Hebron

HEBRON PROJECT

Comprehensive Study Report:
Response to Comments, Part II

February 2011

ExxonMobil Chevron Suncor Energy Statoil nalcor energy

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1.0 INTRODUCTION

AMEC (2009) has been superseded by ASA (2010a, 2010b). As a result, Sections 14-2 and 14-3 of the June (2010) CSR have been completely revised and are enclosed with this Response Document.

2.0 RESPONSES TO COMMENTS RELATED TO OIL SPILL TRAJECTORY MODELLING

2.1 Response to Section 4 Comments

Comment 40: C-NLOPB 17

40-C-NLOPB 17	**EA Reference:**	Section 4.3.2.1 Page 4-6
Preamble:		
Request:	The Offshore Affected Area and/or Study Area boundaries must be reconsidered, and if necessary amended, in light of results from revisiting the oil spill trajectory modelling work for the Project.	
Response:	The Study Areas for nearshore and offshore consider all Project-environment interactions and are compilations of the various Affected Areas as described in Section 4.3.2.1. The results of the oil spill model informed the selection of the Affected Areas and Study Areas; however, the model was not the sole determining factor in the delineation of these areas. The Affected Area is also dependent on the nature of the Project activity and the nature of the VEC being assessed. The environmental effects of an oil spill have been assessed within the geographic area indicated by the oil spill trajectory model probability contours. The geographic area is, therefore, defined as that area where there is a 1 percent or greater probability for a sheen (0.01 mm thick) to occur, in accordance with a 30-day model run. This approach to determining the geographic extent is conservative because the geographic extent for a slick of greater thickness or higher probability would be smaller. An assessment of potential environmental effects from accidental events will be provided, where applicable, for each VEC.	

2.2 Response to Section 7 Comments

Comment 85: C-NLOPB 28

85-C-NLOPB 28	**EA Reference:**	Section 7.5.4.2 Page 7-78, final paragraph
Preamble:	The paragraph states that “Given the potential spill scenarios within the Nearshore and Offshore Study Areas. There is more potential for diesel to interact with the benthic community than crude oil.”	
Request:	The statement should be justified and/or referenced.	
Response:	**This statement will be deleted.**	

2.3 Response to Section 9 Comments

Comment 123: GF 25

123-GF 25	**EA Reference:**:	Section 9.5.4.3 Potential Mortality Page 9-59, Table 9-13
Preamble:	Subsea blow-out predicted as reversible to marine bird populations.	
Request:	A prediction of a blow-out, which could last 36 months as being reversible to all seabird populations present in the study area is not substantiated. EMCP must discuss the potential effects of a blow-out separately and provide details on a worst case scenario and justify and provide species-specific population models which support this prediction**.**	
Response:	A blow-out that could last for 36 months is not a reasonable worst case scenario. The recent blow-out in the Gulf of Mexico was one of the worst blow-outs in history and lasted less than three months. Accidental events including blow-outs are discussed in detail in Section 14. Additional modelling was conducted to represent blow-out scenarios for 30-day and 100-day durations (ASA 2010b). Based on the results of the spill trajectory modelling, it is predicted that a blow-out at the Hebron site could result in significant environmental effects on seabird populations. In the case of mortalities, effects are not reversible at the individual level but they are considered reversible at the population level. No oil spill, including major ones such as *Ixtoc 1* or *Exxon Valdez*, have caused irreversible declines in seabird populations. Effects of blow-outs are discussed in Subsection 9.5.4 of the CSR. It is not possible to provide realistic species-specific population models because of the lack of detailed data on bird distributions and the numerous variables involved in assessing the effects of an oil spill. For example, at the time of a spill, variables may include population sizes and their inherent variability from natural and anthropogenic causes, the specific behaviour, distribution and numbers of birds in time and space, sea and weather conditions, characteristics of the spill, and so forth. The CSR accounts for this uncertainty by predicting a significant effect on seabirds from an oil spill.	

Comment 128: EC 48

128-EC 48	**EA Reference:**:	Section 9.5.4.3 Potential Mortality Page 9-58, Table 9-13 – Environmental Effects Assessment: Accidental Events
Preamble:	The table indicates that environmental effects from an OLS spill, subsea blow-out or crude oil surface spill could be of high magnitude, high geographic extent but moderate duration. If a large oil spill occurred during the marine-bird breeding season and the oil slick moved towards the Witless Bay bird colonies, a large proportion of the breeding birds could be oiled. Direct mortality along with prolonged sublethal effects on reproduction and health of the marine birds could have a drastic impact on the breeding population for many years.	
Request:	The proponents should more accurately assess the duration and reversibility of environmental effects of a major oil spill on local breeding colonies of marine birds.	
Response:	In the event of a blow-out and depending on the time of year in which it occurs, different species of birds may be affected by oil that is predicted to move towards the Avalon Peninsula. During the summer months, nesting birds from the Witless Bay Islands' colonies (*i.e.*, murres, puffins, kittiwakes) use the inshore areas adjacent to the potentially affected shoreline for foraging or resting. Smaller numbers of nesting Herring Gull, Great Black-backed Gull and Black Guillemot will likely be present in the potentially affected area. In addition, birds that nest on Baccalieu Island forage in areas that may be affected by a blow-out. Large numbers of Greater Shearwater also forage in nearshore waters during the period of capelin spawning.	

	During the winter months, large numbers of eiders (mostly Common Eiders with small numbers of King Eiders) occur in nearshore waters of the Avalon Peninsula and could be affected by a spill, if the oil comes ashore. Murres (mostly Thick-billed Murres) and Dovekies forage mostly offshore but could also occur in smaller numbers in nearshore waters. Regardless, these species of birds are particularly vulnerable to a blow-out during winter because they spend so much time on the water. Some of the birds in the potentially affected area may suffer immediate, lethal or sublethal effects (as previously addressed in Response to Comment 119: EC 47). If effects on individuals were extensive enough to cause large numbers of mortalities and/or severe sublethal effects on growth and reproduction, then effects could be measured at the population level. The duration of any sublethal effects would likely vary by species, life stage, type and degree of exposure, and many other factors. The maximum duration of any effect at the individual level would be the life span of that individual. It is impossible to predict with any level of realistic precision how a range of sublethal effects might affect a particular population and thus, the CSR predicted a significant residual adverse environmental effect on seabirds, if a spill were to occur. Based on previous studies of seabird populations relative to oil spills, effects are considered reversible at the population level. As described in Section 14, in the unlikely event that a blow-out occurs, a post-spill monitoring program will be undertaken to assess the environmental effects on the marine environment with a particular focus on marine birds.

2.4 Response to Section 14 Comments

Comment 141: C-NLOPB 37

141-C-NLOPB 37	**EA Reference:**:	Section 14 Accidental Hydrocarbon Spill Events Page 14-1
Preamble:		
Request:	a) Statistical background data and its treatment should be in one section and exposure calculations should be in a different section (i.e. Drilling, Production / Maintenance). b) There does not appear to be a discussion of small (<1 bbl) spills.	
Response:	a) The statistical background data are used in determining exposure calculations. These exposure calculations are discussed in Sections 14.1.1.1 (Blow-outs during Drilling) and 14.1.1.2 (Blow-outs during Production and Workovers). b) The historical record small spills in NL waters, with categories for “Spills Greater Than 1 L and Less Than 159 L (1 bbl)” and “Spills of 1 L and Less”, for the years 1997 through 2009, is presented in Table 14-13. **The text on page 14-13 (June 2010 CSR) will be revised as follows:** The C-NLOPB also provides a statistical record of spills of greater than 1 L but less than 1 bbl (159 L), and of spills of 1 L and less. These are presented in Table 14-13. As in the previous category of spill size, a disproportionate number of these spills occurred in the first three years of operations, so it is reasonable to focus on the more recent years of production experience – *2000 to 2010*. For these years (*2000 to 2010*), there were a total of *452* producing well-years, with *86* spills in the 1 to 159 L category, and *218* spills less than 1 L. Note that the totals in Table 14.3 indicate all spills from 1997 to *2010*.	

