Table 5-2 - Thermal Efficiencies

Thermal efficiency data for the Gas Turbine power generators was calculated from the OEM datasheet plot, presented in Appendix B.1. This data was cross-checked against the Asset A Energy Efficiency report [Ref. 8] and verified by Turbine OEM A

For the MPX compression drivers, thermal efficiency data was taken from the following plot within the Asset A Energy Efficiency report.

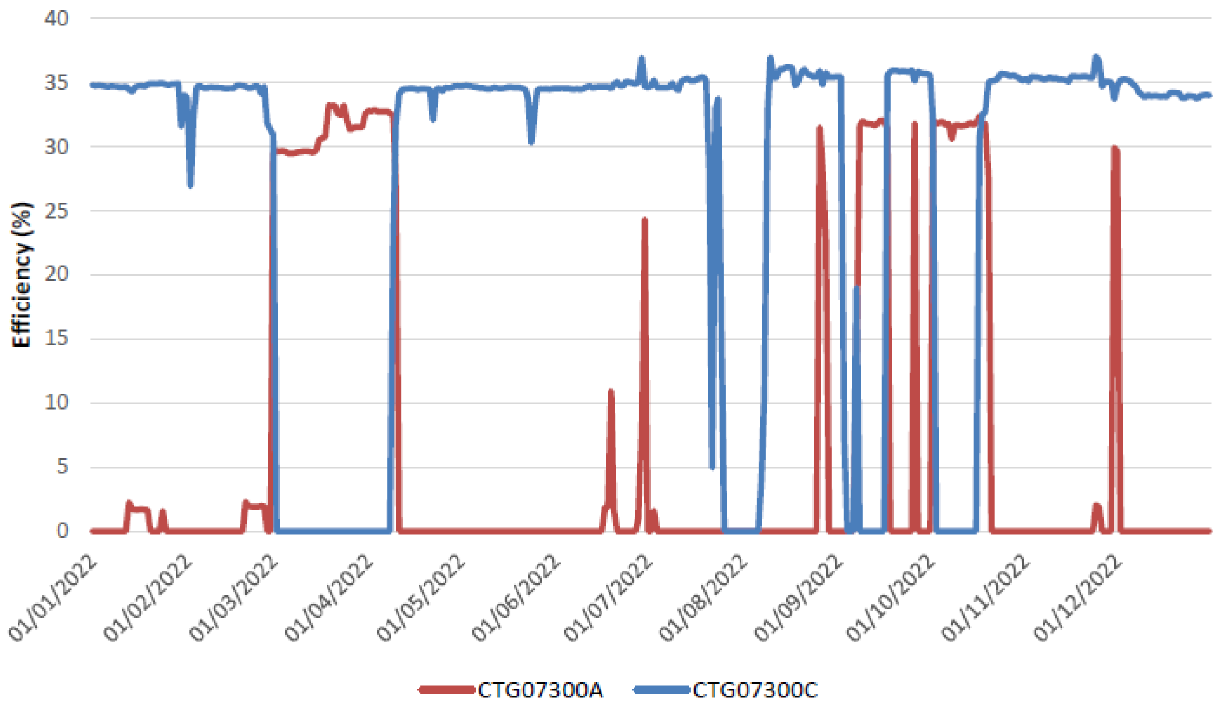

Figure 5-1 - MP and Export Compressor A and C Turbine Thermal Efficiency 2022 [Ref. 8]

For the temporary HV diesel generators, thermal efficiency was extracted from the equipment datasheet [Ref. 9].

5.3 Fuel Consumption

For each power load scenario, the fuel consumptions of methanol, HVO and the base fuel (diesel or fuel gas) has been calculated and is presented in the following table. The densities and lower heating values presented in Table 4-7 have been used for calculation purposes.

POWER LOAD SCENARIO	POWER CONSUMPTION (MW)	FUEL	FUEL CONSUMPTION		
			kg/h	m^3/h	m^3/d
1A	1.5	Diesel	1,252	1.5	36.2
		Methanol	2,714	3.4	81.3
		HVO	1,216	1.6	37.4
1B	1.5	Diesel	359	0.4	10.4
		Methanol	777	1.0	23.3
		HVO	348	0.4	10.7
2A	6.0	Fuel Gas	2,422	-	-
		Methanol	5,169	6.4	154.8
		HVO	2,317	3.0	71.3
2B	10.4	Fuel Gas	3,327	-	-
		Methanol	7,100	8.9	212.6
		HVO	3,182	4.1	97.9
3	27.2	Fuel Gas	7,395	-	-
		Methanol	15,783	19.7	472.6
		HVO	7,074	9.1	217.7

Table 5-3 - Fuel Consumption

6 DEVELOPMENT CONCEPTS

6.1 Fuel Storage Options

It can be assumed that a reasonable storage volume requirement would be based on 14 days of fuel supply. Using the fuel consumption figures from Section 5.3, the following storage volumes are required for each fuel option.

POWER LOAD SCENARIO	FUEL	14 DAY STORAGE VOLUME REQUIREMENTS (m^3)
1A	Methanol	1,138
	HVO	524
1B	Methanol	326
	HVO	150
2A	Methanol	2,167
	HVO	998
2B	Methanol	2,976
	HVO	1,371
3	Methanol	6,616
	HVO	3,047

Table 6-1 - Indicative Fuel Storage Volume Requirements

6.1.1 Platform Storage

Asset A's existing topsides liquid fuel storage capacity was assessed alongside available space on the platform, and it was concluded that for power load scenarios 2A, 2B & 3 that topsides fuel storage is not viable. Scenarios 1A & 1B however, have reduced fuel storage volumes and importantly are temporary arrangements during TAR shutdown periods. This suggests that during these TAR shutdown of 21 days, more frequent fuel supply may be possible allowing for reduce storage volumes.

For power load scenarios 1A & 1B platform storage solutions have been developed, these are discussed in detail within the concept descriptions, Sections 7.1 & 7.2.

The following off-platform storage options were identified.

- Subsea Fuel Storage
- Floating Storage and Offloading Vessel

These storage concepts are discussed in the following sections.

6.1.2 Subsea Storage Concept

NZTC are technology partners for a concept being developed by NOV – a subsea storage solution which utilises a membrane-based storage tank. The storage concept is being developed for energy storage systems and can be used in both renewable methanol and HVO applications. It should be noted that other subsea storage tank systems are available, but these were not reviewed as part of this study.

A subsea storage module consisting of a cluster frame, subsea storage units (membrane-based tanks), monitoring instrumentation and a fluid transfer system would be positioned on the seabed within Asset A's 500m safety zone. This module is known as a Subsea Storage Unit (SSU). The membrane-based tanks can be pressurised externally as an open system by sea pressure or as a closed system by a connected utility. The pressure allows the fluid to flow to the users. Alternatively, a subsea pump can be used.

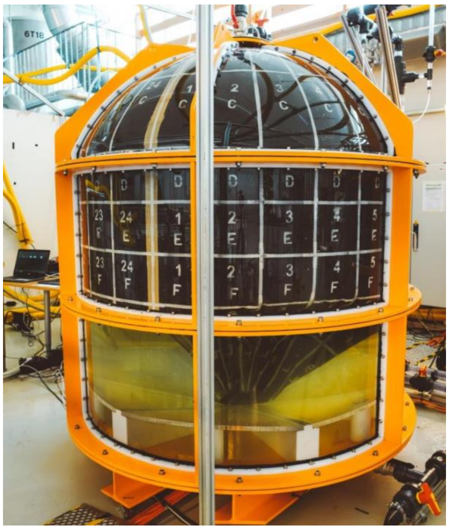

Figure 6-1 - NOV Subsea Storage Unit [Ref. 10]

The tanks would be connected to the platform via a single umbilical comprising piping and E&I conduits. The tanks would be monitored for pressure and level and have remotely operated fill and discharge valves.

A ship would be used to refill the SSU via a separate fill riser connected to a buoy system such as a Single Anchor Loading (SAL) system.

For a SSU which is pressurised by the platform's seawater utility - during the filling operation the seawater in the SSU, external to the membrane, is discharged to sea to allow a rapid filling operation.

Figure 6-2 - Subsea energy Storage System Illustration [Ref. 10]

The SSU concept is currently at TRL4 (API 17N) with product validation ongoing. The development of the technology is aiming to progress to pilot deployment in 2024. Refer to Appendix C for more detail on the NOV storage solution.

Subsea fluid storage is not a new concept for the oil and gas industry or the North Sea with oil being stored subsea on several assets.

6.1.3 Floating Storage and Offloading Vessel Concept

A sensitivity option for fuel storage has been reviewed. This sensitivity option applies a Floating Storage and Offloading Vessel (FSO) or tanker for fuel storage.

The FSO would be moored at a safe distance from Asset A with a single flexible flowline connecting the FSO to the platform. Fuel would be delivered to the FSO and fuel would be transferred by ship-to-ship bunkering. Fuel would be pumped from the FSO to the platform.

This option is seen as a low CAPEX option but would see increased OPEX associated with FSO or tanker charter.

FSOs are typically converted single hull tankers. FSOs are currently utilised in the North Sea for oil storage where there is no direct oil export route.

6.2 Concepts Overview

A review of the fuel storage concepts, and possible fuel distribution configurations concluded that there are several potentially viable design options available. An overview of the design concepts is presented below and discussed further in subsequent sections.

Each concept has considered the implications of both renewable methanol and HVO fuels being implemented. At this early concept stage, no option selection work has been undertaken; option selection should be concluded in subsequent project phases if the design is taken forward.

Concepts have been split into TAR Shutdown Concepts and Continuous Operation Concepts.

6.2.1 TAR Shutdown Concepts

The TAR shutdown concepts feature platform storage and focus upon a single 21-day TAR shutdown period in 2027. An overview of these concepts is presented below.

DESCRIPTION		POWER LOAD SCENARIO	FUEL STORAGE METHOD	NOTES
Concept 1A	TAR Shutdown with GTG	1A	Platform Storage	OPEX assessment versus continued diesel usage
Concept 1B	TAR Shutdown with Temp HV Power	1B	Platform Storage	OPEX assessment versus continued diesel usage

Table 6-2 - TAR Shutdown Concept Overview

6.2.2 Continuous Operation Concepts

Continuous operation concepts utilise off-platform storage and consider continuous operation from 2027 to CoP in 2035. An overview of these concepts is presented below.

DESCRIPTION		POWER LOAD SCENARIO	FUEL STORAGE METHOD	NOTES
Concept 2A	Subsea Storage Tanks, 6 MW Power Generation GTG	2A	Subsea Storage	Full cost estimate
Concept 2B	Subsea Storage Tanks, 10.4 MW Power Generation GTG	2B	Subsea Storage	Full cost estimate

DESCRIPTION		POWER LOAD SCENARIO	FUEL STORAGE METHOD	NOTES
Concept 3A	Subsea Storage Tanks, 27.2 MW Power Generation GTG	3	Subsea Storage	Full cost estimate
Concept 3B	Single FSO Comparison	3	Single FSO	Full cost estimate
Concept 3C	Dual FSO Comparison	3	2 off. FSO vessels operating back-to-back	Full cost estimate

Table 6-3 - Continuous Operation Concept Overview

7 BROWNFIELD MODIFICATIONS – TAR SHUTDOWN CONCEPTS

This section discusses options for alt-fuel storage and distribution and the associated required brownfield modifications. Also presented are the required upgrades to the platform's gas turbines for each fuel option.

7.1 Concept 1A (Shutdown Diesel Comparison OPEX Assessment: GTG)

Concept 1A considers the modifications required to utilise an alt-fuel (Renewable Methanol or HVO) to power the Alpha main power generation units during a TAR shutdown period.

This option considers the following principles:

- Fuel is to be delivered during the TAR period via platform supply vessel.
- Fuel is to be stored on the platform.
- Equipment will be required to distribute the fuel to the Alpha main power generator (GT-A).

A schematic for this option is presented on the following page

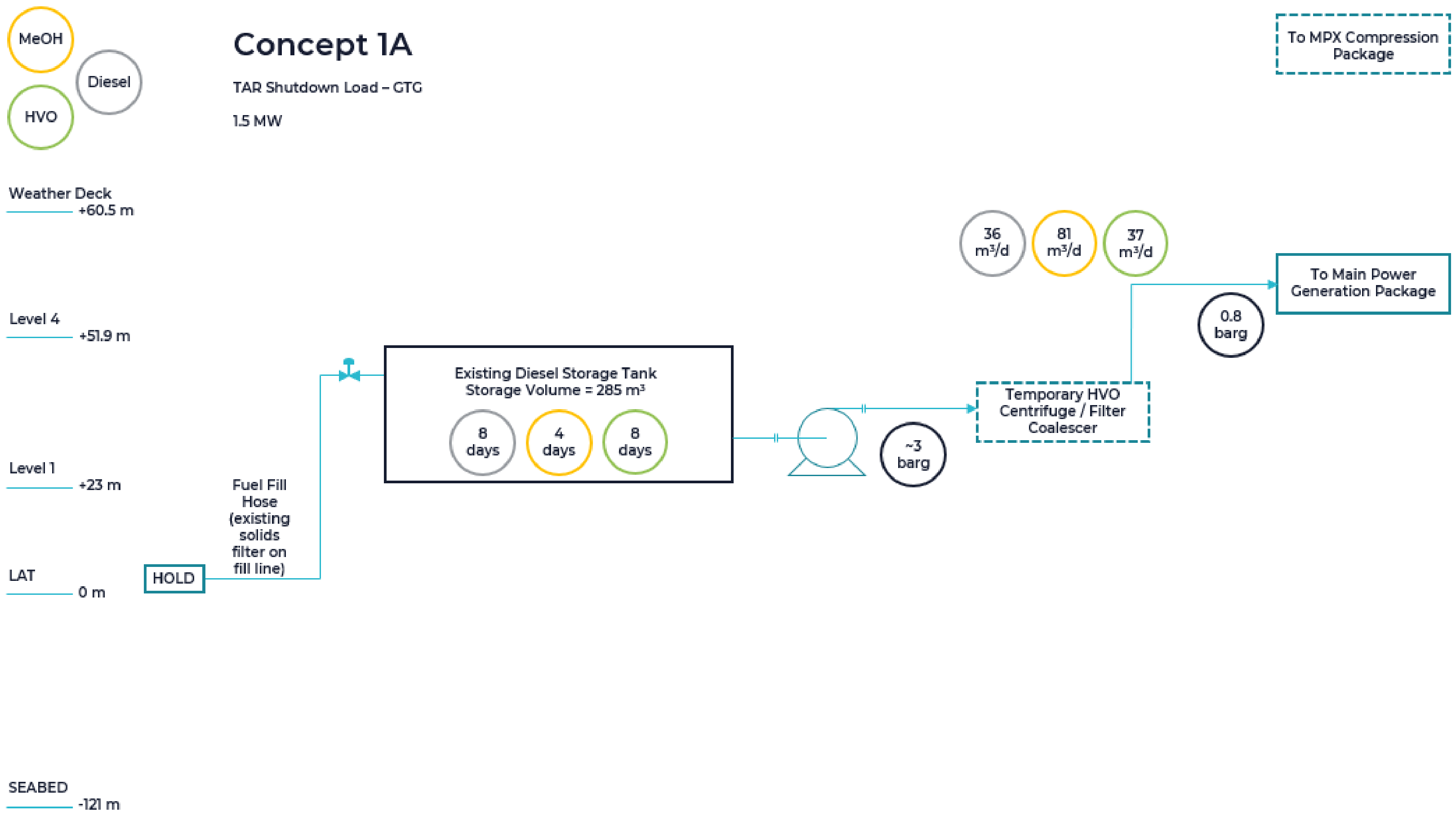

Figure 7-1 - Concept 1A Schematic

7.1.1 Concept Description

Note that storage volumes, distances, line sizes and flowrates described within this section are preliminary only and are to be defined in subsequent project phases.

Asset A's existing topsides liquid fuel storage capacity was assessed to determine if any spare storage capacity existed for alt-fuels required during the TAR shutdown period. Due to the GTGs location on level 4 of the PUQ platform, the preference is for the selected alt-fuel storage location to be on the PUQ. The PUQ platforms diesel system has been investigated with the following storage vessels being identified [Ref. 11, 12].

VESSEL DESCRIPTION	VESSEL TAG	LOCATION	STORAGE CAPACITY (m^3)	STORAGE DURATION (DAYS)	
				METHANOL	HVO
Diesel Storage Tank	T-A	Level 1 in deck	220	2.7	5.9
Diesel Storage Tank	T-B		285	3.5	7.6
Diesel Day Control Tank	T-C	Located in the crane pedestal	55	0.7	1.5
Diesel Day Control Tank	T-D		55	0.7	1.5

Table 7-1 - Existing Asset A PUQ Platform Diesel Storage Tanks

Initial observations indicate that Diesel Storage Tank T-B is the most suitable candidate due to its storage capacity. 285m^3 would provide 3.5 days of methanol storage and 7.6 days of HVO storage. Modifications to the tank will be required to allow for its temporary isolation from the diesel distribution system to ensure that other diesel users are not impacted. These modifications are shown in the marked-up sketch P&ID in Figure 7-2.

REDACTED

Figure 7-2 - Diesel Storage Tank B Required Modifications

The location of the tank within PUQ Level 1 deck, means that there are complex accessibility issues to carry out the required modifications. To finalise this selection, a full survey would be required on the tanks condition, material compatibility, cleanliness & suitable fill/discharge arrangements to confirm suitability.

REDACTED

Figure 7-3 - Diesel Storage Tank B Location

To transfer the fuel from the existing storage tank to the GT, temporary 2" hosing will be required. Additionally, temporary fuel transfer pumps must be installed to provide the required liquid fuel inlet pressure to the main power generation package, circa 0.8 barg. Alternatively, there is the option to use existing diesel fuel transfer pump, subject to discharge pressure requirements.

An allowance has been made for alt-fuel pre-treatment treatment, such as a centrifuge or filter coalescer, as per Asset A's current diesel system. A temporary rental filter coalescer was selected for Concept 1A to achieve a simple design solution and small footprint for this short-term service. The package is only required for the removal of water from HVO; no equivalent unit is proposed for methanol service due to water being miscible with methanol hence a separate water phase is not expected. The use of conductivity meters to detect water ingress to fuels has also not been allowed for. The inclusion of systems for proving fuel quality should be considered in the next engineering phases depending on the downstream combustion equipment requirements and fuel supply contracts.

The basis considers that only the Alpha main power generator (GT-A) will be modified for alt-fuel usage. It is expected that the existing diesel system can supply the secondary generator as back-up.

7.1.2 Process Flow Diagram & Equipment List

A Process Flow Diagram for Concept 1A is presented in Appendix D. An Equipment List is provided in Appendix E.

7.1.3 Concept Opportunities & Risks

The opportunities and risks relating to Concept 1A are shown below.

OPPORTUNITIES	RISKS / CHALLENGES
No subsea CAPEX	Low thermal efficiency of GTGs at 1.5 MW result in fuel inefficiency. Operator A's preference to use temporary HV units.
Temporary minor modifications	Required frequency of platform supply vessel fuel deliveries
Temporary repurposing of existing storage tank	

Table 7-2 - Concept 1A Opportunities & Risks

7.2 Concept 1B (Shutdown Diesel Comparison OPEX Assessment: Temp HV Power)

Concept 1B considers the modifications required to utilise an alt-fuel (Renewable Methanol or HVO) to power the Temporary HV Power units during a TAR shutdown period.

This option considers the following principles:

- Fuel is to be delivered during the TAR period via platform supply vessel.
- Fuel is to be stored on the drilling platform.
- Equipment will be required to distribute the fuel to the Temporary HV Power units.

A schematic for this option is presented on the following page.

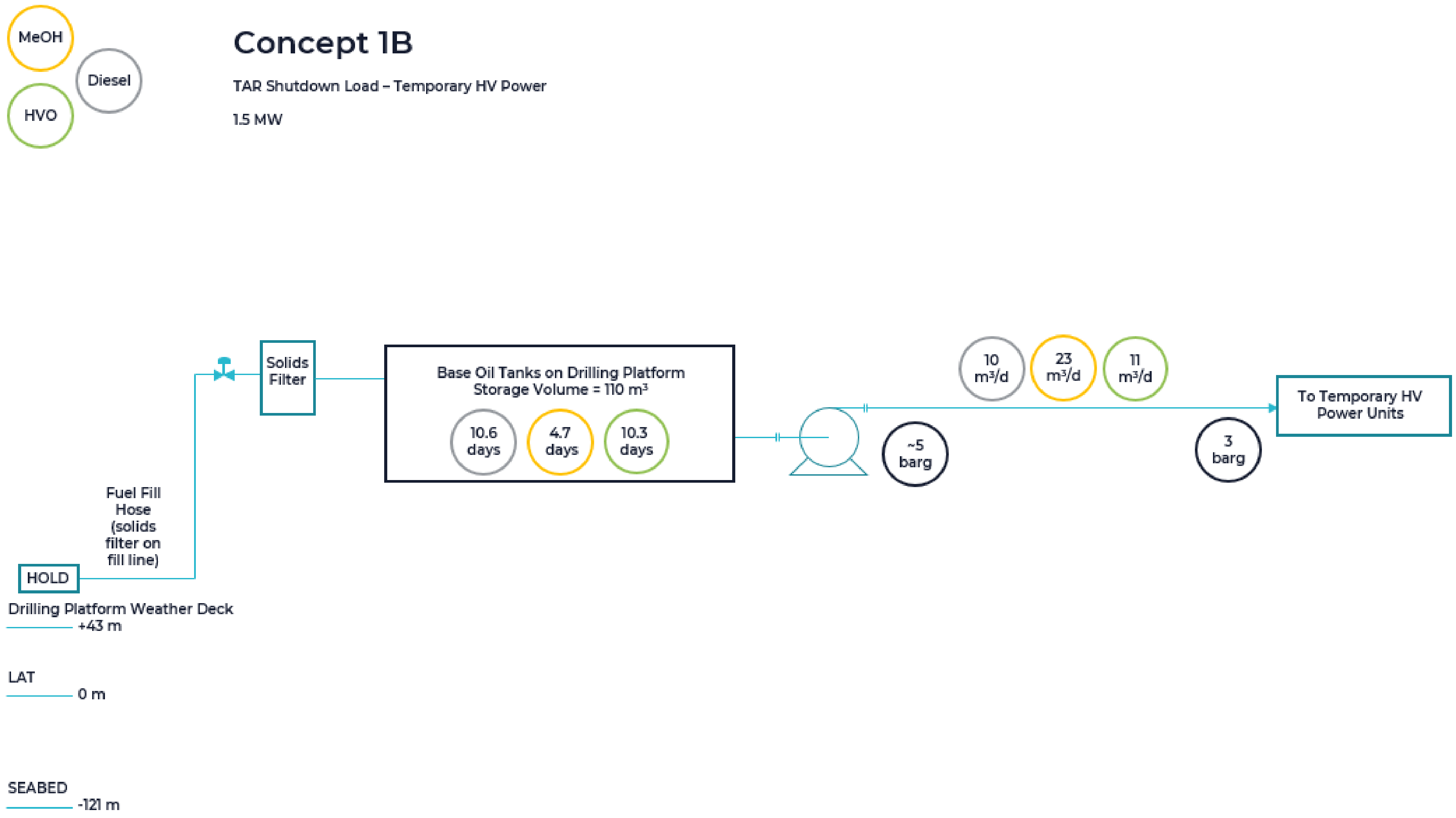

Figure 7-4 - Concept 1B Schematic

7.2.1 Concept Description

Note that storage volumes, distances, line sizes and flowrates described within this section are preliminary only and are to be defined in subsequent project phases.

Asset A's existing topsides liquid fuel storage capacity was assessed to determine if any spare storage capacity existed for alt-fuels required during the TAR shutdown period. Due to the temporary HV power generator's location on the Weather Deck of the Drilling Platform, there are opportunities for alt-fuel storage on either the PUQ or Drilling platform.

The option to utilise Diesel Storage Tank T-B on the PUQ was investigated with regards to required tie-in and fuel transfer logistics. The diesel distribution route from PUQ to the Drilling Platform is via a single hose and manifold across Bridge P60. To avoid mingling of the alt-fuel with the diesel, which will still be required by a variety of users on the PUQ and Drilling Platforms (firewater pumps, cementer units, emergency power etc.), a new hose and manifold would be required stretching across the P60 Bridge to the temporary HV generators. As such, the preferred location would be on the Drilling Platform.

An initial assessment of tanks on the Drilling Platform highlighted the possibility of utilising tanks, currently used within the mud mixing, storage, and transfer system during drilling operations. The storage capacities these tanks would provide is 384 m^3, representing fuel capacities of 16.6 days methanol and 35.9 days HVO. Xodus consulted Operator A regarding the condition and suitability of the tanks for alt-fuel storage, who advised that due to the mud tanks being open top pits rather than enclosed tanks they would not be suitable for fuel storage.

Operator A indicated that the platform Base Oil Tanks (T-E/F) have potential to be utilised for alt-fuel storage [Ref. 14]. While the capacities are limited, the 21 days basis for the TAR period suggests it is feasible for the short duration.

VESSEL DESCRIPTION	VESSEL TAG	LOCATION	STORAGE CAPACITY (M^3)	STORAGE DURATION (DAYS)	
				METHANOL	HVO
Base Oil Storage Tank	T-E	Level 1 in deck	55	4.7	10.3
Base Oil Storage Tank	T-F		55		

Table 7-3 - Existing Asset A Base Oil Storage Tanks [Ref. 14]

The Base Oil Storage Tanks are located in-deck on the Weather Deck, local to the temporary HV power units.

Both tanks have not been in active service for some time and the pumps have been removed with the CRI Centrifuge equipment. If intending going forward with the Base Oil Tanks for alt fuel storage, a full survey would be required on the tanks condition, cleanliness & suitable fill/discharge arrangements. If these tanks are deemed unsuitable for temporary repurposing, a dedicated alternative fuel storage tank will be required on either a permanent or temporary basis.

The three generator sets are provided with a fuel 'autofill' arrangement allowing the package's internal day tanks to be filled on demand from the modified Base Oil Storage Tanks. The generators were located during the previous TAR on temporary support grillage, due to existing deck dividers, with a supply and drains manifold. To transfer the fuel from the storage location to the temporary HV power units, new 2" hosing will be temporarily installed to allow for repeated future use. Additionally, fuel transfer pumps will be temporarily installed to provide the required liquid fuel inlet pressure to the power units, 3 barg.

The turbine package vendor, NOV Portable Power, were contacted regarding the power gen unit's suitability for use with alternative fuels. They advised the following:

"The OEM (Cummins) have only just type approved the KTA 50 G3 Engine series to run on HVO, no test results from running Methanol based fuels have been released as yet so we cannot comment on its use. We currently have no units in the field, (with 100% utilisation of our hire fleet this TAR season), running on HVO". – [Ref. 15].

This highlighted that there would be no issues running the engines on HVO fuel, however, methanol usage would not yet be advised by the current vendor due to there being no testing results published on its use in the engines. Discussions with Methanol Vendor A indicated that there may be an opportunity to utilise existing methanol capable containerised generators, within the 1.5 MW range, to provide the temporary TAR shutdown power.

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Figure 7-5 - Previously Installed Hose & Piping Arrangement [Ref. 7]

A fuel solids filter will be required upstream of the Base Oil Storage Tanks. There may be an option to re-use the F-66104 from Base Oil Storage Tanks T-E/F common fill line [Ref. 14].

No allowance has been made for alt-fuel pre-treatment treatment, such as a centrifuge or filter coalescer, as per Asset A's current operation of the temporary HV power units. The use of conductivity meters to detect water ingress to fuels has also not been allowed for. The inclusion of systems for proving fuel quality should be considered in the next engineering phases depending on the downstream combustion equipment requirements and fuel supply contracts.

7.2.2 Process Flow Diagram & Equipment List

A process flow diagram for Concept 1B is presented in Appendix D. An Equipment List is provided in Appendix E.

7.2.3 Concept Opportunities & Risks

The opportunities and risks relating to Concept 1B are shown below.

OPPORTUNITIES	RISKS / CHALLENGES
No subsea CAPEX	Required frequency of platform supply vessel fuel deliveries
Temporary minor modifications	OEM has performed no testing on their engines with methanol fuel
Repurposing of existing redundant storage tank	

Table 7-4 - Concept 1B Opportunities & Risks

8 BROWNFIELD MODIFICATIONS – CONTINUOUS OPERATION CONCEPTS

8.1 Concept 2A (Subsea Storage Tanks, 6 MW Power Generation GTG)

Concept 2A considers the modifications required to utilise an alt-fuel (Renewable Methanol or HVO) to power the Alpha main power generation units for the normal base power load of 6.0 MW.

This option considers the following principles:

- Fuel is delivered and stored subsea as described in Section 6.1.2.
- The subsea storage is pressurised using Asset A's existing seawater utility.
- The pressure in the subsea storage tank is used to flow the fluid up to a topside alt-fuel intermediate storage tank.
- Fuel is pumped from the day tank to each alt-fuel user at the required pressure for the turbines without the need for further downstream pumping.

A schematic for this option is presented on the following page.

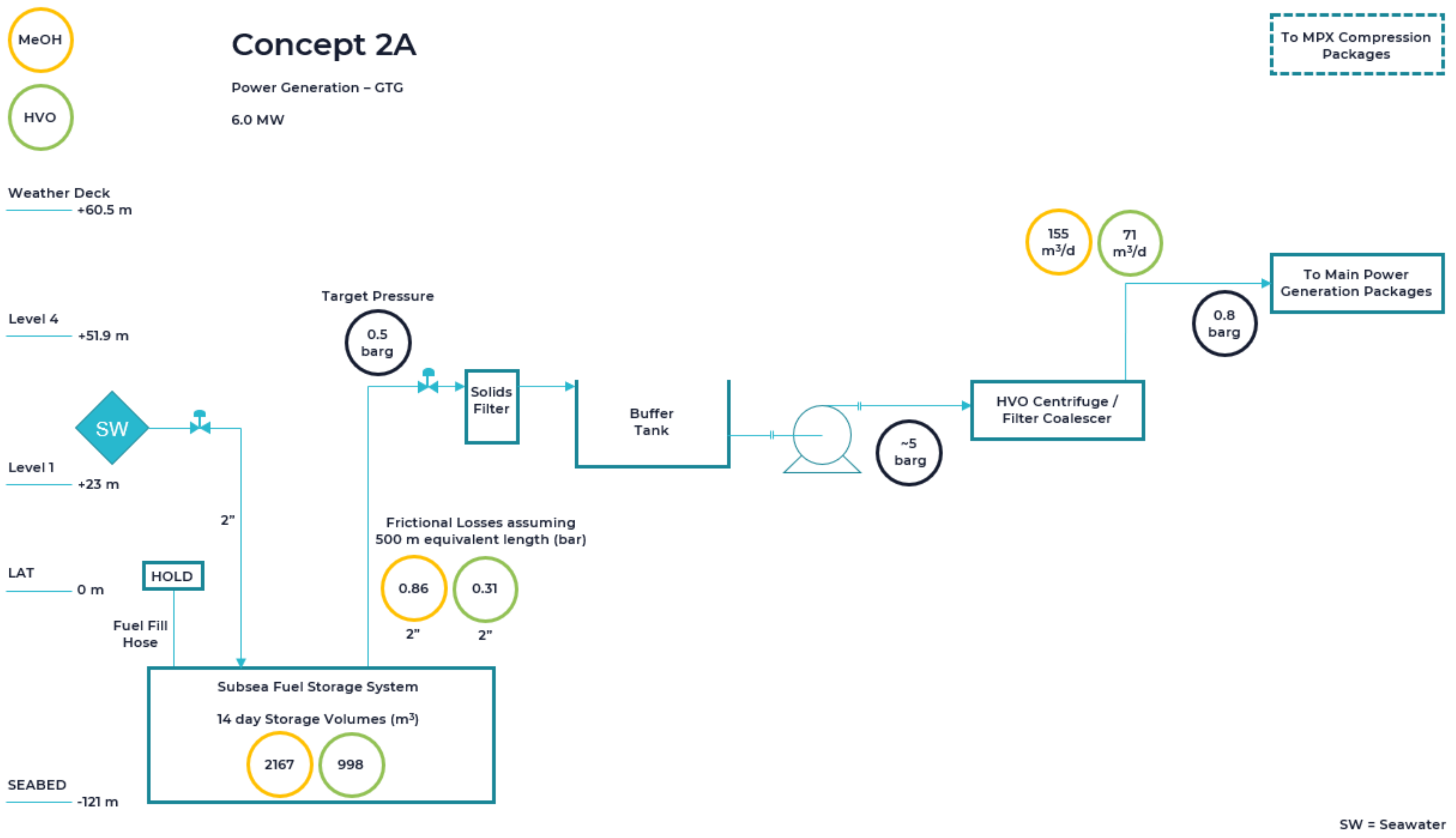

Figure 8-1 - Concept 2A Schematic

8.1.1 Concept Description

Note that storage volumes, distances, line sizes and flowrates described within this section are preliminary only and are to be defined in subsequent project phases.

It has been assumed at this stage of design that a NOV SSU with 14-days storage capacity will be used to store fuel subsea. The exact configuration of tanks and their storage volumes is to be refined, in collaboration with NOV, in later stages of the project if this concept is to be carried forward.

Fuel is delivered by vessel. The ship connects to a Single Anchor Loading type system (mooring system TBC) which is anchored to the seabed and integrates a mooring turret, in-line swivel and hose end valve. The vessel freely weathervanes around the SAL subsea turret via a mooring polyester rope.

A safety zone scheme has been developed – see Section 8.1.6. This is a conservative approach and should be revisited in the next phase of design, but is considerate of requirements for safe cargo, manoeuvring, dynamic positioning, and weather limitations offshore.

The SSU and new facilities need to be south and west of Asset A PUQ due to the proximity of export pipelines. The final location is dependent on a dropped object assessment and protection for the flowline routing would need considered accordingly. Asset A's 500m safety zone would be extended from the new SSU.

It is considered that fuel should be bunkered within a reasonable time frame and therefore a transfer rate of 1000m^3/hr has been used as an initial sizing basis. This rate is dependent on fuel delivery vessel selection – see Section 11.3. The fuel fill hose providing this flow has been sized as 12".

Asset A is connected to the SSU by a single umbilical comprising a storage pressurisation riser, a fuel supply riser, and a power/signal umbilical. The umbilical is routed through an available conductor slot.

The SSU is pressurised by Asset A's seawater utility which pressurises the SSU's membrane. Seawater is available from the seawater distribution P10 ring main above the Level 1 deck at a pressure of circa 5.0 barg. Hydraulic calculations have verified that this supply pressure is sufficient to supply a topsides intermediate fuel storage tank via an import strainer. The upstream Seawater Filter Package has a design duty of 8064m^3/h [Ref. 16], the required seawater rate for Concept 3A (worst case with methanol) is 19.7 m^3/h representing $<$ 0.3% of the system's capacity. This is seen as the preferred method to transport fuel from the SSU to topsides. NOV have indicated that there are options which include a subsea pump SSUs open to seawater - these options would bring O&M challenges and so are not preferred.

An allowance has been made for alt-fuel pre-treatment, such as a centrifuge or filter coalescer, as per Asset A's current diesel system. Preliminary inputs are based on a centrifuge package being installed for Option 2A, to be conservative for new permanent equipment power requirements. The package is only required for the removal of water from HVO; no equivalent unit is proposed for methanol service due to water being miscible with methanol hence a separate water phase is not expected. The package is to be located on Level 1 – see Piping & Layout section below. The use of conductivity meters to detect water ingress to fuels has also not been allowed for. The inclusion of systems for proving fuel quality should be considered in the next engineering phases depending on the downstream combustion equipment requirements and fuel supply contracts.

Based on topsides space constraints, the storage tank has a volume of 27.5m^3 (W x L x H = 2.5 m x 5.0 m x 2.2 m) and is located on Level 1 – see Piping & Layout section below. The tank is filled via a level control valve. The topside tank provides some backup capacity in the event of supply interruption as well as providing a buffer during SSU refill operation where instability in the fuel supply may be more likely. The tank provides 4.3 hours hold up capacity for methanol and 9.2 hours hold up capacity for HVO.

The Main Power Generation units currently require class A1 diesel fuel at normal minimum pressure of 0.73 barg (max. flow) [Ref. 17]. To provide the alt-fuel to the power units at ~1.0 barg, overcoming static head and piping losses, pumps are required to distribute the fuel from the tank with a discharge pressure of circa 5.0 barg. A duty/standby arrangement has preliminarily been selected for the pumps as there is adequate space in the proposed area (see Piping & Layouts section).

The seawater supply to the subsea storage is equipped with pressure control valve, relief valve and ESDV.

Fuel flowrates are measured on the main fuel supply line as well as at the individual users. Modifications are required to the turbine packages as per Section 9.

8.1.2 Process Flow Diagram & Equipment List

A process flow diagram for Concept 2A is presented in Appendix D. An Equipment List is provided in Appendix E.

8.1.3 Piping & Layout

For the Development Concepts requiring permanent installation of additional topsides equipment (Concept 2A, 2B 3A & 3B) only locations on the PUQ platform were considered due to this being the location of the existing main Power Generation and MP Compression packages which will be the main users for the alternative fuel.

The preferred location for the new topsides equipment is an existing deck area on the North Side of the PUQ Level 1 (shown in the plot plan in Figure 8-2 below as PWRI Pump Deck Extension).

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Figure 8-2 - Extract PUQ Level 1 Plot Plan showing Proposed Equipment Locations

This area is an extension to the original platform and was installed to house 3-off Produced Water Re-Injection (PWRI) pumps. These pumps were never brought online and are now redundant. Destruct of these pumps and associated pipework would create a space of approx. 47.5m^2 (9.5m long x 5m wide) for installation of the new fuel storage, transfer pumps and treatment packages. Dimensions of this area have been verified utilising the GDI vision model (Ref Figure 8-3 & Figure 8-4).

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Figure 8-3 - View North in GDI Vision Model of PWRI Deck Extension on PUQ Level 1

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Figure 8-4 - View West in GDI Vision Model of PWRI Deck Extension on PUQ Level 1

Alternative locations on the PUQ Level 4 at the East end of platform (in an area previously allocated for a future separator) and on Level 3 (in place of the redundant LP Compressor) were initially considered however due to the clear suitability of the PWRI deck area these locations were discounted and not investigated further.

High level preliminary layouts in this PWRI pump deck area for the new topsides equipment were developed for both the Renewable Methanol (Figure 8-5) and HVO (Figure 8-6) concepts and are shown below.

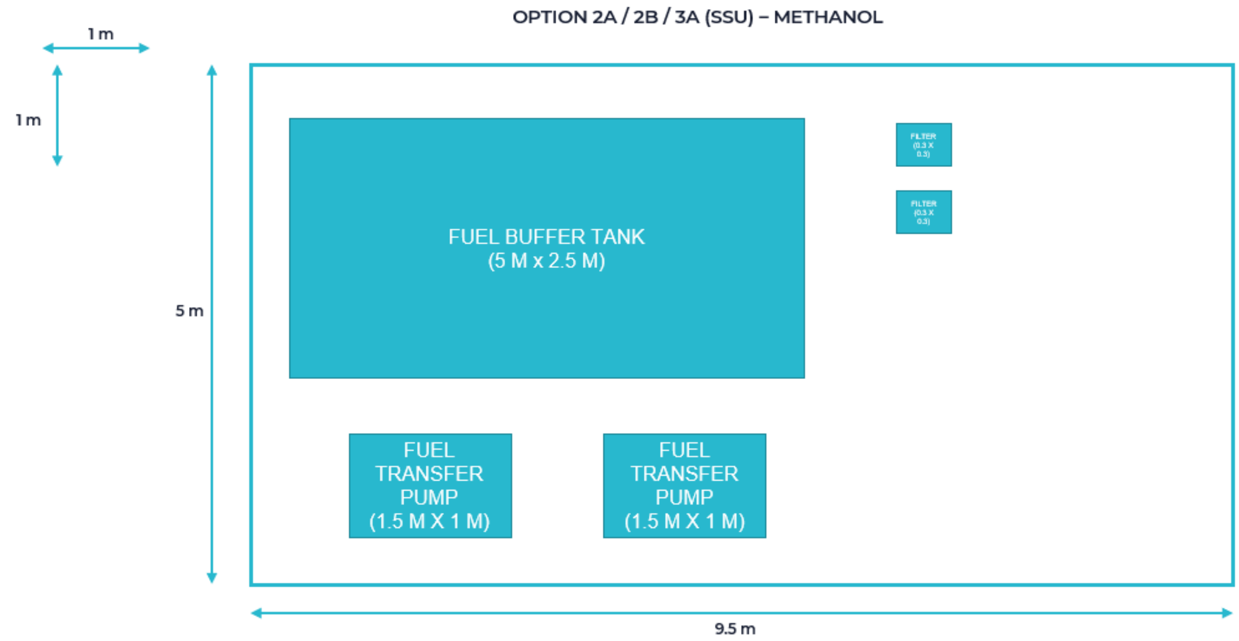

Figure 8-5 - Equipment Layout for Methanol on PUQ Level 1 PWRI Deck (Option 2A / 2B & 3A)

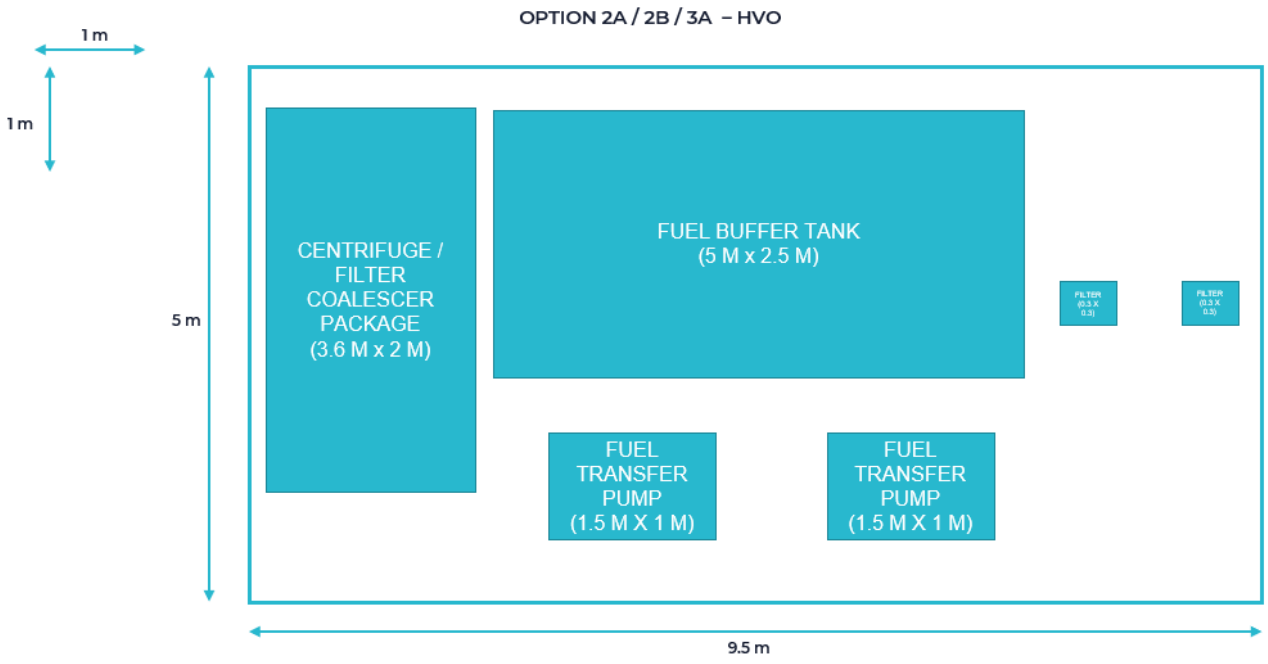

Figure 8-6 - Equipment Layout for HVO on PUQ Level 1 PWRI Deck (Option 2A / 2B & 3A)

Due to the requirement for the additional centrifuge/coalescer package for treating the HVO this does cause a more congested layout and the feasibility of installing all require equipment c/w pipework, valves and instrumentation in this area should be reviewed further if this is selected as the chosen Development Concept.

The alt-fuel will be supplied to the buffer tank (via the solids filters) from the new TUTU. As per discussion within Section 8.1.6 it is proposed that existing spare riser R2 will be used for the pull in of a new umbilical which will contain the seawater lift line to the subsea storage tanks and the new alt-fuel fuel supply line. A location is proposed for this new TUTU on PUQ Level 1 in an existing void area local to the termination point of the R2 riser under the Level 1 cellar deck. The area available is approx. 2.5m x 3.3m with the height available restricted by an existing structural brace (2m clearance available at the lowest point).

The proposed area for the TUTU is shown in Figure 8-7 with the location of this area in location to the PWRI deck extension and the R2 riser termination points shown in the Plot Plan in Figure 8-2.

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Figure 8-7 - View East in GDi Vision Model of Proposed Location for New TUTU

The pipe routing for each of the new required lines has not been modelled at this stage and will need to be further assessed in future phases of this project, however for the basis of the cost estimate, the following pipe run lengths have been assumed (based on plot plan locations for existing or proposed new equipment with an additional 40% allowance for actual pipe routing):

- Seawater Supply to TUTU – 60m
    - Tie in location to seawater system has not been confirmed however it is assumed that this will be downstream of the Seawater Filtration Package on PUQ Level 2
- Alt. Fuel Supply from TUTU to Solids Filters – 45m
- Fuel Transfer Pumps to GT-A /B – 90m
    - Tie in location to the fuel supply lines to GT's has not been confirmed however it is assumed this will be local to the GT package enclosures on PUQ Level 4

For the new relief line on the seawater supply and the open hazardous drains from the fuel packages, tie in points within these existing systems have not been identified, however an allowance of 20m of new pipework for each of these has been included within the cost estimates.

8.1.4 Controls & Instrumentation

The following section provides a summary of the topsides PUQ Platform ICSS interfaces and I/O requirements for the various options assessed as part of the Alternate Fuel Study. The instrument and control scope for each Concept is summarised below:

- Concept 2A and 2B (Methanol)- Field instrumentation, actuated valves, F&G devices, Fuel Booster Pumps, TUTU, and MCS interfaces.
- Concept 2A and 2B (HVO)- Field instrumentation, actuated valves, F&G devices, Fuel Booster Pumps, Centrifuge / Coalescer Package TUTU, and MCS interfaces.
- Concept 3A (Methanol)- Field instrumentation, actuated valves, F&G devices, LP Fuel Distribution Pumps, HP Fuel Distribution Pumps, TUTU, and MCS interfaces.
- Concept 3A (HVO)- Field instrumentation, actuated valves, F&G devices, LP Fuel Distribution Pumps, HP Fuel Distribution Pumps, Centrifuge / Coalescer Package, TUTU, and MCS interfaces.
- Concept 3B and 3C (Methanol)- Field instrumentation, actuated valves, F&G devices, and HP Fuel Distribution Pumps
- Concept 3B and 3C (HVO)- Field instrumentation, actuated valves, F&G devices, HP Fuel Distribution Pumps, Centrifuge / Coalescer Package interfaces

The I/O estimates for all options are provided in the following sections and have been based on the study assumptions detailed in this report and the study PFDs and P&IDs.

Control and Monitoring System (CMS)

It is anticipated that all new CMS I/O for new hardwired field instrumentation and actuated valves associated with all concepts shall be interfaced with the existing PUQ platform Yokogawa CMS Marshalling and System cabinets, located within the P10 LER.

Due to I/O requirements for both options it is anticipated that modifications may be required to P10 CMS marshalling and system panels to accommodate the new project I/O. Requirements for expansion and status of any spare I/O capacity within the P10 CMS which may be utilised will require further investigation in future project phases.

Table 8-1 below provides an estimate of the estimated CMS I/O requirements for each option.

HARDWIRED I/O	SUB-SYSTEM	AI	AO	DI	DO
Concept 2A & 2B (Methanol)					
Base Hardwired I/O Estimate	CMS - P10 LER	7	1	12	4
I/O Required (Inc. 20% Contingency)	CMS - P10 LER	9	2	15	5
Concept 2A & 2B (HVO)					
Base Hardwired I/O Estimate	CMS - P10 LER	7	1	18	10
I/O Required (Inc. 20% Contingency)	CMS - P10 LER	9	2	22	12
Concept 3A (Methanol)					
Base Hardwired I/O Estimate	CMS - P10 LER	9	1	20	8
I/O Required (Inc. 20% Contingency)	CMS - P10 LER	11	2	24	10
Concept 3A (HVO)					
Base Hardwired I/O Estimate	CMS - P10 LER	9	1	26	14
I/O Required (Inc. 20% Contingency)	CMS - P10 LER	11	2	32	17
Concept 3B & 3C (Methanol)					
Base Hardwired I/O Estimate	CMS - P10 LER	6	0	14	4
I/O Required (Inc. 20% Contingency)	CMS - P10 LER	8	0	17	5
Concept 3B & 3C (HVO)					
Base Hardwired I/O Estimate	CMS - P10 LER	6	0	20	10
I/O Required (Inc. 20% Contingency)	CMS - P10 LER	8	0	24	12

Table 8-1 - All Concepts for Methanol and HVO- CMS Estimated I/O Requirements

Emergency Shutdown System (ESD)

It is anticipated that all new ESD I/O for new hardwired SDV trip signals and limit switches, field ESD Pushbuttons, pump motor and package trip functions required for the various options shall be interfaced with the existing platform Yokogawa ESD Marshalling and System cabinets located within the PUQ Platform P10 LER.

As with the CMS, due to I/O requirements for all Options it is anticipated that modifications may be required to P10 ESD marshalling and system panels to accommodate the new project I/O. Requirements for expansion and status of any spare I/O capacity within the P10 ESD which may be utilised will require further investigation in future project phases.

Table 8-2 below provides an estimate of the estimated ESD I/O requirements for each option.

HARDWIRED I/O	SUB-SYSTEM	AI	AO	DI	DO
Option 2A & 2B (Methanol)					
Base Hardwired I/O Estimate	ESD - P10 LER	2	0	2	6
I/O Required (Inc. 20% Contingency)	ESD - P10 LER	3	0	3	8
Concept 2A & 2B (HVO)					
Base Hardwired I/O Estimate	ESD - P10 LER	2	0	2	9
I/O Required (Inc. 20% Contingency)	ESD - P10 LER	3	0	3	11
Concept 3A (Methanol)					
Base Hardwired I/O Estimate	ESD - P10 LER	2	0	2	10
I/O Required (Inc. 20% Contingency)	ESD - P10 LER	3	0	3	12
Concept 3A (HVO)					
Base Hardwired I/O Estimate	ESD - P10 LER	2	0	2	13
I/O Required (Inc. 20% Contingency)	ESD - P10 LER	3	0	3	16
Concept 3B & 3C (Methanol)					
Base Hardwired I/O Estimate	ESD - P10 LER	1	0	2	7
I/O Required (Inc. 20% Contingency)	ESD - P10 LER	2	0	3	9
Concept 3B & 3C (HVO)					
Base Hardwired I/O Estimate	ESD - P10 LER	1	0	2	10
I/O Required (Inc. 20% Contingency)	ESD - P10 LER	2	0	3	12

Table 8-2 - All Concepts for Methanol and HVO- ESD Estimated I/O Requirements

Fire and Gas System (F&G)

An allowance has been made for new ultraviolet / infrared flame detection, point gas detection and manual alarm call points for each option based on proposed new facilities, package equipment, equipment size and locations.

A full fire and gas coverage detection assessment will need to be carried out in future project phases to verify adequate coverage is in place.

It is anticipated that all new fire and gas detection devices will be interfaced with the existing PUQ Platform Yokogawa F&G marshalling and system cabinets located within the PUQ Platform P10 LER.

