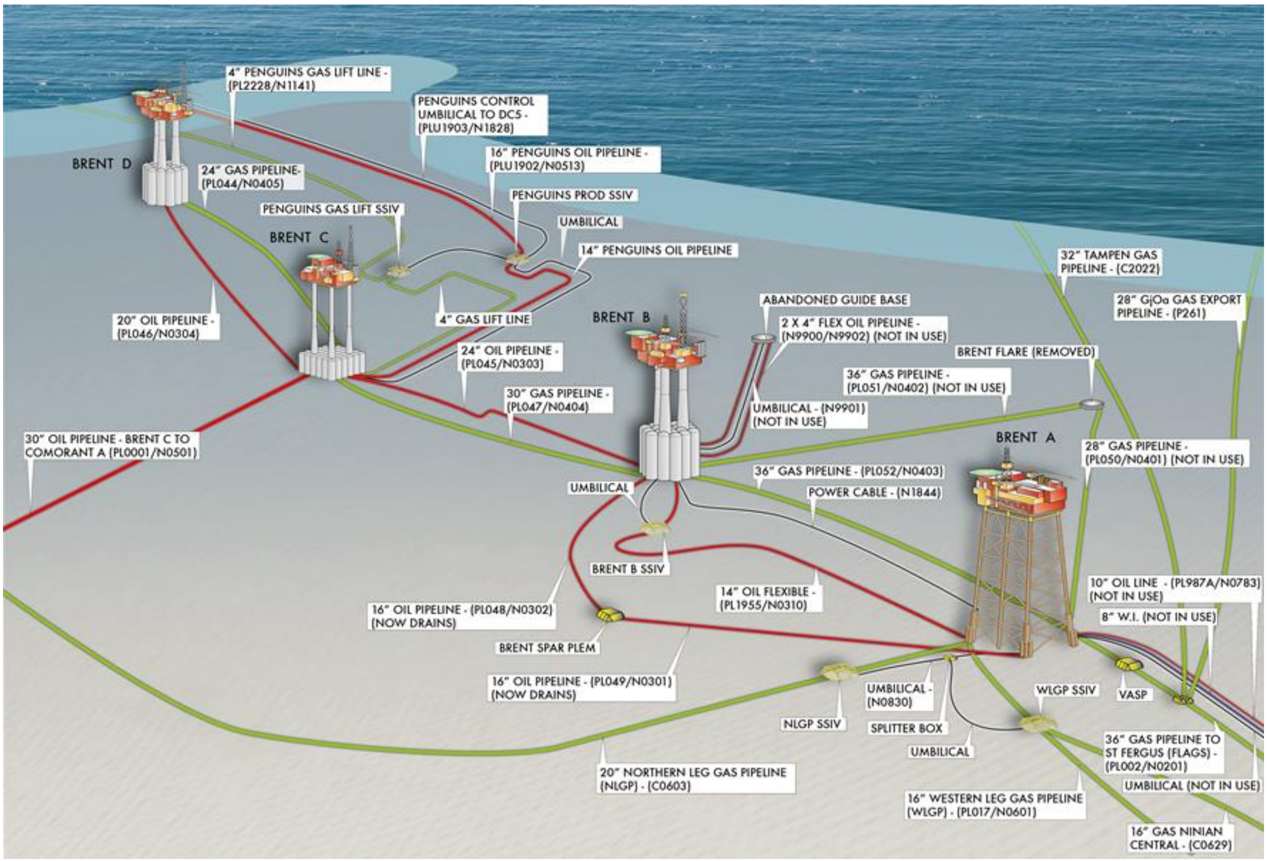
Shell U.K. Limited

BRENT FIELD DECOMMISSIONING PROGRAMMES



Submitted to the UK Department for Business, Energy and Industrial Strategy

Shell Report Number BDE-F-GEN-AA-5880-00015

February 2017

Consultation Draft

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EXECUTIVE SUMMARY

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1 EXECUTIVE SUMMARY

Introduction

This document contains two Decommissioning Programmes (DP), for (1) the Brent Field installations and (2) the Brent Field pipelines (Figure 1). The owners of the infrastructure are Shell U.K. Limited (Shell, the operator) 50%, and Esso Exploration and Production UK Limited (Esso) 50%. Shell has prepared these Programmes in accordance with Section 29 of the *Petroleum Act* 1998 [1], and Esso confirms that it supports the proposals described in them. A letter of support from Esso is presented at the end of this Executive Summary. Throughout this document therefore, the terms 'owners', 'we', 'us', and 'our' refer to 'Shell and Esso'.

The Petroleum Act provides the framework for the implementation in the UK of *OSPAR*[1] *Decision 98/3 on the Disposal of Disused Offshore Installations* [2]. The *DECC Guidance Notes: Decommissioning of Offshore Oil and Gas Installations and Pipelines under the Petroleum Act 1998* [3] provide guidance and advice in the preparation of DPs.

Background

At the time of its discovery the expected lifespan of the Brent Field was 25 years. Through continuous improvement and significant investment in the 1990s, we have extended the life of the Field well beyond original expectations. After many years of service to the UK, however, the Brent Field is now reaching the stage where all the economically recoverable reserves of oil and gas have been extracted. The next step is to 'decommission' the Field's four platforms and their related infrastructure. Before considering decommissioning options, we explored potential ways to reuse the platforms ranging from wind farms to carbon capture and storage facilities. After a thorough review, we concluded that reuse was not a credible option because of the age of the infrastructure, its distance from shore, the lack of demand for reuse and the cost of converting the facilities. We have therefore concluded that the Field must be decommissioned.

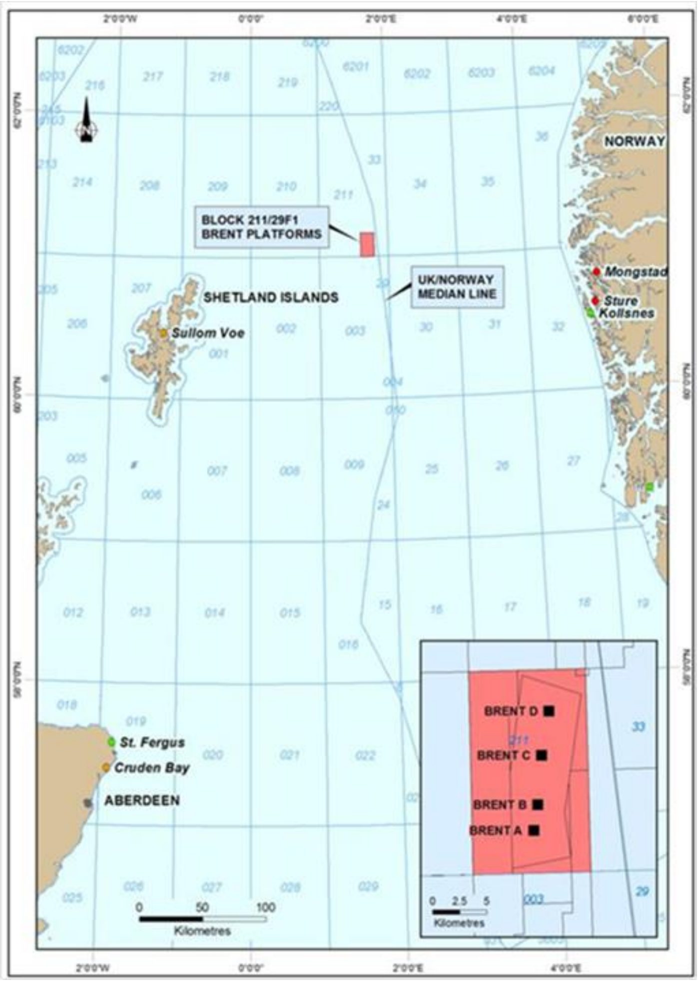
Figure 1 Brent Field Installations

[1] OSPAR, Oslo Paris Commission, protecting and conserving the North-East Atlantic [including the North Sea] and its resources.

Layout and Adjacent Facilities

The Brent Field is located in the East Shetland Basin in Block 211/29 (Figure 2), midway between the Shetland Islands and Norway. The nearest oil and gas installation is the Statfjord B platform operated by Statoil Petroleum (9.6 km) (Figure 5). Shipping activity is low and dominated at present by oil industry support vessels, and there are no Ministry of Defence (MOD) exercise areas near the Field. The nearest submarine cable is the CANTAT 3 operated by BT located approximately 60 km away. There are no renewable energy developments or dredging or aggregate extraction operations in the area.

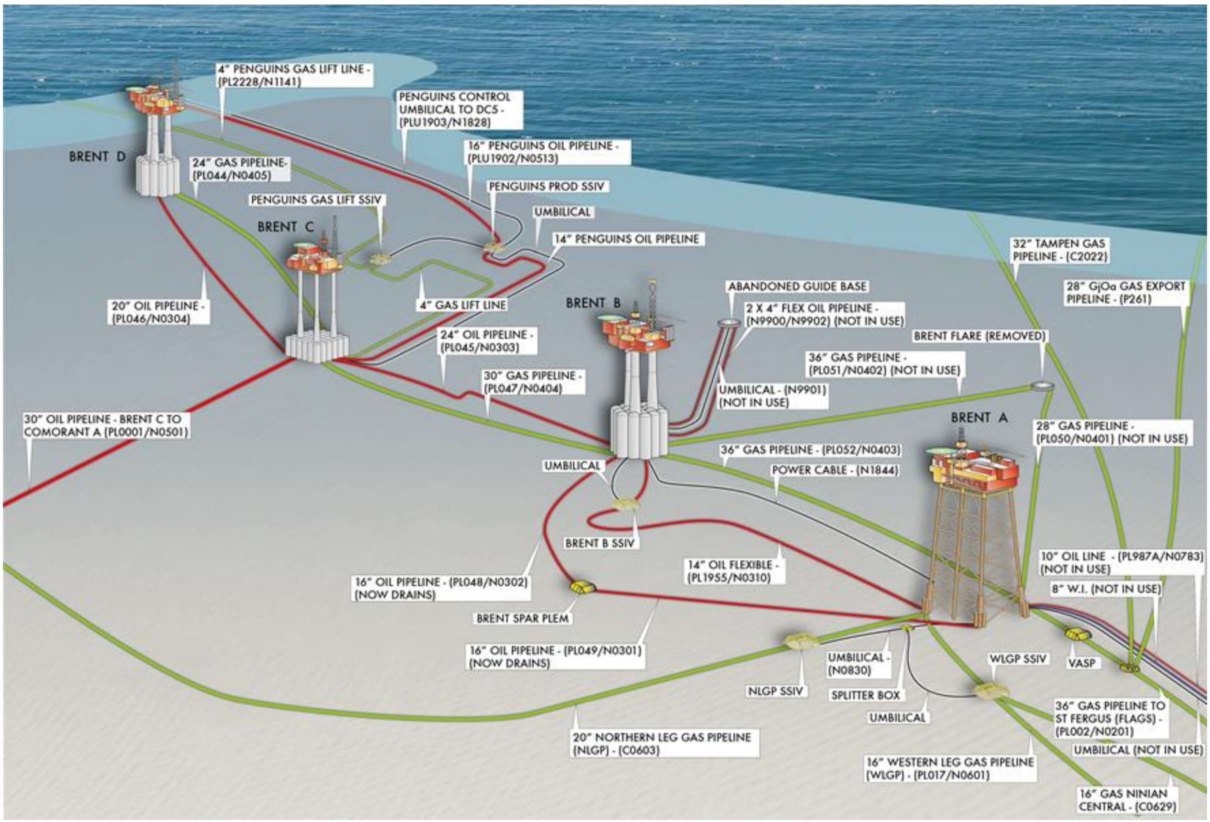
Figure 2 Location of the Brent Field



Several species of fish and shellfish are present in the area, but none is protected or of conservation importance. The Brent area is subject to commercial fishing operations, and although bottom trawling is the predominant vessel activity, the weight and value of landings from this area are dominated by mid-water (pelagic) species. Fishing intensity is low to moderate in comparison with other areas of the North Sea and is classified by Marine Scotland as being of 'low' value. The main species landed by UK vessels are mackerel, herring and haddock.

Many species of seabirds are found in the area and their abundances vary seasonally. The most frequently sighted species of marine mammal in the Field is the bottlenose dolphin. With the exception of marine mammals, there are no species or habitats in the area which have been designated for their conservation importance. The nearest Special Area of Conservation is the Braemar Pockmark, approximately 225 km from the Field.

Figure 3 Layout of Facilities in the Brent Field



The Brent Field infrastructure comprises four installations Alpha, Bravo, Charlie and Delta, which support topsides that house the accommodation block, helipad, drilling and other operational areas (Figure 3).

The support structure at Alpha is a steel jacket weighing 31,500 tonnes. The support structures at Bravo, Charlie and Delta are concrete gravity base structures (GBS) weighing more than 300,000 tonnes each.

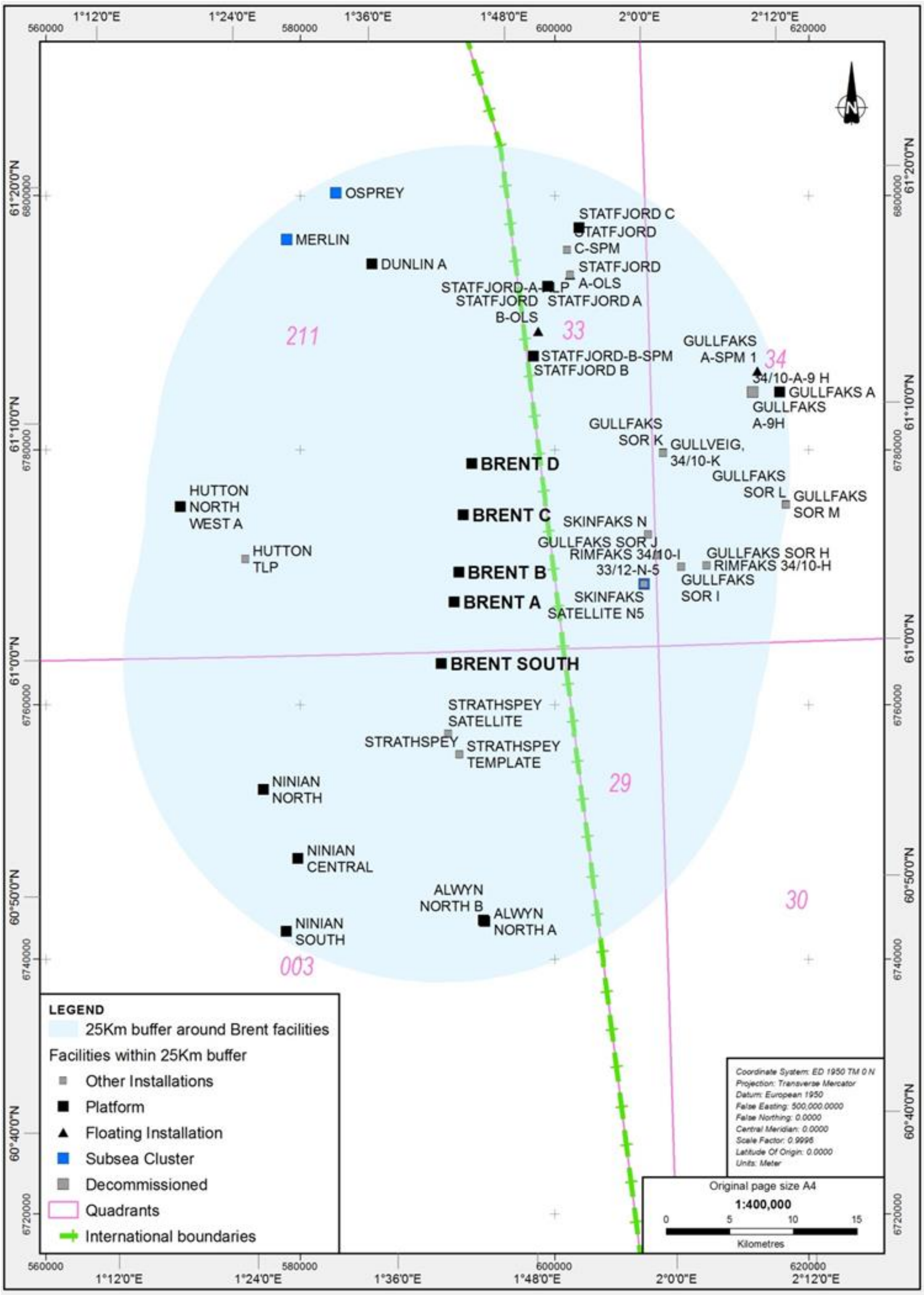
Figure 4 Brent Charlie GBS during construction, showing the cells at the bottom of the legs

The Bravo and Delta GBSs comprise 16 reinforced concrete tanks, called cells, that were used to store and separate crude oil before export (Figure 4 and Figure 6). On Charlie the GBS comprises 32 cells; 10 were used to store and separate oil and the other 22 were used to provide additional ballast.

The Field is served by 103 km of pipeline and 4 small seabed structures which are part of the pipelines system. Overall, the 1.8 million tonnes of material covered by the two DPs includes approximately 295,000 tonnes of steel, 568,000 tonnes of concrete, 238,000 tonnes of sand ballast and 16,000 tonnes of rock-dump.

Table 1 provides an overview of the installations being decommissioned. Table 3 provides an overview of the pipelines being decommissioned.

Figure 5 Location of Adjacent Facilities

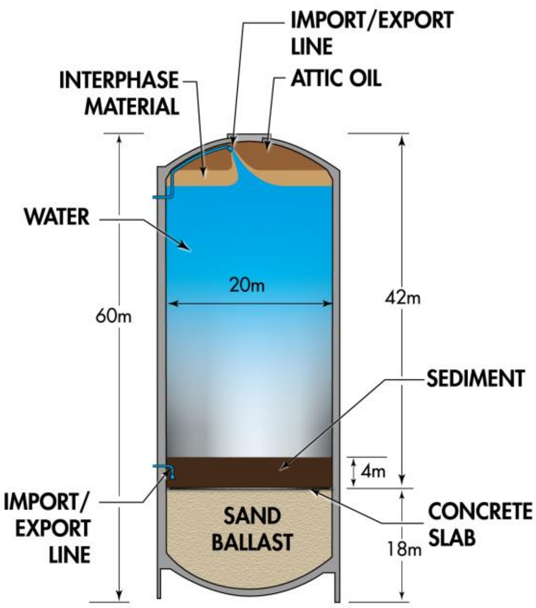


Materials in the GBS

The cells of the GBS are made of concrete just under 1 m thick, reinforced with steel bars. On Bravo and Delta the cells are circular and approximately 60 m tall and 20 m in diameter, and on Charlie the cells are rectangular and approximately 60 m tall and 13 m by 13 m. Of the total of 74 cells in the GBSs, 10 serve as the bases of the legs, 42 were designed for oil storage, 2 contain conductors and 20 contain circulating cooling water. The cells formerly used for oil storage typically now contain the following materials, in descending order from the top of the cell:

- An estimated 50 m^3 (Delta) or 600 m^3 (Charlie) layer of crude oil (called attic oil) at the top of the oil storage cells[2]
- A layer of interphase material
- A large intermediate layer of water
- A layer of sediment comprising a mixture of oil, sand particles and water; on average this layer is 4 m thick
- A 22 cm thick concrete diaphragm, covering the sand ballast
- A 14 m thick layer of sand ballast[3]

Figure 6 Materials in the GBS oil storage cells



One of our commitments to stakeholders was to sample the sediment prior to submitting our DPs. We had previously estimated the volume and composition of the cell contents from our historical operating records and computer modelling studies, but we wanted to verify our assumptions about volume and composition with sediment samples. Taking samples within the cells had never been done before, and the technologies and know-how did not exist. It took six years and a number of unsuccessful attempts to develop the techniques and expertise to overcome the inherent complexity associated with this challenging task. In 2014, we were able to collect up to 6 kg of sediment from three different cells on Brent Delta, as well as water samples. A 3D sonar device was also successfully launched in each of the three cells, to measure the sediment's surface topography to enable the volume of sediment to be calculated.

The survey and sampling programme found that, for the three cells sampled, the average volume of sediment in each cell was 1,044 m^3, which is close to our assumption of 1,080 m^3. Physically, the sediment is a mixture of about 50% water, 25% oil and 25% sand. Chemically, the sediment contains no significant amounts of non-biodegradable compounds. This was in line with our assumptions.

[2] We do not think there is any attic oil in the Brent Bravo oil storage cells.

[3] There is no concrete diaphragm or sand ballast in the Brent Charlie cells.

Table 1 Installations being Decommissioned in DP1.

<table>
<tr><td colspan="2">Field</td><td colspan="2">BRENT</td><td colspan="2">Blocks</td><td colspan="2">211/29 UKCS</td><td colspan="2">Water depth</td><td colspan="2">140 m to 142 m</td></tr>
<tr><td colspan="2" rowspan="2">Owners</td><td colspan="10">Shell U.K. Limited 50%</td></tr>
<tr><td colspan="10">Esso Exploration and Production UK Limited 50%</td></tr>
<tr><td colspan="3">Operator</td><td colspan="9">Shell U.K. Limited</td></tr>
<tr><td colspan="6">Section 29 Notices issued to Owners</td><td colspan="6">12 December 2014</td></tr>
<tr><td colspan="3">Distance to UK</td><td colspan="3">136 km, Shetland Islands</td><td colspan="3">Distance to median line</td><td colspan="3">11 km Norway</td></tr>
<tr><td colspan="3">Pre-decommissioning environmental survey</td><td colspan="9">2007: Full baseline benthic survey at all 4 locations; physical, chemical and biological data; MBES[4]. Included sampling/coring of seabed cuttings piles.</td></tr>
<tr><td colspan="3">Previous surveys</td><td colspan="9">At various platforms in 1986, 1997, 2004, and 2006.</td></tr>
<tr><td colspan="3">Cuttings pile screening</td><td colspan="9">As reported 2007, all screening results below both of the OSPAR thresholds.</td></tr>
<tr><td colspan="3">Nearest SAC</td><td colspan="9">Braemar Pockmark, 225 km</td></tr>
<tr><td colspan="3">Nearest platform</td><td colspan="9">Statfjord B, 9.6 km NE</td></tr>
<tr><td colspan="2">ICES rectangle</td><td colspan="2">45F1</td><td colspan="2">Fishing intensity</td><td colspan="2">'Low'</td><td colspan="2">Fishing value</td><td colspan="2">'Low'</td></tr>
<tr><td colspan="2">Shipping activity</td><td colspan="2">'Low'</td><td colspan="2">MOD activity</td><td colspan="2">None</td><td colspan="2">Wrecks</td><td colspan="2">None</td></tr>
<tr><td colspan="4">Facility</td><td colspan="2">Alpha</td><td colspan="2">Bravo</td><td colspan="2">Charlie</td><td colspan="2">Delta</td></tr>
<tr><td colspan="4">Type</td><td colspan="2">Drilling, Production</td><td colspan="2">Drilling, Production</td><td colspan="2">Drilling, Production</td><td colspan="2">Drilling, Production</td></tr>
<tr><td colspan="4">Topsides (tonnes)</td><td colspan="2">Modular, 16,000</td><td colspan="2">Modular, 24,100</td><td colspan="2">Modular, 31,000</td><td colspan="2">Modular, 24,200</td></tr>
<tr><td colspan="4">Support structure (tonnes)</td><td colspan="2">6 leg steel piled jacket; 25,834</td><td colspan="2">3 leg GBS with storage; 340,717</td><td colspan="2">4 leg GBS with storage; 290,880</td><td colspan="2">3 leg GBS with storage; 325,418</td></tr>
<tr><td colspan="4">GBS cell sediment</td><td colspan="2">No cells</td><td colspan="2">16 cells; 17,280 m^3</td><td colspan="2">11 cells[5]; 6,035 m^3</td><td colspan="2">16 cells; 17,280 m^3</td></tr>
<tr><td colspan="4">Drill cuttings in Tri-Cells[6]</td><td colspan="2">No Tri-Cells</td><td colspan="2">12,039 m^3</td><td colspan="2">No open Tri-Cells</td><td colspan="2">14,733 m^3</td></tr>
<tr><td colspan="4">Historic drill cuttings piles</td><td colspan="2">Seabed 6,300m^3</td><td colspan="2">Cell-top 1,887m^3
Seabed 5,300m^3</td><td colspan="2">Cell-top 7,735m^3
Seabed 4,922m^3</td><td colspan="2">Cell-top 3,790m^3
Seabed 2,230m^3</td></tr>
<tr><td colspan="4">Extent of pile</td><td colspan="2">25 m from platform</td><td colspan="2">60 m from platform</td><td colspan="2">45 m from platform</td><td colspan="2">80 m from platform</td></tr>
<tr><td colspan="4">Derogation candidate</td><td colspan="2">Yes >10,000 Te</td><td colspan="2">Yes, concrete GBS</td><td colspan="2">Yes, concrete GBS</td><td colspan="2">Yes, concrete GBS</td></tr>
</table>

[4] Multi-Beam Echo Sounder

[5] On Charlie there is sediment in the 8 oil storage cells and in 3 of the ballast water cells.

[6] Estimated maximum volume

Stakeholder Engagement

Since 2007 we have been working on the long-term planning necessary to stop production and decommission the Brent Field. This has involved in-depth work with independent experts, academics and other interested stakeholders.

Stakeholder engagement has played a significant role in the development of the Brent Decommissioning Programmes. For more than 10 years we have carried out a thorough and transparent process of stakeholder engagement with interested parties. This has involved discussing and informing stakeholders of the different risks, challenges and benefits associated with decommissioning. More than 180 organisations across Europe have been engaged including non-governmental organisations such as environmental groups, government representatives and bodies, academics and professional institutes, fisheries organisations, oil and gas industry bodies, and media and community groups. Our stakeholder engagement activities have included individual visits to stakeholders, hosting larger stakeholder events (facilitated by independent third-party facilitators The Environment Council and then latterly Resources for Change), publishing an online newsletter and maintaining a dedicated Brent Decommissioning website.

These discussions have enabled stakeholders to share their views and concerns, which we have taken into account when assessing the different decommissioning options. Their expertise and input have made a valuable contribution to the project (see Section 10).

Independent Review

To inform decision-making, we completed a wide range of engineering and technical studies, using either our own expertise or external companies and consultancies. All the important supporting studies have been scrutinised by an independent review group (IRG) chaired by Professor John Shepherd of Southampton University. Professor Shepherd appointed a team of leading academics from across Europe, comprising technical, engineering and environmental experts, and their remit was to review and report on the completeness, objectivity and rigour of supporting studies and the validity of the conclusions or findings (see Section 10.9). The IRG has produced a final report, over which we did not have any editorial control.

Cell Management Stakeholder Task Group

The samples we collected from the GBS storage cells were taken in controlled conditions, with the offshore operation witnessed throughout by independent observers from Bureau Veritas, a global leader in testing, inspection and certification. A specialist independent laboratory carried out chemical and physical analyses of the samples. The results were shared with an invited group of 15 highly engaged stakeholders, the Cell Management Stakeholder Task Group (CMSTG), which we established to provide input on how to manage, safely and effectively, the contents of the oil storage cells (see Section 10.8).

Comparative Assessments

Decommissioning in the UK sector of the North Sea takes place under a mature regulatory process that is stipulated in the UK's Petroleum Act and regulated by the Department for Business, Energy and Industrial Strategy (BEIS[7]), formerly the Department of Energy and Climate Change (DECC). OSPAR 98/3 requires

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[7] In July 2016 the Department of Energy and Climate Change (DECC) was replaced by Department for Business, Energy and Industrial Strategy (BEIS) and further reference to DECC should be taken as BEIS. However, at that time a number of DECC regulatory responsibilities also transferred to the new Oil and Gas Authority (OGA) and where this is the case that will be notified accordingly.

that at the end of their lifecycles, qualifying offshore installations must be removed from the sea. In accordance with the Petroleum Act and OSPAR 98/3 we will therefore complete the following programmes of work (see Table 2):

- Plugging and making safe the wells
- Removing all four of the installations' topsides
- Removing all sea-bed debris that originated from oil and gas activities
- Removing the attic oil at the top of some of the GBS oil storage cells.

OSPAR 98/3 recognises, however, that there may be particular difficulties associated with the removal of large steel structures or the gravity bases of concrete platforms. OSPAR 98/3 therefore provides for operators to make a case for exemption from the general rule of complete removal, known as a 'derogation'. Operators who wish to seek a derogation are required to demonstrate, by way of a fully evaluated and reasoned Comparative Assessment (CA), that there are significant reasons why leaving in place is preferable to re-use, recycling or final disposal on land.

All the Brent installations are derogation candidates under OSPAR 98/3 and as such we have prepared a CA for each one. Considerations for the CA include balancing the safety risks, technical feasibility, societal impacts, environmental impacts and cost of each viable option (see Section 8.5).

Over the last ten years, we and expert consultants have completed a wide range of studies to inform the CAs. Each one of those studies has been subsequently reviewed by the IRG to ensure that they are robust. The results of the CAs form the basis of the evaluation to inform our decision making process. Broader considerations, including stakeholder feedback and other non-technical elements have also been taken into account to inform the recommendations. We have conducted CAs for:

- The Brent Alpha steel jacket footings
- Each of the GBSs
- The contents of each GBS, namely the contents of the oil storage cells and the materials in the minicell annulus and the drilling legs
- Some of the drill cuttings piles
- Each of the 28 Pipelines

Decommissioning the Brent Field – Our Recommendations

Table 2 presents our proposed programmes for the facilities covered in DP1 Installations, and Table 3 presents our proposals for DP2 Pipelines.

Table 2 Summary of Proposed Decommissioning Programme DP1, Installations.

1 WELLS
Selected Option: Plug and make safe. Reason for Selection: Meets regulatory requirements. Proposed Decommissioning Solution: All platform wells (Brent South already plugged and abandoned) will be plugged and made safe in accordance with Oil & Gas UK Guidelines for the Suspension and Abandonment of Wells. All necessary permitry will be obtained.
2 TOPSIDES
Selected Option for all 4 topsides: Complete removal to shore. Reason for Selection: Meets regulatory requirements. Proposed Decommissioning Solution: After suitable preparation the topsides will be cut from the substructures and transported in one piece to the shore for recycling, with a target of recycling 97% of the material returned to shore.
3 SUBSTRUCTURE BRENT ALPHA STEEL JACKET
Selected Option Partial removal to 84.5m below Lowest Astronomical Tide (LAT). Reason for Selection: CA indicates that removal to the top of the footings provides the best option on safety, technical and cost grounds. Proposed Decommissioning Solution: Using diamond wire cutting, the upper part of jacket will be removed down to -84.5m, leaving footings 55.5m high on the seabed. Removed section will be transported to shore for recycling.
4 SUBSTRUCTURES BRENT BRAVO, CHARLIE and DELTA GBSs
Selected Option Leave in place, legs upright. Reason for Selection: GBSs cannot be refloated or dismantled in place. CA indicates that leaving place with legs upright provides the best option on safety, technical and cost grounds. Proposed Decommissioning Solution: After removal of the topsides, the cut ends of the legs will be closed with concrete caps and fitted with Aids to Navigation. The status of the GBSs will be marked on charts and on FishSAFE[8].
5 ATTIC OIL and INTERPHASE MATERIAL IN GBS CELLS
Selected Option Complete removal to shore. Reason for Selection: Meets regulatory requirements. Proposed Decommissioning Solution: Attic oil and interphase material (where present) will be removed and taken to shore for recycling and disposal.
6 GBS CELL CONTENTS
Selected Option Leave in place. Reason for Selection: CA indicates that leaving the contents contained in the concrete GBS cells provides the best option on safety, technical and cost grounds. Proposed Decommissioning Solution: After removal of the attic oil and interphase material, if present, the cells will be sealed.

[8] FishSAFE is an electronic means of alerting vessels to the proximity of a structure in the sea.

Table 2, continued Summary of Proposed Decommissioning Programme DP1, Installations.

7 MATERIAL IN GBS DRILLING LEGS and MINICELL ANNULUS
Selected Option: Leave in place. Reason for Selection: CA indicates that leaving these materials enclosed in the base of the concrete GBS legs provides the best option on safety, technical and cost grounds. Proposed Decommissioning Solution: After removal of the topsides, the legs will be closed with concrete caps.
8 DRILL CUTTINGS
Selected Option: Leave in place. Reason for Selection: Meets regulatory requirements. Except for the Charlie cell-top pile, modelling supports earlier desk-top screening which suggests that all the Brent cuttings piles fall below both thresholds in OSPAR Recommendation 2006/5. In Charlie, the modelled oil-loss rate in some cases exceeds 10Te/Yr. A Stage 2 CA for this pile indicates that leaving it undisturbed in place provides the best option on environmental, technical, and safety grounds. Proposed Decommissioning Solution: Piles on seabed under Alpha, around the bases of the GBS, on the GBS cell-tops, and in GBS tri-cells will be left undisturbed, and will not be significantly affected by any decommissioning activities on other Brent facilities. As required, small amounts of cell-top drill cuttings on Bravo and Delta will be displaced by water-jetting to gain access to cells for removal of attic oil.
8 SUBSEA INSTALLATIONS PLEM, SSIV, SPLITTER BOX and VASP
Selected Option: Complete removal to shore. Reason for Selection: Meets regulatory requirements. Proposed Decommissioning Solution: Subsea installations will be cut from lines, with anchoring piles (if present) cut 3m below the seabed. All material will be returned to shore for recycling.
9 SEABED DEBRIS
Selected Option: Complete removal to shore. Reason for Selection: Meets regulatory requirements. Proposed Decommissioning Solution: All visible protruding parts of seabed and cell-top debris relating to oil and gas operations in the Field that is present within 500m radius of installations or a 200m wide corridor centred on each pipeline, will be removed and taken to shore for recycling.
10 MARKING OF REMAINS
Brent Alpha footings: 500 m safety zone; UK Hydrographic office notified; marked on FishSAFE. Each GBS: Automatic Aid to Navigation on 1 leg; 500 m safety zone; UK Hydrographic office notified; marked on FishSAFE.
11 MONITORING
'As left' survey of remains once programme completed. First post-decommissioning environmental survey on completion of whole programme. Second post-decommissioning environmental survey about 5 years later. Subsequent long-term environmental monitoring and maintenance schedule to be agreed with BEIS.
11 INTERDEPENDENCIES
Removal of the Alpha jacket to top of the footings will leave the seabed drill cuttings pile undisturbed. All 3 GBS in place, legs upright, will leave seabed and cell-top drill cuttings piles undisturbed. Leaving all 3 GBSs in place, legs upright, will leave the GBS cell contents, materials in the drilling legs and minicell annulus, and the drill cuttings in the tri-cells undisturbed. The removal of all four subsea installations will facilitate subsequent decommissioning operations on those pipelines (see Table 3).

Table 3 Installations being Decommissioned and Summary of Proposed Programme in DP2, Pipelines.

Field	BRENT	Blocks	211/29, 211/28, and 211/26 UKCS	Depth	140-42 m
Owners	Shell U.K. Limited 50% Operator				
	Esso Exploration and Production UK Limited 50%				
Section 29 Notices issued to Owners			23 January 2014		
Min. distance to UK	136 km, Shetland Islands		Min. distance to median line		11 km Norway
ICES rectangles 45F1 and 45F2	Fishing intensity	'Low' to 'Moderate'	Fishing value	'Low' to 'Moderate'	

Line number	Diam.	Present status	Length (km)	Recommended option for whole length
PL051/N0402	36"	Surface-laid	2.6	Trench and backfill
PL052/N0403	36"	Surface-laid	2.3	Trench and back-fill
PL002/N0201	36"	Surface-laid	1.3	Trench and back-fill
PL051/N0402A	36"	Surface-laid	0.15	Remove by cut and lift
PL001/N0501	30"	Part trenched	35.9	Partial trench and rock-dump
PL047/N0404	30"	Surface-laid	4.4	Trench and back-fill
PL050/N0401	28"	Surface-laid	3	Trench and back-fill
PL045/N0303	24"	Surface-laid	4.6	Trench and back-fill
PL044 N0405	24"	Surface-laid	4.2	Trench and back-fill
—/N9903A	24"	Surface-laid	1.7	Trench and back-fill
—/N9903B	24"	Surface-laid	1.7	Trench and back-fill
PL046 N0304	20"	Surface-laid	4	Trench and back-fill
PL049/N0301	16"	Surface-laid	2.8	Trench and back-fill
PL048/N0302	16"	Surface-laid	2.3	Trench and back-fill
PL017/N0601	16"	Surface-laid	0.4	Remove by cut and lift
PL1955/N0310	12"/14"	Surface-laid	2.7	Remove by reverse reeling
PL1955/N0311	12"	Surface-laid	0.27	Remove by reverse reeling
PL987A/N0738	10"	Trenched & rock-dumped	5	Leave in trench
PL987A/N0739	10"	Surface-laid	1.8	Leave in trench
PL988A/N0913	8"	Trenched & rock-dumped	5	Leave in trench
PL050/N0952	8"	Rock-dumped	0.03	Leave in existing rock-dump
PL987A1-3/N0841	5"	Trenched & rock-dumped	5.3	Leave in trench
—/N1844	5"	Surface-laid	2.9	Remove by reverse reeling
—/N9902	4"	Surface-laid	2.3	Remove by cut and lift
—/N9901	4"	Surface-laid	2.2	Remove by cut and lift
—/N9900	4"	Surface-laid	2.1	Remove by cut and lift
—/N0830	4"	Trenched and back-filled	0.5	Remove by reverse reeling
—/N2801	2.5"	Surface-laid	0.4	Remove by reverse reeling

Table 3, continued Installations being Decommissioned, Summary of Programme in DP2, Pipelines.

GENERIC EXPLANATION OF SELECTIONS	
Cut and Lift	Removes the whole line. Provides a clear seabed and removes a snagging risk for fishermen.
Reverse Reeling	Removes the whole line. Provides a clear seabed and removes a snagging risk for fishermen.
Partial Trench and Rock-dump	Lowers an already partially trenched line so that adequate cover over the top of pipe (at least 0.6m) is obtained. Rock-dump on selected sections that cannot be adequately buried provides additional cover and stability, and minimises future snagging risk.
Leave in Existing Rock-dump	Line lies under existing and stable rock-dump, in area where incidence of spanning is low.
Leave in Existing Trench	Line lies in existing trench with adequate (>0.6m) cover over top of pipe, in area where incidence of spanning is low. Cut ends of line will be stabilised by a short section of additional rock-dump.
ADDITIONAL INFORMATION on PIPELINE DECOMMISSIONING	
Cleaning	Regardless of decommissioning option all the pipelines will be flushed to remove hydrocarbon inventory. The oil lines will also be pigged, to remove any residual hydrocarbons adhering to the walls of the pipe.
Treatment of ends	All disconnected ends on seabed will be buried or protected by rock-dump.
Mattresses	All mattresses which are associated with subsea structures and pipelines that are to be removed, will be removed if safe to do so.
Grout Bags	All grout bags will be removed if safe to do so, unless needed to protect *in situ* pipe.
Rock-dumps	Existing stable rock-dumps will be left in place.

Supporting Studies

We engaged with a wide range of engineering, safety and environmental experts to examine all the options subject to CA. Their reports are listed in the DPs and in the Technical Documents (TD) that support them. In addition to the Environmental Statement, prepared with support from DNV GL, the aspects or issues examined by major supporting studies included:

- Refloating or lifting the Brent Alpha jacket in one piece
- Refloating the Brent GBSs
- Partially removing the GBSs
- Safety risk to other users of the sea from GBSs left in place
- Degradation and collapse of GBSs left in place
- Sampling and analysis of GBS cell contents
- Modelling dispersion and fate of exposed GBS cell contents
- Ecotoxicological assessment of effects of exposure of cell contents
- Safety risk to fishermen from decommissioned Brent pipelines
- Economic effects on commercial fisheries from structures left in Brent Field
- Employment and economic effects of proposed Brent decommissioning programmes of work

Key Recommendations

Decommissioning the Gravity Base Structures: The GBSs are very large structures made from thick concrete reinforced with steel bars. They contain solid ballast and during installation were ballasted down by flooding the cells with water. Decommissioning was not a design consideration or a regulatory requirement when they were built, and they were not intended to be removed once they had been placed on the seabed.

The only way to remove the GBSs would be to refloat them, in a long, complex multi-phase programme including preparation, refloating without loss of control, towing, and dismantling while floating at a deep water site near the shore. Given their size, age and condition, and the reality that many systems and parts of the structures are now inaccessible or inoperable, it is impossible to categorically confirm that any such operation would be successful. Our analysis has shown that the risk of not being able to complete refloat operations successfully is unacceptably high, some 40-70 times higher than would normally be accepted for any new project in the offshore oil and gas industry. Similarly, the risk that project personnel would be killed or seriously injured is much higher than we would ever be prepared to accept. As a result of the high risk of technical failure and the unacceptable risk to human life, we have concluded that for all 3 GBSs the option 'Refloat and dismantle near shore' is not viable. In accordance with the DECC Guidance Notes, this option was ruled out of the CA process.

Two options were taken forward for detailed CA (i) 'Partial removal' which involves removing the upper part of the legs to -55 m below sea level in line with International Maritime Organisation's (IMO) guidance and (ii) 'Leave in place'. After a detailed review of partial removal we concluded that cutting and removing the upper parts of the concrete legs (each 20 m diameter, about 6,000 tonnes weight), which has never been done before, would be extremely technically challenging. The legs would have to be cut underwater, lifted clear of the water and carried to shore for dismantling. On balance there are few tangible safety, environmental or societal benefits to be gained from the removal of the upper legs, and the risks associated with partial removal outweigh the benefits. Multiple divers would have to be deployed which would substantially increase the safety risk to offshore personnel. The potential risk of snagging on the submerged leg 'stubs' is also recognised by fishermen, who prefer the legs to be left upright where they can be seen.

As a result of this analysis and extensive stakeholder engagement, our recommendation is to leave the GBS structures in place. They would be fitted with remotely operated navigation aids, marked on charts and included on the FishSAFE database. The very small risk of collision risk to other users of the sea from leaving the legs in place will be further reduced by the navigational and warning measures described above.

Our studies suggest it is likely that the visible part of the legs would remain in place for 150-250 years. We predict that the legs would degrade slowly as the seawater penetrates the concrete and the steel bars begin to corrode. This slow process of degradation and corrosion would have no measurable impact on the environment. It is difficult to predict how and when the legs will eventually collapse, but once the visible part has degraded the subsea section of the legs is expected to last for another 300-500 years. The present 500 m radius safety zones would remain in place as long as any part of the GBSs was above sea level, and we would apply for a continuation of these zones once the GBSs were no longer visible.

Decommissioning the GBS Cell Contents: After consultation with BEIS, we carried out a CA for the cell contents, to ensure there was consistency in the process across the different Brent facilities. A comprehensive list of potential management options was created using expert input from chemical engineers, environmental scientists and remediation specialists. Further analysis indicated that there were five technically feasible options, comprising three 'leave in place' options (with or without *in situ* treatment) and two 'removal' options.

Both of the removal options involve cutting large (3-5m diameter) holes into the top of all 42 oil storage cells in the GBSs, and removing the cell water and sediment as a watery "slurry". The slurry, which would be approximately 10 times the volume of the actual sediment removed, would then be handled several times, either to transport it to another location for pumping down a new well, or to shore for storage and then treatment and disposal. For the purpose of the CAs of these feasible options, we assessed the safety risks, environmental impacts, societal risks, technical feasibility and cost implications of activities and operations both offshore and onshore. An important part of these studies was the assessment of the environmental implications of leaving untreated or partially treated materials in the GBSs.

Our long-term fate modelling studies and ecotoxicological assessment – both of which were undertaken by independent organisations – show that while the GBSs remain intact little will happen to the sediment if it is left untreated inside the cells. The Environmental Impact Assessment (EIA), supported by the ecotoxicological assessment and the extensive numerical fate modelling, has concluded that release of the cell contents would not have a significant negative impact on the marine environment. For the water phase, the results show that there would be acute transient potential impacts that would not exceed 17 km from the point of release at the platform and would not last more than 3-5 days. For the sediment phase, there would be a long-term but localised impact on the seabed within 2 km of the platform, but this would only occur in the unlikely event that a significant proportion of the sediment were fully exposed on the seabed after the final degradation and collapse of the GBSs. Given the estimated volume and characteristics of the cell sediment, and its location deep within concrete cells, the recommended option for its management is to leave it in place untreated, encased in the cells. The significant technical difficulties and cost of mobilising and removing the cell sediment, as well as onshore treatment and disposal, proves disproportionate to the small and localized environmental legacy impact of leaving the sediment in place.

Conclusion

The final recommendations contained in this document are the result of 10 years of exhaustive studies, the completion of the detailed CA process and extensive stakeholder engagements. In order to understand the environmental impact of the recommendations, an EIA has been performed by DNV GL for Shell and is presented in the Brent Field Decommissioning Environmental Statement (ES). The EIA shows that decommissioning operations offshore and onshore would not be likely to have any significant adverse environmental or societal impacts. The legacy effects offshore would either be transient or confined to areas within 2km of the platforms, and in both cases would not be likely to result in noticeable negative impacts at a regional level.

Decommissioning is under way and is estimated to be completed by 2026. We have started with Brent Delta and will finish with the programme of subsea debris clearance around Brent Charlie. The proposed programmes of work are expected to generate approximately 10,000 person-years of work over the period 2016 to 2026. About 36% would be associated with the remaining P&A programme, 48% with offshore preparations and lifting, and 16% with onshore dismantling and disposal. On completion of the offshore decommissioning operations, we propose that two surveys would be undertaken around each Brent site to determine if the decommissioning programmes have had any measurable effects on the adjacent seabed. The first survey would be shortly after decommissioning, and the second about five years later. The timing, frequency and scope of subsequent environmental surveys will be discussed and agreed with BEIS. On completion of all the offshore programmes of work, a detailed survey of each structure, pipeline and cuttings pile would be undertaken to assess and record its 'as-left' condition. The timing, frequency and scope of subsequent visual surveys will be discussed and agreed with BEIS.

In accordance with the Petroleum Act 1998, the responsibility for the subsequent management of on-going residual liabilities, including managing and reporting the results of the agreed post-decommissioning monitoring, evaluation and any remedial programme, will remain with the present owners. All the structures and pipelines which are proposed to be left in place remain the property and responsibility of the Brent Field licensees.

PARTNER LETTER OF SUPPORT FROM
ESSO EXPLORATION AND PRODUCTION UK LIMITED

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PARTNER LETTER OF SUPPORT FROM
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Aberdeen
AB10 1BJ

30th January 2017

Dear Sir or Madam

PETROLEUM ACT 1998
BRENT FIELD DECOMMISSIONING PROGRAMMES

We acknowledge receipt of your letters dated 23rd January 2014 and 12th December 2014 regarding the abandonment programmes for the Brent pipelines and the Brent installations respectively.

We, Esso Exploration and Production UK Limited, confirm that we authorise Shell U.K. Limited to submit on our behalf abandonment programmes relating to the Brent installations and Brent pipelines as directed by the Secretary of State on the above date.

We confirm that we support the proposals detailed in the consultation draft of the Brent Decommissioning Programmes document, which is to be submitted in February 2017 by Shell U.K. Limited.

Yours faithfully

Carole J Gall
CNNS Asset Manager – UK Joint Interest

For and on behalf of Esso Exploration and Production UK Limited

Registered in England
Number 3834848
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PART ONE
INTRODUCTION AND BACKGROUND INFORMATION

These Sections present:

1. Background information about the Brent Field and its history.
2. A summary of the environmental conditions in the Brent Field.
3. A description of how we have managed the Brent end-of-field-life operations.
4. An overview of the range of facilities to be decommissioned.
5. A summary inventory of the materials on and in the facilities to be decommissioned.

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2 INTRODUCTION

This document presents the Decommissioning Programmes (DP) for the Brent Field installations and associated pipelines (Figure 10 and Table 5). Shell U.K. Limited (the operator of the Brent Field) and Esso Exploration and Production UK Limited are the owners in equal shares of the Brent Field.

The Brent Field comprises 4 platforms, 28 pipelines and 4 subsea structures with a total mass of about 1.8 million tonnes. In various ways all the platforms are linked to each other or to third party assets, and in our initial planning we carefully considered the chronological sequence of decommissioning and the implications for other platforms and systems. We started planning these complex decommissioning programmes in 2006, and as a result of this extensive period of study, evaluation and assessment there is a substantial body of work which:

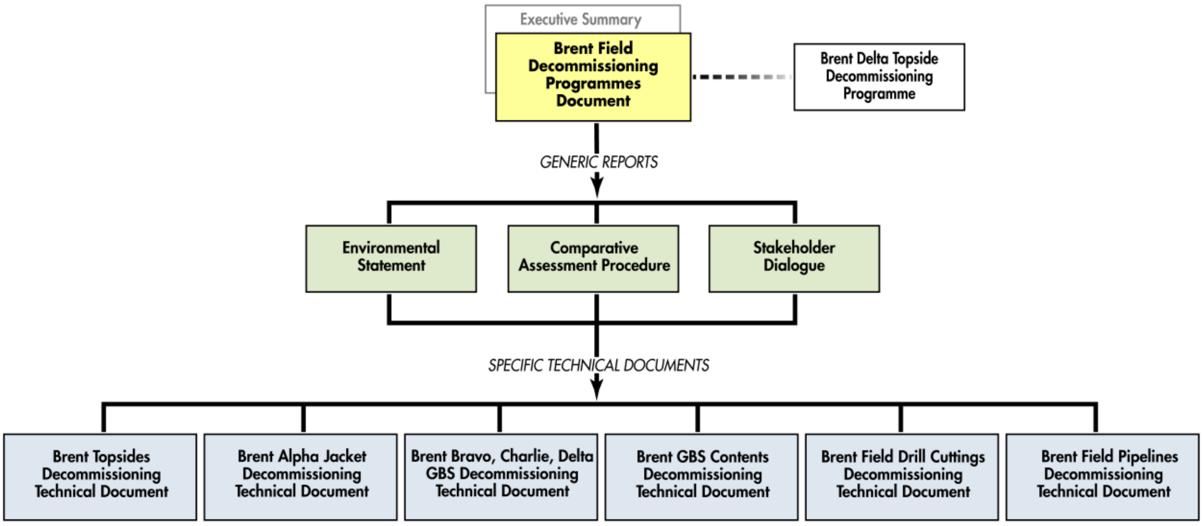
- Describes the facilities and their environmental settings
- Provides information on the technical and engineering aspects of a range of decommissioning options, and the ways in which those options could be undertaken; and
- Examines the advantages and disadvantages of technically feasible options

After discussion with BEIS we have chosen to present essential, detailed descriptive and factual information, and where necessary full Comparative Assessments (CA), in six separate Technical Documents (TD) which support and inform the DPs. The DPs in this document therefore focus on describing:

- The process we followed to identify technically feasible options.
- The safety, technical, environmental, economic and societal implications of different options.
- The important differences between options.
- The recommended options for each of the facilities.
- The proposed programmes of work for decommissioning the Brent Field.
- The continuing responsibilities that we will have for any assets or material remaining in the Brent Field.
- The monitoring programme that we would undertake to assess the environmental impacts of any assets or material left in the Brent Field.

Figure 7 shows the suite of documentation for the DPs. The TDs are designed to be read after the DP document, supplementing it and providing detail to the facts, assessments and conclusions presented in the DPs. The full title of each reference is given when first cited, and thereafter by the document's number in brackets [ ] as listed in Section 25 Supporting Material.

Figure 7 Brent Field Decommissioning Programmes and their Supporting Documentation.



The decommissioning of oil and gas facilities on the United Kingdom Continental Shelf (UKCS) is regulated by the *Petroleum Act 1998* [1] and amendments, which provides the framework for the implementation in the UK of *OSPAR Decision 98/3 on the Disposal of Disused Offshore Installations* [2]. The *DECC Guidance Notes: Decommissioning of Offshore Oil and Gas Installations and Pipelines under the Petroleum Act 1998* [3] provide guidance and advice in the preparation of DPs. Owners must prepare a programme for the decommissioning of all installations and pipelines, and submit a formal DP to BEIS in a timely manner for review and approval.

As a result of OSPAR Decision 98/3 there is a presumption that all installations will be removed from their present locations on the seabed, and re-used, recycled, or disposed of onshore. OSPAR 98/3 recognises, however, that this may not be practical or safe in all circumstances, and has indicated certain categories of facilities that may be candidates for derogation from the general presumption of total removal. If a facility is a candidate for derogation, the owners are required to carry out a CA of feasible options, including the option of full removal.

Under the Petroleum Act 1998 and the Section 29 Notices that have been served on the co-venturers, Shell and Esso have a joint and several obligation for the decommissioning of the Brent Field. Esso confirms that it fully supports and endorses the proposed programmes, and that it authorises Shell to submit DPs as directed by the UK Secretary of State.

The installations and facilities in the Brent Field are covered by two Section 29 Notices, and in accordance with the Notices that have been issued to the owners, and as required by the Petroleum Act 1998, two DPs are presented in this document (Table 4). The Brent Delta topside is covered by a separate Section 29 Notice, dated 12th December 2014, and the *Brent Delta Topside Decommissioning Programme* [4] was approved in July 2015.

Table 4 The Two Decommissioning Programmes in this Document.

Decommissioning Programme	Section 29 Notice Date	Facilities Covered
DP1 – Installations	12th December 2014	Brent Alpha, Bravo and Charlie platforms, and the Brent Delta substructure being the whole of the structure located beneath the steel transition pieces on top of the concrete legs, and including without limitation all associated subsea equipment.
DP2 – Pipelines	23rd January 2014	The Brent Field pipeline system, and associated seabed infrastructure, namely: PL001 PL002 PL002A[9] PL017 PL044 PL045 PL046 PL047 PL048 PL049 PL050 PL051 PL052 PL987A PL987A.1 PL987A.2 PL987A.3 PL988A PL1955 It is noted that some of these PWA[10] numbers cover several of Shell's pipelines number prefix 'N'.

Table 5 shows how the various Sections of this Decommissioning Programmes document relate to these two Programmes.

[9] PL002A is listed on the Section 29 Notice, but is not within the scope of the Brent Decommissioning Project

[10] PWA: Pipeline Works Authorisation

Table 5 The Arrangement of Sections in this Decommissioning Document.

No	Section Heading	DP1 Installations	DP2 Pipeline System
	Executive Summary		
1	Executive Summary	Combined	
	Partner Letter of Support	Combined	
	Part 1: Introduction and Background Information		
2	Introduction	Combined	
3	Background Information	Combined	
4	End of Field Life Management	Combined	
5	Facilities to be Decommissioned	Combined	
6	Inventory of Materials	Combined	
	Part 2: Assessment of Decommissioning Options		
7	Alternative Uses for Platforms and Facilities	Combined	
8	Decommissioning Options and Comparative Assessment Method	Combined	
9	Method used to Assess Environmental Impacts	Combined	
10	Stakeholder Engagement	Combined	
	Part 3: Decommissioning the Brent Facilities		
11	Decommissioning the Brent Field Wells	11	N/A
12	Decommissioning the Platform Topsides	12	N/A
13	Decommissioning of the Brent Alpha Steel Jacket	13	N/A
14	Decommissioning the Brent Concrete GBSs	14	N/A
15	Decommissioning the GBS Cell Contents	15	N/A
16	Decommissioning Other Materials in the GBSs	16	N/A
17	Decommissioning the Brent Field Drill Cuttings Piles	17	N/A
18	Decommissioning the Seabed Infrastructure	18	N/A
19	Decommissioning the Brent Pipeline System	N/A	19
20	Programme of Work for Debris Clearance	Combined	
	Part 4: Programme Management		
21	Schedule and Industrial Implications	Combined	
22	Environmental Impact Assessment	Combined	
23	Project Management and Verification	Combined	
24	Pre- and Post-Decommissioning Monitoring	Combined	
	Part 5: Supporting Material		
25	Supporting Material	Combined	
26	Acronyms and Glossary	Combined	

3 BACKGROUND INFORMATION

3.1 Introduction

The Brent Field and its pipeline system are located in Block 211/29 of the UK sector of the North Sea, approximately 136 km east of the Shetland Islands (Figure 8). The Field is part of the extensive oil and gas infrastructure which has been established over the last 40 years in the East Shetland Basin; there are 11 platforms, 3 floating installations, 17 templates and 4 subsea clusters within 25 km of the Brent locations covered in this DP document (Figure 9).

Figure 8 Block Location of the Brent Field and Pipeline System.

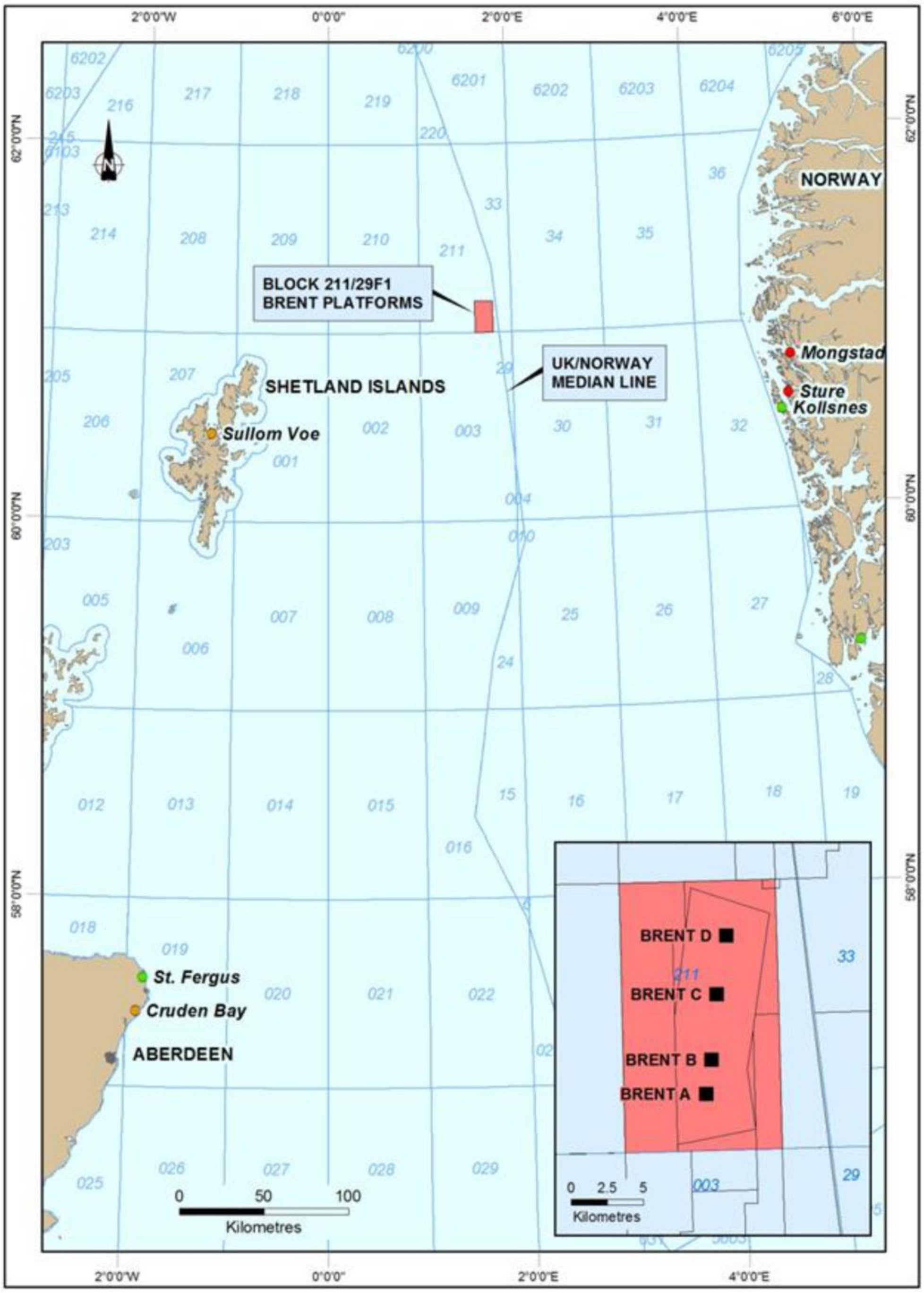


Figure 9 Location of Other Facilities within 25 km of the Brent Field.

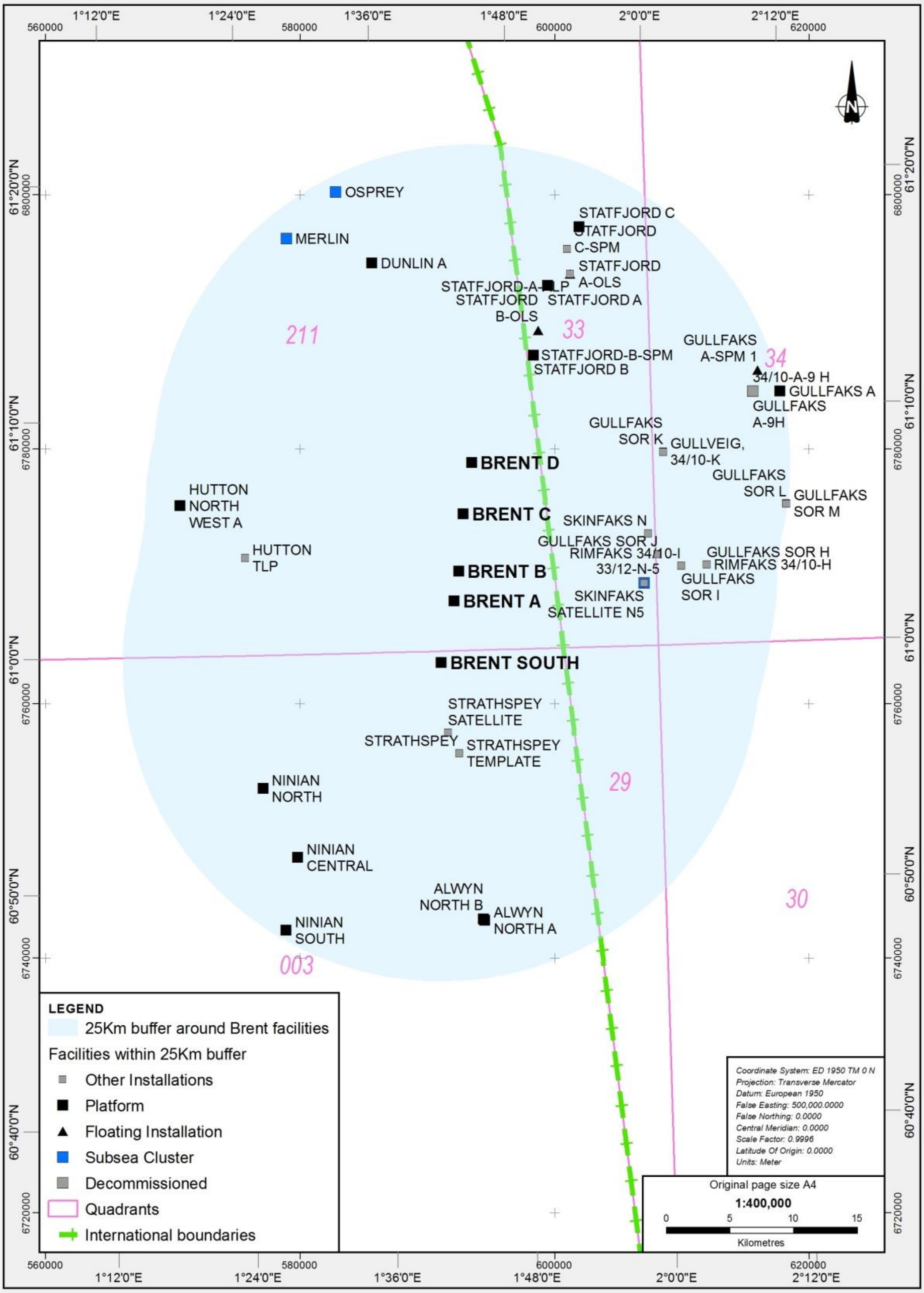
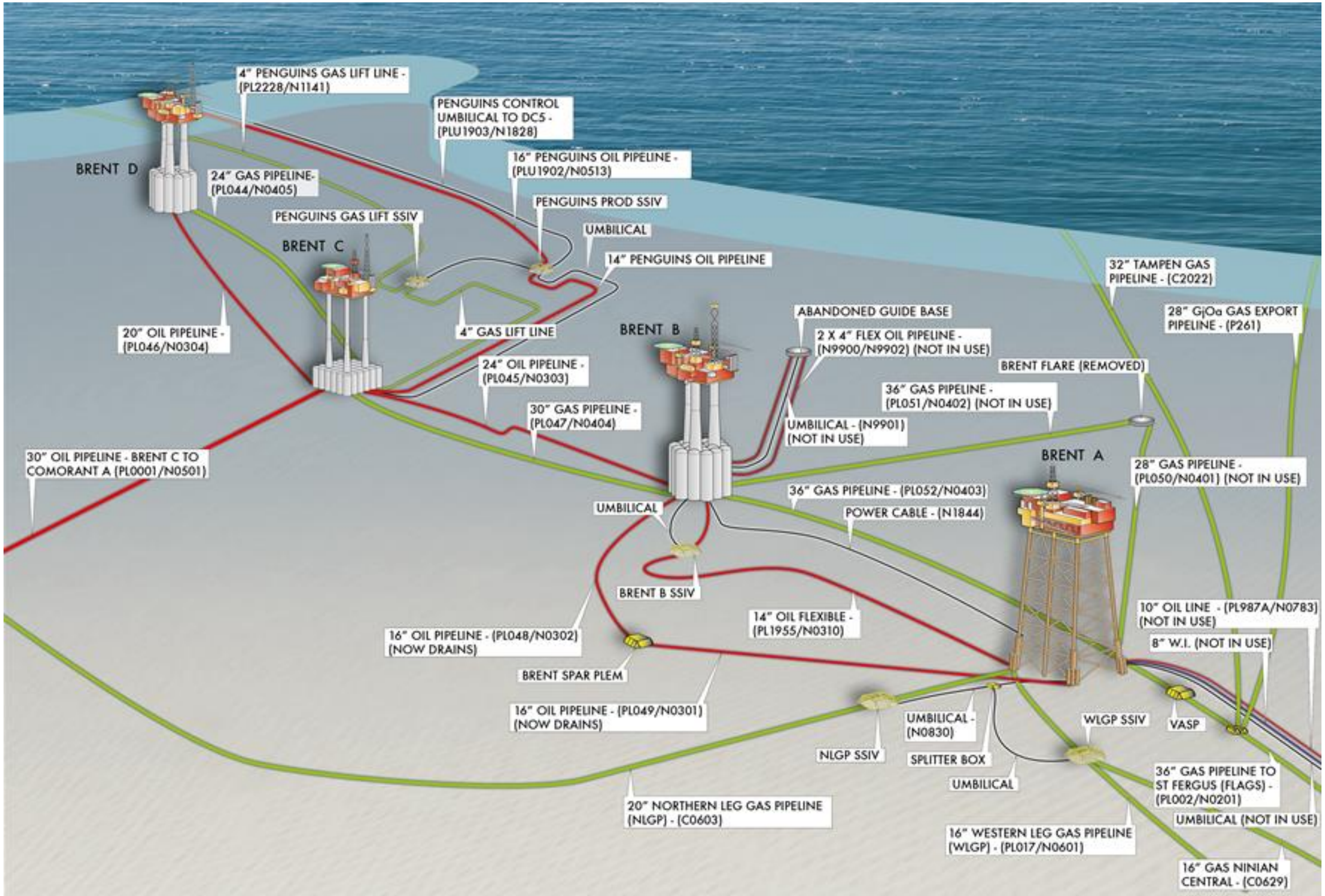


Figure 10 The General Arrangement of Facilities in the Brent Field.



3.2 Development History

Brent was discovered in 1971, and during 40 years of operations (Table 6) has produced approximately 2 billion barrels of oil and 6.0 trillion cubic feet of gas, together amounting to some 3 billion barrels of oil equivalent. At its peak in the late 1980s to early 1990s, the Brent Field alone provided approximately 8% of the UK's total gas consumption. To date, about 99.5% of the economically recoverable reserves in the Brent Field have been recovered, a historically high value for North Sea fields. The Brent Field has also created and sustained thousands of jobs, contributed more than £20 billion[11] in tax revenue, and provided the UK with a substantial amount of its oil and gas.

Table 6 History of the Development of the Brent Field.

Date	Event	Date	Event
1971	Brent Field discovered	1995	Brent Spar removed from the Field
1975	First platform, Brent B, installed	1995	Brent upgraded for major gas export
1976	Development drilling begins	1996	Brent South decommissioned
1976	First oil produced, from Brent Bravo	1998	Discharge of oil-based mud cuttings ceases
1976	Brent A and D installed	2004	Well plug and abandonment begins (at Brent South)
1978	Brent C installed	2009	Dates for Cessation of Production (CoP) agreed with DECC
1981	First gas exported	2011	Brent Delta ceases production
1988	Pipeline to Sullom Voe installed	2014	Brent Alpha and Brent Bravo cease production

3.3 Environmental Setting

The Brent Field: The environmental setting of the Brent Field is summarised below. A full description of the environmental settings can be found in our *Brent Field Decommissioning Environmental Statement* (ES) [5] which has been prepared for us by Det Norske Veritas (DNV GL). Table 7 summarises the physical, biological and socio-economic environments in the Brent Field.

The character of the benthos, and in particular the changes that have occurred as a result of the permitted discharge of cleaned oily cuttings and the recovery that has begun since those discharges ceased in 1996, are well documented by a series of seabed surveys, the most recent of which was in 2015. With the exception of work along the export pipeline PL001/N0501, the vast majority of offshore work in the Field will occur within the 500 m safety zones around the four installations, areas which have been covered by all the benthic surveys.

Transportation route to shore and transfer site: We have contracted Able UK Limited to dismantle and dispose of three topsides and the Brent Alpha upper jacket, and this work will be undertaken at the Able Seaton Port (ASP) facility on Teesside. The characteristics of the offshore route from the Brent Field to the River Tees, and the nearshore transfer site off The Headland at Hartlepool, are described in the ES [5]. The proposed transit route passes twelve offshore conservation areas and directly through one conservation area, the NE of Farnes Deep Marine Conservation Zone (MCZ). The transfer site is outside but close to areas of potential Annex 1 sandbank and reef habitats. Numerous conservation areas are present within a 40 km radius of the centre of the proposed transfer site.

[11] In today's money

Onshore dismantling, treatment and disposal sites: The characteristics of the short tow route into the River Tees, and the ASP facility and its environs, are described in the ES [5]. A detailed description of the onshore facilities at the ASP facility is given in the ES and the *Brent Topsides Decommissioning Technical Document* [6]. The ASP facility is located on the north side of the Tees estuary, adjacent to the Teesmouth National Nature Reserve (NNR), where Annex II common seals and grey seals haul out at low tide. This is the only area on England's north-east coast where common seals regularly breed.

Table 7 Summary of the Physical, Biological and Socio-economic Environments in the Brent Field.

Aspect	Summary Data			
Water column	Water depth	140.2-142.1 m	Tidal range	1.83 m
100 year return wave	Amplitude	26.2 m	Period	15.5 seconds
Maximum current speeds	Surface	0.86 $m.s^{-1}$	Seabed	0.46 $m.s^{-1}$
Water temperature	Maximum	13°C	Minimum	6°C
Seabed sediments	Muddy sand, with holes and mounds created by burrowing fauna especially Norway lobster *Nephrops*.			
Benthos	Characterised as 'North British Coastal zone' and 'offshore Northern North Sea', dominated by polychaetes, crustaceans, bivalves and echinoderms.			
Fish	Demersal and pelagic species, predominantly cod, haddock, whiting and herring. Platform located within spawning areas for herring, whiting, lemon sole, Norway pout, sandeels, sprat and *Nephrops*.			
Shellfish	Norway lobster *Nephrops*.			
Marine mammals	Low densities of cetaceans; most commonly occurring species are harbour porpoise and white-beaked dolphin. White-sided dolphin, Risso's dolphin, bottlenose dolphin, fin whale and minke whale have also been recorded.			
Seabirds	Important area for seabirds, particularly in summer, especially guillemot, fulmar, kittiwake and razorbill. Other species include puffin, herring gull, little auk, arctic tern, gannet, great skua, arctic skua, sooty shearwater, cormorant and common tern.			
Conservation interests	Marine mammals are designated species. There are numerous colonies of coral *Lophelia pertusa* on all four platforms. The nearest offshore SAC is Braemar Pockmark, 225 km away.			
Commercial fishing	The relative value of commercial fisheries in ICES rectangle 51F1, in the Brent Field area, is 'Moderate' to 'Low'. Fishing effort in 51F1 is 'Low' and dominated by demersal gear types.			
Shipping	Within 50 km there are 14 recognised shipping lanes, used by 8,430 vessels each year. Shipping density in the Brent Field ranges from 'low' to 'very low'.			
Nearest oil and gas activities	Statfjord Field, 9.6 km to the northeast.			
Commercial activity	With the exception of oil and gas activity, and commercial fishing, there is no other commercial activity at the site.			
MOD activity	None			
Wrecks	Nearest marked wrecks are 9 km away from Brent Alpha and Brent Bravo.			

4 END OF FIELD LIFE MANAGEMENT

4.1 Managing Declining Production

The Brent Field was discovered in 1971 and production started in 1976. In total, 146 wells and side-tracks have been drilled, accessing all parts of the extensive Brent reservoir.

We completed a major restructuring programme (called the Long-Term Field Development project, LTFD) in 1996 and this changed the Field from producing predominantly oil to producing predominantly gas. This boosted production and extended field life by approximately 10 years. Further upgrades, reconfigurations and management of the provision and distribution of fuel gas from Brent Charlie have all contributed to maximising production and minimising costs. In recent years, therefore, Alpha has produced oil and some gas, Bravo and Charlie have produced mostly gas, and Delta has produced mostly oil.

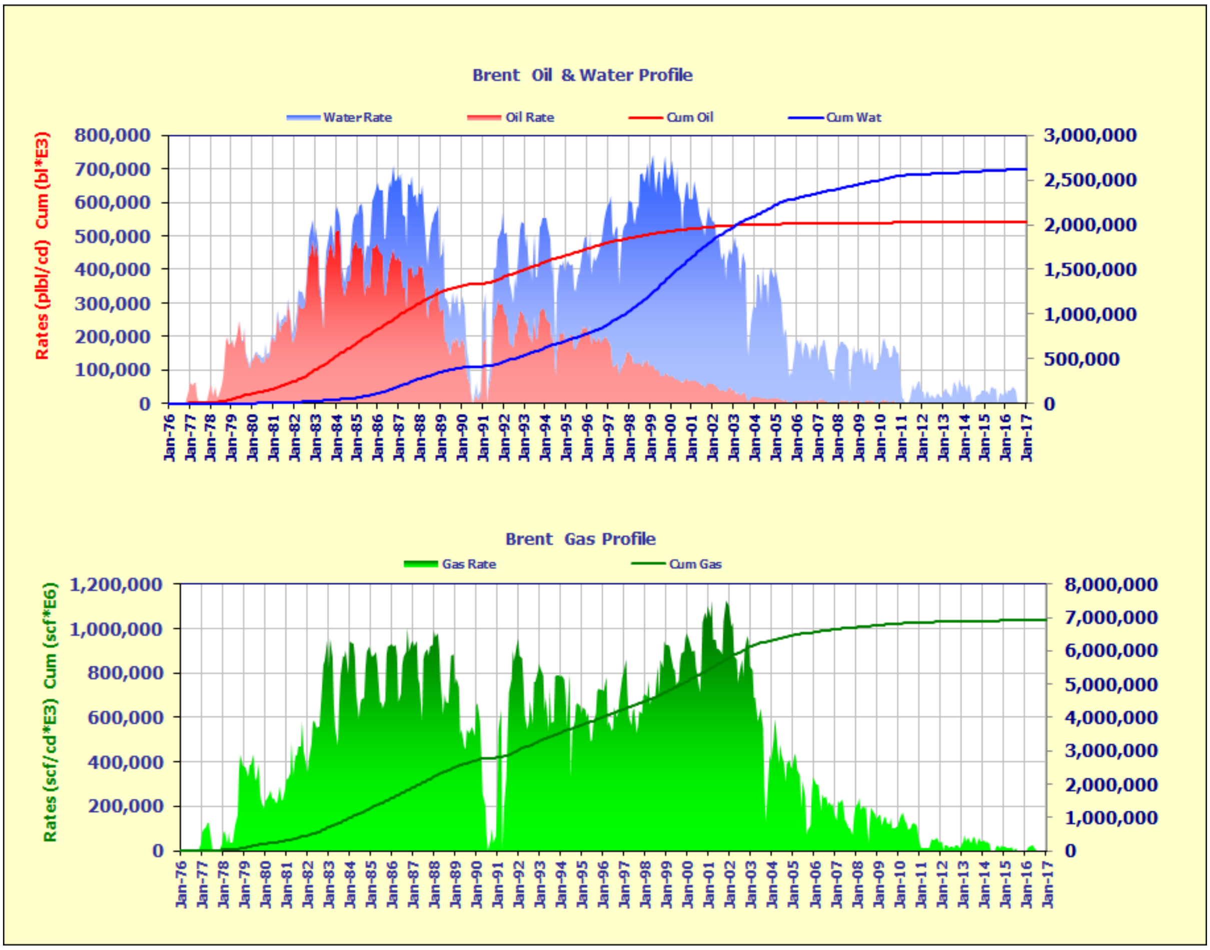
Up to 1991 oil was exported from the Field by shuttle tanker, loading oil from the Brent Spar buoy. The three GBSs have storage cells that allowed oil production to be stored for several days between tanker visits, but they were also designed to help process and separate the crude oil. When the Brent Charlie-Cormorant Alpha oil export line (PL001/N0501) was commissioned, loading from the Spar ceased and the cells were mostly used for processing oil, rather than storing it.

We have continually evaluated the Field's performance and the state of its reservoir and producing wells, and updated our forecasts of future production and remaining reserves. The challenge faced in managing end-of-field life is to maximize production from the reservoir safely and cost-effectively. End-of-life management, and determining a date for cessation of production (CoP), need careful consideration because the Brent Field is a complex set of facilities and processes. The platforms in the Field interact with each other by providing various services and functions, and also with platforms and fields belonging to third parties. For each platform, the options available for managing end-of-field life and for eventual decommissioning are strongly influenced by these interactions – some options may not be possible because of the influence of other assets, and some may not be acceptable because of the influences they would have on other assets.

4.2 Timing of Cessation of Production

Plateau production levels were achieved in the period 1998 to 2002, and since then production of both oil and gas have declined significantly. Figure 11 presents graphs showing the daily and cumulative production of oil and water (red and blue lines respectively in the upper graph) and gas (lower graph) since 1976. Despite detailed investigations since 2006, no viable or economically sustainable programmes or measures can be put in place to extend production.

Figure 11 Brent Field Production Profile, 1976 to 2008.



Upper graph: Red line is Cumulative Production of Oil: Blue line is Cumulative Production of water

Lower graph: Green line is Cumulative Production of Gas

In 2006 we initiated detailed discussions with DECC (now BEIS) about possible dates for CoP which examined fiscal, economic, technical and safety implications both for ourselves as owners and the UK Government. As these progressed it became clear that, despite earlier hopes that it would be economically viable to continue production on some platforms and thus carry out a phased cessation of production, all four platforms were rapidly coming to the end of production.

Three of the four Brent platforms have now ceased production (Table 8) and we have reached agreement with DECC (now BEIS) that Brent Charlie will cease production in the near future.

Table 8 CoP Dates for Three Brent Platforms.

Platform	Date of CoP
Alpha	1st November 2014
Bravo	1st November 2014
Delta	31st December 2011

5 FACILITIES TO BE DECOMMISSIONED

5.1 Overview

The Field is served by four platforms, each comprising a substructure which supports the topsides. At Brent Alpha, the substructure is a steel jacket, fixed in place by steel piles driven into the seabed. At Bravo, Charlie and Delta the substructure is a concrete Gravity Base Structure (GBS) comprising a matrix of large storage cells (called the caisson) made of reinforced concrete. The GBSs are held in place by their own weight, additional solid ballast (in Bravo and Delta), and vertical skirts and dowels that penetrate up to 9 m into the seabed.

We have confirmed by sampling that the Brent Delta GBS contains various solid and liquid materials in the oil storage cells. All the GBSs processed fluids from the same reservoir and operated in broadly the same way. Samples taken from the topsides process systems on all three GBSs have very similar physical characteristics and chemical composition. We have therefore assumed that the oil storage cells on Brent Bravo and Brent Charlie contain the same type of solids (called 'sediment') as Brent Delta. From historical records on sand production we have derived estimates of the volumes of sediment in the bottom of the oil storage cells on all three GBSs. The sonar surveys have shown that the average mapped volume of sediments in the 3 cells on Brent Delta (1,044 m^3 per cell) is close to the estimated volume we derived from our desk-top studies (1,080 m^3 per cell).

We also know that the Brent Delta GBS contains various solid and liquid materials in the bottom of the drilling legs and the minicell annulus[12]. We have sampled these materials in the Brent Delta drilling legs and minicell annulus, and in the Brent Bravo minicell annulus. We have assumed that the Brent Bravo drilling legs have the same types and amounts of materials as Brent Delta, and will carry out sampling operations on Bravo to confirm this.

As discussed in Section 8.1 we have considered all these materials to be substances that determine the characteristics of the GBSs. Options for their management were therefore assessed and compared according to our CA procedure.

Drill cuttings containing amounts of hydrocarbons are present on the seabed beneath Brent Alpha and at Brent South, and on the cell-tops and around the bases of Brent Bravo, Brent Charlie and Brent Delta. In a 2007 survey the total volume of seabed and cell-top drill cuttings in the Field was approximately 32,000 m^3.

We completed a further comprehensive seabed survey around all five Brent sites in 2015. This included further sampling of the cuttings piles. The samples from the 2015 survey are currently being analysed. This survey did not include the Brent Charlie drill cuttings piles within 50 m of the platform because of the expected length of time until Brent Charlie CoP. We will sample these drill cuttings pile again closer to CoP.

The platforms are connected to each other and to other platforms by approximately 103 km of subsea pipelines, umbilicals and power cables that fall within the scope of the Brent Field Pipelines DP. These lines range in diameter from 2.5 inches (control umbilical) to 36 inches (gas export pipeline). Approximately 54 km (53%) of the pipeline network is either trenched into the seabed or covered by stable rock-dump.

Four subsea structures are included in this DP document; the Sub-Sea Isolation Valve (SSIV), the PipeLine End Manifold (PLEM), the Valve Assembly Spool-Piece (VASP) and the splitter box.

[12] The minicell annulus is the space between the minicell and the wall of the utility leg, and is described and illustrated in Section 16.3

The subsea wells at Brent South were taken out of service in 1996. The wells were plugged and abandoned between October 2004 and March 2005, and during this period the wellheads and upper casings were removed and taken to shore. All that remains are the historic cuttings pile, four pipelines, and short sections of rock-dump with approximately 109 concrete mattresses beneath the rock-dump.

The well at Brent 7 was taken out of service in 1977 and subsequently plugged and abandoned. All that remains is a steel conductor guide frame.

Overall, the materials covered by the Brent Field DPs include approximately 295,000 tonnes of steel, 568,000 tonnes of concrete, 238,000 tonnes of sand ballast and 16,000 tonnes of rock-dump. Table 9 summarises our best estimates of the material in the two DPs.

Table 9 Summary of Brent Field Materials.

- *Brent Platforms*
    - Brent Alpha topsides and steel jacket (including conductors), 47,453 tonnes
    - Brent Bravo topside and GBS, 364,817 tonnes
    - Brent Charlie topside and GBS, 327,880 tonnes
    - Brent Delta GBS, 325,418 tonnes
    - Sediments in oil storage cells of the concrete gravity base structures, approximately 73,300 tonnes in total
    - Oily ballast water in GBS storage cells, approximately 638,500 tonnes in total
    - Other solid wastes in GBS caissons and legs, approximately 8,100 tonnes in total
    - Historic drill cuttings piles at all four installations and at Brent South, approximately 68,700 tonnes in total
    - Historic drill cuttings in GBS tri-cells, approximately 53,500 tonnes in total.
    - Seabed debris, approximately 600 tonnes
- Brent Field Pipeline System
    - 28 lines, approximately 103 km; approximately 25,129 tonnes of steel, 21,896 tonnes of concrete and 16,000 tonnes of rock-dump
    - 4 subsea structures, approximately 467 tonnes
    - Concrete mattresses, approximately 489 (1,762 tonnes)
    - Grout bags, approximately 4,156 (104 tonnes)

6 INVENTORY OF MATERIALS

6.1 Introduction

We have prepared inventories of the materials presently on and in all the facilities (Table 10 and Table 11). These are based primarily on the original plans for the structures, our databases of weight and centre-of-gravity calculations, and the records of modifications and additions that have been made over the years. We have surveyed the topsides, and carried out some intrusive inspection where necessary and where it was safe to do so. The various TDs supporting the DP present detailed information about the inventories of individual structures and the whole pipeline system.

