TotalEnergies EP South Africa B.V.

ENVIRONMENTAL AND SOCIAL IMPACT ASSESSMENT (ESIA) FOR THE OFFSHORE PRODUCTION RIGHT AND ENVIRONMENTAL AUTHORISATION APPLICATIONS FOR BLOCK 11B/12B - REF NO: 12/4/13 PR

Draft Environmental and Social Impact Assessment Report

REPORT NO: 41105306-358669-10
SEPTEMBER 2023

PUBLIC

TotalEnergies EP South Africa B.V.

ENVIRONMENTAL AND SOCIAL IMPACT ASSESSMENT (ESIA) FOR THE OFFSHORE PRODUCTION RIGHT AND ENVIRONMENTAL AUTHORISATION APPLICATIONS FOR BLOCK 11B/12B – REF NO: 12/4/13 PR

Draft Environmental and Social Impact Assessment Report

PUBLIC

PROJECT NO. 41105306

OUR REF. NO. REPORT NO: 41105306-358669-10

DATE: SEPTEMBER 2023

WSP

Building 1, Maxwell Office Park
Magwa Crescent West, Waterfall City
Midrand, 1685
South Africa

Phone: +27 11 254 4800

WSP.com

QUALITY CONTROL

Issue/revision	Final issue
Date	18 September 2023
Prepared by	Olivia Allen Rizqah Baker
Signature	
Checked by	Helen Crosby
Signature	
Authorised by	Olivia Allen
Signature	
Project number	41105306
Report number	41105306-358669-10

CONTENTS

TABLES

FIGURES

6 PROJECT DESCRIPTION

This section describes the current proposed Project components and activities as well as the exploration programme previously undertaken for Block 11B/12B. The location and characteristics of Block 11B/12B, the estimated gas and condensate resource and the proposed Project phases are described.

The section provides a detailed description of the technical activities to be undertaken in each of the Project phases and discusses resource consumption, waste generation and emissions from these activities. Marine environment and operational aspects are discussed together with the regulatory requirement for financial provisions to be made to ensure that funds are available for possible clean-up and remediation costs in case of an environmental incident.

TEEPSA is planning to develop Block 11B/12B if a Production Right (PR) is granted and if commercial agreements for the sale of the gas into the domestic market can be achieved. To date, no offtake agreement has been concluded.

Project alternatives, as required by the EIA Regulations 2014, as amended, are also described in this section.

6.1 BLOCK 11B/12B PRODUCTION RIGHT APPLICATION DETAILS

A PR application as defined in Section 83 of the MPRDA was submitted to the Competent Authority (CA) on 05 September 2022. The CA acknowledged receipt of the application on 19 September 2022. The PR application information is summarised in Table 6-1.

Table 6-1 –PR Application Information

Licence Block No.	11B/12B
Production Right Application No.	Ref. No. 12/4/13 PR
Number of wells	Up to 6[15] development and appraisal wells, in the south-western portion of the Block. Up to 4 exploration and appraisal wells, in the east-northeast portion of the Block.
Size of Area of Interest / application area	12 000 km^2
Water depth range	Water depth range of area of interest: 500 to 2 300 m
Distance offshore	75 km to 120 km

The extent of the PR Application Area is approximately 12 000 km^2. The north-east corner of the PR Application Area is approximately 75 km offshore from Cape St. Francis; the north-west corner is approximately 120 km offshore from Mossel Bay (see Figure 6-1).

[15] At this stage of the engineering design, five production wells will be drilled in the Project Development Area with the option for a sixth well should it be required.

TEEPSA is the main Joint Venture Partner (JV Partner) in the licence holding and the operator of the Block. Details on JV Partners are provided in Table 6-2.

Table 6-2 – Structure of Licence Holding and Shareholding of Block 11B/12B

Organisation	JV Partner Shareholding
TEEPSA	45%
Canadian Natural Resources International (South Africa) Limited	20%
QatarEnergy International E&P LLC (previously Qatar Petroleum International Upstream LLC)	25%
Main Street 1549	10%

The purpose of the PR application is to develop the discovery of commercially viable reserves of hydrocarbons and the effect will be to transition from the expired Exploration Right (Section 6.2) to a PR.

6.2 PREVIOUS EXPLORATION ACTIVITIES IN BLOCK 11B/12B

Exploration activities in Block 11B/12B commenced in 2012 and ended in 2020. Drilling efforts were focused on the south-west section of the Block, where the drilling of the Brulpadda – 1AX exploration well was completed in February 2019, and the drilling of the Luiperd – 1X exploration well was completed in October 2020. Extensive 3D and 2D seismic surveys were also acquired between 2019 and 2020 to further define the potential reservoir.

This exploration programme led to an important gas discovery, and after further completion of technical and feasibility studies, the potential viability of the gas and associated condensate resources was confirmed; however commercial agreements for the sale of the gas into the domestic market must still be achieved.

Table 6-3 –Previous Exploration Right Information

Exploration Right No.	12/3/067 (expired 6 September 2022)
Extent	18 734 km^2
Authorisations	▪ Addendum EMPr (EA issued 21 May 2012): • 2D seismic surveys (whole block) • 3D seismic surveys (whole block) • Drilling of up to 10 exploration wells (in defined area in south west portion)
	▪ EMPr Amendment (Approval granted on 24 March 2015) • Sonar bathymetry survey (whole block, defined period) • Sediment sampling (whole block)
	▪ EMPr Amendment (Approval 6 February 2019): • Change of well completion status

6.3 PROPOSED PROJECT OVERVIEW

The primary objective of the Project is to develop and produce the discovered gas and associated condensate on Block 11B/12B if a PR is granted and if commercial agreements for the sale of the gas into the domestic market can be achieved. The development for gas and associated condensate will take place in the south-western area of Block 11B/12B. This area is known as the Project Development Area (Figure 1-1). The Project concept comprises of drilling development wells and installation of a subsea production system in the south-western section of the Block to produce the gas and associated condensates.

Block 11B/12B is adjacent to Block 9 from which gas has already been produced. The Block 9 gas field is owned and operated by PetroSA to supply domestic gas to the PetroSA Gas-to-Liquid (GTL) plant located in Mossel Bay. The F-A Platform was constructed in the early 1990's and used to produce gas until 2020 from Block 9. This facility will be used to process gas and condensate from Block 11B/12B and the products will be conveyed from the Platform to shore via the existing subsea pipelines.

While the primary objective of the proposed TEEPSA Project is gas and condensate production, there is still a need for drilling further exploration and appraisal wells in the application area. The objective of the proposed exploration drilling campaign is to further understand the extent of hydrocarbon resources in Block 11B/12B. In some areas of the Block, such as in the central and eastern areas of the Block, no exploratory drilling has been conducted to date. However, as mentioned above, extensive 3D and 2D seismic surveys were acquired between 2019 and 2020 and various potential additional prospects were identified. It is also understood from these assessments that gas and condensates are the potential hydrocarbon resource in these areas but could possibly include oil.

The exploration drilling programme will take place in the east-northeast area of the Block referred to as the Exploratory Priority Area (Figure 1-1).

Further, the Project's activities also include undertaking survey works (sonar, coring, etc.) in specific areas in the Block to inform specific areas of interest, the final location of the wells, the subsea infrastructure and the final pipeline route. Survey vessels could also deploy buoys with instrumentation arrays to gather further metocean data, to increase the understanding of the conditions in the Block. While the Project is located offshore, the offshore activities will require onshore support in terms of supplies, logistics, etc.

Table 6-4 summarises the Project activities; details are provided in Section 6.5.

Table 6-4 –Details of Proposed Project Activities

Activity	Details
Exploration and appraisal drilling (eastern portions of Block, Exploratory Priority Area)	▪ Mobilisation of drill unit to site. ▪ Drilling of up to four (4) exploration and appraisal wells. ▪ Possible well flow testing, vertical seismic profiling (VSP), well logging for each well drilled. ▪ Plugging and abandonment of each well. ▪ Demobilisation of drill unit from site. ▪ Onshore support.
Offshore surveys (Whole Block)	▪ Mobilisation of specialised vessels for survey work. ▪ Bathymetry and sonar surveys. ▪ Seafloor sampling surveys. ▪ Metocean surveys. ▪ Demobilisation of survey vessels. ▪ Onshore support.

Activity	Details
Development and production activities (Western Portion of Block, Project Development Area)	
Construction Phase	Offshore
	▪ Mobilisation of drill unit to site. ▪ Drilling of up to six (6)[16] production and appraisal wells and testing. ▪ Installation of well-heads and Christmas-Trees (XMT). ▪ Laying of deep-water subsea production manifolds and jumpers connecting the wells. ▪ Installation of subsea production pipeline (“flowline”). ▪ Connection of manifolds to the F-A Platform via the production pipeline, riser and umbilical. ▪ Demobilisation of drill unit from site. ▪ Demobilisation of pipeline installation and support vessels.
	Onshore
	▪ Establishment of logistics base within the Mossel Bay port, which includes material and equipment laydown or storage areas, and areas for engineering manufacturing and maintenance work. ▪ Support vessels transport of equipment, bulk materials and general supplies from shore to drill unit, survey and pipeline laying vessels. ▪ Helicopter flights for ship/shore personnel movement and in emergency events. ▪ Periodic bulk delivery (equipment) from Gqeberha and/or Cape Town port.
Production Operations Phase	Offshore
	▪ Operation of gas field, including subsea infrastructure to supply the F-A Platform. ▪ Operation of F-A Platform and associated infrastructure. ▪ Vessel movements for maintenance and inspections of subsea infrastructure and flowlines pigging.
	Onshore
	▪ Movement of support vessels from shore to F-A Platform for transportation of equipment, bulk materials and general supplies. ▪ Helicopter flights for ship/shore personnel rotation and in emergency events. ▪ Periodic bulk delivery (equipment) from Gqeberha and/or Cape Town port.
Decommissioning Phase	Offshore
	▪ Mobilisation of drill unit to site. ▪ Mobilisation of specialised vessel for survey/ROV work. ▪ Movement of support vessels from shore to drill unit for transportation of equipment, bulk materials and general supplies. ▪ Helicopter flights for ship/shore personnel movement and in emergency events. ▪ Decommissioning of production manifold, flowlines, umbilical and riser. ▪ Decommissioning of subsea distribution units and power cable(s). ▪ Retrieval of shallow water infrastructure, such as production risers and umbilicals.

[16] At this stage of the engineering design, five production wells will be drilled in the Project Development Area with the option for a sixth well should it be required.

Activity	Details
	▪ Pigging of production flowline including subsea tie-in. ▪ Abandonment of wells. ▪ Demobilisation of drill unit and support vessels from site.
	Onshore
	▪ Movement of support vessels from shore to drill unit for transportation of equipment, bulk materials and general supplies. ▪ Helicopter flights for ship/shore transport. ▪ Salvage of retrieved equipment and shipping to Gqeberha and/or Cape Town port.

6.4 RESOURCE ESTIMATES AND PRODUCTION TIMEFRAME

The Block 11B/12B well field is expected to have a production life of 25 years, tapering off after 15 years.

The resources recovery for the initial phase of the development is based on producing from 3 production wells and was estimated to be:

- Between 1.0 Tcf (Trillion Cubic Feet) and 2.0 Tcf with a mid-case of 1.4 Tcf for gas.
- Between 46 MMstb (Millions of standard tank barrels) and 97 MMstb, with a mid-case of 63 MMstb for condensate.

The drilling of two additional production wells in Year 10 will provide an estimated incremental increase in gas and condensate at between 0.5 Tcf and 1.0 Tcf and between 14 MMstb and 38 MMstb respectively.

6.5 PROJECT COMPONENTS AND ACTIVITIES

The activities undertaken, and the technical equipment utilised, for the Project phases are described below. In summary, the activities include exploration and appraisal well drilling; marine surveys and data collection; production and appraisal well drilling; installation of the subsea production system, pipeline and riser; and decommissioning of the exploration and production wells and subsea infrastructure.

The anticipated personnel and logistic needs (support and specialised vessels and helicopters) as well as resources requirements are described in Sections 6.7 and 6.8 respectively, and discharges to the sea, waste and emissions associated with the Project activities are described in Sections 6.9 to 6.13.

6.5.1 EXPLORATION AND APPRAISAL WELL DRILLING COMPONENTS AND ACTIVITIES

6.5.1.1 Drilling Unit

The choice of technology for well drilling primarily depends on the metocean conditions and the depth of the seabed. Based on the regional metocean conditions and the experience gained in drilling the exploration wells in Block 11B/12B, TEEPSA is likely to semi-submersible drill unit (6^{th} or 7^{th} generation) with a dynamic positioning system suitable for the deep-water offshore environment (Figure 6-1). The final drill unit selection however will be made depending upon availability of suitable drill units at the preferred time.

Figure 6-1 - Example of semi-submersible drilling unit

A drill unit is a custom-built vessel designed to operate in deep water and dynamic ocean conditions. A semi-submersible drilling unit is a floating structure of pontoons that, when, at well location, are partially flooded (or ballasted), with seawater, to submerge the pontoons to a pre-determined depth below the sea level where wave motion is minimised. This gives stability to the drilling vessel thereby facilitating drilling operations. The drilling “derrick” is normally located towards the centre of the vessel and well operation is done through the moonpool, with support operations undertaken from both sides of the vessel using fixed cranes. The drilling unit may be supported by one or two tugboats, depending on metocean conditions anticipated for the period of the operations, to keep it on location.

Given the specialised equipment required for deep sea well drilling, the drill unit and supply vessels could mobilise directly to Block 11B/12B from outside South African waters or from a South African port, depending on which drill unit is selected and where it was last based. Core specialist and skilled personnel would arrive in South Africa onboard the drilling unit and the rest of the personnel will be flown to George, Cape Town or Gqeberha, depending on the onshore base selected. Drilling units are usually supplied with the required technical specialist core team on board.

Drilling materials, such as casings, mud components, cement and other equipment and materials will be brought into the country on the drilling unit itself and/or imported via a container vessel directly to the onshore logistics base from where the supply vessels will transfer it to the drilling unit.

All I&APs, including the Competent Authority (DMRE), SAMSA, local authorities, operators of neighbouring licence blocks, and the commercial and small-scale fishing industry, will be notified prior to commencement of construction activities. At the end of the drilling operations the drilling unit and supply vessels will demobilise from the offshore licence area and either mobilise to the following drilling location or relocate into port or a regional base for maintenance, repair or resupply.

6.5.1.2 Well Drilling Sequences

Well drilling will be conducted from a drilling unit described in Section 6.5.1.1 above. The selection of the specific well locations will be based on several factors, including detailed analysis of the seismic and pre-drilling survey(s) data and confirmed by a Remote Operating Vehicle (ROV) surveying the seafloor for obstacles or the presence of any ecologically sensitive features.

Drilling is undertaken in two stages, namely the riserless and risered drilling stages.

At the start of drilling, a 36- or 42-inch hole will be drilled on the seabed using a rotating drill string, a hollow column of pipes with a drill bit at the bottom end which crushes the rock into small particles, called "cuttings". At approximately 70 m deep, a pipe will be placed into the hole and cemented into place, after which a low-pressure wellhead will be placed on the seabed on top of the pipe.

Further sections will then be drilled at a 26-inch diameter to a depth of approximately 1 070 m. These initial sections of the hole will be drilled using seawater (with viscous sweeps, a special drilling fluid, formulated to transport cuttings from the hole) and water-based muds (WBMs). All cuttings and WBM from this initial drilling stage will be discharged directly onto the seafloor adjacent to the hole. See more details on drilling fluids in Section 6.5.1.4 and the proposed disposal methods in Section 6.11.1.1.

The second stage commences with the lowering of a Blow-Out Preventer (BOP) for installation on the wellhead, which seals the well and prevents any uncontrolled release of fluids (e.g., oil, gas or condensate) from the well (a 'blow-out'[17]) (see Section 6.5.1.3 for details). A lower marine riser package is installed between the drilling unit and the top of the BOP, which isolates the drilling fluid and cuttings from the environment creating a "closed loop system". Drilling is continued by lowering and rotating the drill string through the riser and BOP.