It is anticipated that sufficient spare I/O capacity is present within the existing F&G System to accommodate the new signals for each option and phase. Available system and I/O capacity will further investigation in future project phases.

Table 8-3 below provides an estimate of the estimated F&G I/O requirements for each option.

HARDWIRED I/O	SUB-SYSTEM	AI	AO	DI	DO
Concepts 2A, 2B, 3A, 3B and 3C (Methanol and HVO)					
Base Hardwired I/O Estimate	F&G - P10 LER	4	0	2	0
I/O Required (Inc. 20% Contingency)	F&G - P10 LER	5	0	3	0

Table 8-3 - All Concepts for Methanol and HVO- F&G Estimated I/O Requirements

ICSS Interfaces

Package Interfaces

Dual redundant Modbus RTU serial data communication links are proposed to allow for integration of the new MCS for options 2A, 2B, and 3A with the PUQ platform CMS.

Table 8-4 below details the estimated CMS serial I/O requirements for the MCS communications interface.

PACKAGE / INTERFACE	QUANTITY	NO. OF LINKS	ESTIMATED CMS SERIAL I/O
Concepts 2A, 2B and 3A (Methanol and HVO)			
MCS	1	2	100

Table 8-4 - Estimated CMS Serial I/O Requirements - 2A, 2B and 3A

MCC Interfaces

It is assumed that control, monitoring and shutdown of fuel distribution pumps and motors and Centrifuge / Coalescer Package pumps and motors will be implemented via hardwired signals installed between the P10 LER ICSS and the P10 Platform MCC.

Table 8-5 below provides a summary of the anticipated pumps associated with all options. Hardwired I/O has been included in the I/O summary based on each load requiring Start/Stop control signals, Trip signals and Running/Available indication signals.

PACKAGE / INTERFACE	QUANTITY
Concept 2A & 2B (Methanol)	
Topside Fuel Distribution Pumps A/B	2
Concept 2A & 2B (HVO)	
Topside Fuel Distribution Pumps A/B	2
Coalescer Package (1 x centrifuge motor, 1 x delivery pump motor, 1 x sludge pump motor)	3
Concept 3A (Methanol)	
Topside LP Fuel Distribution Pumps A/B	2
Topside HP Fuel Distribution Pumps A/B	2
Concept 3A (HVO)	
Topside LP Fuel Distribution Pumps A/B	2
Topside HP Fuel Distribution Pumps A/B	2
Coalescer Package (1 x centrifuge motor, 1 x delivery pump motor, 1 x sludge pump motor)	3
Concept 3B and 3C (Methanol)	
Topside HP Fuel Distribution Pumps A/B	2
Concept 3B and 3C (HVO)	
Topside HP Fuel Distribution Pumps A/B	2
Coalescer Package (1 x centrifuge motor, 1 x delivery pump motor, 1 x sludge pump motor)	3

Table 8-5 - Motor Pump MCC Interfaces - All Concepts

8.1.5 Electrical

The electrical assessment has focussed on the additional power supplies required for the various alt-fuel system option and these are summarised in Table 8-6.

EQUIPMENT	CONCEPT 2A		CONCEPT 2B		CONCEPT 3A		CONCEPT 3B	
	METHANOL	HVO	METHANOL	HVO	METHANOL	HVO	METHANOL	HVO
1 off Subsea fuel storage package supply via equivalent of a topsides MCS/EPU (subsea MOVs - 2 off 12" and 2 off 2")	63A	63A	63A	63A	-	-	-	-
1 off UPS supply for topsides MCS/EPU (controls and monitoring)	16A	16A	16A	16A	-	-	-	-
1 off centrifuge / coalescer package (1 x centrifuge motor, 1 x delivery pump motor, 1 x sludge pump motor)	-	18.5kW 1kW 1kW	-	18.5kW 1kW 1kW	-	18.5kW 2.5kW 2.5kW	-	18.5kW 2.5kW 2.5kW
2 off topsides HP fuel distribution skids (2 x motors)	-	-	-	-	37kW	17kW	37kW	17kW
2 off topside fuel distribution pumps (2 x motors)	2kW	1kW	3kW	1.5kW	7.5kW	3kW	-	-

Table 8-6 - Electrical Power Supply Summary

It is proposed the rotating equipment packages are located on PUQ Level 1 and the switchrooms in this vicinity were checked to establish capacity for adding the additional electrical loads. 440V Normal Switchboard is located within the main switchroom on the PUQ Level 1 Mezz Deck.

Based on a review of the existing single line diagrams [Ref. 33, 34] there are various spare compartments on the existing 440V normal switchboard. These spares are mainly 1/8 size compartments which would be suitable for motors < 11kW but not for the larger centrifuge motor or the HP fuel distribution skid motors. To supply the larger motors two adjacent compartments shall require to be combined.

The compartments on the existing single line diagrams shown as spare or to be modified are listed in Table 8-7.

COMPARTMENT NO.	CIRCUIT RATING	DESCRIPTION	REMARKS
FL2.6		Equipped spare	Centrifuge motor
FL2.7		Equipped spare	
FL2.8		Equipped spare	Delivery pump motor
FL3.5		Equipped spare – motor feeder	Sludge pump motor
FL6.5		Equipped spare	HP fuel distribution pump motor A
FL6.6		Equipped spare	
FL6.7		Equipped spare	Fuel distribution pump motor A
RR2.2	80A	Spare	
RR3.4	10A	Equipped spare – switched fuse	
RR4.4		Semi-equipped	(1/4 size compartment)
RR5.1	400A	Spare	(1/2 size compartment)
RR5.3	10A	Equipped spare	
RR6.6		Equipped spare	HP fuel distribution pump motor B
RR6.7	3A	Equipped spare	
RR6.8		Equipped spare	Fuel distribution pump motor B
FR2.3	4A	Spare	
FR2.4	10A	Equipped spare – switched fuse	
FR3.3	4A	Equipped spare	
FR3.4	4A	Equipped spare	
FR3.5	4A	Equipped spare	
FR3.6	16A	Spare	
FR3.7	25A	Spare	
FR3.8		Equipped spare – motor feeder	

COMPARTMENT NO.	CIRCUIT RATING	DESCRIPTION	REMARKS
FR4.6		Semi-equipped	
FR4.7		Semi-equipped	
FR5.1		Semi-equipped	
FR6.3	63A	Spare	Subsea fuel storage package
FR6.4		Semi-equipped	
FR6.5		Semi-equipped	

Table 8-7 - Modifications to 440V Normal Switchboard (ESW 43303)

The UPS supply will be derived from an existing 240V AC UPS distribution board. There are several UPS system on the PUQ platform, and the selection of the optimum UPS system will be reviewed in future project phases.

A provisional sum shall also be included for modifications to the existing Load Management System but no review of this existing system or any engineering associated with its modification have been carried out at this stage.

8.1.6 Subsea

J-Tube/Riser Availability

This option involves pull in of a flexible riser/umbilical bundle to the PUQ. The flexible would contain 2 x circa 3" process lines and power / signal cables. The dimensions and characteristics of this flexible product are currently not defined. The recent Asset A Infill Feasibility Study assessed the available risers/J-tubes on Asset A as summarised below [Ref. 32]

There are 3 off 10" NB spare J-tubes on PUQ (J34, J36 & J37) located on the NW corner of the PUQ platform within the jacket structure. The J34 J-tube terminates on the west face of the Jacket subsea whereas J36 and J37 route towards the east face where they terminate at the end flanges. The current integrity status of the J-tubes is unknown. It is also unclear whether these spare J-tubes have been in service previously or have been spare since platform installation. The current annulus and end termination status is also unknown (whether a redundant product is contained the J-tube, whether the J-tube is flooded and if so, what the fluid type is; whether a bellmouth is in place or whether there is a blind fitted at the base of the J-tubes etc.).

The only available spare riser on Asset A (riser R2) is located on the SE corner of the PUQ platform as illustrated on Figure 8-8 and Figure 8-9. Key parameters for riser R2 are presented in Table 8-8.

The R2 riser was installed with the PUQ platform in 1992 and has been 'spare' for the entire duration since. Prior to installation, the riser was hydrotested onshore to 490.8 barg then nitrogen filled to 5psi to check for leaks in the bolted connections.

The riser is fully contained within the jacket structure throughout its length and at EL-119m the riser diverts towards the east face where the subsea tie-in flange is located.

Recent external inspection of the riser (above and below LAT) has shown it to be in a good condition with no significant integrity concerns noted. However, there has been no recent internal inspection / wall thickness survey of the riser, so riser bore condition (dry / flooded) and pipe / weld integrity is unknown.

PARAMETER	UNIT	VALUE
Outer Diameter	mm	519.0
Wall Thickness	mm	29.9 (Carbon Steel) + 2.0 (internal cladding)
Material of Construction	-	Carbon Steel (API 5L X65) internally clad with Stainless Steel
Minimum Bend Radius	mm	2540.0
Design Pressure	barg	310
Hydrotest Pressure	barg	490.8
External Coating	-	Polychloroprene below EL+12.75m
Bore Condition (Dry / Flooded)	-	Unknown

Table 8-8 - Riser 'R2' Details

Note 1: The riser was installed with a blind flange at the base, it is unclear whether there is any DB&B / flooding valve arrangement connected to the blind.

In light of the uncertainty around the dimensions of the flexible/umbilical product to be pulled in to the PUQ platform, and the J-tube status, it will be assumed for the purposes of this study that access to topsides will be accomplished via the R2 riser. At a later stage, when more details on the product dimensions are known, the suitability of the existing J-tubes could be examined further.

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Figure 8-8 - Riser R2 Location on PUQ Platform - Plan

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Figure 8-9 - Riser R2 Location on PUQ Platform - Elevation

The R2 Riser terminates above water above the EL + 14 brace with a capped termination as illustrated on Figure 8-10.

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Figure 8-10 - R2 Riser Topside Termination

To enable pull-in of flexible flowline (FSO option) or umbilical bundle (SSU option) the R2 riser will need to be extended with a 20" NB pipe section from the EL +14 level to approx. EL +28 level (Cellar Deck). The routing of the riser extension piece will be governed by where a suitable location for the umbilical/flexible hang-off and umbilical TUTU can be found. The TUTU will ideally be located close to the hang off on the riser with connection made by flying leads/hoses. Deviation from purely vertical extension piece may need to be considered dependent upon available space.

Above the EL +28 level access will be required for siting a winch or a rigging system for winch to facilitate the pull-in as illustrated in outline on Figure 8-11. The winch wire may require to be rigged with sheaves/pulleys if a direct vertical pull is not possible.

REDACTED

Figure 8-11 - R2 Riser Topsides Extension Requirement

A further consideration for the pull-in operation to riser R2 is the presence of 2 off 90-degree 5D bends at the base of the riser in the horizontal and vertical planes. Design details and dimensions of the umbilical bundle (and associated pullhead) will dictate whether pull-in can be safely achieved.

In the event that existing bend radii are restrictive for pull-in operations, there is the option of cutting into R2 in vertical leg close to the seabed and installing a new bellmouth thereby eliminating the 5D bends from pull-in path as shown outline on Figure 8-12. Additional diving time would be required to cut the riser and remove part of the lower section. Bellmouth fitting will be required for both approaches described above.

REDACTED

Figure 8-12 - Cut and Retrofit Bellmouth on R2

Subsea Layout at PUQ for SSU

The major components comprising the subsea storage option include:

- Shuttle vessel.
- Single Anchor Loading (SAL) Unit for connection to shuttle vessel.
- 12" NB Refilling line from SAL to Subsea storage units.
- Umbilical Bundle from SSU to PUQ topsides.

A proposed layout for the subsea facilities is illustrated on Figure 8-13 which shows the shuttle vessel at a nominal stand-off location 1.1km south west of PUQ. The quadrant to the south and west of PUQ is clear of existing facilities. The SSU location is chosen with sufficient clearance from the existing gas and oil export pipelines and SSIV structures. The umbilical would preferably be installed by a pull-in at PUQ with layaway to the SSU location, laydown and subsequent pull-in to the SSU unit. Installing the umbilical in the opposite direction, although not impossible, would be complicated by the seabed space restrictions at PUQ for a second end pull-in.

REDACTED

Figure 8-13 - Subsea Layout of SSU Facilities

8.1.7 Concept Opportunities & Risks

The opportunities and risks relating to Concept 2A are shown below.

OPPORTUNITIES	RISKS / CHALLENGES
Live fuel inventory monitoring	Subsea CAPEX
Independent of weather conditions	Subsea O&M
No charter OPEX	

Table 8-9 - Concept 2A Opportunities & Risks

8.2 Concept 2B (Subsea Storage Tanks, 10.4 MW Power Generation GTG post-LPBC revamp & electrification)

Concept 2B considers the modifications required to utilise an alt-fuel (renewable methanol or HVO) to power the Alpha main power generation units for a power load of 10.4 MW, post the revamp and electrification of the Low-Pressure Booster Compression units.

This option considers the following principles:

- Fuel is delivered and stored subsea as described in Section 6.1.2.
- The subsea storage is pressurised using Asset A's existing seawater utility.
- The pressure in the subsea storage tank is used to flow the fluid up to a topside alt-fuel intermediate storage tank.
- Fuel is pumped from the day tank to each alt-fuel user at the required pressure for the turbines without the need for further downstream pumping.

A schematic for this option is presented on the following page.

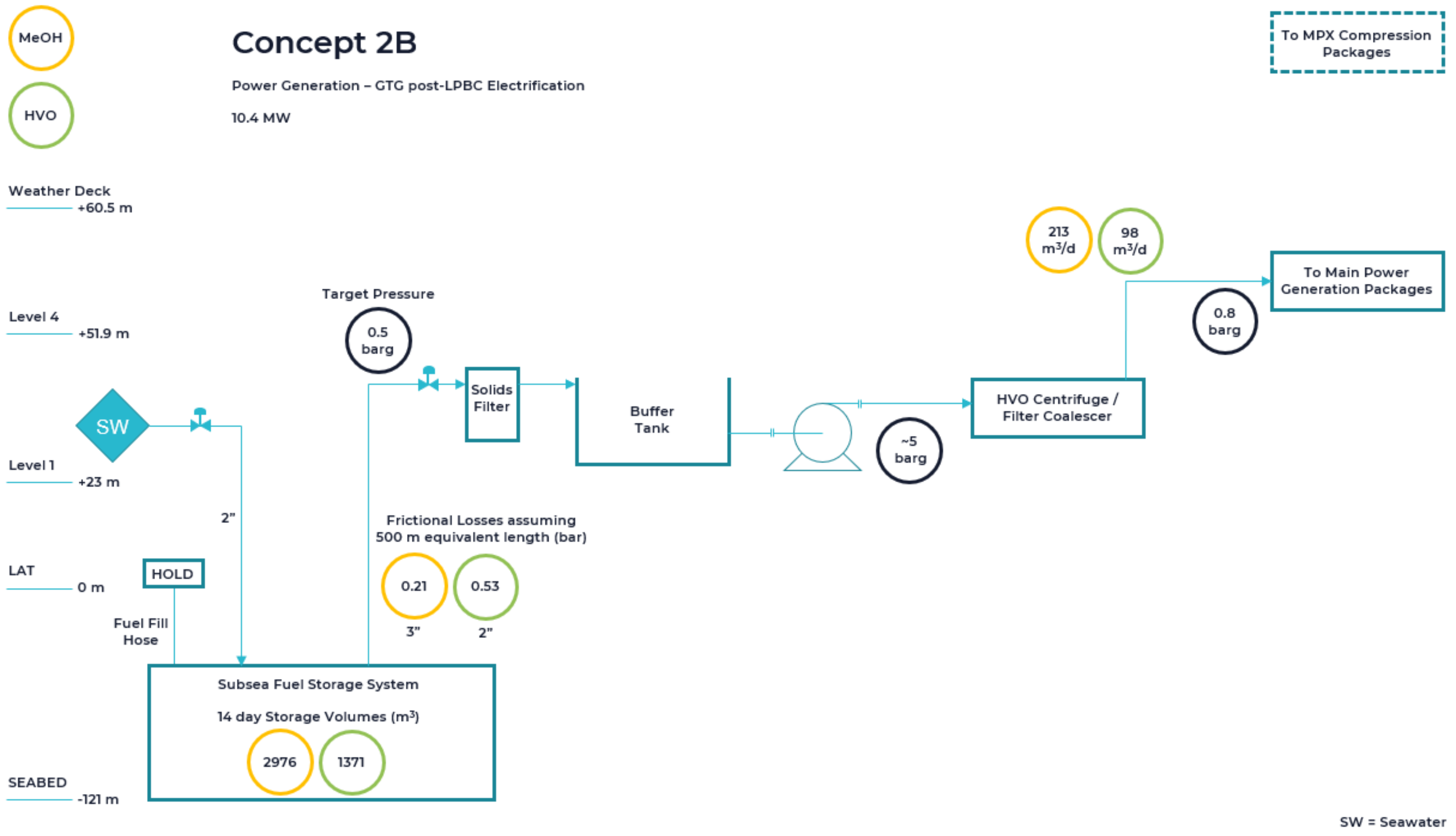

Figure 8-14 - Concept 2B Schematic

8.2.1 Concept Description

As Concept 2A – see Section 8.1.1. Engineering discipline descriptions are not included in this section as they are as per Option 2A with the exclusion of fuel distribution pump and line sizes.

The intermediate topsides storage tank dimensions discussed for Concept 2A will be utilised, for concept 2B the tank provides 3.1 hours hold up capacity for methanol and 6.7 hours hold up capacity for HVO.

8.2.2 Process Flow Diagram & Equipment List

A process flow diagram for Concept 2B is presented in Appendix D. An Equipment List is provided in Appendix E.

8.3 Concept 3A (Subsea Storage Tanks, 10.4 MW Power Generation GTG plus 16.8 MW MPX Compression Drives Post Dual Fuel Upgrades)

Concept 3A considers the modifications required to utilise an alt-fuel (renewable methanol or HVO) to power the Alpha main power generation units for a power load of 10.4 MW, post the revamp and electrification of the Low-Pressure Booster Compression units. In addition, dual-fuel upgrades will be made to the MP / Export Compression Drivers allowing their utilisation of alt-fuel to provide the power load of 16.8 MW.

This option considers the following principles:

- Fuel is delivered and stored subsea as described in Section 6.1.2.
- The subsea storage is pressurised using Asset A’s existing seawater utility.
- The pressure in the subsea storage tank is used to flow the fluid up to a topside alt-fuel intermediate storage tank.
- Fuel is pumped from the day tank to each alt-fuel user at the required pressure for the turbines without the need for further downstream pumping.

A schematic for this option is presented on the following page. Please note the MPX fuel forwarding pumps will likely be located on skid, however, have been shown upstream to indicate the requirement for new equipment.

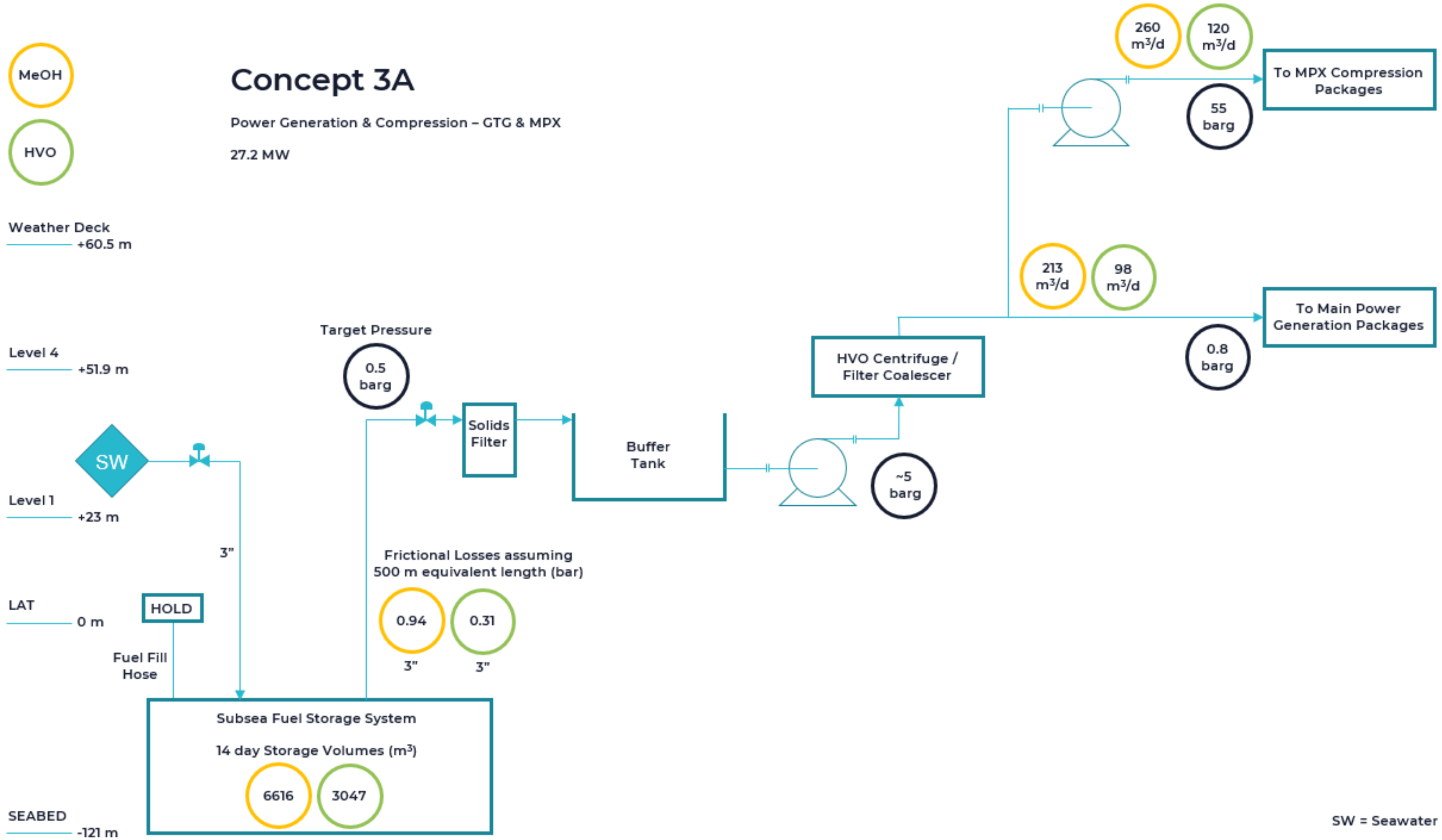

Figure 8-15 - Concept 3A Schematic

8.3.1 Concept Description

As Concept 2A – see Section 8.1.1. Engineering discipline descriptions are not included in this section as they are as per Concept 2A with the exclusion of fuel distribution pump and line sizes.

The intermediate topsides storage tank dimensions discussed for Concept 2A will be utilised, for Concept 3A the tank provides 1.4 hours hold up capacity for methanol and 3.0 hours hold up capacity for HVO.

Additional piping and Fuel Distribution Pumps will also be required to transfer the alt-fuel to the MP / Export Compression skids. New pumps required as part of dual fuel modification to MP Compression turbine drivers. Discharge pressure of 55 barg quoted based on Asset A existing dual fuel power generation unit HP fuel pumps which have 65 barg discharge PSVs, and an assumed upper operating pressure of 85% of this has been considered. Turbine OEM A are to assess this in more detail at next project phase based on the specific fuel and expected range of turbine loads (methanol requires more flow than diesel fuel and may require a higher operating pressure so more detailed assessment required).

The new HP liquid fuel pump and supply manifold with filters would preferably be installed within the existing turbine enclosures. This offers space saving benefits and is inherently safer as it minimises any line routings with high pressure fuel. See Section 9 for turbine package modifications details.

8.3.2 Process Flow Diagram & Equipment List

A process flow diagram for Concept 3A is presented in Appendix D. An Equipment List is provided in Appendix E.

8.3.3 Concept Opportunities & Risks

The opportunities and risks relating to Concept 3A are shown below.

OPPORTUNITIES	RISKS / CHALLENGES
Live fuel inventory monitoring	Subsea CAPEX
Independent of weather conditions	Subsea O&M
No charter OPEX	Requirement to modify existing MP/Export Compression drivers
Full power load provided by alt-fuels	

Table 8-10 - Concept 3A Opportunities & Risks

8.4 Concept 3B (Single FSO Comparison)

This option has been developed to provide an alternative concept to Concept 3A, which does not utilise subsea storage. It features Power Load Scenario 3, the full power load of 27.2 MW.

- This option considers the following principles.
- Fuel is delivered to a stationary FSO / tanker as per Section 6.1.2
- Fuel is pumped from the FSO / tanker at high pressure to the turbine packages without an intermediate storage vessel. A single 3" circa 1.1 km flexible flowline / riser is routed from the FSO and terminating topside at Asset A.

A schematic for this option is presented on the following page. Please note the MPX fuel forwarding pumps will likely be located on skid, however, have been shown upstream to indicate the requirement for new equipment.

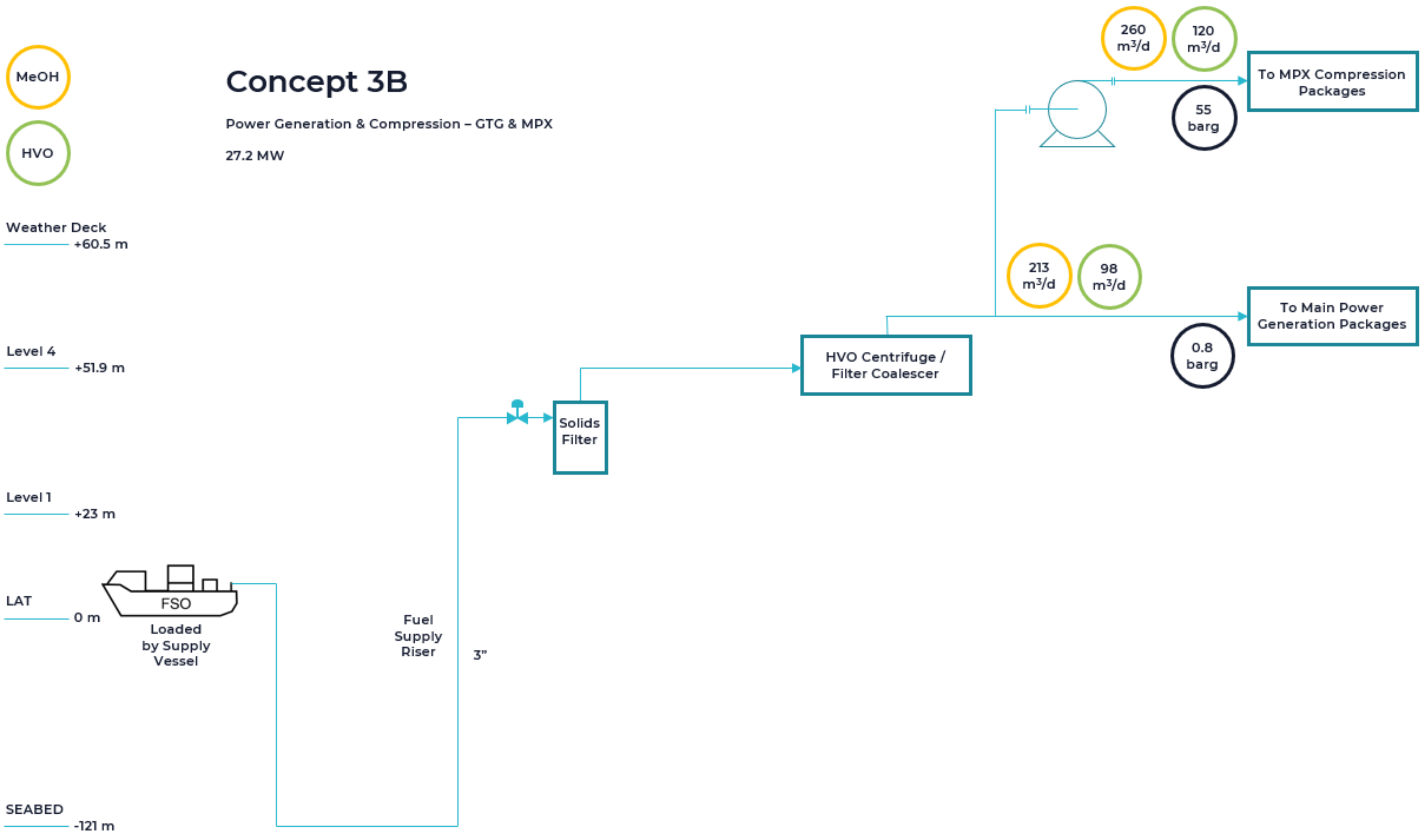

Figure 8-16 - Concept 3B Schematic

8.4.1 Concept Description

Note that storage volumes, distances, line sizes and flowrates described within this section are preliminary only and are to be defined in subsequent project phases.

A FSO or tanker is used to store fuel.

Fuel is delivered by vessel. The ship connects to the FSO and transfers fuel in a ship-to-ship bunker operation.

A sketch layout of a proposed safety zone scheme is shown below. This is a conservative approach and should be revisited in the next phase of design, but is considerate of requirements for safe cargo, manoeuvring, dynamic positioning, and weather limitations offshore.

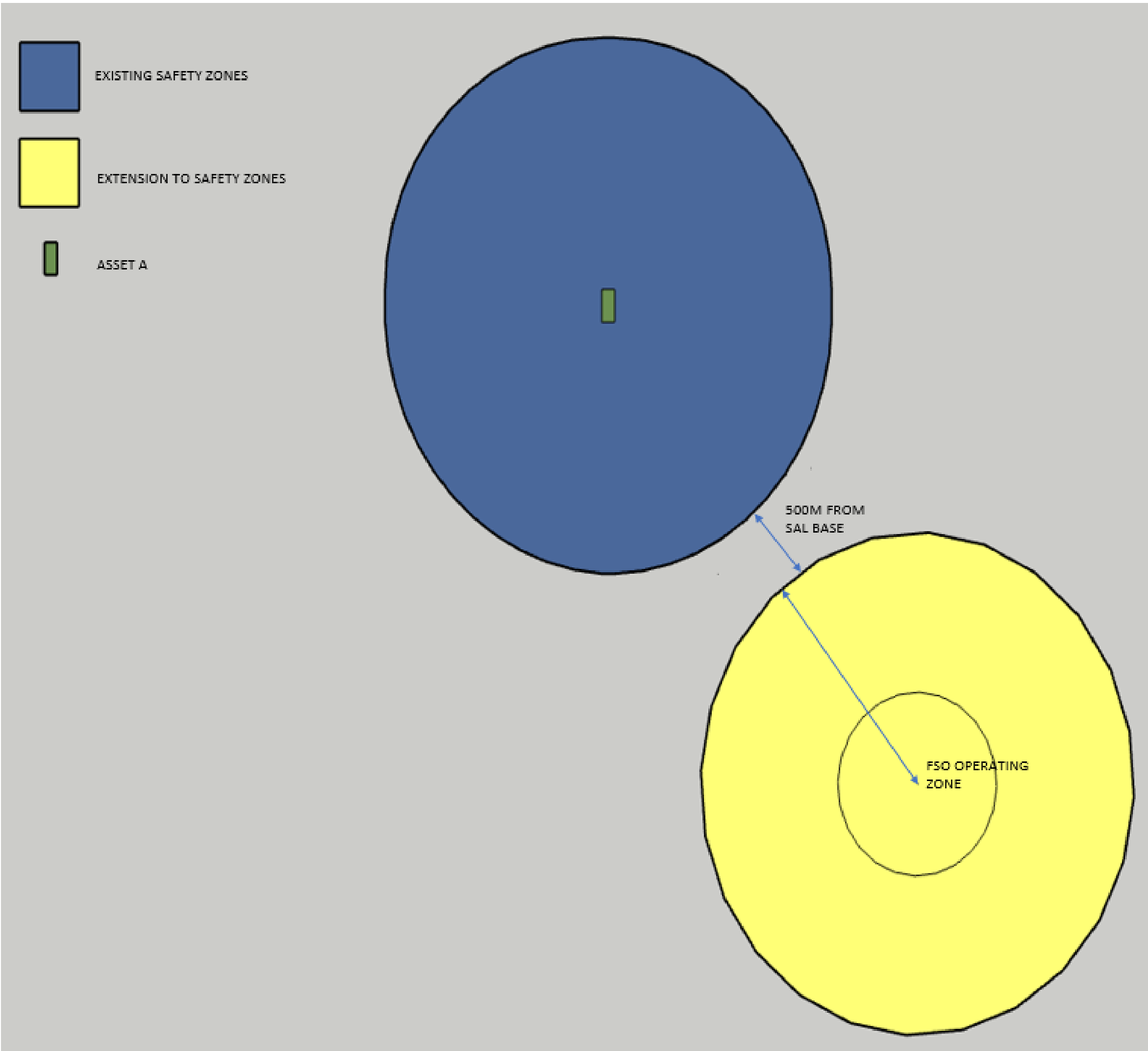

Figure 8-17 - Floating Storage Options Concept Sketch Safety Zones

This places the FSO approximately 1.1km from Asset A. The FSO is connected by a 3" flexible flowline to Asset A. Fuel is pumped from the FSO via an import strainer to the turbine packages.

An allowance has been made for alt-fuel pre-treatment treatment, such as a centrifuge or filter coalescer, as per Asset A's current diesel system. Preliminary inputs are based on a centrifuge package being installed for Option 2A, to be conservative for new permanent equipment power requirements. The package is only required for the removal of water from HVO; no equivalent unit is proposed for methanol service due to water being miscible with methanol hence a separate water phase is not expected. The package is to be located on Level 1 – see Piping & Layout section below. The use of conductivity meters to detect water ingress to fuels has also not been allowed for. The inclusion of systems for proving fuel quality should be considered in the next engineering phases depending on the downstream combustion equipment requirements and fuel supply contracts.

Fuel from the FSO is discharged at medium pressure (~20 barg) to allow distribution to the GTG enclosures. This pressure is required to overcome the pressure losses and static head associated with the flowline, filter equipment and piping. Downstream distribution at the turbines is as per Concept 3A.

8.4.2 Process Flow Diagram & Equipment List

A process flow diagram for Concept 3B is presented in Appendix D. An Equipment List is provided in Appendix E.

8.4.3 Piping & Layout

As the HVO fuel supply would still require the centrifuge/filter coalescer package downstream of the import strainer the proposed location for this would be the same as Option 2A & 2B on the PWRI deck area on North side of PUQ Level 1.

For the HVO alt-fuel option the pipe routing for each of the new lines required has not been modelled at this stage and will need to be further assessed in future phases of this project, however for the basis of the cost estimate the following pipe run lengths have been assumed (based on plot plan locations for existing or proposed new equipment with an additional 40% allowance for actual pipe routing):

- HVO Supply from Riser Hang-Off to Solids Filter – 45m
- Centrifuge Filter/Coalescer Package to G-41300A/B – 90m
    - Tie in location to the fuel supply lines to GT's has not been confirmed however it is assumed this will be local to the GT package enclosures on PUQ Level 4
- G-41300A/B HVO Supply to MPX Compressor A & C – 20m
    - Tie in Location to MPX Compressor A & C has not been confirmed however assumed will be local to compressor enclosures on PUQ Level 5.

For the methanol supply with the only topsides equipment required being the Solids Filters these could be located local to the R2 riser termination point in the area shown Figure 8-7. A preliminary layout including both the riser hang off (assumed dimensions of 1.5m x 1.5m) and the solids filters in this area is shown in Figure 8-18 below.

Suitable space is also available for the pipework and valving required. Utilising this area for both the riser hang off and the strainers removes the requirement to destruct the redundant PWRI pumps and therefore reducing the topsides construction scope.

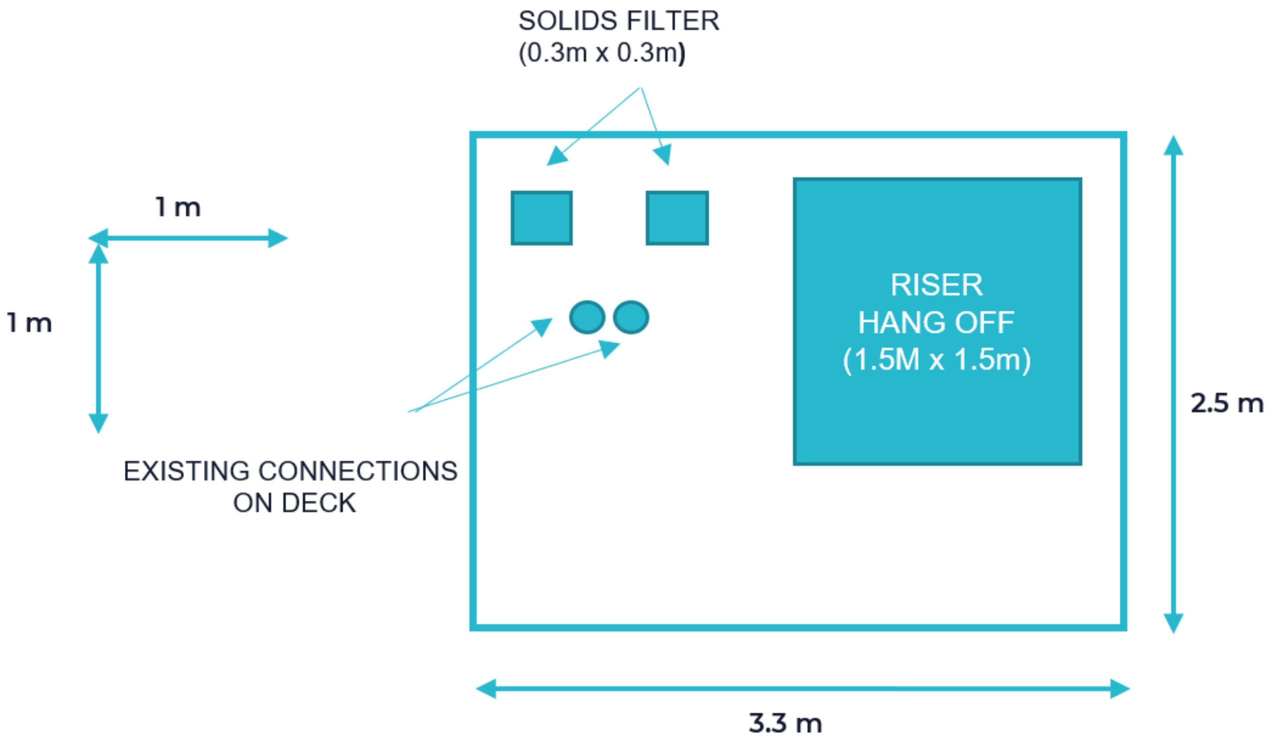

Figure 8-18 - Equipment Layout for Methanol on PUQ Level 1 Are Local to Riser Termination Point (Option 3B)

For the renewable methanol alt-fuel option the pipe routing for each of the new lines required has not been modelled at this stage and will need to be further assessed in future phases of this project, however for the basis of the cost estimate the following pipe run lengths have been assumed (based on plot plan locations for existing or proposed new equipment with an additional 40% allowance for actual pipe routing):

- Methanol Supply from Riser Hang-Off to Solids Filter – 1m
- Solids Filter to GT-A/B– 100m
  - Tie in location to the fuel supply lines to GT's has not been confirmed however it is assumed this will be local to the GT package enclosures on PUQ Level 4
- GT-A/B HVO Supply to MPX Compressor A & C – 20m
  - Tie in Location to MPX Compressor A & C has not been confirmed however assumed will be local to compressor enclosures on PUQ Level 5

For both the HVO and Methanol alt-fuel options an allowance of 20m of pipework has been included in the cost estimates for the drains line from the solids filters.

8.4.4 Controls and Instrumentation

The controls and instrumentation scope for this concept is captured in Section 8.1.4

8.4.5 Electrical

The electrical scope for this concept is captured in Section 8.1.5.

8.4.6 Subsea

J-Tube/Riser Availability

The platform access issues via J-Tube/Riser are identical to the SSU option as discussed in Section 8.1.6 and are based on use of the existing spare R2 riser.

Subsea Layout at PUQ for Single FSO

The major components comprising the single FSO option include:

- Permanently moored FSO vessel.
- 3" NB flexible fuel supply flowline from FSO to PUQ topsides.

A proposed layout for the subsea facilities is illustrated on Figure 8-19 which shows the FSO vessel at a nominal stand-off location 1.1km south west of PUQ. The quadrant to the south and west of PUQ is clear of existing facilities. The routing of the supply flowline is chosen with sufficient clearance from the existing gas and oil export pipelines and SSIV structures. The flowline would preferably be installed by a pull-in at PUQ with layaway to the FSO location, laydown and subsequent pull-in to the FSO turret. Installing the flowline in the opposite direction, although not impossible, would be complicated by the seabed space restrictions at PUQ for a second end pull-in.

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Figure 8-19 - Subsea Layout for Single FSO

8.4.7 Concept Opportunities & Risks

The opportunities and risks relating to Concept 3B are shown below.

OPPORTUNITIES	RISKS / CHALLENGES
Subsea CAPEX	Ship charter OPEX
Less topside interfaces	Risk of detachment during bad weather

OPPORTUNITIES	RISKS / CHALLENGES
Less brownfield modifications	O&M challenges related to the ship
Full power load provided by alt-fuels	No fuel buffer if supply interrupted
	Radio communication for fuel inventory monitoring

Table 8-11 - Concept 3B Opportunities & Risks

8.5 Concept 3C (Dual FSO Comparison)

Concept 3C has been developed to review the feasibility of operating a FSO or tanker for both fuel transportation and storage with two vessels operating back-to-back. It features Power Load Scenario 3, the full power load of 27.2 MW.

A schematic for this option is presented on the following page. Please note the MPX fuel forwarding pumps will likely be located on skid, however, have been shown upstream to indicate the requirement for new equipment.

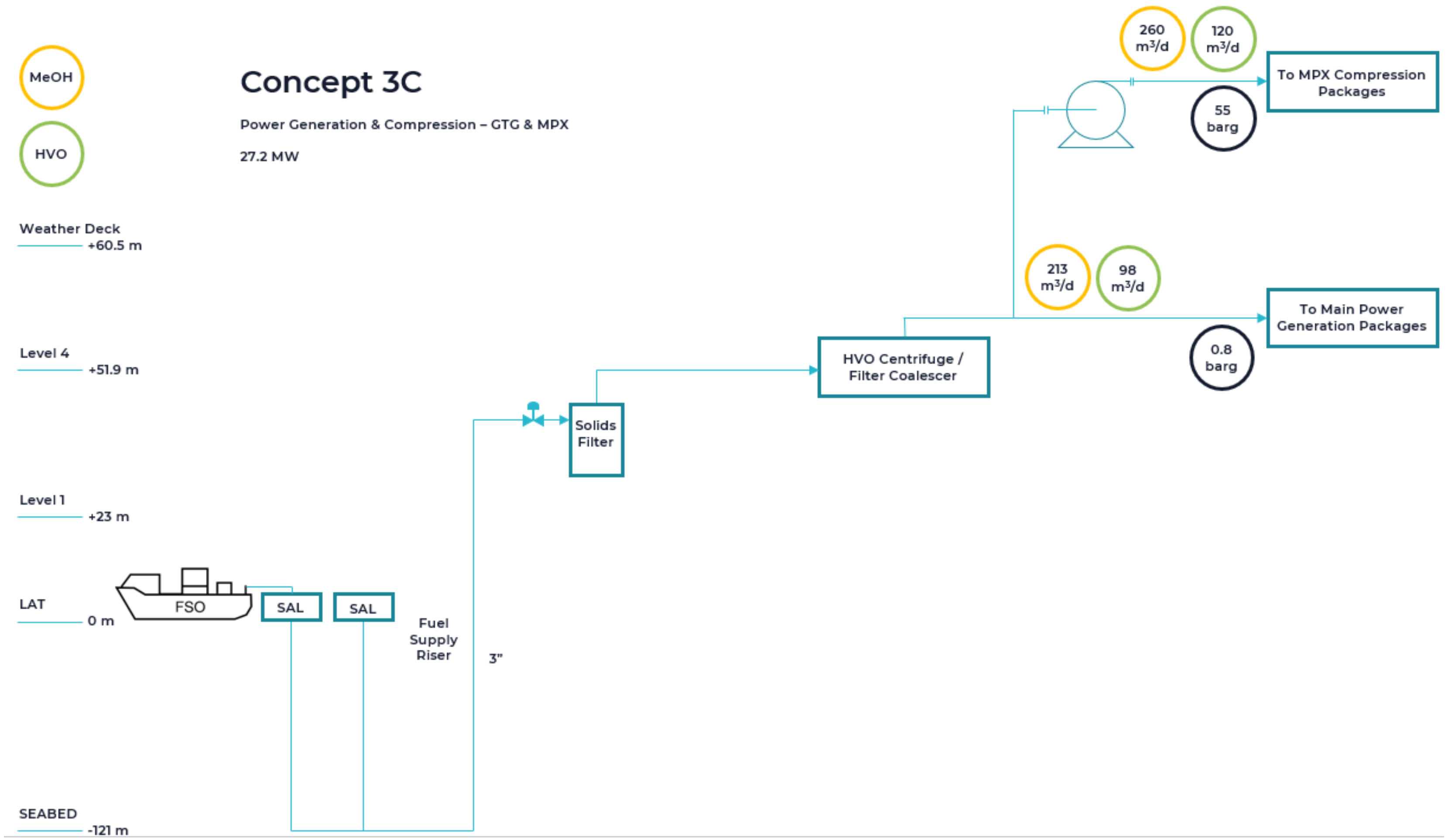

Figure 8-20 - Concept 3C Schematic

8.5.1 Concept Description

For this option, two SALs and fill risers would be required. All other aspects are as per Option 3B.

8.5.2 Process Flow Diagram & Equipment List

A process flow diagram for Concept 3C is presented in Appendix D. An Equipment List is provided in Appendix E.

9 BROWNFIELD MODIFICATIONS - TURBINE PACKAGE MODIFICATIONS

9.1 Turbine Package Proof of Concept

This section is applicable to the Turbine OEM A GT-A/B (Turbine Model A) and CTG-A/B (Turbine Model B) only.

As part of Turbine OEM A's New Technologies work, a Turbine Model C bio-methanol demonstration test has been completed in conjunction with NZTC. This test proved the concept of methanol fuelled operation in a very similar model of GT to those installed on Asset A. Safe operation was demonstrated from start-up to full power. A reduction in NOx and CO_2 and lower combustion temperatures were also noted when compared with natural gas operation [Ref. 18].

Turbine OEM A recognise that HVO is a viable fuel option for their engines and their turbines could be adapted for HVO through standard dual fuel modifications - although a 100% HVO fuel is not currently approved for use.

9.2 Turbine Package Modifications

9.2.1 Main Power Generation Units

Asset A's main power generation units are dual fuel capable and their liquid fuel systems consist of the following:

- Filter assemblies
- Pressure instrumentation
- HP fuel forwarding pump
- Fuel flow metering and control

The defined maximum flow through the system is defined as 9.1 m^3/h [Ref. 17]. For Power Load Scenario 3, the required fuel flows for the main power generation units are 8.9 m^3/h of methanol or 4.1 m^3/h of HVO. This suggests that the installation of larger diameter fuel injectors will not be required, however, a review of the existing system should be concluded to determine their suitability.

In the next project phase, it should be confirmed whether existing Gas Turbine Model A power generator HP fuel pumps require replacement for alternative fuels based on a more detailed assessment by Turbine OEM A Methanol flow requirement are higher than diesel fuel and both HVO and methanol have a lower density than diesel. However, current operation at lower loads versus turbine rated load may allow the existing pumps to be re-used hence a more detailed assessment required.

The main power generator packages will require the following upgrades:

RENEWABLE METHANOL TURBINE MODIFICATIONS	HVO TURBINE MODIFICATIONS
Turbine control system and logic updates	Turbine control system and logic updates
Fire and gas system upgrades	

Table 9-1 - Main Power Generation Package Modifications for Renewable Methanol and HVO Fuel Options

9.2.2 MP / Export Compression GTs

Asset A's MP / Export Compression gas turbines are currently driven by fuel gas only. To facilitate renewable methanol or HVO as an alt-fuel, dual fuel modifications are required.

The modifications discussed in this section are inclusive of the requirement to maintain fuel gas combustion capability.

Turbine OEM A have reviewed the alt-fuel adaptation concepts and provided an overview of the package modifications required to facilitate the combustion of an alternative liquid fuel from the gas only driven system:

RENEWABLE METHANOL TURBINE MODIFICATIONS	HVO TURBINE MODIFICATIONS
Installation of liquid fuel system (larger diameter and capacity than standard dual fuel system) consisting of: • Filter assemblies; • pressure instrumentation; • HP fuel forwarding pump; • fuel flow metering and control.	Installation of standard dual fuel system modifications consisting of: • Filter assemblies; • pressure instrumentation; • HP fuel forwarding pump; • fuel flow metering and control
Installation of large diameter fuel injectors	
Turbine control system and logic updates	Turbine control system and logic updates
Fire and gas system upgrades	

Table 9-2 - MP/ Export Compression Turbine Package Modifications for Renewable Methanol and HVO Fuel Options

Note that the requirement for fire and gas system upgrades for renewable methanol turbine modifications is dependent on a review of the existing CO_2 gaseous fire suppression system within the turbine enclosure. A review of the existing system should be concluded to determine if the current design will detect and extinguish a methanol pool fire. It is assumed that the existing fire and gas system would be suitable for HVO operation.

10 REGULATORY

10.1 Safety

10.1.1 Renewable Methanol

Major Accident Hazards (MAH)

Methanol is not currently stored on Asset A as Asset A uses Industrial Methylated Spirit (IMS) for hydrate inhibition, IMS is mostly ethanol with approximately 5% methanol, so has similar hazards.

Methanol is an acute toxin, classified in The Classification, Labelling and Packaging of Chemicals Regulations 2015 (CLIP) as 'very toxic' due to Specific Target Organ Toxicity (STOT), Classification H370, methanol has an Occupational Exposure Limit (OEL) of 200ppm. IMS is classified as an acute toxin, Classification H371. H370 means 'definitely toxic to humans from a single exposure', determined on the basis of animal experiments. H371 means 'can be presumed to be toxic following single exposure' also on the basis of animal experiments.

IMS toxicity is not currently included in the Major Accident Hazard (MAH) Register for Asset A. A pool of methanol will not give rise to an extensive vapour cloud extending from the pool so there is no credible mechanism for a release to give rise to fatalities due to its toxicity. Introducing pure methanol onto the platform will not change this assessment; as although methanol has greater toxicity than IMS, it is not common practice to consider methanol toxicity as a MAH.

Methanol is flammable, with a flash point of 11°C and presents a very similar flammable hazard to IMS. Methanol and IMS pool fires have lower flux levels than hydrocarbon pool fires, so, although fatality to personnel from these fires is possible, critical damage to structures and vessels is not considered to be credible. So, there will be no increase in escalation potential resulting from the new methanol inventory.

IMS pool fire is assessed in the Asset A Safety Case, within the non-process fire category, as follows. Depending on the wind direction, smoke generation this could impair the muster area and TEMPSC located on D platform. Due to the large amount of physical separation between the D platform and the TR on PUQ, it is unlikely to cause impairment of the TR and TEMPSC on PUQ. It is unlikely that the original event would cause impairment of the TEMPSC on both D and PUQ.

Concept 1A which utilises the 285 m^3 storage diesel tank on PUQ for methanol, potentially changes this assessment and this would need to be reviewed, although simultaneous impairment on both D and PUQ platforms remains unlikely. Concept 1B which utilises existing platform drilling tanks on D platform would not lead to different conclusions from the current assessment. It is worth noting that pure methanol burns with very little smoke so smoke impairment of the TR is unlikely, however, the potential consequences of a methanol fire on PUQ would need to be assessed to support an updated Safety Case.