Comment 142: C-NLOPB 38

142-C-NLOPB 38	**EA Reference:**:	Section 14 Accidental Hydrocarbon Spill Events Page 14-1
Preamble:	The probability plots for a spill at the Hebron project are presented.	
Request:	a) The CSR should describe the spill scenario that the model was run on. b) Also in the last paragraph, "The Study" should be referenced.	
Response:	**The following text will be added to Section 14.3** a) The Hebron Project modelled a number of scenarios all related to blow-out occurring either at the Hebron Platform or from a MODU under a future expansion opportunity. The scenarios presented in the spill trajectory model consider the rate at which oil could flow under a blow-out scenario; this rate was derived based on existing knowledge of well properties and reservoir data for the Hebron field. A blow-out from the platform (at approximately 70 m above mean sea level) was modelled at a rate of 5,600 m^3/d (approximately 35,000 bbl/d). A subsea blow-out was also modelled in consideration of potential drilling that may occur from a mobile offshore drilling unit (MODU) should expansion opportunities develop. A blow-out from a MODU (subsea blow-out) was modelled at a rate of 3,200 m^3/d (approximately 20,000 bbl/d). ExxonMobil's well control philosophy is focused on prevention using safety / risk management systems, management of change procedures, and global standards. ExxonMobil has a mature Operations Integrity Management System (OIMS) that emphasizes relentless attention to Safety, Well Control, and Environmental Protection. This includes proper preparation for wells (well control equipment inspections / tests), detecting the influx early, closing-in the well efficiently (personnel training / drills), and circulating out the kick with kill weight mud in a controlled manner. In the event of a blow-out, ExxonMobil's primary objective would be to stop the flow as quickly as possible. For both surface and subsea wells, this would involve shutting in at the wellhead and killing the well through the wellhead. Relief well drilling, and the subsequent dynamic kill, is considered a back-up strategy in the event shut-in and/or killing through the wellhead is not possible or is unsuccessful. Two blow-out scenarios were included in the spill trajectory modelling: a platform case and a subsea case. In developing these scenarios the following factors were considered. **Platform Blow-out:** • For a blow-out through a surface wellhead, multiple options are available to stop the flow, depending on the magnitude and composition of the flow, configuration of the blow-out preventer (BOP), and the accessibility of the wellhead. If the wellhead is accessible, capping the well would result in a relatively short flow duration, as surface capping equipment, such as safety valves for inside pipe flow, are maintained on the rig and manual BOP closing is possible. Additionally, industry maintains surface capping equipment. Depending on the scenario, the duration to cap the well and stop flow may be within just a few hours, or if initial attempts are unsuccessful, is estimated at two to three weeks. If a fire renders the platform inaccessible, the most appropriate method to access the well would be evaluated given the condition of the platform and surrounding wells. • If Platform-based well interventions were not successful, the time it would take to secure a drilling unit locally, secure the required well equipment, mobilize the unit it to the Hebron location, and drill a relief well. This duration is estimated to be 100 days in the summer months and 120 in the winter months. If a MODU was sourced internationally additional time would be required. **Subsea Blow-out** • If the subsea wellhead is accessible and the drilling rig is intact, operational, and can work over the wellhead, the rig would be used to cap or kill the well. In this scenario, multiple options exist to kill the well, including wellbore	

	intervention to perform a dynamic kill or to set a packer. In addition, using the existing BOP stack or a capping BOP stack to shut-in the well is also possible. If the drilling rig is intact and the wellbore is accessible, a dynamic kill could take place within days of the blow-out. If it is necessary to assemble and mobilize a capping stack and a second MODU, then a time period of approximately 60 days would be required. If a MODU is available locally and the rig stack can be used as a capping stack, this time period is reduced to 30 days. • If it is not possible to work over the wellhead, or if the wellhead is inaccessible, then a relief well will be required to kill the well. If a MODU was sourced locally, the time it would take to secure a drilling unit locally, secure the required well equipment, mobilize the unit it to the Hebron location, and drill a relief well. This duration is estimated to be 100 days in the summer months and 120 in the winter months. If a MODU was sourced internationally additional time would be required. As stated above, the probability of a blow-out from development drilling or production operations resulting in the need to drill a relief well is extremely low. Therefore, for the purposes of environmental assessment, the environmental impact analysis will focus on a 30-day platform blow-out at a rate of 5,600 m^3/d, and a 100-day subsea blow-out at 3,200 m^3/d. b) The Study will be modified to read **This Section**

Comment 143: C-NLOPB 39

143-C-NLOPB 39	**EA Reference:**:	Section 14 Accidental Hydrocarbon Spill Events Page 14-1
Preamble:	Blow-outs are described as lasting hours, days, or weeks. Blow-outs can last for months and in the Newfoundland and Labrador offshore, mobilization of a drilling unit can likely take weeks to arrive and begin drilling.	
Request:	The CSR should not only consider how long it may take to drill a relief well but also the time required to mobilize a rig.	
Response:	See response provided in 142-C-NLOPB 38	

Comment 144: EC 49

144-EC 49	**EA Reference:**:	Section 14 - Accidental Hydrocarbon Spill Events
Preamble:	Section 5.3.4.3 of the Scoping Document clearly states that the EA will consider quantification of risk of hydrocarbon / chemical spills of all volumes, from all facilities associated with the project. Section 14 highlights the potential for discharges from the OLS but none are discussed.	
Request:	There have been at least 6 incidents in 2008-2009 of spills involving the OLS from the 3 active oil fields off Newfoundland. The proponent should quantify the risk associated with potential incidents involving the OLS.	
Response:	**The following replaces Section 14.1.3, added / changed text is *italicized*.** **14.1.3 Platform Spills Involving Small Discharges** Small spills occur with some regularity at offshore platforms. The data in Table 14-10 are derived from a more detailed table in MMS (1997) and covers small spills of all pollutants from facilities and operations on Federal OCS leases from the period 1971 to 1995. The spills involved various pollutants including crude oil, condensate, refined product, mineral oil and diesel. The period between 1971 and 1995 involved the production of 8.5 billion bbl of oil and condensate and 186,058 well-years of oil and gas production activity (MMS 1997). See Table 14-10 for the spill frequency.	

Table 14-10 Frequency of Platform Spills in the Ranges of 1 to 49.9 bbl and 50 to 999 bbl (US OCS 1971 to 1995)

Spill Size Range	Number of Spills
1 to 49.9 bbl	1,898
50 to 999 bbl	90
Total volume of 1898 + 90 spills = 123,023 bbl	

There have been very few large spills related to development or production in Canadian waters, which has necessitated the use of US and world-wide statistics. However, there is a reasonably-sized database on small spill incidents in Newfoundland and Labrador waters. Spill statistics are maintained and reported by the Canada-Newfoundland and Labrador Offshore Petroleum Board (C-NLOPB) (C-NLOPB 2010).

