6. PROJECT DESCRIPTION

This chapter describes the project scope and activities, provides technical information on the proposed exploration and appraisal activities, and summarises the project alternatives.

6.1 LICENCE BLOCK DETAILS AND EXPLORATION RIGHT HOLDERS

TEEPNA holds the controlling interest in Block 2912, with Qatar Petroleum International Upstream LLC, Impact Oil and Gas and the National Petroleum Corporation of Namibia (NAMCOR) holding the remaining interest. Refer to Tables 6-1 to 6-3 for licence block information and the breakdown of shareholding and Figure 6-1 for an indication of the drilling area of interest within Block 2912.

Table 6-1: Licence Block information

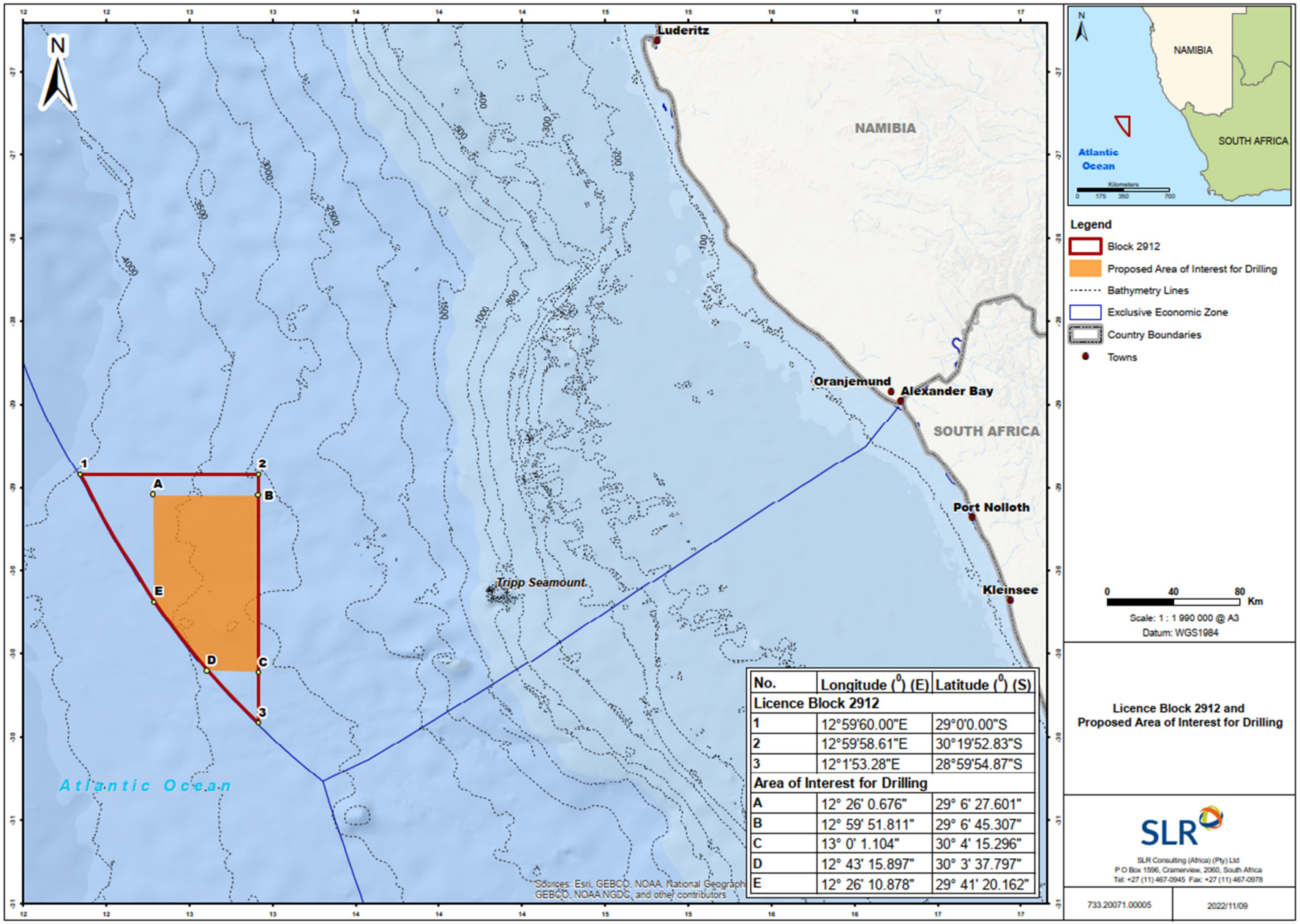
Exploration Right No.:	PEL0091
Licence Block No.:	2912
Size of licence area:	9 955 km^2
Water depths across licence area:	2 940 m to 3 850 m
Distance offshore:	290 km to 400 km

Table 6-2: Coordinates of Licence Block 2912

No.	Longitude (^{0}) (E)	Latitude (^{0}) (S)
1	12°59'60.00"E	29°0'0.00"S
2	12°59'58.61"E	30°19'52.83"S
3	12°1'53.28"E	28°59'54.87"S

Table 6-3: Structure of licence holding and shareholding of Block 2912

Organisation	Shareholding
TEEPNA	37.77%
Qatar Petroleum International Upstream LLC	28.33%
Impact Oil and Gas	18.9%
NAMCOR	15%



No.	Longitude (°) (E)	Latitude (°) (S)
Licence Block 2912		
1	12°59'60.00"E	29°0'0.00"S
2	12°59'58.61"E	30°19'52.83"S
3	12°1'53.28"E	28°59'54.87"S
Area of Interest for Drilling		
A	12° 26' 0.676"	29° 6' 27.601"
B	12° 59' 51.811"	29° 6' 45.307"
C	13° 0' 1.104"	30° 4' 15.296"
D	12° 43' 15.897"	30° 3' 37.797"
E	12° 26' 10.878"	29° 41' 20.162"

Figure 6-1: Outline of Block 2912 and the area of interest for proposed exploration and appraisal activities.

6.2 OVERVIEW OF PROPOSED PROJECT ACTIVITIES

The key components and activities of the proposed exploration programme are summarised in Table 6-4 and are detailed more fully in Sections 6.3 and 6.4.

Table 6-4: Summary of exploration activities and phases

Exploration phases		Exploration activities
1. Pre-Drilling Surveys		Operation of survey vessels
		Appointment of local service providers
		Seabed surveying, including : - multi and single beam echo sounding, and sub-bottom profiling - piston and box core sampling
2. Drilling	**2.1 Mobilisation Phase**	Establish onshore logistic base using existing infrastructure and rental of quay space for use as laydown area and warehouse. For the preparation and supply of drilling fluids, an existing mud plant operation in Walvis Bay would possibly be used.
		Appointment of specialised international and local service providers and staff
		Procurement of long lead items, importation and transportation of drilling equipment and bulk materials
		Accommodation rental and local spend (e.g., food and supplies)
		Transit of drilling unit and supply vessels to drill site
		Discharge / exchange of ballast water
	2.2 Operation Phase	Presence and operation of drilling unit and supply vessels - routine discharges to sea / air and lighting
		Operation of helicopters
		Well drilling (including ROV site selection; spudding; installation of conductor pipes, wellhead, BOP, marine riser, etc.)
		Discharge of cuttings, drilling fluid and residual cement
		Vertical Seismic Profiling (VSP)
		Well (flow) testing and flaring including the possible discharge of treated produced water
		Interaction with local economy (jobs and business opportunities; use of local services and facilities)
	2.3 Demobilisation Phase	Abandonment of well (plugging well with cement, test integrity and seabed clearance survey)
		Demobilisation of drilling unit and support vessels from drill site
		Demobilisation of logistics base, services and work force

6.3 PRE-DRILLING SURVEYS

Pre-drilling surveys may be undertaken prior to drilling in order to confirm baseline conditions at the drill site and to identify and delineate any geo-hazards that may impact the proposed exploration drilling operations. Such hazards could include:

- Seabed hazards:
  - Seafloor geologic features such as slumps or faults extending up to the seabed;
  - Synthetic objects, for example, wrecks, mines, pipelines, etc.; and
  - Seafloor conditions such as very soft clay or cemented sand.
- Sub-seabed hazards:
  - Shallow gas or shallow water flow reservoirs;
  - Gas hydrates;
  - Layers of boulders;

- Unconsolidated formations; and
- Shallow prospects.

Pre-drilling surveys may involve sonar surveys and sediment sampling.

A summary of the key pre-drilling survey components is provided in Table 6-5.

Table 6-5: Key components of pre-drilling surveys

Seabed Sediment Coring	
Method	• Piston core • Box corer
Number	20 cores
Duration	4 weeks
Location	Water depth < 2 940 m. No specific target identified yet
Safety Zone	500 m
Sonar Surveys	
Purpose	To investigate the structure of the ocean bed sediment layers
Method	• Multi beam echo-sounder (70-100kHz) • Single beam echo-sounder (38-200kHz) • Sub bottom profiler (2-16kHz)
Duration/Extent	4 weeks / target areas to be identified at a later stage
Location	Water depth from 2 940 to 3 500 m. Specific location not confirmed, but localised areas within the block.
Safety Zone	500 m

6.3.1 Sonar Surveys

Pre-drilling sonar surveys may involve multi- and single beam echo sounding and sub-bottom profiling. TEEPNA is proposing to undertake these surveys in water depths beyond 2 940 m. These surveys would take up to four weeks to complete. A description of the proposed techniques is provided below.

6.3.3.1 Echo Sounders

The majority of hydrographic depth/echo sounders are dual frequency, transmitting a low frequency pulse at the same time as a high frequency pulse. Dual frequency depth/echo sounding has the ability to identify a vegetation layer or a layer of soft mud on top of a layer of rock. TEEPNA is proposing to utilise a single beam echo-sounder with a frequency range of 38 to 200 kHz. In addition to this single beam echo sounder technique, TEEPNA is also proposing to utilise multibeam echo sounders (70 - 100 kHz range and 200dB re 1µPa at 1m source level) that are capable of receiving many return “pings”. This system produces a digital terrain model of the seafloor (see Figure 6-2).

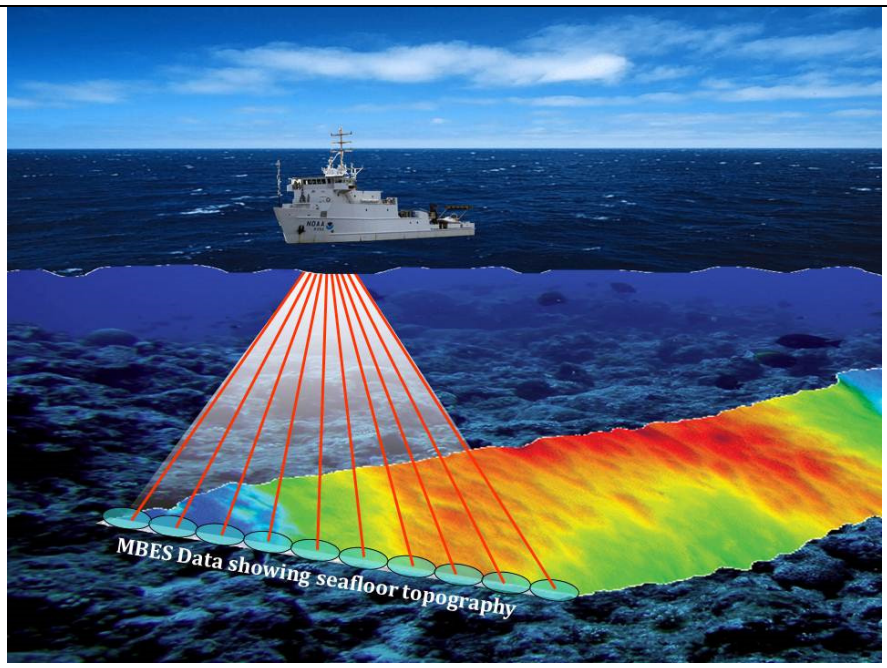


Figure 6-2: Illustration of a vessel using Multi-Beam Echo Sounder (MBES)
Source: US National Oceanic and Atmospheric Administration

6.3.3.2 Sub-bottom profilers

Sub-bottom profilers are powerful low frequency echo-sounders that provide a profile of the upper layers of the ocean floor. TEEPNA is proposing to utilise a bottom profiler emitting an acoustic pulse at frequencies ranging between 2 and 16 kHz, typically producing sound levels in the order of 200-230 db re 1µPa at 1m.

6.3.2 Seabed Sediment Coring

Seabed sediment sampling may involve the collection of sediment samples in order to characterise the seafloor and for laboratory geochemical analyses in order to determine if there is any naturally occurring hydrocarbon seepage at the seabed or any other type of contamination prior to the commencement of drilling.

No specific target area has as yet been identified by TEEPNA for the sediment sampling. It is currently anticipated that up to 20 samples could be taken across the entire area of interest. The sediment sampling process would take up to four weeks to complete.

Piston and box coring (or grab samples) techniques may be used to collect the seabed sediment samples. These techniques are further described below.

6.3.2.1 Piston Coring

Piston coring (or drop coring) is one of the more common methods used to collect seabed geochemical samples. The piston coring rig is comprised of a trigger assembly, the coring weight assembly, core barrels, tip assembly and piston. The sequence of operation is illustrated in Figure 6-3). The core barrels are in lengths of 6 to 9 m with a diameter of 10 cm. TEEPNA is proposing to collect samples up to a depth of 6 m in Block 2912.