The existing IMS storage utilises nitrogen blanketing and due to the very similar flammable hazard profile and properties it can be anticipated that this will also be required for any topsides methanol storage tank. Nitrogen is currently used on PUQ; however, a local capacity check would be required to extend this to a methanol storage tank.

Safety Case Implications

IMS for hydrate inhibition is currently stored on Asset A in a storage tank on D platform, and methanol has a very similar hazard profile to IMS. For the options where methanol is to be stored topsides the identified MAH would need to be assessed and this would lead to a Major Change to the Safety Case; however, it is not assessed that there would be any major hurdles regarding this update.

Other Regulatory Requirements

Due to the classification of methanol within CLIP, methanol comes within the definition of a dangerous fluid in the Pipeline Safety Regulations (PSR), specifically:

- Very toxic fluids with saturated vapour pressure > 0.001 bar at 20 °C

As a result, a riser from subsea storage of diameter greater than 40 mm will need to meet the requirements of the PSR, including the provision of a Riser Emergency Shutdown Valve (RESDV) and suitable fire and explosion protection of this valve.

Safety & Environmental Critical Elements (SECE)

Fire & Gas (F&G) System

F&G detection is currently provided on Asset A, infra-red (IR) detectors are used in areas containing equipment used in any hydrocarbon and other flammable material processes, and detectors these will detect methanol flames. The current technology is appropriate, as detectors for IMS will detect methanol, but additional detectors will be required to cover any new areas where methanol pool formation is possible.

Active Fire Protection

Mobile foam units for dealing with fires that involve alcohol-based liquids are provided on Asset A. A total of 8 units are available, 2 on PUQ, 4 on D and 2 on CR. Where additional topsides methanol storage is installed, the provision and location of mobile foam units for dealing with additional methanol fire scenarios would need to be reviewed with the potential that a small number of mobile foam units may be required.

Module Pressurisation and HVAC

Power generation turbine enclosures on Asset A are ventilated, the HVAC system ensures dilution of any gas, or mists of liquid fuel on dual fuel units, is achieved to prevent any build-up of hazardous atmospheres and to maintain the hazardous area classification. The turbine enclosure ventilation system would not require upgrading if methanol is used as fuel.

Risers ESDVs and SSIVs

In compliance with PSR a new RESDV would be required for a methanol subsea storage system riser, on the assumption that the riser would be of a diameter of 40mm or greater. This would need to be included within the list of SECE and meet the requirements of the current Risers ESDV Performance Standard. Due to the low escalation potential, it is very unlikely that the riser and ESDV would need further protection beyond that required by PSR, and a separate SSIV would not be justified.

Ignition Prevention

Hazardous area equipment requirements for most oil and gas facilities are gas group IIA and temperature class T3, based on the presence of hexane. Equipment for methanol will be IIA T2, the T2 temperature class is less onerous so current equipment will be suitable.

New methanol handling equipment could lead to an extension of Zone 2 areas on the platform and use of existing diesel storage on PUQ for methanol storage is likely to give rise to a new Zone 2 hazardous area.

10.1.2 HVO

Major Accident Hazards (MAH)

With respect to toxicity HVO is classified as H304: (may be fatal if swallowed and enters airways), and as there is no credible mechanism for HVO poisoning from a loss of containment, its toxicity does not give rise to a MAH. By way of comparison, HVO is less hazardous than petrochemical derived diesel.

HVO is flammable, with a flash point of >55°C, compared to 60°C for diesel. A diesel pool fire is a recognised existing hazard on Asset A, within the scope of the non-process fires and is included within the asset QRA. HVO pool fire would need be incorporated within the overall non-process fires category, with an update to the asset QRA, however this will not be a significant change to the Asset A hazard profile. Like diesel, ignition of HVO is very unlikely without a pre-existing fire event.

Safety Case Implications

The presence of large volumes of HVO on the platform would need to be recognised within the Safety Case but does not give rise to a new category of MAH, this would be a major change requiring an update to the current Safety Case, however there would be no major hurdles regarding this update.

Other Regulatory Requirements

HVO does not meet the definition of a dangerous fluid in the Pipeline Safety Regulations, as a result, a HVO riser from subsea storage would not come within the scope of PSR, although not a regulatory requirement consideration would need to be given to provision of a RESDV in line with best practice.

Safety & Environmental Critical Elements (SECE)

Fire & Gas (F&G) System

Infrared detectors are used in areas containing equipment used in any hydrocarbons and other flammable material processes, these will be suitable for HVO, but additional detectors will be required if HVO is introduced into areas of the platform that don't currently handle hydrocarbons.

Active Fire Protection

An extension to the platform deluge system will be required to cover new areas where HVO pool formation is possible.

Module Pressurisation and HVAC

Power generation turbine enclosures are ventilated, the HVAC system ensures dilution of any gas, or mists of liquid fuel on dual fuel units, is achieved to prevent any build-up of hazardous atmospheres and to maintain the hazardous area classification. The turbine enclosure ventilation system would not require upgrading if HVO is used as fuel.

Risers ESDVs and SSIVs

HVO does not meet the definition of a dangerous fluid within the Pipeline Safety Regulations (PSR), so a Riser ESDV is not required for subsea storage options. Due to the low escalation potential an SSIV would not be justified.

Ignition Prevention

Current practice is that pressurised diesel systems can give rise to a flammable mist that can be ignited below the material flash point; and this will also apply to HVO. Leak points from pump pressurised HVO systems will give rise to Zone 2 areas, however this can be addressed by measures to prevent mist formation, such as flange guards. Atmospheric pressure HVO will not give rise to hazardous areas.

10.2 Environment

10.2.1 Fuel Release

This section briefly reviews the environmental impact from a potential release of renewable methanol or HVO.

Renewable Methanol

Methanol is commonly used in the North Sea. It is on the OSPAR list of substances used and discharged offshore which are considered to Pose Little or No Risk to the Environment (PLONOR). It Is not toxic to marine life. It is readily biodegradable which means that in non-dispersive locations a release could cause an anoxic environment. This is not applicable to Asset A as a release is expected to rapidly disperse and have no impact on marine life.

HVO

HVO is a similar composition to diesel in terms of impact on environment and therefore any HVO spills offshore would be treated in the same way as a diesel release.

10.2.2 UK ETS

Within this section the implications of fuel choice in relation to the UK ETS scheme are discussed.

Operator A engaged OPRED to provide feedback on how alternative fuels may be treated under the UK ETS scheme. The following feedback was obtained.

OPRED feedback provided [Ref. 40] "At this point we're still determining if OPRED could permit this (biofuels) under the ETS legislation (it's not as easy as it first seems from the reviewing the ETS Order)" The following conclusions were made from this response.

- It's not clear which suite of fuels the OPRED review encompasses as only biofuels are mentioned by OPRED
- It's not clear how the OPRED comment relates to the document "UK Emissions Trading Scheme (UK ETS): monitoring and reporting biomass in installations" [Ref. 41]

For the purposes of this ETS review, it has been assumed that the BEIS (2021) document could apply to bio-methanol and renewable diesel from waste (HVO) as these are encompassed within the definition of bioliquids (per the Renewable Energy Directive (RED), as amended).

While the EU ETS isn't applicable to UK activity, reference to the EU ETS is made in this note as it may provide an indication of the direction of travel for the UK ETS.

Particularly within the EU, legislation is actively being revised to incorporate alternative fuels. There is a focus on fuels for transport as the maritime sector will enter the EU ETS at the beginning of 2024. [Maritime sector will enter the UK ETS in 2026]. Examples of recent legislation include:

- 20 June 2023, the European Commission published delegated acts outlining detailed rules on renewable fuels of non-biological origin (RFNBOs) and recycled carbon fuels (RCF)
- On 12 October 2023, the EU Council adopted implementing legislation updating Article 14 of the EU ETS Directive
- On 18 October 2023, the EU Council adopted the amended Renewable Energy Directive ("RED III").

From a UK and an EU ETS perspective, the origin of the fuel is of fundamental importance, i.e., bio-methanol and e-methanol are significantly different.

Fuel used in stationary installations (i.e., on O&G assets) should be referred to as bioliquids. Per RED, 'bioliquids' are liquid fuel for energy purposes other than for transport, including electricity and heating and cooling, produced from biomass. 'biofuels' means liquid fuel for transport produced from biomass.

Bio-methanol and HVO (Bioliquids)

An assumption was made that ETS savings would be based on the ratio of carbon stemming from biomass to the total carbon content of a fuel. An emission factor of 0 can be claimed for the fraction of fuel or material that is biomass and fulfils sustainability criteria.

There are two sustainability criteria:

1. Land use: focuses on the land from which the biomass is sourced.
2. Greenhouse gas (GHG) emission savings: accounts for the life cycle GHG emissions of the biomass. The calculation should be conducted as per the Renewable Energy Directive Annex V Section C, or default factors utilised.

Not all bioliquids must demonstrate compliance with both sustainability criteria. For example, bioliquids produced from waste and residues, other than agricultural, aquaculture, fisheries, and forestry residues, do not have to demonstrate compliance with the land use criteria as they are already assumed to comply. To use the land use criteria exemption for waste, operators must provide evidence to their UK ETS verifier that the fuel is a waste. Examples of suitable evidence to demonstrate that a fuel is a waste or derived from a waste may include environmental permits or waste transfer notes

For UK and EU markets, fuel suppliers complete Proof of Sustainability certificates which demonstrate alignment with these requirements and can be used in ETS verification.

E-methanol and Recycled Carbon Fuels

Xodus understanding is that RFNBO and RCF are not currently incorporated within the UK ETS. From a high-level review of EU legislation (RED and ETS), “direction of travel” would seem to indicate that legislative modifications will incorporate these fuels.

RFNBO and RCF will only be counted towards EU's renewable energy target if a minimum GHG emission saving threshold is achieved of 70 % compared to fossil fuels [expanded to be beyond just transport].

Fuel EU Maritime [Ref. 42]:

- RFNBOs, and RCF that meet the sustainability and greenhouse gas reduction criteria of the RED), reducing emissions by 70% from a fossil fuel baseline, can use actual values for well-to-tank and tank-to-wake emissions. Actual well-to-tank emission values must be certified through a system approved by the European Commission. Fuels that do not meet GHG reduction standards, unsustainable biofuels, and biofuels from food or feed crops are considered fossil fuels and must use default factors for the same fuel type.
- For non-fossil fuels, additional information, including evidence of sustainability standard certification and greenhouse gas intensity, will be required with the fuel delivery note.

UK ETS consultation (2023), in relation to expanding the UK ETS to domestic maritime, raised the question “What consideration needs to be given to blended fuels, or renewable and partly renewable fuels.” Respondents cited the need to develop conversion factors for additional marine fuels, the authority response indicated that there would be additional consultation conducted.

11 SUPPLY CHAIN

This section reviews the supply chain constraints of the chosen fuel options and reviews how the fuels could be transported to the platform.

11.1 Renewable Methanol

11.1.1 E-methanol Production

E-methanol is produced by reacting CO_2 and hydrogen in a one-step catalytic process. This is currently the only practical e-methanol production method [Ref. 1].

First, hydrogen is produced in an electrolyser from a renewable energy source. To produce net carbon neutral e-methanol, green hydrogen is used in combination with CO_2 that has been directly captured from atmosphere using direct air capture (DAC) technology or from biomass conversion with carbon capture. Other sources of CO_2 are available, but these are net CO_2 positive. This is summarised below.

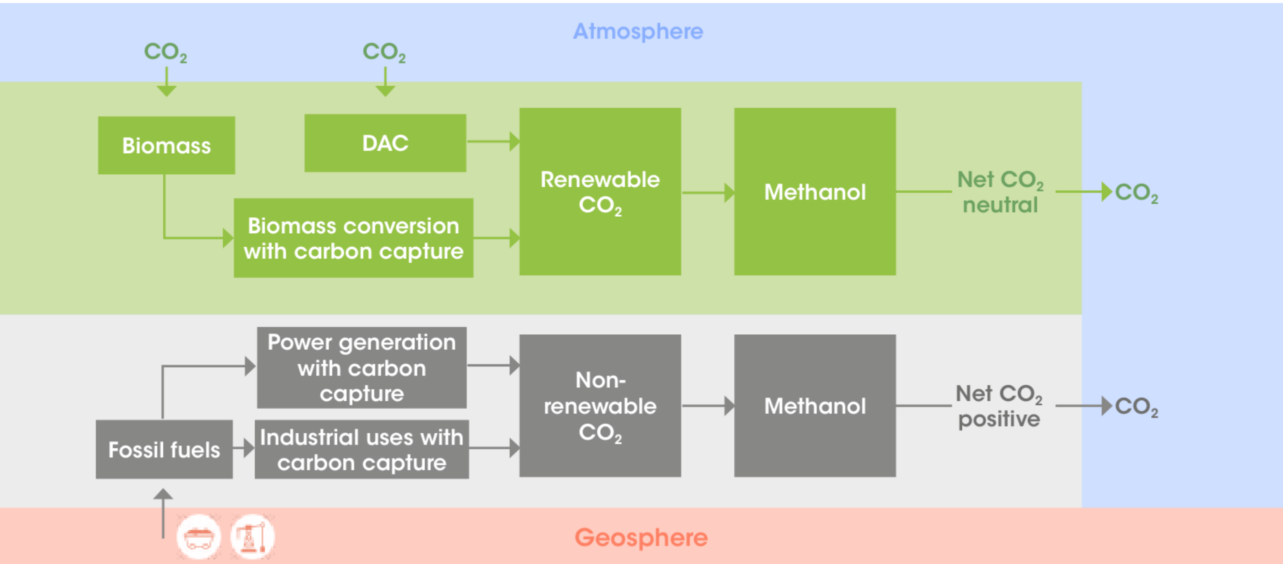

Figure 11-1 - CO_2 Feedstock to Produce E-methanol [Ref. 1]

To ensure sustainability and net CO_2 neutrality, biogenic sources of CO_2 will increasingly have to be used. However, the amount of CO_2 of these sources is limited. This necessitates the use of DAC technologies. DAC technologies are developing rapidly but many are at early TRLs.

Hydrogen is currently produced worldwide on a large scale of ~120 Mt/y, of which two-thirds are pure hydrogen and one-third is in mixture with other gases. Pure hydrogen is essential for various industrial processes, mostly petroleum refining and ammonia synthesis. However, over 95% of it comes from fossil fuels and only about 4% is presently supplied via electrolysis [Ref. 19].

To be sustainable in the long term, most hydrogen will have to be produced from renewable energy sources and will thus depend on the cost and availability of these resources. While any renewable source can be used, solar and wind are the renewables with the highest potential for expansion to the size needed for large-scale deployment of e-methanol. The progression and development of increased scale electrolysis technology is also required. Further reduction in costs of renewable power generation and electrolysers as well as increasing technology efficiencies should be targeted.

11.1.2 Bio-methanol Production

Bio-methanol is produced through the gasification of biomass followed by catalysed synthesis. The biomass feedstocks include forestry & agricultural waste, biogas from landfill, sewage, municipal solid waste, and black liquor.

The technologies used in the production of bio-methanol are relatively well-known since they are similar to or the same as technologies used in the commercial gasification-based industry, where feedstocks are usually coal, heavy residual oil and natural gas. However, the gasification aspect differs in feedstock preparation. Scaling-up from advanced demonstration plants to full-scale application still lies ahead for a majority of technologies, but some large plants are up and running or close to being ready for start-up. The main processes in a conventional methanol plant are [Ref. 1]:

1. Feedstock pretreatment
2. Gasification
3. WGS
4. Gas cleaning
5. Methanol synthesis
6. Purification

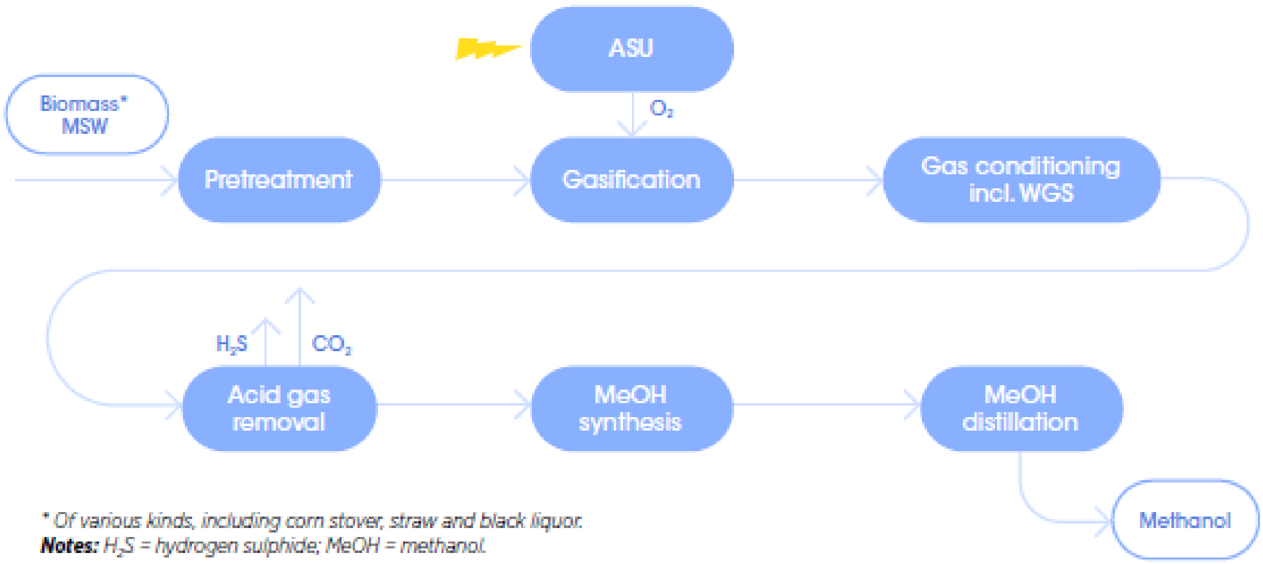

Figure 11-2 - Bio-methanol Production Process [Ref. 1]

To maximise the sustainability of bio-methanol particular attention should be paid to the feedstock and optimisation of the process. Bio-methanol production utilising other industrial processes waste streams (e.g., black liquor from paper mills and MSW) offer opportunities to simplify feedstock logistics and improve overall plant economics as well as removing waste streams. Co-production of heat, electricity or other chemicals could also potentially improve the economics and lifecycle emissions of bio-methanol production.

11.1.3 Supply Constraints & Worldwide Production

The Methanol Institute (MI) is tracking more than 80 renewable methanol projects around the globe that are projected to produce more than eight million metric tonnes per year by 2027. Below are some examples of existing and planned renewable methanol production facilities in Europe.

	COUNTRY	OPERATOR	START-UP	CAPACITY (T/Y)	FEEDSTOCK
E-methanol	Norway	CRI	2024	100,000	CO_2 and green hydrogen
	Iceland	CRI	2011	4,000	Geothermal CO_2 and green hydrogen
	Sweden	Liquid Wind	2023	45,000	Upcycle industrial CO_2 and green hydrogen
	Germany	Dow	Unknown	~200,000	CO_2 and green hydrogen

	COUNTRY	OPERATOR	START-UP	CAPACITY (T/Y)	FEEDSTOCK
	Denmark	European Energy	2023	32,000	Green hydrogen and CO_2 from biogas
Bio-methanol	Denmark	Vordingborg Biofuel ApS	2024	300,000	Straw
	Finland	Veolia, Metsa	2024	300,000	Black Liquor
	Netherlands	Gidara Energy	2024	350,000	MSW
	Spain	Enerkem	2026	200,000	MSW

Table 11-1 - Examples of European Renewable Methanol Production Facilities [Ref. 1, 20]

Circa 3.5 Mt bio-methanol and 4.5 Mt e-methanol global production capacity per year expected by 2027 [Ref. 47] totalling circa 8 Mt renewable methanol production. To date, the majority of e-methanol and bio-methanol plants have been in the range 4,000 to 10,000 tonnes/year, but the industry is now seeing more plants in the range 50,000, 100,000, > 250,000 tonnes/year [Ref. 20]. Methanol production has nearly doubled in the past decade, with a large share of that growth being in China [Ref. 1], importing fuel from China would present sustainability challenges relating to the shipping, to avoid these issues the preference would be to source the renewable methanol from within Europe. Under current trends, global production could rise to 500 Mt per annum by 2050.

For Power Load Scenario 3, full platform power, the annual methanol requirement is equal to 117,521 t/y. This equates to 1.47% of global production of renewable methanol forecast for 2027, meaning security of supply of the required volumes is likely to be a challenge by 2027.

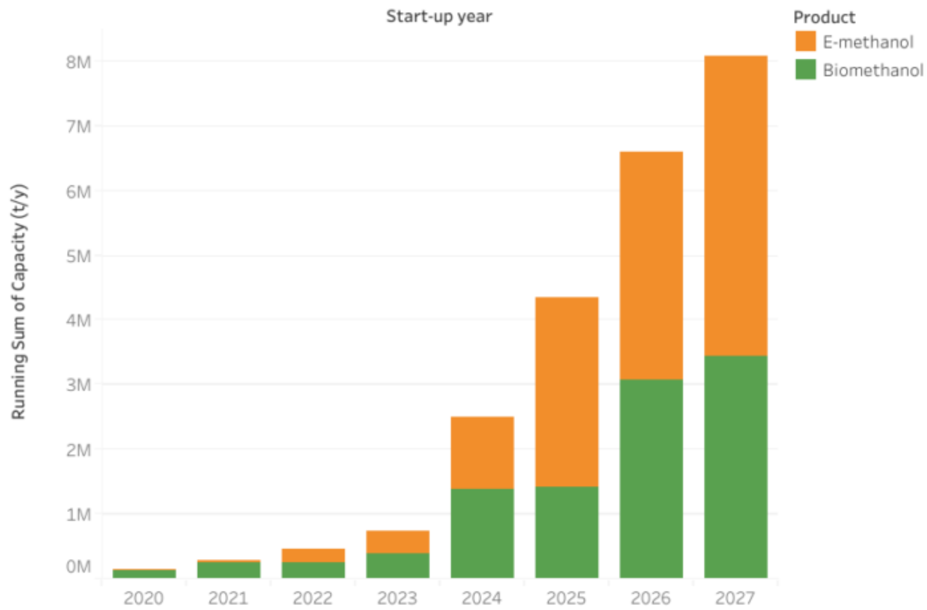

Figure 11-3 - Projected Renewable Methanol Production Capacity [Ref. 20]

Currently the main barrier to renewable methanol uptake is its higher cost compared to fossil fuel-based alternatives, and that cost differential will persist for some time to come. However, its value is in its emission reduction potential compared to existing options.

11.1.4 Methanol Vendor A

On the 1st and 16th of November 2023, Xodus, Operator A, Turbine OEM A and Methanol Vendor A had discussions regarding the supply chain and product capabilities of Methanol Vendor, who are a global methanol supplier. Methanol Vendor A were optimistic that they could provide the volumes of fuel required. They offer a range of methanol fuels, each with a unique cost and associated carbon intensity. Information provided by Methanol Vendor A has been included in methanol fuel economic sensitivities within Section 14.3.4.

11.2 HVO

11.2.1 Production

HVO is produced by the hydrotreatment of vegetable oil or suitable wastes or fats. The hydrotreatment requires hydrogen as a feedstock. Hydrogen is used to remove oxygen from the triglycerides to create molecules similar to diesel components.

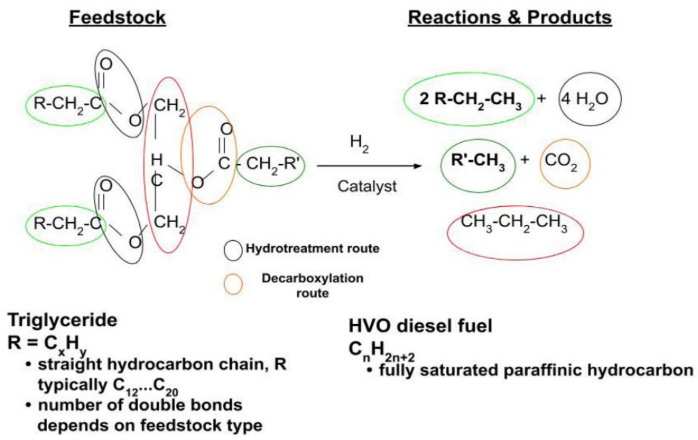

Figure 11-4 - Chemical Formation and Composition of HVO [Ref. 3]

Hydrotreatment is a complex, although already widely adapted process which requires high pressure and temperature. Examples of HVO production processes and names are as follows.

PRODUCER	TECHNOLOGY	PRODUCT NAME	PRODUCTION LOCATION
Neste	NEXBTL	Neste MY Renewable Diesel	Netherlands
Axens IFP	Vegan	-	France
Honeywell UOP/ENI	Ecofining	Green Diesel	USA

Table 11-2 - HVO Industrial Production Processes

Feedstocks required for HVO production are shown below. Example variations of these feedstocks are also shown.

Hydrogen

The hydrogen used in the hydrogenation process can be used from a number of sources. An overview of these is presented below.

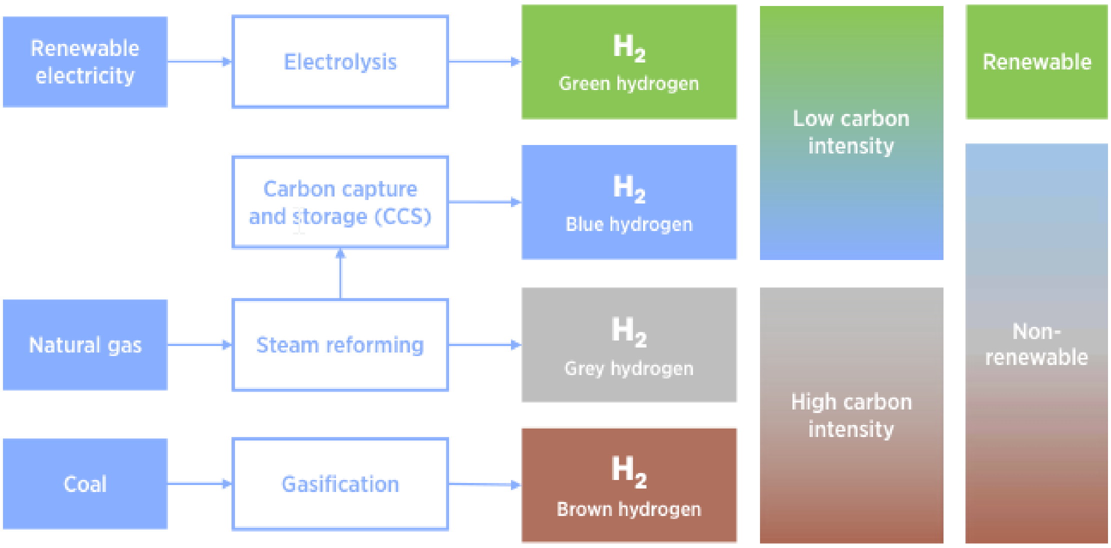

Figure 11-5 - Types of Hydrogen According to Production Processes [Ref. 1]

The source of hydrogen impacts the lifecycle emissions of the product and is discussed further in Section 12.

The hydrogen used in production would normally be generated at the HVO production site. Water is required for hydrogen production.

Triglycerides

There are many possible sources of the triglyceride feedstock. The most sustainable of those are waste based. Examples of these include:

- Waste cooking oil;
- sunflower oil;
- rapeseed oil;
- soybean oil;
- palm oil; and
- animal fats.

11.2.2 Supply Constraints & Worldwide Production

There are indications that renewable diesel producers may be constrained by limitations on triglyceride feedstock supplies. The IEA estimate that the demand for vegetable oil, waste and residue oils and fats will increase by 56% to 79 million tonnes in 2027 [Ref. 22]. Fuels made from wastes have higher demand due to their low GHG impact (see

Section 12). Their low GHG impact means that there are feedstock policy objectives in the US and Europe. Demand appears to be approaching the supply limits of the most-used wastes.

If waste feedstocks are limited, this could see increased costs and a changeover to crop feedstocks. This would lead to increased lifecycle emissions and reduced fuel sustainability as well as challenges related to the food vs. fuel debate. It is expected that strong HVO demand will prompt companies and government to improve feedstock supply chains and therefore, improve sustainable biofuel production overall [Ref. 22].

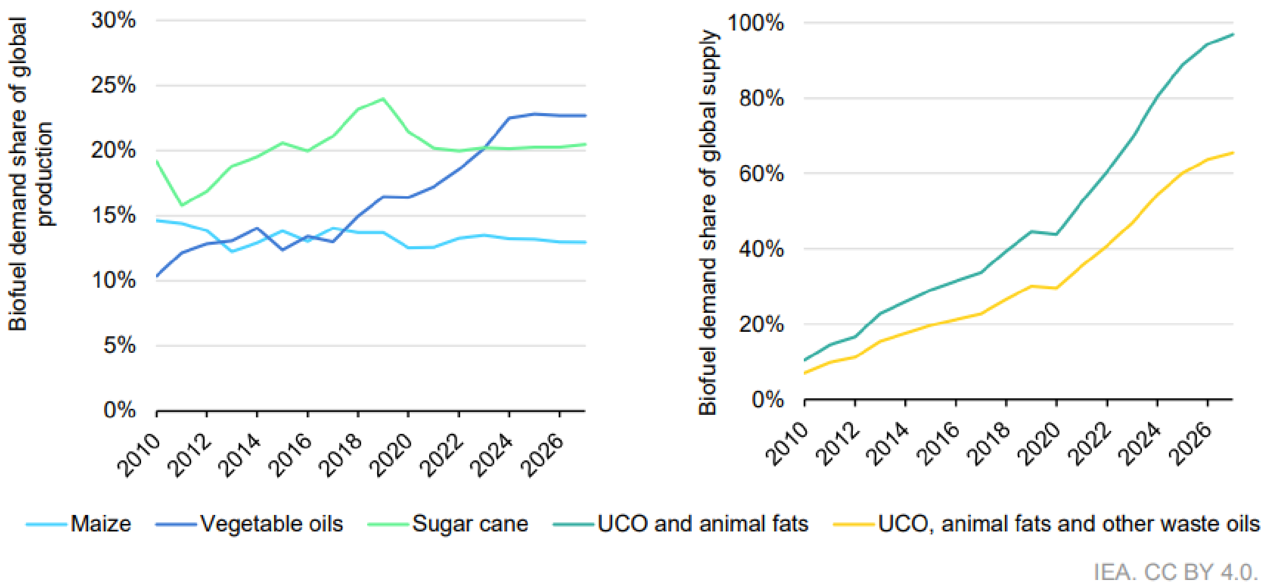

Figure 11-6 - Biofuel Demand Shares of Global Crop Production (left) and Wastes and Residues (Right) 2010-2027 [Ref. 22]

Currently there are no HVO production facilities in the UK. All HVO consumed in the UK is imported from either mainland Europe or from USA.

From discussion with UK HVO fuel wholesalers, the UK currently imports around ~350M litres/yr. To compare that volume with Asset A, Asset A's Power Load Scenario 3 HVO requirement is ~68M litres/yr. Worldwide HVO production is ~20,000 M litres/yr.

		ASSET A CONSUMPTION AS % OF TOTAL
UK HVO Consumption 2023	~350 M Litres/yr	19%
Worldwide HVO Consumption 2023	~20000 M Litres/yr [Ref. 22]	0.34%

Table 11-3 - Asset A HVO Requirements vs. UK and Worldwide Consumption

UK demand for HVO Is increasing and HVO is now being sourced from the US as well as Europe. Conversations with UK based wholesalers have indicated that securing Asset A's required HVO volume from 2027 is feasible. The IEA accelerated case worldwide production forecast is growth to ~35,000 M Litres/yr in 2027 [Ref. 22].

A UK based HVO supplier, have provided comment to Xodus regarding the current state of their supply chain [Ref. 23]:

1. *They have partnered with Neste for our HVO to ensure the product meets not only Marine Specification but also to ensure the sustainability can be tracked fully, this is certified by ISCC.*
2. *They are currently finishing the works at Aberdeen terminal to allow them to supply by pipe and by road. This will involve initially storing between 3kt and 5kt in Aberdeen, but they are comfortable scaling up their storage capabilities if and when required.*
3. *They will be receiving our HVO by ship and currently have supply locations in Teesport, Harwich, Liverpool and (before the end of the year) Aberdeen. Future plans would be to expand supply locations to customer requirements and increase storage at locations they already have supply. Aberdeen is seen as a key location and both the existing harbour and South Harbour opportunities are being investigated.*
4. *From Oct/November (2023) when Aberdeen becomes operational, they will be able to supply HVO by Pipe and by Road in Aberdeen and by Road tanker in Peterhead.*

11.3 Fuel Transport

The transport of liquid alt-fuels renewable methanol and HVO is discussed in this section.

Asset A's alt-fuel consumption would be significant in terms of shipping capacity. While Concept 1A and 1B have their storage capacities restricted to the size of the fuel storage tanks on the platform, the subsea and FSO concepts (2A, 2B, 3A, 3B & 3C) require large storage volumes. As presented in Section 6.1, the minimum renewable methanol storage volume based on 14 days fuel consumption ranges from 2000 m^3 to >6000 m^3. These figures are approximately halved for HVO.

It is considered that a standard platform supply vessel could be suitable for supplying fuel to Asset A without further modifications, although this would have to be investigated and confirmed e.g., storage tank materials compatibility for methanol. However, while a standard platform supply vessel may be equipped for liquid fuel deliveries to a SSU or FSO, a platform supply vessel's constraint on capacity does provide challenges. Standard platform supply vessels have a liquid fuel capacity of ~1200m^3 and the largest in the North Sea ~1700m^3 [Ref. 24]. If we consider the larger of these platform supply vessel sizes, this will result in the following bunkering frequencies.

CONCEPT	FUEL	CAPACITY (DAYS)
2A	Renewable Methanol	11.0
	HVO	23.8

CONCEPT	FUEL	CAPACITY (DAYS)
2B	Renewable Methanol	8.0
	HVO	17.4
3A & 3B	Renewable Methanol	3.6
	HVO	7.8

Table 11-4 - Large Platform Supply Vessel Bunkering Frequency

For Concepts 3A & 3B, to transport the full capacity for less frequent bunkering, a ship with a liquid fuel capacity of ~6600m^3 would be required for renewable methanol and ~3000m^3 for HVO. These capacities lie in between typical capacities of vessels chartered in the North Sea. A small Handymax shuttle tanker has a DWT of ~37000. A standard shuttle tanker may also not be equipped for fuel bunkering to a SSU or FSO.

If a specialist vessel was to be deployed for fuel transport, the deployment of this specialist vessel should consider but not be limited to the following requirements.

- The vessel's renewable methanol cargo-tank required capacity is >5000m^3. The economy of scale would apply to the application of a bespoke vessel – should other Operator A assets look to alt-fuels as a decarbonisation method then a larger capacity would be favoured.
- A cargo pumping rate of ~550m^3/hr. This would complete the fuel bunkering operation in ~12 hours. If a longer fuel bunkering duration could be considered, the required cargo pumping rate could be decreased. The pump head would need to exceed the subsea storage pressure.
- It is assumed that a dynamic positioning system of at least class DP 2 would be required for positioning during bunkering and to minimise risks related to platform collision and disconnection of the offloading hose end valve.
- Provision of a relief valve which is specified to relieve at least the full cargo pumping flowrate (to avoid over pressuring any interfacing equipment, e.g., the NOV SSU).
- Flow metering with totalising function.
- Inclusion of a system designed to pick up the single arm loading system from the seabed. The inclusion of an in-built pick-up system would negate the requirement for attendance by any additional attending assist vessels.
- There may be the opportunity to reduce emissions associated with fuel transport by utilising renewable methanol as the ship's own fuel source (see Section 11.1.3).

Costs to modify and charter a vessel for this requirement are unknown and should be defined in the next project phases.

In conclusion, although a large platform supply vessel would result in a sub optimal bunkering frequency, this has been considered the viable shipping option at this stage and costs for a platform supply vessel are used in the economic analysis. A platform supply vessel also has the advantage of being able to transport other platform consumables for Asset A and offload these adjacent to the platform.

For both fuel options, considering the likely location of production facilities, the most probable port of departure would be in mainland western Europe. This is used to determine trip durations as part of economic analysis.

It should be noted that vessel selection impacts the DP offshore loading system, safety zones design and potential final selected storage capacity.

12 EMISSIONS & ENVIRONMENTAL IMPACT

A complete cradle-to-grave analysis for both fuel options cannot yet be completed to assess the environmental impact of each production and distribution step. For this study, the exact sources of supply are not currently known e.g., exact production feedstocks, production by-product generation and fuel transport methods. Therefore, this lifecycle emissions assessment for the fuel options is intended to be an indicative comparison only.

12.1 Renewable Methanol

The complete combustion of methanol (CH_3OH) produces CO_2 and H_2O. E-methanol is intended to be net carbon neutral. This is demonstrated by the simplified carbon cycle diagram below.

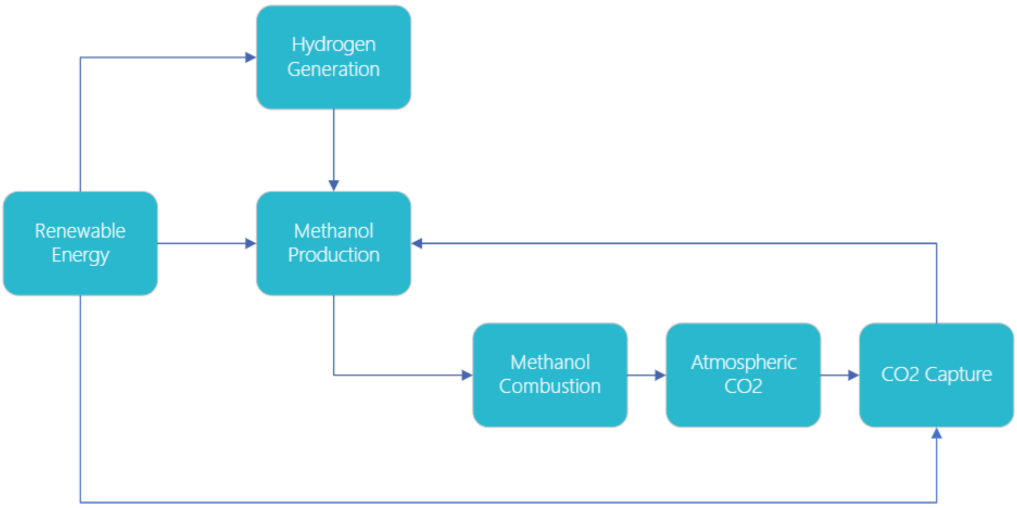

Figure 12-1 - Carbon Cycle for Carbon Neutral E-methanol Production

Similarly, bio-methanol is considered a renewable fuel if its feedstocks are green hydrogen and biomass, which itself removes carbon from the atmosphere. To qualify as renewable, all feedstocks used to produce the methanol need to be of renewable origin.

However, from a full life cycle perspective, there are areas of renewable power generation that still contribute to a carbon footprint. A complete life cycle analysis should consider the following areas:

- Embodied carbon i.e., emissions associated with production and fabrication of materials & equipment, this should be calculated for equipment installed during construction and replaced during operation and maintenance.
- Transportation of equipment from fabrication location to site.
- Site preparation/Construction emissions e.g., survey vehicles/cranes/drill rigs/HGVs/mobile generators/vessels (there may be some requirement for similar equipment during operation and maintenance)

- Operation and maintenance.
  - The source of water for electrolysis can alter environmental impact. The use of an inland fresh water source could add to water scarcity issues depending on the climate. The use of a seawater source if the plant is located nearshore would be preferrable, however, more energy and processing would be required for desalination prior to further water treatment. Although, the concept of a sustainable renewable methanol economy does suggest that water produced by renewable methanol combustion is released to the atmosphere to then end up in rivers and oceans [Ref. 25].
- Plans for inspection and equipment/component replacement.
- Carbon intensity of electricity/power utilised.
  - If grid connected, it would be the carbon intensity of the grid which defines the carbon emissions of a renewable methanol fuel production facility. However, the power for the fuel manufacture considered for this study is assumed to be from 100% renewable energy sources.
- Fuel transportation to site - if fuel is transported from the facility by truck or ship, the fuel used to power the transport can be an additional emissions source. This can be offset using electrified vehicles or alt-fuel powered ships.
- Decommissioning assumptions e.g., recycling/reuse/landfill

It is clear from the above list that a detailed understanding of specific methanol supply chain would be required to do an accurate life cycle carbon emissions assessment, and this level of detail is not available at this early concept study phase. As an indication of lifecycle carbon emissions, data from the [Ref. 26] carbon footprint of methanol work commissioned by the Methanol Institute has been used which includes the estimates below for e-methanol from wind and solar power.

FUEL	RENEWABLE ELECTRICITY SOURCE	LIFECYCLE CARBON EMISSIONS (gCO_2/MJ)
e-methanol	Wind	10
e-methanol	Solar	4
Bio-methanol (Low)	-	10
Bio-methanol (High)	-	40

Table 12-1 - Renewable Methanol Lifecycle Carbon Emissions [Ref. 26]

Other combustion by-products can be produced by combustion inefficiencies. These can include particulate matter (PM), NOx, SOx and CO. Quantities of these by-products is dependent on the combustion equipment. Typically, methanol is cleaner burning than conventional carbon-based fuels and reduces the emissions of PM, NOx and SOx. When utilised as a marine fuel and compared with fuel oil combustion, SOx, PM and NOx emissions decreased by more than 99% [Ref. 27]

For Asset A, the reduction of these pollutants when compared with diesel or fuel gas combustion would need to be measured through ongoing emissions monitoring post alt-fuel implementation. The NZTC / Turbine OEM A Model C Bio-methanol demonstration test saw an 80% reduction in NOx when compared with kerosene and a 10% reduction in CO_2 emissions from direct combustion when compared with diesel [Ref. 18].

12.2 HVO

Lifecycle GHG emissions account for collection and processing of crops or biomass waste, production and transport of feedstocks, manufacture of fuel, distribution of fuel and combustion of fuel. HVO supplier Neste have estimated this overview of HVO emissions when waste is used as the HVO feedstock.

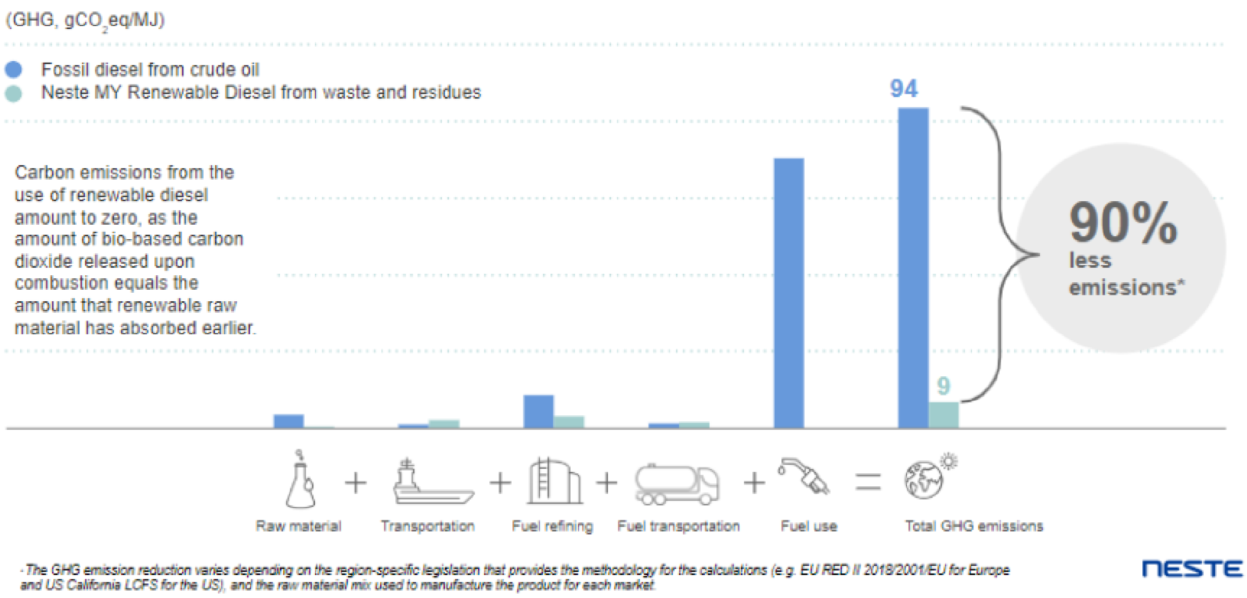

Figure 12-2 - Neste HVO Emissions Reduction Overview [Ref. 28]

Transportation is required for bringing feedstocks to the production facility as well as for fuel distribution. If fuel is transported from the facility by truck or ship, the fuel used to power the transport can be an emissions source. This can be offset using electrified vehicles or alt-fuel powered ships.

HVO is produced as per the process described in Section 11.2.1. Key to the sustainability of HVO is the source of the triglyceride feedstock. Feedstocks massively impact the lifecycle GHG impact of HVO.

- HVO with a waste feedstock can have a lifecycle emissions value as low as 13.9 gCO_2e/MJ [Ref. 29]
- HVO with a rapeseed oil feedstock can have a lifecycle emissions value as high as 73.4 gCO_2e/MJ [Ref. 29]

Rapeseed oil based HVO can have higher GHG emissions than fuel gas or diesel. From discussion with UK HVO fuel wholesalers, the HVO imported to the UK is currently from waste oil as the feedstock. However, this may change in the future with demand growth so securing a supply with lifecycle emissions as low as possible should be a focus area if HVO use is considered.

12.3 Overview

An overview of the emissions of fuel options and their varying feedstocks is presented:

FUEL	LIFECYCLE CARBON EMISSIONS (gCO_2/MJ)	SOURCE DATA
Fuel Gas	60.2	Note 1
Diesel	75.1	Note 2
e-methanol - Solar	4	[Ref. 26]
e-methanol - Wind	10	[Ref. 26]
Bio-methanol - Low	10	[Ref. 26]
Bio-methanol - High	40	[Ref. 26]
HVO - Waste	13.9	[Ref. 28]
HVO - Rapeseed	73.4	[Ref. 28]

Table 12-2 - GHG Lifecycle Emissions Overview

Note 1: As advised by previous study conducted by Xodus for Operator A – Asset A Flare Gas Recovery Study. CO_2 emission factor of 2.52 from EEMS for fuel gas turbine combustion. CH_4 EEMS emissions factor for gas turbines of 0.00092 and CH_4 equivalent CO_2 factor of 29.8 tCO_2e/t pollutant. N_2O EEMS emissions factor for gas turbines of 0.00000328 and N_2O equivalent CO_2 factor of 273 tCO_2e/t pollutant.

Note 2: CO_2 emission factor of 3.2 from EEMS for diesel turbine combustion. CH_4 EEMS emissions factor for gas turbines of 0.0000328 and CH_4 equivalent CO_2 factor of 29.8 tCO_2e/t pollutant. N_2O EEMS emissions factor for gas turbines of 0.00022 and N_2O equivalent CO_2 factor of 273 tCO_2e/t pollutant.

For the purposes of emissions estimates for this study, a renewable methanol lifecycle carbon emission of 10.0 gCO_2/MJ has been assumed and HVO is assumed to be derived from waste cooking oil providing lifecycle carbon emissions of 13.9 gCO_2/MJ.

12.4 Concept Emissions

These emissions are presented below in the context of Asset A operation for each concept.

CONCEPT	FUEL	ENERGY CONSUMPTION (MJ/yr)	LIFECYCLE EMISSIONS ($TonnesCO_2/yr$)	EMISSIONS SAVINGS VS. NORMAL OPERATION ($TonnesCO_2/yr$)	EMISSIONS SAVINGS %
1A	Diesel	27,216,000	2,044	-	-
	R Methanol		272	1,771	87%
	HVO		378	1,665	81%
1B	Diesel	7,788,784	585	-	-
	R Methanol		78	507	87%
	HVO		108	477	81%

Table 12-3 - TAR Shutdown Concepts Asset A Emissions Savings Results

Please note, emissions from fuel burning are considered the same for Concepts 3A, 3B & 3C. For Concept 3A, a comparison has been included for all fuel types displayed in Table 12-2.

CONCEPT	FUEL	ENERGY CONSUMPTION (MJ/yr)	LIFECYCLE EMISSIONS ($TonnesCO_2/yr$)	EMISSIONS SAVINGS VS. NORMAL OPERATION ($TonnesCO_2/yr$)	EMISSIONS SAVINGS %
2A	Fuel Gas	765,874,286	46,100	-	-
	R Methanol		7,659	38,441	83%
	HVO		10,646	35,454	77%
2B	Fuel Gas	1,051,993,358	63,322	-	-
	R Methanol		23,387	52,802	83%
	HVO		32,507	48,699	77%

3A/B/C	Fuel Gas	2,338,662,158	140,770	-	-
	E-methanol (Solar)		9,355	131,415	93%
	E-methanol (Wind)		23,387	117,383	83%
	Bio-methanol (Low)		23,387	117,383	83%
	Bio-methanol (High)		93,546	47,223	34%
	HVO – Waste		32,507	108,262	77%
	HVO - Rapeseed		171,658	-30,888	-22%

Table 12-4 - Continuous Operation Concepts Asset A Emissions Savings Results

The following plot compares the annual lifecycle CO_2 emissions for each fuel type, relative to Concept 3A.

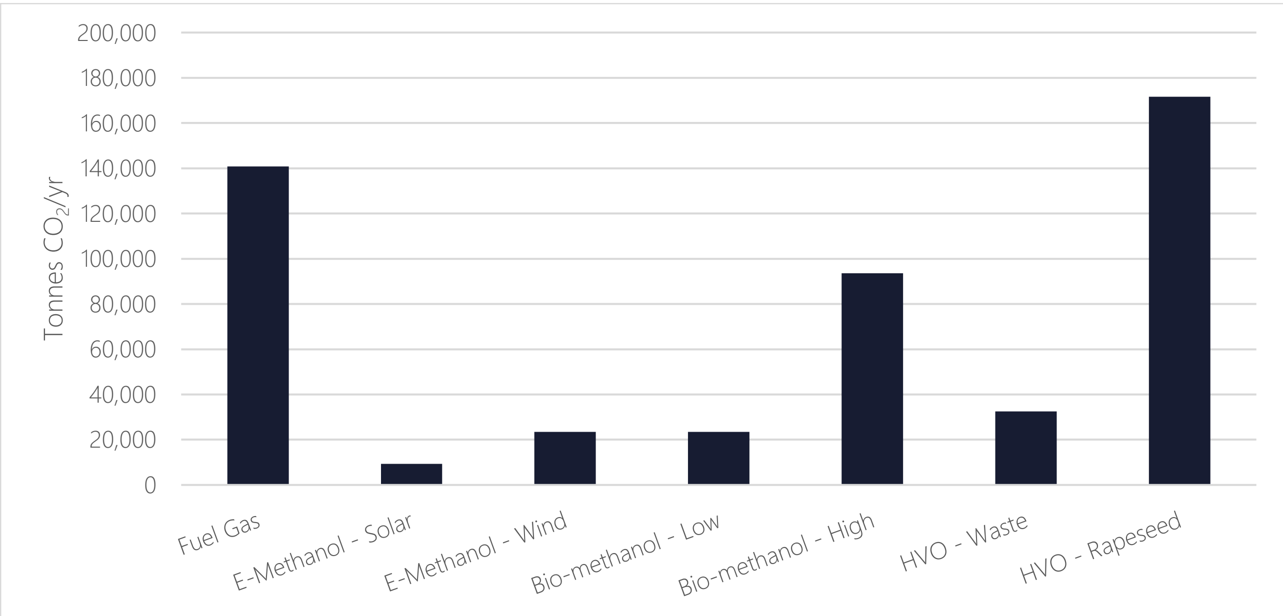

Figure 12-3 - Asset A Lifecycle CO_2 Equivalent Emissions vs Fuel

13 OPERATIONS & MAINTENANCE

13.1 OEM

The low flame temperatures of renewable methanol in the gas turbines may result in the requirement for less frequent GT inspections. This philosophy would need to be developed with a solid evidence basis over many operating hours and would need to be in agreement with NOV and Turbine OEM A.