6.2 Condition of Facilities after CoP

After CoP the topside process systems will be drained, purged and vented (via the cold flare system), as appropriate, to ensure that no pockets of hydrocarbon liquid or gas are present. As a safety measure, additional vents may be created at selected locations in the topside process system to ensure they are not recharged from any trapped inventories. All drained systems will be left open to the atmosphere to allow free-venting to occur so that gases do not build up. Pipes and tanks in the topsides will be cleaned to the extent required to ensure that there is no risk to personnel or the environment during the removal of the topside, but final cleaning may be undertaken onshore where cleaning can be carried out more efficiently and safely. A detailed description of how we will prepare the topside for removal by the Single Lift Vessel (SLV) *Pioneering Spirit* is given in Section 12.

The subsea pipeline system will be depressurised and flushed to remove remaining inventory; the oil lines will also be pigged to remove any residual solid hydrocarbons adhering to the walls of the pipes. All the lines will then be left filled with inhibited seawater, pending the approval of the Decommissioning Programme. Pipeline cleaning operations are described in Section 19.7.6.

Table 10 Inventory of Materials Covered in DP 1, Brent Field Installations.

Material (tonnes)	Alpha	Bravo	Charlie	Delta	South	All Subsea Note 1
Steel topsides	11,921	19,572	25,448	Note 2	N/A	N/A
Steel support structure	18,974	33,300	57,700	35,700	N/A	N/A
Grout (concrete)	5,204	12,747	9,082	12,747	N/A	N/A
Risers steel	345	302	365	78	N/A	N/A
Wells steel	4,285	6,039	6,357	7,628	N/A	N/A
Other steel structures	5,122	7,003	7,428	8,404	N/A	384
Stainless steel	459	1,349	1,732	1,311	N/A	N/A
Copper and copper alloys	174	396	510	407	N/A	N/A
Alloy steel	216	285	329	276	N/A	N/A
Anodes	256	N/D	N/D	N/D	N/A	N/D
NORM	43	123	152	119	N/A	N/A
Asbestos	4	9	9	9	N/A	N/A
Ethylene/Propylene & PVC	104	65	88	72	N/A	N/A
Halon	0	1	0	0	N/A	N/A
Rubber and Neoprene	28	28	28	28	N/A	N/A
Insulation	31	99	83	105	N/A	N/A
Lead	11	6	13	11	N/A	N/A
Titanium	28	31	32	31	N/A	N/A
Concrete (GBS)	N/A	132,500	230,000	142,000	N/A	N/A
Paint (topsides)	1,245	961	899	899	N/A	N/A
Ballast sand	N/A	133,227	N/A	115,234	N/A	N/A
Attic oil	N/A	0 (Note 3)	4,219 (Note 4)	640	N/A	N/A
Oily water	N/A	163,840	311,667	163,040	N/A	N/A
Sediment in GBS cells	N/A	31,104	10,863	31,104	N/A	N/A
Material in minicell annulus	N/A	325	N/A	325	N/A	N/A
Material in drilling legs	N/A	2,640	N/D	2,640	N/A	N/A
External drill cuttings	12,600	14,374	25,314	12,040	4,332	N/A
Cuttings in tri-cells (assumed)	N/A	24,078	N/A	29,466	N/A	N/A
Debris on seabed & celltops	109	337	109	77	0	N/A
Total	61,159	584,741	692,427	564,391	4,332	384

Note 1. 'All subsea' comprises 4 structures – the SSIV, the PLEM, the splitter box and the VASP. Being subsea structures they are technically part of DP 1.

Note 2. The Delta topside has been covered by a separate DP [4]

Note 3. Interphase material only

Note 4 Only the oil storage cells.

Table 11 Inventory of Materials Covered in DP 2, Brent Field Pipelines.

Material (tonnes)	Pipeline Type			
	Rigid Lines	Flexible Lines	Umbilicals and Power Cables	Total
Steel	24,486	585	58	25,129
Other metals	0	0	7	7
Concrete	21,896	0	0	21,896
Zinc anodes	184	0	0	184
Asphalt enamel	1,194	0	0	1,194
Polypropylene	180	61	2	243
Other plastics	0	73	0	73
Concrete mattresses	0	1,762	0	1,762
Total	48,005	2,478	67	50,488

Note: 1. The values in Table 11 assume that the pipelines has been flushed and pigged as described in Section 19.7.

PART TWO
ASSESSMENT OF DECOMMISSIONING OPTIONS

These Sections present:

1. A summary of our review of possible alternative uses for some or all of the Brent facilities.
2. A description of the procedure we used to identify suitable decommissioning options, and the method we used to prepare detailed Comparative Assessments of options, where required.
3. A summary description of the method used to assess the potential environmental impacts of all the options subject to Comparative Assessment.
4. An overview of the work that we performed to establish and maintain effective dialogue with our stakeholders.

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7 ALTERNATIVE USES FOR PLATFORMS AND FACILITIES

7.1 Screening Method

While preparing the Final Field Development Plan (FFDP) in support of our application to DECC (now BEIS) to agree CoP, we examined the feasibility of many options for the Brent Field and its facilities. We then performed a high level review of a long-list of alternative uses for the Brent facilities, using the following general approach and principles:

- Options should be permissible under the current legislation, and should have due regard to the requirements of OSPAR Decision 98/3 and the Petroleum Act 1998.
- The level of safety risk to project personnel and third parties should be tolerable and As Low As Reasonably Practicable (ALARP).
- The principles of the Waste Hierarchy should be followed.
- Options should be technically feasible using existing vessels, equipment, facilities and procedures, or using vessels or facilities that are expected to become commercially proven and available within the timescale of the Brent Decommissioning Project (BDP). It should be noted that at the time of screening, the SLV *Pioneering Spirit* was still a concept, and it was not envisaged that it would be commercially available within the timeframe of the BDP. Clearly this situation has changed, and the SLV option is discussed in Section 13. The outcome of our screening of alternative uses would not have changed, however, had the SLV been available.
- Options were considered in light of the owners' Business principles (Shell General Business Principles.[13]

After examining possible options, and in the light of the considerable general literature concerning the viability of alternative uses and options for offshore structures in the North Sea, we divided possible options into three categories, as defined below.

No action required	We did not investigate these options any further because we concluded that: • The option was extremely unlikely to be undertaken • There were no, or few, business drivers within Shell or Esso for this option • There was little or no stakeholder expectation that this option would be undertaken by anyone
Check required	We considered these options in more detail because we concluded that: • The option was technically feasible but unlikely to be undertaken • There may be business drivers within Shell or Esso for this option, but they were unclear • There was some stakeholder expectation that this option would be undertaken by someone
Study required	We completed some specific studies on these options because we concluded that: • The option was technically feasible • There were clear business drivers within Shell or Esso for this option • There was a clear stakeholder expectation that this option would be undertaken

[13] Shell General Business Principles; http://www.shell.com/content/dam/shell-new/local/global-content-packages/corporate/sgbp-english-2014.pdf).

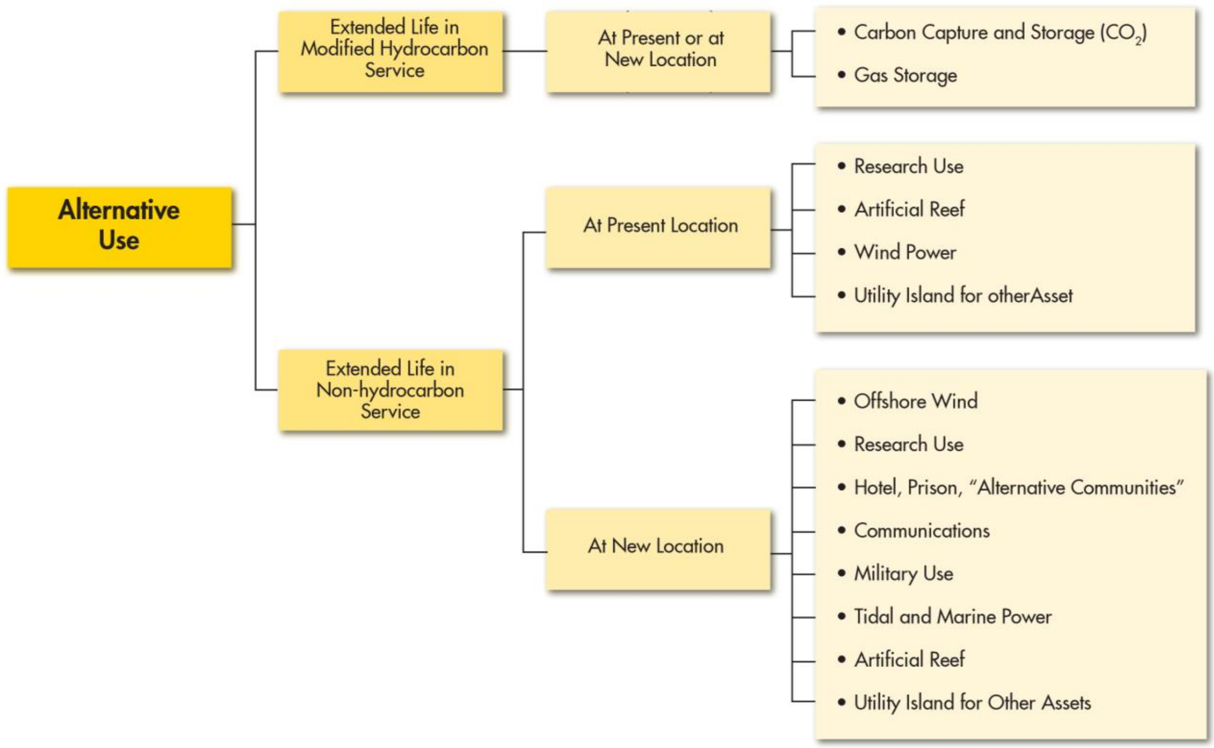
7.2 Generic Opportunities for Re-use

Generic studies have identified many possible alternative uses for decommissioned oil and gas structures (mostly for platforms) (Figure 12).

In planning their own decommissioning programmes, individual owners have examined some or all of these alternatives to determine if any were applicable and viable for their specific site or platform. For owners, the important issues that must be considered in such an assessment include confirmation that:

- The proposed alternative use falls within the owners' core business activities or is an opportunity to significantly advance its sustainable development aspirations.
- There is a strong demand from other industries, or society, for this use.
- The facility is suited for the new use and/or can be cost-effectively converted to this use.
- The alternative use will be economically viable, and, in particular, have no net negative effect on the owners' commercial operations.
- If the liability for decommissioning remains with the present owners, the alternative use will not make the ultimate decommissioning programme riskier or more expensive.

Figure 12 Possible Alternative Uses for Decommissioned Oil and Gas Structures.



7.2.1 Re-use Options Examined for Brent Facilities

7.2.2 Introduction

As described below, we have assessed several possible generic or specific re-use options for the Brent Field facilities and assigned them to one of the categories defined in Section7.1.

7.2.3 Other Oil and Gas Operations

We have checked the availability of such uses. We have tried to identify other oil and gas uses for the facilities in their present locations, for example as tie-in points for small fields that could be developed using subsea wells. We have not been able to identify any such opportunities to use Brent platforms *in situ* for oil and gas operations.

If it were technically feasible to move the whole Brent Alpha jacket, it could be installed in another field with new or refurbished topsides, but we have not found any opportunities to use it for oil and gas operations at any other location. Given the age and probable life-expectancy of the jacket, and the costs of repairs, modernisation and recertification, it is very unlikely that this option would be economically viable.

7.2.4 Carbon Capture and Storage

We have conducted studies on this option. The report by Sigma3 *Brent Facilities CO_2 re-use study* [7] examined the possibility of using the Brent Field and some or all of the platforms as a site for Carbon Capture and Storage (CCS). We concluded that it would not be technically feasible to use the Brent Field for CCS, and it would not be economically viable to use any of the platforms as injection sites. The recent report *Murchison Decommissioning Comparative Assessment Report* [8] by Canadian Natural Resources (CNR) highlighted the technical difficulties and economic realities of offshore CCS and reached a similar conclusion. The main reasons why the Brent Field and facilities could not be used for CCS are as follows:

1. The Brent Field is remote from sources of Carbon Dioxide (CO_2).
2. After all the Brent platforms have ceased production the FLAGS pipeline will continue to be used by other operators for the export of gas. A major new pipeline about 450 km long would have to be laid to carry gas from St Fergus (the only realistic existing landfall) to the Brent Field.
3. The facilities on the Brent platforms are not adequate for handling CO_2 because of the significant corrosion risk associated with CO_2, and they would have to be replaced.
4. The existing Brent wells are not in a condition to enable CO_2 injection and would, as a minimum, have to be worked over.
5. The present well locations may not be optimal for injection.
6. Because of the number of side-tracks into the Brent reservoir, there is a high risk that CO_2 would react with the cement grout, which would eventually lead to the migration of CO_2 to the surface.
7. The Brent reservoir is not suited to CCS. It would be difficult to fracture the rock and achieve sufficient penetration to accommodate the large volume of CO_2 that would have to be pumped down-hole in any commercially viable scheme. In addition, the reservoir is complex and contains several fault lines and isolated pockets, and does not lend itself to the cost-effective creation of a sub-surface store.

7.2.5 Other Uses

We have considered the viability of these options. Historically, particularly in generic decommissioning studies, it has often been proposed that redundant offshore oil platforms could be converted for a variety of non-oil and gas uses such as prisons, marine research stations, aquaculture, or renewable energy. No such conversions have been undertaken on the UKCS to date, and any such proposals are likely to fail the tests of technical feasibility and commercial viability. Put simply, the costs of maintaining and running ageing platforms for alternative uses would be too high, and any extension of useful life would just delay the eventual decommissioning.

We have concluded that no alternative use option for any Brent platform would be technically feasible or economically viable, and therefore that no further action is required on any of them.

7.2.6 Artificial Reefs

We have considered the viability of this option. Redundant oil platforms have been used as 'modules' in artificial reefs in other parts of the world, most notably in the Gulf of Mexico where they help to support a thriving offshore sports fishing industry. Several coastal states in America have State Artificial Reef Plans that are managed under the auspices of the National Artificial Reef Plan. There are clear guidelines for the selection of reef sites and the approval of materials for donation to reefs, and there are legally binding agreements on the transfer of the ownership of, and liability for, reef modules.

No such framework exists in the North Sea, and there is evidence to suggest that commercial fishermen in general do not support the creation of offshore reefs on the European continental shelf. OSPAR has established *Guidelines on artificial reefs in relation to living marine resources* [9] which explicitly excludes the use of redundant oil and gas platforms as reefs materials, unless they are first brought to shore and cleaned. Such onshore cleaning operations would negate any reductions in safety risk or cost that could be achieved by leaving the structures *in situ* or moving them while submerged to an approved reef location.

Finally, research work undertaken by UKOOA in the late 1980s and early 1990s, culminating in a report for the Offshore Decommissioning Communications Project (ODCP) called *Creating artificial reefs from decommissioned platforms in the North Sea* [10], indicates that the beneficial effects of individual, isolated offshore platform reefs would be small in relation to the sizes and geographic distribution of North Sea fish stocks.

With little support from European fishermen, no framework for the transfer of ownership and liability, marginal ecological benefits, and the need for expensive and risky cleaning and preparatory work, we have concluded that it would be neither feasible nor economically viable to develop the Brent platforms into artificial reefs and, therefore, that no further action is required.

7.3 Conclusion

We have not been able to identify any technically feasible and economically viable alternative uses for any of the Brent facilities, either for oil and gas or non-oil and gas opportunities. Accordingly, all the facilities covered by these two DPs will have to be decommissioned.

8 DECOMMISSIONING OPTIONS AND THE COMPARATIVE ASSESSMENT METHOD

8.1 Introduction

OSPAR Decision 98/3 states: *'The dumping, and the leaving wholly or partly in place, of disused offshore installations within the maritime area is prohibited'*. OSPAR recognised, however, that there may be difficulties in removing the footings of large steel jackets weighing more than 10,000 tonnes, and in removing concrete installations, and created a provision for owners of such structures to apply for derogation from the general rule of complete removal. If owners wish to apply for derogation, they must demonstrate that *'…an assessment shows that there are significant reasons why an alternative disposal [option] is preferable to re-use or recycling or final disposal on land'* [2]. To achieve this, the owners must carry out a CA of viable options, including the option of complete removal.

OSPAR Decision 98/3 lists the following categories of installations (excluding their topsides) where derogation may be considered:

a. Steel installations weighing more than 10,000 tonnes in air[14].

b. Gravity based concrete installations.

c. Floating concrete installations.

d. Any concrete anchor-base which results, or is likely to result, in interference with other legitimate uses of the sea'.

We completed CAs in accordance with the OSPAR requirements for all four installations [2], and in accordance with the requirements of the DECC Guidance Notes [3] for each of the pipelines. Having devised a quantitative method for performing these CAs, and after consultation with BEIS, we applied exactly the same method to the assessment of options for the cell contents (since they are *'substances contained within the GBSs'* and the GBSs are subject to CA), and to the materials in the minicell annulus and the drilling legs (because they too are 'substances in the GBS', and because the CA fulfils the role of a Best Available Technique (BAT) assessment for the purposes of identifying a suitable option for the management of these materials). All the seabed drill cuttings piles in the Brent Feld fall below both the thresholds set out in *OSPAR Recommendation 2006/5 on a Management Regime for Offshore Cuttings Piles* [11], but because the Brent Alpha seabed would have to be disturbed in one of the options for the Brent Alpha footings we performed a CA of options for the management of that pile to inform recommendations about the BA footings. The cell-top cuttings piles on Bravo and Delta both fall below the OSPAR thresholds, but we performed precautionary CAs for them in case they have to be moved to permit decommissioning operations to be carried out on other facilities or materials. Modelling showed that the cell-top cuttings pile on Charlie exceed the annual oil loss rate, and so we performed a Stage 2 CA of management options for this pile, as required by OSPAR Recommendation 2006/5 [11].

This section:

- Summarises the options that were compared for each facility
- Identifies and describes the criteria that we selected to compare options
- Summarises the method that we used to complete the Comparative Assessments

[14] DECC Guidance Notes [3] state that only the footings or part of the footings may be left in place.

The results of the Comparative Assessments are presented in Sections 13 to 19 which:

- Describe the important aspects of the options for each facility
- Identify the recommended option for each facility, and the reasons for that recommendation

A comprehensive description of our CA procedure, with some discussion of sensitivity to changes in weightings, is presented in our document *Brent Field Decommissioning Comparative Assessment Procedure* [12].

8.2 Decommissioning the Topsides

The topsides of all four Brent platforms, which are not subject to any CA, will be removed and returned to shore for dismantling and recycling as described in Section 12. The removal of the Delta topside has already been approved following our submission of a separate DP [4]. We have determined that no technically feasible option for the platform support structures (the BA jacket and the concrete GBSs) would require the continuing presence of the topsides. The options for the BA jacket and for the GBSs therefore assume that the topsides have been removed, and the removal of the topsides does not form any part of their programmes of work.

8.3 Infeasible Options for Substructures

As a result of our detailed studies we came to the following conclusions, which have determined the technically feasible options for the Brent substructures:

1. As described fully in the *Brent Alpha Jacket Decommissioning Technical Document* [13] and summarised in Section 13.2 to Section 13.4, there is no technically feasible method for removing the whole of the Brent Alpha jacket in one piece. All options, including the use of the SLV *Pioneering Spirit*, would require the jacket to be removed in two or more pieces, beginning with the removal of the upper jacket down to 84.5 m below Lowest Astronomical Tide (LAT). Consequently, we confirm that the upper part of the Brent Alpha jacket will be removed to shore for dismantling and recycling, and our CA considers only the technically feasible options for the decommissioning of the footings (see Section 13.3 for a definition of footings).
2. For a number of very significant technical and safety reasons that are discussed fully in the *Brent Bravo, Charlie and Delta GBS Decommissioning Technical Document* [14] and summarised in Section 14.5, the removal of any of the GBSs by refloating - essentially the reverse of the original installation procedure – is not considered to be viable. Consequently, we confirm that we will be applying for derogation for the each of the Brent GBSs, and our CAs examine the costs and benefits of removing parts of the legs while leaving the bulk of the substructure in place.

8.4 Decommissioning Options

Decommissioning options comprise logical combinations of:

- The 'operations' that may be carried out offshore and onshore to decommission, dismantle, remove, recycle or treat components and materials from offshore facilities.
- The legacies or consequences that may be achieved by the successful completion of operations.

This distinction between operations and legacies is useful when considering the relative advantages and disadvantages of options. It reflects the fact that operational effects may be more or less immediate, local and possibly short-lived, whereas end-point effects may be slow-acting and diffuse.

Table 12 lists the installations or items subjected to CA, and the technically feasible options that were assessed. All the options are summarised in Sections 13 to 19, and the detailed CAs for each of these facilities are presented in the Alpha Jacket TD [13], the GBS TD [14], the *Brent GBS Contents Decommissioning Technical Document* [15], the *Brent Field Drill Cuttings Decommissioning Technical Document* [16] and the *Brent Field Pipelines Decommissioning Technical Document* [17].

Table 12 The Technically Feasible Decommissioning Options for each Brent Installation or Item which was Subjected to CA.

Installation or Item	Feasible Options Identified for Comparative Assessment
BA steel jacket footings, after removal of topside and upper jacket	1. Complete removal to shore.
	2. Leave in place.

BA seabed cuttings pile	1. Remove, treat on platform, discharge treated material to sea.
	2. Remove, treat all material onshore.
	3. Remove, dewater, treat solids onshore.
	4. Remove, inject down hole at new remote well.
	5. Leave in place.

Cell-top drill cuttings: *(i) For Charlie because the oil release rate exceeds 10 TE/year. (ii) For other cuttings piles that may have to be moved for the removal attic oil and interphase material.*	1. Displace small amount into water column (Bravo and Delta only).
	2. Remove, treat on platform, discharge treated material to sea.
	3. Remove, treat all material onshore.
	4. Remove, dewater on platform, treat solids onshore.
	5. Remove, inject down hole at new remote well.
	6. Leave in place (Brent Charlie only).

Concrete GBSs, after removal of topsides	1. Partial removal of legs to -55 m.
	2. Leave in place.

GBS cell contents and Material in MiniCell Annulus and Material in Drilling Legs	1. Remove and inject into new remote wells offshore.
	2. Remove and treat slurry onshore, and dispose onshore.
	3. Leave in place and cap.
	4. Leave in place with monitored natural attenuation (MNA).
	5. Leave in place.

Pipelines, umbilicals and power cables Note: This is a list of all the technically feasible options for the pipelines. Not all of these options apply to every pipeline, umbilical or power cable, because of their size, characteristics or present status.	1. Leave tied in place with no further remediation.
	2. Leave tied-in at platforms, trench remote ends.
	3. Leave tied-in at platforms, rock-dump remote ends.
	4. Disconnect from platforms/infrastructure and trench and backfill whole length.
	5. Disconnect from platforms/infrastructure and rock-dump whole length.
	6. Remove whole length by cut and lift.
	7. Remove whole length by reverse S-lay (single joint).
	8. Partial trench and backfill with isolated rock-dump on all shallow trenched sections (PL001/N0501 only).
	9. Partial rock-dump all shallow trenched sections (PL001/N0501 only).

8.5 Method Used to Complete Comparative Assessments

8.5.1 Introduction

This section describes the method that we used to perform the CAs on those facilities that were subject to CA (Table 12). A description and discussion of the full procedure is presented in the Brent Decommissioning Project's (BDP) CA Procedure [12].

Throughout this description and the subsequent narratives on CA, the term 'performance' is used for simplicity to describe the ability of an option to result in desirable effects, either when expressed in terms of the raw data or weighted score for a particular *sub-criterion*, or the total weighted score of the *option*.

8.5.2 Comparative Assessment Criteria

All the CAs were performed following the DECC Guidance Notes [3] and the Shell BDP CA Procedure [12], with appropriate modification for the materials and the options under consideration. Technically feasible options were assessed using the five main DECC criteria, namely:

- Safety
- Environmental
- Technical
- Societal
- Economic

We used the advice provided in the Guidance Notes which lists those matters which are to be considered during a CA of feasible management options. These include but are not restricted to:

- Technical and engineering aspects
- Timing
- Safety
- Impacts on the marine environment
- Impacts on other environmental compartments
- Consumption of natural resources and energy (and climate change)
- Other consequences to the physical environment
- Impacts on amenities and the activities of communities
- Economic aspects

In line with this guidance, therefore, we assessed each option's performance by dividing that criterion into more specific sub-criteria. For example, the main criterion 'Environmental' encompasses both the potential environmental impacts arising during the work programme (which is likely to be on a timescale of a few months) and the potential environmental impact arising from the exposure or release of the GBS contents to the marine environment over an extended period of time. By evaluating these different risks as separate sub-criteria, we were able properly to record the performance of options in these two measures and examine how environmental impacts changed with different options.

We decided that the main criterion 'Safety' should be assessed using three sub-criteria, 'Environmental' using four sub-criteria and 'Societal' using three sub-criteria (Table 13). The main criteria 'Technical' and 'Economic' were each assessed by one sub-criterion.

Table 13 The DECC 5 Main Criteria and the Selected Sub-criteria used in all Brent CAs.

DECC Main Criterion	Sub-criterion	Description
Safety	Safety risk to offshore project personnel	An estimate of the safety risk to offshore personnel as a result of completing the proposed offshore programme of work.
	Safety risk to other users of the sea	An estimate of the safety risk to other users of the sea from the long-term legacy of the structure after completion of the proposed programme of work.
	Safety risk to onshore project personnel	An estimate of the safety risk to onshore personnel as a result of completing the proposed onshore programme of work.
Environmental	Operational environmental impacts	An assessment of the environmental impacts that could arise as a result of the planned operations offshore and onshore.
	Legacy environmental impacts	An assessment of the environmental impacts that could arise as a result of the long-term legacy effects of the structure or facility after completion of the proposed programme of work.
	Energy use	An estimate of the total net energy use of the proposed programme of work, including an allowance for energy saved by recycling and energy used in the manufacture of new material to replace otherwise recyclable material left at sea.
	Gaseous emissions	An estimate of the total net emissions of CO_2 from the proposed programme of work, including an allowance for emissions from the manufacture of new material to replace otherwise recyclable material left at sea.
Technical	Technical feasibility	An assessment of the technical feasibility of being able to complete the proposed programme of work as planned.
Societal	Effects on commercial fisheries	An estimate of the financial gain or loss compared with the current situation that might be experienced by commercial fishermen as a result of the successful completion of the planned programme of work.
	Employment	An estimate of the man-years of employment that might be supported or created by the option.
	Communities	An assessment of the effects of the option on communities and onshore infrastructure.
Economic	Cost	An estimate of the total likely cost of the option, including an allowance for long-term monitoring.

8.5.3 Comparative Assessment Data

We elected to use a method of assessment that uses 'global scales' as a way of i) providing a unit-less scale on which to compare different sub-criteria (e.g. safety risk to other users of the sea and environmental impact of operations) and ii) providing a way to compare the performance of the options across all of facilities within the BDP. The procedure for generating the global scales involved the following three steps:

1. For each sub-criterion the data for each option for each facility were generated using the same method of calculation. For example, if the cost estimate for a Brent Alpha jacket option had been generated using current vessel day rate estimates and ignoring any effect of inflation that might be expected to occur between now and the execution of the work, then the cost of a GBS option was calculated using these same assumptions.
2. Considering each sub-criterion in turn, the 'best' and 'worst' data from any option and for any facility was used to fix the top and bottom of the scale for that sub-criterion. For example, the option with the highest Potential Loss of Life (PLL) is the least desirable and therefore marks the bottom of the scale and is therefore '0' on the scale. The option with the lowest PLL is the most desirable and is therefore '1' on the scale. This resulted in a 'global scale' spanning the whole data range for each sub-criterion.
3. We then arithmetically transformed the data for all other options onto these global scales. Thus, a single global scale for each sub-criterion could be used and applied consistently in all of the CAs for all of the facilities. This process of transformation converted the different sub-criteria into a common measure which then allowed us more easily and robustly to examine and compare the overall performances of the options.

For the majority of the sub-criteria listed in Table 13 we generated numerical data such as values for PLL, energy use (in gigahoules, GJ) and cost (£); the methods used to obtain these data are described in the CA Procedure [12].

The estimation of safety risk was an important aspect of this work, and the following description of the derivaion and application of PLLs is taken from our CA procedure [12]:

> 'PLL is one of the prime outputs of a quantitative risk assessment (QRA). It provides a measure of cumulative risk which is directly dependent on the number of people exposed to the risk and the duration of the activity. In this context it therefore provides a simple measure of the relative safety risk between project personnel who may be engaged in operations to complete an option, and third-parties who may be exposed to the long-term risk from the planned end-point of the option. PLLs can and are therefore used in the overall decision-making process (such as in a CA) along with considerations of the environmental impacts, costs and other criteria.
>
> There are absolute values of risk tolerability used by authorities such as the Health and Safety Executive (HSE). For example, risks between 1×10^{-1} and 1×10^{-3} are considered intolerable and risks between 1×10^{-3} and 1×10^{-6} are in the region where it has to be shown that the risks are tolerable and are ALARP. Within a decision-making process such as a CA, however, it should be stressed that PLL figures should not be used as an absolute measure of risk because the total PLLs here represent the cumulative predicted risk for different groups of people and activities, and there is no analysis of the options to determine the effects of any risk-reduction measures that would or could be applied. Such detailed analysis occurs once an option has been selected, and it is at this point that the specific PLLs for a given activity could be compared with the HSE thresholds above'.

The assessment of four of the sub-criteria - 'operational environmental impacts', 'legacy environmental impacts', 'technical feasibility' and 'impact on communities' - required the use of expert judgements on the performance of the options, and therefore had no fixed numerical scale against which to score the options. Following advice from the independent consultancy Catalyze, who are Multi-Criteria Decision Analysis (MCDA) experts, we established a methodology for ensuring that the scores provided by the experts could be used to create a global scale that maintained the mathematical accuracy of the performances of the options relative to each other on the global scale.

For the sub-criterion 'Technical Feasibility' (TF), Shell engineers attended a series of facility-based workshops to discuss and score each of the options under consideration. An aid to scoring was developed, which listed factors which would affect the likelihood of successfully executing the option and included considerations such as the novelty of the equipment required and the susceptibility of the workscope to unplanned events. This resulted in a score on a 'local scale' (which was out of 45) and an understanding of the reasons behind this score. The Shell engineers then assessed whether the initial scores gave a realistic and justifiable measure of the relative technical feasibility of the options, and ranked the options from best to worst. The Shell engineers then examined the differences between each of the scores to satisfy themselves that the relative position of each option was consistent and justifiable. For example, if Option A scored 30, Option B scored 15 and Option C scored 45, then the technical feasibility of Option B was half that of Option A and the difference in technical feasibility between Option B and Option C was twice that of the difference between Option A and Option B. The Shell engineers discussed and agreed any adjustments to the scores that they deemed necessary to ensure that the scores of the options on the local scale were correct relative to each other, and the reasons for any adjustments were recorded.

A plenary TF workshop was then held at which the technical feasibilities of the options across the facilities were discussed and compared, with the objective of agreeing an assessment for each option which was relative to and consistent with all options across all facilities. This plenary workshop was facilitated by Catalyze and witnessed by the IRG. In summary, using the judgement of the Plenary TF Team, the best option with respect to of technical feasibility across all of the BDP facilities was defined as '1' on the global scale. Similarly, the worst option for TF across all facilities was defined as '0' on the global scale. The best and worst options for each facility were then placed on the global scale, referring to the record of the facility-based workshops as necessary. The intermediate options (those between 'best' and 'worst') were placed onto the global scale by simple arithmetic mapping from the local scale position for each facility onto the global scale, using the 'best' and 'worst' options for each facility as reference points. The resulting option placements on the global scale were then reviewed and any further changes documented.

DNV GL assessed the potential environmental impacts that could arise from each of the options under consideration in the CA as part of their work to complete the EIA. We therefore asked DNV GL to provide their expert judgement for the scoring of the two environmental impact sub-criteria and the 'impact on communities' sub-criterion. As an initial step, DNV GL reviewed the type and degree of impact for each of the options under consideration. They then discounted any impact which duplicated any other sub-criterion that had been separately assessed for the purpose of the CAs; for example, the impact under the EIA category 'Fisheries' was removed because the commercial effect on fisheries was the subject of a separate sub-criterion in the CA. This resulted in a judgement of the overall impacts arising from the execution of the different options and the reasons for each judgement, similar to the process used in the facility-based workshops held by Shell to generate scores for TF. The DNV GL scores for the environmental impacts of each option were therefore informed by the EIA, but do not necessarily directly correspond to the impact assessments presented in the ES because the EIA assessments consider each facility in turn and do not assess the magnitude of impacts across the different facilities. DNV GL then attended a plenary workshop, again facilitated by the MCDA experts and witnessed by both the IRG and Shell representatives. The same process as described for TF was followed for operational environmental impacts, legacy environmental impacts and impacts on communities, producing scores on a global scale for each of the three sub-criteria which reflected each option's relative position.

Ultimately the work described here resulted in a suite of data appropriate for use in the BDP CA (Table 14), and a set of global scales for each sub-criterion (Table 15).

Table 14 The Source and Type of Data used to Assess the Performance in each Sub-criterion.

Sub-criterion	Source of Information	Type of Data	Unit
Safety risk to offshore project personnel	Internal study by Shell	Numerical	PLL
Safety risk to other users of the sea	Studies by Anatec [15, 16], [17]	Numerical	PLL
Safety risk to onshore project personnel	Internal study by Shell	Numerical	PLL
Operational environmental impacts	Score provided by DNV GL	Score	
Legacy environmental impacts	Score provided by DNV GL	Score	
Energy use	Environmental Statement	Numerical	Gigajoules
Emissions	Environmental Statement	Numerical	Tonnes
Technical feasibility	Score provided by Shell	Narrative & Score	
Effects on commercial fisheries	Study by McKay Consultants [18]	Numerical	GBP
Employment	Study by McKay Consultants [19]	Numerical	Man-years
Impact on communities	Score provided by DNV GL	Score	
Cost	Internal study by Shell	Numerical	GBP

Table 15 Global Scales for each Sub-criterion used in Brent Decommissioning CAs.

Sub-criterion	Units	Best Value	Worst Value
Safety risk to offshore project personnel	PLL	0.0000	0.2640
Safety risk to other users of the sea	PLL	0.0000	0.2640
Safety risk to onshore project personnel	PLL	0.0000	0.2640
Operational environmental impacts *	Score	1.00	0.00
Legacy environmental impacts *	Score	1.00	0.00
Energy use (GJ)	GJ	0	1,738,959
Emissions (CO_2)	Tonnes	1	156,726
Technical feasibility*	Score	1.00	0.00
Effects on commercial fisheries	GBP	2,318,040	0.00
Employment	Man years	2,128	0.00
Communities *	Score	1.00	0.00
Cost	GBP (million)	0.00	534.14

* The maximum possible score for these sub-criteria is 1.0.

[15] Anatec, 2011. Assessment of the safety risk to fishermen from derogated footings of the Brent Alpha steel jacket [18]

[16] Anatec, 2015. Assessment of safety risks to mariners from Brent GBS [19]

[17] Anatec, 2014. Assessment of safety risk to fishermen from decommissioned pipelines in the Brent Field [20]

[18] Mackay Consultants, 2011. Brent Decommissioning: Assessment of socio-economic effects on commercial fisheries [21]

[19] Mackay Consultants, 2014. Brent Decommissioning: Likely economic and employment impacts [22]

8.6 Assessing the Performance of each Option

To begin our assessment and comparison of options, we decided to weight each of the 5 DECC main criteria equally. Where a criterion was represented by more than one sub-criterion, we decided that these too should be weighted equally. Table 16 shows the weightings for the criteria and sub-criteria, in a weighting scenario we have called the 'standard weighting'.

Table 16 'Standard Weights' for the DECC Main Criteria and Sub-criteria.

Selected Sub-criteria		DECC Main Criteria	
Description	Weight	Weight	Description
Safety risk to offshore project personnel	6.7%	20%	Safety
Safety risk to other users of the sea	6.7%		
Safety risk to onshore project personnel	6.7%		
Operational environmental impacts	5.0%	20%	Environmental
Legacy environmental impacts	5.0%		
Energy use (GJ)	5.0%		
Emissions (CO_2)	5.0%		
Technical feasibility	20.0%	20%	Technical
Effects on commercial fisheries	6.7%	20%	Societal
Employment	6.7%		
Communities	6.7%		
Cost	20.0%	20%	Economic

The scores from the global scales for each sub-criterion were multiplied by the standard weights and then summed to derive a total weighted score for each option. The option with the highest total weighted score was identified as the 'CA-recommended option'.

8.7 Examining the Sensitivity of the CA-recommended Option

The OSPAR Framework for CAs state that the CA shall be *'sufficiently comprehensive to enable a reasoned judgement on the practicability of each disposal option'*, and that *'the conclusion shall be based on scientific principles…….and linked back to the supporting evidence and arguments'* [2]. DECC Guidance Notes also state *'it is unlikely that cost will be accepted as the main driver unless all other matters show no significant difference'* [3].

To examine the sensitivity of the CA recommended option, therefore, we applied five 'selected weighting scenarios' to the scores, to generate new total weighted scores for each option. The selected weighting scenarios were derived after a consideration of the relative values in the global scales, and reflect our view, informed by feedback from meetings and dialogue, of the importance of the various criteria and sub-criteria to all our Stakeholders. Table 17 lists the five scenarios we used, and Table 18 lists the resultant weights for each of the sub-criteria in each of the selected weighting scenarios as well as the 'standard weights'.

We then examined the total weighted scores in each scenario, and assessed how the scores changed, and determined if the order of the options changed in some scenarios. This resulted in the identification of the option that was the 'Emerging recommendation'. It should be noted that this option may have been so identified because, although not necessarily always the best option in every scenario, overall it performed well in a number of the scenarios.

Table 17 The Five Weighting Scenarios used to Assess the Sensitivity of the CA-recommended Decommissioning Option.

Scenario	Description
2	Weighted to Safety: DECC criterion Safety weighted 40%.
3	Weighted to Environment: DECC criterion Environmental weighted 40%.
4	Weighted to Technical: DECC criterion Technical Feasibility weighted 40%
5	Weighted to Societal: DECC criterion Societal weighted 40%.
6	DECC 5 main criteria without Economic.

Table 18 Weighting Applied to Sub-criteria in Selected Weighting Scenarios.

Sub-criteria	Weighting Scenario					
	1	2	3	4	5	6
Safety risk to offshore project personnel	6.7%	13.3%	5.0%	5.0%	5.0%	6.7%
Safety risk to fishermen	6.7%	13.3%	5.0%	5.0%	5.0%	6.7%
Safety risk to onshore project personnel	6.7%	13.3%	5.0%	5.0%	5.0%	6.7%
Operational environmental impacts	5.0%	3.8%	10.0%	3.8%	3.8%	5.0%
Legacy environmental impacts	5.0%	3.8%	10.0%	3.8%	3.8%	5.0%
Energy use (GJ)	5.0%	3.8%	10.0%	3.8%	3.8%	5.0%
Gaseous emissions (CO_2)	5.0%	3.8%	10.0%	3.8%	3.8%	5.0%
Technical feasibility	20%	15.0%	15.0%	40.0%	15.0%	20.0%
Effects on commercial fisheries	6.7%	5.0%	5.0%	5.0%	13.3%	6.7%
Employment	6.7%	5.0%	5.0%	5.0%	13.3%	6.7%
Communities	6.7%	5.0%	5.0%	5.0%	13.3%	6.7%
Cost	20%	15.0%	15.0%	15.0%	15.0%	20.0%[1]

Note 1. On elimination of sub-criterion 'cost': In this weighting scenario, to preserve the spread of the weightings across the other sub-criteria, the sub-criterion 'cost' retains a weighting of 20% but all the options are accorded a cost of 'nil'; this means that cost does not contribute to the overall weighted score of an option.

Key to Weighting Scenarios

Scenario	Description
1	Standard weighting; equal weight to the DECC 5 main criteria
2	Weighted to Safety
3	Weighted to Environmental
4	Weighted to Technical
5	Weighted to Societal
6	DECC 5 main criteria, without Economic

8.8 Identifying the Recommended Option

We used all the above assessments and sensitivity analyses, and wider business and corporate considerations (such as reputation, 'licence to operate', and our General Business Principles) to compare and contrast the performances of the options being assessed by means of CAs, in order to identify our 'Recommended option'. The results of our comparison and the reasons for our recommendations were then presented in a narrative and in two types of diagram. Firstly, the total weighted scores of the options are presented in coloured charts such as the example in Figure 13. These show the relative contributions of each of the sub-criteria to the overall performance of the option; the larger the coloured segment, the greater the contribution that sub-criterion has made. Secondly, to aid our examination of the important sub-criteria (the 'drivers') and enable our assessment of the trade-offs between sub-criteria, we prepared 'difference charts', as shown in Figure 14. The bars show the difference in the total weighted score between the options in each of the sub-criteria; the longer the bar, the greater the difference. In this example, green bars show where Option 2 is better than Option 1 and red bars show where Option 1 is better than Option 2. The dotted line bars show the *maximum* size of the difference that there could be between any two options in each sub-criterion.

Figure 13 Example of a Bar Chart Showing the Total Weighted Scores of Three Options.

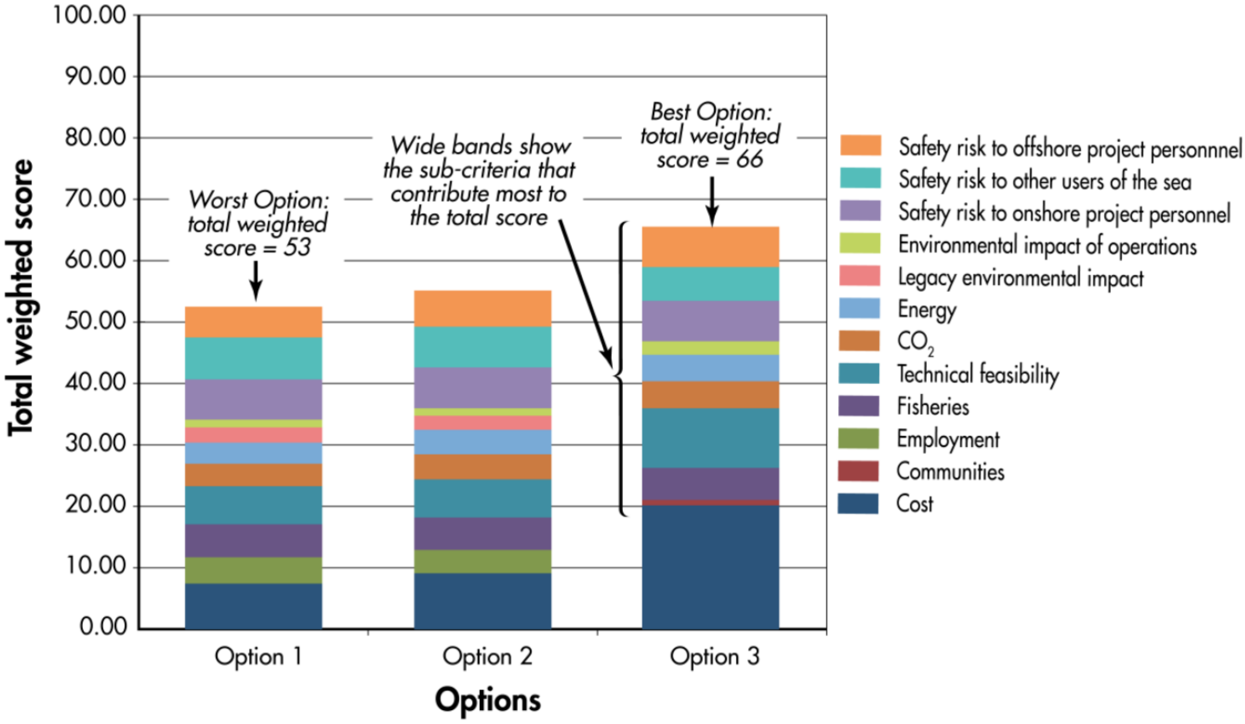
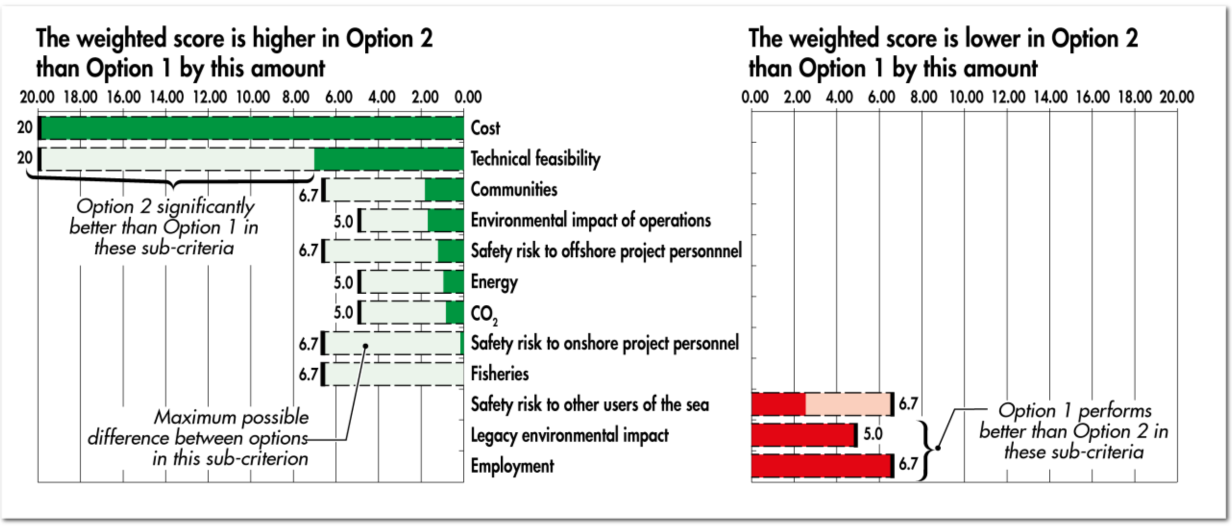


Figure 14 Example of a Difference Chart Showing the Difference between Two Options in each of the Sub-criteria.



9 METHOD USED TO ASSESS ENVIRONMENTAL IMPACTS

9.1 Introduction

DNV GL prepared an Environmental Statement on behalf of and as endorsed by Shell U.K. Limited and Esso Exploration and Production UK Limited, as the Brent Field owners, under the responsibility of the Brent Field owners to provide an Environmental Impact Assessment in support of the Brent Field Decommissioning Programme. The environmental impact assessment was completed in accordance with the requirements of the DECC Guidance Notes [3] and the UK *Offshore Petroleum Production and Pipelines (Assessment of Environmental Effects) (Amendment) Regulations* [23].

This section presents a summary of the methods that were used to assess and compare the potential impacts of short-listed options, and the way they presented their results.

9.2 Summary of Method Used to Assess Environmental Impacts

To complete the EIA and prepare the ES, DNV GL:

1. Described the possible programmes of work that would be undertaken to complete each of the short-listed options. This was done with reference to reports, studies and data supplied by the BDP and through numerous interviews and meetings with each of the lead engineers on the BDP.
2. Described the 'environmental settings', all the locations and sites offshore, nearshore and onshore, where project-related activities or operations may be carried out. This was done with reference to site-specific offshore data gathered by the BDP, project-specific baseline descriptions provided in other studies, and published data.
3. Identified the types, number and possible severity of all potential impacts from the BDP in these settings. This was done by means of a scoping report that was undertaken following the international guidance given in the EU document *'European Commission (EC) Guidance in EIA Scoping'* [24] and the EU *'Guidance Checklist of Criteria for Evaluating the Significance of Environmental Effects'* [25]. The *'Brent Decommissioning Environmental Assessment Scoping Report'* prepared by DNV [26] was published in June 2011, and stakeholders were invited to comment on its findings.
4. Calculated the total energy use and the total gaseous emissions of the proposed programmes of work. To prepare these estimates DNV GL used the widely-accepted method, reference data and factors in the Institute of Petroleum's (IoP) '*Guidelines for the calculation of estimates of energy use and gaseous emissions in the removal and disposal of offshore structures'* [27].
5. Identified those potential impacts that were considered significant, and assessed their effects in greater detail. This was achieved by scrutinising the results of the scoping report, and the comments and concerns expressed by stakeholders either in our programme of stakeholder engagement or as a result of the scoping report. Particularly significant or important issues were examined in greater depth, often by means of specialist independent studies, reports or modelling.
6. Assessed the potential cumulative effects of the both proposed Brent Decommissioning Programmes. This was done by examining the phasing of the offshore and onshore work, the numbers and magnitudes of impacts, and the ways in which these impacts might overlap or interact spatially and temporally. Specialist studies and modelling by independent experts were again used as necessary.

9.3 Assessment of Impacts and Presentation of Results

Following the EU guidance [24], potential impacts were assessed in terms of 12 criteria (Table 19).

Table 19 Criteria Selected to Examine Potential Environmental Effects.

Local Onshore: Effects of operations on local nearshore and onshore communities	Accidents: Effects of possible accidental events on the marine environment
Resource Use: Effects of the use of resources, such as fuel and raw materials	Employment: Assessment of possible employment effects from the option
Hazardous Substances: Effects of the presence, handling, treatment of hazardous substances	Legacy: Long-term physical and chemical impacts from both operations and end-points
Waste: Effects of the handling and treatment of other wastes	Fisheries: The effects of offshore *operations* on fisheries. Long-term effects assessed in *legacy*
Physical: Physical effects of offshore operations on the marine environment	Free Passage: Effects of *operations* on navigation; long-term effects assessed in *legacy*
Marine: Ecological effects of operations on the marine environment, including underwater noise	Energy and Emissions: Estimate of energy use and gaseous emissions from the complete option.

(Derived from [24].)

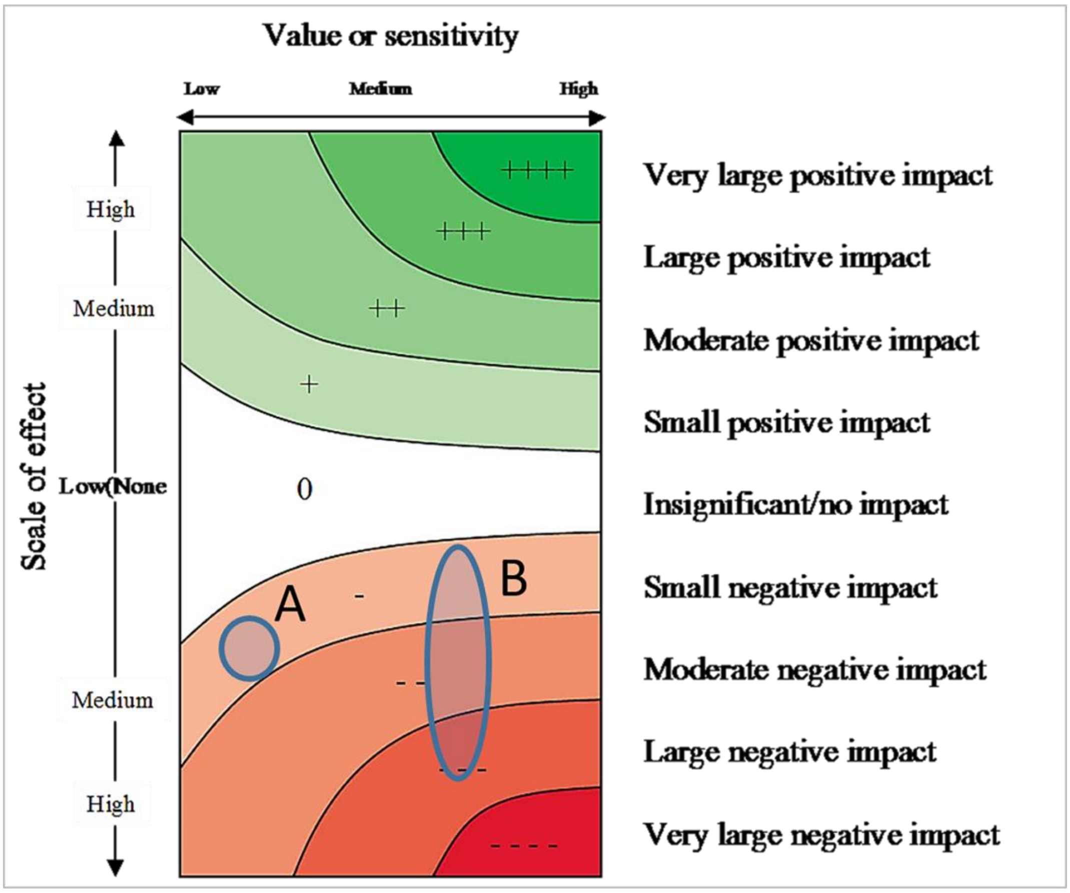
For each potential impact, DNV GL assessed the likely scale of effect, taking into consideration standard mitigation measures commonly applied by the offshore industry and the project- and site-specific mitigation measures that are identified in the ES.

The likely overall severity of the effect was determined by considering the sensitivity of the receptor or the environment and the scale or magnitude of the potential impact. For every facility, the severity of the overall effect of the option on each receptor is shown on a single diagram, as shown in Figure 15.

In these diagrams, the four curved bands shaded green indicate positive impacts of increasing (positive) effect, and the four curved bands shaded red indicate negative impacts of increasing effect. The white zone indicates where the combination of sensitivity and severity would result in no impact or an insignificant impact. The labels on the right of the diagram indicate the severities of each band. The position of the circular or elliptical area within a band or straddling a band indicates the degree of certainty or uncertainty in the assessment. For example, Point A has a small negative impact and a relatively small degree of uncertainty, as indicated by the small circle. The value or sensitivity (horizontal axis) is well defined, and the assessment of effect (vertical axis) has been determined with confidence. By contrast, Point B represents a relatively larger degree of uncertainty, because although the value or sensitivity is well defined, there is a high uncertainty about the scale of effect, and this translates into an impact ranging from 'small negative' to 'large negative'. DNV GL noted that detailed planning of activities, substantial knowledge, and robust methodologies and procedures can contribute to a reduction in the uncertainty of the assessment.

As a result of applying this methodology, the same scale of effect may give a different impact depending on the value or sensitivity of the receptor or environment. DNV GL consider this a sound basis for assessing and presenting environmental impacts. They noted that a 'moderate negative' or 'large negative' impact does not necessarily mean that the impact is unacceptable, but that further consideration should be given to it.

Figure 15 An Example of the Diagrams Used to Portray the Severity of an Impact.



9.4 Estimation of Energy Use and Gaseous Emissions

Decommissioning options will use energy and emit gases as a result of several different types of activity, including the use of vessels offshore, the running of platforms during decommissioning operations, the transportation of material at sea and on land, and the dismantling, treatment, recycling or disposal of material onshore.

All these activities are 'direct' sources of energy use. To properly account for any energy 'savings' that may be made when material is removed and taken to shore for recycling, options in which no such removal is undertaken must be 'debited' with the energy and emissions that would be associated with the new manufacture of replacement materials [27].

The total net energy use and the total masses of gaseous emissions for all short-listed options were estimated by following the IoP guidelines [27]. DNV GL took the IoP factors for the amounts of energy used and gases emitted during the combustion of different fuels and during the recycling or new manufacture of different types of materials, and applied these to our estimates of the durations of operations, the sizes of the vessel spreads for each option, and inventories of the masses of materials in structures and of the material that would be removed or left in the sea under different options.

10 STAKEHOLDER ENGAGEMENT

10.1 Introduction

Throughout the development of the Brent Decommissioning Programmes we have carried out a programme of engagement with both formal and informal consultees and stakeholders. The aims of this programme were to:

- Provide all interested parties with news and information about the BDP, the issues that we were addressing and the information that we were obtaining.
- Create a means by which stakeholders could tell us of their concerns and views on any aspect of the BDP.
- Provide mechanisms for stakeholders to learn about, and discuss, the views and concerns of other stakeholders.
- Allow us to appreciate and understand our stakeholders' concerns, and take these into account when assessing the advantages and disadvantages of different options, and identifying recommended options.

This section summarises our programme of stakeholder engagement and its important findings that informed our decision-making process. A full description of our stakeholder engagement programme, our stakeholders, and the concerns and issues they raised is given in our *Brent Decommissioning Stakeholder Engagement Report* [28].

10.2 Identifying Stakeholders

The Oil and Gas UK (OGUK) *Guidelines on Stakeholder Engagement during Decommissioning Activities* [29] define stakeholders as '*someone with a specific and defined interest in your activities; either because they could be impacted by the decisions you make and what you do, and/or because they can have impact or influence on what you do*'.

We developed a stakeholder database by referring to previous decommissioning projects, identifying organisations interested in current operations in the North Sea and following DECC's Guidance Notes [3] and the OGUK Stakeholder Guidelines [29]. Our database now contains information on over 180 organisations, involving more than 400 individuals in the UK and Europe. These cover a wide cross section of stakeholder groups including regulators, statutory[20] and other identified 'formal' consultees as listed by DECC in [3], trade unions, Non-Governmental Organisations (NGOs), business groups, local councils and community groups, and academics/researchers.

10.3 Stakeholder Engagement

We developed processes and tools for conducting a long-term programme of engagement with our stakeholders, and this comprised five main elements:

- A public website (www.shell.co.uk/brentdecomm)
- A regular e-newsletter, available from the website
- Stakeholder dialogue meetings

[20] The statutory consultees are: The National Federation of Fishermen's Organisations, The Scottish Fishermen's Federation, the Northern Ireland Fish Producers Organisation Ltd and Global Marine Systems Limited.

- One-to-one meetings with individual stakeholders or stakeholder organisations
- Presentations at conferences and meetings

Two other important activities within the BDP supported the programme of stakeholder engagement:

- The work of the IRG in reviewing our technical studies
- The publication of DNV GL's Scoping Report [26]

10.4 Stakeholder Dialogue Events

10.4.1 Organisation, Facilitation, Participation

Since the beginning of 2007 we have held seven pairs of dialogue events (in Aberdeen and London) to which all the stakeholders were invited. The events were held at 9-12 month intervals and about 50 stakeholders attended each combined event.

The events were independently run and facilitated by The Environment Council (TEC) a UK-registered charity that specialised in multi-stakeholder engagement processes, and then by Resources for Change (R4C). They were held under a 'non-attribution' rule to encourage the free exchange of views, issues and concerns, and to provide an opportunity for stakeholders to discuss topics in depth.

At the request of stakeholders, each event focussed on specific aspects of the decommissioning scope. This allowed participants to examine the various technical, environmental, safety, economic and social issues in detail, enabling them to acquire a greater level of understanding and an appreciation of the project's challenges and trade-offs. Accordingly, appropriate technical specialists from the BDP attended the events as necessary, supporting the Director of the BDP who attended every event. Representatives of the IRG attended all the events and, in the later meetings, gave short presentations on their activities, views and conclusions.

10.4.2 Disseminating Information, Recording Views and Concerns

Before each event we sent stakeholders a comprehensive set of pre-reading materials on the topics to be discussed, to enable them to participate as fully as possible on the day. At each meeting, new stakeholders were offered an introductory briefing. Following each pair of events, the independent facilitators produced a transcript of the proceedings and a full set of responses to the issues and questions raised by stakeholders; we sent this directly to all stakeholders and published it on the BDP website.

We met regularly with TEC and R4C to ensure that our engagement activities were meeting stakeholders' expectations. Stakeholder feedback was sought after every event, and consolidated and analysed by the facilitators, and published on the BDP website.

10.4.3 The Brent Decommissioning Website

In addition to the full reporting of the dialogue events and the publication of our presentation material and the pre-read information, the BDP website presents:

- The project's statement on 'Stakeholder Dialogue – Our Commitment'.
- Project background, status, technical information and frequently asked project questions.
- A full record of all the issues raised by stakeholders and our responses to those issues.
- The IRG's pages. These pages allow the IRG to publish their views on any aspect of the BDP and its work, and their content is fully under the control of the IRG. The Terms of Reference for the IRG's activities is also published.
- Contracting and procurement information.
- A 'Contact Us' facility to allow all stakeholders and members of the public to email the Brent stakeholder engagement team directly with queries, comments or views.

10.4.4 Brent Newsletter

At the request of stakeholders, we have regularly published a Brent decommissioning newsletter which provides an update on the status of the BDP and additional technical information on various aspects of the project. Seventeen editions of the newsletter have been produced since 2009, and these were sent electronically to every stakeholder and published on the website.

10.4.5 Conferences and Speeches

Since 2007, Brent decommissioning staff have attended many public and industry events on decommissioning, and presented updates on the BDP at more the 50 conferences and industry events. These have included the annual NPF (Norske Petroleumsforening) Decommissioning Conference in Oslo, the joint OGUK/Decom North Sea conferences held in Dunblane and more recently in St Andrews, various supply chain events, and specialized technical events and seminars. All of this engagement has facilitated greater exchange of information and learning within the industry, supply chain and other stakeholders.

10.5 Stakeholder Input to the Decision-making Process

As a result of the broad engagement process described above, stakeholders have made many comments, asked a large number of questions, and brought many issues and concerns to our attention. We have recorded all the issues that our stakeholders have raised and the questions they have asked. The specific and generic issues raised by our stakeholders, and the views and concerns they expressed throughout the programme of stakeholder engagement, have informed the way in which we have carried out our CAs and framed our recommended decommissioning options.

The issues relating to specific structures, facilities or proposed decommissioning options are highlighted in the appropriate parts of Section 11 to Section 19. We have taken note of all the issues that stakeholders have brought to our attention, but the following issues appeared to us (from a review of all the records of stakeholder engagement) to be of particular or recurring concern:

- Cell remediation: Stakeholders said that it was important to obtain information on the composition of the cell contents, and to understand the fate and effect of exposed cell sediment. From an early stage in the project we committed to attempting to sample the cell contents to verify our desk-top estimates, and part of the EIA includes an assessment of the fate and effects of these materials. As our studies on this topic progressed, we established the CMSTG (Section 10.8) to share more detailed technical information regarding the options for the management of the cell contents. In support of the EIA, we carried out detailed modelling of sediment dispersion, and a detailed assessment of the potential eco-toxicological effects of this material once exposed.
- Long-term fate: Stakeholders wished to learn more about the long-term fate of structures if derogation were granted, and in particular the pros and cons of removing the legs of the GBSs. In response, we completed a series of engineering, environmental and societal studies, including an analysis of the collision risks for commercial shipping and fishing vessels.
- Cumulative impacts: Stakeholders wished to understand better the potential cumulative impacts from decommissioning operations at each of the individual sites. In response, we amended the scope of the EIA.
- Long-term monitoring: Stakeholders wanted to learn more about our plans for the long-term monitoring of structures that may be left in place, bearing in mind that the GBSs might remain extant for more than 500 years. We presented our initial thoughts on monitoring to stakeholders, and asked them for feedback.

The following more generic issues and concerns were also raised at more than one event:

- Protection of the marine environment
- Safety
- The derogation process and proposed candidate derogation facilities

- Management of the cells' contents
- Re-use of facilities
- Costs
- Jobs and development of the industry decommissioning sector
- Stakeholder engagement and communication

10.6 Consultation with Statutory Consultees and Public Notification

In accordance with the DECC Guidance Notes, we are undertaking a programme of formal statutory consultation on this Consultation Draft DP Document.

Public notifications have been published in local and national newspapers to provide an opportunity for representations to be made regarding the programmes. All parties who registered their interest during the dialogue sessions have been informed of the public notice via e-mails.

10.7 Publication and Advertisement of Decommissioning Programmes

Copies of the Consultation Draft DP Document and its supporting documentation have been submitted to BEIS.

Letters or emails have been sent to every stakeholder advising them that this Consultation Draft DP Document has been published. Advertisements to this effect have also been placed in selected National newspapers.

The Consultation Draft DP Document and its supporting documentation, including the ES, are freely available through the Brent Decommissioning website www.shell.co.uk/brentdecomm. The Consultation Draft DP Document and the ES are available on the BEIS website (https://www.gov.uk/guidance/oil-and-gas-decommissioning-of-offshore-installations-and-pipelines.

10.8 Work of the Cell Management Stakeholder Task Group

To gain greater insight into stakeholders' views and aid our deliberations on options for the management of the sediment in the GBS oil storage cells, we invited selected stakeholders to join the CMSTG, which was formed in 2011. A total of 16 stakeholders worked with us over a period of 21 months from September 2011 to June 2013, and at a final plenary meeting in November 2015. During this programme we completed a total of 5 workshops, in which the advantages and disadvantages of the options were examined and discussed, and the performances of the options assessed against a range of criteria. The work of the CMSTG was facilitated by the independent consultant Catalyze, with the Shell team providing data and information as requested. To manage the data and assessment, Catalyse used the proprietary software HiView3™ to permit the CMSTG to build and then interrogate a MCDA model. The CMSTG identified the criteria with which they wished to assess the performance of the options, scored the performances of the options in each criterion, and weighted the criteria relative to each other.

The CMSTG identified and assessed a wide range of criteria that they considered were important when weighing the advantages and disadvantages of options for the cell sediment. Their remit was not to make a decision for us, but to give us greater insight into the criteria that were important and the significance of any 'trade-offs' between the various options.

We took the work of the CMSTG into account in our CA in three ways; through working with the CMSTG and supporting them in their deliberations and listening to their discussions, we:

- Gained a deep appreciation of the criteria that they wished to take into account when comparing the options.
- Obtained a clear view of the relative importance of each criterion, and a strong steer on the criteria that they thought were particularly important in identifying a recommended option.
- Gained a great insight into the 'trade-offs' between options that were important for our stakeholders.

The work of the CMSTG helped us to interrogate our own findings and to determine which criteria might in fact be ones on which we should be placing emphasis. It also informed our deliberations about some of the qualitative scores or rankings that we made. The CMSTG gave us a very clear picture of the 'drivers' that were important to our stakeholders. The work of the CMSTG and its findings are fully reported in the Catalyze Report *Shell Cell Management Stakeholder Task Group (CMSTG): Analysis Report* [30], and summarised in Sections 16.6 and 16.7.

10.9 Work of the Independent Review Group

10.9.1 Introduction

OSPAR states that the conclusions of Comparative Assessments *'…shall be based on scientific principles and…linked back to the supporting evidence and arguments*' [2]. In their Guidance Notes [3] DECC state '*…it is important that the studies and the assessment process that supports the chosen decommissioning option are subject to independent expert verification to confirm that the assessments are reliable….*'

In view of the breadth and complexity of our CAs and of the technical engineering and environmental studies performed to support them, we established an IRG to review and report on the completeness, objectivity and rigour of the supporting studies, and the methods used to assess and compare options. The IRG, which comprised technical, engineering and environmental experts, did not comment or express any view on our final recommendations, confining its comments solely to whether our conclusions were supported by the evidence we presented. It should be noted that its remit did not cover the wells P&A programme or the decommissioning of the topsides.

The IRG was chaired by Professor John Shepherd, Professorial Research Fellow in Earth System Science in the School of Ocean & Earth Science at the National Oceanography Centre, University of Southampton, and comprised; Professor Torgeir Bakke of the University of Oslo, Professor Günther F. Clauss of the Technical University Berlin, Professor William D. Dover of University College London, Professor Jürgen Rullkötter of the University of Oldenburg, Professor W Brian Wilkinson of the Universities of Reading and Newcastle Upon Tyne, and Mr Richard J Clements. For the specific assessment of the feasibility of sub-surface re-injection of cell sediments, the IRG was supported by three additional experts; Professor David Davies of Heriot-Watt University, Professor Ian Main of the University of Edinburgh and Professor Quentin Fisher of the University of Leeds. The IRG met on twenty-three occasions from January 2007 to September 2016. Details of the IRG and its terms of reference can be found at http://www.shell.co.uk/sustainability/decommissioning/brent-field-decommissioning/brent-field-stakeholder-engagement/irg.html.

10.9.2 IRG Final Report

In February 2017, the IRG published a final report on its assessments and reviews of our important supporting engineering studies, the six TDs, the DNV GL EIA, our CA procedure and the consultation draft DP. The full report may be found at the Brent Decommissioning website. We did not have any editorial control over the IRG's report on its findings.

PART THREE
DECOMMISSIONING THE BRENT FACILITIES

These sections describe the recommended decommissioning programmes for all the structures and materials in the Brent Field. For each facility in turn, these sections present:

1. A description of the facility or material.
2. An inventory of materials present.
3. Descriptions of the options subject to formal Comparative Assessment, if required.
4. The results of the Comparative Assessment and the reasons for the selection of the recommended option.
5. A description of the proposed programme of work to undertake the recommended decommissioning option.
6. A summary assessment of our stakeholders' concerns about the decommissioning of the facility.
7. A summary of the environmental impacts of the proposed decommissioning programme for the facility.

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11 DECOMMISSIONING THE BRENT FIELD WELLS

11.1 Introduction

Since 1974 a total of 399 wellbores (388 excluding wells where conductors only were run) have been drilled in the Brent Field, from 154 platform well slots (Figure 16) and the 3 subsea wells at Brent South. Table 93 to Table 97 in Appendix 1 summarise the status of the Brent wells at 1st February 2017.

The Brent Field discovery well was drilled in 1971, and was followed by six further exploration and appraisal wells. The Field was developed with four production platforms distributed along the axis of the Field (approximately North-South), close to the crest (East) of the tilted fault block that constitutes the reservoir. Development drilling comprised crestal producers in both Brent and Statfjord reservoirs, with first production in 1975. Water-injection wells were placed down-dip for water-flood and pressure maintenance. Early in the Field's life, when no gas export facilities were in place, gas was injected back into the reservoir. The Field was depressurised in 1998 to allow the liberation of gas, and the Field became predominantly a gas production field. In 2001 and 2002 several new wells[21] were drilled to further reduce the pressure and increase the volumes of liberated gas. In summary, the drilling programme comprised:

- 28 development wells*, drilled from Alpha over the period 1977 to 2001
- 37 development wells*, drilled from Bravo over the period 1975 to 2004
- 38 development wells*, drilled from Charlie over the period 1979 to 2003
- 40 development wells*, drilled from Delta over the period 1977 to 2007
- 3 subsea wells* at Brent South, drilled from a semi-submersible drilling rig in 1993

* These figures reference the number of well slots used for development drilling. The total number of wellbores is determined by the number of sidetracks performed from each well slot as detailed in Table 93 to Table 97 in Appendix 1.

11.2 Issues and Concerns Raised by Stakeholders

The main issue and concern raised by stakeholders during the programme of stakeholder engagement was:

- The need for Shell to use best practice to P&A the wells.

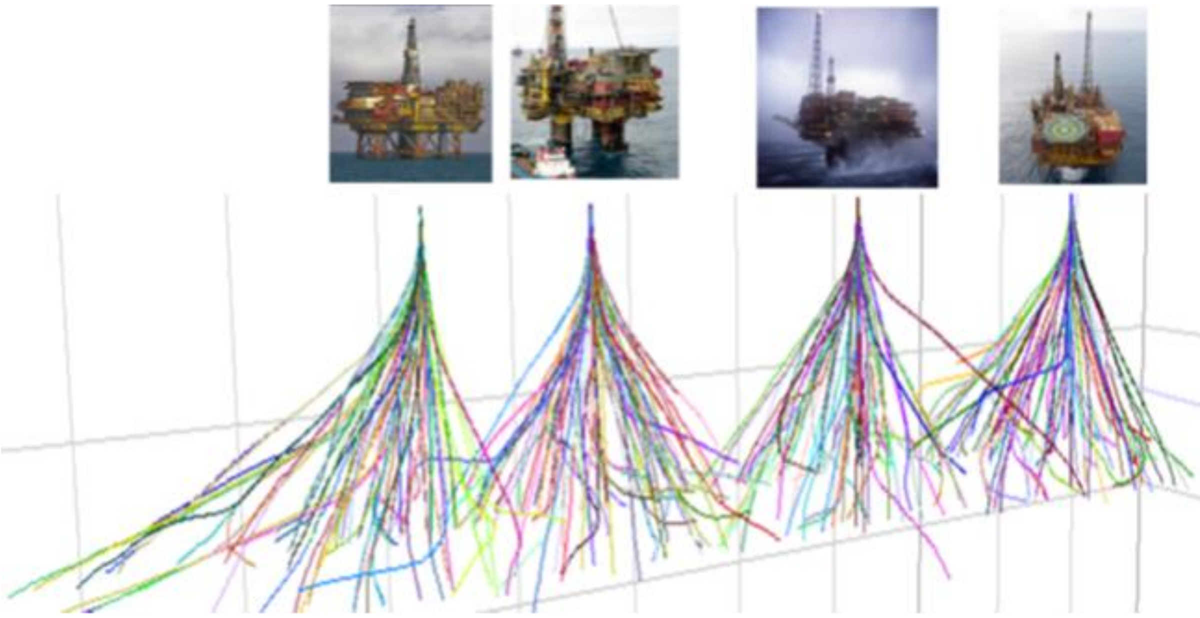
11.3 P&A Programme

The campaign to 'plug and make safe' the Brent wells began in 2004 with the three Brent South subsea wells. Well abandonment activities on the main Brent Field started in December 2008 and will continue until about 2020. As of 1st February 2017, all of the 48 Brent Delta well slots have been fully decommissioned, and permanent barriers have been set on 36 Brent Bravo wells and 3 Brent Alpha wells. Full decommissioning of the Brent Bravo wells is expected to be completed in the first quarter of 2017.

All the work is carried out from the platforms as part of the end-of-life activities before and after CoP. The programmes use the existing drilling derricks and other equipment on the platform, and are carried out under all necessary permits, including those required under the *Offshore Chemicals Regulations* [31].

[21] These were, specifically, high rate Electric Submersible Pump (ESP)-lifted water production Enhanced-Voidage (EV) wells. Enhanced voidage wells are essentially water producer wells that are used to reduce pressure in the reservoir.

Figure 16 Schematic Showing the Tracks of all the Brent Field Wells.



11.4 P&A Guidelines

The OGUK *Guidelines for Suspension and Abandonment of Wells* [32] is considered to be the industry-wide standard to be achieved for all well abandonment operations performed in the UK. These guidelines have been refined and updated over the years, and the latest guidance was published in 2015. The Brent P&A programme is constructed in accordance with the Shell Global Well Abandonment Manual and associated UK Supplement, using the OGUK Guidelines as a basis.

A global well abandonment Principal Technical Expert (PTE) is also available for guidance and support covering all well abandonment operations.

In addition to these documents, Shell has global Well Integrity Management and Pressure Control Manuals which provide guidance and set standards for well control and well integrity management before, during and after well abandonment.

11.5 Brent Abandonment Philosophy

11.5.1 Introduction

The Brent Abandonment Philosophy provides a methodology for ensuring that the abandonment work carried out in the Brent Field is consistent across the Field, and that any risk of unplanned hydrocarbon release from the well to the surface via the wellbore or annuli - now and for the future – is reduced to a level that is ALARP.

11.5.2 Current Philosophy

The philosophy employed has evolved over time, as OGUK Guidelines have been updated and our understanding of the Brent reservoir has improved. The current philosophy base case involves the setting of two, combined permanent barriers[22] to isolate specific formations with flow potential, as follows:

[22] Zones with flow potential need to be isolated by two barriers. It is acceptable, however, to combine these two barriers into one barrier that is twice the size of a single barrier.

Barrier 1 – The objective of this barrier is to isolate the reservoir and existing accessible wellbores, to prevent movement of fluids from the Brent and Statfjord reservoirs into shallower permeable formations or to the seabed.

Barrier 2 – The primary objective of the second combined barrier is to isolate the Balder Formation underlying the Horda shales (as this is considered to be a zone of flow potential) from the surface, and to provide an additional barrier for any previously-abandoned and inaccessible hole sections. In certain circumstances this barrier can also act as a back-up to Barrier 1, allowing Barrier 1 to be set as a single rather than combined barrier.

Environmental Plug – A shallow cement plug is placed where oil based muds are present behind casing strings that require isolation from the environment. The methodology employed to set this plug, where required, may vary depending upon the well architecture.

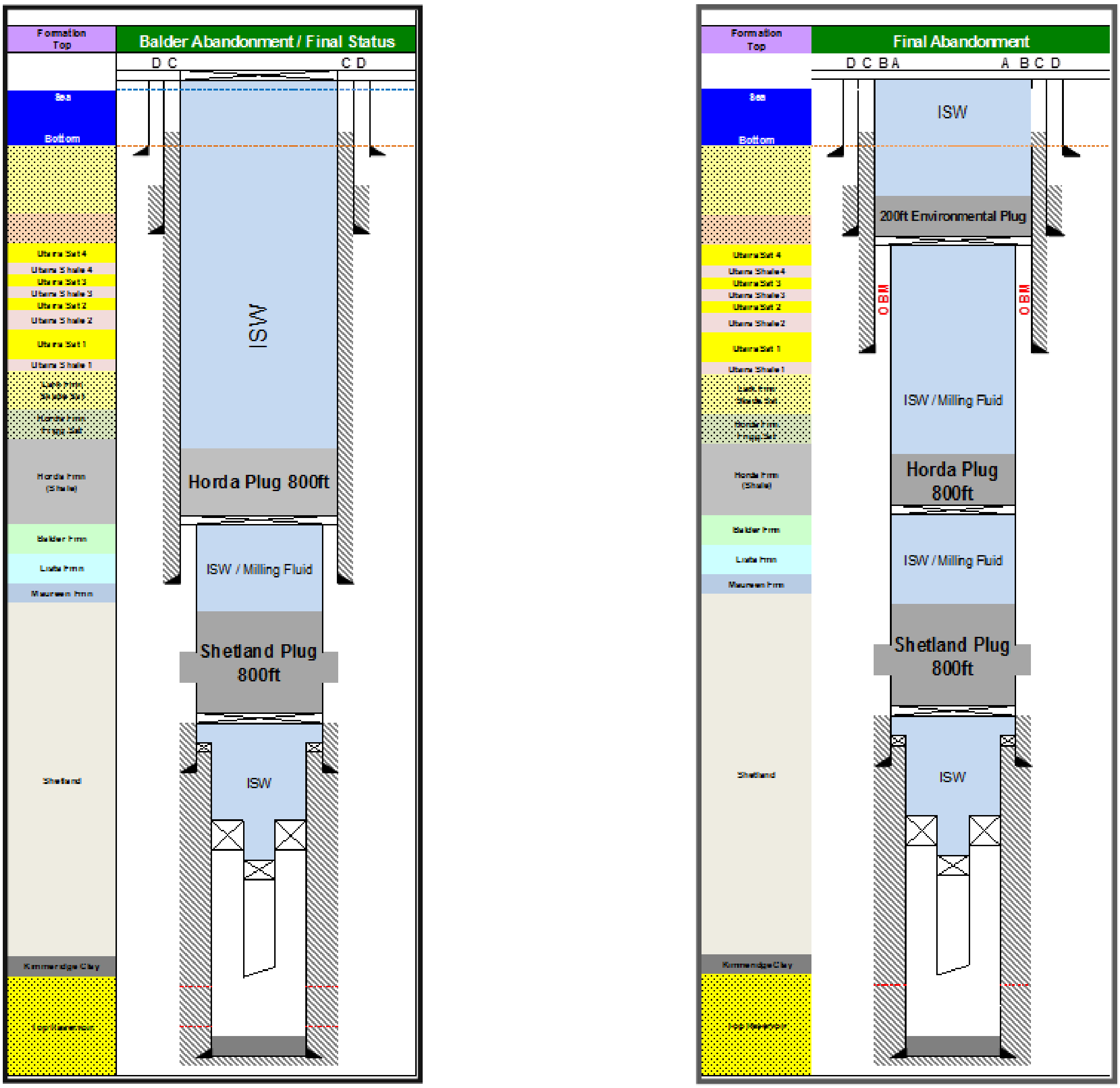
Upon completion of the placement of the barriers in the wellbore, each well must be monitored to assess any potential build-up of pressure, and the composition and flow rate of any fluid. All wells are therefore fitted with a suspension flange[23] and pressure gauges, and monitored for a minimum of 90 days. Once the well is confirmed as being stable and has been successfully risk-assessed, conductor removal operations may begin.

It should be noted that although this philosophy is applied to all the Brent abandonments, each well is still considered on a case-by-case basis and a specific programme is developed for every well. In certain non-routine cases it may be necessary to set additional barriers or barriers in alternative locations.

Figure 17 shows the two main abandonment designs currently being employed on Brent.

[23] A cap that is put on the top of the well while suspended, with a gauge for monitoring pressure.

Figure 17 Schematic Showing the Current Brent Well Abandonment Philosophy.



Left diagram:
Final Abandonment: Deep Intermediate Casing

Right diagram
Final Abandonment: Shallow Intermediate Casing

11.6 Procedure for Suspension and Decommissioning of Wells

In summary, the Brent P&A programme comprises of the following sequence of operations:

- The reservoir is isolated by setting a temporary mechanical plug.[24]
- The completion tubing is cut or punched, allowing existing hydrocarbon fluids to be circulated out of the well and replaced by a kill-weight fluid.
- A second mechanical plug is set at a shallow depth to allow well control equipment to be installed in place of the Xmas tree.
- Operations continue using the main rig, following the retrieval of the shallow plug.

[24] Made of metal and rubber.

- The completion tubing is retrieved, allowing the well to be logged to assess the quality of existing cement behind the production casing.
- The reservoir abandonment barrier cement plug is set. If the annular cement quality is insufficient, then the original cement bond will be remediated (generally by section milling and setting a cement plug across the milled window[25]). Otherwise, a cased hole cement plug[26] will be set.
- The barrier for the Balder formation is set using similar techniques to the reservoir barrier, although in cases where the intermediate casing is set across the Horda shale, the production casing will first be cut and recovered in order to set an effective rock-to-rock barrier.
- In circumstances where it is necessary to ensure that oil based muds are isolated from the environment, a final cement plug (the 'environmental' plug) is set above the earlier two plugs.
- Following final well monitoring, the wellhead and remaining conductor/casing strings are cut and recovered to complete the operations.

Retrieved sections of tubing, casing and conductors are returned to shore for recycling. An estimate of the total mass of steel that will be recovered and recycled onshore during the whole P&A programme is presented in Table 20.

On completion of the P&A programme for each well, individual close-out reports are prepared and then stored in the UK Oil and Gas Data site, with other important information, as required by the Petroleum Operations Notice (PON) 9.

Table 20 Inventory of Materials Returned to Shore during Wells P&A Programme.

Material	Mass of Material Returned to Shore (tonnes)			
	Brent Alpha	Brent Bravo	Brent Charlie	Brent Delta
Steel tubing	2,100	2,800	3,000	3,000
Steel casing	3,640	4,940	5,200	5,200
Conductor steel	2,000	1,900	2,000	2,400
Well head steel	140	190	190	200
Xmas tree steel	160	220	220	240
Total	8,040	10,050	10,610	11,040

11.7 Submission of Permits, Consents and Notifications

The following permitry is required before locating over a well to begin abandonment operations:

- Application to suspend/abandon the well (OGA via the Well Operations Notification System (WONS) in the UK Oil Portal). This details the planned timing of the P&A programme and describes the operations that will be carried out.
- Chemical permit (BEIS)
- Oil Discharge Permit (BEIS)
- The Oil Pollution Emergency Plan, (OPEP) (Offshore Safety Directive Regulator, OSDR)

[25] The steel casing is milled away so that the cement plug extends across the well bore from one rock face to the other.

[26] A cement plug that is set within the steel casing, in circumstances where there is already a good isolation (a good cement grout seal) between the outside of the casing and the rock face.

- Well Notification (OSDR). A specific notification for each well is sent to the OSDR detailing the current and proposed well status, the operational sequence to be carried out and the anticipated hazards.
- Well Programme (NRG Well Examination Ltd., NRG). For each well abandonment a specific well programme is developed and sent to an independent well examiner for approval. Once approved, critical programme steps must be followed exactly. If there is any change to the plan, a formal amendment must be sent to the well examiner for review and examination before the changed operation can continue.
- Radiation Permits (Scottish Environmental Protection Agency, SEPA). The radiation requirements for abandonment operations vary from well to well. For this reason, Shell collaborate with Aberdeen Radiation Protection Services (ARPS) approximately 6 months before beginning abandonment operations, to ensure that all relevant radiation related legislation is being complied with and appropriate permits have been applied for.