The piston corer is lowered over the side of the survey vessel on a line and allowed to free fall from about 1 m above the seafloor to allow better penetration (see Figure 6-3 A). As the trigger weight hits the bottom (see Figure 6-3 B), it releases the weight on the trigger arm and the corer is released to "free-fall" the 3 m distance to the bottom (see Figure 6-3 B & C), forcing the core barrel to travel down over the piston into the sediment

(see Figure 6-3 D). The movement of the core barrel over the piston creates suction below the piston and expels the water out the top of the corer. When forward momentum of the core has stopped, a slow pull-out of the winch commences. This suction triggers the separation of the top and bottom sections of the piston (see Figure 6-3 E). The corer and sample are then slowly pulled from the seafloor and retrieved.

The recovered cores are visually examined at the surface for indications of hydrocarbons (gas hydrate, gas parting or oil staining) and sub-samples retained for further geochemical analysis in an onshore laboratory.

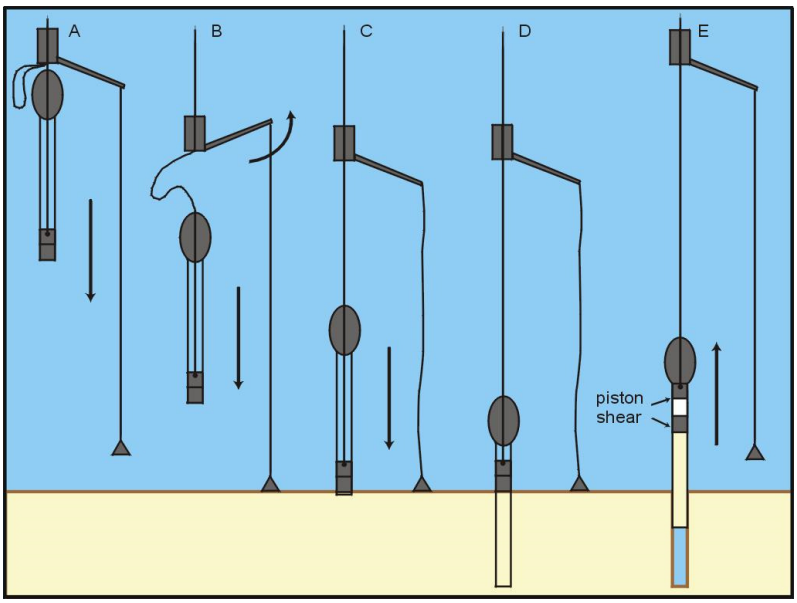


Figure 6-3: Schematic of a drop piston core operation at the seabed
Source: TDI Brooks International

6.3.2.2 Box Coring

The box corer (see Figure 6-4) is deployed for a survey vessel by lowering it vertically to the seabed. At the seabed the instrument is triggered by a trip as the main coring stem passes through its frame. The stem has a weight of up to 800 kg to aid penetration. While pulling the corer out of the sediment, a spade swings underneath the sample to prevent loss. The recovered sample is completely enclosed after sampling, reducing the loss of finer materials during recovery. Stainless steel doors, kept open during the deployment to reduce any "bow-wave effect" during sampling, are triggered on sampling and remain tightly closed, sealing the sampled water from that of the water column. On recovery, the sample can be processed directly through the large access doors or via complete removal of the box together with its cutting blade. A spare box and spade can then be added, ready for an immediate redeployment. TEEPNA is proposing to take box core samples (50 cm x 50 cm) at a depth of less than 60 cm.

Figure 6-4: A Box corer
Source: TEEPNA

6.4 EXPLORATION AND APPRAISAL WELL DRILLING

The description presented below is based on standard drilling requirements for a typical well where details may vary slightly for each well for aspects such as water depth, location, geology and seafloor conditions.

TEEPNA is proposing to drill **up to ten exploration and appraisal wells** within an Area of Interest in Block 2912. This section describes the site selection, anticipated timing, the different logistical components (i.e. drilling unit, vessels, etc.), the proposed drilling phases and the anticipated discharges, waste and emissions from the drilling unit and support vessels.

6.4.1 Area of Interest for Proposed Drilling and Anticipated Timing

The Area of Interest has been selected based on the results of previous seismic investigations. This area is **5 206 km^2** in extent and is **located offshore of southern Namibia close to the South African border, approximately 350 km southwest of Lüderitz and 340 km west-southwest of Oranjemund at its closest point, in water depths between 2 940 m and 3 700 m** (see Figure 6-1). The co-ordinates for Block 2912 and the Area of Interest are presented in Table 6-6.

The schedule for drilling the wells is not confirmed yet; however, the earliest anticipated date for commencement of drilling, if an ECC is granted, is between the **third quarter of 2023 (Q3 2023) and second quarter of 2024 (Q2 2024)**. The expected target drilling depth is not confirmed yet and a **notional well depth of 3 500 m** is assumed at this stage. It is expected that it would take **approximately three to four months to complete the physical drilling and testing of each well (excluding mobilisation and demobilisation)**. TEEPNA's strategy for future drilling is that drilling could be undertaken throughout the year (i.e. not limited to a specific seasonal window period).

Table 6-6: Coordinates of the area of interest for proposed exploration and appraisal drilling

No.	Longitude (^{0}) (E)	Latitude (^{0}) (S)
Area of Interest for Drilling		
A	12° 26' 0.676"	29° 6' 27.601"
B	12° 59' 51.811"	29° 6' 45.307"
C	13° 0' 1.104"	30° 4' 15.296"
D	12° 43' 15.897"	30° 3' 37.797"
E	12° 26' 10.878"	29° 41' 20.162"

6.4.2 Exploration Drilling Logistics

This section describes the main drilling logistical components, these include the following:

- Drilling unit;
- Supply vessels;
- Helicopters; and
- Onshore logistics base.

A summary of the key drilling project components is provided in Table 6-7.

Table 6-7: Summary of key drilling project components

Purpose	To confirm and test the presence and quality of hydrocarbon resources
Number of exploration and appraisal wells	Up to 10 wells
Size of Area of Interest for proposed exploration drilling	5 206 km^2
Well depth (below seafloor)	Variable depth of 1 500 to 3 500. A notional well depth of 3 500 m is assumed for the ESIA
Water depth range	• Water depth range of area of interest: 2 940 to 3 700 m

Duration to drill each well	• Mobilisation phase: up to 45 days
	• Drilling phase:
	  ○ Exploration well: Up to three months
	  ○ Appraisal well: Up to four months
	• Well abandonment: up to 15 days
	• Demobilisation phase: up to 10 days

Commencement of drilling and anticipated timing	Commencement is not confirmed, but possibly between fourth quarter of 2023 (Q4 2023) and second quarter of 2024 (Q2 2024) to drill first well
Proposed drilling fluids (muds)	Water-based Muds (WBM) will be used during the riserless drilling stage and Non-Aqueous Drilling Fluid (NADF) during the risered drilling stage (closed loop system)
Drilling and support vessels	• Semi-submersible drilling unit or drillship • Three support vessels during mobilisation and two during the risered drilling phase. These vessels will be on standby at the drilling site, as well as moving equipment and materials between the drilling unit and the onshore base

Operational safety zone	Minimum 500 m around drilling unit
Flaring	If hydrocarbons are discovered, one Drill Stem Test (DST) will be performed. If a production logging tool (PLT) is used, test would run 246 h / 10,25 days (+ 4 days build up). Without PLT, the test could run 218 hours / 9,1 days (+ 4 days build up).
Logistics base	Lüderitz
Logistics base components	Office facilities, laydown area, mud plant
Support facilities	Crew accommodation in Lüderitz
Staff requirements:	• Specialised drilling staff supplied with hire of drilling unit • Additional specialised international and local staff at logistics base
Staff changes	Rotation of staff every four weeks with transfer by helicopter to shore

6.4.2.1 Drilling Unit

Various types of drilling technology can be used to drill an exploration well (e.g., barges, jack-up rigs, semi-submersible drilling units (rigs) and drill-ships) depending on, *inter alia*, the water depth and marine operating conditions experienced at the well site (see Figure 6-5). Based on the anticipated sea conditions, TEEPNA is proposing to utilise a drillship (as used for the drilling of the Venus X-1 well in the adjacent Block 2913B in 2021) with dynamic positioning system suitable for the deep-water harsh marine environment. The final drillship selection will be made depending upon availability and final design specifications.

A drill-ship is a fit for purpose built drilling vessel designed to operate in deep water conditions. The drilling “rig” is normally located towards the centre of the ship with support operations from both sides of the ship using fixed cranes. The advantages of a drill-ship over the majority of semi-submersible units are that a drill-ship has much greater storage capacity and is independently mobile, not requiring any towing and reduced requirement of supply vessels.

The use of a semi-submersible drilling unit might also be considered in future, depending on vessel availability. A semi-submersible drilling unit is essentially a drilling rig located on a floating structure of pontoons. When at the well location, the pontoons 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.

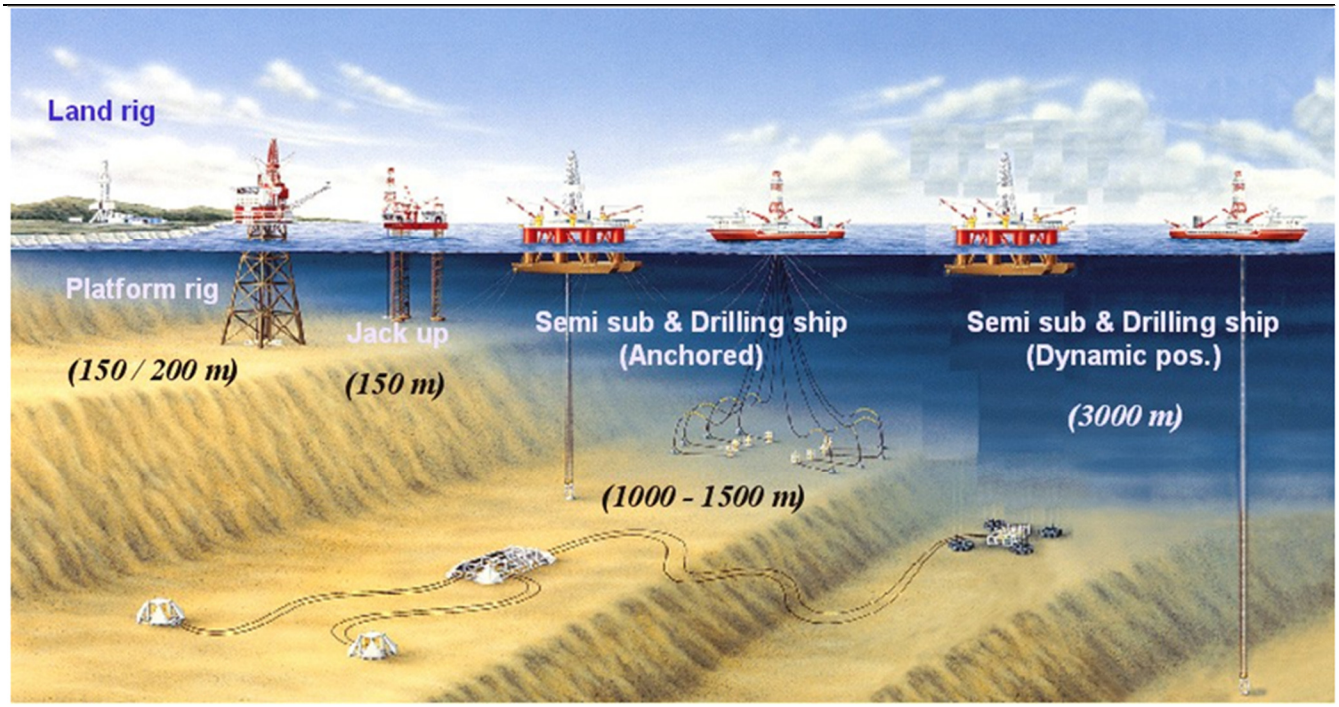


Figure 6-5: Drilling unit types

Source: https://seekingalpha.com/article/4043883-offshore-drilling-comprehensive-valuation-mobile-offshore-drilling-unit-today

Under the Convention on the International Regulations for Preventing Collisions at Sea (COLREGS, 1972, Part B, Section II, Rule 18), a drilling unit that is engaged in underwater operations is defined as a "*vessel restricted in its ability to manoeuvre*", which requires that power-driven and sailing vessels give way to such vessels. Fishing vessels are required to keep out of the way of the well drilling operation and observe the operational safety zones.

Furthermore, under the Marine Traffic Act, 1981 (No. 2 of 1981), a vessel used for the purpose of exploiting the seabed falls under the definition of an "offshore installation" and as such it is protected by a 500 m safety zone. It is an offence for an unauthorised vessel to enter the safety zone. The temporary 500 m safety zone around the drilling unit will be enforced at all times during operation and will be described in a Notice to Mariners as a navigational warning.

6.4.2.2 Support Vessels

The drilling unit will be supported / serviced by up to three support vessels operating an expected two to three rotations per week, to facilitate the moving of equipment and materials between the drilling unit and the onshore base.

A support vessel will always be on standby near the drilling unit to provide support for firefighting, oil containment / recovery, rescue in the unlikely event of an emergency and supply any additional equipment that may be required. Support vessels can also be used for medical evacuations or transfer of crew if needed.

6.4.2.3 Helicopters

Transportation of personnel to and from the drilling unit by helicopter is the preferred method of transfer. It is estimated that there could be up to four trips per week between the drilling unit and the helicopter support

base in Lüderitz (i.e. 17 weeks (~120 days) x 4 = 68 trips per well). The helicopters can also be used for medical evacuations from the drilling unit to shore (at day- or night-time), if required.

