Tilt Cove Exploration Drilling Program

Chapter 2: Project Description

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2.0 PROJECT DESCRIPTION

2.1 Rationale and Need for the Project

On January 15, 2019, Suncor Energy Offshore Exploration Partnership (Suncor) and its co-venturers Cenovus Energy Inc. and Equinor Canada Ltd. were awarded the exploration right to exploration licence (EL) 1161 with a work expenditure bid of $51,999,555. The term of the EL is from January 15, 2019, to January 15, 2028, with the first period (i.e., period within which the work expenditure bid is committed for spending) ending January 15, 2025. The issuance of an EL confers the exclusive right to drill and test for petroleum within the EL. As of Jan 21, 2023, Suncor is the sole interest owner, and Suncor is required to drill one exploratory well on or before the expiry date of the first period of the EL as a condition of the EL to maintain tenure for the second term. The temporal scope of the Project extends to 2029.

EL 1161, which is located in the southwestern part of Jeanne d'Arc Basin, presents potentially important geological formations and hydrocarbon resources. In Suncor's estimation, the combination of stratigraphy, structure, and timing has contributed to a high potential for hydrocarbon accumulation in the area (e.g., Bell and Campbell 1990). In addition to previous geophysical data that have been collected in the region, further exploration drilling is required to determine the presence, nature, and quantities of any potential hydrocarbon resources within EL 1161.

The Project is expected to create economic, social, and technological benefits realized on local, regional, and national scales, including a potential contribution to local benefits, energy diversity and supply (Section 1.4). As oil and natural gas are expected to play an important part in meeting energy demand for several decades, ongoing exploration is a critical activity to enable continued oil and gas discoveries to maintain production to meet Canadian and global demand for energy.

2.2 Location and Designated Project Area

The Project Area is defined as the overall geographic area within which all Project-related components and activities will take place. The Project Area includes "CEAA 2012-designated project" EL currently operated by Suncor (EL 1161) where exploration drilling activities may be conducted. The Project Area includes a surrounding area to account for planned and potential ancillary and support activities at and around the well sites. Suncor is proposing to drill up to 12 to 16 exploration and delineation wells on EL 1161, which covers 142,448 net hectares (576.5 km^2) and is located approximately 300 km east of St John's, NL. The nearest community is Blackhead, NL (299 km from the EL) (Figure 2-1). Water depths in the EL range from 61 to 87 m. Corner coordinates for EL 1161 are in Table 2.1. The Project Area includes an approximate 40 km buffer around the EL (Table 2.2).

While the term of EL 1161 is 2019 to 2028, the temporal scope of the Project extends until the end of 2029, to provide an adequate and conservative timeframe within which planned Project activities (including well drilling, testing, suspension and abandonment, and associated activities) may occur.

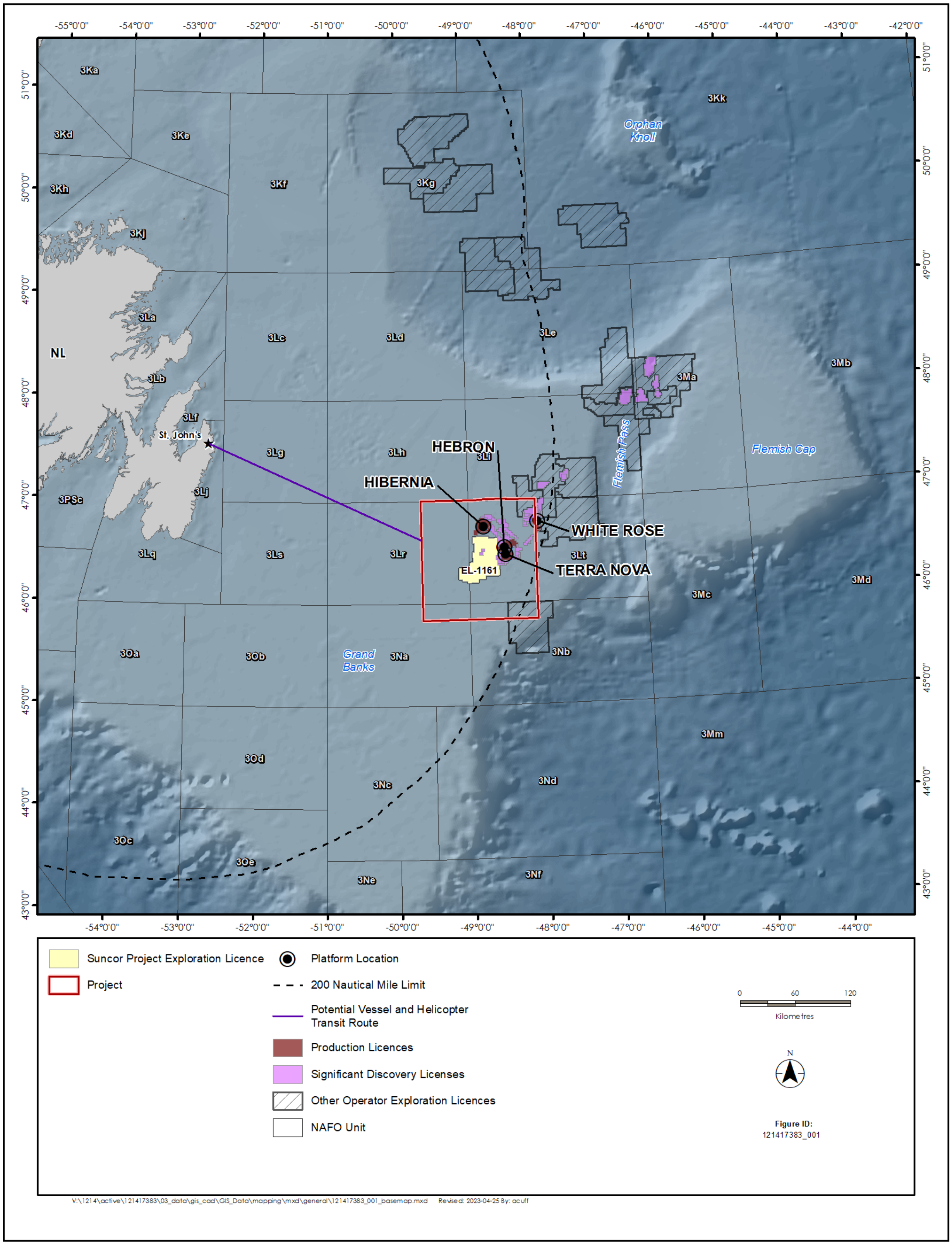


Figure 2-1 Project Area and Potential Transit Route

Table 2.1 EL 1161 Corner Coordinates and Area

No	Vertex_Position	Lat	Long	Lat_DD	Long_DD
1	Outside	46° 38' 59.772" N	48° 43' 26.123" W	5168780.232	674164.4113
2	Outside	46° 37' 59.773" N	48° 43' 26.125" W	5166928.353	674217.9021
3	Outside	46° 37' 59.916" N	48° 35' 56.112" W	5167216.831	683785.6216
4	Outside	46° 30' 59.918" N	48° 35' 56.120" W	5154253.717	684180.2189
5	Outside	46° 30' 59.888" N	48° 34' 26.117" W	5154311.429	686097.9265
6	Outside	46° 28' 59.889" N	48° 34' 26.120" W	5150607.732	686211.7016
7	Outside	46° 28' 59.919" N	48° 35' 56.122" W	5150550.017	684292.8198
8	Outside	46° 27' 59.920" N	48° 35' 56.124" W	5148698.193	684349.0962
9	Outside	46° 27' 59.931" N	48° 37' 26.126" W	5148640.477	682429.6442
10	Outside	46° 24' 59.932" N	48° 37' 26.130" W	5143084.994	682596.6205
11	Outside	46° 24' 59.922" N	48° 35' 56.127" W	5143142.714	684517.8321
12	Outside	46° 21' 59.922" N	48° 35' 56.131" W	5137587.227	684686.4282
13	Outside	46° 21' 59.892" N	48° 34' 26.128" W	5137644.953	686609.4146
14	Outside	46° 15' 59.895" N	48° 34' 26.134" W	5126534.203	686949.7076
15	Outside	46° 15' 59.784" N	48° 46' 26.155" W	5126078.421	671538.0114
16	Outside	46° 13' 59.785" N	48° 46' 26.157" W	5122374.846	671641.9645
17	Outside	46° 13' 59.946" N	48° 52' 26.167" W	5122168.225	663931.2178
18	Outside	46° 11' 59.946" N	48° 52' 26.169" W	5118464.637	664030.4399
19	Outside	46° 11' 59.794" N	49° 1' 26.184" W	5118160.787	652457.6099
20	Outside	46° 12' 59.794" N	49° 1' 26.183" W	5120012.588	652411.51
21	Outside	46° 12' 59.943" N	49° 5' 56.189" W	5119875.859	646626.6712
22	Outside	46° 13' 59.943" N	49° 5' 56.188" W	5121727.664	646582.3114
23	Outside	46° 13' 59.945" N	49° 8' 56.193" W	5121636.518	642726.9882
24	Outside	46° 20' 59.940" N	49° 8' 56.185" W	5134599.217	642424.3148
25	Outside	46° 20' 59.699" N	48° 59' 56.173" W	5134872.605	653965.8793
26	Outside	46° 23' 59.699" N	48° 59' 56.169" W	5140428.166	653825.445
27	Outside	46° 23' 59.855" N	48° 56' 56.164" W	5140531.44	657668.9398
28	Outside	46° 29' 59.851" N	48° 56' 56.157" W	5151642.526	657380.6852
29	Outside	46° 29' 59.899" N	48° 55' 26.154" W	5151694.156	659298.9358
30	Outside	46° 34' 59.900" N	48° 55' 26.149" W	5160953.641	659055.4158
31	Outside	46° 34' 59.851" N	48° 56' 56.151" W	5160902.02	657140.1016
32	Outside	46° 38' 59.849" N	48° 56' 56.146" W	5168309.602	656947.3963
33	Inside	46° 29' 59.896" N	48° 49' 26.144" W	5151900.68	666972.0837
34	Inside	46° 29' 59.926" N	48° 50' 56.147" W	5151849.048	665053.7745
35	Inside	46° 27' 59.928" N	48° 50' 56.149" W	5148145.368	665154.6061
36	Inside	46° 27' 59.848" N	48° 47' 56.144" W	5148248.639	668993.5866
37	Inside	46° 29' 59.846" N	48° 47' 56.141" W	5151952.314	668890.408

Table 2.1 EL 1161 Corner Coordinates and Area

No	Vertex_Position	Lat	Long	Lat_DD	Long_DD
38	Inside	46° 29' 59.776" N	48° 46' 26.139" W	5152003.948	670808.7477
39	Inside	46° 31' 59.777" N	48° 46' 26.137" W	5155707.725	670704.3349
40	Inside	46° 31' 59.897" N	48° 49' 26.142" W	5155604.464	666870.0195

Table 2.2 Project Area Coordinates

X_UTM NAD 83, Zone 22	Y_UTM NAD 83, Zone 22	x_deg	y_deg
620946.5971	5187236.225	49° 24' 51.161" W	46° 49' 39.658" N
705019.3721	5189686.068	48° 18' 42.408" W	46° 49' 44.896" N
623478.9907	5097410.568	49° 24' 17.183" W	46° 1' 8.885" N
708196.7254	5099733.539	48° 18' 36.946" W	46° 1' 10.255" N

Prior to the issuance of EL 1161, seven plugged and abandoned wells were drilled between 1973 and 2000 within the current boundaries of the EL. An eighth well is located within one of the two Significant Discovery Licences (SDLs) that are located within the boundaries of EL 1161 (Figure 2.1). Suncor is operator and 36.75% interest holder in SDL 1035, and holds a 15% working interest in SDL 1036, in association with the East Rankin H-21 discovery well. Several other wells have been drilled to the east and north of EL 1161, as the Hibernia, Hebron, and Terra Nova development projects are located adjacent to the EL and within the boundary of the Project Area. The Project Area occurs within the study area for the Eastern Newfoundland Strategic Environmental Assessment (SEA) completed by the C-NLOPB in August 2014 (AMEC 2014). As well, the Project will take place on lands that have been subject to a regional study as described in Sections 73-77 of CEAA 2012. The Project Area occurs within the study area of the Regional Assessment of Offshore Oil and Gas Exploratory Drilling East of Newfoundland and Labrador, initiated in October 2018 under CEAA 2012.

Specific well sites are not yet known but drilling operations will be conducted within the defined boundaries of EL 1161. Prospective areas will be selected to optimize the potential discovery of hydrocarbon reservoirs.

2.3 Project Components

2.3.1 Drilling Vessel

As water depth in EL 1161 is relatively shallow, Suncor will complete the exploration drilling for this Project with a semi-submersible rig (referred to generically as a mobile offshore drilling unit, or MODU). A drillship will not be considered by Suncor for use in the shallow waters of EL 1161, as this type of drilling rig cannot operate in anchored mode, and is typically used in deep waters or in areas where increased mobility is required due to ice or other factors and operational risks. . Therefore, use of drillships is not considered part of the scope of the Project. The use of a jack up rig is also not considered within the scope of this project.

2.3.1.1 MODU Selection and Approval Process

Suncor will use several selection criteria to identify a MODU able to drill safe, compliant, and reliable wells; the criteria focus on regulatory compliance, meteorological and physical oceanographic conditions, and the technical capability of the MODU. The MODU is expected to be winterized to allow year-round drilling, if required.

When a MODU has been identified, it will be subject to Suncor's internal rig intake activities, which identify and effectively manage risks for rig start-ups and verify that contracted rigs conform to industry standards and Suncor's specific requirements. Pursuant to the Accord Acts and the requirements of an OA, a Certificate of Fitness for the drilling vessel will be required. The Certificate of Fitness will be obtained for the MODU from a recognized independent third-party Certifying Authority prior to the commencement of drilling operations in accordance with the *Newfoundland Offshore Certificate of Fitness Regulations* or any other applicable legislation during the period of the lease.

The MODU selected by Suncor will, at a minimum, satisfy the operational requirements listed in Table 2.3.

Table 2.3 Operational Requirements for Mobile Offshore Drilling Unit

General: The MODU will be equipped with the following for the rig to operate:	
Drilling Mast	The support structure for the equipment used to lower and raise the drill string into and out of the wellbore.
Ballast Control	Maintains stability during operations.
Power System	Diesel generated power system to safely operate the MODU and all associated drilling equipment. The rig shall also be equipped with an emergency power system.
Positioning System	Dynamic Positioning (DP) system to maintain position under a range of meteorological and ocean conditions. Thrusters on the MODU are automatically controlled by the DP system to maintain the MODU in position. A variety of sensors, monitoring the ambient conditions and in combination with global positioning system (GPS) and acoustic referencing control the DP system.
Subsea Equipment	Inclusive of well control equipment such as blowout preventers (BOP), and a marine riser to act as a conduit from seafloor to rig floor. BOPs are devices installed on the wellhead that act as barriers to prevent the uncontrolled release of formation fluids escaping from the wellbore. These can take the form of annular pipe rams or blind shear rams.
Logistics Support: The MODU will be equipped with the following to support drilling operations:	
Helicopter Deck and Refuelling Equipment	For safe landings and departures for helicopters which are used for transfer of personnel and equipment.
Storage Space	Houses material used in drilling operations. This can include bulk storage for liquids, (e.g., drilling fluid, fuel oil, cement, etc.), as well as drilling equipment (e.g., casing, drilling equipment).
Cranes	To transfer equipment between the supply vessels and the MODU.
Waste Management Facilities	To allow for offshore treatment or temporary storage of hazardous and non-hazardous waste streams prior to shipment to shore or disposal in accordance with the OWTG.
Emergency and Lifesaving Equipment	Inclusive of firefighting equipment, lifeboats, and rafts for emergency evacuation.

Table 2.3 Operational Requirements for Mobile Offshore Drilling Unit

Accommodation Quarters with Sprinkler System Fire Protection	Inclusive of welfare facilities, such as sleeping, washing, toilet and mess facilities, and recreational facilities and medical facilities. Accommodation facilities will be provided for a maximum of 160 individuals on board, depending on the unit. Potable water will be provided through an onboard desalinization unit and/or bottled water. Daily estimates for offshore potable water use is approximately 20m^3 for 160 individuals, although the actual number on board would likely be closer to 140 to 150 persons

Additional details on the types of semi-submersible MODUs currently under consideration for use by Suncor is presented below.

2.3.1.2 Semi-Submersible MODU

A semi-submersible rig (Figure 2-2) is typically used at moderate water depths, such as on the Grand Banks, and is either towed into position or is self-propelled. It is comprised of two longitudinal lower hulls that support several vertical cylinders or columns, which in turn support the main deck of the rig. The hulls and columns are filled with water so that the rig floats with the main deck sitting above water and the hulls below the surface. Because much of the mass is well below the waterline, semi-submersibles are quite stable in rough seas thereby providing a relatively stable drilling platform. Given the shallow water depths over the EL (61 to 87 m) anchors will primarily be used to maintain MODU position, and assisted by dynamic positioning, as required by weather. Typically, when a MODU rig enters NL waters, it spends time in one of the deep-water ports such as Bay Bulls, and does not enter St. John's harbour, prior to mobilizing to the Project Area.