11.8 Environmental Impacts of Well P&A

11.8.1 Stakeholder Environmental Concerns

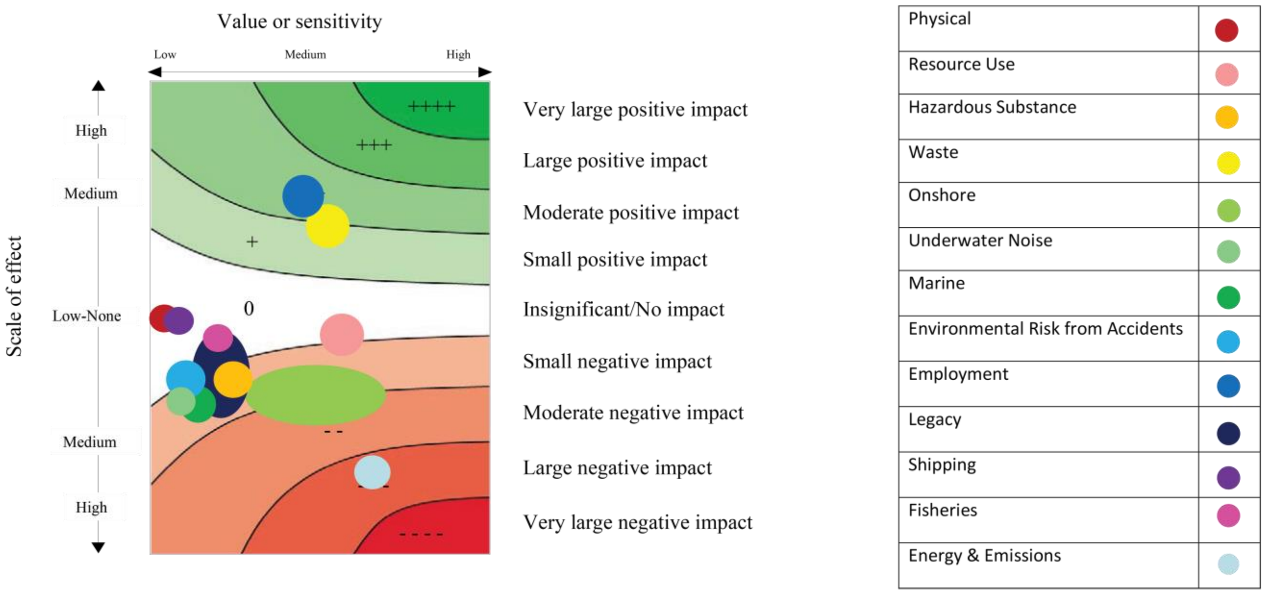
For the programme of work to P&A the Brent wells, the specific environmental concerns or issues raised by our stakeholders were:

- The number of wells and whether they are being shut-off.
- Whether the wells will be revisited in the future.

11.8.2 Potentially Significant Impacts in ES

Figure 18 presents DNV GL's summary of the results of the environmental impact assessment of the programme of work that will be completed to P&A all 146 of the Brent Field wells [5]. This includes the xmas trees, wellheads, tubulars and the upper sections of casings and conductors, which in total amount to approximately 40,000 tonnes of steel (Table 20).

Figure 18 Environmental Impacts from the Whole Brent P&A Programme for 146 Wells.



11.8.3 Impacts from operations

The most significant negative impacts from this activity were the use of energy and the gaseous emissions offshore which was assessed as 'large negative', and onshore impacts from dismantling and recycling wellheads and associated infrastructure which was assessed as 'small-moderate negative' [5]. There was a 'small-moderate positive' impact from the offshore employment associated with this programme.

With the exception of the normal permitted discharges of cleaned water, and the local discharges of exhaust gases from combustion, no wastes or chemicals are discharged to sea; all waste and retrieved materials are returned to shore for re-use, recycling or disposal. There are no significant offshore environmental impacts from the P&A of the wells.

11.8.4 Energy and Emissions

The offshore operations to plug and abandon all 146 Brent Field wells, and retrieve and recycle approximately 40,000 tonnes of steel, would use approximately 3.3 million GJ of energy and result in the emission of approximately 241,000 tonnes of CO_2 (Table 21).

Table 21 Total Energy Use and Gaseous Emissions from Programme of Work to P&A Brent Field Wells.

Operations	Energy (GJ)	Emissions to Atmosphere (tonnes)		
		CO_2	NO_X	SO_2
Direct				
At field operations (Note 1)	2,792,880	205,416	4,536	181
New Materials	41,890	7,558	6	2
Onshore dismantling	30,872	2,271	50	2
Onshore transport	13,556	997	22	1
Sum	*2,879,198*	*216,242*	*4,614*	*186*
Recycling				
Material recycling	377,530	17,088	64	151
Material Replacement				
Materials not recycled	41,890	7,558	6	2
Total	3,298,618	240,888	4,683	340

Note 1: 'At field operations' are all the activities carried out from or on the platform itself.

NO_x, Nitrogen oxides
SO_x, Sulphur oxides

11.9 Status of the Well P&A Programme of Work

Table 93 to Table 97 in Appendix 1 show the status of the Brent Field wells P&A programme at 1st February 2017.

11.10 Mitigation Measures for the Wells P&A Programme of Work

- All the Brent wells subject to P&A in the current DP are platform wells and so the decommissioning activities are being performed from the existing platform through the conductors. The three Brent South wells have already been plugged and made safe, so no sub-sea operations are required in the current programme.
- All wells are being decommissioned according to the requirements of Shell standards and the OGUK Guidelines [32].
- The plans and programmes, including the number and lengths of barriers, are individually planned for each well, bearing in mind its characteristics and the rock strata through which it passes.
- A specific application in accordance with PON9 is submitted to OGA for each well abandonment programme. In addition, each individual P&A programme is reviewed by an independent Well Examiner and a well-specific notification sent to the HSE.
- All the well fluids are contained, or retuned to shore for treatment and disposal.
- All mud and cementing chemicals are controlled under the Offshore Chemical Notification Scheme (OCNS) and Offshore Chemical (Pollution Prevention and Control) Regulations 2002.
- An approved Oil Pollution Emergency Plan (OPEP) is in place on each platform during P&A. Procedures, systems and trained personnel are in place to deal with any accidental spill that may occur during these operations.
- All barriers set in the well as part of the abandonment process are verified once set.
- The rate and composition of any gaseous emission after P&A is monitored in each well.
- Wastes returned to shore are treated or disposed of at suitably licensed sites.

12 DECOMMISSIONING THE PLATFORM TOPSIDES

12.1 Description of Topsides

A separate DP for the Brent Delta topside [4] was approved in July 2015, and this topside will be removed in 2017.

The topsides on the three other Brent platforms comprise several decks containing the living quarters, power generation, drilling derrick, process systems and all the other facilities required for the operation of a production platform. Figure 19 to Figure 21 show the general arrangement of such facilities on the Alpha, Bravo and Charlie topsides respectively (note that the topsides will not be split into three deck levels for removal). Detailed descriptions and inventories of the topsides of all the platforms are given in the Brent Topsides TD [6]. Table 22 presents a summary of the physical characteristics of each topside; the Brent Bravo topside is similar in all important respects to the Brent Delta topside.

Table 22 Summary Physical Data on Brent Topsides.

Data	Platform		
	Alpha	Bravo	Charlie
Number of decks or levels	3	3	3
Approximate footprint area (m)	81 x 37	73 x 46	80 x 49
Approximate maximum height (m) (Note 1)	46	42	57
Total mass (tonnes) (Note 2)	16,000	24,100	31,000

Notes:
1. From the cutline on the legs to the helideck, excluding the drill derrick and flare tower. Charlie is higher because most of the 15.7 m long steel transition piece will be removed with the topside.
2. Without inventory and before preparation for lifting.

Figure 19 The Three Main Deck Levels on the Brent Alpha Topside.

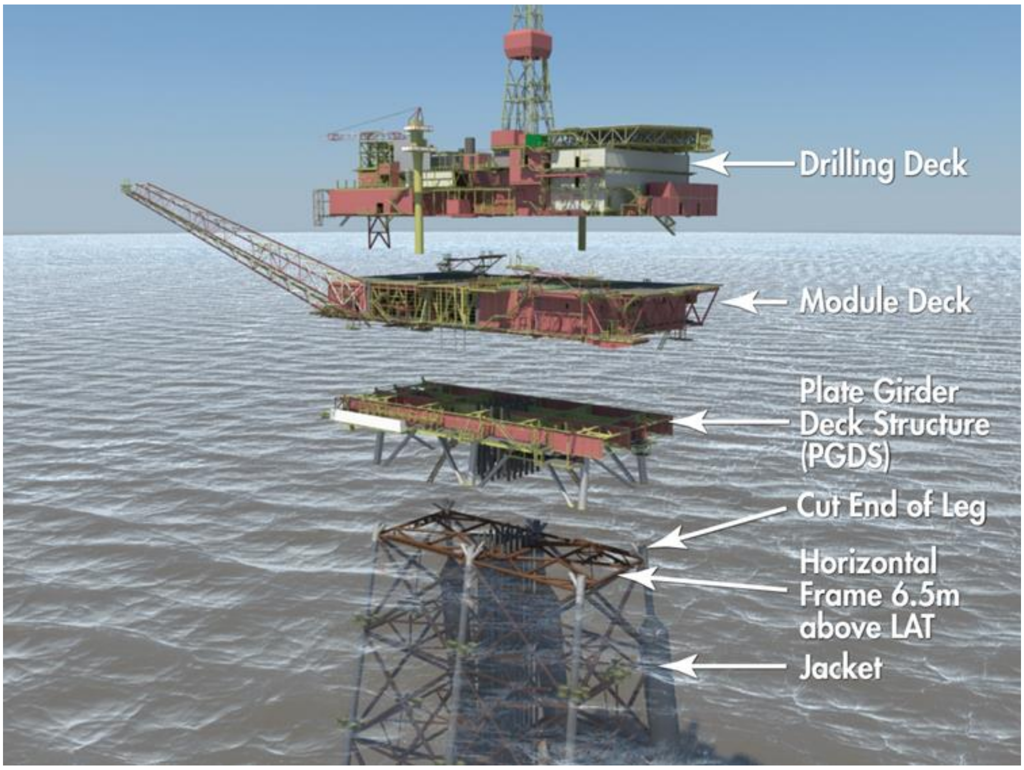


Figure 20 The Three Main Deck Levels of the Brent Bravo Topside.

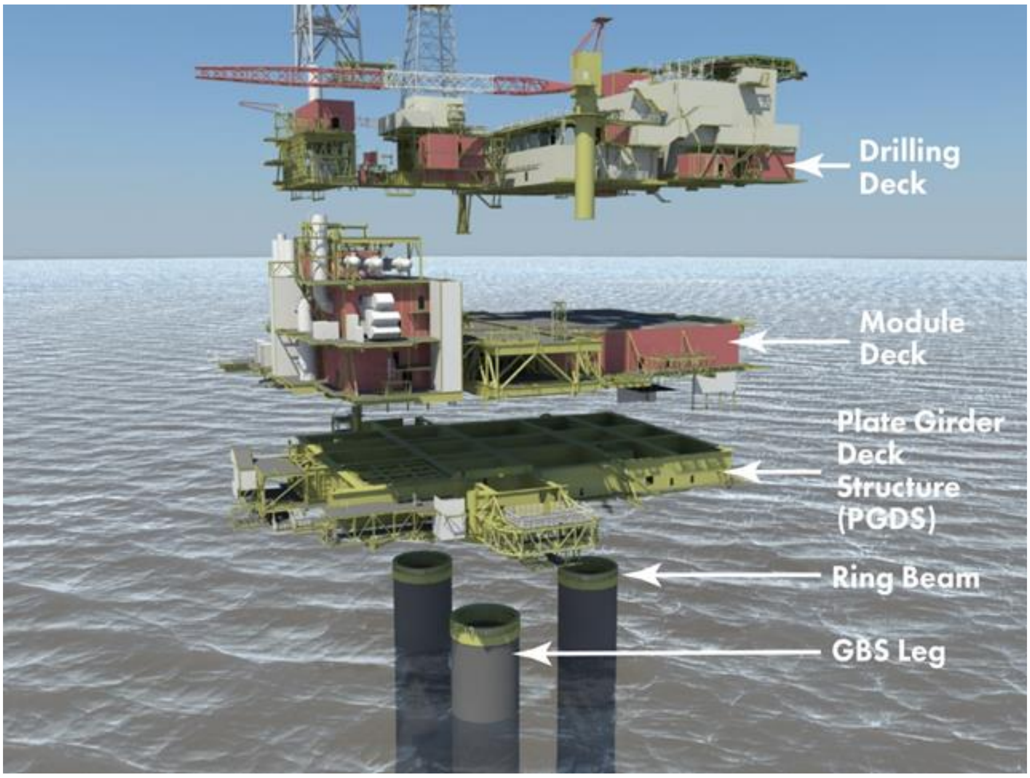
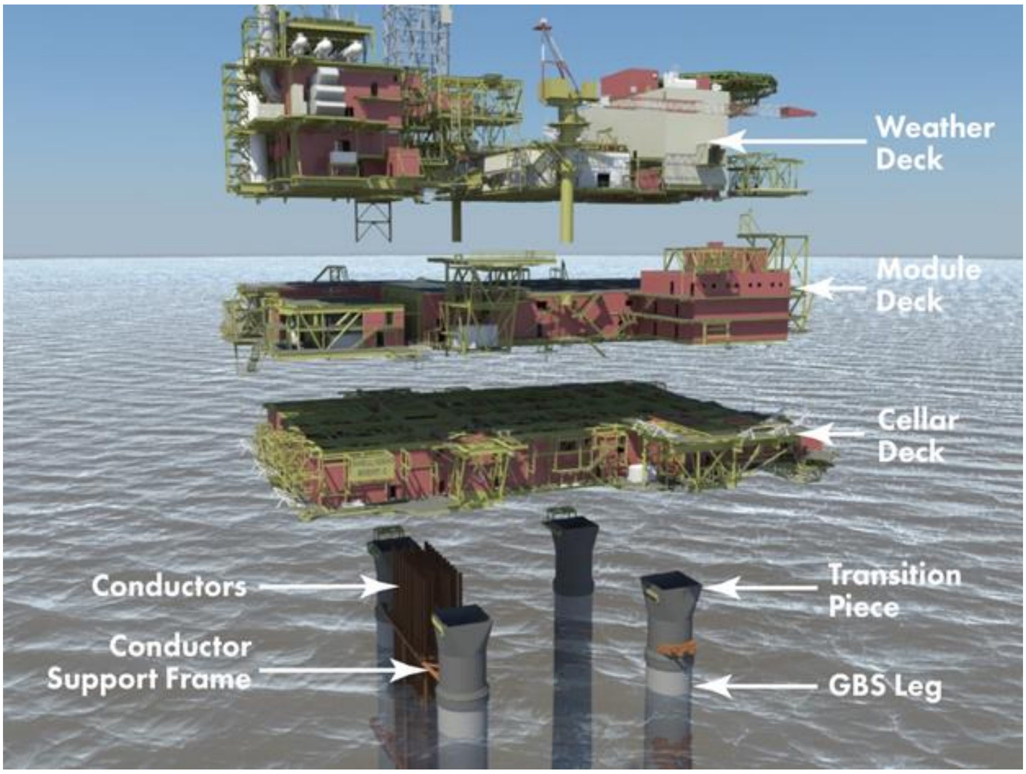


Figure 21 The Three Main Deck Levels of the Brent Charlie Topside.



12.2 Issues and Concerns Raised by Stakeholders

The main issues and concerns raised by stakeholders during the programme of stakeholder engagement were:

- The method or procedures that will be used to remove the topsides.
- The investment that Shell might make in onshore dismantling or recycling sites.
- The employment or local benefit that would be generated by the onshore dismantling and recycling activities.
- Competition with other activities at such sites e.g. manufacture or deployment of offshore wind turbines.

12.3 Recommended Option

As described in Section 7 we have not been able to identify any further use for any of the Brent topsides. Accordingly, as required under OPSAR 98/3, they must be removed to shore.

We plan to remove the topsides from Brent Alpha and Brent Bravo as single units by the SLV and transport them to shore for dismantling. Equipment and materials in the topsides will be re-used, recycled, treated or disposed of as appropriate. The removal of the Brent Charlie topside will be the subject of a separate tendering exercise.

The sections below summarise our proposed generic programme of work for removing the Alpha and Bravo topsides by SLV. Although details of the programmes of work will vary from installation to installation, the Alpha, Bravo and Charlie topsides are not so different in terms of their structure and components that unique programmes have to be devised for each one. The procedures used to strengthen the topsides before lifting, and to set-down and support the topsides on the cargo barge, may not be exactly as described below.
In particular, the configuration of the jacket and Plate Girder Deck Structure (PGDS) supporting the topside on Brent Alpha will require a specially-designed lifting arrangement. For both Brent Alpha and Brent Bravo, however, the outcome will be the same, namely a topside delivered to the ASP facility.

12.4 Preparation

After the completion of the P&A programme, the topsides will be prepared for decommissioning and will change from operating in a 'hot' mode to a 'cold' mode. Stocks of chemicals will be reduced to the minimum required for the safe operation of the platform. All pressurised hydrocarbons will be removed from the topsides systems. Measures will be taken offshore to ensure that piping, tanks, vessels and void spaces are either drained, or suitably closed or sealed, to minimise the risk that contaminants would be spilled during removal or transit. All hydrocarbons and other wastes collected by these procedures will be contained, collected and transported to shore for recycling or disposal.

The topsides modules will be strengthened with additional steel plates, because they were not designed to be lifted away in one piece. Carefully designed lifting points will be attached on the underside of the supporting structure (Module Support Frame (MSF) or Truss Deck) to receive the loads exerted by the SLV's lifting beams. Most of this work will be undertaken from temporary scaffolding built under the MSF. On Brent Delta, because of the long interval between cutting the legs in 2016 and removing the topside in 2017, we have attached 'shear restraints' inside the legs. These strong steel structures, each weighing some 36 tonnes, have been bolted in place just at the height of the cut line to ensure that the topside remains firmly in place after the cuts have been made. No significant environmental impacts are expected from any of these preparatory activities.

On the GBS legs, as a precaution, we will remove external steel risers and caissons down to about -20 m LAT, so as to minimise damage to the hull of the SLV in the unlikely event of an interaction with the GBS.

12.5 Cutting the Legs

All the cuts will be made using a diamond wire cutting (DWC) system. On Brent Alpha, the DWC will be deployed by a suitable vessel to make 18 cuts at approximately 6.5 m above sea level. On the GBSs, the legs will be cut *from the inside* by making a series of DWC cuts 'on the tangent' through holes drilled in the legs. On Bravo the legs will be cut at a height of approximately 19.8 m above sea level, but on Charlie, with its long steel transition piece, the cuts will be made at approximately 7 m above sea level.

12.6 Removal of Topsides

The SLV will move into the Field and take station close to the platform, operating on Dynamic Positioning (DyP), and then will move under the topsides. The lifting beams will be slid under the topsides and the dynamic lifting jacks will be located onto each of the lifting pads on the underside of the topsides. When all is ready, the hydraulically-operated jacks will be activated to carry out a 'fast lift' whereby the topsides are raised 1.5 m clear of the tops of the legs in about 90 seconds. Once clear, the SLV will move away from the legs and begin the process of securing the topsides to the lifting beams, for transportation to shore (Figure 22).

Before leaving the Field, the SLV will place new 300 tonne concrete caps over the cut end of each GBS leg. On each GBS one of the caps will carry an Aid to Navigation (AtoN), as described in Section 23.

In good conditions, it is planned that the whole lifting operation will take about 2 days and that the SLV will operate around each platform for a total of about 4 days. The majority of vessel activity associated with topside decommissioning will occur within the 500 m safety zone. As shown in the schedule (Section 21), we plan to remove only one topside in any one summer season.

The topside will be considered 'cargo' in this phase of the project, and because it contains some hazardous materials that are subject to special permitting requirements, these materials will be itemised in the vessel's cargo manifest; all necessary permits and consents will have been obtained for the carriage and movement of these materials. The removal and transportation of Low Specific Activity (LSA) scale, for example, will be in accordance with the *Radioactive Substances Act (RSA) 1993)* [33]. All sealed radioactive sources, for example in instruments and gauges, will be transported in accordance with the requirements of the *Radioactive Substances Exemption (Scotland) Order 2011*.

Figure 22 Artist's Impression of the Brent Bravo Topsides being Removed in a Single Piece by the SLV *Pioneering Spirit*.

12.7 Onshore Dismantling

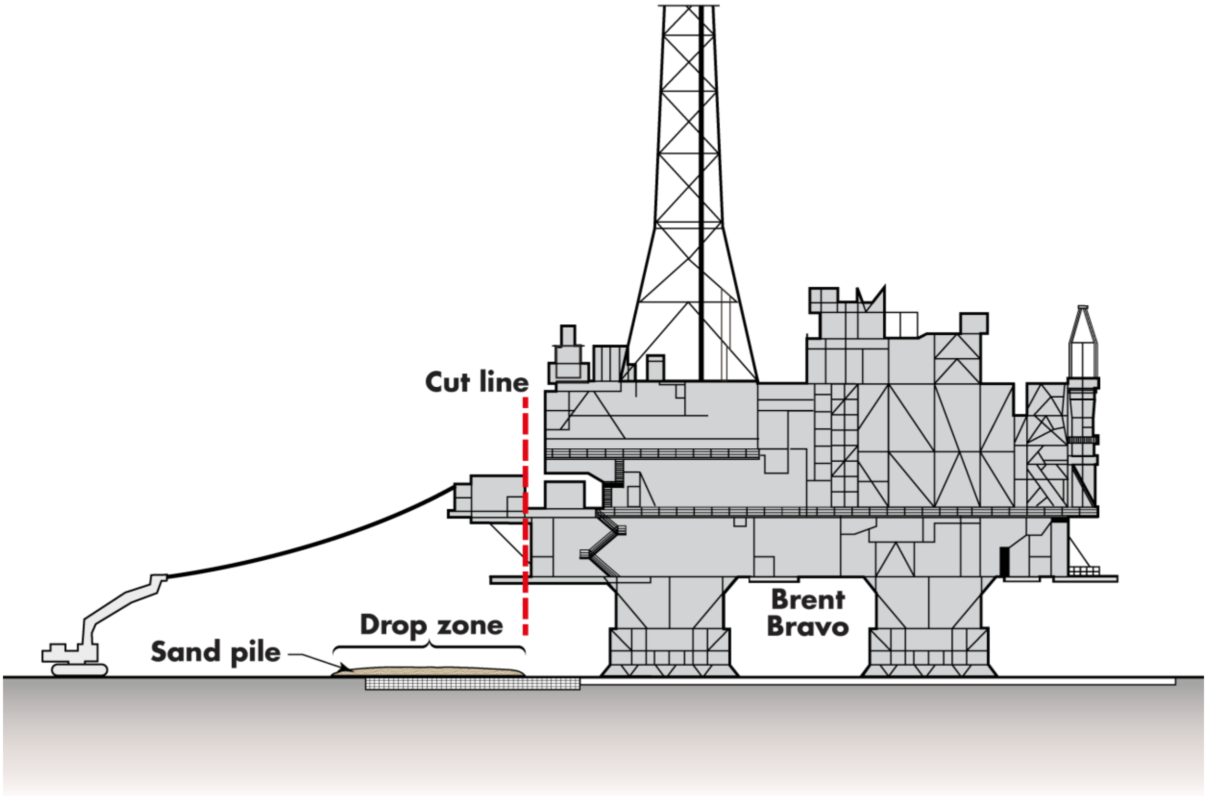
It will take the SLV about 2 days to transport a topside from the Field to the northeast coast of England. At a designated transfer site 5.5 nautical miles (nm) northeast of the River Tees, the topsides will be skidded from the SLV onto the new cargo barge *Iron Lady*. Barge transfer is required because the Able quayside is too shallow for the SLV. At the ASP facility the topsides will be skidded off to the quayside at Quay 6, where they will be dismantled (Figure 23).

It is planned that the first topside to arrive at the onshore dismantling facility will be Brent Delta in the summer of 2017, and we expect that it will take 12-24 months to dismantle this topside after load-in. According to our current schedule, the Brent Bravo topside will be brought ashore in 2020, Brent Alpha in 2021, and Brent Charlie probably not before 2025. The ASP facility has the space to accommodate all three Brent topsides if necessary.

Figure 23 Aerial Photograph of the ASP Dismantling Facility on Teesside.

The essence of the programme of work proposed by our dismantling and disposal contractor Able is to quickly reduce the height of each topside by cutting it into sections and pulling the sections to the ground, where it will be safer and easier to dismantle them. In this 'cut and pull' method, the internal and external walls will be partially cut by a variety of 'hot' and 'cold' cutting techniques, then connected by wire ropes to a large vehicle which will pull the section to the ground inside a designated drop zone (Figure 24). A thick bed of sand will be laid around the topside to absorb the shock of these falling sections. Dismantling operations at the ASP facility will be performed in accordance with *British Standard BS 6178:2011 Code of Practice for Full and Partial Demolition* [34].

Figure 24 Cut and Pull Method for Initial Dismantling of a Brent Topside at the ASP Facility.



12.8 Management, Recycling and Disposal of Waste

A description of onshore dismantling and the management and disposal of material is provided in the Topsides TD [6]. The programme of work for removing, dismantling and disposing of the Brent Delta topside is described in a separate DP which has already been approved by DECC [4].

Onshore dismantling will reduce the topsides into their component materials or 'waste streams'. These will be segregated and stored on site before being transported to other onshore facilities for re-use, recycling or disposal as appropriate. On the basis of the present topsides inventory, we plan to recycle at least 97% by mass of topsides material which is returned to shore (Table 23). All material will be tracked from its present offshore location to its final destination.

Table 23 Estimated Inventory of Topsides Material and Proposed Fate after Decommissioning.

Material	Unit	Alpha	Bravo	Charlie	Notes
ABS	tonnes	2	2	2	Plastic pipes
Ac 228	MBq	n/q	n/q	n/q	In smoke detectors
Alloy steel	tonnes	216	285	329	Pipework, pumps
Aluminium	tonnes	419	15	15	Anodes, engines
Aluminium bronze	tonnes	1	1	1	Pumps
Americium 241	MBq	5	16	20	Smoke detectors
Anodes (total)	Tonnes	419			See Aluminium and Zinc
Asbestos blue	tonnes	n/q	n/q	n/q	Not yet quantified
Asbestos white/brown	tonnes	n/q	n/q	n/q	Not yet quantified
Asbestos (total)	tonnes	4	9	9	Insulation, gaskets
Batteries	tonnes	28	16	36	Various battery sets
Brass	tonnes	1	1	1	Pumps, piping
Bronze	tonnes	1	1	1	Pumps, piping
Buna	tonnes	1	1	1	O-ring seals
Butyl rubber	tonnes	2	2	2	O-ring seals
Carbon steel	tonnes	11,921	19,572	25,448	Structural steel, equipment
Cement (powder)	tonnes	2	n/q	n/q	Residual bulk material
Ceramics	tonnes	5	5	5	White ware
Chartex/fire protection	tonnes	27	103	122	Penetrations
Chromium	tonnes	n/q	n/q	n/q	Alloy steel only
Copper	tonnes	107	222	281	Pipes, cables, transformers
Copper nickel alloys	tonnes	67	174	229	Pipe-valves, pumps
Cork	tonnes	2	2	2	Lifebuoys
Cotton	tonnes	2	5	5	Bedding
Diesel	m^3	<1	<1	<1	Bulk and day tanks
Drill cutting residues	tonnes	12	12	12	Behind shale shakers
EPDM	tonnes	23	5	23	Cables
Ethylene/polypropylene	tonnes	72	46	120	Cables
Fire foam	m^3	10	10	10	Firefighting systems
Fluorescent tubes	nos.	1,396	2,984	3,116	Lighting
Formica	tonnes	2	2	2	Living areas
Glass	tonnes	5	5	5	Living areas
GRP	tonnes	7	21	16	Replaced floor grids
Graphite/charcoal	tonnes	0.1	0.1	0.1	Water filters
Gun metal	tonnes	1	1	1	Pumps, valves
Halon (CFC)	kg	0	0	0	Has been removed
Heli-fuel	m^3	<1	<1	<1	Volume for safe operations
Inconel/nimonics	tonnes	6	13	13	Generators
Insulation	tonnes	31	99	83	Structures, pipes
Iron (cast)	tonnes	3	3	3	Weights
Lead	tonnes	11	6	13	Batteries

Table 23, continued Estimated Inventory of Topsides Material and Proposed Fate after Decommissioning.

Material	Unit	Alpha	Bravo	Charlie	Notes
LSA scale (NORM)	tonnes	22	43	323	Pipework, vessels
Lube oil	m^3	<1	<1	<1	Compressors, generators
Melamine	tonnes	1	1	1	Laminates
Mercury (lamps only)	grams	15	32	33	Lamps
Monel	tonnes	0.1	0.1	0.1	Pumps and valves
Neoprene	tonnes	5	5	5	Various
Nickel	tonnes	n/q	n/q	n/q	Alloy steel only
Ni-resist	tonnes	10	10	10	Pump valves
Nylon	tonnes	10	10	10	Electrical equipment, rope
Paint	tonnes	930	961	899	Paint on structural steel
Pb-210 (NORM)	MBq	13	513	411	LSA scale and sludge
PCBs	ppm	<5	<5	<5	Residues in transformer oil
PTFE	tonnes	0.1	0.1	0.1	Seals
Plastics	tonnes	4	3	4	Floor coverings
PVC	tonnes	32	19	65	Cable covering
Radium (Ra-226)(NORM)	MBq	376	734	3,141	LSA scale and sludge
Radium (Ra-228) (NORM)	MBq	261	663	1,340	LSA scale and sludge
Residual hydrocarbons	tonnes	7	<1	<1	Walls of pipes and tanks
Rubber	tonnes	20	20	20	Floor coverings
Sewage	tonnes	1	1	1	Sewage system bilges
Smoke detectors	number	384	510	560	Smoke detectors
Stainless steel	tonnes	459	1,349	1,732	Pipes and vessels
Stellite	tonnes	n/q	n/q	n/q	Valve facings
Tin	tonnes	1	1	1	Solder
Titanium	tonnes	28	31	32	Pipes and machines
Wood	tonnes	20	20	20	Accommodation
Zinc	tonnes	537	532	519	Anodes, galvanising
Total mass (approximate)	tonnes	15,068	23,636	30,423	69,127

N/Q, Not Quantified

Notes:

ABS, Acrylonitrile Butadiene Styrene
Ac, Actinium
CFC, Chlorofluorocarbon
EPDM, Ethylene propylene diene monomer
GRP, Glass-reinforced plastic
LSA, Low Specific Activity
NORM, Naturally Occurring Radioactive Material
Pb, Lead
PCB, Polychlorinated Biphenyls
PTFE, Polytretrafluoroethylene
PVC, Polyvinylchloride
Ra, Radium

12.9 Environmental Impacts of Decommissioning the Topsides

12.9.1 Stakeholder Environmental Concerns

The specific environmental concerns or issues raised by our stakeholders were:

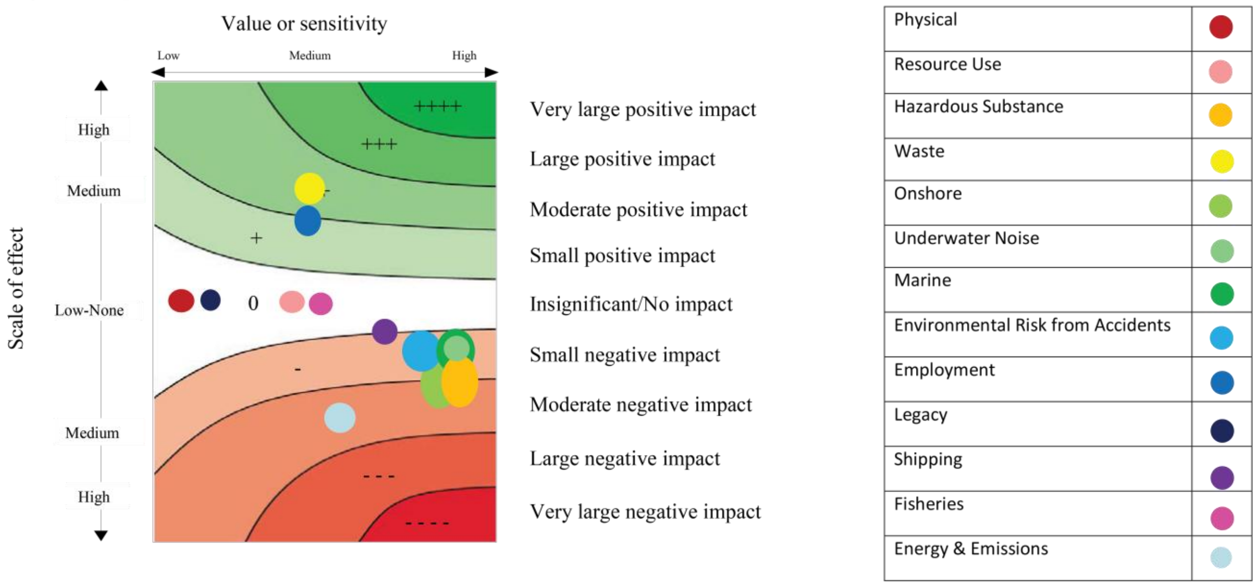
- Accidental discharges or releases of hydrocarbons to sea.
- Accidental loss of large components to sea.
- Impacts to local communities at onshore dismantling or recycling sites caused by noise, dust and odour.
- Impacts to onshore infrastructure.
- The need to manage waste disposal properly and according to best practice.

12.9.2 Potentially Significant Impacts in ES

Figure 25 presents DNV GL's summary of the results of the environmental impact assessment of the programme of work that would be carried out to remove the topsides completely by SLV, and dismantle, recycle or dispose of this material onshore at the ASP facility [5].

The most significant negative impacts from this activity were the use of energy and the gaseous emissions offshore which was assessed as 'moderate negative', and onshore impacts noise and the handling of hazardous wastes, both of which were assessed as 'small-moderate negative' [5]. There were 'small-moderate positive' impacts from the offshore employment associated with this programme and from the treatment and recycling of waste materials.

Figure 25 Environmental Impacts from Decommissioning of all Four Brent Topsides by SLV.



12.9.3 Impacts of Offshore Operations

Barring a major and very unlikely accident during lifting or transportation, the main potential impact offshore would be the underwater noise from the SLV. The presence of the SLV and attendant vessels will increase the level of underwater noise in the area of the platform. Modelling showed that this would be localised and transient, and unlikely to reach a level that would cause more that short-term disturbance to a few individual marine mammals. This noise will be very similar to that already experienced at the site, and is likely to vary depending on the levels of activity. Noises will not begin suddenly, but are likely to increase steadily as vessels enter the 500 m safety zone. Modelling has shown that although the noise frequency from the vessel spread will be within the hearing range of several species of marine mammals, the received noise levels at distances of more than about 900 m are not likely to be high enough to cause 'disturbance behaviour' in marine mammals, and certainly not high enough to cause a temporary threshold shift in their hearing ability. The noise will not cause any harm to fish or other marine species.

12.9.4 Impacts of Onshore Operations

The most likely source of potential impact during topsides decommissioning will be the long phase of onshore dismantling. At the ASP facility, the programme of hot and cold cutting, the 'cut and pull' operations to separate the sections of topsides, the lifting, handling and transportation of increasingly smaller sections of the topsides will generate noise, dust, and odour, and additional light and road traffic, in and around the site. Small spills of hydrocarbons and other fluids may occur. Consequently, the main impacts of the topsides decommissioning are onshore, to the local community and infrastructure. Decommissioning the topsides onshore was estimated to have a 'small-moderate negative' impact on local receptors owing to a combination of potential noise, dust, traffic and visual impacts upon local residents and birds, that could occur over a significant period of time as a result of the large volumes of topsides materials that will come to shore. When considered together, however, and bearing in mind the sensitive nature and proximity of the Special Protection Area (SPA), and the significant length of time the decommissioning activities will take, the overall potential impact is higher. The impacts are manageable, however, and the necessary controls will be in place to ensure that the impacts are minimised. With regard to the handling and management of hazardous materials, the ES found that the handling and treatment of hazardous wastes from the decommissioning of the topsides are estimated to have a 'small-moderate negative' impact. The assessment reflects the current uncertainty about the exact volumes of mercury, asbestos and NORM wastes, and the potential presence of pyrophoric scale (although to date Shell has no evidence that pyrophoric scale is present in the topsides). In practice, however, the impact of the planned management of hazardous waste may be less than this, even 'insignificant'. The ASP facility will be fully licensed to receive decommissioning wastes and all work will be conducted under the necessary permits and consents. We will ensure a Duty of Care assurance programme is in place, to monitor the management of the ASP facility and ensure that all appropriate controls are in place and complied with. The ASP facility will be audited by a third party to ensure compliance with its stated management systems.

12.9.5 Legacy Impacts

We aim to recycle at least 97% by weight of the topside material retrieved to shore. Some types of material which are present in small quantities will not be recyclable and these will have to be disposed of to landfill. Essentially, however, there will be no negative legacy impacts from the decommissioning of the topsides.

12.9.6 Energy and Emissions

The proposed programme of work for all four topsides would have a net energy use (i.e. including any savings that may be achieved by recycling material) of approximately 1.2 million GJ (Table 24). It would take about 320,000 GJ to recover the topsides to shore and dismantle them, and about 0.8 million GJ to recycle them. The greatest use of energy, and the greatest single source of gaseous emissions, will be the recycling of all the different waste streams. DNV GL estimate that the whole programme for all four topsides would result in the emission of about 63,000 tonnes of CO_2.

Table 24 Energy and Emissions Associated with SLV Removal and Onshore Disposals of all Four Brent Topsides.

Operations	Energy (GJ)	Emissions to Atmosphere (tonnes)		
		CO_2	NO_X	SO_2
Direct				
Marine operations	254,958	19,423	527	284
Onshore dismantling	43,511	3,200	71	3
Onshore transport	21,340	1,570	35	1
Sum	*319,809*	*24,193*	*633*	*288*
Recycling				
Material recycling	837,199	38,852	135	407
Materials not recycled	42,125	ND	ND	ND
Total	1,199,133	63,045	768	695

ND = No Data

12.10 Mitigation Measures for Topsides Programme of Work

12.10.1 Assurance

Although the Intellectual Property rights associated with the design, construction and operation of the SLV belong to AllSeas, we have carried out extensive technical reviews of the SLV methodology during specific phases of the project including; a General SLV Concept Review (Pre-Qualification for Tender) in 2009, a *Pioneering Spirit* SLV-specific review during Front-End Engineering and Development (FEED) in 2012, and a Pre-Contract Award review (as part of a Development Release procedure) in 2013. Throughout this process the BDP has been fully engaged with STASCO (Shell Trading and Shipping Company), the appointed Marine Warranty Surveyor DNV GL, an Independent Verification Body (Bureau Veritas), and our own Technical Authorities. DNV GL will review and accept all relevant calculations, specifications, procedures and marine spread for the programmes of work for removal, transportation and load-in, such that a Certificate of Approval can be provided to assure our insurers that the marine activities are ready to proceed safely. Bureau Veritas will provide an independent verification of platform modifications of Safety Critical Elements (SCE) that affect the Dismantlement Safety Case, subject to approval by the HSE.

The technical requirements for which compliance will be demonstrated include:

- Lloyd's Register Class requirements for Dynamic Positioning (DyP) Class 3 Standard and appropriate redundancy concept for DyP system.
- Robustness against single point failures of systems for ballasting, power management, dynamic positioning and lifting.
- Application of two compartment damage stability standard.
- Strengthening of topsides such that the support structure is robust against the worst combination of loads corresponding to failure of a single lifting point.

Considerable effort has been made to reduce the likelihood that a Brent topside would topple during removal, transportation or back-loading. By then of 2016, AllSeas had finalised their installation of twelve of the lifting beams, performed a trial lift using a test-lift platform weighing 5,000 tonnes, and successfully lifted the 13,500 tonne topside from the Yme platform[27] (Figure 26). Together, these two lifts provide further

[27] Yme is a platform in the Norwegian sector of the North Sea.

assurance that any unforeseen problems in design, systems or operating procedure have been identified and resolved. The remaining four lifting beams are currently being installed before the Brent Delta topside lift which is planned to take place in summer 2017.

Figure 26 *Pioneering Spirit* Lifting the Yme Topsides, August 2016.

We are working closely with the appropriate Regulators and local Marine or Harbour authorities to ensure that all the contingency plans will be in place before removing the first Brent topside – Brent Delta – in 2017. Emergency response plans will be in place for the removal and transportation activities including a Brent Field System Oil Pollution Emergency Plan (OPEP) incorporating a contract for specialist response services through Oil Spill Response Limited (OSRL). Once a topside is secured on the SLV any spill of hydrocarbons will be managed through the vessel's Shipboard Oil Pollution Emergency Plan (SOPEP). A bridging document will be in place between Shell and AllSeas to confirm all the responsibilities and response arrangements.

With AllSeas, Able, the warranty surveyor and the Harbour Master, we will perform a detailed Marine Hazard Identification (HAZID) exercise for the transfer, tow-in and load-in of the topside. This will be informed by knowledge that has been gained from the transfers and load-ins that have been performed in and around Teesside over the last few years. The Delta Dismantlement Safety Case, detailing the management of the remaining offshore Major Accident Hazards (MAH), and the associated environmental BEIS permits, were approved in 2016.

The potential environmental impacts of the entire topsides removal and disposal programme – including offshore separation, lifting, transportation, barge transfer, skidding, onshore dismantling and disposal – have been identified and assessed in the ES [5]. In addition to the project-wide ES, we engaged AECOM Limited to prepare the *Brent Removals and Dismantlement Impact Assessment (ESHIA)* (Environmental, Social and Health Impact Assessment) [35] of the potential environmental, social and health impacts of the operations at the nearshore transfer site, and at all the Able facilities used for dismantling, storing, handling, treating and disposing of all material from the topsides. This provides the information necessary for us to satisfy ourselves that we are ready to bring material shore, and that we understand the risks and have suitable mitigation measures in place.

12.10.2 Summary of Mitigation Measures

- The programme of work to remove and dismantle the Brent topsides will be conducted under all necessary permits.
- Appropriate Notices to Mariners will be issued to alert other users of the sea to the proposed operations in the Brent Field, along the tow route and at the nearshore transfer site.
- Explosives will not be used to remove the structures.
- Before removal, a comprehensive programme of depressurisation, draining and flushing will be performed to remove the bulk of hydrocarbons and other fluids and gases from the topsides systems, so as to minimise the risk that residual fluids will escape to sea.
- On completion of offshore operations to remove the topside, other users of the sea will be advised of the changed status or condition of the installation.
- On each GBS, one of the legs will be fitted with an AtoN to alert shipping.
- At Brent Alpha, if the upper jacket is not removed immediately after the removal of the topside (Section 13.11), an AtoN will be designed and fitted to the top of the jacket to alert shipping.
- If there is any delay in the fitting of AtoNs on any structure, a guard vessel will be deployed to alert other users of the sea.
- The dismantling of the topsides, and the treatment and disposal of all resultant waste streams, will take place at the ASP facility on Teesside, which is fully licensed for the dismantling of offshore structures and the management of these wastes.
- The topsides will be dismantled in accordance with the Code of Practice for full and partial demolition [34].
- Able UK will apply a range of mitigation measures to minimise the potential impacts of onshore dismantling. These will include carefully planned work practices and programmes, limits to night work, dust-control measures, and measures to plan and monitor additional road traffic and the movement of large loads.

13 DECOMMISSIONING THE BRENT ALPHA STEEL JACKET

13.1 Description of the Brent Alpha Jacket

Brent Alpha was designed in the 1970s and is a first-generation steel platform. It is fixed to the seabed by steel piles, and provides all the facilities and systems needed to drill and service wells, process oil and export it to shore via Brent Charlie and Cormorant Alpha. The platform has accommodation for approximately 120 persons. Since 1997 power for the platform has been provided by gas turbines on Brent Bravo, supplying electricity via a subsea cable; before this, all the power was generated by on-board diesel generators. Table 25, and Figure 27 and Figure 28 show the main features of the platform, and further detailed descriptions are given in the *Brent Alpha Jacket Decommissioning Technical Document* [13].

An important feature of the jacket is the three wide pontoon legs on Face A (Figure 28). During emplacement, the jacket was towed into the Brent Field on a barge and then skidded off into the sea where it floated on its pontoon legs which at that time were sealed and full of air. The legs were then flooded to rotate the jacket into a vertical orientation and lower it onto the seabed.

After removal of the topsides (Figure 29) the weight in air of the jacket, complete with its piles and conductors, would be about 31,500 tonnes. Table 26 summarises the jacket inventory after removal of the topsides.

Table 25 Data on the Brent Alpha Jacket.

Topic		Information			
Type of facility		Steel piled platform			
Position, decimal (WGS84)[28]		61.034384N, 1.703685E			
Position, decimal minute (WGS84)		61°02.063'N, 01°42.221'E			
Shortest distance to nearest coast		136 km, Shetland Islands, UK			
Shortest distance to median line		12 km to UK/Norway			
Jacket height from seabed to underside of Plate Girder Support Structure		161.9 m	Jacket height above LAT	21.7 m (to underside of PGDS)	
'Footprint' areas	Seabed footprint	5,775 m^2	Truss Deck	2,280 m^2	
Total estimated weight of jacket in place, to 3 m below seabed				31,453 tonnes	
Total weight of piles, including grout (included in the total weight above)				8,645 tonnes	
Pontoon Legs					
3, full height, on Frame 'A'	Diameter	7.32 m	Thicknesses	16-25 mm	
Other Legs					
3, full height, 2 partial height	Diameters	1.83 m to 2.74 m	Thicknesses	38-48 mm	
Steel Piles					
32, maximum stick-up ~10 m	Diameter	1.83 m	Thickness	48 mm	
Risers					
9, full height of jacket	Diameters	0.2 m to 0.7 m	Thicknesses	10-25 mm	
Conductors					
28, full height of jacket	Diameter	0.66 m to 0.76 m	Thickness	25.4 mm	

[28] WGS84, World Geodetic System 1984

Figure 27 The Brent Alpha Platform in 2006.

Figure 28 The Main Components of the Brent Alpha Platform.

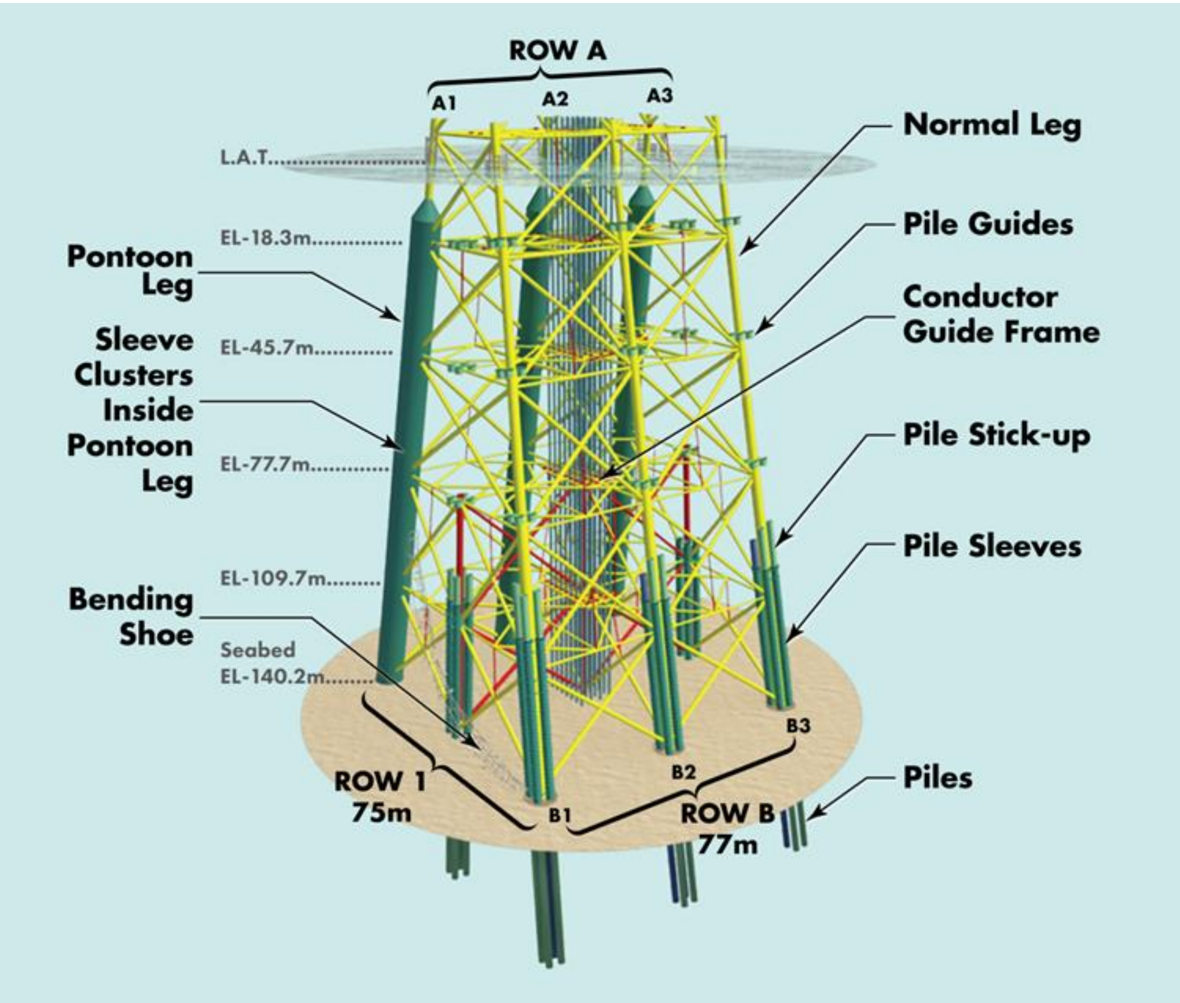


Figure 29 Condition of the Brent Alpha Jacket after the Removal of the Topside.

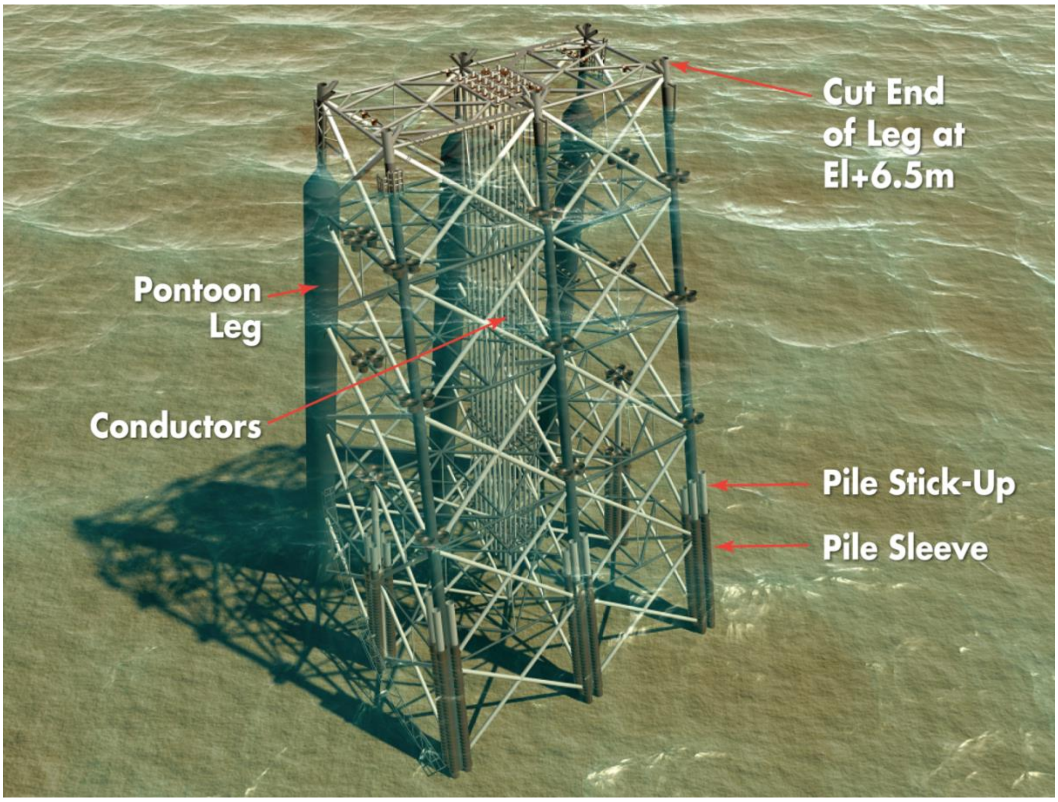


Table 26 Inventory for BA Jacket after Removal of Topside.

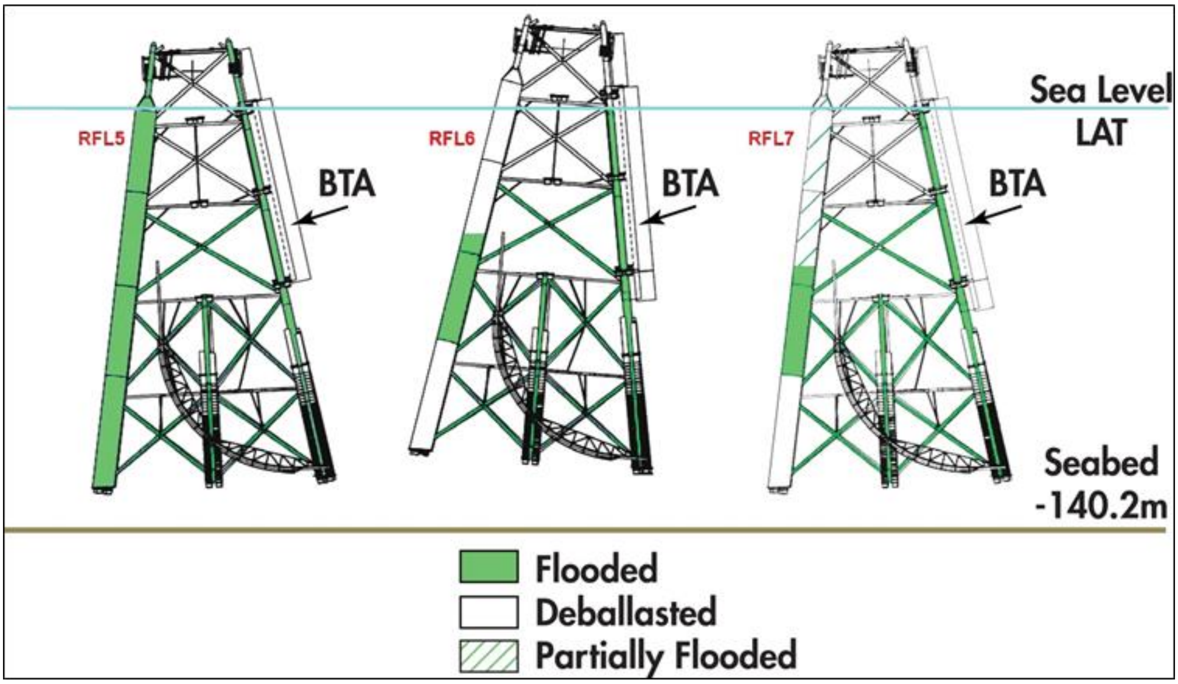
Component	Material and Estimated Mass (tonnes)[29]			
	Steel	Grout	Marine Growth	Anodes
Jacket	14,813	0	2,120	256
Conductors	2,029	720	614	0
Casings	2,256	0	0	0
Piles	4,161	4,484	0	0
Total	23,259	5,204	2,734	256

13.2 Refloating the Whole Jacket in One Piece

The Brent Alpha jacket was not designed to be refloated, but because the final stage of the original installation process involved the ballasting of the pontoon legs and submergence of the floating jacket, we examined whether it might be possible to reverse this process and remove the jacket in one piece by refloating [13]. In their report *Brent Alpha Jacket Removal Refloat Feasibility Study* [36], GL Nobel Denton investigated how the jacket could be made buoyant by dewatering the original buoyancy chambers in the pontoon legs and adding additional buoyancy using Buoyancy Tank Assemblies (BTAs). Figure 30 illustrates a possible configuration for refloating the whole jacket.

[29] Our inventory records do not indicate that any NORM or other hazardous materials will be present on or in the BA jacket. Once the upper jacket has been received at the ASP facility, one of the pre-dismantling tasks will be a survey of the structure to check for the presence of NORM.

Figure 30 Possible Configuration for Refloating the BA Jacket.



In addition to the need to release the jacket from the seabed by severing the piles, described in more detail in Section 13.7, the following technical issues would have to be overcome in any option to refloat the jacket:

- Strengthening the jacket legs so that BTAs could be attached.
- Installing strong lifting points for the attachment of the BTAs.
- Re-establishing some of the water-tight compartments in the pontoon legs to give essential extra buoyancy.
- Ensuring that legs could withstand and sustain the gas pressure required to displace internal water to permit the legs to be floated even with BTAs.
- Controlling ascent and trim with the remains of piles and their grout in place.
- Developing a safe and cost-effective way of dismantling the jacket at a deep water site nearshore.

The original buoyancy chambers in the pontoon legs were ruptured during pile-driving, and our studies have shown that it is very unlikely that they could be repaired to re-establish their integrity. However, some buoyancy would be needed in the original buoyancy chambers, even with the addition of external BTAs. Because the original buoyancy chambers cannot be re-instated, we have concluded that it is not technically feasible to refloat the whole Brent Alpha jacket.

13.3 Options for the Brent Alpha Jacket

Having made the decision to remove the topsides as single lifts using the SLV *Pioneering Spirit*, we examined if the whole jacket could be removed in one piece by this vessel. As described in the Alpha Jacket TD [13] we concluded that because of the size and weight of the jacket plus piles, the strength and integrity of the structure, and the complexity of attaching suitably strong and secure lifting points, it was not technically feasible to remove the whole of the BA jacket in one piece using the SLV or any other type of heavy lift vessel. Consequently, all options for decommissioning the BA jacket would necessarily have as their starting point the removal of the upper part of the jacket.

OSPAR Decision 98/3 recognises that there may be difficulties in removing the footings of very large steel structures (those weighing more than 10,000 tonnes in air), and makes provision for the owners to apply for a derogation from the general rule of complete removal. In the case of a piled steel jacket such as Brent Alpha, the OSPAR definition of footings is '*those parts of a steel installation which are below the highest point of the piles which connect the installation to the seabed*'. The Brent Alpha footings is thus a candidate for derogation, and our technical studies have shown that the technically feasible options for the jacket are (i) complete removal in pieces and (ii) partial removal, in one or more pieces, leaving the footings in place.

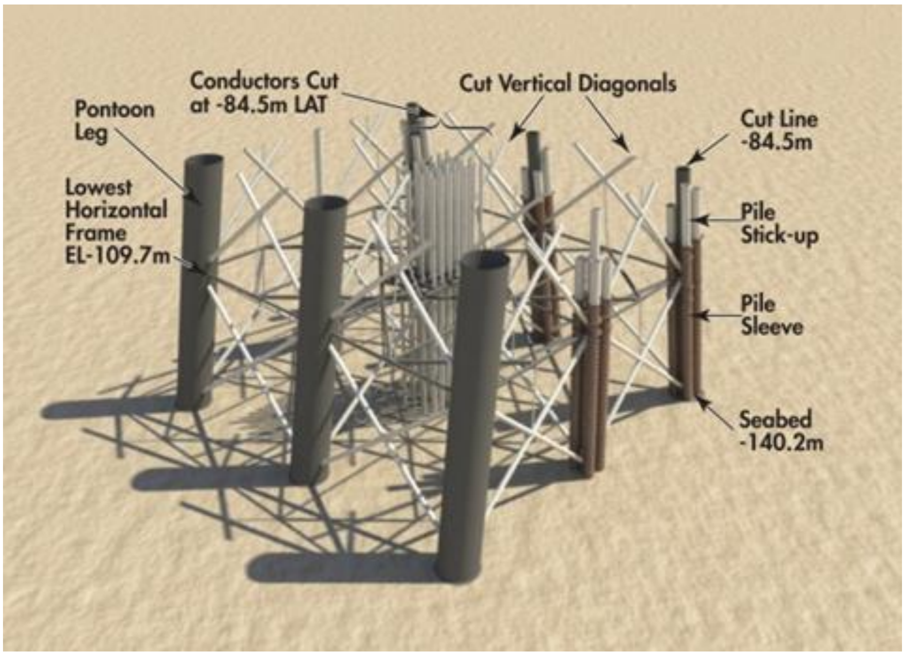
On Brent Alpha, the external pile sleeves extend to a height of 41 m above the seabed, but some of the piles within them are not driven to their full depth and protrude up to 10 m above the sleeve. Consequently the top of the pile (the 'pile stick-up') is approximately 51m above the seabed, which is approximately 89 m below LAT. Considering the way that the vertical and vertical-diagonal members are attached to the legs at about this depth, and the logistics of manoeuvring a DWC machine in this area, we determined that the most suitable depth for cutting the jacket near the top of the footings was -84.5 m LAT.

The decommissioning options for the BA jacket thus focus on options for decommissioning the footings; the upper jacket would be removed regardless of which option was selected for the footings, and does not form any part of the programme of work for the footings.

13.4 Options for the Brent Alpha Footings

The starting point for all the options for the Brent Alpha footings would be that the upper jacket and its conductors have been removed down to -84.5 m LAT (Figure 31).

Figure 31 Condition of the Brent Alpha Footings after Removal of the Upper Jacket.



The footings are fixed to the seabed by 24 hollow steel piles filled with grout, and these would have to be severed at 3 m below the seabed if the footings were to be removed. The piles could be cut *externally*, after excavating a large pit around each leg, or *internally*, after drilling out the grout inside the pile (Figure 32). The footings would be cut into sections on the seabed, and lifted to the surface by a suitable heavy lift vessel (HLV), most probably a semi-submersible crane vessel (SSCV). Consequently, there are three options for the BA jacket footings, as summarised in Table 27.

Figure 32 Typical Arrangement of a Pile Bore Grout Plug in the Brent Alpha Footings.

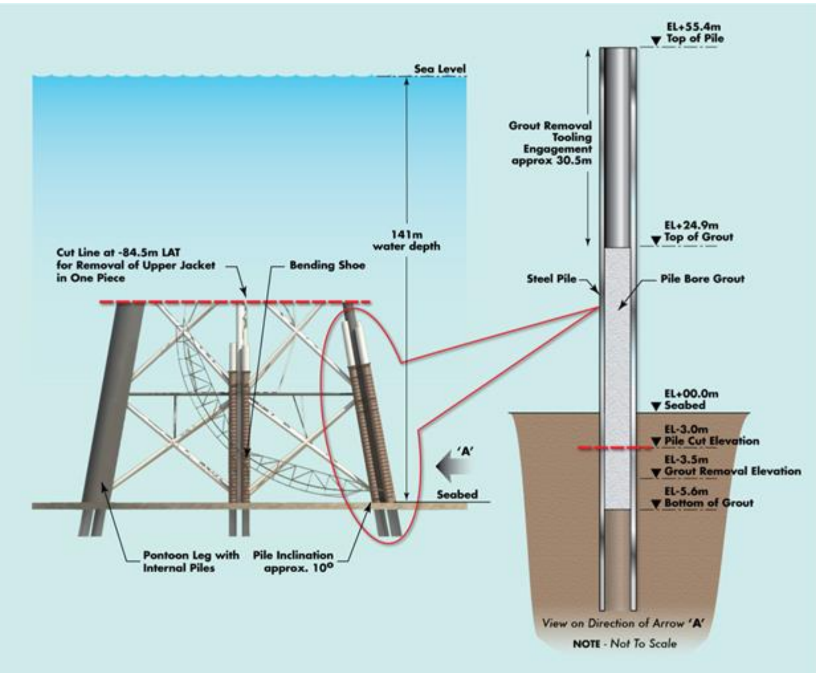
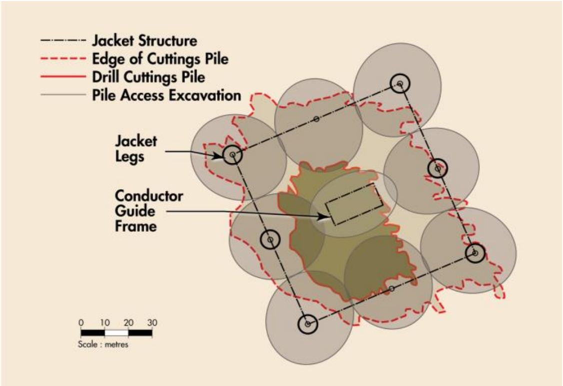
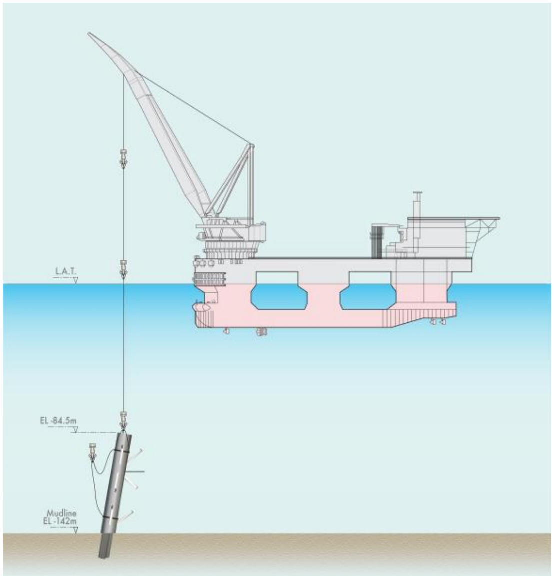


Table 27 Summary of Options for the BA Footings.



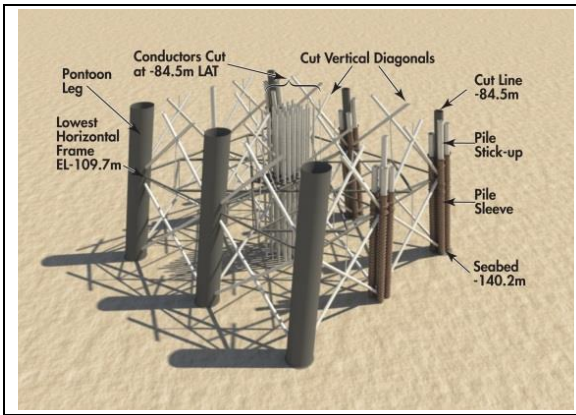
Option 1. Complete removal after external pile cutting. After removing the majority of the drill cuttings pile and excavating 4 m deep pits around each leg, all the piles would be cut externally 3 m below the seabed using a DWC machine. The footings would be systematically cut into large sections, which would be lifted to the surface by an SSCV and transported to shore for further dismantling and recycling. The former site of the BA jacket would be left clear of platform components and debris, and the drill cuttings pile would have been removed.

Locations and sizes of pits to permit external pile-cutting



Option 2. Complete removal after internal pile cutting. The pile-bore grout would be drilled out, and the piles cut internally 3 m below the seabed using an abrasive water jet. The footings would be systematically cut into large sections, which would be lifted to the surface by an SSCV, and transported to shore for further dismantling and recycling. The former site of the BA jacket would be left clear of platform components and debris, and the seabed drill cuttings pile would be left in place and largely undisturbed.

Removal of a jacket leg after cutting the piles internally



Option 3. Leave in place. The footings would be left in place in the condition attained after the removal of the upper jacket, and no further operations would take place. The footings would corrode and eventually collapse completely over a period of about 500 years. The seabed drill cuttings pile would be left in place.

BA jacket footings after removal of upper jacket to -84.5 m LAT

13.5 Issues and Concerns Raised by Stakeholders

For the technically feasible options for the Brent Alpha footings, the main issues and concerns raised by stakeholders during the programme of stakeholder engagement were:

- The principle of leaving a clean seabed.
- Effects of underwater cutting and lifting (especially noise on marine mammals).
- Disturbance to the cuttings pile and effects on the benthos.
- Risk of dropped objects/loss of footings at sea or nearshore.
- Effects on communities of onshore dismantling and disposal.
- Benefits of recycling.
- Safety risk to fishermen from remains left offshore.
- Creation of debris from remains left offshore.
- Continued loss of access to fishing grounds from remains left offshore.

13.6 Interaction with the Seabed Cuttings Pile

We performed two CAs for the BA jacket footings. The first examined options for the footings alone, without consideration of the presence of the seabed drill cuttings pile. The second examined options for the footings in combination with the most appropriate option for the management of the cuttings pile. Options for the management of the BA cuttings pile are described and assessed in detail in Section 17 and in the Drill Cuttings TD [16]. The recommended options for managing the BA drill cuttings in combination with the BA footings are shown in Table 28. In summary, if the footings were to be removed by external pile-cutting, all of the drill cuttings pile would have to be displaced to allow the piles to be cut, and the recommended option for this would be 'Treat slurry onshore', in which the cuttings would be dredged as a slurry, collected by a vessel and taken to shore, and treated and disposed of onshore (Section 17.8). If the jacket footings were to be removed by internal pile-cutting, or if they were to be left in place, the recommended option for the cuttings pile would be 'Leave in place for natural degradation' since this drill cuttings pile falls below both of the OSPAR thresholds (see Section 17).

Table 28 Recommended Combination of Options for BA Jacket Footings and Seabed Drill Cuttings Pile.

Combined Option	Option for Footings	Option for Drill Cuttings Pile
1. Complete removal of footings after removing the cuttings pile.	Complete removal with external pile-cutting	Retrieve and treat onshore
2. Complete removal of footings leaving the cuttings pile in place.	Complete removal with internal pile-cutting	Leave in place
3. Leave footings and cuttings pile in place.	Leave in place	Leave in place

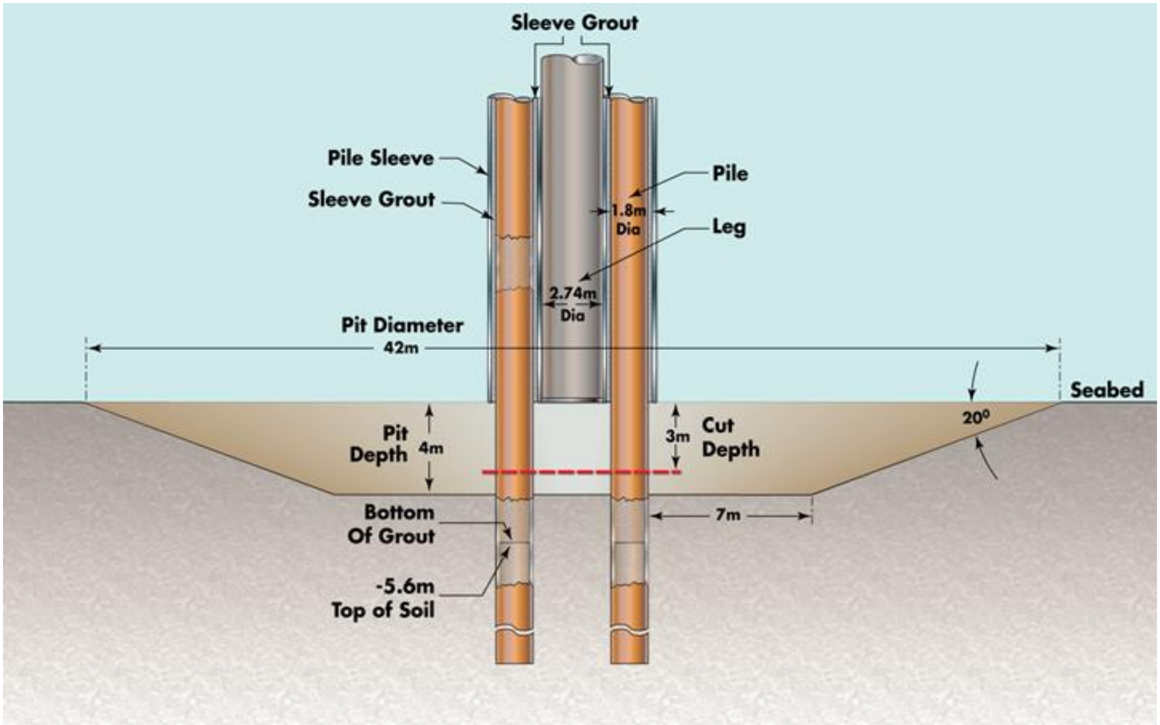
13.7 Technical Issues for Removing the Footings

The main technical issue associated with the removal of the Brent Alpha footings is the cutting of the steel piles anchoring the structure to the seabed.

In Option 1, the piles could be cut externally by DWC after excavating pits around each leg. Because of the arrangement and spacing of the external piles on the Row B and Row AB legs, and the diameter of the Row A pontoon legs, the piles would have to be cut individually in four separate deployments of the DWC around each leg. In order to achieve a cut at 3 m below the seabed, the DWC machine would have to be positioned at the bottom of a 4 m deep pit excavated around the leg; and to provide sufficient space for manoeuvring the DWC, the bottom of each pit would have to be a flat surface approximately 7 m wide from the side of the steel piles (Figure 33).

The angle of repose of the soil at Brent Alpha has conservatively been assumed to be 20°. On this assumption, and given the constraints and requirements mentioned above, we have calculated that the pits around each leg would have to be approximately 42 m in diameter (Figure 33, which shows only two of the four piles on the leg). We estimate that 3,147 m^3 of clean seabed sediment would have to be excavated around each leg, giving a total of 25,176 m^3 of material to be excavated. This would be in addition to the 6,300m^3 of drill cuttings that would have to be removed.

Figure 33 Cross-section through a Typical Pit Excavated Around each Leg.



There are several existing tools and systems, for example, the 'Scanmachine™' and the 'Scandredge™', that could be used to excavate the pits and relocate material either onto the adjacent seabed or to a surface vessel. The pits around each leg would be excavated in turn and the excavated soil would be used to backfill the previous pit. There would have to be a considerable period of planning and trialling before attempting to cut the large diameter piles of the Brent Alpha footings.

In Option 2 the piles would be cut internally by Abrasive Water Jet (AWJ) after drilling out the pile-bore grout. The drilling method is similar to conventional well drilling in hard clay or rock, and would be performed using a drill string consisting of drill pipe and a Bottom-hole Assembly (BHA). The BHA provides weight and stabilises the drill bit attached to the tip of the BHA. The drill bit is rotated in the conventional way and is provided with roller cutters which grind away the grout. Because the piles on Brent Alpha are inclined in line with the legs, the drill rig would have to be inclined in order to access the pile through the pile guides. Figure 34 shows such an arrangement on top of a pile above the sea. For the Brent Alpha footings, the removal of the upper jacket would facilitate access and make it easier to attach this equipment to the top of the piles.

Figure 34 Pile-Top Drill Rig for Battered Piles (Source: Seacore)

There is a concern that drilling the grout could vibrate the pile within the sleeve, and break the grout bond between the outside of the pile and the inside of the pile sleeve. This would loosen the pile and allow it to fall onto the seabed as the section of footings was being lifted, or to jam partially out of the sleeve in such a way as to make it difficult to load the footings onto the cargo barge. Existing pinning techniques could, however, be used to secure the piles in place. Any pinning operation would have to be performed after the removal of the pile bore grout and internal cutting because the pin(s) would restrict or prevent access for this equipment.

Once the grout plug had been removed, an internal AWJ cutter could be deployed inside the pile to cut through the steel wall of the pile. Clearly, the stability of the jacket footings would have to be understood when determining the sequence of cutting the piles; the Brent Alpha jacket has minimal mud mats[30] and no horizontal bracing[31] members resting on the seabed. The removal of the upper jacket would, however, reduce the weight on the piles and the turning moment caused by wave and current action, and thus the on-bottom stability of the footings would be greater than that of the whole jacket after topside removal. If the leg sections were removed in sequence it is very likely that with careful planning the remaining footings (comprising the untouched legs, intact piles and cut bracings) would stay stable and secure on the seabed. As with Option 1, a considerable period of planning and trialling would be required before attempting this operation offshore.

There are no technical issues associated with Option 3. No further offshore operations would be performed after the removal of the upper jacket.

[30] Mud mats are horizontal steel structures fitted to the bases of legs to spread the load of a jacket onto a larger area of seabed.

[31] The bracings are the horizontal, diagonal and vertical diagonal hollow steel members linking jacket legs.

13.8 Result of the Comparative Assessment of Options for the Brent Alpha Footings

The CA for the BA jacket footings is presented in detail in the Alpha Jacket TD [13].

Table 30 presents the weighted sub-criteria scores for each of the three options examined for the Brent Alpha footing alone. On the basis of this assessment, the 'CA-recommended option' for the Brent Alpha footings alone is Option 3 'Leave in Place'. It has a total weighted score of 81.05, in contrast to Option 1's total weighted score of 75.54 and Option 2's weighted score of 74.21.

Table 29 Transformed and Weighted Sub-criteria Scores for the Brent Alpha Footings Alone.

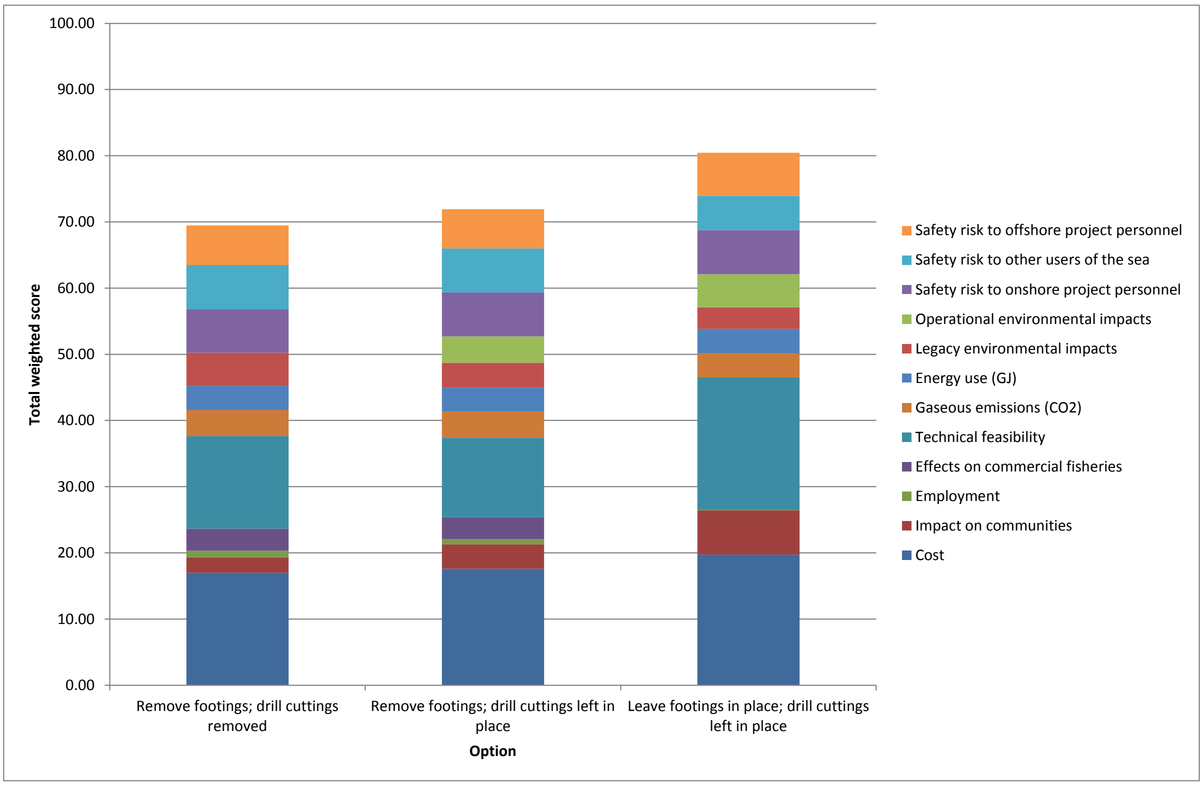
Sub-criterion	Option 1 Complete Removal with External Pile-cutting	Option 2 Complete Removal with Internal Pile-cutting	Option 3 Leave in Place
Safety risk offshore project personnel	6.14	6.00	6.61
Safety risk to other users of the sea	6.67	6.67	5.18
Safety risk onshore project personnel	6.61	6.61	6.67
Operational environmental impacts	3.55	4.70	5.00
Legacy environmental impacts	5.00	5.00	3.50
Energy use	3.87	3.70	3.74
Emissions	4.17	4.03	3.77
Technical feasibility	14.00	12.00	20.00
Effects on commercial fisheries	3.31	3.31	0.00
Employment	0.73	0.75	0.04
Communities	3.67	3.67	6.67
Cost	17.81	17.76	19.87
Total weighted score	75.54	74.21	81.05

Table 30 presents the weighted sub-criteria scores for each of the three options examined for the Brent Alpha footing in combination with the appropriate options for the drill cuttings pile, and Figure 35 shows the results. The sensitivity analysis shows that Option 3 has the highest total weighted score in every scenario. On the basis of this assessment, the 'CA-recommended option' for the Brent Alpha footings in combination with the drill cuttings pile is Option 3 'Leave in place'. It has a total weighted score of 80.46, in contrast to Option 2's total weighted score of 71.91 and Option 1's weighted score of 69.48.

Table 30 Transformed and Weighted Sub-criteria Scores for the Brent Alpha Footings in Combination with the Drill Cuttings Pile.

Sub-criterion	Combined Options for Brent Alpha footings		
	1 Remove Cuttings and Footings, with External Pile-cutting	2 Leave Cuttings, Remove Footings with Internal Pile-cutting	3 Leave Footings and Cuttings in Place
Safety risk offshore project personnel	5.99	5.91	6.52
Safety risk to other users of the sea	6.67	6.67	5.18
Safety risk onshore project personnel	6.60	6.61	6.67
Operational environmental impacts	0.00	4.00	5.00
Legacy environmental impacts	5.00	3.75	3.25
Energy use	3.62	3.62	3.65
Emissions	3.96	3.96	3.70
Technical feasibility	14.00	12.00	20.00
Effects on commercial fisheries	3.31	3.31	0.00
Employment	1.01	0.79	0.09
Communities	2.33	3.67	6.67
Cost	16.98	17.62	19.73
Total weighted score	69.48	71.91	80.46

Figure 35 The Total Weighted Scores for Combined Options for BA Jacket Footings in Combination with the Drill Cuttings Pile, and the Contributions of the Sub-criteria.

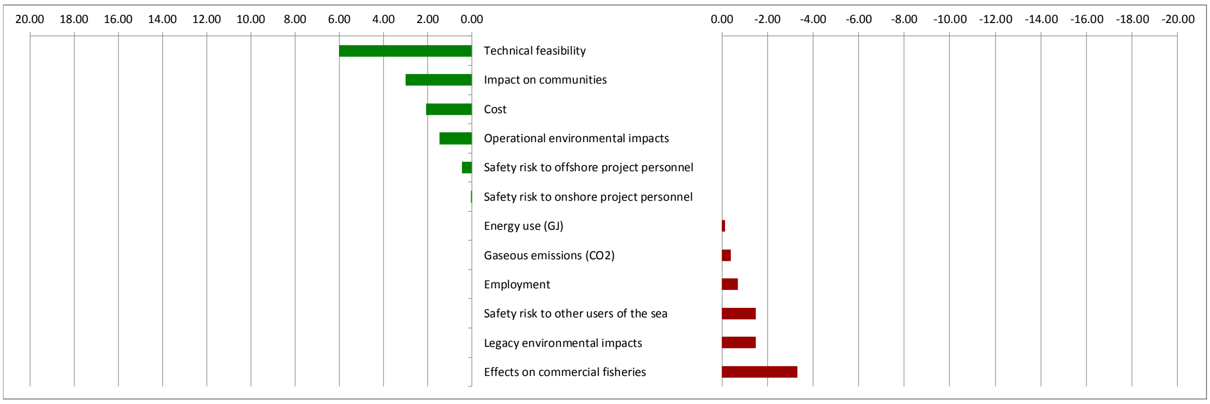


13.9 Discussion of the Comparative Assessment

13.9.1 Discussion for the Footings Alone

Examination of both the raw data and the weighted scores [13] for each of the sub-criteria shows that the differences between Option 3 and the two 'removal' options are driven by the differences in performance in '**technical feasibility**', '**impact on communities**', '**cost**' and '**operational environmental impacts**' (which are better in Option 3 than in either Option 1 or 2), and in '**effects on commercial fisheries**', '**legacy environmental impacts'** and **'safety risk to other users of the sea**' (which are better in both of the 'removal' options). All the other sub-criteria show no or only trivial differences between the options in terms of their weighted scores. This is illustrated in Figure 36 which shows the differences (positive or negative) in the weighted scores in each sub-criterion for Option 1, 'Complete removal with external pile-cutting', which is the better of the 'removal' options, and Option 3 'Leave in place'. In Figure 36 the green bars indicate sub-criteria where Option 3 has the better performance and the red bars indicate sub-criteria where Option 1 has the better performance.

Figure 36 Difference Graph Comparing the Weighted Scores of each Sub-criterion in the Better 'Removal' Option for the BA Jacket Footings Alone, with the 'Leave in Place' Option, Under the Standard Weighting.



Green bars: Option 3 'Leave in place' is better than Option 1 'Complete removal with external pile-cutting'

Red bars: Option 1 'Complete removal with external-pile-cutting' is better than Option 3 'Leave in place'

The removal of the Brent Alpha footings would present several technical challenges but could be achieved at a cost of about £60 million. As a result of the discussion presented in the Alpha Jacket TD [13], however, we have concluded that, objectively, few environmental or societal benefits would be gained from the additional expenditure and risk that would be incurred in removing the footings. One of the tangible benefits would be the elimination of the ongoing liability that we would have if the footings were left in place. If the footings were left in place, the residual long-term safety risk to fishermen – from the footings on their own and in combination with the derogated GBS – would be very low and amenable to further reduction by means of a number of mitigation measures, discussed in Section 13.12.