During the risered drilling stage, should the WBMs not be able to provide the necessary viscosity characteristics required to safely drill the well, a low toxicity Non-Aqueous Drilling Fluid (NADF) will be used. In instances, where NADFs are used, cuttings will be treated on the drilling unit to reduce oil content and discharged overboard. At this stage of the Project though, it is anticipated that WBMs will be used for both the riserless and risered stages.

Data record and tests will be possibly performed before completion of the well, plugging and abandonment.

6.5.1.3 Blow-out Prevention and Well Control

One of the primary safeguards against a blow-out is the column of drilling fluid in the well, which maintains hydrostatic pressure on the wellbore. Under normal drilling conditions, this pressure should balance or exceed the natural rock formation pressure to help prevent an influx of gas or other formation fluids. As the formation pressures increase, the density of the drilling fluid is increased to help maintain a safe margin and prevent "kicks" or "blow-outs." However, if the density of the fluid becomes too heavy, the formation can be damaged and fracture. If drilling fluid is lost in the resultant fractures, a reduction of hydrostatic pressure occurs which can lead to an influx from a pressured formation. Therefore, maintaining the appropriate fluid density for the wellbore pressure regime is critical to safety and wellbore stability.

[17] Provisions in the event of an emergency blow-out are described in Section 6.15.

Abnormal formation pressures are detected by primary well control equipment, which generally consists of two sets of pit level indicators and return mud-flow indicators with one set manned by the drill crew and the other by the 'mud logger'. The 'mud logger' also has a return mud gas detector, which monitors return mud temperature and changes in shale density for abnormal pressure detection. The drilling fluid is also tested frequently during drilling operations and its composition can be adjusted to account for changing downhole conditions.

The likelihood of a blow-out is further minimised by installing a specially designed item of safety equipment called a Blow-Out Preventer (BOP), which is a secondary control system used for prevention of blow outs. BOPs contain a stack of independently operated cut-off mechanisms, so there is redundancy in case of failure, and the ability to work in all normal circumstances with the drill pipe in or out of the wellbore. The BOP is installed on the wellhead (on the seabed) and is designed to close in the well to prevent the uncontrolled flow of hydrocarbons from the reservoir in case the pressure of the reservoir exceeds the pressure of the drilling fluid in the reservoir resulting in hydrocarbons entering the wellbore. If this cannot be controlled, hydrocarbons could eventually exit the wellbore into the marine environment and atmosphere. Hence, the BOP system plays a key role in preventing potential risks to people, the environment and equipment. The BOP will undergo a thorough inspection prior to installation and will be subsequently pressure and function tested on a regular basis in terms of good industry practices.

TEEPSA will have a Blow-Out Contingency Plan (BOCP) in place that sets out its detailed response plan and intervention strategy, to be implemented in the unlikely event of a blow-out. Provisions in the event of an emergency blow-out are described in Section 6.15.

6.5.1.4 Preliminary Well Design

The preliminary well specifications are provided in Table 6-5. Final well architecture and specifications will only be refined once the final well locations are determined.

Table 6-5 – Preliminary Well Design

Section	Description
Terminal Depth criteria: Geological (based on marker)	The well base case design is described as below: 1st section: 42" section to be drilled riserless with Sea Water & Hi-vis Sweep & Water Based Mud (WBM=PAD mud) 2nd section: 26'' section to be drilled riserless using Sea Water & Hi-vis Sweep & WBM (PAD mud) 3rd section: 17 ½'' section to be drilled with a riser using HydroGuard High Performance Water Base Mud 4th section: 12 ¼" to be drilled with a riser using HydroGuard High Performance Water Base Mud 5th section: 8 ½" to be drilled with a riser using KCl/Glycol/ Polymer Water Base Mud

6.5.1.5 Drilling Fluids

Drilling fluid (also known as mud) is a mixture of fluid, chemicals and solids that are tailored to provide the correct chemical and physical characteristics that are required for safe drilling of a well. The key functions of the drilling fluid are to:

- Maintain a stable wellbore and preventing the open well from collapsing;
- Provide sufficient hydrostatic pressure to control subsurface pressures and prevent kicks or blow-outs;

- Transport the cuttings to the surface;
- Cool and lubricate the drill bit[18] and drill string, i.e., the drill bit and pipe (reduce friction);
- Power the mud motors and downhole tools during the drilling process;
- Regulate the chemical and physical characteristics of returned mud slurry on the drilling unit; and
- Displace cements during the cementing process.

Two types of drilling fluids could be used for well drilling, namely Water-Based Muds (WBM) and Non-Aqueous Drilling Fluids (NADF) (descriptions provided below); however, at this stage of the Project, it is anticipated that only WBMs will be used for Block 11B/12B:

- Water-Based Muds (WBM) - Freshwater or seawater constitutes 85 to 90% of the total volume of WBM. The remaining 10 to 15 % of the volume typically comprises barite, potato or corn starch, cellulose-based polymers, xanthan gum, bentonite clay, soda ash, caustic soda and salts (either potassium chloride or sodium chloride) with other minor additives such as citric acid for pH control, or polyethylene glycol butyl ether for clay inhibition; and
- Non-Aqueous Drilling Fluids (NADF) - a fluid comprising a base oil, brine, gelling products, lime and emulsifiers. NADFs base fluid and other chemicals have a higher toxicity than WBMs. TEEPSA uses low toxicity NADF (Group III NADF) which is mostly biodegradable with a lower aromatic content that will not persist in the water column in the long-term.

The first two sections (42” and 26”) will be drilled riserless with sea water and the mixture of both sea water and cuttings will be discharged at the seabed. All the other sections (17 ½’’, 12 ¼” and 8 ½”) will be drilled risered. Two batch releases of KCl/Glycol/ Polymer WBM will occur during Logging and Plugging and Abandonment (P&A) phases respectively.

The drilling fluids and cement composition will be refined as the Project detailed engineering progresses. An indicative drilling fluid composition, used in the Drilling Discharges Modelling for the proposed exploration well drilling in the eastern section of the Block is presented in a technical report (appended in Appendix 7 of Volume 2 of this ESIA report).

Section 6.11.1.1 more details regarding drill cuttings and mud management.

6.5.1.6 Cementing

Cementing is the process of pumping cement slurry through the drill pipe at the bottom of the hole and back up into the space between the casing and the borehole wall (annulus) to fill the annulus between the casing and the drilled hole to form an extremely strong, seal, thereby permanently securing the casings in place. Once the cement has set, a short section of new hole is drilled, then a pressure test is performed to ensure that the cement and formation are able to withstand the higher pressures of fluids from deeper formations.

Cementing serves to:

- Isolate and segregate the casing seat for subsequent drilling;
- Protect the casing from corrosion;
- Provide structural support for the casing; and

[18] A drill bit is a tool used to crush or cut rock (www.glossary.slb.com)

- Stabilise the formation.

To ensure effective cementing, an excess of cement is often used. Until the marine riser is set, excess cement from the first two casings emerges out of the top of the well onto the seafloor. This cement does not set and is slowly dissolved into the seawater.

Offshore drilling operations typically use Portland cements, defined as pulverised clinkers consisting of hydrated calcium silicates and usually containing one or more forms of calcium sulphate. The raw materials used are lime, silica, alumina and ferric oxide. The cement slurry used is specially designed for the exact well conditions encountered. Additives make up a small portion (<10%) of the overall amount of cement used for a typical well. Typically, there are three main additives used: retarders, fluid loss control agents and friction reducers, which are made of organic material and are considered non-toxic.

6.5.1.7 Mud Logging

Mud logging is carried out routinely during the drilling operation and involves the examination of the drill cuttings brought to the surface by the drilling fluid to evaluate the properties of the hydrocarbon formation and monitor for gases and the volume or rate of returning fluid which aids in controlling the well. No specific waste or emissions are associated with mud logging.

6.5.1.8 Well Logging

Once the target depth is reached, wireline logging or Logging While Drilling (LWD), using a radioactive source, is performed to evaluate the physical and chemical properties to confirm the presence of hydrocarbons and the characteristics of the seafloor geology and sediment. The testing does not generate radioactive waste.

6.5.1.9 Well Flow Testing – Non routine Flaring

The economic potential of any discovery is undertaken per appraisal well before the well is abandoned or suspended. Testing may take 3 to 4 days of flow to complete and involves burning hydrocarbons at the well site (also called non-routine flaring). An estimated flaring rate is 900 000 m^3/day per test.

A high-efficiency flare (see example in Figure 6-3) is used to maximise combustion of the hydrocarbons over a wide range of weather conditions, to minimise emissions to air and unburnt droplets at sea. If produced water arises during well flow testing (typically in small quantities), it would be treated on-board to separate the hydrocarbons to comply with the TotalEnergies specification, prior to discharge too sea or ship to shore.

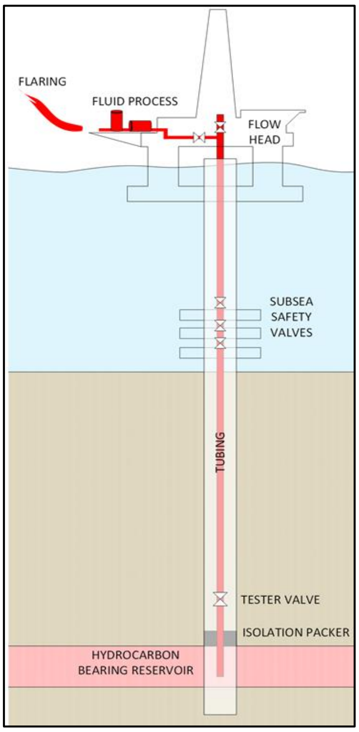


Figure 6-2 – Schematic of a typical well testing apparatus

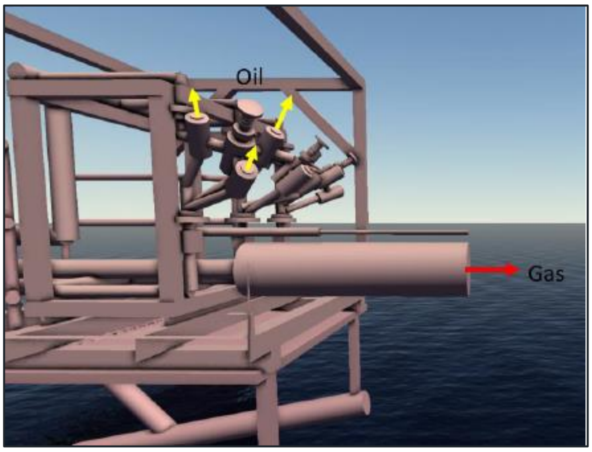


Figure 6-3 – Sea Emerald burner heads: 99.993% efficiency under a wide range of conditions

6.5.1.10 Vertical Seismic Profiling

Vertical seismic profiling (VSP) of the wells will also be conducted. VSP is an evaluation tool that is used when the well reaches target depth to generate a high-resolution seismic image of the geology in the well's immediate vicinity. The VSP images are used for correlation with surface seismic images and for forward planning of the drill bit during drilling. VSP uses a small airgun array, which is operated from the drill unit.

It is expected that a Dual Delta Sodera G-Gun (or equivalent) will be used for the Project, which has six active G-Gun airguns (three 250 cubic inch [CUI] airguns and three 150 CUI airguns for a total of 1,200 CUI). The airgun array is deployed on average 10 m below sea level and has a gun pressure of 2 000 per square inch (psi).

During VSP operations, four to five receivers are positioned in a section of the borehole and the airgun array is discharged approximately five times at 20 second intervals. The generated sound pulses are reflected through the seabed and are recorded by the receivers to generate a profile along a 60 to 75 m section of the well. This process is repeated for different stations in the well and may take between 8 to 12 hours per well to complete, depending on the well's depth and number of stations being profiled. A typical VSP arrangement is provided in Figure 6-4.

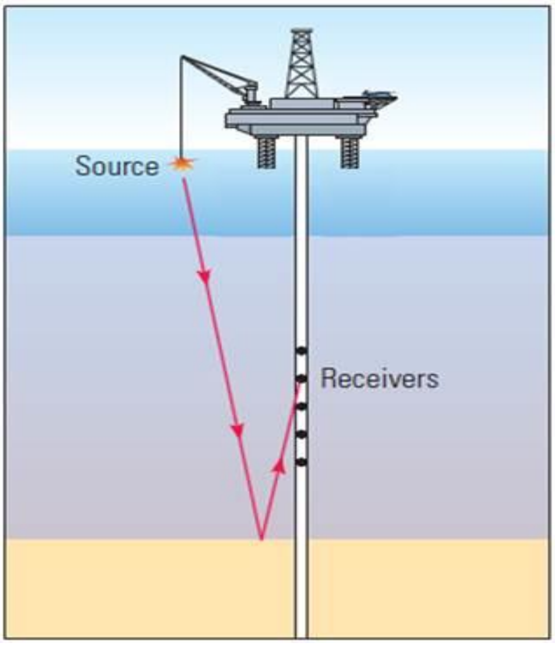


Figure 6-4 – Schematic of typical VSP arrangement

6.5.1.11 Well Plugging and Abandonment

Once drilling and needed tests have been completed, the exploration well(s) will be sealed with cement plugs and tested for integrity according to international best practices prior to being abandoned. In case of discovery and if deemed relevant, appraisal well(s) can be temporarily abandoned for further re-entry, in this instance, well heads will be left on the seafloor with an over trawl cap designed to allow for trawling activity without damaging trawling gear.

The following section has been extracted from the Closure Plan (WSP Group Africa (Pty) Ltd, 2023) (appended in Appendix 16 of this ESIA report).

The purpose of well sealing and plugging is to isolate permeable and hydrocarbon bearing formations. Well sealing and plugging aims to restore the integrity of the formation that was penetrated by the wellbore. The principal technique applied to prevent cross flow between permeable formations is plugging of the well with a properly designed cement mix, thus creating an impermeable barrier between two zones.

Once drilling and logging have been completed, the wells will be sealed with cement plugs, tested for integrity, and abandoned according to international best practices and company rules. Cement plugs will be set to isolate hydrocarbon bearing and/or permeable zones and cementing of perforated intervals (e.g., from well logging activities) will be evaluated where there is the possibility of undesirable cross flow. These cement plugs are set in stages from the bottom up. At least two cement plugs would be installed: i.e., one each for isolation of the deep reservoir and the main reservoir; and a second as a second barrier for the main reservoir.

Typical cement plug formulation (composition) for plugging and abandonment application in South Africa (based on drilling in Block 11B/12B, the exact formulation will depend on the selected contractor providing the services) is presented in Table 6-11. Cement plug formulation is based on several well conditions and status, viz. depth, fluids in the well, gas or oil reservoir, temperature, etc. As such, it can be adjusted based on the logistics and product availability, without compromising the objectives.

The integrity of cement plugs can be tested by several methods. The cement plugs will be tag tested (to validate plug position) and weight tested, and if achievable then a positive pressure test (to validate seal) and/or a negative pressure test will be performed. Additionally, a flow check may be performed to ensure sealing by the plug. Once the well is plugged, seawater will be displaced before disconnecting the riser and the BOP.

Table 6-6 - Typical Cement Plug Formation

Product	Function	Chemical Definition
G Neat Cement	Binder	Portland Cement Clinker
Fresh Water	Base fluid	Water
NF-6	Anti-foam agent	Glycol
HALAD-344	Fluid Loss agent	Polymer
HALAD-413	Fluid Loss Agent	Polymer
CFR-3L	Polymer	Dispersant (friction reducer)
HR-4L	Retarder	Lignosulfonate
GasCon-469	Bonding Agent	Silica

** Barite may be used as a weighting material for the spacer. However, it is not generally needed when Newtonian fluids (i.e., a fluid in which the viscous stresses arising from its flow are at every point linearly correlated to the local strain rate) are in the wellbore, in which case the spacer would be water.*

The choice of a specific well plugging and sealing design configuration is driven by several factors including locality and depth, geological substrate conditions, access and logistical considerations, and cost. However, regardless of these factors the basic plugging and abandonment configuration consists of a surface plug, two or more barrier plugs (towards potential overburden and reservoir flow zones, respectively), and in some instances filling of a section of the well shaft with concrete or other material (Figure 6-5).