Production in Newfoundland waters commenced in 1997 at the Hibernia location, with Terra Nova coming on stream in 2001 and White Rose in 2004. Using the well statistics on the C-NLOPB website, these three fields have a total of *472* producing well-years to the end of 2010. An overview of spill statistics for the Newfoundland and Labrador Offshore Area *are provided in Table 14-11 to 14.14. The spill incidents involving 1 bbl or more of hydrocarbon during that period are listed in Table 14-11*. *These spills include spills of crude, diesel and other hydrocarbons resulting from production and loading operations. Spills of synthetic-based muds (SBMs) are provided in [new] Table 14.14. As noted in Section 4.1.2, there was one crude spill of greater than 1,000 bbl, in 2004.*

Table 14-11 Frequency of Platform Spills in the Ranges of 1 to 49.9 bbl and 50 to 999 bbl (Newfoundland Waters, 1997 to present)

Spill Size Range	Number of Spills
1 to 49.9 bbl	*12*
50 to 999 bbl	*0*

A disproportionate number *(7 of 12)* of these spills occurred in the first three years of operations, so it is reasonable to focus on the more recent years of production experience (Table 14-12). For the years 2000 to *2010*, there were a total of *452* producing well-years.

Table 14 12 Frequency of Platform Spills in the Ranges of 1 to 49.9 bbl and 50 to 999 bbl (Newfoundland waters, 2000 to present)

Spill Size Range	Number of Spills
1 to 49.9 bbl	*5*
50 to 999 bbl	*0*

For the smallest size range, statistics from Newfoundland and Labrador operations can be used, but as there have been zero spills in the second category, US GOM statistics will be used. *Based on this, the frequency of spills in the range of 1 to 49.9 bbl is 1.1 x* 10^{-2} *(5/452), and for the range 50 to 999 bbl is 4.8 x* 10^{-4} *(90/186,058).*

This will change the entry in Table 14-14 (now Table 14-15), item 11:

11. Hydrocarbon spill 1 to 49 bbl	*1.1 x* 10^{-2}/well-year	200 well-years	one in *14*

Just considering spills from the offshore loading systems for all production facilities, from 1997 to 2010, there were 14 spills greater than 1 L. Of these, one was in the range of 1 to 49.9 bbl, none in the 50 to 999 bbl range, and none greater than 1,000 bbl.

Comment 145: EC 50

<table>
<tr><td>145-EC 50</td><td>EA Reference::</td><td>Section 14 - Accidental Hydrocarbon Spill Events</td></tr>
<tr><td>Preamble:</td><td colspan="2">Section 5.3.4.3 of the Scoping Document clearly states that the EA will consider quantification of risk of hydrocarbon / chemical spills of all volumes, from all facilities associated with the project. Hydrocarbons must not be limited to crude oil, but also include synthetic / oil based drilling fluids and refined hydrocarbons.</td></tr>
<tr><td>Request:</td><td colspan="2">Releases of drilling fluids has been an issue in the past in the Newfoundland offshore, the proponent should quantify the risk associated with these potential incidents as well as with refined products as stated in the scope.</td></tr>
<tr><td>Response:</td><td colspan="2">To be added as Section 14.1.4, with “Summary …” becoming Section 14.1.5:

The C-NLOPB records spills of SBM and fluids, and these are summarized in Table 14-14 for the years 1997 through 2010. In the largest such spill to date, in 2004, approximately 96,600 L (608 bbl) of SBM were spilled from the diverter line of the GSF Grand Banks at the White Rose location. The spill frequency is calculated based on the 219 wells spudded during this period.

Table 14-14: Spills of Synthetic-based Muds, 1997 to 2010
<table>
<tr><th>Spill Size Range</th><th>Number of Spills</th><th>Frequency, per well</th></tr>
<tr><td>>1 L</td><td>36</td><td>0.16</td></tr>
<tr><td>159 to 7,934 L (1 to 49.9 bbl)</td><td>18</td><td>0.082</td></tr>
<tr><td>7,935 to 159,000 L (50 to 999 bbl)</td><td>5</td><td>0.023</td></tr>
<tr><td>>159,000 L (1000 bbl)</td><td>0</td><td>0</td></tr>
</table></td></tr>
</table>

Comment 146: C-NLOPB 40

<table>
<tr><td>146-C-NLOPB 40</td><td>EA Reference::</td><td>Section 14.1 Hydrocarbon Spill Probabilities
Page 14-2</td></tr>
<tr><td>Preamble:</td><td colspan="2"></td></tr>
<tr><td>Request:</td><td colspan="2">Is the concept safety analysis (CSA) being prepared. The spill / blow-out frequency estimates from the CSR should agree with the CSA.

The data on wells drilled with ExxonMobil as operator from 1999-2009 should be presented to give a snapshot of spill / blow-out performance.</td></tr>
<tr><td>Response:</td><td colspan="2">a) The CSA and CSR have been reviewed to ensure there is consistency regarding frequency of spills / blow-outs. The spill probability analysis presented in the CSR is consistent with the probability analysis presented in the CSA.

b) As reported by the C-NLOPB and C-NSOPB, since 2001, ExxonMobil drilling operations in eastern Canada have not had a reportable spill greater than 1 bbl for the 63 wells drilled in the region. There were 14 wells drilled with a jack-up drilling unit in Nova Scotia, 46 wells were drilled from the Hibernia Platform, and three wells were drilled from floating mobile offshore drilling units in Nova Scotia and on the Grand Banks. In the Newfoundland and Labrador offshore area, ExxonMobil has not had a crude spill greater than one litre associated with its drilling operations.

ExxonMobil's well control philosophy is focused on prevention using safety / risk management systems, management of change procedures, and global standards. ExxonMobil has a mature Operations Integrity Management System (OIMS) that emphasizes relentless attention to Safety, Well Control, and Environmental Protection. This includes proper preparation for wells (well control equipment inspections / tests), detecting the influx early, closing-in the well efficiently (personnel training / drills), and circulating out the kick with kill weight mud in a controlled manner.

Defining "blow-out" as an uncontrolled flow that was not brought under control using the rig's well control system, the last offshore drilling "blow-out" experienced by Exxon was in the GOM in 1983 (Penrod 52 jackup rig). The last offshore "blow-out" was experienced by Mobil in the North Sea in 1990 (Maersk Vinlander semisubmersible rig). Both were shallow gas "blow-outs" with no personnel injuries or release of liquid hydrocarbons to the sea. ExxonMobil has had other well control incidents, but were</td></tr>
</table>

	safely brought under control using well control equipment and procedures. None escalated into "blow-outs". Since the implementation of OIMS (circa 1992), neither Exxon nor ExxonMobil have experienced a "blow-out" during offshore drilling operations.