6.4.2.4 Onshore Logistics Base

The primary onshore logistics base will most likely be located at the Port of Lüderitz. The shore base will provide for the storage of materials and equipment (including pipes, drilling fluid, cement, chemicals, diesel and water) and a mud plant for mixing drilling fluids that will be transported by sea to / from the drilling vessel. The shore base will also be used for offices (with communications and emergency procedures / facilities), accommodation, waste management services, bunkering vessels, and stevedoring / customs clearance services.

The supply vessels will occupy the quay for about 12 hours per trip, depending on the quantity of material to be loaded / unloaded and time required for custom clearance.

The service infrastructure required to provide the necessary onshore support is already in place in Lüderitz and it is not anticipated that any additional permanent onshore infrastructure would be required for the project. The Port of Lüderitz was also used by TEEPNA as a logistics base for its 2021 drilling campaign in the adjacent Block 2913B.

6.4.2.5 Accommodation

Shore-based staff will be accommodated in Lüderitz. This could be either via house rental or at Bed and Breakfast (B&B) type accommodation and hotels. In addition, accommodation during crew changes may be required for incoming or departing offshore staff. The only TEEPNA personnel stationed in Lüderitz would be the logistics base personnel, while other shore-based staff would be based in TEEPNA's Windhoek office.

6.4.3 Mobilisation Phase

The mobilisation phase will entail the required notifications, establishment of the onshore base, appointment of local service providers, procurement and transportation of equipment and materials from various ports and airports, accommodation arrangements and transit of the drilling unit and support vessels to the drilling area.

6.4.3.1 Stakeholder Notification

A formal notification will be submitted to MME prior to mobilisation of the drilling unit. This will include details of the activity location, drilling schedules, drilling unit / supply vessel specifications and contractor details. MME will be routinely notified through regular reports and meetings on the progress of activities throughout the drilling campaign.

Key stakeholders (e.g., fishing associations and companies, operators of the neighbouring licence blocks, local authorities, etc.) from the stakeholder database will also be notified of planned exploration activities prior to commencement. Relevant authorities will be engaged as necessary for the establishment of the onshore logistics base (e.g., NAMPORT, local authority, etc.).

6.4.3.2 Mobilisation of Drilling Unit, Supply Vessels and Personnel

The procurement of a drilling unit could take six months to a year, depending on availability. The drilling unit and supply vessels could sail directly to the well site from outside Namibian waters or from a Namibian port, depending on which drilling unit is selected, and where it was last used. The drilling unit and supply vessels will be subject to customs clearance.

To maintain the stability and trim of the drilling unit and the support vessels, seawater would be pumped into designated ballast tanks and released to sea during mobilisation and transit to site.

Core specialist and skilled personnel would arrive in Namibia onboard the drilling unit and the rest of the personnel will be flown to Lüderitz. 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 or imported via a container vessel directly to the onshore logistics base from where the supply vessels will transfer it to the drilling unit.

6.4.4 Operation Phase

6.4.4.1 Final Drilling Site Selection

The selection of the specific well locations will be based on a number of factors, including further detailed analysis of the seismic and pre-drilling survey data and the geological target. A ROV[3] will be used to finalise the well position based on *inter alia* the presence of any seafloor obstacles or the presence of any sensitive features that may become evident.

6.4.4.2 Drilling Systems

The main systems of a drilling unit are hoisting, rotating, mud and drill cutting circulation, blow-out prevention and well-control, power, and storage. The general layout of the drilling infrastructure is shown in Figure 6-6.

6.3.4.2.1 Hoisting System

The hoisting system is used to raise and lower drill pipe in and out of the hole and to support the drill string to control the weight on the drill bit during drilling. The hoisting system consists of the derrick, traveling and crown blocks, the drilling line and the draw works.

The drilling unit uses a derrick, which is a steel tower that is used to support the traveling and crown blocks which are a set of pulleys that raise and lower the drill string (i.e. the drill bit and pipe) via a large diameter steel cable connected to a winch or draw-works). The crown block is a stationary pulley located at the top of the derrick while the traveling block moves up and down and is used to raise and lower the drill string. The draw-works contain a large drum around which the drilling cable is wrapped and which spools the cable off or on in order to lower or raise the drill string depending on the direction the drum is rotated.

6.4.4.2.2 Rotating System

The rotating equipment turns the drill bit that is used to create the hole. It consists of the top drive, the rotary table, the drill pipe and the drill collars (drill string), Bottom Hole Assembly (BHA) equipment and the drill bit. The top drive is a motor attached to the bottom of the traveling block, which is suspended from the derrick or mast of the rig, and turns a shaft to rotate the drill string during drilling. A top drive allows drillers to more quickly engage and disengage pumps or the rotary while removing or running the pipe. It travels up and down the vertical rails to avoid the mechanism from swaying with the movement of the ocean.

[3] Remote Operated Vehicle – A small, unmanned, highly maneuverable underwater machine that is used to explore underwater features / seafloor, while being operated by someone at the water surface.

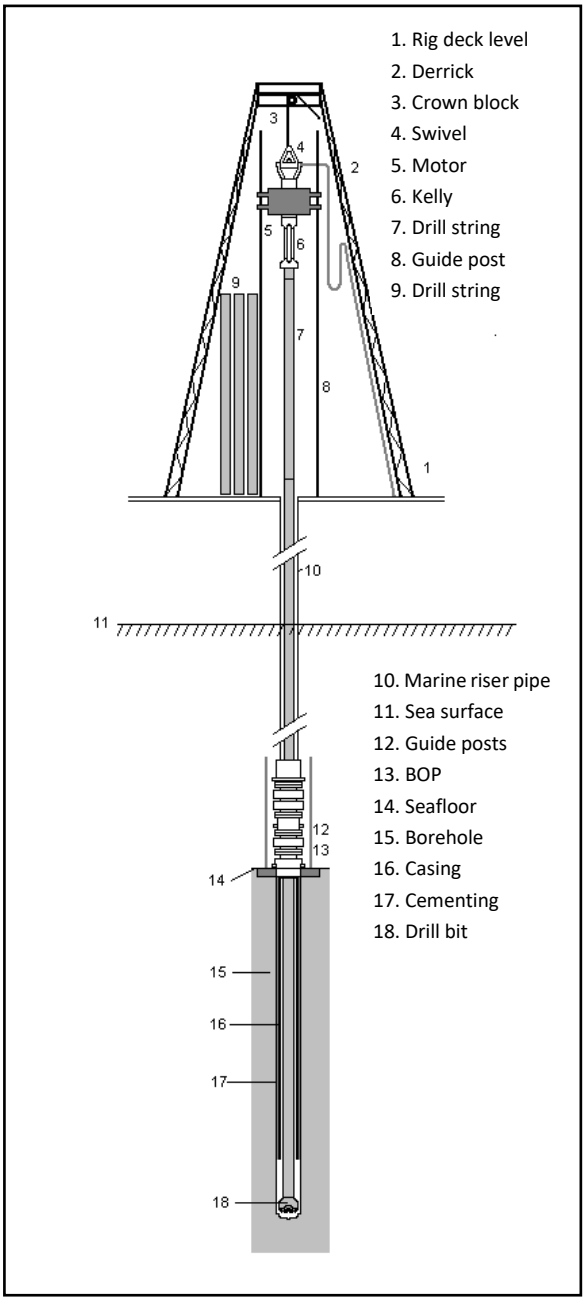


Figure 6-6: Generalised components of the drilling unit and drill string
Source: Jahn *et al*. 1998

A hose, through which the drilling fluid enters the drill pipe, is connected to the top of the top drive. The drill pipe is a round pipe about 9 m long with a typical diameter of 5 or 5.5 inch (12.7 or 14 cm). Drill collars are heavy thick pipes that are used at the bottom of the drill string to add weight to the drill bit. The drill pipe has threaded connections on each end that allow the pipe to be joined together to form longer sections as the hole is drilled deeper. Drill bit sizes typically range from 36 inches (91 cm) to 6 inches (15 cm) in diameter.

6.4.4.2.3 Mud and Drilling Discharges Circulating System

The drilling operation uses drilling fluids (often referred to as 'muds') to reduce friction (lubricate and cool the drill bit), remove the drilled rock fragments (cuttings), and to equalise pressure in the wellbore and prevent other fluids from flowing into the wellbore.

During the risered drilling stage, the riser isolates the drilling fluid and cuttings from the environment, thereby creating a "closed loop system". The circulation system of drilling fluid consists of the suction pits, pumps, surface piping (flowlines and standpipe), rotary hose (or kelly hose) and swivel, which is connected to the top drive.

The flow path of the drilling fluid is shown in Figure 6-7 and Figure 6-8. The circulating system pumps the drilling fluids (or drilling muds) down the hole, out of the nozzles in the drill bit and returns them to the surface where the cuttings are separated from the drilling fluid.

While drilling is in progress, drilling fluid is continuously pumped down the inside of the hollow drill string. The fluid emerges through ports ("nozzles") in the drill bit and then rises (carrying the rock cuttings with it) up the annular space between the sides of the hole (the casing and riser pipe) and the drill string, to the drilling unit. The returned drilling mud is treated to remove the cuttings (shale shakers) from the re-circulating mud stream (see Figure 6-7).

The solids control system sequentially applies different technologies to recover and separate the drilling fluid for reuse from the cuttings. The solids waste stream will comprise the drilling discharges (small pieces of stone, clay, shale and sand) and solids in the drilling fluid adhering to the cuttings (barite and clays). A typical solids control system consists of the following main components:

- Shale shakers (to remove large-sized cuttings);
- Degasser (to remove entrained gas);
- Desanders (to remove sand-sized cuttings);
- Desilters (to remove silt-sized cuttings); and
- Centrifuge (to recover fine solids and weighting materials such as barite).

The components of the solids control system depend on the type of drilling fluid used, the type of geological formations being drilled, the available equipment on the drilling unit and the specific requirements of the disposal option. Solids control may involve both primary and secondary treatment steps.

As part of primary treatment, cuttings are first processed through shale shakers – the primary solids control devices. These are designed to trap cuttings on the screens and remove large cuttings through a series of shale shakers with sequentially finer mesh sizes designed to remove progressively smaller drill cuttings. The mud passes through the screens into the mud pits. The circulating pumps pick up this clean mud and pumps it back down the hole. Each stage of the process produces partially dried cuttings and a liquid stream.

Where secondary treatment is used, the partially dried cuttings may be further processed using specialised equipment commonly called cuttings dryers. This is followed by additional centrifugal processing and desanders (i.e. secondary solids control equipment that use a hydrocyclone to separate solids from the incoming fluid using the centrifugal force). Centrifuges are used to remove particles that can contribute to fines build-up. Secondary treatment allows recovery of additional synthetic-based drilling fluid for re-use and results in a waste stream (cuttings) with a lower percentage of the drilling fluid retained on the cuttings. The waste streams from the

cuttings dryer and decanting centrifuge are then disposed overboard through a cutting chute a few metres below the sea surface.