The O&M aspects of adapting to HVO fuel were reviewed. It has been concluded that topsides there are no further requirements than what would be required for a regular diesel fuelled dual fuel turbine system. High cetane numbers in HVO products can aid smoothness of operation, misfiring, smoke emissions, noise and ease of starting [Ref. 3]. This could lead to reduced maintenance requirements over time when compared to diesel operation.

13.2 Sparing

A sparing philosophy has not been developed at this stage but for applicable concepts, a duty/standby distribution pump is currently allowed for. Any sparing philosophy should be considerate of the option to revert to fuel gas in an alt-fuel failure scenario.

13.3 Material Selection

For new equipment, renewable methanol and HVO are non-corrosive substances and carbon steel with a nominal corrosion allowance (1-3mm) is acceptable. This is dependent on a clean supply – if contamination were to be expected then 316L stainless steel is required.

For interfaces with existing equipment including the turbine packages then more detailed checks on materials should be carried out in the next project phases in conjunction with vendors.

While HVO material compatibility is typically similar to fossil diesel, in principle, the lack of aromatic compounds may shrink elastomers that have already been swollen due to aromatic or FAME containing fuels, but Neste have experienced no leakage during 12 years of field operations [Ref. 3].

Diesel Storage Tank & Base Oil Tanks Materials Review

The data available for the base oil tanks and the diesel storage tanks indicate both are constructed from carbon steel. However, the diesel tank also had an internal coating of glass flake vinyl ester, given the age of the tank the status of this coating is uncertain. Note inspection of these tanks has yet to be conducted so no data is available about their current integrity.

In terms of material compatibility for short term storage the HVO is expected to act very much like standard diesel and therefore there should be no issues. However, the methanol, as a polar solvent has been associated with coating breakdown (albeit typically epoxy tank coating) and can lead to increased rates of galvanic corrosion, particularly trim materials of aluminium, lead, magnesium, copper, zinc, and platinum alloys. Galvanized steel is not suitable for methanol service and methanol may cause Stress Corrosion Cracking in titanium alloys. Note details of the tank trim materials have not been investigated at this stage.

If longer term storage is contemplated, then the HVO would need to be treated as per diesel – i.e., with inspections to ensure lack of microbial issues and removal of separated water. Longer terms storage of methanol could have issue with the hydroscopic nature in that it can attract water which can lead to corrosion, failure of methanol tanks in carbon steel have been reported. This is typically dealt with by inert gas blanketing.

Due to the painted coating on the base oil tanks it is recommended that a swab test is performed to see if methanol has a significant effect on the paint, a blocked fuel filter contaminated with paint would be detrimental to the operation of the storage unit, especially during a shutdown.

14 ECONOMICS

14.1 OPEX

This section summarises the OPEX calculations for all design concepts. Please note, all OPEX calculations for Concept 1A and Concept 1B consider only one 21-day duration, equivalent to the assumed TAR duration. The remaining concepts assume 7,446 annual operating hours (85% up-time).

For economic analysis and measurement of commercial metrics, implementation of an alt-fuel is targeted for 2027 with an asset CoP of 2035.

14.1.1 Renewable Methanol Fuel Cost

Bio-Methanol

As production is currently low, limited data are available on actual costs, meaning that potential costs need to be estimated. The bio-methanol production cost will depend on the bio-feedstock cost, investment cost and the efficiency of the conversion processes.

The Methanol Institute estimates bio-methanol costs of between £261/te and £810/te in 2020 and £181/te to £675/te in 2030 [Ref. 1].

E-Methanol

The cost to produce e-methanol fuel is heavily dependent on the cost of producing hydrogen and the source of CO_2. The study has assumed DAC as the base method of capturing CO_2.

The Methanol Institute estimates e-methanol costs (for CO_2 from DAC) of between £656/te and £1904/te in 2020 and £201/te to £505/te in 2030 [Ref. 1]. The Methanol Institute's wide range of fuel cost estimates demonstrate that the cost of e-methanol is highly dependent on the feedstock costs which are complex to forecast for a developing green hydrogen and DAC CO_2 market.

Selected Fuel Cost

A summary of the fuel costs reported by the Methanol Institute is displayed below.

FUEL	PRICE – LOW ESTIMATE		PRICE – HIGH ESTIMATE	
	£/GJ	£/tonne	£/GJ	£/tonne
Fossil Methanol	8	161	16	320
Bio-methanol Current	13	261	41	810

Bio-methanol Mature Process 2030 - 2050	9	181	34	675
E-methanol Current	33	656	96	1904
E-methanol Mature Process 2030 - 2050	10	201	25	505
Diesel (before Tax)	13	552	13	552

Table 14-1 - Methanol Fuel Price Summary

To compare with the above ranges, the Xodus eFuel production costs model has been used to forecast an e-methanol cost in 2027. The Xodus eFuel production costs model calculates fuel cost accounting for site CAPEX, OPEX and feedstock costs. The following basis has been used:

- Green hydrogen £3.4/kg
- DAC CO_2 £164/kg
- Start of fuel production 2027
- Operation to 2035.

The Xodus eFuel production costs model forecasts a 2027 e-methanol cost of £1076/te. This is within the range of forecasts by the Methanol Institute and therefore this cost has been used in subsequent fuel cost calculations. It is in the 52nd percentile between the lower cost (£181/t) and the upper cost (£1904/t) range. If the low-cost estimate was to be selected, it could be expected that the associated lifecycle emissions would increase due to a less sustainable supply chain. As such, a mid-range cost can be justified by the selection of a mid-range lifecycle carbon emissions value. This cost has been decreased by 5 % each year accounting for the Methanol Institute forecast of a decreasing fuel cost.

The renewable methanol fuel costs for each concept are summarised below. The results are displayed for 2027, these will vary in later years due to inflation and the assumed reduction in methanol cost. Additionally, the total OPEX from 2027 – 2035 is displayed. Please note, required methanol fuel is considered the same for Concepts 3A, 3B & 3C.

CONCEPT	ANNUAL RENEWABLE METHANOL REQUIRED (TONNES)	2027 ESTIMATED RENEWABLE METHANOL FUEL COST (£M/YR)
1A	1,368	£1.47M
1B	391	£0.15M

Table 14-2 - TAR Shutdown Concepts Renewable Methanol Fuel Cost OPEX

CONCEPT	ANNUAL RENEWABLE METHANOL REQUIRED (TONNES)	2027 ESTIMATED RENEWABLE METHANOL FUEL COST (£M/YR)	ESTIMATED TOTAL RENEWABLE METHANOL FUEL COST (£M)
2A	38,486	£41.4M	£330M
2B	52,864	£56.9M	£453M
3A/B/C	117,521	£126.5M	£1,007M

Table 14-3 - Continuous Operation Concepts Renewable Methanol Fuel Cost OPEX

Within Section 14.3.4, a variety of renewable methanol fuels, each with different prices and lifecycle carbon emissions have been considered to assess the impact upon concept economics.

14.1.2 HVO Fuel Cost

Figures from the IEA analysis presented below in Figure 14-1 below, demonstrate that biofuel costs are somewhat tied to the costs of the carbon equivalent. Therefore, it is difficult to predict the cost of HVO for the year of implementation and beyond to CoP. An estimate has been made based on current market conditions.

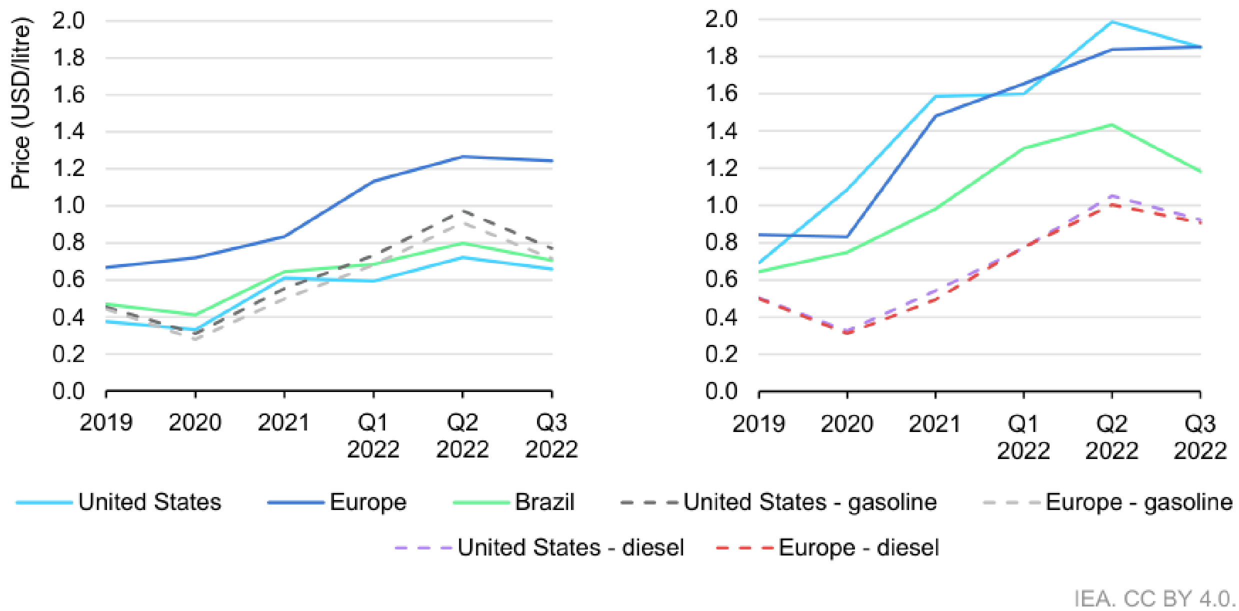

Figure 14-1 - Petrol and Ethanol (left), Biodiesel and Diesel Prices (right) from IEA Biofuels Market Analysis [Ref. 22]

From discussions with UK fuel distributor Crown Oil, HVO is currently 69% more expensive than diesel at ~£1.59/litre ex vat. This figure is used to forecast costs up to 2035 – although this is dependent on taxation policies and market conditions which may aid the commercial case for biofuels.

Although diesel prices fluctuate with markets, the current September 2023 HVO price, adjusted for inflation is used to predict an HVO price in 2027.

The HVO price used excludes VAT and is **£2207/te**. This figure is an average and assumed to increase with inflation annually from 2027 to CoP for the purposes of estimating OPEX.

The HVO fuel costs for each concept are summarised below. The results are displayed for 2027, these will vary in later years due to inflation. Additionally, the total OPEX from 2027 – 2035 is displayed. Please note, required HVO fuel is considered the same for Concepts 3A, 3B & 3C.

CONCEPT	ANNUAL HVO REQUIRED (TONNES)	2027 ESTIMATED HVO FUEL COST (£M/YR)
1A	613	£1.35M
1B	175	£0.39M

Table 14-4 - TAR Shutdown Concepts HVO Fuel Cost OPEX

CONCEPT	ANNUAL HVO REQUIRED (TONNES)	2027 ESTIMATED HVO FUEL COST (£M/YR)	ESTIMATED TOTAL HVO FUEL COST (£M)
2A	17,249	£38.1M	£371M
2B	23,694	£52.3M	£510M
3A/B/C	52,673	£116.3M	£1,134M

Table 14-5 - Continuous Operation Concepts HVO Fuel Cost OPEX

14.1.3 Shipping

Section 11.3 described the shipping options and the chosen basis of a platform supply vessel.

Using Xodus in-house cost estimating tools, the daily charter rate for a platform supply vessel is estimated to be approximately 18,233 GBP/day.

For Concept 1A and Concept 1B, it has been assumed that during the TAR shutdown period of 21-days, there will be 2 platform supply vessel trips regardless of alt-fuel type. As such, the OPEX costs for shipping consider the required additional trips to the platform. Concepts 1A & 1B also consider that the maximum amount of fuel that each supply vessel trip can provide is equal to available platform storage space, 285 m^3 and 110 m^3 respectively.

Shipping costs are identical for Concept 3A & 3B, FSO charter costs are discussed in the following Section.

It is estimated that a round trip to supply Asset A from mainland western Europe would take approximately 3 days. For this trip duration and vessel capacity, the estimated annual cost for each fuel option is as follows.

CONCEPT	FUEL	NO. OF TRIPS PER YEAR (3 DAYS PER TRIP)	2027 ESTIMATED SHIPPING COST (£/YR)
1A	Renewable Methanol	4	£218,796
	HVO	1	£54,699
1B	Renewable Methanol	4	£218,796
	HVO	2	£109,398

Table 14-6 - TAR Shutdown Concepts Estimated Fuel Shipping Costs

CONCEPT	FUEL	NO. OF TRIPS PER YEAR (3 DAYS PER TRIP)	2027 ESTIMATED SHIPPING COST (£/YR)	ESTIMATED TOTAL SHIPPING COST (£)
2A	Renewable Methanol	29	£1,719,743	£16,775,459
	HVO	13	£792,032	£7,725,977
2B	Renewable Methanol	39	£2,362,214	£23,042,517
	HVO	18	£1,087,923	£10,612,286
3A/B	Renewable Methanol	87	£5,251,383	£51,225,288
	HVO	40	£2,418,537	£23,591,928

Table 14-7 - Continuous Operation Concepts Estimated Fuel Shipping Costs

14.1.4 Vessel Charter

For Concept 3B and Concept 3C, FSO vessel charter costs have been considered. The basis for Concept 3B is one vessel being required on an annual basis, Concept 3C requires two vessels operating back-to-back.

Using 2022 cost data for vessel charters [Ref. 30] adjusted for inflation, the following costs were assumed to charter a Handysize vessel for the purposes of floating fuel storage and offloading.

CONCEPT	VESSEL	2027 DAILY CHARTER RATE	2027 ESTIMATED CHARTER COST (£M/YR)	ESTIMATED TOTAL CHARTER COST (£M)
3B	Handysize	£13,237	£4.19M	£40.9M
3C			£8.38M	£81.8M

Table 14-8 - Estimated Floating Storage Charter Costs

If the project progresses, these costs should be re-visited.

14.1.5 Diesel Savings

The resulting savings from the reduced diesel usage associated with the implementation of alt-fuels for power generation during TAR periods are described in this section. Diesel savings are realised for both Concept 1A and Concept 1B.

As of October 2023, diesel cost data indicates a current price of 87.26 pence per litre [Ref. 31]. Adjusted for inflation, the diesel price in 2027 is assumed to be £0.94/L.

CONCEPT	AVOIDED DIESEL USAGE (L)	COST SAVING (£)
1A	760,797	£718,596
1B	217,728	£205,651

Table 14-9 - Diesel Savings

14.1.6 Sales Gas & Emissions Pricing

In the interest of providing accurate results for a range of future market conditions, Operator A provided Xodus with the 5 pricing cases used for their economic evaluations. The carbon price range reflects the current ETS value up to the value embedded in the NSTA's GHG valuation guidance document. The natural gas prices reflect a spread of real market forecast.

PRICING CASE	GAS PRICE (P/THERM)	CARBON PRICE (£/TONNE)
High High	200	280
High	200	120
Medium	100	100
Low	40	80
Extreme	40	280

Table 14-10 - Pricing Cases

For the purposes of presenting OPEX estimates, the sales gas revenue and emissions allowance savings detailed in the following sections apply the High High forecast. Within Section 14.3.3, sensitivities have been developed to consider the impact of implementing the range of pricing cases.

14.1.7 Sales Gas Revenue

The resulting revenue from exporting gas which would otherwise have been consumed as fuel gas is described in this section. The revenues in Table 14-11 represent the High High pricing case.

CONCEPT	SALES GAS FOR EXPORT (MMBTU/YR)	2027 ESTIMATED SALES GAS REVENUE (£M/YR)	ESTIMATED TOTAL SALES GAS REVENUE (£M)
2A	725,909	£15.7M	£153M
2B	997,098	£21.6M	£211M
3A/B/C	2,216,626	£48.0M	£468M

Table 14-11 - Sales Gas Revenue (High High Pricing Case)

For reference, the estimated total sales gas revenue values for the range of pricing cases are displayed below for to demonstrate the impact that gas price will have on the overall OPEX.

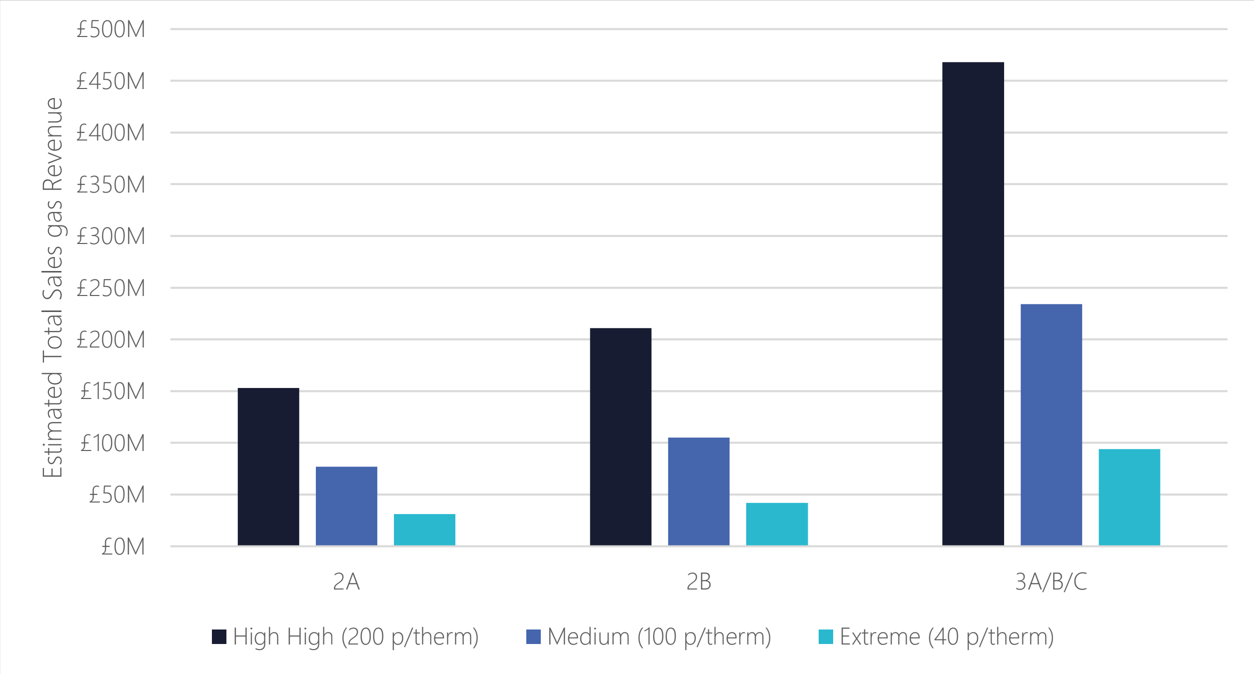

Figure 14-2 - Sales Gas Revenue

14.1.8 Emissions Allowance Savings

For each fuel option, the resulting savings from reduced eCO_2 production have been calculated.

For this comparison, it has been assumed that lifecycle carbon emissions from alternative fuels will be part of the UK ETS scheme. This means that ETS CO_2 saving comprise the ETS savings from not burning fuel gas minus the cost of equivalent CO_2 emissions from the alternative fuel. The presented renewable methanol CO_2 savings are based on life cycle emissions 10 gCO_2e/MJ and the HVO savings are based on 13.9 gCO_2e/MJ (refer to Table 12-2 for potential ranges in CO_2 emissions for the alternative fuels).

Emissions savings calculations are displayed in Table 12-3.

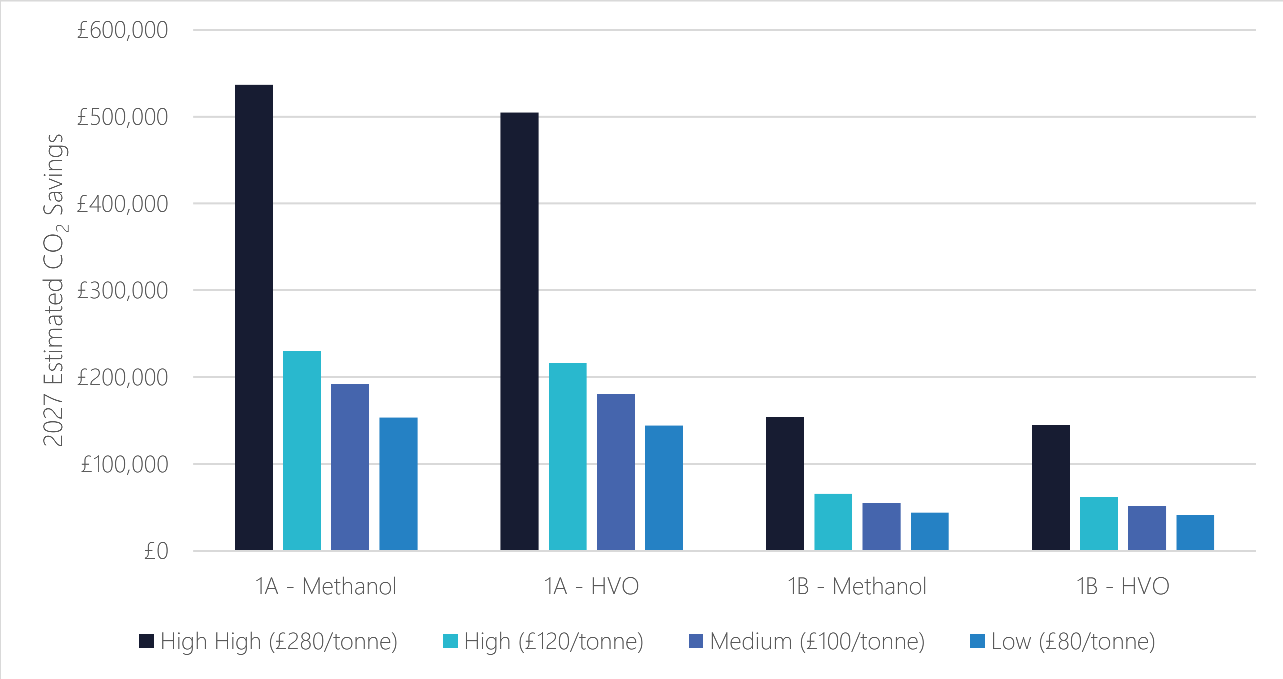

Figure 14-3 - TAR Shutdown Concepts ETS CO_2 Savings

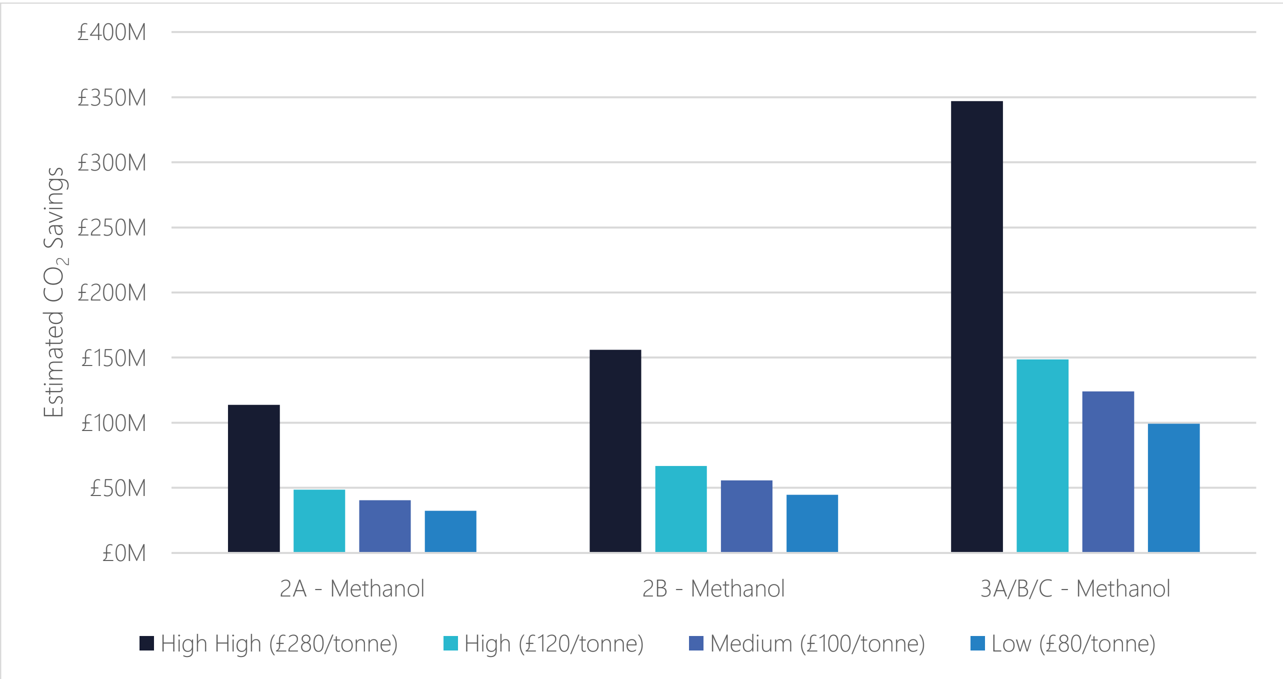

Figure 14-4 - Continuous Operation Concepts ETS CO_2 Savings (Renewable Methanol)

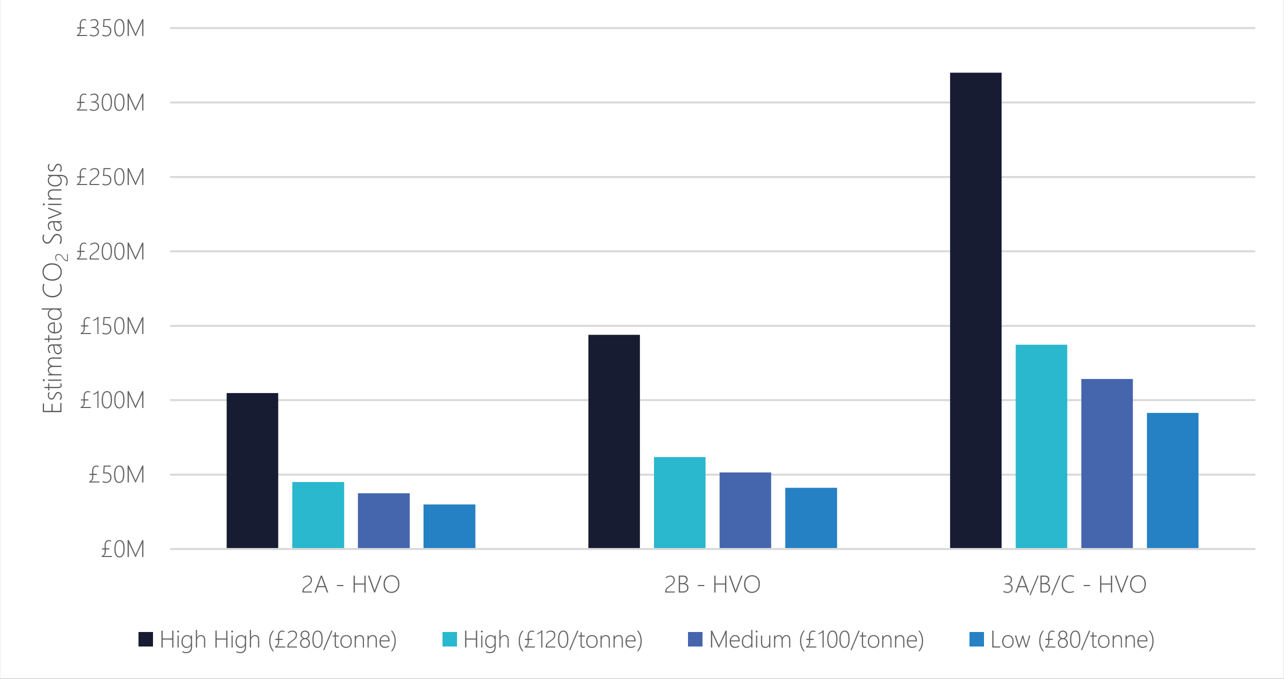

Figure 14-5 - Continuous Operation Concepts ETS CO_2 Savings (HVO)

14.1.9 OPEX Summary

Figure 14-6 summarises the 2027 OPEX for the TAR shutdown for Concept 1A and Concept 1B.

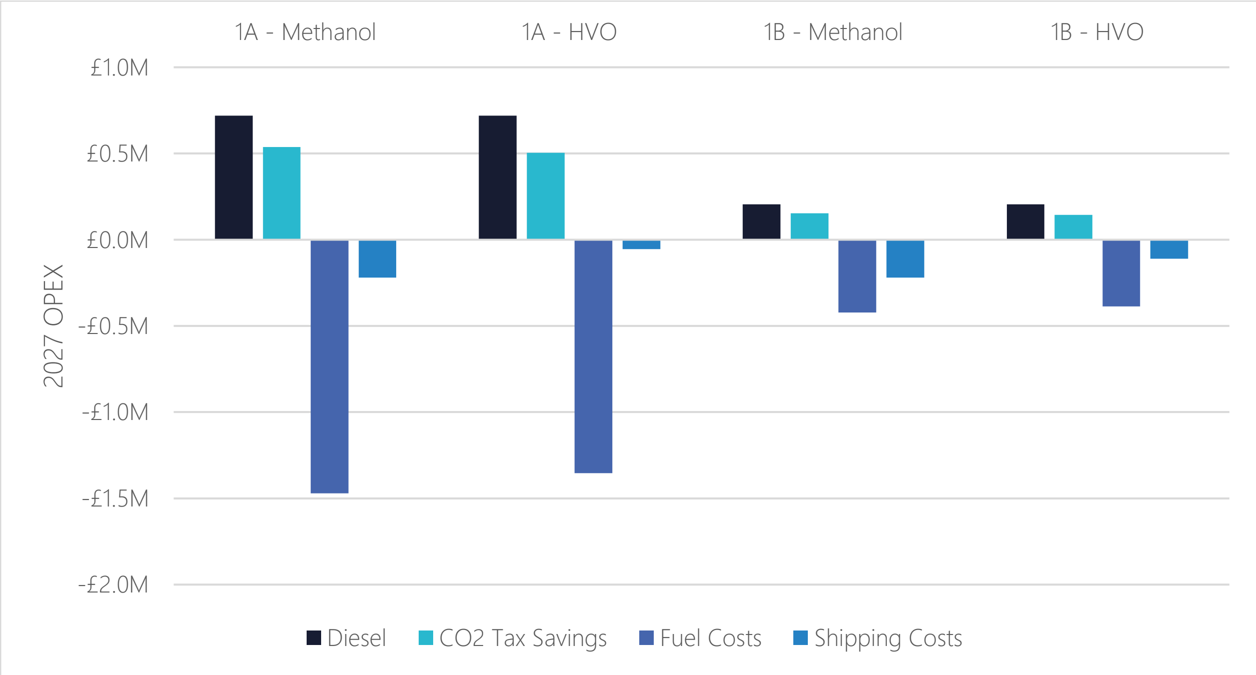

Figure 14-6 - TAR Shutdown Concepts 2027 OPEX

Figure 14-7 summarises the 2027 OPEX for Concept 3A allowing comparison between the two alt-fuel options.

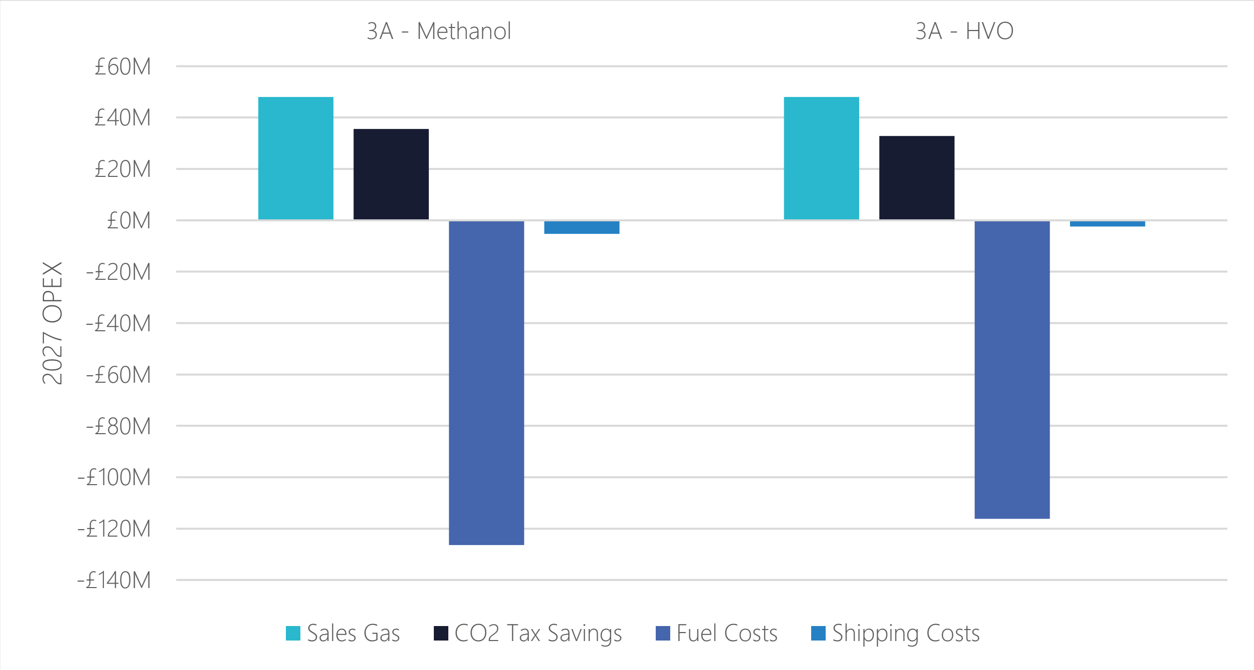

Figure 14-7 - Concept 3A 2027 OPEX Alt-Fuel Comparison

Figure 14-8 summarises the 2027 OPEX for Concepts 3A, 3B & 3C with renewable methanol fuel, allowing comparison between the fuel storage options.

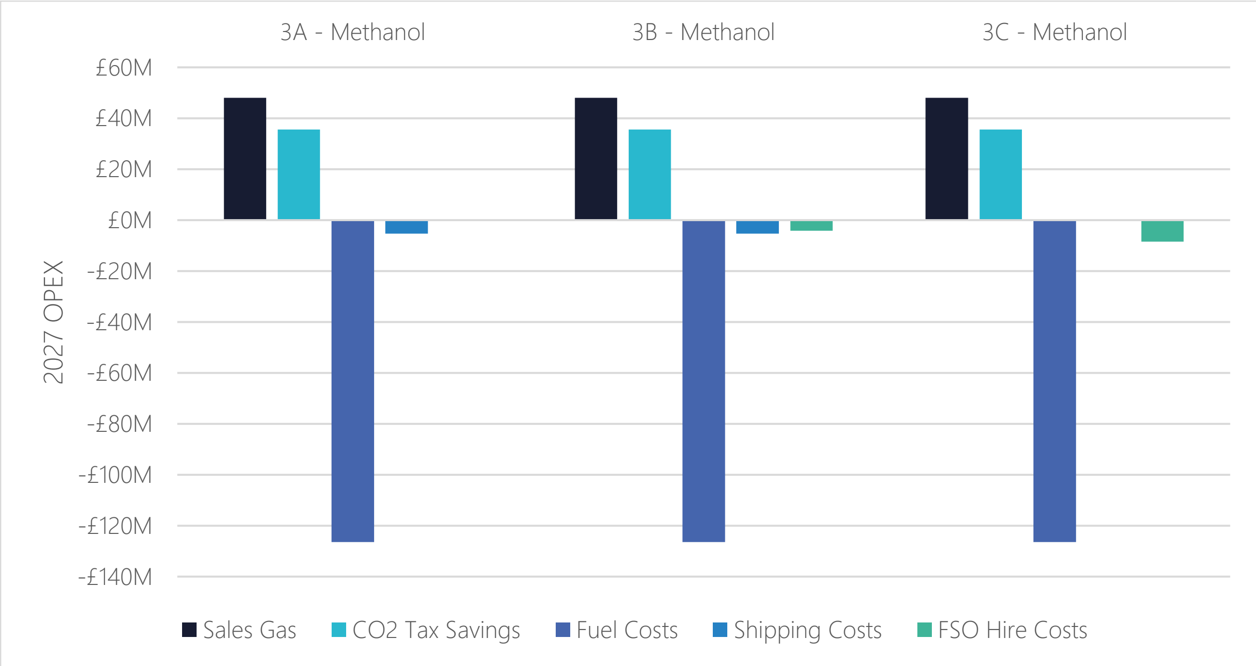

Figure 14-8 - 2027 OPEX Fuel Storage Comparison

14.2 CAPEX

CAPEX summaries for each cost block can be found in Appendix F. The CAPEX estimates are Class 5 as defined by AACE.

ESTIMATE CLASS	MATURITY LEVEL OF DELIVERABLES	END USAGE	METHODOLOGY	EXPECTED ACCURACY RANGE
Class 5	0% to 2%	Conceptual planning – Assess Phase	Capacity factored, parametric models, judgement, or analogy	Low: -20% to -50% High: +30% to +100%
Class 4	1% to 15%	Screening authorisation – Concept Select Phase	Equipment factored or parametric models	Low: -15% to -30% High: +20% to +50%
Class 3	10% to 40%	Funding authorisation – Concept Define Phase	Semi-detailed unit costs with assembly level line items	Low: -20% to -50% High: +10% to +30%
Class 2	30% to 75%	Project control – FEED Phase	Detailed unit cost with forced detailed take-off	Low: -5% to -15% High: +5% to +20%

ESTIMATE CLASS	MATURITY LEVEL OF DELIVERABLES	END USAGE	METHODOLOGY	EXPECTED ACCURACY RANGE
Class 1	65% to 100%	Fixed price bid check – Detailed Design Phase	Detailed unit cost with forced detailed take-off	Low: -3% to -10% High: +3% to +15%

Table 14-12 - Cost Estimate Classification Matrix [Ref. 43]

14.2.1 Topsides Brownfield CAPEX

Concept 2A

A unique CAPEX estimate for the implementation of both HVO and renewable methanol fuels has been developed for Concept 2A, reflecting the topsides brownfield modifications required.

Equipment CAPEX Basis

The following equipment has been included in the cost estimate:

- 1 off. 27.5m^3 stainless steel intermediate fuel storage tank
- 2 off. LP fuel distribution pumps
- 1 off. fuel import strainer package
- 1 off. TUTU
- 1 off. MCS package
- 1 off. Centrifuge package (HVO Fuel only)

The destruct of the following redundant equipment has been included in the cost estimate:

- 3-off Produced Water Re-Injection Pumps

Instruments CAPEX Basis

The following assumptions have been made during the instrument assessment. All assumptions shall require further evaluation in subsequent project phases.

- Existing CMS, PSD and F&G Systems shall require minor modifications to accommodate all new project I/O. Spare I/O capacity to be assessed during future project phases.

- For options 2A, 2B and 3A, a new MCS shall be provided for topsides control of all new subsea equipment. Topsides scope limited to provision of dual redundant Modbus TCP/IP or RTU communication links between the MCS and the ICSS and associated ICSS modifications to integrate data communication with the ICSS.
- New instrument cabling shall utilise existing containment where possible with new intermediate cable tray installed where required.
- Multipair cable runs from the field locations to the P10 LER conservatively estimated at 80m.
- Local field cabling between instrumentation and actuated valves and local junction boxes estimated at 20m.
- Multipair cabling between the P10 LER and the MCC estimated at 40m.
- There is sufficient capacity within existing P10 LER cable transits for all new project cabling.
- New tubing required for ESV pneumatic supplies assumed to be 1/2" 316 Stainless Steel. Allowance has been included for 1/2" Ball Valves in each tubing run.

Electrical CAPEX Basis

The following assumptions have been made during the electrical assessment and these will require further evaluation in subsequent project phases.

- The subsea storage package shall require a single 440V power supply and be rated for < 20kW (primarily for the 2 off 12" MOVs and 2 off 2" MOVs).
- Various spare compartments on the existing 440V normal switchboard ESW 43303. These spares are mainly 1/8 size compartments which would be suitable for motors < 11kW but not for the larger centrifuge motor or the HP fuel distribution skid motors. To supply the larger motors two adjacent compartments shall require to be combined.
- The UPS supply will be derived from an existing 240V AC UPS distribution board. There are several UPS system on the PUQ platform, and the selection of the optimum UPS system will be reviewed in future project phases.
- The Load Management System shall require minimal modifications.
- New cables shall utilise existing ladder racks with new ladder racks local to new TUTU / high-pressure pumps.
- There is capacity in existing switchroom / LER cable transits.

Piping & Valves CAPEX Basis

The following assumptions have been made during the piping assessment and these will require further evaluation in subsequent project phases.

- Piping length estimates have been made for the following runs.

- Riser Hangoff to Fuel Treatment & Storage Package
- Fuel Treatment & Storage Package to 2 off. GT packages
- SW Supply to TUTU
- SW Supply line PSV
- Fuel Package to Open Hazardous Drains

- For pipework between the new equipment this has been covered under an "Equipment" bulks allowance
- PCVs, ESVs and LCVs have been allowed for as per the concept sketch PFD.
- Typical isolations have been allowed for instrumentation and equipment.

Topsides CAPEX Summary Concept 2A

Costs for topside brownfield modifications are summarised below for Concept 2A.

ITEM	RENEWABLE METHANOL OPTION	HVO OPTION
Procurement	£2.39M	£3.22M
Fabrication	£0.08M	£0.10M
Onshore Construct / Build	£0.03M	£0.05M
Offshore Construct / Build	£2.23M	£3.16M
Logistics	£0.94M	£1.16M
Engineering	£3.73M	£5.16M
Owner's Cost	£1.41M	£1.93M
Insurance & Certification	£0.38M	£0.51M
Contingency (30%)	£3.36M	£4.59M
TOTAL	£14.55M	£19.87M

Table 14-13 - Concept 2A Topsides Brownfield Modifications CAPEX Summary

Concept 2B

For the purposes of this study, Concept 2B is assumed to have the same CAPEX basis as per Concept 2B. In practise, the costs for Concept 2B can be expected to be marginally higher due to increased fuel flowrate requirements, pumping duties and methanol fuel line size. These increased costs are expected to be minor compared to the total costs of topsides, subsea and turbine modifications and have therefore been assumed negligible for this economic assessment.

Concept 3A

A unique CAPEX estimate for the implementation of both HVO and renewable methanol fuels has been developed for Concept 3A, reflecting the topsides brownfield modifications required.

Equipment CAPEX Basis

The following equipment has been included in the cost estimate:

- 1 off. 27.5m^3 stainless steel intermediate fuel storage tank
- 2 off. LP fuel distribution pumps
- 2 off. HP fuel distribution pumps (on-skid at MP/Export Compressor GTs)
- 1 off. fuel import strainer package
- 1 off. TUTU
- 1 off. MCS package
- 1 off. Centrifuge package (HVO Fuel only)

The destruct of the following redundant equipment has been included in the cost estimate:

- 3-off Produced Water Re-Injection Pumps

Instruments CAPEX Basis

As per Concept 2A

Electrical CAPEX Basis

As per Concept 2A

Piping & Valves CAPEX Basis

The following assumptions have been made during the piping assessment and these will require further evaluation in subsequent project phases.

- Piping length estimates have been made for the following runs.

- TUTU to Fuel Treatment & Storage Package
- Fuel Treatment & Storage Package to 2 off. GT packages
- SW Supply to TUTU
- SW Supply line PSV
- Fuel Package to Open Hazardous Drains
- Power Gen to 2 off. MP/Export GT packages

- For pipework between the new equipment this has been covered under an “Equipment” bulks allowance
- PCVs, ESVs and LCVs have been allowed for as per the concept sketch PFD.
- Typical isolations have been allowed for instrumentation and equipment.

Topsides CAPEX Summary Concept 3A

Costs for topside brownfield modifications are summarised below for Concept 3A.

ITEM	RENEWABLE METHANOL OPTION	HVO OPTION
Procurement	£2.50M	£3.33M
Fabrication	£0.09M	£0.11M
Onshore Construct / Build	£0.03M	£0.05M
Offshore Construct / Build	£2.34M	£3.27M
Logistics	£0.97M	£1.19M
Engineering	£3.92M	£5.34M
Owner’s Cost	£1.48M	£1.99M
Insurance & Certification	£0.39M	£0.53M
Contingency (30%)	£3.51M	£4.75M
TOTAL	£15.22M	£20.57M

Table 14-14 - Concept 3A Topsides Brownfield Modifications CAPEX Summary

Concept 3B

A unique CAPEX estimate for the implementation of both HVO and renewable methanol fuels has been developed for Concept 3B, reflecting the topsides brownfield modifications required.

Equipment CAPEX Basis

The following equipment has been included in the cost estimate:

- 2 off. HP fuel distribution pumps (on-skid at MP/Export Compressor GTs)
- 1 off. fuel import strainer package
- 1 off. Centrifuge package (HVO Fuel only)

The destruct of the following redundant equipment has been included in the cost estimate:

- 3-off Produced Water Re-Injection Pumps (HVO Fuel Only)

Instruments CAPEX Basis

As per Concept 3A less subsea storage and LP fuel distribution pump associated equipment.

Electrical CAPEX Basis

As per Concept 3A less subsea storage and LP fuel distribution pump associated equipment.

Piping & Valves CAPEX Basis

The following assumptions have been made during the piping assessment and these will require further evaluation in subsequent project phases.

- Piping length estimates have been made for the following runs.
    - Riser Hang-off to Fuel Treatment Package (HVO Fuel only)
    - Fuel Treatment Package to 2 off. GT packages (HVO Fuel only)
    - Riser Hang-off to Solids Filter (Methanol Fuel only)
    - Solids Filter to 2 off. GT packages (Methanol Fuel only)
    - Fuel Treatment Package / Solids Strainers to Open Hazardous Drains
    - Power Gen to 2 off. MP/Export GT packages
- For pipework between the new equipment this has been covered under an "Equipment" bulks allowance

- PCVs, ESVs and LCVs have been allowed for as per the concept sketch PFD.
- Typical isolations have been allowed for instrumentation and equipment.

Topsides CAPEX Summary Concept 3B

Costs for topside brownfield modifications are summarised below for Concept 3B.

ITEM	RENEWABLE METHANOL OPTION	HVO OPTION
Procurement	£0.45M	£1.24M
Fabrication	£0.04M	£0.08M
Onshore Construct / Build	£0.00M	£0.03M
Offshore Construct / Build	£0.53M	£2.16M
Logistics	£0.16M	£0.55M
Engineering	£0.81M	£2.77M
Owner's Cost	£0.30M	£1.02M
Insurance & Certification	£0.08M	£0.27M
Contingency (30%)	£0.72M	£2.44M
TOTAL	£3.10M	£10.55M

Table 14-15 - Concept 3B Topsides Brownfield Modifications CAPEX Summary

Concept 3C

For the purposes of this study, Concept 3C is assumed to have the same CAPEX basis as per Concept 3B. In practise, the costs for Concept 3C can be expected to be marginally higher due to the additional SAL requirement. These increased costs are expected to be minor compared to the total costs of topsides, subsea and turbine modifications and have therefore been assumed negligible for this economic assessment.

14.2.2 Turbine Modification CAPEX

This section summarises the CAPEX required for modifying the Turbine OEM A Models A & B.

Modifications required for all turbines are as described in Section 9.

Main Power Generation Units Vendor Costs

Costs to modify the two Turbine Model A units is as per correspondence with Turbine OEM A. The Turbine OEM A costs are not finalised and are non-binding indicative estimates only, with a high level of uncertainty +/- 30 %. Turbine OEM A vendor costs per turbine Model A reflective of 2023 are summarised below:

ITEM	RENEWABLE METHANOL OPTION	HVO OPTION
Dual Fuel System	N/A	N/A
Fire & Gas	£0.20M	N/A
Controls	£0.15M	£0.15M
Labour	£0.10M	£0.10M
Total (1 x Unit)	£0.45M	£0.25M

Table 14-16 - Main Power Generation Units Upgrade Vendor Costs 2023 (1 x Gas Turbine)

MP / Export Compression GTs Vendor Costs

Costs to modify the two Turbine Model B units is as per correspondence with Turbine OEM A. The Turbine OEM A costs are not finalised and are non-binding indicative estimates only, with a high level of uncertainty +/- 30 %. Turbine OEM A vendor costs per Turbine Model B reflective of 2023 are summarised below:

ITEM	RENEWABLE METHANOL OPTION	HVO OPTION
Dual Fuel System	£1.00M	£0.80M
Fire & Gas	£0.20M	N/A
Controls	£0.15M	£0.15M
Labour	£0.40M	£0.30M
Total (1 x Unit)	£1.75M	£1.25M

Table 14-17 - Main Power Generation Units Upgrade Vendor Costs 2023 (1 x Gas Turbine)

Concept 2A & 2B Turbine Modification CAPEX

Concept 2A & 2B require modifications to the main power generation units only.

The vendor costs have been doubled to account for modifications to two Turbine Model A, adjusted for inflation to reflect 2026 costs and added to the Xodus Brownfield Modification CAPEX estimating tool so that additional allowance can be included for aspects such as engineering costs, insurance and certification, owner's cost, contingency.

Costs are summarised below. These costs are applicable across Concepts 2A & 2B.

ITEM	RENEWABLE METHANOL OPTION	HVO OPTION
Parts & Labour	£1,049k	£593k
Engineering	£811k	£451k
Owner's Cost	£279k	£157k
Insurance & Certification	£74k	£42k
Contingency (30%)	£664k	£373k
TOTAL	£2.88M	£1.61M

Table 14-18 - Concept 2A & 2B Turbine Modification CAPEX

Concept 3A, 3B & 3C Turbine Modification CAPEX

Concept 3A, 3B & 3C require modifications to the main power generation units and the MP / Export Compression GTs.

The vendor costs for both the main power generation units and the MP / Export compression GTs have been doubled to account for modifications to all four Turbine Model As, adjusted for inflation to reflect 2026 costs and added to the Xodus Brownfield Modification CAPEX estimating tool so that additional allowance can be included for aspects such as engineering costs, insurance and certification, owner's cost, contingency.

Costs are summarised below. These costs are applicable across Concepts 3A, 3B & 3C.

ITEM	RENEWABLE METHANOL OPTION	HVO OPTION
Parts & Labour	£5,042k	£3,445k
Engineering	£3,966k	£2,704k
Owner's Cost	£1,351k	£922k
Insurance & Certification	£360k	£246k

ITEM	RENEWABLE METHANOL OPTION	HVO OPTION
Contingency (30%)	£3,215k	£2,195k
TOTAL	£13.94M	£9.51M

Table 14-19 - Concept 3A, 3B & 3C Turbine Modification CAPEX

14.2.3 Subsea CAPEX

NOV Subsea Storage Unit Vendor Costs

NOV have provided cost estimates considering a 2023 cost basis for their subsea storage systems, excluding installation, at the following two volumes:

- 2 off. 1000m^3 Subsea Storage Units = 15.0 MMUSD
- 2 off. 3000m^3 Subsea Storage Units = 24.5 MMUSD

Utilising these two estimates, Xodus have interpolated the CAPEX costs associated with the subsea units making use of the 6/10ths economy of scale factor to adjust for the required storage volume. The following equation was solved via Excel's Goal Seek function to determine a Cost Estimate Factor.

$$24.5\ MMUSD = \frac{6000\ m^3}{2000\ m^3}^{Cost\ Estimate\ Factor\ \times 15.0\ MMUSD}$$

This allowed determination of procurement cost estimates reflecting the variation in Subsea Storage unit volumes. These costs are indicative and subject to change following guidance from NOV in later phases of design. Table 14-20 displays the SSU procurement costs after conversion to GBP.