Source: Transocean 2019

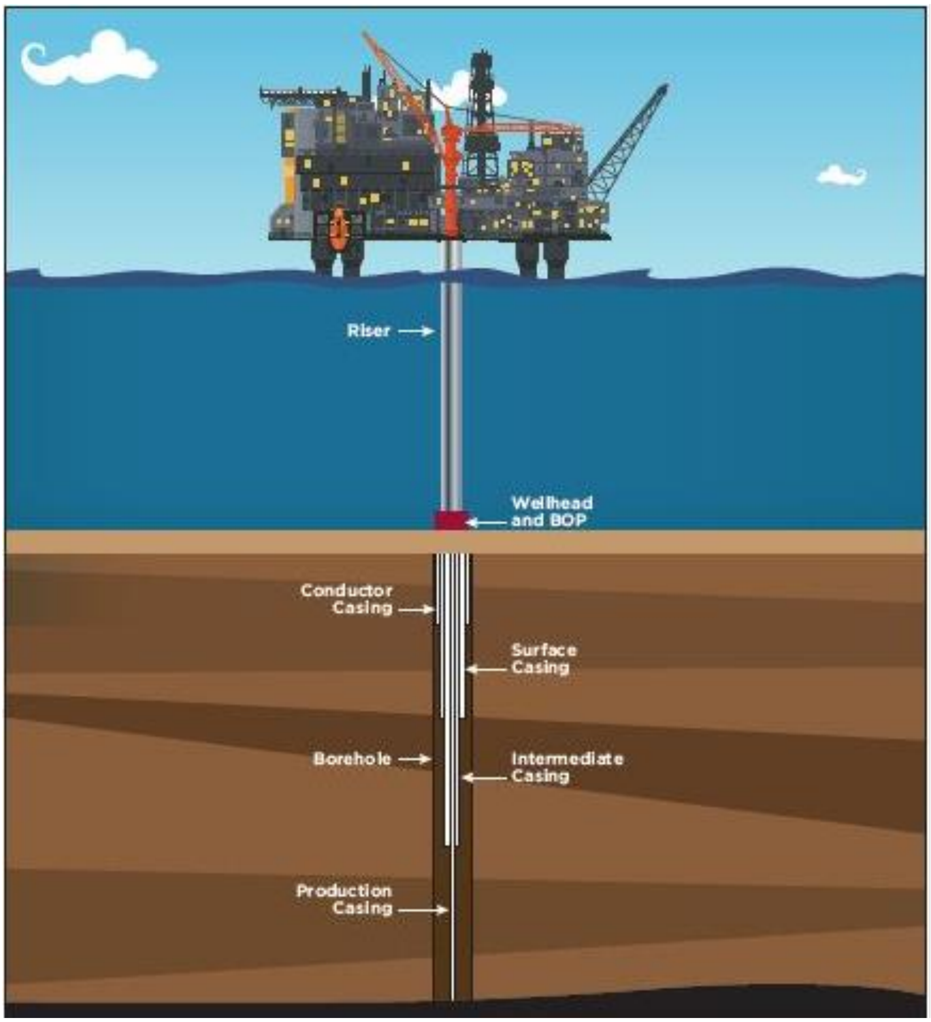
Figure 2-2 Typical Semi-submersible Drilling Unit

2.3.2 Offshore Exploration Wells

Suncor may drill up to 12-16 exploration and delineation (appraisal) wells within EL 1161 over the term of the Project. Wells will be of varying duration, lasting approximately between 45 to 120 days, unless unexpected operational or sea state issues cause a well to require more time. The well design and location for the proposed wells have not yet been finalized. Well design will depend on several factors including the geology of the formations.

Each section of the well will be drilled with an increasingly smaller drill bit and the borehole will then be secured with casing (liner installed within the wellbore). Casing is made up of a series of steel pipes that form a major structural component of the wellbore. It also serves several important functions, such as preventing the formation from caving into the wellbore, isolating the different formations to prevent flow or cross flow of formation fluids, and providing a means of maintaining control of formation fluids and pressure as the well is drilled.

A schematic of a completed offshore well, showing typical casing configuration, is presented in Figure 2-3. This figure is illustrative and does not necessarily represent the Project casing design.



Source: CAPP 2017
NOTE: For general illustration only, Drilling unit and well components not to scale

Figure 2-3 Schematic of a Floating Rig While Drilling in a Closed Loop Circulating System

More information on the offshore wells and drilling process is provided in Section 2.4.

2.3.3 Supply and Servicing Components

Offshore drilling operations will be supported by logistical arrangements for supply and servicing activity, via platform supply vessels and helicopters. These arrangements will allow the transportation and movement of equipment and personnel between the MODU and land to allow sufficient stocks of equipment and supplies to be maintained for safe, reliable, ongoing drilling operations.

Supply and servicing components and activities included in the scope of assessment encompass supply vessel operations (e.g., loading, transit, and unloading of vessels) to / from the Port of St. John's, or other industrial ports such as Bay Bulls or Argentia, NL, and the Project Area and helicopter support (e.g., crew transport and delivery of supplies and equipment) to / from St. John's International Airport and the Project Area.

Supply vessels and helicopters will be used to transport personnel, equipment, and materials to and from the MODU during the offshore drilling program according to work schedules and rotations, workforce numbers, distances, and other factors. Supply vessels will typically make regular trips to the drilling unit throughout a drilling program. Supply vessels will be used to: supply food, fuel, dry bulk, drilling fluids and drilling tools and equipment; transport waste transportation; assist in emergency response situations; and monitor the safety zone around the MODU and intercept vessels if required. A dedicated stand-by vessel will attend to the rig during drilling activities to provide operational assistance or emergency response support, and to provide secondary storage of well tubulars and drilling mud if required.

As with all offshore projects in this region, logistics and service requirements for a drill rig can be challenging especially during seasons of heavy weather, fog, Arctic ice, and high sea states. Helicopter and vessel support for the Project would originate mostly in St. John's from third-party suppliers operating from existing licensed / permitted facilities. In addition to the stand-by vessel, another vessel will service the rig by transporting equipment and personnel (in the event helicopters cannot fly) to and from the rig. It is anticipated that approximately two to three sailings per week will be required, but more are possible if a rig crew change is required. Similar to the drill rig, supply vessels will need certification and approval in order to work in NL waters.

Supply vessels selected for this Project will be equipped for safe all-weather operations, including stability in rough sea conditions and inclement weather. Measures to reduce superstructure icing hazards on supply vessels, such as those outlined in Ice Navigation in Canadian Waters (DFO 2012) will be implemented as necessary and may include: reducing vessel speed in heavy seas; placing gear below deck and covering deck machinery when possible; moving objects that may prevent water drainage from the deck; making the ship as watertight as possible; and manually removing ice under severe icing conditions if required.

Helicopter support from St. John's will be the primary method to transport personnel to and from the rig. Helicopters may also be used to transfer light supplies. Helicopters will be used for emergency support services, including medical evacuation from the MODU and monitoring in the event of an accidental release, as well as search and rescue operations if requested by the Canadian authorities. If helicopters cannot fly because of poor visibility from fog, high winds or high seas, consideration will be given to transport by vessel depending on the long-term weather forecast and the urgency to get individuals to or from the rig. Emergency response, safety procedures, and protocol will be in place for transport of personnel offshore.

Figure 2.1 illustrates the potential transit route for Project vessels. The oil and gas industry has established communication and cooperation methods with other marine users, primarily commercial fisheries, to coordinate vessel traffic. The specific route taken by an individual vessel between the onshore base of operations and the Project site would be the safest, most efficient route available at that time.

Additional information on supply and servicing activities are provided in Section 2.4.4.

2.4 Project Activities

2.4.1 MODU Mobilization and Drilling

The MODU will be subject to Suncor's rig intake procedure as well as the standard regulatory review and inspections required to obtain a Certificate of Fitness prior to approval for use. The MODU will be deployed to the drilling location once permits, regulatory approvals, and authorizations are obtained.

The MODU will be moved to the drilling location, either by towing or by its own propulsion. Given the shallow water depth of EL 1161 the MODU will be moored using anchors. The number of anchors chains can vary, as can the chain length, depending on the selected MODU and water depth. The pontoons are filled with water to partially submerge the MODU so that its deck is floating above water. This provides a platform that remains stable in rough seas.

A marine safety zone (i.e., a 500-m radius from the well location) will be established around the MODU in accordance with the *Newfoundland Offshore Petroleum Drilling and Production Regulations* to prevent collisions between the MODU and other vessels (e.g., fishing, research, or cargo vessels) operating in the area. This safety zone will be established around the MODU during initial mobilization activities and drilling operations, including well evaluation and abandonment processes. The standby vessel at the MODU will monitor the safety zone. Suncor will communicate details of the safety zone to the Marine Communication and Traffic Services for broadcasting and publishing in the Notice to Shipping and Notice to Mariners. Details of the safety zone will also be communicated with Indigenous and non-Indigenous fishers.

Standard marine safety measures will be implemented on the MODU and supply vessels including the maintenance of obstruction lights, navigation lights, and foghorns in working condition. Functional radio communication systems will be in place to contact other marine vessels if necessary. Additionally, the MODU will be equipped with local communication equipment to enable radio communication between the supply vessel and the MODU's bridge. Communication channels will also be put in place to enable communication between the MODU and shore.

Typically, oil and gas wells are drilled using a drill bit in sections of progressively smaller-diameter intervals. The top interval is drilled starting at the sea floor and has the largest diameter hole. The drill bit is controlled from the MODU through a series of joints of pipe, referred to as the drill string, which rotate the drill bit. The drill bit is lubricated by drilling fluids, also known as drilling "muds" that are formulated according to the well design and the expected geological conditions. They consist of a base fluid, weighting agents, and other chemicals that give the drilling fluid the properties required to drill a well safely and efficiently. Several types of drilling fluids are available including water-based mud (WBM) and synthetic-based mud (SBM). The OCSG (NEB et al. 2009) provides a framework for chemical selection to minimize the potential for environmental effects from the discharge of chemicals in drilling fluids used in offshore operations (refer to Section 2.9.3 for more information on chemical management). Drilling fluids are pumped from the MODU through the drill string to the drill bit. As the drill bit rotates downward through the rock layers, it grinds the rock, breaking it up and generating rock fragments known as drill cuttings. The drill cuttings are circulated by the drilling fluid out of the wellbore through the annulus. It is estimated that each well may take up to 120 days to drill.

Exploration wells are drilled in two phases: riserless drilling (i.e., an open water operation with no conduit for returns back to the MODU) and riser drilling (i.e., closed loop system that allows fluid returns back to the MODU). During riserless drilling, which occurs during the drilling of the initial sections of the well, there is no closed loop system in place to return drilling fluid and solids back to the MODU. Drilling fluids, excess cement, and cuttings are released directly to the seafloor strictly in accordance with regulatory guidelines. After the initial phase of drilling, the riser is installed, which is the main conduit for remaining drilling activities at depth and allows drilling fluid and solids from the wellbore to be transported from the well to the MODU for treatment.

Wellbore construction will typically begin with the spud of the well into the seabed, installing and setting the conductor and surface casing, followed by cementing. The initial well sections (conductor and surface strings) are drilled using WBM or seawater to cool the drill bit and transport the cuttings to the seabed. The conductor section provides the initial structural foundation for the borehole and the foundation for the subsea wellhead. A larger diameter hole, up to 42 inches (106.7 cm) diameter, will be drilled to approximately 100 m depth below the seafloor. Once the section has been drilled, the conductor pipe can be installed and cemented to secure the wellbore. The conductor can also be “jetted” into place, which effectively means that the conductor string is directly drilled into place. No cement is required when the conductor string is jetted in place. Riserless drilling is typically only carried out in the shallow sections of the well before the equipment that allows the riser to be connected to the well is installed.

After cementing the surface casing, the blowout preventer (BOP) is installed. The BOP is a piece of safety equipment which prevents hydrocarbons from escaping the wellbore into the environment. It is put in place to protect the crew and the environment against unplanned fluid releases from the well. It allows the wellbore to be closed through a series of rams and annular preventers, thereby closing the annulus, preventing any hydrocarbons from escaping the wellbore. The BOP is put in place around the marine riser, which extends from the drill rig to the seabed and lowered to the seabed where it is latched onto the wellhead (Figure 2.4). Additional information on the BOP and well control features is in Section 2.5.

Following placement of the BOP, drilling will then resume in a closed loop drilling mud circulation system. It is unknown at this stage which drilling fluids will be used to drill the remaining well sections. It is currently proposed that either WBM or SBM will be used. The mud will be pumped down the drilling string where it will cool and lubricate the bit and to transport cuttings and formation gas back to the rig for geological evaluation. The mud is then processed on the drill rig and then recirculated back into the well. Drilling parameters including mud volumes will be closely monitored. The choice of which drilling fluids and other components of well design, such as section depths, will be determined by the specific geology and predicted pore pressures of each individual well. The process of drilling, casing, and cementing is continued for the remaining hole sections. This sequence of events is repeated until the total depth of the well is reached. Drilling operations could be continuous until each well is completed or also completed in batches and suspended in between sections (riserless drilling sections, casing drilling sections, and completion operations).

If a planned section total depth cannot be reached, contingency casing sections will be available. A contingency string is effectively an additional string inserted into the well to enable the well to be drilled to total depth. Typical contingency strings include casing or liner sizes of 18", 11$^{3}/_{4}$", and 7".

An unplanned or planned side-track (i.e., drilling laterally from an original wellbore) may be drilled to meet the Project objectives. In the event of sidetracking, a secondary wellbore will be “kicked-off” from the original wellbore using a similar methodology described above. The original wellbore will be abandoned using cement prior to commencing side-track drilling. The details and design of the sidetrack will be contingent on the results of the original well and therefore have not yet been finalized. Once they have been established, plans and designs for the sidetrack will be submitted to C-NLOPB for approval.

As the Project is related to exploratory drilling and associated activities, commercial production of oil from these drill sites will not be considered within the scope of this assessment. For information on drilling fluids and drilling waste management, refer to Section 2.8.2.

2.4.2 Geophysical, Environmental and Geotechnical Surveys

Various wellsite surveys, including geophysical, environmental, and geotechnical) are typically conducted prior to drilling to collect information necessary for well location planning and well design.

2.4.2.1 Geophysical Survey

Geophysical surveys (used to identify shallow gas deposits and other unstable areas beneath the seafloor and hazards such as large boulders) are conducted to avoid these hazards when drilling. If geophysical data exists for a proposed drilling location, they may be used to analyze potential geohazards, negating the need for a new geohazard survey. If a geohazard survey is required, the seabed mapping can be conducted using seismic sound sources, multibeam echosounder (MBES), side-scan sonar (SSS), sub-bottom profiler (SBP), video and other non-invasive equipment, deployed either by vessel or ROV / AUV.

VSPs are used to collect data from within the wellbore ahead of the drill bit to assist in further defining a petroleum resource by correlating the collected surface seismic data with the geological formations encountered in the wellbore. A VSP uses receivers (hydrophones) at different depths within the wellbore and can deploy a number of different sound source positions, including zero-offset VSP at the well bore, or offset VSP (deployed over the side of the MODU to a depth of 3 to 5 m below the water surface). In a success case, Suncor would likely conduct zero offset VSP. However, the objectives of the VSP will determine the specific details of the program (e.g., type of VSP frequency, duration, air gun source array design). A VSP typically takes one day or less to complete.

VSPs use a source array similar to that used in seismic operations but with a much smaller size and volume than a traditional surface seismic survey. As the VSP operation is focused around a wellbore the sound effects will be localized to the MODU (refer to Section 2.8.5 for more information on sound emissions generated by VSP). As with any sound-generating activity, Suncor will apply the requirements of the Statement of Canadian Practice with respect to the Mitigation of Seismic Sound in the Marine Environment (SOCP) (DFO 2007) when conducting VSP.

2.4.2.2 Environmental Survey

Given the water depth of the EL (maximum ~ 85 - 90metres) and the predominance of a sand substrate, it is unlikely that there are extensive areas of corals or sponges in the EL. As indicated in Section 6.1.2, Canadian RV trawls conducted within the Project Area between 2004 and 2021 had few documented occurrences of corals and sponges and these were all below the NAFO thresholds for significant concentrations of corals and sponges. There are no sensitive areas identified within the EL or within the Project Area, with the exception of two small significant Benthic Areas illustrated in Figure 6.56 in section 6.4.2.2. However, Suncor will conduct a coral and sponge seabed survey of drill locations using an ROV / AUV prior to drilling operations. A coral and sponge survey plan will be provided to DFO and the C-NLOPB for acceptance prior to survey implementation and a report of findings will be provided upon completion. The survey will be conducted with a qualified marine biologist on board to identify and assess coral structures.

Other environmental surveys may include oceanography, meteorology, ice / iceberg surveys, and ROV-video or drop camera surveys, as well as collection of biota, water, and sediment samples. Environmental surveys may occur throughout Project life at any time of the year (in advance of placement of a drill rig), using vessels of opportunity associated with the Project. Environmental surveys typically take 5 to 20 days to complete.

2.4.2.3 Geotechnical Survey

Geotechnical surveys collect sediment samples and conduct in-situ testing to measure the physical properties of the seabed and subsoil. Sample collection typically includes drilled boreholes (including installation of piezometers to measure soil properties) or gravity coring, while cone penetration testing are used for in-situ testing. Geotechnical surveys may occur throughout the Project life at any time of the year, using dedicated vessels provided by marine geotechnical specialist suppliers.

2.4.3 Well Evaluation and Testing

If hydrocarbons are discovered during an exploration drilling program, well evaluation and possible testing would be conducted to help determine the commercial potential of the reservoir and the viability of a prospect. Well evaluation and testing include wireline logging and possible formation testing (i.e., well flow), which involves passing the well fluids through the MODU's test equipment.