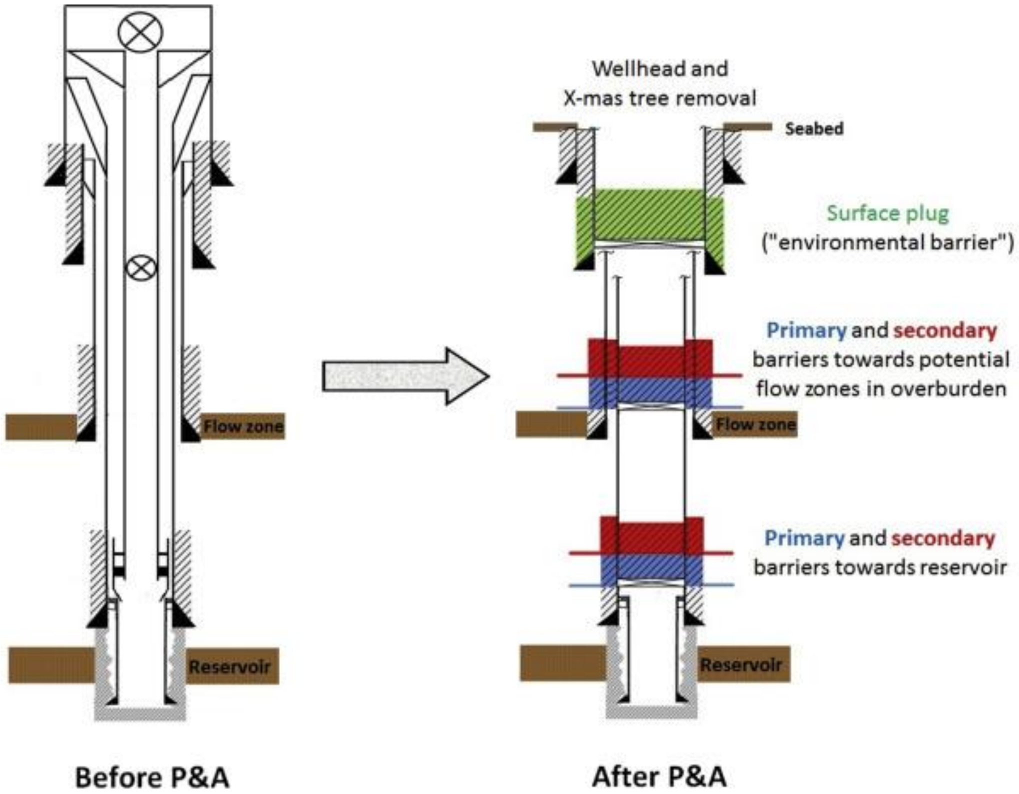


Figure 6-5 - Diagrammatic Example of Typical Well Plug and Abandon Measures (Vralstad, 2019)

Where it is deemed to be safe, based on risk assessment, the wellhead will be left in place on the seafloor and fitted with an over-trawlable abandonment cap (Figure 6-7). The risk assessment criteria will consider factors such as the water depth and use of the area by other sectors, noting that the drilling water depths is well outside that of trawling and most other maritime activities. The over-trawlable cap is estimated to measure approximately 5.2 m x 5.2 m, with a height of 4.4 m. In this regard, it is noted that in developed deep-water fields in the North Sea and Gulf of Mexico (GoM), regulators generally do accept that decommissioned wellheads are left *in situ* without the need for further structures to be added on top. The need for the envisaged cap may therefore be revised at a later stage, after consultation with local regulators and based on specific project considerations, although these structures have been included in the closure planning and costs, as a worst-case scenario. It must be noted that these structures are installed to prevent fishing equipment from becoming entangled or damaged by the well heads, rather than as a protection mechanism for the plugged wells themselves.

Monitoring gauges to monitor pressure and temperature through wireless communication with frequencies between the transmitter and the receiver in the 12.75 to 21.25 kHz range may be installed on wells where TEEPSA will return in the future for appraisal or production purposes. The gauges will be placed and remain under the over-trawlable cap. Monitoring gauges will not be installed on wells which are earmarked for abandonment.

Except for the abandoned wellheads and associated over-trawlable caps, and drilling discharges deposited on the seabed, no further physical remnants of the drilling operation will remain on the seafloor. A final clearance survey check will be undertaken using an ROV. The drilling unit and supply vessels will demobilise from the offshore Block and either mobilise to the following drilling location or relocate into port or a regional base for maintenance, repair, or resupply.

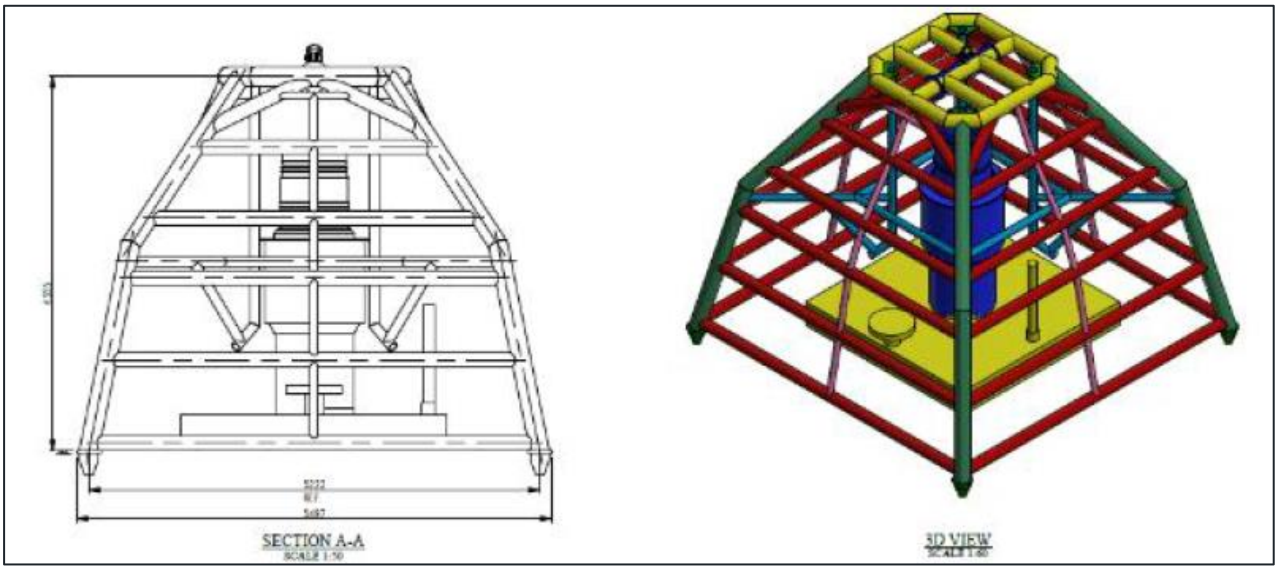


Figure 6-6 - Example of Over-trawlable Cap to be Installed on Wellhead on Sea Floor (image provided by TEEPSA)

6.5.2 SURVEY AND DATA COLLECTION ACTIVITIES

Various offshore surveys and data collection will be conducted in Block 11B/12B subject to identification of specific needs.

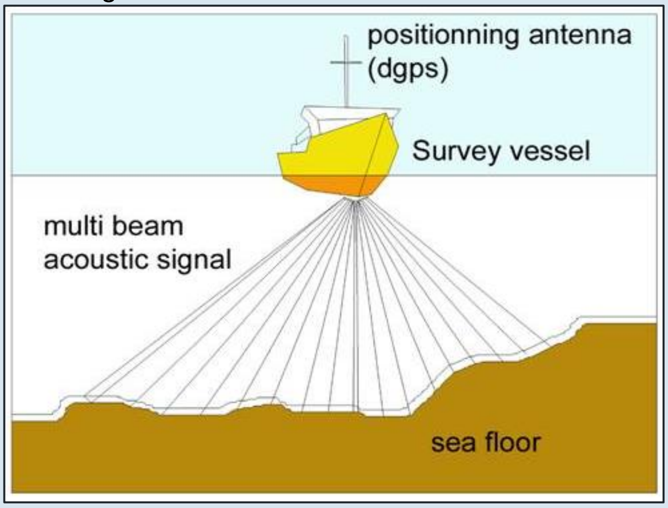
6.5.2.1 Sonar Surveys

Sonar surveys will be used to investigate the structure of the seabed (bathymetry) in the vicinity of future wells, if needed. Surveys will be conducted from a vessel and might use multi-beam echo-sounding, single beam echo-sounding and sub-bottom profiling. Such surveys entail transmitting frequency pulses down to the seafloor to produce a digital terrain model and identify any seafloor obstructions or hazards.

Sonar survey activities associated with the proposed project are summarised in Table 6-7, where a typical sonar survey diagram is also depicted.

Table 6-7 – Summary of Sonar Surveys

Activities	Description
Duration	15-30 days
Location, extend	Estimated 50 km^2 for the development area and along the pipe routing

Activities	Description
Equipment / source specifications	Multi-beams Echo Sounder Side Scan Sonar Sub-bottom Profiler Ultra-High Resolution Seismic 

6.5.2.2 Sediment Sampling

Seafloor sampling will possibly be undertaken to collect sea floor sediment samples for environmental baseline data collection and studies as well as for monitoring of the environment during / post operations. It can also be used to supplement geotechnical and geophysical studies. Sediment sampling activities possibly associated with the Project are summarised in Table 6-8.

Table 6-8 – Seafloor Sampling Activities

Activities	Description
Extent of the zone	Selected sites within Block 11B/12B Application area
Duration	15-30 days
Technology used	Core box, drop cores, and dredge pipes for hard substrate if ROV is used for sampling
How many cores	Dependant on area to be surveyed
Diameter + depth of the samples	Not defined

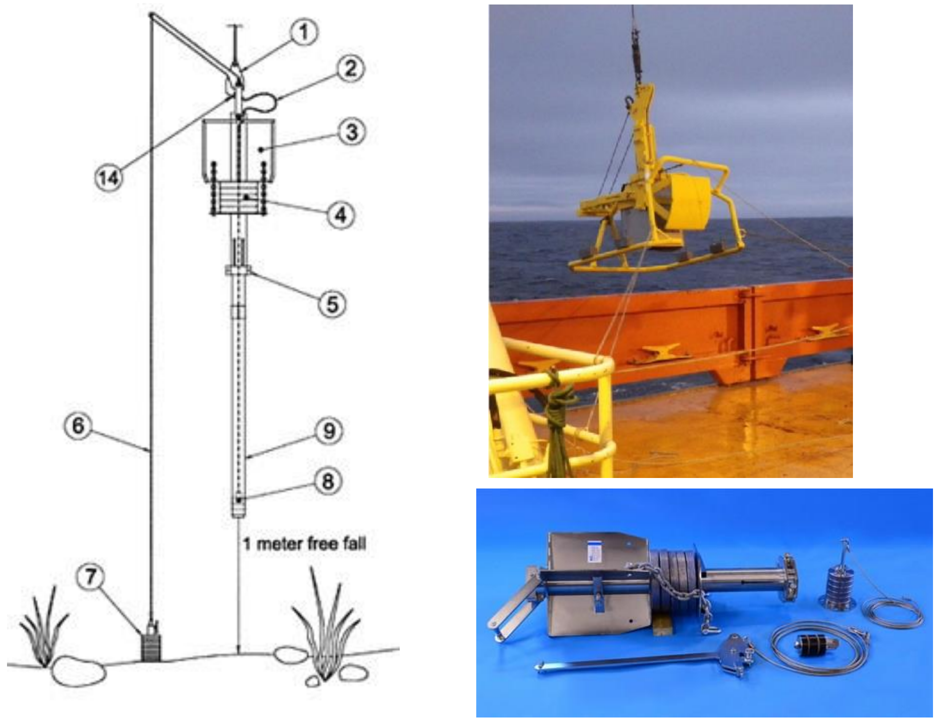


Figure 6-7 – Examples of sea floor sediment sampling tools

6.5.2.3 Metocean Buoy Deployment

TEEPSA is proposing to deploy metocean buoys within Block 11B/12B to measure oceanographic, meteorological and possibly acoustic data, i.e., currents, waves, water temperature, ambient water noise levels, wind and air parameters. The scope of the metocean survey will be defined depending on the need for parameters to inform the understanding of the physical conditions in the area.

A typical metocean buoy current mooring setup and surface wave buoy is shown in Figure 6-8.

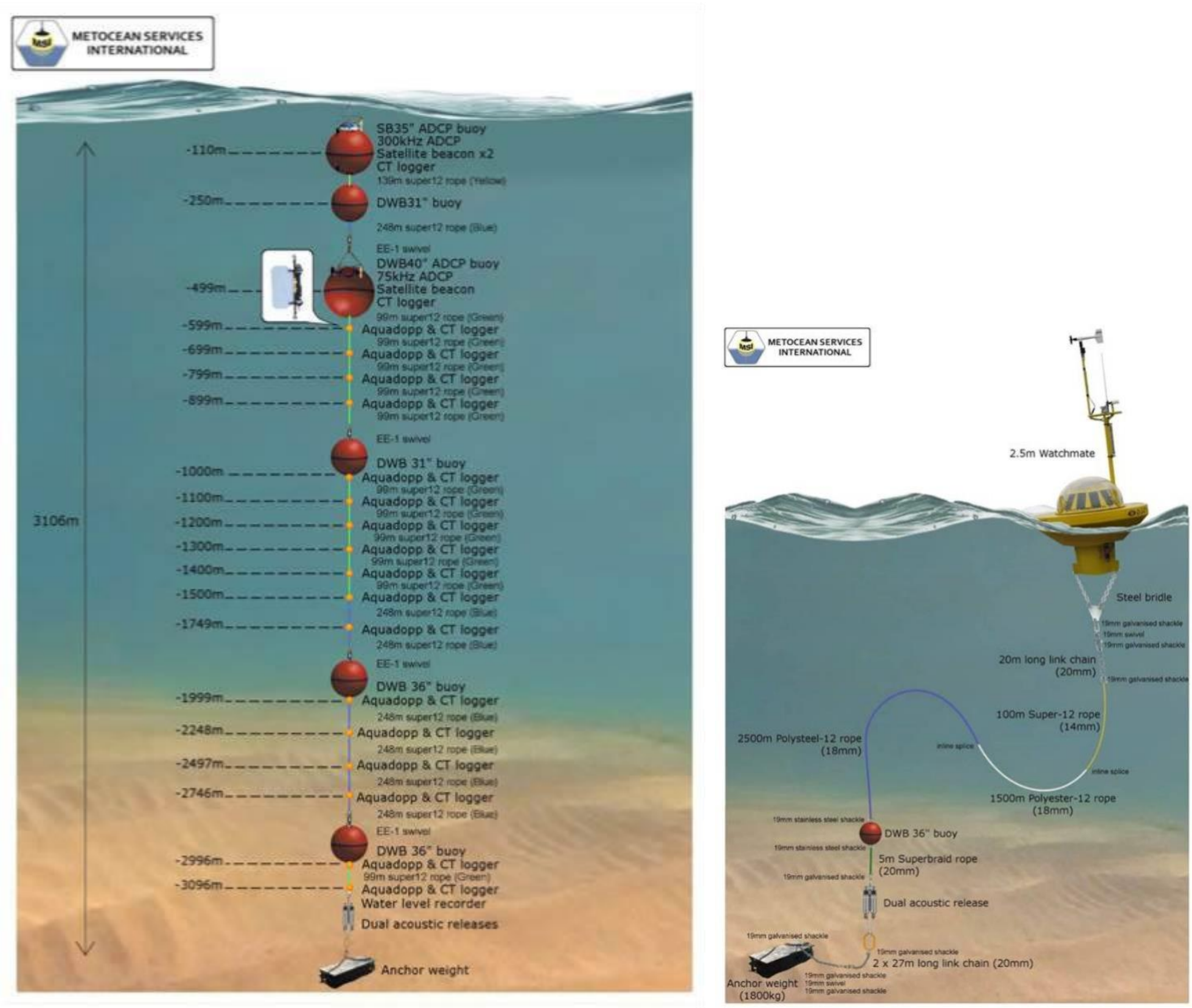


Figure 6-8 – Typical Metocean Buoy System with Weather Station Buoy (Source: Metocean Services, in SLR, 2020)

6.5.3 PRODUCTION COMPONENTS AND ACTIVITIES

6.5.3.1 Project Development Concept

The proposed development and production Project in Block 11B/12B is adjacent to the offshore Licence Block 9 and the F-O field; in which the existing F-A Platform is located (the platform is located approximately 40 km north-west of the Block 11B/12B). The proposed Project assumes no further production from this field, enabling the Block 11B/12B development to exclusively use the offshore installation for the treatment and export of gas and condensate.