Comment 147: C-NLOPB 41

147-C-NLOPB 41	**EA Reference:**:	Section 14.1.1 Blow-outs Page 14-3, Table 14-2
Preamble:		
Request:	Please provide the reference for the definitions in Table 14-2. Also, SI units (i.e. m^3) should be used and intervals should be reported as ranges (i.e. large = >1000 bbl to <10,000 bbl).	
Response:	Table 14-2 provides a description of the sizes of oil spills discussed in the CSR. These size categories were established by the US Bureau of Ocean Energy Management, Regulation and Environment (formerly MMS) in its early work on spill risk (Anderson and Labelle 2001). **Table 14-2 will be revised as follows:**	

Table 14-2 Definition of Hydrocarbon Spill Sizes

Hydrocarbon Spill Type	Spill Size	
	bbl	***m^3***
Extremely Large	>150,000	*23,850*
Very Large	10,000 to 150,000	*1,590 to 23,850*
Large	1,000 to 10,000	*159 to 1,590*
Small	1 to 1,000	*0.159 to 159*

Comment 148: C-NLOPB 42

148-C-NLOPB 42	**EA Reference:**:	Section 14.1.1 Blow-outs Page 14-3, Table 14-3
Preamble:		
Request:	Is this data set up to date? Table does not appear to be broken down by classes set out in Table 14-2.	
Response:	**Table 14-3 will be updated as follows:**	

Table 14-3 Historical Very Large Hydrocarbon Spills from Offshore Oil Well Blow-outs

Area	***Reported Spill Size (bbl)***	***Date***	***Operation Underway***	***Duration (days)***
Extremely Large Spills (>150,000 bbl)				
US, Gulf of Mexico (GOM)[A]	*4,000,000*	*2010*	*Exploration drilling*	*91*
Mexico (Ixtoc 1)[B]	*3,000,000*	*1979*	*Exploratory Drilling*	*293*
*Dubai****	*2,000,000*	*1973*	*Development Drilling*	*??*
Iran[C]	*see note*	*1983*	*Production*	*--*
Mexico	*247,000*	*1986*	*Workover*	*??*
Nigeria	*200,000*	*1980*	*Development Drilling*	*14*
North Sea / Norway	*158,000*	*1977*	*Workover*	*7*
Very Large Spills (10,000 to 150,000 bbl)				
Iran	*100,000*	*1980*	*Development Drilling*	*8*
US, Santa Barbara	*77,000*	*1969*	*Production (platform)*	*11*
Saudi Arabia	*60,000*	*1980*	*Exploratory Drilling*	*8*
Mexico	*56,000*	*1987*	*Exploratory Drilling*	*51*

US, S. Timbalier 26	*53,000*	*1970*	*Wireline*	*138*
US, Main Pass 41	*30,000*	*1970*	*Production (platform)*	*49*
Australia[D]	*30,000*	*2009*	*Development drilling (primarily gas)*	*74*
US, Timbalier Bay / Greenhill	*11,500*	*1992*	*Production*	*11*
Trinidad	*10,000*	*1973*	*Development Drilling*	*4*

Source: Gulf 1981, updated to present by reference to the Oil Spill Intelligence Report and other sources

[A] *Varying estimates of spill volume, most recent estimate reported*

[B] *Spill volume widely believed to be underestimated*

[C] *The Iranian Norwuz oil well blow-outs in the Gulf of Arabia, which started in February 1983, were not caused by exploration or drilling accidents, but were a result of military actions during the Iraq / Iran war*

[D] *Currently under investigation, spill volume is best estimate and may be subject to revision*

Comment 149: C-NLOPB 43

149-C-NLOPB 43	**EA Reference:**:	Section 14.1.1.1 Blow-outs during Drilling Page 14-4, 1st paragraph
Preamble:		
Request:	Please review for agreement with Table 14-3	
Response:	**Section 14.1.1 (last paragraph) text will be revised:** Using the definition of "extremely large" spills (i.e., hydrocarbon spills 150,000 bbl in size or greater), there have been *six* such spills in the history of offshore drilling, two of which occurred during development drilling, and two of which occurred during production or workover activities; *and two occurred* during exploration drilling.	

Comment 150: C-NLOPB 44

150-C-NLOPB 44	**EA Reference:**:	Section 14.1.1.1 Blow-outs during Drilling Page 14-4
Preamble:		
Request:	Data are poorly referenced. Please refer to Chevron work for that year. The data should be better documented or links to all base data should be provided for verification.	
Response:	**The first two paragraphs of Section 14.1.1.1 will be replaced with following:** Spill frequencies are best expressed in terms of a risk exposure factor such as number of wells drilled. On a world-wide basis an estimated that 66,469 offshore development wells were drilled as of May 2010 (Deloitte 2010). There have been two extremely large spills during offshore development drilling, so the frequency up to the present is (2/66,469) 3.0 x 10^{-5} spills per well drilled or one such spill for every 33,000 wells drilled. A similar analysis can be done for very large spills. Up to the present, five development-drilling blow-outs have produced spills in the very large spill category (Table 14-3, including the recent incident in Australia). The spill frequency for these is (5/66,469) 7.5 x 10^{-5} spills per well drilled or one such spill for every 13,000 wells drilled. **The following reference will be added:** Deloitte Petroleum Services. 2010. *List of Offshore Petroleum Wells to May 31, 2010*. Report generated on request from Deloitte LLP. London, England. ***** **Note that this will change the calculations in the text (two bullet points, page 14-9):**	

	• Predicted frequency of extremely large hydrocarbon spills from blow-outs during a drilling operation, based on an exposure of wells drilled: 40 x 3.0 x 10^{-5} = 1.2 x 10^{-3}, or a 0.12 percent chance over the drilling period • Predicted frequency of very large hydrocarbon spills from drilling blow-outs based on an exposure of wells drilled: 40 x 7.5 x 10^{-5} = 3.0 x 10^{-3} or a 0.30 percent chance over the drilling period ***** **This will also change the entries in Table 14-14 (now Table 14-15), items 4 and 5:**

4. Development drilling blow-out with hydrocarbon spill > 10,000 bbl	7.5 x 10^{-5}/wells drilled	40 wells drilled	one in 10,000
5. Development drilling blow-out with hydrocarbon spill > 150,000 bbl	3.0 x 10^{-5}/wells drilled	40 wells drilled	one in 25,000

This will also change the text following Table 14-14 (now Table 14-15):

Over the 30-year life of the Project, the annual probability of this happening is *1-in-25,000* for the extremely large spill; and *1-in-10,000* for a very large spill.

Comment 151: GF 27

151-GF 27	**EA Reference:**:	Section 14.1.1.1 Blow-outs during drilling Page 14-7
Preamble:	"The reason for this, according to Scandpower (2000), is that North Sea operators are required by law to always have two barriers during exploration and development drilling, and this is not the case in the US. Regulations similar to the North Sea's apply in Canada (i.e., two barriers), so it is fair to derive blow-out frequencies for Canada on the basis of North Sea statistics*."*	
Request:	The specific guidelines for a two-barrier requirement in Canada should be referenced in this statement.	
Response:	The following text will be added to Section 14.1.1.1 Section 36 paragraph (2) of the *Newfoundland Offshore Petroleum Drilling and Production Regulations* states that "After setting the surface casing, the operator shall ensure that at least two independent and tested well barriers are in place during all well operations." It is the Operator's intention to adhere to all requirements for Well Control and regulatory requirements.	