CONCEPT	FUEL	14 DAY STORAGE VOLUME REQUIREMENTS (m^3)	2023 VENDOR PROCUREMENT COSTS (MMGBP)
2A	Renewable Methanol	2,167	12.44
	HVO	998	11.00
2B	Renewable Methanol	2,976	17.91
	HVO	1,371	12.67
3A	Renewable Methanol	6,616	25.59

CONCEPT	FUEL	14 DAY STORAGE VOLUME REQUIREMENTS (m^3)	2023 VENDOR PROCUREMENT COSTS (MMGBP)
	HVO	3,047	18.10

Table 14-20 - SSU Vendor Costs (2023)

The scope of supply from NOV includes the following:

- SCS Cluster Unit
    - Subsea Storage Unit with 14-day capacity
    - Refilling and offloading module including cluster frame foundation and anchoring
- Control and monitoring system
    - Control system specification and interface work
    - SSU instrumentation
    - SSU wet mates/receptacles/valves
- Umbilical and refilling system
    - Fuel supply and control umbilical
    - Refilling system umbilical
- Topside interface equipment
    - Instrumentation
    - Topside manifold
- Acceptance testing

Concept 2A

In addition to the cost for the subsea storage system, Xodus have estimated an installation cost for this scope of supply of £6.97M (2026). The cost associated with the required R2 extension has been estimated by Xodus to be £0.20M (2026). The SSU costs in the previous section have been inflated to reflect 2026 costs. An additional allowance has also been included for engineering contractor engineering (in addition to NOV) and owner's cost, insurance and certification and contingency.

ITEM	RENEWABLE METHANOL OPTION	HVO OPTION
Parts & Labour (inc. SSU & R2 Extension)	£21.88M	£17.74M
Engineering	£3.31M	£2.68M

ITEM	RENEWABLE METHANOL OPTION	HVO OPTION
Owner's Cost	£3.78M	£3.06M
Insurance & Certification	£1.01M	£0.82M
Contingency (30%)	£9.00M	£7.30M
TOTAL	£39.0M	£31.6M

Table 14-21 - Concept 2A Subsea CAPEX Estimate

Concept 2B

The subsea CAPEX basis for Concept 2B is as per Concept 2A, the only differentiator is the CAPEX requirement for the NOV subsea storage unit due to the increased capacity.

ITEM	RENEWABLE METHANOL OPTION	HVO OPTION
Parts & Labour (inc. SSU & R2 Extension)	£24.05M	£19.26M
Engineering	£3.64M	£2.92M
Owner's Cost	£4.15M	£3.33M
Insurance & Certification	£1.11M	£0.89M
Contingency (30%)	£9.88M	£7.92M
TOTAL	£42.8M	£34.3M

Table 14-22 - Concept 2B Subsea CAPEX Estimate

Concept 3A

The subsea CAPEX basis for Concept 3A is as per Concept 2A, the only differentiator is the CAPEX requirement for the NOV subsea storage unit due to the increased capacity.

ITEM	RENEWABLE METHANOL OPTION	HVO OPTION
Parts & Labour (inc. SSU & R2 Extension)	£31.06M	£24.22

ITEM	RENEWABLE METHANOL OPTION	HVO OPTION
Engineering	£4.70M	£3.67M
Owner's Cost	£5.36M	£4.18M
Insurance & Certification	£1.43M	£1.12M
Contingency (30%)	£12.77M	£9.96M
TOTAL	£55.3M	£43.1M

Table 14-23 - Concept 3A Subsea CAPEX Estimate

Concept 3B

The subsea estimate for Option 2A has been developed by the Xodus Subsea team. The estimate assumes a 1.3km 3" flexible riser and flowline system routed from FSO to Asset A. This includes:

- Flexible pipe and ancillaries;
- hold back anchor and tether;
- hold down anchor and tether;
- buoyancy units; and
- mattresses.

The subsea estimate for this Concept is as follows:

ITEM	RENEWABLE METHANOL & HVO OPTION
Parts & Labour (inc. SSU & R2 Extension)	£7.10M
Engineering	£2.57M
Owner's Cost	£1.45M
Insurance & Certification	£0.39M
Contingency (30%)	£3.45M
TOTAL	£15.0M

Table 14-24 - Concept 3B Subsea CAPEX Estimate

Concept 3C

At this stage of design, Concept 3C subsea CAPEX is assumed to be the same as Concept 3B. It is likely that the cost increase associated with the SAL anchoring system is to be negligible. As such Concept 3C is to be compared on an OPEX basis only against Concept 3B.

14.2.4 CAPEX Summaries

The CAPEX requirements for Concepts 2A, 2B, 3A, 3B & 3C are summarised in Table 14-25. Please note that all figures are representative of 2026 estimates, as discussed in Section 2.2.

CONCEPT	FUEL	TOPSIDES BROWNFIELD CAPEX	TURBINE CAPEX	SUBSEA CAPEX	TOTAL CAPEX
2A	Renewable Methanol	£14.55M	£2.89M	£38.96M	**£56.41M**
	HVO	£19.87M	£1.61M	£31.59M	**£53.07M**
2B	Renewable Methanol	£14.55M	£2.89M	£42.83M	**£60.26M**
	HVO	£19.87M	£1.61M	£34.31M	**£55.80M**
3A	Renewable Methanol	£15.22M	£13.93M	£55.32M	**£84.47M**
	HVO	£20.57M	£9.51M	£43.14M	**£73.23M**
3B & 3C	Renewable Methanol	£3.10M	£13.93M	£14.97M	**£32.01M**
	HVO	£10.55M	£9.51M	£14.97M	**£35.04M**

Table 14-25 - CAPEX Summary

14.3 Commercial Metrics

14.3.1 Basis

This section summarises the CAPEX and OPEX estimates associated with each option and provides P&L or NPV as a commercial metric. Accounting for inflation, OPEX costs in all cases have been increased by 2 % each year from 2027 rates. Methanol has been decreased by 5 %. Note that CAPEX has been included for continuous operation concepts, however, the Finance (No. 2) Act 2023 suggests that assets storing alternative energy fuels may offer an opportunity to be reimbursed for a portion of the CAPEX estimate. The applicability and availability of this funding for Asset A should be investigated further.

Please note the following:

- For the TAR shutdown concepts, the economics are presented as profit / loss values for the single 21-day TAR duration in 2027.
- For continuous operation concepts, NPV estimates have been developed.
- All economics results depicted within this section are representative of the high high sales gas and emissions pricing case. This is because they provide each concept with the greatest chance of profitability.
- Economics sensitivity analysis, within Section 14.3.3, provides insight into the impact of variations in fuel costs, sales gas prices, ETS CO_2 prices, diesel price by making use of tornado charts. Additionally, the economics values for each sales gas and emissions pricing case are presented for Concepts 1B & 3B, to provide an indication of the impact these pricing cases will have upon NPV.
- Economic results shown for renewable methanol and HVO are relative to the do-nothing case of continued usage of either diesel or fuel gas. For reference, the estimated economic results considering the OPEX associated with doing nothing are included.
- A discount rate of 10% has been applied for NPV estimates.

TAR Shutdown Concepts 'Do Nothing' Costs

CONCEPT	FUEL	FUEL	ETS CO_2 TAX	TOTAL 'DO NOTHING' COSTS
1A	Diesel	-£0.72M	-£0.62M	-£1.34M
1B	Diesel	-£0.21M	-£0.18M	-£0.38M

Table 14-26 - TAR Shutdown Concepts Do Nothing Costs – High High Sales Gas and Emissions Pricing Case

Continuous Operation Concepts 'Do Nothing' NPV Results

CONCEPT	FUEL	FUEL	ETS CO_2 TAX	TOTAL 'DO NOTHING' NPV
2A	Fuel Gas	-£153.3M	-£136.3M	-£166.4M
2B	Fuel Gas	-£210.6M	-£187.2m	-£228.5M

CONCEPT	FUEL	FUEL	ETS CO_2 TAX	TOTAL 'DO NOTHING' NPV
3A/B/C	Fuel Gas	-£468.1M	-£416.2M	-£508.0M

Table 14-27 - Continuous Operation Concepts Do Nothing NPV Results – High High Sales Gas and Emissions Pricing Case

14.3.2 Concept Results

The economic results for all concepts are summarised in the following tables.

TAR Shutdown Concepts

CONCEPT 1A		
		2027
Diesel Savings		£718,596
Renewable Methanol	Fuel Cost	-£1,471,579
	CO_2 Savings	£536,905
	Shipping Costs	-£218,796
	FSO Charter Cost	-
	CAPEX	-
	Delta Profit / Loss	-£434,874
HVO	Fuel Cost	-£1,352,880
	CO_2 Savings	£504,735
	Shipping Costs	-£54,699
	FSO Charter Cost	-
	CAPEX	-

CONCEPT 1A	
Delta Profit / Loss	-£184,248

Table 14-28 - Concept 1A Economic Summary

CONCEPT 1B		
		2027
Diesel Savings		£205,651
Renewable Methanol	Fuel Cost	-£421,142
	CO_2 Savings	£153,654
	Shipping Costs	-£218,796
	FSO Charter Cost	-
	CAPEX	-
	Delta Profit / Loss	-£280,634
HVO	Fuel Cost	-£387,173
	CO_2 Savings	£144,447
	Shipping Costs	-£109,398
	FSO Charter Cost	-
	CAPEX	-
	Delta Profit / Loss	-£146,473

Table 14-29 - Concept 1B Economic Summary

Continuous Operation Concepts

CONCEPT 2A											
		2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Sales Gas Revenue		-	£16M	£16M	£16M	£17M	£17M	£17M	£18M	£18M	£18M
Renewable Methanol	Fuel Cost	-	-£41M	-£40M	-£39M	-£38M	-£37M	-£35M	-£34M	-£33M	-£32M
	CO_2 Savings	-	£12M	£12M	£12M	£12M	£13M	£13M	£13M	£13M	£14M
	Shipping Costs	-	-£2M	-£2M	-£2M	-£2M	-£2M	-£2M	-£2M	-£2M	-£2M
	FSO Charter Cost	-	-	-	-	-	-	-	-	-	-
	CAPEX	-£56M	-	-	-	-	-	-	-	-	-
	Delta NPV	-£103M									
HVO	Fuel Cost	-	-£38M	-£39M	-£40M	-£40M	-£41M	-£42M	-£43M	-£44M	-£45M
	CO_2 Savings	-	£11M	£11M	£11M	£11M	£12M	£12M	£12M	£12M	£13M
	Shipping Costs	-	-£1M	-£1M	-£1M	-£1M	-£1M	-£1M	-£1M	-£1M	-£1M
	FSO Charter Cost	-	-	-	-	-	-	-	-	-	-
	CAPEX	-£53M	-	-	-	-	-	-	-	-	-
	Delta NPV	-£118M									

Table 14-30 - Concept 2A Economic Summary

CONCEPT 2B		2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Sales Gas Revenue		-	£22M	£22M	£22M	£23M	£23M	£24M	£24M	£25M	£25M
Renewable Methanol	Fuel Cost	-	-£57M	-£55M	-£53M	-£52M	-£50M	-£49M	-£47M	-£46M	-£44M
	CO_2 Savings	-	£16M	£16M	£17M	£17M	£17M	£18M	£18M	£18M	£19M
	Shipping Costs	-	-£2M	-£2M	-£2M	-£3M	-£3M	-£3M	-£3M	-£3M	-£3M
	FSO Charter Cost	-	-	-	-	-	-	-	-	-	-
	CAPEX	-£60M	-	-	-	-	-	-	-	-	-
	Delta NPV	-£126M									
HVO	Fuel Cost	-	-£52M	-£53M	-£54M	-£55M	-£57M	-£58M	-£59M	-£60M	-£61M
	CO_2 Savings	-	£15M	£15M	£15M	£16M	£16M	£16M	£17M	£17M	£17M
	Shipping Costs	-	-£1M	-£1M	-£1M	-£1M	-£1M	-£1M	-£1M	-£1M	-£1M
	FSO Charter Cost	-	-	-	-	-	-	-	-	-	-
	CAPEX	-£56M	-	-	-	-	-	-	-	-	-
	Delta NPV	-£146M									

Table 14-31 - Concept 2B Economic Summary

CONCEPT 3A		2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Sales Gas Revenue		-	£48M	£49M	£50M	£51M	£52M	£53M	£54M	£55M	£56M
Renewable Methanol	Fuel Cost	-	-£126M	-£123M	-£119M	-£115M	-£111M	-£108M	-£105M	-£101M	-£98M
Renewable Methanol	CO_2 Savings	-	£36M	£36M	£37M	£38M	£39M	£39M	£40M	£41M	£42M
Renewable Methanol	Shipping Costs	-	-£5M	-£5M	-£5M	-£6M	-£6M	-£6M	-£6M	-£6M	-£6M
Renewable Methanol	FSO Charter Cost	-	-	-	-	-	-	-	-	-	-
Renewable Methanol	CAPEX	-£85M	-	-	-	-	-	-	-	-	-
Renewable Methanol	Delta NPV	-£235M									
HVO	Fuel Cost	-	-£116M	-£119M	-£121M	-£123M	-£126M	-£128M	-£131M	-£134M	-£136M
HVO	CO_2 Savings	-	£33M	£33M	£34M	£35M	£36M	£36M	£37M	£38M	£38M
HVO	Shipping Costs	-	-£2M	-£2M	-£3M	-£3M	-£3M	-£3M	-£3M	-£3M	-£3M
HVO	FSO Charter Cost	-	-	-	-	-	-	-	-	-	-
HVO	CAPEX	-£73M	-	-	-	-	-	-	-	-	-
HVO	Delta NPV	-£279M									

Table 14-32 - Concept 3A Economic Summary

CONCEPT 3B		2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Sales Gas Revenue		-	£48M	£49M	£50M	£51M	£52M	£53M	£54M	£55M	£56M
Renewable Methanol	Fuel Cost	-	-£126M	-£123M	-£119M	-£115M	-£111M	-£108M	-£105M	-£101M	-£98M
Renewable Methanol	CO_2 Savings	-	£36M	£36M	£37M	£38M	£39M	£39M	£40M	£41M	£42M
Renewable Methanol	Shipping Costs	-	-£5M	-£5M	-£5M	-£6M	-£6M	-£6M	-£6M	-£6M	-£6M
Renewable Methanol	FSO Charter Cost	-	-£4M	-£4M	-£4M	-£4M	-£5M	-£5M	-£5M	-£5M	-£5M
Renewable Methanol	CAPEX	-£32M	-	-	-	-	-	-	-	-	-
Renewable Methanol	Delta NPV	-£211M									
HVO	Fuel Cost	-	-£116M	-£119M	-£121M	-£123M	-£126M	-£128M	-£131M	-£134M	-£136M
HVO	CO_2 Savings	-	£33M	£33M	£34M	£35M	£36M	£36M	£37M	£38M	£38M
HVO	Shipping Costs	-	-£2M	-£2M	-£3M	-£3M	-£3M	-£3M	-£3M	-£3M	-£3M
HVO	FSO Charter Cost	-	-£4M	-£4M	-£4M	-£4M	-£5M	-£5M	-£5M	-£5M	-£5M
HVO	CAPEX	-£35M	-	-	-	-	-	-	-	-	-
HVO	Delta NPV	-£268M									

Table 14-33 - Concept 3B Economic Summary

CONCEPT 3C											
		2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Sales Gas Revenue		-	£48M	£49M	£50M	£51M	£52M	£53M	£54M	£55M	£56M
Renewable Methanol	Fuel Cost	-	-£126M	-£123M	-£119M	-£115M	-£111M	-£108M	-£105M	-£101M	-£98M
	CO_2 Savings	-	£36M	£36M	£37M	£38M	£39M	£39M	£40M	£41M	£42M
	Shipping Costs	-	-	-	-	-	-	-	-	-	-
	FSO Charter Cost	-	-£9M	-£9M	-£9M	-£9M	-£9M	-£9M	-£9M	-£10M	-£10M
	CAPEX	-£32M	-	-	-	-	-	-	-	-	-
	Delta NPV	-£205M									
HVO	Fuel Cost	-	-£116M	-£119M	-£121M	-£123M	-£126M	-£128M	-£131M	-£134M	-£136M
	CO_2 Savings	-	£33M	£33M	£34M	£35M	£36M	£36M	£37M	£38M	£38M
	Shipping Costs	-	-	-	-	-	-	-	-	-	-
	FSO Charter Cost	-	-£9M	-£9M	-£9M	-£9M	-£9M	-£9M	-£9M	-£10M	-£10M
	CAPEX	-£35M	-	-	-	-	-	-	-	-	-
	Delta NPV	-£278M									

Table 14-34 - Concept 3C Economic Summary

CONCEPT	FUEL	DELTA PROFIT / LOSS (£M)				
	Pricing Case	Extreme	Low	Medium	High	High High
1A	Renewable Methanol	-£0.43M	-£0.82M	-£0.78M	-£0.74M	-£0.43M
	HVO	-£0.18M	-£0.54M	-£0.51M	-£0.47M	-£0.18M
1B	Renewable Methanol	-£0.28M	-£0.39M	-£0.38M	-£0.37M	-£0.28M
	HVO	-£0.15M	-£0.25M	-£0.24M	-£0.23M	-£0.15M

Table 14-35 - TAR Shutdown Concepts Profit / Loss Summary

CONCEPT	FUEL	DELTA NPV (£M)				
	Pricing Case	Extreme	Low	Medium	High	High High
2A	Renewable Methanol	-£174M	-£220M	-£189M	-£140M	-£103M
	HVO	-£188M	-£231M	-£200M	-£152M	-£118M
2B	Renewable Methanol	-£223M	-£287M	-£244M	-£177M	-£126M
	HVO	-£243M	-£302M	-£260M	-£193M	-£146M
3A	Renewable Methanol	-£450M	-£593M	-£498M	-£349M	-£235M
	HVO	-£494M	-£625M	-£531M	-£384M	-£279M
3B	Renewable Methanol	-£426M	-£568M	-£474M	-£325M	-£211M
	HVO	-£483M	-£614M	-£520M	-£373M	-£268M
3C	Renewable Methanol	-£420M	-£563M	-£468M	-£319M	-£205M
	HVO	-£493M	-£624M	-£530M	-£383M	-£277M

Table 14-36 - Continuous Operation Concepts NPV Summary

14.3.3 Economics Sensitivity Analysis

Economic results in the previous section have been presented with the following basis:

- High High sales gas & emissions pricing case
- Gas price of 200 p/therm
- Carbon price of £280/tonne
- Fixed 2027 renewable methanol price of £1076/tonne
- Fixed 2027 HVO price of £2207/tonne
- Fixed 2027 diesel price of £0.94/L

To determine the impact upon the economic estimates when each of these values is varied, tornado charts have been developed to visually quantify the range of profit / loss and NPV values along with the required breakeven points. These breakeven points represent when the profit / loss or NPV is zero and therefore equal to the 'do-nothing' costs. Concepts 1B and 3B have been selected for this analysis.

The methanol price range shown on the charts represent the estimations made by the Methanol Institute discussed within Section 14.1.1.

Concept 1B Economics Sensitivity Analysis

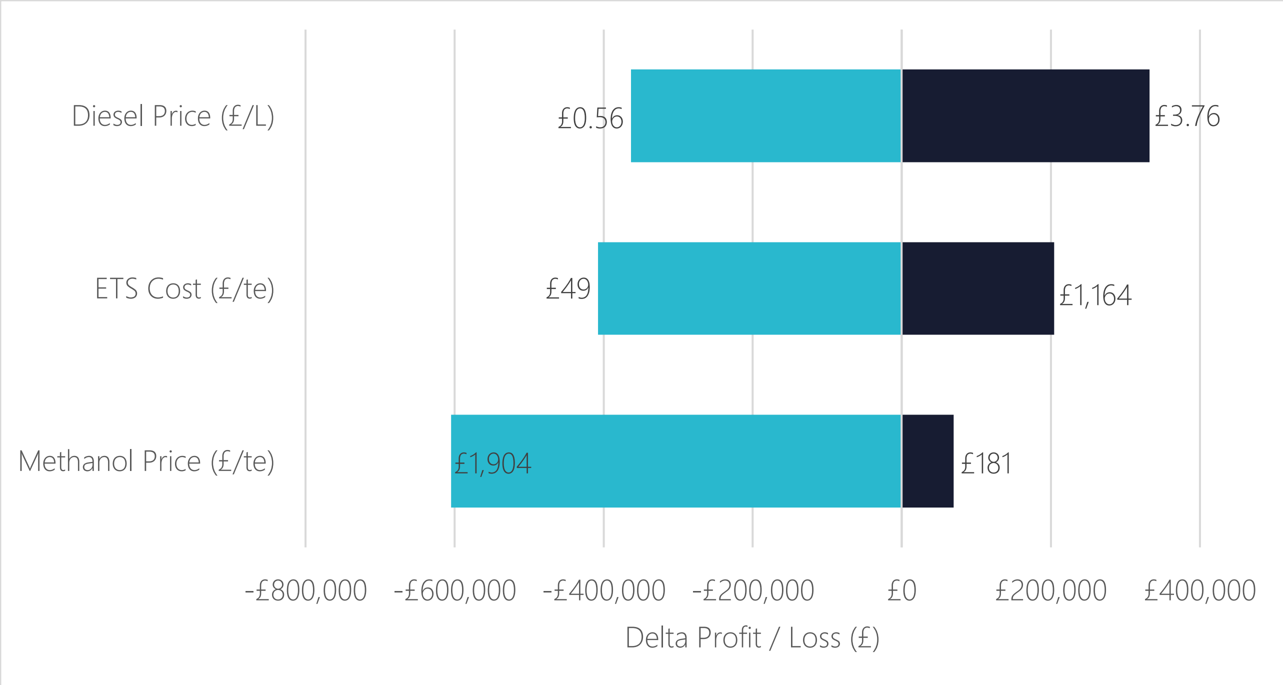

Figure 14-9 - Concept 1B Methanol Tornado Chart

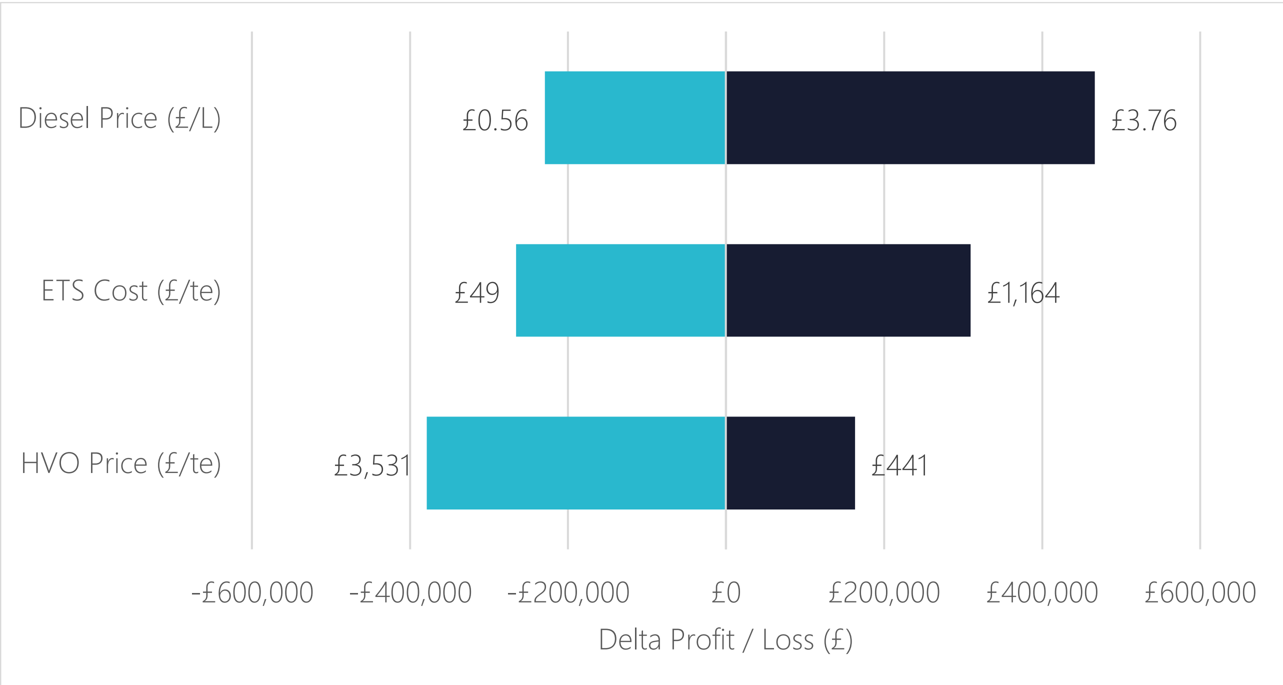

Figure 14-10 - Concept 1B HVO Tornado Chart

The two tornado charts indicate the impact that variations in diesel price, ETS cost and alt-fuel costs have upon NPV. From the charts, the breakeven points of each parameter have been determined. These breakeven points represent when the profit / loss is zero and therefore costs are equal to the 'do-nothing' costs. Please note these charts consider variations singularly by changing one parameter at a time.

CONCEPT 1B BREAKEVEN COSTS	DIESEL PRICE (£/L)	ETS COST (£/TE)	METHANOL PRICE (£/TE)	HVO PRICE (£/TE)
Renewable Methanol	2.23	791	359	-
HVO	1.62	564	-	1,372

Table 14-37 - Concept 1B Breakeven Costs

Concept 1B Sales Gas & Emissions Pricing Case Economics Sensitivity Analysis

To assess the impact the emissions pricing case has upon concept economics, for Concept 1B utilising renewable methanol fuel, the profit / loss results have been calculated for each.

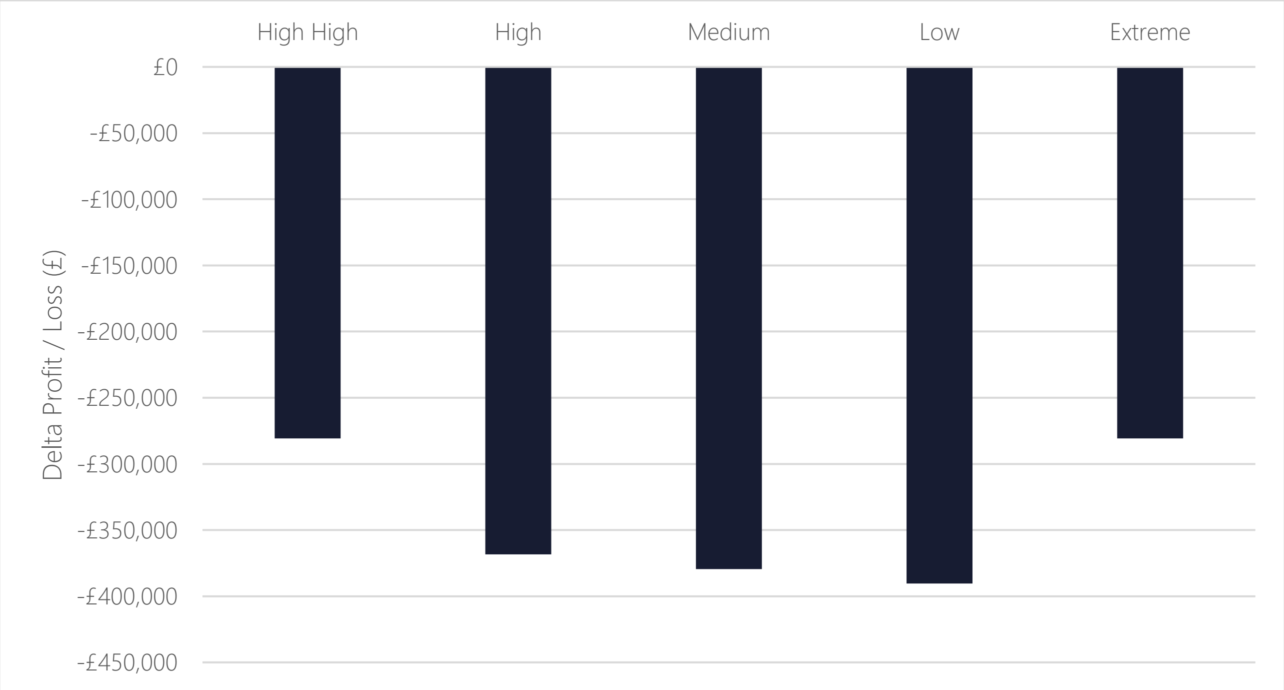

Table 14-38 - Concept 1B Sales Gas & Emissions Pricing Case Economics Sensitivity Analysis

Concept 3B Economics Sensitivity Analysis

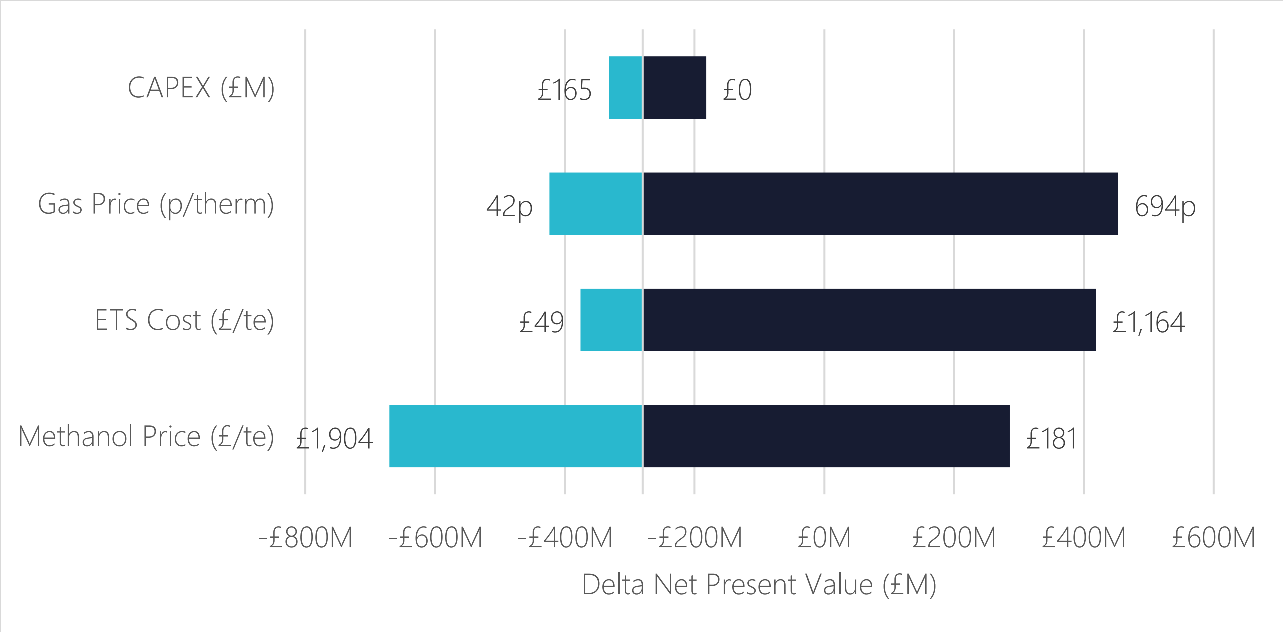

Figure 14-11 - Concept 3B Methanol Tornado Chart

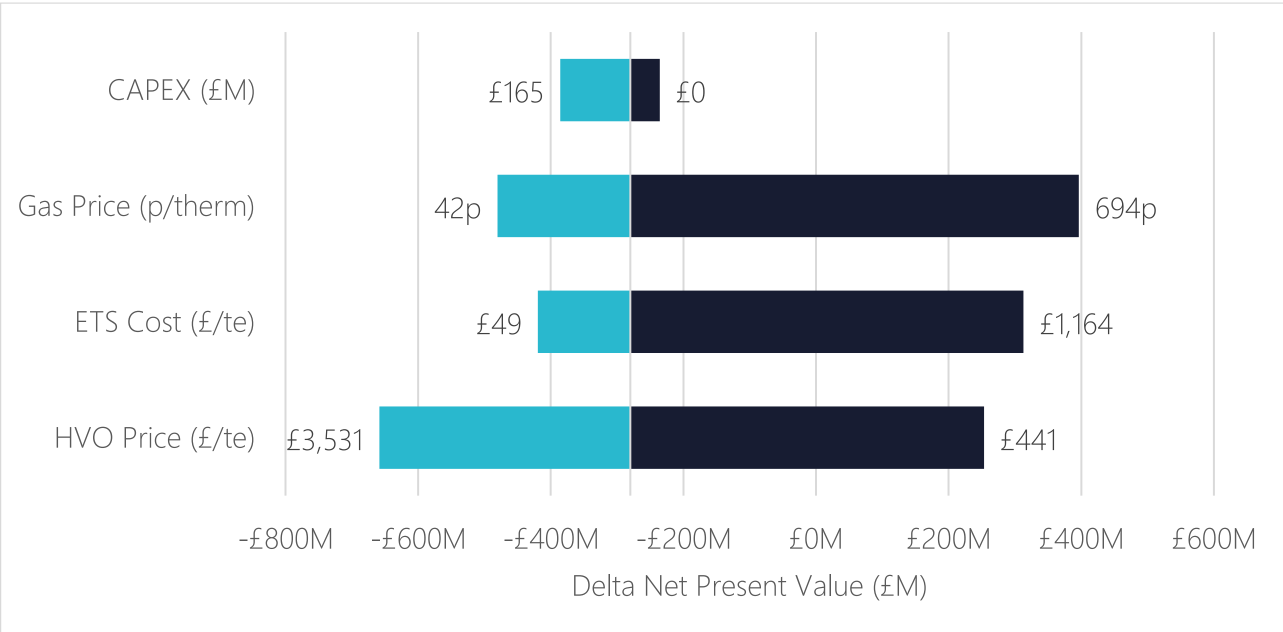

Figure 14-12 - Concept 3B HVO Tornado Chart

The two tornado charts indicate the impact that variations in gas price, ETS cost and alt-fuel costs have upon NPV. From the charts, the breakeven points of each parameter have been determined. These breakeven points represent when the NPV is equal to the 'do-nothing' NPV. Please note these charts consider variations singularly by changing one parameter at a time.

CONCEPT 3B BREAKEVEN COSTS	GAS PRICE (P/THERM)	ETS COST (£/TE)	METHANOL PRICE (£/TE)	HVO PRICE (£/TE)
Renewable Methanol	357	576	696	-
HVO	399	687	-	1,301

Table 14-39 - Concept 3B NPV Breakeven Costs

Concept 3B Sales Gas & Emissions Pricing Case Economics Sensitivity Analysis

To assess the impact the sales gas and emissions pricing case has upon concept economics, for Concept 3B utilising renewable methanol fuel, the NPV results have been calculated for each.

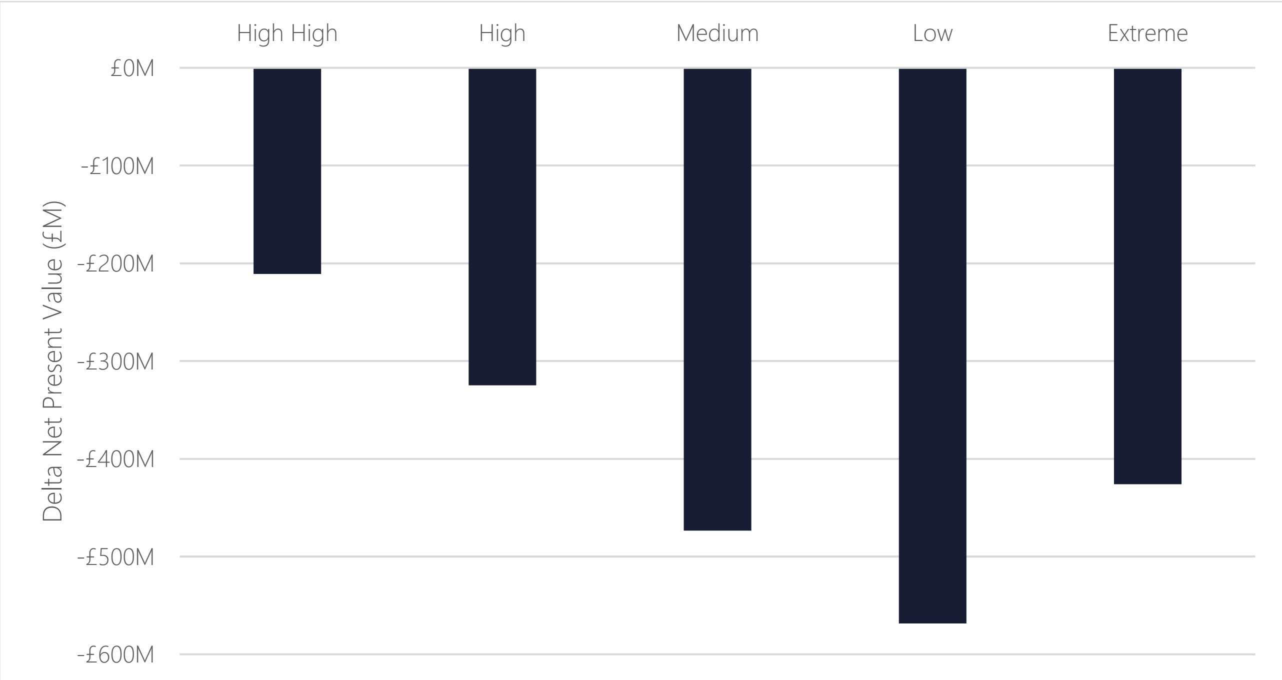

Figure 14-13 - Concept 3B Sales Gas & Emissions Pricing Case Economics Sensitivity Analysis

This demonstrates that the concepts are most promising if the high high pricing case is realised.

14.3.4 Renewable Methanol Fuel Economics Sensitivity Analysis

On the 1st and 16th of November 2023, Xodus, Operator A, Turbine OEM A and Methanol Vendor A had discussions regarding the supply chain and product capabilities of Methanol Vendor, a methanol manufacturer and wholesaler. These meetings highlighted the wide variety of available methanol fuels which are available for purchase. Whilst the price and lifecycle carbon emissions for HVO are relatively fixed when opting for waste cooking oil derived options, renewable methanol prices and lifecycle carbon emissions vary considerably depending on the production, feedstocks and blends.

With renewable methanol fuels, there is a trade-off between the carbon intensities of the chosen fuel and its price. When considering the project economics there is therefore optimisation to be done to select the right renewable methanol fuel which allows for the best balance of CO_2 savings and fuel costs. Within this section, the economics of Concept 1B and Concept 3B have been developed considering a variety of renewable methanol fuel options. These fuel options are as follows.

RENEWABLE METHANOL FUEL OPTION	LIFECYCLE CARBON EMISSIONS (gCO_2/MJ)	PRICE (£/tonne)
Base Case (e-methanol)	10	1076
Recycled Carbon Fuel (RCF)	14	520 – 800
Bio-methanol	40	696 – 957
Manure Derived Methanol	0	1088
Manure Derived Methanol (-ve emissions)	-96	1088

Table 14-40 - Renewable Methanol Fuel Options [Ref. 38]

Recycled carbon fuels are produced from fossil wastes that cannot be avoided, reused, or recycled – such as used tyres. They are therefore considered to be a sustainable option so long as their feedstock is demonstrated to be derived from facilities that have adequate separation processes to remove recyclable material [Ref. 39]. Currently RCFs are not covered by ETS, however, they are still included as a potential option should this change.

Methanol Vendor A can provide a manure derived bio-methanol fuel which has lifecycle carbon emissions of -96 gCO_2/MJ at a price of £1088/tonne. Currently, negative emissions factors are not accounted for within the UK ETS scheme, hence a 0 gCO_2/MJ value would apply. To demonstrate the benefits of the UK ETS adopting the inclusion of negative lifecycle carbon emissions values both have been included within this analysis.

For the purposes of this economic evaluation, for RCF and bio-methanol the prices have been assumed to be at the lower end of the range and representative of 2027 prices. As per the previous economic results, 2% inflation is still applicable, and the 2027 methanol fuel cost has been decreased by 5 % each year accounting for the Methanol Institute forecast of a decreasing fuel cost.

To allow for consideration of the impact of sales gas and emissions pricing cases, sensitivities have been performed at both the high high and the medium price cases.

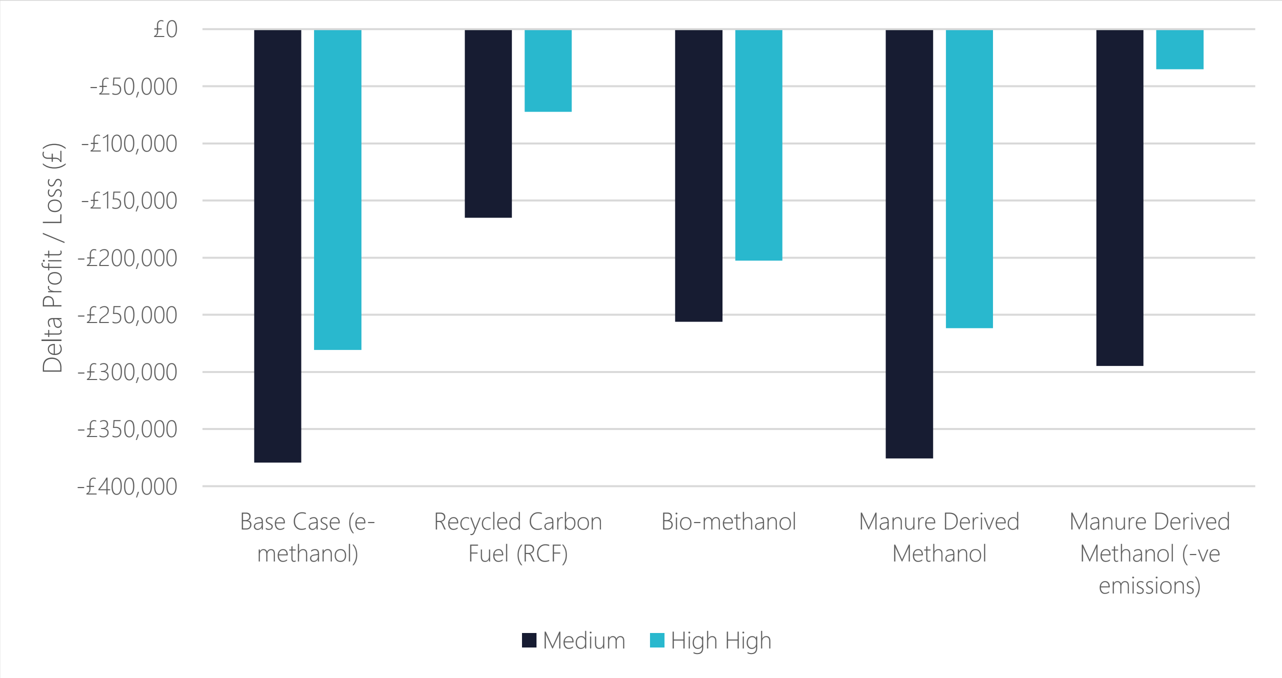

Figure 14-14 - Concept 1B Renewable Methanol Fuel Economics Sensitivity Analysis Profit / Loss Summary

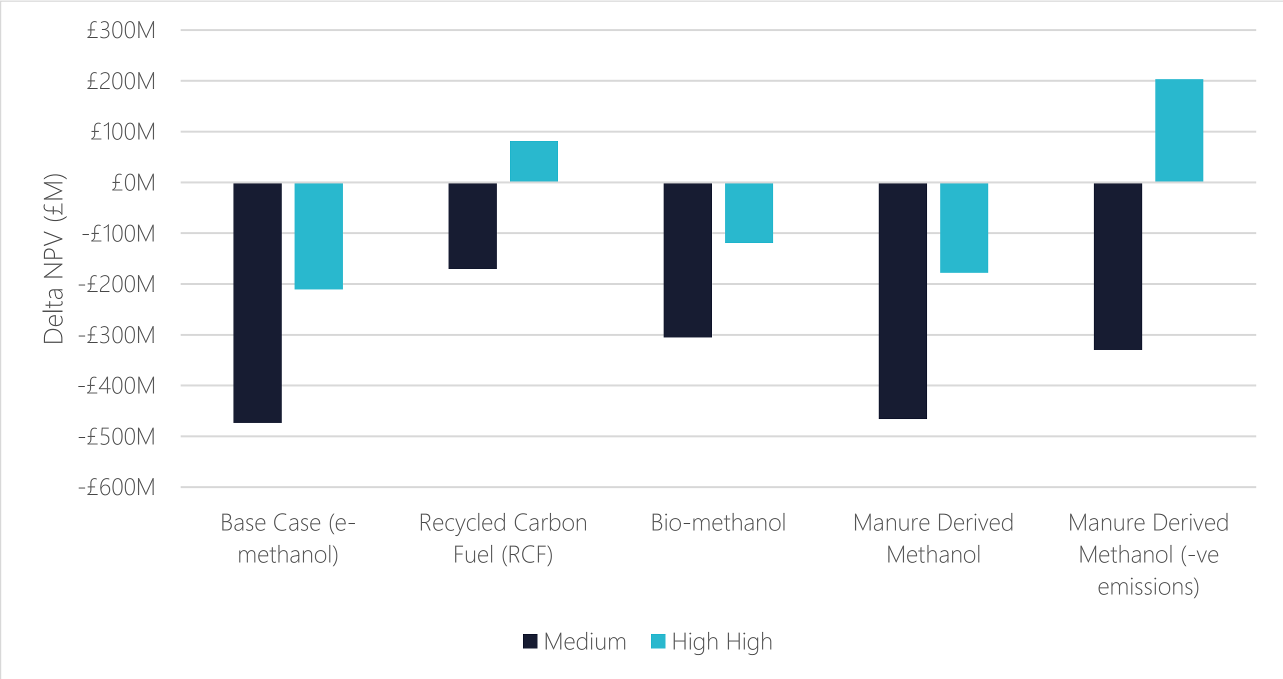

Figure 14-15 - Concept 3B Renewable Methanol Fuel Economics Sensitivity Analysis NPV Summary

14.3.5 Cost per Tonne of CO_2 Abated

The economic results discussed in previous sections have converted to provide a cost per tonne of CO_2 abated. This allows for comparison against alternative emissions reduction technologies which could instead be implemented.

The results are presented in the following two tables. As a comparison, the Methanol Institute estimate current Direct Air Capture (DAC) technologies to be in the order of £240-480/teCO_2 but are expected to decrease substantially to about £40-120/teCO_2 in the future (by 2050) as the technology is improved and scaled up [Ref. 1].

CONCEPT	FUEL	EMISSIONS SAVINGS VS. NORMAL OPERATION (TONNESCO_2/YR)	DELTA PROFIT / LOSS (£)	£ / TONNE CO_2 (NOTE 1)	DELTA PROFIT / LOSS (£)	£ / TONNE CO_2 (NOTE 1)
Pricing Case			Low		High High	
1A	Renewable Methanol	1771	-£818,377	462	-£434,874	245
	HVO	1665	-£544,724	327	-£184,199	111
1B	Renewable Methanol	507	-£390,386	770	-£280,634	554
	HVO	477	-£249,635	524	-£146,459	307

Table 14-41 - TAR Shutdown Concepts CO_2 Removal Costs per Tonne

Note 1: The CO_2 cost is calculated per TAR from: Delta Profit / Loss ÷ CO_2 Emissions Savings

CONCEPT	FUEL	EMISSIONS SAVINGS VS. NORMAL OPERATION ($TONNESCO_2/YR$)	DELTA NPV (£)	£ / TONNE CO_2 (NOTE 2 & 3)	DELTA PROFIT / LOSS (£)	£ / TONNE CO_2 (NOTE 2 & 3)
Pricing Case			Low		High High	
2A	Renewable Methanol	38441	-£220M	637	-£103M	298
	HVO	35454	-£231M	725	-£118M	369
2B	Renewable Methanol	52802	-£287M	604	-£126M	265
	HVO	48699	-£302M	689	-£146M	334
3A	Renewable Methanol	117383	-£593M	561	-£235M	223
	HVO	108262	-£625M	642	-£279M	286
3B	Renewable Methanol	117383	-£568M	538	-£211M	200
	HVO	108262	-£614M	630	-£268M	275
3C	Renewable Methanol	117383	-£563M	532	-£205M	194
	HVO	108262	-£624M	640	-£277M	285

Table 14-42 - Continuous Operation Concepts CO_2 Removal Costs per Tonne

Note 2: The CO_2 cost is calculated for project life from: Delta NPV ÷ (CO_2 emissions savings per year x 9 years operation between 2027 and 2035).

Note 3: CO_2 emissions have not been discounted in the above Note 2 equation.

14.3.6 Post-Tax Economics

To conclude the commercial metrics assessment, a post-tax economic assessment has been performed on the Continuous Operation Concepts.

Basis

Xodus' in-house post-tax NPV model has been utilised for the purposes of this assessment.

As per the previous NPV calculations, the inflation rate has been assumed to be 2% with a 10% discount factor applied. All results shown are for the high-high sales gas and emissions pricing case.

The applicability and availability of any funding related to assets storing alternative energy has been investigated, particularly with reference to the Finance (No. 2) Act 2023 [Ref. 46]. Section 12, which features amendments to The Energy (Oil and Gas) Profits Levy Act 2022, discusses the additional tax-relief available to companies who incur expenditure on the de-carbonisation of upstream petroleum production. Specific reference is made to relief for alternative energy assets which are defined as any asset which generates or stores power (wholly or mainly) from sources of energy other than fossil fuels. As such the tax-relief associated with the initial capital expenditure has been incorporated within the post-tax economic estimates.

Additionally, the Xodus' in-house post-tax NPV model considers the Energy Profits Levy, the temporary additional charge on a company's ring fence profits introduced in 2022.

The tax rates utilised within this assessment are as follows:

Corporate Tax Rate	30%
Supplementary Charge to Tax	10%
Supplementary Charge to Tax Investment Allowance	62.5%
Energy Profits Levy Rate	35%
Energy Profits Levy Investment Allowance	29%
Energy Profits Levy De-Carbonisation Allowance	80%
Energy Profits Levy End Date	March 2028

Table 14-43 - Basis for Post-Tax Assessment

Results

All results shown are for the high-high sales gas and emissions pricing case. For comparison, the costs per tonnes of CO_2 abated are also shown as pre-tax and post-tax figures based on the emissions savings presented earlier in Section 14.3.5. The results are summarised in the table below with the detailed calculations included in Appendix G.