There are several processes involved in well evaluation. While drilling, the well will be monitored and evaluated by a variety of means including "Measurement While Drilling and Logging While Drilling" techniques, mud logging, drilling parameters evaluation, and subsurface pressure evaluation activities. Wireline logging may also be performed after drilling activity has been completed based on the results of the primary evaluation tools. Well flow testing may take place on a subsequent appraisal well following a discovery, but likely not on an initial exploration well, unless it was suspended and the MODU returned at a later date to allow time for proper planning and safe execution of a well testing program.

Project appraisal wells may require well testing to gather information about subsurface characteristics such as potential productivity, connected volumes, fluid properties, composition, flow, pressure, and temperature. This dynamic data set in turn enables the confirmation of data in logs and cores assimilated during drilling activity. Considered in concert, the testing results can build a comprehensive picture of reservoir potential. Suncor may use well flow testing data to demonstrate the reservoir deliverability prior to a future investment decision. Well testing will be subject to Suncor's well test assurance process, designed to promote safe and efficient well test operations. Testing, if needed, would be conducted over a one-month period (after drilling is complete) on an appraisal or delineation well, following an initial discovery, depending upon the hydrocarbons discovered.

Suncor will carefully consider the need for well flow testing that requires flaring to safely dispose of gases or other hydrocarbons that come to surface. Flaring associated with the Project's well testing if required would occur over an approximately 36-hour period. Flaring would be via one of two horizontal burner booms, to either a high efficiency burner head for liquids, or simple open-ended gas flare tips for gases. High efficiency combustion equipment will be used that maximizes complete combustion, thereby reducing the likelihood of black smoke in flaring activity and drop-out of un-combusted hydrocarbon liquids onto the sea surface. Other methods of flow testing that do not require flaring include wireline techniques of Modular Dynamic Testing (MDT) and Flow Testing While Tripping (FTWT). These are Suncor's preferred methods of well testing. The Modular Dynamic Tester (MDT) uses a downhole wireline tool with a pressure sensor and a sample chamber to sample reservoir fluids in situ, without free hydrocarbons coming to surface. FTWT employs a wireline tool with a pressure sensor and a downhole pump to deliver small amounts of hydrocarbons from the reservoir up the annulus and into a tank on the rig, and does not require flaring. Use of alternative MDT or FTWT methods will be conducted and considered first along with production data from the same reservoirs in adjacent areas, before any decision to conduct a well test via well flow testing requiring flaring will be carried out. However for the purposes of the effects assessment flaring is included in case it is required. Flaring will only be carried out if the alternative wireline methods (MDT or FTWT) are not able to provide sufficient reservoir information.Flow testing of hydrocarbons is addressed in the C-NLOPB's *Newfoundland Offshore Petroleum Drilling and Production Regulations* (Sections 35 and 52). Section 52 states that: an operator may conduct flow testing but a detailed testing program must be submitted to the C-NLOPB for approval, and the C-NLOPB "shall approve a flow test if the operator demonstrates that the test will be conducted safely, without pollution and in accordance with good oilfield practices". Additionally, the Approval to Drill a Well (ADW) application that operators must file with the C-NLOPB in advance of drilling, requires information regarding flow tests for exploration or appraisal (delineation) wells, and references the requirements under the Regulations (Section 52). Suncor will relay plans for well test flaring to the C-NLOPB as part of the ADW process and will report on any flaring activity to the C-NLOPB, as required. Any updates to operations regulations as the pertain to flow testing regulations issued as part of the Federal Government's Frontier and Offshore Regulatory Renewal Initiative (FORRI) will be incorporated into Suncor's operational procedures.

Well flow testing using drill stem testing (DST) or FTWT may be delayed due to rig schedule, anticipated sea states, or weather conditions and may occur at a later date. In the event of a delayed well flow test, Suncor will secure and suspend the well with required barriers in place prior to moving the drill rig off location.

Collecting a fluid sample is a key objective of well testing via DST, MDT or FTWT. A DST generally requires perforating casing that has been set across the hydrocarbon-bearing reservoir. Once the casing and reservoir have been perforated, reservoir fluids are allowed to flow into and up the wellbore to the MODU, which will have a temporary testing facility installed on the MODU to handle the flow of any fluids from the wellbore. The hydrocarbons in the reservoir fluids are measured and separated from any produced water. If testing with DST does happen to be conducted, it will not occur at more than one out of four to five wells. Seawater is sprayed through a series of high-pressure nozzles during a DST to dissipate heat between the flare and the MODU. This seawater curtain is likely to deter birds near the flare.

Test wells will be suspended or abandoned in accordance with the *Newfoundland Offshore Petroleum Drilling and Production Regulations*.

2.4.4 Well Suspension, Abandonment and Decommissioning

Two possible scenarios exist for an exploratory well following drilling to Total Depth: suspension or abandonment. Operators are required to provide detailed plans to the C-NLOPB for monitoring suspended wells and are also required to provide information regarding the specific proposed methods of suspension of each well. For a suspended well, a suspension cap is installed to protect the wellhead connector. The suspension cap will protrude above the seabed. Proper notification via Notice to Shipping is made to identify the subsea obstruction until it is removed.

Well abandonment is the permanent decommissioning of a well and will be designed in compliance with the *Newfoundland Offshore Petroleum Drilling and Production Regulations*, standard industry abandonment procedures and practices in accordance with C-NLOPB regulations, and Suncor's applicable practices. As abandonment is intended to be permanent, there is no requirement for ongoing monitoring under the Regulations. Well abandonment could include plugging the well with a cement mixture to isolate the wellbore and removing the wellhead and any associated equipment to below the seafloor with mechanical cutters. In this scenario, the plugs would be placed at varying depths in the wellbore and the well casing would be typically cut just below the surface of the seal. Wellheads may be removed by the drill rig or by an ROV from a vessel. The seabed is inspected using an ROV to confirm no equipment or obstructions remain. Suncor's removal strategy for wellheads will consider water depth and the likelihood of potential interactions with fishing activities. However, the abandonment program has not yet been defined. Final details about the well abandonment program will be confirmed with the C-NLOPB as part of the well planning process.

2.4.5 Supply and Servicing

An existing supply base facility in the St. John's region or an alternate facility will be used to support logistical requirements for offshore operations. Supply base activities will be conducted by an existing third-party contractor and are outside the scope of this EIS.

2.4.5.1 Supply Vessel Operations

Supply vessels will support the MODU by re-supplying the drilling vessel with fuel, equipment, drilling mud, and other supplies, and by removing waste. Two supply vessels will be required, with one vessel on stand-by at the drill rig at all times. It is estimated that the supply vessels will make approximately two to three round-trips per week between the MODU and the supply base.

As supply vessels typically travel at approximately 12 knots at service speed, transit time between the Project Area and the onshore supply base would be approximately 18 to 24 hours. As the Project Area is near the development projects of Hibernia, Terra Nova, and Hebron, the long established shipping lanes will be used to access EL 1161 (Figure 2-4).

Once in the Project Area, the supply vessels will select the most appropriate route for reaching the destination. When operating in near-shore or harbour areas, the supply vessels will follow applicable Port Authority requirements when in a port and will be compliant with the *Eastern Canadian Vessel Traffic Services Zone Regulations*. Supply vessel transit has an existing regulatory regime with best management practices, and is an ongoing, routine activity among all operators in the region, including Suncor.

Supply vessels will be evaluated through Suncor's internal marine assurance process as well as additional external inspections / audits inclusive of the C-NLOPB pre-authorization inspection process in preparation for the Project. Procedures will be in place to ensure that hoses are inspected and operated correctly to minimize the risk of an unintended release. The supply vessels and MODU will be equipped with primary spill contingency equipment.

Supplies will be loaded and unloaded onto supply vessels using personnel and cranes for drilling materials and closed piping systems (e.g., pumps, hoses) for bulk powders, liquid supplies, and waste (e.g., drilling fluids). The supply vessels will transfer diesel fuel, also referred to as marine gas oil, to the MODU from shore. Fuel is required offshore to power the MODU, including drilling equipment and thrusters. Fueling operations, according to standard vessel fueling procedures, are expected to take place up to two to three times per week by a third-party contractor.

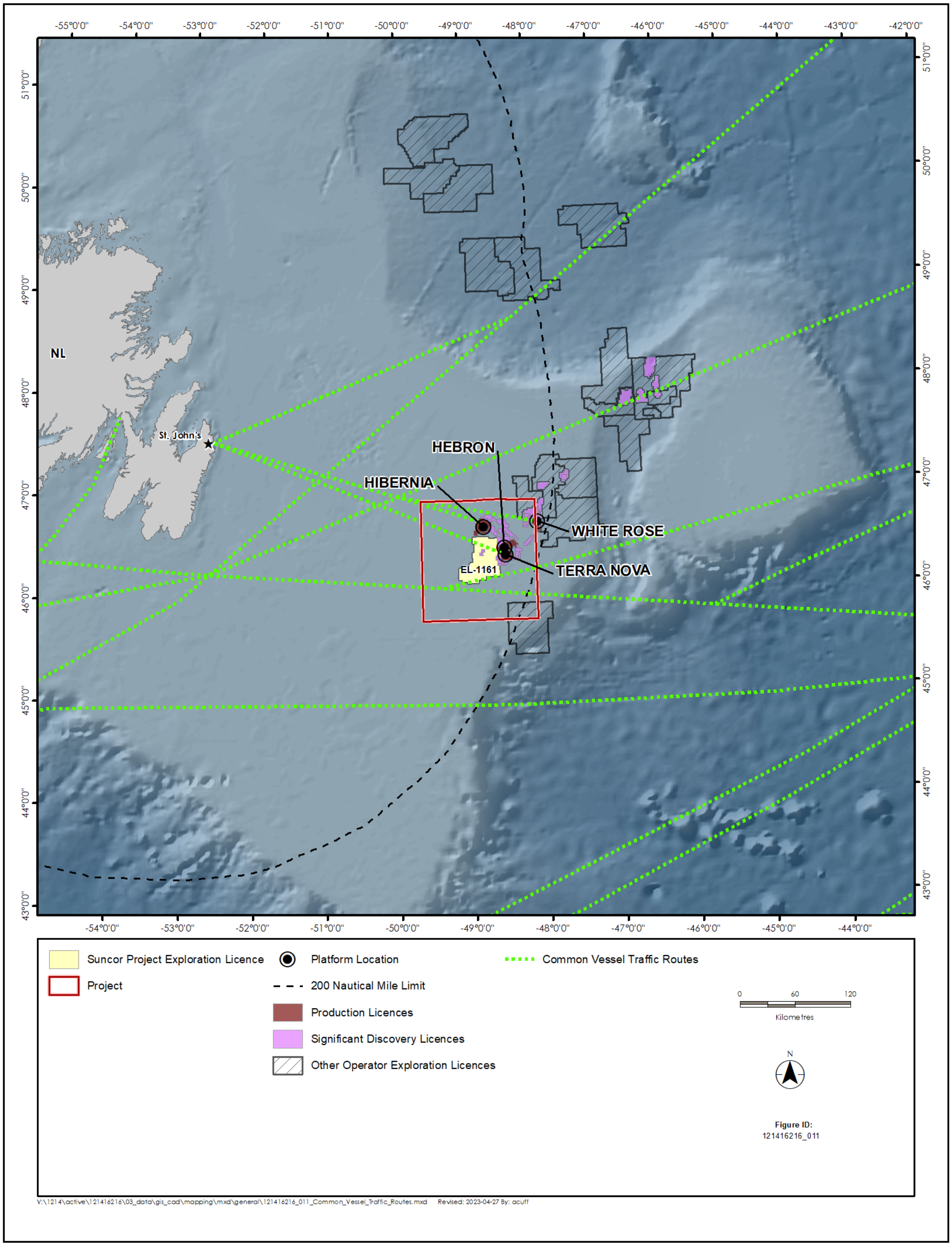


Figure 2-4 Common Vessel Traffic Routes in Offshore Newfoundland and Labrador

2.4.5.2 Helicopter Traffic and Operations

Helicopters will be primarily used for regular crew changes, but also to support medical evacuation from the MODU and search and rescue activities in the area, if required. It is anticipated that up to one to two helicopter trips per day would be required to transfer crew and any supplies not carried by the supply vessel to the MODU. The MODU will be equipped with a helideck for safe landings. Helicopter operations will be conducted out of St. John's International Airport.

Helicopter routings between the well locations and shore will typically take a straight-line course to the well location. The maximum flight time is expected to be approximately 1.5 hours as the maximum distance between St. John's International Airport and the farthest boundary of the EL is approximately 350 km.

The helicopters that will be used for this Project have not yet been contracted, however, it is expected that the helicopters used by the Project will have a capacity of approximately 12 to 15 passengers and a maximum range of approximately 540 NM (1,000 km) without refuelling. Refuelling operations are expected to take place at St. John's International Airport. However, the MODU will be equipped with refuelling equipment. The distance to the Project area and return will likely not require that auxiliary fuel tanks be installed on the Helicopters.

2.5 Well Control and Blowout Prevention

Drilling operations include a number of mechanisms to control formation pressure, including the drilling fluid, casing, and dedicated pressure control equipment. Formation pressures are managed to prevent a blowout, which is an uncontrolled flow of formation fluids. A blowout can occur when one or more of the specific well control barriers have failed.

The first level of blowout prevention is the implementation of primary well control measures and procedures. This includes monitoring the formation pressure and controlling the density of the drilling fluid accordingly. The density, or weight, of the drilling fluid is adjusted as required to maintain an overbalance of pressure against the formation pressure, thereby keeping the wellbore stable. If a primary barrier fails, the next line of defense is a BOP system, which is a secondary well control barrier.

A BOP is a mechanical device, designed to seal off the wellbore at the wellhead when required. The system consists of a series of different types of closing mechanisms including rams, which are pistons that move horizontally across the top of the wellbore to create a seal around the drill string. The BOPs that will be used as part of the Project will comply with American Petroleum Institute (API) standards, specifically Standard 53 (Blowout Prevention Equipment Systems for Drilling Wells). For each well drilled as part of the Project, a BOP rated to 15,000 psi working pressure will be installed and pressure tested, and it will accommodate the anticipated formation pressures for the wells drilled at part of the Project. These BOPs will consist of a series of control measures, including hydraulically-operated valves and sealing mechanisms that remain open during drilling to allow the mud to circulate, but can be quickly closed if reservoir fluids enter the wellbore, an event referred to as a “kick”. If a kick occurs and additional controls are required, an annular preventer will be closed to prevent any further influx from the reservoir into the well when there is a pipe in the wellbore. The next line of defense are the pipe rams, of which there are multiple for redundancy. The last line of defense is the blind shear rams, which, if necessary, cut through the drill pipe and seal the well completely. There will also be a ram that is capable of cutting planned casing sizes, which is called a casing shear ram. If no pipe is in the hole when a kick occurs, the blind shear rams will be closed.

Prior to installation on the well, the BOP stack will be pressure tested on the MODU deck, and then again following installation on the well to test the wellhead connection with the BOP and operability on the seafloor. The BOP will be pressure tested periodically throughout the drilling program as per the *Drilling and Production Guidelines* (C-NLOPB and C-NSOPB 2017a). The Guidelines specify that further to the post-installation pressure test described above, pressure testing will occur at several specified points: before drilling out any string of casing, before commencing a formation flow test, following repairs or any event that requires disconnecting a pressure seal, and once every 14 operational days. Where well conditions or other hazards preclude pressure testing within the 14-day timeframe, the test may be delayed by up to 7 days. Pressure testing will be conducted in line with the C-NLOPB Guidelines and all pressure test details and results will be recorded.

When the BOP is initially installed, the ROV intervention capability for operating the BOP, if necessary, will also be tested. This is done by physically engaging the ROV control panel to function the controls. The BOP will only be removed once the well has been plugged and abandoned and the casing pressure tested above the abandonment plugs to confirm plug integrity.

A discussion of emergency response measures and strategies is presented in Section 16.4.

2.6 Project Personnel

The Project will be managed by Suncor through a multidisciplinary Project Team that will be responsible for planning and delivering the Project as a whole. Several contractors will be engaged to carry out specific components of the work including: the drilling contractor, who will provide and operate the MODU, well services providers who will provide equipment and services to support drilling operations, and logistics contractors who will provide and operate the supply base, supply vessels, and helicopters.

2.7 Project Schedule

Suncor proposes to commence exploration drilling activities starting as early asQ2, 2024, although these activities could begin earlier or later pending regulatory approval, and potentially continue intermittently until end of 2029 with proper authorizations in place. This has been selected to align with the terms of the EL, as well as to provide an adequate and conservative timeframe within which planned Project activities including well drilling, testing, suspension and abandonment, and associated activities may occur. Up to 12 to 16 wells could be drilled on EL 1161 over the term of the Project. The number of days on each well may range from 45 to 120 days for each well with the potential to occur year-round. Drilling activities will not be continuous over the term and will be in part determined by rig availability and previous years' results.

For the purposes of the effects assessment this EIS assumes year-round drilling.. Drilling will be conducted using a semi-submersible rig and VSP operations will take approximately one day per well, and the various components of well testing, where required, would occur over a one-month period annually. Well suspension and abandonment will be conducted following drilling and/or well testing. Wells may be designed for suspension and re-entry, this will be determined through further prospect evaluation.

Figure 2-5 shows key elements of the proposed Project schedule for the initial well drilling campaign.