The Project development concept comprises wells and a subsea production system (SPS) in the south-west corner of Block 11B/12B to produce gas and associated condensates. The development concept also includes a subsea pipeline to carry the gas and condensate to existing treatment and export facilities on the F-A platform where it will go to shore via the existing pipelines.

The proposed development concept will eventually connect up to 6 wells in the Project Development Area via a multiphase pipeline carrying both gas and associated condensates from the wells up to the F-A Platform. From there, it will be carried for further treatment and exporting via the existing PetroSA-operated gas and condensate pipelines to onshore.

Any construction, modification or upgrades at the F-A Platform, the existing PetroSA-operated gas and condensate pipelines to onshore, or of any onshore facility, if required by the off-taker of gas or condensates, are excluded from the scope of this ESIA and will be subjected to a separate EA application.

Figure 6-9 is a schematic diagram of the proposed subsea production development infrastructure in relation to the existing F-A Platform related infrastructure.

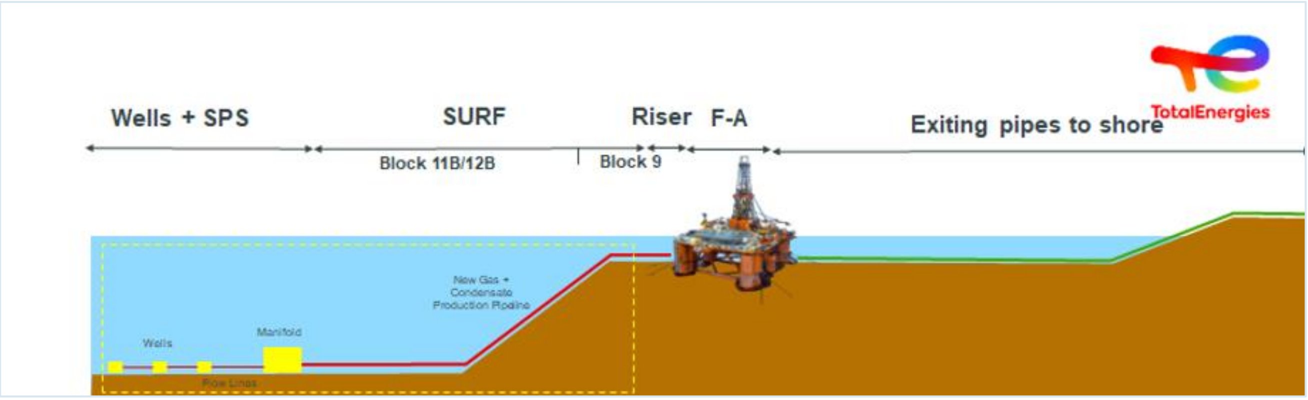


Figure 6-9 - Project Development Area cross-section

6.5.3.2 Detailed Project Components and Activities

For development and production, the Project activities and components have already been presented in Table 6-4.

The production activities programme can be summarised as below:

- Drilling of up to six (6) development and appraisal wells.
- Installation of the subsea production system.
- Installation of a rigid 18” subsea production pipeline from the project development area to the F-A Platform.
- Installation of 16” riser to the F-A Platform – the vertical section that connects the production pipeline to the platform.
- F-A Platform modifications.

The main offshore components and activities are detailed in Section 6.5.3.2.1 to 6.5.3.2.6, while the onshore activities are detailed in Section 6.5.4.

The anticipated resources requirements and various discharges, wastes and emissions from the production related activities are described in Sections 6.7 to 6.13.

6.5.3.2.1 Production and Appraisal Well Drilling

It is proposed that up to 6 development and appraisal wells are drilled in the Project Development Area within Block 11B/12B, in proximity to the previously approved drill area where the Brulpadda and Luiperd wells were drilled. These wells will ultimately be connected to the F-A platform for further treatment and transportation to shore.

The information contained in Section 6.5.1 pertaining to exploration and appraisal well drilling will largely also apply to production and appraisal well drilling, with key differences mostly related to well design and drilling fluids and drill cuttings and mud management, provided in the sections below. Well flow testing and VSP, as described in Sections 6.5.1.9 and 6.5.1.10 respectively, will also possibly be done for the development appraisal wells Section 6.6 the anticipated timing for the production and appraisal well drilling activities.

6.5.3.2.1.1 Preliminary Well Design

The current design concept is planned to have a combination of vertical wells (Figure 6-10) and deviated wells (Figure 6-11) connected with a manifold at a mid-location. A description of the specifications of a production well is provided in Table 6-9 where the term “section” refers to individual portions of a single wellbore. As with the exploration wells, final well architecture and specifications will only be refined once the final well location/s are determined.

Table 6-9 – Preliminary production well design

Section	Description
Conductor pipe	Drill 26” x 42” hole section and run 36” Conductor pipe. Drill [~90 meters below the mud line (BML)] and cement.
26” Hole section / 22” Surface Casing	Shallow hazard (SHAZ) assessment is performed to a depth of 1000m below mud line to avoid any gas bearing formations, however the possibility of shallow water flow must be managed. Drill 26” hole 500-600m below the mud line. The objective is to obtain aims good formation integrity test (FIT) at the 22” shoe, to safely circulated the kick without fracturing the shoe to be able to increase MW in the 14 ¾” hole section if necessary. Run and cement 22” casing up to seabed.
14 ¾” hole section / 10 ¾” casing	Terminal Depth criteria: Geological (based on marker) Drill 14 ¾” hole section up to 50m above top of reservoir (or as close as safely possible). Ensuring not entering the reservoir in this phase. Run 10 ¾” casing and cement 500m above the shoe. A contingency casing (13 5/8” or 14”) will remain available to deploy in order to avoid any uncertainties due to poor pressure and fracture gradient or potential open hole issues.
8 ½” open hole (no casing)	Drill 8 ½” hole up to Max Terminal Depth.

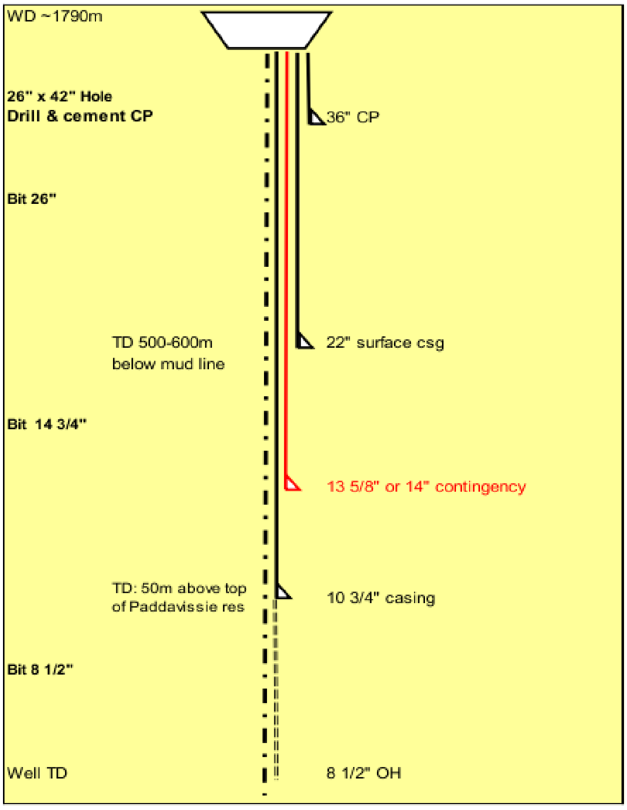


Figure 6-10 – Vertical well

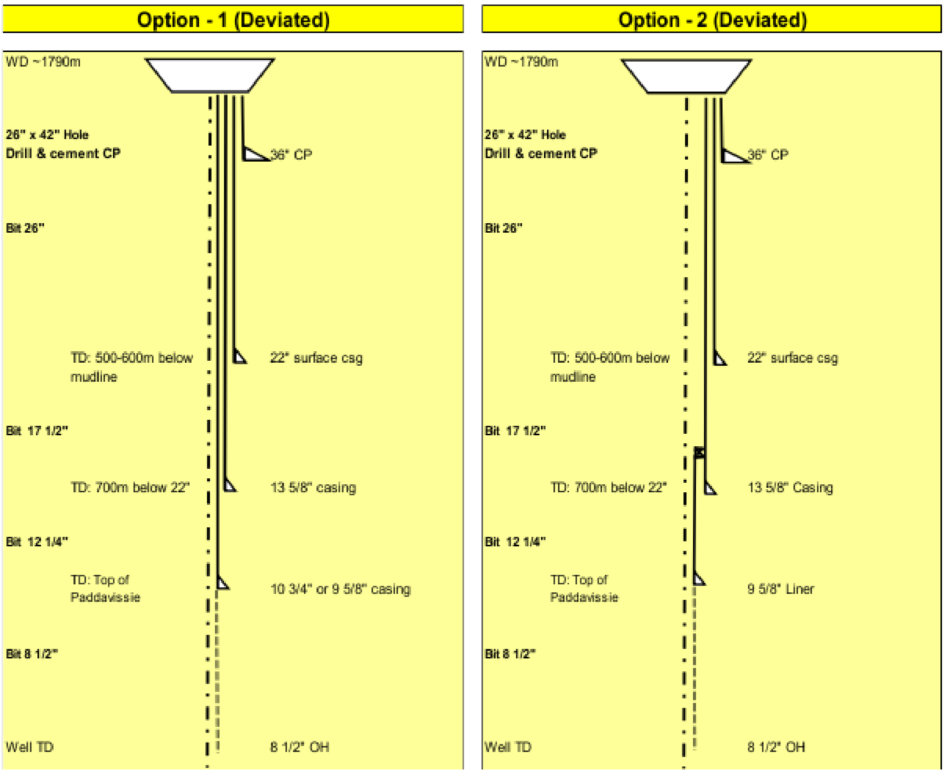


Figure 6-11 – Options for deviated wells

6.5.3.2.1.2 Drilling Fluids

Drilling fluid (also known as mud) is a mixture of fluid, chemicals and solids that are tailored to provide the correct chemical and physical characteristics that are required for safe drilling of a well. The key functions of the drilling fluid are to:

- Maintain a stable wellbore and preventing the open well from collapsing;
- Provide sufficient hydrostatic pressure to control subsurface pressures and prevent kicks or blow-outs;
- Transport the cuttings to the surface;
- Cool and lubricate the drill bit[19] and drill string, i.e., the drill bit and pipe (reduce friction);
- Power the mud motors and downhole tools during the drilling process;
- Regulate the chemical and physical characteristics of returned mud slurry on the drilling unit; and
- Displace cements during the cementing process.

The drilling fluids associated with each drilling section of the well are as follows:

- 42" section to be drilled riserless with Sea Water & & Gel / Polymer Sweeps and 42" displacement section KCL / Polymer mud.
- 26'' section to be drilled riserless using Sea Water & Gel / Polymer Sweeps and 26'' displacement section KCL / Polymer mud.
- 12 ¼" to be drilled with a riser using HydroGuard High Performance Water Base Mud.
- 8 ½" to be drilled with a riser using KCl/Glycol/ Polymer Water Base Mud.

An indicative mud composition, used in the Drilling Discharges Modelling for the proposed production well drilling in the western section of the Block is presented in a technical report (appended in Appendix 7 of this ESIA report). A summary of cuttings and mud volumes as well as description of how they will be managed are provided in Section 6.11.1.1.

6.5.3.2.2 Subsea Production System

A subsea production system (SPS) will connect the development wells to the F-A Platform (see **Figure 6-9**). The current plan is to have a direct subsea tie-back to the F-A Platform via a new 16" riser.

Figure 6-12 - Subsea infrastructure typical layout

Subsea structures including Flow Line End Termination (FLET) and a production manifold at the end of the pipeline will allow the

[19] A drill bit is a tool used to crush or cut rock (www.glossary.slb.com)

connection of the production wells (see Figure 6-12).

The structures also house a subsea distribution unit, jumpers to transport the production from wells to the manifolds, flowmeters, isolation valves and pressure and temperature monitoring instruments.

Hydrate inhibitor methyl ethylene glycol (MEG) will be distributed to the wells via a 11” umbilical together with other chemicals as corrosion inhibitor. The umbilical controls the electric, hydraulic, and production chemicals required for the wells. Preliminary flow assurance studies place the MEG injection rates between 2 and 15 m^3/h (for ramp-up operations).

A ‘pig’ is a cleaning device that is pushed through the pipeline under pressure to convey highly viscous fluids out of pipelines. The feasibility of installing pigging facilities in the flowlines connecting the wells to the pipeline is under investigation.

The foundations for both the new manifolds and subsea structure are gravity based, however this is to be confirmed by the planned geophysical/geotechnical surveys and foundation structures will be optimised in future design work.

From an installation perspective, the main umbilical would be laid in a single pass from a carousel (cable drum) on a specific dynamically positioned vessel.

6.5.3.2.3 Subsea Pipeline and Riser

A rigid 18” subsea pipeline (also known as the production pipeline) will be installed from the Project Development Area to the F-A Platform. A 16” riser (vertical section of pipeline) will be installed to connect the production pipeline to the F-A Platform.

Given the location of the gas fields and the F-A Platform versus critical biodiversity areas, options for the production pipeline route are limited. Two options have been identified:

- The base case pipeline alignment is approximately 109 km long direct route pipeline from the gas field to the F-A Platform; and
- The alternative route is approximately 115 km, the longer section of which is routed to the northeast then a shorter section turning northwest to connect to the F-A Platform.

Further seabed surveys will possibly complement the feasibility assessment in terms of profile, geotechnical aspects and habitat sensitivity.

For the purpose of the ESIA, a corridor with a 10 km width along the proposed alignment of the production pipeline options has been assessed. The co-ordinates (start and end points) for the pipeline alignments are provided in Table 6-10.

The pipeline route options are considered in Section 6.5.3.2.3.

Table 6-10 – Co-ordinates for Production Pipeline

Section	Longitude (°) (E)	Latitude (°) (S)	Depth (m)
Base Case			
Start (F-A Platform)	22° 10' 15.227" E	34° 58' 28.061" S	-106m
End (in Project Development Area)	23° 6' 54.363" E	35° 34' 43.239" S	-1 810m
Optional			
Start (F-A Platform)	22° 10' 15.227" E	34° 58' 28.061" S	-106m
End (in Project Development Area)	23° 7' 38.547" E	35° 32' 37.681" S	-1 764m

The pipe-laying method that will likely be used is the conventional S-lay method, in which single lengths of pipe (joints) are welded, inspected and coated in a horizontal working plane on board a pipelay vessel. As the vessel moves forward, the pipe gradually exits the working plane, curving downward through the water until it reaches the touchdown point on the seabed[20]. The inventory of support and specialised vessels required for the construction of the pipeline and SPS are described in Section 6.5.4.2.

Pipe sections would be supplied from an onshore logistics bases most likely in Cape Town or Gqeberha harbours. They would be welded together onboard the pipelay vessel.

6.5.3.2.4 F-A Platform Modifications

Although this component of the project is outside the scope of this ESIA, indicative information regarding the required modifications to the PetroSA F-A platform has been described in this section, for the sake of completeness.

Technical evaluations were done by TEEPSA to confirm the capability of the F-A Platform to handle the proposed production quantity from Block 11B/12B. As part of the assessment, preliminary flow assurance studies were performed to determine the volume of slug[21] in the line especially during the transient periods. Based on these studies a new separator may be required to handle the accumulated liquid in the pipeline. A slug catcher capable of handling around 300 m^3 of slug is to be installed in F-A Platform. Sizing and configuration of the slug catcher will be defined during conceptual studies, prior to the construction phase.

Considering the production profile and Condensate Gas Ratio (CGR) of the production wells, an increase in the condensate treatment could also be envisaged. Additional pumps and coalescer vessel are likely required to increase condensate capacity in the platform for processing.