13.9.2 Conclusion of Assessment for Jacket Footings Alone

In accordance with the requirements of OSPAR 98/3 [2], we have examined the decommissioning of the Brent Alpha jacket starting from the presumption of full removal. We have concluded that it is not tenable to consider refloating or lifting the whole jacket in one piece, so all options would start with the removal of the upper jacket to -84.5 m LAT. The CA therefore focussed on three options for the management of the remaining footings. We have considered the raw data and the scores, and assessed the performances of the options, and have concluded that there is very little to choose between the options in many of the sub-criteria. In some, the difference is very small, or, after considering the raw data, we think the sub-criterion itself is in fact not an important one for our decision-making. In others, although there is a difference in the raw data, this would be reduced or eliminated through management and control of the actual operations.

We have therefore concluded that there are few real differences between the options, except safety risk to fishermen, technical feasibility, and cost.

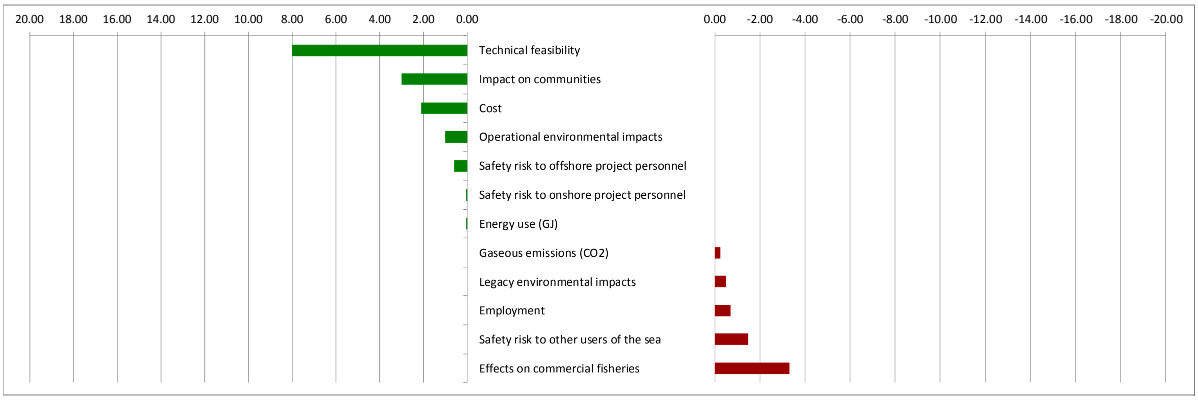
We have examined the estimated long-term safety risk to fishermen, which is necessarily a prediction based on current levels of fishing and current practices, and is intended to be a conservative or pessimistic estimate (as required by the DECC guidelines). In their study *Assessment of safety risks to fishermen from derogated footings of the Brent Alpha steel jacket* [18], Anatec present an estimate of the long-term snagging risk to pelagic and demersal fishing operations from the presence and slow collapse of the approximately 58 m high footings left on the seabed after the removal of the upper jacket. We conclude that the estimated safety risk to other users of the sea, an average annual PLL of 0.12×10^{-3}, is below the upper limit of tolerability (an annual PLL of 1×10^{-3}) and is amenable to further reduction by additional site-specific management measures. We have therefore concluded that, overall, there is little to choose between the options – their performances are broadly equal (with the exception of 'employment' which is directly correlated with 'cost') – and thus that the influences of two remaining criteria – technical feasibility and cost – are material to our decision-making. In this regard, Option 3 is clearly more assured of technical success and is an order of magnitude cheaper – it would be the condition that is achieved after the removal of the upper jacket. On balance, since Option 1 does not yield any significant benefits or improvements in the other measures, we conclude that, for the footings alone, the risks and costs of Option 1 are disproportionate to the small benefits (if any) that would be gained by full removal, and that Option 3 'Leave in place' is preferable to the 'removal' option.

13.9.3 Discussion for the Footings in Combination with the Drill Cuttings Pile

Examination of both the raw data and the weighted scores for each of the sub-criteria shows that the differences between Combined Option 3 'Leave footings and cuttings in place' and the two 'removal' options are very strongly driven by the differences in performance in 'technical feasibility' and, to a lesser extent, 'impact on communities', 'cost' and 'operational environmental impacts' (which are better in Combined Option 3 than in either Combined Option 1 or Combined Option 2), and in 'safety risks to other users of the sea', and 'effects on commercial fisheries' (which are better in both of the 'removal' options). All the other sub-criteria show no or only trivial differences between the options in terms of their weighted scores. This is illustrated in Figure 37, which shows the differences (positive or negative) in the weighted scores in each sub-criterion for Combined Option 2, 'Leave cuttings, remove footings with internal pile-cutting', which is the better of the 'removal' options, and Combined Option 3 'Leave footings and cuttings in place'. In Figure 37 the green bars indicate sub-criteria where Combined Option 3 has the better performance and the red bars indicate sub-criteria where Combined Option 2 has the better performance.

There are two technically feasible options for the complete removal of the Brent Alpha footings in the presence of the seabed drill cuttings pile. Either the seabed drill cuttings pile could be removed to permit pits to be dug around each leg so that the piles could be cut externally by DWC, or the pile bore grout could be removed to permit the piles to be cut internally by AWJ. Although feasible, both options have numerous uncertainties and technical issues (Section 13.7) that would have to be resolved during any detailed FEED of a possible programme of work. The CA showed that Combined Option 2 'Leave Cuttings, Remove Footings with Internal Pile-cutting' was, marginally, better than the other 'removal' option, Combined Option 1 'Remove Cuttings, Remove Footings with External Pile-cutting'.

Figure 37 Difference Graph Comparing the Weighted Scores of each Sub-criterion in the Better Combined 'Removal' Option for the BA Jacket Footings and Seabed Cuttings Pile, with the Combined 'Leave in Place' Option, Under the Standard Weighting.



Green bars: Combined Option 3 'Leave footings and cuttings in place' is better than Combined Option 2 'Leave cuttings, remove footings with internal pile-cutting'

Red bars: Combined Option 2 'Leave cuttings, remove footings with internal pile-cutting' is better than Combined Option 3 'Leave footings and cuttings in place'

The advantages that would be realised by the complete removal of the footings would be the elimination of a long-term legacy safety risk for fishermen, the removal of a small source of seabed debris, and support for additional employment offshore and onshore. These could be realised without the need to remove and treat the whole cuttings pile, by removing the pile bore grout and cutting the piles internally, and then extracting sections of footings through the relatively thin layers of drill cuttings around the perimeter of the footings. This operation would disturb some cuttings, which would drift and settle on the adjacent seabed but would probably not increase the present extent of hydrocarbon contamination around the jacket.

Following our assessment of the real data informing those scores, we have concluded that in terms of the BA footings in combination with the seabed drill cuttings pile, the sub-criteria serving to differentiate the options are 'technical feasibility' and, to a lesser extent 'impact on communities', 'cost' and 'operational environmental impacts' (which are better in Combined Option 3 than in Combined Option 2), and 'safety risks to other users of the sea' and 'effects on commercial fisheries' (which are better in Combined Option 2). The drivers and trade-offs for the decommissioning of the BA footings in combination with the drill cuttings involve a consideration of how feasible and safe it would be to remove the footings and leave the cuttings in place, and what real reduction in safety risk to other users of the sea or benefit to commercial fisheries would thus be achieved.

As far as can be determined on the basis of a conceptual programme, the *increases* in technical difficulty, cost and safety risk for project personnel associated with the programme of work to drill out the pile bore grout, cut the piles internally and extract the footings while leaving the cuttings pile undistributed, is not balanced by any real commensurate *decrease* in safety risk to other users of the sea or legacy environmental impacts or *increase* in benefit to commercial fisheries. If the footings were to be removed, the safety risk to fishermen would be zero and the total safety risk to project personnel engaged in these operations offshore and onshore would be a PLL of 0.0323; that is, if we were to decommission the whole of the 'Brent Alpha footings and cuttings pile' in this way approximately 31 times (by drilling out the pile bore grout and cutting the piles internally then cutting and lifting the sections of footings) there is a risk that one project person might be killed. In terms of the overall BDP this value is low and transforms to a value of close to 1 on the normalised global scale of safety risk where the maximum estimated total risk of any option for any facility for any exposed group of persons is a PLL of 0.2640.

If the footings were to be left in place they would present a potential snagging risk to fishermen. Initially this would be for both pelagic and demersal gear, but as the footings degraded and the height of the remains above the seabed decreased, the risk to pelagic gear would decrease and then disappear. The estimate of total PLL for fishermen for the whole predicted lifetime of the footings on the seabed as they degrade is intended to be conservative. It ignores the fact that fishing practices, vessels and equipment are all likely to change over time in a way that reduces safety risks for fishermen, and that fishermen themselves would take active measures to ensure that their gear did not interact with any remains on the seabed. As discussed elsewhere, it would be our intention to apply for the continuation of the 500 m safety zone around the submerged remains of any platform support structure left in the Brent Field. We would work with the fishermen and the Fisheries Offshore Oil & Gas Legacy Trust Fund Limited (FLTC) to ensure that any remains were properly marked and maintained, and included in the FishSAFE system, to ensure that any risks to fisherman were minimised. We will have a long-term commitment to monitoring and management in the Brent Field and will be able to review the developing situation in conjunction with BEIS and take any necessary mitigation measures as appropriate.

The removal of the Brent Alpha footings, leaving the cuttings pile in place and largely undisturbed, would present several technical challenges but could be achieved at a cost of about £64 million. As a result of the discussion presented in this Section, however, we have concluded that, objectively, few environmental or societal benefits would be gained from the additional expenditure and risk that would be incurred in removing the footings in this way. One of the tangible benefits would be the elimination of the ongoing liability that we would have if the footings were left in place. If the footings were left in place, the residual long-term safety risk to fishermen – from the footings on their own and in combination with the derogated GBS – would be very low and amenable to further reduction by means of a number of mitigation measures.

13.9.4 Conclusion of Assessment for BA Jacket Footings in Combination with the Drill Cuttings Pile

Although we have performed two CAs, one for the footings options on their own and one for the combined options for the jacket footings and seabed cuttings pile, it is impossible to ignore the implications of the cuttings pile when considering options for the footings. The Brent Alpha cuttings pile falls below both of the OSPAR thresholds and, as described in Section 17 and the Drill Cuttings TD [16], the best option for the pile would be to leave it undisturbed to degrade naturally. Considering the drill cuttings pile alone, there is little to be gained by undertaking a programme of work to remove it. The additional safety risk, environmental impacts, energy use, emissions and cost of removing the pile would therefore be incurred simply to gain access to the footings.

When the footings alone is considered, Option 3 'Leave in place' is the recommended option in all of the six sensitivity scenarios. There is therefore no indication that a programme of work to remove the cuttings pile would then yield significant, or even any, benefits through being able to remove the footings [16].

When the footings options are considered in combination with the appropriate best options for the cuttings pile, examination of the raw data shows that the significant criteria differentiating the Combined Options are 'Safety risk to fishermen', 'Technical Feasibility' and 'Cost'. The estimates of the long-term legacy safety risk to fishermen have already been discussed and assessed as being tolerable and amenable to additional mitigation measures. More importantly, the safety risks to fishermen are much smaller than the estimated safety risks to project personnel who might be engaged in drilling out the pile-bore grout and retrieving the sections of footings.

The technical challenges, safety risks and cost of Combined Option 2 'Leave cuttings, remove footings with internal pile-cutting' are significant and disproportionately large in relation to the very small benefits that would be gained. Consequently, this assessment reinforces the earlier conclusion (Section 13.9.2) that for the Brent Alpha jacket footings, Option 3 'Leave footings and cuttings in place' is preferable to full removal.

13.10 Recommended Option for the Brent Alpha Jacket

The detailed CA of feasible options (13.8), carried out in accordance with the requirements of OSPAR Decision 98/3, and using the selection criteria and matters to be considered set out in Annex 2 of that Decision, has indicated that the recommended option for the Brent Alpha jacket in the presence of the seabed drill cuttings pile is follows:

- Brent Alpha Jacket: 'Partial Removal to -84.5m LAT'

13.11 Recommended Programme of Work for Decommissioning the Brent Alpha Jacket

13.11.1 Preparation

The topsides (including the PGDS) will be removed in a single lift by the SLV *Pioneering Spirit* and returned to land for dismantling, recycling and disposal (Section 12).

A separate programme of work will then be performed by an HLV to remove the conductors down to -84.5 m. All 28 conductors, each 91 m long and weighing 158 tonnes, will be cut by AWJ and taken to shore for dismantling and recycling. In total, we estimate that 2,576 tonnes of steel will be removed.

No significant environmental impacts are expected from any of these preparatory activities.

13.11.2 Removal of the Upper Jacket

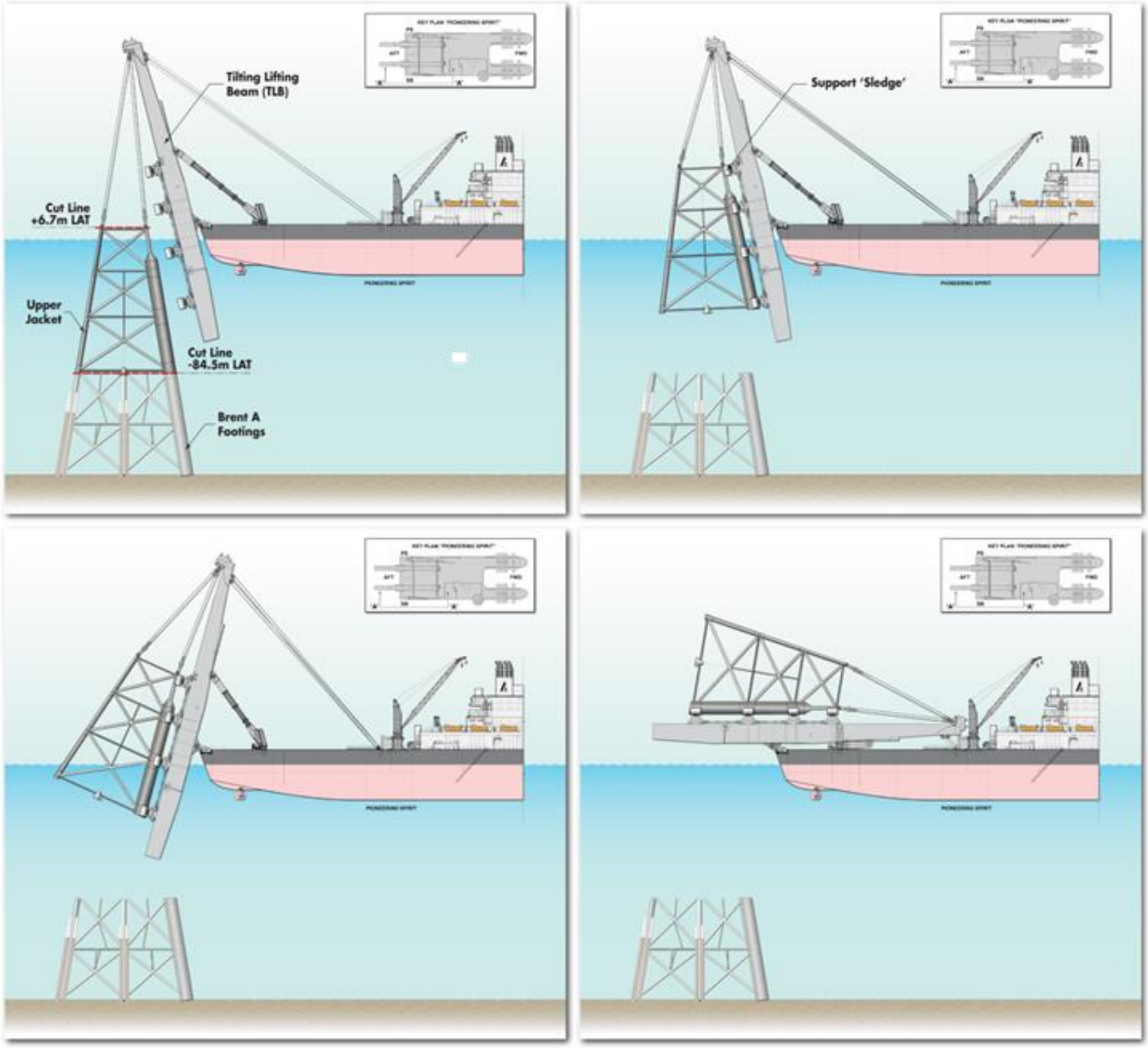
After the removal of the Brent Alpha topside it may be several years before the upper jacket is removed. In such circumstances, the jacket will be fitted with an AtoN and mariners will be advised by means of a Notice to Mariners issued by the UK Hydrographic Office. The schedule for decommissioning the Brent Field is presented in Section 21.

For the removal of the upper jacket, a series of 40 cuts will be made to separate it from the footings. The cut line will be just above the top of the pile stick-up, at a depth of approximately -84.5 m LAT. A DWC system will be deployed by a Remotely Operated Vehicle (ROV) from a Multi support Vessel (MSV), and will sever members, vertical diagonal bracing and legs in a carefully planned sequence of cuts around the jacket. ROVs will locally remove marine growth from the sites to be cut. On selected legs and diagonals, angled cuts will be created to ensure that the upper section remained stable and in place until all the cuts had been completed. We do not expect that temporary restraining guides will have to be fitted around any cut to ensure that the jacket does not move. Nor is it likely that, as the cutting progresses, the weight of the jacket will have to be taken by the SLV's Jacket Lifting System (JLS). Calculations have confirmed that the severed upper part of the jacket could withstand a 1 year return summer storm; if poor weather was experienced the vessels will stand off, leaving the jacket in a secure and stable condition.

Explosives will not be used for any cutting. If unforeseen or accidental circumstances arose where the use of explosives would safeguard lives or major assets, we would consult with BEIS and the Joint Nature Conservation Committee (JNCC). If their use were sanctioned, we would follow the JNCC *Guidelines for minimizing the risk of injury to marine mammals from using explosives* [37] to ensure that, as far as the exceptional circumstances would allow, there was no harm or injury to marine mammals.

Before the final cuts are made, lifting pins will be installed by drilling holes though the tops of the legs. Once all the cuts have been completed and verified, the lifting strops will be attached and the upper jacket retrieved and placed onto the deck of the SLV (Figure 38), which will transport it to the nearshore site for final transfer to the cargo barge and onwards to the ASP facility. The structural analysis reported by Amec in *Study for Removal by Pieter Schelte Vessel: Brent Alpha Jacket Structural Assessment* [38] confirms that the upper jacket, which is approximately 55 m shorter and 18,700 tonnes lighter than the whole jacket, is strong enough to be carried horizontally on the stern of the SLV.

Figure 38 Removal of the Upper Part of the BA Jacket by SLV.



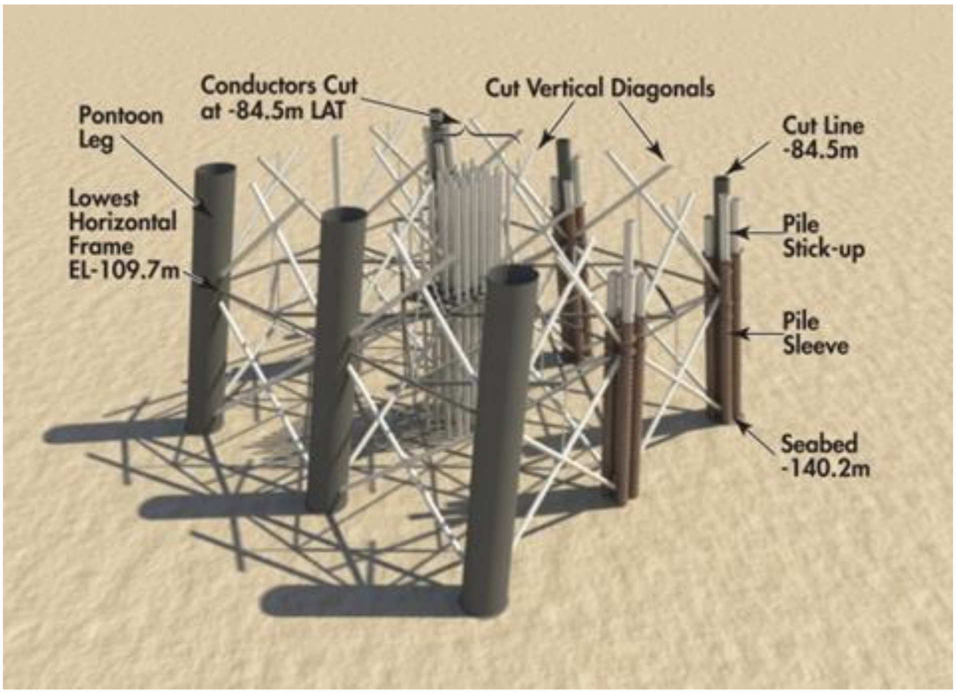
13.11.3 Material Retrieved and Material Left in Place

Figure 39 shows the state of the footings after the removal of the upper jacket, and Table 31 shows the approximate amounts of material that will be removed or left in place on completion of this programme of work.

Table 31 Amounts of Brent Alpha Jacket Material Retrieved and Left in Place following Partial Removal.

Material	Removed on Upper Jacket	Recycled	Disposed of in Landfill	Left in Place
Steel	8,411	8,411	0	14,848
Aluminium/Zinc	101	101	0	155
Organic marine growth	1,601	0	1,601	1133
Cementitious grout	0	0	0	5,204
Totals	10,113	8,512	1,601	21,340

Figure 39 State of the Brent Alpha Footings after Removal of the Upper Jacket.



13.11.4 Onshore Dismantling and Recycling

At the ASP facility, Able will use a variety of hot and cold cutting techniques to quickly reduce the height of the jacket and bring the whole structure down to ground level. With a mass of about 8,400 tonnes, a much simpler construction and a more limited materials inventory than a topside, it is likely that the jacket would be dismantled to ground level within a matter of months. All material will be segregated into different waste streams for storage and, ultimately, recycling, treatment or disposal. All the anodes will be removed and recycled and all the steel will be recycled. Residual marine growth, which will have partially dried during transportation, will be removed and recycled or disposed of to landfill. Since there is no cement grout in the upper jacket, it is expected that at least 97% (by weight) of the removed jacket will be recycled.

Section 23 summarises how we will manage the dismantling and recycling phases of the project.

13.12 Management of Footings

Section 24 describes the measures we will put in place to periodically monitor the condition of the footings.

13.13 Degradation and Longevity of Footings

The footings are still protected by sacrificial anodes which have an estimated remaining life of approximately 20 years. The steel footings will only begin to corrode freely when the bulk of these anodes have wasted away. Lighter horizontal and vertical diagonal members would corrode and begin to fall from the footings after perhaps 30-40 years of corrosion. All four jacket faces are inclined inwards and so it is likely that these components would fall largely within the existing perimeter of the jacket footings.

Legs with external pile clusters, and the pontoon legs with internal piles and grout, will also begin to corrode freely after this time. Although the shells of the pontoon legs (16 mm to 25 mm thick) might exist for up to about 190 years, the piles are expected to degrade much more slowly because the walls of these hollow steel tubes are 48 mm thick. Is it difficult to calculate exactly how long the piles would last, but estimates show that they could remain upright for perhaps 500 years. Eventually, however, perhaps after 300-500 years, all the steel will have corroded [13]. The former site of Alpha will comprise the remains of the historic cuttings pile, overlain with corrosion products from the steel jacket and pieces of concrete from the grout in the piles and pile sleeves.

13.14 Environmental Impacts of Decommissioning the BA Jacket

13.14.1 Stakeholder Environmental Concerns

For the recommended option for the Brent Alpha jacket, the specific environmental concerns or issues raised by our stakeholders were:

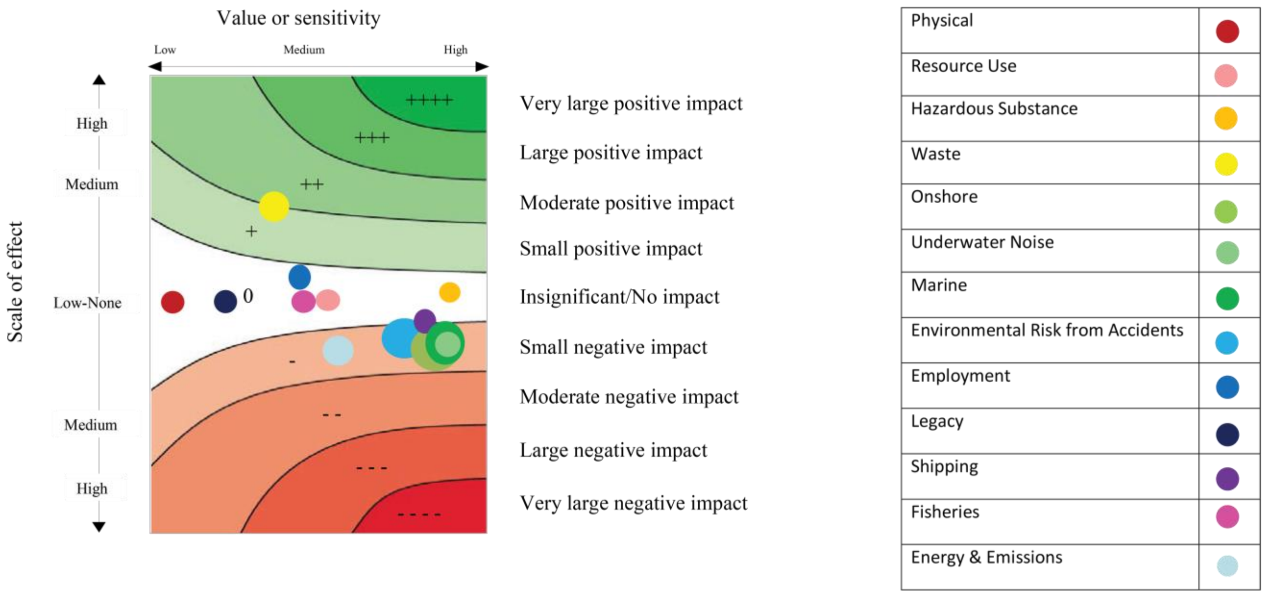
- Accidental loss of large components to sea.
- Impacts to local communities at onshore dismantling and recycling sites caused by noise, dust and odour.
- Recycling and disposal of recovered materials.
- Impacts to commercial fisheries from remains left at sea.
- Effects of collapsing footings on seabed cuttings pile.
- Creation of debris from remains left at sea.

13.14.2 Potentially Significant Impacts in ES

Figure 40 presents DNV GL's summary of the results of the environmental impact assessment of the programme of work that would be carried out to partially remove the BA jacket to -84.5 m by SLV. Figure 41 presents their summary of the results of the environmental impact assessment of leaving the footings in place on the seabed [5].

The most significant impacts from this activity were the treatment and recycling of recovered steel in the upper jacket which was assessed as 'small-moderate positive', and the long-term presence of the footings on the seabed which was assessed as 'small negative.

Figure 40 Environmental Impacts from Partial Removal and Onshore Dismantling of the Brent Alpha Jacket.



13.14.3 Impacts of Offshore Operations

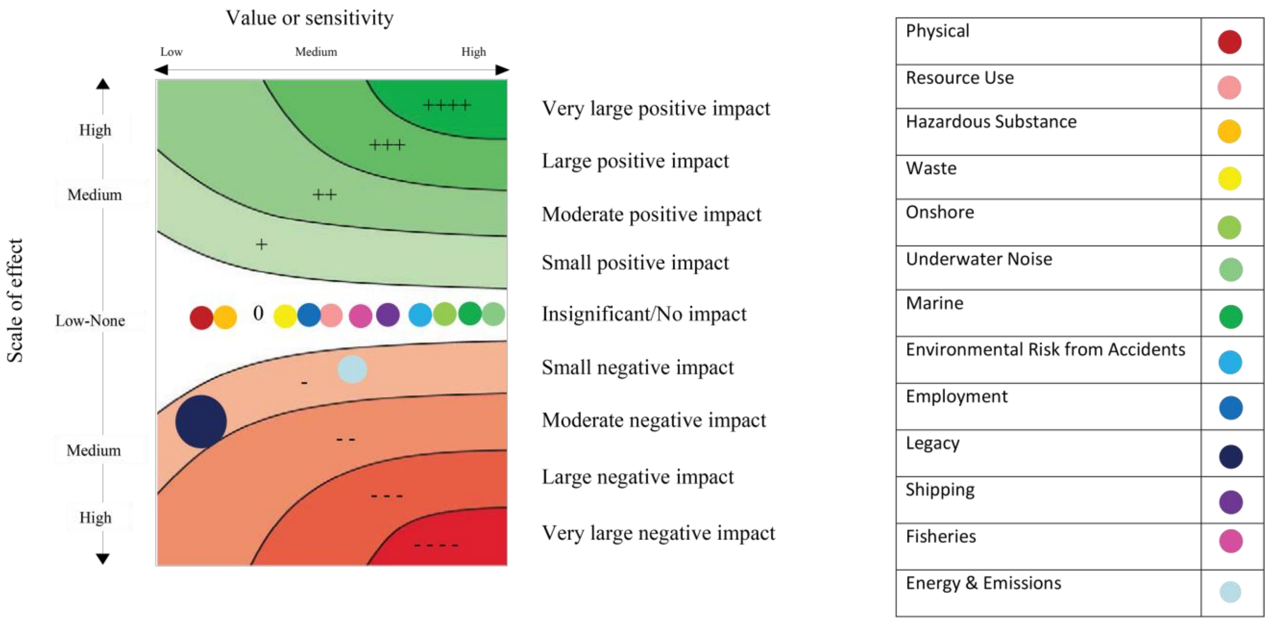
There are no significant negative impacts from the offshore operations to remove the upper jacket. All identified impacts were either insignificant or small [5]. The footings left in place have no operational environmental impacts.

13.14.4 Impacts of Onshore Operations

All the potential onshore impacts for the decommissioning of the Brent Alpha jacket are associated with the dismantling and recycling of the upper jacket.

The ES identified no onshore impacts that were worse than 'small negative'. In addition, the removal of the upper jacket is estimated to have a 'small-moderate positive' effect with regards to waste, primarily because of the quantity of steel that will be recycled. The onshore programme to dismantle the jacket will be simpler and shorter than those to dismantle any of the topsides and consequently any localised short-term impacts to communities and infrastructure are also likely to be smaller. The same mitigation used for topsides dismantling and recycling will be applied as necessary to the upper jacket.

Figure 41 Environmental Impacts from Leaving the Brent Alpha Footings in Place



13.14.5 Legacy Impacts

All the legacy impacts of decommissioning the jacket are associated with the long-term presence of the footings at the Brent Alpha site, and its interaction with the seabed drill cuttings pile.

As shown in Figure 41, the legacy impact of the footings left in place is estimated to be 'small negative'. This includes the impacts to the marine environment as a result of the degradation and collapse of the footings, and on commercial fisheries as a result of the long-term presence of the footings.

As parts of the footings degrade they will collapse onto the cuttings pile, and so from time to time over a period of perhaps up to 500 years, some small amounts of cuttings may be re-suspended into the water column, and drift and then settle on the adjacent seabed. Modelling of such disturbance events suggests that any impacts will be localised and relatively short-lived, and would be most likely to affect areas of seabed that were previously impacted by the discharge and presence of oil-based mud (OBM) drill cuttings, or are in the process of recovering from such impacts (Section 17).

13.14.6 Energy and Emissions

DNV GL estimate that the planned programme of work for the removal, dismantling and recycling of the upper part of the BA jacket will use about 240,000 GJ of energy and result in the emission of about 16,000 tonnes of CO_2 (Table 32).

Table 32 Energy and Emissions Associated with Partial Removal and Onshore Dismantling of Brent Alpha Jacket.

Operations	Energy (GJ)	Emissions to Atmosphere (tonnes)		
		CO_2	NO_X	SO_2
Marine operations	148,600	11,200	290	110
Onshore dismantling	5,100	400	8	0.3
Onshore transport	2,400	200	4	0.2
Sum	*156,100*	*11,800*	*303*	*110*
Recycling				
Material recycling	82,800	3,800	10	30
Materials not recycled	412,900	36,600	40	30
Total	651,800	52,200	353	170

13.15 Mitigation Measures for BA Jacket Programme of Work

- The programme of work to remove and dismantle the Brent Alpha upper jacket will be conducted under all necessary permits.
- Appropriate Notices to Mariners will be issued to alert other users of the sea to proposed offshore operations, including the tow to shore and the transfer of the topsides at the nearshore site.
- Explosives will not be used to remove the structure.
- After the upper jacket has been removed, an as-left structural survey will be performed to accurately determine the condition of the remaining footings and provide a baseline against which to monitor its future condition.
- After the upper jacket has been removed, debris in a 500 m radius area around the footings will be removed and an over-trawling survey will be conducted by an independent organisation to ensure that the area is free of debris. These programmes may be conducted as part of the wider debris removal programme and over-trawling surveys that will be conducted after the decommissioning of the pipelines.
- On completion of offshore operations, other users of the sea will be advised of the changed status or condition of the former installation.
- The location and status of the Brent Alpha footings will be entered onto the FishSAFE system to alert fishermen when approaching the structure.
- The dismantling of the upper jacket and the treatment and disposal of all resultant waste streams will take place at the ASP facility on Teesside, which is fully licensed for the dismantling of offshore structures and the management of these wastes.
- The upper jacket will be dismantled in accordance with the Code of Practice for full and partial demolition [34].
- Able UK will apply a range of mitigation measures to minimise the potential impacts of onshore dismantling. These include carefully planned work practices and programmes, limits to working at night, dust-control measures, and measures to plan and monitor additional road traffic and the movement of large loads.
- A risk-based environmental and structural monitoring programme, to track the long-term degradation and fate of the Brent Alpha footings, will be discussed and agreed with BEIS.

14 DECOMMISSIONING THE BRENT CONCRETE GBSs

14.1 Introduction

As described in Section 7 there are no viable alternative uses for the Brent GBSs Bravo, Charlie or Delta at their present locations, either for oil and gas use or other applications. The Brent Field is not a suitable location for CCS.

14.2 Description of the Gravity Base Structures Bravo, Charlie and Delta

The Brent GBSs are large, heavy support structures which rest on the seabed under their own weight. Bravo and Delta are 3-legged 'Condeep' designs, whereas Charlie is a 4-legged 'Sea Tank' design. The legs, storage cells and base-slab (Charlie only) are constructed of concrete reinforced with mild steel bars and pre-stressed with high-tensile steel tendons. The main body of the GBS, called the caisson, comprises an array of large tanks (cells) and lateral movement is prevented by skirts and dowels beneath the cells or the base slab that penetrate into the seabed sediment. Three (Bravo and Delta) or four (Charlie) of the cells extend upwards as legs that carry the PGDS (or, on Charlie, the cellar deck) on which all the topsides modules are located. Figure 44 illustrates the main features of a Condeep GBS (in this case Brent Bravo), and Figure 45 shows the main features of the SeaTank GBS Brent Charlie. Specific differences between the Condeeps are noted in Table 33 and detailed descriptions of each GBS are given in the *Brent Bravo, Charlie and Delta GBS Decommissioning Technical Document* [14].

Bravo and Delta were constructed in Norway (Figure 42), and Charlie was constructed at Ardyne Point on the Clyde in Scotland (Figure 43) before being towed to Norway. All three structures had parts of their topside fitted at deep-water inshore locations in Norway, before being towed to the Brent Field and then ballasted down onto the seabed by controlled flooding.

Each platform was designed to provide all the facilities and systems needed to drill and service wells, process oil and gas, and export hydrocarbons. At present, the Bravo, Charlie and Delta platforms have accommodation for approximately 150, 190, 160 persons respectively. Originally, they were designed to operate more or less independently but, following the LTFD project and other upgrades, Charlie now supplies all the fuel gas required by Alpha and Bravo.

On each GBS at least one of the legs – the utility leg – provides a conduit between the topsides and the cells for pipes, risers and other services. On Bravo and Delta the other legs are used for drilling and contain conductors, but on Charlie the conductors are located externally, between the legs.

All three GBSs are designed to achieve the required structural strength and integrity when the pressure of the fluids in the cells is lower than that of the seawater outside. This is achieved by a process called drawdown. This is a specific feature of the Brent GBSs that uses a system of pipes and pumps to keep the fluids inside the structure at 4 atmospheres (or bars) below the ambient pressure from the sea. This pressure difference keeps the GBS in compressions at all times, to compensate for the weight of the topsides and the heat stress from the hot fluid in the oil storage cells. The Safety Cases for the GBSs require that drawdown is maintained while the platform is manned.

Figure 42 Brent Bravo GBS During Construction.

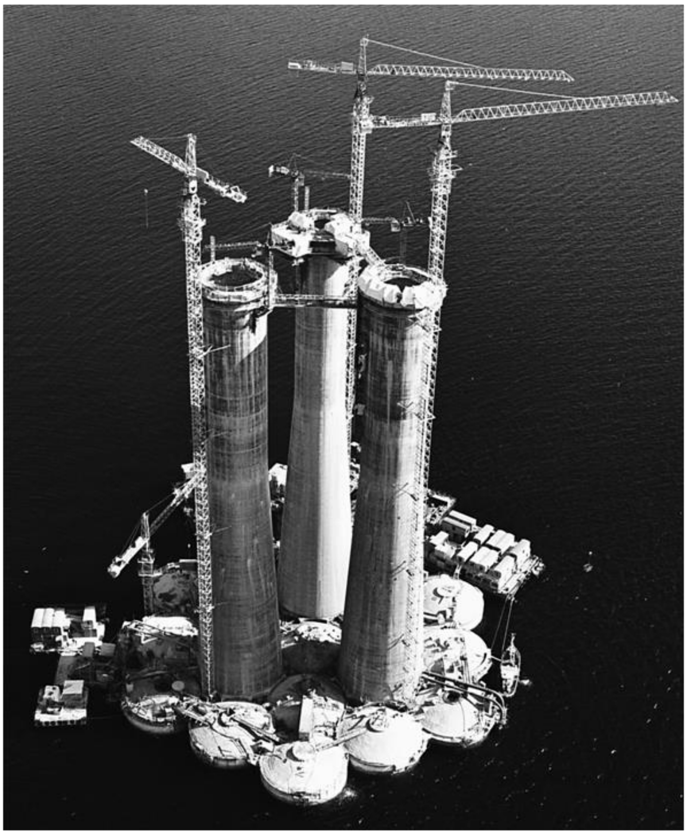


Figure 43 Brent Charlie GBS During Construction.

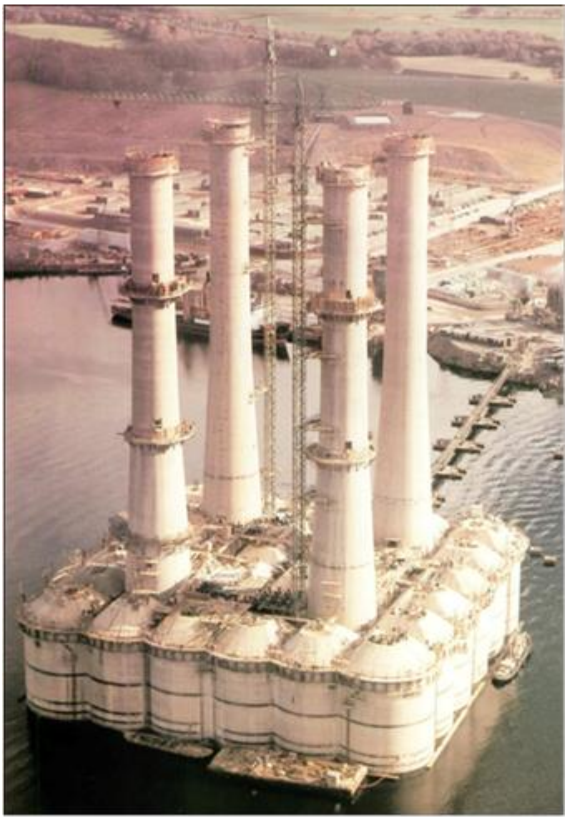


Figure 44 The Main Structural Features of the Condeep GBS Brent Bravo.

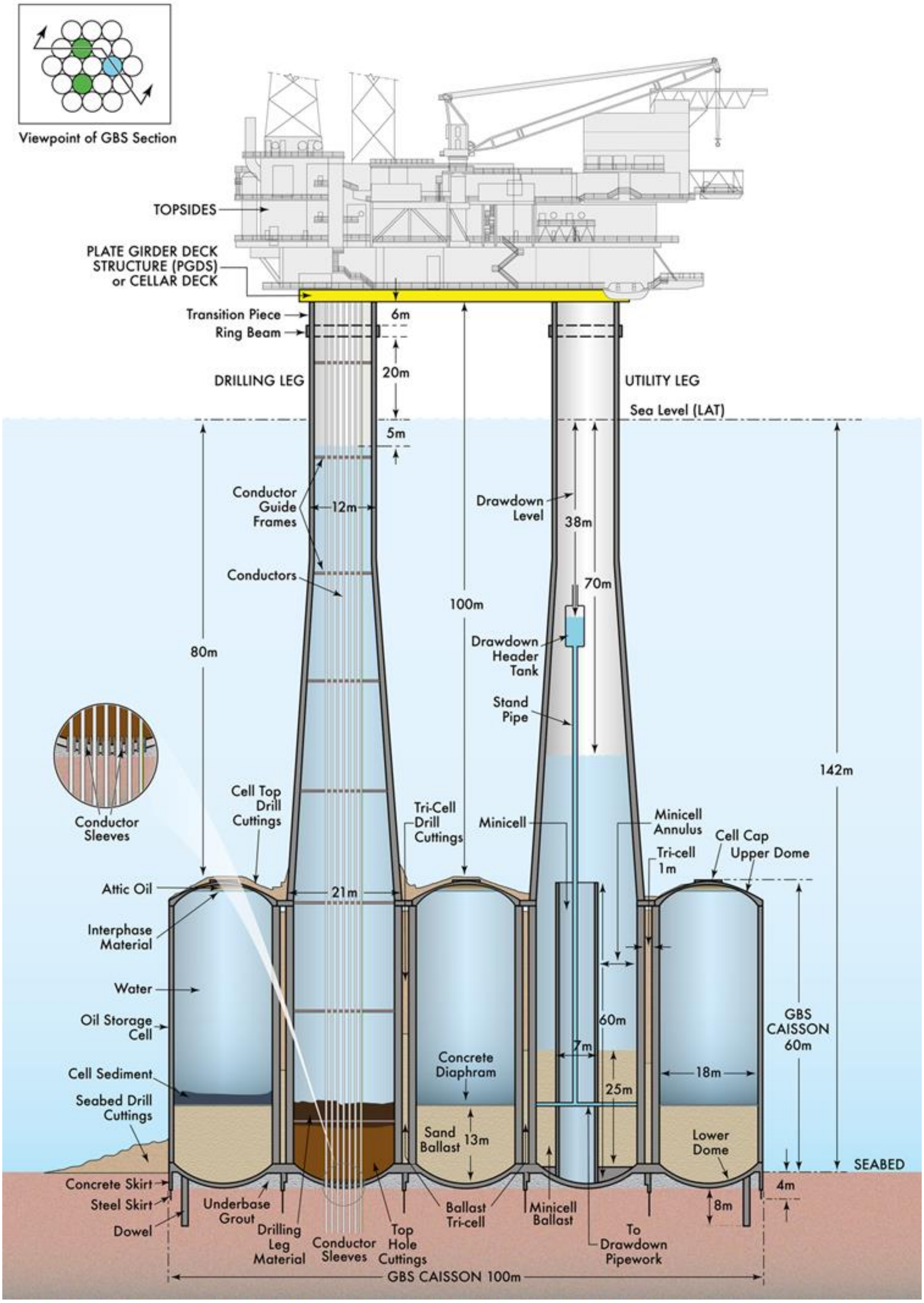


Figure 45 The Main Structural Features of the SeaTank GBS Brent Charlie.

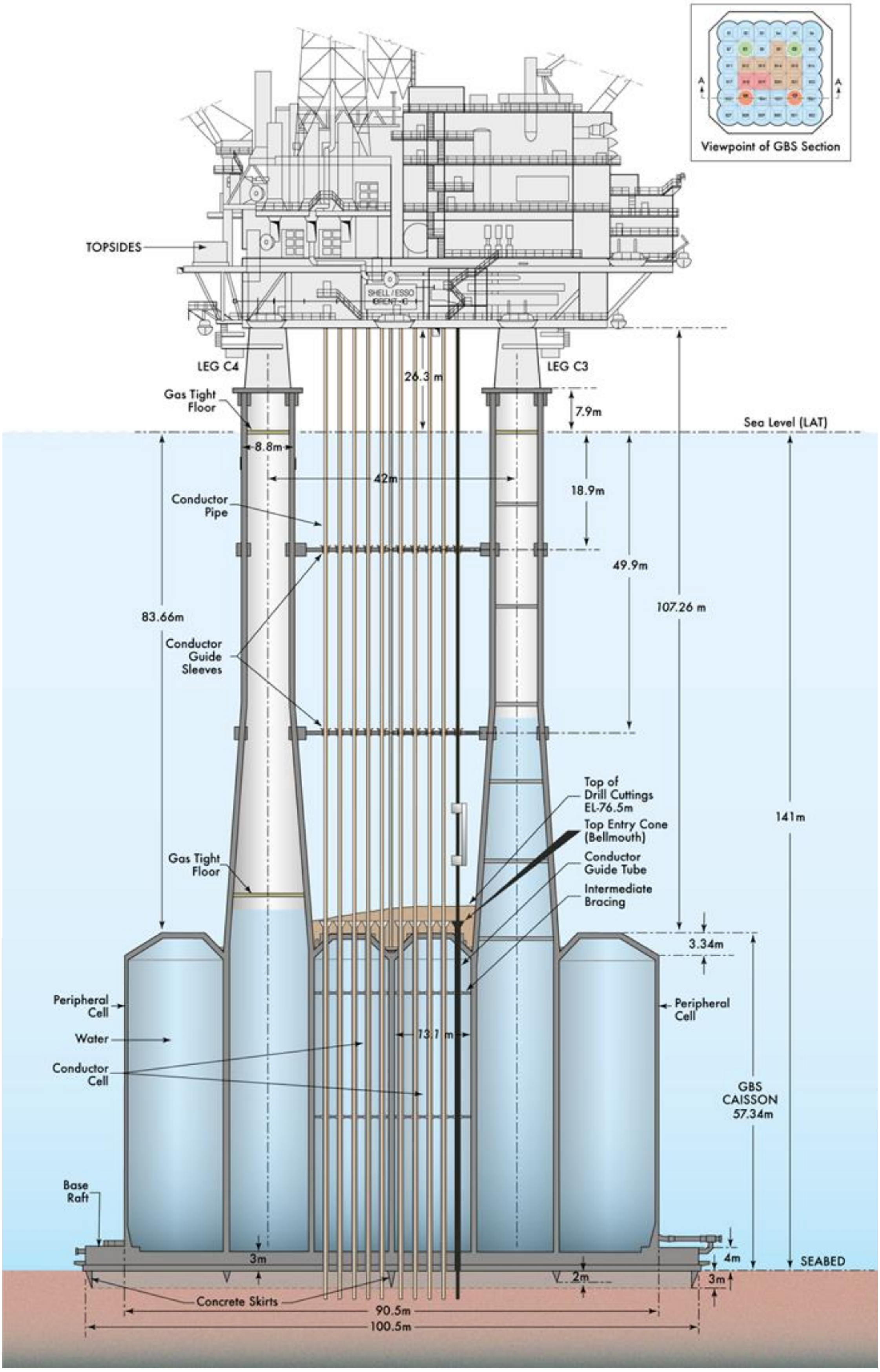


Table 33 Data on the Brent GBS Installations.

<table>
<tr><th colspan="2">Topic</th><th colspan="4">Information</th></tr>
<tr><td colspan="2">Type of Facility</td><td colspan="4">Concrete Gravity Based Structures</td></tr>
<tr><td colspan="2">Section 29 Notice</td><td colspan="4">12 December 2014</td></tr>
<tr><td colspan="2">Operator</td><td colspan="4">Shell U.K. Limited</td></tr>
<tr><td rowspan="3">Co-ordinates (WGS 84)</td><td>Bravo</td><td colspan="2">61.05533583 N 1.71136889 E</td><td colspan="2">61.03.32015 N 01.42682133 E</td></tr>
<tr><td>Charlie</td><td colspan="2">61.09562556 N 1.72009361 E</td><td colspan="2">61.05.737533 N 01.4320561 E</td></tr>
<tr><td>Delta</td><td colspan="2">61.13183806 N 1.73443056 E</td><td colspan="2">61.07.910283 N 01.44.0658 E</td></tr>
<tr><td colspan="2">Distance to nearest coast</td><td colspan="4">140 km, from Brent Bravo to coastline of the Shetland Islands, UK</td></tr>
<tr><td colspan="2">Distance to median line</td><td colspan="4">11 km, from Brent Delta to UK/Norway</td></tr>
<tr><td colspan="2">Water column (m)</td><td>Water depths (m)</td><td>140.2 to 142.1</td><td>Tidal range</td><td>1.83 m</td></tr>
<tr><td colspan="2">100 year return wave</td><td>Amplitude (Hmax)</td><td>26.2 m</td><td>Period</td><td>15.5 seconds</td></tr>
<tr><td colspan="2">Maximum current speeds</td><td>Surface</td><td>0.86 ms^{-1}</td><td>Seabed</td><td>0.46 ms^{-1}</td></tr>
</table>

Specific Differences in Design or Construction			
Aspect or Issue	Condeep BB	SeaTank BC	Condeep BD
Year of installation	1975	1978	1976
Maximum height above LAT (m)	19.7	6.8	19.8
Total mass of sand ballast in caisson (tonnes)	124,901	N/A	101,228
Total mass of GBS excluding water ballast	340,717	296,880	325,418
Dimensions of base of caisson (m)	89.2 x 100	91 x 91 (Note)	89.2 x 100
Number of legs	3	4	3
Height from seabed to top of ring beam (m)	159.9	148.9	161.8
External diameter of legs (m)	12.2 to 21	8.8 to 15	12.2 to 21
Thickness of leg walls (m)	0.55 to 1.15	0.4 to 0.9	0.55 to 1.15
Number of conductors inside legs	38	N/A	48
Number of external conductors	N/A	40	N/A
Number of cells	19	36	19
Number of cells used for oil storage	16	10	16
Total oil storage capacity (m^3)	180,025	98,125	180,025
Height of cells (m)	60	57	58
Plan dimensions of oil storage cells (m)	18.54 m diam	13 x 13 m^2	18.54 m diam
Area of base of each oil storage cell (m^2)	270	171	270
Thickness of storage cell walls (m)	0.73	0.7, 0.9, 1.0	0.73
Number of with water only	0	22	0
Number of tri-cells	22	16	22
No. conductor penetrations through cells	N/A	40	N/A
No. other external-facing penetrations	474	6	252
Total number of penetrations in GBS	512	86	300
Total depth of skirts in the seabed (m)	4.0	2.0 and 3.0	5.0
Total number of dowels	3	N/A	3
Maximum depth of dowel penetration (m)	8.0 m	N/A	9.0 m

Note: For the caisson itself. The overall dimensions of base slab are 100.5 m x 100.5 m.

After the removal of the topsides the Bravo, Charlie and Delta GBSs will, respectively, weigh approximately 341,000 tonnes, 297,000 tonnes and 325,000 tonnes, excluding the fluids in the cells and legs. Table 34 summaries the inventories for the GBSs after removal of the topsides, excluding the sediments and fluids in the oil storage cells and other materials in the GBSs (Section 15 and Section 16).

Table 34 Inventories for GBSs Bravo, Charlie and Delta after Removal of Topsides.

Material (tonnes)	Bravo	Charlie	Delta
Steel[32]	38,847	38,594	40,354
Concrete	176,969	258,286	183,836
Sand Ballast	124,901	0	101,228
Total mass of GBS structure	340,717	296,880	325,418

14.3 Options for the GBSs

We carried out a high level assessment of the operations that would be required to dismantle the GBSs at their present locations offshore. This would be an extremely long, difficult and risky process (Section 14.5), with an unacceptably high level of safety risk for offshore personnel, and for this reason the option of *in situ* dismantling has not been considered further.

Since all three concrete gravity base structures are candidates for derogation under OSPAR Decision 98/3, we identified the following options for decommissioning the GBSs after removal of the topsides:

1. Complete removal by refloating
2. Partial removal, by removing some or all of each of the legs
3. Leave in place

14.4 Issues and Concerns Raised by Stakeholders

For the options for the GBSs, while some stakeholders suggested there might be some beneficial 'reef' effects from the GBSs left at sea, the main issues and concerns raised by stakeholders during the programme of stakeholder engagement were:

- The technical challenges, safety risks and costs of refloating the whole of a GBS.
- The risks of cutting and lifting parts of the legs.
- The effects of spills or release of contaminants during any programme to remove all or parts of the GBSs.
- Safety risk to other users of the sea from any remains.
- Long-term integrity and subsequent maintenance of any remains in the sea.
- The difficulty of carrying our remediation on the GBS once the legs have collapsed.
- Effects of leg collapse on GBS cell contents and on drill cuttings.
- Safety risk to project personnel from dismantling and recycling activities onshore.
- Impacts to onshore communities from a major dismantling programme.

[32] We estimate that on Bravo, Charlie and Delta GBSs, 18%, 13% and 18% respectively of the total mass of the reinforced concrete is steel.

14.5 Technical Feasibility of Removal by Refloating

14.5.1 Introduction

The only realistic method that could be contemplated for completely removing any of the GBSs would be to undertake a reversal of the original installation programme, and attempt to refloat the structures and tow them back to shore for dismantling. Since the GBSs were designed in the 1970s, however, and were never intended to be refloated, this would require an extremely complex, difficult and prolonged programme of work on each structure. We have examined the technical feasibility of refloating the GBSs in considerable detail, as described in the GBS TD [14]. The majority of our studies have been undertaken on the Condeep Brent Delta, which will be the first Brent GBS to be decommissioned. Much of this work is, however, directly applicable to the other Condeep Brent Bravo and, after checking for differences, we have transferred knowledge and findings from Delta to Bravo. Many of the major issues and principles researched for the Condeeps were also applicable to the refloating of the SeaTank Brent Charlie. Because of the important differences in the design, construction and operation of the SeaTank, however, we have undertaken a separate assessment of the feasibility of refloating the Brent Charlie GBS.

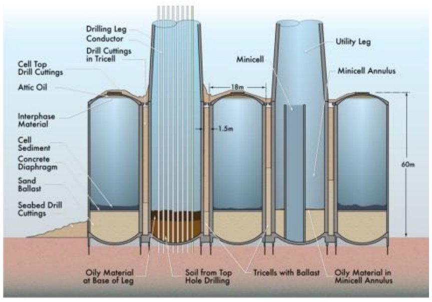
The following sections:

- Describe the critical engineering difficulties that would have to be addressed before attempting to refloat any of the GBSs.
- Summarise the assessments of technical risk and safety risk that we have carried out.
- Present our conclusions on the feasibility of refloating the Brent GBSs Bravo, Charlie and Delta.

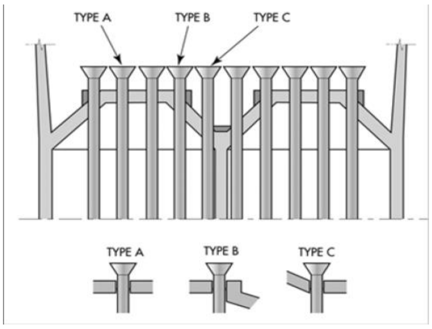
14.5.2 Programme of Work for Refloating

Table 35 summarises the main steps in the long and complex programme of work that would have to be undertaken if any of the GBSs were to be refloated and taken to shore for dismantling. The illustrations for nearshore and onshore dismantling are taken from the report *Brent Delta deconstruction inshore-onshore final report*, by ODE Ltd [39].

Table 35 Main Steps in the Programme of Work for Refloating and Dismantling a Brent GBS.

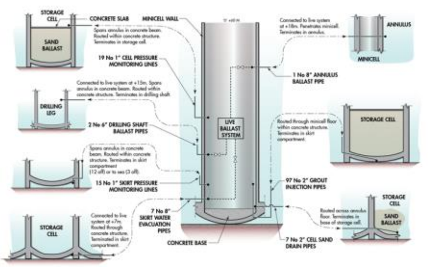
<table>
<tr>
<td>
</td>
<td>Remove cell sediment or sand ballast: The GBSs are now heavier than they were during original float-out, as a result of the addition of solid ballast, the conductors, grout, and sediment inside the cells. All of the sediment and some sand ballast (Bravo and Delta) would therefore have to be removed to reduce the total weight. For the purposes of reducing weight, some locations in the GBSs would be difficult to access, others impossible.</td>
</tr>
</table>

Locations of materials in Brent Delta Cells

<table>
<tr>
<td>
</td>
<td>Remove the conductors: All the conductors would have to be removed to reduce weight, since they were installed after float-out.</td>
</tr>
</table>

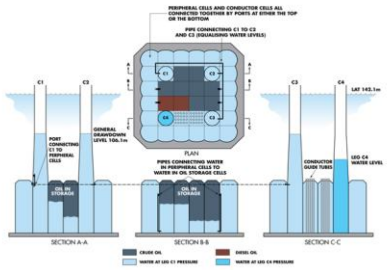
Conductors through Brent Charlie Cells

Table 32, continued Main Steps in the Programme of Work for Refloating and Dismantling a Brent GBS.



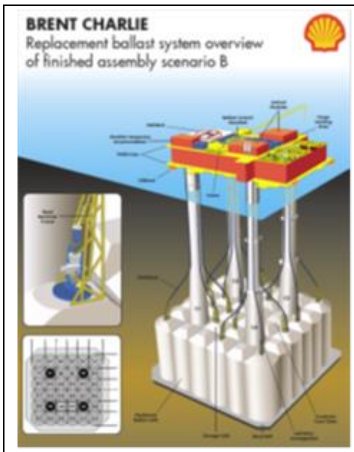
Pipework connected to the minicell on Brent Delta

Seal all penetrations: Every penetration by a pipe or cable through the legs and through the cell walls (both internally and externally) would have to be sealed, to prevent water flooding into the structure during the refloating operation, while being towed to shore, and while being dismantled at a nearshore deep water location. To maintain gas pressure in the cells, all the redundant pipework used for float-out would have to be sealed, the GBSs would have to be free of cracks, and all external penetrations – such as the 24 inch diameter holes for the conductors – would have to be sealed.



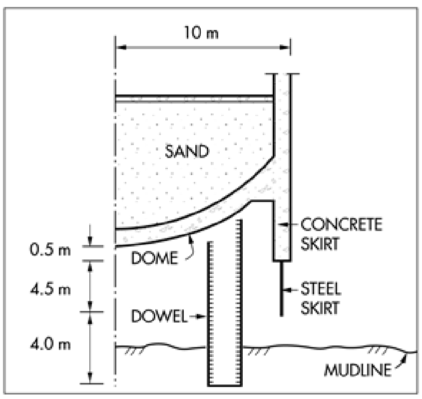
Water ballast levels on Brent Charlie

Install new control systems: A number of new systems would be required, to monitor pressure in the cells, monitor and control the break-out of the GBS, and monitor and control its draught and orientation during the tow to shore and for 18 months while floating at the nearshore dismantling site. These systems would have to be fitted onto various parts of the GBS, and controlled remotely from an attendant vessel.



Possible new ballast control system for Brent Charlie

Install equipment to remove water from the cells and legs: All the water in the cells and legs would have to be removed in order to achieve the required buoyancy. Water would be displaced by high pressure air, and a completely new system of pipes, pumps, valves and control equipment would have to be installed in the cells and on the legs to achieve this.



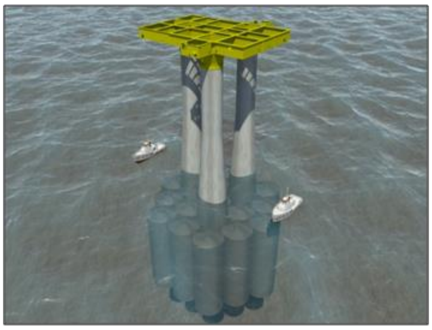
Skirts and dowels below base of Brent Delta

Install equipment to break the under-base suction: The space between the base of the GBS and the underlying seabed would have to be pressurised, to help prise the GBS and its skirts from the seabed. Water would have to be injected under high pressure under all the base compartments, and a completely new system of pipes, pumps, valves and control equipment would have to be installed on the GBS and adjacent seabed to achieve this. The seabed around the base of each GBS would also have to be reinforced by rock-dumping, to prevent the high pressure water escaping.

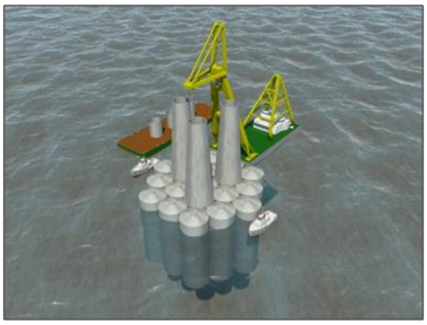
Table 32,concluded Main Steps in the Programme of Work for Refloating and Dismantling a Brent GBS.

	Remove topsides: The topsides would have to be removed to reduce the total weight, because the GBSs are now heavier than they were during the original float-out.

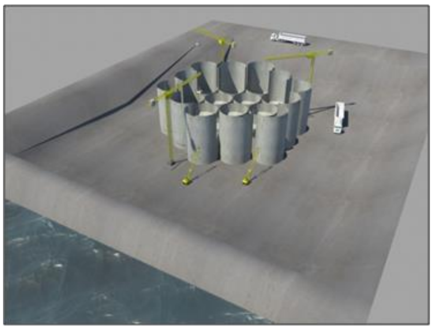
Removing Brent Delta topsides with SLV Pioneering Spirit

	Refloat and tow the GBS: The water in the cells and leg would be displaced by high pressure air. The combination of additional buoyancy forces and under-base water pressure would prise the GBS from the seabed and it would rise to the surface. Once on the surface and stable, the floating GBS would be towed to a deep-water nearshore site.

Towing the Refloated Brent Delta

	Dismantle nearshore: The floating GBS would be securely moored at a nearshore deepwater site. Using a variety of cold cutting techniques it would be progressively dismantled over a period of 12-18 months. Concrete and steel would be removed and taken ashore for recycling.

Dismantling the Floating Brent Delta at a Nearshore Site

	Dismantle in dry dock: The remaining lower part of the caisson, approximately 17 m high and 100 m in diameter, and weighing about 53,000 tonnes, would be towed into a new, specially constructed dry dock for final dismantling. This would take approximately 6 months.

Dismantling the Base of the Brent Delta Caisson in a New Dry Dock

As fully described in the GBS TD [14], the design engineers Dr Tech Olav Olsen (DTOO) and Doris Engineering (DE) examined how the GBSs could be refloated, and the engineering firm ODE Limited examined how they could be dismantled inshore. These expert companies developed method statements for all the major facets of the removal programme. They then supported our engineers as they worked with the consulting engineers COWI to assess the technical feasibility of refloating each of the GBS. To do this, the whole refloat programme was broken down into a logical series of operations (or “steps”), and data and expert judgement were then used to assess the likelihood or probability that:

- The operation could be completed successfully
- Unplanned or accidental events would occur
- The programme could be put back on plan if there were unplanned or accidental events

In this way, individual probabilities were assigned to a large number of operations and accidents, and to the possible interactions and implications of different events and accidents. As a result, we were able to quantify, in an auditable way, the likelihood that any particular step in the programme could be completed successfully, and thus the likelihood that the whole option could be completed successfully. These results were presented in a series of reports by COWI, including the *Brent Delta technical risk assessment for refloat* [40], and similar reports for *Bravo* [41] and *Charlie* [42].

These assessments of risk were prepared before we made the decision to remove the topsides by SLV. It is important to note that the only credible refloat programme of work would require the continued presence and use of the topsides for several years prior to refloat, to enable all the essential inspections, modifications, checks and verifications to be made. The assessments of risk therefore remain appropriate. Work would have to be done before the removal of the topside, and there is a small risk associated with topside removal which, through the selection of the SLV option and with the support of AllSeas and Able, we are working to reduce even further. The fact that we will remove the topside and support frame as a single piece by SLV makes only a very small difference to the estimated probability of failure at the beginning of offshore operations and does not invalidate the assessments, discussions and conclusions presented in this Section.

Figure 46 to Figure 48 show the results of this comprehensive assessment of the feasibility of the refloat option for each GBS. The graphs show the estimates of ‘Technical Project Failure’ (TPF), the probability that the operation would experience an ‘unrecoverable’ failure – an unplanned or accidental event from which it would be impossible to recover – which would mean that refloat could not be completed successfully. The ‘best’ estimate shows the main result and the ‘low’ and ‘high’ estimates show the results of a sensitivity analysis in which optimistic and pessimistic assumptions, respectively, were used to estimate the likelihood of failure at each step.

At the beginning of the programme of work in each estimate – when the GBS is being prepared for refloat, the penetrations are being sealed, and leaks and cracks are being sealed – the probability of failure is high, and it gradually decreases as each step in the programme is successfully completed.

14.5.3 Acceptable Levels of Technical Risk

For several years, oil and gas companies have used criteria to limit the risk of asset-loss arising from different levels of damage to offshore platforms. Based upon these criteria, the maximum acceptable probability of a major incident during the decommissioning operations has been set as 1×10^{-3} (1 in 1,000).

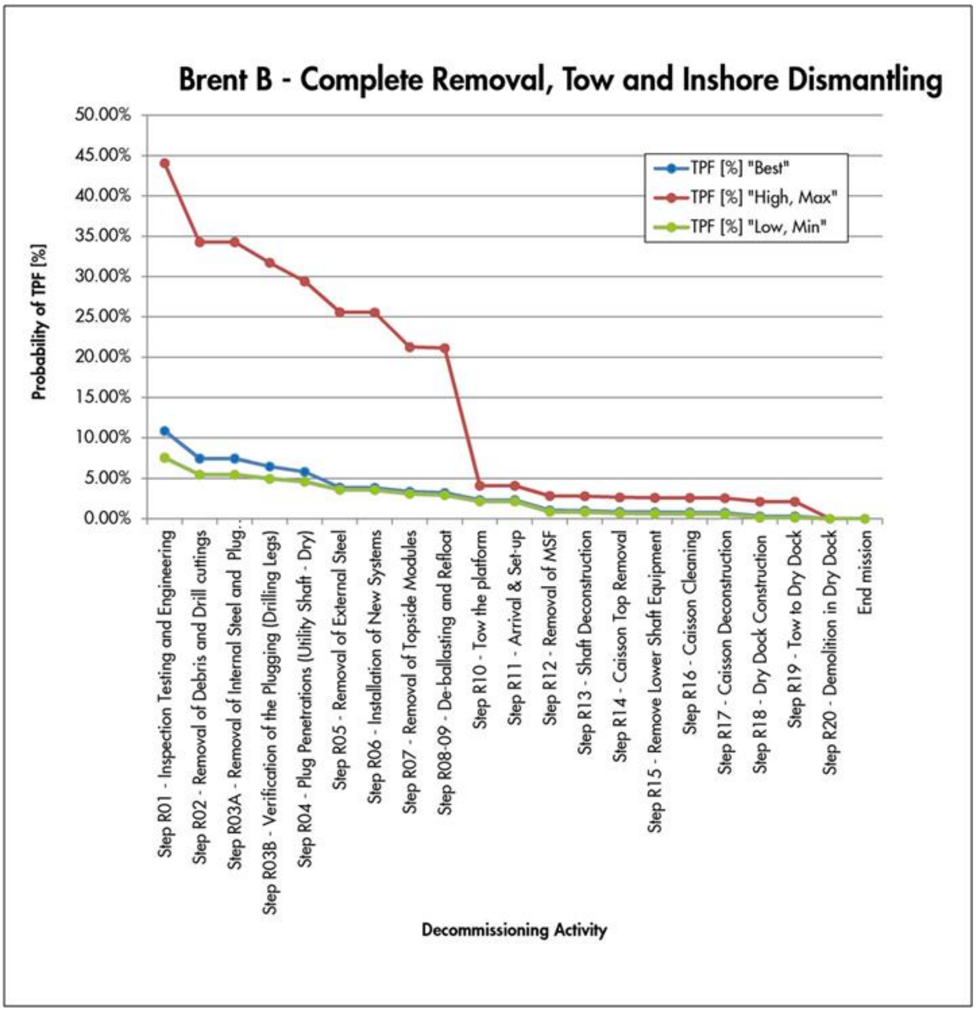
This figure is in line with the guidance contained in Part 1 of the *Rules for the Planning and Execution of Marine Operations* published by DNV [43]. In these rules DNV stated that ‘a probability of total loss equal to or better than 1/1,000 per operation will then be aimed at’. These same rules indicate that during marine operations, a probability of structural failure ten times less than this (that is 1 in 10,000) should be aimed at. These risk acceptance criteria would be used at present if a new platform were to be installed. In reality, a risk level considerably lower than this would be sought in accordance with general risk- acceptance principles.

14.5.4 Results of Assessment of Brent Bravo Refloat

The technical risk assessment for Bravo concluded that the complete removal by refloat, tow and nearshore dismantling has a best estimate aggregate of 7.4% probability of TPF at the beginning of the offshore operations (Figure 46). This assumes that various inspection, testing and engineering activities have been successfully completed before initiating the refloat operation. A sensitivity study has shown that taking what might be considered a range of practical assumptions into account the probability of TPF ranges from 5.5% to 34.3% on commencement of offshore operations.

In the 'high' (pessimistic) estimate for Brent Bravo there is a major decrease in the probability of TPF at Step 08/09 'deballasting and refloat', when the GBS has been successfully refloated. To reach this point all the preceding steps, including sealing of pipes, sealing conductors, installing and operating a ballasting system, and hydraulic jacking, with their attendant risks and uncertainties, will have to have been completed successfully. The major risk contributor for the offshore operations is the plugging of the conductor penetrations in the drilling legs. Problems with installing the plugs, or failure during verification, could make refloat unviable. After Step 08/09 the remaining steps in the refloat programme, including towing, maintaining water-tight in integrity, achieving the required freeboard, and dismantling, also have risks and uncertainties, but in the 'high' scenario these account for only approximately 15% of the original cumulative likelihood of TPF at the beginning of the refloat programme of work.

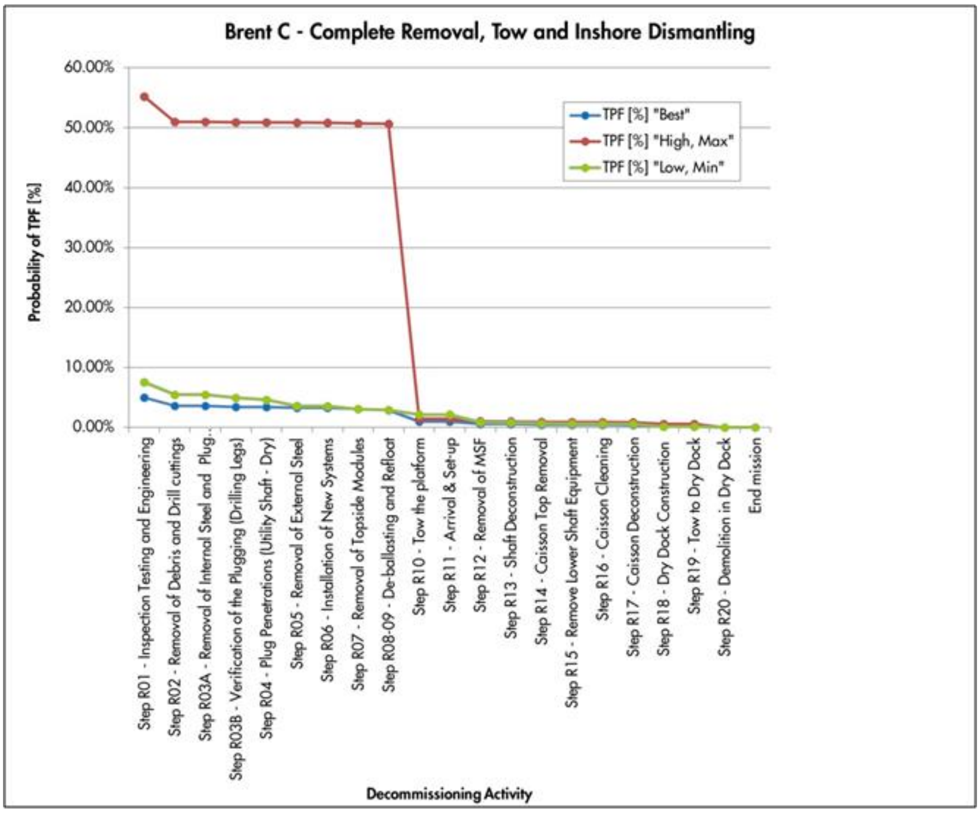
Figure 46 Marginal Probability of Project Failure in Refloat Option for Brent Bravo GBS.



14.5.5 Results of Assessment of Brent Charlie Refloat

The technical risk assessment for Charlie found that at the beginning of the offshore operations, after the successful completion of the required inspections, testing and engineering, complete removal by refloating followed by tow and nearshore dismantling, has an aggregate best (most realistic) estimate of 3.6% probability of TPF (Figure 47). A sensitivity study of the assumptions has shown that the probability of TPF ranges from 1.9% to 51.0% at the beginning of the offshore operations. As discussed in the GBS TD [14], the dominant risk contributions for the refloat of Brent Charlie relate to Step R08 De-ballast and Step R09 Refloat. The main contributor to project failure in Step 09 relates to a failure of the connection between the roof and the outer wall of the caisson caused by an uncontrolled heave or excessive ascent. Once the buoyant structure is released from the seabed, it will ascend and oscillate over a period of approximately 50 seconds before settling at its natural equilibrium draught. During deballasting, water would have been removed from the cells, and the caisson would have to be pressurised in order to compensate for the structural inadequacy of the external walls as they experience an imbalance of hydrostatic pressure. If the caisson is pressurised and the initial ascent excessive, the pressure inside would not vent quickly enough; the pressure inside the caisson would be greater than outside, and this could result in the failure of the connection between the roof and the wall.

Figure 47 Marginal Probability of Project Failure in Refloat Option for Brent Charlie GBS.



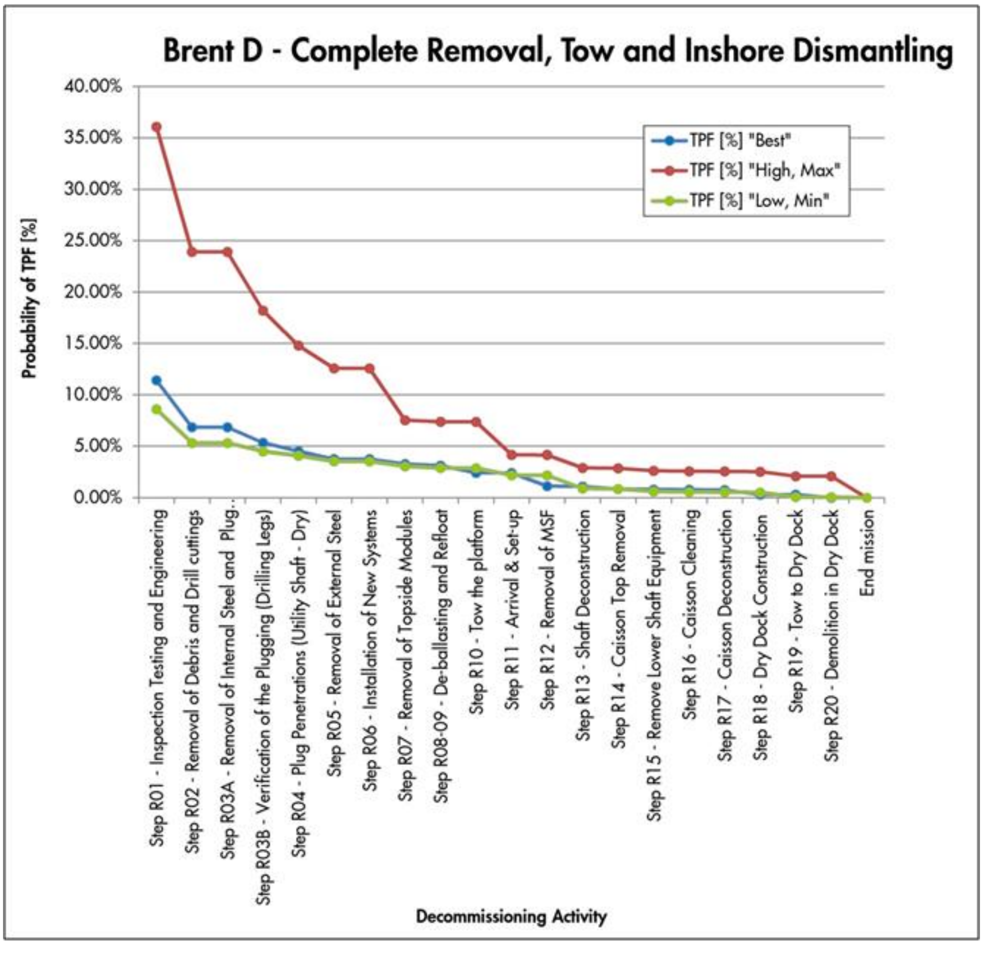
In the 'high' (pessimistic) estimate for Brent Charlie there is a major decrease in the probability of TPF at Step 08/09, when the GBS has been successfully refloated. This decrease is much more marked on Charlie than on either Bravo or Delta, and reflects the fact that on Charlie the retraction procedure is dominated by a number of failure mechanisms that are directly or indirectly correlated. In the refloat Step 09 this means that in many cases the ability to solve a specific issue related to a failure mechanism would leave another dominating failure mechanism of nearly the same magnitude. The majority of these failure mechanisms arise and interact during Step 09, the stage that reflects attempted refloat.

The major risk contributor for offshore operations is in the procedure of refloating the structure. The wedge-shaped skirts make it difficult to predict the retraction forces. In addition, the shape makes it difficult to apply hydraulic jacking pressure under the skirts in order to safely push the GBS from the seabed. If hydraulic jacking fails, the refloat procedure would use the de-ballasting capacity of the GBS, and this introduces a risk of exceeding the structural capacities of the GBS if the structure suddenly breaks free of the seabed by means of buoyancy alone. After refloat, the remaining steps in the refloat programme including towing, maintaining water-tight in integrity, achieving the required freeboard, and dismantling, also have risks and uncertainties, but in the 'high' scenario these account for only approximately 6% of the original cumulative likelihood of TPF at the beginning of the refloat programme of work.

14.5.6 Results of Assessment of Brent Delta Refloat

The technical risk assessment for Delta found that at the beginning of the offshore operations the complete removal by refloat, tow and nearshore dismantling has a best estimate aggregate of 6.8% probability of TPF. This assumes that various inspections, testing and engineering activities have been successfully completed before initiating the refloat operation. A sensitivity study has shown that, taking what might be considered a range of practical assumptions into account, the probability of TPF ranges from 5.3% to 23.9% on commencement of offshore operations.

Figure 48 Marginal Probability of Project Failure in Refloat Option for Brent Delta GBS.



In the 'high' (pessimistic) estimate for Brent Delta there is only a small decrease in the probability of TPF at Step 10, when the GBS has been successfully refloated and towed away. To reach this point, all the preceding steps, including the sealing of pipes, sealing conductors, installing and operating a ballasting system, and hydraulic jacking, with their attendant risks and uncertainties, will have to have been completed successfully. As with Brent Bravo, a major risk contributor for the offshore operations is the plugging of the conductor penetrations in the drilling legs, including the damaged slot 24. Problems with installing the plugs, or failure during verification, could make refloat unviable. Many risks, such as the capacity of the seabed soil to withstand hydraulic jacking and the ability to verify the successful plugging of the conductor penetrations, would remain as residual risks until it was known that refloat had been successful. After Steps 08, 09 and 10 the remaining steps in the refloat programme, including towing, maintaining water-tight in integrity, achieving the required freeboard, and dismantling, also have risks and uncertainties, but in the 'high' scenario these account for approximately 21% of the original cumulative likelihood of TPF at the beginning of the refloat programme of work.

14.6 Assessment of Refloat Safety Risks

As well as assessing the technical risks associated with refloating the GBSs, we estimated the safety risk for all the project personnel who would be engaged in such operations. We described several potential refloat scenarios, drawing on the offshore programme of work used in the COWI assessments of TPF and the ODE descriptions of nearshore and then onshore dismantling. We then estimated the total PLL based on the numbers and occupations of the persons exposed, the published Fatal Accident Rates (FAR) for different occupations or activities, and the duration of exposure. This assessment included the risk of fatalities arising from the collision of project vessels with the GBSs during the course of the refloat programme.

One scenario examined was the same as that used in the assessment of TPF. In this scenario, the GBS would be refloated using a new ballast system installed externally and the refloated structure would bedismantled at a deep water nearshore site and then in a dry dock. The total PLL for project personnel in this scenario was estimated to be 1.12, 1.08 and 1.12 for Bravo, Charlie and Delta respectively, that is, about 1,000 times greater than the PLL value of 1×10^{-3} which is accepted as the upper limit of the 'tolerable' range (described in Section 8.5.3).

14.7 Conclusion on Option to Refloat the GBSs

The assessments of refloat risks were completed before we had made the decision to remove the Bravo and Delta topsides using the SLV *Pioneering Spirit*. The steps – and risks - associated with the removal of the topsides and the PGDS support structure would therefore not apply to the assessment of refloat risk. The cumulative risks of TPF would thus be slightly lower than those presented here, but as described below the risk is so much higher than would be generally accepted in an offshore project that this adjustment does not materially affect our overall conclusions regarding refloat.

For Bravo, Charlie and Delta, the best estimate of TPF at the beginning of the complex programme of work to refloat and dismantle the GBS is several orders of magnitude greater than what might be considered to be the maximum tolerable level of risk of failure of 1 in 1,000. For each GBS there is a significant likelihood that the option to refloat and dismantle nearshore would not be completed successfully. If the programme of work were unsuccessful or only partially successful, the outcomes might be one of the following:

- The offshore procedures to extract the skirts from the seabed and refloat the GBS fail, and the GBS remains *in situ* offshore.
- The systems to maintain buoyancy fail after refloating, and the whole GBS sinks irretrievably at its present site, or at some point along the tow route.
- The systems to maintain buoyancy fail once at the nearshore deep-water dismantling site and the whole or part of the GBS sinks irretrievably at the nearshore site.
- The systems to maintain buoyancy fail, or the structure breaks up, such that the lower part of the caisson sinks while being towed from the nearshore site into the dry dock.

At the beginning of the possible operations (as opposed to the earlier steps of inspection and testing), the 'best' estimate probability of project failure is 7.4%, 3.6% and 6.8% for Bravo, Charlie and Delta respectively. It should be noted that these values have been derived after taking into account measures that could be employed to reduce the likelihood of failure. These estimates are very high (from about 30 times to about 60 times greater) in terms of the levels of failure that would normally be accepted by the Exploration and Production (E&P) industry at the beginning of any new project. Typically, as described in the DNV *Guidelines of the technical feasibility of projects* [44], the industry would not contemplate embarking on a new project or programme if the likelihood of technical failure were greater than about 1 in 1,000 (0.1%).

As a result of the detailed and exhaustive engineering, technical and risk assessments that we have completed on each of the individual GBSs, we have concluded that it is not technically feasible to remove any of the GBS substructures by refloating; the risks of partial or complete failure are unacceptably high. In addition our studies have shown that, in the refloat option for each Brent GBS individually, the safety risks to project personnel are intolerable. We have therefore concluded that, in line with the DECC Guidance Notes, the refloat option for the GBSs may be ruled out and not subjected to a CA.

14.8 Comparative Assessment of Options for the GBSs

14.8.1 Introduction

For the Brent GBSs Bravo, Charlie and Delta the option of complete removal by refloating has not been taken forward to a CA because it has been ruled out on Technical and Safety grounds. At the beginning of any realistic programme of work to refloat any of the GBSs, the risks of failure are about 1,000 times higher than would be considered acceptable by the E&P industry at the beginning of any *n*ew project. Similarly, the estimated risk of a fatality in a refloat programme for any individual GBS is about 1,000 times higher than a value that is considered to be the upper limit of tolerability for E&P activities.