2.8 Changes to the Project Since Originally Proposed

The following is a list of the changes that have been made to the Project since originally proposed:

- Addition of a specific temporal scope, to assess effects until the end of 2029, in addition to the lease period, this is to allow Project activities to continue if regulatory approvals are in place.
- Addition of environmental surveys, including coral and sponge surveys to list of Project activities, to allow for identification of corals and sponges prior to activities taking place.
- Change number of wells from 12, to a range of 12 to 16, with a resulting change of maximum number of wells per year from three to four. Note that the maximum number of drilling days (360) remains unchanged for the purposes of the effects assessment, as an individual well could take from 45 to 120 days to drill.
- Change VSP to Geophysical (including VSP), Environmental and Geotechnical Surveys. This includes geohazard assessments and the environmental surveys indicated in the second bullet.

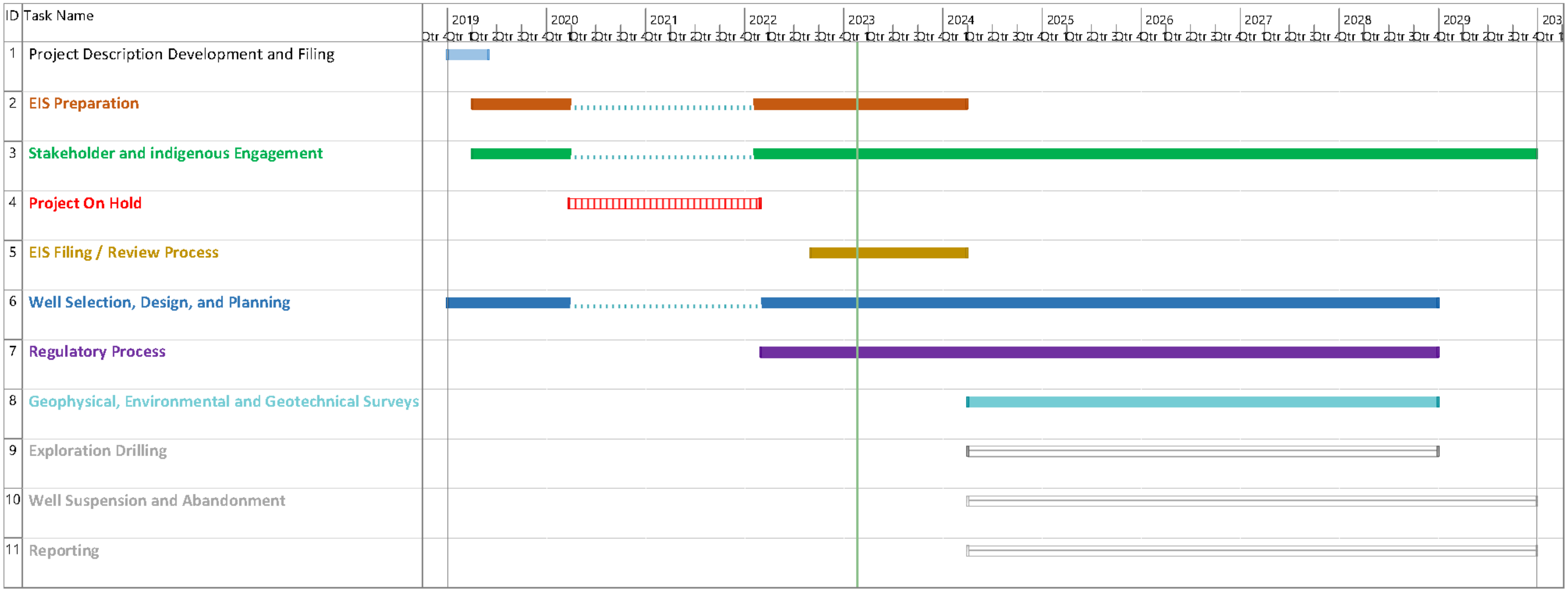


Figure 2-5 Planned Project Schedule

2.9 Emissions, Discharges and Waste Management

An overview of the key emissions, discharges, and waste streams that are likely to originate from proposed Project activities as part of routine operations are outlined in this section. Key emission and waste streams from the Project have been classified into the following groups:

- Drilling waste
- Liquid discharges
- Hazardous and non-hazardous waste
- Sound emissions
- Light and thermal emissions

Some wastes will be managed, treated and discharged in accordance with the Offshore Waste Treatment Guidelines (OWTG) (NEB et al. 2010) from the MODU and the supply vessels, while others will be brought to shore for disposal. Offshore waste discharges and emissions associated with the Project (i.e., operational discharges and emissions from the MODU and supply vessels) will be managed in accordance with relevant regulations and municipal bylaws as applicable, including the OWTG and the *International Convention for the Prevention of Pollution from Ships* (MARPOL 73/78) that have been incorporated into provisions under various sections of the *Canada Shipping Act*. All waste not covered in this guidance will be brought to shore for disposal.

Waste management plans and procedures will be developed as part of the Environmental Protection Plan (EPP) for the Project and implemented to define waste storage, transfer, and transportation measures.

Information on the releases, wastes, and discharges will be reported as part of a regular environmental reporting program in accordance with regulatory requirements as described in the OWTG and further in Suncor's EPP.

2.9.1 Drilling Waste Discharges

Drilling muds are an essential component of drilling operations. Drilling muds are the fluids which lubricate and cool the drill bit and well bore, circulate cuttings and carry them back to the surface, and help maintain appropriate pressure in the well to overbalance formation pressure, providing the primary barrier for well control (BOP forms part of the secondary barrier). Different types of drilling muds will be used for different sections of the well. Several drilling related waste streams will be generated as part of the Project, including:

- Drill cuttings
- Drill fluids
- Cement

All drilling related waste streams will be disposed of in accordance with the OWTG.

As described in Section 2.4.1, the shallow sections of the wells will be drilled with WBM or seawater, and then deeper sections with either WBM or SBM.

WBM will be used for the riserless sections of a well where no hydrocarbons are anticipated. WBM is primarily composed of seawater, with other additives including bentonite (clay), barium sulphate (barite), and potassium chloride. Bentonite clay is added as a viscosifier to thicken the mud to suspend and carry drill cuttings to the surface. Barite is also added to the water in WBM to control mud density and thus help balance formation pressures within the well. Other substances such as thinners, filtration control agents, and lubrication agents can be added to the WBM as required to manipulate the required mud properties. During this initial drilling, mud and cuttings will be returned to the seabed where they will accumulate near the wellhead. The majority of WBM discharged is classified as Poses Little or no Risk (PLONOR) to the environment under the United Kingdom Offshore Chemical Notification Scheme (OCNS) which is outlined in the Offshore Chemical Selection Guidelines. The discharge of WBM cuttings at the seabed, while drilling the first two-hole sections, is accepted as industry standard practice and is consistent with the OWTG.

SBM is a water-in-oil emulsion that contains non-aqueous (water insoluble) fluids manufactured through chemical processes. SBM can be made up of internal olefins, alpha olefins, polyalphaolefins, paraffins, esters, or blends of these materials. The same weighting materials used in WBM to control density are typically also added to SBM, as well as other additives to manage viscosity, fluid loss, alkalinity, emulsion stability, and wettability, where required. SBM may be selected over WBM as they can offer improved lubricity, thermal stability, wellbore integrity, and protection against gas hydrates in the well. SBM is generally used to drill the deeper (i.e., lower hole) sections of the wells, once the riser has been installed. The marine riser, which connects the MODU to the well, allows for the return of drilling mud and cuttings back to the MODU where cuttings can be treated to meet the requirements of the OWTG prior to disposal to the marine environment. The MODU will be equipped with specialized solids control equipment to separate and clean the drilled cuttings and SBM. The purpose of solids control is to quickly and simply remove as much of the drilling fluids as possible from the cuttings for re-use in the drilling process. Initially, the SBM carrying the drilled cuttings returns and is passed through a shale shaker where most of the mud is separated from the cuttings. Shale shakers are made up of a system of coarse and fine mesh screens that collect cuttings while allowing drilling fluids to pass through and be collected. Additional solids control equipment, such as centrifuges, may be required depending on the drilling fluid basis of design, and geological characteristics for reconditioning of the drilling fluid for re-use. The cuttings from the shale shaker are passed through a cuttings dryer, which removes SBM from cuttings. Following treatment with solids control, WBM cuttings can be discharged to sea from the MODU through a caisson below the sea surface. For SBM, the cuttings are treated and sampled for % SBM on cuttings in accordance with the OWTG and residual synthetics-on-cuttings are discharged to the marine environment. Monitoring of the residual base mud-on-cuttings levels is carried out during well sections involving use of SBM. After recovery and treatment of drill muds, the drill cuttings are discharged at the well site. No surplus SBM is discharged to the sea; spent SBM that cannot be reused during drilling is brought to shore for disposal in an approved licensed facility, or is stored for use on a subsequent drilling operation.

Drill waste deposition modelling has been conducted to demonstrate the expected deposition of drill waste from the drilling program. Although the precise location of wellsites for the drilling program are not currently known, the drill waste modelling employed the same representative wellsites as used for the oil spill modelling exercise and acoustic assessment. Table 2.4 indicates the locations of representative wellsites for modelling.

Table 2.4 Drill Waste Deposition Modelling Location in EL 1161

Lat	Long	Lat_DMS	Long_DMS	Water Depth (m)
46.546252	-48.618508	46° 32' 46.507" N	48° 37' 6.629" W	100 m

Operational discharges from the five planned drilling sections were modelled (using the RPS MUDMAP modelling system) as either seafloor or sea surface releases. The MUDMAP model has been validated on numerous occasions, through past projects (client confidential) and publications (Burns et al. 1999; King and McAllister 1998). MUDMAP is also a software package that was developed by and is currently being maintained by RPS, as the current state of scientific knowledge evolves and advances. RPS has performed a qualitative review of the HYCOM time series between 2006-2010 and 2006-2012, comparing current statistics (speeds and directions) from each year at multiple depths for each modelled timeframe (see RPS MUDMAP technical report; Tajalli-Bakhsh et al. 2018). Current trends for the two model periods during 2012 were congruent with the overall seven-year trend and were thus deemed suitable as a representative modelling period. The two periods chosen represented worst-case discharges for both extent of discharge (during periods with higher current velocities and enhanced sediment transport) and overall depositional thickness (during periods with lower current velocities and increased sediment accumulation).

The release rate and location of the discharges in the water column depended on each drilling stage (Table 2.5). The sizes of the SBM particles were averaged for each size class based on the provided information from particle size analysis and measured weight % material (MW%M) from Terra Nova well E-19 dried drill cuttings samples.

The first two sections were simulated as seafloor releases of WBM and cuttings, while the remaining three sections were simulated as surface releases of cuttings with 6.9% by mass of the synthetic based mud (SBM) retained on the cuttings. Each of these simulations were performed for two different seasons (Summer and Fall) to evaluate how ocean current variability in the region may affect the patterns of cuttings and mud dispersion and deposition. This dispersion modelling targeted the most likely drilling windows for the Project, which were May-June and October-November, and referred to as Summer and Fall.

In each modelled case, the deposition of muds and cuttings from operational discharges onto the seabed was controlled by the settling velocities of particles, the currents within the water column, and the depth of the water column. Modelled operational discharges from EL 1161 (approximately 100 m) were predicted to produce a spatially confined depositional area of 7.28 mm thickness (Tables 2.6 and 2.7).

Table 2.5 Proposed Drilling Program for Tilt Cove (provided by Suncor)

Section	Diameter (mm)	Drilling Period		Drilling Duration (days)	Discharge Duration (days)	Cuttings Discharge			Drilling Fluid (Mud) Discharge[1]			Mud Type	Release Depth[2]
		Scenario 1	Scenario 2			Vol. (m^3)	Solid Mass (tonnes)**	Rate (m^3/d)	Vol. (m^3)	Solid Mass (tonnes)**	Rate (m^3/d)		
1	1,067	Summer	Fall	1	0.5	55	143	110	3271	799	6541	WBM	Seabed
2	660	Summer	Fall	2	1	150	390	150	6541	1,599	6541	WBM	Seabed
3	445	Summer	Fall	7	4	140	385	35	9.7	27	2.4	SBM	Sea Surface
4	311	Summer	Fall	10	7	115	316	16.4	7.9	22	1.1	SBM	Sea Surface
5	216	Summer	Fall	7	4	20	55	5	1.4	4	0.3	SBM	Sea Surface
Total				27	16.5	480	1,289		9,831	2,451			

Each row defines drilling sections beginning with the sediment-water-interface (1) down to the reservoir (5)

Notes: 1. Cuttings from sections drilled with SBM were modelled with an additional 6.9% by weight to account for base fluid that was assumed to be adhered to cuttings

2. Releases were simulated at 5 m above seabed or 5 m below the sea surface

**Values used for the drilling simulations; Mass is calculated using volumes of muds and cuttings, as well as bulk densities of the materials and percent solid by weight

Table 2.6 Areal Extent of Predicted Seabed Deposition (by thickness interval) for Operational Discharge Simulations in Summer and Fall

Deposition Thickness (mm)	Cumulative Area Exceeding (km^2)			
	Summer		Fall	
	Cumulative Sections	Riserless Sections	Cumulative Sections	Riserless Sections
≥0.1	1.4349	1.3319	2.1381	2.0186
≥0.2	0.8752	0.8310	1.2438	1.1697
≥0.5	0.4574	0.4338	0.5143	0.4722
≥1	0.2616	0.2494	0.1996	0.1507
≥1.5	0.1752	0.1642	0.0777	0.0700
≥2	0.1289	0.1204	0.0269	0.0216
≥6.5	0.0029	0.0005	0.0000	0.0000
≥10	0.0000	0.0000	0.0000	0.0000
Maximum Thickness (mm)	7.28	6.72	2.64	2.53

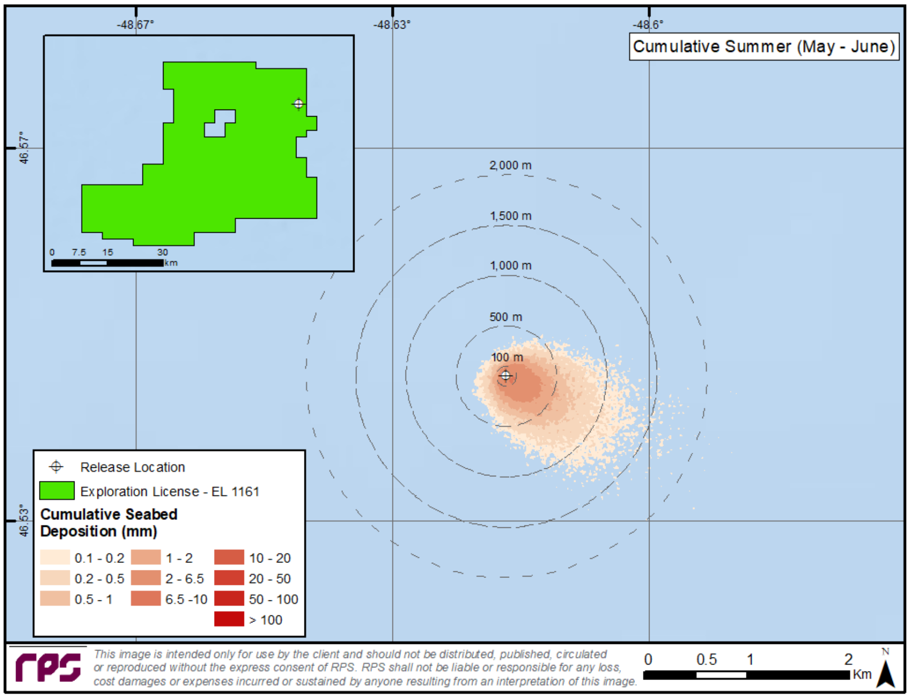
Table 2.7 Maximum Distance of Thickness Contours (distance from release site) Predicted for Operational Discharge Simulations

Deposition Thickness (mm)	Maximum extent from release site (km)			
	Summer		Fall	
	Cumulative Sections	Riserless Sections	Cumulative Sections	Riserless Sections
≥0.1	1.79	1.76	2.43	2.42
≥1.0	0.62	0.62	0.76	0.75
≥1.5	0.47	0.47	0.55	0.54
≥6.5	0.11	0.09	0.00	0.00
≥10	0.00	0.00	0.00	0.00

During the summer (Figure 2-6), depositional thicknesses at or above 0.1 mm were predicted to extend to the southeast up to 1.79 km and cover an area up to 1.45 km². Predicted depositional thicknesses at or above 1 mm extended to a maximum of 0.62 km and covered an area no greater than 0.27 km². Depositional thicknesses that reached 1.5 mm in thickness were predicted to extend less than 0.5 km from the wellhead and covered a maximum area of 0.18 km². The deposition at or above the predicted no effect concentrations (PNEC) threshold of 6.5 mm (Smit et al. 2008) was predicted to cover a maximum of 0.003 km² and extended up to 0.11 km from the wellhead. The maximum thickness during the summer simulations was predicted to be 7.28 mm, which is below the 10 mm thickness threshold that was also assessed.

Fall simulations for the EL 1161 site (Figure 2-7) were characterized by stronger subsurface current regimes, with greater variability, which led to slightly more elongated depositional footprints, when compared to summer scenarios. While the predominant current direction during the fall was southeasterly, the discharge of finer sediments in the WBM cuttings and muds were predicted to be transported by northerly and southwesterly currents that occurred temporarily during the first two drilling sections. This resulted in a broader depositional footprint that was predicted to extend to the north and southeast. This current variability resulted in a broader depositional footprint that extended to the north and southeast of the wellhead. During the fall simulations, thicknesses at or below 0.5 mm were predicted to extend further and had greater areal extents than the summer simulations. This was due to the stronger current regime that transported fine sediments with low settling velocities further from the wellhead. Because of this increased transport, the larger area of deposition had less accumulation of the sediments (i.e., thinner deposition). When comparing the cumulative and riserless simulations during the fall, the predicted areal extents for all depositional thicknesses were very similar. Depositional thicknesses at or above 0.1 mm were predicted to extend to the southeast up to 2.43 km and cover an area up to 2.14 km² during the fall. Predicted depositional thicknesses at or above 1 mm extended to a maximum of 0.76 km and covered an area no greater than 0.2 km². Depositional thicknesses that reached 1.5 mm in thickness were predicted to extend less than 0.6 km from the well head and cover a maximum area of 0.08 km². The maximum thickness predicted during the fall simulations was 2.64 mm, well below the thresholds of 6.5 and 10 mm, which were never reached.