Comment 152: C-NLOPB 45

152-C-NLOPB 45	**EA Reference:**:	Section 14.1.1.1 Blow-outs during Drilling Page 14-7, Table 14-7
Preamble:	The blow-out risk frequency for Hebron will be calculated as per Scandpower (2000) as the average of the four frequencies provided in Table 14-7 yielding an adjustment factor. The statistical basis for derivation of the adjustment factor is not explained or understood. The CSR should use a more rigorous statistical analysis to show a decreasing trend over time. The data set used for analysis ends at 2000. There is potentially 9 more years of data that could be included in the data set for analysis.	
Request:	The CSR should expand the data set used for blow and spill analysis to include data as close to 2010 as possible. Also, the statistical analysis showing that population is different statistically should be provided.	
Response:	**The last two paragraphs on page 14-7** The blow-out risk frequency for Hebron …… On the basis of the above analysis, ……. **will be replaced with:**	

	A more recent analysis by Scandpower (2006), summarized in IAOGP (2010), confirms the reduced frequencies in recent years. The data, based on the 20-year record to 2005, indicate a deep blow-out frequency of *4.8 x 10⁻⁵*. Using this figure results in a probability of one blow-out for every *21,000* wells drilled. For a drilling program involving 40 wells, this statistic yields a deep well blow-out probability of approximately *1-in-520*. ***** **This will change item 1 in Table 14-14 (now Table 14-15):** 1. Deep gas blow-out during development drilling | *4.8 x 10⁻⁵*/wells drilled | 40 wells drilled | one in *16,000* ***** **This will also change 7th paragraph, page 14-9:** In summary, the probability of having a deep blow-out is a *0.02* percent chance (1-in-*520*), with virtually no chance of hydrocarbon release. During production, the risk of having a gas blow-out will decrease to a *1-in-1,300* chance per year; and gas blow-outs involving small amounts of discharged hydrocarbon (>1 bbl) would be expected once every 14,000 years. **The following references will be added:** Scandpower Risk Management AS. 2006. *Blow-out and Well Release Frequencies – based on SINTEF Offshore Blow-out Database, 2006*. Report No. 90.005.001/R2. IAOGP (International Association of Oil & Gas Producers). 2010. *Blow-out Frequencies*. Report No. 434-2.

Comment 153: C-NLOPB 46

153-C-NLOPB 46	**EA Reference:**:	Section 14.1.1.1 Blow-outs during Drilling Page 14-8
Preamble:		
Request:	Previously mentioned statistical testing is required to allow use of 0.51 factor and 64% as a useable ratio.	
Response:	**The second and third paragraph following Table 14-8, page 14-8:** Again, as was done earlier for ….. A certain percentage of the blow-outs .... **Will be replaced with:** A more recent analysis by Scandpower (2006), summarized in IAOGP (2010), does not allow a comparison for each of the operations listed in Table 14-8, but confirms the overall blow-out frequency for production, wireline operations, completions and workovers in recent years. The data, based on the 20-year record to 2005, indicate an overall blow-out frequency for these operations of 1.85×10^{-4}, based on 33 incidents over 177,474 well-years. A certain percentage of the blow-outs involved some discharge of hydrocarbon. Of the 78 blow-outs that occurred during the four operations of production, wirelining, workovers and completions, only 12, or 15.4 percent, involved hydrocarbon (note that the average size of the 12 spills was only 72 bbl). Therefore, the frequency of blow-outs that produced a hydrocarbon spill from well blow-outs during the four above-noted operations is calculated to be $0.154 \times 1.85 \times 10^{-4} = 2.8 \times 10^{-5}$ blow-outs/well-year. ***** **This will change items 2 and 3 in Table 14-14 (now Table 14-15):** 2. Gas blow-out during production | 1.85×10^{-4}/well-years | 200 well-years | one in 810 3. Blow-out during production involving some hydrocarbon discharge >1 bbl | 2.8×10^{-5}/well-years | 200 well-years | one in 5,300	

Comment 154: C-NLOPB 47

154-C-NLOPB 47	**EA Reference:**:	Section 14.1.1.1 Blow-outs during Drilling Page 14-9
Preamble:		
Request:	The calculations here may be supported in the data but the presentation is not easily followed (i.e. A table corresponding to classes in Table 14-2 with frequency numbers). The probability of a gas blow-out is 0.0234 over life of project. 1 in 1,300 per year is a bit disingenuous.	
Response:	Table with historical frequency, Hebron exposure, and probability is presented as a summary, Table 14-14 (now Table 14-15). **The text on page 14-9, paragraph 5 will be revised as follows:** For gas blow-outs occurring during production and workovers, the statistic for Hebron becomes 200 well-years x 1.17 x 10^{-4} blow-outs/well-year, approximately a 1-in-1,300 chance per year, or approximately 2.3 percent probability over the 30-year life of the Project.	

Comment 155: C-NLOPB 48

155-C-NLOPB 48	**EA Reference:**:	Section 14.1.2 Page 14-11
Preamble:		
Request:	*What is a "major" platform spill. Define "major" or use one of the classifications from Table 14-2.*	
Response:	**Section 14.1.2 will be renamed as follows:** **Large** Platform Spills	

Comment 156: GF 28

156-GF 28	**EA Reference:**:	Section 14.1.3 Platform Spills Involving Small Discharges Page 14-13, Table 14-12
Preamble:	Nowhere in this section does the proponent discuss the accidental spills of synthetic-based drill cuttings or drilling fluids. Yet, spills of these substances, including some in the 50-99 bbl category, have occurred in the C-NLOPB's jurisdiction. Given the exchange with the C-NLOPB over the reporting of these types of spills and how they were not accounted for in past EAs, it is disappointing to see this information is not present (Fraser, G.S. and J. Ellis 2008. Reply from Gail Fraser and Joanne Ellis to a letter from C-NLOPB. *Journal of Environmental Assessment Policy and Management.* 10 (4): 475-481).	
Request:	There must be a section that describes the discharge of these pollutants into the marine environment, even if they cannot be presented in terms of probability of occurrence, there should be a table that presents the spills associated with SBMs. In light of O'Hara and Morandin's (2010) work this is outright negligence by the proponents not include this information and by C-NLOPB to allow the draft CSR to go forward without this information.	
Response:	Refer to response to Comment 145-EC 50.	

Comment 157: C-NLOPB 49

157-C-NLOPB 49	**EA Reference:**:	Section 14.3.5 Additional Modelling considerations Page 14-32
Preamble:	It is stated that blow-outs were model for 45 days.	
Request:	Blow-outs should be modeled based on the actual time the well would be flowing oil and should continue until the well is killed or until the criteria for ending the model run is met.	
Response:	See response to 142-C-NLOPB 38	

Comment 158: C-NLOPB 50

158-C-NLOPB 50	**EA Reference:**:	Section 14.3.5 Additional Modelling Considerations Page 14-33, Table 14-16
Preamble:	Column 2 of Table 14-16 is labeled "Flow M^3". Column 2 is the volume of the batch spill and not flow.	
Request:	The labeling of this heading should re-examine and should coincide with what is in the column and the discussion on batch spills.	
Response:	Oil spill trajectory modeling has been updated by Applies Science Associates, Inc. (ASA), to address review comments. There is no comparable table in the new report or corresponding summary section in the CSR.	

Comment 159: C-NLOPB 51

159-C-NLOPB 51	**EA Reference:**:	Section 14.4.5 External Assistance Relief Well Consideration Page 14-42
Preamble:	The process and time required to mobilize a drilling facility to drill a relief well is outlined. Obtaining a drilling rig is one aspect however there are additional considerations such as consumables and well components that will also be required to drill a relief well.	
Request:	The CSR should outline how these items will be obtained.	
Response:	ExxonMobil operates and maintains a world-wide drilling operation that encompasses a fleet of drilling units and drilling equipment inventory. Knowledge and awareness of ongoing operations is maintained company-wide. In the event a relief well is required and the required materials are not available in local stock, ExxonMobil will access this world-wide inventory to procure necessary materials to execute the required operations and/or will obtain the materials directly from vendors through our Global Procurement organization. The time to source these materials has been considered in the oil spill scenarios described in Comment 142-C-NLOPB 38.	