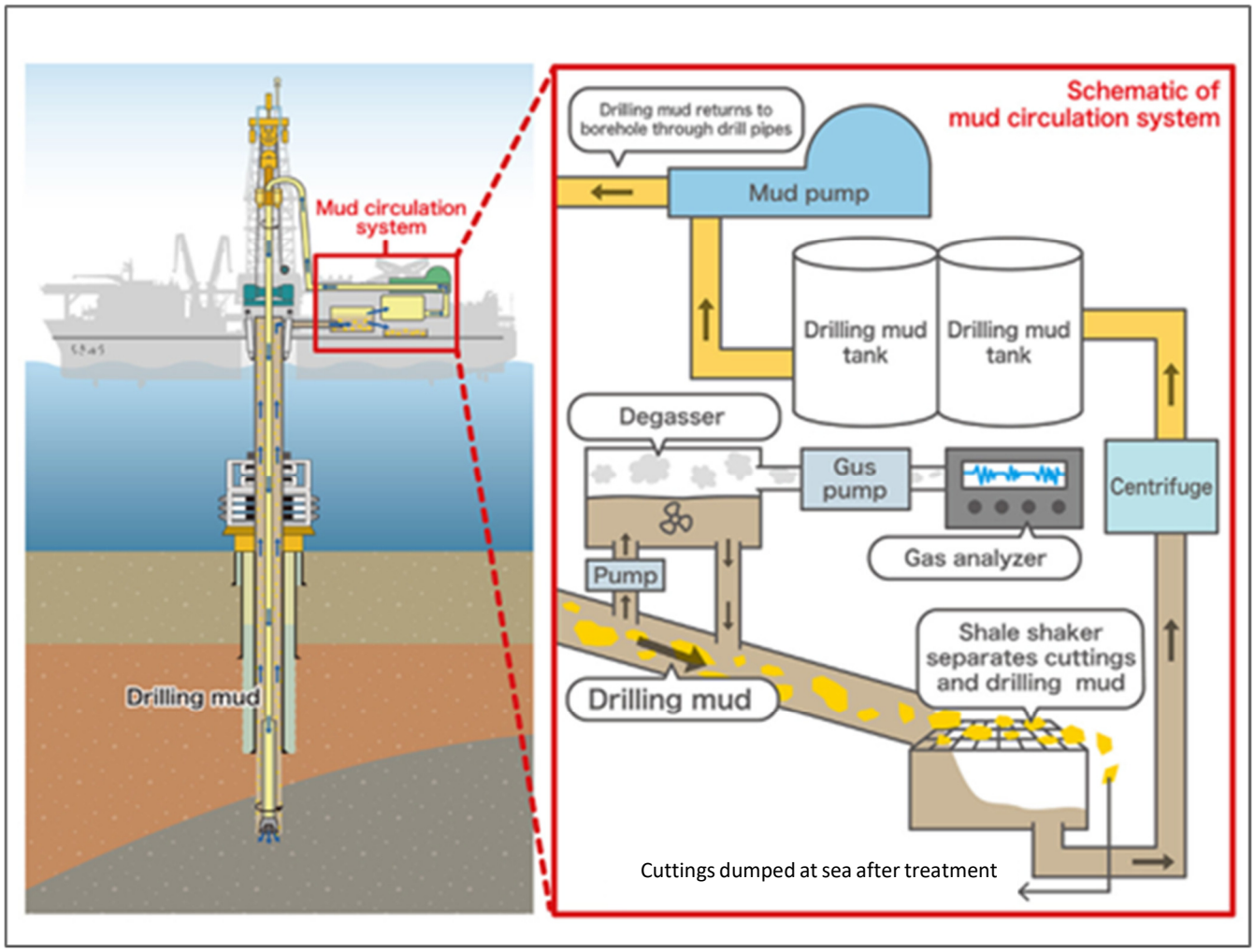


Figure 6-7: Simplified illustration of a mud circulating system

Source: Google Image

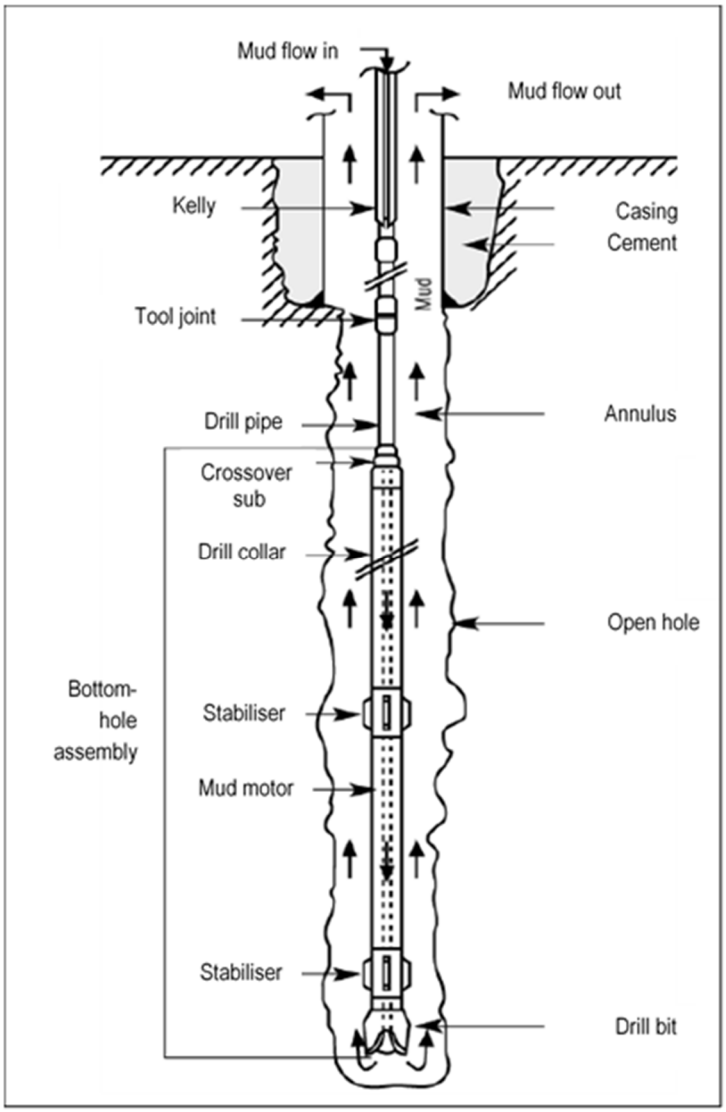


Figure 6-8: Drilling mud circulates down the drill pipe

Adapted from: Candler and Leuterman, 2008

6.4.4.2.4 Blow-out Prevention and Well Control

Although the probability of a well blow-out is extremely low, it is a worst-case scenario that provides the greatest environmental risk during drilling operations. TEEPNA 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.

The primary safeguard against a blow-out is the column of drilling fluid in the well, which exerts 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 break down 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.

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) (see Figure 6-9), which is a secondary control system that is especially important in deep-sea and strong metocean conditions. 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 well bore. 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 / 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 best industry practices.

The BOP stack usually consists of the following:

- Annular preventer: The annular-type blow-out preventer can close around the drill string, casing or a non-cylindrical object, such as a Kelly (i.e. a piece of equipment shaped like a pipe that is used in drilling). The drill pipe, including the larger-diameter tool joints (threaded connectors), can be "stripped" (i.e. moved vertically while pressure is contained below) through an annular preventer by careful control of the hydraulic closing pressure. Annular BOPs are typically located at the top of a BOP stack, with one or two annular preventers positioned above a series of several ram preventers.
- Ram type preventers: Ram type preventers are similar in operation to gate valves, but use a pair of opposing steel plungers or rams. The rams extend toward the centre of the wellbore to restrict flow or retract open in order to permit flow. There are four common types of rams or ram blocks used in a BOP stack (or combination thereof):
    - Pipe rams close around a drill pipe, restricting flow in the annulus (ring-shaped space between concentric objects) between the outside of the drill pipe and the wellbore, but do not obstruct flow within the drill pipe. Variable-bore pipe rams can accommodate tubing in a wider range of outside diameters than standard pipe rams, but typically with some loss of pressure capacity and longevity;
    - Blind rams (also known as sealing rams), which have no openings for tubing, can close off the well when the well does not contain a drill string or other tubing and seal it;
    - Shear rams cut through the drill string or casing with hardened steel shears; and
    - Blind shear rams (also known as shear seal rams or sealing shear rams) are intended to seal a wellbore, even when the bore is occupied by a drill string, by cutting through the drill string as the rams close off the well.

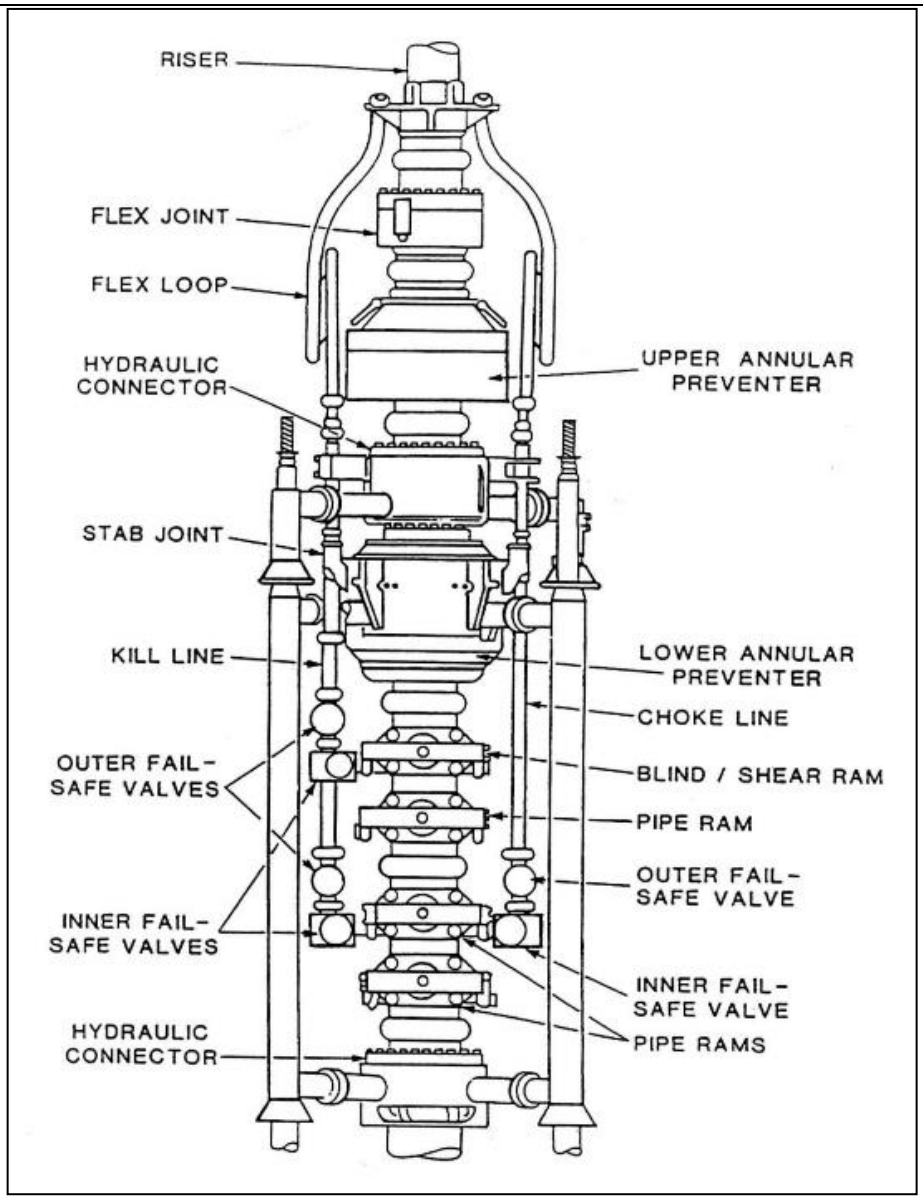


Figure 6-9: Schematic of a typical subsea BOP stack
Source: CCA & CSM, 2001

In deeper offshore operations, there are four primary ways in which a BOP can be controlled, including (in order of priority):

- Electrical control signal, which is sent from the surface through a control cable (MUX cable). Functioning valves on the stack release high pressurised hydraulic fluid to function the rams or annulars. This method allows for multiple commands to be sent via a single conductor very rapidly;
- Acoustical control signal, which is sent from the surface via a modulated / encoded pulse of sound transmitted by an underwater transducer. This new technique allows for communication with the subsea BOP without the need of an umbilical;
- ROV intervention, which mechanically controls valves and provides hydraulic pressure to the stack (via "hot stab" panels); and

- Emergency Disconnect System (EDS) - in the event the rig loses communication with the subsea BOP, then the BOP will automatically close the blind shear rams. High pressurised hydraulic fluid (released from accumulator bottles) is used to engage the shear rams.

Provisions in the event of an emergency blow-out are described in Section 6.4.6.6.

6.4.4.2.5 Power System

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

6.4.4.2.6 Heating Ventilating Air Conditioning

The cooling of the drilling unit Living Quarter will involve a Heating Ventilating Air Conditioning (HVAC) system using refrigerant gas.

6.4.4.2.7 Storage Areas

The drilling unit will have dedicated storage for a variety of fluids and chemicals, including fuel (diesel), fresh water, drilling water, bulk (or liquid) mud and cement, mud chemicals, and cementing chemicals.

6.4.4.3 Drilling Fluids or Muds

Drilling fluid is a complex mixture of fluids, solids and chemicals that are carefully tailored to provide the correct physical and chemical characteristics required to safely drill the well. The main functions of drilling fluid or drilling mud (terms used interchangeably) are to:

- Maintain a stable wellbore and preventing the open hole 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 and drill string (reduce friction);
- Power the mud motors / 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 fluid may be used during offshore drilling, namely Water-Based Mud (WBM) and Non-Aqueous Drilling Fluid (NADF). TEEPNA is proposing to use WBM during the riserless drilling stage and NADF during the risered drilling stage for operations in Block 2912.

6.4.4.3.1 Water-Based Muds

Due to the variability in conditions that can be encountered drilling fluid mixtures vary to some extent. Typically, the major ingredient making up 85 to 90 % of the total volume of a WBM is fresh and / or seawater. The remaining 10 to 15 % of the volume of WBMs typically comprise barite, potato or corn starch, cellulose-based polymers, xanthan gum, bentonite clay, soda ash, caustic soda and salts (these are usually either potassium chloride [KCl] or sodium chloride [NaCl]). Other minor additives may be used in special circumstances such as citric acid for pH control; or polyethylene glycol butyl ether for clay inhibition, amongst others.

- Barite (barium sulphate) is an inert compound used as a weighting agent;
- Potato or corn starch and other cellulose-based polymers are used to control the rate of filtration of water in the mud into the formation being drilled by forming a thin filter cake on the borehole wall;
- Xanthan gum and minor amounts of bentonite clay are used to provide viscosity and impart rheological properties (i.e. materials responding with plastic/liquid flow or flow of matter as a "soft solid") to the mud for cuttings transport, as well as to provide gel strength for cuttings suspension;
- Caustic soda (sodium hydroxide) is used to maintain the required pH in the drilling fluid; and
- KCl or NaCl are used to reduce the swelling tendencies of clays being drilled and help to maintain a stable wellbore.

All the chemicals to be used will have associated Material Safety Data Sheet (MSDS) or other bioassay information for ecotoxicology data. Selection of constituents will follow best industry practices and will consider ecotoxicity, biodegradability and bioaccumulation criteria.
Categories of materials typically used in WBM, their functions and typical chemicals in each category are provided in Table 6-8.