The variations within predicted model results between the seasonal simulations were due to two main factors including: 1) settling velocity associated with different release substances and 2) current patterns (i.e., velocity, which is composed of speed and direction). The discharges modelled in this study may be considered representative of other potential discharges within the Project Area, as the depth of the sites (approximately 100 m) are similar in depth to other locations within the Project Area. This dispersion modelling targeted the most likely drilling windows for the Project, which were May-June and October-November. Together, both drilling periods consist of representative current regimes for the area and the predicted results could be applicable to timeframes outside of the modelled temporal windows.



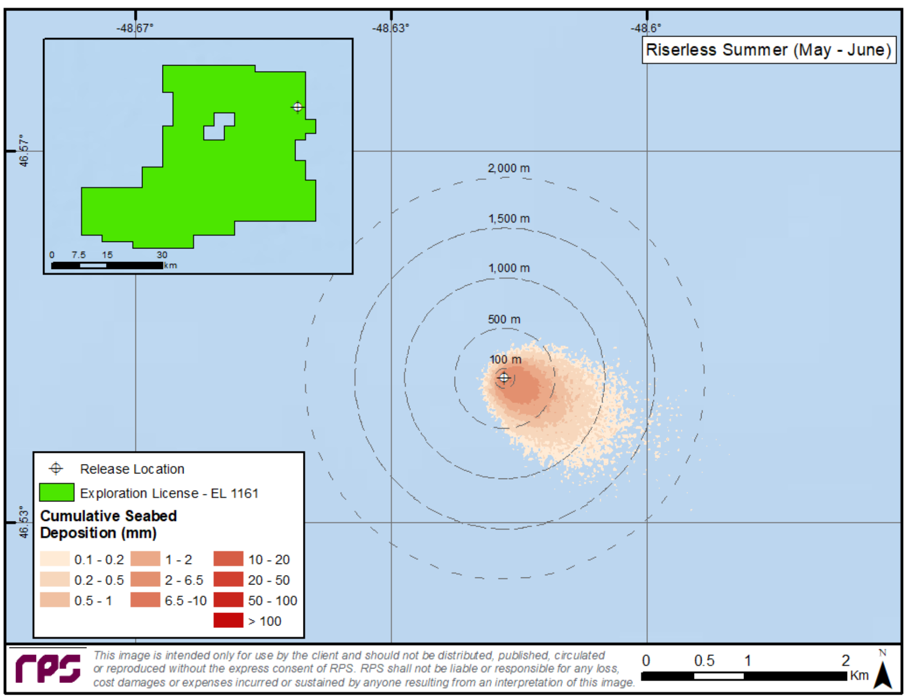
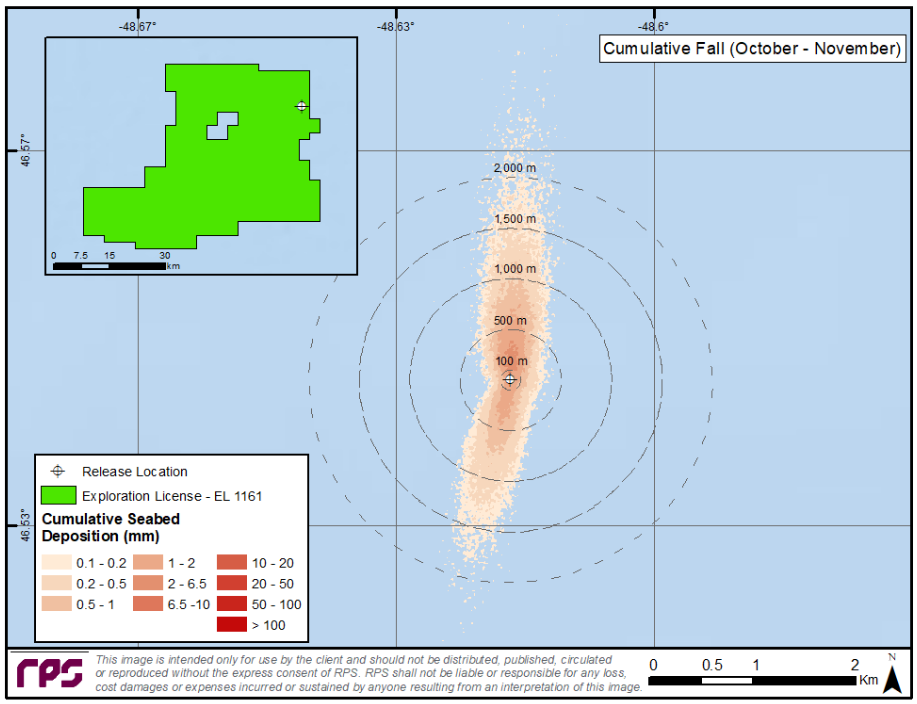


Figure 2-6 Scenario 1: Predicted Thickness of Seabed Deposition of Discharged Mud and Cuttings Resulting from All Drilling Sections (top) and from Only the Riserless Drilling Sections (bottom) during the Summer at EL 1161



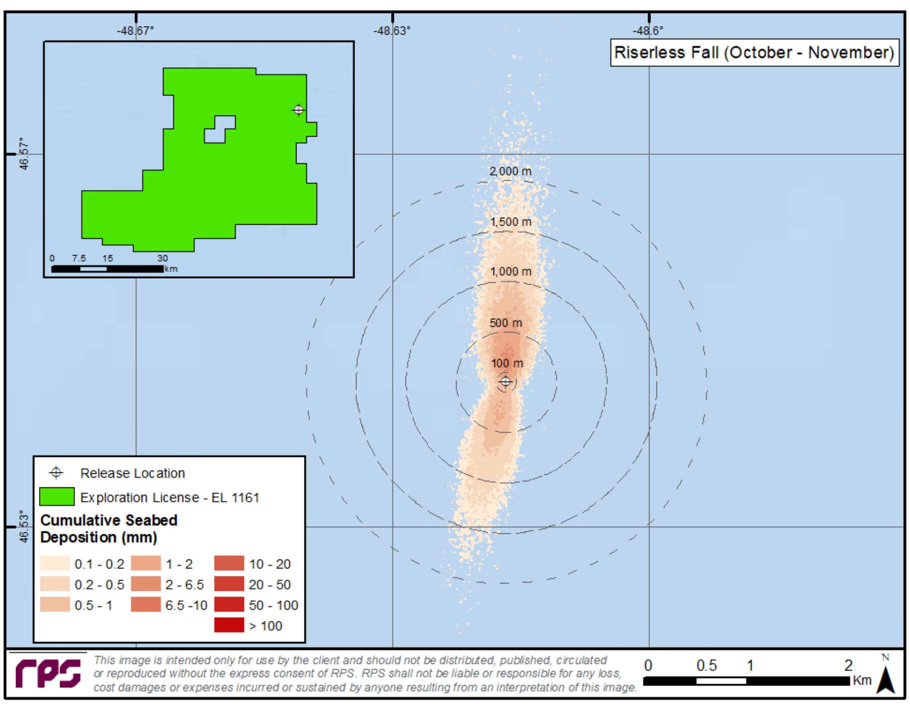


Figure 2-7 Scenario 2: Predicted Thickness of Seabed Deposition of Discharged Mud and Cuttings Resulting from All Drilling Sections (top) and from Only the Riserless Drilling Sections (bottom) during the Fall at EL 1161

The predicted deposition patterns were very different in size, shape, and depositional thickness between the modelled scenarios at EL 1161 (Figures 2-7 and 2-8)). The differences in deposition patterns resulted from differences in metocean conditions between summer and fall scenarios, despite identical release volumes and durations. Additional information on modelling methodology, environmental and engineering data input, and results can be found in Appendix E.

Drilling cement is pumped into the casing / wellbore annulus after the casing is installed. Prior to installation of the marine riser and BOP, excess cement is discharged on the seabed surrounding the wellhead. Cement returned to the drilling unit will be transported back to shore and disposed of at an appropriate facility. During commissioning and testing of a cement unit, small volumes of cement may be discharged into the sea.

Excess cement slurry and drilled (hard) cement may be discharged to the seabed during the initial phases of the well, which will be drilled without a riser. The volume of cement discharged to the seafloor during the riserless sections of the well is expected to be in the range of approximately 8 to 10 tonnes. Once the riser has been installed, cement waste will be circulated back to the MODU. After every cementing operation, the cement unit will be cleaned (rinsed) to prevent cement from hardening in the tanks and lines. Each cleaning operation is estimated to result in a discharge of approximately 2.5 to 5 m^3 of cement slurry from the MODU below the water surface. Unused cement bulks and additives will be transported to shore for future re-use or disposed at an approved facility.

There are no other options for cement management and discharge during the riserless phase of drilling, however, Suncor will use logging techniques to help improve the accuracy of calculations to estimate how much cement is required. This will help to minimize the volume of excess cement. Additionally, Suncor will visually monitor the extent of any discharged excess cement by ROV surveys. An ROV survey will be conducted at the outset of drilling operations, once during drilling operations, and at the end of the drilling program.

2.9.2 Liquid Discharges

Liquid wastes generated from the MODU and/or the supply vessels may include:

- Produced water (if well testing is conducted)
- Bilge and deck drainage water
- Ballast water
- Grey / black water (sewage)
- Cooling water
- Well treatment fluids
- Fire control testing water
- BOP fluid

The OWTG specifies allowable discharge streams and the required properties for their disposal to the marine environment and associated reporting requirements. This may include required sampling and analysis prior to ocean discharge or in-line analyzer monitoring. Where discharges occur offshore, the points of discharge will be typically just below or above the sea surface although specific discharge points will depend on the MODU design. Liquid discharges that do not meet OWTG performance targets for ocean disposal (e.g., including but not limited to waste chemicals, cooking oils, and lubricating oils) are transported back to shore for disposal at an approved licensed disposal facility (Section 2.8.4).

Description of the potential liquid wastes and how they will be managed and disposed is shown in Table 2.8.

Table 2.8 Potential Project-Related Liquid Discharges

Discharge	Source and Characterization	Waste Management
Produced water	Produced water includes formation water encountered in a hydrocarbon bearing reservoir. Produced water would only be produced during well evaluation and testing processes when formation fluids are brought to surface.	Small amounts of produced water may be flared (although Suncor does not anticipate well test flaring for the initial wells). If volumes of produced water are large, some produced water may be brought onto the MODU for shipment to shore or treatment so that it can be discharged according to the OWTG.
Bilge and deck drainage water	Deck drainage is water on deck surfaces of the MODU from precipitation, sea spray or MODU activities such as rig wash-down, or from fire control system or equipment testing. Bilge water is seawater that may seep or flow into parts of the MODU. Water may pass through pieces of equipment into other spaces of the MODU. As it may contact equipment and machinery, deck drainage and bilge water may be contaminated with oil and other chemicals.	Deck drainage and bilge water will be discharged according to the OWTG which state that deck drainage and bilge water can only be discharged if the residual oil concentration of the water does not exceed 15 mg/L.
Ballast water	Ballast water is used in MODU and supply vessels for stability and balance. It is taken up or discharged when the cargo is loaded or unloaded, or when extra stability is needed to manage weather conditions. The water typically does not contain hydrocarbons or chemicals as it is stored in dedicated tanks on the vessel.	Ballast water will be discharged according to IMO *Ballast Water Management Regulations* and Transport Canada's *Ballast Water Control and Management Regulations.* The MODU will carry out ballast tank flushing prior to arriving in Canadian waters.
Grey and black water	Black and grey water will be generated from ablution, laundry and galley facilities onboard the MODU and supply vessels. Grey water will be generated from washing and laundry facilities, and black water includes sewage water generated from the accommodation areas.	Sewage will be macerated prior to discharge in accordance with MARPOL and OWTG.
BOP fluids	The BOP is regularly pressure and function tested. BOP fluids are released directly to the ocean during BOP installation and removal (approximately 23 m^3 per well, over 90 days, during BOP operations and testing activity approximately 1 m^3 per well in the event of non-routine BOP retrieval or riser unlatching (e.g., disconnect for weather – assumed once per well). BOP control fluid would also be discharged to the marine environment if the BOP is activated in response to an emergency event. BOP fluids are typically mixtures of ethylene glycol and water (typically a 30% ethylene glycol solution).	BOP fluids and any other discharges from the subsea control equipment will be screened and discharged according to OWTG and OCSG.

Table 2.8 Potential Project-Related Liquid Discharges

Discharge	Source and Characterization	Waste Management
Cooling water	Cooling water is seawater that is pumped onto the MODU and passed over or through equipment such as machinery engines using heat exchangers. Cooling water may be required on the MODU; however, volumes are likely to be minimal. Water may be treated through biocides or electrolysis prior to use.	Cooling water will be discharged according to the OWTG which states that any biocides used in cooling water are selected according to the OCSG. Cooling water is likely to be warmer than the ambient water temperature upon discharge but will be rapidly dispersed, reaching ambient temperatures.
Well treatment and testing fluids	Well testing may be required as part of the Project to gather information about the subsurface characteristics, or to convert an EL to an SDL. Depending on well success, formation fluids, including hydrocarbons and associated water are likely to be brought to surface during a well test.	Any hydrocarbons, such as gas, oil or formation water that are brought to surface as part of well test activity will be flared for safe disposal. All flaring will be via one of two horizontal burner booms, to either a high efficiency burner head for liquids, or simple open-ended gas flare tips for gases to minimize fall out of un-combusted hydrocarbons. Flaring, if required, will be optimized to the amount necessary to characterize the well potential and as necessary for the safety of the operation.

2.9.3 Hazardous and Non-Hazardous Waste

Hazardous and non-hazardous solid wastes will be generated by Project activities. Waste generated offshore on the MODU and supply vessels will be handled and disposed in accordance with relevant regulations and municipal bylaws. Waste management plans and procedures will be developed and implemented to prevent unauthorized waste discharges and transfers. Nonhazardous wastes may include domestic waste, scrap metal, recyclables, and other miscellaneous non-hazardous wastes. Hazardous wastes (including waste dangerous goods) could include oily waste (filters, rags, waste oil), waste chemicals and containers, batteries, and biomedical waste.

Food wastes and domestic sewage will be macerated in accordance with the OWTG and MARPOL prior to discharge at sea (below the water surface). There will be no discharge of macerated food waste within 3 NM from land. Non-hazardous wastes, such as other domestic wastes, packaging material, scrap metal, and other recyclables such as waste plastic for example, will be stored in designated areas on board the MODU. At scheduled intervals, other solid waste generated offshore will be transferred to the supply vessels so that it can be transported to shore where it will be transferred to a third-party waste management contractor at an approved facility for appropriate treatment and/or disposal in accordance with applicable regulations and municipal by-laws.

Some solid and liquid hazardous wastes are likely to be produced as part of the Project, including oily wastes (e.g., filters, rags, and waste oil), waste chemicals and containers, batteries, biomedical waste, and spent drilling fluids. Biomedical waste will be collected onboard by the medical personnel and stored in special containers before being sent onshore for incineration. Hazardous wastes will be stored dedicated and appropriate waste receptacles in designated areas on the MODU and will be transferred to shore by supply vessel for disposal by a third-party licensed waste management contractor at an approved facility. Transfer of hazardous wastes will be conducted according to the *Transportation of Dangerous Goods Act.*

Any applicable approvals for the transportation, handling, and temporary storage of these hazardous wastes will be obtained as required.

2.9.4 Sound Emissions

Underwater sound will be generated by the MODU and supply vessels, as well as by the air gun source array during VSP operations. The MODU will generate sound continuously during drilling activity, with levels dependent on the specific drilling vessel (e.g., generation of semi-submersible). Anchoring of the MODU will minimize Dynamic Positioning (DP) as a source of underwater sound. Underwater sound would also be generated by supply and standby vessels. In general, the propagation of underwater sound would depend on several factors including water column, water depth, salinity, temperature, and seabed characteristics. The Project Area includes a 40 km buffer around the EL to encompass the area of potential sound interactions, as per previous project assessments in the region.

The acoustic fields modelled in this study were tested against various impact criteria defined in terms of a single event, per-pulse in case of impulsive sources and per-second for non-impulsive sources, and continuous source operation for a specific time period.

All of these modelling assumptions are precautionary in the sense that, while not exemplifying a worse-case scenario, they are nevertheless assuming somewhat more aggressive sound generation than would probably be the case most of the time.

A summary of expected source levels and transmission loss for the MODU, VSP survey, and supply vessels is presented in the following sections; refer to Appendix D for more information.

2.9.4.1 MODU and Supply Vessel Sound Emissions

The MODU and supply vessel operations were modelled for the propagation conditions for the months of February and August.

The source levels were designed to represent operation of the vessels with power output equivalent to operating four of the eight dynamic positioning thrusters (i.e., DP-assisted). The modelling was performed for the frequency range from 10 to 25,000 Hz along 72 transects up to 100 km range from the source. For the simplicity of the interpretation, these sources were modelled as a point source. The thruster-generated sound is non-impulsive and is a continuous noise source.