Following our screening of options (Section 7) and detailed technical assessments of the feasibility of refloating, we have concluded that there are only two technically feasible options for decommissioning the GBSs after the removal of the topsides, namely:

- Option 1: 'Partial removal'; and
- Option 2: 'Leave in place'

It is not feasible to refloat or otherwise remove any of the GBSs in the Brent Field, but their legs could be removed and taken ashore for recycling. Taking into account the weight and strength of the legs, and their stability while being cut, the technical and engineering studies by Dr Tech Olaf Olsen, Aker Kvaerner and Smit (reported in the GBS TD [14]) suggest that the most efficient and safe way to do this would be to remove each leg as a single piece by SSCV, and transport it to shore vertically (Figure 49). In accordance with the IMO *Guidelines and Standards for the Removal of Offshore Installations and Structures on the Continental Shelf and in the Exclusive Economic Zone* [45], the minimum clearance for safe navigation above the remains of a GBS would be 55 m. If the GBS legs were cut and partially removed to provide such clearance, this would result in leaving leg stubs approximately 28 m, 32 m and 31 m high on the Bravo, Charlie and Delta GBSs respectively. For Bravo, Charlie and Delta respectively, the total mass of removed leg, comprising reinforced concrete only, would be 14,825 tonnes, 10,130 tonnes and 17,145 tonnes.

Although there may be some small differences between the installations, the programmes of work that would be required to complete these two options would essentially be identical for all three GBSs, and are summarised in Table 36. These options were subjected to a full CA as required by OSPAR 98/3. The potential effects or implications of any residual sediment in the oil storage cells (Section 15), or of the materials in the drilling legs and minicell annuli (Section 16), were not taken into consideration in this assessment; it was assumed that the sediment and materials had either been removed or were present in only small quantities and therefore had no bearing on the performance of either option.

Figure 49 A Proposed Method for Removing the Upper Leg from a GBS.

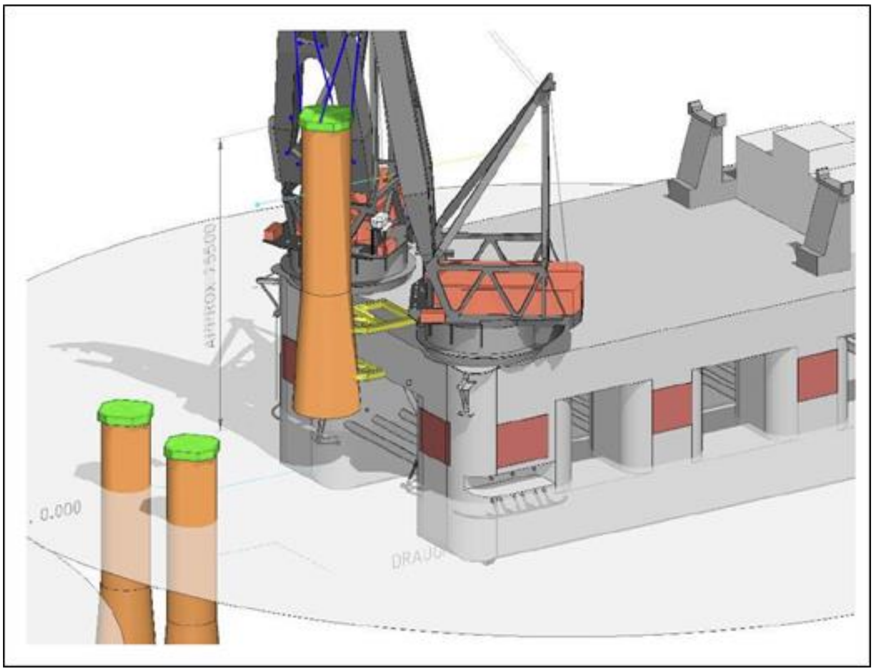
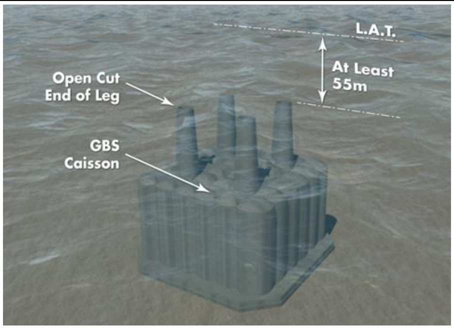
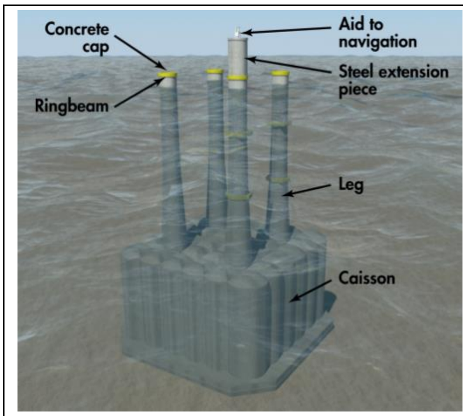


Table 36 Summary of Viable Options for the GBSs, as Illustrated by Brent Charlie.

	Option 1: Partial Removal After removal of the topside, the legs would be cut using diamond wire cutting techniques and lifted away vertically by an SSCV or similar vessel. On Bravo and Delta, each removed leg would weigh about 4,900 tonnes and 5,700 tonnes respectively, and on Charlie they would weigh about 2,500 tonnes each. Legs would be returned to shore for dismantling and recycling. The ends of the cut legs would be left open to the sea. Partial removal the legs to a depth of at least 55 m below LAT would provide the necessary clearance for navigation.

	Option 2: Leave in Place No further work would be undertaken on the GBSs. After removal of the topsides, 3 legs (Bravo and Delta) and 4 legs (Charlie) would protrude above sea level. The operations to remove the topsides would also include placing purpose-built reinforced concrete caps onto the top of each leg to protect it from the elements. An automatic AtoN would be fitted to the top of one leg on each platform. On Charlie, one of the legs would be extended by the addition of a 22 m long steel column, to carry the AtoN above wave height.

14.8.2 Technical Issues Concerning Partial Removal of Legs

We engaged specialist contractors, including DTOO the original designers of the Condeep GBS, Kvaerner, Atkins and Cut UK, to perform a range of studies examining the equipment, techniques and procedures that could be used to remove the upper parts of the GBS legs to provide 55 m clearance for safe navigation. This work is fully described in the GBS TD [14] which cites extensively from the DTOO studies *Brent GBS Leg Removal: Feasibility Assessment of Specific Issue* [46], *Brent Bravo Lifting Arrangement for Leg Removal; Feasibility of Lifting Arrangement for Brent Bravo* [47], *Brent Charlie Lifting Arrangement for Leg Removal; Feasibility of Lifting Arrangement for Brent Charlie* [48] and *Brent Delta Lifting Arrangement for Leg Removal; Feasibility of Lifting Arrangement for Brent Delta* [49]. The main technical issues and uncertainties are as follows:

1. Cutting the reinforced concrete. We have discussed technologies and procedures with leading contractors and specialists in DWC, and performed onshore trials of cutting reinforced concrete under load. The major concerns are; the time required to complete each cut and the availability of suitable weather windows, the reliability of the DWC and the failure rate of the diamond wire and, the viability of equipment and procedures that can be used to keep the cut open and prevent jamming.
2. Attaching the lifting strops. On Delta it may be possible to attach the lifting strops under the ring beam at the top of the leg, although there remain concerns about the strength of the leg if lifted from the top. Such an attachment is not possible on Bravo because the ring beam is not strong enough, and its legs would have to be lifted from the bottom. Conceptual designs for suitable lifting attachments have been made but detailed designs have not been undertaken. This concept has not yet been studied on Charlie.
3. Lifting and transportation. Heavy lift contractors have confirmed that in principle it should be possible to lift each leg (weighing up to 5,700 tonnes in air) using an HLV or SSCV. A suitable lifting beam would have to be designed and fabricated. Suitable procedures would have to be developed both for attaching the severed leg to the HLV lifting beam, and then lifting the leg using both of the HLV's cranes working together. Studies have shown that the GBS legs are not strong enough to be rotated to the horizontal position, so each leg would have to be carried vertically to shore by the HLV, one at a time. Cutting and lifting the legs could only be undertaken in a clearly defined weather window in which wind speeds and sea states over the whole period of time would be forecast not to exceed specified limits.
4. Reception and dismantling: The leg may be set down vertically on a quayside at sites that had sufficient draught for an HLV to go alongside. It would then have to be secured vertically so that it could be dismantled safely from the top down by hydraulic cutting and crushing equipment. Alternatively, the legs would have to be rotated and laid horizontally on the quayside, for dismantling. Neither of these procedures has been subject to detailed design. If it were not possible to land the legs onshore, they would have to be placed on the seabed near the onshore dismantling site, secured, and then dismantled in air and then in water. A conceptual programme of work for dismantling legs has been devised by ODE, but again detailed engineering (FEED) and risk assessment has not been performed.

14.8.3 Results of Comparative Assessments of Options for the GBSs

The individual results for Bravo, Charlie and Delta are presented in detail in the GBS TD [14], and are summarised below.

Table 37 presents the weighted sub-criteria scores for two options examined for Brent Bravo and Figure 50 illustrates the results. On the basis of this assessment the 'CA-recommended option' for the Brent Bravo GBS is Option 2 'Leave in Place'. It has a total weighted score of 71.65 in contrast to Option 1's total weighted score of 55.36.

Table 37 Transformed and Weighted Sub-criteria Scores for the Brent Bravo GBS.

Sub-criterion	Option 1. Partial Removal	Option 2. Leave in Place.
Safety risk offshore project personnel	5.73	6.66
Safety risk to other users of the sea	6.03	3.13
Safety risk onshore project personnel	6.62	6.67
Operational environmental impacts	4.25	5.00
Legacy environmental impacts	2.00	1.00
Energy use	0.26	1.40
Emissions	0.25	1.14
Technical feasibility	12.00	20.00
Effects on commercial fisheries		
Employment	1.05	0.01
Communities	0.33	6.67
Cost	16.84	19.98
Total weighted score	55.36	71.65

Figure 50 The Total Weighted Scores of the Options for the Brent Bravo GBS, and the Contributions of the Sub-criteria.

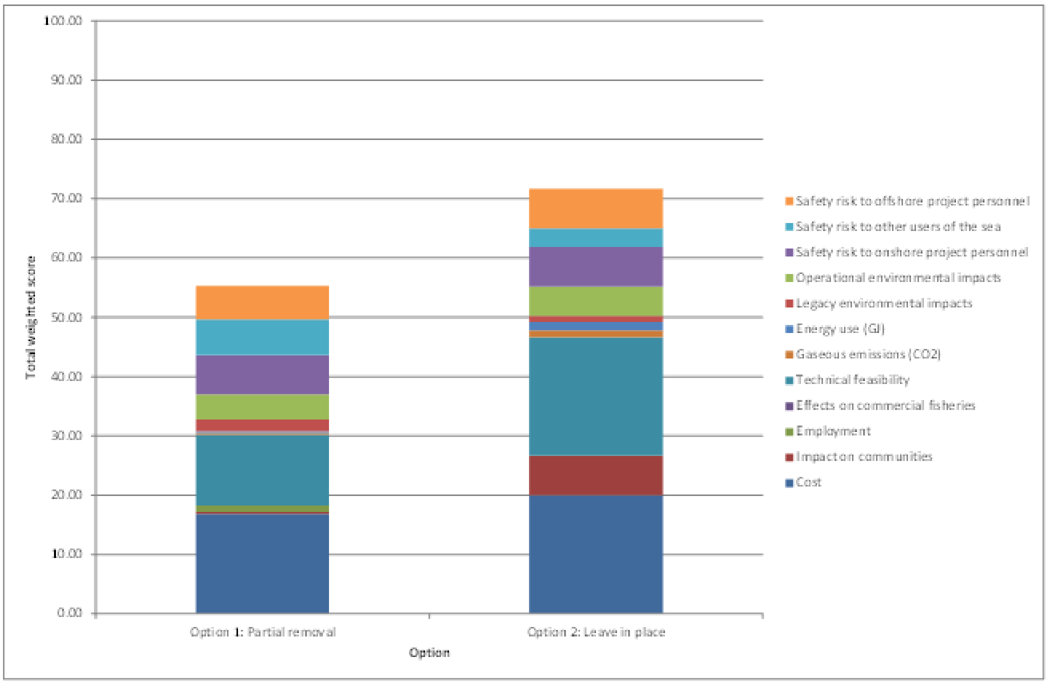


Table 38 presents the weighted sub-criteria scores for two options examined for Brent Delta and Figure 51 illustrates the results. On the basis of this assessment the 'CA-recommended option' for the Brent Delta GBS is Option 2 'Leave in Place'. It has a total weighted score of 68.65 in contrast to Option 1's total weighted score of 54.31.

Table 38 Transformed and Weighted Sub-criteria Scores for the Brent Delta GBS.

Sub-criterion	Option 1. Partial Removal	Option 2. Leave in Place.
Safety risk offshore project personnel	5.67	6.66
Safety risk to other users of the sea	6.03	0.61
Safety risk onshore project personnel	6.61	6.67
Operational environmental impacts	4.25	5.00
Legacy environmental impacts	2.00	1.00
Energy use	0.00	1.17
Emissions	0.00	0.89
Technical feasibility	12.00	20.00
Effects on commercial fisheries		
Employment	1.13	0.01
Communities	0.00	6.67
Cost	16.62	19.98
Total weighted score	54.31	68.65

Figure 51 The Total Weighted Scores of the Options for the Brent Delta GBS, and the Contributions of the Sub-criteria.

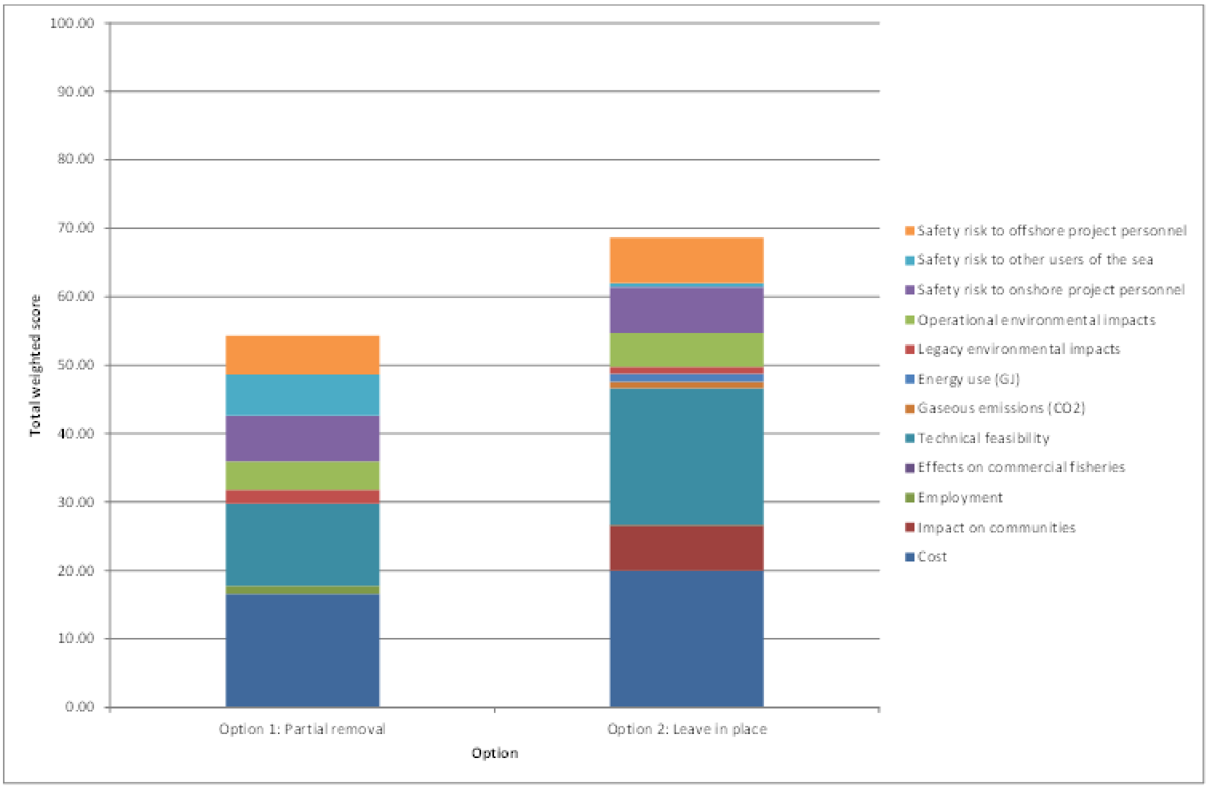
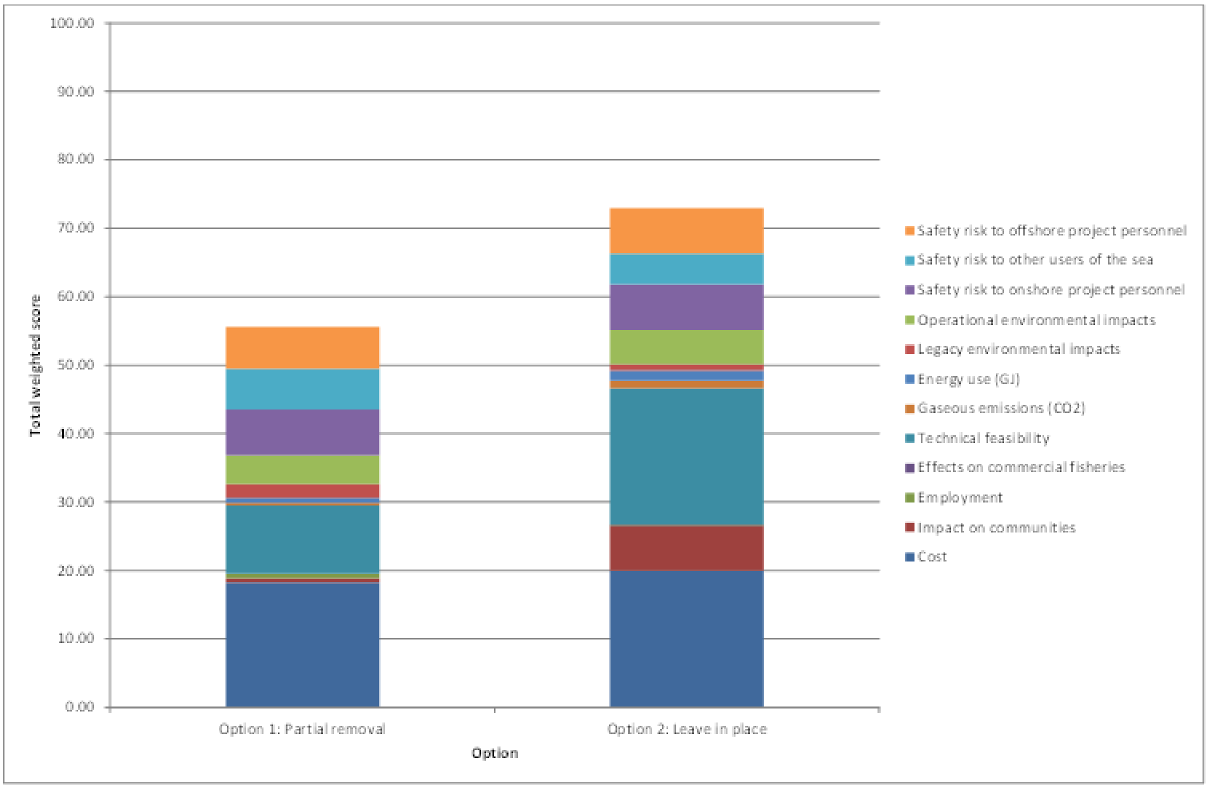


Table 39 presents the weighted sub-criteria scores for two options examined for Brent Charlie and Figure 52 illustrates the results. On the basis of this assessment the 'CA-recommended option' for the Brent Charlie GBS is Option 2 'Leave in Place'. It has a total weighted score of 72.94 in contrast to Option 1's total weighted score of 55.54.

Table 39 Transformed and Weighted Sub-criteria Scores for the Brent Charlie GBS.

Sub-criterion	Option 1. Partial Removal	Option 2. Leave in Place.
Safety risk offshore project personnel	6.10	6.66
Safety risk to other users of the sea	5.98	4.44
Safety risk onshore project personnel	6.63	6.67
Operational environmental impacts	4.25	5.00
Legacy environmental impacts	2.00	1.00
Energy use	0.65	1.44
Emissions	0.44	1.07
Technical feasibility	10.00	20.00
Effects on commercial fisheries (£)		
Employment	0.59	0.01
Communities	0.67	6.67
Cost	18.22	19.98
Total weighted score	**55.54**	**72.94**

Figure 52 The Total Weighted Scores of the Options for the Brent Charlie GBS, and the Contributions of the Sub-criteria.



For all three GBSs the sensitivity analysis of the results shows that in every scenario, including the scenario in which the criterion 'Economic' is removed, Option 2 'Leave in place' has a higher total weighted score than Option 1 'Partial removal'. The topsides will have been removed and the legs capped as part of the topsides removal programme of work, so in this option there are no operational risks or technical difficulties, and no risks to project personnel. As discussed in Section 14.9, however, there is considerable uncertainty associated with estimating the long term safety risks to other users of the sea, primarily relating the difficulty of forecasting future shipping and fishing activity, and the timing, mode and duration of GBS degradation. The average annual long-term legacy safety risk to other users of the sea is a PLL of less than 1.0 x 10^{-3} and thus in the 'tolerable' band. The total cumulative risk for each GBS, for an estimated period of 1,000 years, is about two orders of magnitude greater. Our proposed plans for mitigating these risks are presented in Section 14.17. If the GBSs are essentially inert, then the short- and long-term impacts to the environment are low.

14.9 Discussion of the Comparative Assessments for the GBSs

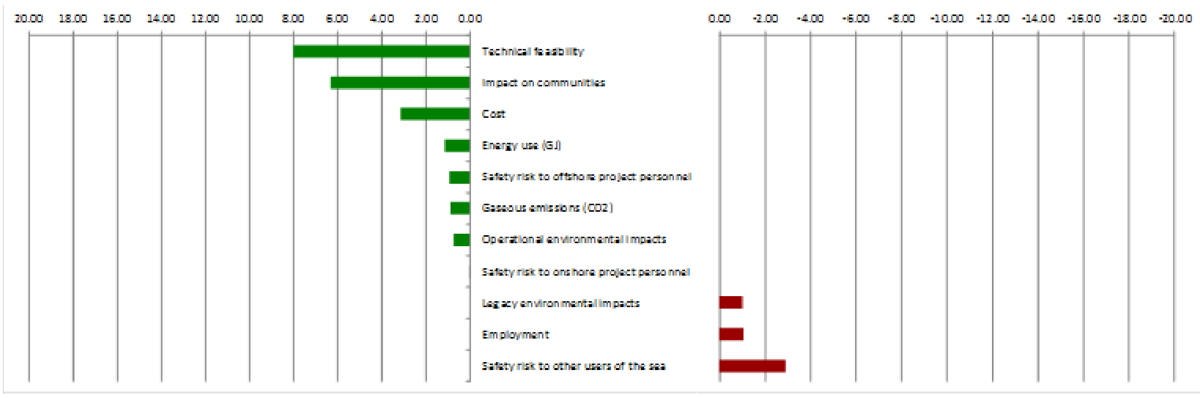
14.9.1 Discussion

Examination of both the transformed unweighted data and the weighted scores for each of the sub-criteria shows that for each GBS the differences between the two options are driven by the differences in performance in '**technical feasibility**', '**impact on communities**' and '**cost**' (which are better in Option 2 'Leave in place') and in '**safety risk to other users of the sea**', '**legacy environmental impacts**' and '**employment**' (which are better in Option 1 'Partial removal'). All the other sub-criteria show only small differences between the options in terms of their weighted scores.

This pattern is illustrated in Figure 53 to

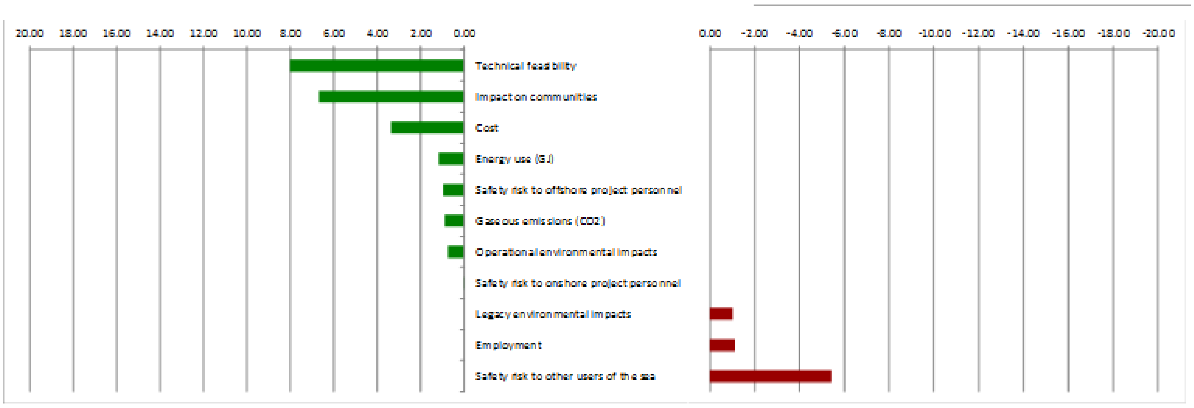
Figure 55 which show the differences (positive or negative) in the weighted scores in each sub-criterion for the two options for the Brent Bravo, Delta and Charlie GBSs respectively. The green bars indicate sub-criteria where Option 2 has the better performance and the red bars indicate sub-criteria where Option 1 has the better performance. It should be noted that in these charts the sub-criteria are ranked according to the differences between the two options, and thus may appear in different orders in the three figures.

Figure 53 Difference Chart Comparing the Weighted Scores for each Sub-criterion in Two Options for the Brent Bravo GBS, under the Standard Weighting, Assuming Degraded Legs Remained at LAT for 750 Years.



Green bars: Option 2 'Leave in place' is better than Option 1 'Partial removal	Red bars: Option 1 'Partial removal' is better than Option 2 'Leave in place'

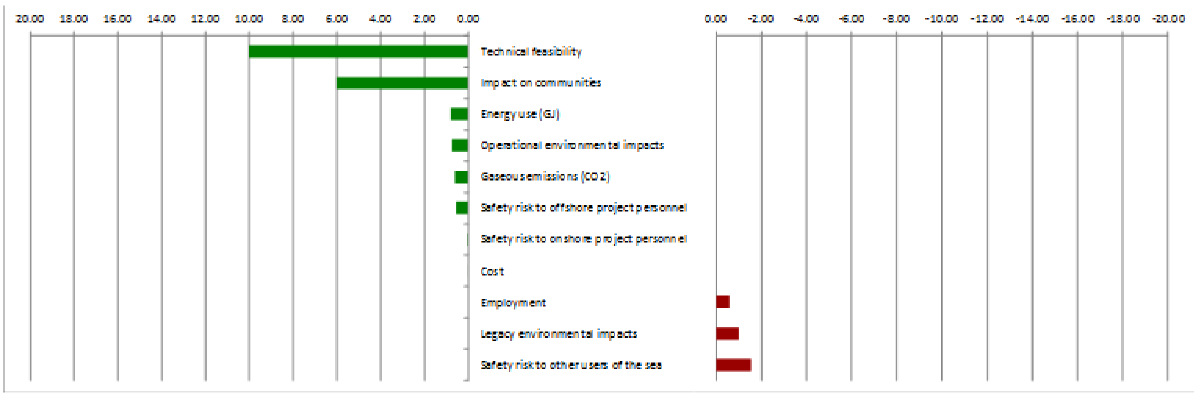
Figure 54 Difference Chart Comparing the Weighted Scores for each Sub-criterion in Two Options for the Brent Delta GBS, under the Standard Weighting, Assuming Degraded Legs Remained at LAT for 750 Years.



Green bars: Option 2 'Leave in place' is better than Option 1 'Partial removal

Red bars: Option 1 'Partial removal' is better than Option 2 'Leave in place'

Figure 55 Difference Chart Comparing the Weighted Scores for each Sub-criterion in Two Options for the Brent Charlie, under the Standard Weighting, Assuming Degraded Legs Remained at LAT for 750 Years.



Green bars: Option 2 'Leave in place' is better than Option 1 'Partial removal

Red bars: Option 1 'Partial removal' is better than Option 2 'Leave in place'

Following our assessment of the real data informing those scores, we have concluded that in terms of the GBS alone the sub-criteria serving to differentiate the options are **technical feasibility**, **cost** and **safety risk to other users of the sea**. The drivers and trade-offs for the decommissioning of the Brent GBSs involve a consideration of how feasible and safe it would be to remove the upper parts of the legs, and what real reduction in safety risk to other users of the sea would thus be achieved. When assessing the benefit of reducing the potential future risk to other users of the sea by removing the upper parts of the GBS legs, the potential risk to project personnel that arises through the need to complete the additional offshore and onshore work must also be considered. A balance must therefore be struck between reducing the long-term risk to other users of the sea and exposing project personnel to risk in order to achieve this, with the understanding that the assessment of risk for each party is on a different timescale and has been calculated using a number of assumptions.

We engaged the specialist consultancy Anatec to perform quantitative assessments of the likely risk to other users of the sea for the two options 'Partial removal' and 'Leave in place', using a number of stated assumptions about the degradation and longevity of the GBSs. Their findings are presented in their report *Assessment of safety risks to mariners from Brent GBS* [19]. This study was informed by two other studies, the Mackay report *Assessment of socio-economic effects on commercial fisheries* [21], which included an assessment of the likely future levels of fishing activity in the Brent area, and, importantly, by the Atkins studies *Brent Charlie leg collapse and caisson damage assessment – final report* [50] and *Brent Delta derogation and longevity study, technical report* [51].

The Atkins studies attempted to predict how the GBS legs and caisson would degrade and collapse if left in the sea. They inform our view of how long the GBSs might be a risk to other users of the sea through direct collision or through snagging of pelagic or demersal fishing gear, and how the degradation of the GBSs might lead to the exposure and/or ejection of material from the cells into the sea. Atkins acknowledged that the character and rate of GBS degradation are determined by the interaction of several factors and processes, and cannot be predicted with certainty. The estimates by Atkins could, therefore be regarded as indicative of the likely order of magnitude of the timescale. The 'best' estimate suggests that the legs might remain upright for up to 250 years before failing at or around sea level. They may then continue to degrade more or less linearly, but they may also remain upright for about 750 years, gradually losing strength until they fail at or around the top of the caisson.

Because of the considerable difficulty in predicting the character and rate of GBS degradation, and thus the timing and manner of the collapse of legs in Option 2 'Leave in place', Anatec assessed the safety risk to other users of the sea under two contrasting scenarios – Scenario 1 'Linear degradation from sea level' and Scenario 2 'Collapse at caisson'. The results of their assessment are shown in Table 40 and Figure 56.

The safety risk to other users of the sea is expressed in terms of the PLL. The total PLL is the estimate of how likely it is that one person may be killed as result of the option. The average annual PLL is simply that total estimate averaged over the whole period under consideration, which, for the purposes of assessing safety risks to other users of the sea from the degrading remains of the GBSs, we have taken to be 1,000 years. In oil and gas offshore projects, an annual PLL of 1.0E-03 is sometime regarded as the very maximum level of safety risk that would be tolerated before proceeding with a project.

Table 40 Total PLL for Other Users of the Sea for GBS options, with Safety Zones in Place.

Brent GBS	Total PLL for Option if 1000 years for leg degradation		
	Option 1 Partial Removal	Option 2 Leave in Place	
		Scenario 1 'Linear'	Scenario 2 'Collapse'
Bravo	2.54E-02	6.95E-02	14.0E-02
Charlie	2.72E-02	6.94E-02	8.84E-02
Delta	2.55E-02	8.21E-02	24.0E-02
Total	7.81E-02	22.1E-02	46.84E-02

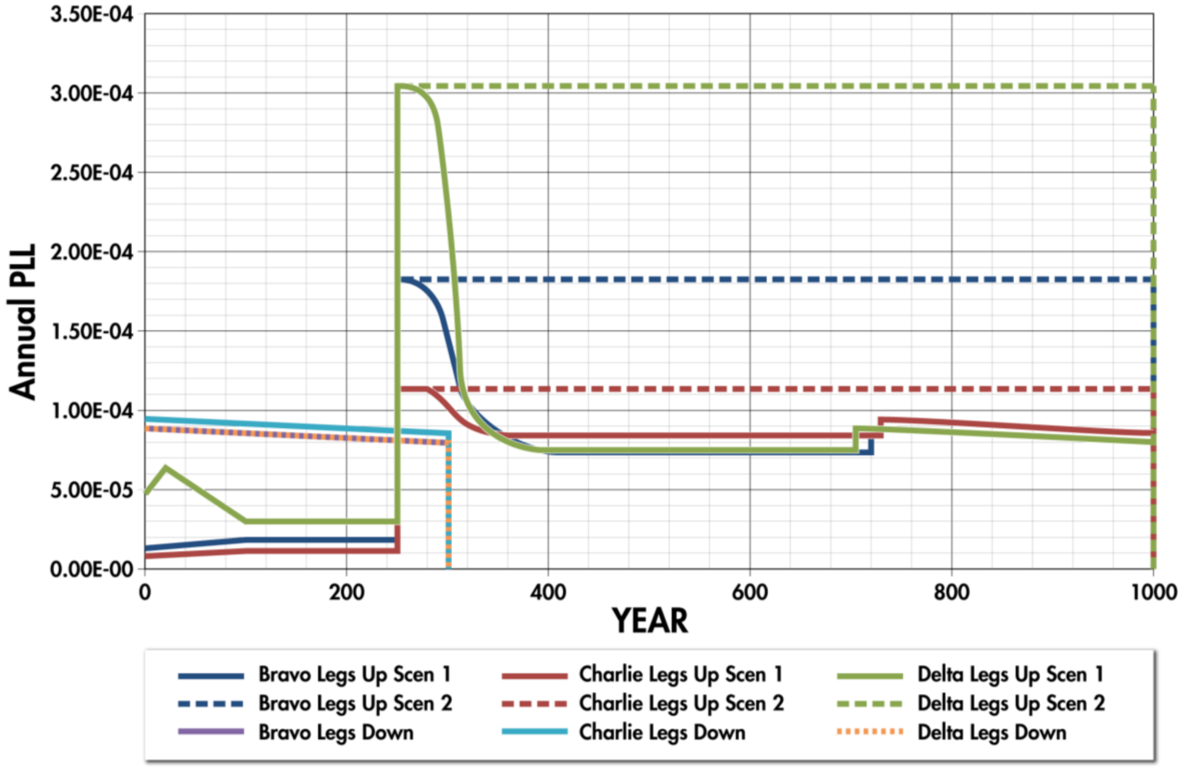
In Option 2 'Leave in place' scenario 1, if the legs degrade linearly the total safety risk to other users of the sea is estimated to be a PLL of 22.1E-02, giving an average annual PLL over the whole 1,000 year period of leg degradation of approximately 2.2E-04. In Option 2 Scenario 2, if the legs remained upright at sea level for 750 years the total safety risk to other users of the sea would be a PLL of 46.84E-02 which is an average annual PLL of approximately 4.7E-04. In contrast, in Option 1 'Partial removal' where the legs are removed down to approximately -55 m LAT, the total PLL would be 7.81E-02 which over a period of 1,000 years gives an average annual PLL of approximately 7.8E-05.

These values can be expressed in another way. The estimated PLL for other users of sea if the Brent GBSs were decommissioned by adopting Option 2 'Leave in place', and the legs failed at around sea level after 250 years and then degraded steadily over the next 750 years from sea level to the tops of the caisson, would be 22.1E-02. That means that if about 4 sets of 'Brent GBSs' were decommissioned in this way and degraded over 1,000 years, this might result in one fatality to an 'other user of the sea.'

It was these various values for safety risk to other users of the sea that we compared with the estimated safety risks for our project personnel who would be engaged in removing the upper parts of the legs. In the difference charts in Figure 53 to

Figure 55, we have used what were intended to be the conservative estimates from Anatec, because it is these estimates of the potential long-term safety risk to other users of the sea that influence our consideration of the GBS options. Recognising that any predictions of safety risk to other users of the sea so far into the future are subject to very considerable uncertainty, we have proposed a "rolling" programme of assessment in which the risk estimate will be updated from time to time using latest data. This is described in Section 14.17.1.

Figure 56 Estimates of PLL for Other Users of the Sea for GBS Options, with Safety Zones in Place.



14.9.2 Interaction with GBS Contents

The DECC Guidance Notes state that the options for installations should be examined '*bearing in mind the characteristics of the installation and the materials on and in it*' [3]. The Brent GBSs contain sediment in the former oil storage cells, and oily material in the drilling legs and minicell annulus. The nature of these contaminants, the feasible options for their management, and the results of their individual CAs are presented in Section 15 and Section 16 respectively. A description of the potential cumulative effects of the proposed decommissioning programme, including a description of the interaction between the GBS and their contents, is presented in Section 22.7.

Our assessments of options for the decommissioning of the GBSs were performed without considering the implications of the presence and effects of the cell sediments or the oily material in the drill legs and the minicell annulus, for the following reasons:

1. We wished to examine the technically feasible options for the GBSs in their own right.
2. Both options for each of the GBSs can be performed with all of the options for the GBS contents, and *vice versa*. Neither decisions about the legs nor decisions about the GBS cell contents preclude any option for either facility.
3. Decisions about the cell contents are therefore decoupled from decisions about the GBS legs.

4. With the exception of Option 5 for the cell contents ('Leave in place') all the options for the management of the cell contents, if combined with an option for the GBS legs, would add to the technical difficulty, safety risk, operational environmental impact, energy use, gaseous emissions, societal impact and cost of the 'GBS legs' portion of the assessment. This addition would be the same for both the GBS options, and thus the differences in performance between the two options for the GBS would remain unchanged.

5. For each of the GBSs on their own, the difference in 'legacy environmental impact' between the two options is small (1.0 on the weighted scale). If the options were combined with options for the cell contents, the legacy impacts would change as follows:

    a. Combining either GBS option with Cell Contents Option 5 'Leave in Place': Only the performance and weighted score of the sub-criterion legacy environmental impact would change. The weighted score for the legacy environmental impact for Option 5 for the cell contents is small, and smaller than the legacy environmental impacts of the GBSs on their own. For the GBS and cell contents combined, therefore, the weighted score for legacy environmental impact would decrease, but it would decrease equally for both the 'legs down' and 'legs up' GBS options. Since each GBS option had now acquired the legacy impacts from the cell contents *equally*, the difference in legacy impact between the options would decrease somewhat. The differences between the two options for the GBSs would continue to be driven mainly by the sub-criteria that drive the differences between the GBS on their own.

    b. Combining either GBS option with Cell Contents Options 3 or 4, the two 'treat in place' options: The same argument applies to these combinations. The weighted scores for the legacy environmental impact of these two options for the cell contents are quite low and about the same weighted score as the legacy impacts of the legs, so the *difference* in legacy impacts between the options for the GBS combined with the cell contents would decrease somewhat. In addition, both the GBS options would now acquire the safety risk, technical risks, costs and operational environmental impacts of the particular sediment option, and would do so equally. The differences between the two options for the GBSs would continue to be driven mainly by the sub-criteria that drive the differences between the GBS on their own.

    c. Combining either GBS option with Cell Contents Options 1 'Recover and Re-inject' or Option 2 'Recover and treat slurry onshore'. The weighted score for the legacy environmental impacts for both these options for the cell contents are quite high, near the maximum possible. For the GBS and cell contents combined, therefore, the weighted score for legacy environmental impact would hardly decrease from the weighted score for the GBS alone, and the differences between the two options for the GBS in legacy environmental impacts would remain about the same. However, the weighted scores for all the other sub-criteria would *decrease* because the additional operations would lead to a deterioration in the performance of the sub-criteria safety risk, operational impacts, energy use, gaseous emissions, societal impacts, technical feasibility and cost, and this deterioration would be equal in both the 'legs down' GBS option and the 'legs up' option. The difference between the options in these sub-criteria would, however, remain driven by the differences in the contributions from the GBS part of the combined option, rather than from the cell contents part.

14.9.3 Conclusion of Assessments for Brent GBSs

Our best assessments suggest that the removal of the upper parts of the GBSs legs would be feasible but technically difficult. It would require several years' of preparation, the design and trialling of a suitable-sized DWC system, and the design and testing of a means of attaching the cut leg sections to the HLV cranes. For the three Brent GBSs combined, the estimated total safety risk to our project personnel offshore and onshore who would be engaged in operations to cut, remove, dismantle and recycle the retrieved leg sections is a PLL of approximately 105×10^{-3}. If leg removal operations were spread over three years (as would be likely) the average annual PLL would be approximately 35 x 10^{-3}, which is approximately thirty-five times greater than the maximum 'tolerable level' for annual PLL.

If the upper parts of the legs on all the Brent GBSs were not removed, and they remained upright for 750 years once they had degraded to sea level, and the safety zone in place remained in place, we estimate that the total average annual safety risk for all other users of the sea – from collisions and snagging – would be a PLL of approximately 4.68 x 10^{-4}, which is about 1% of annual risk for project personnel who would be engaged in the work required to remove the upper leg. In contrast, if all the Brent GBS legs were removed and the safety zone remained in place, the average annual PLL for other users of the sea would decrease by about 45% to approximately 2.6 x 10^{-4}. It is important to note that the estimated average annual PLL for other users of the sea varies depending on which assumptions are made about degradation rates and whether an effective safety zone is maintained –and observed – around the remains of the GBSs.

As a result of extensive discussions with Anatec, the specialist consultants in assessing shipping and snagging risk, our view is that the estimates of the long-term safety risk for other users of the sea are conservative. They take no account of likely future improvements in technology, navigation or seamanship in the next five centuries, or of how shipping traffic or commercial fishing patterns and practices will change. If the GBSs were left in place with their legs upright, and marked on charts and on FishSAFE, they will continue to be a known and fixed feature of the seascape in the former Brent Field, and mariners will be able to take them into consideration when passage-planning and watch-keeping. We believe that the forecasted low-level, very long-term risks to other users of the sea are outweighed by the very tangible risks to which our project personnel would be exposed if the legs were to be removed.

14.10 Recommended Options for the Brent GBSs

The detailed CA of feasible options (Section 14), carried out in accordance with the requirements of OSPAR Decision 98/3, and using the selection criteria and matters to be considered set out in Annex 2 of that Decision, has indicated that the recommended options for the GBSs after the removal of the topsides are as follows:

- Brent Bravo: 'Leave in place'
- Brent Charlie: 'Leave in place'
- Brent Delta: 'Leave in place'

14.11 Recommended Programmes of Work for Decommissioning the Brent Field GBSs

After the removal of the topsides and the fitting of the concrete caps and AtoNs – all of which are part of the programme of work for the removal of the topsides (Section 12) – no further work would be carried out on the Condeeps Bravo and Delta. The conductors and casings in the drilling legs, and all the pipework and steel infrastructure in the utility legs, would be left in place. As part of our leg clearance scope of work on Brent Delta our execution team has ensured that all items within the drilling and utility legs are secure. In our ongoing preparations for the removal of the Bravo and Charlie topsides we will complete various checks and sweeps that will provide similar assurance that the internal pipework and steelwork will be left secure after the topside lifts.

We appreciate that if parts of the GBS legs had to be removed some years in the future, the potential cut line (around -69 m LAT for the utility leg) could be obstructed by corroded pipes and steelwork. Before any DWC cutting operations began, we would deploy an ROV through a large opening in the side of the leg to either confirm that the cut zone was clear or to remove obstructions. In their study on specific issues of leg removal DTOO, the original designers of the Condeep GBSs, concluded that a nominal 2 m x 2 m opening would not be likely to affect the structural integrity of the concrete leg [46].

On the SeaTank Charlie, the external conductors and conductor guide frames located between Legs C3 and C4 would be cut and taken to shore for dismantling and recycling. Cutting would be undertaken by external AWJ or DWC, and the conductors would be cut at a height of 2 m to 4 m above the cell-tops, as close as possible to the top of the cell-top drill cuttings pile but without disturbing the pile. The removal of the Brent Charlie conductors would not form part of the GBS decommissioning programme of work but would be undertaken as part of topsides removal or a wider programme of subsea removals.

External pipework and other 'appurtenances' on the legs would be removed, but this forms part of the subsea programme of work described in Section 18.

14.12 Marking of the GBSs

The position and new status of each GBS will be formally notified to other users of the sea through the UK Hydrographic Office, and marked on charts. All three GBSs will be incorporated in the FishSAFE system to provide early warning to commercial fishing vessels.

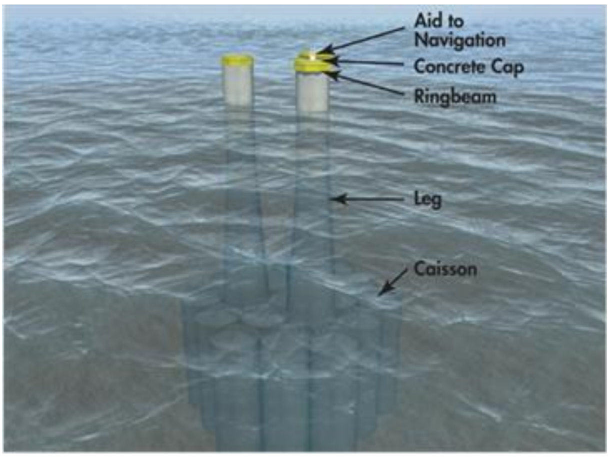
AtoNs will be fitted to the concrete cap on one leg of each GBS (Figure 57). On Charlie, one leg will be heightened by the addition of a 22 m long steel extension, to raise the AtoN clear of wave action (Figure 57). Two support structures will be installed on the leg cap so that a second, replacement AtoN, could be fitted before the old AtoN was removed for repair or servicing. The solar/battery-powered AtoNs are typically designed to operate for up to 4 years without maintenance and they can be changed using a helicopter or vessel, without the need for personnel to access the leg. According to the International Association of Lighthouse Authorities (IALA) the minimum requirement for an AtoN is the provision of light, but other features, including an Automatic Identification System (AIS) transmitter with the capability to fit a Racon[33] unit in the future, will be incorporated in our AtoNs. Remote monitoring for system health and diagnostics will be provided using a satellite link, including the possibility of remote basic power management facilities to allow faulty systems to be powered-down if required.

When it is clear that the legs can no longer support the AtoN, we will discuss and agree with BEIS a suitable alternative warning device. Under present legislation it is likely that this will be a tethered buoy, with appropriate lighting.

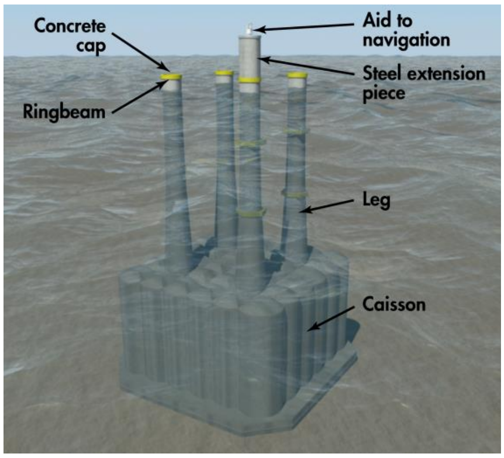
The present 500 m radius safety zone centred on each GBS will remain in force for as long as a leg protrudes above the sea. After degradation, when the leg is about to disappear below sea level, we will apply to the HSE for a continuation of the 500 m zone as an additional safety measure.

Section 24 describes the measures we would put in place to periodically monitor the condition of the GBSs.

Figure 57 Condition of the Brent Bravo and Brent Charlie GBSs on Completion of Decommissioning Activities, with AtoN in Place.



Brent Bravo



Brent Charlie

[33] Radar beacon

14.13 Material Retrieved and Material Left in Place

Figure 57 shows the condition of the Brent GBSs after removal of the topside and the fitting of concrete caps and the AtoN. At Bravo, Charlie and Delta the amounts of GBS material (concrete, steel and sand ballast) remaining in place on completion of the proposed programmes of work would be as were shown in Table 34.

14.14 Onshore Dismantling and Recycling

With the exception of the attic oil and interphase material that will be removed and treated as part of the management programme for cell contents (Section 9), the main items that will be retrieved from the GBSs will be the external conductors and conductor guide frames on Brent Charlie. Section 20 summarises how we would manage the dismantling and recycling of such material.

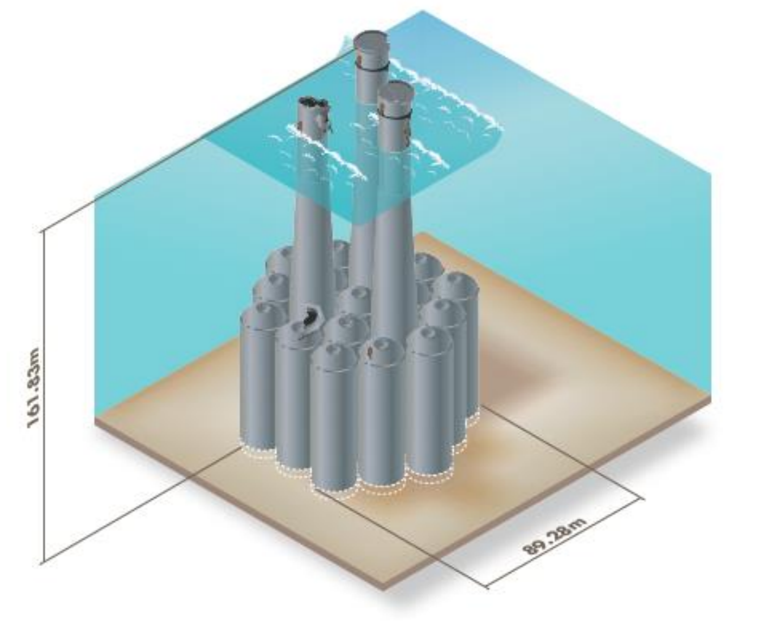
14.15 Degradation and Longevity of GBSs

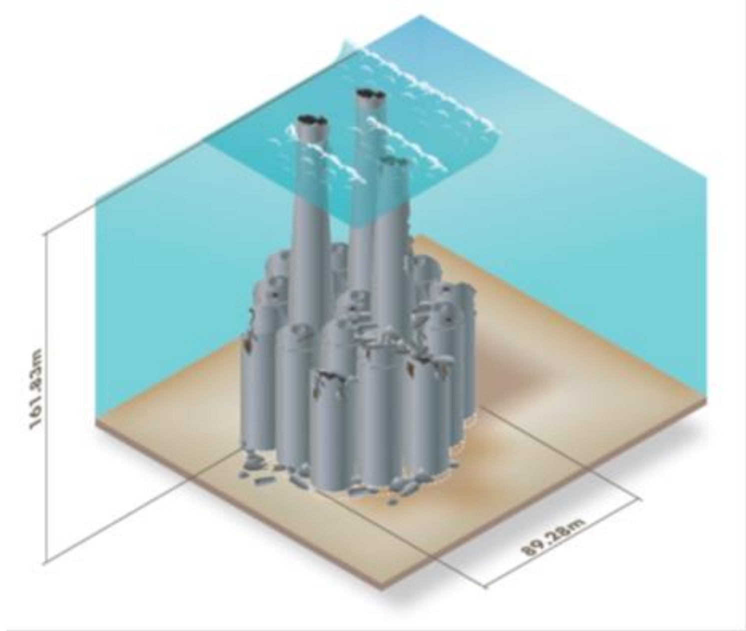
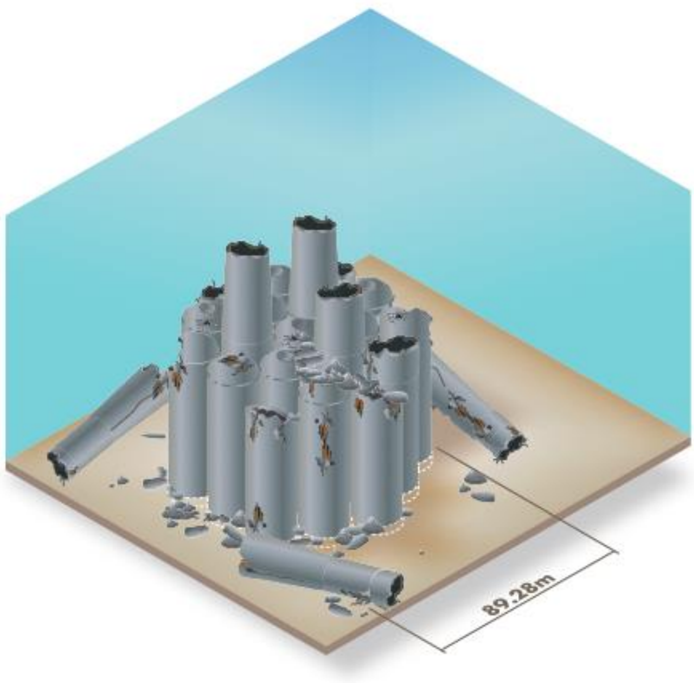
The GBS are very strong and durable structures, and are likely to last a very long time. The assessments performed and the predictions prepared by Atkins [50] [51] suggest that they will deteriorate and then collapse over a period of about 1,000 years, and that this process will comprise four phases (Figure 58). The possible sequence of degradation and collapse was investigated using various assumptions, and these gave a range of timescales for the phases, as described in the GBS TD [14]. It is acknowledged that the timescales estimated by Atkins, while based on best available knowledge, attempt to forecast the timing and character of a long process. They could be regarded as indicative of the likely duration of degradation and collapse, and it is on this understanding that we have used it them the basis for estimating the long-term risk to other users of the sea.

An artist's impression of the possible condition of a GBS after about 1,000 years of degradation is presented in Figure 59; this attempts to show the total mass of degraded concrete after corrosion of the reinforcing steel and collapse of the whole structure.

The possible impacts of the eventual exposure of residual cell sediment are described in Section 22.3.

Figure 58 Four Main Phases of GBS Degradation and Collapse.

<table>
<tr>
<td>
</td>
<td>Phase 1, lasting perhaps from Year 0 to Year 150.
The legs will remain upright and intact, although areas of spalling may begin to appear as the embedded steel reinforcing corrodes and expands, cracking the concrete. Similarly, unless impacted by falling debris from the upper part of a leg, the domes and walls of the cells will remain largely intact, although some fine cracking may develop.</td>
</tr>
</table>

	Phase 2, from about Year 150 to Year 250. Degradation of the legs will continue, and at some point the caps will fall off and it will no longer be possible to fit the AtoN. Degradation will be most noticeable around sea level, and it is likely that the legs will fail at or around sea level after perhaps 250 years. Spalling and falling debris from the upper legs will crack and perhaps puncture the cell domes. If large parts of legs fall away, individual cell domes and parts of cell walls may be destroyed.
	Phase 3, from about Year 250 to about Year 600. All the legs will have degraded to below sea level. Spalling of concrete is more evident over all parts of the GBS legs and caisson, and steel reinforcing will increasingly become exposed. Many of the cell domes will be punctured or destroyed, and some of the upper parts of the cell walls, particularly of outer cells, will also be damaged.

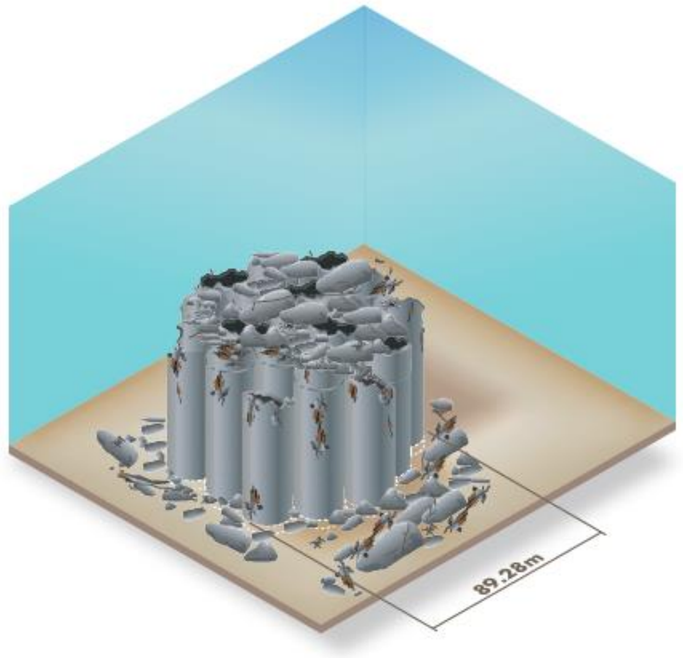
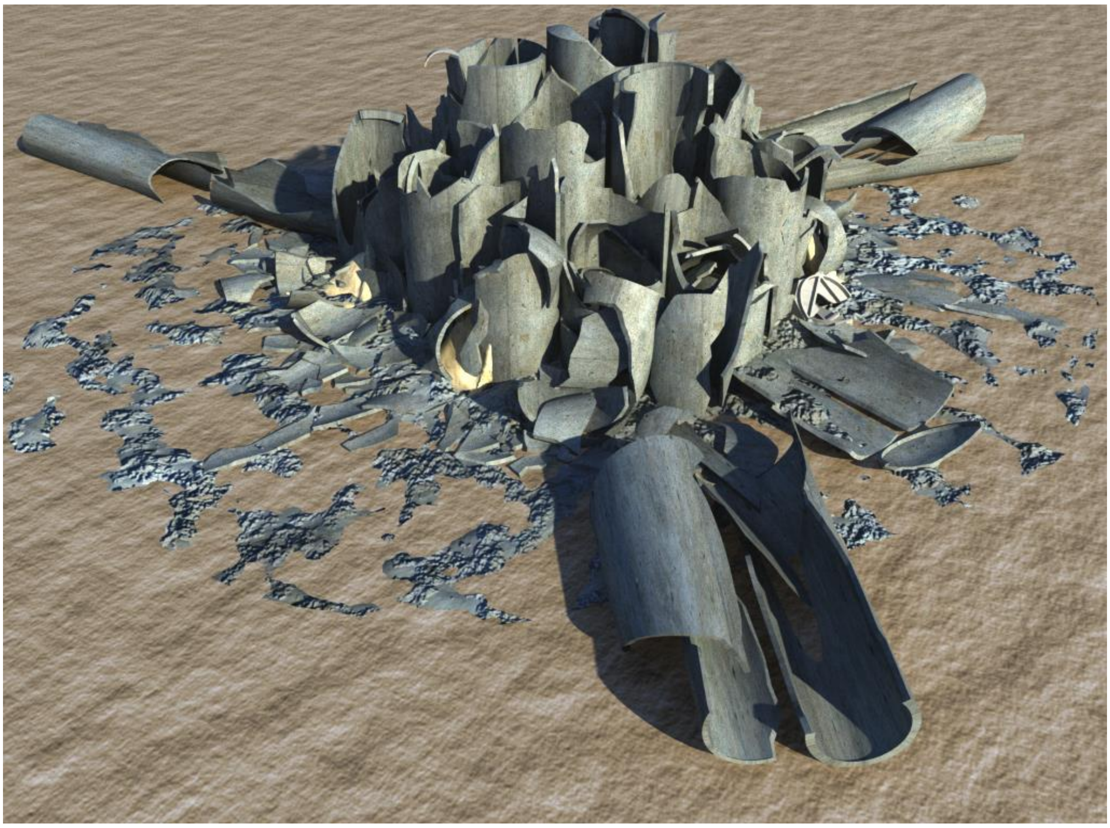
	Phase 4, from about Year 600 to about Year 1,000. All the legs will have collapsed by this stage, and will have come to rest across the cell-tops and on the adjacent seabed. During this period most if not all of the cells will have been breached, and most of the domes will have failed and collapsed into the cells. The cell walls will be breaking up and collapsing into the cells or onto the adjacent seabed. Only the lower parts of the cell walls may remain intact, rising above the base plate or the lower domes. Most of the steel reinforcing will have corroded away, and the material on the seabed will comprise fractured pieces of concrete lying in a rough mound over the former sites of the GBSs.

Figure 59 Artist's Impression of the Condition of a GBS after Complete Collapse.



14.16 Environmental Impacts of Decommissioning the GBSs

14.16.1 Stakeholder Environmental Concerns

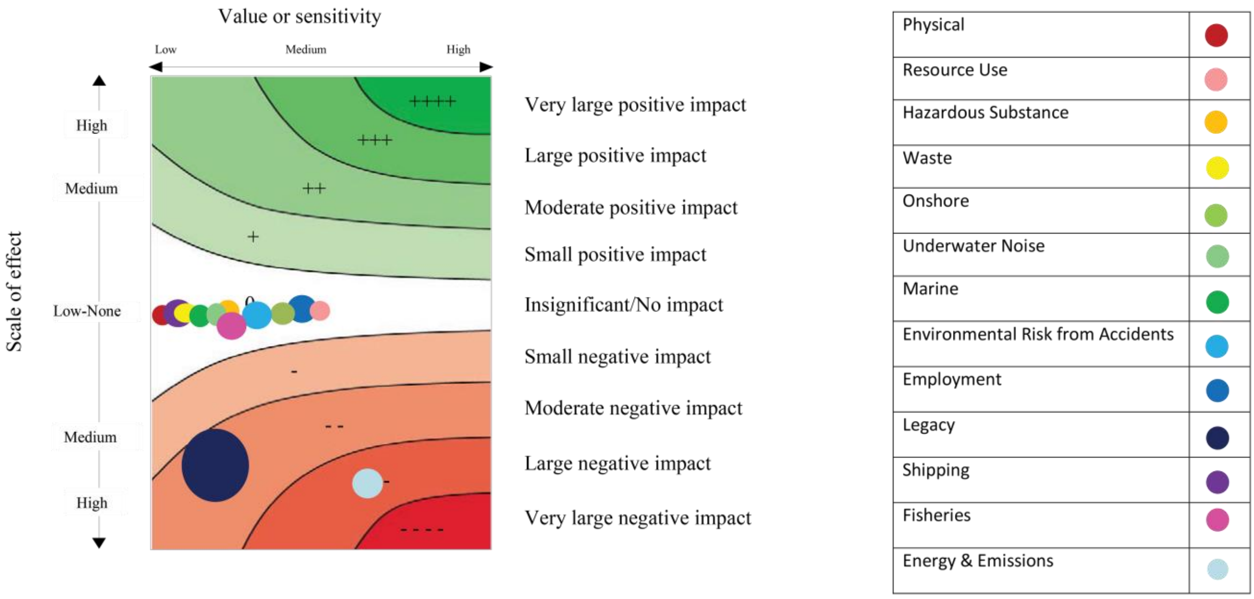
For the recommended option for each GBS, the specific environmental concerns or issues raised by our stakeholders were:

- Accidental discharges or releases of hydrocarbons to sea.
- Legacy impacts to the marine environment.
- Impacts on commercial fisheries.
- The effects of falling debris on the drill cuttings piles.
- The impacts of falling debris and legs on the oil storage cells.
- The difficulty of carrying our remediation on the GBS once the legs have collapsed.

14.16.2 Potentially Significant Impacts in ES

Figure 60 presents DNV GL's summary of the results of the environmental impact assessment of the programme of work that would be undertaken on the GBSs, and of their long-term presence offshore with legs upright [5]. The most significant impacts in this activity would be the large (theoretical) use of energy and gaseous emissions which is assessed as 'large negative', and the legacy impact which is assessed as 'moderate negative'.

Figure 60 Environmental Impacts Associated with the Decommissioning of all Three GBSs by Option 2 'Leave in Place'.



14.16.3 Impacts of Offshore Operations

There will be no impacts from offshore operations, because the GBSs would be left in the condition that was achieved after the removal of the topsides and the capping of the cut legs (Section 12).The only activities that would take place after the removal of the topsides would be associated with (i) the possible water-jetting of a small volume (in the order of tens of cubic metres) of cell-top drill cuttings (Bravo and Delta), or the removal of the whole of the Charlie cell top pile, if required, to permit subsea intervention for the removal of attic oil and interphase material (see Section 17), (ii) the removal of any visible cell-top debris (see Section 20) and, (iii) the removal of the external conductors on Brent Charlie (see Section 18). The potential impacts of all these operations are described in the relevant Sections and are not part of the operations to decommission the GBSs.

14.16.4 Legacy Environmental Impacts

The main potential source of impact associated with the decommissioning of the GBSs is their long-term presence on the seabed and eventual disintegration. Ignoring the potential impacts of the exposure of cell contents (Section 15) the main potential impacts from this outcome are the final 'footprint' of the collapsed GBS on the seabed, and the eventual exposure of drill cuttings in the tri-cells.

The ES estimated that the overall legacy impact of leaving the three GBSs in place was 'moderate negative', as a result of the combination of effects on the marine environment, fishing and shipping.

The slow degradation and collapse of the steel and concrete GBSs over a very long period of time would change the character of the local seabed, and provide a habitat for the settlement of hard-bottom species of invertebrates. Depending on the rate of GBS collapse and the violence of any such collapse, some adjacent parts of the seabed, perhaps within 100 m of the edge of the present structure, may be covered or partially covered by the rubble. In addition, falling debris would disturb and resuspend seabed sediments in the immediate area, which might impact local benthic fauna. For both these effects, however, (covering of the local seabed and local disturbance of sediments) the ES comments that the benthic fauna that would be impacted are diverse, abundant and typical of a wider region, and that there do not appear to be any species of conservation concern.

The degrading materials themselves are inert and will have very little impact on the marine environment. The steel will corrode to inert ferrous oxide and then crumble, and the concrete will probably break down into rubble of various sizes. The degradation of the GBSs and their eventual collapse would expose any cell contents to the marine environment, and the potential consequences of this are discussed in Section 15.

14.16.5 Energy and Emissions

After the removal of the topsides and the fitting of the concrete legs caps, which would be part of the topsides removal programme, the only direct use of energy if the GBSs were left in place with their legs upright would be the planned post-decommissioning structural and environmental surveys (Section 24). By far the majority of energy use and gaseous emissions would be indirect. DNV GL estimate that to 'replace', by new manufacture, the approximately 540,000 tonnes of concrete and the approximately 156,000 tonnes of steel that would be left behind and not recycled, would require about 3.8 million GJ of energy and result in the emission of about 370,000 tonnes of CO_2 (Table 41). This estimate is based on the optimistic assumption that recovered concrete can be recycled; experience to date shows that concrete that has been immersed in seawater for decades is only fit for road in-fill or harbour breakwaters.

Table 41 Energy and Emissions Associated with the Decommissioning of all Three GBS by Option 2 'Leave in Place'.

Operations	Energy (GJ)	Emissions to Atmosphere (tonnes)		
		CO_2	NO_X	SO_2
Direct				
Marine operations	13,965	1,029	21	6
Recycling				
Materials not recycled	3,810,767	372,079	302	215
Total	3,824,732	373,108	323	221

DNV GL also estimated, however, that if the three GBSs were to be refloated and taken inshore for dismantling and recycling, the total use of energy would be some 31 million GJ, and the total CO_2 emission some 2.3 million tonnes. In other words, operations to remove and recycle the GBSs, even if technically feasible, would not save energy or reduce emissions. Removal would result in the actual use of about 30 times more energy and the real emission of about 30 times more CO_2 than leaving the GBSs in place. Finally, it is worth noting that in the 'leave in place' option, approximately 78% of the energy use and 83% of the CO_2 emissions are 'theoretical', only occurring if concrete and steel has to be newly manufactured to replace material left in the sea.

14.17 Mitigation Measures for GBS Programme of Work

14.17.1 Reviewing the Safety Risk to Other Users of the Sea

We engaged Anatec to estimate the safety risk to other users of the sea from the long term presence of the GBSs with the legs in place [19]. The risk is presented by the short- to medium-term risk of collision and the medium- to long-term risk of snagging fishing gear.Any estimation of the long term safety risk to other users of the sea (the 'legacy' safety risk) depends, crucially, on forecasting (i) the intensity of various types of fishing operations around the GBSs and, (ii) the intensity, routes and nature of commercial shipping in the area. Shell, Anatec and Mackay Consultants have acknowledged that it is very difficult to make long-term forecasts of fishing and shipping. Consequently, the assessments of safety risk to other users of the sea have been based on the recent levels of fishing and shipping, calibrated with historical collision data. At present, the estimates of safety risks to other users of the sea over the next 100 years result in an estimate of annual PLL that is within the range regarded as 'tolerable'.

In the short term (perhaps 20-30 years), recent historical data may give a reasonable prediction of future levels, and hence of future safety risks. Given the pace of changes in maritime technology and practices, the probable changes in both shipping levels and types, and fishing activity, predictions based on recent trends are likely to quickly become out of date.

Recognising these uncertainties we propose, as part of our ongoing monitoring programme, to repeat the assessment of safety risks to other users of the sea at regular intervals using the latest published data. This would involve an examination of the most recent new data and trends on fishing activity and commercial shipping activity, and an update of historical collision data. This would be used to re-model the risk and provide a revised short-term prediction of the safety risks to other users of the sea. In this way a "rolling" programme of risk assessment could be established and maintained, based on short-term predictions that were periodically updated, and in which there could be a high degree of confidence. Given the pace of technology development (for example satellite tracking, improvements in AtoNs, and the introduction of unmanned fishing vessels) it may be prudent to complete the first update about 10 years after the completion of the decommissioning programme. The frequency of subsequent updates may be determined by a risk-based approach informed by the pace of technology development, and would be agreed with BEIS in the monitoring programme. Such a rolling programme would, in due course, also take into account the changing condition of the GBSs left in place on the seabed.

If any re-assessment showed that the level of risk was unacceptably high, we would consult with both the authorities and the other users of the sea to consider and agree what actions could or should be taken to mitigate the revised risks.

14.17.2 Summary of Other Mitigation Measures

- Appropriate Notices to Mariners will be issued to alert other users of the sea to the changed status or condition of the GBSs.
- Aids to Navigation will be fitted to each GBS and maintained to ensure they are effective.
- The locations and status of the GBSs will be entered onto the FishSAFE system to alert fishermen when approaching the structures.
- A 500 m safety zone will be retained around each GBS while any part of the structure remains above sea level. After degradation, when the leg is about to disappear below sea level, we will apply to the HSE for a continuation of the 500 m zone as an additional safety measure.
- A post-decommissioning as-left structural survey will be performed on each GBS to accurately determine its condition, for use as a baseline to monitor the future condition of each structure.
- A risk-based environmental and structural monitoring programme, to track the long-term degradation and fate of the GBSs, will be discussed and agreed with BEIS.

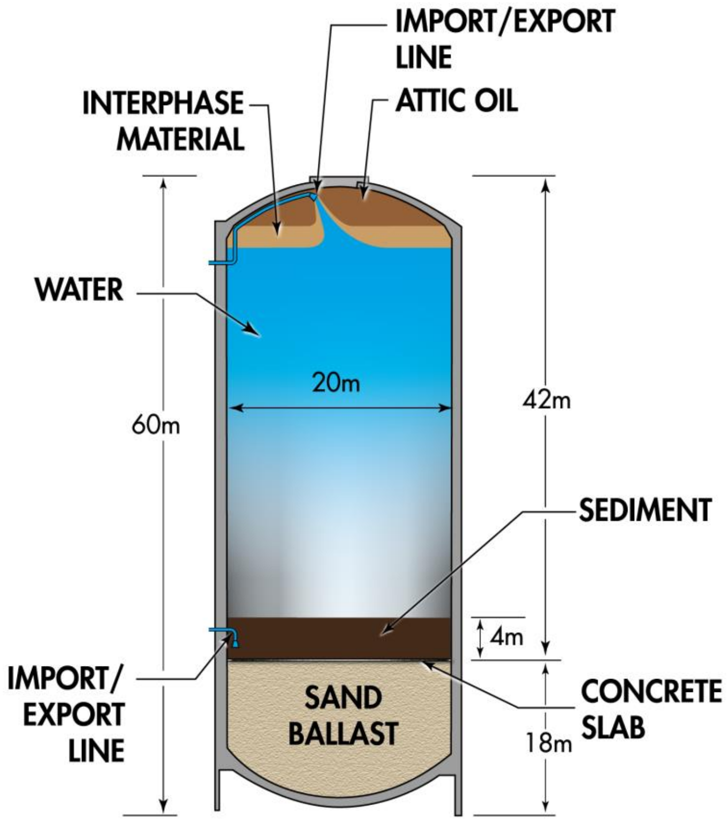
15 DECOMMISSIONING THE GBS CELL CONTENTS

15.1 Introduction

A full description of the former GBS oil storage cells is presented in the GBS Contents TD [15]. In summary, after the final export of crude from the cells, the oil storage cells will contain four types of material (Figure 61):

- Attic oil: A small volume of crude oil trapped beneath the cell dome (Charlie and Delta only).
- Interphase material: A stiff emulsion of oil and water formed at the interface between the attic oil and the cell water.
- Water: Produced water and seawater, which was pumped into the cell to replace the oil being exported.
- Sediment: A mixture of fine particles of sand, crude oil and water. On all three GBSs, some of the cells in the caisson were used as part of the oil separation process and for storing crude oil before export. During storage, fine particles of sand will have settled-out from the liquid phase and accumulated in the base of each oil storage cell, forming a layer of oily sediment.

Figure 61 Schematic Diagram Illustrating the Expected Disposition of Materials in a Brent GBS Oil Storage Cell at CoP.



15.2 Characteristics of Cell Contents

15.2.1 Introduction

We have committed to removing the attic oil and the interphase material from every former oil storage cell (Section 15.11.2). We have therefore examined options for the management of the remaining materials, the cell water and the cell sediment. To identify and develop feasible options in the absence of any sediment samples from the cells, we performed desk-top studies to estimate the volume of sediment and the likely types and concentrations of contaminants that it would contain. These studies were informed by data from sludge samples taken from the topsides separators, the Brent Spar, and the Sullom Voe oil terminal where Brent crude was received.

In July and August 2014, after a long period of design, planning and trialling, we successfully surveyed and sampled three of the sixteen oil storage cells on Delta, in a programme called the cell sampling project (CSP). The challenge of the CSP was to devise a sampling programme that could be realistically and safely undertaken offshore on a working platform. During the initial phase of engineering development, it emerged that the scope of the sampling and surveys had to be balanced against the corresponding technical challenges in order to keep the offshore execution within pragmatic boundaries. Taking such considerations into account, the objectives of the CSP were as follows:

i. To collect samples of the water and sediment phases from three oil storage cells.

ii. To launch a 3D sonar device to obtain data on the surface topography of the sediment, and measure the depth and thickness of the sediment.

The major technical constraints to obtaining any samples from the storage cells while a GBS was operational were (i) gaining access to the interior of the cell and, (ii) maintaining the integrity of the cell and of drawdown[34].

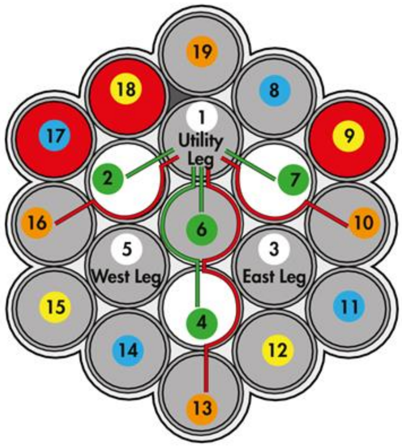
We concluded that it would be more efficient to deploy equipment from the topsides than from a vessel under the overhang of the topsides. We also realised that although the use of the existing pipework seemed more cost-efficient, it posed significant constraints on the tooling to be used and so would be likely to require a bespoke design. We therefore decided to gain access to the storage cells through newly created subsea holes drilled through the concrete cell tops, but we continued to investigate the development of bespoke tooling that could be deployed through the existing pipework.

In the light of these major findings and decisions, we selected three storage cells for access - Cells number 9, 17 and 18 shown in red in Figure 62 - mainly because of their favourable location with respect to the topside cranes which were required to deploy the equipment from the topside. Using these cranes rather than a Dive Support Vessel (DSV) reduced the cost of the sampling project.

As a result of the CSP, the layer of sediment in the base was mapped and quantified by sonar, and 6 kg of sediment and approximately 10 litres of water were retrieved for analysis.

[34] In order to execute this project with the topside in place, the design of the equipment had to accommodate the particular constraint of the drawdown system. This means that if a hole is drilled into a cell for the deployment of measuring or sampling equipment, it must be protected by two barriers so that the pressure difference across the roof of the cell is maintained.

Figure 62 The Location of Storage Cells 9, 17 and 18 on Brent Delta Selected for Sampling in the CSP.



15.2.2 Summary of physical and chemical characteristics

The majority of values for the various physical and chemical parameters of the sampled material were within the ranges that we had estimated during our desk-top studies. The GBS Contents TD [15] presents a detailed description of the estimated characteristics of the cell contents and compares this with the results from our samples.

The average thickness of the sediment layer was 4 m, and using this data from Delta, and assuming that all the oil storage cells exhibit a similar depth of sediment, we have calculated that on Bravo and Delta each oil storage cell contains 1,080 m^3 of sediment and on Charlie each contains 676 m^3 (Table 42). Approximately 25% of the sediment was hydrocarbon, so the Bravo and Delta cells each contain approximately 300 tonnes of oil and the Charlie cells approximately 168 tonnes of oil.

Table 42 Calculated Amounts of Sediment and Oil in GBS Oil Storage Cells.

Parameter	GBS		
	Bravo	Charlie	Delta
Cell Sediments			
Base area of each cell (m^2)	270	172	270
Thickness of sediment (m) (Note 1)	4.0	4.0	4.0
Volume of sediment each oil storage cell (m^3)	1,080	676	1,080
Number of oil storage cells	16	8	16
Total volume of sediment in GBS (m^3)	17,280	6,035	17,280
Percentage TPH in sediment (Note 1)	15.2	15.2	15.2
Estimated total mass of oil in sediment (Te) (Note 2)	4,806	1,678	4,806
Cell Water			
Volume of cell water (m^3)	163,840	311,667	163,040
Average concentration of oil in water (mg/l) (Note 1)	417	417	417
Estimated total mass of oil in cell water (Te)	68	130	68

Notes:

1. Percentage Total Petroleum Hydrocarbons from the Brent Delta CSP in 2014, also applied to Bravo and Charlie.
2. Bulk density of cell sediments is 1.83.

The cell samples obtained in 2014 showed that the majority of our predictions for the concentrations of contaminants were over-estimates. Table 43 compares the analytical results obtained from the sediment samples with the initial assumptions derived at the outset of the engineering work; the full results are presented in the GBS Contents TD [15]. This shows that in the cell samples the concentrations of most of the chemicals were lower or much lower than we had assumed from our original (desktop) studies. The average concentrations of two parameters, Benzene Toluene Ethylbenzene Xylene (BTEX) and Total Hydrocarbon Concentration (THC), were, however, 10% and 28% higher respectively than the assumed values. These differences have been addressed by using the actual values to complete further modelling runs to investigate the potential long-term fate and effect of exposed sediments, as described in Section 15.5 and the GBS Contents TD [15].

Table 44 compares the physical parameters measured on the sediment samples with the initial assumptions used during the engineering work, and there are three important observations on these results:

- The sediment samples from Cell 17 and Cell 18 contained more water than we assumed. This might be linked to the fact that the sediment samples were collected from the surface layer of the sediment (at a depth of 0.5 m to 1 m in a 4 m deep deposit), where the sediments is less compacted than in deeper layers and where there is more pore water.
- The specific gravities of the oil phase and the solid particles were well in line with our assumptions, which were based on materials produced by the Brent reservoir.
- The shear strength was higher than anticipated. It should be noted that the sampled values should be treated with some caution because the sediment samples had to be disturbed during extraction from the gravity corer. It can be reasonably assumed, however, that undisturbed samples would have exhibited higher shear strengths than those actually measured.

Table 43 Comparison of Predicted and Actual Chemical Composition of Cell Sediment.

Sediment Constituent	Estimated	Average Delta
Proportion solids (%)	39	27
Proportion oil (%)	28	25
Proportion water (%)	33	49
Total Hydrocarbon Concentration (THC) (mg/kg)	110,000	152,600
Napthalene (mg/kg)	301	30
Benzo(a)pyrene (mg/kg)	172	0.4
Phenanthrene (mg/kg)	913	14
Benzene (mg/kg)	1,010	1,122
Mercury (mg/kg)	4	0.15
Copper (mg/kg)	1,118	42
Zinc (mg/kg)	2,028	84
Total PCBs (mg/kg)	0.12	<0.001
Tributyl tin (mg/kg)	0.26	<0.001
Phenols (mg/kg)	83	80

Table 44 Comparison of Predicted and Actual Physical Parameters of Cell Sediment.

Parameter	Brent Delta Assumptions in Original Modelling	Results from Cell Sampling			
		Average	Cell 9	Cell 17	Cell 18
Shear strength (Pa)	8	82.8	43.8	124	80.5
Density (specific gravity)	Oil: 0.859	0.812	0.806	0.817	??
	Solids: 2.650	2.55	2.28	2.72	2.65
	Water: 1.021				
	Bulk density: 1.611	1.83	1.25	2.09	2.15
Initial cell sediment material Proportions (% volume)	Oil: 28	24.7	38.8	22.1	13.2
	Water: 33	48.8	38.5	51.3	56.5
	Sediment: 39	26.5	22.7	26.6	30.2

On the basis of this comparison of our estimated values with the values obtained in cell samples, we believe that the results of the detailed modelling, toxicological and environmental impact assessments (with appropriate updating), which were necessarily performed while we planned and then performed the operation of sampling cells on a working platform, are relevant and appropriate to inform our CAs.

15.3 Other Materials in the GBSs

In addition to the materials in the oil storage cells the GBSs are known to contain, or assumed to contain, materials in the drilling legs and the minicell annuli. These materials are dealt with in Section 16.

15.4 Management of the Cell Contents

15.4.1 Introduction

It is not possible to return the cell sediments to shore by refloating the GBSs; none of the GBSs could be refloated with the cell sediments in place because they would be too heavy.

With expert input from chemical engineers and remediation specialists, we identified a range of options for the management of the cell contents [15]. Further studies, informed by the CSP results from the three Brent Delta cells, indicated that there were five technically viable options for managing the cell contents, and these were subjected to a CA.

The options are briefly described below. The starting point for all these options is that any attic oil and interphase material will have been removed. For all these options, we have determined that the sediments could only be accessed by drilling or cutting a hole in the dome of every cell, and attaching pipes and pumps and other equipment to the tops of the cells. The existing internal or external pipework to the cells is either inadequate or unserviceable.

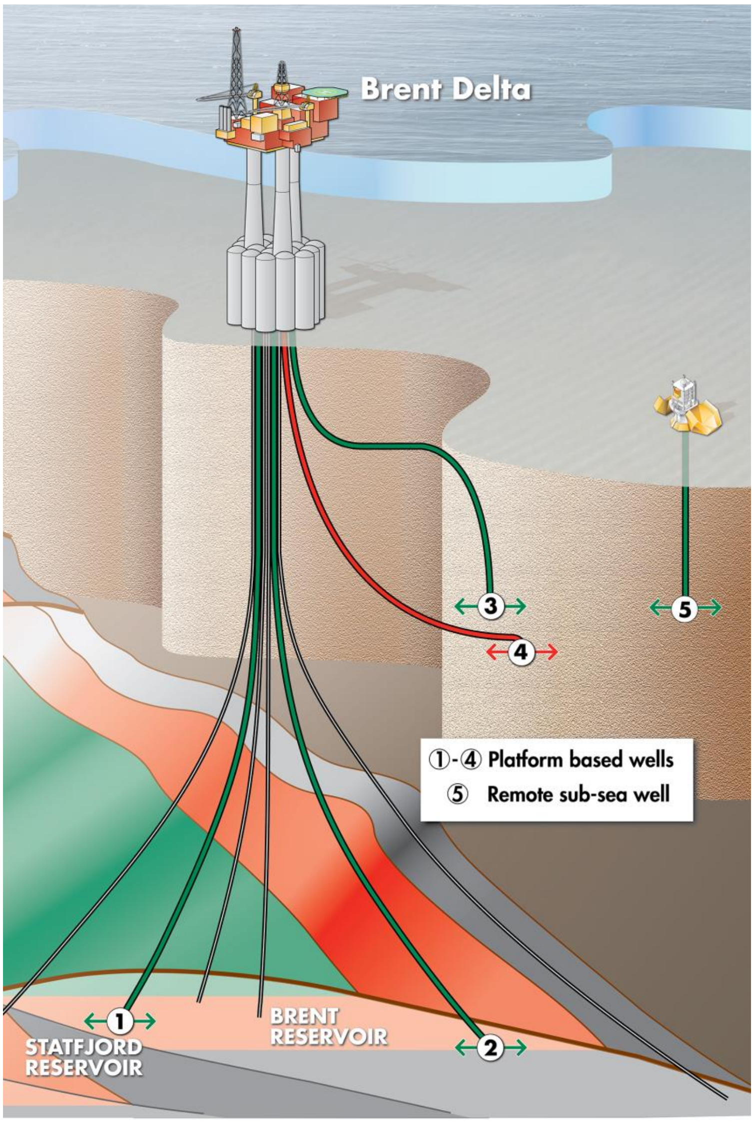
15.4.2 Option 1: Recover and Re-inject

Using a pipe inserted through the hole drilled to extract the attic oil (see Section 15.11.2), or a new 3 ½" (89 mm) diameter hole in the cell dome, the water phase would be pumped to a tanker and replaced with seawater. The hole would then be enlarged to about 5 m diameter and a subsea dredger deployed into the cell to mobilise and recover the sediment, in a slurry with the seawater. From published data and industry experience we have assumed that this slurry would be 1 part solids and 10 parts water. The slurry would be pumped to the tanker, and the water phase and slurry transported to the site of the injection well.