Table 6-8: Categories of materials used in water-based mud, their functions and typical chemicals

Functional category	Function	Typical chemicals
Weighting Materials	Increase density (weight) of mud, balancing formation pressure, preventing a blowout	Barite, hematite, calcite, ilmenite
Viscosifiers	Increase viscosity of mud to suspend cuttings and weighting agent in mud	Bentonite or attapulgite clay, carboxymethyl cellulose, & other polymers
Thinners, dispersants, & temperature stability agents	Deflocculate clays to optimize viscosity and gel strength of mud	Tannins, polyphosphates, lignite, ligrosulfonates
Flocculants	Increase viscosity and gel strength of clays or clarify or de-water low-solids muds	Inorganic salts, hydrated lime, gypsum, sodium carbonate and bicarbonate, sodium tetraphosphate, acrylamide-based polymers
Filtrate reducers	Decrease fluid loss to the formation through the filter cake on the wellbore wall	Bentonite clay, lignite, Na-carboxymethyl cellulose, polyacrylate, pregelatinized starch
Alkalinity, pH control additives	Optimize pH and alkalinity of mud, controlling mud properties	Lime (CaO), caustic soda (NaOH), soda ash (Na_2CO_3), sodium bicarbonate ($NaHCO_3$), & other acids and bases
Lost circulation materials	Plug leaks in the wellbore wall, preventing loss of whole drilling mud to the formation	Nut shells, natural fibrous materials, inorganic solids, and other inert insoluble solids
Lubricants	Reduce torque and drag on the drill string	Oils, synthetic liquids, graphite, surfactants, glycols, glycerine
Shale control materials	Control hydration of shales that causes swelling and dispersion of shale, collapsing the wellbore wall	Soluble calcium and potassium salts, other inorganic salts, and organics such as glycols
Emulsifiers & surfactants	Facilitate formation of stable dispersion of insoluble liquids in water phase of mud	Anionic, cationic, or non-ionic detergents, soaps, organic acids, and water-based detergents
Bactericides	Prevent biodegradation of organic additives	Glutaraldehyde and other aldehydes

Functional category	Function	Typical chemicals
Defoamers	Reduce mud foaming	Alcohols, silicones, aluminium stearate ($C_{54}H_{105}AlO_6$), alkyl phosphates
Pipe-freeing agents	Prevent pipe from sticking to wellbore wall or free stuck pipe	Detergents, soaps, oils, surfactants
Calcium reducers	Counteract effects of calcium from seawater, cement, formation anhydrites, and gypsum on mud properties	Sodium carbonate and bicarbonate (Na_2CO_3 & $NaHCO_3$), sodium hydroxide (NaOH), polyphosphates
Corrosion inhibitors	Prevent corrosion of drill string by formation acids and acid gases	Amines, phosphates, specialty mixtures
Temperature stability agents	Increase stability of mud dispersions, emulsions and rheological properties at high temperatures	Acrylic or sulfonated polymers or copolymers, lignite, lignosulfonate, tannins

Source: Boehm *et al.,* 2001

6.4.4.3.2 Non-Aqueous Drilling Fluids

As indicated previously, TEEPNA plans to use NADF during the risered drilling stage ("closed loop system"). NADF are used to:

- Provide optimum wellbore stability and enable a near gauge hole to be drilled;
- Reduce torque and drag in high angle to horizontal wells;
- Minimise damage to reservoirs that contain clays that react adversely to WBM; and
- Obtain irreducible water saturation log data for gas reservoirs.

The main chemicals typically used in a NADF are presented in Table 6-9.

Table 6-9: Main chemicals used in a non-aqueous drilling fluid

Material	Description
Base oil	Non-aqueous drilling fluids use base fluids with significantly reduced aromatics and extremely low polynuclear aromatic compounds. New systems using vegetable oil, polyglycols or esters have been and continue to be used.
Brine phase	$CaCl_2$, NaCl, KCl.
Gelling products	Modified clays reacted with organic amines.
Alkaline chemicals	Lime e.g., $Ca(OH)_2$.
Fluid loss control	Chemicals derived from lignites reacted with long chain or quaternary amines.
Emulsifiers	Fatty acids and derivatives, rosin acids and derivatives, dicarboxylic acids, polyamines.

Adapted from: Swan *et al.,* 1994

The disadvantage of using NADFs is that base fluid and other chemicals have a higher toxicity than WBMs and may result in an increase in toxicity in the marine environment where drill cuttings are discharged. Drill cuttings that derive from the reservoir section contain residual base fluids, which cannot be removed easily. The trend in the industry has been to move towards low toxicity NADF (Group III NADF) that are biodegradable with a lower aromatic content and will not persist in the long-term.

Three types of NADF are generally used for offshore drilling, as follows:

- Group I NADF (high aromatic content): These base fluids were used during initial days of oil and gas exploration and include diesel and conventional mineral oil-based fluids. They are refined from crude oil and are a non-specific collection of hydrocarbon compounds including paraffins, olefins and aromatic and polycyclic aromatic hydrocarbons (PAHs). Group 1 NADF is defined by having PAH levels greater than 0.35%.
- Group II NADF (medium aromatic content): These fluids are sometimes referred to as Low Toxicity Mineral Oil Based Fluids and were developed to address the rising concern over the potential toxicity of diesel-based fluids. They are also developed from refining crude oil but the distillation process is controlled such that the total aromatic hydrocarbon concentration is less than Group I NADF (0.5 – 5%) and the PAH content is less than 0.35% but greater than 0.001%.
- Group III NADF (low to negligible aromatic content): These fluids are characterised by PAH contents of less than 0.001% and total aromatic contents less than 0.5%. This group includes Synthetic Oil-Based Mud (SOBM) or synthetic-based muds (SBM), which are produced by chemical reactions of relatively pure compounds and can include synthetic hydrocarbons (olefins, paraffins and esters). Using special refining and/or separation processes, base fluids of Group III can also be derived from highly processed mineral oils (paraffins, enhanced mineral oil-based fluid).

For the current project, TEEPNA would only consider using Group III type NADF.

6.4.4.4 Drilling Method and Sequence

6.4.4.4.1 Drilling Method

Two drilling methods – rotary or downhole motor drilling - can be used on a drilling unit.

- In rotary drilling, the whole drill string, from the surface to the bit, is rotated to penetrate the formations. In downhole motor drilling a downhole motor is included in the bottom hole assembly to provide additional power to the bit and provides for steering and directional drilling to be conducted. The downhole motor is driven by the drilling fluid, which is pumped down the drill string.
- Downhole motor drilling also allows a well to be directionally drilled to achieve any inclination from vertical to horizontal and to also change the azimuth direction (direction measured from north, where north is 0^0) in order to reach the geological target (see Figure 6-10). The direction of the well can be changed by holding the drill string stationary and pointing the downhole motor, which has a slight bend in its body, in the direction required and slide drilling ahead.

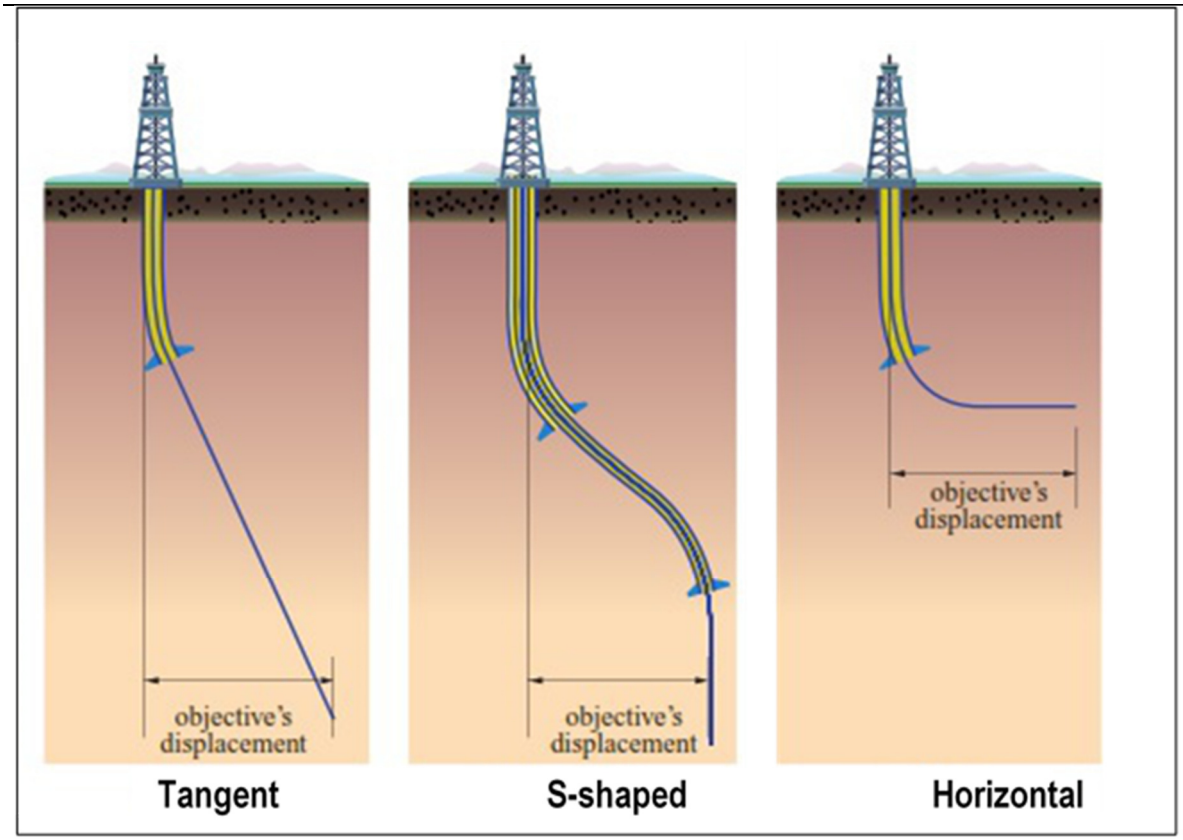


Figure 6-10: Tangent, Horizontal or S-shaped drill trajectories
Adapted from http://www.valiantenergy.ca/services-2

6.4.4.4.2 Drilling Sequence or Stages

The well will be created by drilling a hole into the seafloor with a drill bit attached to a rotating drill string, which crushes the rock into small particles, called "cuttings". After the hole is drilled, casings (sections of steel pipe), each slightly smaller in diameter, are placed in the hole and permanently cemented in place (cementing operations are described below). The hole diameter decreases with increasing depth (see Figure 6-11).

The casings provide structural integrity to the newly drilled wellbore, in addition to isolating potentially dangerous high-pressure zones from each other and from the surface. With these zones safely isolated, and the formation protected by the casing, the well will be drilled deeper with a smaller drill bit, and also cased with a smaller sized casing. For the current project, it is anticipated that there will be five sets of subsequently smaller hole sizes drilled inside one another, each cemented with casing, except the last phase that will remain an open hole without casing.

Drilling is essentially undertaken in two stages, namely the riserless and risered drilling stages (see Figure 6-12 and Table 6-10).

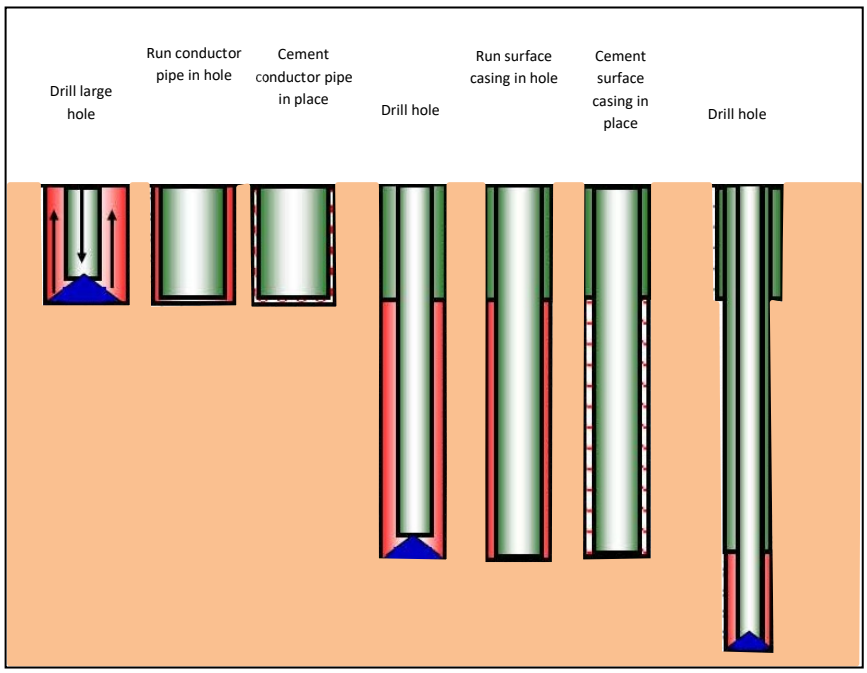


Figure 6-11: Simplified view of well drilling stages

Adapted from Nergaard, 2005

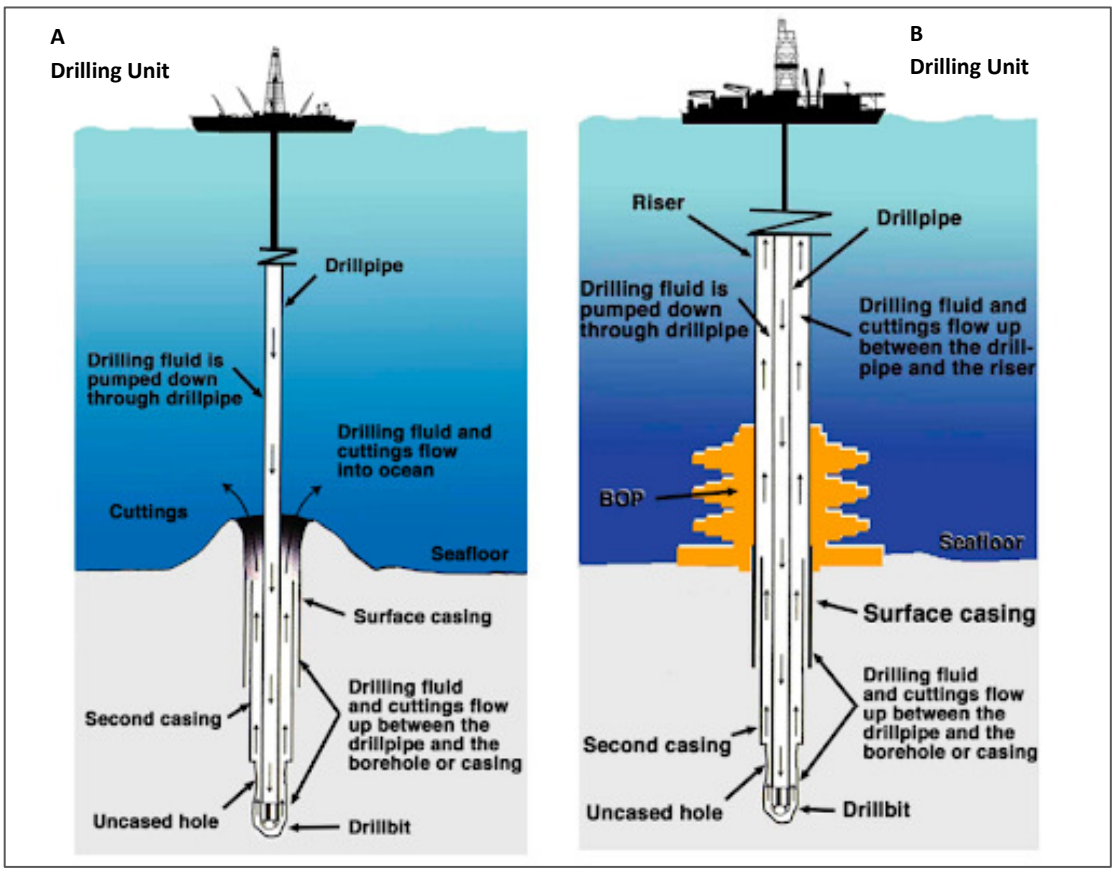


Figure 6-12: Drilling stages: (A) Riserless drilling stage; and (B) Risered drilling stage