The injury thresholds ranges from the semisubmersible (MODU) drilling operations (continuous source type) were more impactful for the 24-hour sound exposure level (SEL) criteria than the sound pressure level (SPL-based criteria), for most species. The SEL_{24} injury threshold for low-frequency cetaceans extended to approximately 365 m from the MODU and 145 m for high-frequency cetaceans. The SPL injury criteria threshold extended to less than 20 m. The injury threshold ranges to the other animals were less than 40 m (Table 2.9). The range to the SPL-based behaviour response threshold from the MODU (120 dB) was approximately 75 km in February and 38 km in August, the SEL-based criteria were only a fraction of this (Table 2.9).

Table 2.9 Seadrill West Sirius; Safe Distances (in metres) from the Source to Permanent Thresholds Shift (PTS)- and Temporary Threshold Shift (TTS)-onset Thresholds NMFS (2018) based on the 24-hr Sound Exposure Level Field

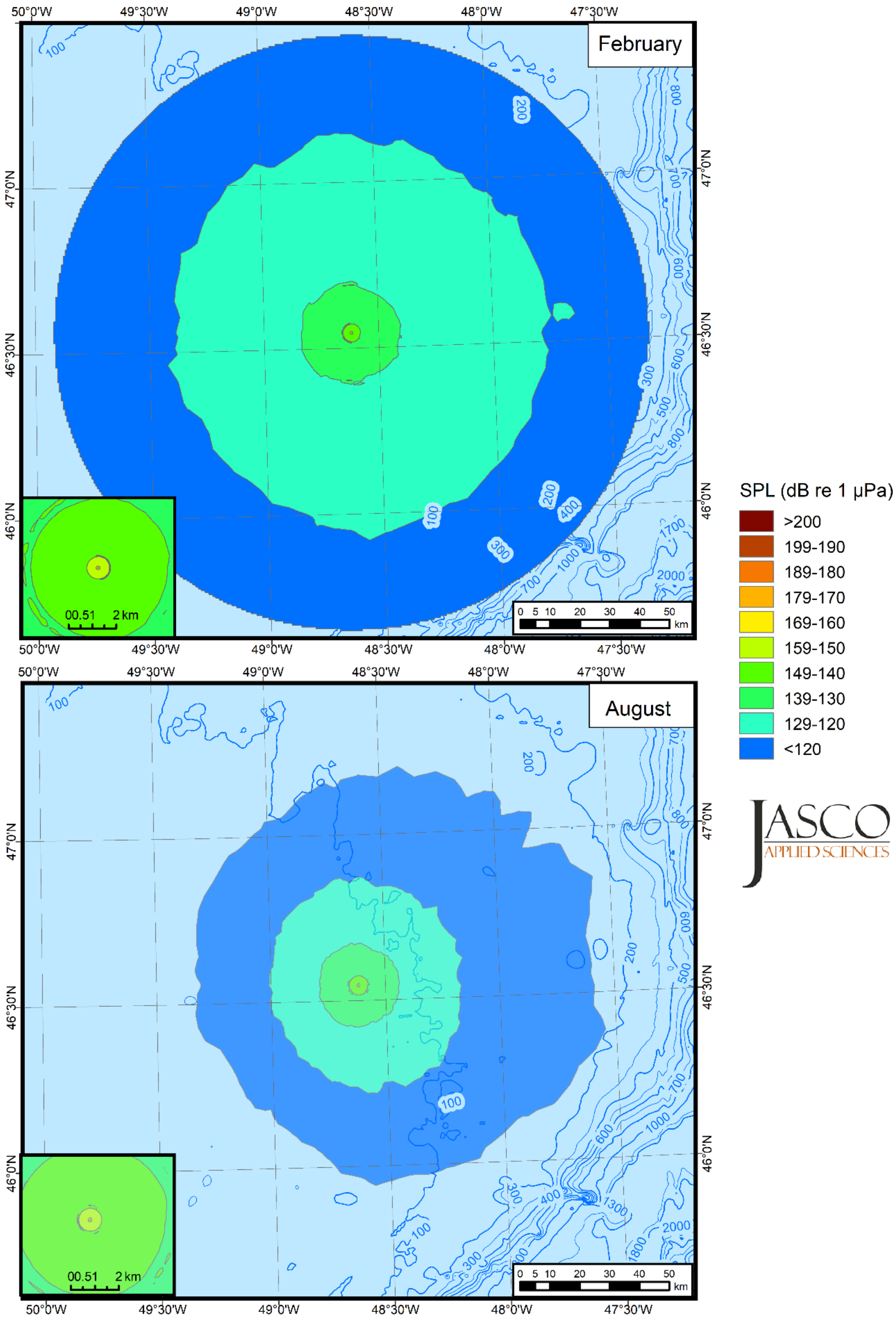
Marine Mammal Group	PTS-onset					TTS-onset				
	SEL (dB re 1 µPa²·s)	February		August		SEL (dB re 1 µPa²·s)	February		August	
		R_{max}	$R_{95\%}$	R_{max}	$R_{95\%}$		R_{max}	$R_{95\%}$	R_{max}	$R_{95\%}$
Low-frequency cetaceans	199	0.364	0.345	0.365	0.351	179	12.2	11.1	10.0	9.93
Mid-frequency cetaceans	198	< 0.014	< 0.014	< 0.014	< 0.014	178	0.108	0.103	0.106	0.103
High-frequency cetaceans	173	0.142	0.139	0.149	0.143	153	3.83	3.60	4.78	4.46
Phocid pinnipeds (underwater)	201	0.036	0.036	0.036	0.036	181	1.40	1.18	1.96	1.84
Otariid pinnipeds (underwater)	219	< 0.014	< 0.014	< 0.014	< 0.014	199	0.045	0.045	0.051	0.051
Thresholds source: National Marine Fisheries Service (NMFS) 2018										

The ranges to the injury thresholds for the support vessel were well under those for the MODU. These typically are between ½ to ¼ of the threshold distance for low-frequency cetaceans and phocid pinnipeds, although more comparable for high-frequency cetaceans. The details can be seen in the previously referenced tables and figures. This is because although the MODU is primarily anchored, the DP-assist uses four of the eight available thrusters; one thruster would be more comparable to a supply vessel. However, the support vessels are modelled as always operating at the same location, which is typical when on standy at the MODU location or offloading and waiting to offload cargo, equipment or passengers, but not when sailing to or from shore.

The contour maps of the estimated acoustic fields in SPL are presented in Figures 2-8 and 2-9.

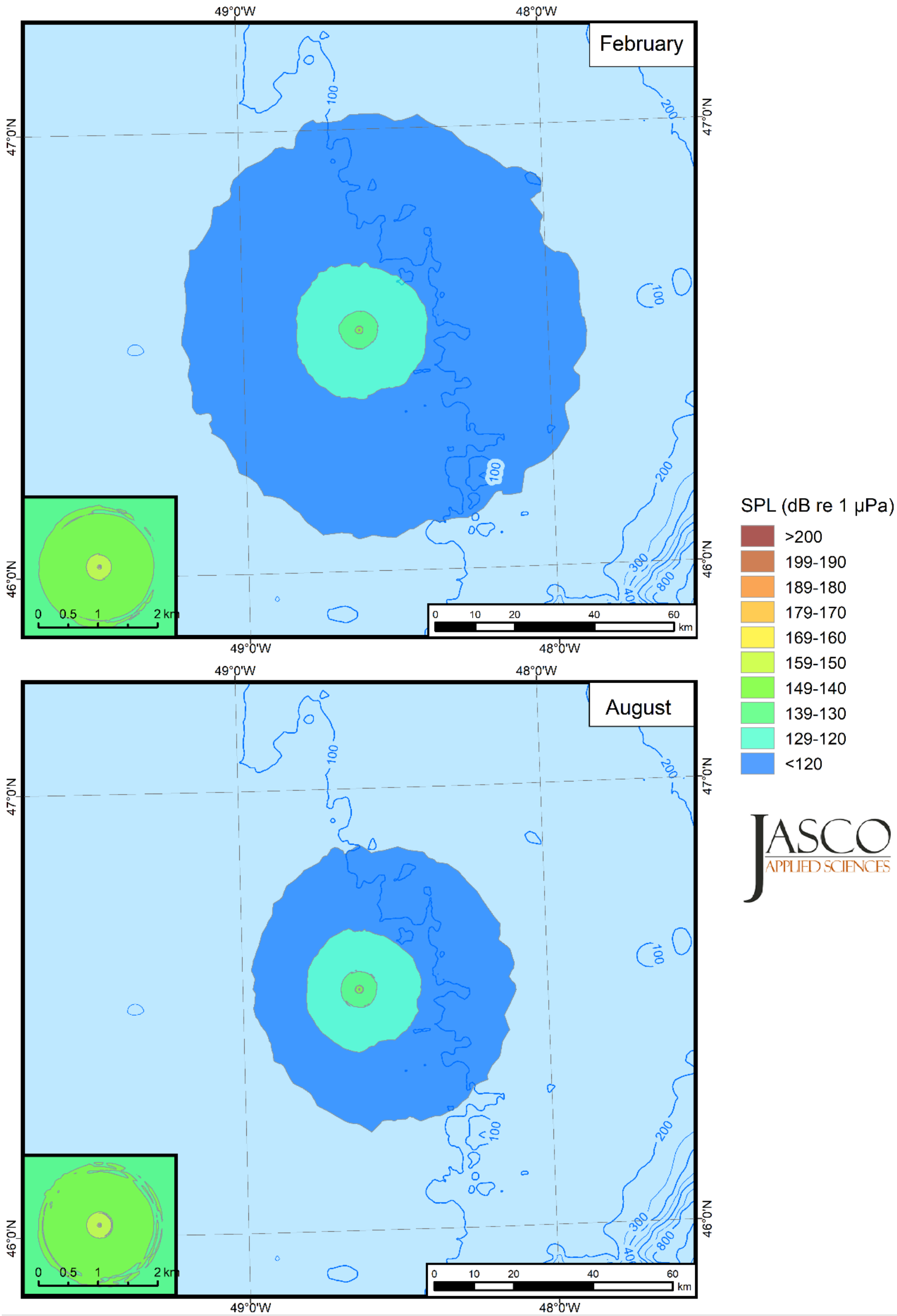
2.9.4.2 VSP Survey Sound Emissions

When applying impact criteria based on the SPL signal metric (NMFS 2018) to the sound field from the seismic (VSP) source (impulsive source type), the ranges from the source to the injury thresholds (in round numbers) were about 82 m and 490 m, for pinnipeds (190 dB) and cetaceans (180 dB), respectively, and 6.50 km to the behavior response threshold (160 dB) for all mammals. The PK-based injury criteria were less impactful, in comparison. The 24-hour SEL-based criteria were also less impactful for this source (Table 2.10) for most species, except for low-frequency cetaceans, which had an injury threshold distance of about 2.5 km in February and 2.2 km in August. A contour map of the maximum-over-depth SPL field around the source is provided in Figure 2-10.



Broadband (10 to 25,000 Hz) maximum-over-depth SPL field. Blue contours indicate water depth in metres

Figure 2-8 Semisubmersible (Seadrill West Sirius)

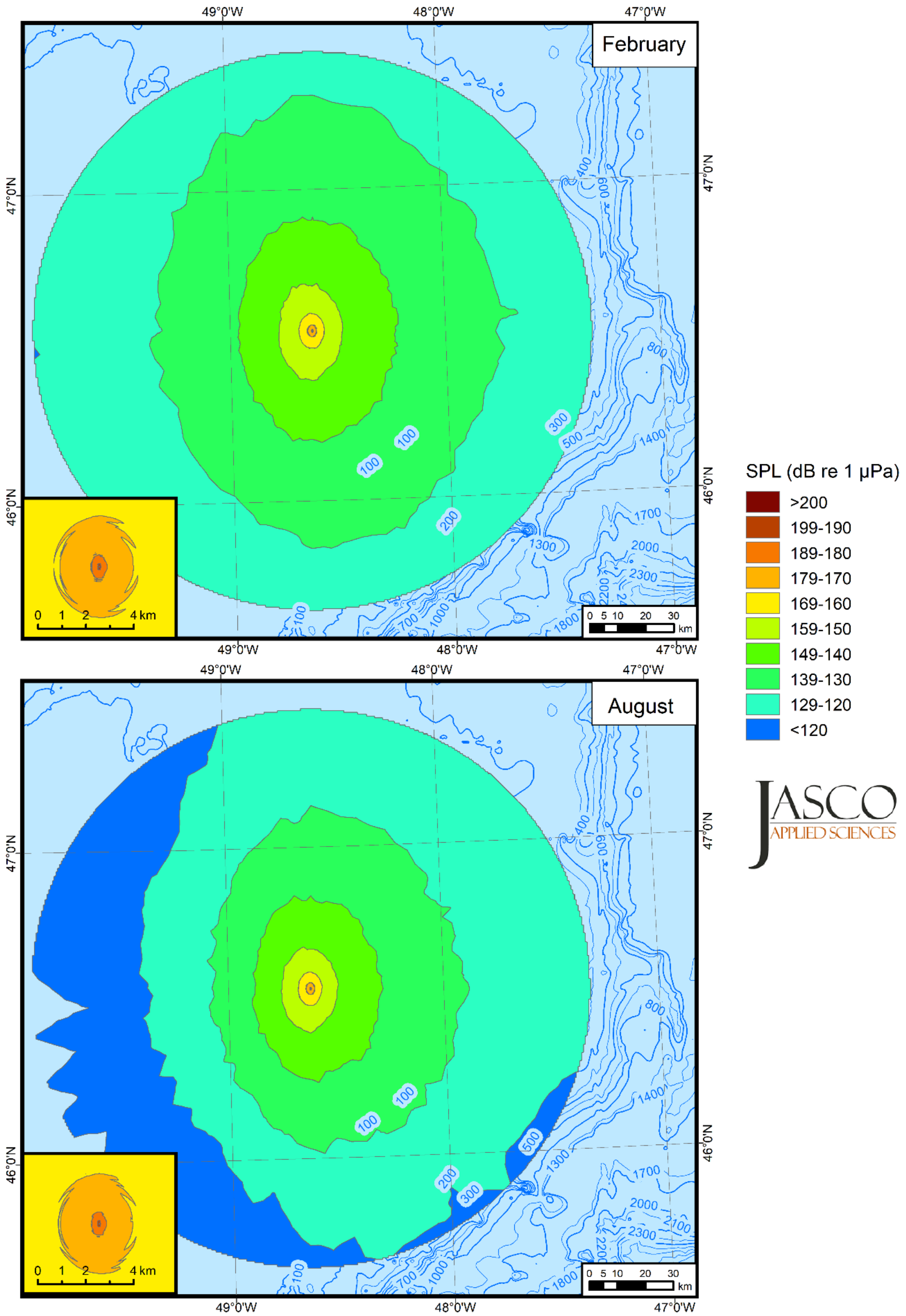


Broadband (10 to 25,000 Hz) maximum-over-depth SPL field. Blue contours indicate water depth in metres.

Figure 2-9 Support Vessel Ops (DVS Fu Lai)

Table 2.10 VSP 1,200 in³ Airgun Array: Maximum (R_{max}, km) and 95% ($R_{95\%}$, km) Horizontal Distances from the Source to PTS-onset and TTS-onset Thresholds based on the 24 hr M-weighted Sound Exposure Level Field

Marine Mammal Group	PTS-onset					TTS-onset				
	SEL (dB re 1 μPa²·s)	February		August		SEL (dB re 1 μPa²·s)	February		August	
		R_{max}	$R_{95\%}$	R_{max}	$R_{95\%}$		R_{max}	$R_{95\%}$	R_{max}	$R_{95\%}$
Low-frequency cetaceans	183	2.45	1.95	2.19	1.88	168	16.6	14.5	15.2	13.0
Mid-frequency cetaceans	185	< 0.010	< 0.010	< 0.010	< 0.010	170	0.014	0.014	0.014	0.014
High-frequency cetaceans	155	0.040	0.036	0.040	0.036	140	0.491	0.411	0.480	0.420
Phocid pinnipeds (underwater)	185	0.073	0.071	0.071	0.063	170	1.37	1.25	1.43	1.26
Otariid pinnipeds (underwater)	203	0.014	0.014	0.014	0.014	188	0.030	0.030	0.030	0.030
Thresholds source is NMFS 2018										



Modelled maximum-over-depth sound pressure level (SPL) field, tow heading of 90°

Figure 2-10 VSP 1,200 in³ Airgun Array

2.9.4.3 Atmospheric Sound

Atmospheric or in-air sound (i.e., sound above the sea surface) is not of particular concern given the relative low level of atmospheric sound sources above sea level and the limited transmission of underwater sound through the air-sea interface. The nearest “residence” to the Project Area would be the Hebron and Terra Nova developments, approximately 9 and 13 km, respectively, from EL 1161. Potential receptors associated with these developments or coastal communities on the island of Newfoundland would not perceive atmospheric sound generated by Project activities due to separation distance.

Helicopter traffic associated with the Project will generate atmospheric sound emissions although the use of an existing operational airport (St. John’s International Airport) will reduce effects on human receptors. Effects of helicopter traffic (including atmospheric sound) on wildlife will be mitigated through avoidance of bird colonies (refer to Section 10.3).

2.9.5 Light and Thermal Emissions

The Project will generate artificial lighting from several sources. Navigation and deck lighting will be operating on the MODU and supply vessel 24 hours a day throughout drilling and supply vessel operations for maritime safety and crew safety.