These modifications will be done once the relevant permits and licenses have been obtained by PetroSA.

6.5.3.2.5 F-A Platform Operation

Gas and condensate production from Block 11B/12B production wells would be processed at the F-A Platform by means of existing facilities with some modifications.

Gas and condensate production from the Block 11B/12B SPS would be separated at the F-A Platform and pumped onshore through two separate subsea pipelines. With the implementation of the Block 11B/12B Project, the flow rate of gas and condensates from the F-A Platform to shore is expected to be at full capacity. However, this will be finalised once the off-take agreements are finalised.

All operations at the F-A Platform would be managed in accordance with PetroSA's existing integrated management system for Safety, Health, Environmental management and Quality control

[20] allseas.com/activities/pipelines-and-subsea/pipeline-installation/

[21] A slug is an uneven distribution of liquid and gas in a pipeline. Pipelines transport both gas and liquids in two-phase flow. Liquids tend to settle in the bottom of pipelines, while the gases occupy the top section. Under certain conditions, the liquids and gases may group together to form slugs.

(SHEQ). The integrated SHEQ system includes certification to ISO 9 001 and 14 000 for the F-A Platform.

All identified aspects and impacts at the F-A Platform would be managed and monitored according to methodologies set out in PetroSA's EMP, which may require updating for the proposed platform modifications (Section 6.5.3.2.4). The plan addresses the following categories of environmental related activities:

- Pollution prevention under normal operating conditions;
- Waste management;
- Incidents and emergency reporting and management;
- Stakeholder engagement;
- Environmental awareness;
- Systems administrative requirements; and
- Air quality monitoring.

6.5.3.2.6 Decommissioning and Closure

This section provides a description of the closure activities that will be undertaken once production activities cease. Key elements have been extracted from the Closure Plan (WSP, 2023c) (appended in Appendix 16 of this ESIA report). Aspects related to cleaning of decommissioned equipment and waste management during the decommissioning process are described in Sections 6.9 to 6.12.

6.5.3.2.6.1 Closure Vision and Objectives

The following conceptual closure vision and objectives have been formulated for the Project, to guide the identification of appropriate well plugging and abandonment and infrastructure decommissioning measures, as well as to inform refinement of future planning and design in this regard:

- Closure vision: to return the Project site to a condition that encourages ecological processes and functionality to re-establish pre-project conditions and ensure that any elements that remain in situ are rendered safe and pose no demonstrable risk to the environment or people.
- Closure objectives:
  - Ensuring that the wells, once plugged and abandoned, are stable and non-leaking, and will not detrimentally impact marine life or maritime activities/users;
  - Ensuring that other abandoned infrastructures do not pose any risks to the marine life or human activities/users and can in time be naturally integrated into the seafloor landscape; and
  - Safeguarding the long-term functioning of the seabed and marine ecosystems.

6.5.3.2.6.2 Summary of Planned Closure Actions

For production wells, once production activities have ceased, the well will be plugged and abandoned in the same manner as described in Section 6.5.1.11 for exploration wells. The wellhead may be removed or left in place and, if it is left in place on the seafloor, an over-trawlable cap will be fitted if required to minimise the hazard to trawling activities undertaken in the area.

Other closure activities include the removal of subsea infrastructure especially in shallow water to remove the navigation hazard to maritime vessels and fishing activities.

A summary of the key closure components and actions is provided in Table 6-11 below.

Table 6-11 – Closure Components and Actions

Equipment	Location	Abandonment Action
Production wells	Deep water	Decommissioned and plugged *in situ*
Production manifolds	Deep water	Left on seabed following a visual inspection
Flowline end termination (FLET) units	Deep water	Left on seabed following a visual inspection
Subsea distribution units (SDU)	Deep water	Left on seabed
Production flowline (pipeline)	Deep water / Shallow water	Pigged to remove potential contaminants then left on seabed
Umbilical	Deep water / Shallow water	Disconnected, flushed and laid on seabed for deepwater - retrieved for shallow water
Subsea pig launcher (SPL)	Shallow water	Retrieved
Production riser	Shallow water / FA-Platform	Retrieved (excluded from Block 11B/12B project)

6.5.4 SUPPORT ACTIVITIES AND COMPONENTS

The Project components will include an onshore logistics base to support offshore operations and several support and specialised vessels for specific activities.

Supporting activities will also include helicopter transportation from existing airport facilities to move personnel to and from the offshore facilities.

6.5.4.1 Logistics Bases

During all Project phases, support operations will include transportation of equipment, supplies and personnel by vessel. The transport of bulk equipment will be done from the ports of Gqeberha and/or Cape Town.

It is anticipated that the supply base for the Project will be located within the Mossel Bay Port.

The supply base will likely include areas for:

- Equipment and material storage;
- Operations and maintenance centres;
- Quayside services to support vessels; and
- Loading/offloading supplies and equipment being transported to and from the drill units and the F-A Platform.

The shore base will provide for the storage of materials and equipment (including pipes, drilling fluid, cement, chemicals, diesel and water) and include a mud plant for mixing drilling fluids that will be transported by sea to and from the drilling vessel. The shore base will also be used for offices (with communications and emergency facilities).

6.5.4.2 Support and Specialised Vessels

Supporting activities will include the use of supply and support vessels as well as tugboats to support construction and installation activities, operations, and decommissioning. Vessels will also be used to support drilling operations. Such vessels will very likely operate from the Mossel Bay Port.

All vessels will need to comply with applicable International Maritime Organization (IMO) standards relevant to their proposed use (e.g., double-hulled vessels for tankers, etc.).

The types of vessels and their utilisation in the Project phases is summarised in Table 6-12. While this list does not include the drill unit, the drill unit will also comply with IMO standards (and its emissions and discharges are considered in sections below).

Table 6-12 - Summary of Support Vessel Requirements

Project Phase	Vessel Description
Drilling	Tugboat Supply vessels
Surveys	Specialised vessel(s)
Construction	S-Lay vessel J-Lay vessel Heavy lift vessel ROV survey vessel Pipe carrier vessel Dive support vessel Multi service vessel Supply vessel Umbilical installation vessel Project patrol vessel
Operation	Support vessel
Decommissioning	Tugboat Supply vessels Heavy lift vessel

6.5.4.3 Transport

Transportation of personnel to and from the drilling unit by helicopter is the preferred method of transfer for well drilling operations and decommissioning. It is estimated that there could be up to two trips per day between the drilling vessel and the airport at George during crew changes. The helicopters can also be used for medical evacuations from the drilling unit to shore (at day- or night-time), in an emergency.

During operations, helicopters will also be used to transport personnel, provisions and other goods between Mossel Bay and the F-A Platform (PetroSA, 2013).

6.5.4.4 Accommodation

Shore-based staff will be accommodated at the selected onshore base at Mossel Bay, Gqeberha or Cape Town. This could be either via hotels, guesthouses, Bed and Breakfast (B&B) type accommodation or long-term rentals of self-catering apartments. In addition, accommodation during crew changes may be required for incoming or departing offshore staff.

6.6 PROJECT TIMEFRAMES

Indicative timeframes for the commencement of the local construction phase (Year 0) are 2027/2028, with first gas (Year 1) in 2029/2030. It is anticipated that the first two production and appraisal wells will be drilled in Year 0, followed by one additional well in Year 1 and two additional wells in Year 10. The timeframe for the exploration activities is not known at this stage but the duration of the exploration activities is expected to be 3 to 4 months per well. Similarly, the timeframes for the marine surveys are not yet known, but, depending on the survey, could range between 15 and 30 days per survey (sonar and seafloor sampling), with metocean buoy monitoring taking up to a year. Once production ceases, the decommissioning phase will commence, anticipated to be in Year 26, over a period of 2 years.

A summary of the timeframes associated with the Project activities is provided in Table 6-13.

Table 6-13 – Project activities timeframes

Project Component	Phase	Timeframe	Duration of Activities	No. of wells
Exploration	Mobilisation	To be determined	120 days per well	Not applicable
	Operations, including plugging and abandonment			Up to four (4)
	De-mobilisation			Not applicable
Offshore Surveys (for Development and Exploration)	Operations	To be determined	▪ Sonar: 15 – 30 days for 1 survey ▪ Seafloor sampling: 15 – 30 days for 1 survey ▪ Metocean Buoy: 7 – 15 days for deployment, 2 services and 1 retrieval for 1 year monitoring	Not applicable
Development	Final well site selection, pipeline alignment selection	To be determined	To be determined	Not applicable
	Construction (including mobilisation)	Year 0	120 days per well	Two (2)
		Year 1	120 days per well	One (1)
		Year 10	120 days per well	Two (2)
	Production	Year 1 to Year 25	-	Year 1 to 10 – 3 wells Year 11 to 25 – 5 wells
	Decommissioning (including plugging and abandonment, and demobilisation)	Year 26	-	Five (5)

6.7 PERSONNEL REQUIREMENTS

For both production and exploration well drilling, the workforce working on the drilling unit and support vessels will be highly specialised and experienced in working in offshore conditions. An estimated 180 - 200 personnel will be on board depending on drilling operations. A limited number of personnel would be employed at the onshore base during each well drilling phase (for exploration and production).

The employment opportunities associated with the construction phase for the TEEPSA Project component is estimated to be around 600 and the refurbishment and recommissioning of the F-A Platform will support approximately an additional 5 000 employment opportunities (Urban-Econ, 2023) and will mainly consist of engineers and artisans, crew on support and specialised vessels and support services at the onshore base.

With the re-commissioning of the F-A Platform, approximately 150 people can be accommodated on the offshore F-A Platform for two weeks at a time operating the facility (PetroSA, 2013). Additional crew will also be required for *ad hoc* maintenance purposes and for support services at the onshore base.

A small (±45) TEEPSA workforce will be responsible for the overall management of the Project activities. The use of local labour will be prioritised where possible in line with TEEPSA's local content commitments and the Project's Social and Labour Plan (SLP).

Decommissioning activities will require the use of several vessels in the Project Development Area, and around the F-A platform. It is estimated that the personnel requirements during decommissioning would be less than that for the construction phase. However, the type and number of vessels required for decommissioning and their personnel requirements will depend on the content of the Final Restitution Plan, which will contain the detailed programme for the decommissioning and closure of Block 11B/12B and will be prepared by TEEPSA five years prior to the end of the production phase, as per the Closure Plan (WSP, 2023c) (appended in Appendix 16).

Given the specialised nature of offshore survey activities in terms of the skilled personnel and the equipment used, together with the limited requirement for this activity to be undertaken, fewer than 20 personnel are likely to be required for each of the offshore surveys to be conducted for Block 11B/12B.

A commercial company will be appointed to provide helicopter transport services for conveying personnel on rotation to and from the F-A platform during the operational phase. The helicopter service will also be used for emergency events, if appropriate.

6.8 RESOURCE REQUIREMENTS

The focus of this section is on energy and water resource requirements for the Project, given the potential overlap with local needs. Limited energy and freshwater will be required from local onshore sources as energy demand will be met either by the vessels using on-board fuel supplies or by the produced gas at the F-A Platform. Freshwater will mostly be supplied by on-board desalination units.

6.8.1 WELL DRILLING

The drilling unit will require fresh water for water supply, cement and mud preparation. Fresh water will be supplied by tanker vessels and will also be produced onboard the drilling unit via seawater desalination. Onshore, fresh water (for drilling fluids preparation, etc.) will be supplied from municipal water supply and/or a source of industrial grade water.

The drilling unit will require power to operate the circulating, rotating and hoisting systems. Marine Fuel Oil (MFO) will be used to generate power and transmit electricity to the drilling unit.

6.8.2 CONSTRUCTION

During the construction phase, energy and water supplies for the logistics base established in the Mossel Bay port will be sourced from local electricity and municipal water supplies.

Construction vessels, the pipelaying vessel and the survey vessel operating during the construction phase will produce their energy and water requirements from on-board systems. Small support vessels will obtain fuel and water provisions from the Mossel Bay port supply.

6.8.3 PRODUCTION

The F-A Platform is a self-sufficient facility as it generates its own fresh water from the on-site desalination plant and power from the produced gas (PetroSA, 2013). It will also provide power to the Subsea Production System (SPS) through the umbilicals connection.

6.8.4 DECOMMISSIONING

As for the construction phase, electricity and water will be self-generated by the main specialised vessels used during the decommissioning phase. The supply base established in the Mossel Bay port will be utilised to support the decommissioning activities.

6.9 CHEMICALS AND HAZARDOUS MATERIALS

A variety of chemicals, including both non-hazardous and hazardous chemicals, will be used during the various phases of the Project.

6.9.1 WELL DRILLING

Chemicals are required for the well drilling process, including drilling and cementing activities. Refer to Section 6.5.1.4 for a description of the drilling fluids, cement and additives, that will be used in drilling.

Other chemicals also available for the drilling unit include completion fluids and dispersants.

Completion fluids are solids-free liquids used to complete a production well. The fluid is placed in the well to facilitate final operations prior to initiation of production, such as setting screens, production liners, packers, and downhole valves. The fluid enables control of a well should downhole hardware fail, without damaging the producing formation or completion components. Completion fluids are typically brines (chlorides, bromides) and formulations with a number of additives;

Radioactive materials are limited to small amounts of radioactive elements found within specialised tools used during the drilling and well evaluation process; most of these radioactive materials are sealed within tools.

Dispersants are typically stored aboard the drill unit or the support vessel while at sea to provide for immediate response in the event of an oil spill. Additional stores of dispersant are located onshore at the supply bases and on the support vessels. Dispersant kits will be placed aboard one or more of the support vessels, with kits containing pumps, spray kits, and dispersant for boat application. Dispersant is stored in industrial bulk containers with an individual volume of 1 000 litres. Dispersants may only be deployed upon approval from DFFE.

For storage of well equipment and supplies, supply bases in the ports will be used. The drilling team may store drilling tubulars, wellheads, XMAS trees and other drilling equipment at these onshore locations. Some inventories of pipe grease, fluids and chemicals may be stored by contractors.

6.9.2 CONSTRUCTION

As part of the pipeline installation and commissioning, it will be flooded with seawater containing chemicals such as biocides, oxygen scavengers and corrosion inhibitors. The pipes will also be hydrostatically tested to ensure they can withstand the pressure of the water at the depth at which they are installed. Before startup, the production flowlines and export pipeline will be dewatered.

6.9.3 PRODUCTION

Operation and maintenance of the F-A Platform requires the use of fuels for local generators, biocides, cleaning agents, medical supplies, oils, paints, spare parts and other goods and chemicals. Some chemicals will also be required for operation and maintenance of the subsea system and pipeline (for instance during pigging).

6.9.4 DECOMMISSIONING

A variety of chemicals, including both non-hazardous and hazardous chemicals, will likely be employed during the decommissioning of the Project. The selected chemicals will depend on the decommissioning approach agreed at the time. Following good industry practice and complying with applicable legislation at the time of abandonment will support chemical selection. Key decommissioning processes which will include chemicals are pigging of the production pipeline as well as flushing and cleaning of the subsea infrastructures.

6.10 AIR EMISSIONS

The principal emissions emanating within Block 11B/12B, that can possibly reach the coast and at the Port(s) will be exhaust gas emissions produced by the combustion of fuel in vessel engines (including the drill unit), and helicopters (see

Table 6-14 below for estimated fuel consumption volumes). For exploration wells, flow testing may be undertaken to determine the economic potential of a discovery before the well is either abandoned or suspended. Flow testing will also be required for each development well before connection to the subsea production system.

The onshore operations at the proposed laydown area are expected to make use of existing port infrastructure for any heating and power requirements. Although the PetroSA operated F-A Platform does not form part of TEEPSA's proposed activities, it is an associated an associated facility with regard to the Project, and hence an indicative assessment of production related emissions from the F-A Platform has been provided. Emissions produced by the combustion of gas used for generators, heaters, and engines (referred to as gas auto consumption) at the PetroSA F-A Platform have been provided, as well as emissions from routine flaring of process gas at the F-A Platform.

These emissions include:

- Greenhouse gases (GHGs).
- Other pollutants:
  - Particulate matter (PM).
    - PM10 - Particulate matter with an aerodynamic diameter of less than 10 micrometres (µm).
    - PM2.5 - Particulate matter with an aerodynamic diameter of less than 2.5 µm.
    - Carbon monoxide (CO).
    - NO_x (Oxides of Nitrogen).
    - Sulphur dioxide (SO_2).
    - Volatile organic compounds (VOCs).