Source: http://www.kochi-core.jp/cuttings/

Initial (Riserless) Drilling Stage

The process of preparing the first section of a well is referred to as "spudding." Sediments just below the seafloor are often very soft and loose, thus to keep the well from caving in and to carry the weight of the wellhead, a 30- or 36 inch diameter structural conductor pipe is drilled and cemented into place or in some cases jetted.

For the proposed wells, the *drill and cement* option is preferred. It is usually implemented where the nature of the seafloor sediments (hard sediments) necessitate drilling. A hole of diameter 36 to 42 inches will be drilled and the conductor pipe will be run into the hole and cemented into place. The cement returns exit the bottom of the conductor and travel up the annular space between the conductor and the hole with some cement being deposited on the seabed around the conductor pipe.

When the conductor pipe and low-pressure wellhead are at the correct depth, approximately 96 m deep (depending upon substrate strength), a new drilling assembly will be run inside the structural conductor pipe and the next hole section will be drilled by rotating the drill string and drill bit.

Below the conductor pipe, a hole of approximately 26 inches in diameter will be drilled to a depth of approximately 870 m below the seabed. The rotating drill string causes the drill bit to crush rock into small particles, called "cuttings". While the wellbore is being drilled, drilling fluid is pumped from the surface down through the inside of the drill pipe, the drilling fluid passes through holes in the drill bit and travels back to the seafloor through the space between the drill string and the walls of the hole, thereby removing the cuttings from the hole. At a planned depth the drilling is stopped and the bit and drill string is pulled out of the hole. A surface casing of 20 inch diameter is then placed into the hole and secured into place by pumping cement through the casing at the bottom of the hole and back up the annulus (the space between the casing and the borehole). The 20-inch casing will have a high-pressure wellhead on top; which provides the entry point to the subsurface and it is the connection point to the BOP.

These initial hole sections will be drilled using seawater (with viscous sweeps) and WBM. All cuttings and WBM from this initial drilling stage will be discharged directly onto the seafloor adjacent to the wellbore.

Risered Drilling Stage

The risered drilling stage (see Figure 6-12) commences with the lowering of a BOP and installing it on the wellhead. The BOP is designed to seal the well and prevent any uncontrolled release of fluids from the well (a 'blow-out'). A lower marine riser package is installed on top of the BOP and the entire unit is lowered on riser joints. The riser isolates the drilling fluid and cuttings from the environment, thereby creating a "closed loop system".

Drilling is continued by lowering the drill string through the riser, BOP and casing, and rotating the drill string. During the risered drilling stage, should the WBMs not be able to provide the necessary characteristics, a low toxicity NADF will be used. The drilling fluid emerges through nozzles in the drill bit and then rises (carrying the rock cuttings with it) up the annular space between the sides of the hole to the drilling unit.

The cuttings are removed from the returned drill mud (as described in Section 6.4.4.2.3) and discharged overboard. In instances where NADFs are used, cuttings will be treated to reduce oil content and discharged overboard around 10 m below the seal level. Operational discharges are discussed further in Section 6.4.6.

The hole diameter decreases in steps with depth as progressively smaller diameter casings are inserted into the hole at various stages and cemented into place. The expected target drilling depth is not yet confirmed but the

notional well depth is up to 3 500 m below the seafloor with a final hole diameter of between 8.5 and 12 inches and a casing diameter of between 7 and 9.6 inches (see Figure 6-13).

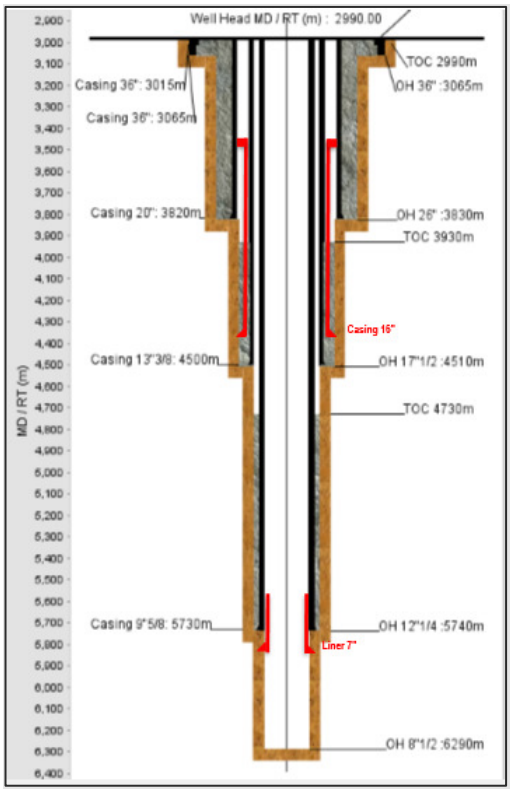


Figure 6-13: The well architecture from a recent drilling campaign in Block 2913B
Source: TEEPNA

6.4.4.4.3 Cementing operation

Cementing is the process of pumping cement slurry through the drill pipe and / or cement stinger at the bottom of the hole and back up into the space between the casing and the borehole wall (annulus). Cement fills the annulus between the casing and the drilled hole to form an extremely strong, nearly impermeable seal, thereby permanently securing the casings in place. To separate the cement from the drilling fluid in order to minimise cement contamination a cementing plug and/or spacer fluids are used. The plug is pushed by the drilling fluid to ensure the cement is placed outside the casing filling the annular space between the casing and the hole wall.

Cementing has four general purposes: (i) it isolates and segregates the casing seat for subsequent drilling, (ii) it protects the casing from corrosion, (iii) it provides structural support for the casing, and (iv) it stabilises 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 can be used to adjust various properties in order to achieve the desired results. There are over 150 cementing additives available. The amount (concentrations) of these additives generally make up only a small portion (<10%) of the overall amount of cement used for a typical well. Usually, there are three main additives used: retarders, fluid loss control agents and friction reducers. These additives are polymers generally made of organic material and are considered non-toxic.

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.

6.4.4.4.4 Notional well design (Base Case)

The well design ultimately depends upon factors such as planned depths, expected pore pressures and anticipated hydrocarbon-bearing formations. The various components of the notional well design are shown in Table 6-10. It should be noted that several contingency strings are typically made available depending on the geological uncertainties of a well.

Table 6-10: Notional base case well design and estimated drilling discharges

Drill Section	Hole diameter (inches)	Depth 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	36”	96	Seawater, viscous sweeps & WBM	324	209	At sea bottom
2	26”	773		540	877	
-	Suspension / Displacement before drilling Section 3	-	High Viscous Gel sweeps / KCl Polymer PAD mud	1 040	-	1 m above seabed
Risered drilling stage						
3	17.5”	731	NADF	51.9*	376	10 m below mean sea level
4	12.25”	1 265		44*	319	
5	8.5”	467		7.8*	57	
Totals	-	**3 332**	-	**2 007.7**	**1 838**	-

Note: * Total quantity of NABM mud discharged including Oil On Cuttings (OOC) @ 6,9% by weight of cuttings (metricT) + Other constituents.

6.4.4.4.5 Mud Logging

Evaluation of the petro-physical properties of the penetrated formations is carried out routinely during the drilling operation. Mud logging involves the examination of the drill cuttings brought to the surface by the drilling fluid. Mud logging also monitors for hydrocarbon gases that relate to changes in formation pressure and the volume or rate of returning fluid, which can aid in controlling the well, and to the intersection of reservoir rocks.

6.4.4.5 Well Logging and Testing

Once the target depth is reached, the well will be logged and possibly tested.

6.4.4.5.1 Well Logging

The evaluation of the physical and chemical properties of the rocks in the sub-surface, and their component minerals, including water, oil and gas, is undertaken during the drilling operation using Wireline Logging or Logging While Drilling (LWD) to log core data from the well. Information from engineering and production logs, as well as mud logging, may also be used.

Petrophysical evaluation typically includes the following activities:

- Distinguishing between reservoir and non-reservoir rock, thickness intervals, etc.;
- Determining the presence of hydrocarbons in reservoir rocks (for the reservoir intervals);
- Calculating oil and gas saturation in reservoir rocks to determine the hydrocarbon fraction; and
- Calculating petrophysical properties of rocks e.g., porosity, permeability, density, etc.

Radioactive sources may be used for certain types of data acquisition. The sources can be mounted in the Wireline and LWD tools, where it generates a radioactive field that interacts with the rocks penetrated at the wellbore. The measured response is directly related to the physical properties of the rocks. Where radioactive sources are used during well testing, they would be of minimal volumes and would be managed in line with the relevant legislation and guidelines for the management of radioactive sources. Contractors with the necessary accreditation and certification will handle radioactive sources. The testing does not generate radioactive wastes. The findings of the evaluation may provide proof of the presence of hydrocarbons and, if present, an indication of the level of difficulty that will be associated with the extraction of the hydrocarbons in place. This will enable the design of reservoir management strategies to optimise long-term hydrocarbon recovery.

6.4.4.5.2 Vertical Seismic Profiling

Vertical Seismic Profiling (VSP) is an evaluation tool that would be undertaken as part of the conventional wireline logging programme 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 (1 000 cubic inch volume), which is operated from the drilling unit. The airgun array is deployed between 7 m and 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 as required for different stations in the well and it may take up to nine hours to complete approximately 250 shots, depending on the well's depth and number of stations being profiled. A typical VSP arrangement is provided in Figure 6-14.

TEEPNA is proposing to undertake one VSP operation per well, which would be scheduled towards the end of the drilling operations.

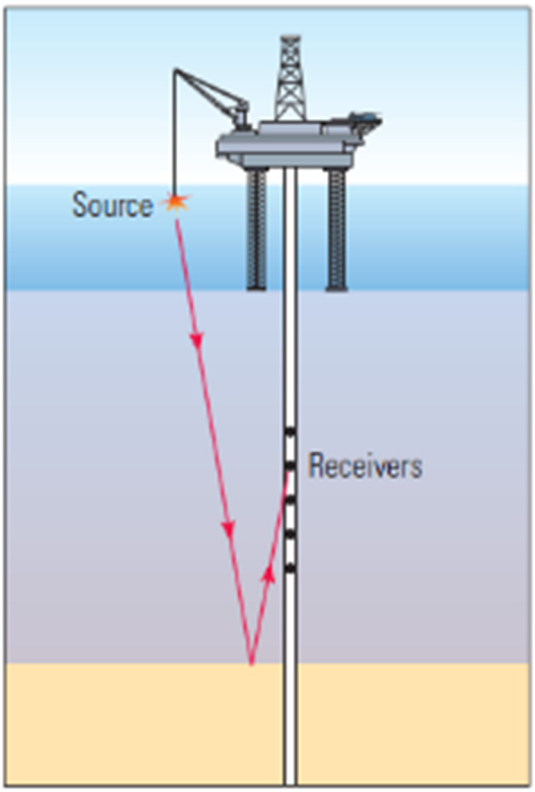


Figure 6-14: Schematic of a typical VSP arrangement

Source: http://researchgate.net/figure/Rig-Source-Vertical-Seismic-Profile

6.4.4.5.3 Well (Flow) Testing

Well or flow testing is undertaken to determine the economic potential of the discovery before the well is either abandoned or suspended (see Figure 6-15). One test would be undertaken per exploration well should a resource be discovered and up to two tests per appraisal well. Each test would take up to 7 days to complete (5 days of build-up and 2 days of flowing and flaring). For well flow-testing, hydrocarbons would be burned at the well site. A high-efficiency flare is used to maximise combustion of the hydrocarbons. Burner heads which have a high burning efficiency under a wide range of conditions will be used.