CONCEPT	FUEL	DELTA NPV (£M)		£ / TONNE CO2	
		Pre-Tax	Post-Tax	Pre-Tax	Post-Tax
2A	Renewable Methanol	-£103M	-£22M	298	63
	HVO	-£118M	-£34M	369	108
2B	Renewable Methanol	-£126M	-£32M	265	67
	HVO	-£146M	-£49M	334	111
3A	Renewable Methanol	-£235M	-£75M	223	71
	HVO	-£279M	-£113M	286	116
3B	Renewable Methanol	-£211M	-£92M	200	88
	HVO	-£268M	-£130M	275	133
3C	Renewable Methanol	-£205M	-£89M	194	84
	HVO	-£277M	-£135M	285	139

Table 14-44 - Post-Tax Economic Results (High-High Case)

Additional Concept 2A sensitivities with fuel costs adjusted to give a delta NPV of zero were carried out and are included in

For Concept 2A, High High case, a post-tax delta NPV of zero can be achieved if:

- Renewable methanol can be purchased for a 2027 cost of £850/tonne (21 % reduction compared with the study base case 2027 methanol cost of £1,076/tonne)

  or

- HVO can be purchased for a 2027 cost of £1,570/tonne (29 % reduction compared with the study base case 2027 HVO cost of £2,207/tonne)

Note: the study economics take credit for an approximate 5 % per year reduction in renewable methanol costs. Ignoring inflation, this means a lower methanol cost of £564/tonne in 2035 would be assumed for a 2027 cost of £850/tonne.

The above fuel prices may be viable, but they require the High High UK ETS scheme carbon price to rise to £280/tonne which would be a significant increase in UK-ETS carbon costs. For Concept 2A, Low case (carbon price = £80/tonne and and gas price 40 p/therm), significantly higher fuel price reductions would be required and are not expected to be achievable. A post tax delta NPV of zero can be achieved for the Concept 2A Low case if:

- Renewable methanol can be purchased for a 2027 cost of £200/tonne (81 % reduction compared with the study base case 2027 methanol cost of £1,076/tonne)

  or

- HVO can be purchased for a 2027 cost of £400/tonne (82 % reduction compared with the study base case 2027 HVO cost of £2,207/tonne)

15 ADDITIONAL ECONOMIC & EMISSIONS SENSITIVITIES

The purpose of this section is to detail the impacts of various sensitivities upon the study's economic and emissions assessments. The following areas were investigated in further detail:

1. Study economics assuming a zero emissions factor.
    a. The main study scope assumed small emissions factors would still be applied to alternative fuels but there is potential for zero emissions factors to be applicable for alternative fuels if they meet certain sustainability criteria.
2. The impact of fuel blending
    a. Are the any benefits in blending HVO with diesel.
    b. Methanol blending options e.g., are there any benefits in blending grey methanol at lower cost (but higher emissions) with renewable methanol options.
3. An alternative economics assessment for each of the study options using the NSTA/UK government high series social cost of carbon. This uses a discount rate of 3.5% for carbon savings and 10% for other OPEX (e.g., the 10% discount factor will still apply to gas export revenue, shipping costs, etc.). High series social cost of carbon is defined within the NSTA's Explanatory Note on Valuation of Greenhouse Gas Emissions [Ref. 2].
4. Comparison of the increase in gas exported from Asset A (due to the use of alternative fuels) with the savings from reduced LNG requirements. The impact on study economics is summarised.

15.1 Zero Emissions Factor Assessment

15.1.1 Background

A key assumption so far is that the lifecycle carbon emissions from alternative fuels will be part of the UK ETS scheme. This means that ETS CO_2 savings comprise of the ETS savings from not burning fuel gas / diesel minus the cost of equivalent CO_2 emissions from the alternative fuel. The presented renewable methanol CO_2 savings were based on life cycle emissions 10 gCO_2e/MJ and the HVO savings were based on 13.9 gCO_2e/MJ.

Engagement with Xodus' Environment team highlighted that bioliquids, bio-methanol and HVO, can potentially claim an emission factor of 0 gCO_2e/MJ. From a UK and an EU ETS perspective, the origin of the fuel is of fundamental importance. An emission factor of 0 can be claimed for the fraction of fuel or material that is biomass and fulfils sustainability criteria. Those sustainability criteria being:

1. Land use: focuses on the land from which the biomass is sourced.

2. Greenhouse gas (GHG) emission savings: accounts for the life cycle GHG emissions of the biomass. The calculation should be conducted as per the Renewable Energy Directive Annex V Section C, or default factors utilised.

E-fuels are not currently incorporated within the UK ETS. From a high level review of EU legislation (RED and ETS), "direction of travel" would seem to indicate that legislative modifications will incorporate these fuels. For additional background into Xodus' understanding of the UK ETS with regards to alternative fuels refer to Section 10.2.2.

The key point from the above is that there may be potential to claim a zero-emissions factor for alternative fuels but there may be some caveats to that dependent on the source of the fuel. This work has been carried out to assess the implications of a zero-emissions factor for the selected alternative fuel.

So far, e-methanol was preferred to bio-methanol due to its lower lifecycle emissions of 4-10 gCO_2e/MJ compared to 10-40 gCO_2e/MJ, even though the renewable fuel cost is typically higher for e-methanol fuels. If an emissions factor of zero can be claimed, it would be beneficial to choose a lower cost bio-methanol fuel; however, consideration should be made to lifecycle GHG emissions of the biomass to ensure it fulfils the sustainability criteria. The cost ranges for e-methanol and bio-methanol fuels are displayed in Table 15-1.

COST BASIS	DESCRIPTION	COST (£/TONNE)
e-methanol	The Xodus eFuel production model forecasted 2027 e-methanol cost	1,076
Current bio-methanol	Bio-methanol current costs provided by the Methanol Institute [Ref. 1]	261 - 810
2030 – 2050 bio-methanol	Bio-methanol predicted costs for matured processes provided by the Methanol Institute [Ref. 1]	181 - 675
Methanol Vendor A bio-methanol	Vendor quoted cost for bio-methanol (2023)	696 - 957

Table 15-1 - Renewable Methanol Fuel Costs

A bio-methanol cost of £696/te has been selected for the purposes of the revised economic calculations. The previously predicted HVO cost of £2,207/te will continue to be applicable for the purposes of this assessment.

This zero-emissions factor assessment will revisit the required breakeven costs for the bio-methanol and HVO fuels assuming an emission factor of 0 gCO_2e/MJ. Whilst an emissions factor of 0 gCO_2e/MJ can be applied when considering CO_2 tax savings under UK ETS, when calculating the costs per tonne of CO_2 abated the actual emissions relating to the fuel's combustion should be considered. For the representative bio-methanol selected an emissions factor of 25 gCO_2e/MJ has been used, this represents the middle of the range provided by the Methanol Institute [Ref. 26].

15.1.2 Results

For each of the concepts, the bio-methanol and HVO fuel costs breakeven points have been determined. These breakeven points represent when the profit / loss (or NPV) is zero and therefore costs are equal to the 'do-nothing' costs. For completeness, these breakeven fuel costs have been found for both pre- and post-tax economics for the High High sales gas and emissions pricing case.

CONCEPT	FUEL	EMISSIONS SAVINGS VS. NORMAL OPERATION (TONNESCO_2/YR)	REQUIRED 2027 FUEL BREAKEVEN COSTS (£/TONNE)
			Pre-Tax
1A	Bio-methanol	1,363	818
	HVO	1,665	2,094
1B	Bio-methanol	390	419
	HVO	477	1,559

Table 15-2 - TAR Shutdown Concepts Required 2027 Fuel Breakeven Costs with Zero Emissions Factor (High High Case)

CONCEPT	FUEL	EMISSIONS SAVINGS VS. NORMAL OPERATION (TONNESCO_2/YR)	REQUIRED 2027 FUEL BREAKEVEN COSTS (£/TONNE)	
			Pre-Tax	Post-Tax
2A	Bio-methanol	26,953	580	930
	HVO	35,454	1,176	1,761
2B	Bio-methanol	37,022	643	919
	HVO	48,699	1,293	1,741
3A	Bio-methanol	82,303	724	905
	HVO	108,262	1,450	1,714
3B	Bio-methanol	82,303	768	847
	HVO	108,262	1,488	1,614

CONCEPT	FUEL	EMISSIONS SAVINGS VS. NORMAL OPERATION (TONNESCO$_2$/YR)	REQUIRED 2027 FUEL BREAKEVEN COSTS (£/TONNE)	
3C	Bio-methanol	82,303	778	858
	HVO	108,262	1,454	1,581

Table 15-3 - Continuous Operation Concepts Required 2027 Fuel Breakeven Costs with Zero Emissions Factor (High High Case)

The results shared within Table 15-3 indicate that for a high high pricing case it is feasible that through application of zero emissions and selection of a low-cost bio-methanol positive project post-tax NPV can be reached. For HVO, even for Concept 2A (which has the highest post-tax breakeven fuel costs) a fuel cost reduction of 20 % compared with the study base case HVO cost of would be required to breakeven.

The delta NPV results for each concept are displayed within Table 15-4, for the high-high sales gas and emissions pricing case. For comparison, the costs per tonnes of CO_2 abated are also shown as pre-tax and post-tax figures.

CONCEPT	FUEL	DELTA NPV (£M)		£ / TONNE CO_2	
		Pre-Tax	Post-Tax	Pre-Tax	Post-Tax
2A	Renewable Methanol	-£21M	£23M	87	-97
	HVO	-£100M	-£24M	312	76
2B	Renewable Methanol	-£13M	£31M	40	-92
	HVO	-£121M	-£35M	277	79
3A	Renewable Methanol	£15M	£64M	-21	-86
	HVO	-£224M	-£82M	229	84
3B	Renewable Methanol	£40M	£46M	-54	-62
	HVO	-£212M	-£98M	218	101
3C	Renewable Methanol	£46M	£49M	-62	-67

CONCEPT	FUEL	DELTA NPV (£M)		£ / TONNE CO_2	
	HVO	-£222M	-£104M	228	107

Table 15-4 - Continuous Operation Concepts Post Zero Emissions Factor Assessment Economic Results (High-High Case, Renewable Methanol at £696/tonne and HVO at £2,207/tonne)

Although a positive post-tax NPV is feasible when applying the high high sales gas and emissions pricing case, this is not true of all pricing cases. Through selection of a reasonable bio-methanol cost, £696/tonne as quoted by a methanol vendor, the post-tax NPV results have been quantified for each pricing case for Concept 2A.

SALES GAS & EMISSIONS PRICING CASE	CONCEPT 2A DELTA NPV (£M)		£ / TONNE CO_2	
	Pre-Tax	Post-Tax	Pre-Tax	Post-Tax
High High	-£21M	£23M	87	-97
High	-£66M	-£2M	271	7
Medium	-£115M	-£30M	476	122
Low	-£147M	-£48M	608	196
Extreme	-£92M	-£16M	377	67

Table 15-5 - Concept 2A Bio-Methanol Costs with Zero Emissions Factor (High High Pricing Case)

Note 1: The CO_2 cost is calculated for project life from: Delta NPV ÷ (CO_2 emissions savings per year x 9 years operation between 2027 and 2035).

Note 2: CO_2 emissions have not been discounted in the above Note 1 equation.

15.1.3 Conclusions

Application of a zero emissions factor allows for cost savings due to not having to pay any CO_2 tax relating to the use of alternative fuels.

For renewable methanol, the ability to choose a bio-methanol rather than an e-methanol reduces the price of the fuel from £1,076/te to £696/te. This significantly improves the economics of renewable methanol implementation and even results in a positive post-tax delta NPV for Concept 2A for the High High pricing case.

Further work will be required to ensure that any biofuel fulfils the sustainability criteria relating to land use and GHG emissions savings, or else application of a 0 gCO_2e/MJ may not be accepted under UK ETS.

For the High High pricing case Concept 2A allows the highest alternative fuel breakeven cost:

- 2027 breakeven cost for renewable methanol is £930/te versus an estimated cost of £696/te for bio-methanol or £1,076 for e-methanol.
- 2027 breakeven cost for HVO is £1,761/te versus an estimated cost of £2207/te.

The above bullets suggest that bio-methanol with a zero emissions factor may allow a positive NPV if the High High pricing case is realised. Cost impacts for Concept 2A are visualised in the updated table below and this predicts that all other pricing cases except the High High case will not return a positive delta NPV as required breakeven bio-methanol costs are all less than £696/te (the High case is marginal with a breakeven cost of £679/te but as the economics assume a 5 % real terms decrease in methanol costs each year then caution should be applied to accepting the economics on such a marginal basis). HVO and e-methanol are not expected to be economical. The updated key parameters in the table are shown below in bold:

- Pricing case applies to sales gas and emissions pricing
- **Bio-Methanol** properties:
  - **£696/te** (2027)
  - UK ETS Emissions Factor: **0 gCO_2e/MJ**
  - Actual Emissions Factor: **25 gCO_2e/MJ**
- HVO properties:
  - £2,207 (2027)
  - UK ETS Emissions Factor: **0 gCO_2e/MJ**
  - Actual Emissions Factor: 13.9 gCO_2e/MJ
- A discount rate of 10% has been applied for NPV estimates

FUEL CHOICE	SCENARIO	PRICING CASE	MAIN STUDY RESULTS				ZERO EMISSIONS FACTOR ASSESSMENT			
			Pre-Tax Assessment		Post-Tax Assessment		Pre-Tax Assessment		Post-Tax Assessment	
			Delta NPV	Alt-Fuel Price (£/te)	Delta NPV	Alt-Fuel Price (£/te)	Delta NPV	Alt-Fuel Price (£/te)	Delta NPV	Alt-Fuel Price (£/te)
Renewable Methanol	Selected Renewable Methanol Price	High High	**-£104M**	1,076	**-£22M**	1,076	**-£21M**	696	**£23M**	696
		High	**-£140M**	1,076	**-£43M**	1,076	**-£66M**	696	**-£2M**	696
		Medium	**-£189M**	1,076	**-£70M**	1,076	**-£115M**	696	**-£30M**	696
		Low	**-£220M**	1,076	**-£88M**	1,076	**-£147M**	696	**-£48M**	696
		Extreme	**-£174M**	1,076	**-£62M**	1,076	**-£92M**	696	**-£16M**	696
	Required Renewable Methanol Breakeven Price	High High	0	509	0	857	0	580	0	930
		High	0	303	0	648	0	334	0	679
		Medium	0	35	0	374	0	61	0	400
		Low	0	-136	0	199	0	-115	0	220
		Extreme	0	121	0	461	0	193	0	534
			NPV	Fuel Price (p/therm)	NPV	Fuel Price (p/therm)	NPV	Fuel Price (p/therm)	NPV	Fuel Price (p/therm)
Fuel Gas	Continued Fuel Gas Usage	High High	-£166M	200	-£94M	200	-£166M	200	-£94M	200
		High	-£122M	200	-£68M	200	-£122M	200	-£68M	200
		Medium	-£72M	100	-£41M	100	-£72M	100	-£41M	100
		Low	-£40M	40	-£22M	40	-£40M	40	-£22M	40
		Extreme	-£96M	40	-£54M	40	-£96M	40	-£54M	40
			Delta NPV	Alt-Fuel Price (£/te)	Delta NPV	Alt-Fuel Price (£/te)	Delta NPV	Alt-Fuel Price (£/te)	Delta NPV	Alt-Fuel Price (£/te)
HVO	Selected HVO Price	High High	**-£118M**	2,207	**-£34M**	2,207	**-£100M**	2,207	**-£24M**	2,207
		High	**-£152M**	2,207	**-£54M**	2,207	**-£144M**	2,207	**-£49M**	2,207
		Medium	**-£200M**	2,207	**-£81M**	2,207	**-£194M**	2,207	**-£77M**	2,207
		Low	**-£231M**	2,207	**-£98M**	2,207	**-£226M**	2,207	**-£95M**	2,207
		Extreme	**-£188M**	2,207	**-£74M**	2,207	**-£170M**	2,207	**-£64M**	2,207
	Required HVO Breakeven Price	High High	0	989	0	1,574	0	1,176	0	1,761
		High	0	633	0	1,218	0	713	0	1,298
		Medium	0	133	0	718	0	200	0	785
		Low	0	-185	0	400	0	-131	0	454
		Extreme	0	260	0	845	0	447	0	1032

Table 15-6 - Updated Study Economics for Concept 2A

15.2 Fuel Blending Assessment

15.2.1 Background

The economic and emissions impacts of fuel blending are to be assessed within this section considering the following blends:

1. HVO blended with conventional diesel.
2. Renewable methanol options with grey (fossil) methanol.

15.2.2 HVO/Diesel Fuel Blending

Basis

The fuel blending assessment is to consider HVO/diesel blending at the following volumetric concentrations:

- 100% HVO / 0% diesel
- 75% HVO / 25% diesel
- 50% HVO / 50% diesel
- 25% HVO / 75% diesel
- 0% HVO / 100% diesel

The assessment is to focus upon the high high sales gas and emissions pricing case for Concept 1B and Concept 2A. As Concept 1B relates to a 'do-nothing' scenario of continued diesel usage, the assessment will be performed for Concept 1B to assess if there is any benefit from the addition of HVO into the diesel fuel. Concept 2A has been considered to represent the impacts of fuel blending on Continuous Operation Concepts.

FUEL BLEND	EF (gCO_2/MJ)	COST (£/TONNE)	DENSITY (KG/M^3)	LHV (MJ/KG)
100% HVO	0 (13.9 for abatement cost calcs)	2,207	780.0	44.40
75% HVO / 25% Diesel	18.8 (29.2 for abatement cost calcs)	1,940	792.5	44.06
50% HVO / 50% Diesel	37.6 (44.5 for abatement cost calcs)	1,673	805.0	43.73
25% HVO / 75% Diesel	56.3 (59.8 for abatement cost calcs)	1,405	817.5	43.41

100% Diesel	75.1	1,138	830.0	43.10

Table 15-7 - HVO/Diesel Fuel Blend Properties

Results - Concept 1B

The results of the HVO/diesel fuel blending assessment, applied to Concept 1B, are captured within Table 15-8. For simplicity, the comparison is shown assuming no additional PSV supply trips for any of the cases, ignoring the slight differences in HVO vs diesel density where 100 % HVO fuel requires approximately 4 % more fuel volume than 100 % diesel.

FUEL BLEND	EMISSIONS SAVINGS VS. NORMAL OPERATION (TONNESCO_2/TAR)		CONCEPT 1B PRE TAX DELTA PROFIT / LOSS VS NORMAL OPERATION (£)
100% HVO	477	81%	-£4.2k
75% HVO / 25% Diesel	357	61%	-£4.3k
50% HVO / 50% Diesel	238	41%	-£3.6k
25% HVO / 75% Diesel	119	20%	-£2.2k
100% Diesel	0	0%	£0

Table 15-8 - HVO/Diesel Fuel Blending Results Concept 1B (High High Pricing Case)

Note: Credit has been taken for HVO having a zero emissions factor in the delta profit / loss column. The £4.2 k loss may seem small for 100 % HVO but this becomes > £100 k loss for the High pricing case.

Results - Concept 2A

The results of the HVO/diesel fuel blending assessment, applied to Concept 2A, are captured within this Section.

FUEL BLEND	EMISSIONS SAVINGS VS. NORMAL OPERATION (TONNESCO_2/YR)	CONCEPT 2A DELTA NPV (£M)		£ / TONNE CO_2	
		Pre-Tax	Post-Tax	Pre-Tax	Post-Tax
100% HVO	35,454	-£100M	-£24M	312	76
75% HVO / 25% Diesel	23,736	-£100M	-£24M	467	113

FUEL BLEND	EMISSIONS SAVINGS VS. NORMAL OPERATION (TONNESCO$_2$/YR)	CONCEPT 2A DELTA NPV (£M)		£ / TONNE CO$_2$	
50% HVO / 50% Diesel	12,018	-£99M	-£24M	918	222
25% HVO / 75% Diesel	301	-£98M	-£24M	36,390	8,706
100% Diesel	-11,417	-£97M	-£23M	-	-

Table 15-9 - HVO/Diesel Fuel Blending Results Concept 2A (High High Pricing Case)

As shown within Table 15-9, reducing the fraction of HVO within the fuel blend has a negative impact upon the emissions saved, as is to be expected. Usage of 100% diesel fuel will be worse than continuing the 'do-nothing' case as diesel has a higher emissions factor (75.1 gCO_2e/MJ) than the platform fuel gas (60.2 gCO_2e/MJ). The intention of the Alternative Fuel Study is to look at the feasibility of conversion of a fixed offshore oil and gas asset to a low carbon alternative fuel; therefore, selection of a fuel which would increase emissions can be rejected.

The cost savings are minimal when increasing the fraction of diesel in the fuel, a reduction of less than 6% for the post-tax delta NPV.

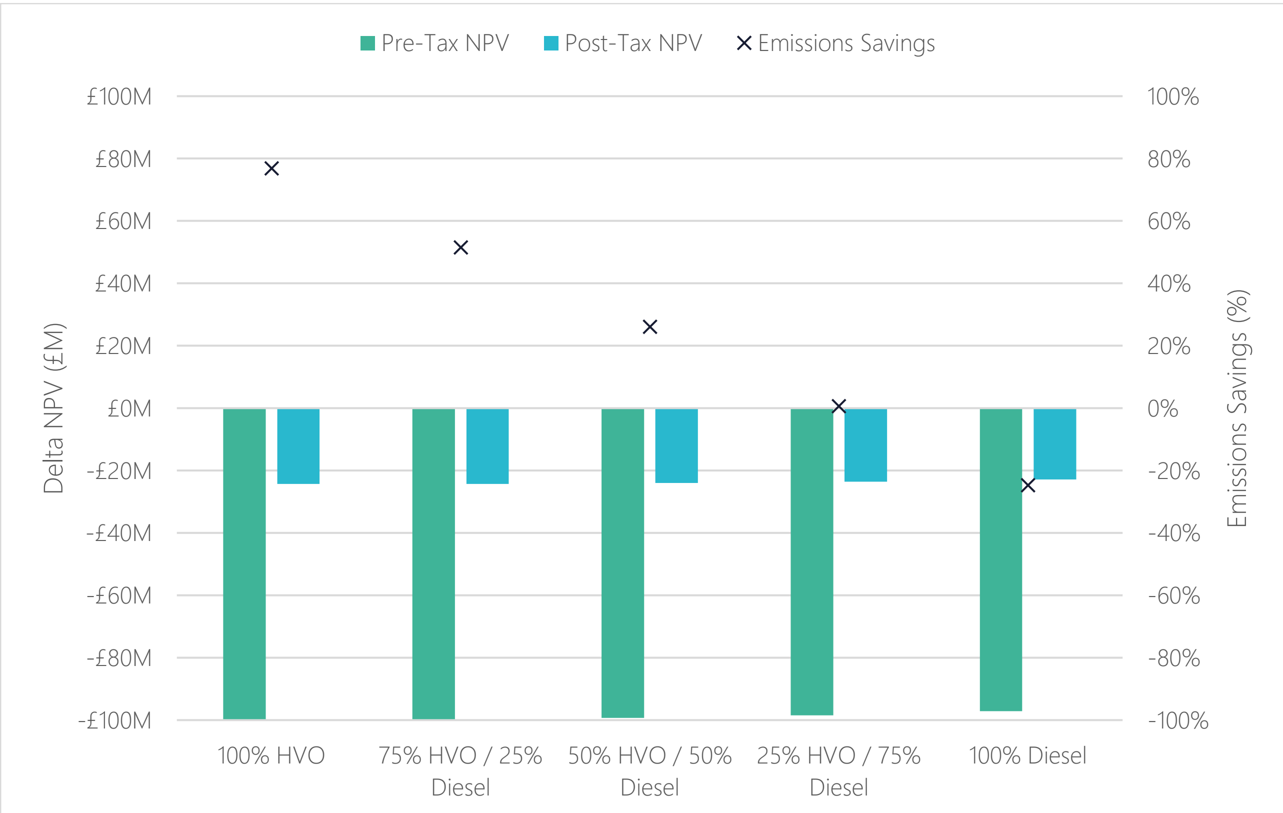

Figure 15-1 - HVO/Diesel Fuel Blending Results Concept 2A (High High Pricing Case)

Figure 15-1 visualises the negatives of increasing the share of diesel in the fuel blend. Minimal cost benefits are far outweighed by the reduced emissions savings.

15.2.3 Renewable/Grey Methanol Blending

Basis

As discussed in Section 15.1, a bio-methanol is the most attractive renewable methanol option due to its low cost and the ability to assign an emissions factor of 0 gCO_2e/MJ under the ETS.

The physical properties of bio-methanol and grey methanol are identical with only the production process differing between the two fuel options. The fuel blending assessment is to consider bio-/grey methanol blending at the following concentrations:

- 100% Bio-methanol / 0% Grey methanol
- 75% Bio-methanol / 25% Grey methanol
- 50% Bio-methanol / 50% Grey methanol
- 25% Bio-methanol / 75% Grey methanol
- 0% Bio-methanol / 100% Grey methanol

FUEL BLEND	EF (gCO_2/TONNE)	COST (£/TONNE)	DENSITY (KG/M^3)	LHV (MJ/KG)
100% Bio	0 (25 for abatement cost calcs)	696	801.5	19.9
75% Bio / 25% Grey	27.5 (46.3 for abatement cost calcs)	582	801.5	19.9
50% Bio / 50% Grey	55.0 (67.5 for abatement cost calcs)	469	801.5	19.9
25% Bio / 75% Grey	82.5 (88.8 for abatement cost calcs)	355	801.5	19.9
100% Grey	110 [Ref. 26]	241	801.5	19.9

Table 15-10 - Bio-/Grey Methanol Fuel Blend Properties

Note: Methanol price from Ref. 1. This is a mid-range 2021 value with the Ref. 1 range being £160 to £320.

Results

The results of the bio-/grey methanol fuel blending assessment, applied to Concept 2A, are captured within this Section.

FUEL BLEND	EMISSIONS SAVINGS VS. NORMAL OPERATION (TONNESCO_2/YR)	CONCEPT 2A DELTA NPV (£M)		£ / TONNE CO_2	
		Pre-Tax	Post-Tax	Pre-Tax	Post-Tax
100% Bio	26,953	-£21M	£23M	87	-97
75% Bio / 25% Grey	10,678	-£36M	£15M	376	-153
50% Bio / 50% Grey	-5,597	-£51M	£6M	-	-
25% Bio / 75% Grey	-21,872	-£66M	-£3M	-	-
100% Grey	-38,146	-£81M	-£11M	-	-

Table 15-11 - Bio-/Grey Methanol Fuel Blending Results Concept 2A (High High Pricing Case)

As shown within Table 15-11, reducing the fraction of bio-methanol within the fuel blend has a negative impact upon the emissions saved, as is to be expected. Usage of more than 50% grey methanol within the fuel blend will be worse than continuing the 'do-nothing' case as grey methanol has a higher emissions factor (110 gCO_2e/MJ) than the platform fuel gas (60.2 gCO_2e/MJ). The intention of the Alternative Fuel Study is to look at the feasibility of conversion of a fixed offshore oil and gas asset to a low carbon alternative fuel; therefore, selection of a fuel which would increase emissions can be rejected instantly.

In addition, any cost savings relating to the lower price of grey methanol are negated by the increased CO_2 tax payments.

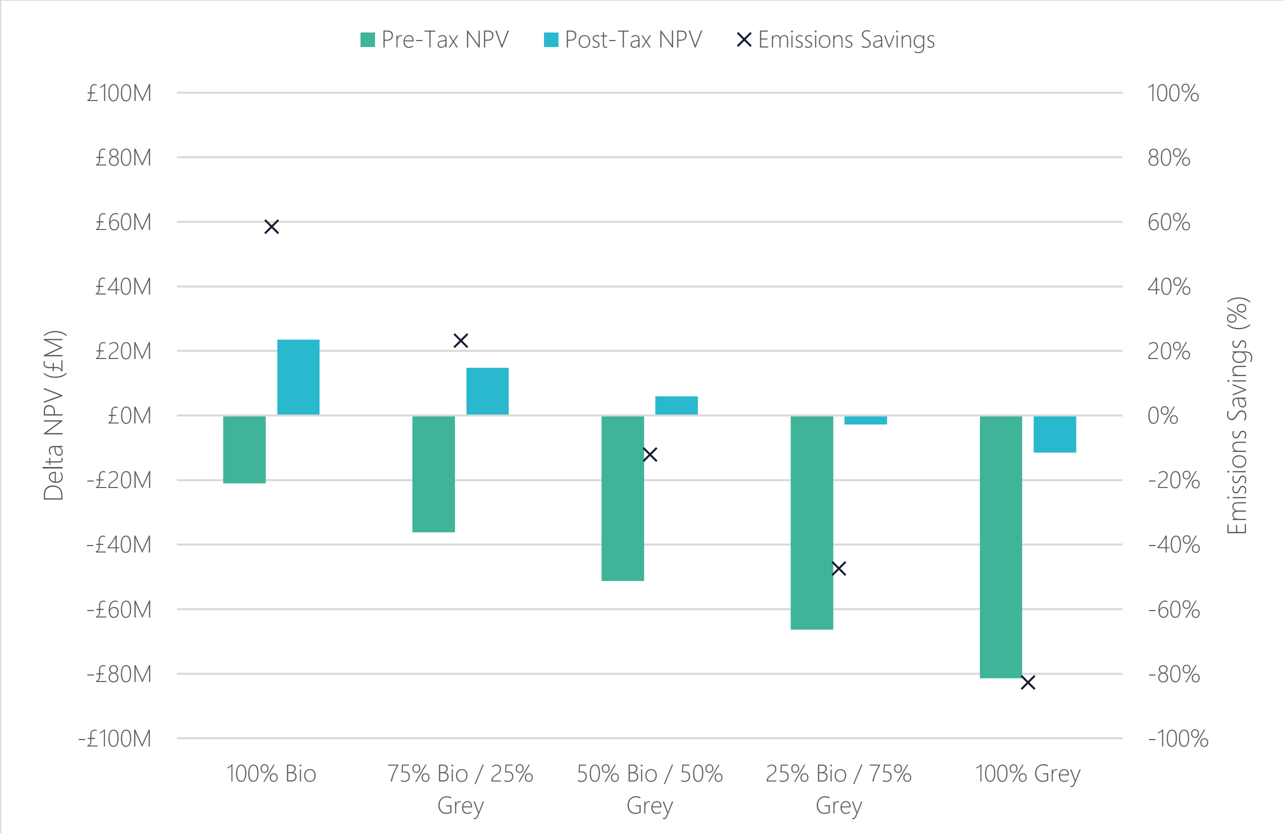

Figure 15-2 - Bio-/Grey Methanol Fuel Blending Results

Figure 15-2 visualises the negatives of increasing the share of grey methanol in the fuel blend.

The Medium pricing case considers a carbon price of £100/tonne versus £280/tonne for the High High pricing case. Table 15-12 shows that blending on the Medium pricing case may marginally improve delta NPV but it is still significantly negative, plus the £/tonne CO_2 saved is significantly reduced by blending making it less attractive.

FUEL BLEND	EMISSIONS SAVINGS VS. NORMAL OPERATION (TONNESCO_2/YR)	CONCEPT 2A DELTA NPV (£M)		£ / TONNE CO_2	
		Pre-Tax	Post-Tax	Pre-Tax	Post-Tax
100% Bio	26,953	-£115M	-£30M	-474	-124
75% Bio / 25% Grey	10,678	-£107M	-£25M	-1,113	-260

Table 15-12 - Bio-/Grey Methanol Fuel Blending Results (Medium Pricing Case)

15.2.4 Conclusions

For Concept 1B, an HVO/diesel blend was considered, and results demonstrated that increasing the HVO fraction to 100 % in the fuel leads to significant emissions savings for minimal extra costs (there is no clear benefit in blending).

For Continuous Operation Concepts, such as Concept 2A, a HVO/diesel fuel blend marginally improves the project economics. Due to the project aim being emissions reduction, a HVO/diesel blend should be disregarded as an option on the basis of this assessment due to minimal cost savings being outweighed by reduced emissions savings.

For bio-/grey methanol fuel blends, both the project economics and the emissions savings are negatively affected by increasing the fraction of grey methanol in the fuel in the High High pricing case. This is linked with the high emissions factor of grey methanol; a split of 50% grey methanol would incur additional emissions over current fuel gas usage due to this. Note: For the Medium pricing case there may a be marginal reduction in NPV from a methanol blend but similar to the HVO analysis, any minimal cost savings are outweighed by reduced emissions savings.

In addition to the points already discussed, implementation of a fuel blend may result in the loss of ‘alternative energy asset’ status which is required in order to obtain the 80% Energy Profits Levy De-Carbonisation allowance. This is the tax-relief available to companies who incur expenditure on the de-carbonisation of upstream petroleum production. To benefit from this CAPEX tax relief Asset A must generate or store power (wholly or mainly) from sources of energy other than fossil fuels. One could infer from this that a split of less than 50% renewable methanol or HVO would result in the loss of this tax relief.

Fuel blending will not be considered any further as a result of this assessment.

15.3 Societal Carbon Costs High Series Assessment

15.3.1 Background

For all economic assessments performed so far in the interest of providing accurate results for a range of future market conditions, Operator A provided Xodus with the 5 pricing cases used for their economic evaluations. The carbon price range reflected the current ETS value up to the carbon appraisal values embedded in the NSTA’s GHG valuation guidance document [Ref. 47]. The natural gas prices reflect a spread of real market forecast. The economics calculations assumed that these represented 2023 values and were adjusted for inflation accordingly.

PRICING CASE	GAS PRICE (P/THERM)	CARBON PRICE (£/TONNE)
High High	200	280
High	200	120

PRICING CASE	GAS PRICE (P/THERM)	CARBON PRICE (£/TONNE)
Medium	100	100
Low	40	80
Extreme	40	280

Table 15-13 - Main Study Operator A Provided Pricing Cases

Note: A carbon price of £280/te corresponds to the Ref. 47 central series carbon price in 2030.

An alternative economics assessment for each of the study options using the NSTA/UK government high series social cost of carbon [Ref. 47] has been developed. The carbon costs represent a monetary value that society places on 1 tonne of carbon dioxide equivalent (£/tCO_2e in 2020 prices) and are calculated based on estimated marginal abatement costs consistent with the UK's national and international climate commitments, including net zero and a series of interim carbon budgets. The Ref. 47 high series social carbon costs represent a significant increase in UK ETS carbon costs and whilst they will provide the most attractive project economics, it should be noted that the likelihood of these prices being implemented is considerably lower than the carbon prices provided by Operator A. The high series social carbon costs are displayed within Table 15-14, no additional inflation has been applied to these real terms values during subsequent calculations.

YEAR	CARBON PRICE (£/TONNE)	
	High High Series	NSTA High Series Social Carbon Costs
2023	280	378
2024	286	384
2025	291	390
2026	297	396
2027	303	402
2028	309	408
2029	315	414
2030	322	420
2031	328	427
2032	335	433

YEAR	CARBON PRICE (£/TONNE)	
2033	341	440
2034	348	447
2035	355	453

Table 15-14 - BEIS High Series Social Carbon Costs [Ref. 47]

The 5 pricing cases used for their economic evaluations consider gas prices of 200, 100 and 40 p/therm; the economics analysis in this section will consider each of these by applying the Ref. 47 high series social carbon costs to the high high, medium and extreme sale gas pricing cases.

Application of the Ref. 47 high series social carbon costs will use a discount rate of 3.5% for carbon savings and 10% for other OPEX (e.g., the 10% discount factor will still apply to gas export revenue, shipping costs, etc.). Previously, a discount rate of 10% was used for all costs, however, the 3.5% value is recommended within the NSTA's Explanatory Note on Valuation of Greenhouse Gas Emissions. The social discount rate measures the rate at which society values the present compared to the future and provides a series of discount factors which are applied to costs and benefits in appraisal. The standard social discount rate is currently set at 3.5% in real terms [Ref. 47]. Apart from carbon costs, present values for all other costs of extraction and for all revenue streams have been calculated using a 10% discount rate.

15.3.2 Results

The impact of applying the NSTA's guidance is two-fold, firstly the delta NPV will tend toward more positive upon the application of the 3.5% discount rate and secondly the increased carbon pricing will make the utilisation of alt-fuel (with zero emissions factors applied) more attractive. Table 15-15 shows the post-tax delta NPV results for Concept 2A; the results shown represent three cases:

1. High High sales gas and emissions pricing with a 10% discount rate applied to carbon savings
2. High High sales gas and emissions pricing with a 3.5% discount rate applied to carbon savings
3. High High sales gas and high series social carbon costs emissions pricing with a 3.5% discount rate applied to carbon savings

CONCEPT	FUEL	HIGH HIGH EMISSIONS PRICING 10% CO_2 DISCOUNT RATE	HIGH HIGH EMISSIONS PRICING 3.5% CO_2 DISCOUNT RATE	NSTA HIGH EMISSIONS PRICING 3.5% CO_2 DISCOUNT RATE
2A	Bio-methanol	£23M	£41M	£60M
	HVO	-£24M	-£6M	£12M

Table 15-15 - Impact of the Application of NSTA Guidance

The delta NPV results for each concept are displayed within Table 15-16, for the high-high sales gas and emissions pricing case. For comparison, the costs per tonnes of CO_2 abated are also shown as pre-tax and post-tax figures.

CONCEPT	FUEL	DELTA NPV (£M)		£ / TONNE CO2	
		Pre-Tax	**Post-Tax**	Pre-Tax	Post-Tax
2A	Renewable Methanol	£45M	£60M	-185	-246
	HVO	-£34M	£12M	106	-38
2B	Renewable Methanol	£77M	£81M	-232	-242
	HVO	-£31M	£15M	70	-34
3A	Renewable Methanol	£217M	£175M	-293	-236
	HVO	-£22M	£29M	23	-30
3B	Renewable Methanol	£241M	£157M	-325	-212
	HVO	-£11M	£12M	11	-13
3C	Renewable Methanol	£247M	£160M	-333	-216
	HVO	-£21M	£7M	22	-7

Table 15-16 - Continuous Operation Concepts Post Societal Carbon Costs High Series Assessment Economic Results (High High Pricing Case for Gas Cost)

15.3.3 Conclusions

Application of the NSTA's guidance improves the project economics for all concepts and both alternative fuels. The impact of the use of a social discount rate of 3.5% for carbon savings is significant. Application of the high series social carbon costs improves the CO_2 tax savings for all concepts and both alternative fuels.

The high series social carbon costs represent a significant increase in UK ETS carbon costs; the UK ETS Authority determined that the carbon price for the scheme year beginning on 1st January 2023 was £83.03/tonne [Ref. 48]. The high series social carbon costs indicate a 2023 carbon price of £378/tonne which represents a 450% increase. The likelihood of this occurrence and therefore the implementation of the high series social carbon costs can be considered low.

The cost impacts, for Concept 2A are visualised in the updated summary table. The updated key parameters are shown below in bold:

- Pricing case applies to sales gas pricing (200, 100 and 40 p/therm cases considered) – **emissions pricing follows the NSTA/UK government high series social cost of carbon**
- Bio-Methanol properties:
    - £696/te (2027)
    - UK ETS Emissions Factor: 0 gCO_2e/MJ
    - Actual Emissions Factor: 25 gCO_2e/MJ
- HVO properties:
    - £2,207 (2027)
    - UK ETS Emissions Factor: 0 gCO_2e/MJ
    - Actual Emissions Factor: 13.9 gCO_2e/MJ
- A discount rate of **3.5% for carbon savings and 10% for other OPEX** (e.g., the 10% discount factor will still apply to gas export revenue, shipping costs, etc.) has been applied for NPV estimates

FUEL CHOICE	SCENARIO	PRICING CASE	MAIN STUDY RESULTS				ZERO EMISSIONS FACTOR ASSESSMENT				HIGH SERIES SOCIAL CARBON COSTS ASSESSMENT			
			Pre-Tax Assessment		Post-Tax Assessment		Pre-Tax Assessment		Post-Tax Assessment		Pre-Tax Assessment		Post-Tax Assessment	
			Delta NPV	Alt-Fuel Price (£/te)	Delta NPV	Alt-Fuel Price (£/te)	Delta NPV	Alt-Fuel Price (£/te)	Delta NPV	Alt-Fuel Price (£/te)	Delta NPV	Alt-Fuel Price (£/te)	Delta NPV	Alt-Fuel Price (£/te)
Renewable Methanol	Selected Renewable Methanol Price	High High	-£104M	1,076	-£22M	1,076	-£21M	696	£23M	696	£45M	696	£60M	696
		High	-£140M	1,076	-£43M	1,076	-£66M	696	-£2M	696				
		Medium	-£189M	1,076	-£70M	1,076	-£115M	696	-£30M	696	£1M	696	£35M	696
		Low	-£220M	1,076	-£88M	1,076	-£147M	696	-£48M	696	-£26M	696	£20M	696
		Extreme	-£174M	1,076	-£62M	1,076	-£92M	696	-£16M	696				
	Required Renewable Methanol Breakeven Price	High High	0	509	0	857	0	580	0	930	0	943	0	1,293
		High	0	303	0	648	0	334	0	679				
		Medium	0	35	0	374	0	61	0	400	0	701	0	1,046
		Low	0	-136	0	199	0	-115	0	220	0	555	0	897
		Extreme	0	121	0	461	0	193	0	534				
			NPV	Fuel Price (p/therm)	NPV	Fuel Price (p/therm)	NPV	Fuel Price (p/therm)	NPV	Fuel Price (p/therm)	NPV	Fuel Price (p/therm)	NPV	Fuel Price (p/therm)
Fuel Gas	Continued Fuel Gas Usage	High High	-£166M	200	-£94M	200	-£166M	200	-£94M	200	-£190M	200	-£107M	200
		High	-£122M	200	-£68M	200	-£122M	200	-£68M	200				
		Medium	-£72M	100	-£41M	100	-£72M	100	-£41M	100	-£146M	100	-£82M	100
		Low	-£40M	40	-£22M	40	-£40M	40	-£22M	40	-£120M	40	-£67M	40
		Extreme	-£96M	40	-£54M	40	-£96M	40	-£54M	40				
			Delta NPV	Alt-Fuel Price (£/te)	Delta NPV	Alt-Fuel Price (£/te)	Delta NPV	Alt-Fuel Price (£/te)	Delta NPV	Alt-Fuel Price (£/te)	Delta NPV	Alt-Fuel Price (£/te)	Delta NPV	Alt-Fuel Price (£/te)
HVO	Selected HVO Price	High High	-£118M	2,207	-£34M	2,207	-£100M	2,207	-£24M	2,207	-£34M	2,207	£12M	2,207
		High	-£152M	2,207	-£54M	2,207	-£144M	2,207	-£49M	2,207				
		Medium	-£200M	2,207	-£81M	2,207	-£194M	2,207	-£77M	2,207	-£78M	2,207	-£13M	2,207
		Low	-£231M	2,207	-£98M	2,207	-£226M	2,207	-£95M	2,207	-£104M	2,207	-£28M	2,207
		Extreme	-£188M	2,207	-£74M	2,207	-£170M	2,207	-£64M	2,207				
	Required HVO Breakeven Price	High High	0	989	0	1,574	0	1,176	0	1,761	0	1,858	0	2,429
		High	0	633	0	1,218	0	713	0	1,298				
		Medium	0	133	0	718	0	200	0	785	0	1,402	0	1,973
		Low	0	-185	0	400	0	-131	0	454	0	1,129	0	1,700
		Extreme	0	260	0	845	0	447	0	1032				

Table 15-17 - Updated Study Economics for Concept 2A

15.4 UK LNG Import Requirements Assessment

15.4.1 Background

Within this section, the economic and emissions consequences of the increase in gas exported from Asset A (due to the use of alternative fuels) with the savings from reduced LNG requirements are assessed. If Asset A were to export the gas currently used on the platform, this would feed into the UK's energy network and could be utilised to generate power. This would lead to reduction in the requirement to import natural gas from other countries, both as natural gas via pipelines and as LNG shipments.

Analysis published by the NSTA in July 2023 [Ref. 49] shows that the carbon intensity of producing gas domestically is on average almost four times lower compared with importing gas in LNG form. This is because of both the way the gas is transferred and, in some cases, the methods of extraction. The analysis resulted in values to show that gas extracted from the UK Continental Shelf (UKCS) has an average production emissions intensity of 21 kgCO_2/boe compared to 79 kgCO_2/boe for imported LNG. The process of liquefaction, combined with the emissions produced by the transportation and regasification of the LNG once in the UK, are responsible for the considerably higher emissions intensity.

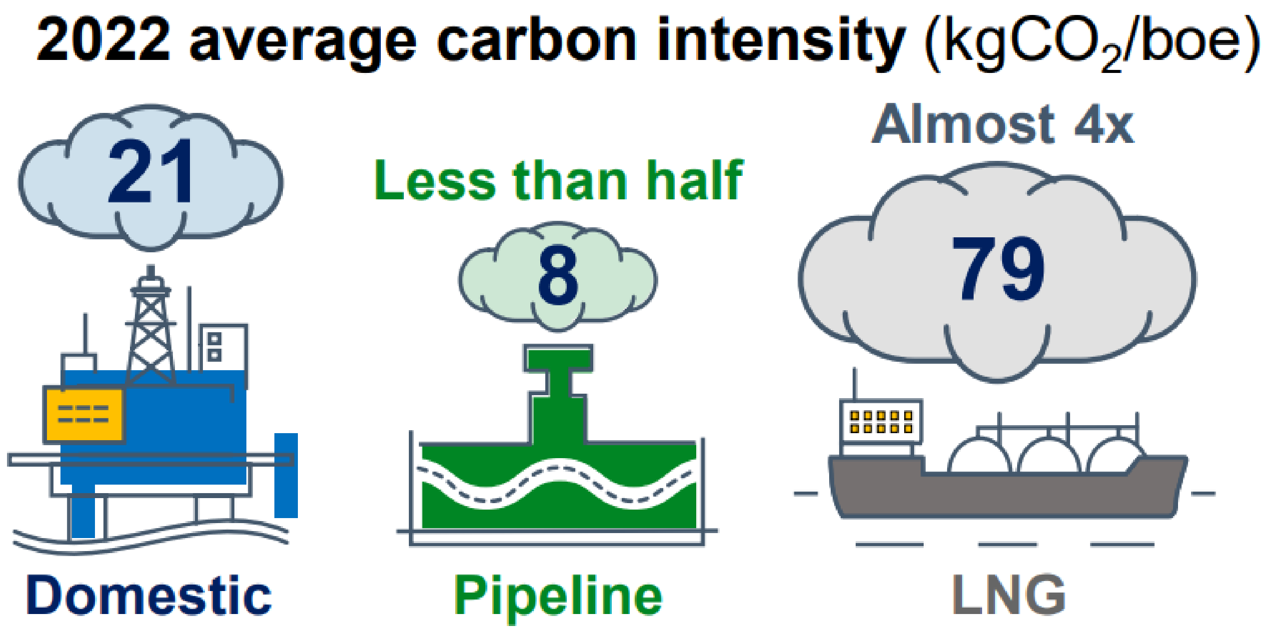

Figure 15-3 - 2022 Average Carbon Intensity [Ref. 49]

If Asset A can instead export the gas the UK can begin to import a smaller fraction of its natural gas requirements, in 2022 for example the UK imported 63% of natural gas supply. The aim of the UK LNG import requirements assessment is to quantify the volume of LNG that would no longer be required for each of the Concepts. A cost and emissions assessment is to be performed on these savings to represent the value that Asset A exporting could potentially have to the UK as a whole.

Conversely, natural gas pipeline imports from Norway have lower production emissions intensities (8 $kgCO_2$/boe) than domestic production. It is to be assumed within this assessment that any energy exported from Asset A will translate directly to LNG imports rather than pipeline imports.

15.4.2 Basis

The key parameters used within the assessment are displayed within Table 15-18.

UKCS Average (and Assumed Asset A) Production Emissions Intensity	21 $kgCO_2$/boe
Imported LNG Production Emissions Intensity	79 $kgCO_2$/boe
1 Barrel of Oil Equivalent =	6118 MJ
Current Natural Gas Price UK (2024)	73 p/therm [Ref. 50]
Current Imported LNG Price UK (2023)	13.05 USD/MMBTU [Ref. 51]

Table 15-18 - UK LNG Import Requirements Assessment Basis

Cost data for current UK natural gas and LNG imports has been obtained to provide a 2024 and 2023 reflective price, these have had inflation applied to reflect 2027 costs within the calculations.

15.4.3 Results

The emissions results are displayed within Table 15-19.

			2A	2B	3A/B/C
	Annual Energy Requirement	MJ/yr	765,874,286	1,051,993,358	2,338,662,158
		boe/yr	125,187	171,954	382,268
Export Gas	Averaged Emissions	$teCO_2$/yr	2,629	3,611	8,028
Import LNG		$teCO_2$/yr	9,890	13,584	30,199

		2A	2B	3A/B/C
Emissions Savings	$teCO_2/yr$	7,261	9,973	22,172

Table 15-19 - UK LNG Import Emissions Results

In addition to increased emissions, there is an additional cost associated with the import of LNG. The results shown in Table 15-20 are representative of 2027 values.

		2A	2B	3A/B/C
Sales Gas Price	p/therm (2024)	73	73	73
	£/MMBTU (2027)	7.7	7.7	7.7
Export Gas Cost	£/yr	£5,623,488	£7,724,338	£17,171,798
Import LNG Price	USD/MMBTU (2023)	13.05	13.05	13.05
	£/MMBTU (2027)	11.3	11.3	11.3
Import LNG Cost	£/yr	£8,202,776	£11,267,209	£25,047,872
Additional Import Costs (£/yr)	£/yr	£2,579,288	£3,542,871	£7,876,074

Table 15-20 - UK LNG Import Economic Results

The results displayed highlight that there are benefits to the wider UK energy picture if Asset A can export additional natural gas to be used within the UK. These potential cost savings do not directly impact the Asset A platform or Operator A and for that reason are not included within the study economics.

However, it is still interesting to understand if the additional NGL import cost savings would significantly improve the study economics if they were to be included, as there could be a driver for the UK government to incentivise alternative fuel projects if this were to be the case. Table 15-21 shows a comparison of the savings to the UK from reduced NGL imports in terms of pre-tax NPV with the yearly savings applying between 2027 and 2035 as per the Asset A project (10 % discount factor). For comparison, the table includes Asset A alternative fuel project pre-tax NPV for the High-High, High and Medium pricing cases for the bio-methanol scenario with a fuel cost of £696/te and a zero UK-ETS emissions factor (bio-methanol case selected as it presents the best economics with HVO and e-methanol cases showing more negative NPVs). Other than the High High pricing case, the additional import gas cost savings would not be enough to make the pre-tax project delta NPVs positive.

		2A	2B	3B
Additional Import Costs (£/yr)	£/yr	£2,579,288	£3,542,871	£7,876,074
Additional Import Cost Savings Converted to a Pre-Tax NPV for Asset A Project (Note 1)	£M	14	19	41
High High Case Pre-Tax Delta NPV	£M	-21	-13	40
High Case Pre-Tax Delta NPV	£M	-66	-75	-97
Medium Case Pre-Tax Delta NPV	£M	-115	-142	-248

Table 15-21 - Pre-Tax NPV Comparison for Reduced NGL Import Savings

15.4.4 Conclusions

The results displayed within this section highlight that there are benefits to the wider UK energy picture if Asset A was able to export additional natural gas to be used within the UK. There are, albeit minor, emissions and cost savings which can be realised from reduced LNG imports. These, however, do not directly impact the Asset A platform or Operator A and for that reason are not included within the study economics. Even if the cost savings were included in the alternative fuel project economics then they are insufficient to make the pre-tax project delta NPVs positive for the majority of the cases studied (certain high high pricing case may change -ve pre-tax delta NPVs to +ve but these cases are less likely to be realised based on current UK-ETS carbon costs).

To provide context to the energy requirements, in 2022 the UK imported circa 280,000 GWh (10^{12} MJ) [Ref. 52] of LNG. The LNG imports which would be avoided by exporting all the available sales gas for Concepts 3A/B/C represent less than 0.2% of the total UK LNG imports.

16 CONCLUSIONS & RECOMMENDATIONS

16.1 Conclusions

The study has concluded the following points, these are displayed in relation to the scope workstreams set out within Section 2.1.