We evaluated existing Brent Delta wells for injection, and concluded that because of their poor integrity they were unsuitable for use as injectors for retrieved slurry. Consequently, new disposal wells would have to be drilled if the cell contents were to be disposed of downhole. We investigated the technical issues associated with drilling new wells into the Brent formation and found that because of the high depletion in the Brent formation there is no conventional drilling window, and that even utilising wellbore strengthening techniques the well could not be completed to the functional requirements. Drilling a subsea injector for direct injection into the Frigg Sandstone formation was studied and we concluded that it would be technically feasible to drill such a well from a semi-submersible drilling rig (Option 5 in Figure 63). As a result of our work investigating the possibilities of re-injection, we have concluded that, with the exception of new injector wells into the Frigg Sandstone formation, all options have associated technical issues which increase the likelihood of failure to an unacceptably high level. At least one new remote subsea well would have to be drilled for each GBS.

At the injector well site, the retrieved water and slurry would be pumped via floating hoses to a Light Well Intervention Vessel (LWIV) and injected down hole, in an operation lasting approximately 110 days for Bravo and Delta, and approximately 60 days for Charlie. The injection well would then be plugged and abandoned (Section 10). The injected slurry would be effectively sealed-in and would not become exposed to or released into the marine environment. The former oil storage cells would be left filled with seawater, possibly with small amounts of chemicals to treat any residual oil.

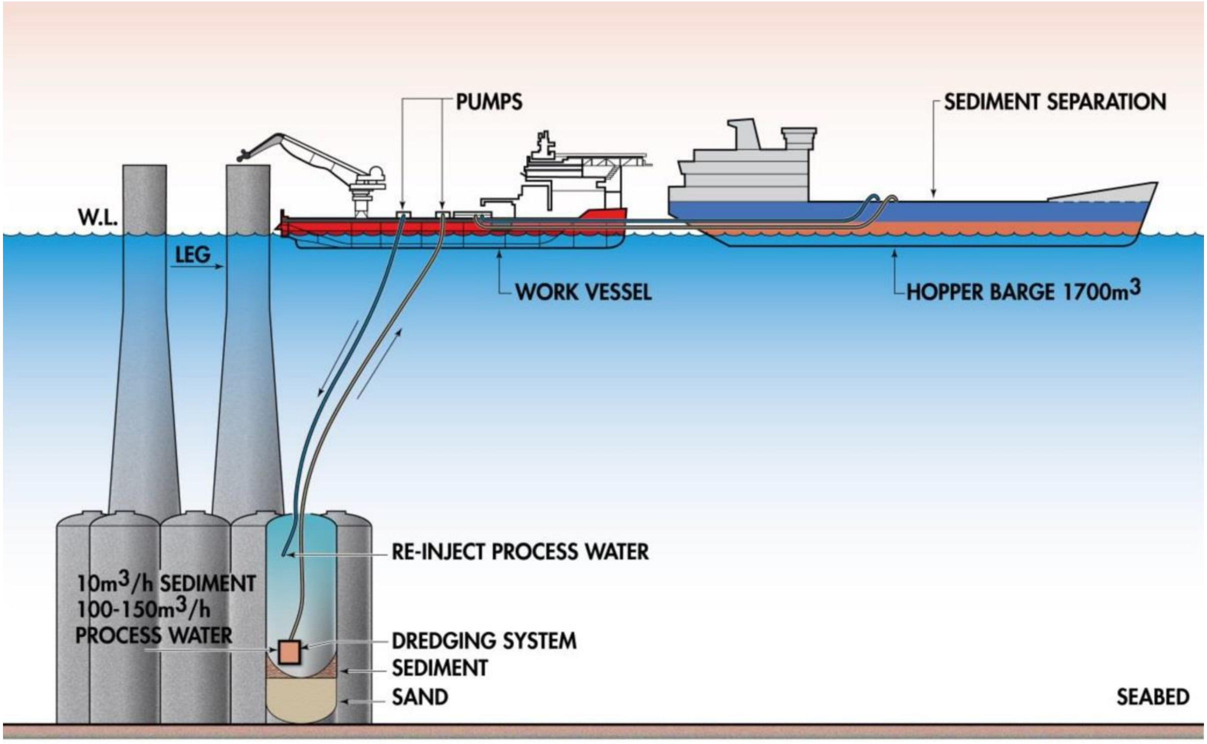
Figure 63 Schematic showing Possible Method for Option 1 'Remove and Re-Inject'.



15.4.3 Option 2: Recover and Treat Onshore

The water phase and sediment slurry would be recovered, separately, in the same way as in Option 1, using the same dredging system (Figure 64). Both materials would be taken to shore by tanker and pumped ashore to holding tanks. The water would be treated by an existing waste water treatment plant and then discharged to sea under permit. The slurry would be dewatered and the excess water treated and discharged to sea under permit. The dewatered slurry would be treated by Low Temperature Thermal Desorption (LTD); the recovered hydrocarbons would be recycled or disposed of and the inert solids disposed of to landfill. Offshore, the former oil storage cells would be left full of seawater. We estimate that on Bravo and Delta the operations to recover, treat and dispose of the cell contents (water plus sediments) would take about 20 days for each cell if the programme of work was continuous.

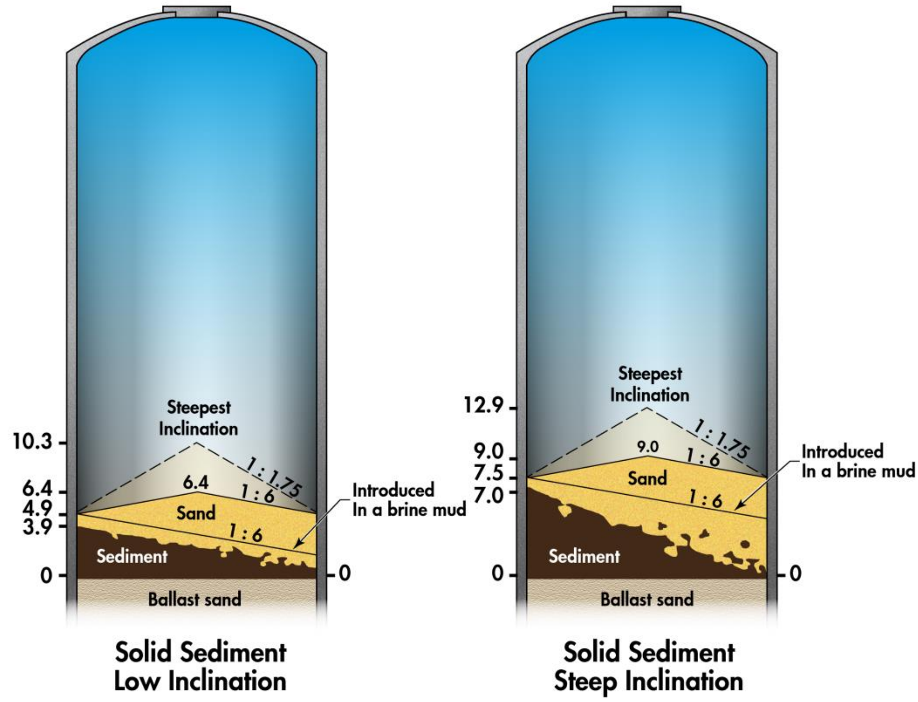
Figure 64 Schematic of Offshore Operations in Option 2 'Remove and Treat Slurry Onshore'.



15.4.4 Option 3: Leave In Place and Cap

Using a pipe inserted through the 3 ½" (89 mm) hole in the cell domes, the water phase in each cell would be dosed with up to approximately 1,400 m^3 (on Charlie up to 2,500 m^3) of chemicals (for example calcium nitrate and sodium hexametaphosphate). This would reduce its oil content and thus reduce the local environmental impacts when the water phase eventually escapes from the cells when they are breached. H_2S scavenger may also have to be injected. The hole would then be enlarged to perhaps 5" (127 mm) or 8" (203 mm) to permit the deployment of an injection tool (a long pipe). This would be used to deposit approximately 300 m^3 of sand into each cell, to create a protective layer about 1 m thick on the sediments at the bottom of the cell (Figure 65). Before adding this capping layer, approximately 500 m^3 of additional material (gravel and bentonite) may have to be added to each cell as a 'structural agent', to enable the underlying sediment to bear the weight of the copping layer. Water displaced by introducing structural and capping materials would be recovered onto the vessel and stored, and disposed of onshore. After capping, the cells would be sealed. We estimate that on Bravo and Delta it might take 8 days to complete these operations on each cell, so the whole operation on each of the Condeep GBS Bravo and Delta might take approximately 128 days.

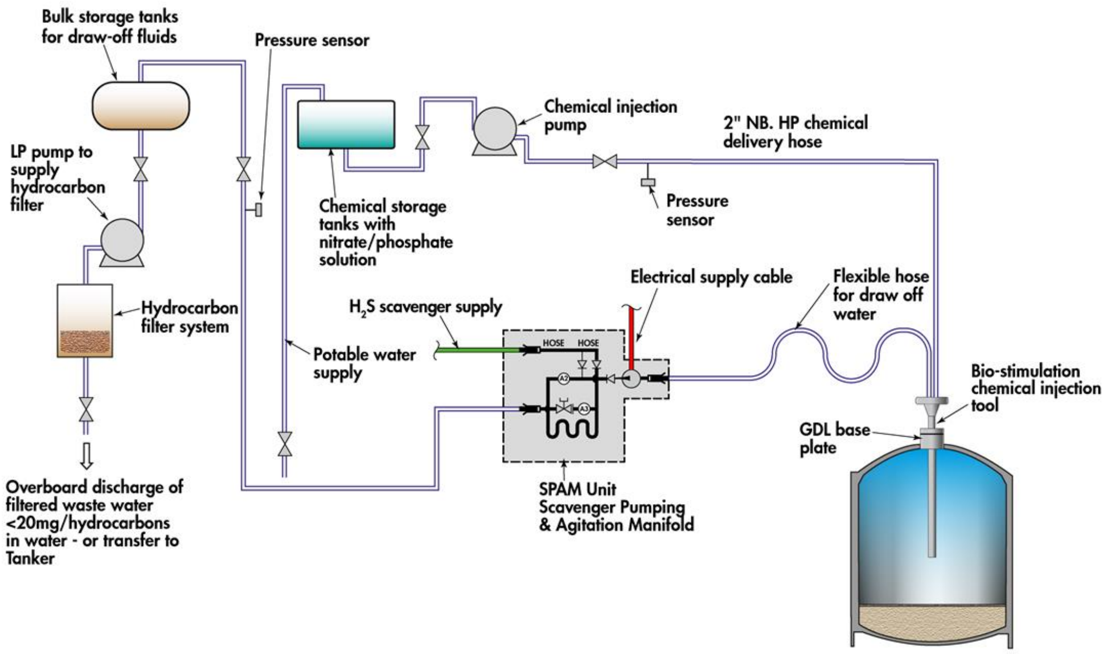
Figure 65 Possible Configuration of Capping Layer in Option 3 'Leave in Place Capped'.



15.4.5 Option 4: Leave In Place with Monitored Natural Attenuation (MNA)

A mixture of chemicals (H_2S scavenger, calcium nitrate and, in some cases, additional sodium hexametaphosphate) would be injected into each cell, using a specially-designed tool deployed through the 3 ½ " (89 mm) hole at the top of each cell (Figure 66). The type of chemical and the dose applied would be designed to reduce the amount of biodegradable hydrocarbon in the water phase and in the upper layer of the cell sediment. For the Condeeps, we estimate that approximately 4,000 m^3 of chemicals would be required for each GBS, but for Charlie we estimate that a total of about 8,000 m^3 would be needed. In the absence of any mechanical mixing it is unlikely that the chemicals would penetrate more than about 20-30 cm into the sediment. After the chemicals had been injected, the holes in the cell domes would be sealed. We estimate that on Bravo and Delta it would take about 18 days to complete these operations on each cell, making a total of approximately 288 days for each of the Condeep GBSs. The material in the cells would be monitored at some time after the introduction of the chemicals, to ensure that the planned degradation had taken place. If necessary, further chemicals would be added to the cells. Once the cell contents had attained the planned or satisfactory condition, the cells would be permanently sealed.

Figure 66 Schematic of Chemical Injection System in Option 4 'Leave in Place with MNA'.



15.4.6 Option 5: Leave In Place

After the removal of the attic oil and interphase material, the cell would be sealed by plugging the hole in the dome. The layer of sediment in each cell would remain in place. In the absence of any agitation or oxygenation, and at the low temperature found at a depth of 140 m in the northern North Sea, the hydrocarbons in the sediment would degrade very slowly.

15.5 Fate and Effect of Sediment Left in Cells

15.5.1 Summary

To inform the CA we carried out studies (described in [15]) to assess and quantify:

- The long-term degradation and collapse of legs left upright, and how their collapse might damage cells and expose sediment to the marine environment.
- The long-term degradation and collapse of the GBS and its cells.
- The long-term fate and effects of various amounts of cell sediment if it were exposed in the marine environment and then subject to erosion, dispersion and the effects of physical, chemical and biological degradation.

The final stage of the degradation of the storage cells, leading to the exposure of the sediment, is directly linked the failure mode of the legs. For the sediment at the bottom of the storage cells to be released into the marine environment, large pieces of the legs must fall directly onto the cell tops. In such events the degradation of the storage cells can be described in two phases: (i) a single collapse event or a series of such events, followed by (ii) the long term erosion of the resulting mixture of rubble and sediment. During the collapse phase the containment of the cell sediment is breached and the sediment exposed to the marine environment. If large pieces of concrete were to fall directly onto the sediment, a proportion of the sediment could be re-suspended in the water column and re-settle on the seabed around the platform, where it would biodegrade. When the collapse has reached its final stages, the cell sediment is likely to remain partially shielded by the concrete remains of the structure. At that point, biodegradation and erosion will take place at the surface of the sediment exposed to the marine environment. During this whole process, the sediment is not predicted to travel any further from the platform than 2 km. The edge of the re-deposited pile of sediment will be thin and this will enable quick recovery through biodegradation.

15.5.2 Modelling fate and effect of exposed cell contents

We engaged BMT to perform detailed modelling of the likely spread and dispersion of both the cell water phase and sediment phase, using a particle dispersion model. Their findings are summarised in the report *GBS Cell Water and Sediment Modelling – Overarching Report* [52]. For the water phase, the modelling performed by BMT has shown that for an extreme case (the release of 100,000 m^3 of cell water over a short period of time), the plume would be dispersed and diluted such that the concentrations of contaminants would be below the level of concern within a few days, and stay within a distance of approximately 17 km from the platform. In their study *Impact Assessment of the Exposure of Brent Field GBS Cell Contents to the Marine Environment* [53], DNV GL concluded that the environmental impacts of such a release are limited to significant transient effects close to the release point, and that the size of the impacted area is not large enough to be measurable on the population level of water column resources.

For the sediment, if the effects of biodegradation are excluded, the long term erosion of the pile does not extend beyond 2.1km after 1,000 years. If biodegradation of the organic compounds were taken into account, however, this footprint on the seabed would be significantly reduced. For the transient phase (corresponding to some of the worst case collapse scenarios of the GBS), the sediment footprint on the seabed does not exceed 1.5-2km, depending on the release scenario. For cell sediment release, DNV GL concluded that the environmental impact would be small owing to the relatively small amounts of bioaccumulating substances involved, and was not expected to induce any measurable effects at the regional level [5] [53].

15.6 Issues and Concerns Raised by Stakeholders

For the technically feasible options for the GBS cell contents, the main issues and concerns raised by stakeholders during the programme of stakeholder engagement were:

- The amounts and composition of sediments in the cells, and the variation between cells and between the GBSs.
- The types and amounts of contaminants in the cell water.
- Accidental discharges or releases of hydrocarbons to sea.
- Effects of eventual escape or release of cell water and cell sediment to sea.
- The application of the precautionary principle[35].
- Effects of sediment treatment operations on onshore communities.

As described in Section 10.8 we engaged with the CMSTG to better understand the views of our stakeholders on options for the management of the cell contents. The outcome of the work undertaken by the CMSTG is reported by Catalyze in the CMSTG Analysis Report [30] and summarised in Section 15.7.2, where we compare their findings with the results of our CA. The purpose of the CMSTG work was to inform our consideration of the performances of the technically feasible options for the cell contents. It was clearly understood by the CMSTG that they were not being asked to select a recommended option on our behalf.

[35] With respect to the Precautionary Principle, the 1992 Rio Declaration on Environment and Development stated *'Where there are threats of serious or irreversible environmental damage, lack of full scientific certainty shall not be used as a reason for postponing cost effective measures to prevent environmental degradation'*. Useful guidance on the application of the precautionary principle may be found in the paper *The Precautionary Principle: Policy and Application* (2015) from the United Kingdom Interdepartmental Liaison Group on Risk Assessment.

15.7 Results of Comparative Assessment of Options for the Cell Contents

15.7.1 Results of CAs

The individual results for our CAs of options for the cell contents in Bravo, Charlie and Delta are presented in detail in [15]. Table 45 to Table 47 and Figure 67 to Figure 69, below, show the results of the individual CAs for the cell contents in Bravo, Charlie and Delta respectively.

For each of the GBSs, the total weighted scores of the two 'recover' options are much lower than the total weighted scores of any of the three 'leave' options. Of the 'recover' options, Option 2 'Recover and treat onshore' has a higher total weighted score than Option 1 'Recover and Re-inject'. The three options in which the sediments may be left in the cells, with or without some form of treatment, have similar total weighted scores but Option 5 'Leave in place' clearly has a higher score than the other two. This option performs well because there are no operations and hence no operational safety or environmental risks, no technical difficulties and no costs. To a greater or lesser degree all the other options have such costs or impacts and thus exhibit lower weighted scores in these sub-criteria, but these are not offset by a commensurate increase in the weighted score for 'legacy environmental impacts'.

For each of the GBSs, the sensitivity analysis of the results shows that Option 5 'Leave in place' has the highest total weighted score in every scenario, including the scenario in which the criterion 'Economic' is removed. The results of the CAs indicate that the recommended option for the management of the cell contents is 'Leave in place'.

Table 45 Transformed and Weighted Sub-criteria Scores for the Five Options for the Brent Bravo Cell Contents.

Sub-criterion	Options				
	1	2	3	4	5
Safety risk offshore project personnel	1.49	3.89	4.49	4.21	6.66
Safety risk to other users of the sea					
Safety risk onshore project personnel	6.67	6.64	6.67	6.67	6.67
Operational environmental impacts	3.25	3.60	4.50	4.50	5.00
Legacy environmental impacts	4.65	5.00	2.05	2.20	1.50
Energy use	0.67	3.89	3.79	3.49	4.93
Emissions	1.42	4.09	4.00	3.75	4.93
Technical feasibility	0.00	4.00	14.00	18.00	20.00
Effects on commercial fisheries					
Employment	6.59	1.63	0.72	0.84	0.03
Communities	6.67	3.34	6.34	6.34	6.67
Cost	0.24	15.12	17.84	17.49	19.90
Total weighted score	**31.65**	**51.19**	**64.39**	**67.49**	**76.30**

Option1	Remove and re-inject in new remote well
Option 2	Remove and treat slurry onshore
Option 3	Leave in place capped
Option 4	Leave in place with MNA
Option 5	Leave in place

Figure 67 The Total Weighted Scores for Options for the Brent Bravo Cell Contents, and the Contributions of the Sub-criteria.

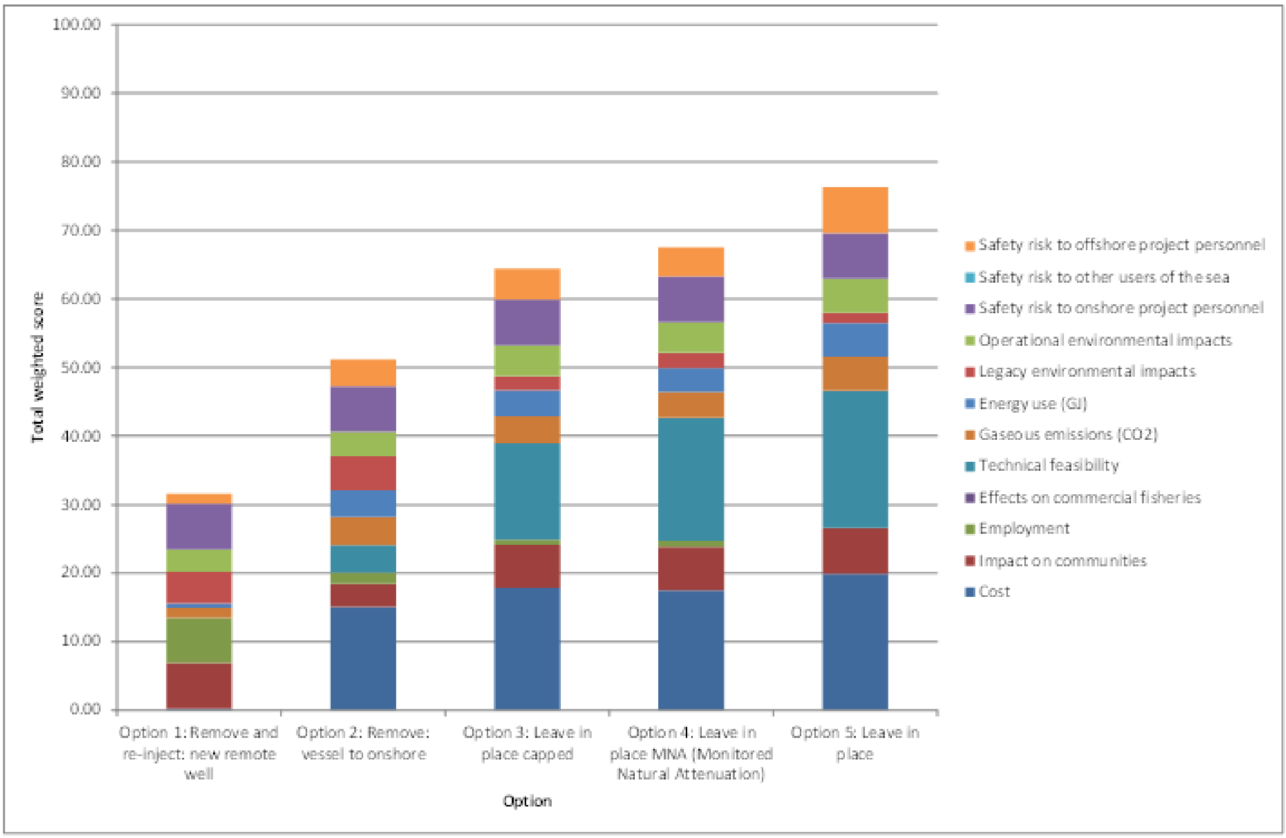


Table 46 Transformed and Weighted Sub-criteria Scores for the Five Options for the Brent Charlie Cell Contents.

Sub-criterion	Options				
	1	2	3	4	5
Safety risk offshore project personnel	0.61	4.70	5.04	4.88	6.66
Safety risk to other users of the sea					
Safety risk onshore project personnel	6.67	6.66	6.67	6.67	6.67
Operational environmental impacts	3.25	3.95	4.50	4.50	5.00
Legacy environmental impacts	4.75	5.00	2.90	3.00	2.50
Energy use	1.54	4.24	4.07	3.89	4.93
Emissions	2.14	4.38	4.24	4.09	4.94
Technical feasibility	0.00	4.00	14.00	18.00	20.00
Effects on commercial fisheries					
Employment	5.66	1.16	0.55	0.61	0.03
Communities	6.67	4.67	6.60	6.60	6.67
Cost	3.04	16.52	18.35	18.16	19.90
Total weighted score	34.32	55.28	66.92	70.40	77.31

Option1	Remove and re-inject in new remote well
Option 2	Remove and treat slurry onshore
Option 3	Leave in place capped
Option 4	Leave in place with MNA
Option 5	Leave in place

Figure 68 The Total Weighted Scores for Options for the Brent Charlie Cell Contents, and the Contributions of the Sub-criteria.

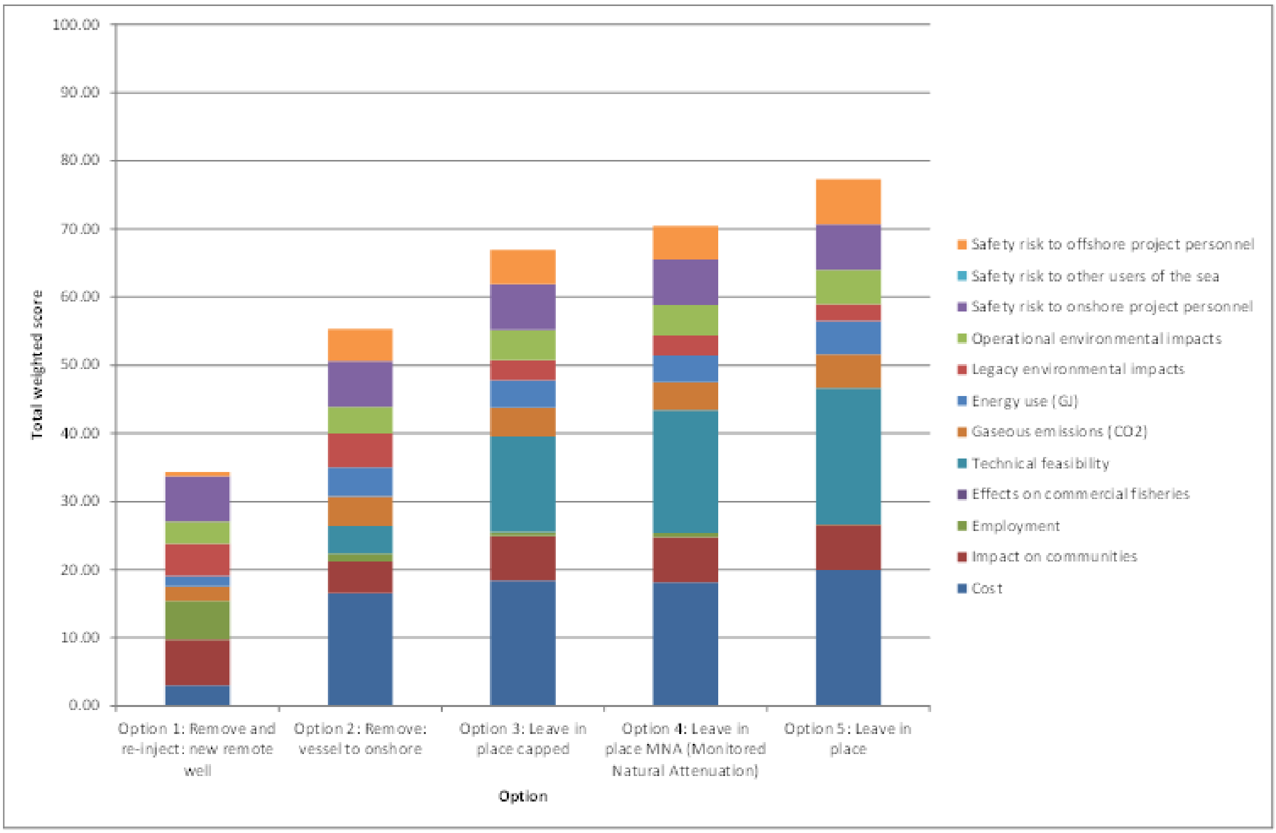
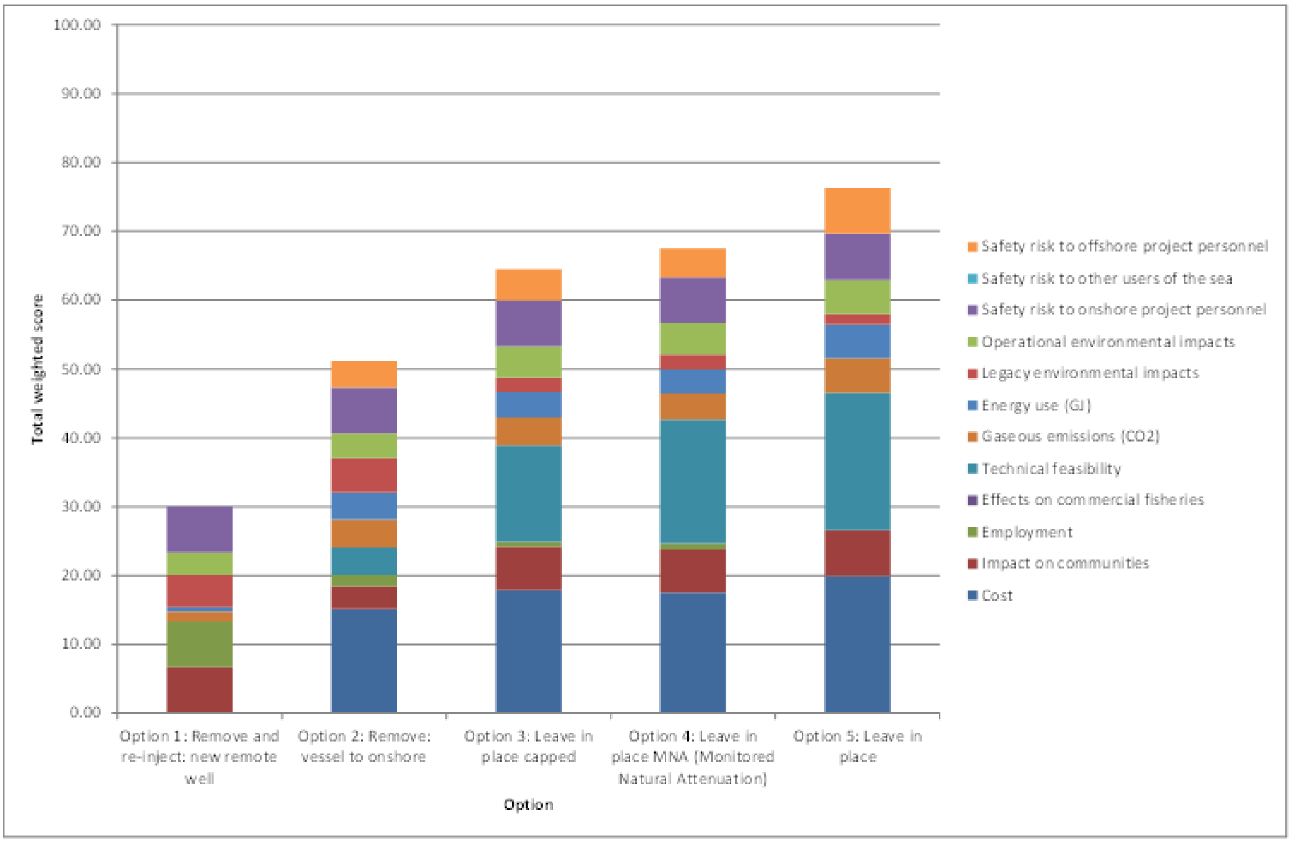


Table 47 Transformed and Weighted Sub-criteria Scores for the Five Options for the Brent Delta Cell Contents.

Sub-criterion	Options				
	1	2	3	4	5
Safety risk offshore project personnel	0.00	3.89	4.50	4.21	6.66
Safety risk to other users of the sea					
Safety risk onshore project personnel	6.67	6.64	6.67	6.67	6.67
Operational environmental impacts	3.25	3.60	4.50	4.50	5.00
Legacy environmental impacts	4.65	5.00	2.05	2.20	1.50
Energy use	0.66	3.89	3.81	3.49	4.93
Emissions	1.42	4.09	4.01	3.76	4.93
Technical feasibility	0.00	4.00	14.00	18.00	20.00
Effects on commercial fisheries					
Employment	6.67	1.63	0.71	0.83	0.03
Communities	6.67	3.34	6.34	6.34	6.67
Cost	0.00	15.12	17.86	17.50	19.90
Total weighted score	29.00	51.19	64.45	67.51	76.30

Option1	Remove and re-inject in new remote well
Option 2	Remove and treat slurry onshore
Option 3	Leave in place capped
Option 4	Leave in place with MNA
Option 5	Leave in place

Figure 69 The Total Weighted Scores for Options for the Brent Delta Cell Contents, and the Contributions of the Sub-criteria.



15.7.2 Comparison with the CMSTG Results

CMSTG criteria: The CMSTG identified a large number of criteria that they wanted to take into consideration when assessing the relative advantages and disadvantages of the different options for the cell contents. They assessed the performance of each option in each criterion and used the MCDA model facilitated by Catalyse to examine the overall performance of each option. Although the CMSTG identified 33 individual criteria, the weighting they subsequently applied showed that only 2 were accorded weights of more than 10% and only 7 were accorded weights of more than 5% (Figure 70). Consequently, it was these 7 criteria (Table 48) that ultimately determined the final results of the assessment by the CMSTG. The results of the work undertaken by the CMSTG are presented in [30] and discussed in Section 15.7.2. We shared the results of our CSP with the CMSTG, and in November 2015 had a final meeting with them to discuss the implications of the CSP results for the CMSTG modelling, as reported by R4C in *Cell Management Stakeholder Task Group (CMSTG) Plenary Session 27 November 2015, Summary Report* [54].

Figure 70 Weightings Given by the CMSTG to Criteria for Assessment of Cell Sediment Options.

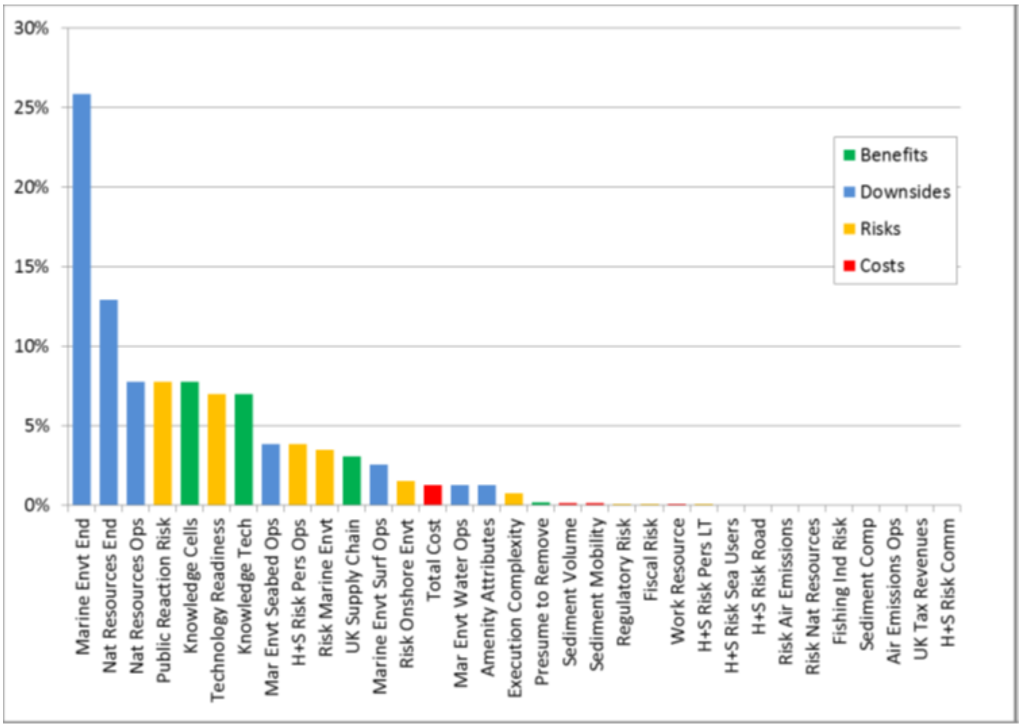
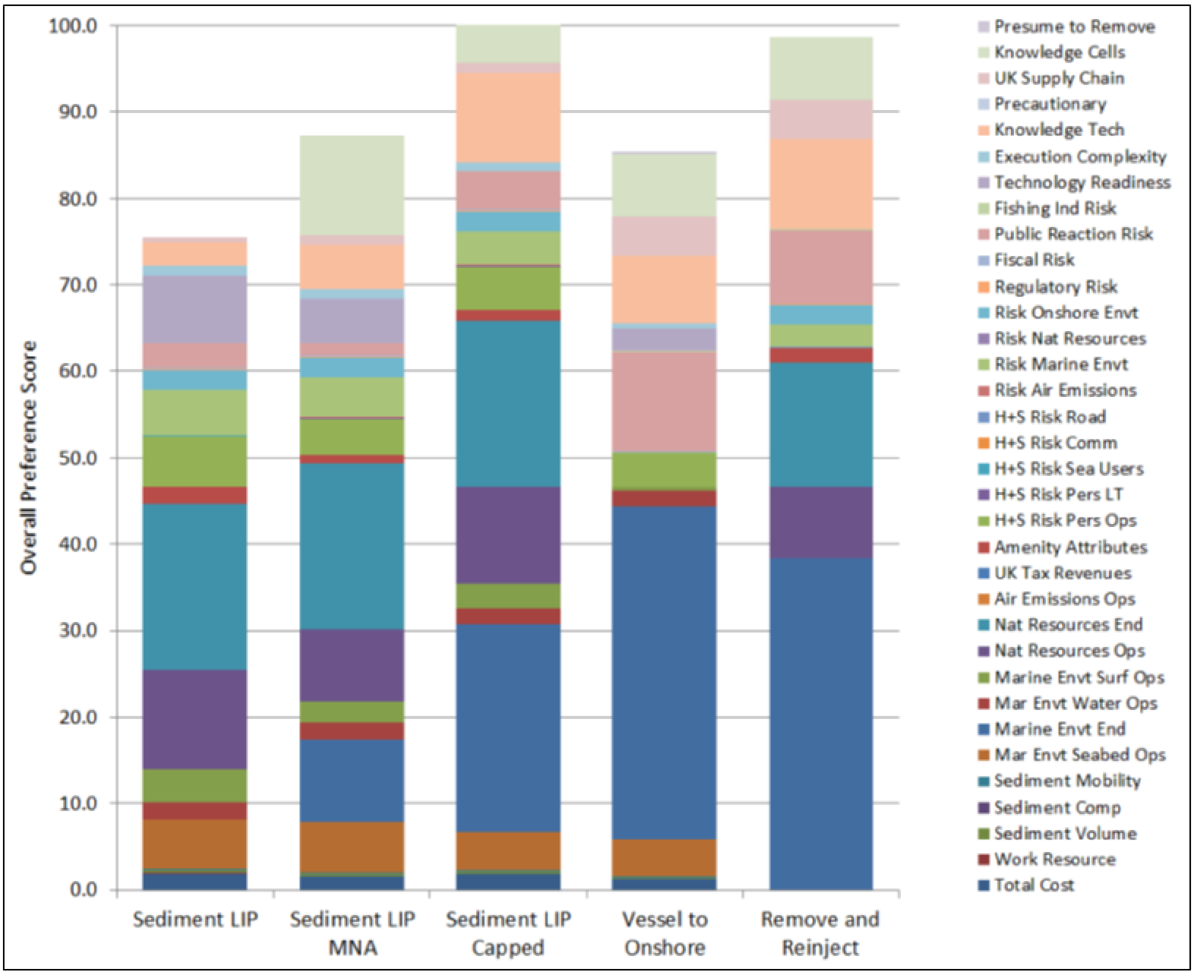


Table 48 Definition of Top Seven Criteria Weighted by the CMSTG.

CMSTG Criterion Name	Definition
Marine environment end-point	The extent to which an option will change the environment in which it takes place as a result of the planned end-points or legacy effects of cell remediation activities.
Natural resources end-point	The extent to which an option uses natural resources after decommissioning activities have been completed.
Natural resources operations	The extent to which an option uses natural resources as a result of planned activities.
Public reaction risk	The extent to which an option has the potential to generate a measurable/demonstrable negative reaction with the public, stakeholders or media.
Knowledge cells	The extent to which an option contributes to the creation of valuable knowledge about the cell content for the oil and gas industry (including Shell and Esso) and society.
Technology readiness	The relative risk posed to a successful operation by the availability and maturity of the critical technology used by the option.
Knowledge technology	The extent to which an option contributes to the creation of valuable knowledge of new exploitable technology and processes for the oil and gas industry (including Shell and Esso) and society.

Figure 71 Results of the comparative assessment performed by the CMSTG.



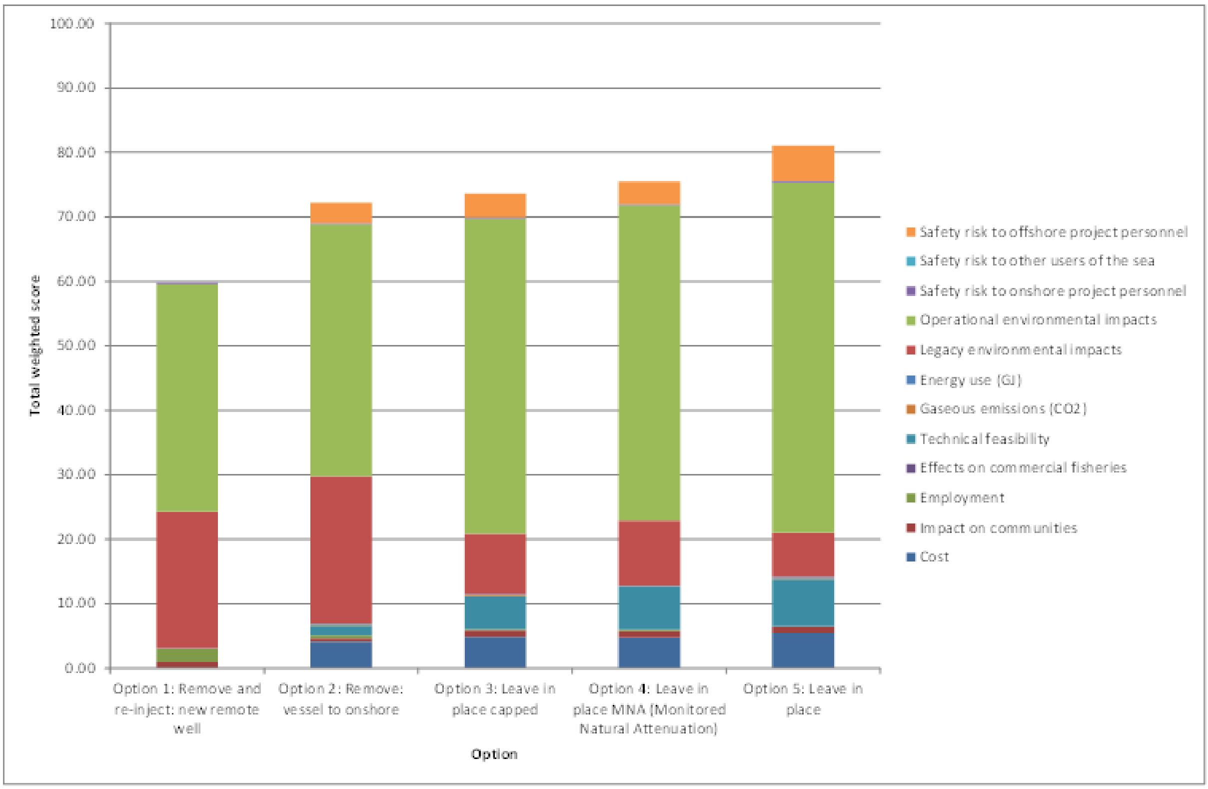
Shell CA criteria: The results of the three individual CAs that we performed for the cell contents in Bravo, Charlie and Delta are different to the result of the single CA performed by the CMSTG using their model, as reported in the GBS Contents TD [15] and shown in Figure 71. That exercise suggested that the preferred option was our Option 3 'Leave in place capped', and that our Option 5 'Leave in place' was the least preferred. It is noted, however, that in the CMSTG Analysis Report [30], Catalyze make this comment in the Executive Summary:

> *'The most significant criteria in the model favour different options, i.e. they pull in different directions. Also, as one of the CMSTG members noted in the final workshop, none of the effects modelled are very significant; the risks and impacts evaluated in the model are all relatively small. The net effect is that when the 'pros and cons' are aggregated there is little to choose between the options. The resulting model is finely balanced and sensitive to changes in criteria weight; however it also represents wealth of information and judgement. This report aims to explore and explain that information to support Shell's comparative assessment process.'*

The model created by the CMSTG used 33 sub-criteria (Section 15.6) and only considered raw data from the options to manage the Delta GBS cell contents, not the raw data scales we created covering all options for all facilities (described in Section 8.5). One notable feature of the CMSTG model was the very considerable weighting the CMSTG gave to their sub-criterion 'marine environment end-points' (that is '*the extent to which an option will change the environment in which it takes place as a result of the planned end-points or legacy effects of cell remediation activities*'. We do not give such a high weighting to the global scale of our equivalent sub-criterion 'legacy environmental impacts'. However, we did apply a sensitivity scenario to 'environmental'.

As discussed in our CA procedure [12], we performed an exploratory CA using *our* data and *the CMSTG weightings* (applying their 33 sub-criteria as closely as possible to our 12 sub-criteria). The results showed that in these circumstances the CA-recommended option was our Option 5 'Leave in place', driven to a large extent by its good performance in 'operational environmental impacts' (Figure 72). At the final CMSTG meeting reported by R4C [54], our CA process and our results for the GBS Cell contents CAs were presented in detail to the members, who were satisfied with the process and science.

Figure 72 Results of CA of Options for Management of the Brent Delta GBS Cell Contents using the CMSTG-Derived Weights.



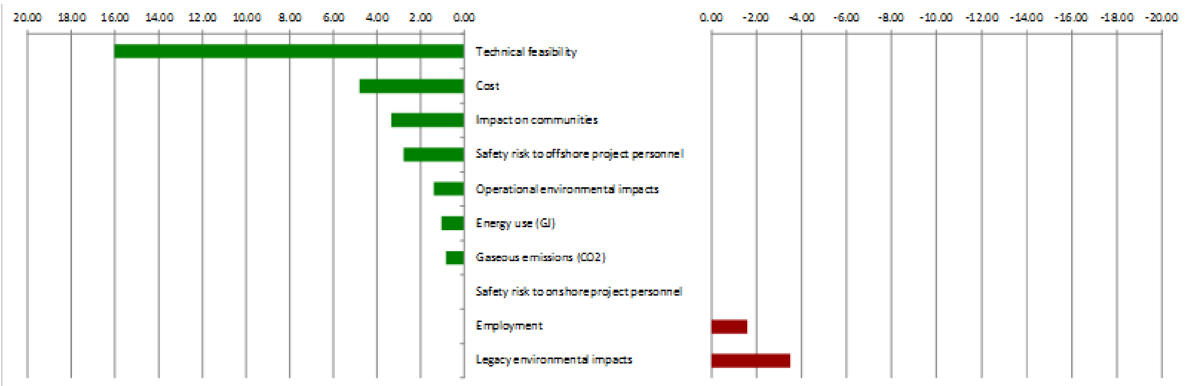
15.8 Discussion of the Comparative Assessments for the Cell Contents

Option 1 'Remove and re-inject in new remote well' and Option 2 'Remove and treat slurry onshore' would both result in the removal of the cell sediment from its present location at the bottom of the former oil storage cells of the GBS, and thus prevent the eventual exposure of the sediment (and the oily water above it) to the marine environment. Option 2 is the better of the 'removal' options.

Option 5 'Leave in place' is consistently the best option with a total weighted score that is greater than the next best option (Option 4 'Leave in place with MNA'). Option 5's total weighted score is significantly and consistently greater than that of the better of the 'removal' options, Option 2. The sections below therefore examine the differences between Option 2 'Remove and treat slurry onshore' (the better of the 'removal' options) and the emerging recommendation, Option 5 'Leave in place'.

Examination of both the transformed unweighted data and the weighted scores for each of the sub-criteria shows that for the cell contents of each GBS the differences between the two options are driven by the differences in performance in '**technical feasibility**', '**cost**', '**impact on communities**' and '**safety risk to offshore project personnel**' (which are better in Option 5 'Leave in place') and in '**employment**', and '**legacy environmental impacts**' (which are better in Option 2 'Remove and treat slurry onshore'). All the other sub-criteria show only small differences between the options in terms of their weighted scores. This is illustrated in Figure 73 to Figure 75 which show the differences (positive or negative) in the weighted scores in each sub-criterion for these two options for the cell contents in Brent Bravo, Brent Charlie and Brent Delta respectively; the green bars indicate sub-criteria where Option 5 has the better performance and the red bars indicate sub-criteria where Option 2 has the better performance.

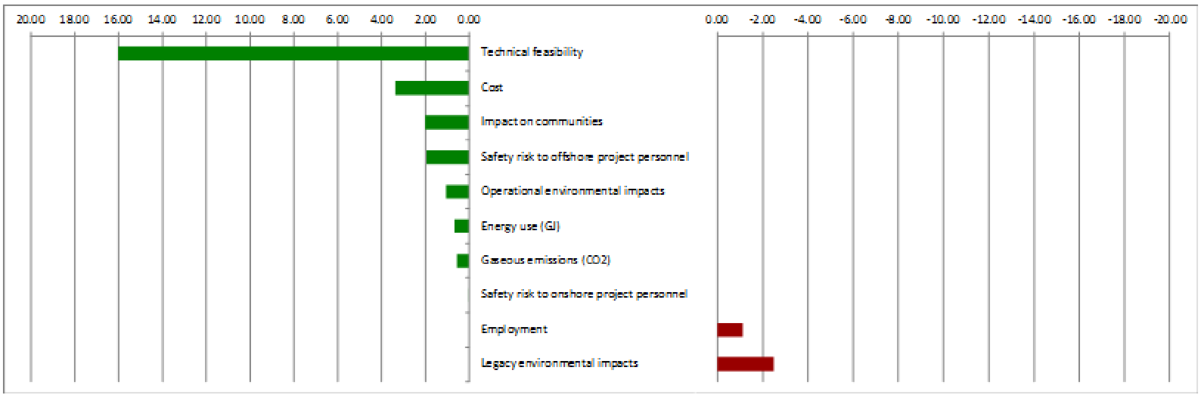
Figure 73 Difference Chart Comparing the Weighted Scores for each Sub-criterion in Two Options for the Management of the Brent Bravo Cell Contents, under the Standard Weighting.



Green bars: Option 5 'Leave in place' is better than Option 2 'Remove and treat slurry onshore'

Red bars: Option 2 'Remove and treat slurry onshore' is better than Option 5 'Leave in place'

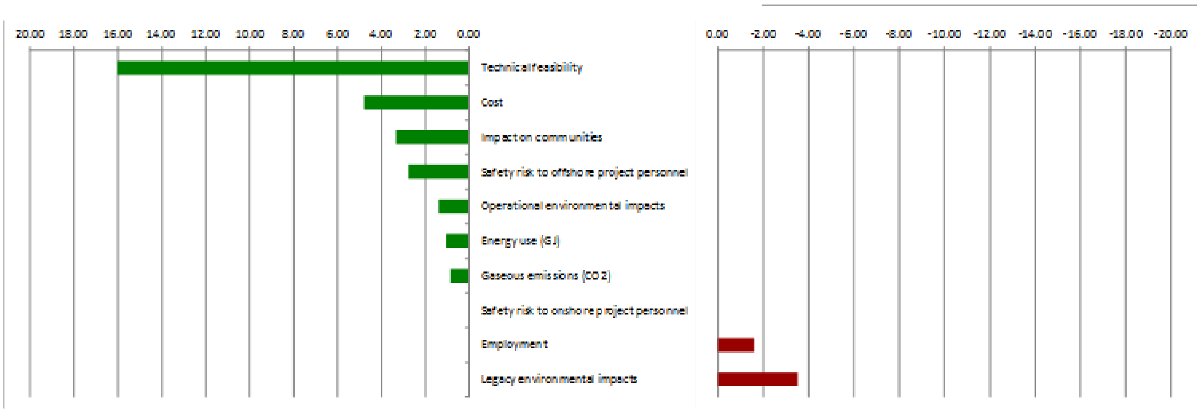
Figure 74 Difference Chart Comparing the Weighted Scores for each Sub-criterion in Two Options for the Management of the Brent Charlie Cell Contents, under the Standard Weighting.



Green bars: Option 5 'Leave in place' is better than Option 2 'Remove and treat slurry onshore'

Red bars: Option 2 'Remove and treat slurry onshore' is better than Option 5 'Leave in place'

Figure 75 Difference Chart Comparing the Weighted Scores for each Sub-criterion in Two Options for the Management of the Brent Delta Cell Contents, under the Standard Weighting.



Green bars: Option 5 'Leave in place' is better than Option 2 'Remove and treat slurry onshore'

Red bars: Option 2 'Remove and treat slurry onshore' is better than Option 5 'Leave in place'

The drivers and trade-offs for the decommissioning of the Brent GBS cell contents involve a consideration of how feasible and safe it would be to remove the cell sediments (as a slurry mixed with the oily water phase), and how proportionate this would be in relation to the elimination of a localised but low-level and long-term impact to the marine ecosystem that might otherwise occur after 200-500 years when the cell contents are exposed following the collapse of the cell domes and then the cell walls.

We engaged BMT to model how exposed sediment might spread on the seabed and leach into the water column, and thus calculate the likely concentrations of the various contaminants from the cell sediments in the seabed and water column. The modelling was conducted using assumptions that were intended to be conservative, in particular the assumption that the volumes of sediment chosen for modelling would be instantaneously and completely exposed on the seabed with no protection or partial shielding from the remains of the GBS cells or debris from the partially collapsed GBSs. We then engaged DNV GL to assess what the likely impacts might be in the environment, using these data on concentration gradients and durations of exposure and published data on the concentrations of substances that are known to cause impacts to various trophic levels.

The modelling by BMT [52] showed that the escape of cell water would lead to an increase in the concentrations of hydrocarbons and other contaminants in the water. Depending on the volumes released and the durations of such releases, elevated concentrations might be found up to 17 km from the GBS. Given the energetic offshore environment, however, and the effects of mixing and dilution, such elevated concentrations would be relatively short-lived. As described more fully in Section 15.12, the sediment footprint of concern (where the PEC:PNEC[36] is >1) is not predicted to travel more than 2 km from the platform. The edge of the re-deposited pile of sediment will be quite thin, and this will enable quick recovery through biodegradation. Over a long period of time this might lead to an increase in the concentrations of hydrocarbons and other contaminants in the seabed sediments adjacent to the GBSs.

In their report assessing the impact of cell contents on the marine environment [53], DNV GL determined that the short-term exposure of marine organisms to elevated concentrations of contaminants (most notably dissolved hydrogen sulphide (H_2S)) from the release of cell water would not cause significant environmental impacts. It is most likely that any impacts would be acute but transient (3 to 5 days) effects, and would cease as the water phase was further diluted by spreading. Likewise, DNV GL concluded that, overall, the exposure of cell sediments would only cause small, localised environmental impacts.

Following our examination of the real data informing the CA scores, we have therefore concluded that the sub-criteria that serve to strongly differentiate the options are '**technical feasibility**', '**cost**', '**impact on communities**', and, to a lesser extent '**safety risk to project personnel offshore**', and these are the significant reasons why 'leave in place' is preferable to 'remove and treat slurry onshore'. The CA has shown that the technical difficulties and cost associated with the removal of the sediment would be disproportionate to the benefit of eliminating the legacy environmental impact and supporting employment.

15.9 Conclusion of Assessments for the Cell Contents

We have found that the volumes of sediment in the three Delta oil storage cells that have been sampled are very similar to the estimates we derived from desk-top studies and available data, and that the concentrations of contaminants are within the ranges we predicted from our analysis of analogous samples. Engineering studies (summarised in the GBS TD [14]) have suggested that the GBS cells themselves are likely to remain intact for at least 250 years, and then gradually fail and collapse over a period of perhaps 250-1,000 years. Debris falling from the degrading legs, and larger sections of collapsing legs are, however, likely to breach the cell domes within the first 250 years. This would allow the water phase to escape to sea where it would quickly disperse. During the collapse of the cell domes and the upper parts of the cell walls, the containment of the cell sediment will be breached and the sediment will be exposed to the marine environment. If large pieces of concrete were to fall directly onto the sediment, a proportion of the sediment could be re-suspended in the water column and re-settle on the adjacent seabed. The edge of the re-deposited pile of sediment will be thin and this will enable quick recovery through biodegradation. Later, as the cell domes collapse, the remaining volume of oily water will be released to sea where it will quickly disperse. When the collapse has reached its final stages, the cell sediment is likely to remain partially shielded by the concrete remains of the structure. At that point, biodegradation and erosion will take place at the surface of the sediment exposed to the marine environment. The exposure pathway between the cell sediment and the open sea would thus be partial and restricted, and the amounts of material that would be removed by natural forces each year would be small.

Modelling, using data that were intended to be conservative, has shown that any undisturbed exposed cell sediments would disperse very slowly into the marine environment. It is predicted that after 1,000 years, the sediment footprint of concern would have spread no more than 2 km from a platform. If the biodegradation

[36] PEC, Predicted Environmental Concentration: PNEC, Predicted No-Effects Concentration. When the ratio of PEC and PNEC (often referred to as the PEC:PNEC ratio or the RCR – Risk Characterisation Ratio) exceeds one, biological organisms may experience an effect as a result of exposure to the specific chemical. The PEC:PNEC Ratio (or RCR) is just an indication of the likelihood and not a quantification of the environmental risk.

of organic compounds is taken into account, however, the 'footprint' of effect on the seabed would be significantly smaller. Overall, DNV GL concludes that the environmental impact of sediment exposure would be small, owing to the relatively small amounts of bioaccumulating substances involved, and is not expected to induce any measurable effects at the regional level..

If the cell sediments were to be removed, this would require the handling and pumping of considerable volumes of slurry from the cells to a support vessel and then by floating hose to a tanker and then from the tanker to the shore. The slurry would be stored then dewatered onshore, with the bulk of the water being treated and discharged back to sea. The sediments would be treated by LTD to remove the oil in a programme of work that, overall, would require much more energy than would be recovered or 'saved' by the recycling of the oil. The residual inert solids would be disposed of to landfill.

We have concluded that the potential small and localised impacts from the eventual release and then exposure of the cell contents are within the assimilative capacity of the offshore environment of the northern North Sea. The GBSs will continue to provide physical containment and protection to the cell contents as the legs and caisson slowly degrade. Once failures and collapses begin, the GBSs will continue to provide partial protection and shielding to the cell sediments. It is therefore unlikely that the cell sediments would ever be fully exposed on the seabed. Even after the complete degradation of the GBSs, leaving essentially concrete rubble on the seabed after the steel reinforcing has corroded away, it is not likely that the cell sediments will spread quickly or far because of their physiochemical characteristics.

15.10 Recommended Options for the GBS Cell Contents

The detailed CA of feasible options (Section 15.7 and Section 15.8), carried out in accordance with OSPAR's requirements [2], and using the selection criteria and matters to be considered set out in Annex 2 of that Decision, has indicated that the recommended options for the GBS cell contents (after removal of the attic oil and interphase material if present) are as follows:

- Brent Bravo GBS Cell Contents: 'Leave in place'
- Brent Charlie GBS Cell Contents: 'Leave in place'
- Brent Delta GBS Cell Contents: 'Leave in place'

15.11 Recommended Programme of Work for Decommissioning the GBS Cell Contents

15.11.1 Introduction

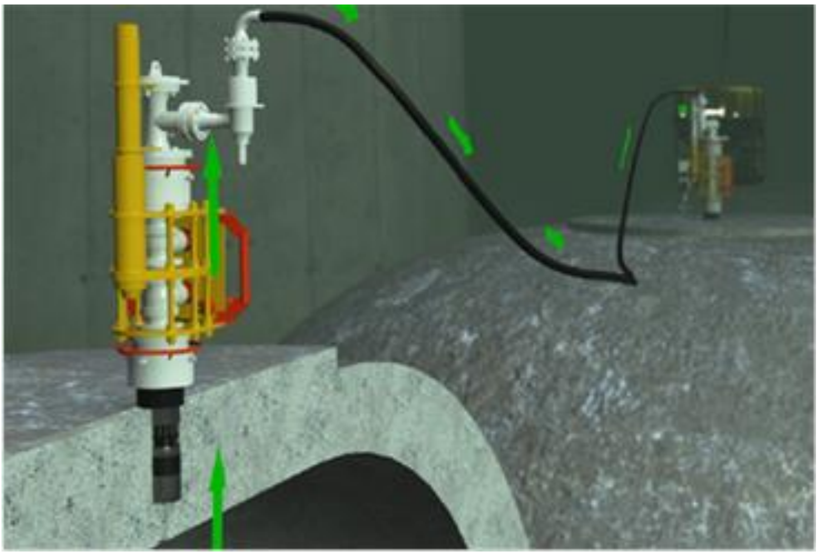
After completing individual CAs we have determined that the recommended option for managing the cell contents is the same for each of the GBSs. Although there are differences between the GBSs themselves and the volumes of sediment in their cells, the management programme that we will undertake is broadly the same for all three installations. The sections below describe our proposed programme to manage the GBS cell contents.

15.11.2 Removal of Attic Oil and Interphase Material

We have designed a programme of work to access every oil storage cell on Delta and move the attic oil and interphase material to a single designated holding cell. To permit these operations, a small amount of drill cuttings and some debris has been cleared from the cell caps (Section 9) to give a clear and safe working surface for divers and ROVs. The attic oil is being accessed by drilling a 3½ inch diameter hole through the cell cap, and then removed by fitting a valve and pumping material from the cell through a hose to the holding cell (Figure 76); the extracted fluids are replaced with seawater. This programme of work has started and will be completed after the Delta topside has been removed; the remaining cells will be accessed in a similar manner to transfer their oil and/or interphase content into the holding cell. At some time in the future all the material gathered in the Delta holding cell will be pumped to a tanker and taken ashore for recycling and disposal.

A similar programme of work will be performed on the Brent Charlie storage cells after CoP, unless it is possible to recover the attic oil and interphase material through the existing 2" vent lines. There is evidence of the presence of interphase material on Brent Bravo and it is our intention to verify this on every cell by means of subsea intervention, and remove any material found.

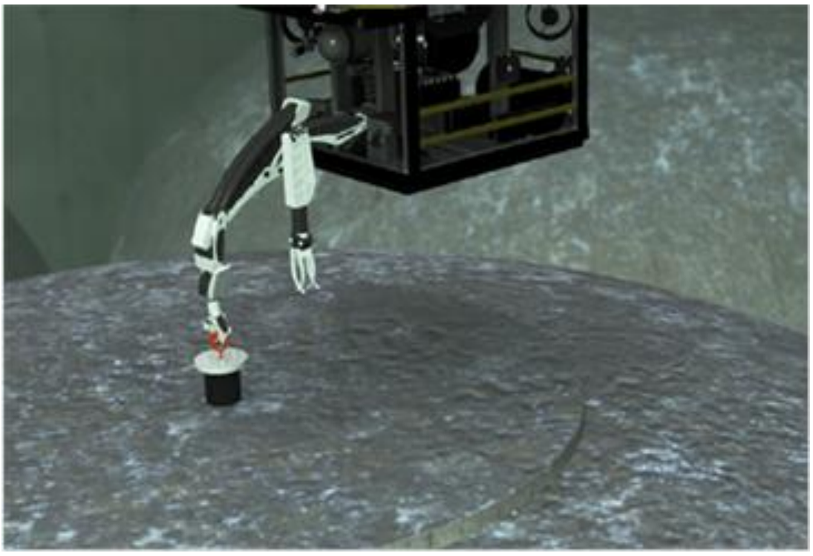
Figure 76 Accessing a GBS Cell to Attic Oil and Interphase Material.



15.11.3 Management of Remaining Cell Contents

After the removal of the attic oil and interphase material, the holes in the cell domes will be plugged and the cells, containing the existing oily water, will be left sealed (Figure 77). The long-term monitoring programme for the GBSs is described in Section 24.

Figure 77 Installing the Debris Cap on an Oil Storage Cell after Removal of Attic Oil.



15.11.4 Material Retrieved and Material Left in Place

Figure 78 shows the state of the contents of a typical oil storage cell (in this case on Brent Delta) after the removal of the attic oil. Table 49 shows the approximate amounts of material that would be removed or left in place on completion of these programmes of work at Bravo, Charlie and Delta.

Figure 78 State of a Typical Oil Storage Cell on Completion of the Proposed Decommissioning Operations.

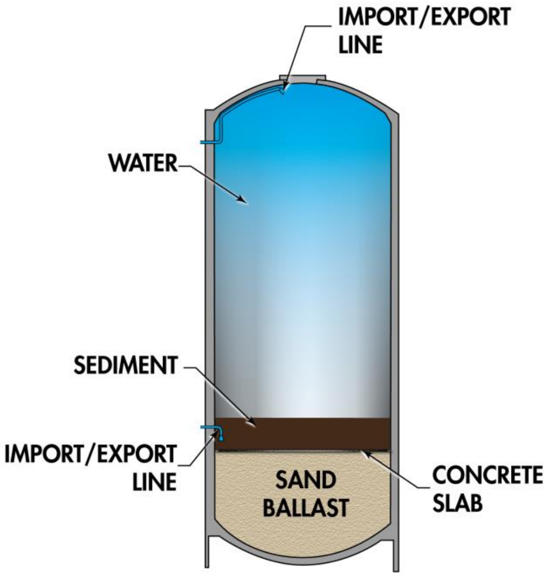


Table 49 Estimated Amounts of Material Retrieved and Left in Place on Completion of the Proposed Decommissioning Programmes for the Cell Contents on Bravo, Charlie and Delta.

Material (m^3)	Bravo		Charlie		Delta	
	Before	After	Before	After	Before	After
Attic oil	0	0	11,116[37]	0	800	0
Interphase material	ND	0	ND	0	ND	0
Water	163,840	163,840	311,667	311,667	163,040	163,040
Sediment	17,280	17,280	6,035	6,035	17,280	17,280

ND = No data

15.11.5 Long-term Degradation of Cell Contents

The concrete GBS cells themselves are expected to degrade only very slowly as a result of the gradual ingress of water into the concrete and the subsequent corrosion of steel reinforcing, which will thus expand and begin to crack the concrete [14]. Before the cells are breached by natural degradation processes, however, the concrete on the legs may flake or the legs may partially or completely fail, and the cell domes may be cracked, pierced or even demolished by falling debris. It is therefore possible that pathways may be created whereby the cell contents (particularly the water phase) may be exposed to or released into the marine environment. Since the pressure and temperature of the water inside the cells will be the same as that of the surrounding seawater[38], there will be few forces driving cell fluids out into the sea, other than perhaps

[37] This is our estimate of the minimum volume of attic oil, if it is only present in the oil storage cells. As described in the GBS Contents TD [15] we estimate that the total volume of residual attic oil in the Brent Charlie GBS is between 6,000 m^3 and 12,000 m^3 depending on how much oil might be present in the peripheral and/or the conductor cells.

[38] Drawdown will cease when the topsides are removed.

the buoyancy resulting from the presence of a small amount of oil in suspension in the cell water. It is therefore possible that small volumes of oily cell water will be released into the sea over a long period of time as cracks develop or as cell domes are punctured by falling debris. Small amounts of oil in the water column will be quickly dispersed by currents and wave action, and will not cause any environmental impact.

Unless damaged by a powerful impact from a vessel collision, best assessments suggest that the legs will fail in perhaps 150-250 years. We have investigated various scenarios in which one or more legs on one or more of the GBSs collapses across the top of the GBS caisson, resulting in the complete or partial breaching of several cells. Such an event would result in the release, over a very short period of time, of all the oily water in those cells that were broken or breached, the possible ejection of some sediment, and the partial exposure of all the sediment to the marine environment. The most likely scenario is that the legs will be weakened and degrade at or around sea level, and that the upper part of the leg will fall onto the caisson below.

As described in Section 14.17.1 we propose to undertake a rolling programme to update the assessment of the future safety risk to other users of the sea. This will provide refreshed data with which to determine the likelihood of a vessel colliding with any of the GBSs, and will include information from periodic offshore structural surveys. Even after being breached, however, the damaged but largely intact cell walls are likely to offer considerable protection to the cell sediment from the forces of currents and wave action, and are therefore expected to contain this material to a greater or lesser extent for many years after.

15.12 Environmental Impacts of Decommissioning the GBS Cell Contents

15.12.1 Stakeholder Environmental Concerns

For the recommended option for the GBS cell contents, the specific environmental concerns or issues raised by our stakeholders were:

- The need to remove the attic oil and the interphase material.
- Impacts on water column and benthos of eventual release/exposure of cell water and cell sediment.
- Potential toxic effects of such releases on commercially-caught fish.
- The need to monitor the cells and their contents as the GBSs slowly degrade.
- The potential difficulties of carrying out any remediation, especially as the cells and legs degrade or are damaged.

15.12.2 Potentially Significant Impacts in ES

Figure 79 presents DNV GL's summary of the results of the environmental impact assessment of the programme of work that would be carried out to remove attic oil, where present, on all three GBSs. Figure 80 presents their summary of the results of the environmental impact assessment of leaving the water phase and the cell sediment in place untreated, and of the possible long-term effects of the presence of sediments in all three GBSs [5].

The most significant impacts of operations in this activity were from the underwater noise, risk of accidents and energy use of operations to remove attic oil and interphase material, which were all assessed as 'small negative'. There was also a 'small-moderate' positive impact from the treatment and recycling of these oily materials. The most significant legacy impact was from the eventual exposure and release of cell contents which was assessed as 'moderate negative'.

Figure 79 Environmental Impacts Associated with the Removal of Attic Oil and Interphase Material from the Oil Storage Cells on all Three Brent GBSs.

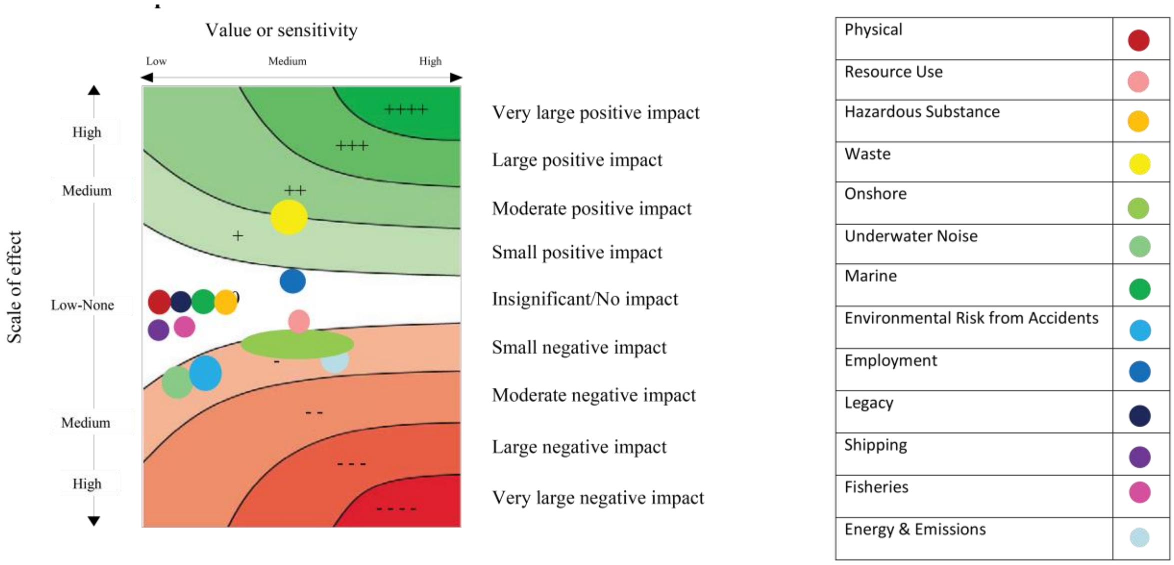
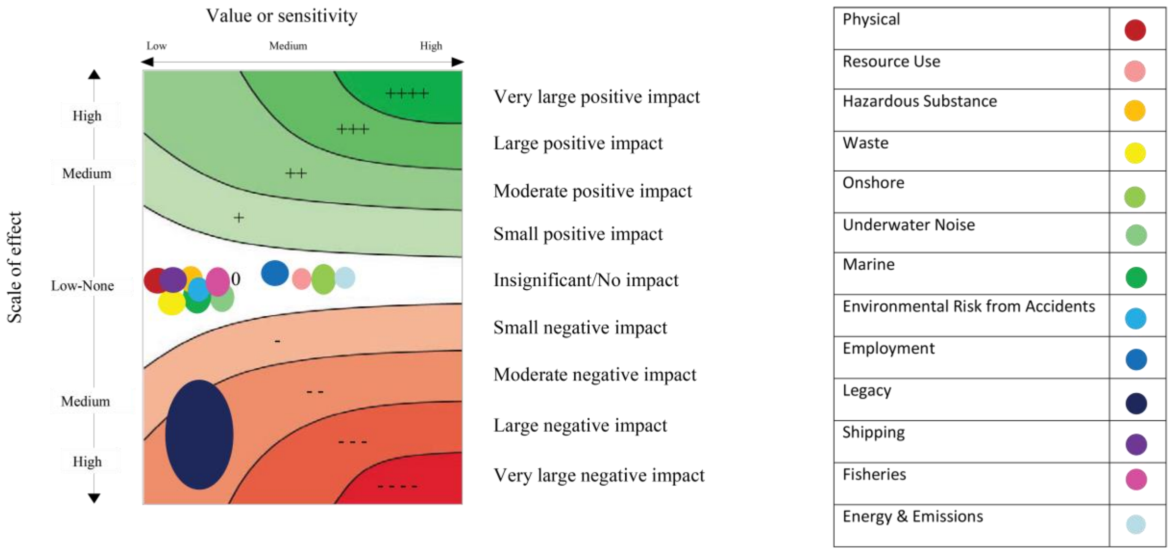


Figure 80 Environmental Impacts Associated with Option 5 'Leave in Place' for Decommissioning the Contents of the Oil Storage Cells on all Three Brent GBSs.



15.12.3 Impacts of Offshore and Onshore Operations

All the operational environmental impacts are associated with the removal and recycling of the attic oil and interphase material. The processing of this material would be identical to existing operations. As shown in Figure 79, the most significant impact identified is a 'small-moderate positive' effect as result of the recovery and recycling of an estimated 12,000-14,000 m^3 of attic oil and interphase material. The impacts for all other categories were estimated to be 'small negative' or 'insignificant'.

15.12.4 Legacy Environmental Impacts

All the legacy impacts are associated with the eventual exposure or release of cell contents into the marine environment as the GBSs degrade and collapse. The ES found that the most significant impact from the proposed option 'leave in place' was the legacy environmental impact from the eventual release of the cell water and then exposure of the cell sediment, which was estimated to be 'moderate negative'.

To assess the potential impacts of the inevitable collapse of the legs we modelled various release or exposure scenarios, and used what was intended to be a conservative assumption that all the water phase and all the cell sediment in the affected cells would be exposed completely and instantaneously to the marine environment by this event. For the cell water, our worst-case scenario was that a leg, falling across a caisson, would breach 10 of the former storage cells and this would result in the rapid release of approximately 101,900 m^3 of oily water. For the cell sediments, we examined several hypothetical situations in which a proportion of the sediments in the cells would somehow be instantaneously and fully exposed on the seabed. For our worst case, we examined the effects of the exposure of 12,960 m^3 of sediment (as a result of the simultaneous exposure of the contents of 12 cells, from one or more GBSs) which had a THC which was approximately twice the THC measured in the samples from the Brent Delta cells. These are clearly extreme scenarios; in particular, although a cell dome may fail or collapse, this does not mean that all of the cell sediment would be completely exposed. Nonetheless this is the scenario modelled by BMT and assessed by DNV GL [53] and [5], to give a view as to the possible magnitude and severity of the eventual release and exposure of the materials in the oil storage cells.

Modelling of these unlikely scenarios shows that the pelagic ecosystem exposed to the cell water phase could experience elevated concentrations of some contaminants for periods of hours to days, and that such elevated concentrations could extend up to 17 km from the GBS. In the event that all three GBS were to fail at the same time there might be some, very limited, overlap of the plume of contamination, leading to a localised increase in the concentrations of contaminants. In their report assessing the impact of the exposure of cell contents to the marine environment [53] DNV GL states:

> 'In summary, DNV GL considers the predicted environmental impact following a worst-case release of 101,900 m^3contaminated cell water[39] to be limited to significant transient effects close to the release point. Such effects would not be measurable on the regional level of water column resources. The size of the impacted area is not large enough to be measurable on the regional level of water column resources'.

Given the characteristics of the cell sediment (15.2), modelling shows that any exposed 'mound' of material would erode only very slowly under the generally low seabed currents at a depth of 140 m in this part of the North Sea. Natural forces of current and wave action will have very little effect on the sediment, which would persist for many centuries. For a worst case modelled scenario, the release of 12,960m^3 of sediment with a THC that is 33% greater than the maximum THC found in the Brent Delta cell samples from the CSP, DNV GL [53] states that:

> 'Modelling results predict the highest impact related to a worst case cell sediment release comes from the hydrocarbons (THC, naphthalene, phenanthrene and benzo[a]pyrene), with predicted impact areas ranging between 0.6-1.7 km^2.
>
> Worst case results are for phenanthrene. The chemically-impacted seabed area as a result of a worst case release event is predicted to be a maximum area of 1.7 km^2 and to extend to a maximum distance of up to 2 km from the platform after 10 years after release (without considering biodegradation).
>
> Released sediments exceeding a thickness of 1 cm are predicted only for a small distance (36 m from release point after 10 years. Although the modelling has not included biodegradation (and consequently the impacted area continues to grow over the entire modelling period of 1,000 years), in reality the biodegradation rates of most of the hydrocarbons released are expected to be relatively quick based on the modelled prediction that the cell sediment would form thin layers (<1 cm) on the seabed. It is estimated that the advancing front of hydrocarbon-contaminated sediments with time, due to the erosion effect, would be counteracted by biodegradation and consequently the impacted area would not expand significantly with time.

[39] The volume of 101,900m^3 is the volume of water phase that would be released from 10 oil storage cells in total.

For more complex hydrocarbons (particularly benzo[a]pyrene, biodegradation would be slow, and possibly take decades before non-toxic sediment concentrations are achieved. The impacted seabed area (0.6 km^2 after 10 years) is nevertheless too small to have an effect in the regional benthic fauna.

A potential concern from cell sediment release is from bioaccumulating and prioritized substances (substances that might merit action under OSPAR due to their persistency, potential to bioaccumulate and toxicity) which may give rise to delayed toxic effects in higher trophic levels. The major portion of released mercury would accumulate in sediments where it would become susceptible to methylation and subsequent release to the water column. The rate of methylmercury release has not been modelled, however the released amount of mercury (261 kg in a worst case scenario) is not considered sufficient to have any measurable effects in higher trophic levels including humans. Benzo[a]pyrene is modelled to be released in significant amounts in a worst case scenario (10.7 tonnes); however metabolism of this substance in vertebrates such as fish would hinder bioaccumulation in higher trophic levels. Furthermore, benzo[a]pyrene has limited mobility and would largely remain adsorbed to the seabed sediments.

When considering both the potential water and sediment release, DNV GL presented the following conclusion in the ES regarding the legacy impacts of the cell contents [5]:

'A combined release of cell water and sediment would not significantly alter the total risk from the assessed substances. The amount of bioaccumulating and persistent substances released with cell water and likely to accumulate in marine sediments, is small compared to what would be released with cell sediments. Release of hydrocarbons from sediments to the water column would be slow and the impact on water column resources (such as fish) would be very local.'

'In conclusion, based on modelling results and using estimates of released substance concentrations, a major release of cell water and sediments from a GBS would pollute the local environment but is not expected to induce any measurable effects at the regional level. Effects on water column resources would be restricted to acute and transient effects close to the release point. A major static sediment release would result in an impacted area around each platform that is comparable to the area already impacted around each platform by historic drill cuttings (although this impacted area would have significantly decreased in size by the time the cell contents are released). The released amounts of persistent, bioaccumulating and toxic substances (PCBs, organic mercury, TBT[40] and to some extent benzo[a]pyrene) have the potential to biomagnify in marine food webs in theory, but DNV GL's assessment concludes that the environmental impact would be small owing to the relatively small amounts of bioaccumulating substances involved, so is not expected to induce measurable effects at the regional level'.

Effects on water column resources would be restricted to acute and transient effects close to the release point. A major static sediment release would result in an impacted seabed area of approximately 0.05 km^2 around each platform, up to a distance of approximately 250 m. Although dynamic (disturbed) sediment releases would result in larger areas of the seafloor where PEC:PNEC>1, the vast majority of the area would have a sediment thickness of less than 1 mm, and hence is not expected to have any harmful impact on biota once mixing by bioturbation has been taken into account'.

'It should be noted that there are three GBSs that contain cell water and cell sediment, all of which could become exposed to the marine environment (probably at different times) in the long-term future if they are left *in situ*. The cumulative impact from all three GBSs (based on worst case modelling results would be increased localized pollution and short-term acute effects (but most likely at different times), but there continues to be no expected measurable effects on the regional level. There would be some increased potential to biomagnify in marine food webs in theory, but because the environmental

[40] Tri-butyl Tin

impact remains small in nature owing to the relatively small amounts of bioaccumulating substances involved, this is unlikely to have any measurable effects in higher trophic levels including humans.'

'DNV GL has also reviewed the literature on interacting effects from co-exposure to relevant contaminants. THC and Hydrogen Sulphide (H_2S) account for the vast amount of assessed contaminants released with cell water (99%) and cell sediment (97%). Hydrogen sulphide is unstable in alkaline and oxidized environments and interacting effects involving this substance are therefore considered unlikely. Potential interacting effects would therefore be limited to hydrocarbons, which have a common or similar mode of action once taken up by an organism, and can act jointly to produce combination effects. Based on this, DNV GL concludes that no significant interacting effects from co-exposure to relevant contaminants would occur other than additive toxicity.'

'Impacts to the marine environment could also result from NORM contamination present in any sediment that is exposed to the environment. A study by ARPS [Aberdeen Radiological Projection Services *Assessment of the Release of NORM-Contaminated Sediment from the Brent Delta Cells* [55]] analyzed the impact of a release of sediment containing NORM to the ocean floor. Both a fast release (lasting one year) and gradual release (lasting 250 years) were modelled using the UK Health Protection Agency assessment model. Results showed that the maximum dose (to adults, children or infants) to be extremely low, approximately 5 microseiverts per year or less. Hence the radiological impact of the release of sediment contaminated with NORM would be very small to human health. In relation to impact upon the environment, the NORM levels of between 2 Bq[41] to 20 Bq in sediment (based on a Brent Spar sediment sample) are typical of produced water in the North Sea oil and gas industry and would mostly only affect some sediment-dwelling organism in the vicinity of the deteriorated GBS.'

15.12.5 Energy and Emissions

The offshore operations to recover attic oil would use approximately 69,000 GJ of energy and result in the emission of approximately 5,900 tonnes of CO_2, even allowing for the benefits of recycling the recovered attic oil (Table 50 and Table 51).

Table 50 The Combined Total Energy Use and Gaseous Emissions from Programme of Work to Leave in Place the GBS Cell Contents in Bravo and Delta.

Operations	Energy (GJ)	Emissions to Atmosphere (tonnes)		
		CO_2	NO_X	SO_2
Direct				
Marine operations	46,290	3,414	70	22
Materials not Recycled				
Materials not recycled	ND	670	ND	ND
Total	46,290	4,084	70	22

ND = No Data

[41] Bq, Becquerel

Table 51 Total Energy Use and Gaseous Emissions from Programme of Work to Leave in Place the Brent Charlie GBS Cell Contents.

Operations	Energy (GJ)	Emissions to Atmosphere (tonnes)		
		CO_2	NO_X	SO_2
Direct				
Marine operations	23,145	1,707	35	11
Materials not Recycled				
Materials not recycled	ND	ND	ND	ND
Total	23,145	1,827	35	11

ND = No Data

15.13 Mitigation Measures for GBS Contents Programme of Work

15.13.1 Mitigation for Loss of Cell Contents

The recommended option for the cell contents has been proposed following a detailed assessment of alternative options, thorough engagement with our stakeholders (including the work of the CMSTG), detailed modelling, toxicological assessment and the completion of an EIA. When the cells are breached the water phase will be released into the marine environment. Later, when the cell domes and cell walls collapse, the cell sediment will be exposed to or released into the marine environment. In our 'worst case' scenario (the release of 101,900 m^3 of the water phase from 10 cells) our environmental assessments have shown that the releases of the water phase are likely to cause only transient effects lasting a few days within a 17 km of the GBS. The exposure of the cell sediments, at a later time, will not add to these effects and are likely to cause only localised effects on the seabed within 2 km of the GBSs. We have concluded that such effects, either from a single GBS or all three Brent GBSs, would not cause measurable effects at a regional level on animals living in the water column or in the seabed.

It is possible that large items of debris falling from degrading legs will puncture the cell domes and cause large pieces of reinforced concrete to fall into the storage cells. Likewise, if large sections of a leg or a whole leg became detached these falling items would land across several cell tops and probably demolish the cell domes and possibly also demolish upper parts of some cell walls. Some of the resulting large mass of reinforced concrete debris would fall into the cell, and could eject cell sediment out of the cell, particularly on an outer cell if part of an outer cell wall had been destroyed and was no longer able to contain resuspended sediment.