The volume of hydrocarbons (to be burned) and possible associated produced water from the reservoir which could be generated during well testing cannot be reliably predicted due to variations in gas composition, flow rates and water content. Burners are manufactured to ensure emissions are kept to a minimum. The estimated volume of hydrocarbons to be burned cannot be with much accuracy because the actual test requirements can only be established after the penetration of a hydrocarbon-bearing reservoir. However, an estimated 20 Mscf (million standard cubic feet) of gas per day and 20 400 bbl oil could be flared per test (refer to emissions in Section 6.4.6.4). If produced water is generated during well testing, it will be separated from the hydrocarbons (refer to discharges to sea in Section 6.4.6.2).

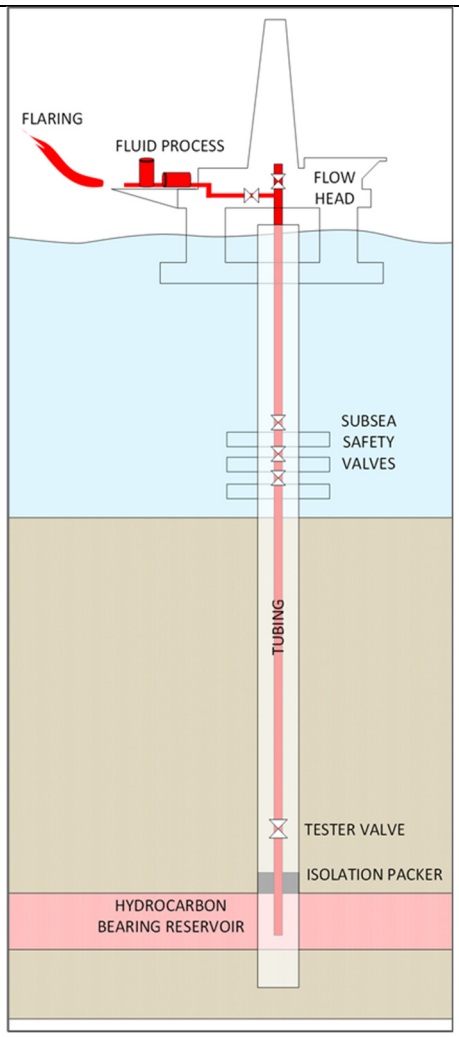


Figure 6-15: Schematic of a typical well testing arrangement
Source: TEEPNA

6.4.4.6 Well Sealing and Plugging

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 cement, thus creating an impermeable barrier between two zones.

Once drilling and logging have been completed, the exploration wells will be sealed with cement plugs, tested for integrity and abandoned according to international best practices. 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. Three cement plugs would be installed: i.e. one each for isolation of the deep reservoir and the main reservoir; and a third as a second barrier for the main reservoir.

The integrity of cement plugs can be tested by a number of 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.

6.4.4.7 Resource Requirements

6.4.4.7.1 Personnel

The majority of the workforce will comprise highly specialised skilled staff on the drilling unit and support vessels (180 - 200 people on board depending on drilling operations). A limited number of local staff would also be employed at the onshore base for up to six months for an appraisal well (including mobilisation and demobilisation). The use of local labour will be prioritised where possible.

6.4.4.7.2 Water requirements

The drilling campaign will use an estimated 4 800 m^3 of 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 and supply vessels via seawater desalination.

6.4.4.7.3 Fuel consumption

Marine gas oil (MGO) with low sulphur (<0.5%) will be used as fuel for all vessels. Fuel will preferentially be obtained locally and transported to the drilling unit by the supply vessels. Jet fuel will be used for helicopters. Estimates for the fuel use by a proposed drilling unit, supply vessels and helicopters during the drilling and mobilisation/demobilisation periods are presented in Table 6-11.

Table 6-11: Estimated fuel consumption for drilling of one well

Source		Quantity	Units	No. units	Consumption of marine fuel (Tons)	Kerosene consumption (Tons)
Well Drilling (per well)	1 x Drilling unit	40	Tons / day	120 days	4 800	-
	3 x Supply vessels	25	Tons / day	140 days	3 500	-
	Helicopter**	1.5	Tons / round trip	68 round trips	-	102
	Total				**8 300**	**102**

* Values provided by TEEPNA, based on previous drilling campaigns.
** Calculations based on 4 round trips per week (i.e. 17 weeks (~120 days) x 4 = 68 trips per well).

6.4.4.7.4 Chemicals, fuels, oils and lubricants

The majority of chemicals to be used will be chemicals associated with drilling operations (e.g., drilling mud and additives – see Section 6.4.4.3) or fuels and lubricants. In addition, small quantities of various other chemicals will also be used (e.g., for maintenance and cleaning) aboard the vessels, at the supply base and at the helicopter base. The drilling unit could have a combustible and chemicals storage capacity of up to 5 000 m^3.

6.4.4.7.5 Explosive and Radioactive Materials

The drilling unit will be equipped with a secure store for explosives, plus igniter, booster, detonator and detonating cord. The drilling unit will also be equipped with a secure store for radioactive materials (see Section 6.4.4.5.1).

6.4.4.7.6 Waste disposal facilities

Depending on waste type, volume and timing, accumulated wastes may be stored temporarily at the onshore base and disposed at appropriately licenced waste facilities. Alternatively, wastes will be transferred directly to a waste contractor for treatment and / or disposal. Specific separated waste types would be disposed of in line with Namibian legal requirements for waste disposal. For TEEPNA's recent drilling campaign in the adjacent Block 2913B, onshore waste disposal took place at the Walvis Bay municipality's hazardous waste facility, while non-aqueous based mud cuttings was reused as a raw material in a cement manufacturing process at a cement plant in Otavi. Envisaged waste types are summarised in Section 6.4.6.3.

6.4.5 Demobilisation Phase

After the exploration wells have been sealed, tested for integrity and abandoned (see Section 6.4.4.6), the intention is to abandon the wellheads on the seafloor if deemed safe to do so based on a risk assessment. The risk assessment criteria will consider factors such as the water depth and use of the area by other sectors (e.g., fishing). Due to the water depth and no trawl fishing taking place in the area, it is proposed to leave the wellhead in place without installing over trawlable protective equipment.

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 TEEPNA will return in the future for appraisal / production purposes. The gauges will be placed and remain on the wellhead. Monitoring gauges will not be installed on exploration wells which are earmarked for abandonment

With the exception of the abandoned wellheads and drilling discharges deposited on the seabed, no further physical remnants of the drilling operation will be left 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 licence area and either mobilise to the following drilling location or relocate into port or a regional base for maintenance, repair or resupply.

6.4.6 Discharges, Wastes and Emissions

6.4.6.1 Introduction

This section presents the main sources of discharges to water, waste and emissions that will result from the prosed drilling operations (including mobilisation and demobilisation).

All vessels will have equipment, systems and protocols in place for prevention of pollution by oil, sewage and garbage in accordance with international MARPOL requirements. Any oil spill related discharges would be managed by an Oil Spill Contingency Plan (OSCP) that TEEPNA will be required to compile and have approved by government. Onshore licenced waste disposal sites and waste management facilities will be identified, verified and approved prior to commencement of drilling operations.

6.4.6.2 Discharges to Sea

Potential discharges to sea are expected to include:

- Drilling fluids/muds;
- Cement and cement additives;
- BOP hydraulic fluid;
- Produced water
- Bilge water from vessel machinery spaces;
- Deck drainage;
- Brine generated from onboard desalination plant;
- Sewage;
- Food wastes;
- Ballast water; and
- Detergents.

These discharges and their management are described in further detail below.

6.4.6.2.1 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. This is in line with most countries (including South Africa) for early exploration development phases. 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, TEEPNA proposes to use the “offshore treatment and disposal” option for their drilling campaign in Block 2912. The same method was applied and approved for drilling of TEEPNA's other exploration well in the adjacent Block 2913B and TotalEnergies’ exploration wells in Block 11B/12B (namely Brulpadda and Luiperd wells) off the South Coast of South Africa.

During the riserless drilling stage, all cuttings and WBM will be discharged directly onto the seafloor adjacent to the wellbore. An estimated volume of 1 086 t of cuttings and 864 t of drilling fluid will be discharged on the seafloor.

Where NADFs are used (possibly during the risered drilling stage, if WBMs are not able to provide the necessary characteristics), these are sometimes treated onshore and disposed, treated to recover oil and disposed offshore and sometimes re-injected into wells. For the current project TEEPNA, in instances where NADFs are used, cuttings will be treated offshore to reduce oil content to <6.9% Oil On Cutting (OOC) and discharged overboard. An estimated volume of 752 t of cuttings and 104 t of drilling fluid will be discharged per well (based on notional depth of 3 332 m) (refer to Table 6-10). During this drilling stage the circulated drilling fluid will be cleaned and the cuttings discharged into the sea at least 10 m below sea level. The drill cuttings will be treated to reduce their mud content using shakers and a centrifuge as described in Section 6.4.4.2.3.

Cuttings released from the drilling unit during the risered drilling stage will be dispersed by the current and settle to the seafloor. The rate of cuttings discharge decreases with increasing well depth as the hole diameter becomes smaller and penetration rates decrease (refer to Table 6-10). Discharge is intermittent as actual drilling operations are not continuous while the drilling unit is on location.

Further drilling fluid totalling 1 040 tons will be released 1 m above the seafloor during well suspension and displacement (between drilling section 2 and 3). The mud used during these processes is a High Viscous Gel sweeps / KCl Polymer PAD mud[4].

The expected fall and spatial extent of the deposition of discharged cuttings will be investigated in the Drilling Discharges Modelling Study during the Assessment Phase (see Section 9.1.1.1 for the terms of reference for this study).

6.4.6.2.2 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.

6.4.6.2.3 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.

6.4.6.2.4 Produced Water

If water from the reservoir arises during well flow testing, these 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:
  - (i) if hydrocarbon content is < 30 mg/l, discharged overboard; or
  - (ii) 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.

6.4.6.2.5 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

[4] 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)

keel). In accordance with MARPOL Annex I, bilge water will be retained on board until it can be discharged to an approved reception facility, unless it is treated by an approved oily water separator to <15 ppm oil content and monitored before discharge. The residue from the onboard oil/water separator will be treated / disposed of onshore at a licenced hazardous landfill site.

6.4.6.2.6 Deck Drainage

Deck drainage consists of liquid waste resulting from rainfall, deck and equipment washing (using water and a water-based detergent). Deck drainage will be variable depending on the vessel characteristics, deck activities and rainfall amounts.

In areas of the drilling unit where oil contamination of rainwater is more likely (i.e. the rig floor), drainage is routed to an oil / water separator for treatment before discharge in accordance with MARPOL Annex I (i.e. 15 ppm oil and grease maximum). There will be no discharge of free oil that could cause either a film, sheen or discolouration of the surface water or a sludge or emulsion to be deposited below the water's surface. Only non-oily water (i.e. <15 ppm oil and grease, maximum instantaneous oil discharge monitor reading) will be discharged overboard. If separation facilities are not available (due to overload or maintenance) the drainage water will be retained on board until it can be discharged to an approved reception facility. The oily residue from the onboard oil / water separator will be treated / disposed of onshore at an approved hazardous landfill site.

6.4.6.2.7 Brine generated from onboard desalination plant

The waste stream from the desalination plant 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. Water chemical agents will not be used in the treatment of seawater and therefore the brine reject portion would be in a natural concentrated state. 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).

6.4.6.2.8 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 vessels intermittently throughout the project and will vary according to the number of persons on board, estimated at an average of 200 litres per person. All sewage discharges will comply with MARPOL Annex IV.

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.

6.4.6.2.9 Food (Galley) Wastes

The disposal into the sea of food waste is permitted, in terms of MARPOL Annex V, when it has been comminuted or ground to particle sizes smaller than 25 mm and the vessel is *en route* more than 3 nautical miles

(approximately 5.5 km) from land. Disposal overboard without macerating is permitted for moving vessels greater than 12 nautical miles (approximately 22 km) from the coast. On the drilling unit, all food waste will be macerated to particles sizes <25 mm and the daily discharge is typically about seven tonnes per month.

6.4.6.2.10 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 unit to Namibia. 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 will 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.

6.4.6.2.11 Detergents

Detergents used for washing exposed marine deck spaces will be discharged overboard. The toxicity of detergents varies greatly depending on their composition. Water-based detergents are low in toxicity and are preferred for use. Preferentially biodegradable detergents should be used. Detergents used on work deck space will be collected with the deck drainage and treated as described under deck drainage above.

6.4.6.3 Waste Management

A number of other types of solid wastes generated during the exploration drilling activities will not be discharged at sea, but will be transported to shore for ultimate disposal in Lüderitz or Walvis Bay (where there are general and hazardous landfill sites). All onboard waste will be segregated, duly identified and transported to shore for disposal at a licenced waste management facility approved by the Operator. The treatment, disposal and recycling of all waste onshore will be fully traced through a waste manifest system.

In the event that NADF is necessary to be used for drilling, bulk volumes of NADF remaining at the end of well drilling, will either be shipped for onshore treatment and disposal through a licenced waste disposal company or re-used during the drilling of subsequent wells in the area or another drilling campaign.

The services of a licenced waste contractor will be used to collect all operational waste for treatment, disposal or recycling. A summary of the typical waste types expected to be generated are listed in Table 6-12.