16.1.1 Technical Workstream

- The adaptation of alt-fuels to a fixed oil and gas platform located in the North Sea is technically feasible.
- No 'silver bullet' fuel option exits, each has their own merits and drawbacks.
- TAR Shutdown Concepts make use of existing on platform storage which can be repurposed for temporary alt-fuel storage.
- Continuous Operation Concepts rely on off platform fuel storage, either subsea or utilising FSOs.
- Fuel will be delivered to the platform via either frequent platform supply vessel trips or FSO.

16.1.2 Technology Workstream

- Combustion equipment is readily adaptable for the chosen fuel options.
- The required topsides modifications are not extensive or cost prohibitive.
- Subsea fuel storage concepts are available, but these require development as it would be a new concept for UKCS assets.

16.1.3 Regulatory Workstream

- Both alternative fuels are acceptable for use on the platform from a safety perspective, modifications to the Safety Case will be required but these can be accommodated.
- Regarding the environmental impact from a potential release of renewable methanol or HVO, methanol release is expected to rapidly disperse and have no impact on marine life. HVO spills offshore would be treated similarly to diesel spills.

- The introduction of both renewable methanol and HVO will have minor impacts upon the Safety and Environmental Critical Elements. The fire and gas system will likely require new detectors in areas where the alt-fuels are to be introduced. Reviews are suggested for active fire protection, HVAC and ignition protection.
- HVO and bio-methanol are currently covered by UK ETS as bioliquids; it is possible to claim an emissions factor of 0 if the chosen fuel fulfils sustainability requirements relating to its feedstock and emissions savings. It is Xodus' understanding that e-methanol is not currently incorporated within the UK ETS, however, from a high-level review of EU legislation (RED and ETS), "direction of travel" would seem to indicate that legislative modifications will incorporate these fuels. Note that this study has conservatively applied small emissions factors of 10 gCO_2/MJ for renewable methanol and 13.9 gCO_2/MJ as per Section 12, further sensitivities on the economics with an emissions factor should be a consideration for further work.
- With regards to the OGA Plan there is the expectation that financial investments must be made in low carbon power alternatives where it is reasonable to do so weighting the total remaining value of reserves and resources that will or may be developed through that asset and the expected emissions reductions against the expected costs. This study involving Operator A has demonstrated that the expected emissions reductions against the expected costs of alternative fuel implementation are not considerable enough to justify implementation. Investment and resources could be better applied to alternative carbon reduction solutions.

16.1.4 Supply Chain Workstream

- The main challenges lie in the volumes of fuel required to provide the large power requirements for the asset. These volumes bring challenges in terms of fuel storage and fuel supply.
- Discussions with fuel suppliers have indicated their capabilities to scale up their current operations to accommodate the fuel volumes required for Asset A.
- If supply of alt-fuels was to become constrained, reverting to a high CO_2 bio-methanol or crop based HVO would have its sustainability challenges – the lifecycle for these less sustainable fuel options should be fully analysed before any temporary change is made.

16.1.5 Operation Workstream

- The TAR Shutdown Concepts are an additional application for alternative fuel implementation to reduce emissions associated with continued diesel use.
- The low flame temperatures of renewable methanol in the gas turbines may result in the requirement for less frequent GT inspections. High cetane numbers in HVO products can aid smoothness of operation, misfiring,

smoke emissions, noise and ease of starting potentially reducing maintenance requirements compared to diesel operation.

16.1.6 Economics Workstream

- Savings can be made relating to reduced diesel usage (for TAR Shutdown Concepts), additional sales gas revenue (for Continuous Operation Concepts) and emissions allowance savings.
- CAPEX estimates for the brownfield modifications required for Continuous Operation Concepts have been developed and capture topsides, subsea and turbine scopes.
- The commercial metrics indicate that the economics are primarily dictated by OPEX rather than CAPEX.
- The use of alt-fuels is commercially challenging from an OPEX perspective. The cost of the fuels looks to be prohibitive without government incentives – even when assuming the greenest of fuel supply chain options.
- Xodus, in agreement with Operator A, conclude that the project economics deem the implementation of alternative fuels on the Asset A platform to be unreasonable.

16.2 Recommendations

As part of the next study phase (only applicable if additional design development phases are carried out), the following should be developed:

- Concept select for fuel storage and topsides fuel distribution;
- Further investigation into charter rates for FSOs/tankers for fuel storage;
- Engage with the alt-fuel supply chain for both renewable methanol and HVO to understand security of supply for 2027, and the availability of a suitable supply vessel / tanker to deliver the fuel; and
- It has been assumed that the life cycle emissions of alternative fuels will apply to the ETS. It is recommended that Operator A's engagement with OPRED is continued to confirm if alternative energy fuels will be treated in the scheme.

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APPENDIX A BIOFUELS SCREENING

A.1 Biofuels Initial Screening

BIOFUEL		SCREENING JUSTIFICATION
Straight vegetable oils (SVO)	Sustainability & Operability	• Food versus fuel ethics • Reduced engine life due to the build-up of carbon deposits • High viscosity makes in unattractive for gas turbine usage due to fouling and injection nozzle issues
Biodiesel	Sustainability & Operability	• Food versus fuel ethics • Maximum storage limit of 6 months • Can have issues with poor filterability • Has a polar nature and can dissolve significant amounts of water increasing microbial contamination risk • High levels of oxygen in the fuel • Increasing use of crops for biofuels production has raised concerns about sustainability
Biobutanol	Sustainability	• Currently primarily used blended into conventional gasoline rather than as standalone fuel. Low availability due to its high demand for usage in petrol. • Food versus fuel ethics
Bioethanol	Sustainability	• Low calorific value and low flashpoint • Turbine OEM A are not doing any development work on ethanol due to preference for bio-methanol. • In Europe, wheat is the main crop grown for bioethanol production - accounting for 0.7% of EU agricultural land and 2% of Europe's grain supply • The EC has proposed to limit biofuel produced from "food crops" at 7% of energy use in transport, due to concerns about food price and land use impacts • Initially discounted due to sustainability concerns (although it is produced at large volumes and blending the supply with cellulosic ethanol may address the sustainability concern).

BIOFUEL		SCREENING JUSTIFICATION
Ethyl tert-butyl ether (ETBE)	Sustainability	• Requires fossil fuels to produce the isobutylene • Typically used blended rather than pure
Bio-oil	Operability	• Highly corrosive due to formic and acetic acids, difficult to modify existing turbines to cope with the acidic nature and low heating value • High viscosity • Unstable, not miscible with petroleum oils & often contains water
Bioelectricity	Operability	• Less developed than conventional renewable electricity methods (e.g., wind, solar) • Energy would need to be produced onshore and distributed to platform • Operator A have completed offshore electrification screening for the Asset A platform and found it to not be a reasonable balance between maximising economic recovery and net zero
Biohydrogen	Operability	• Currently producing low yields with further research required into suitable microorganisms • Traditional green hydrogen has been discounted during fuel screening. Bio-hydrogen is less readily available so offers no improvement
BioSNG	Operability	• Gaseous fuel requiring large storage volumes and transportation to offshore facilities would pose difficulties • More common to convert to liquid advanced biofuels such as DME & F-T diesel
Biogas	Operability	• Gaseous fuel requiring large storage volumes • Transportation to offshore facilities would pose difficulties

A.2 Biofuels Research Spreadsheet

A.3 A-100870-S00-Y-PRES-002 Rev A01 - Biofuels Assessment

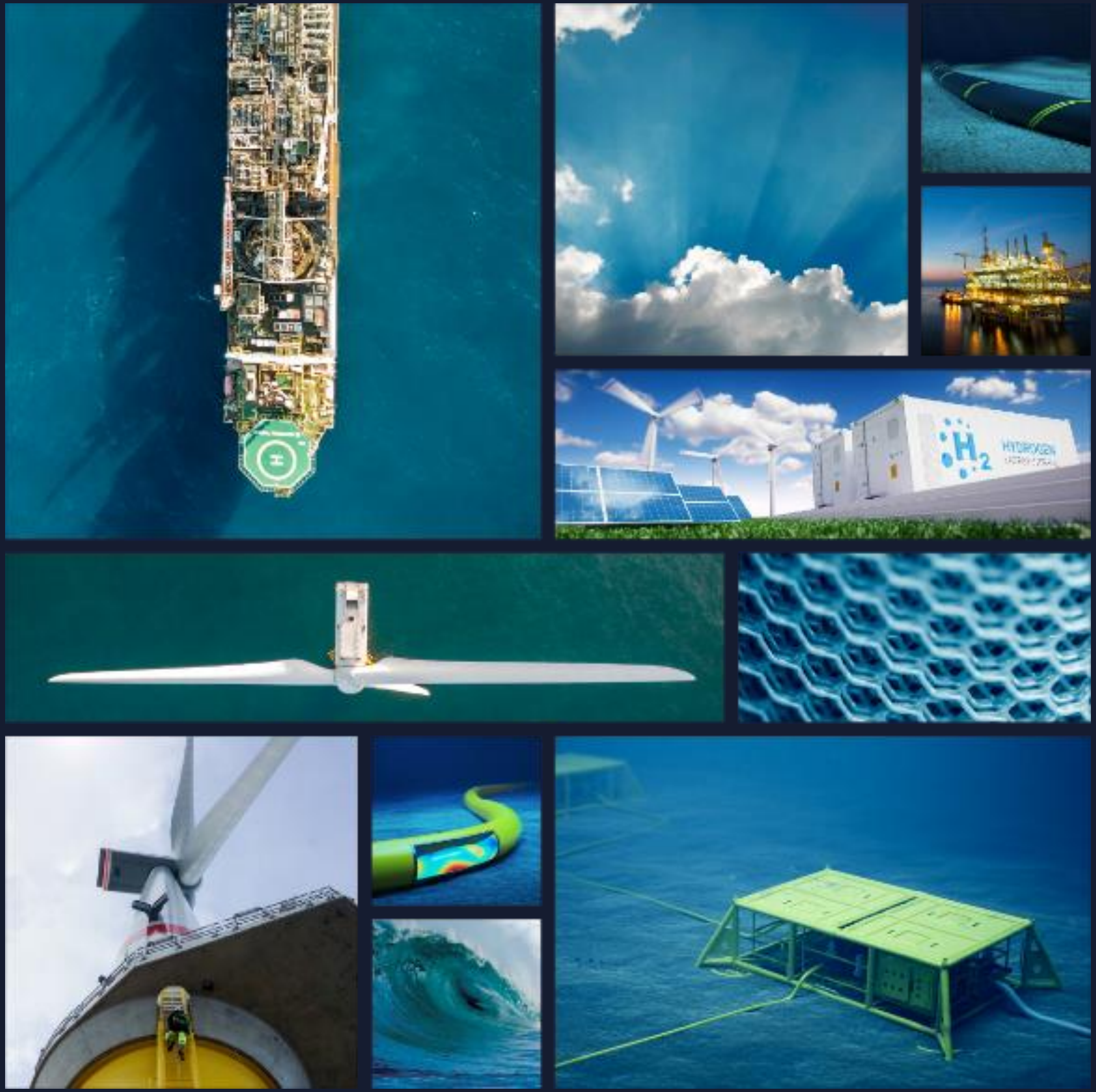
XODUS

Initial Fuels Assessment

Alternative Fuel Study
Net Zero Technology Centre

A-100870-S00-Y-PRES-002 Rev A01

WWW.XODUSGROUP.COM



Agenda

- Introduction
- Required fuel volumes
- Renewable methanol (biomethanol and e-methanol)
  - Renewable methanol presented separately from the other biofuels because renewable methanol already expected to be studied, these slides are aiming to select a biofuel to study along with renewable methanol
- Biofuels screening & selection

Introduction

Scope

- As per agreement with Operator Aduring the Kick-Off Meeting, previous fuel screening work performed by Xodus has been used to discount 2 fuel options:
  - Hydrogen
  - Ammonia
- The two fuels proposed be carried to the next stage of assessment are to be renewable methanol and HVO.

Renewable-Methanol

HVO

- An assessment of all biofuels and justification behind the selection of HVO via a screening process is detailed within these slides.

Asset A Power Load Scenarios

The following cases are to be assessed during this study:

- 1a – TAR shutdown with GTG power **1.5 MW**
- 1b – TAR shutdown with temporary HV power **1.5 MW**
- 2a – Power generation with GTG **6 MW**
- 2b – Power Generation with GTG (post-LPBC electrification) **10.4 MW**
- 3 – Full load (GTG + MPX) **27.2 MW**

Asset A Power Load Scenarios

The power scenarios are summarised in the table below

Case	1a	1b	2a	2b	3
Description	TAR shutdown: GTG	TAR shutdown: Temp HV Power	Power Generation	Power Generation post-LPBC Electrification	Power Generation and MP/Export Compression
Power Gen Type	GTG	Temporary Diesel HV	GTG	GTG	GTG
Power Gen Load (MW)	1.5	1.5 (3 units at 0. 5 MW each)	6.0	10.4	10.4
Power Gen Thermal Efficiency	10.0%	34.9%	21.0%	26.5%	26.5%
Compression Type	-	-	-	LPBC Electrified	Charlie MP & Export
Compression Driver Load (MW)	-	-	-	-	16.8
Compression Driver Thermal Efficiency	-	-	-	-	35.0%
Total Load (MW)	1.5	1.5	6.0	10.4	27.2

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Thermal Efficiencies

- Thermal efficiencies at respective power loads have been taken from data provided by Operator A.

- The values used have been confirmed with Turbine OEM A, who provided an estimate for efficiency of the GTGs at 1.5 MW.

Fuel Volumes

Case			1a	1b	2a	2b	3
Description			TAR shutdown: GTG	TAR shutdown: Temp HV Power	Power Generation	Power Generation post-LPBC Electrification	Power Generation and MP/Export Compression
Total Load (MW)			1.5	1.5	6.0	10.4	27.2
Required Fuel Thermal Energy (MW)			15.0	4.3	28.6	39.3	87.3
Required Fuel Thermal Energy Annually (PJ)			0.40	0.12	0.77	1.05	2.34
Volume for 14 days Supply (m^3)	Methanol	Power Gen	1,138	326	2,167	2,967	2,967
		Compression	0	0	0	0	3,649
		Total	**1,138**	**326**	**2,167**	**2,967**	**6,616**
	HVO	Power Gen	524	150	998	1,371	1,371
		Compression	0	0	0	0	1,676
		Total	**524**	**150**	**998**	**1,371**	**3,047**

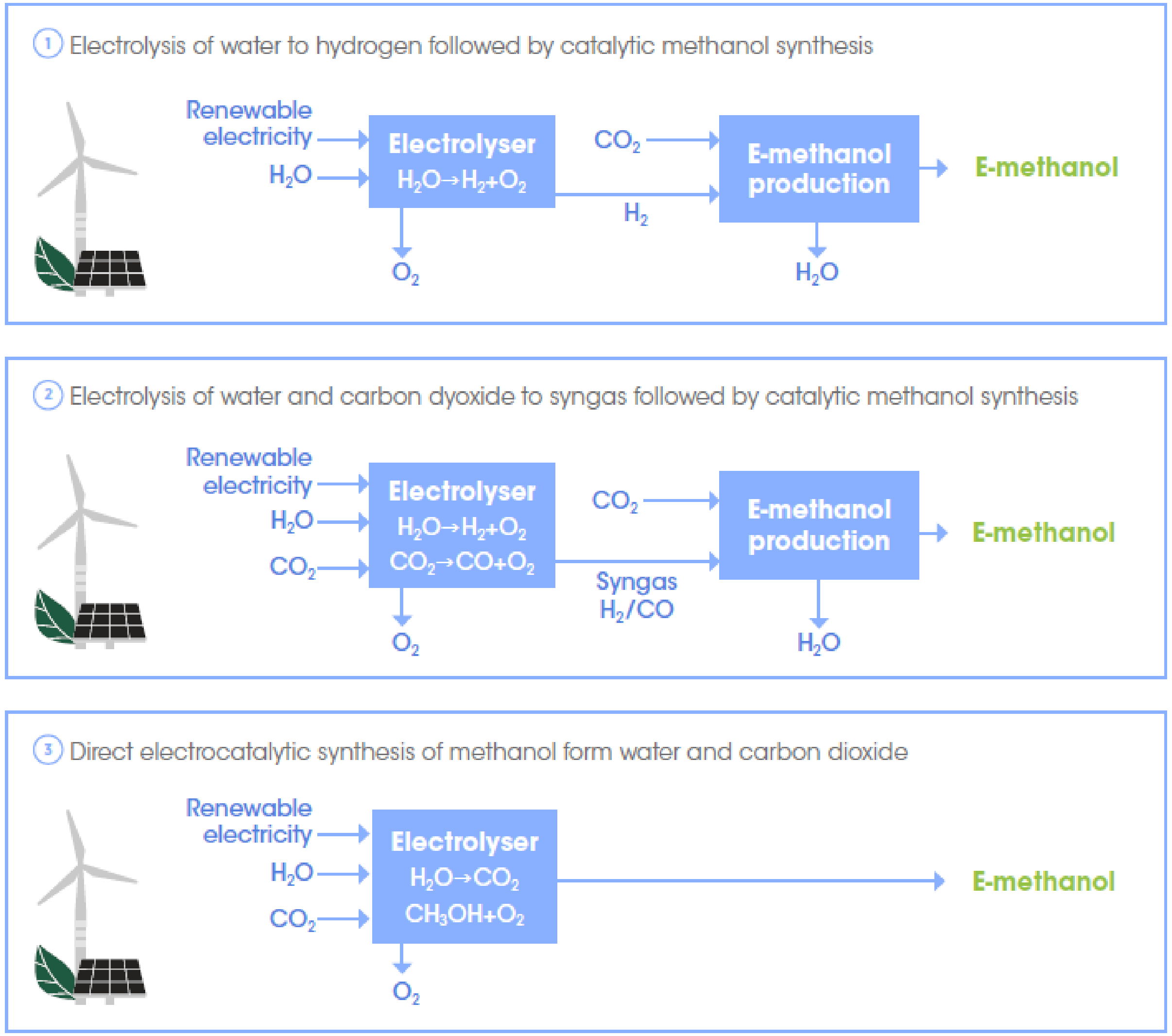
Renewable Methanol

Renewable Methanol

- E-methanol and biomethanol can be used to make up renewable methanol supply.
- E-methanol and biomethanol are chemically identical, it is just the feedstocks and manufacturing process that differs.

Renewable Methanol - E-methanol

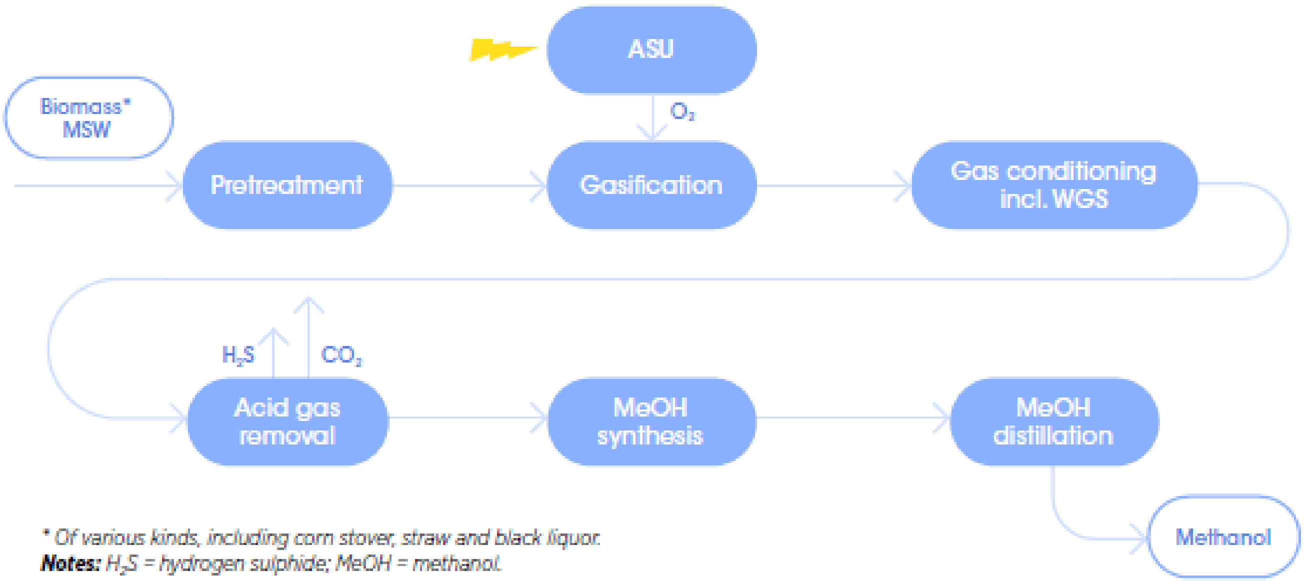
- E-methanol is a liquid product obtain from CO_2 and green hydrogen through a one-step catalytic process.



Source: Ellis et al. (2019).

Renewable Methanol - Bio-methanol

- Bio-methanol is produced through the gasification of biomass followed by a catalyzed synthesis.
- The biomass feedstocks include:
  - Forestry & agricultural waste
  - Biogas from landfill
  - Sewage
  - Municipal solid waste
  - Black liquor

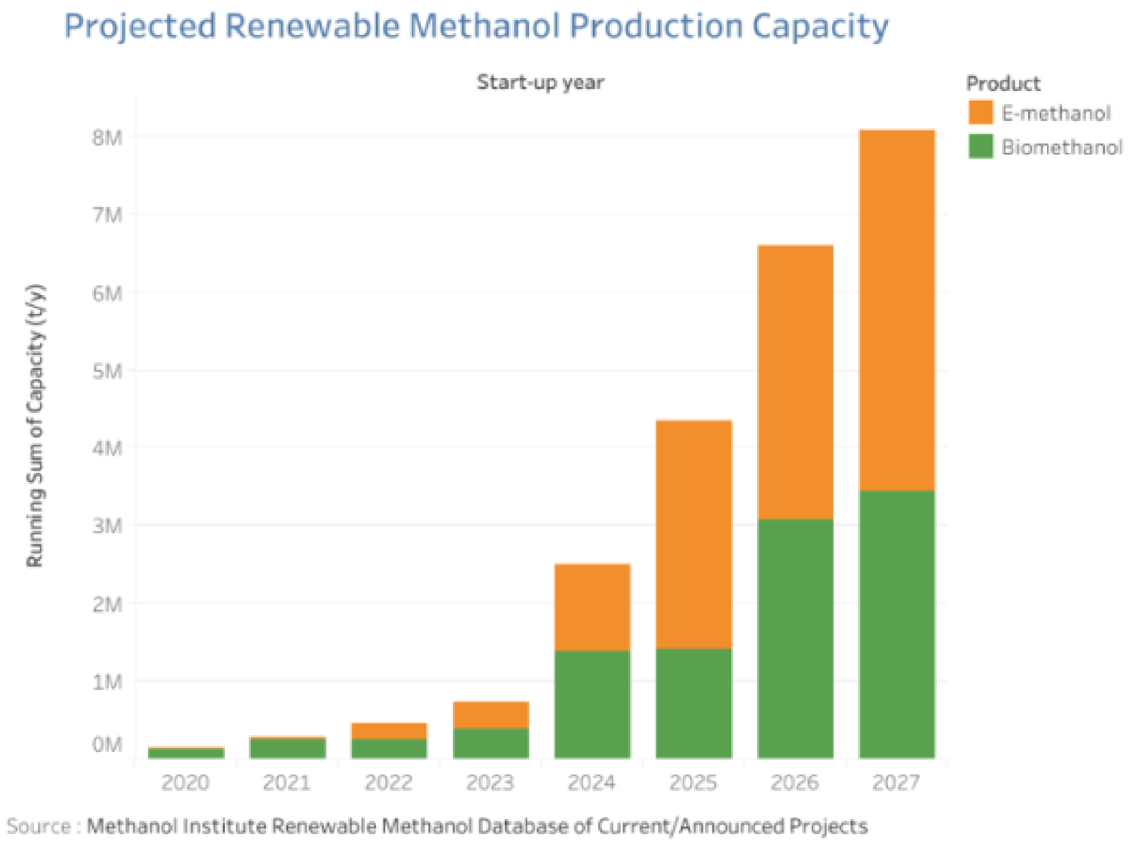


* Of various kinds, including corn stover, straw and black liquor.
Notes: H_2S = hydrogen sulphide; MeOH = methanol.

Source: IRENA and Methanol Institute (2021)

Renewable Methanol

- The Methanol Institute (MI) is tracking more than 80 renewable methanol projects around the globe that are projected to produce more than eight million metric tonnes per year by 2027.
- Increasing scale: To date, the majority of e-methanol and biomethanol plants have been in the range 4,000 to 10,000 tonnes/year, but now seeing more plants in the range 50,000, 100,000, > 250,000 tonnes/year
- Asset A demand is potentially 0.127 Mt/yr - 1.6 % of 2027 renewable methanol production for the highest load scenario (Case 3) and a significant proportion of some of the future planned methanol plant capacities.



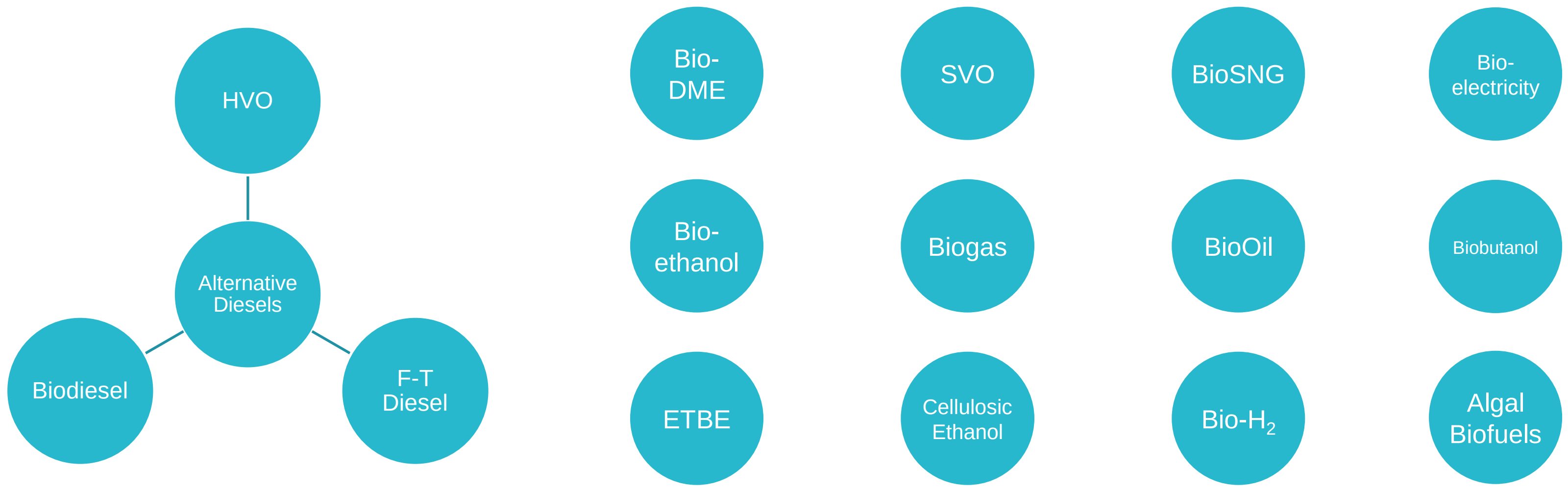
Renewable Methanol – Lifecycle Carbon Emissions

- E-methanol = 4 – 10 gCO2eq/MJ (dependent on renewable energy source)
- Biomethanol = Typically 10 to 40 gCO2eq/MJ (dependent on feedstock)
- Methanol from natural gas = 110 gCO2eq/MJ
- If methanol supply was a blend of renewable methanol and fossil based methanol, there is a risk of a higher carbon footprint than fuel gas combustion.
- Please note while carbon intensity has been assessed during this initial screening, energy intensity has not been considered. The carbon emissions quoted above are lifecycle emissions and as such will include any emissions produced during the required energy production.

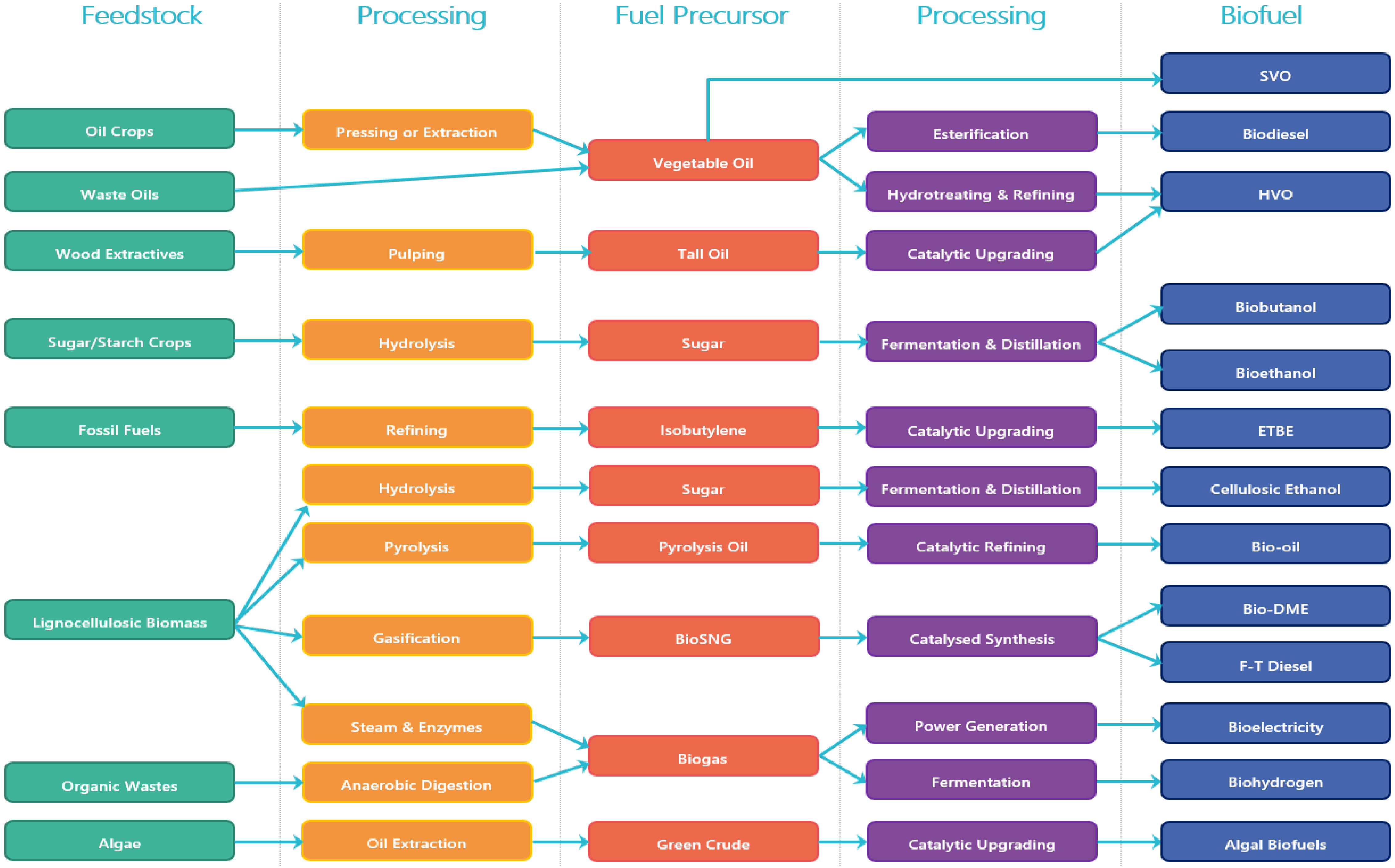
Biofuels Screening and Selection

Biofuels Screening

- To allow a comprehensive assessment to be carried out, all of the following biofuels have been investigated.



- Initial screening was performed to remove options which have showstoppers relating to operational or sustainability issues.


Feedstock
Processing
Fuel Precursor
Processing
Biofuel
SVO
Oil Crops
Pressing or Extraction
Vegetable Oil
Esterification
Biodiesel
Waste Oils
Hydrotreating & Refining
HVO
Wood Extractives
Pulping
Tall Oil
Catalytic Upgrading
Biobutanol
Sugar/Starch Crops
Hydrolysis
Sugar
Fermentation & Distillation
Bioethanol
Fossil Fuels
Refining
Isobutylene
Catalytic Upgrading
ETBE
Hydrolysis
Sugar
Fermentation & Distillation
Cellulosic Ethanol
Pyrolysis
Pyrolysis Oil
Catalytic Refining
Bio-oil
Bio-DME
Lignocellulosic Biomass
Gasification
BioSNG
Catalysed Synthesis
F-T Diesel
Steam & Enzymes
Power Generation
Bioelectricity
Biogas
Organic Wastes
Anaerobic Digestion
Fermentation
Biohydrogen
Algae
Oil Extraction
Green Crude
Catalytic Upgrading
Algal Biofuels

Biodiesel (FAME, RME, SME, PME, UCOME)

Feedstock: Oil crops (Palm, Jatropha, Castor, Jojoba, etc), industrial waste oils (used cooking oil)

Production method: Esterification of vegetable oils or fats

Pros	Cons
• Biodiesel is widely available and has been mixed with conventional diesel • IEA main case world production 2027 = 52,513 million litres per year (Asset A demand is < 0.2 % of production) • Non-toxic and biodegradable	• Maximum storage limit of 6 months • Can have issues with poor filterability • Has a polar nature and can dissolve significant amounts of water increasing microbial contamination risk • High-levels of oxygen in the fuel • Increasing use of crops for biofuels production has raised concerns about sustainability

Discounted due to operability concerns

Bioethanol

Feedstock: Sugar crops (Wheat, Corn, sugar cane, sugar beet, etc)

Production method: Fermentation of sugars produced during hydrolysis of feedstock

Pros	Cons
• Simple and established production process • IEA main case world production 2027 = 115,743 million litres per year (Asset A demand is < 0.2 % of global production) • IEA forecast shows potentially 6,196 -7,068 million litres per year in Europe 2027 main vs accelerated cases)	• Low calorific value and low flashpoint • Turbine OEM A are not doing any development work on ethanol. • In Europe, wheat is the main crop grown for bioethanol production - accounting for 0.7% of EU agricultural land and 2% of Europe's grain supply • The EC has proposed to limit biofuel produced from "food crops" at 7% of energy use in transport, due to concerns about food price and land use impacts

Initially discounted due to sustainability concerns (although we will revisit this later as it is produced at large volumes and blending the supply with cellulosic ethanol may address the sustainability concern)

Biobutanol

Feedstock: Sugar crops (Wheat, Corn, sugar cane, sugar beet, etc)

Production method: Fermentation of sugars produced during hydrolysis of feedstock

Pros	Cons
• Established global market due to use in butyl acrylates • Better suited for fuel usage than bioethanol due to physical properties 1. Immiscible in water 2. Higher energy content 3. Lower RVP, which means lower volatility and less evaporative emissions	• Currently primarily used blended into conventional gasoline • The same food vs fuel sustainability issues exist with relation to the sustainable production of sugar crop feedstocks

Discounted due to sustainability concerns

Straight Vegetable Oils (SVOs)

Feedstock: Oil crops (Palm, Jatropha, Castor, Jojoba, etc)

Production method: No further production

Pros	Cons
• No additional processing required providing low costs	• The same sustainability issues exist with relation to the sustainable production of oil crop feedstocks • Reduced engine life due to the build up of carbon deposits • High viscosity makes in unattractive for gas turbine usage

Discounted due to sustainability and operability concerns

Ethyl Tert-Butyl Ether (ETBE)

Feedstock: Bioethanol and fossil fuels

Production method: Catalytic reaction of ethanol and isobutylene

Pros	Cons
• Currently accounts for the majority of bioethanol destined for the EU gasoline market • 11 PJ supplied to the EU in 2020 (1.5% of biofuels)	• Still requires fossil fuels to produce the isobutylene • Typically used blended rather than pure

Discounted due to sustainability concerns

Biogas

Feedstock: Organic wastes

Production method: Natural production of gas through anaerobic digestion

Pros	Cons
• Widely available with over >13m toe of biogas primary energy produced annually in 2013 • A simple well-established technology • Biogas derived from organic wastes does not compete with food production	• Gaseous fuel requiring large storage volumes • Transportation to offshore facilities would pose difficulties

Discounted due to operability concerns

Biosynthetic Natural Gas (Bio-SNG)

Feedstock: Lignocellulosic biomass (e.g. forestry residues, energy crops)

Production method: Gasification of cellulosic materials

Pros	Cons
• Well suited for existing natural gas applications • Feedstock does not compete with food production	• Gaseous fuel requiring large storage volumes and transportation to offshore facilities would pose difficulties • More common to convert to liquid advanced biofuels such as DME & F-T diesel

Discounted due to operability concerns

Bio-Oil

Feedstock: Lignocellulosic biomass (e.g. forestry residues, energy crops)

Production method: Pyrolysis

Pros	Cons
• Feedstock does not compete with food production • Can be produced from a wide range of waste materials	• Highly corrosive due to formic and acetic acids, difficult to modify existing turbines to cope with the acidic nature and low heating value • High viscosity • Unstable, not miscible with petroleum oils, often contains water

Discounted due to operability concerns

Bio-Hydrogen

Feedstock: Biomass and biogas

Production method: Microbial fermentation of sugars during which hydrogen is produced

Pros	Cons
• Lower cost than conventional green hydrogen • Potential to be carbon negative if obtained from feedstocks such as waste or manure	• Currently producing low yields with further research required into suitable microorganisms • Traditional green hydrogen has been discounted during fuel screening. Bio-hydrogen is less readily available so offers no improvement

Discounted due to operational concerns

Bio-Electricity

Feedstock: Biomass and biogas

Production method: Gasification of biomass to produce power

Pros	Cons
• A clean renewable electricity can be produced from a wide range of biomass	• Less developed than conventional renewable electricity methods (e.g. wind, solar) • Energy would need to be produced onshore and distributed to platform • Operator A have completed offshore electrification screening for the Asset A platform and found it to not be a reasonable balance between maximising economic recovery and net zero

Discounted due to operational concerns

Biofuels

- The remaining options were assessed with regards to their Technology Readiness Levels and supply chains

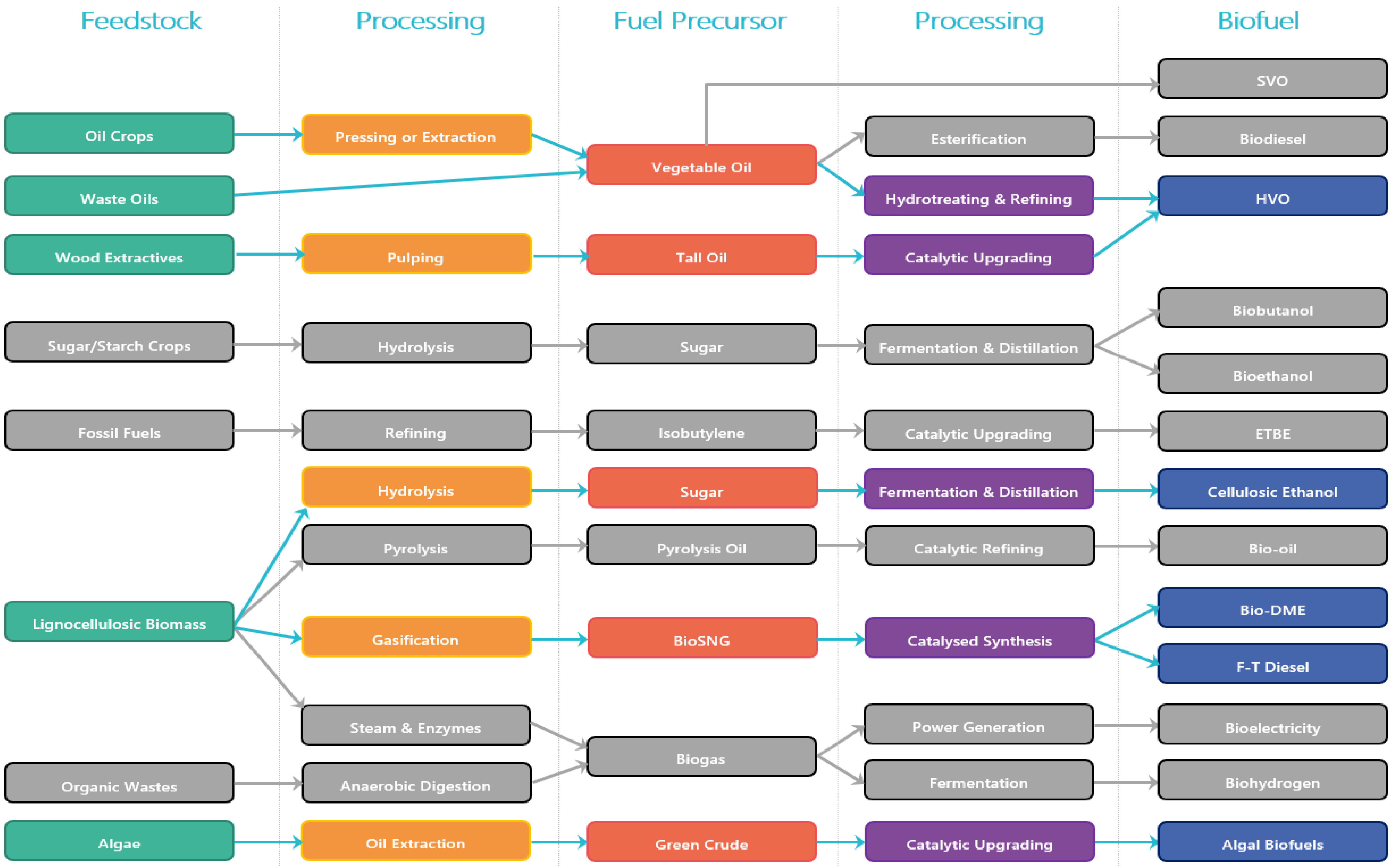
Bio-DME

F-T Diesel

Cellulosic Ethanol

HVO

Algal Biofuels



Feedstock
Processing
Fuel Precursor
Processing
Biofuel
SVO
Oil Crops
Pressing or Extraction
Esterification
Biodiesel
Vegetable Oil
Waste Oils
Hydrotreating & Refining
HVO
Wood Extractives
Pulping
Tall Oil
Catalytic Upgrading
Biobutanol
Sugar/Starch Crops
Hydrolysis
Sugar
Fermentation & Distillation
Bioethanol
Fossil Fuels
Refining
Isobutylene
Catalytic Upgrading
ETBE
Hydrolysis
Sugar
Fermentation & Distillation
Cellulosic Ethanol
Pyrolysis
Pyrolysis Oil
Catalytic Refining
Bio-oil
Bio-DME
Lignocellulosic Biomass
Gasification
BioSNG
Catalysed Synthesis
F-T Diesel
Steam & Enzymes
Power Generation
Bioelectricity
Biogas
Organic Wastes
Anaerobic Digestion
Fermentation
Biohydrogen
Algae
Oil Extraction
Green Crude
Catalytic Upgrading
Algal Biofuels

F-T Diesel (Biomass to Liquids)

Feedstock: Lignocellulosic biomass

Production method: Gasification of biomass followed by conversion to liquid biofuels via Fischer Tropsch

Pros	Cons
• Good viscosity, density and calorific energy properties • Each stage of process is developed • Current and announced commercial FT installations indicate nearly 300 million litres of FT liquid production by 2025 (Asset A demand is potentially > 24 % of production)	• Not currently beyond the development stage • Very little F-T diesel currently produced globally

Algal Biofuels

Feedstock: Algae

Production method: Oil extraction followed by catalytic upgrading

Pros	Cons
• Low cost and no competition for food resources, algae grow in large concentrations on ponds • Algal formations can remove GHG from the atmosphere	• Development towards commercialisation has stalled due to struggles developing algal species with high enough oil production per m^3 • Global research investment has dried up suggesting commercialisation is multiple decades away

Bio-DME

Feedstock: Lignocellulosic biomass

Production method: Gasification followed by gas shift, synthesis and distillation

Pros	Cons
• Capable of using waste from industries • Each stage of process is developed • Similar properties to LPG	• Technology is currently at demonstration scale • Historically conventional DME is used as a fuel additive rather than a standalone fuel

Cellulosic Ethanol

Feedstock: Lignocellulosic biomass (e.g. forestry residues, energy crops)

Production method: Cellulose hydrolysis of agricultural residues

Pros	Cons
• Utilises more sustainable feedstock than conventional bioethanol • Feasibility has been proven • Ambitious estimates suggest 3,800 million litres could be produced in EU by 2030 . Asset A demand is 3 % of this prediction. Note: The forecast assumes a favourable policy environment extending beyond 2030 exists for cellulosic ethanol, which would make the ramp up to 2030 viable.	• Worlds largest CE producer, Raízen, guarantees only 280 million litres by 2024 • Turbine OEM A are not doing any development work on ethanol e.g. they don't have ethanol fuel injectors or any data using ethanol in any of their turbines. • EU production in 2017 at 31 million litres • Low mass and energy density

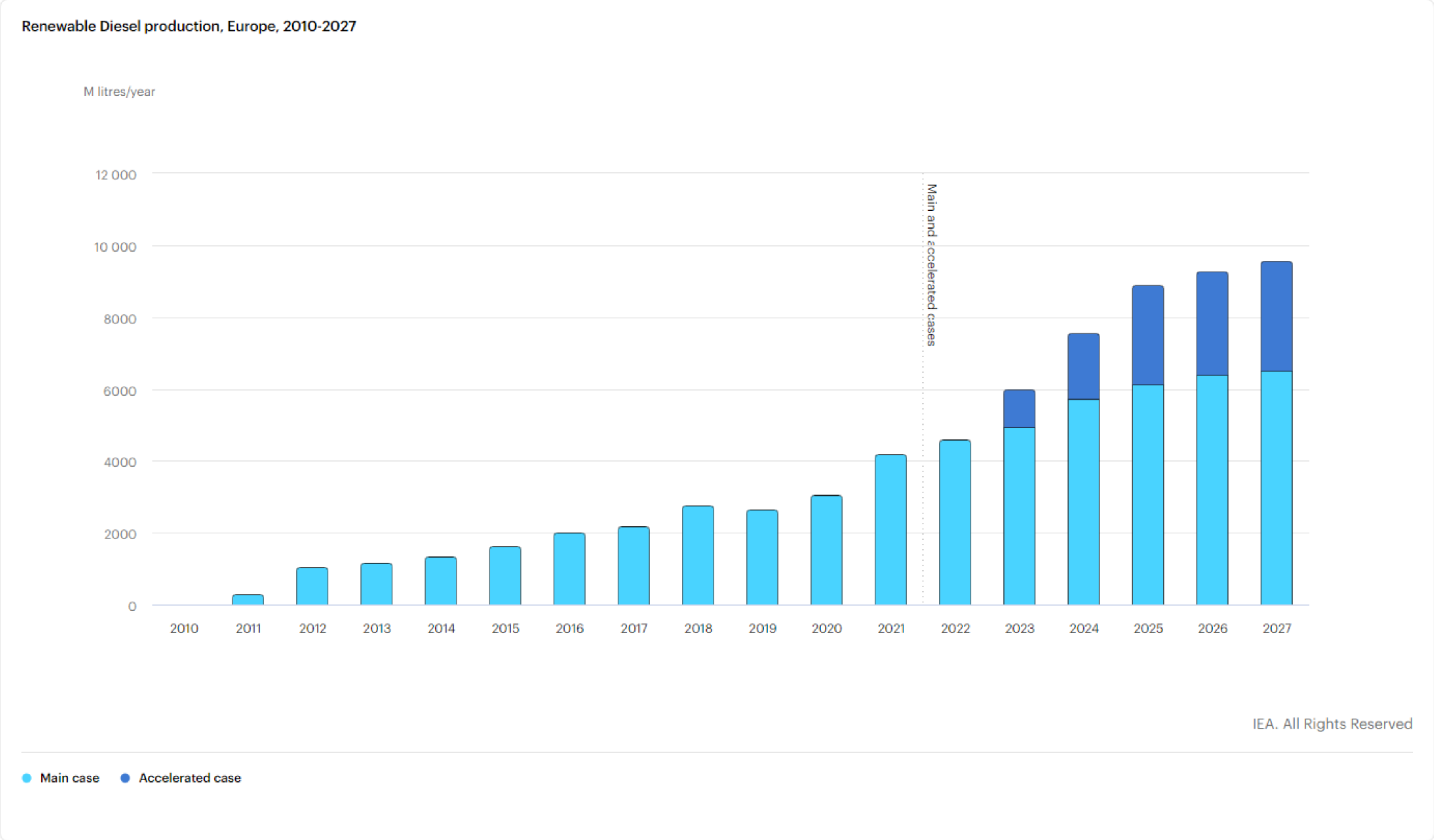
HVO

Feedstock: Oil crops, tall oil & industrial waste oils (used cooking oil)

Production method: Hydroprocessing of oils and fats

Pros	Cons
• IEA main case world production 2027 = 26,588 million litres per year (potentially 6,511 - 9,566 million litres per year in Europe 2027 main vs accelerated cases). Asset A demand is < 0.3 % of global production. • Feasible to use as a fuel source for GTs • Low freezing point (-25C to -40C) • Low water solubility (non-polar as per fossil diesel) • Good filterability, not prone to precipitation above the cloud point • Stability is similar to fossil diesel so no need for a 'use by' date as there is for biodiesel	• Material compatibility typically similar to fossil diesel - In principle, the lack of aromatic compounds may shrink elastomers that have already been swollen due to aromatic or FAME containing fuels, but Neste have experienced no leakage during 12 years field operations. • Slightly lower density than diesel so review of existing re-used pumps, etc. required (HVO density 780 kg/m^3, conventional diesel circa 830 kg/m^3).