Table 6-14 - Marine fuel and kerosene consumption

Phase	Period of the project	Source	Quantity in t/d	No. Units	Consumption of marine fuel (tonnes)	Kerosene consumption (tonnes)
Exploration						
Well Drilling (EXPLO) - 1 Well	NA	1 x Drilling unit	88.5	120	10,620	
		1 x Tugboat	28.32	120	3,398	
		2 x Supply vessels*	15.93	120	1,912	
		Helicopter (2 trips/day)	1.3	120		156
		Total			*15,930*	*156*
Surveys						
Survey	NA	1 x survey vessel	17.7	30	531	
		Total			*531*	
Development						
Well Drilling (DEV) - 5 wells	Year 0 (226 days) And Year 1 (113 days)	1 x Drilling unit	88.5	339	30,002	
		1 x Tugboat	28.32	339	9,600	
		2 x Supply vessels*	15.93	339	5,400	
		Helicopter (2 trips/day)	1.3	339		440.7
	Year 10 (250 days)	1 x Drilling unit	88.5	250	22,125	
		1 x Tugboat	35.4	250	8,850	
		2 x Supply vessels*	17.7	250	4,425	
		Helicopter (2 trips/day)	1.3	250		325
	Year 0, 1 and 10	*Total*			*80,402*	*765.7*
Construction	Year 0 And Year 10	3 x Large FSV (Y0)**	28.32	221	6,259	
		2 x FSV (Y0)**	17.7	307	5,434	
		2 x Large FSV (Y10)**	28.32	94	2,662	
		1 x FSV (Y10)	17.7	30	531	
		Total			*14,886*	
Production	Year 1 to 25***	1 x Supply vessel	8.85	9131	80,809	
		Total			*80,809*	
Decommissioning	Year 26	1 x Drilling unit	88.5	100	8,850	
		2 x Tugboat/Large FSV*	56.64	100	5,664	
		2 x Supply vessels*	15.93	100	1,593	
		Helicopter (1 trip/day)	0.65	100		65
		Total			*16,107*	*65*
Development	Years 0 to 26	Total			192,204	830.7

Notes :
- Vessel fuel Conversion factor from m³ to tonnes = 0.885
* Consumption for 2 vessels
** Cumulative days in no. units
***A full year is 365 or 366 days (each 4 years)

6.10.1 GREENHOUSE GASES

GHG emissions for the Project were calculated in the climate change specialist report conducted for the Project (WSP Group Africa (Pty) Ltd, 2023b) and are presented Table 6-16 and Table 6-17. Greenhouse gases considered in the assessment include carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O), reported as carbon dioxide equivalents (CO_2e). Table 6-15 presents a summary of the sources of GHG emissions for which TEEPSA provided estimates, and which were considered in the GHG assessment.

Table 6-15 – Block 11B/12B and associated facility GHG emissions sources

Scope		Project Source Type
Scope 1	Direct GHG emissions – occur from sources that are owned or controlled by the organisation.	Marine fuel oil combustion for vessels engine and power generation (drilling unit, tugboats, supply & support vessels, specialised vessels).
		Kerosene consumption in helicopters.
		Flaring (well flow testing).
Scope 2	Indirect GHG emissions – occur from the generation of purchased electricity or steam that is bought into the organisation's property.	Not applicable to the Project as no electricity/ steam/ heat/ cooling is imported into the Project boundary
Scope 3	Other indirect GHG emissions – occur from sources that are not owned or controlled by the organisation.	FA-Platform use of hydrocarbon (Flaring and auto-consumption in turbines).
		Qualitative assessment of processing and use of sold product.

It should be noted that the **GHG emissions from the F-A Platform are reported as Scope 3 emissions** as the existing offshore installation F-A Platform will be owned and controlled by Petro SA. The F-A platform is considered **as an associated facility to the Project**, as it is necessary to the operation of the Project.

It should also be noted that GHG's associated with offshore surveys were excluded from the GHG the assessment, due to limited vision on the planning at this stage but also the short duration and limited logistic involved for each.

Table 6-16 - Offshore Emissions over Life of Project (Scope 1 emissions)

Total Direct Project Emissions	Stationary Combustion	Mobile Combustion	Total TCO_2e
Exploration and Appraisal	182 450	69 461	251 911
Development - Construction	643 965	139 538	783 503
Development - Drilling	-	165 554	165 554
Development - Production	-	256 650	256 650
Decommissioning	-	51 170	51 170
Total GHG Emissions			1 508 788

Table 6-17 - Offshore Emissions over Life of Project (Scope 3 emissions)

No.	Emission Category	Emission Source	Source Data	Unit	TCO_2e/annum	Total TCO_2e over Project Life
1	Stationary Combustion	Fuel gas auto consumption Combustion - Gas Turbines	62.39	$MMSm^3$ / annum	143 613	3 590 318
2		Flaring	0.0066	$MMSm^3$ / hr	18 375	459 381
Total GHG Emissions					161 988	4 049 699

6.10.2 OTHER POLLUTANTS

The potential influences of the above-mentioned emissions on air quality were assessed in the air quality specialist report conducted for the Project (WSP Group Africa (Pty) Ltd, 2023a). The results of the study are presented in Table 6-18 and Table 6-19. Please note that emissions relating to offshore survey and helicopter operations were calculated, and presented but were excluded from modelling given they are generally low emissions, infrequent, and covering a large area.

Table 6-18 - Emission rates for offshore operations

Source	Fuel use (t/yr) / Gas combusted (scf/yr)	Emission Rate (t/yr)					
		CO	NOx	PM	SO_2	VOC	Benzene
Offshore Surveys							
All survey vessels engines	531	1.95	36.7	2.76	5.31	0.887	8.87E-04
Total		**1.95**	**36.7**	**2.76**	**5.31**	**0.887**	**8.87E-04**
Exploration							
All vessels engines (including drill unit)	15,930	58.5	1,101	82.8	159	26.6	0.03
Helicopter	156	1.51	10.4	-	0.156	0.905	1.81E-04
Flaring (well test)	134,125,324.90	17.1	8.56	0.213	0.006	8.69	0.036
Total		**77.1**	**1,119**	**83.0**	**160**	**36.2**	**0.063**
Year 0 (Drilling and Construction)							
All vessels engines (including drill unit)	41,694	153	2,881	217	417	69.6	0.070
Helicopter	294	2.85	19.5	-	0.29	1.70	3.41E-04
Flaring (well test)	1,352,292,961.42 (associated gas)	172	86.3	2.14	0.063	87.6	0.364
	1,518,533,167.59 (natural gas)	194	97.0	2.41	0.070	1.49	0.619
Total		**522**	**3,084**	**221**	**417**	**160**	**1.05**

Source	Fuel use (t/yr) / Gas combusted (scf/yr)	Emission Rate (t/yr)					
		CO	NOx	PM	SO_2	VOC	Benzene
Year 1 (Construction and TEEPSA operations only)							
All vessels engines (including drill unit)	18,231	66.9	1,260	94.80	182	30.4	0.03
Helicopter	147	1.42	9.75	-	0.147	0.852	1.7E-04
Flaring (well test)	676,146,480.89 (associated gas)	86.2	43.2	1.07	0.031	43.8	0.182
	759,266,583.79 (natural gas)	96.8	48.5	1.20	0.035	0.745	0.309
Total		**251**	**1,361**	**97.1**	**183**	**75.8**	**0.522**
Year 2 – 9 & 11 – 25 (TEEPSA operations only) – Leap year worst case							
All vessels engines	3239	11.9	224	16.8	32.4	5.41	0.005
Total		**11.9**	**224**	**16.8**	**32.4**	**5.41**	**0.005**
Year 10 (Drilling, Construction and TEEPSA operations only)							
All vessels engines (including drill unit)	41 823	153	2,889.99	217.48	418.23	69.84	0.07
Helicopter	325	3.15	21.58	-	0.33	1.89	3.77E-04
Flaring (well test)	1,352,292,961 (associated gas)	172	86.34	2.14	0.06	87.59	0.36
	1,518,533,168 (natural gas)	194	96.95	2.41	0.07	1.49	0.62
Total		**523**	**3,095**	**222**	**419**	**161**	**1.05**
Year 26							
All Vessels Engines	16,107	59.11	1,112.99	83.76	161.07	26.90	0.03
Helicopter	65	0.63	4.32	-	0.07	0.38	7.54E-05
Total		**59.74**	**1,117.31**	**83.76**	**161.14**	**27.28**	**0.03**
F-A Platform Year 1 (365 days)							
Process Flaring	204,794,327.04	26.10	13.08	0.32	0.01	57.40	23.84
Heaters and Engines	2,409,006,187.14	93.18	352.28	7.50	0.07	2.39	0.01
Total		**119.29**	**365.35**	**7.82**	**0.08**	**59.78**	**23.85**
F-A Platform Year 10 (365 days)							
Process Flaring	204,794,327	26.1	13.08	0.32	0.01	57.40	23.84
Heaters and Engines	2,445,507,218	94.6	357.61	7.61	0.07	2.42	0.01
Total		**121**	**370.69**	**7.94**	**0.08**	**59.82**	**23.85**
F-A Platform Year 12 (366 days)							

Source	Fuel use (t/yr) / Gas combusted (scf/yr)	Emission Rate (t/yr)					
		CO	NOx	PM	SO_2	VOC	Benzene
Process Flaring	205,355,407	26.18	13.11	0.33	0.01	57.55	23.90
Heaters and Engines	2,488,808,272	96.27	363.95	7.75	0.07	2.47	0.01
Total		**122.44**	**377.06**	**8.07**	**0.08**	**60.02**	**23.92**

Table 6-19 – Emission rates for port operations

Source	Fuel Use at Port (t/yr)	CO	NOx	PM	SO2	VOCs	Benzene
Year 0							
Hotelling	46.03	0.033	0.131	0.013	0.009	0.004	7.27E-07
Manoeuvring	5.36	0.020	0.370	0.028	0.054	0.009	8.95E-06
Year 1							
Hotelling	37.99	0.027	0.108	0.011	0.008	0.003	6.00E-07
Manoeuvring	4.49	0.016	0.310	0.023	0.045	0.008	7.50E-06
Year 2 – 9 & 11 – 25							
Hotelling	23.46	0.017	0.067	0.007	0.005	0.002	3.71E-07
Manoeuvring	2.88	0.011	0.199	0.015	0.029	0.005	4.82E-06
Year 10							
Hotelling	59.59	0.042	0.169	0.017	0.012	0.005	9.41E-07
Manoeuvring	7.67	0.028	0.530	0.040	0.077	0.013	1.28E-05
Year 26							
Hotelling	25.71	0.018	0.073	0.007	0.005	0.002	4.06E-07
Manoeuvring	6.48	0.024	0.448	0.034	0.065	0.011	1.08E-05

6.11 EFFLUENT DISCHARGES

Discharges will occur from various Project activities. Phase-specific details of effluent discharges are described below.

6.11.1 WELL DRILLING

Drilling activities will produce effluents that include drilling cuttings and muds, cement, sanitary and domestic wastes, deck drainage and other miscellaneous discharges as described below. Effluents will be discharged following appropriate treatment to meet applicable standards for marine water quality.

Discharges of sewage and garbage will meet limits stipulated by the MARPOL[22] regulations Annex IV and Annex V respectively.

This section is based on standard drilling requirements for a typical well provided by TEEPSA, as well as the input data used for the Drilling Discharges Modelling Studies conducted for the Project (see Appendix 7 of this ESIA report).

6.11.1.1 Drill Cuttings and Mud

Drill cuttings, which range in size from clay to coarse gravel and reflect the types of sedimentary rocks penetrated by the drill bit, are the primary discharge during well drilling. Drilling discharges would be disposed at sea in line with accepted drilling practices for most countries (including South Africa). The rationale for this is based on the low density of drilling operations in the vast offshore area and the high energy marine environment. As such, TEEPSA proposes to use the “offshore treatment and disposal” option for their drilling campaigns in Block 11B/12B. The same method was applied and approved for drilling of TEEPSA's exploration wells in Block 11B/12B (namely the Brulpadda and Luiperd wells).

During the riserless drilling stage, all cuttings and WBM will be discharged directly onto the seafloor adjacent to the wellbore. An estimated volume of 866 t of cuttings and 3 289 t of drilling fluid will be discharged per well for the exploration and appraisal wells in the Exploratory Priority Area (eastern) section of the Block (see Table 6-20). For the production and appraisal wells in the Project Development Area (western) section of the Block, an estimated volume of 1 127 t of cuttings and 3 289 t of drilling fluid will be discharged per well (Table 6-21).

Where NADFs are used (possibly during the risered drilling stage, if WBMs are not able to provide the necessary fluid properties for successful drilling), these are sometimes treated offshore using shakers and centrifuge to recover the oil fraction for reuse in the drilling process or for onshore disposal. In instances where NADFs are used, cuttings will be treated offshore to reduce the percentage of NADF discharged to the sea with cuttings and centrifugation residues (fines) not exceeding 8% by weight (weight of base fluid by weight of dry retorted cuttings, measured with the Retorkit 50 cc method) for each completed well and only for the sections drilled with NADF. In addition, daily, the average content of NADF in the dry drill cuttings discharged to the sea shall never exceed 14% by weight. Cuttings that cannot be discharged, will be transported back to shore for further treatment, landfill disposal, or for use in cement plants. For the current Project though, it is anticipated that only WBMs will be used.

For the risered drilling stage, an estimated volume of 422 t of cuttings and 1 637 t of drilling fluid will be discharged per well (based on notional depth of 2 100 m) for the exploration and appraisal wells in the eastern section of the Block (Table 6-20). For the production and appraisal wells in the western section of the Block, an estimated volume of 478 t of cuttings and 1 526 t of drilling fluid will be discharged per well (based on notional depth of 2 442 m) (Table 6-21).

[22] The International Convention for the Prevention of Pollution from Ships, 1973

Cuttings released from the drilling unit at a depth between 1 m and 5 m below the surface during the risered drilling stage will be dispersed by the current and settle to the seafloor. The rate and quantity of cuttings discharge decreases with increasing well depth as the hole diameter becomes smaller (see Table 6-20 and Table 6-21).

Table 6-21 Discharge is intermittent as actual perforation operations are not continuous while the drilling unit is on location (time is required for casing, displacement, installation of seafloor equipment, etc.).

Further drilling fluid totalling 1 480 t and 2 900 t will be released from the drilling unit during well logging and plugging, for the exploration and appraisal wells and production and appraisal wells, respectively. The mud used during these processes is a KCl/Glycol/Polymer WBM.

The expected spatial extent of the deposition of discharged cuttings from the wells and associated environmental risk have been investigated in Drilling Discharges Modelling Studies (see Appendix 7). The modelling results are summarised in Section 9.

Table 6-20 – Notional well design and estimated drilling discharges: Exploration

Drill section	Hole diameter (inches)	Length of section (m)	Type of drilling fluid used	Mass of drilling fluid discharged (tonnes)	Mass of cuttings released (tonnes)	Drilling fluid and cuttings discharge location
Riserless drilling stage						
1	42"	83	Pad[23] mud	768	260	At sea bottom
2	26"	504	Pad mud	2 521	606	
Risered drilling stage						
3	17.5"	504	HPWBM	836	253	1 m below sea surface
4	12.25"	504	HPWBM	475	114	1 m below sea surface
5	8.5"	505	KCL WBM	326	55	1 m below sea surface
-	Suspension / displacement before drilling Section 3	-	KCl/Glycol/Polymer WBM	1 480	-	1 m above sea bed
Totals	-	2 100	-	6 406	1 288	-

[23] PAD mud = Heavy weight mud pumped into the well prior to tripping pipe or prior to setting cement plug (source: https://www.sigmaquadrant.com/glossary-drilling-operations)

Table 6-21 – Notional well design and estimated drilling discharges: Production Wells

Drill section	Hole diameter (inches)	Length of section (m)	Type of drilling fluid used	Mass of drilling fluid discharged (tonnes)	Mass of cuttings released (tonnes)	Drilling fluid and cuttings discharge location
Riserless drilling stage						
1	42”	122	Sea water + Gel / Polymer Sweeps	270	433	At sea bottom
2	26”	510	Sea water + Gel / Polymer Sweeps + KCL Muds	756	694	
Risered drilling stage						
3	12.25”	1 392	HPWBM	1 200	421	10 m below sea surface
4	8.5”	418	HPWBM	326	57	10 m below sea surface
-	Suspension / displacement before drilling Section 3	-	KCl/Polymer WBM	2 900	-	1 m above sea bed
Totals	-	2 442	-	5 452	1 605	-

6.11.1.2 Cement and Cement Additives

Typically, cement and cement additives are not discharged during drilling. However, during the initial cementing operation (i.e., surface casing), excess cement emerges out of the top of the well and onto the seafloor in order to ensure that the conductor pipe is cemented all the way to the seafloor. During this operation a maximum of 150-200% of the required cement volume may be pumped into the space between the casing and the borehole wall (annulus). In the worst-case scenario, approximately 100 m^3 of cement could be discharged onto the seafloor.