Table 6-12: Estimated 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

6.4.6.4 Air Emissions

The principal sources of emissions to air from the proposed exploration activities will be from vessel engines (drill unit, support vessels and helicopters) and well flow testing (i.e. flaring). The vessels will be supplied with marine gas oil (MGO) or heavy fuel oil (HFO) with less 0.5% sulphur (mass) and helicopters will use kerosene. Conservative estimates for the fuel use by a drilling unit, supply vessels and helicopters during the drilling and mobilisation/demobilisation periods are presented in Table 6-11. Typical combustion products from these unit operations include sulphur oxides (SO_x), oxides of nitrogen (NO_x, N_2O), carbon dioxide (CO_2), carbon monoxide (CO), volatile organic compounds (VOC) Methane (CH_4) and non-methane volatile organic compounds (NMVOC) and particulate matter (PM). Other minor sources include diffuse emissions from refrigerants.

As noted in Section 6.4.4.5.3, the estimated volume of hydrocarbons to be burned during possible well testing cannot be estimated with much accuracy. However, TEEPNA has estimated that 20 MScf/d gas and 20 400 bbl oil could be flared per test.

The anticipated emissions (GHG and non-GHG) from the proposed project will be investigated in the Climate Change and Air Emissions Impact Assessment (see terms of reference in Section 9.1.2.5).

6.4.6.5 Noise Emissions

The key sources generating underwater noise are vessel propellers (and positioning thrusters), drag on the riser, supply vessels and from drilling activities. This is expected to result in highly variable sound levels, being dependent on the operational mode of each vessel. The VSP survey would generate a short-term noise (less than nine hours).

The main sources of noise from these activities are categorised below.

- Drilling noise: Drilling units generally produce underwater noise in the range of 10 Hz to 100 kHz (OSPAR commission, 2009) with major frequency components below 100 Hz and average source levels of up to

190 dB re 1 µPa at 1 m (rms) (the higher end of this range from use of bow thrusters). These noise levels will be assumed as indicative for the current project.

- Propeller and positioning thrusters: Noise from propellers and thrusters is predominately caused by cavitation around the blades whilst transiting at speed or operating thrusters under load in order to maintain a vessel's position. The noise produced by a drilling unit's dynamic positioning systems can be audible for many kilometres. Noise produced is typically broadband noise, with some low tonal peaks. The supply vessels will also contribute to an overall propeller noise generation.
- Machinery noise: Machinery noise is often of low frequency and can become dominant for vessels when stationary or moving at low speeds. The source of this type of noise is from large machinery, such as large power generation units (diesel engines or gas turbines), compressors and fluid pumps. Sound is transmitted through different paths, i.e. structural (machine to hull to water) and airborne (machine to air to hull to water) or a mixture of both. The nature of sound is dependent on a number of variables, such as the type and size of machinery operating; and the coupling between machinery and the vessel body. Machinery noise is typically tonal in nature. A ROV will be used to conduct a sweep of the drilling site to identify any debris; however, this is not expected to form a significant noise source.
- Well logging noise: If relevant, VSP will be undertaken in order to generate a high-resolution image of the geology in the well's immediate vicinity (see Section 6.4.4.5.2). It is expected to use a small dual airgun array, comprising a system of four 250 cubic inch airguns with a total volume of 1 000 cubic inches of compressed nitrogen at about 2 000 psi. The volumes and the energy released into the marine environment are significantly smaller than what is required or generated during conventional seismic surveys[5]. The airguns will be discharged approximately five times at 20 second intervals. This process is repeated, as required, for different sections of the well for a total of approximately 250 shots. A VSP is expected to take up to nine hours per well to complete, depending on the well's depth and number of stations being profiled.
- Well testing noise (see Section 6.4.4.5.3): Flaring would produce some air-borne noise above the sea level where flaring is implemented for up to a maximum of 10 days of flowing and flaring.
- Equipment in water: Noise is produced from equipment such as the drill string. The noise produced will be low relative to the drilling noise and the dynamic positioning system.
- Helicopter noise: Helicopters will also form a source of noise, which can affect marine fauna both in terms of underwater noise beneath the helicopter and airborne noise.

The extent of project-related noise above the background noise level may vary considerably depending on the specific vessels used and the number of supply vessels operating. It will also depend on the variation in the background noise level with weather and with the proximity of other vessel traffic (not associated with the project).

An Underwater Noise Modelling Study will be undertaken to determine the underwater noise transmission loss with distance from well site and compare results with threshold values for marine fauna to determine zones of impact (refer to the terms of reference in Section 9.1.1.3). These modelling results will be used in the assessment of impacts on marine fauna and commercial fisheries.

[5] A typical seismic volume of energy is 3 000 cubic inches, while a VSP is around 1 000 cubic inches. In addition, the energy dissipated by a VSP is concentrated in one place, while a seismic survey covers a larger area.

6.4.6.5.1 Light Emissions

Operational lighting will be required on the drilling unit and supply 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 their spill out to sea.

6.4.6.5.2 Heat Emissions

Flaring during well testing generates heat emissions from the combustion of hydrocarbons at the burner head.

6.4.6.6 Emergency Response

TEEPNA has contract agreements with global response companies to use globally advanced capping stacks in the event of a well blow-out. One contract is held with Oil Spill Response Limited (OSRL) and another with Wild Well Contain (WWC). Capping stacks are designed to shut-in an uncontrolled subsea well in the unlikely event of a blow-out. OSRL has a 10K[6] capping stack housed at its Saldanha Bay Base off the West Coast of South Africa (see Figure 6-16), while WCC has 15K capping stacks housed in the UK (Aberdeen) and Singapore. TotalEnergies also has a capping stack (10K) in West Africa (Gulf of Guinea). These are available for global mobilisation and transportation by sea and/or air in the event of an incident.

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 co-ordinated 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 carefully manoeuvred 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 contained in TEEPNA's OSCP and BOCP.

TEEPNA motivates that 20 days is a reasonable and realistic assumption for the installation of a capping stack in the unlikely event of a blow-out. The current state of knowledge, available technology and approach to well blow-out responses by the drilling industry has advanced since, and because of, the Deepwater Horizon spill event. As a result of this advancement, the duration of the Deepwater Horizon event is not considered relevant as a benchmark of a reasonable response period. It is relevant that subsea capping and subsea containment equipment (managed by OSRL, a cooperative dedicated to response to marine pollution by hydrocarbons) is installed at Saldanha and, therefore, well placed for a rapid response to an unplanned event in Block 2912.

Note: As part of the well response strategy, TEEPNA would also initiate the mobilisation of the Subsea Dispersant Injection (SSDI) kit from OSRL.

[6] 10k and 15 k refers to a pressure rating of 10 000 and 15 000 pounds force per square inch (psi), respectively.

Figure 6-16: Example of an Oil Spill Response Limited capping stack
Source: https://www.oilspillresponse.com/services/subsea-well-intervention-services/capping

6.5 PROJECT ALTERNATIVES

"Alternatives" to a proposed activity are defined as "*a different means of meeting the general purpose and requirements of the activity, which may include alternatives to the:*

- *Property on which or location where the activity is proposed to be undertaken;*
- *Type of activity to be undertaken;*
- *Design or layout of the activity;*
- *Technology to be in the activity; or*
- *Operational aspects of the activity*."

A summary of the project alternatives considered during the project design are summarised in Table 6-13 below. These are presented in alignment with the mitigation hierarchy principles, which prioritises the need for avoidance over minimisation and both of these before consideration of restoration or offsetting requirements. Avoidance measures are typically the most important way of minimising project impacts primarily through site selection or timing of activities.

A comparative assessment of the project alternatives will be provided in the ESIA Report.

Table 6-13: Summary of project alternatives

MH	No.	Alternatives	Description	Comment on Status
Avoidance	**1. Site / location alternatives**			
	1.1	Drill site locations	The specific drill site locations have not been finalised. However, TEEPNA has confirmed the drill sites will be located within a 5 206 km^2 Area of Interest within Block 2912 (see Figure 6-1), which avoids all MPAs and Ecologically or Biologically Significant Areas (EBSA) (see Figure 7-21).	Since the TEEPNA is the holder and operator of Block 2912, drilling will be limited to the Block 2912 licence area. TEEPNA is, however, proposing to limit the well drilling to an Area of Interest within the block (see Figure 6-1). Although the final well locations within the Area of Interest will be based on a number of factors, including further analysis of the seismic data, the geological target and seafloor obstacles, this ESIA assumes that the wells could be drilled anywhere within the Area of Interest. Drill site locations within the Area of Interest for the Drilling Discharges and Oil Spill Modelling will be selected based on a number of criteria (including metocean dataset, water depths, and proximity to coast and sensitive areas) in order to assess the worst-case scenarios for oil spill dispersion for an unplanned event or predicted cuttings dispersion. Drill cutting modelling will determine the extent of the cuttings plume and potential impacts on nearby sensitive areas (EBSAs / MPAs). Modelling results will be presented in the ESIA Report. These results will be used in the assessment of impacts on marine fauna and commercial fisheries. Should modelling show that drilling discharges may have significant impacts on sensitive areas close to the selected well sites then mitigation would be required to ensure that any proposed well locations are sufficiently set back from these areas.
	1.2	Onshore base location	Lüderitz was utilised as the onshore logistics base for the recent drilling campaign in the adjacent Block 2913B. It is thus proposed to utilise Lüderitz as the base again.	The ESIA will consider only one logistics base option, i.e. Lüderitz.
	2. Timing / Scheduling Alternatives			
	2.1	Timing of Exploration and Appraisal Drilling	Drilling may have impact on marine fauna, such as whales, dolphins and turtles, that have seasonal occurrences in the Project Area.	The ESIA will consider the implications of drilling in different seasons. The results of the modelling studies (drilling discharge, and underwater noise) will be used in the assessment of impacts on marine fauna and commercial fisheries and the possible need for mitigation e.g., restricting certain activities to specific seasons.

MH	No.	Alternatives	Description	Comment on Status
Avoidance	**3. No-Go alternative**			
	3.1	No-Go option	The No-Go alternative represents the option not to proceed with exploration and appraisal drilling and represents maintaining the status quo, except for variations from natural causes or other human activities. This leaves the project areas of influence (see Section 7.1) in their current state and precludes the opportunity of potential future oil and gas development and attendant economic and social benefits that may be derived.	The ESIA will consider the implications of the No-Go alternative.
Minimisation	**4. Design and Technology Alternatives**			
	4.1	Number of wells	The proposal is to drill up to ten wells in the licence area.	The ESIA will assess the potential impacts associated with exploration drilling of up to ten wells in any locations within the Area of Interest for proposed exploration drilling.
	4.2	Drilling unit	Given the high energy oceanographic conditions and significant depth of the Block, a drill ship is the most feasible option for well drilling for technical safety reasons.	The ESIA will assess the potential impacts of a drill ship. Although the alternative of using a semi-submersible drilling platform is not to be assessed, as it is not technically feasible, there are no additional impacts or differences in impact significance relating to the choice of drilling unit (semi-submersible or drill ship).
	4.3	Drilling method	Two drilling methods can be employed on a drilling unit, namely rotary or downhole motor drilling.	The ESIA will assess the potential impacts related to either drilling method and will not distinguish between the two options. The environmental consequences of both methods are similar and do not make a material difference to the findings of the ESIA.
	4.4	Drilling fluid	Two types of drilling fluid could be used during drilling: WBM or NADF. TEEPNA proposes using WBMs during the riserless drilling stage and NADF during the risered drilling stage, if WBMs are not able to provide the necessary characteristics.	The ESIA will assess the potential impacts related to both drilling fluids.
	4.5	Drill cuttings disposal methods	Options for drill cuttings disposal include discharge to sea; onshore disposal; and re-injection.	Drilling discharges will be disposed at sea. This is in line with most countries (including Namibia and South Africa) for early exploration development phases. 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, TEEPNA proposes to use the "offshore treatment and disposal" option for their drilling campaign in Block 2912. The same method was applied for drilling of their exploration wells in the adjacent Block 2913B (Venus X-1 well) and in the South African Block 11B/12B (Brulpadda and Luiperd wells). Thus, this ESIA will only assess this disposal method. Drill cuttings modelling will be undertaken to confirm the extent of plume dispersion and will be used to assess impacts on marine habitats and species. Should significant impacts be identified alternative disposal methods may need to be considered.

MH	No.	Alternatives	Description	Comment on Status
Minimisation	4.6	Helicopter flight paths	Helicopter flights between the shore base and the drilling unit may impact on seabirds or seals on coastal rocky shores or islands during specific breeding seasons.	The ESIA will assess the risk of helicopter flights on seabirds or seals to confirm whether helicopter flight paths need to be rerouted to avoid certain sensitive areas. It will also consider additional mitigation such as minimum flight heights when flying over seal or bird islands or MPAs.
	4.7	Well abandonment	Wellheads can be either be left in place or removed from the seafloor as is standard practice for deep-water wells. Given the water depth over most of the proposed drill area (up to 3 700 m), the preferred option would be to leave the wellheads on the seafloor. Fish trawling does not take place within Block 2912 and it is thus not anticipated that remaining wellheads can pose a hazard to trawling.	The ESIA will assess the potential impacts and risks related to removing wellheads versus leaving them in place.
Restoration	**5. Rehabilitation**			
	5.1	Rehabilitation of sea floor	No restoration measures are considered technically feasible or warranted at the drilling depths of between 2 940 m and 3 700 m.	The ESIA will not consider any physical restoration measures for the marine environment. However, an ROV clearance survey will be conducted to confirm the status of seafloor around the well to ensure no dropped objects remain.
Offset	**6. Offsetting**			
	6.1	Biodiversity Offsets	Biodiversity offsets are required for significant residual impacts on biodiversity values of high importance such as unique or threatened ecosystems or priority threatened species, which can include MPAs and EBSAs.	Should significant adverse impacts on sensitive marine habitats or species be identified from exploration drilling and other activities in the ESIA, then biodiversity offsets or feasible conservation actions may need to be considered, where appropriate. This will be confirmed by the marine faunal assessment.