Comment 160: C-NLOPB 52

160-C-NLOPB 52	**EA Reference:**:	Section 14.6 Offshore Spill Response Operations Page 14-48
Preamble:	The CSR does not discuss how it intents to deal with wildlife such as birds, marine mammals or fish that have been affected by a spill.	
Request:	The CSR should include a section on responding to and mitigating wildlife that is affected by an oil spill	
Response	In the event of a spill, as part of its oil spill response plan, EMPC will develop a wildlife recovery plan that will identify key sensitive areas, detail what will be done to protect those areas and, in the event of oil effects upon wildlife, what they will do to recover and rehabilitate oiled wildlife. Mitigation measures are discussed in relation to the environmental effects assessment of each VEC in the following sections:	

	• Fish and Fish Habitat – Section 7.5.4; Table 7-14 • Commercial Fisheries – Section 8.5.3.1; Table 8-15 • Marine Birds – Section 9.5.4; Table 9-13 • Marine Mammals and Sea Turtles – Section 10.5.4; Table 10-13 • Species at Risk – Sections 11.4.3, 11.5.3 and 11.6.3; Tables 11-7, 11-13 and 11-19 • Sensitive of Special Areas – Section 12.5.1; Table 12-3

Comment 161: EC 51

161-EC 51	**EA Reference:**:	Section 14.6.4.1 – Response Options Page 14-49
Preamble:	Section 5.3.6.5 of the Scoping Document clearly states that the EA should identify types and location of response equipment; and target times for equipment deployment. Section 14.6.4.1 states a contracted Response Organization will provide Tier 2/3 containment and recovery equipment but no time frame is provided.	
Request:	There appears to be a lack of containment and recovery equipment as well as available offshore supply vessels capable of handling a Tier 2/3 spill response in a timely manner. How will the proponent address this issue? Mutual aid agreements can provide vessels but not in timely manner, a lack of dedicated response vessels in the offshore not tied to specific programs such as stand by, can create unnecessary delays in response. The oil fields are over 300 km from St. John's, NL, transits from port to the Hebron oil field can be over 18 hours one way not including port time for equipment to be loaded, vessels modified to handle and deploy the equipment How will the proponent address these issues and propose solutions to make response efforts much more timely and effective. Target times for equipment deployment need to be provided.	
Response:	**The following text will be added to Section 14.6.4.2:** The Hebron Project is at the conceptual stage of development. The Oil Spill Response Plan (OSRP) has not been developed. The Hebron crude has a lower API than the crude of existing offshore Newfoundland operations, and is therefore a heavier product. In developing the Hebron offshore OSRP, as with existing offshore oil and gas OSRPs, the OSRP will outline a tiered response to oil spills. Depending on the size and nature of the spill (*i.e.*, Tier 1, 2 or 3), the OSRP will include the type and quantity of response equipment specific for Hebron crude. In addition, it will identify equipment that will be available within local, regional and global Response Organizations, and equipment that may be available through mutual aid agreements with other operators. For a Tier 2 or Tier 2 response, Hebron can request oil spill project management support through ExxonMobil corporate response organization. Estimated response times for deployment will also be identified. The Hebron Project is aware of the recent initiative currently being undertaken between the existing Newfoundland and Labrador operators regarding the evaluation of the level of equipment and its capability to respond to oils spills on the Grand Banks. Existing Tier 2 oil containment equipment is being upgraded and supply vessels are being configured for quick installation of the equipment. Enhanced training for vessel crews will also be provided. During the development of the Hebron OSRP, the Hebron Project will consider the response equipment available, the time it will take to deploy, if it is capable of handling Hebron crude, and determine if additional resources are required. Tier 1 equipment will be available on-site and will be appropriate for Hebron crude. Current Tier 2 equipment readily available onshore consists of industry and Eastern Canada Response Corporation (ECRC) equipment. In addition, and if required, the Canadian Coast Guard has an inventory of oil spill response equipment stored at their depot in Mount Pearl, some of which is suitable for offshore use.	

	ECMP will commit to continue working with other Grand Banks operators to enhance the existing pool of equipment based on the best available technology to support production operations. . In addition to maintaining and operating the producing operators' equipment, the Response Organization, ECRC (located in Mount Pearl) has its own open ocean containment and recovery equipment, temporary storage tankage, and oil transfer pumps. In addition to the equipment available for a Tier 2 response, it is likely that Tier 3 resources available to Hebron production operations will be sourced from agencies outside of Newfoundland and Labrador. Principle sources include: • The installation of diving and ROV systems to support production field maintenance programs • ECRC equipment in other eastern Canada depots (*e.g.*, Ocean Buster high-speed boom stationed in Quebec) • Equipment sources identified through the ExxonMobil Corporate response organization • OSR aerial dispersant capability based in Southampton, England • Appropriate oil spill response equipment secured from international Tier 3 response organizations by either ECRC and OSR through their membership in the Global Response Network Estimated response times will be outlined in the Hebron OSRP. Again, depending on the nature of the spill and the required response, response times will vary. Tier 1 resources will be available immediately at site. Sorbent boom can be deployed in less than one hour after the spill occurs. Other equipment can take up to three to six hours to deploy. Deployment time for Tier 2 resources will depend on their location and are staged for rapid deployment. Including mobilization and delivery of gear, and activation of necessary field personnel a Tier 2 response vessel could be ready to sail from St. John's within two to three hours. Fastest transit to the spill site from St. John's would be approximately 12 to 18 hours in good conditions. Response times for Tier 3 equipment will depend on source location. The Hebron Project will develop synergies with the Hibernia Project and will augment the current two standby vessel, one supply vessel arrangement supporting Hibernia. It is anticipated that in order to meet production and drilling operations for Hebron, an additional standby vessel and supply vessel will be added to the pool of resources. With regard to the availability of vessels, the industry has demonstrated that it can cope with unusual demands on vessel resources. During the spring of 2009, the core fleet was temporarily increased to a high of eighteen to meet the following demands: • The installation of diving and ROV systems to support production field maintenance programs • A heavy ice season that required vessels to be involved in increased ice management operations as well as unscheduled rig moves • The grounding of all helicopter traffic to and from the Grand Banks requiring that all personnel had to travel offshore by vessel • A high level of shipyard time for scheduled and unscheduled maintenance of vessels and platforms • The installation of diving and ROV systems to support production field maintenance programs To ensure that operations could continue, several additional vessels from throughout Atlantic Canada were also contracted. While not all of these vessels were capable of

	assuming full platform supply or standby duties, they were all useful. Through mutual aid agreements with the Grand Banks operators, vessel assignment during an oil spill response may be similar to the spring 2009 case. Vessels of opportunity may be sourced from existing operations, where available, or sourced regionally.

Comment 162: EC 52

162-EC 52	**EA Reference:**:	Section 14.6.4.1 – Response Options Page 14-49
Preamble:	Section 5.3.4.3 of the Scoping Document clearly states that the EA will provide Contingency Plans to be implemented in the event of a spill, including an analysis of the likely efficiency of spill response measures and any equipment upgrade or acquisition that may be required to support the Project.	
Request:	Information has not been provided in the report to address the efficiency of any of the spill response options listed, whether there are any equipment upgrades or acquisitions needed to provide an appropriate and timely response to spills and releases of pollutants from the Hebron project. Therefore, more information is needed for review in order to meet the requirements of the Scope.	
Response:	See response to Comment 161-EC 51.	