6.11.1.3 Blow Out Preventor (BOP) Hydraulic Fluid

As part of routine opening and closing operations, the subsea BOP stack elements will vent some hydraulic fluid into the sea at the seafloor. It is anticipated that between approximately 500 and 1 000 litres of oil-based hydraulic emulsion fluid could be vented per month during the drilling of a well. BOP fluids are completely biodegraded in seawater within 28 days.

6.11.1.4 Produced Water

If water from the reservoir arises during well flow testing (note: 14.5 m^3 was produced during the Luiperd well drilling campaign in 2020), this would be separated from the oily components and treated onboard to reduce the remaining hydrocarbons from these produced waters. The hydrocarbon component will be burned off via the flare booms, while the water is temporarily collected in a slop tank. The water is then either directed to:

- a settling tank prior to transfer to supply vessel for onshore treatment and disposal; or
- a dedicated treatment unit where, after treatment, it is either:

- if hydrocarbon content is < 30 mg/l, discharged overboard; or

- if hydrocarbon content is > 30 mg/l, subject to a 2nd treatment or directed to tank prior to transfer to supply vessel for onshore treatment and disposal.

Reinjection of the produced water may be considered if volumes are large and cannot be managed onboard the drilling unit.

6.11.1.5 Vessel Machinery Spaces (Bilge Water)

Vessels will occasionally discharge treated bilge water. Bilge water is drainage water that collects in a ship's bilge space (the bilge is the lowest compartment on a ship, below the waterline, where the two sides meet at the keel). Bilge and drain systems are monitored for hydrocarbon contamination. Oily water separators will process bilge and contaminated drain system water. Threshold maxima for the discharge will be 15 mg/L (parts per million, ppm) of hydrocarbons, per MARPOL Annex I requirements. Treated water (below 15 ppm) is discharged overboard; separated oil is transferred to the waste oil tank. The residue from the onboard oil/water separator will be treated and disposed onshore at a licenced hazardous landfill site.

6.11.1.6 Deck Drainage

Deck drainage is applicable to project vessels, including the drill unit and support vessels during drilling, and the specialised subsea infrastructure and pipeline installation vessels and support vessels during construction. Deck drainage consists of all waste resulting from rainfall, spillage, deck washings, and runoff from drains and gutters, including drip pans and work areas. Vessels have been, or will be, designed to contain runoff and prevent oily drainage from being discharged. Project vessels and surface infrastructure will be equipped with catchments (drip pans) in areas where hazardous chemicals are stored.

Typically deck drainage on board support vessels is routinely routed directly overboard, except in areas where hydrocarbons may be released; in these latter cases, deck drainage is directed to the oil skimmers/oily water separators for treatment prior to discharge. Threshold maxima for the discharge will be 15 mg/L (parts per million, ppm) of hydrocarbons, per MARPOL requirements. Water below 15 ppm hydrocarbons content is discharged overboard with sea surface sheen monitoring. Separated oil is transferred to the waste oil tank which will be treated / disposed of onshore at an approved hazardous landfill site.

6.11.1.7 Brine Generated from Onboard Desalination Plant

The waste stream from the desalination plant on the drill unit (and possibly specialised / support vessels) is brine (concentrated salt), which is produced in the reverse osmosis process. The brine stream contains high concentration of salts and other concentrated impurities that may be found in seawater. Based on previous well drilling operations, freshwater production amounts to approximately 40 m^3/day, which will result in approximately 35 g salt for each litre water produced (i.e., approx. 1 400 kg salt/brine per day).

6.11.1.8 Sewage and grey water

Discharges of sewage (or black water) and grey water (i.e., wastewater from the kitchen, washing and laundry activities and non-oily water used for cleaning) will occur from the drill unit and vessels intermittently throughout the Project and will vary according to the number of persons on board. Maximum daily generation rates for sewage and grey water are expected to be approximately 0.123 and 0.177 m^3/person, respectively.

All sewage discharges will comply with MARPOL Annex IV requirements.

- Sewage and grey water will be treated using a marine sanitation device to produce an effluent with:
  - A Biological Oxygen Demand (BOD) of <25 mg/l (if the treatment plant was installed after 1/1/2010) or <50 mg/l (if installed before this date);
  - Minimal residual chlorine concentration of 0.5 mg/l; and
  - No visible floating solids or oil and grease.

6.11.1.9 Food (Galley) Waste

Food wastes are generated from galley and food service operations. It is anticipated that food waste, a type of domestic waste, will be ground up prior to discharge (i.e., comminuted) to <25 mm diameter to meet discharge requirements, in accordance with MARPOL (i.e., for vessels 400 gross tonnage and above) requirements.

When ground to these specifications, food waste discharges are allowed if the vessel is more than 3 nmi (5.6 km) offshore. Food waste that is not ground may be discharged if the vessel is at least 12 nmi (22.2 km) offshore when sailing.

The drill rig will be located more than 12 nmi offshore but will not be underway while working in Block 11B/12B and, to comply with MARPOL Regulations, food waste will be ground prior to discharge.

6.11.1.10 Ballast Water

Ballast water is used during routine operations to maintain safe operating conditions onboard a ship by reducing stress on the hull, providing stability, improving propulsion and manoeuvrability, and compensating for weight lost due to fuel and water consumption.

While it is essential for safe operations, discharge of ballast water can pose a risk to the receiving environment when discharged due to foreign marine species (e.g., bacteria and larvae) being carried in a ships' ballast water from one location to another when mobilising the drilling ship to site. Ballast water is, therefore, discharged subject to the requirements of the 2004 International Convention for the Control and Management of Ships' Ballast Water and Sediments. The Convention stipulates that all ships are required to implement a Ballast Water Management Plan and that all ships using ballast water exchange do so at least 200 nautical miles (nm) (± 370 km) from nearest land in waters of at least 200 m deep when arriving from a different marine region. Where this is not feasible, the exchange should be as far from the nearest land as possible, and in all cases a minimum of 50 nm (± 93 km) from the nearest land and preferably in water at least 200 m in depth. Project vessels will be required to comply with this requirement.

6.11.1.11 Detergents

Detergents used for washing exposed deck spaces will be discharged overboard. Water-based detergents that are low in toxicity are preferred and detergents used on deck space will be collected with the deck drainage and treated as described under deck drainage above.

6.11.2 CONSTRUCTION

Prior to installation, the pipeline will be flooded with seawater containing chemicals (e.g., biocides, oxygen scavengers and corrosion inhibitors) and hydrotested. These chemicals are used for pipeline integrity preservation. Prior to commissioning, the pipeline will be dewatered and content release to the sea. The estimated[24] quantity of solution discharged to sea is 19,000 m^3.

The same discharges from vessels described for well drilling will apply to the Construction Phase specialised and support vessels.

6.11.3 PRODUCTION

Indicative timeframe for first gas is 2029 and gas and associated condensate will flow to the F-A Platform for processing. Routine effluents linked to the F-A Platform, such as treated sewage effluent and brine from the desalination plant, will be discharged as per the existing PetroSA EMP and related authorisations.

During the production phase, the ongoing monitoring of the wells and subsea infrastructure will be conducted remotely due to the offshore conditions.

There would be no increase in throughput capacity at the F-A Platform as a result of the operation of the Block 11B/12B. No additional produced water or other effluents would be generated during the production phase.

The same discharges from vessels described for well drilling will apply to the production phase maintenance and supply vessels.

The Block 11B/12B well field is expected to have a production life of 25 years, tapering off after 20 years.

6.11.4 DECOMMISSIONING

Ten years prior to the end of the production phase, TEEPSA will prepare a detailed Final Restitution Plan that will contain a decommissioning programme based on a risk assessment of options for removal of deep and shallow water infrastructure. The Plan will include implementation of good international practices and technologies available at the time.

South Africa does not have any specific guidelines pertaining to the decommissioning of subsea and seabed infrastructures and current practices. The Closure Plan (WSP, 2023) for the ESIA, prepared in terms of the Financial Provisioning Regulations 2015, as amended, describes well plugging and abandonment and subsea infrastructure and pipeline decommissioning activities as undertaken worldwide. This provides the basis for the estimate of the closure costs and the financial provision set aside for closure. There is a requirement that the Closure Plan is updated annually and submitted to PASA.

Plugging and abandonment of wells will likely be undertaken in a multi-phase programme to fully isolate the well prior to removal of the well infrastructure. During decommissioning operations small discharges of cement, condensate, MEG and brine may escape from the well head in small quantities.

[24] Calculation based on a pipeline length of 120 km and a pipeline diameter of 45 cm

If the subsea pipeline from the well head to the F-A Platform is abandoned *in situ*, it will be decontaminated using a pigging system to remove the contents assumed to be condensate, gas, water, MEG and wax prior to being flooded with seawater and abandoned.

The assumption is that the well will still be online with minimal flow to be able to push the pigging unit through the line. It is also assumed that the F-A Platform will be able to receive the flowlines contents. The umbilicals will also be flushed prior to retrieval (shallow water) or left *in situ* (deep water). No effluent will be release to sea as part of this cleaning and abandonment process. The same discharges from vessels described for well drilling will apply to the decommissioning phase specialised and support vessels.

6.12 SOLID WASTE

A summary of the typical waste types expected to be generated as a result of all Project activities are listed in Table 6-22.

Table 6-22 – Typical waste types

Category	Waste Type
Non-hazardous	General domestic waste
	Wood
	Plastic
	Scrap metal
Hazardous	Oil rags and oil filters
	Used oil
	Batteries
	Medical waste
	Oil water (slops)
	Filter cartridges
	Drums (with residues)
	Other various wastes

General waste landfill sites are located at the three onshore base options, Cape Town, Mossel Bay and Gqeberha. Hazardous landfill sites are also located at Cape Town and Gqeberha, with a new hazardous waste facility currently in the process of being established in Mossel Bay.

For all Project phases, the treatment, disposal and recycling of all waste onshore will be fully managed through a waste manifest system.

6.12.1 WELL DRILLING

In the event that NADF is used in well drilling, any quantity of NADF remaining at the end of well drilling will most likely be re-used during the drilling of subsequent wells in the area or another drilling campaign or shipped for onshore treatment and disposal by a licenced waste disposal company. At this stage of the Project though, it is anticipated that only WBMs will be used.

6.12.2 CONSTRUCTION

Waste generated at the onshore logistic base in the Mossel Bay port including hazardous waste and general municipal waste will be managed in terms of the existing port waste management system. The waste materials that cannot be recycled will be sent for disposal at a licensed landfill.

6.12.3 OPERATION

There would be no increase in throughput capacity at the F-A Platform as a result of the operation of the Block 11B/12B development. No additional solid waste would be generated during the production phase. Waste from the F-A Platform will be returned to shore every two weeks on average (PetroSA, 2013) and disposed at appropriately licensed waste disposal facilities.

6.12.4 DECOMMISSIONING

Taking into consideration the state and availability of local waste management facilities and best available technologies, the waste management hierarchy will be applied to waste generated as a result of retrieved equipment / facilities during the decommissioning phase. A waste management plan for decommissioning waste will be prepared at least 5 years prior to decommissioning.

6.13 LIGHT AND NOISE EMISSIONS

Light and sound will be generated by all Project activities. The light sources will primarily be operational lighting on the drill unit and vessels and offshore surface infrastructure (i.e., F-A Platform), while noise (both airborne and 'underwater) will be generated from vessel engines and equipment operation as well as the scheduled helicopter flights.

6.13.1 AIRBORNE SOUND

The primary sources of airborne noise from Project activities conducted in the offshore environment will be from vessel engines and operational plant and equipment, including engines, generators, pumps and cranes.

Onshore, the primary noise source will be from helicopters used for personnel transport. The level of airborne noise is dependent on the height of the overflight path and the position relative to the receiver as shown in Figure 6-13 and Figure 6-14.

The scheduled flights will operate from a designated airport during daylight hours. At this stage, the type of helicopter that would be used is not known; however, the noise impact arising from this activity would be primarily determined by the weight of the helicopter and the height of the flightpath above the receptor.

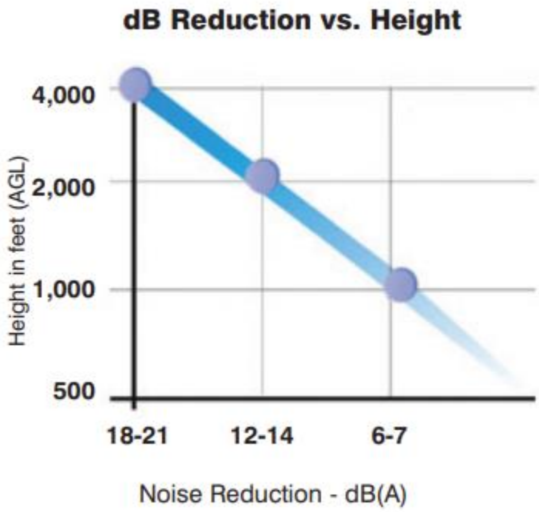


Figure 6-13 – dB Reduction vs. Height (Helicopter Association International; Fly Neighborly Committee, Undated)

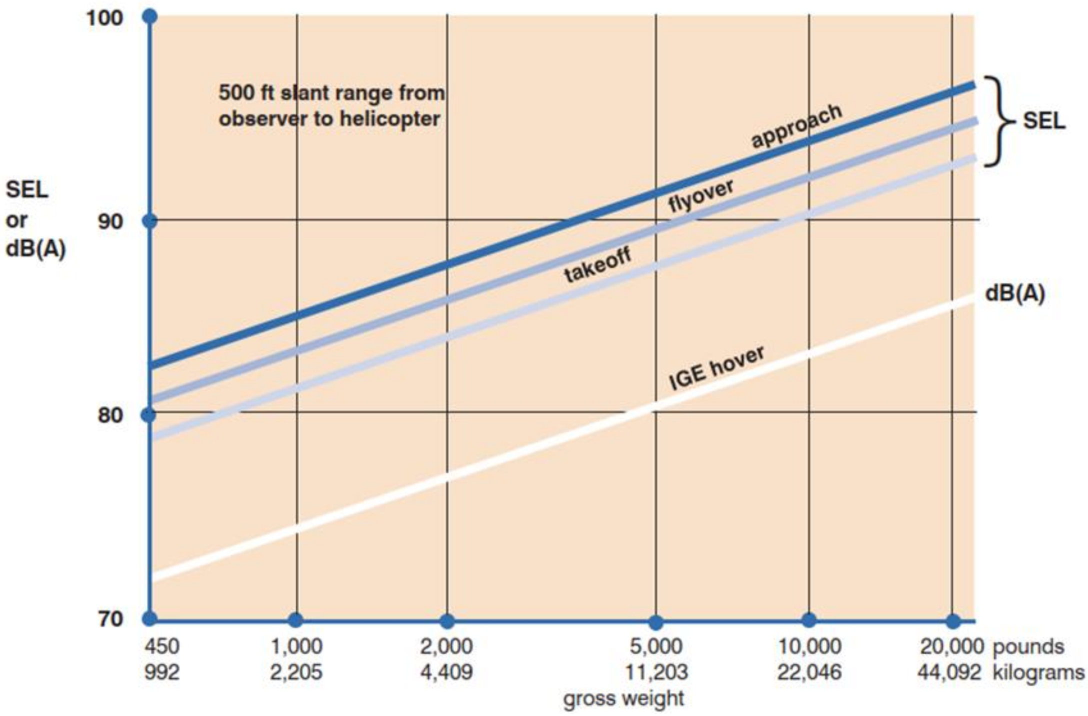


Figure 6-14 – Relationship Between Sound Level and Weight (Helicopter Association International; Fly Neighborly Committee, Undated) **(SEL = sound exposure level)**

6.13.2 UNDERWATER SOUND

Noise from drilling activities are expected to represent the greatest noise impacts associated with the Project. An underwater noise modelling study was undertaken for the Project (WSP Group Africa (Pty) Ltd, 2023f). These modelling results were used in the assessment of impacts on marine fauna and fisheries and are summarised in Section 9.