Such events might lead to the active ejection (as opposed to the passive exposure) of amounts of cell sediment into the water column. The sediments ejected from cells under such circumstances would enter the marine environment at a height of at least 19 m (the height of the sand ballast in each cell) and probably higher than this because of the presence of at least some part of the cell wall. Some material would fall back into the cell, some into adjacent cells (if also open) or onto the cell tops, and some would drift with the water current and then settle on the adjacent sea bed. DNV GL concluded that the area physically impacted by such dynamic releases would be greater than from the natural erosion of exposed cell sediment, but still would only give rise to a small to moderate impact.

The modelling of dynamic releases indicates that the area with chemical contamination above PNEC[42] levels will be widespread. The contaminated sediment layer will mainly be extremely thin (<0.1 mm), however,

[42] PNEC, Predicted No Effect Concentration

and rapidly diluted with the fresh seabed sediment. It is assessed that the area with potentially harmful impact from THC will be less than 0.4 km^2 and restricted to less than 490 m from the release point. These results are based on modelling that is considered to be conservative, and are assessed to cause a relatively small negative impact on the environment.

As discussed in Section 24 the timing of such events cannot be predicted, but the rolling programme of risk assessment described in Section 14.17.1 will give some information on the progress of degradation and possibly some early warning of the likelihood of major leg collapse. There is no mitigation that can be applied to such unpredictable events once they occur at some time in the future.

15.13.2 Summary of Mitigation Measures

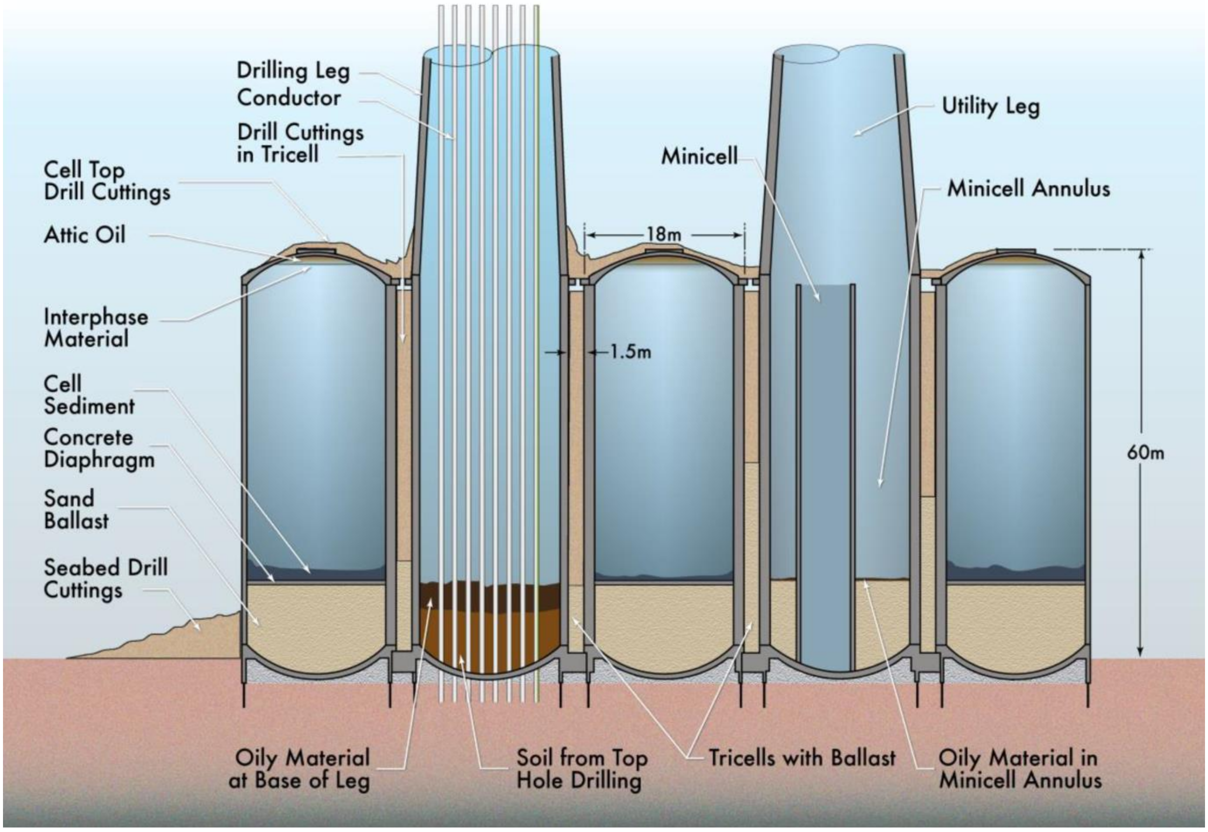
- The attic oil and interphase material (where present) will be removed from each former oil storage cell and returned to shore for reuse, recycling or disposal, depending on its exact condition.
- At the end of these operations, any small diameter access hole that may been created in the cap of each storage cell for the removal of attic oil and interphase material, will be plugged and sealed.
- As described in Section 14.17 the GBSs themselves will be fitted with AtoNs, marked on charts and entered into the FishSAFE system. These measures should minimise the risk that the GBSs will be damaged by accidental collisions with vessels.
- As described in Section 14.17.1 we will conduct periodic reassessments of the safety risk to other users of the sea from the long-term presence of the GBSs, and this will include updating data on the likelihood of vessel collisions.
- As described in Section 24 we will discuss and agree a risk-based programme of environmental and structural monitoring with BEIS, to track the degradation and fate of the GBSs and the materials they contain.
- In our proposed option there are no mitigation measures that would be necessary once the GBSs have collapsed, releasing the water phase and exposing the cell sediments to the marine environment. The CAs (Section 15.7 and Section 15.8) concluded that the option 'Leave in Place' provided the optimal balance between the different sub-criteria in the CA, given the small localised impacts that the release of cell water and exposure of cell sediment might cause.

16 DECOMMISSIONING OTHER MATERIALS IN THE GBSs

16.1 Introduction

In addition to the materials in the oil storage cells we know that the Condeep GBSs Bravo and Delta contain oily materials in their minicell annulus. We also know that on Delta there is contaminated material in the bases of the drilling legs, and we have assumed that similar amounts of such material are also present in the bases of Bravo drilling legs. The locations of all these materials in Brent Delta are shown in Figure 81, estimates of their volumes are summarised in Table 52 and they are described fully in the GBS Contents TD [15].

Figure 81 Locations of Other Materials in the Brent Delta GBS.



16.2 Material in the Drilling Legs

In Delta, a layer of oily material has been found on top of the water-based mud (WBM) top-hole cuttings in the both the East and West drilling legs. From samples and surveys, the total volume of this material in Delta has been estimated to be 2,000 m^3, with an average oil content of 1.4%. No samples have been obtained from Bravo but we have assumed that its drilling legs contain the same type and amounts of material. There are no such accumulations in Charlie because the conductors are external.

16.3 Material in the Minicell Annulus

In Bravo and Delta we have found that there is a small accumulation of material at the bottom of the minicell annulus - the space between the wall of the minicell and the wall of the utility leg. From surveys and samples on Delta, we have found that this material comprises water, oil and solid particles and has an oil content of 5%, and we estimate that its total volume is approximately 250 m^3 [15]. The samples from Bravo are being analysed, and we have assumed that its utility leg contains the same type and amount of material as Delta. There are no such accumulations in Charlie because it does not have a minicell or a utility leg.

16.4 Material in the Tri-cells

On Delta we have found drill cuttings in some of the tri-cells – the spaces created when the circular walls of three storage cells meet. A description of tri-cell cuttings and our estimates of possible volumes are presented in Section 17, which describes the Brent Field drill cuttings piles.

Table 52 Inventories of Other Materials in GBSs.

Material and location	Estimated volume (m^3)		
	Bravo	Charlie	Delta
Material in drilling legs	2,000	N/A	2,000
Material in minicell annulus	250	N/A	250
Estimated total volume	2,250	N/A	2,250

N/A = Not Applicable to this GBS

16.5 Management of the Drilling Leg Material

16.5.1 Options for Drilling Leg Material

The options available for the management of these materials are the same as those for the sediment in the oil storage cells, as described in the GBS Contents TD [15].

The most significant technical issue for any option other than 'Leave in place' is gaining access to the materials which are located approximately 160 m down the drilling legs. Each leg contains 19 (Bravo) or 24 (Delta) conductors supported by 7 guide frames that span the whole width of the legs; there is no existing access for personnel. It is therefore not feasible to deploy equipment in the space between the conductors and the leg wall. The only feasible way of accessing the material while the conductors are in place would be to use one or more conductors as conduits, and drill holes through the walls of the conductors into the material, as described below. On Bravo, all the options requiring intervention could be carried out either before the removal of the topsides (designated Option 1a to Option 5a) or from a temporary work-over platform deployed by an SSCV or similar after the removal of the topsides (designated Option 1b to Option 5b). For Delta, the intervention options can now only be undertaken from the temporary work-over platform over the cut ends of the legs. The options for the material in the drilling legs are summarised below and Figure 82 illustrates how the material in the drilling legs might be recovered, with and without the topside in place.

Option1: Recover and re-inject in a new well: From the topsides or a work-over platform, holes would be drilled through selected conductors just above the level of the material at the bottom of the leg. Pumps and venturi pumps would slurrify the material and underlying top-hole WBM cuttings, and recover the slurry to a surface vessel. The slurry would be transported by tanker to a newly-drilled subsea well and injected.

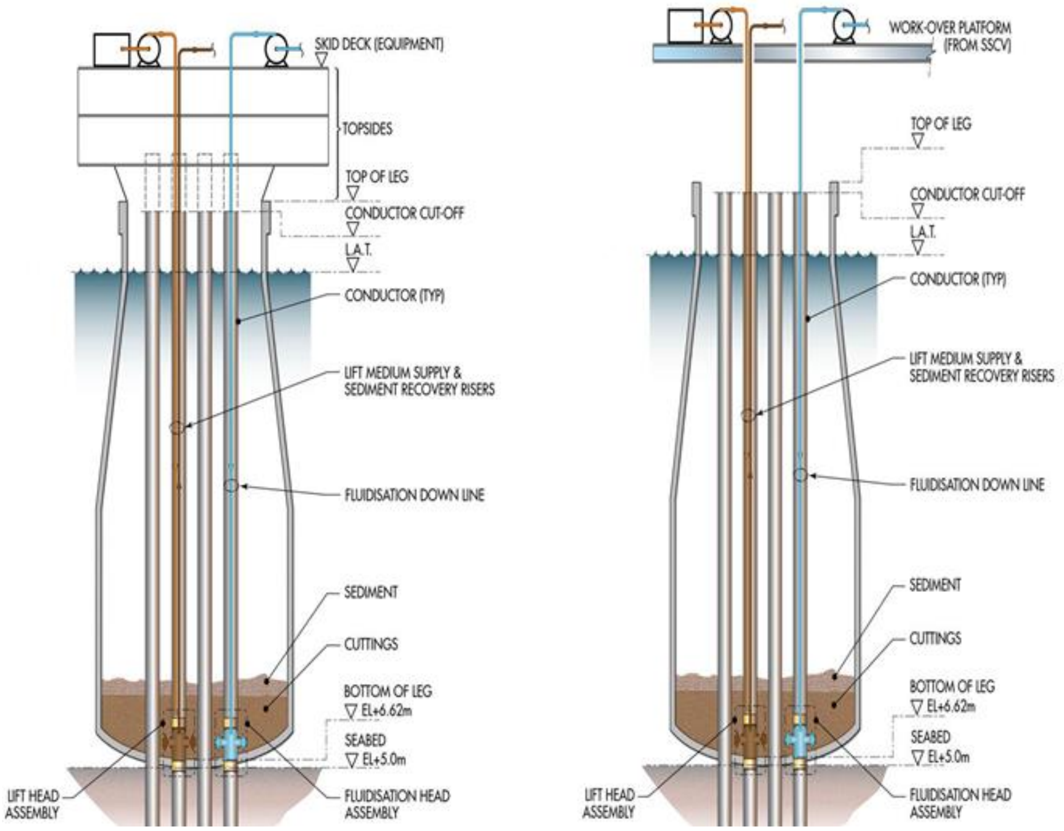
Option 2: Recover and treat onshore: From the topsides or a work-over platform, holes would be drilled through selected conductors just above the level of the material at the bottom of the leg. Pumps and venturi pumps would slurrify the material and underlying top-hole WBM cuttings, and recover it to a surface vessel. The slurry would be transported by tanker to shore for treatment by LTD. Recovered oil would be recycled and the inert solids disposed of to landfill.

Option 3: Leave in place and cap: From the topsides or a work-over platform, holes would be drilled through selected conductors at appropriate heights above the level of the material at the bottom of the leg. Pumps and hoses would be used to deposit suitable capping material (for example sand). The material in the drilling leg would then be left in place.

Option 4: Leave in place and treat by monitored natural attenuation (MNA): From the topsides or a work-over platform, holes would be drilled through selected conductors into the materials in the leg and also above the level of the material at the bottom of the leg. Pumps and hoses would be used to inject chemicals into the material and the water column above it. The material in the drilling leg would then be left in place.

Option 5: Leave in place: No operations would be undertaken. The material in the drilling leg would be left in place.

Figure 82 Options for the Recovery of Material in the Drilling Legs.



With topside in place Topside removed

16.6 Results of Comparative Assessment of Options for Drilling Leg Material

The individual results for Bravo and Delta are presented in detail in [15].

Table 53 and Figure 83 show the results for Brent Bravo.

Table 54 and Figure 84 show the results for Brent Delta, where the options can only be undertaken in the absence of the topside.

Figure 83 The Total Weighted Scores for Options for the Material in the Brent Bravo Drilling Legs, and the Contributions of the Sub-criteria.

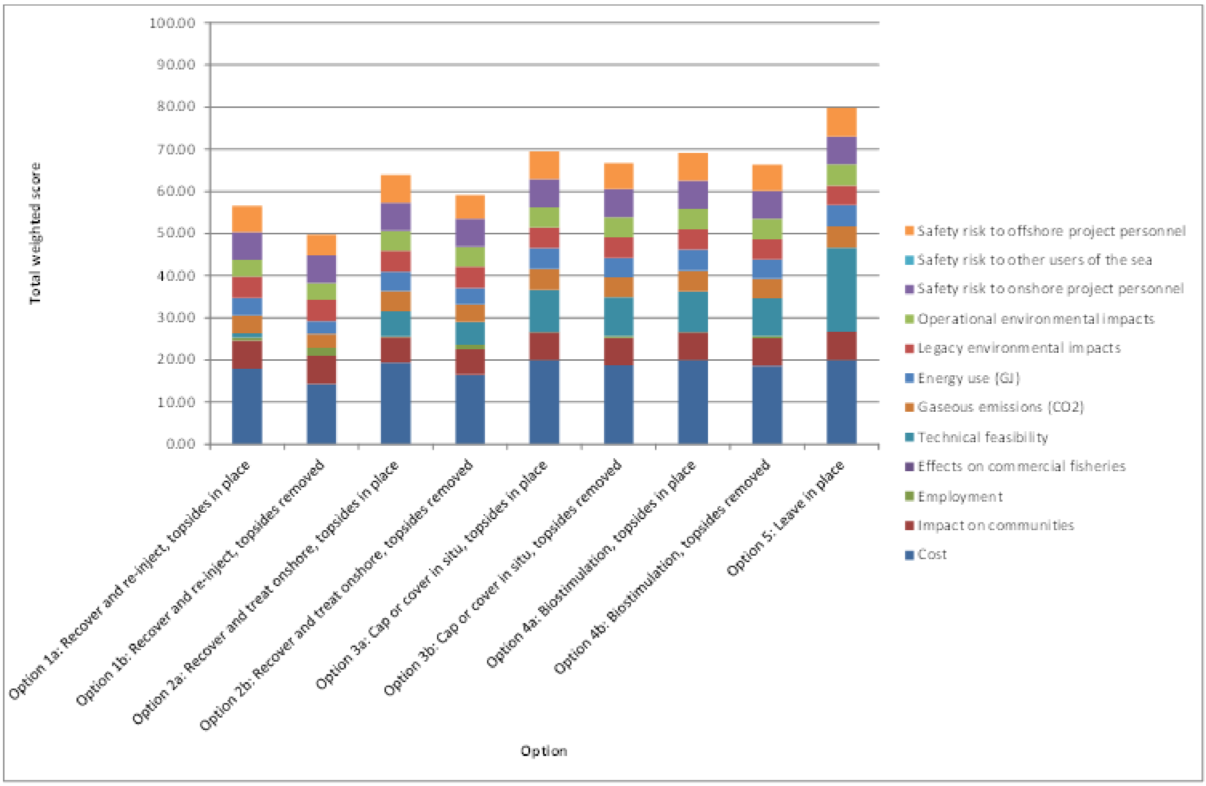


Table 53 Transformed and Weighted Sub-criteria Scores of Options for Material in the Brent Bravo Drilling Leg.

Sub-criterion	Options								
	1a	1b	2a	2b	3a	3b	4a	4b	5
Safety risk offshore project personnel	6.11	4.84	6.59	5.57	6.66	6.22	6.66	6.19	6.67
Safety risk to other users of the sea									
Safety risk onshore project personnel	6.67	6.67	6.67	6.67	6.67	6.67	6.67	6.67	6.67
Operational environmental impacts	4.00	4.00	4.70	4.70	4.85	4.85	4.85	4.85	5.00
Legacy environmental impacts	5.00	5.00	5.00	5.00	4.80	4.80	4.80	4.80	4.75
Energy use	4.14	3.01	4.66	3.97	5.00	4.63	5.00	4.58	5.00
Emissions	4.30	3.35	4.72	4.14	5.00	4.68	5.00	4.64	5.00
Technical feasibility	1.00	0.00	6.00	5.40	10.00	9.20	9.60	9.00	20.00
Effects on commercial fisheries									
Employment	0.70	1.91	0.20	1.19	0.01	0.46	0.01	0.48	0.00
Communities	6.67	6.67	6.00	6.00	6.60	6.60	6.60	6.60	6.67
Cost	17.91	14.27	19.40	16.44	19.98	18.63	19.98	18.55	20.00
Total weighted score	56.49	49.71	63.93	59.08	69.57	66.74	69.16	66.37	79.76

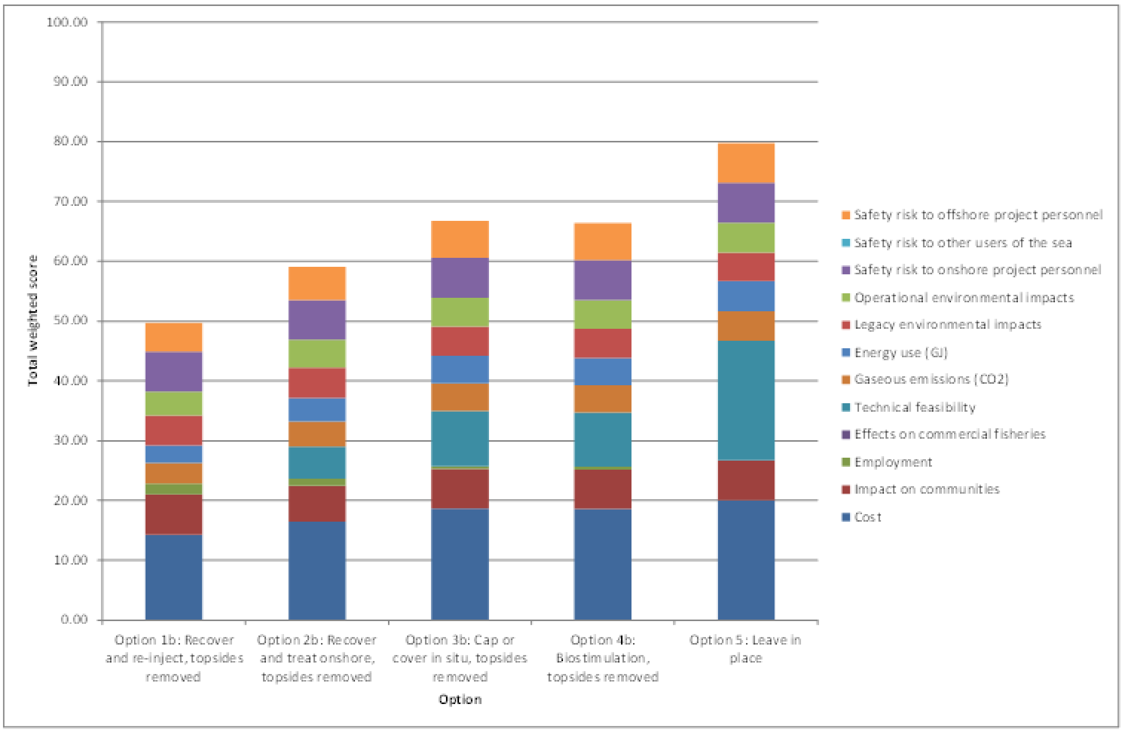
Option 1a	Remove and re-inject in new remote well, topside in place	Option 1b	Remove and re-inject in new remote well, topside removed
Option 2a	Remove and treat slurry onshore, topside in place	Option 2b	Remove and treat slurry onshore, topside removed
Option 3a	Leave in place capped, topside in place	Option 3b	Leave in place capped, topside removed
Option 4a	Leave in place with MNA, topside in place	Option 4b	Leave in place with MNA, topside removed
Option 5	Leave in place		

Table 54 Transformed and Weighted Sub-criteria Scores of Options for Material in the Brent Delta Drilling Leg.

Sub-criterion	Options				
	1	2	3	4	5
Safety risk offshore project personnel	4.84	5.57	6.22	6.20	6.67
Safety risk to other users of the sea					
Safety risk onshore project personnel	6.67	6.67	6.67	6.67	6.67
Operational environmental impacts	4.00	4.70	4.85	4.85	5.00
Legacy environmental impacts	5.00	5.00	4.80	4.80	4.75
Energy use	3.01	3.97	4.63	4.58	5.00
Emissions	3.35	4.14	4.68	4.64	5.00
Technical feasibility	0.00	5.40	9.20	9.00	20.00
Effects on commercial fisheries					
Employment	1.91	1.19	0.46	0.48	0.00
Communities	6.67	6.00	6.60	6.60	6.67
Cost	14.27	16.44	18.63	18.55	20.00
Total weighted score	49.71	59.08	66.74	66.37	79.76

Option 1	Remove and re-inject in new remote well
Option 2	Remove and treat slurry onshore
Option 3	Leave in place capped
Option 4	Leave in place with MNA
Option 5	Leave in place

Figure 84 The Total Weighted Scores for Options for the Material in the Brent Delta Drilling Legs, and the Contributions of the Sub-criteria.



16.7 Discussion and Conclusion on Options for Drilling Leg Material

In the following assessments and discussion it should be noted that the Option 2 for Brent Bravo is Option 2a 'Recover and treat onshore, topsides in place', and that the Option 2 for Brent Delta is Option 2b 'Recover and treat onshore, topsides removed'.

For both Brent Bravo (with or without the topside) and Brent Delta, Option 1 'Remove and re-inject in new remote well' and Option 2 'Remove and treat slurry onshore' would both result in the removal of the material from its present location in the drilling legs and thus prevent the eventual exposure of this material to the marine environment. In both GBSs, Option 2 is the better of the 'removal' options.

Option 5 'Leave in place' is consistently the best option with a total weighted score that is greater than the next best option (Option 3 'Leave in place capped, topside in place'). Option 5's total weighted score is significantly and consistently greater than that of the better of the 'removal' options, Option 2. The sections below therefore examine the differences between Option 2 'Remove and treat slurry onshore' (the better of the 'removal' options), and the emerging recommendation Option 5 'Leave in place'.

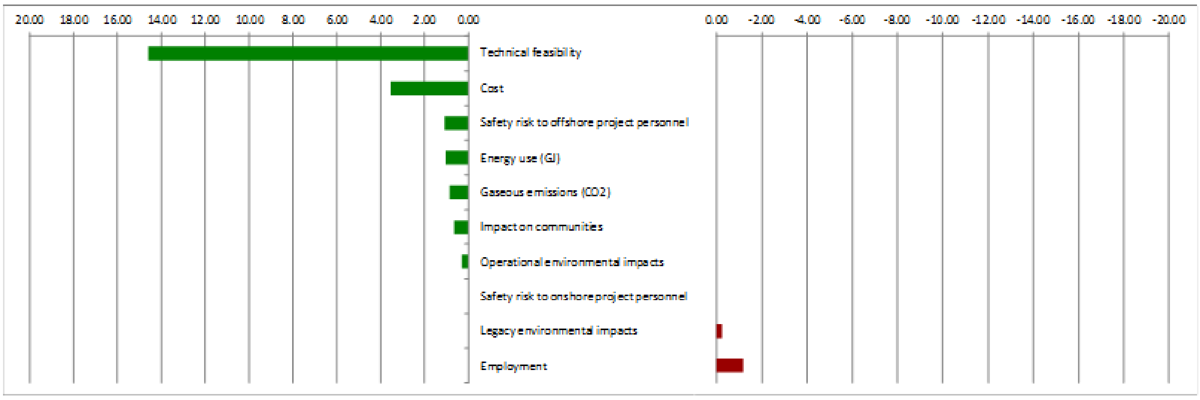
Examination of both the transformed unweighted data and the weighted scores for each of the sub-criteria shows that the differences between the two options are driven by the difference in performance in '**technical feasibility**', which is very much better in Option 5 'Leave in place'. All the other sub-criteria show only very small differences between the options in terms of their weighted scores. This is illustrated in Figure 85 and Figure 86 which show the differences (positive or negative) in the weighted scores in each sub-criterion for these two options for the material in the Brent Bravo drilling legs and Brent Delta drilling legs respectively; the green bars indicate sub-criteria where Option 5 has the better performance and the red bars indicate sub-criteria where Option 2a has the better performance.

Figure 85 Difference Chart Comparing the Weighted Scores for each Sub-criterion in Two Options for the Management of Material in the Brent Bravo Drilling Legs, under the Standard Weighting.

Green bars: Option 5 'Leave in place' is better than Option 2a 'Remove and treat slurry onshore, topside in place'

Red bars: Option 2a 'Remove and treat slurry onshore, topside in place' is better than Option 5 'Leave in place'

Figure 86 Difference Chart Comparing the Weighted Scores for each Sub-criterion in Two Options for the Management of Material in the Brent Delta Drilling Legs, under the Standard Weighting.



Green bars: Option 5 'Leave in place' is better than Option 2b 'Remove and treat slurry onshore, topside removed'	Red bars: Option 2b 'Remove and treat slurry onshore, topside removed' is better than Option 5 'Leave in place'

The drivers and trade-offs for the decommissioning of the material in the Brent Bravo drilling legs are the same as those for the Delta drilling legs, and involve a consideration of how feasible and safe it would be to remove the material (as a slurry mixed with the water above it and some or all of the top-hole cuttings below it), and how proportionate this would be in relation to the elimination of a very localised but low-level and long-term impact to the marine ecosystem that might otherwise occur after 200-500 years when the material in the drilling legs is exposed following the collapse of the legs.

Following our assessment of the real data informing those scores, we have concluded that the sub-criterion serving to strongly differentiate the options is 'technical feasibility'; all the other sub-criteria show no differences or trivial differences between the options. With the topsides still in place and the conductors cut only at about 16 m above LAT, it would be possible to use the conductors as conduits to the material lying on top of the top-hole cuttings in the drilling legs. A suitable suction system could be developed and deployed through holes cut in the conductors using technology that already exists. The resultant slurry could be returned to the topsides and off-loaded into a tanker for transportation to shore. Such operations have not been performed before and would require some planning and testing before they could be executed safely and with a high likelihood of success.

The CA has shown, however, that the additional technical difficulty and extra cost associated with the removal of the material in the Bravo drilling legs would be disproportionate to the benefit of eliminating the small additional legacy environmental impact that might occur at some time well into the future.

For Brent Delta, with the topsides no longer in place, either a vessel stationed alongside the leg or a temporary work-over platform on top of the leg would have to be used to gain access to the top of the drilling legs. This would enable the conductors to be accessed and used as conduits for the deployment of a suction system and the return of slurry to the surface. Such operations have not been performed before and would require a considerable amount of planning and testing before they could be executed safely and with a high likelihood of success. As with the Bravo drilling legs, the technical difficulty and cost of gaining access to the drilling leg material are significant reasons why 'leave in place' is preferable to 'remove and treat slurry onshore'.

The CA has shown that the technical difficulty and cost associated with the removal of the material in the Delta drilling legs would be disproportionate to the benefit of eliminating the small additional legacy environmental impact.

16.8 Recommended Options for the GBS Drilling Leg Material

The detailed CAs of feasible options (Section 16.6 and Section 16.7), carried out in accordance with OSPAR's requirements for CAs [2], and using the selection criteria and matters to be considered set out in Annex 2 of that Decision, has indicated that the recommended option for decommissioning of the material in the drilling legs is as follows:

Brent Bravo drilling leg material: Leave in place.

Brent Delta drilling leg material: Leave in place.

16.9 Recommended Programme of Work for Decommissioning the Material in the Drilling Legs

The proposed management programme for the Drilling Leg Material is described in Section 16.14, along with the proposed programme for managing the material in the minicell annulus.

16.10 Management of the MiniCell Annulus Material

16.10.1 Options for Minicell Annulus Material

The options available for the management of these materials are the same as those for the sediment in the oil storage cells and the material in the drilling leg [15].

The most significant technical issue for any option other than 'Leave in place' is gaining access to the materials which are located approximately 140 m down the utility legs. The utility legs are extremely congested with pipework, and are divided horizontally by eight 'platforms' which span the whole width of the leg and carry equipment, pumps and life-support systems. In the past, trained personnel with suitable safety and personal protection equipment (PPE) have worked in the utility leg down to the top of the minicell. Such work is, however, no longer undertaken or contemplated; it carries a high safety risk, and a large amount of planning, preparation and re-instatement of life-support and safety systems would be required before it would be safe for personnel to work at such low levels deep in the utility leg.

Consequently, the only credible means of accessing the material in the minicell annulus, either before or after the removal of the topsides, would be to cut a hole in the side of the utility leg (Figure 87).

Because there can be no access by personnel, the creation of access through the utility leg's platforms or floors and the deployment of pumps and hoses would have to be carried out by a work-class ROV. No preparatory work could be performed before the topside was removed and no assistance could be delivered by personnel on the topside. In all of the options requiring some intervention, therefore, the access hole in the leg would have to be at least 2 m by 3 m. A hole of this size may not fatally weaken the leg but it would be technically challenging to cut such a hole and remove a large section of the concrete wall, and then to create clear space deep into the annulus for an ROV. The options for the material in the minicell annulus are summarised below and fully described in the GBS Contents TD [15].

Option1: Recover and re-inject in a new well: An ROV deployed from a support vessel would cut a hole in the side of the utility leg above the cell-tops. The ROV would enter the leg, cut and clear access through one or more floors, and then deploy hoses and a venturi lift head into the material. The slurrified material mixed with the remobilised sand ballast would be lifted to a surface vessel (Figure 87). The slurry would be transported by tanker to a newly-drilled subsea well and injected.

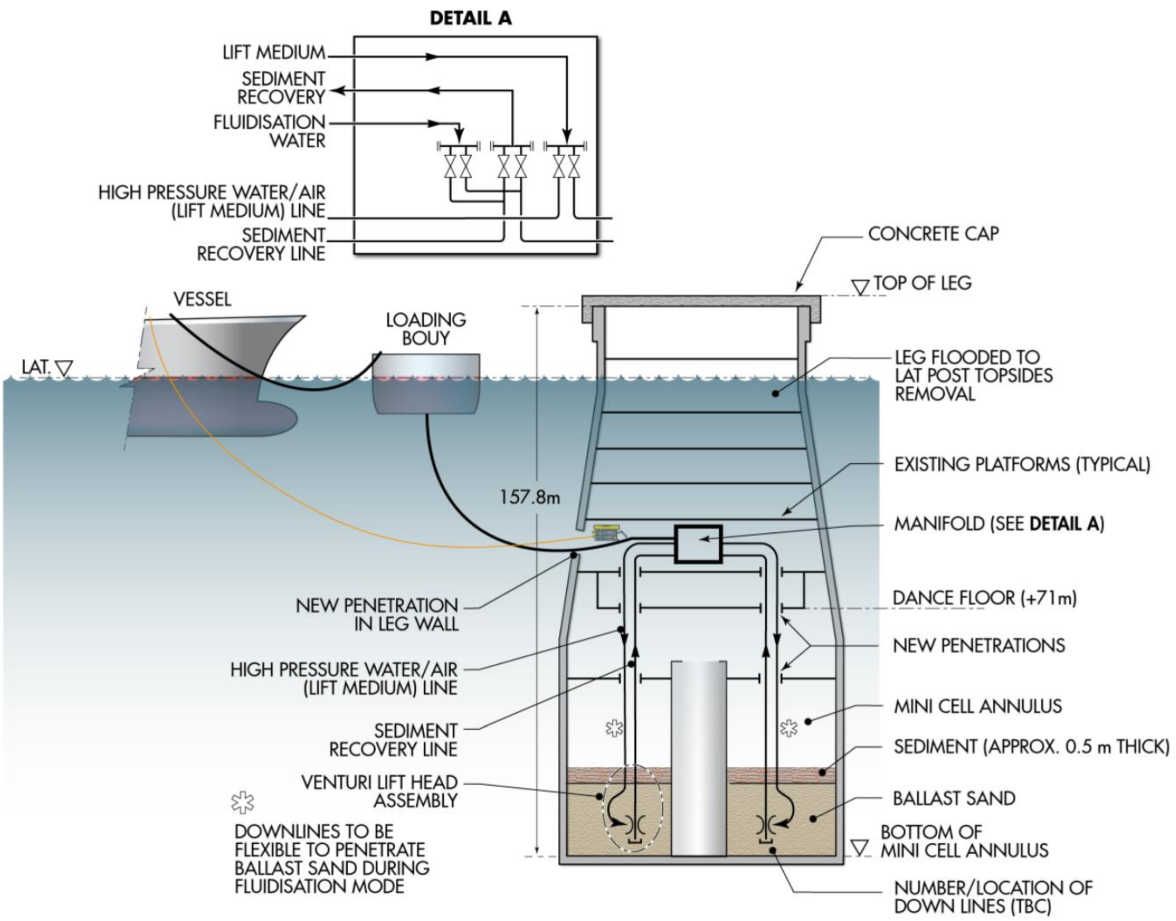
Option 2: Recover and treat onshore: An ROV deployed from a support vessel would cut a hole in the side of the utility leg above the cell-tops. The ROV would enter the leg, cut and clear access through one or more floors, and then deploy hoses and a venturi lift head into the material. The slurrified material mixed with the remobilised sand ballast would be lifted to a surface vessel (Figure 87). The slurry would be transported by tanker to shore for treatment by LTD. Recovered oil would be recycled and the inert solids disposed of to landfill.

Option 3: Leave in place and cap: An ROV deployed from a support vessel would cut a hole in the side of the utility leg above the cell-tops. The ROV would enter the leg, cut and clear access through one or more floors, and then deploy hoses and pumps to deposit suitable capping material (for exampe sand). The material in the annulus would then be left in place.

Option 4: Leave in place and treat by monitored natural attenuation (MNA): An ROV deployed from a support vessel would cut a hole in the side of the utility leg above the cell-tops. The ROV would enter the leg, cut and clear access through one or more floors, and then deploy hoses and pumps to inject chemicals into the material and the water column above it. The material in the annulus would then be left in place.

Option 5: Leave in place: No operations would be undertaken. The material in the minicell annulus would be left in place.

Figure 87 Schematic for the Recovery of the Material from the Minicell Annulus.



16.11 Results of Comparative Assessment of Options for the Management of Material in the Minicell Annulus

The individual results for Bravo and Delta are presented in detail in the GBS Contents TD [15]. Table 55 and Figure 88 show the results for the material in the Brent Bravo minicell annulus, and Table 56 and Figure 89 show the results for the material in the Brent Delta minicell annulus.

Table 55 Transformed and Weighted Sub-criteria Scores of Options for Material in the Brent Bravo Minicell Annulus.

Sub-criterion	Options				
	1	2	3	4	5
Safety risk offshore project personnel	6.18	6.43	6.44	6.46	6.67
Safety risk to other users of the sea					
Safety risk onshore project personnel	6.67	6.67	6.67	6.67	6.67
Operational environmental impacts	4.00	4.80	4.85	4.85	5.00
Legacy environmental impacts	5.00	5.00	4.80	4.80	4.75
Energy use	4.59	4.79	4.83	4.86	5.00
Emissions	4.67	4.83	4.86	4.88	5.00
Technical feasibility	0.00	0.00	4.40	4.40	20.00
Effects on commercial fisheries					
Employment	0.53	0.19	0.17	0.16	0.00
Communities	6.67	6.34	6.67	6.67	6.67
Cost	18.43	19.42	19.50	19.54	20.00
Total weighted score	56.73	58.47	63.19	63.28	79.76

Option 1	Remove and re-inject in new remote well
Option 2	Remove and treat slurry onshore
Option 3	Leave in place capped
Option 4	Leave in place with MNA
Option 5	Leave in place

Figure 88 The Total Weighted Scores for Options for the Material in the Brent Bravo Minicell Annulus, and the Contributions of the Sub-criteria.

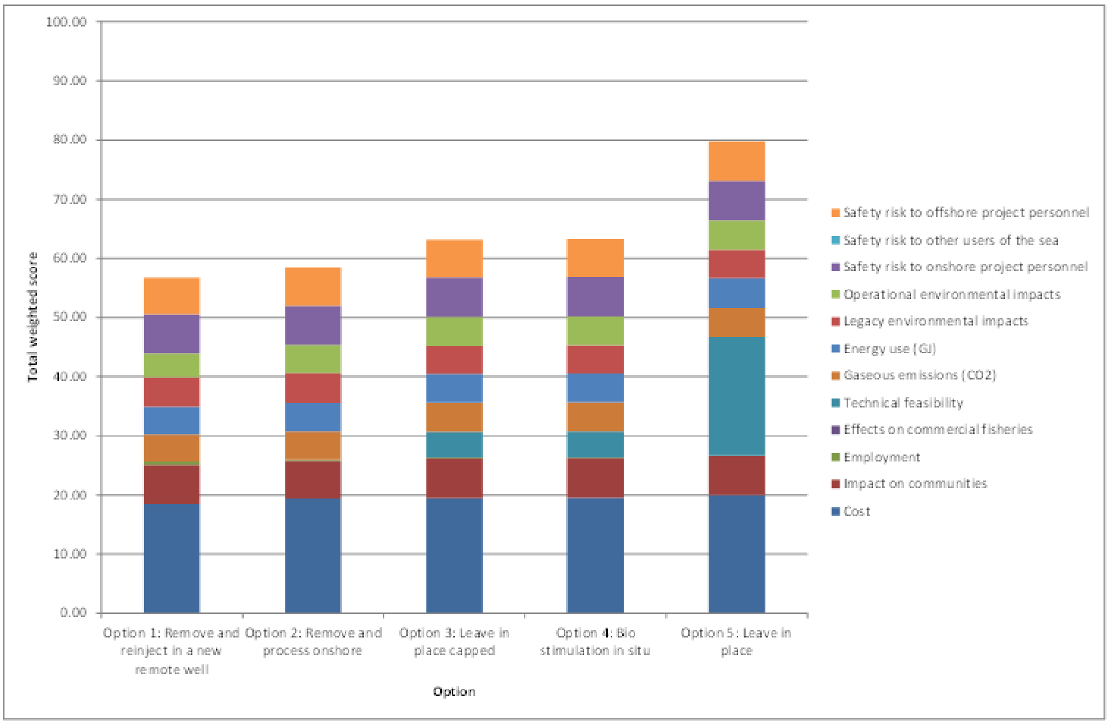
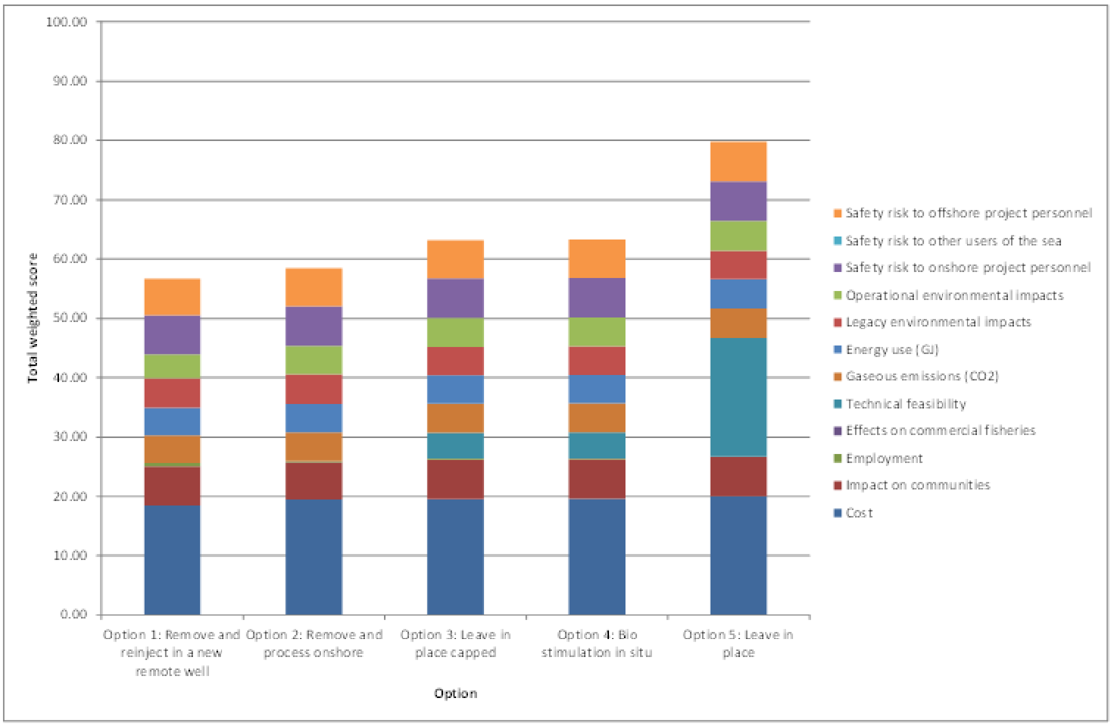


Table 56 Transformed and Weighted Sub-criteria Scores of Options for Material in the Brent Delta Minicell Annulus.

Sub-criterion	Options				
	1	2	3	4	5
Safety risk offshore project personnel	6.18	6.43	6.44	6.46	6.67
Safety risk to other users of the sea					
Safety risk onshore project personnel	6.67	6.67	6.67	6.67	6.67
Operational environmental impacts	4.00	4.80	4.85	4.85	5.00
Legacy environmental impacts	5.00	5.00	4.80	4.80	4.75
Energy use	4.59	4.79	4.83	4.86	5.00
Emissions	4.67	4.83	4.86	4.88	5.00
Technical feasibility	0.00	0.00	4.40	4.40	20.00
Effects on commercial fisheries					
Employment	0.53	0.19	0.17	0.16	0.00
Communities	6.67	6.34	6.67	6.67	6.67
Cost	18.43	19.42	19.50	19.54	20.00
Total weighted score	56.73	58.47	63.19	63.28	79.76

Option 1	Remove and re-inject in new remote well
Option 2	Remove and treat slurry onshore
Option 3	Leave in place capped
Option 4	Leave in place with MNA
Option 5	Leave in place

Figure 89 The Total Weighted Scores for Options for the Material in the Brent Delta Minicell Annulus, and the Contributions of the Sub-criteria.



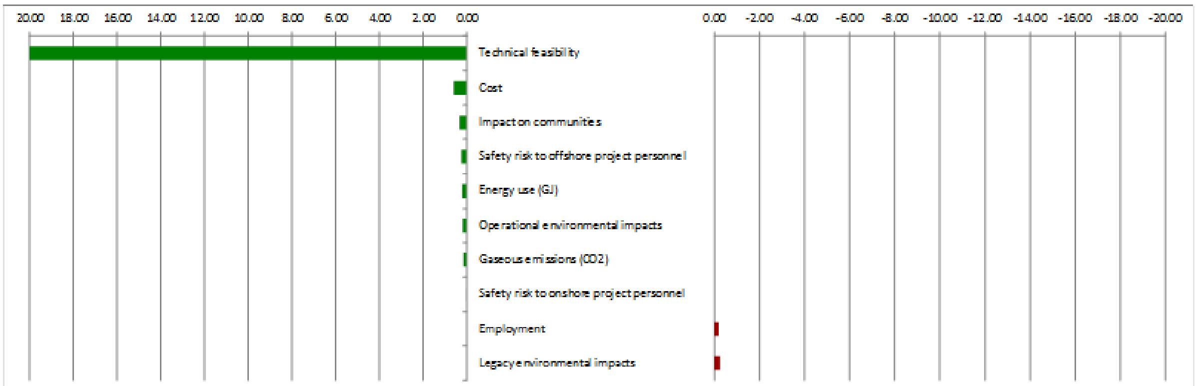
16.12 Discussion and Conclusions on Options for Minicell Annulus Material

For both Brent Bravo and Brent Delta, Option 1 'Remove and re-inject in new remote well' and Option 2 'Remove and treat slurry onshore' would both result in the removal of the material from its present location at the bottom of the minicell annulus and thus prevent the eventual exposure of this material to the marine environment. For both installations, Option 2 is the better of the 'removal' options.

Option 5 'Leave in place' is the best option with a total weighted score that is significantly and consistently greater than that of the better of the 'removal' options, Option 2. The sections below therefore examine the differences between Option 2 'Remove and treat slurry onshore' (the better of the 'removal' options), and the emerging recommendation Option 5 'Leave in place'.

Examination of both the transformed unweighted data and the weighted scores for each of the sub-criteria shows that the differences between the two options are driven by the difference in performance in 'technical feasibility', which is very much better in Option 5 'Leave in place'. All the other sub-criteria show only very small differences between the options in terms of their weighted scores. This is illustrated in Figure 90 which shows the differences (positive or negative) in the weighted scores in each sub-criterion for these two options for the material in the Brent Bravo minicell annulus, and Figure 91 which shows differences in the same options for Brent Delta. In both figures the green bars indicate sub-criteria where Option 5 has the better performance and the red bars indicate sub-criteria where Option 2 has the better performance.

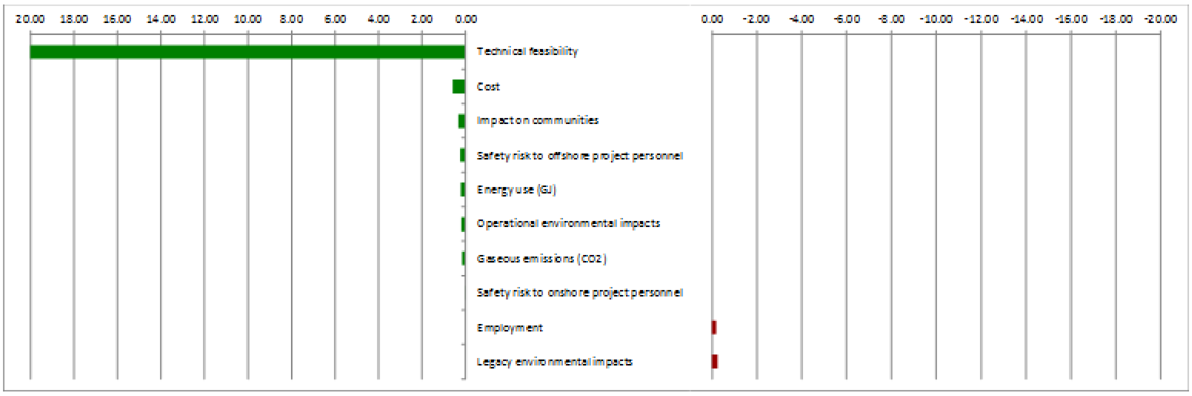
Figure 90 Difference Chart Comparing the Weighted Scores for each Sub-criterion in Two Options for the Management of Material in the Bravo Minicell Annulus, under the Standard Weighting.



Green bars: Option 5 'Leave in place' is better than Option 2 'Remove and treat slurry onshore'

Red bars: Option 2 'Remove and treat slurry onshore' is better than Option 5 'Leave in place'

Figure 91 Difference Chart Comparing the Weighted Scores for each Sub-criterion in Two Options for the Management of Material in the Delta Minicell Annulus, under the Standard Weighting.



Green bars: Option 5 'Leave in place' is better than Option 2 'Remove and treat slurry onshore'

Red bars: Option 2 'Remove and treat slurry onshore' is better than Option 5 'Leave in place'

The drivers and trade-offs for the decommissioning of the material in the minicell annulus involve a consideration of how feasible and safe it would be to remove the material (as a slurry mixed with the oily water above it), and how proportionate this would be in relation to the elimination of a localised but low-level and long-term impact to the marine ecosystem that might otherwise occur after 200 to 500 years when the material in the minicell annulus is exposed following the collapse of the legs.

Following our assessment of the real data informing those scores, we have concluded that the sub-criterion serving to strongly differentiate the options is '**technical feasibility**'. With or without the topsides in place and functioning, the only credible and realistic way of gaining access to the material in the minicell annulus would be through a large hole cut in the side of the utility leg. This would enable a work-class ROV to enter the leg and create access through decking and pipework so that hoses and suction dredgers could be deployed remotely onto the layer of material lying on top of the sand ballast in the annulus. Such operations have not been performed before and would require a considerable amount of planning and testing before they could be executed safely and with a high likelihood of success. The technical difficulty in gaining access to the minicell material is a significant reason why 'leave in place' is preferable to 'remove and treat slurry onshore'.

The CAs have shown that the technical difficulties associated with the removal of the material in the minicell annulus would be disproportionate to the benefit of eliminating the small additional legacy environmental impact that would arise from the eventual exposure of this material.

16.13 Recommended Options for the GBS Minicell Annulus Material

The detailed CA of feasible options (Section 16.11 and Section 16.12), carried out in accordance with OSPAR's requirements for CAs [2], and using the selection criteria and matters to be considered set out in Annex 2 of that Decision, has indicated that the recommended option for decommissioning of the material in the minicell annuli is as follows:

Brent Bravo minicell annulus material:	Leave in place
Brent Delta minicell annulus material:	Leave in place

16.14 Recommended Programmes of Work for Decommissioning the Materials in Drilling Legs and Minicell Annulus

No further work would be performed on or in the legs of the GBSs after the removal of the topsides and the fitting of concrete caps (Section 14.11). The solid material at the bottom of these legs would be left in place, to degrade naturally. As the legs and then the GBS caissons degraded and began to collapse these materials will be exposed to the marine environment, as has been described for the cell sediments (Section 15.5). Given the small volumes of these materials, however, and the large volumes of concrete in the legs above, it is likely that the materials in the drilling legs and utility legs will be substantially buried in the bases of the legs by concrete debris. The potential environmental impacts of such exposure are assessed in Section 16.16.

16.15 Material Retrieved and Material Left in Place

If the proposed recommendations for the material in the drilling legs and minicell annuli are accepted, the estimated 2,250 m^3 of such materials on Brent Delta, and the assumed similar volumes on Brent Bravo, would be left in place as shown in Table 52.

16.15.1 Long-term Degradation of Materials in Drilling Legs and Minicell Annulus

We have not performed specific studies to determine how the materials in the drilling legs and minicell annulus might disperse and behave in the marine environment. If left in place they will remain undisturbed and secure some 40-60 m below the tops of the caissons. There will be limited biological changes to these materials, partly because the lighter organic components have already been biodegraded leaving mostly heavy metals and persistent organic compounds, and also because the cold environment and limited input of nutrients significantly reduces bacterial activity.

The legs above sea level may remain intact for 150-250 years [14]. Because of the central position of the legs within the GBS caisson there are at least 2 concrete walls between the materials in the drilling legs or minicell annuli and the marine environment. Therefore, the most plausible pathway to the marine environment is upward through the legs themselves.

When the legs begin to fail, and in particular when they have degraded to below sea level, there will be pathways for these materials to be potentially exposed to or released into the marine environment. Since the materials will still be contained within a tall narrow 'tube' some 60 m long and heavily congested with the remains of the steelwork from the infrastructure (including conductors, decks and pipework), it is unlikely that they will be ejected out into the sea, even by large items of falling debris. Even after the collapse of the upper legs, the damaged but largely intact bases of the legs will offer considerable protection from the forces of currents and wave action and will therefore encase this material to a greater or lesser extent for many more years.

16.16 Environmental Impacts of Decommissioning the Other Materials in the GBSs

16.16.1 Stakeholder Environmental Concerns

Stakeholders have not expressed a specific view on the other materials in the GBSs, but based on the comments and observations made concerning the cell contents it is clear that their concerns about leaving the other materials would be:

- Long-term legacy effects from escape or release of hydrocarbons to sea.
- The cumulative effect of these materials with the cell sediments.
- The difficulties of carrying out remediation as the GBSs degrade and the legs collapse.

16.16.2 Potentially Significant Impacts in ES

DNV GL's assessment of the potential environmental impacts of the exposure of drilling leg material and the minicell annulus material [5] was informed by the modelling that had been performed on the cell sediments (Section 15.5). The total volume of material in the drilling legs on Delta is about 17% of the total volume used for the worst case modelling of cell sediment release, and the oil content of the drilling leg material is approximately 5% that of the cell sediments. DNV GL concluded that the legacy environmental impact from the eventual exposure of the drilling leg material in both GBSs combined would be 'small negative'. The results of this assessment are shown in Figure 92.

Likewise, the total volume of material in the minicell annulus on Delta is about 2% of the total volume used for the worst case modelling of cell sediment release, and the oil content of the minicell annulus material is approximately 5% that of the cell sediments. DNV GL concluded that legacy environmental impact from the eventual exposure of the minicell annulus material in both GBSs combined would be 'insignificant-small negative'. The results of this assessment are shown in Figure 93.

As the drilling legs and utility legs degrade and collapse, concrete debris is likely to accumulate in the bottom of the leg and smother the material. Although falling debris may resuspend some material in the leg, it may not reach the open sea since it is some 60 m below the top of the caisson (which is likely to remain largely intact even as the legs above degrade) and there are at least two vertical concrete walls between the materials in the drilling leg material or minicell annulus and the sea.

Figure 92 Environmental Impacts Associated with Option 5 'Leave in Place' for Decommissioning the Materials in the Drilling Legs of both Brent Condeep GBSs.

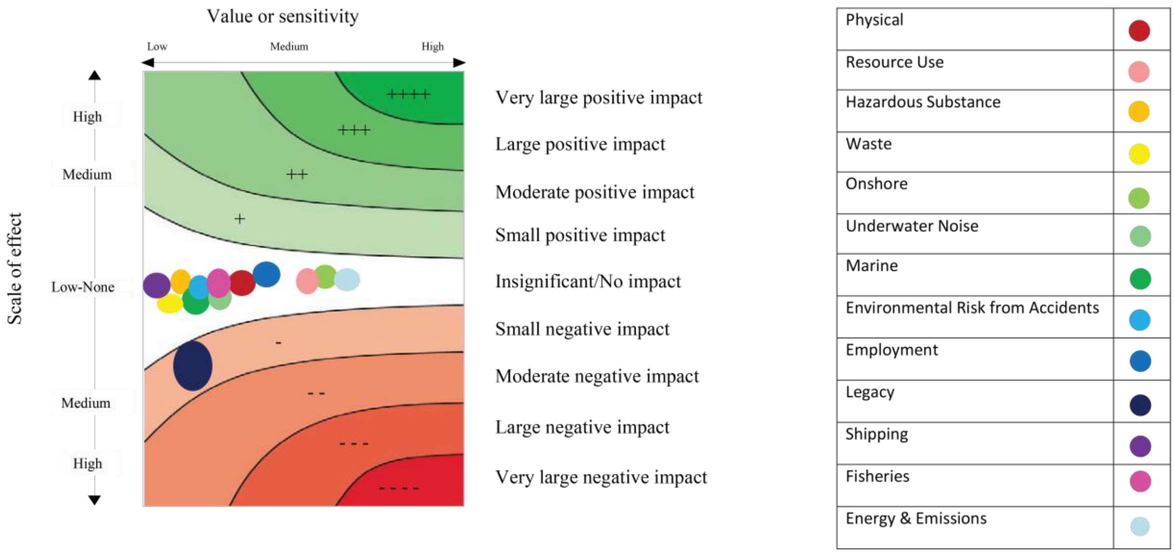
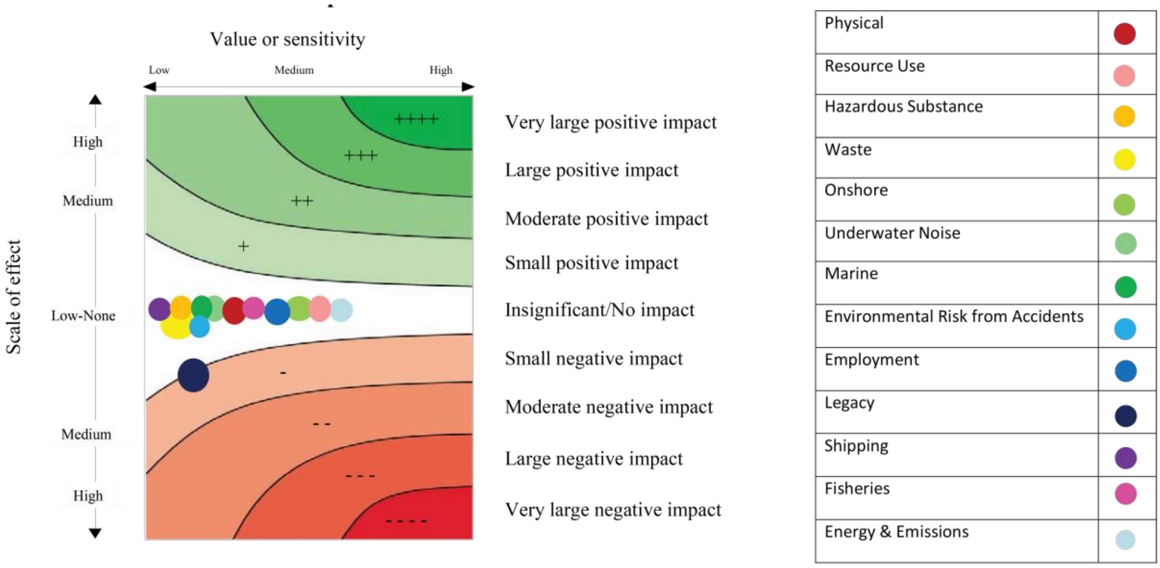


Figure 93 Environmental Impacts Associated with Option 5 'Leave in Place' for Decommissioning the Materials in the Minicell Annulus of both Brent Condeep GBSs.



16.16.3 Impacts of Offshore and Onshore Operations

There will be no offshore or onshore operations.

16.16.4 Legacy Environmental Impacts

The legacy environmental impacts of these materials were not modelled specifically because the volumes concerned and their hydrocarbon concentrations are very much smaller than those of the cell sediments. DNV GL therefore used the results of the modelling and toxicological assessments for the cell sediments to inform their assessment of the legacy impacts of options for the management of the drilling leg and minicell annulus materials. With respect to the proposed decommissioning option for both the drilling leg material and the minicell material (Option 5 'Leave in place for natural degradation'), the ES concluded [5]:

> 'The key negative environmental impact identified [for this option[is the legacy impact from the localised pollution that will occur after the degradation of the GBS when the drilling leg and minicell material is exposed to the marine environment. However…the minicell and drilling leg material

volumes are much smaller than the volumes of GBS cell sediment and contain much less oily content than the cell sediment. Also, as the material is located within the structure of the GBS, it is likely that much of the minicell and drilling leg contents would actually be restricted from entering the marine environment. It is envisaged that as the GBS disintegrates much of the wastes may remain buried under the GBS. Taking these factors into account, the legacy impact from leaving the drilling leg material and the minicell [annulus] material *in situ* is estimated to be 'small negative'.

16.16.5 Energy and Emissions

There will be no operations or activities associated with the management of materials in the drilling legs and minicell annuli. The only sources of energy use and gaseous emissions would be the structural and environmental surveys that would be carried out from time to time, as part of the wider surveys relating to materials left in the oil storage cells described in Section 24.

We estimate that there might be about 66 tonnes of oil in the leg materials; if this were not recovered and recycled, the theoretical costs of 'replacing' it by new manufacture would be emissions of approximately 7 tonnes of CO_2.

16.17 Mitigation Measures for Drilling and Minicell Annulus Programmes of Work

- As described in Section 14.17 the GBSs themselves will be fitted with AtoNs, marked on charts and entered into the FishSAFE system. These measures should minimise the risk that the GBS will be damaged by accidental collisions with vessels.
- As described in Section 24 we will discuss and agree a risk-based programme of environmental and structural monitoring with BEIS, to track the degradation and fate of the GBSs and the materials they contain.
- There is no mitigation that can be applied to the long-term presence and eventual gradual exposure of the materials at the bottom of the drilling and utility legs. The CAs (Section 15.7 and Section 16.6) concluded that no other option would be appropriate, given the very small localised impacts that might arise when these materials are finally exposed.

17 DECOMMISSIONING THE BRENT FIELD DRILL CUTTINGS PILES

17.1 Introduction

Drill cuttings are the small pieces of rock, soil and other material created when a well is drilled. During the process of drilling 'mud' is circulated down the well and then back to the topsides to lubricate and cool the drill bit, provide hydrostatic pressure to maintain the integrity of the well-bore and to return the drill cuttings to the topsides. This mixture of drill cuttings and mud is then either returned to shore for cleaning and disposal or treated and discharged under permit from the platform or drilling rig to the marine environment. When discharged offshore the cuttings typically settle on the seafloor close to the platform or drilling rig, and where water depths are great and/or current and wave action weak they can accumulate as noticeable 'cuttings piles'.

The drilling muds used in drilling operations vary in composition and include Water-based Muds (WBMs) and Organic Phase Fluids (OPFs which include Oil-based Muds (OBMs), synthetic based muds (otherwise known as Low Toxicity Oil-based Muds (LTOBMs) and Pseudo Oil-based Muds (POBMs).

A total of 146 wells have been drilled from the 154 Brent platform well slots, and 3 subsea wells have been drilled at Brent South. As described in the Drill Cuttings TD [16], these wells have been drilled using a variety of drilling muds and over the period 1976 to 1998 a maximum of 87,863 m^3 of cuttings have been generated. The permitted discharge of large volumes of drill cuttings in the deep waters of the East Shetland basin has inevitably resulted in the formation of cuttings piles at each site.

17.2 OSPAR Recommendation on Drill Cuttings

In 2000, OSPAR issued *Decision 2000/3 on the Use of Organic-Phase Drilling Fluids (OPF) and the Discharge of OPF-Contaminated Cuttings* [56] whose purpose was to limit and where possible eliminate the discharge of OPF and OPF-contaminated cuttings to the marine environment. This resulted in a change in current and future drilling operations but did not address the presence of the OPF-contaminated cuttings already discharged to sea.

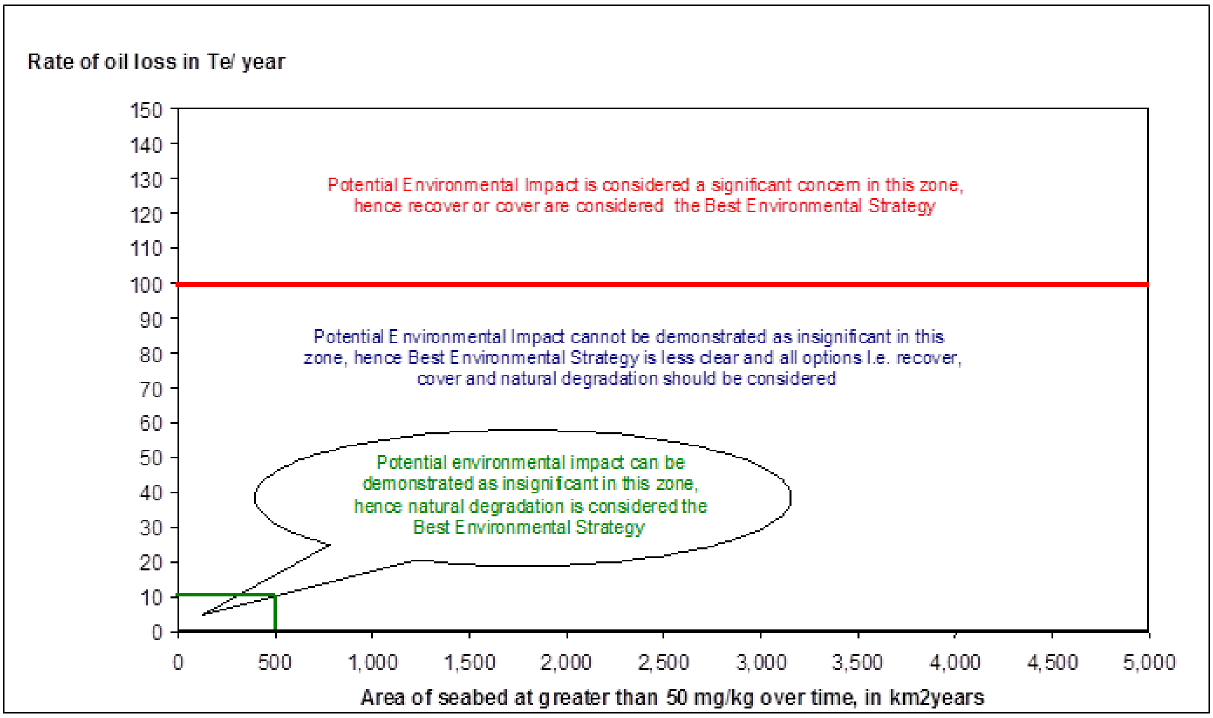
In 2006, after a number of studies had been completed, OSPAR issued their Recommendation 2006/5 which required operators to characterise their OPF-contaminated historic drill cuttings piles [11]. This recommendation set the following two thresholds against which the cuttings piles had to be compared (Figure 94):

- An oil loss rate to the water column of 10 tonnes oil/year
- An area persistence of 500 km^2yr (see Note) in which the seabed sediment exhibited an oil concentration of 50 mg/kg or greater

Note: An area persistence of 500 km^2yr could mean an area of 1 km^2 is contaminated for 500 years or an area of 500 km^2 is contaminated for 1 year.

Where both the oil-loss rate and area persistence of the cuttings pile fall below these thresholds and no other discharges have contaminated the cuttings pile OSPAR concluded, on the basis of detailed scientific examination, that the best option for the management of the pile material is to leave it undisturbed and allow processes of natural degradation to take their course (Figure 94). Where one or other of the threshold is exceeded, a study is required to establish the BAT and/or the Best Environmental Practice (BEP) for managing the drill cuttings pile. It should be subjected to a more detailed programme of sampling and characterisation, with a view to undertaking a comprehensive CA of the different options that might be available for the management of the drill cuttings pile.

Figure 94 OSPAR-Identified Levels of Concern Relating to Historic Drill Cuttings Piles and Likely Best Environmental Strategy.



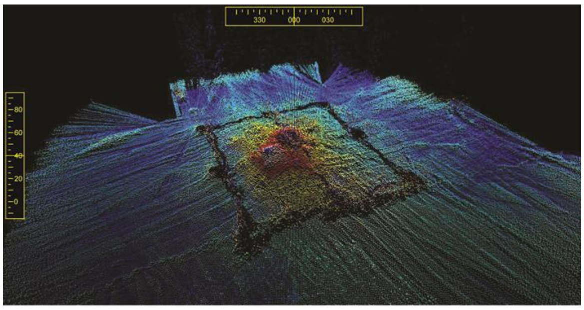
17.3 Characteristics of Brent Drill Cuttings Piles

There are five historic drill cuttings piles in the Brent Field, at Alpha, Bravo, Charlie, Delta and South, as illustrated in Figure 95. The single Brent Alpha seabed cuttings pile is located directly beneath the jacket and is largely contained within its footprint. At Bravo, Charlie and Delta drill cuttings have accumulated on the seabed against the walls of the GBS cells, and on the tops of the GBS cells because they are close to the terminations of the drill cuttings discharge chutes which run down the legs. The Brent South wells were drilled using a semi-submersible drilling rig and the discharged drill cuttings have accumulated in a single pile on the seabed around the wells.

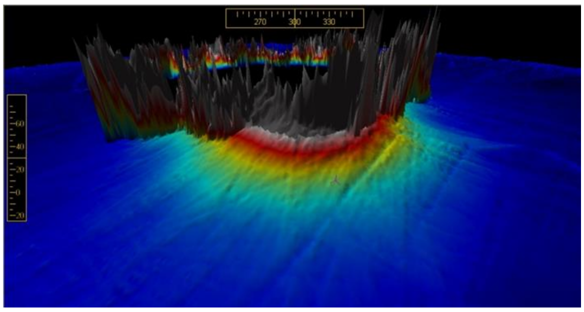
All the piles were surveyed and sampled in 2007, to provide data on their pre-decommissioning status and to inform a detailed assessment of the characteristics of each pile with respect to the requirements of OSPAR Recommendation 2006/5 [11]. The results are presented in the Drill Cuttings TD [16] and summarised in Table 58.

In addition, the areas of seabed around the visible cuttings piles have been sampled to acquire data on the physical, chemical and biological conditions of the benthic environment and to determine if these have changed over time. The most recent surveys (conducted in 2007 and 2011) are reported in Gardline's *Brent A, Brent B, Brent C and Brent South Pre-decommissioning Environmental Survey Report* [57], the *Brent D Pre-decommissioning Environmental Survey Report* [58] and *Brent Charlie cell-top drill cuttings pile environmental survey report* [59].

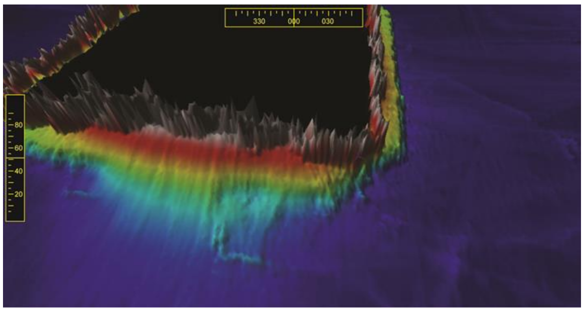
Figure 95 MBES Images of Brent Field Drill Cuttings Piles.



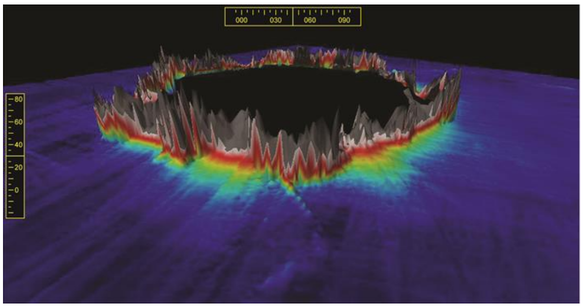
Seabed cuttings pile at Brent Alpha



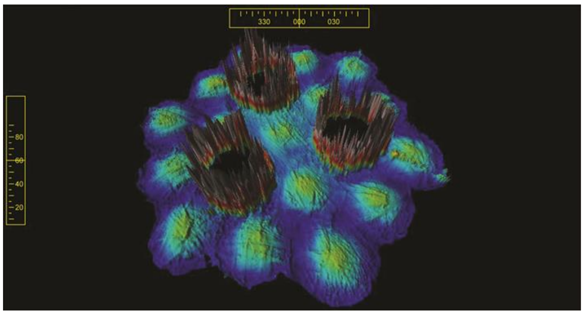
Seabed cuttings pile at Brent Bravo



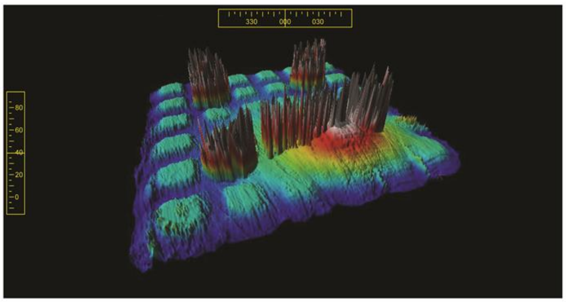
Seabed cuttings pile at Brent Charlie



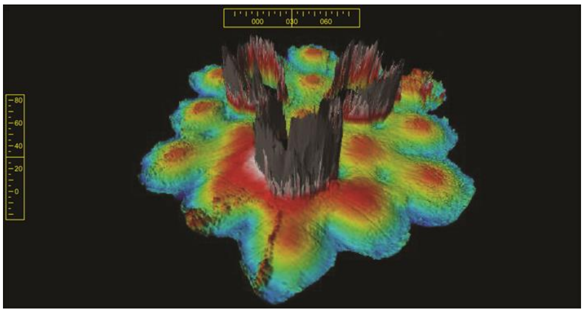
Seabed cuttings pile at Brent Delta



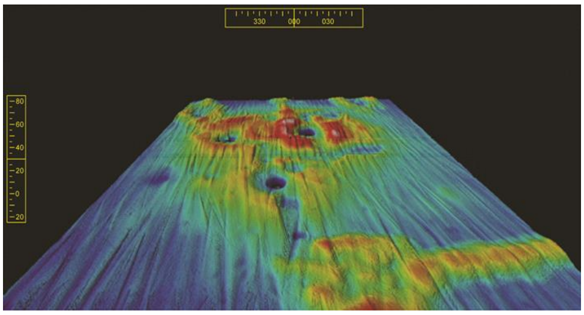
Cell-top cuttings pile on Brent Bravo



Cell-top cuttings pile on Brent Charlie



Cell-top cuttings pile on Brent Delta



Seabed cuttings pile at Brent South

As part of our studies to understand the nature of the Brent drill cuttings piles (including the drill cuttings that have accumulated in the tri-cells (Section 17.4)), we have performed a comprehensive 'data mining' exercise to examine our records of the exact amounts and types of cuttings that have been generated from each well. This has confirmed that different types of muds were used for different sections of each well and that the older wells did not *necessarily* result in the creation of more cuttings or cuttings that were more contaminated. The information from the drilling records indicates that alternating amounts of WBM- and OBM-contaminated drill cuttings were generated. This is likely to have resulted in the creation of layers of WBM and OBM in the deposited drill cuttings. We therefore believe that the pattern of discharge shown in the drilling records suggests that it is unlikely that the cuttings at the bases of the drill cuttings piles will be more contaminated than those that we have sampled near the surface.

17.4 Drill cuttings in the GBS Tri-Cells

In addition to the cuttings piles on the seabed and on the cell-tops, we have found drill cuttings in some of the tri-cells on Delta (Figure 81). On the Condeeps Bravo and Delta every grouping of three circular oil storage cells creates spaces which are triangular in cross-section, called tri-cells. They have sides of approximately 5.8 m and a cross-section area of 14.9 m^2 and run the whole length of the cell (approximately 60 m). There are 22 tri-cells on each of these GBS. The top of each tri-cell is open to the sea and it is therefore likely that some proportion of the drill cuttings discharged from the cuttings chute have accumulated in these spaces (Table 57). The tri-cells are only partially filled with sand ballast leaving void spaces above of approximately 414 m^3 to 596 m^3 in each tri-cell on Brent Bravo and approximately 337 m^3 to 772 m^3 in each tri-cell on Brent Delta. One of the Brent Delta tri-cells was visually inspected and sampled in 2015, and was found to contain drill cuttings with an oil content of approximately 4-9% [16].

The tri-cells of Brent Bravo have not yet been sampled. In the absence of further samples and on the evidence of the drilling records we have assumed that all the tri-cells on Delta and Bravo contain a similar amount and type of drill cuttings.

Charlie has a type of tri-cell, created where the rectangular cells meet the circular legs, but they are not open to the sea.

Table 57 Estimated Maximum Volume of Drill Cuttings in GBS Tri-Cells.

Volume of Drill Cuttings in Tri-cells (m^3)				
Brent Alpha	Brent Bravo	Brent Charlie	Brent Delta	Brent South
NA	12,039	NA	14,733	NA

NA = Not applicable (the tri-cells are not open to the sea)

Table 58 Characteristics of the Brent Field Cuttings Piles, including Drill Cutting in Tri-cells.

Data	Site				
	Alpha	Bravo	Charlie	Delta	South
Number of wells drilled	28	37	38	40	3
Maximum height seabed pile in 2007 (m)	4.0	11.0	9.5	10.3	2.9
Maximum height cell-top pile in 2007 (m)	N/A	3.0	11.2	6.8	N/A
Present area seabed pile (m^2)	8,880	3,414	3,143	1,632	1,620
Present area cell-top pile (m^2)	N/A	673	2,148	234	N/A
Total pile area in 2007 (m^2)	**8,880**	**4,087**	**5,291**	**1,866**	**1,620**
Total volume of cuttings discharged (m^3) [43]	20,047	21,761	22,444	21,616	1995
Present volume seabed pile (m^3)	6,300	5,300	4,922	2,230	2,166
Present volume cell-top pile (m^3)	N/A	1,887	7,735	3,790	N/A
Total external pile volume (m^3)	6,300	7,187	12,657	6,020	2,166
Deduced volume drilling leg cuttings (m^3)	N/A	480	N/A	480	N/A
Deduced max. volume tri-cell cuttings (m^3)	N/A	12,039	N/A	14,733	N/A
Total estimated volume all drill cuttings (m^3)	**6,300**	**19,706**	**12,657**	**21,233**	**2,166**

N/A = Not Applicable

17.5 Assessment of Brent Cuttings Piles against OSPAR Thresholds

In accordance with the requirement of OSPAR Recommendation 2006/5, we completed a desk-top screening study of the Brent Field drill cuttings piles in 2007 to establish whether the cuttings piles exceeded either the oil loss rate or area persistence thresholds as defined in the Recommendation (Stage 1 assessment). These assessments, performed using our historic survey data and published data on the characteristics of North Sea drill cuttings piles and how they have changed over time, indicated that for all five Brent seabed piles, both the rate of oil release and the area of persistence were below the OSPAR threshold (Table 59).

Table 59 Desk-top Assessment of Brent Piles with Respect to OSPAR Thresholds.

OSPAR Criterion and Threshold		Brent Cuttings Pile				
OSPAR Criterion	OSPAR	Alpha	Bravo	Charlie	Delta	South
Total rate of oil release ($tonnes.yr^{-1}$)	10	1.7	0.8	1.0	0.4	0.3
Area persistence (km^2yrs)	500	42	21	35	31	6

Following the submission of this Stage 1 assessment, we also commissioned a long-term fate modelling study by BMT *Long term fate and effects of cuttings piles at Brent Alpha and Brent Charlie* [60] to facilitate prediction of whether the future behaviour of the drill cuttings piles would lead to either OSPAR threshold being exceeded, if they were left undisturbed. This study used the results from the 2007 seabed survey to characterise the drill cuttings piles in the model; Brent Alpha was selected as it is the largest seabed drill cuttings pile in the Field and Brent Charlie was selected as the largest cell-top drill cuttings pile. We surmised that if the modelling indicated that the long-term behaviour of these undisturbed piles would not exceed the OSPAR thresholds in the future, then we could assume that neither would the smaller drill cuttings piles on the

[43] This is an estimate of the volume of OPF discharged obtained from a detailed review of our drilling records.

seabed at Brent South and on the seabed and cell-tops at Brent Bravo and Brent Delta (which have similar physio-chemical characteristics as the Alpha and Charlie cuttings and are exposed to a similar seabed and mid-water current regimes). This initial modelling indicated that for the Brent Alpha and Charlie seabed cuttings piles, and for the Brent Charlie cell-top cuttings piles alone and in combination with the Charlie seabed cuttings pile, neither threshold would be exceeded.

Based on our early understanding that consideration of some level of disturbance and/or management of drill cuttings may be required, we also commissioned a study to investigate the potential impact – both short-term and longer-term – of disturbing the Brent Alpha and Brent Charlie drill cuttings piles by over-trawling or suction dredging a portion of the drill cuttings piles. The results of this study are presented in the BMT Cordah report *Effects of Human Disturbance on the Brent Alpha and Brent Charlie Cuttings Piles* [61].

In 2011 we took further samples of the Brent Charlie cell-top drill cuttings pile and found that the THC of the cell-top drill cuttings was higher than the value previously used in either of the modelling reports. Both the long-term fate and human disturbance modelling scenarios for Charlie were re-modelled using the revised cell-top THC values. The important finding from this work was that using the maximum analysed THC value, the oil loss rate for the undisturbed Brent Charlie cell-top cuttings pile (and therefore the combined cell-top and seabed system) was predicted to exceed the 10 tonnes/year. The remodelled results showed that in the worst case the oil loss rate is not predicted to fall below 10 tonnes/year for about 30 years. As a result of this finding we have performed a Stage 2 assessment of the Brent Charlie cell-top drill cuttings pile, as required by OSPAR Recommendation 2006/5.

17.6 Issues and Concerns Raised by Stakeholders

For the various options for the Brent Field drill cuttings piles, the main issues and concerns raised by stakeholders during the programme of stakeholder engagement were:

- The amounts and composition of drill cuttings piles.
- The accuracy of our knowledge about the composition of the piles, especially the presence of higher hydrocarbon concentrations at greater depth in the piles.
- The effects of disturbing cell-top piles when working over or on the GBS cells.
- Accidental discharges or releases of hydrocarbons to sea during retrieval or treatment operations.
- The long-term spread of cuttings as they are eroded.
- The effects of cuttings treatment operations on onshore communities.
- The use of scarce landfill for the disposal of treated solids.

17.7 Management of Brent Field Cuttings Piles

Our desk-top studies and subsequent modelling have confirmed that all the Brent seabed cuttings piles fall below the OSPAR thresholds and consequently, under OSPAR Recommendation 2006/5, these drill cuttings piles should be left undisturbed to degrade naturally. We also believe that the cell-top drill cuttings piles on Brent Bravo and Delta fall below both the OSPAR thresholds, so again we intend to leave them in place to degrade naturally. The undisturbed Brent Charlie cell-top drill cuttings pile – and therefore the combined cell-top and seabed system - was found to exceed the oil loss rate threshold and has been subjected to a comparative assessment to determine the BAT and/or BEP option for this drill cuttings pile.

The Brent Field drill cuttings piles do not exist in isolation, however, and may be affected by decommissioning activities at other Brent facilities; for example, the Brent platform substructures could not be removed without directly disturbing the seabed and cell-top drill cuttings piles. For the three GBSs our extensive study work has demonstrated that the risk of partial or total project failure is too high and we have concluded that the GBS cannot be re-floated (Section 14.7). Consequently, the seabed cuttings piles that have accumulated against the caisson walls will not be disturbed during the decommissioning of the GBSs, with the exception of minimal disturbance to disconnect any pipelines, retrieve subsea debris and structures, or complete other necessary decommissioning work in order to comply with decommissioning legislation. The wells at Brent South have already been plugged and abandoned and the well infrastructure has been removed; no further work which might disturb the cuttings pile is required at this location.

In contrast, the full removal of the Brent Alpha jacket footings is technically feasible, and because the drill cuttings pile is located within the jacket footprint it must be considered when assessing options for the footings (Section 13.9.3). Our assessment of the management options for this drill cuttings pile is discussed in Section 17.8.

Some of the options under consideration for the decommissioning the GBS cell contents would also require the small- or large-scale disturbance of the GBS cell-top drill cuttings. Our assessment of the management options for the Brent Bravo and Delta cell-top drill cuttings piles are presented in Section 17.9, and include options that may be required if the planned programmes of work for recovering attic oil and interphase material from the GBS cells cannot be completed as expected.

Section 17.10 presents the Stage 2 assessment of the undisturbed Brent Charlie cell-top drill cuttings pile, and includes a precautionary assessment of the management options if the intended attic oil and interphase material recovery method cannot be executed.

17.8 Options for the Management of Brent Alpha Seabed Drill Cuttings Pile

17.8.1 Introduction

We examined options for the management of the Brent Alpha seabed drill cuttings pile because one of the options for the removal of the Alpha jacket footings requires the displacement of a large proportion of the pile. The feasible options for the Brent Alpha seabed drill cuttings pile are described in detail in the Drill Cuttings TD [16] and summarised in Table 60.

Table 60 Technically Feasible Options for the Brent Alpha Seabed Drill Cuttings Pile.

Option	Option Name	Option Description
Option 1	Treat on topsides	Dredge, transfer to Brent Charlie topside, separate the slurry, treat both liquid and solids, and discharge cleaned material to sea.
Option 2	Treat slurry onshore	Dredge, transfer to a vessel and transport to shore for treatment and disposal.
Option 3	Treat solids onshore	Dredge, transfer to Brent Charlie topside, separate and treat the slurry and discharge cleaned water to sea, and transport solids to shore for treatment and disposal.
Option 4	Re-inject in a new well	Dredge, transfer to a vessel and re-inject into a new remote well.
Option 5	Leave *in situ*	Leave in place.