Comment 163: EC 53

163-EC 53	**EA Reference:**:	Section 14.6.4.3 – Response Methods Page 14-50
Preamble:	Section 5.3.4.3 of the Scoping Document clearly states that the EA will consider an analysis of the likely efficiency of spill response measures. Section 14.6.4.3 Response Methods lists chemical dispersion as a response option but no information on testing or whether chemical dispersion is a viable option for Hebron crude.	
Request:	Information on chemical dispersant testing carried out on Hebron crude must be provided for review, as the limited information contained in Section 14.6.3 Characteristics of Spilled Crude Oil at Hebron suggests Hebron crude may not be suitable for chemical dispersion, more information is required on the physical and chemical properties of Hebron crude.	
Response:	SL Ross 1999 provides an overview of the chemical properties of Hebron Crude (D-94) tested to determine the effectiveness of dispersants. In addition, the properties of Hebron Crude can also be found on Environmental Canada's database of crude oil properties (http://www.etc-cte.ec.gc.ca/databases/OilProperties/oil_H_e.html) The most recent testing of the effectiveness of chemicals in the dispersion of Ben Nevis (Hebron) crude were conducted in 1999 and 2000 (SL Ross 1999 and 2000) using small volumes of oil and laboratory techniques. Tests were conducted on various levels of weathered oil at multiple temperatures and with several Dispersant to Oil Ratios (DOR). In these studies, it was difficult to simulate open ocean sea surface energies. The reported range of effectiveness is 0 to 60 percent. In cases of cold water, advanced weathering, and low DOR, the effectiveness of chemical dispersion appears to be low. After production operations commence, when suitable volumes of Hebron crude are available, additional tests will be required. Furthermore, research is needed to investigate the dispersibility of Hebron crude and pursue pre-approval for the use of dispersants as an oil spill countermeasure.	

Comment 164: EC 54

164-EC 54	**EA Reference:**:	Section 14.6.4.4 – Availability of Containment and Recovery Equipment Page 14-50
Preamble:	Section 5.3.6.5 of the Scoping Document clearly states that the EA should identify types and location of response equipment; and target times for equipment deployment. The CSR does not indicate the proponent's timetable for deploying Tier 2 or Tier 3 equipment only to state Tier 1 capability will meet or exceed the current standard for production operators.	
Request:	The proponent is requested to provide a copy of the standard it plans to meet for availability of equipment and spill response capacity for Tier 1, 2 and 3 spills for review.	
Response:	See response to Comment 161-EC 51.	

Comment 165: C-NLOPB 53

165-C-NLOPB 53	**EA Reference::**	Section 14.6.4.4 Availability of Containment and Recovery Equipment, Page 14-50
Preamble:	The containment and recovery equipment available is discussed.	
Request:	More detail should be provided as to what Tier 1 equipment will be available at site. The CSR should also outline what equipment is available onshore for Tier 2 and 3 spill responses and if that equipment is the best available for the Newfoundland and Labrador offshore environment, if there is sufficient equipment quality available to contain and recover oil in a reasonable period of time, and if that equipment is suitable for use with Hebron crude.	
Response:	See response to Comment 161-EC 51.	

Comment 166: C-NLOPB

166-C-NLOPB 54	**EA Reference:**:	Section 14.6.4.5 Waste Hydrocarbon – Temporary Storage and Disposal Options Page 14-51
Preamble:	It is stated that "Most newly built vessels currently operating offshore Newfoundland are built to DNV oil-recovery standards." This statement is meaningless as not all vessels are built as pollution class vessels and there are older vessels that are not pollution class vessels.	
Request:	It should be stated if the vessel used for the project would be pollution class and not allude to possibilities.	
Response:	ECMP will ensure that the core vessels chartered for Hebron operations meet current pollution class standards.	

Comment 167: C-NLOPB

167-C-NLOPB 55	**EA Reference:**:	Section 14.6.5 Investing in Industry Spill Response Capability Page 14-51
Preamble:	The CSR discusses what industry, specifically in relation to specific projects, is doing.	
Request:	Plans and/or intentions for investing and improving spill response should be presented.	
Response:	See response to Comment 161-EC 51.	

3.0 ADDITIONAL DEFICIENCIES AND EDITORIAL COMMENTS FROM FISHERIES AND OCEANS CANADA

179-DFO	F6) Pages 12-18 to 12-20 (Capelin Beaches) Based on the spill trajectories, the CSR suggests that there is less than a 2% probability of a spill reaching the head of Bull Arm. This statement does not seem accurate given the coastal currents, wind conditions, proximity to the GBS fabrication site (~3 km in some cases), etc. Dispersal models tend to be highly dependent upon boundary conditions and assumptions, yet the supporting documentation on the model (prepared by AMEC), appears to contain no material to specifically address this. Due to the significance of any impact on near shore habitat, it is important to fully understand these aspects in order to effectively interpret the results of such models.
	Response: Applied Sciences Associates was contracted to run the oil spill trajectory modelling for revised blow-out scenarios in the offshore area and potential spills of diesel at Bull Arm. Additional information regarding the model can be found in ASA (2010a, 2010b).
	G) 14.0 Accidental Hydrocarbon Spill Events G1) Given recent events in the Gulf of Mexico, it is strongly recommended that some discussion of these events be included in the CSR. Therefore, revisions to the text should reflect the possible ramifications of accidental hydrocarbon spill events in light of the new knowledge obtained from the Gulf of Mexico spill.
	Response: The recent events in the Gulf of Mexico have been discussed in the following sections of the CSR (June 2010): • Section 14.1.1, Table 14-3, page 14.3 • Section 14.1.1.1, Page 14-4, paragraph 3 • Section 14.1.1.2, page 14-10, paragraphs 4 and 5
	G2) 14.2.1 Model Set-up (Fate and Behaviour of Hebron Hydrocarbon Spills in the Near shore Study Area (Trajectory Modeling)); Page 14-15 The base model described in the CSR uses a release point 2 km south of the GBS fabrication site in Bull Arm. It is not clear as to why this distance from the development was selected. The modeled zone of impact in Bull Arm, given the above-mentioned displacement 2 km south of the Bull Arm fabrication site, does not cover two very prominent eelgrass meadows. Placing the modeled spill point at the GBS fabrication site may produce a very different prediction.
	Response: This is an error in the text. The release point for the spill trajectory modelling in Bull Arm is at the approximate location of the GBS deepwater site in Bull Arm.