The following activities were identified as having the potential to impact underwater noise levels:

- The use of a drill unit and support vessels for exploration, appraisal and production well drilling;
- The use of a small airgun array to conduct vertical seismic profiling (VSP) when required before completion of appraisal well drilling;
- The use of a high-frequency sonar source to undertake sonar surveys as part of the offshore surveys; and
- Helicopter use to transport personnel to and from the offshore facilities as required as part of the Project drilling and development activities (including construction, operation, and decommissioning phases).

6.13.3 LIGHT EMISSIONS

Operational lighting will be required on the drilling unit and supply and specialised vessels for safe operations and navigation purposes during the hours of darkness. Where feasible, operational lights will be shielded in such a way as to minimise light spill to sea. Light will also be emitted from non-routine flaring as part of well testing, as well as from the F-A platform.

6.14 SAFETY ZONES AND NAVIGATION

Safety zones refer to permanent or temporarily designated maritime areas around fixed, floating or subsea structures where certain restrictions or special advisories apply to maritime users. This includes precautionary areas, designated tanker waiting areas, safety zones and, during construction periods, development areas. TEEPSA will work with the relevant authorities on the designation and notification of such areas in line with generally accepted international practice.

Section 8B[25] of the Marine Traffic Act (Act 2 of 1981) provides for the inclusion of pipelines in the definition of 'offshore infrastructure' and provides for the establishment of a 500 m safety zone around offshore infrastructure, including pipeline. It is an offence to damage the offshore infrastructure and vessels are prohibited from sailing nearer than 500 m to an offshore installation (other than a pipeline) and from anchoring or dropping or dragging an anchor within a demarcated safety zone.

Chapter 1 (Definitions, interpretation and implementation of the Act) of the Draft Merchant Shipping Bill, 2020 defines an 'offshore installation' as: '(a) Any installation, including a pipeline, which is used for the transfer of any substance to or from -(b) any exploration or production platform used in prospecting for or the mining of any substance'.

Section 320 (Prohibitions in respect of offshore installations) of the Draft Merchant Shipping Bill, 2020 states: (1) The master or a person on board a ship in charge of the navigation of the ship, may not— (b) enter a safety zone, drag or drop anchor nearer than 500m to a pipeline or a telecommunications line, except if rendering an emergency service or a previously agreed service to the offshore installation; and (c) cause the ship bottom to trawl nearer than 500m to a pipeline or telecommunications line while fishing.'

[25] Amendment in terms of the Marine Traffic Amendment Act 1993 (Act 38 of 1993)

TEEPSA will coordinate with the South African Maritime Safety Agency (SAMSA) that is responsible for maritime safety, health and environmental protection regarding safety zones. During well drilling, a 500 m safety zone will be established around the drill unit.

During the Construction Phase, a 500 m safety zone will be established around the vessels where the subsea infrastructure and pipeline installation is conducted. After installation the location of the subsea infrastructure and pipeline will be surveyed and marked on bathymetric and navigation charts as a hazard. Maritime shipping, commercial and small-scale fishing sectors will be notified of the presence of the infrastructure.

Radar, facility lighting and designated navigation channels will be used to manage support vessel traffic, tugboats, and supply vessels. The designated safety zones will be enforced with Project patrol boats during well drilling, construction, and decommissioning Phases.

Deployment of metocean buoys will require a temporary safety zone of between a 500 m and 2 km radius on the sea surface (depending on the water depth). All vessels would be excluded from entering this safety zone.

Once the closure certificate for the plugged wells is issued by the Competent Authority, the requirement for a safety zone will be decided by SAMSA based on an assessment of the risk of the infrastructure as a navigational hazard. Any infrastructure deemed a navigational hazard will remain marked on the navigational charts.

6.15 EMERGENCY RESPONSE

As project operator, TEEPSA will implement operational procedures outlined in its project-specific Health, Safety, Societal and Environment (HSE) management plan for the Block 11B/12B Project. The purpose of the project HSE Management Plan is to define how the project-specific HSE impacts and risks will be managed in conformance with applicable company-wide HSE requirements. Compliance with the project HSE Management Plan will enable TEEPSA and its contractors to conduct Project activities in a safe and environmentally sound manner.

TEEPSA has contract agreements with oil spill global response companies to use advanced capping stacks in the event of a well blow-out. Capping stacks are designed to shut-in an uncontrolled subsea well in the unlikely event of a blow-out. One capping stack is located in Saldanha and others in the UK and Singapore. TotalEnergies also has a capping stack in West Africa (Gulf of Guinea). The mobilisation of these and other incident response equipment and services will be contained in TEEPSA's Oil Spill Contingency Plan (OSCP) and Blow-Out Contingency Plan (BOCP).

The capping stack would only be deployed in a situation where the BOP has failed to serve its purpose and a blow-out has occurred. It is a piece of equipment that is placed over the blown-out well as a "cap." Its purpose is to stop or redirect the flow of hydrocarbons and to buy time for engineers to permanently seal the well. It weighs as much as 100 tonnes and requires coordinated logistical planning and execution in quickly transporting it to the emergency location.

Before a capping stack arrives, an ROV would be deployed to inspect the seabed site for engineers to confirm precisely what equipment is needed. Any debris would then be removed, and the wellhead prepared. After the equipment arrives, the capping stack would be maneuvered into place over the wellhead. The stack's valves would be closed to cap the well ("cap only") or, if necessary, the flow will be redirected to surface vessels through flexible pipes and risers ("cap and flow").

The mobilisation of these and other incident response equipment and services will be detailed in TEEPSA's Oil Spill Contingency Plan (OSCP) and Blow-Out Contingency Plan (BOCP).

The oil spill modelling assumes a 20-day period for the installation of a capping stack in the unlikely event of a blow-out. The closest subsea capping and subsea containment equipment (managed by OSRL, a cooperative dedicated to response to marine pollution by hydrocarbons) is located at Saldanha Bay. As part of the well response strategy, TEEPSA would also initiate the mobilisation of the Subsea Dispersant Injection (SSDI) kit.

At the F-A Platform, emergencies are dealt with according to PetroSA approved standard procedures (PetroSA, 2013).

6.16 FINANCIAL PROVISION AND TEEPSA INSURANCES

The Financial Provisioning Regulations 2015, as amended, published in terms of the NEMA, require Production Right applicants and holders to make provisions for the remediation and rehabilitation of any potential negative environmental impacts that may occur because of the proposed activities. These provisions should also include the financial provisioning for the rehabilitation, closure and ongoing post decommissioning management of environmental impacts.

In accordance with the plans and studies submitted as part of the application for an EA, the quantum to be set aside is determined through a detailed itemisation of all activities and costs required to implement final rehabilitation and decommissioning and remediation of any latent residual environmental impacts. Additionally, for the next ten years, the holder must make sure that the financial provision is adequate to cover the actual costs of putting these measures into effect.

TEEPSA will put in place the required financial provision for the proposed Project activities. The estimated cost for management and rehabilitation of potential negative environmental impacts that might be incurred during the proposed Project activities is provided in Appendix 16 of this ESIA report.

In terms of NEMA, the holder of a Production Right is accountable for any pollution or degradation of the environment as a result of their activities and would be responsible for funding the response to an oil spill.

During drilling operations, an "Operator Extra Expenses" (OEE) policy with a limit of not less than three times the Authorization for Expenditure (AFE) of the well is in place. This policy includes both a Third-Party Liability (TPL) section and a cargo coverage section.

The OEE policy covers the cost of regaining the control of a well under blow-out, the cost of redrilling the well and the cost of pollution clean-up and extends to cover possible leakage during plugging and abandonment activities. TPL covers the liability of the partners for damages, injury, death caused to third parties. Cargo covers the damages to TEEPSA's drilling equipment whilst in transit or intermediate storage.

Subject to the Terms and Conditions of the policy, insurers will indemnify the assureds up to the policy limit for any incident during Block 11B/12B drilling operations (TEEPSA , 2022).

6.17 PROJECT ALTERNATIVES

Alternatives are defined in in terms of the NEMA, as "*different means of meeting the general purpose and requirements of the activity, which may include alternatives to –*

(a) the property on which or location where it is proposed to undertake the activity;

(b) the type of activity to be undertaken;

(c) the design or layout of the activity;

(d) the technology to be used in the activity; and

(e) the operational aspects of the activity."

The alternatives considered for the Project specifically relate to location sites, technology, design and operation. A summary of the Project alternatives considered in this ESIA is provided in Table 6-23. These are presented in alignment with the mitigation hierarchy which prioritises the need for avoidance, minimisation and then consideration of restoration or offsetting requirements. Section 13 provides a comparative assessment of the Project alternatives.

Table 6-23 – Summary of Project alternatives

MH	Alternative	Description	Status
Site / location alternatives			
Avoidance	Offshore location of the areas of interest	The proposed development and exploration wells are constrained by the location of the confirmed reserves of hydrocarbons that were identified following an extended exploration process that included 2D and 3D seismic surveys within the Block, which led to the drilling of two successful wells, namely Brulpadda-1AX and Luiperd-1X. After conducting various technical and feasibility studies, the viability of the Brulpadda and Luiperd discoveries was confirmed. To avoid further operations; a portion of approximately 6 865 km^2 to the north of the Block 11B/12B Application Area has been relinquished as it overlapped a zone of high biodiversity value , including a Marine Protected Area.	No viable alternatives to the Project areas of interest location have been identified. Given that the Project is to exploit a natural resource, the location is constrained by the identification of areas with proven or potential hydrocarbons.
Avoidanc e	Site locations	In the Project Development Area of Block 11B/12B, up to six (6)[26] production wells will be drilled. The exact location of each well will be determined by possible preliminary on-site	Specialist recommendations on well locations, i.e. no-go areas, buffer zones, etc. have been taken into consideration

[26] At this stage of the engineering design, five production wells will be drilled in the Project Development Area with the option for a sixth well should it be required.

MH	Alternative	Description	Status
		survey work, including sonar scans and coring to check the bathymetry and the sea floor characteristics. Prior to drilling commencing, a seabed survey will be performed using a remotely operated vehicle (ROV) to document the condition of the seabed around each well point. If the seabed survey results indicate special environmental features at the planned location, alternative locations will be considered before drilling proceeds. The same procedure will be used to locate up to four (4) appraisal wells to be drilled in the Exploratory Priority Area of Block 11B/12B.	in this ESIA. See Chapter 9 for details.
Avoidance	Onshore support locations	As the closest port to the F-A Platform and onshore pipeline, Mossel Bay will likely be used as the base for support vessels conveying equipment and supplies to the drill unit and specialised vessel during drilling, construction and decommissioning. Support, maintenance and monitoring will also be provided to the F-A Platform and subsea production site during operations. Additional onshore support for the proposed Project could be based in either the port of Cape Town or the port of Gqeberha. These locations will likely be used for the shipping of large equipment that is imported and needs to be transported to the drill unit.	Mossel Bay Port is the onshore location closest to Block 11B/12B and will be used as the primary logistic base. Alternatives to this port will be the ports of Cape Town and Gqeberha will be used for transhipment of bulk equipment, as required. The impacts associated with the usage of these ports are assessed in Chapter 9.
Timing / scheduling			
Avoidance	Timing of well drilling and installation of SPS	For production, the wells will be drilled in sequence (in Year 0 and 1, and again in Year 10) to optimise mobilisation and demobilisation of the drill unit and support vessels. Drilling and installation of the SPS may have impact on marine fauna that is seasonally present within and around the Block 11B/12B area. Although the proposed timing of the well drilling does not affect the significance of the impacts related to drill cuttings deposition, it does have a significant effect on the probability and volume of condensate/oil reaching the shore in the unlikely event of a well blow-out.	The impact of seasonal weather conditions on these activities has been assessed in Sections 9 and 10.
No-go alternative			
Avoida nce	No-go option	The No-Go alternative represents the option to not proceed with the development and exploration activities on Block 11B/12B.	Additional to the Need and Desirability (section 5), the implications of implementing

MH	Alternative	Description	Status
		If the Project does not proceed, the project area of influence (i.e., offshore licence block, southern coastline and near shore of South Africa) remains unchanged in terms of environmental impacts, other than variations arising from natural events in or around Block 11B/12B as well as the continued use of the area for fisheries and shipping purposes. The No-Go option also precludes the opportunity of replacing the depleted supply of gas and condensate from the Block 9 field that provides feedstock for the F-A platform that, in turn, provides feedstock for the PetroSA GTL plant, as well as the opportunity of implementing gas to power (GTP) at Gourikwa Power Plant. Additionally, the potential for new hydrocarbon reserves in the eastern portion of the Block will remain unknown since further exploration in this area will not take place.	the no-go option are described in Section 9.8.
Design and layout alternatives			
Minimisation	Development Subsea system design and footprint	Within Block 11B/12B, preliminary options have been identified for the layout of the system to link the wells and subsea infrastructure in the production area, involving different combinations of vertical wells, manifolds, jumpers, flowline end terminations (FLET). The primary factor determining the choice of subsea equipment is the requirement to operate safely and reliably given the physical conditions at the installation depth. The successful drilling of the Block 11B/12B exploration wells provided TEEPSA with valuable information regarding equipment performance and this will be applied in the equipment selection process. As additional surveys, studies and modelling exercise are completed, a better understanding of the oceanographic and seafloor conditions will inform the design options.	The final positioning of the development wells and subsea infrastructure will be confirmed with on-site ROV surveys prior to work commencing. This is to ensure a suitable substrate for the well installation and avoid ecologically sensitive habitats.
Minimisation	Production pipeline corridor	Given the approximate location of the production wells within the field and the F-A Platform, options in terms of the production pipeline alignment are limited. However, two corridors with a 10km width have been identified:	The final pipeline alignment will to be confirmed pending the outcomes of: ▪ The environmental impact assessment (this assessment);

MH	Alternative	Description	Status
		- The base case is a direct route of approximately 109 km from the anticipated well location to the F-A platform. - The alternative is approximately 115 km, routing slightly northeast from the base case, overlapping an Ecologically or Biologically Significant Area (EBSA), with a bend to reach the F-A Platform. The base case corridor is likely the most suitable alignment as it follows an area already disturbed by previous oil and gas activities, avoids overlap or vicinity of an EBSA and has the smallest footprint on the proposed marine Critical Biodiversity Area (CBA) that it traverses.	▪ Final positions of the production well(s); and ▪ Further bathymetry, geotechnical, benthic and ROV surveys, which will possibly be used to confirm the absence of seafloor obstacles or stability issues as well as any sensitive features prior to finalising the route. The ESIA assesses the potential impacts of both pipeline corridor options and recommends the preferred option in Section 13.
Minimisation	Deep and shallow water infrastructure decommissioning	After decommissioning, well heads and other deepwater infrastructure (Table 6-11) can be either left in place or removed from the seafloor, if this can be done without an adverse impact on the marine environment. Options for removal or abandonment of shallow water infrastructure will be subject to a risk assessed prior to a final decision.	The ESIA (Chapter 9) and the Closure Plan (Appendix 16) assess the potential impacts of deep and shallow water infrastructure being left *in situ* on the seafloor or being retrieved.
Maximisation	Production pipeline	The production pipeline is likely to be imported. If locally manufactured, this would contribute to the local content of the Project.	Impacts of local content on the economic benefits associated with the Project are assessed in Section 9.

Building 1, Maxwell Office Park
Magwa Crescent West, Waterfall City
Midrand, 1685
South Africa

wsp.com