HVO European Supply



IEA (2022), Renewables 2022, IEA, Paris https://www.iea.org/reports/renewables-2022, License: CC BY 4.0

Bioethanol and Cellulosic Ethanol

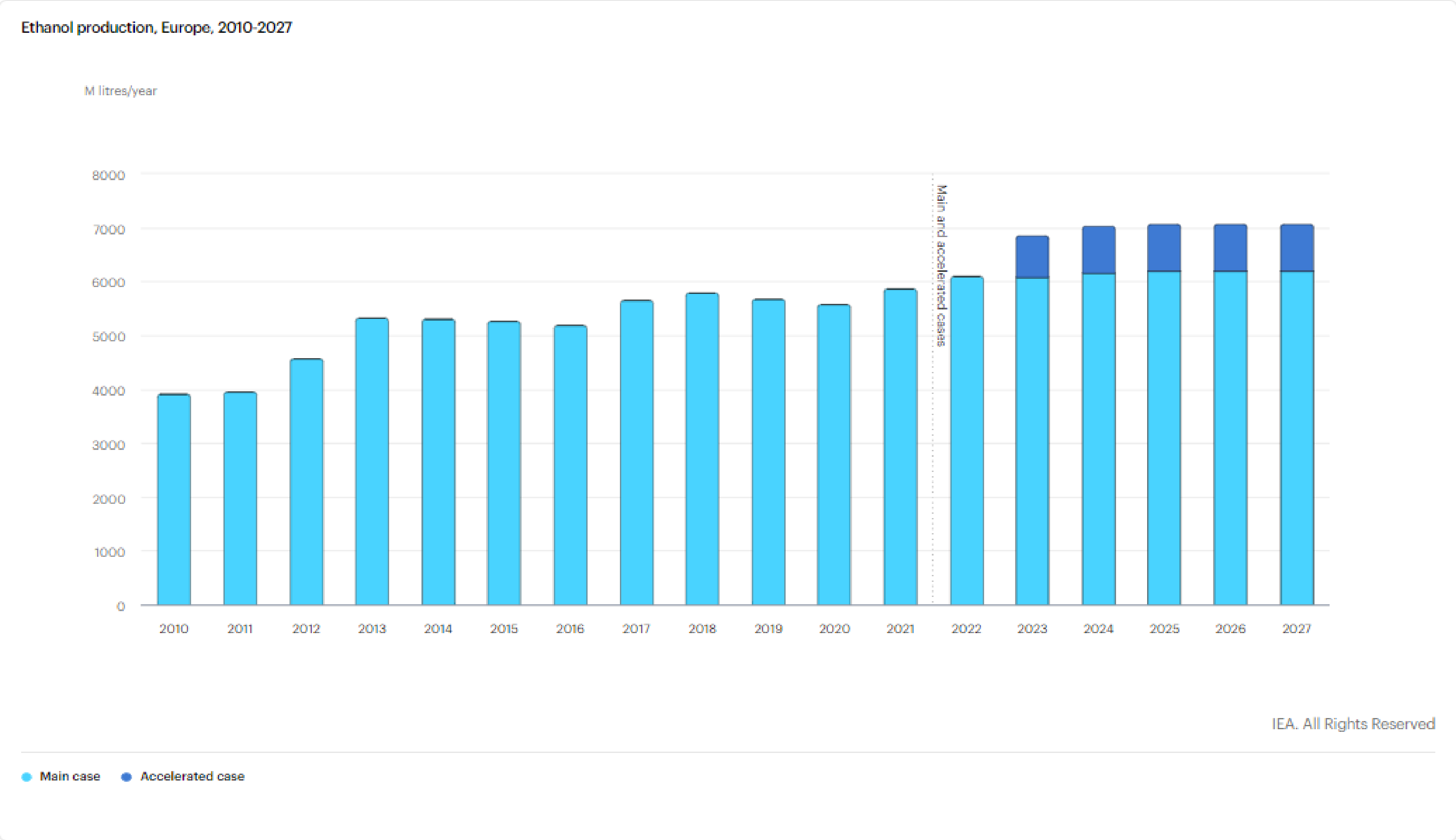
- Earlier bioethanol was discounted based on sustainability concerns however a combination of bioethanol and cellulosic ethanol supplies may be worth considering as biofuels suppliers are working to address sustainability concerns, and bioethanol makes up > 10 % of biofuel production:

"Biofuel producers are also seeking feedstocks produced on degraded land or from crops planted during what were previously fallow periods to increase acreage without appropriating land that would otherwise be used for food and feed production. In Brazil, for instance, 75% of corn ethanol production comes from second-crop production in existing fields. In Europe, some biofuel producers are sourcing oilseeds grown on degraded terrain to meet RED II sustainability criteria, and bio-based diesel feedstock producers globally are establishing new supply chains for bio-oils such as tall oil and fish oil, and expanding those for animal fats and used cooking oil." IEA Renewables 2022 Report - Analysis and Forecast to 2027

HVO UK Supply

- From discussions with fuel suppliers Crown Oil and Prema Energy, plus data in the IEA website:
- All UK HVO is imported.
- There is 364 million litres HVO imported into the UK each year (mostly made from waste oil as the feedstock).
- This is via weekly ship cargos averaging 7 million litres / week.
- Asset A weekly demand for the highest load case (Case 3) is 2.5 million litres (35 % of current imports to the UK).

Ethanol European Supply



IEA (2022), Renewables 2022, IEA, Paris https://www.iea.org/reports/renewables-2022, License: CC BY 4.0

Biofuel Selection

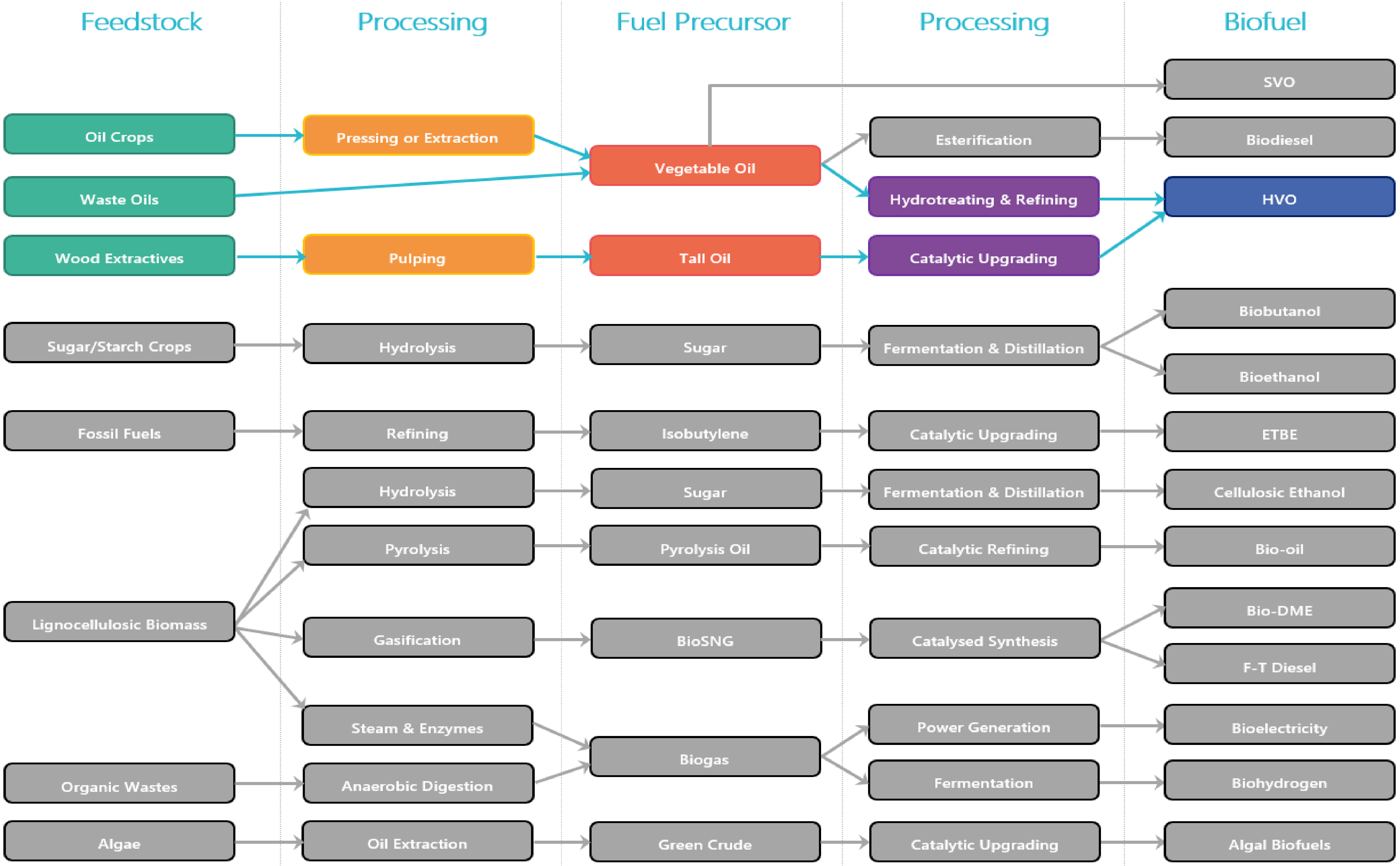
Biofuel	TRL	Current Supply Chain	8,000 hrs Run Time Asset A Consumption (Million Litres)	LHV (MJ/kg)	Density at 20°C (kg/m^3)	Lifecycle Emissions (kgCO_2eq/kg Fuel)
Conventional Diesel	*9*	*Well Established*	*N/A*	*43.1*	*830*	*3.2*
F-T Diesel	6	-	-	43.9	785	1.0 – 2.3
Algal Biofuels	5	-	-	Biodiesel: ~38 Bioethanol: ~26	Biodiesel: ~880 Bioethanol: ~800	0.4 – 1.0
Bio-DME	6	-	-	28.4	670	0.2
Cellulosic Ethanol	9	EU production in 2017 at 31 million litres. Ambitious estimates suggest 3,800 million litres could be produced in EU by 2030.	119	26.7	790	0.3 – 0.4
Bioethanol	9	Potentially 6,196 -7,068 million litres per year in EU 2027 (may be an option to support the supply of cellulosic ethanol)	119	26.7	790	-0.4 – 2.7*
HVO	9	Potentially 9,566 million litres could be produced in the EU by 2027. However, there are expected to be supply constraints related to manufacturing and increased demand.	73	44.4	780	0.6 – 3.2**
Renewable Methanol (bio & e-methanol)	9	Potentially 9,981 million litres globally by 2027 (note that this row is global whereas the above rows show EU production)	158	19.9	802	-1.1 – 0.8***

* For Miscanthus (herbaceous energy crops) and corn grain derived biooethanol respectively
**For waste cooking oil derived HVO and rapeseed oil derived HVO respectively
***For biomethane from cow manure and maize derived methanol respectively

Biofuel Selection

- In addition to studying renewable methanol, HVO and bioethanol / cellulosic ethanol are the best options.
- Given that Turbine OEM A are not doing any development work on ethanol (e.g., they don't have ethanol fuel injectors or any data using ethanol in any of their turbines), progressing with an ethanol fuel would be higher risk.
- Methanol as a fuel type is more comparable to ethanol than HVO. Choosing HVO will allow for a more diverse pairing of alternative fuels for the alternative fuels study.
- HVO is the recommended biofuel

HVO



Feedstock
Processing
Fuel Precursor
Processing
Biofuel
SVO
Oil Crops
Pressing or Extraction
Esterification
Biodiesel
Vegetable Oil
Waste Oils
Hydrotreating & Refining
HVO
Wood Extractives
Pulping
Tall Oil
Catalytic Upgrading
Biobutanol
Sugar/Starch Crops
Hydrolysis
Sugar
Fermentation & Distillation
Bioethanol
Fossil Fuels
Refining
Isobutylene
Catalytic Upgrading
ETBE
Hydrolysis
Sugar
Fermentation & Distillation
Cellulosic Ethanol
Pyrolysis
Pyrolysis Oil
Catalytic Refining
Bio-oil
Bio-DME
Lignocellulosic Biomass
Gasification
BioSNG
Catalysed Synthesis
F-T Diesel
Steam & Enzymes
Power Generation
Bioelectricity
Biogas
Organic Wastes
Anaerobic Digestion
Fermentation
Biohydrogen
Algae
Oil Extraction
Green Crude
Catalytic Upgrading
Algal Biofuels

APPENDIX B THERMAL EFFICIENCY CURVE

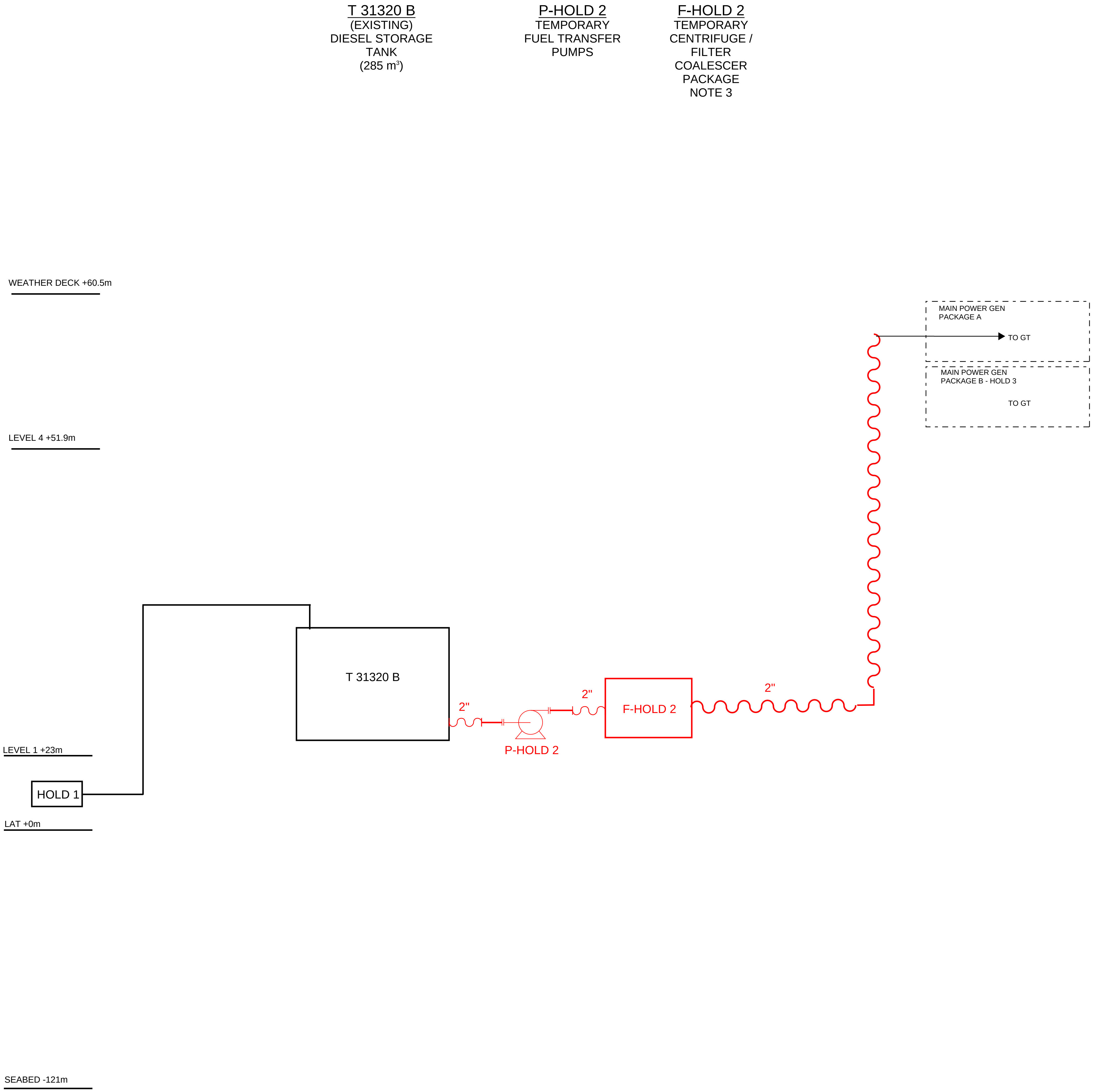
B.1 Turbine OEM A Model A

REDACTED

APPENDIX C NOV SUBSEA STORAGE PRESENTATION

REDACTED

APPENDIX D CONCEPT PFDS



NOTES

1. POWER LOAD SCENARIO FOR OPTION 1A CONSIDERS MAIN POWER GENERATORS OPERATING DURING TAR SHUTDOWN AT 1.5 MW.
2. FOR CONCEPT 1A THE FOLLOWING TEMPORARY MODIFICATIONS WILL BE MADE PRIOR TO TAR SHUTDOWN:
   - REPURPOSING OF EXISTING DIESEL STORAGE TANK FOR ALT FUEL STORAGE.
   - TEMPORARY CENTRIFUGE / FILTER COALESCER AND PUMPS TO BE INSTALLED.
   - FLEXIBLE HOSING REQUIRED TO TRANSFER ALT FUEL TO MAIN POWER GENERATOR PACKAGES.
3. CENTRIFUGE / FILTER COALESCER PACKAGE REQUIRED FOR REMOVAL OF ENTRAINED WATER FROM HVO. NO EQUIVALENT UNIT PROPOSED FOR METHANOL SERVICE DUE TO WATER BEING MISCIBLE WITH METHANOL HENCE SEPARATE WATER PHASE NOT EXPECTED.

HOLDS

1. FUEL LOADING PHILOSOPHY TO BE CONFIRMED.
2. EQUIPMENT TAG NUMBERS TO BE CONFIRMED.
3. EXISTING DIESEL SYSTEM CAN SUPPLY SECONDARY GENERATOR AS BACK-UP.

DRAWING No.	DRAWING TITLE

REFERENCE DRAWINGS

REV	DATE	REVISION	BY	CHK	ENG	CHK	PM
R01	25/09/23	ISSUED FOR INTERNAL REVIEW	SG		SG		

PROJECT
FUEL SWITCHING STUDY

CLIENT: Net Zero Technology Centre

XODUS

XODUS DRG. No.
XODUS DOC. NO.

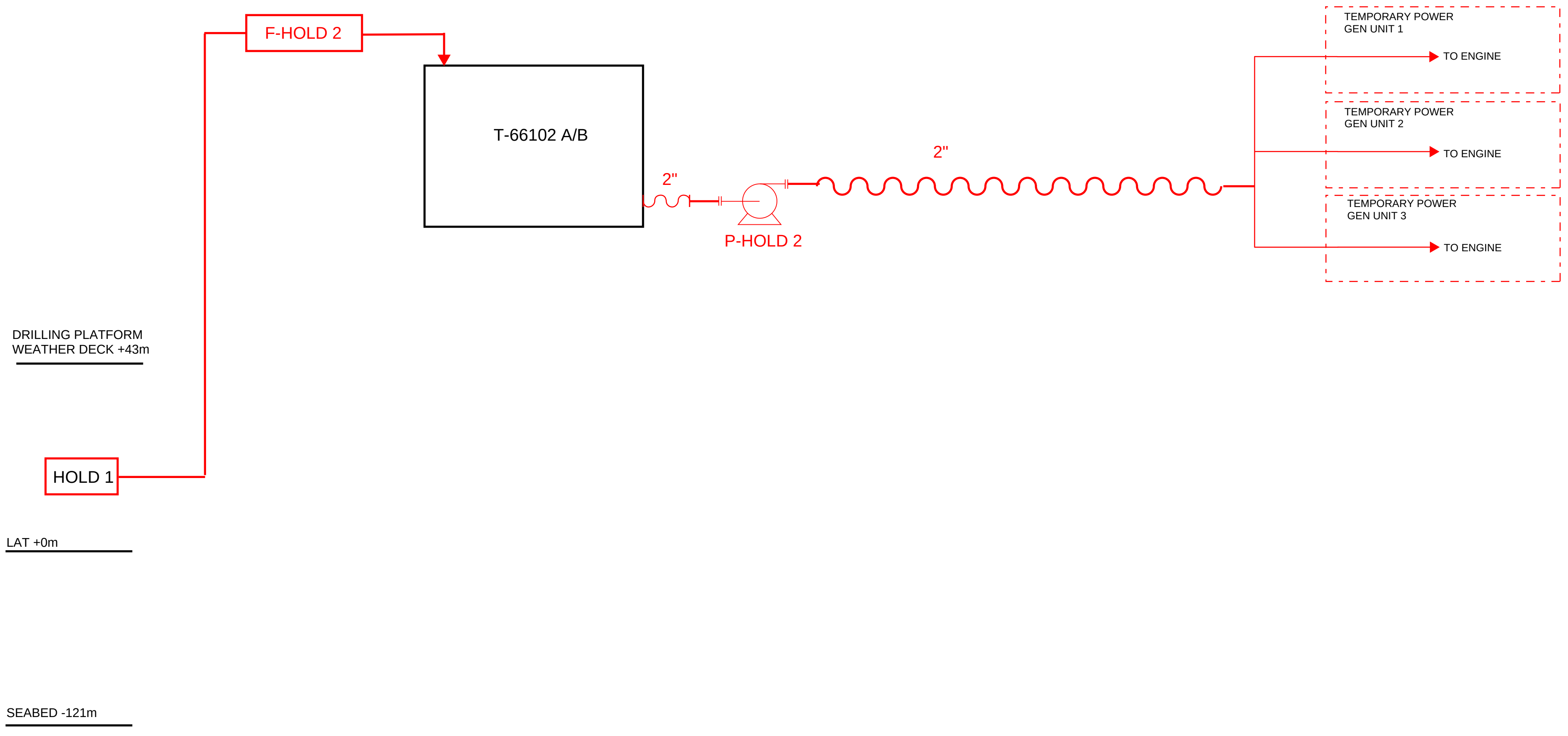
TITLE
PROCESS SCHEMATIC
ALT FUELS STORAGE AND DISTRIBUTION
OPTION 1A

DRAWN	DATE	OFFICE	ASSIGN. No.	SCALE	DWG SIZE
CHECKED	DATE	LON	A100870	NTS	A1
ENG.	DATE	CAD REF. N/A			
CLIENT APP.	DATE	DRAWING NUMBER A100870-S00-P-PFD-001		REV. R01	

F-HOLD 2 A/B
TEMPORARY FUEL SOLIDS FILTER

T-66102 A/B
(EXISTING)
BASE OIL TANKS
(2 X 55 m^3)

P-HOLD 2 A/B
TEMPORARY FUEL TRANSFER PUMPS



NOTES

1. POWER LOAD SCENARIO FOR OPTION 1B CONSIDERS TEMPORARY POWER GENERATORS OPERATING DURING TAR SHUTDOWN AT 1.5 MW.
2. FOR CONCEPT 1B THE EQUIPMENT IS TO BE LOCATED ON THE DRILLING PLATFORM WEATHER DECK IN PROXIMITY TO THE TEMPORARY POWER GENERATORS. TEMPORARY FLEXIBLE HOSING WILL BE REQUIRED TO TRANSFER ALT FUEL TO TEMPORARY HV POWER PACKAGES.

HOLDS

1. FUEL LOADING PHILOSOPHY TO BE CONFIRMED.
2. EQUIPMENT TAG NUMBERS TO BE CONFIRMED.

DRAWING No.	DRAWING TITLE

REFERENCE DRAWINGS

REV	DATE	REVISION	BY	CHK	ENG	CHK	PM
R01	25/09/23	ISSUED FOR INTERNAL REVIEW	SG		SG		

PROJECT
FUEL SWITCHING STUDY

XODUS

CLIENT
Net Zero Technology Centre
Technology Driving Transition

XODUS DRG. No.
XODUS DOC. NO.

TITLE
PROCESS SCHEMATIC
ALT FUELS STORAGE AND DISTRIBUTION
OPTION 1B

DRAWN	DATE	OFFICE	ASSIGN. No.	SCALE	DWG SIZE
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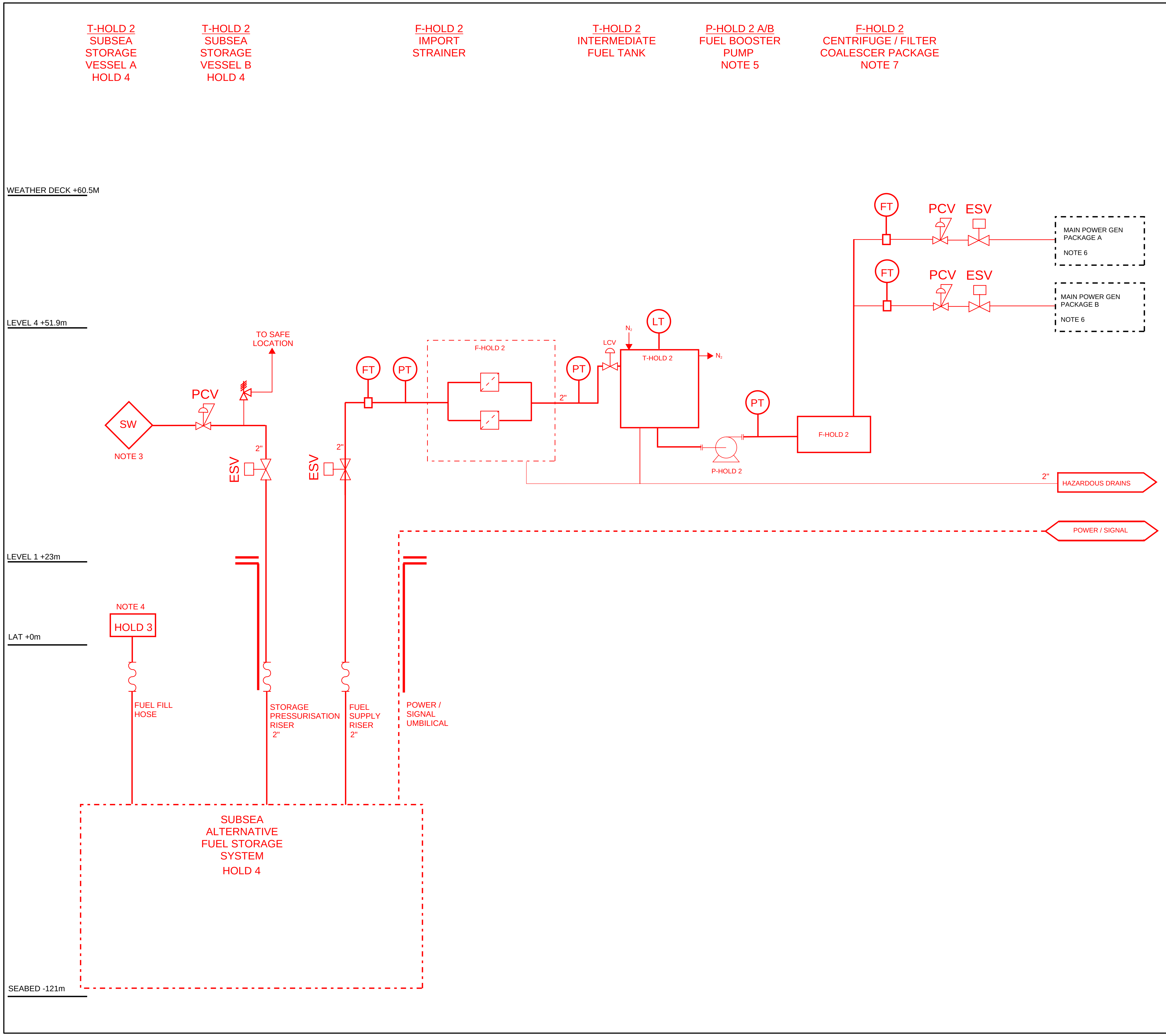

NOTES

1. POWER LOAD SCENARIO FOR OPTION 2A CONSIDERS MAIN POWER GENERATORS OPERATING DURING NORMAL OPERATION AT 6.0 MW
2. TO ALLOW 14 DAYS FUEL STORAGE, THE FOLLOWING MINIMUM CAPACITIES ARE REQUIRED:
   HVO 998 m^3
   METHANOL 2167 m^3
3. TIE-IN TO SEAWATER UTILITY AT LEVEL 1.
4. LOCATED OUTSIDE PLATFORM 500M ZONE.
5. DUTY / STANDBY PUMP CONFIGURATION.
6. REFER TO SUPPORTING REPORT FOR REQUIRED POWER GENERATION PACKAGE MODIFICATIONS.
7. CENTRIFUGE / FILTER COALESCER PACKAGE REQUIRED FOR REMOVAL OF ENTRAINED WATER FROM HVO. NO EQUIVALENT UNIT PROPOSED FOR METHANOL SERVICE DUE TO WATER BEING MISCIBLE WITH METHANOL HENCE SEPARATE WATER PHASE NOT EXPECTED.

HOLDS

1. BUFFER TANK LOCATION AND DIMENSIONS TO BE CONFIRMED.
2. EQUIPMENT TAG NUMBERS TO BE CONFIRMED.
3. FUEL OFFLOADING CONNECTION, LOCATION, MOORING & BUOY TYPE TO BE CONFIRMED.
4. ALL SUBSEA EQUIPMENT & INSTRUMENTATION DETAILS TO BE CONFIRMED.

DRAWING No.	DRAWING TITLE

REFERENCE DRAWINGS

REV	DATE	REVISION	BY	CHK	ENG	CHK	PM
R01	02/10/23	ISSUED FOR INTERNAL REVIEW	SG		SG		

PROJECT: FUEL SWITCHING STUDY

CLIENT: Net Zero Technology Centre

XODUS DRG. No.: XODUS DOC. NO.

TITLE: PROCESS FLOW DIAGRAM
ALT FUELS STORAGE AND DISTRIBUTION
OPTION 2A

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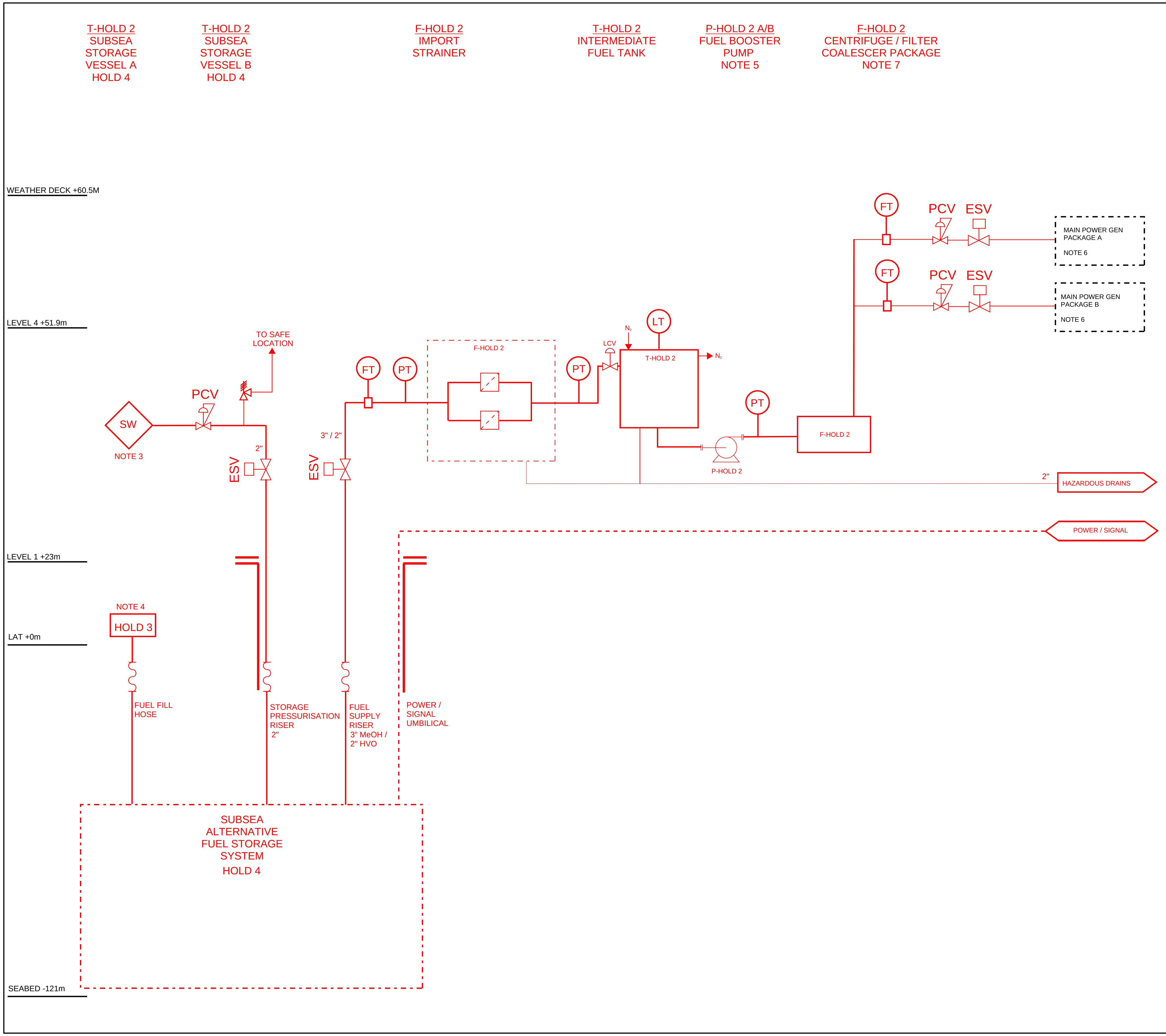

NOTES

1. POWER LOAD SCENARIO FOR OPTION 2B CONSIDERS MAIN POWER GENERATORS OPERATING DURING NORMAL OPERATION, POST-LPBC ELECTRIFICATION, AT 10.4 MW
2. TO ALLOW 14 DAYS FUEL STORAGE, THE FOLLOWING MINIMUM CAPACITIES ARE REQUIRED:
   HVO 1371 m^3
   METHANOL 2976 m^3
3. TIE-IN TO SEAWATER UTILITY AT LEVEL 1.
4. LOCATED OUTSIDE PLATFORM 500M ZONE.
5. DUTY / STANDBY PUMP CONFIGURATION.
6. REFER TO SUPPORTING REPORT FOR REQUIRED POWER GENERATION PACKAGE MODIFICATIONS.
7. CENTRIFUGE / FILTER COALESCER PACKAGE REQUIRED FOR REMOVAL OF ENTRAINED WATER FROM HVO. NO EQUIVALENT UNIT PROPOSED FOR METHANOL SERVICE DUE TO WATER BEING MISCIBLE WITH METHANOL HENCE SEPARATE WATER PHASE NOT EXPECTED.

HOLDS

1. BUFFER TANK LOCATION AND DIMENSIONS TO BE CONFIRMED.
2. EQUIPMENT TAG NUMBERS TO BE CONFIRMED.
3. FUEL OFFLOADING CONNECTION, LOCATION, MOORING & BUOY TYPE TO BE CONFIRMED.
4. ALL SUBSEA EQUIPMENT & INSTRUMENTATION DETAILS TO BE CONFIRMED.

DRAWING No.	DRAWING TITLE

REFERENCE DRAWINGS

REV	DATE	REVISION	BY	CHK	ENG	CHK	PM
R01	02/10/23	ISSUED FOR INTERNAL REVIEW	SG		SG		

PROJECT: FUEL SWITCHING STUDY

CLIENT: Net Zero Technology Centre — Technology Driving Transition

XODUS

XODUS DRG. No.: XODUS DOC. NO.

TITLE

PROCESS FLOW DIAGRAM
ALT FUELS STORAGE AND DISTRIBUTION
OPTION 2B

DRAWN	DATE	OFFICE	ASSIGN. No.	SCALE	DWG SIZE
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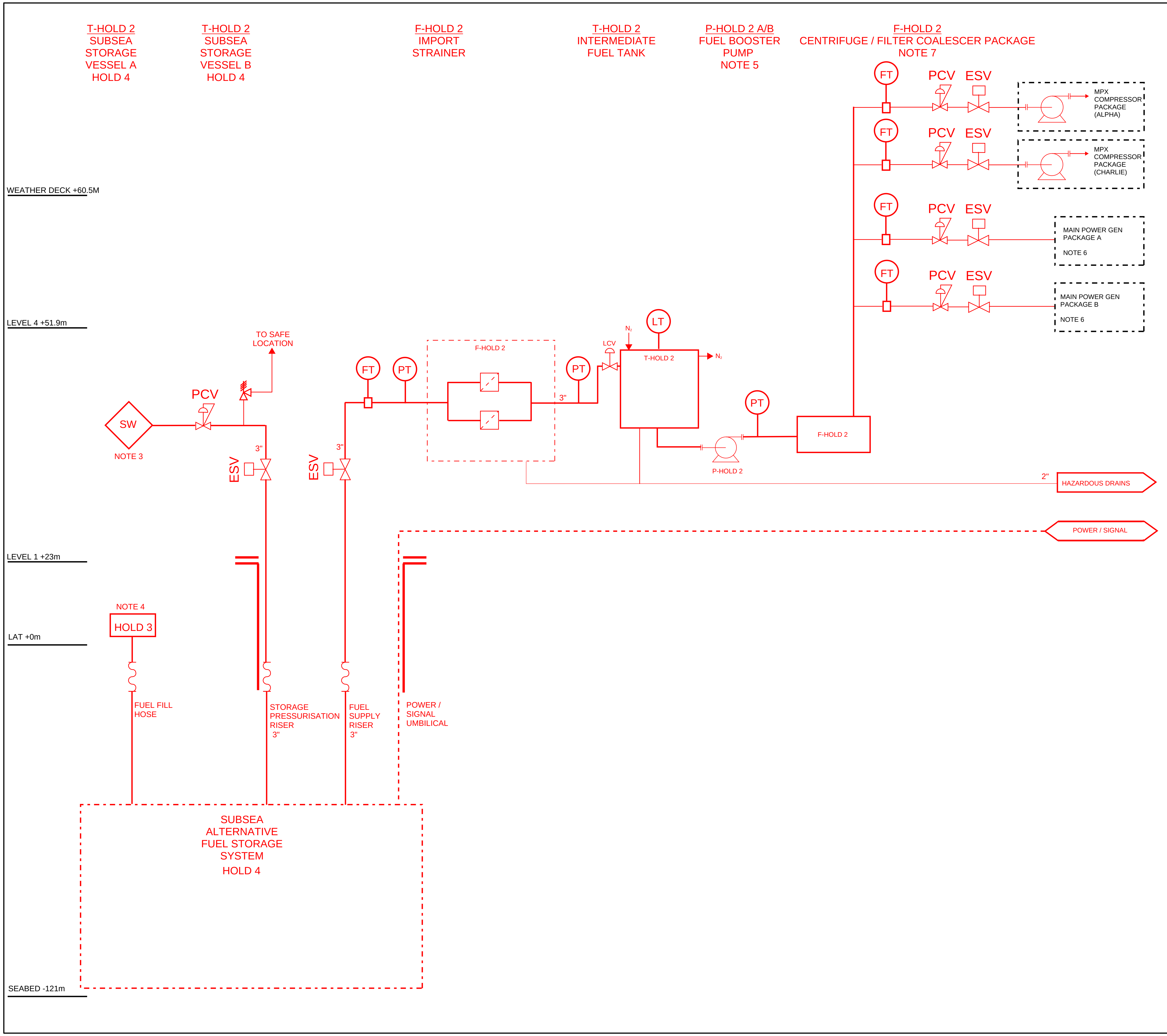

NOTES

1. POWER LOAD SCENARIO FOR OPTION 3A CONSIDERS MAIN POWER GENERATORS OPERATING DURING NORMAL OPERATION, POST-LPBC ELECCTRIFICATION, AT 10.4 MW - PLUS THE MP/EXPORT COMPRESSION AT 16.8 MW.
2. TO ALLOW 14 DAYS FUEL STORAGE, THE FOLLOWING MINIMUM CAPACITIES ARE REQUIRED:
HVO 3047 m^3
METHANOL 6616 m^3
3. TIE-IN TO SEAWATER UTILITY AT LEVEL 1.
4. LOCATED OUTSIDE PLATFORM 500M ZONE.
5. DUTY / STANDBY PUMP CONFIGURATION.
6. REFER TO SUPPORTING REPORT FOR REQUIRED POWER GENERATION PACKAGE MODIFICATIONS.
7. CENTRIFUGE / FILTER COALESCER PACKAGE REQUIRED FOR REMOVAL OF ENTRAINED WATER FROM HVO. NO EQUIVALENT UNIT PROPOSED FOR METHANOL SERVICE DUE TO WATER BEING MISCIBLE WITH METHANOL HENCE SEPARATE WATER PHASE NOT EXPECTED.

HOLDS

1. BUFFER TANK LOCATION AND DIMENSIONS TO BE CONFIRMED.
2. EQUIPMENT TAG NUMBERS TO BE CONFIRMED.
3. FUEL OFFLOADING CONNECTION, LOCATION, MOORING & BUOY TYPE TO BE CONFIRMED.
4. ALL SUBSEA EQUIPMENT & INSTRUMENTATION DETAILS TO BE CONFIRMED.

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REFERENCE DRAWINGS

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PROJECT
FUEL SWITCHING STUDY

XODUS

CLIENT
Net Zero Technology Centre
Technology Driving Transition

XODUS DRG. No.
XODUS DOC. NO.

TITLE
PROCESS FLOW DIAGRAM
ALT FUELS STORAGE AND DISTRIBUTION
OPTION 3A - SSU

DRAWN	DATE	OFFICE	ASSIGN. No.	SCALE	DWG SIZE
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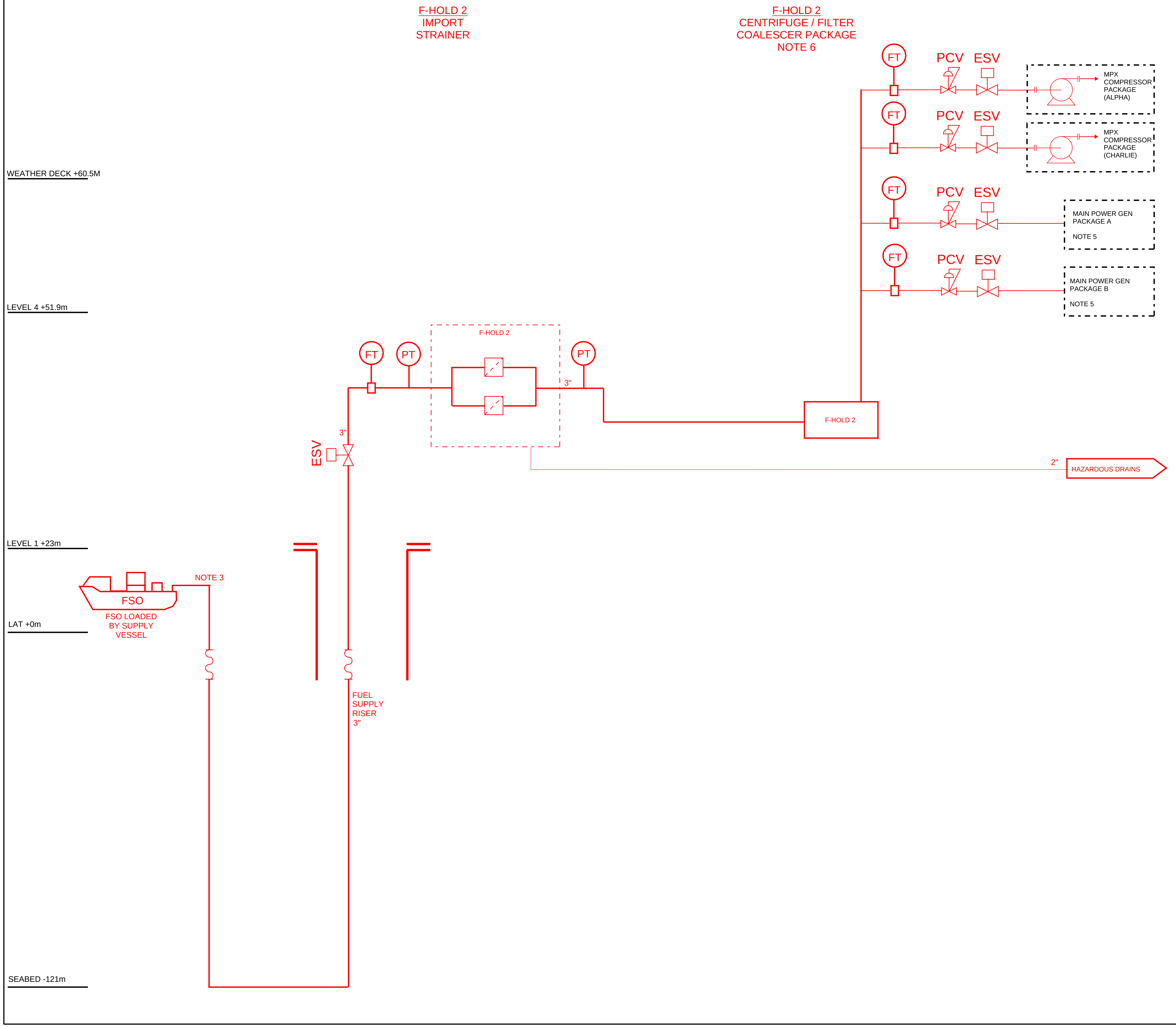

NOTES

1. POWER LOAD SCENARIO FOR OPTION 3B CONSIDERS MAIN POWER GENERATORS OPERATING DURING NORMAL OPERATION, POST-LPBC ELECCTRIFICATION, AT 10.4 MW - PLUS THE MP/EXPORT COMPRESSION AT 16.8 MW.
2. TO ALLOW 14 DAYS FUEL STORAGE, THE FOLLOWING MINIMUM CAPACITIES ARE REQUIRED:

HVO	3047 m^3
METHANOL	6616 m^3

3. LOCATED OUTSIDE PLATFORM 500M ZONE.
4. DUTY / STANDBY PUMP CONFIGURATION.
5. REFER TO SUPPORTING REPORT FOR REQUIRED POWER GENERATION PACKAGE MODIFICATIONS.
6. CENTRIFUGE / FILTER COALESCER PACKAGE REQUIRED FOR REMOVAL OF ENTRAINED WATER FROM HVO. NO EQUIVALENT UNIT PROPOSED FOR METHANOL SERVICE DUE TO WATER BEING MISCIBLE WITH METHANOL HENCE SEPARATE WATER PHASE NOT EXPECTED.

HOLDS

1. BUFFER TANK LOCATION AND DIMENSIONS TO BE CONFIRMED.
2. EQUIPMENT TAG NUMBERS TO BE CONFIRMED.
3. FUEL OFFLOADING CONNECTION, LOCATION, MOORING & BUOY TYPE TO BE CONFIRMED.

DRAWING No.	DRAWING TITLE

REFERENCE DRAWINGS

REV	DATE	REVISION	BY	CHK	ENG	CHK	PM
R01	02/10/23	ISSUED FOR INTERNAL REVIEW	SG		SG		

PROJECT
FUEL SWITCHING STUDY

CLIENT

XODUS DRG. No.
XODUS DOC. NO.

TITLE
PROCESS FLOW DIAGRAM
ALT FUELS STORAGE AND DISTRIBUTION
OPTION 3B - SINGLE FSO

DRAWN	DATE	OFFICE	ASSIGN. No.	SCALE	DWG SIZE
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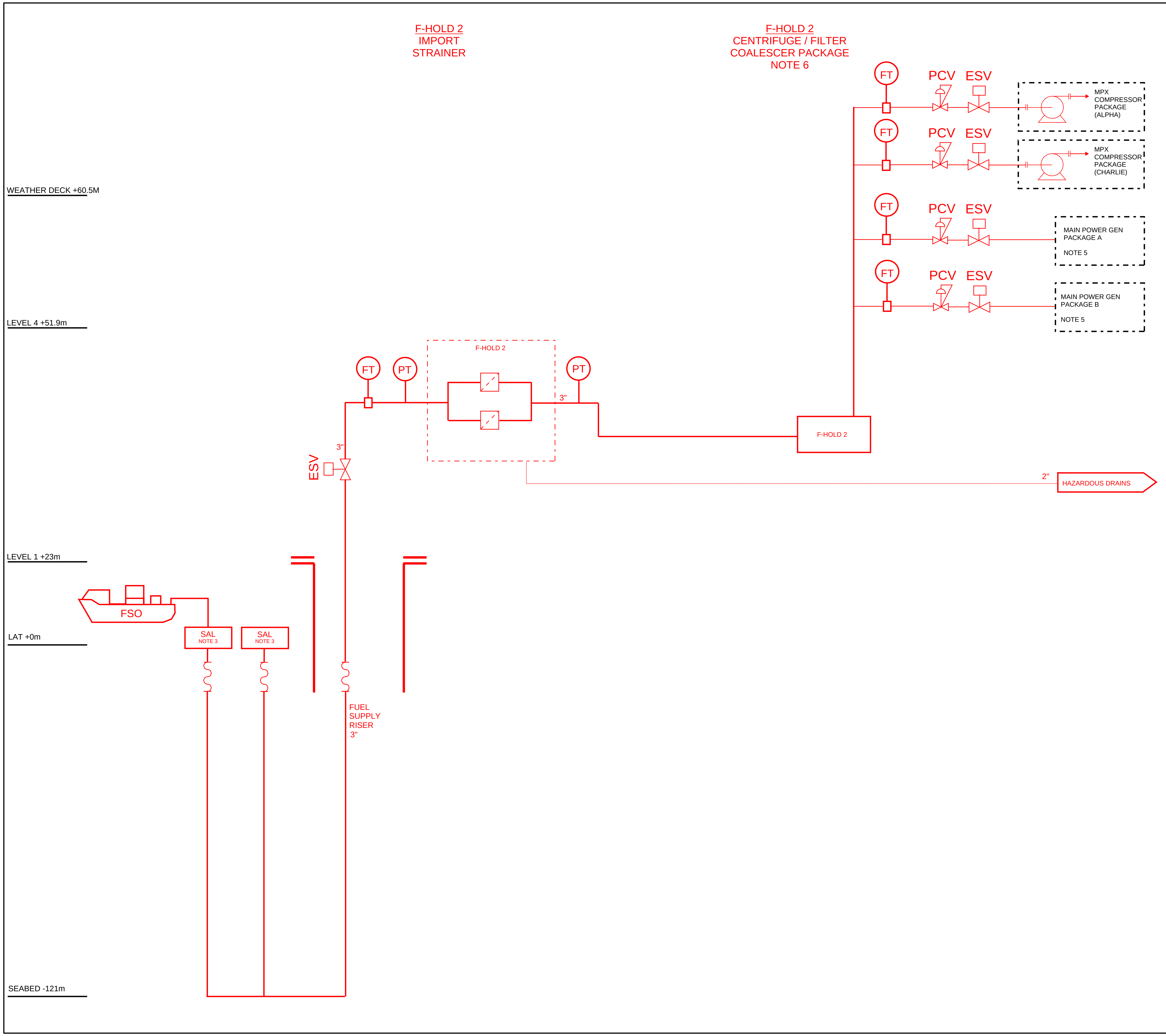

NOTES

1. POWER LOAD SCENARIO FOR OPTION 3B CONSIDERS MAIN POWER GENERATORS OPERATING DURING NORMAL OPERATION, POST-LPBC ELECCTRIFICATION, AT 10.4 MW - PLUS THE MP/EXPORT COMPRESSION AT 16.8 MW.
2. TO ALLOW 14 DAYS FUEL STORAGE, THE FOLLOWING MINIMUM CAPACITIES ARE REQUIRED:

HVO	3047 m^3
METHANOL	6616 m^3

3. LOCATED OUTSIDE PLATFORM 500M ZONE.
4. DUTY / STANDBY PUMP CONFIGURATION.
5. REFER TO SUPPORTING REPORT FOR REQUIRED POWER GENERATION PACKAGE MODIFICATIONS.
6. CENTRIFUGE / FILTER COALESCER PACKAGE REQUIRED FOR REMOVAL OF ENTRAINED WATER FROM HVO. NO EQUIVALENT UNIT PROPOSED FOR METHANOL SERVICE DUE TO WATER BEING MISCIBLE WITH METHANOL HENCE SEPARATE WATER PHASE NOT EXPECTED.

HOLDS

1. BUFFER TANK LOCATION AND DIMENSIONS TO BE CONFIRMED.
2. EQUIPMENT TAG NUMBERS TO BE CONFIRMED.
3. FUEL OFFLOADING CONNECTION, LOCATION, MOORING & BUOY TYPE TO BE CONFIRMED.

DRAWING No.	DRAWING TITLE

REFERENCE DRAWINGS

REV	DATE	REVISION	BY	CHK	ENG	CHK	PM
R01	02/10/23	ISSUED FOR INTERNAL REVIEW	SG		SG		

PROJECT
FUEL SWITCHING STUDY

XODUS

CLIENT
Net Zero Technology Centre
Technology Driving Transition

XODUS DRG. No.
XODUS DOC. NO.

TITLE
PROCESS FLOW DIAGRAM
ALT FUELS STORAGE AND DISTRIBUTION
OPTION 3C - DUEL FSO

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CHECKED	DATE			CAD REF: N/A	
ENG.	DATE	DRAWING NUMBER: A100870-S00-P-PFD-007			REV.: R01
CLIENT APP.	DATE				

APPENDIX E EQUIPMENT LISTS

REDACTED

APPENDIX F CAPEX ESTIMATE SUMMARIES

REDACTED

APPENDIX G POST TAX CALCULATIONS (HIGH HIGH CASE)

REDACTED

APPENDIX H POST TAX CALCULATIONS SENSITIVITIES

REDACTED