4.0 SUPPORTING DOCUMENT COMMENTS

4.1 Spill Trajectory Modelling for the Hebron Project (AMEC Earth & Environmental – April 2010)

200-EC 55	**EA Reference:**:	Spill Trajectory Modelling for the Hebron Project
Preamble:	The study considered two spill sites: a near shore site in Bull Arm in Trinity Bay where the Hebron platform will be built and an offshore site where the Hebron oil production will take place. The study used three oil spill models to conduct this modelling work: ADIOS, the weathering model developed by NOAA and is publicly available, AMEC model developed (and apparently used previously) by AMEC, and finally the Oil map model developed by Applied Science Associates. ADIOS was used to address the oil weathering, AMEC model was used for stochastic modelling, and Oil map was used for trajectory modelling at the offshore spill site using deterministic approach, three blow-out scenarios and three batch spill events. While the study showed a certain trend of the possible trajectory of spills and spatial distribution of the probability of oiling in Bull Arm in Trinity Bay and around the future offshore Hebron production site, the method used to conduct the modelling study is questionable as shown in the following comments. 1. The use of three different oil spill models to conduct this study is misleading and did not bring any benefit to the study, evaluation of the risk / impact associated with oil spills because: a) For the purpose of this study, trajectory modelling and tracking of the mass balance (weathering) should be integrated in the same model as in the Oil map model. The use of ADIOS model to address the weathering and AMEC model to predict the trajectory is not a correct approach as movement of the oil is strongly affected by its weathering states and vice-versa. b) The Oil map model is known to be oil spill software that can be used to conduct trajectory modelling in both deterministic and stochastic modes. Trajectory and weathering modelling are coupled in this model. c) ADIOS software model designed to estimate weathering and masse balance, but does not have any capability to model oil trajectory. d) From the description provided in the report, AMEC is not an oil spill model suitable for this study as described below. 2. Modelling results obtained with the AMEC model and related to probability of oiling are questionable for the following reasons: a) As described in the report, the AMEC model includes oil advection to hydrodynamic current and wind, evaporation and vertical dispersion only. Important processes such as spreading, emulsification and interaction with shorelines are not included. b) The trajectory of the slick is modeled by tracking the centre of the slick only. For large spills, spatial distribution of the probability of oiling obtained with such approach is not correct as the edge of large slicks may reach the shoreline but not its centre. In addition, the same reasoning applies for the time for oiling. Trajectory of oil slicks is commonly tracked using Lagrangian approach using thousands of particles or spillets. This method is used in Oil map software. c) The method used to model vertical dispersion is not based on state-of-the-art knowledge. Much better methods have been developed during the last two decades and were validated with several data sets. The method used is elementary and does not include the effects of oil type and weathering (increase of oil viscosity and emulsification, for instance) in a systematic way (use of appropriate behaviour models). 3. Hydrodynamic currents used to conduct the study in the Bull Arm site are based on one-point conditions and cannot represent the hydrodynamic of the entire modelling grid. In such complex domain, it recommended to use proper gridded current data, such as	

	those provided by the BIO finite element model for Northwest Atlantic area. Vector field of surface currents used in the simulations should be displayed on a couple of figures for illustration of both spill sites. 4. While it is recognized in the report (section 3.5 and 4.5) that there is a good chance that ice coverage at the two spill sites may be significant (50% or more) during the winter season, no modelling under ice condition was performed. The fate and weathering of an oil spill in ice-infested waters is known to be highly affected by ice. 5. A long series (hourly) of wind data (30 years) were used, which is very good to conduct the stochastic simulation, assuming that the data are of good quality. But, what is the rational of using 30 simulations per day? The fact that the number of simulations is greater than the number of data points (in a day), there will be duplicates of the extra simulations (in this case 6 per day). The result of this is that the simulations cannot be considered as independent and the resulting statistics (probability of oiling) become biased. 6. The maximum of the simulations was set between 7 and 45 days. We learned from many spills resulting from well blow-out (including the recent Gulf of Mexico spill) that the spill might last for months. The rationale for the simulation timeframe must be explained and in particular, how the modelling results obtained with such short period of time may be used to assess the risk of oiling? 7. The predicted 17% (section 14.2.3) of the evaporation of IFO 180 is questionable. One notes that the ADIOS model is known to overestimate evaporation of many oils under wind conditions. Revision is necessary. 8. The word “any” in the last paragraph of section 14.2.3 should be removed, as the modeling results cover a small portion only of all possible spill events.
Request:	Redo the oil spill trajectory-modelling taking in to account the comments offered above.
Response:	AMEC 2009 has been superseded by ASA (2010a, 2010b). The above comments have been considered, where applicable, in defining the scenarios used in the revised oil spill trajectory modelling.

201- C-NLOPB Comment #	**Section**	**Sub-section**	**Page**	**Comment**
AMEC 2009 has been superseded by ASA (2010a, 2010b). The following comments have been considered, where applicable, in defining the scenarios used in the revised oil spill trajectory modelling.				
1	2	[N.A.]	1	“Experience with the AMEC model indicates that having at least 60 predictions yields good confidence in the overall resultant statistics for a given month” [Paragraph 3, line 10] A proper statistical justification for this statement should be provided.
2	2	2.1.2	3	The offshore model grid should extend westwards at least to the Avalon Peninsula, and preferably to the Burin, to properly delimit potential landfall areas.
3	2	2.3.1	6	Table 2-2: The source “Fisheries and Oceans Canada, 2009 is not in the Reference section.
4	2	2.3.2	13	Vertical Dispersion: It should be explained how the discussion in this section is relevant to Hebron crude oil. Has the dispersability of Hebron crude been tested using oil samples from the Hebron delineation-drilling program?

201-C-NLOPB Comment #	Section	Sub-section	Page	Comment
5	3	3.5	32	"Recovery of the remaining fuel may only be possible by restraining the sea ice using ice booms and removing the fuel when the ice melts." [Paragraph 1, line 2] The statement does not appear to consider the potential for in-situ burning to be employed.
6	3	3.6	32	The use of an artificial temporal cut-off for spill trajectories, in this case 30 days, is inappropriate. Rather, weathering calculations should form the basis for terminating trajectories that do not either reach shore or leave the model domain.
7	3	3.6.2	35	Paragraph 1, in its final sentence, mentions one trajectory, in April, that reached the head of Trinity Bay. However, other trajectories also appear to leave the model domain at its northern marine boundary: namely four in January and one in July. They also should be discussed.
8	4	4.2	45	The title of the subsection is "Fuel Spill Scenario". The scenarios should deal with Hebron crude oil, as it represents the principal risk exposure for oil spillage during the drilling and production phases of the project.
9	4	4.2	45	Paragraph 2 describes the 30-year wind time series that was used for the spill trajectory simulation. Past trajectory analyses for the northeast Grand Banks have indicated that shoreline contact was relatively rare. Therefore, a longer time series would give additional confidence that those relatively rare conditions had properly been captured, and should have been employed. The reason for not using the entire 52-year wind data set should be explained in light of this.
10	4	4.3.1	46	Paragraph 2: It should be explained why the particular 30 years 1976 through 2005 were chosen from the 52-year wind data set.
11	4	4.4	50	Paragraph 2 describes the choice of a single "representative" year of current data, 2005, to use as input to the trajectory modelling, that 7% of the 2005 data were missing, and that interpolation on these occasions was "not practical". The number of years that current data was available should be provided. The justification for the choice of 2005, the reasons why it was deemed representative, and why only one year of data was deemed sufficient, also should be provided. Additional justification for the lack of interpolation also should be provided.
12	4	4.6	51	Comments 2 and 6 also apply to this section.
13	4	4.6.2	66	Paragraph 2 concludes, with respect to Figures 4-5 through 4-16, that "An inspection of these graphs suggests there should be no shoreline impacts for any trajectories in any months."

201- C-NLOPB Comment #	Section	Sub- section	Page	Comment
				This cannot reliably be concluded from the graphs since the western boundary of the model domain ends east of the Avalon Peninsula, and a number of trajectories impinge upon the western boundary in virtually every month.
14	4	4.7	69	As indicated in comment 13, the conclusion stated in Paragraph 2, line 1 is insupportable.
15	4	4.8	70	The basis for selecting the spill scenarios described in this section should be explained.
16	4	4.8	70	The justification for ending the simulations after 30 days should be provided. They should end only when the oil has weathered / dispersed to an appropriately small fraction, when shoreline is reached, or when the remaining oil leaves the model domain.