Flaring activity during well flow testing, if carried out, would generate light and thermal emissions on the MODU. If well flow testing requiring flaring occurs, it will be carried out on a temporary basis at the end of drilling operations. It is possible that there could be several intermittent, short periods of flaring (up to 36 hours) during a one month window at the end of drilling operations. It is expected that well flow testing would only take place on a delineation well drilled after an initial exploration discovery well, and only if the alternative non-flaring wireline methods (MDT or FTWT) were not able to provide sufficient reservoir information (refer to Section 2.4.3 for further information).

The Project will result in increased night-time light levels, particularly within the Project Area where the MODU will be illuminated at night. The night sky in the Project Area is assumed to be a dark-sky site given the distance from offshore platforms and low level of vessel traffic activity in the area.

2.10 Alternative Means of Carrying Out the Project

2.10.1 Options Analysis Framework

Every environmental assessment of a designated project must consider alternative means of carrying out the project that are technically and economically feasible and consider the environmental effects of any such alternative means, as required under Section 19(1)(g) of CEAA 2012.

Consistent with the CEA Agency's (2015) Operational Policy Statement for Addressing “Purpose of” and “Alternative Means” under the *Canadian Environmental Assessment Act, 2012*, the process for consideration of alternative means of carrying out the Project includes the following steps:

- Consideration of legal compliance, technical feasibility, and economic feasibility of alternative means of carrying out the Project

- Description of each identified alternative to the extent needed to identify and compare potential environmental effects
- Consideration of the environmental (including socio-economic) effects of the identified technically and economically feasible alternatives of carrying out the Project; this includes potential adverse effects on potential or established Aboriginal and Treaty rights and related interests (where this information has been provided)
- Selection of the preferred alternative means of carrying out the Project, based on the relative consideration of effects

There are some components of the Project that will be finalized closer to operations. Some options under review will be confirmed to C-NLOPB as part of the OA and ADW process (e.g., wellsite location).

2.10.2 Identification and Evaluation of Alternatives

The EIS Guidelines for the Project (CEA Agency 2019) identify several components for consideration in the alternative means analysis including:

- Drilling fluid selection (e.g., WBM or SBM)
- Drilling unit selection
- Drilling waste management
- Water management and effluent discharge
- Alternative platform lighting options (including flaring) to reduce attraction and potential associated mortality of birds
- Alternative flow testing methods

A consideration of legal compliance, technical feasibility and economic feasibility, as well as the environmental effects (where applicable) of each alternative means is described for each option.

Technical feasibility considers criteria that could influence safe, reliable, and efficient operations. Technology must be available and proven for use in a similar environment and activity set (i.e., offshore drilling in shallow water), and cannot compromise personnel and process safety for it to be considered. Economic feasibility considers capital and operational project expenditure. Project expenditure can be impacted directly (e.g., equipment and personnel requirements) and indirectly (e.g., schedule delays).

Each option for the alternative means identified above is summarized in a tabular format. The preferred alternative means form the basis for the Project to be assessed (i.e., assumed to be the base case that is assessed for environmental effects in Chapters 8 to 14 of this EIS).

2.10.2.1 Drilling Fluids Selection

The Project could use both WBM and SBM when drilling the exploratory wells. Drilling fluids are specifically formulated according to the well design and the expected geological conditions. In general, SBM can enable more efficient drilling operations than WBM when drilling through challenging geological conditions, including areas containing hydrate shales, or zones of potential high pore pressure. Both WBM and SBM are acceptable according to local regulations, provided that the components of the drilling fluids are selected according to criteria of the OCSG and their disposal is carried out according to the OWTG.

A summary of the comparison between WBM and SBM is presented in Table 2.11. The preferred option is to use both WBM and SBM while drilling different sections of the well considering the technical and economic advantages of using SBM, while recognizing it cannot be used to drill riserless sections of the well. The EIS therefore considers the use of both WBM and SBM in the effects assessment.

Table 2.11 Summary of Drilling Fluid Alternatives Analysis

Option	Legally acceptable?	Technically feasible?	Economically feasible?	Environmental Issues	Preferred Option
SBM only	**No**	Yes	Yes	SBM is not permitted for ocean discharge without treatment, therefore SBM cannot be used for riserless drilling where the cuttings are disposed directly on the seafloor	Not preferred
WBM only	Yes	Yes – although potential challenges with borehole stability	Yes – although potential increased cost from non-productive time and losses	No substantial difference between options. Both are considered acceptable provided that appropriate controls are in place and chemicals are selected in accordance with OCSG (EIS considers both WBM and SBM in effects assessment)	Not preferred
WBM / SBM hybrid for different sections	Yes	Yes	Yes		Preferred

2.10.2.2 Drill Unit Selection

As indicated in Section 2.3.1, only one type of drilling unit may be suitable for offshore drilling in this Project: a semi-submersible rig. A jackup rig is not under consideration due to the metocean conditions of the offshore Newfoundland and Labrador area.

The MODU that will be used to drill the wells for the Project has not yet been selected. Section 2.3.1.1 describes the MODU selection and approval process. Semi-submersible MODUs are considered a technically and economically feasible option. Jackup MODUs would have comparable environmental effects and are economically feasible, however, they are not considered technically feasible due to the potential for rig damage and risk to personnel during severe metocean conditions. Therefore, this EIS considers only the semisubmersible option in the effects assessment. Table 2.12 summarizes the comparison of drilling unit options.

Table 2.12 Summary of Drilling Unit Alternatives Analysis

Option	Legally acceptable?	Technically feasible?	Economically feasible?	Environmental Issues	Preferred Option
Semi-submersible Rig	Yes	Yes	Yes	Both options are considered to be environmentally acceptable and would have comparable environmental effects in terms of lighting, emissions and discharges, and underwater sound	Preferred
Jackup Rig	Yes	No	Yes		Not Preferred

2.10.2.3 Drilling Waste Management

There are three main drilling waste management options for consideration:

- Disposal at sea
- Offshore reinjection
- Ship-to-shore for onshore treatment/disposal

If different drilling fluids are used to drill different sections of the well, it is likely that a combination of drilling waste management options will be used. Ocean disposal of WBM and SBM drilling waste (including required onboard treatment prior to disposal where applicable) is described in Section 2.8.2.

An alternative method of offshore disposal is cuttings reinjection. Reinjection involves creating a cuttings slurry (i.e., mixing them with a liquid) and then pumping the slurry into a dedicated well designed for reinjection. Under pressurized conditions, cuttings pass into targeted formations down the well. Offshore injection of cuttings from fixed wellhead platforms is well proven, however the potential for subsea injection from MODUs is limited. The subsea injection equipment is very specialized (i.e., it requires a flexible injection riser and a specially designed wellhead).

For onshore disposal, cuttings are shipped to shore by supply vessel and then transported to an approved waste management facility for treatment and disposal. There are no approved treatment facilities for SBM waste in Newfoundland and Labrador, therefore the waste would have to be transported out of province. Ship-to-shore treatment of waste reduces offshore effects associated with drilling waste discharge. However, additional effects due to increased transportation (e.g., atmospheric emissions) and onshore treatment and disposal (e.g., habitat alteration) will be introduced instead. Ship-to-shore options are expected to be more expensive than the offshore options due to additional transportation costs. In general, ship-to-shore and associated onshore disposal presents a potentially higher operational risk option as it is dependent on several external factors, specifically onshore waste management facility availability and supply vessel availability. Supply vessel transit may be affected by poor weather conditions, which could impact their ability to collect cuttings on a regular basis from the MODU. If cuttings cannot be removed from the MODU, drilling operations may have to be suspended. There is also additional health, safety and environmental risk introduced with respect to onshore disposal due to additional truck and vessel traffic, and additional exposure and handling of material.

Discharge to the water column following treatment (where applicable) to OWTG standards is the preferred option for cuttings generated as part of the Project and has been assessed as part of the Project (refer to Chapter 9). As noted in Section 2.4.1, during the riserless phase there is no mechanism to return cuttings to the MODU, therefore WBM cuttings and any associated fluid will be discharged at the seafloor as permitted by the OWTG.

This analysis of alternative means for drilling waste management is summarized in Table 2.13.

Table 2.13 Summary of Drilling Waste Management Alternatives Analysis

Disposal Option	Legally acceptable?	Technically feasible?	Economically feasible?	Environmental Issues	Preferred Option
Discharge to water column (following treatment of SBM on cuttings)	Yes	Yes	Yes	Some localized effects are expected on the seafloor from discharge of cuttings (assessed in Section 8)	Preferred
Offshore Reinjection	Yes	No	Not considered as option because not technically feasible		Not preferred
Ship-to-shore (SBM-associated cuttings)	Yes	Yes	Yes – but increased costs from increased transportation and operational delays	Some limited offshore effects are expected from increased transportation, and some onshore effects from transportation and onshore disposal of waste including increased health, safety and environment risks associated with truck and vessel traffic and exposure and handling of waste material	Not preferred

2.10.2.4 Water Management

Section 2.8.3 describes effluent discharges that will be generated on the MODU. Liquid wastes not approved for discharge in the OWTG, including but not limited to waste chemicals, cooking oils, and lubricating oils, will be transported onshore for transfer to an approved disposal facility. Liquid wastes that conform to the OWTG will be discharged from the MODU to the marine environment from effluent discharge points just below or above the sea surface. Specific discharge points will depend on the MODU design; these locations are fixed and cannot be re-configured. Prior to the commencement of drilling program, a Certificate of Fitness will be obtained for the MODU from an independent third-party Certifying Authority (refer to Section 1.5.1) that will include confirmation that effluent discharge and water management systems comply with relevant legislation.

2.10.2.5 Offshore Vessel Lighting

Navigation and deck lighting will be used 24 hours a day on the MODU and the supply vessels throughout drilling and supply vessel operations for maritime safety and crew safety. Lighting is required under Canadian and international law to reduce the risk of collisions between offshore vessels.

Alternative MODU lighting techniques have been tested elsewhere in the industry. In the North Sea, spectral modified lighting has been tested on offshore platforms and has demonstrated a reduced effect on marine birds, particularly the use of green and blue light (Marquenie et al. 2014). Spectral modified lighting has satisfied regulatory requirements in a number of regions, including in the Netherlands, Germany and in the United States. However, implementation in the offshore oil and gas industry has been restricted by commercial availability, limited capability in extreme weather, safety concerns around helicopter approach and landing, and lower energy efficiency (Marquenie et al. 2014). Suncor will continue to evaluate the commercial availability and readiness of spectral modified lighting over the term of the project.

Suncor will lease the MODU and supply vessels chosen to support Project-related exploration drilling activities and has not yet made any direct inquiries with vendors regarding the availability of spectral modified lights for use in association with the Project. The MODU used for the Project will be an existing drilling unit contracted through a third-party drilling contractor and selected based on technical capabilities as well as safety considerations. Suncor is not aware of any operating MODUs currently equipped with spectral modified lighting that have the technical capability to support the Project.

Options to reduce lighting on the MODU as far as practicable will be considered. However, it will be maintained at a level that will not impede the safety of the workforce or drilling operations (see Table 2.14). The EIS considers the environmental effects associated with standard MODU lighting (refer to Chapter 9).

Table 2.14 Summary of Lighting Alternatives Analysis

Option	Legally acceptable?	Technically feasible?	Economically feasible?	Potential Environmental Issues	Preferred Option
Standard MODU lighting	Yes	Yes	Yes	Some localized visual effect is expected which could affect migratory birds (assessed in Section 9)	Preferred
Reduced Lighting (i.e., during nighttime or inclement weather)	Yes	Yes	Yes	Options to reduce lighting on the MODU as far as practicable will be considered. However, it will be maintained at a level that will not introduce safety risks for the workforce or drilling operations	Preferred
Spectral modified lighting	Yes	No – currently limited capabilities in extreme weather; safety concerns with helicopter approach and landing	No – not considered as commercially viable yet	Not considered as option because not feasible	Not preferred (preferred if available)

2.10.2.6 Flaring and Alternative Testing Methods

Flaring, if required, will contribute to platform lighting and potential attraction of birds. Well testing may be required by the C-NLOPB for formation evaluation, and may be used to declare a significant discovery or to convert an EL to an SDL, but non-flaring methods may also be used for this purpose (refer to Section 2.4.3 for more information on well testing). When well flow testing is carried out via Drill Stem testing, flaring is required to safely dispose of hydrocarbons that come to surface.

If flaring is required, an alternative option could be to manage the timing of flaring activity. Flaring could be planned such that it does not begin during periods of poor visibility including at night or during inclement weather to reduce light generated during flaring. However, once the well test with flaring begins, data gathered during the well test could be compromised if the well flow was restricted during this test period (i.e., restricted to certain weather conditions).

Flaring, if required, is expected to be brief and intermittent in nature (lasting up to 36 hours at a time) and could occur several times in the well flow test period, which in total is expected to last one month. If Suncor intends to flare, it will notify the C-NLOPB in accordance with "Measures to Protect and Monitor Seabirds in Petroleum-Related Activity in the Canada-Newfoundland and Labrador Offshore Area" (C-NLOPB n.d.). Suncor will use a water curtain to protect personnel and equipment on the MODU by limiting the transfer of radiated heat from the flare, thereby mitigating risk of fire. A secondary benefit of a water curtain may be potential deterrence of birds from the general vicinity of the flare based on the positioning of the water curtain. A water curtain could be considered a technically and economically feasible option as a flare shield to reduce adverse effects of flaring on birds.

Alternatives to well testing that do not require flaring are MDT and FTWT (Table 2.15). The analysis of Project effects (refer to Chapter 8) assumes there will be flaring during well testing. However, Suncor will fully investigate alternative non-flaring well testing methods for their applicability to the Project prior to use of well testing with flaring.

Table 2.15 Summary of Flaring Alternative Analysis

Disposal Option	Legally acceptable?	Technically feasible?	Economically feasible?	Environmental Issues	Preferred Option
No flaring during DST	**No**	Not considered as option due to regulatory and safety requirements; Industry continues to advocate for alternative methods, which in some cases have been deemed acceptable to obtain an SDL.			Preferred
Reduced flaring (i.e., no flaring during nighttime DST or inclement weather)	Yes	Yes – although activity could give result to compromised data	Yes – but increased MODU costs and risk of delays	Reduced flaring would still result in some measure of light and atmospheric emissions	Not preferred

Table 2.15 Summary of Flaring Alternative Analysis

Disposal Option	Legally acceptable?	Technically feasible?	Economically feasible?	Environmental Issues	Preferred Option
Formation testing while tripping / Interval Pressure Transient Testing and Modular Dynamic Testing	Yes	Yes, although technically inferior as may not fulfill C-NLOPB data requirements in all cases	Yes, although economically superior , associated with inferior data collection	No flaring and therefore reduced atmospheric emissions and light, resulting in reduced risk of bird attraction and mortality	Preferred
DST Flaring as required with flare shield (water curtain)	Yes	Yes	Yes	Some limited offshore effects are expected from the light and atmospheric emissions generated during flaring. These are expected to be intermittent and brief in duration over a temporary period at the end of drilling (assessed in Section 9)	Preferred (if flaring is required)

2.10.3 Chemical Management

The details of chemicals to be used in the Project have not yet been confirmed and potential alternatives have not yet been identified. A drilling fluid and cementing contractor for the Project has not yet been selected, and the drilling fluid basis of design for the wells is under development. As planning for the Project continues, chemical management and selection processes will be followed to define the ways in which chemicals will be chosen and used.

Chemical management processes will be defined prior to the start of any drilling activity and will be conducted in accordance with applicable legislation as summarized in Table 2.16.

At a minimum, drilling chemicals will be selected in accordance with the OCSG. The OCSG establishes a procedure and criteria for offshore chemical selection. The objective of the guidelines is to promote the selection of lower toxicity chemicals to minimize the potential environmental impact of a discharge where technically feasible. Furthermore, Suncor will document the process used to evaluate prospective chemicals.

Table 2.16 Applicable Offshore Chemical Management Legislation and Guidelines

Legislation	Regulatory Authority	Relevance
Canadian Environmental Protection Act, 1999 (CEPA)	ECCC	Provides for the notification and control of certain manufactured and imported substances. The Domestic Substances List is a list of substances approved for use in Canada. Schedule 1 includes a list of substances that are considered toxic and subsequent restrictions or phase out requirements
Fisheries Act	DFO, ECCC	Prohibits the deposition of toxic or harmful substances into waters containing fish
Hazardous Product Act	Health Canada	Standards for chemical classification and hazard communication
Migratory Birds Convention Act, *1994* (MBCA)	ECCC	Prohibits the deposition of harmful substances in waters or areas frequented by migratory birds
Pest Control Products Act	Health Canada	Regulates the importation, sale and use of pest control products, including products used as biocides offshore
Offshore Chemical Selection Guidelines (OCSG)	C-NLOPB	Framework for the selection of drilling and production chemicals for use and possible discharge in offshore areas

2.10.3.1 Proposal of Use: Initial Screening and Regulatory Controls Identification

A screening of the proposed chemical will be carried out to determine if it is restricted through any of the other elements of legislation. This includes specific aspects of the use of the chemical, including likely volume demand and discharge assumptions.

In accordance with the regulations, certain restrictions, controls and prohibitions, in agreement with applicable regulatory agencies, will be placed on:

- Chemicals that will be used as a biocide
- Chemicals that have not been approved for use in Canada previously (i.e., are not registered on the Domestic Substances List) or have not been used previously for the purpose which is proposed
- Chemicals that have been identified as toxic under Schedule 1 of CEPA. In the event that a chemical is proposed for use that is listed under Schedule 1 of CEPA, Suncor will consider alternative means of operation and/or will evaluate less toxic alternatives

2.10.3.2 Chemicals Intended for Marine Discharge: Toxicity Assessment

Following the initial screening activity to identify any restrictions, controls, and prohibitions on proposed chemicals, a further assessment for chemicals that will be discharged to the marine environment will be conducted. This assessment will evaluate the potential toxicity of proposed chemicals (and any constituents of the chemical as applicable) and determine if additional restrictions, controls, or prohibitions are required.

In accordance with the OCSG chemical selection framework, any chemicals intended for discharge to the marine environment shall be reviewed against several criteria. Chemicals that are intended for discharge to the marine environment must:

- Be included on the OSPAR PLONOR list
- Meet certain requirements for hazard classification under the United Kingdom OCNS
- Pass a Microtox test (i.e., toxicity bioassay)
- Undergo a chemical-specific hazard assessment in accordance with the OCNS model
- Have the risk of its use justified through demonstration to the Board that discharge of the chemical will meet OCSG objectives

Suncor will ensure each criterion is reviewed including:

- <u>OSPAR PLONOR List</u>: If a proposed chemical is included on the OSPAR PLONOR list, it will be considered acceptable for use and discharge in line with OCSG.
- <u>OCNS Hazard Classification</u>: If use of a chemical that will be discharged to the marine environment is proposed and it is not included on the OSPAR PLONOR list, the hazard classification will be reviewed in line with the OCNS. This scheme ranks chemical products according to a hazard quotient (HQ) based on a range of physical, chemical and ecotoxological properties of products, including toxicity, biodegradation, and bioaccumulation information.
- <u>The Chemical Hazard and Risk Management model</u> is used to determine the HQ which is subsequently used to rank chemicals into groups, linked to their expected hazard rating. If the chemical that is proposed for use is ranked as being least hazardous under the OCNS scheme (i.e., C, D, or E, gold or silver), Suncor will consider the chemical acceptable for use and discharge in line with the OCSG.
- <u>Risk Justification</u>: Where a chemical is identified for potential use which is not ranked as C, D, or E, or gold or silver under the OCNS scheme, alternative means of operation will be considered, and/or less toxic alternatives evaluated. If it is not possible to identify alternatives, Suncor will conduct a hazard assessment to determine its suitability of use in line with the OCSG. The hazard assessment process will be documented and will be provided to the C-NLOPB to allow them to evaluate whether that the objectives of OCSG have been met.
- <u>Microtox Test and Chemical-Specific Hazard Assessment</u>: If a chemical is proposed for use which does not have an OCNS rating, Suncor will work with the chemical contractors to carry out a Microtox test to determine the potential toxicity of the chemical. If the chemical passes the test and is considered non-toxic, restrictions will be placed on discharge volumes and time limits in line with the OCSG. If the chemical does not pass the test, it will be subject to a hazard assessment as per OCSG to determine suitability for use.

The OCSG apply to the following categories of chemicals which could be used as part of the Project:

- Drilling fluids, including sweeps and displacement fluids
- Cementing
- BOP fluids
- Remotely operated vehicles fluids greases and hydraulic fluids used to control wellheads and blowout preventers
- Chemicals used in the actual production of hydrocarbons, those generated offshore (such as sodium hypochlorite)

The OCSG do not apply to the following categories of chemicals:

- The selection of domestic chemicals and other chemicals that are used on an installation that are not directly associated with drilling activities, such as those used for accommodations, catering, equipment and facility maintenance (e.g., lubricants, paints, etc.), safety systems and laboratory operations
- The selection of chemicals that are used on supply vessels and helicopters

The specific types and volumes of chemicals to be used are not currently known. A Safety Data Sheet (SDS) will be available for chemicals present on the supply vessels and MODU. The inventory of chemicals on board the MODU will be monitored regularly and an annual report will be submitted to the C-NLOPB to outline each chemical used including the hazard rating, quantity used, and its ultimate fate.

2.11 Environmental Management

2.11.1 Suncor's Operational Excellence Management System

The execution of the Project will be conducted in a manner fully consistent with Suncor's Operational Excellence Management System (OEMS), which is Suncor's enterprise-wide management system that organizes and links standards, systems and processes required to manage operational risks, prevent and mitigate environmental impacts and deliver safe, reliable operations. OEMS is based on the Plan-Do-Check-Act continual improvement cycle and follows the internationally recognized management system standards and specifications ISO 14001 and ISO 9001.

The OEMS sets high-level, company-wide mandatory management system requirements with respect to the foundational non-financial risk management processes necessary for a business to achieve operational excellence. Each element of Suncor's OEMS describes the company-wide requirements and expectations for managing operational and asset integrity risks inherent in the business.

Each business area within Suncor accepts responsibility for managing the impact of its activities and products on people, the environment, property and corporate assets. To accomplish this, senior leaders in each organizational and functional unit must:

- Develop, implement, and maintain appropriate systems, processes, procedures, and tools to enable organizational units to meet the OEMS requirements;
- Understand the operational risks associated with its activities and products;
- Regularly report performance against defined objectives and specific performance measures;
- Seek input and feedback from internal and external stakeholders;
- Self-assess and audit the integrity and effectiveness of its systems against OEMS requirements; and
- Identify opportunities for continual improvement.

Risk factors and business requirements within some of Suncor's organizational units will require the development and implementation of issue-specific, dedicated systems, programs and models such as:

- Process Safety Management Program - systems and controls that ensure process hazards are identified, understood, and controlled;
- Suncor's Asset Development and Execution Model - a framework for consistent development and sustainment of physical assets consisting of an integrated 5-stage gate process supported by solid project governance;
- Suncor's Well Delivery Model - the end-to-end process that takes well planning developed as part of the Evaluate Exploration Acreage and Evolve Life of Field Concepts processes and delivers a new well, and abandonment of a well;
- Business unit or business area specific management systems [e.g., East Coast Management System Manual (OD-PE-QM04-X00-001)].
- Programs to ensure the effective implementation of Operational Excellence during non-routine projects.

Through OEMS, Suncor has implemented numerous measures intended to reduce the environmental, health, safety, navigational and aesthetic impacts. Examples of these programs include but are not limited to:

- Completion of regulatory consultations to ensure regulatory expectations and requirements are understood and implemented into project planning, including obtaining necessary regulatory authorizations and permits;
- Development and implementation of Environmental Protection Plans for Suncor's East Coast operations that include procedures relating to chemical management, effluent discharges, waste management, seabird handling / release and rehabilitation, oil spill response, Indigenous and fisheries liaison, compensation, and communication plans, and monitoring;
- Development and implementation of a Safety Plan that outlines organizational structure, roles and responsibilities, risk management procedures, legal and other requirements, environmental and health and safety commitments, goals and targets, management of change, learning and competence, contractor management including vessel selection and audit process, emergency management and response procedures, quality management processes, bridging processes to contractor management systems, diving procedures, vessel mobilization procedures, and safety meetings;
- Completion of risk management processes such as Process Hazard Analyses and Hazard Identification and Risk Assessment when required;
- Implementation of emergency management procedures relating to oil spill response, crisis management, operational emergencies, security and business continuity;
- Implementation of simultaneous operations procedures to ensure identification of Terra Nova Field control and coordination of vessels working in and around the Field.

2.11.2 Environment, Health and Safety Management Planning

In accordance with corporate and regulatory requirements, Suncor will develop environmental management plans to verify that appropriate measures and controls are in place to reduce the potential for environmental effects as well as to provide clearly defined action plans and emergency response procedures to protect human and environmental health and safety.

2.11.3 Standard Mitigative Measures and Best Practices

Given the history of exploration and production projects offshore Newfoundland and Labrador, most potential environmental interactions and mitigation measures are well understood. Many potential adverse environmental effects identified in this EIS can be managed effectively with standard operating procedures and standard mitigation measures, many of which are captured in Suncor's own policies and procedures and/or regulatory guidelines. The offshore regulatory framework administered by the C-NLOPB was described in Section 1.5. Adherence to key guidelines such as the OWTG and OCSG, along with MARPOL requirements, will reduce or eliminate adverse environmental effects of waste discharges on the marine environment. Adherence to the Statement of Canadian Practice with respect to the Mitigation of Seismic Sound in the Marine Environment (DFO 2007) during VSP surveys will reduce adverse environmental effects on marine fish, mammals and sea turtles. Where necessary, site- or Project-specific mitigation measures have also been proposed in this EIS.

Suncor will implement general standard mitigation measures on this Project including those listed in Table 2.17. Additional mitigation measures specific to valued components (VCs) assessed in this EIS are presented in Chapters 8 to 14. Spill prevention and response measures are discussed in Chapter 16.

Table 2.17 Standard Mitigation Measures

General
Contractors and subcontractors will be required to demonstrate conformance with the requirements that have been established, including EH&S standards and performance requirements.
A Certificate of Fitness will be obtained for the MODU from an independent third-party Certifying Authority prior to the commencement of drilling operations in accordance with the *Newfoundland Offshore Certificate of Fitness Regulations*.
The observation, forecasting and reporting of physical environment data will be conducted in accordance with the *Offshore Physical Environment Guidelines* (NEB et al. 2008).
Suncor and contractors working on the Project will regularly monitor weather forecasts to forewarn supply vessels, helicopters and the MODU of inclement weather or heavy fog before it poses a risk to their activities and operations. Extreme weather conditions that are outside the operating limits of supply vessels or helicopters will be avoided, if possible. Captains / Pilots will have the authority and obligation to suspend or modify operations in case of adverse weather or poor visibility that compromises the safety of supply vessel, helicopter, or MODU operations.
Suncor will prepare and submit an Ice Management Plan as part of the application for Drilling Program Authorization as per the *Offshore Physical Environment Guidelines* (NEB et al. 2008). This Plan, which will form part of the Safety Plan submission, will include details on sea ice / iceberg monitoring and detection, and risk assessment, mitigation, and contingency procedures.
Safe work practices will be implemented to reduce exposure of personnel to lightning risk (e.g., restriction of access to external areas on the MODU or supply vessel during thunder and lightning events).
Prior to any drilling activity, Suncor will conduct a geohazard assessment for proposed wellsites.
Project-related damage to fishing gear, if any, will be compensated in accordance with the *Compensation Guidelines with Respecting Damages Relating to Offshore Petroleum Activity* (C-NLOPB and CNSOPB 2017b).
The Project will operate in accordance with all applicable regulations.
Presence and Operation of the MODU
A safety zone will be established around the MODU in accordance with the *Newfoundland Offshore Petroleum Drilling and Production Regulations* SOR/2009-316.

Table 2.17 Standard Mitigation Measures

Suncor will provide details of the safety zone to the Marine Communication and Traffic Services for broadcasting and publishing in the Notices to Shipping and Notices to Mariners. Details of the safety zone will also be communicated during ongoing engagement with commercial and Indigenous fishers.
To maintain navigational safety at all times during the Project, obstruction lights, navigation lights and foghorns will be kept in working condition on board the MODU and supply vessels. Radio communication systems will be in place and in working order for contacting other marine vessels as necessary.
The MODU will be equipped with local communication equipment to enable radio communication between the supply vessels and the MODU's bridge. Communication channels will also be put in place for internet access and enable communication between the MODU and shore.
Suncor will conduct an imagery-based seabed survey at the proposed wellsite(s) to confirm the absence of shipwrecks, debris on the seafloor, unexploded ordnance, and sensitive environmental features, such as habitat-forming corals or sponges. The survey will be carried out prior to drilling and will encompass an area within a 500-m radius from the wellsite. If any environmental or anthropogenic sensitivities are identified during the survey, Suncor will notify the C-NLOPB immediately to discuss an appropriate course of action. This may involve further investigation and/or moving the wellsite if it is feasible to do so.
Artificial lighting will be reduced, where possible with consideration of safety and associated operational requirements. Lighting reductions may include avoiding use of unnecessary lighting, shading, and directing lights towards the deck.
Geophysical (including VSP), Environmental and Geotechnical Surveys
VSP activities will be planned and conducted in consideration of relevant regulations and guidance including the Statement of Canadian Practice with Respect to the Mitigation of Seismic Sound in the Marine Environment (SOCP) (DFO 2007) and C-NLOPB Geophysical, Geological, Environmental and Geotechnical Program Guidelines (C-NLOPB 2019).
Passive acoustic monitoring will be implemented, or equivalent technology, and visual monitoring by marine mammal and sea turtle observers during vertical seismic surveys.
Well Testing and Flaring
High-efficiency burners (flare tip) will be used when flaring is required, if available.
Well testing, if carried out, will be subject to Suncor's well test assurance process, which is designed to promote safe and efficient well test operations.
Alternative testing methods that do not involve flaring will be fully investigated for their applicability and use as a preferred method to flaring.
Discharges
Air emissions from the Project will adhere to applicable regulations and standards.
Offshore waste discharges and emissions associated with the Project (i.e., operational discharges and emissions from the MODU and supply vessels) will be managed in accordance with relevant regulations , such as the OWTG and MARPOL, of which Canada has incorporated provisions under various sections of the *Canada Shipping Act*. Waste discharges not meeting legal requirements will not be discharged to the ocean and will be brought to shore for disposal. Furthermore, a Project-specific EPP and waste management plan will be developed to prevent unauthorized waste discharges (refer to Section 2.10 for details on waste discharges and management).
Selection and screening of chemicals to be discharged, including drill fluids, will be in accordance with the *Offshore Chemical Selection Guidelines* (NEB et al. 2009). Where feasible, lower toxicity drilling muds and biodegradable and environmentally friendly muds and cements will be used. The chemical components of drilling fluids, where feasible, will be those that have been rated as being less hazardous under the OCNS and/or Pose Little or No Risk to the Environment by the Convention for the Protection of the Marine Environment of the North-East Atlantic.

Table 2.17 Standard Mitigation Measures

SBM drill cuttings will be returned to the MODU and treated in accordance with the OWTG before being discharged into the marine environment. The concentration of SBM on cuttings will be monitored onboard the MODU, and in accordance with OWTG. No excess or spent SBM will be discharged, any of this excess or spent SBM that cannot be reused will be brought back to shore for disposal. WBM drill cuttings will be discharged without treatment.
Excess cement may be discharged to the seabed during the initial phases of the well, which will be drilled without a riser. Unused cement bulks and additives will be transported to shore for future re-use or disposed at an approved facility.
Small amounts of produced water may be flared. If volumes of produced water are large, some produced water may be brought onto the MODU for treatment and shipped to shore for disposal.
Deck drainage and bilge water will be discharged according to the OWTG which states that deck drainage and bilge water can only be discharged if the residual oil concentration of the water does not exceed 15 mg/L.
Ballast water will be discharged according to IMO *Ballast Water Management Regulations* and Transport Canada's *Ballast Water Control and Management Regulations.* The MODU will carry out ballast tank flushing prior to arriving in Canadian waters.
Putrescible solid waste, specifically food waste generated offshore on the MODU and supply vessels, will be disposed of according to OWTG and MARPOL requirements. Management of kitchen waste will be conducted in accordance with MARPOL and OWTG. There will be no discharge of macerated food waste within 3 NM from land.
Sewage will be managed in accordance with MARPOL and in line with the OWTG prior to discharge.
Cooling water will be discharged in line with the OWTG, which states that any biocides used in cooling water are selected in line with a chemical management system developed in line with the OCSG.
BOP fluids and any other discharges from the subsea control equipment will be discharged according to OWTG and OCSG.
Liquid wastes, not approved for discharge in OWTG such as waste chemicals, cooking oils or lubricating oils, will be transported onshore for transfer to an approved disposal facility.
Biomedical waste will be collected onboard by the doctor or medic and stored in special containers before being transported onshore for incineration.
Transfer of hazardous wastes will be conducted according to the *Transportation of Dangerous Goods Act.* Any applicable approvals for the transportation, handling, and temporary storage of these hazardous wastes will be obtained as required.
Supply and Servicing Operations
Supply vessels will undergo Suncor's internal verification process and where required, additional external inspections / audits (e.g., C-NLOPB pre-authorization inspections) in preparation for the Project.
Supply vessels will use existing shipping lanes as practicable; where these do not exist, supply vessels will follow a straight-line approach to and from the Project Area.
During transit to/from the Project Area, supply vessels usually travel at vessel speeds not exceeding 22 km/hour (12 knots), except as needed in the case of an emergency. If marine mammals or sea turtles are observed by vessel crews, they will reduce speed and/or alter course if practicable to avoid a collision. More specifically, supply vessels will be required to reduce speed to a maximum of 13 km/hour (7 knots) when a marine mammal or sea turtle is observed or reported within 400 m of a supply vessel, except if not feasible for safety reasons.
Lighting on supply vessels will be reduced to an extent that will not compromise safety of operations. This may include avoiding use of unnecessary lighting, shading lights, and directing lights towards the deck.

Table 2.17 Standard Mitigation Measures

Well Suspension and Abandonment
A seabed survey will be conducted at the end of a drilling program using an ROV to inspect the seabed for debris.
Well suspension or abandonment for this Project will be carried out as per applicable industry practice and in compliance with relevant regulatory requirements. Once wells have been drilled to total depth and well evaluation programs completed (if applicable), the well will be plugged and abandoned in line with applicable Suncor practices and C-NLOPB requirements. The final well abandonment program has not yet been finalized, however, these details will be confirmed to the C-NLOPB as planning for the Project continues.
Note: Refer to Table 18.2 for a complete list of mitigative measures for the Project including Project-specific mitigation.

Additional appropriate mitigation measures will be identified through ongoing consultation and engagement with Indigenous communities, fisheries stakeholders, and regulatory agencies throughout the planning and implementation of the drilling program. Standard and specific mitigation measures to be implemented to reduce potential adverse environmental effects of the Project will be incorporated into the Project EPP.

2.12 References

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