17.8.2 Results of Comparative Assessment of Options for the Management of the Brent Alpha Seabed Drill Cuttings Pile

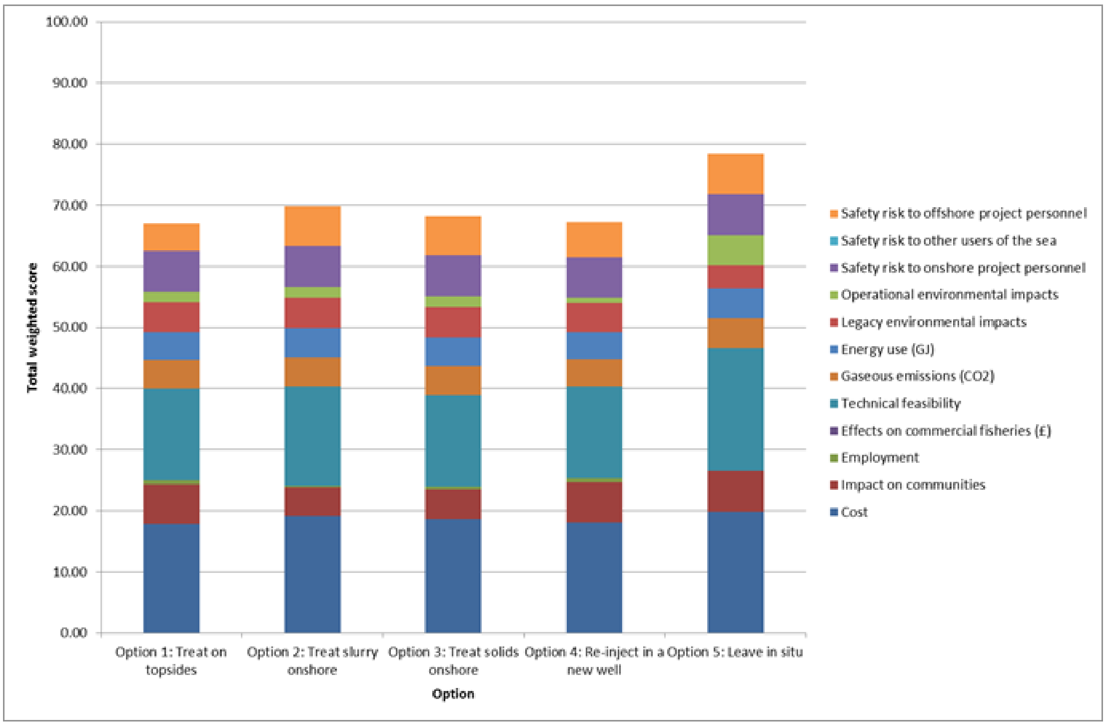
The results of the CA for the Alpha seabed drill cuttings pile are presented in detail in the Drill Cuttings TD [16], and summarised in Table 61 and Figure 96. On the basis of this assessment, the 'CA-recommended option' for the Brent Alpha seabed drill cuttings pile is Option 5 'Leave *in situ*'. The total weighted score for this option is 78.41. The next best performing option is Option 2 'Treat slurry onshore' with a score of 69.83.

Table 61 Transformed and Weighted Sub-criteria Scores of Options for the Brent Alpha Seabed Drill Cuttings Pile.

Sub-criterion	Option 1	Option 2	Option 3	Option 4	Option 5
Safety risk offshore project personnel	4.52	6.52	6.44	5.75	6.58
Safety risk to other users of the sea	-	–	-	-	-
Safety risk onshore project personnel	6.67	6.66	6.67	6.67	6.67
Operational environmental impacts	1.60	1.80	1.80	0.75	5.00
Legacy environmental impacts	5.00	5.00	5.00	4.90	3.75
Energy use	4.55	4.75	4.65	4.33	4.91
Emissions	4.63	4.79	4.71	4.45	4.93
Technical feasibility	15.00	16.20	15.00	15.00	20.00
Effects on commercial fisheries	-	-	-	-	-
Employment	0.72	0.28	0.46	0.65	0.05
Communities	6.47	4.67	4.87	6.67	6.67
Cost	17.84	19.17	18.63	18.05	19.86
Total weighted score	66.99	69.83	68.23	67.22	78.41

Option 1	Treat on topside
Option 2	Treat slurry onshore
Option 3	Treat solids onshore
Option 4	Re-inject in a new well
Option 5	Leave *in situ*

Figure 96 The Total Weighted Scores for Options for the Brent Alpha Seabed Drill Cuttings Pile, and the Contributions of the Sub-criteria.

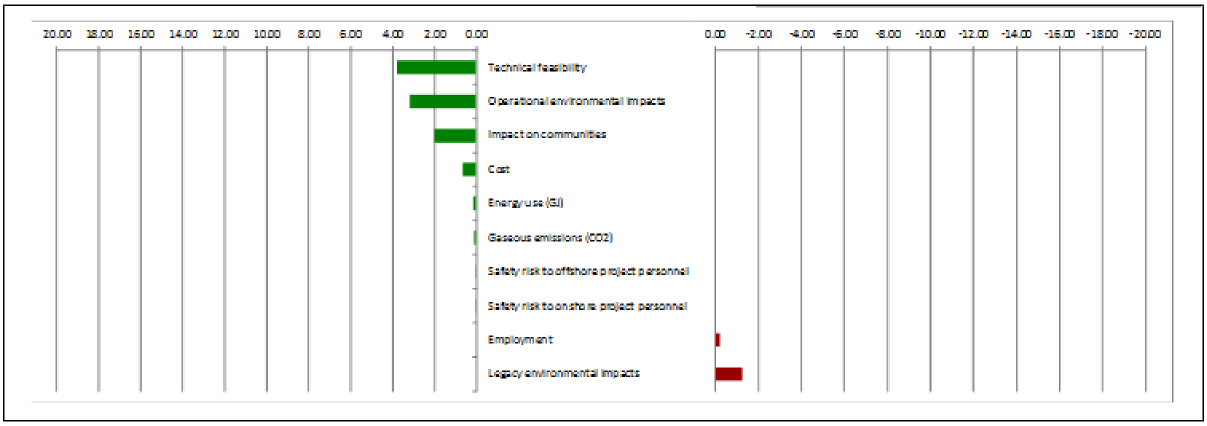


17.8.3 Discussion and Conclusions on Options for Alpha Seabed Drill Cuttings Pile

Option 5 'Leave in place' is consistently the best option in all weighting scenarios. Of the four options which involve the removal of the whole cuttings pile, Option 2 'Treat slurry onshore' is the best option in all the weighting scenarios except 'weighted to Societal'. The section below therefore examines the differences between these two options.

Examination of both the transformed unweighted data and the weighted scores for each of the sub-criteria shows that the differences between the two options are driven by small differences in performance in 'technical feasibility' and 'operational environmental impacts'. All the other sub-criteria show only very small or no difference between the options in terms of their weighted scores. This is illustrated in Figure 97 which shows the differences (positive or negative) in the weighted scores in each sub-criterion; the green bars indicate sub-criteria where Option 5 'Leave *in situ*' has the better performance and the red bars indicate sub-criteria where Option 2 'Treat slurry onshore' has the better performance.

Figure 97 Difference Chart Comparing the Weighted Scores for each Sub-criterion in Two Options for the Management of the Brent Alpha Seabed Drill Cuttings Pile, under the Standard Weighting.



Green bars: Option 5 'Leave in place' is better than Option 2 'Treat slurry onshore'

Red bars: Option 2 'Treat slurry onshore' is better than Option 5 'Leave in place'

The drivers and trade-offs for the decommissioning of the Alpha seabed drill cuttings pile involve a consideration of how feasible it would be to remove the material (a slurry of drill cuttings, natural seabed and seawater) and what environmental impacts there might be to the seabed (from sub-sea operations) and then to onshore communities (from treatment and disposal operations), and how proportionate these would be in relation to the elimination of a localised and low-level environmental impact from an historic cuttings pile that was well below both OSPAR thresholds.

Following the assessment of the weighted scores for each sub-criterion and an examination of the data informing those scores, we have concluded that there are no strong drivers to differentiate the options.

Much of the concern regarding the long-term presence of drill cuttings arises from the potential for a chronic but low level source of contamination affecting the marine environment. The removal of the drill cuttings in order to avoid the potential long-term impacts on the offshore marine environment would result in increased operational impacts as reflected in the scores for this sub-criterion in the two options. The difference in the scores for operational environmental impacts (0.64) is larger than the difference in the legacy environmental impact scores of Options 2 and 5 (0.25). This indicates that the increased operational impacts of recovering the drill cuttings pile are disproportionate to the assessed long-term impacts of leaving the drill cuttings pile in place. DNV GL do not consider the long-term presence of the undisturbed drill cuttings pile to be a significant environmental risk.

17.8.4 Recommended Option for the Brent Alpha Seabed Drill Cuttings Pile

The detailed CA of feasible options (Section 17.8.1) carried out in accordance with a Stage 2 assessment as required by OSPAR 2006/5 [11] and using the selection criteria and matters to be considered set out in

Annex 2 of OSPAR 98/3 [2], has indicated that the recommended option for decommissioning of the Brent Alpha seabed drill cuttings pile, if it is to remain undisturbed, is as follows:

Brent Alpha seabed drill cuttings pile: Leave in place to degrade naturally.

17.9 Options for the Management of Brent Bravo and Brent Delta Cell-Top Drill Cuttings Piles

17.9.1 Introduction

The presence of the cell-top drill cuttings piles on the Brent Bravo and Delta GBSs does not affect the decommissioning of the GBS themselves. We have, however, committed to removing the attic oil and interphase material from the oil storage cells prior to decommissioning. At Brent Delta, this will be achieved by drilling new small (3") access holes in each GBS cell and pumping the liquids to a surface vessel or to another Brent platform, for transportation onshore. For Brent Bravo we think it is unlikely that there will be any significant amounts of attic oil or interphase material in the cells because the oil export line is located at the top of the cell dome. If any attic oil or interphase material is found at Brent Bravo, we intend to use the existing oil fill lines to recover the fluids. In case this is not possible, the CA has been completed on the worst case scenario that the oil fill line cannot be used for this purpose and that, as a minimum, a small diameter hole would have to be drilled to recover these fluids. If the sediments in all the GBS cells had to be removed, a larger diameter (3 m to 5 m) access hole would have to be created in each cell on both Brent Bravo and Delta. To allow the deployment of the necessary cutting equipment, the cell-top drill cuttings piles would have to be disturbed to a greater degree than for attic oil recovery.

For all these reasons, therefore, we have undertaken individual CAs of the disturbance and management of the cell-top drill cuttings piles on each of the Brent GBSs. This Section discusses the cell-top piles on Bravo and Delta, and Section 17.10 discusses the options for the larger cell-top pile on Charlie and includes the Stage 2 assessment required under OSPAR Recommendation 2006/5.

The feasible options for the Bravo and Delta cell-top drill cuttings pile are described in detail in the Drill Cuttings TD [16] and summarised in Table 62.

Table 62 Technically Feasible Options for the Brent Bravo and Brent Delta Cell-Top Drill Cuttings Piles.

Option	Option name	Option Description
Option 1	Water-jet	Water-jet of small volumes (40 m^3 on Brent Bravo and 20 m^3 on Brent Delta) of drill cuttings into the water column.
Option 2	Treat on topside	Dredge, transfer to Brent Charlie topside, separate the slurry, treat both liquid and solids, and discharge cleaned material to sea.
Option 3	Treat slurry onshore	Dredge, transfer to a vessel and transport to shore for treatment and disposal.
Option 4	Treat solids onshore	Dredge, transfer to Brent Charlie topside, separate and treat the slurry, discharge cleaned water to sea and transport solids to shore for treatment and disposal.
Option 5	Re-inject in a new well	Dredge, transfer to a vessel and re-inject into a new remote well.

17.9.2 Results of Comparative Assessment of Options for the Management of the Brent Bravo and Brent Delta Cell-Top Drill Cuttings Piles

The results of the CAs for the Bravo and Delta cell-top drill cuttings piles are presented in detail in [16]. The results of the individual CA for Bravo are summarised in Table 63, Figure 98 and Figure 100, and the results for Delta are summarised in Table 64, Figure 99 and Figure 101. Although there is a considerable difference in the estimated volumes of the two piles (Bravo 1,887 m^3, Delta 3,790 m^3) the results of the CAs are similar and the narrative below that reviews these results is applicable to both Bravo and Delta.

The CA-recommended option for both these cell-top cuttings piles is Option 1 'Water jet'. This is predicated on the assumption that only a small volume (20-40 m^3) of cuttings would have to be displaced from the tops of the cells in order to access the cell caps for the recovery of the attic oil and interphase material (where present). For Bravo, Option 1 'Water jet' has a total weighted score of 79.17 compared to the total weighted score of 71.38 for the next best option, Option 3 'Treat slurry onshore'. The corresponding total weighted scores for Delta are 78.98 for Option 1 and 70.33 for Option 3.

Table 63 Transformed and Weighted Sub-criteria Scores of Options for the Brent Bravo Cell-Top Drill Cuttings Pile.

Sub-criterion	Option 1	Option 2	Option 3	Option 4	Option 5
Safety risk offshore project personnel	6.66	6.33	6.53	6.52	6.30
Safety risk to other users of the sea	–	–	–	–	–
Safety risk onshore project personnel	6.67	6.67	6.67	6.67	6.67
Operational environmental impacts	4.70	1.95	2.15	2.15	0.75
Legacy environmental impacts	4.50	5.00	5.00	5.00	4.90
Energy use	4.99	4.81	4.81	4.79	4.71
Emissions	4.99	4.84	4.84	4.83	4.76
Technical feasibility	20.00	15.00	16.00	15.00	14.00
Effects on commercial fisheries	–	–	–	–	–
Employment	0.01	0.21	0.14	0.17	0.26
Communities	6.67	6.67	5.67	5.74	6.67
Cost	19.98	19.38	19.57	19.50	19.21
Total weighted score	**79.17**	**70.86**	**71.38**	**70.37**	**68.23**

Option 1	Water-jet
Option 2	Treat on topside
Option 3	Treat slurry onshore
Option 4	Treat solids onshore
Option 5	Re-inject in a new well

Figure 98 The Total Weighted Scores for Options for the Brent Bravo Cell-Top Drill Cuttings Pile, and the Contributions of the Sub-criteria.

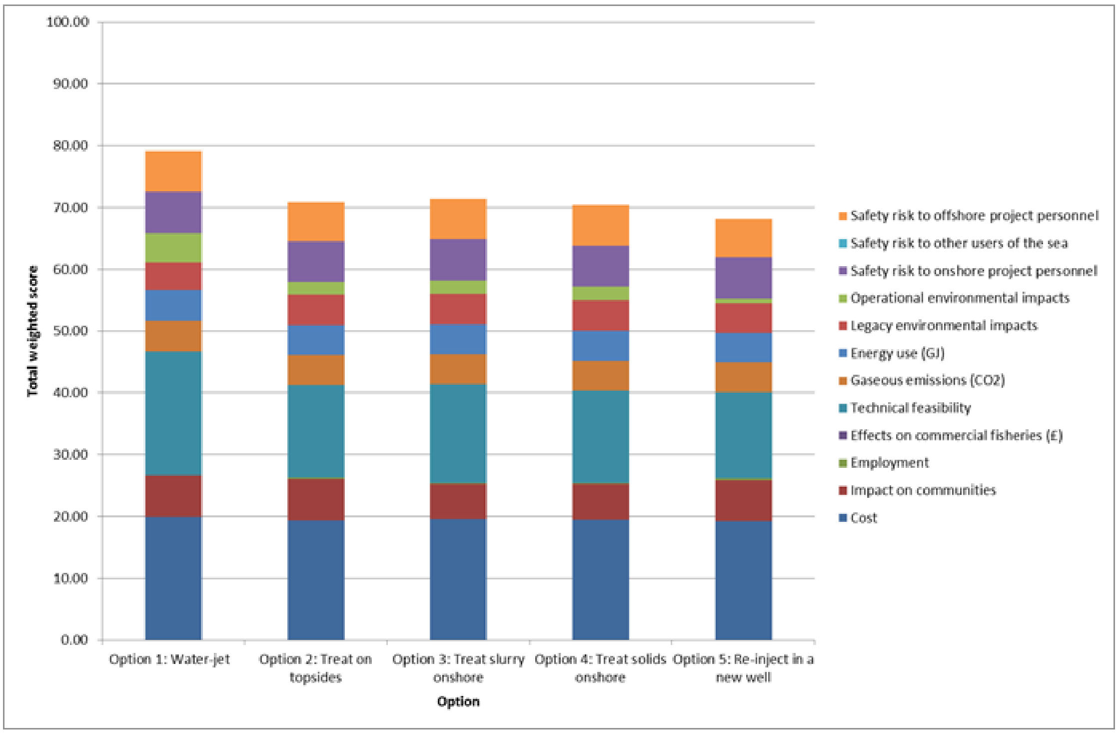
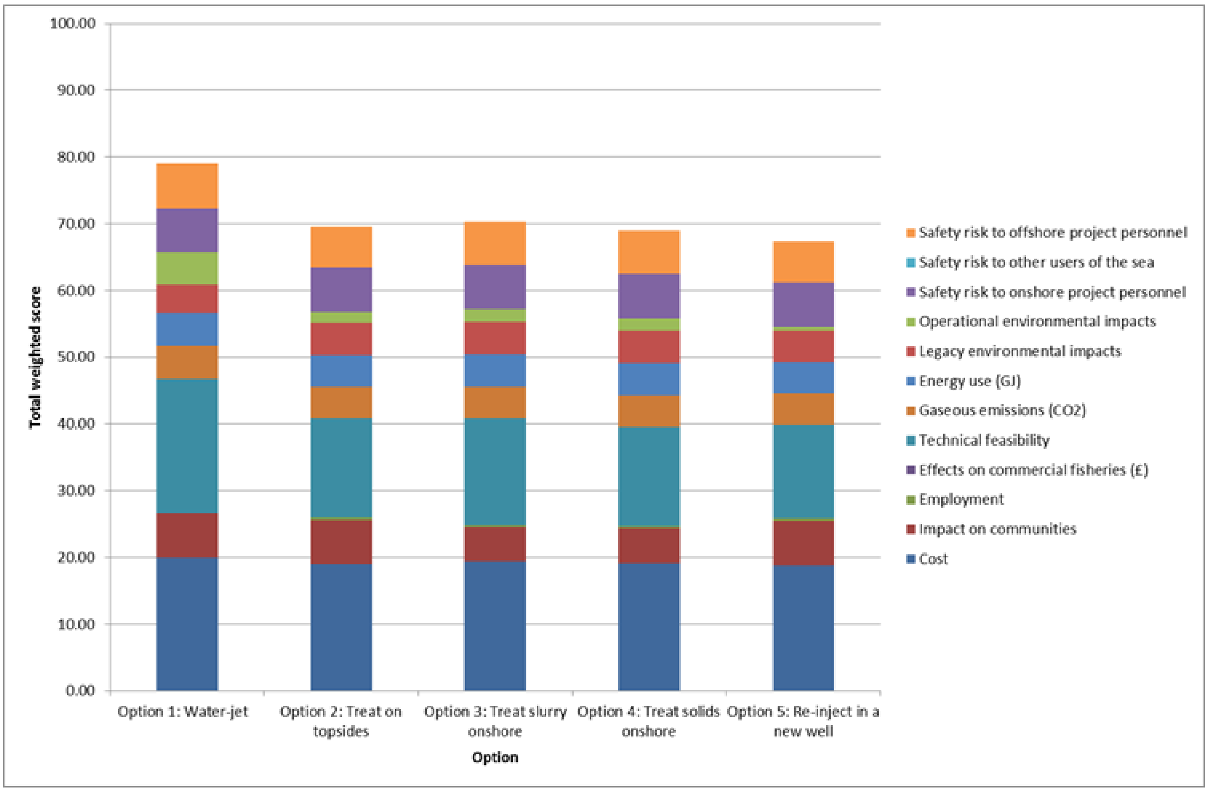


Table 64 Transformed and Weighted Sub-criteria Scores of Options for the Brent Delta Cell-Top Drill Cuttings Pile.

Sub-criterion	Option 1	Option 2	Option 3	Option 4	Option 5
Safety risk offshore project personnel	6.66	6.08	6.51	6.48	6.10
Safety risk to other users of the sea	–	–	–	–	–
Safety risk onshore project personnel	6.67	6.67	6.67	6.67	6.67
Operational environmental impacts	4.75	1.55	1.80	1.80	0.50
Legacy environmental impacts	4.25	5.00	5.00	5.00	4.90
Energy use	4.99	4.71	4.77	4.74	4.61
Emissions	4.99	4.76	4.81	4.79	4.68
Technical feasibility	20.00	14.80	16.00	14.80	14.00
Effects on commercial fisheries	–	–	–	–	–
Employment	0.00	0.35	0.21	0.28	0.40
Communities	6.67	6.67	5.20	5.27	6.67
Cost	19.99	18.94	19.37	19.16	18.79
Total weighted score	78.98	69.54	70.33	68.99	67.32

Option 1	Water-jet
Option 2	Treat on topsides
Option 3	Treat slurry onshore
Option 4	Treat solids onshore
Option 5	Re-inject in a new well

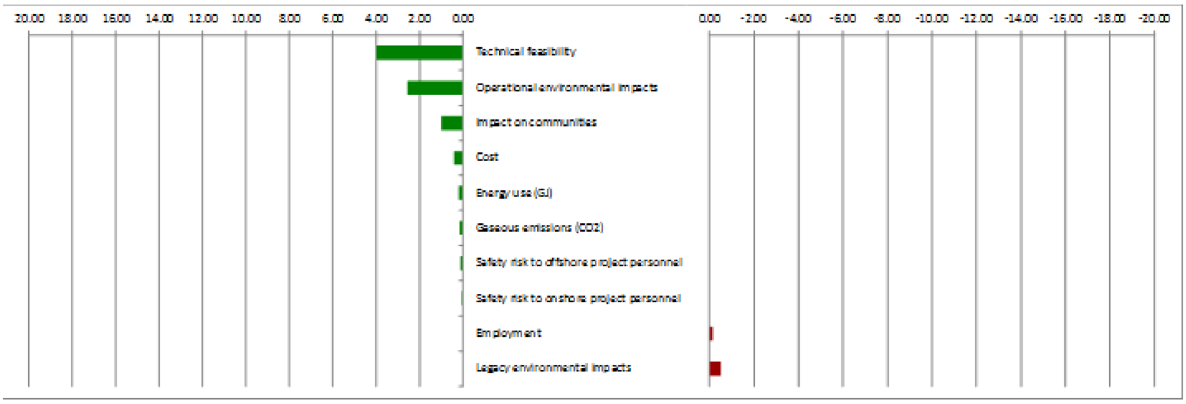
Figure 99 The Total Weighted Scores for Options for the Brent Delta Cell-Top Drill Cuttings Pile, and the Contributions of the Sub-criteria.



17.9.3 Discussion and Conclusions on Options for the Bravo and Delta cell-Top Drill Cuttings Piles

Option 1 'Water jet' is consistently the best option in all the weighting scenarios, for both the Bravo and Delta cell-top cuttings piles. Of the four options which involve the removal of the whole cuttings pile, Option 3 'Treat slurry onshore' is the best option in all the weighting scenarios for both Bravo and Delta. The section below therefore examines the differences between these two options.

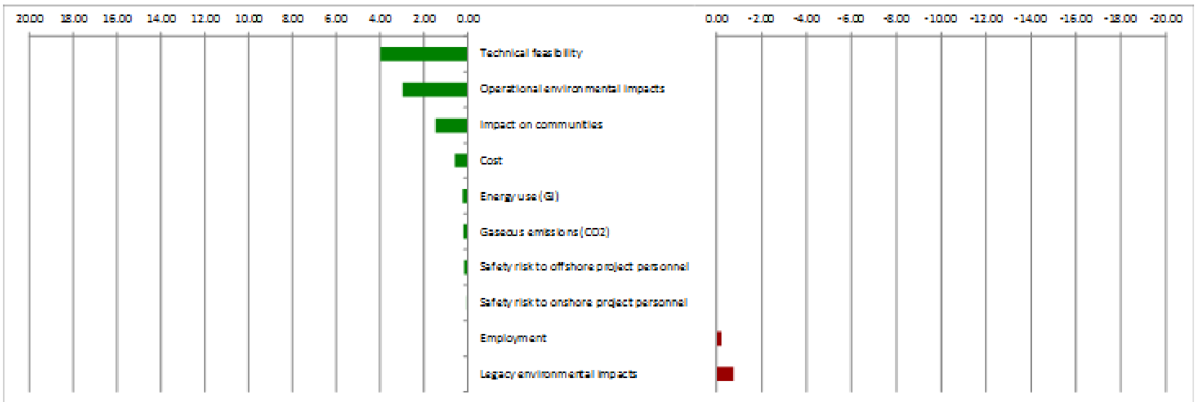
Figure 100 Difference chart Comparing the Weighted Scores for each Sub-criterion in Two Options for the management of the Brent Bravo Cell-Top Drill Cuttings pile, under the Standard Weighting.



Green bars: Option 1 'Water-jet' is better than Option 3 'Treat slurry onshore'

Red bars: Option 3 'Treat slurry onshore' is better than Option 1 'Water-jet'

Figure 101 Difference chart Comparing the Weighted Scores for each Sub-criterion in Two Options for the management of the Brent Delta Cell-Top Drill Cuttings pile, under the Standard Weighting.



Green bars: Option 1 'Water-jet' is better than Option 3 'Treat slurry onshore'

Red bars: Option 3 'Treat slurry onshore' is better than Option 1 'Water-jet'

The results for both Brent Bravo and Delta demonstrate that Option 1 'Water-jet' is preferable to Option 3 'Treat slurry onshore' in terms of technical feasibility, operational environmental impacts, and to a lesser degree impacts on communities, cost, energy and emissions and safety risk to project personnel. Option 3 is preferable in terms of legacy environmental impacts and, to a smaller extent, employment. In terms of the global scales for each of the sub-criteria, however, there are no strong drivers that differentiate the options.

In Option 1 approximately 40 m^3 (Bravo) or 20 m^3 (Delta) of drill cuttings would be moved into the cell valleys to allow access to the cell-tops to drill a small access hole to recover the attic oil and interphase material, and some drill cuttings would unavoidably be dispersed into the water column. In Option 3 we have assumed that the entire cell-top volume of drill cuttings (approximately1,887 m^3 on Bravo and 3,790 m^3 on Delta) would have to be displaced, again releasing a proportion of drill cuttings into the water column during the dredging operation. In real terms, there is no strong environmental driver to select either of the options as neither is expected to cause or result in significant environmental impacts in the short- or long-term. The increased operational impacts, represented by a difference between Option 1 and Option 3 in the weighted scores in this sub-criterion, is disproportionate to the decrease in legacy environmental impacts that Option 3 would achieve over Option 1. It is illogical to remove the drill cuttings pile in Option 3 in an attempt to remove a long-term source of contamination to the marine environment when the dredging operation itself would probably release more drill cuttings into the water column than in Option 1. This is then compounded by the added expenditure of Option 3 to achieve the very minor decrease in the legacy environmental impact arising from Option 1, particularly as the legacy impacts for both options are considered to be low.

17.9.4 Recommended Option for the Brent Bravo and Brent Delta Cell-Top Drill Cuttings Piles

As described in Section 17.5, the Brent Bravo and Delta cell-top drill cuttings piles are believed to fall below the OSPAR thresholds and could therefore be left undisturbed to degrade naturally. However, a small volume of drill cuttings had to be cleared from the Brent Delta cell caps to allow the deployment of the cell access equipment which facilitated the recovery of cell content samples, and which will be used to recover the attic oil and interphase material from the Delta cells. In the event that the oil fill lines on Brent Bravo cannot be used to recover any attic oil or interphase material that may be found to be present, new access holes similar to those on Brent Delta will be required. The CA of options for the management of these cell-top drill cuttings piles has indicated that if a small access hole were required, the displacement of a small amount of drill cuttings into the water column by water-jet is the preferred option for clearing cuttings from the cell cap. If a larger access hole were required for any reason, necessitating the disturbance of a greater volume of drill cuttings, then the recommendation would be to recover the drill cuttings to shore for treatment and disposal.

Brent Bravo cell-top drill cuttings pile: If access to the cells is required, small volumes may be displaced by water-jetting, larger volumes may be removed. If the cuttings are not to be disturbed they will be left in place to degrade naturally.

Brent Delta cell-top drill cuttings pile: Small volumes have been displaced by water-jetting. Larger volumes may be removed if greater access to the cells is required. If greater access is not required, no further disturbance of the cuttings will occur and they will be left in place to degrade naturally.

17.10 Options for the Management of Brent Charlie Cell-Top Cuttings Pile

17.10.1 Introduction

Our modelling indicated that the initial oil loss rate from the Charlie cell-top pile exceeds the OSPAR oil-loss threshold of 10 tonnes/year. This pile was therefore subject to a full CA as required by Stage 2 of OSPAR recommendation 2006/5 [11]. In addition, we have committed to recovering any attic oil and interphase material from the Brent Charlie cells and although we believe this will be possible through the existing vent lines, there is a possibility that new subsea access holes wold be required. This would necessitate the displacement of cell-top drill cuttings and so, as a worst case, this possibility has been considered within the CA. As with Bravo and Delta the management options for the Charlie GBS cell contents may require larger diameter access holes to be created in the Brent Charlie cell-tops, which would require the disturbance of the existing cell-top cuttings pile.

17.10.2 Options for the Brent Charlie Cell-Top Cuttings Pile

Our studies have indicated that an amount of drill cuttings ranging from 20 m^3 to 6,000 m^3 might have to be cleared to permit different programmes of work to be carried out to work on the cell-tops and gain access to the cells. Because of the shape, large size and location of the Charlie cell-top cuttings pile in and around the external conductors, we believe that if water-jetting were to be used to disturb even a small volume of the drill cuttings, for example to clear only the cell-caps, it would probably result in the destabilisation of the whole drill cuttings pile and cause it to partly or wholly collapse. Consequently, the option to water-jet the cuttings has not been considered for Brent Charlie. As a worst case, the CA has been conducted assuming that all of the drill cuttings (7,735 m^3) are removed; it is likely that we would remove the majority of the drill cuttings to leave a clear work-area for any operation that might be required. The five options considered for the Brent Charlie cell-top drill cuttings are presented in Table 65.

Table 65 Technically Feasible Options for the Brent Charlie Cell-Top Drill Cuttings Pile.

Option	Option Name	Option Description
Option 2	Treat on topsides	Dredge, transfer to topside, separate the slurry, treat both liquid and solids, and discharge cleaned material to sea
Option 3	Treat slurry onshore	Dredge, transfer to a vessel and transport to shore for treatment and disposal
Option 4	Treat solids onshore	Dredge, transfer to topside, separate and treat the slurry and discharge cleaned water to sea, and transport solids to shore for treatment and disposal
Option 5	Re-inject in a new well	Dredge, transfer to a vessel and re-inject into a new remote well
Option 6	Leave *in situ*	Leave in place

Note: Option 1 'Water-jet' does not apply to Brent Charlie cell-top drill cuttings pile.

17.10.3 Results of Comparative Assessment of Options for the Charlie Cell-Top Drill Cuttings

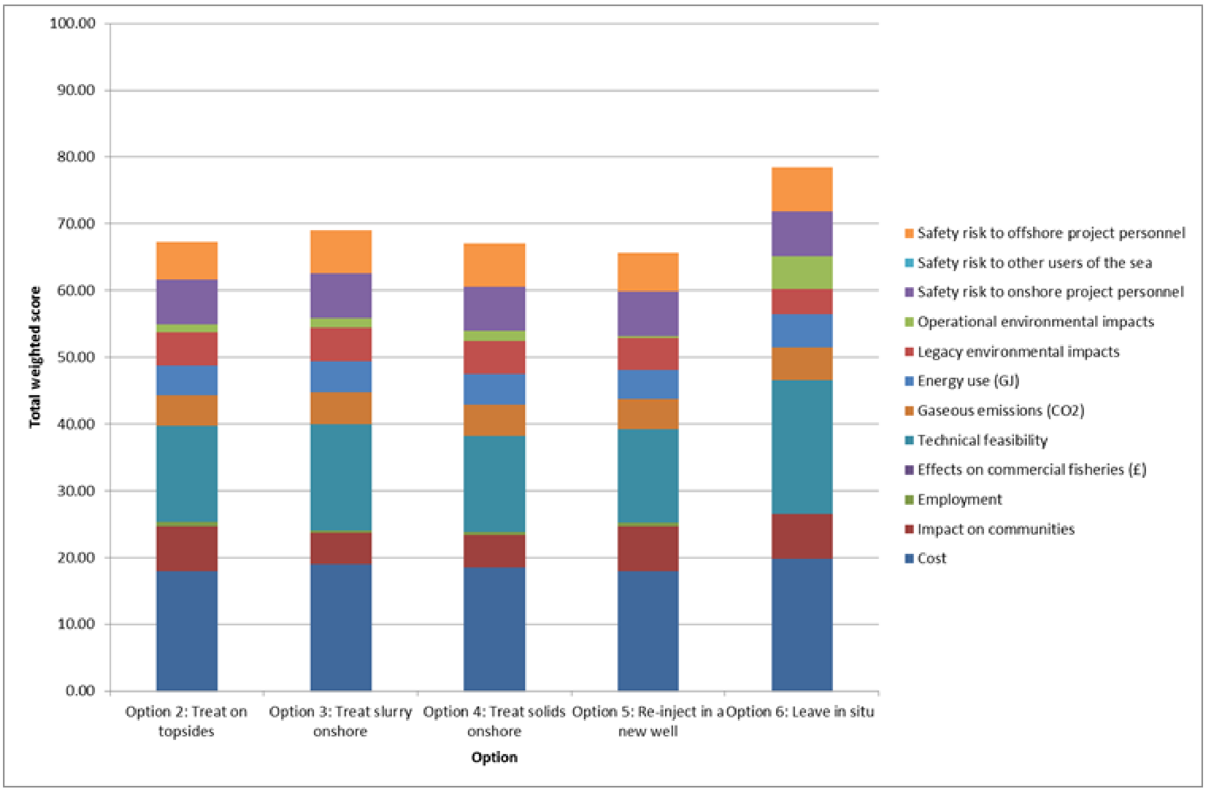
The results of the CA for the Charlie cell-top drill cuttings are presented in detail in the Drill Cuttings TD [16] and summarised below. Table 66 presents the weighted sub-criteria scores for the five options examined and Figure 102 illustrates the results. On the basis of this assessment the 'CA-recommended' option for the management of the Brent Charlie Cell-top drill cuttings is Option 6 'Leave in place'. It has a total weighted score of 78.41 in contrast to Option 3's total weighted score of 69.00.

Table 66 Transformed and Weighted Sub-criteria Scores for the Brent Charlie Cell-Top Drill Cuttings Pile.

Sub-criterion	Option 2	Option 3	Option 4	Option 5	Option 6
Safety risk offshore project personnel	5.68	6.48	6.46	5.72	6.58
Safety risk to other users of the sea	–	–	–	–	–
Safety risk onshore project personnel	6.67	6.66	6.67	6.67	6.67
Operational environmental impacts	1.20	1.45	1.45	0.25	5.00
Legacy environmental impacts	5.00	5.00	5.00	4.90	3.75
Energy use	4.48	4.68	4.60	4.32	4.91
Emissions	4.58	4.74	4.67	4.44	4.93
Technical feasibility	14.40	16.00	14.40	14.00	20.00
Effects on commercial fisheries	–	–	–	–	–
Employment	0.69	0.34	0.50	0.70	0.05
Communities	6.67	4.67	4.80	6.67	6.67
Cost	17.95	18.98	18.50	17.91	19.86
Total weighted score	67.32	69.00	67.06	65.58	78.41

Option 2	Treat on topsides
Option 3	Treat slurry onshore
Option 4	Treat solids onshore
Option 5	Re-inject in a new well
Option 6	Leave *in situ*

Figure 102 The Total Weighted Scores for Options for the Brent Charlie Cell-Top Drill Cuttings Pile, and the Contributions of the Sub-criteria.



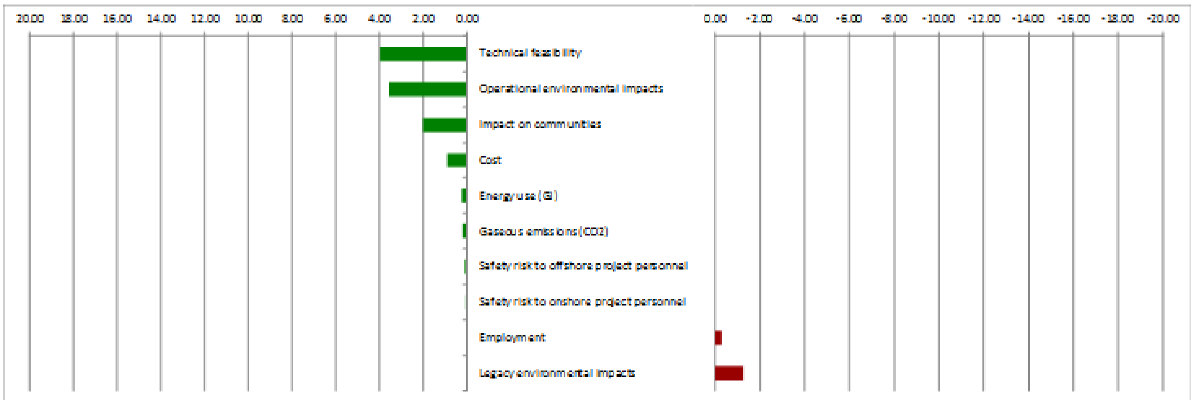
17.10.4 Discussion and Conclusion on Options for the Brent Charlie Cell-Top Cuttings Pile

With the exception of Option 6 all the options would result in the removal of the cuttings pile from the marine environment and thus the elimination of a potential long-term source of hydrocarbon contamination. The total weighted scores for the 'removal' options range from 65.58 to 69.0. This is a range of 3.42 which means that among the 'removal' options the total weighted score of the best option is about 5% higher than that of the poorest option. Thus, by a small margin, Option 3 'Remove and treat slurry onshore' is the best of the 'removal' options.

Option 6 'Leave in place' is the best option overall, with a total weighted score that is consistently greater than the next best option, Option 3. The section below therefore examines the difference between Option 3 'Remove and treat slurry onshore' and Option 6 'Leave in place'.

Examination of both the transformed unweighted data and weighted scores for each of the sub-criteria shows that the differences between the two options are driven by differences in performance in 'technical feasibility', 'operational environmental impacts', and 'impacts on communities' (which are better in Option 6 'Leave in place'), and 'legacy environmental impacts' (which is better in Option 3 'Remove and treat slurry onshore'). All the other sub-criteria show only very small differences between the options in terms of their weighted scores. This is illustrated in Figure 103 which shows the differences (positive or negative) in the weighted scores in each sub-criterion for these two options for the Charlie cell-top cuttings.

Figure 103 Difference Chart Comparing the Weighted Scores for each Sub-Criterion in Two Options for the Management of the Brent Charlie Cell-Top Drill Cuttings, under the Standard Weighting.



Green bars: Option 6 'Leave *in situ*' is better than Option 3 'Remove and treat slurry onshore'

Red bars: Option 3 'Remove and treat slurry onshore' is better than Option 6 'Leave *in situ*'

Following the assessment of the real data informing these scores we have concluded that there are no strong drivers that differentiate the best removal option Option 3 'Remove and treat slurry onshore' and Option 6 'Leave in place'. Much of the concern regarding the long-term presence of drill cuttings arises from the potential for a chronic but low level source of contamination affecting the marine environment. This concern may be elevated in the case of the Brent Charlie cell-top drill cuttings pile given the results of the long-term fate modelling study [60] and the predicted exceedance of the OSPAR Recommendation 2006/5 oil loss rate threshold [60]. In real terms, however, there is no strong environmental driver to select either of the options as neither is expected to cause or result in significant environmental impacts: The assessments made by DNV GL do not indicate any severe environmental impacts from leaving the Brent Charlie cell-top drill cuttings pile in place and the raw data score for legacy environmental impacts in Option 6 reflects this. The difference between the two options in the raw data score for the sub-criterion 'legacy environmental impacts' is 0.25 (the top ("best") end of the raw data scale is 1.0) with Option 3 performing better than Option 6. The difference between the two options in the score for the sub-criterion 'operational environmental impact' (scale size 1.0) is 0.71, with Option 6 performing better than Option 3. This indicates that the increase in operational impacts associated with recovering the drill cuttings pile is greater than the assessed long-term impacts of leaving the drill cuttings pile in place. It also suggests that the increased expenditure of Option 3 (approximately £23 million) would not result in a material decrease in long-term environmental impacts.

The environmental benefits of removing the long-term chronic effects of an *in situ* drill cuttings pile are likely to be outweighed by the potential acute effects of removing the drill cuttings. It therefore appears that no tangible environmental benefit could be achieved by incurring the extra cost of removing the drill cuttings if they do not have to be disturbed or removed for the purposes of other decommissioning operations.

17.10.5 Recommended Option for the Charlie Cell-Top Cuttings

The detailed CA of feasible options (Section 17.10.3), carried out in accordance with OSPAR recommendation 2006/5 [11] and using the selection criteria and matters to be considered set out in Annex 2 of OSPAR Decision 98/3 [2], has indicated that the recommended option for decommissioning the undisturbed Brent Charlie cell-top drill cuttings is as follows:

Brent Charlie cell-top drill cuttings pile: Leave in place to degrade naturally. If any other decommissioning activities are likely to disturb the drill cuttings pile, the entire drill cuttings pile will be removed and taken to shore for treatment and disposal.

17.11 Recommended Programme of Work for Decommissioning the Brent Field Drill Cuttings Piles

17.11.1 Seabed Cuttings Piles

None of the planned decommissioning operations will require the mass disturbance of the historic cuttings piles on the seabed at any of the Brent sites. The recommended option for all seabed drill cuttings pile is therefore to leave them in place, undisturbed, to degrade naturally.

17.11.2 Cell-top Cuttings Piles

To complete the current programme of work to remove the attic oil and interphase material from the cells (where present) and take this material to shore for treatment and recycling we may need to create new subsea access holes, and therefore may need to move small amounts of drill cuttings from the cell-tops by water jetting. Such operations have already been completed on Brent Delta to allow the CSP access to sample the cell contents. The same access holes will be used to recover the attic oil and interphase material. If a large volume of Brent Delta cell-top cuttings has to be removed for any reason, we will take the cuttings to shore for processing and disposal.

On Brent Bravo we intend to reinstate the oil fill lines in order to recover any attic oil and/or interphase material remaining in the cells after the bulk de-oiling operations. If these operations are successful the cell-top drill cuttings will remain undisturbed. If the oil fill lines cannot be reinstated, however, we will water-jet the small amount of drill cuttings from the cell caps. If a large volume of Brent Bravo cell-top cuttings has to be removed for any reason, we will take the cuttings to shore for processing and disposal.

The Stage 2 assessment for Brent Charlie has shown that the recommended option for the cell-top drill cuttings pile is to leave it in place, undisturbed. As we intend to reinstate the vent lines to recover any remaining attic oil and/or interphase material from this platform, we have no cause to disturb the cuttings pile. If any disturbance is required for any reason, we will remove the whole volume of the Charlie cell-top cuttings pile and take the cuttings to shore for treatment and disposal.

17.11.3 Drill cuttings in the Tri-Cells

As discussed in Section 17.3 and Section 17.4, any drill cuttings that are present in the tri-cells will have been created during the same drilling operations that have created the Brent Bravo and Brent Delta cell-top and seabed drill cuttings piles, and will be contaminated with OPF. We have therefore considered them under OSPAR Recommendation 2006/5 and although we have not specifically modelled the long-term fate of these drill cuttings we have estimated their potential oil loss rate and area persistence. We have concluded that neither in isolation nor when combined with the other drill cuttings present at those two GBSs will the *in situ* tri-cell drill cuttings exceed either of the thresholds in that Recommendation. There are no planned operations that would disturb the tri-cell drill cuttings. They will be released and/or disturbed during the eventual collapse of the GBS caissons, but given their location within the structure this is likely to occur in several hundred years' time. These drill cuttings will therefore be left undisturbed.

17.12 Environmental Impacts of Decommissioning Seabed Cuttings Piles

17.12.1 Stakeholder Environmental Concerns

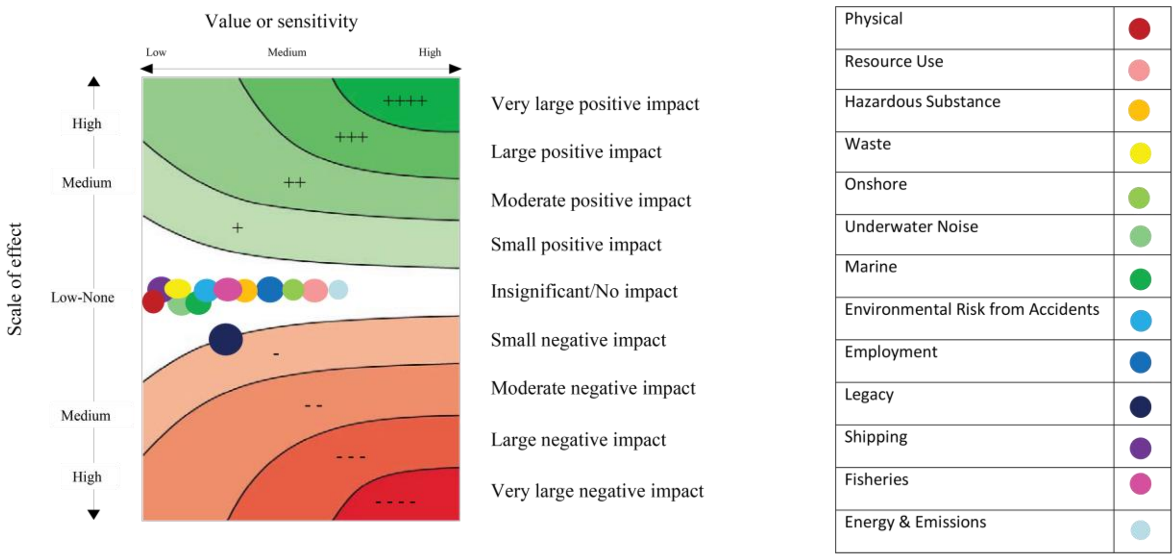
For the recommended options for the drill cuttings, the specific environmental concerns or issues raised by our stakeholders were:

- Long-term legacy impacts from presence of cuttings piles on seabed.
- Disturbance of cuttings by falling debris.
- The long-term spread of cuttings as they are eroded and the effects this would cause.
- The cumulative effects of the cuttings on the seabed with the effects of cell sediment contents when exposed after GBS degradation (potential cumulative impacts are described in Section 22.3).

17.12.2 Potentially Significant Impacts in ES

Figure 104 presents DNV GL's summary of the results of the environmental impact assessment for leaving the seabed drill cuttings piles in place, undisturbed [5]. The ES found that the most significant negative impact from this activity was the legacy impact to the marine environment which was estimated to be 'insignificant-small negative' as result of the long-term presence and slow erosion of the cuttings piles. All the other categories of impacts were estimated to be 'insignificant'.

Figure 104 The Environmental Impacts of Decommissioning all the Brent Seabed Drill Cuttings Piles by Leaving them in Place.



17.12.3 Legacy Environmental Impacts of Undisturbed Cuttings Piles

The area physically covered by drill cuttings at present is approximately 21,744 m^2 (approximately 0.02 km^2) (Table 67) and comprises approximately 18,689 m^2 on the seabed and 3,055 m^2 on the cell-tops of the GBSs. To put this into some context, this total area of 0.02 km^2 represents about 0.0007% of ICES rectangle 51F1. Our seabed surveys have confirmed that the area of seabed around each structure that exhibits THC level of >50 $mg.kg^{-1}$ is between 500 m and 1,000 m in radius and is decreasing [57] [58], and we expect this trend to continue. If the area around each site with a THC >50 mg.kg-1 had a radius of approximately 750 m the total area in the Brent Field exhibiting such THCs would be approximately 9 km^2, that is, about 0.3% of ICES rectangle 51F1.

At 140 m depth in the Brent Field the physical erosion of the piles will be slow, and when left undisturbed the cuttings piles at all five sites will last many hundreds of years. Modelling of the long-term fate and effect of the seabed drill cuttings pile at Brent Alpha shows that the pile would degrade slowly over a long period time, possibly more than 1,000 years, with contaminated material being eroded and re-deposited on the immediately adjacent seabed. At 6,300 m^3 this pile is the largest of the Brent Field seabed cuttings piles (Table 58) and is thus likely to exhibit the greatest physical and chemical persistence. Figure 105 shows the modelled longevity and slow disappearance of the seabed drill cuttings pile at Brent Alpha.

The Brent Charlie cell-top pile, with a slightly greater volume of 7,735 m^3, has been modelled separately as reported in the Drill Cuttings TD [16].

Figure 105 Modelled Degradation and Disappearance of the Seabed Drill Cuttings Pile at Brent Alpha.

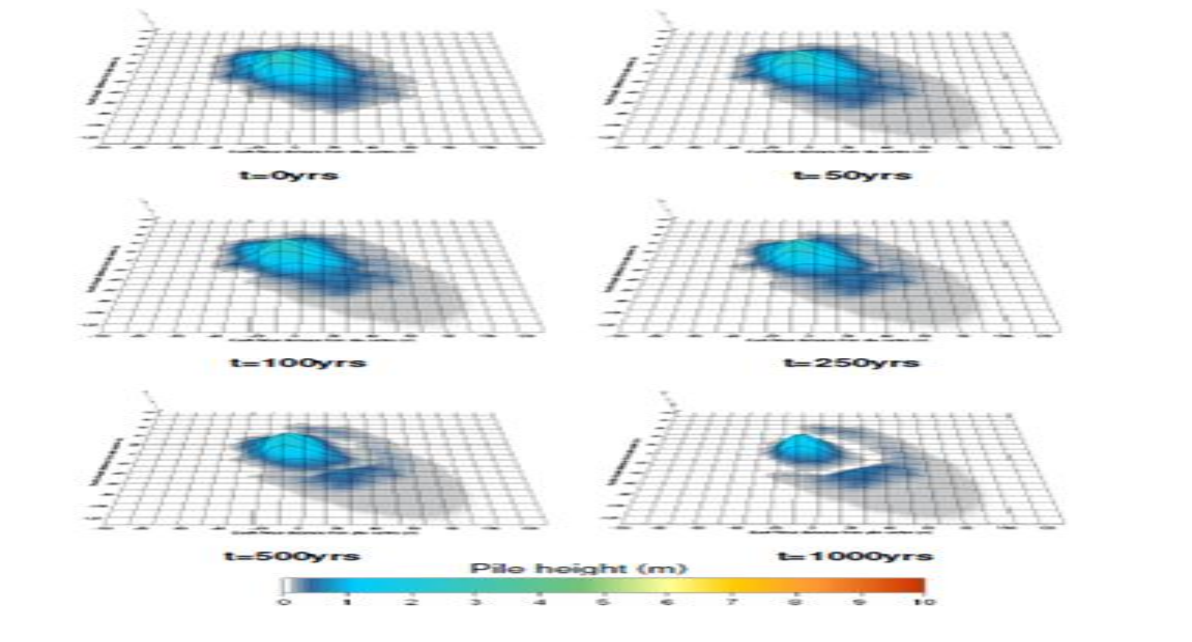


Table 67 Estimates of Seabed Area Physically Covered by Drill Cuttings Piles.

Location	Area Covered by Drill Cuttings (m^2) (2007 survey data)
Brent Alpha seabed	**8,880**
Brent Bravo Seabed	3,414
Brent Bravo Cell-top (Note 1)	673
Brent Bravo combined cuttings piles	**4,087**
Brent Charlie Seabed	3,143
Brent Charlie Cell-top	2,148
Brent Charlie combined cuttings piles	**5,561**
Brent Delta Seabed	1,632
Brent Delta Cell-top (Note 1)	234
Brent Delta combined cuttings piles	**1,866**
Brent South seabed	**1,620**
Total area in Brent Field covered by cuttings	**22,014**

Note: 1. The area covered by the cell-top drill cuttings pile includes the area occupied by the drill cuttings in the tri-cells.

17.12.4 Energy and Emissions

The sources of energy use and gaseous emissions will be the offshore operations to water-jet small volumes of drill cuttings from the Bravo and Delta cell-tops, and the post-decommissioning monitoring surveys. The number and frequency of surveys following the two post-decommissioning surveys has yet to be agreed and discussed with BEIS.

17.12.5 Mitigation Measures for Seabed Cuttings Programme of Work

- The post-decommissioning monitoring of the Field (Section 24) will determine if any new contamination has occurred during decommissioning, and this will include an assessment of whether cuttings have been re-suspended and then caused new contamination.
- The long-term monitoring programme of the Field, to be agreed with BEIS (Section 24.4), will provide data with which to determine if recovery is taking place.

17.13 Environmental Impacts of Decommissioning the Bravo and Delta Cell-Top Cuttings Piles

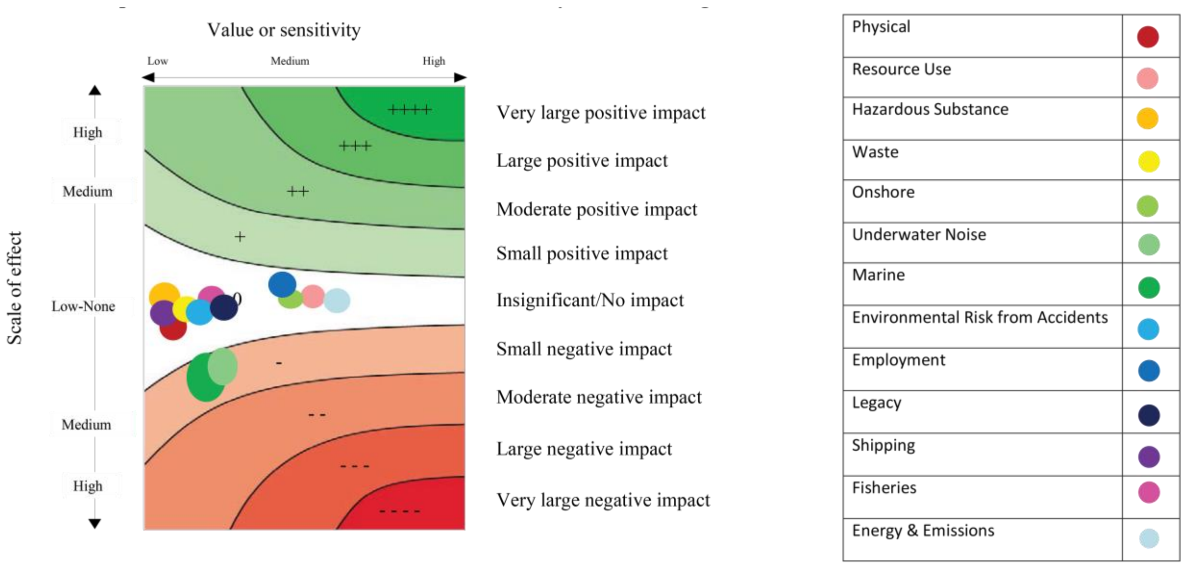
17.13.1 Stakeholder Environmental Concerns

- The specific environmental concerns or issues raised by our stakeholders were: Accidental discharges or releases of hydrocarbons to sea.
- Long-term legacy impacts from presence of cuttings.

17.13.2 Potentially Significant Impacts in ES

Figure 106 presents DNV GL's summary of the results of the assessment of the operational environmental impacts of displacing small volumes of the Bravo and Delta cell-top drill cuttings by water-jetting, and the legacy environmental impacts of leaving the remaining drill cuttings in place to degrade naturally [5]. The ES found that the most significant negative impact from this activity was the operational impact to the marine environment which was estimated to be 'small negative' as result of the resuspension and then settlement of cuttings, and underwater noise from operations. All the other categories of impacts were estimated to be 'insignificant'.

Figure 106 Environmental Impacts of Local Displacement of Small Volumes of Drill Cuttings from Cell-tops on both Bravo and Delta.



17.13.3 Impacts of Operations

If the localised water-jetting operations are carried out carefully the cuttings will be re-suspended and drift from the cell-tops. Some small amounts of free oil may rise through the water column and in very calm conditions could appear on the surface of the sea as a 'sheen', but this will disperse rapidly offshore.

17.13.4 Legacy Impacts

The cell-top cuttings piles at Bravo and Delta will slowly erode and biodegrade, releasing oil and oil-contaminated cuttings into the water column and onto the adjacent seabed. Oil released into the water column will quickly disperse and biodegrade. Resuspended cuttings will mostly settle onto adjacent areas of the seabed around the GBSs, forming a thin new layer of cuttings over areas previously impacted by the historic discharge of cuttings. The settlement of these small additional amounts of material may delay the recovery of the seabed around the platforms but the new layer will be thin and this will facilitate degradation of the THC; no sensitive species or ecosystems will be impacted. DNV GL estimated that the legacy impact of the much larger Charlie cell-top drill cuttings was 'small negative' (Section 17.14.3) and so it is likely that the legacy impacts of the Bravo and Delta cell-top cuttings piles will be less than this, and DNV GL estimated that their legacy impact was 'insignificant-no impact'.

17.13.5 Energy and Emissions

The offshore operations to displace cell-top cuttings from both Bravo and Delta by water jetting would use approximately 5,700 GJ of energy and result in the emission of approximately 542 tonnes of CO_2 (Table 68).

Table 68 Total Energy Use and Gaseous Emissions for Programme of Work to Water Jet Cuttings from the Bravo and Delta Cell-tops.

Operations	Energy (GJ)	Emissions to Atmosphere (tonnes)		
		CO_2	NO_X	SO_2
Direct				
Marine operations	5,732	423	9	3
Recycling				
Materials not recycled	ND	119	ND	ND
Total	5,732	542	9	3

ND = No Data

17.13.6 Mitigation Measures for Cell-Top Cuttings Programme of Work

- If small amounts of cuttings have to be moved from the cell tops to permit the recovery of attic oil and interphase material, we will apply to BEIS for all necessary permits for such an activity.
- The post-decommissioning environmental surveys (Section 24.3) will determine if any new contamination has occurred during decommissioning, and this will include an assessment of whether cuttings have been re-suspended and then caused new contamination.
- The long-term monitoring programme of the Field, to be agreed with BEIS (Section 24.4), will provide data with which to determine if recovery is taking place.

17.14 Environmental Impacts of Decommissioning Charlie Cell-Top Cuttings Piles

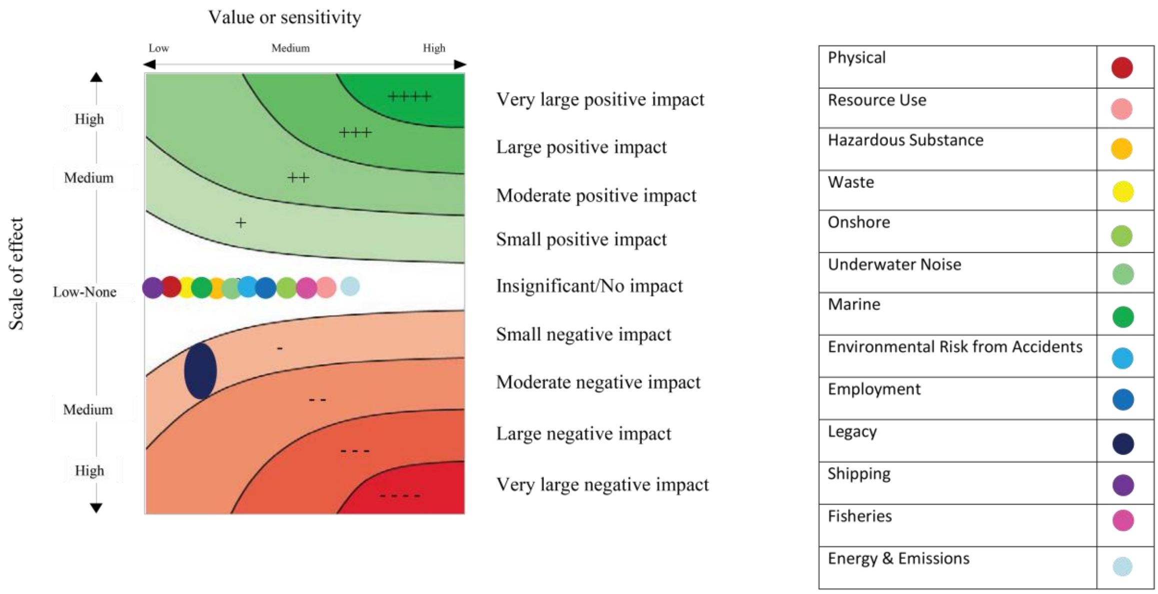
17.14.1 Stakeholder Environmental Concerns

- The specific environmental concerns or issues raised by our stakeholders were: Accidental discharges or releases of hydrocarbons to sea.
- Long-term legacy impacts from presence of cuttings on cell-top.
- Impacts from release of contaminants to water column and seabed.

17.14.2 Potentially Significant Environmental Impacts

Figure 107 presents DNV GL's summary of the results of the assessment of the environmental impacts of leaving the Charlie cell-top cuttings pile in place and undisturbed. There would be no operations and hence no operational environmental impacts. The ES found that the most significant negative impact from this activity was the legacy impact which was estimated to be 'small negative' as result of the erosion, resuspension and then settlement of cuttings, and the associated input of oil into the marine environment. All the other categories of impacts were estimated to be 'insignificant-no impact'.

Figure 107 Environmental Impacts of Decommissioning the Brent Charlie Cell-Top Drill Cuttings by Leaving them in Place.



17.14.3 Legacy Impacts of Brent Charlie Cuttings Pile

The large cell-top cuttings pile on Charlie will slowly erode and within thirty years the rate of oil release from the cell-top drill cuttings pile will fall to below 10 tonnes per year. Modelling suggests that if this cell-top pile were left undisturbed it would persist for approximately 500-750 years, reaching maximum area persistence of approximately 3 km^2years [60]. The assessment of potential legacy environmental impacts in the ES states [5]:

> 'Even though one of the OSPAR thresholds is exceeded, based on the current knowledge, the environmental impact from the cell top cuttings [at Brent Charlie] is local and no major effects have been identified. The environmental impact is evaluated to be 'small negative'. There is limited benthic fauna on the cell tops, and although some oil may leak into the water column and migrate upwards, it is very unlikely to generate any slicks on the sea surface that have any potential for impacts to marine life (seabirds). This condition is likely to proceed as long as the cuttings are left undisturbed.'

17.14.4 Energy and Emissions

The only sources of energy use and gaseous emissions from the proposed 'Leave in place' option for the Brent Charlie cell-top drill cuttings pile would be the planned post-decommissioning environmental surveys (Table 69).

Table 69 Total Energy Use and Gaseous Emissions of Decommissioning the Brent Charlie Cell-top Cuttings pile by Leaving In Place.

Operations	Energy (GJ)	Emissions to Atmosphere (tonnes)		
		CO_2	NO_X	SO_2
Direct				
Marine operations	30,687	2,263	46	14
Recycling				
Materials not recycled	ND	275	ND	ND
Total	30,687	2,539	47	14

ND = No Data

17.14.5 Mitigation Measures for Brent Charlie Cell-top Drill Cuttings

- To avoid disturbing the cuttings the debris wholly buried in the cell-top cuttings pile will not be removed. Any visible sections of partially buried debris will be severed as close to the cuttings as possible without causing disturbance and removed.
- The post-decommissioning environmental surveys (Section 24.3) will determine if any new contamination has occurred during decommissioning, and this will include an assessment of whether cuttings have been re-suspended and then caused new contamination.
- The long-term monitoring programme of the Field, to be discussed and agreed with BEIS (Section 24.4), will provide data with which to determine if recovery is taking place.

17.15 Environmental Impacts of Decommissioning the Tri-Cell Drill Cuttings

17.15.1 Stakeholder Environmental Concerns

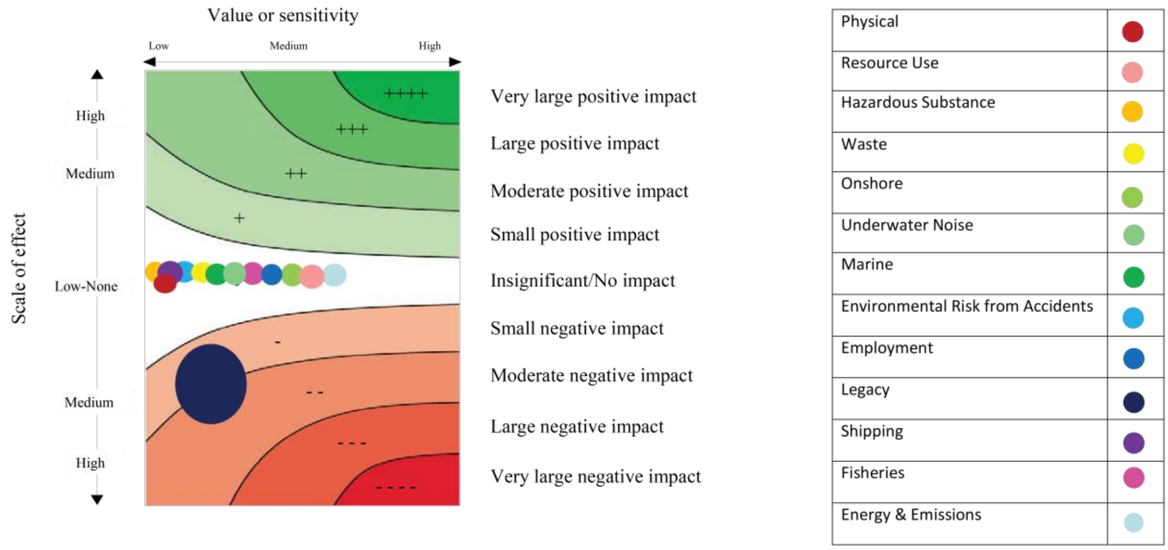
The specific environmental concerns or issues raised by our stakeholders were:

- The status of the tri-cell drill cuttings with respect to OSPAR Recommendation 2006/5 and the two thresholds defined in that Recommendation.
- The environmental effects of the eventual exposure of the tri-cell drill cuttings, both on their own and cumulatively with the other materials in the GBS, when the GBSs degrade and collapse.

17.15.2 Potentially Significant Impacts in the ES

Figure 108 presents DNV GL's summary of the assessment of the environmental impacts of leaving all the approximately 27,000 m^3 of tri-cell drill cuttings in Bravo and Delta in place. There would be no operations and hence no operational impacts. The ES found that the most significant negative impact from this activity was in the legacy category, which was estimated to be 'small-moderate negative'. All the other categories of impacts were estimated to be 'insignificant-no impact'.

Figure 108 Environmental Impacts of Decommissioning the Tri-cell Drill Cuttings in the Brent Condeep GBSs by Leaving them in Place.



17.15.3 Legacy Impacts of Tri-Cell Drill Cuttings

The total estimated volume of drill cuttings inside the tri-cells on Bravo and Delta is approximately 27,000 m^3 and based on the 2007 survey data from seabed and cell-top drill cuttings piles this accounts for approximately 44% of the total estimated volume of drill cuttings in the Brent Field. The total volume of drill cuttings in the 22 tri-cells in Bravo (12,039 m^3) and Delta (14,733 m^3) are respectively about 50% and 100% larger than the volume of the largest external drill cuttings pile in the Brent Field, the 7,735 m^3 accumulation on the Brent Charlie cell tops.

DNV GL estimated that the overall legacy impact of leaving the tri-cell drill cuttings in place was 'small-moderate' negative. Because of the large volume of undegraded cuttings in the tri-cells, the assessment of legacy impacts by DNV GL is given in full below. The cumulative impacts from the combined exposure to the marine environment of the tri-cells drill cuttings and cell contents is discussed in Section 22.7.

DNV GL described the potential legacy impacts of the tri-cell cuttings as follows [5]:

> 'In the short to medium-term the tri-cell drill cuttings are expected to remain covered by the GBS cell-top drill cuttings, or have only a limited area exposed to the water column. Hence there would be an insignificant impact until the GBS degrade over time and the tri-cell drill cuttings become exposed to the marine environment some hundred or more years into the future.
>
> The tri-cell drill cuttings will ultimately become exposed to the sea when the GBS degrade, at this time the impact should be similar (i.e. localised pollution) as for the GBS cell content (if left *in situ*), but probably a little less because:
>
> - The limited sampling of the tri-cell cuttings conducted to date suggests the maximum concentration of oil in the tri-cells is 9.2%. The impact of the cell sediment release is based on 17.5% oil content (for the updated modelling based on sampling results)
> - The volume of tri-cell drill cuttings predicted to be in Brent Bravo and Brent Delta (approximately 26,800 m^3) is less than the [total] volume of GBS cell sediment (approximately 34,560 m^3), and tri-cell drill cuttings are not present at Brent Charlie, where cell sediment is also present
> - Considered together, the two above points suggest the total oil load within the tri-cell cuttings is less than half of that contained within the cell sediment

- As the tri-cell drill cuttings are contained internally in the GBS, they are only likely to be exposed to the marine environment in gradual amounts over a period of time, as more than one wall needs to be breached for them to become exposed. Some of the tri-cell cuttings may be "entombed" within the GBS as they degrade."

Conversely, some of the tri-cell cuttings may be exposed to the marine environment in a dynamic (disturbed) state and released at a higher level [in the water column] above the seafloor, and will thus travel further, albeit they would be more dispersed. No modelling has been conducted by Shell of the exposure of the tri-cell cuttings to the marine environment, and as such DNV GL used other modelling results to predict the impact. Of the dynamic release cell sediment modelling scenarios commissioned by Shell, DNV GL examined the scenario that released 10 m^3/day for 1 year at a height of 20 m above the seafloor (3,650 m^3 cell sediment), representing a significant amount of tri-cells drill cuttings to be fully re-suspended in the water column for dispersion around the platform (ca. 27% of the volume of the tri-cell drill cuttings at a platform) as that gave the biggest impact of the scenarios modelled. The cell sediment dynamic release modelling results show that the majority of the contaminated seafloor will have a sediment thickness of less than 1 mm with a pollution concentration exceeding harmful limits. Because of bioturbation mixing, the contaminated sediment will quickly be diluted in the upper part of the seafloor sediment and hence not have any harmful impact on biota. The seafloor with >10 mm contaminated sediment and PEC:PNEC >1 is expected to cause harmful effects on the biota. Dynamic modelling results show that 0.06 km^2 of seafloor will have such conditions. This is close to the 0.05 km^2 footprint with potential harmful effects that was derived from the updated static modelling.

However, a portion of the tri-cell drill cuttings may be released higher than 20 m above the seafloor. Modelling results of the dynamic disturbance of dredging 7,753 m^3 of Brent C cell top drill cuttings (in which 775 m^3 is released to the marine environment, a volume similar to the amount of cuttings in one tri-cell) over 65 days, 60m above the seafloor show….that the vast majority of the cuttings is widespread and re-settles on the seafloor as a thin layer, less than 1 mm thick and these areas will not harm biota one mixing by bioturbation is taken into account. The maximum thickness was 6 mm.

As described for the legacy assessment of the GBS cell sediment if left in place [Section15.12.4] the modelling results show that, based on the analytical results [of the CSP samples], a major static release of cell sediment from the GBS will pollute the local benthic environment to a distance of approximately 250 m from each platform but is not expected to induce any measurable effects on regional benthic fauna. Therefore, when the drill cuttings from the tri-cells are exposed to the marine environment upon degradation of the GBS, they would similarly pollute the local environment and add to the area persistence.

As such, the overall legacy impact as a result of leaving the tri-cell drill cuttings in place is estimated to be 'small-moderate negative'. The environmental impact would be similar in nature to that currently experienced at the Brent Field as a consequence of the presence of the historical seabed and cell-top drill cuttings, because the oil load contained within the tri-cell drill cuttings is similar, and they were also released from height.'

17.15.4 Mitigation Measures for Tri-Cell Drill Cuttings

- The post-decommissioning environmental surveys (Section 24.3) will determine if any new contamination has occurred during decommissioning, and will include an assessment of whether cuttings have been re-suspended and then caused new contamination.
- The long-term monitoring programme of the Field, to be discussed and agreed with BEIS (Section 24.4), will provide data with which to determine if recovery is taking place.
- A risk-based environmental and structural monitoring programme, to track the long-term degradation and fate of the GBSs, will be discussed and agreed with BEIS.

18 DECOMMISSIONING THE SEABED INFRASTRUCTURE

18.1 Introduction

Four discrete subsea structures are included in this DP document. Regardless of the decommissioning options adopted for the Brent Alpha jacket, the GBSs or any of the pipelines, we will remove these structures because they fall within the scope of OSPAR 98/3 and are not candidates for derogation.

Information about the numbers and masses of grout bags and mattresses associated with the sub-sea structures (where available) is presented in the Pipelines TD [17] and summarised in the description of the Brent Field pipeline system (Section 19.2). Programmes of work for mattresses, grout bags and third-party crossings are fully described in [17] and summarised in the programme of work to decommission the pipelines (Section 19.7).

18.2 Description of Subsea Structures

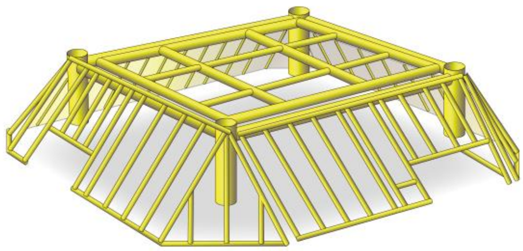
Table 70 presents a summary description of the four subsea structures. Their locations are detailed in Table 71 and shown in Figure 110. A full description of these structures is given in the pipelines TD [17].

18.3 Programmes of Work for Removing Subsea Structures

The four seabed structures will be removed by the DSV's crane after cutting any steel piles at a depth of 3 m below the seabed by AWJ. Cutting and lifting will cause some disturbance of the natural seabed sediment (no structure is within or under a drill cuttings pile) but the impact on the seabed will be very small, localised and fully reversible.

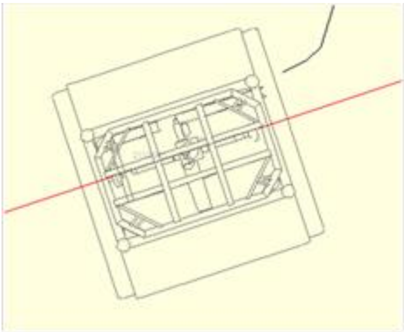
Any grout bags and mattresses associated with these structures will also be removed and returned to shore for recycling or disposal as appropriate.

Table 70 Summary Descriptions of Subsea Structures.



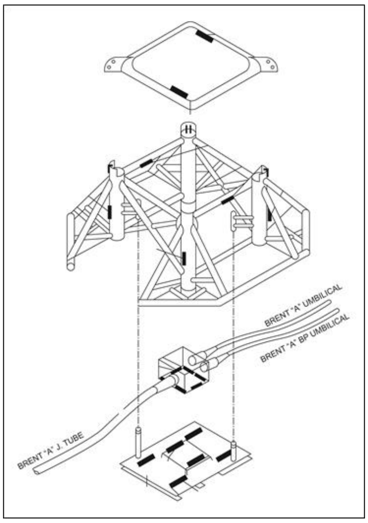
The Spar PLEM was the base connection manifold for the Spar offloading system, which has been removed. The PLEM is made of steel and is 10 m x 6 m x 2.35 m high, with associated pipework and valves. After installation the structure was filled with grout to increase its submerged weight to approximately 134 tonnes.

Pipeline End Manifold (PLEM)



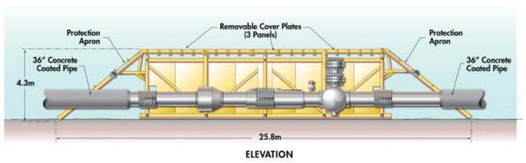
The SSIV consists of steel tubing and valves within a skirted steel frame incorporating a base frame with mud-mats. It is not piled and is held in place on the seabed by ballast “chest” inside the frame. Each ballast chest weighs 19.5 tonnes and there is no evidence of the ballast chests being attached to the main structure. The SSIV is approximately 7.5 m x 7.5 m x 3 m high and weighs approximately 103 tonnes. The structure is protected by mattresses and grout bags.

Subsea Isolation Valve (SSIV)



This structure was installed to house and protect the Brent Alpha SSIV umbilical splitter assembly and consists of three sections; the base, the main structure and the roof panel. The whole structure is approximately 4 m x 4 m x 3 m high and weighs at least 30 tonnes.

Splitter Box



The VASP is a subsea structure forming part of the FLAGS pipeline. It consists of a rectangular structure of steel tubes and sections, and measures approximately 16.4 m x 4.3 m x 3.4 m high and weighs up to 200 tonnes.

Valve Assembly Spool-piece (VASP)

Table 71 Locations of the Sub-Sea Structures in the Brent Field.

Sub-Sea Structure	Location Decimal Minute WGS84	Location Decimal (WGS84)
SPAR PLEM	01°39.973'W 61°03.205'N	01.6662°W 61.0534°N
SSIV	01°42.465'W 61°03.272'N	01.7077°W 61.0545°N
BA Splitter Box	01°39.972'W 61°03.205'N	01.6662°W 61.0534°N
VASP	01°41.874'W 61°01. ' N	01.6979°W 61.0235°N

18.4 Environmental Impacts of Decommissioning the Subsea Infrastructure

18.4.1 Stakeholder Environmental Concerns

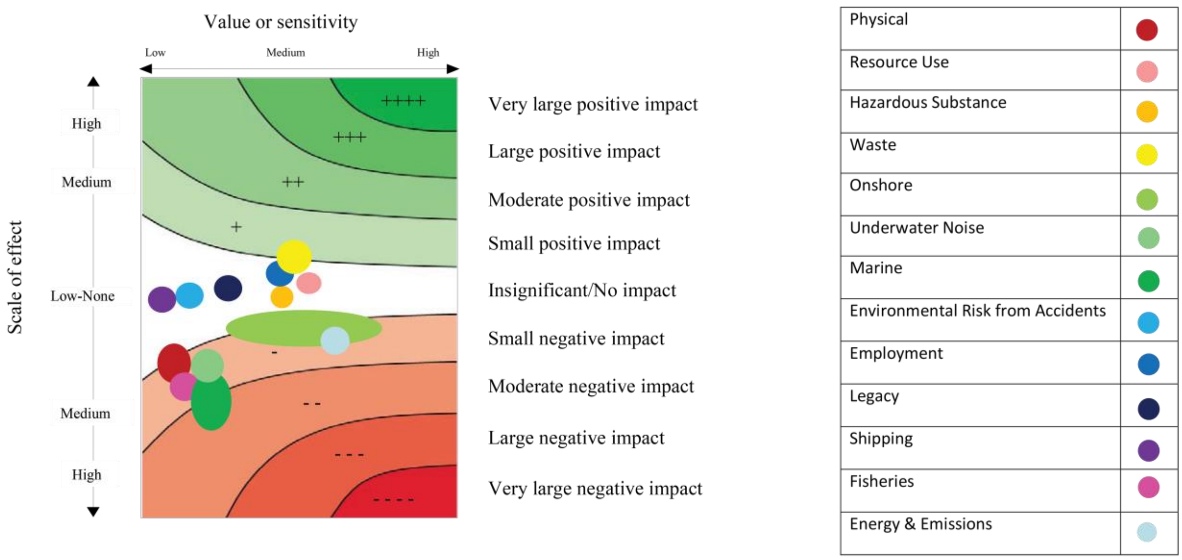
Stakeholders did not express any specific concerns regarding the decommissioning of the subsea infrastructure but from their comments on the decommissioning of the Brent Alpha jacket and the GBS it is clear that their main concerns would be:

- Accidental discharges or releases of hydrocarbons to sea.
- Disturbance to seabed cuttings piles.
- Accidental loss of large components to sea.
- Impacts to the benthos.
- Creation of debris.

18.4.2 Potentially Significant Impacts in ES

Figure 109 presents DNV GL's summary of the assessment of the environmental impacts of the programme of work that would be carried out to remove all the subsea structures and dismantle, recycle or dispose of them onshore [5] and to remove the oil-related debris in the Field (described in Section 20). The ES found that the most significant negative impact from this activity was in the marine category, which was estimated to be 'small-moderate negative'. All the other categories of impacts were estimated to be 'small negative' or 'insignificant-no impact'.

Figure 109 Environmental Impacts from the Removal and Onshore Disposal of all Subsea Infrastructure, including Debris.



18.4.3 Impacts of Operations

The EIA found that the removal of the four sub-sea structures and the debris in the Field will have a 'small-moderate negative' impact on the marine environment primarily as a result of disturbances or impact to benthic communities from the removal activities that disturb marine sediment. The impact will be localised and temporary but will occur in a number of locations. It is noted that the benthic fauna impacted are diverse and abundant and typical of the region, and do not appear to contain any species of particular conservation concern [5].

18.4.4 Energy and Emissions

DNV GL estimated that the removal of the seabed infrastructure will use approximately 32,400 GJ of energy and result in the emission of approximately 2,300 tonnes of CO_2 (Table 72).

Table 72 Total Energy Use and Gaseous Emissions of Programme of Work to Remove all Subsea Structures.

Operations	Energy (GJ)	Emissions to Atmosphere (tonnes)		
		CO_2	NO_X	SO_2
Direct				
Marine operations	28,233	2,082	43	35
Onshore dismantling	203	15	0	0
Onshore transport	146	11	0	0
Sum	*28,582*	*2,108*	*44*	*35*
Recycling				
Material recycling	3,854	174	1	2
Materials not recycled	0	0	0	0
Total	32,436	2,283	44	37

18.5 Mitigation Measures for Subsea Structures Programme of Work

- The campaign to remove the four subsea structures will be conducted under all necessary permits.
- Appropriate Notices to Mariners will be issued to alert other users of the sea to proposed offshore operations.
- Explosives will not be used to remove the structures.
- After the structures and any associated mattresses and grout bags have been removed an over-trawling survey will be conducted by an independent organisation to ensure that the area is free of debris. This may be conducted as part of the wider over-trawling survey that will be conducted after the decommissioning of the pipelines and the removal of debris.
- On completion of offshore operations other users of the sea will be advised of the changed status or condition of the pipelines on which these structures were located.
- Onshore, the retrieved substructures, mattresses and grout bags will be treated, recycled or disposed of through suitably-licensed onshore sites, taking care to identify any hazardous materials that may be present.
- There are no historic drill cuttings piles associated with or in the immediate vicinity of the four sub-sea structures to be removed.
- Impacts to the marine environment will be minimised by not disturbing drill cuttings piles; we will not attempt to retrieve items of debris that are largely or wholly buried in drill cuttings piles.

19 DECOMMISSIONING THE BRENT PIPELINE SYSTEM

19.1 Introduction

The decommissioning of the Brent Field Pipeline system constitutes the second Decommissioning Programme, DP2, presented in this DP Document.

19.2 Description of the Brent Pipeline System

The Brent Field pipeline system comprises 103 km of rigid and flexible pipelines for the transportation of oil or gas, umbilicals for controlling subsea infrastructure or for chemical injection and power cables. These run between the Brent platforms, the former sites of the Brent Spar and Brent Flare, and the various host platforms that link the Brent Field to both Sullom Voe and St Fergus.

Approximately 66 km (64%) of the system comprises pipelines that are more than16 inches in diameter. Approximately 47 km (47%) of the lines are exposed on the seabed and 54 km (53%) are trenched or rock-dumped.

Figure 110 shows the arrangement of pipelines in the Brent Field that are included in DP2, and Table 73 and Table 75 provide factual data on the system and an inventory of materials. Detailed descriptions of every line, including the locations of any areas of rock-dump and mattressing and of four items of subsea infrastructure, are provided in the Pipelines TD [17]. Figure 111 shows an example of the schematic diagrams we have prepared for every line (in this case PL049/N0301). The condition and status of the whole pipeline system has been regularly monitored and surveyed. On each of the lines covered by this DP surveys have been undertaken to provide detailed information on the extent of exposure and spanning.

Detailed information on the extent of spanning on each line is presented in [17] and Figure 112 shows an example of such a 'spanogram', again for line PL049/N0301. In general there is no significant spanning on any line. The Field is in deep water and the seabed currents are weak, so apart from very localised eddies caused by topography or the presence of obstructions on the seabed there are few forces that would cause extensive erosion of seabed sediments. A 'FishSAFE' span is defined as a span more than 0.8 m high and more than 10 m long which represents a potential snagging risk to bottom-towed fishing gear and so should be included in the FishSAFE system to provide an early warning to fishermen as they approach it. Latest information indicates that with the exception of the closing spans – where lines rise from the seabed to attach to platforms – there are only two FishSAFE spans in the Brent Field. These are both found on the 30 inch export line N0501 (PL 001) at around KP[44] 34; one is 0.9 m high and 17.9 m long and the other 1.2 m high and 15 m long.

Table 74 summarises the inventories of each pipeline. In addition to these materials we estimate that in total there is 84 tonnes of zinc anodes on the rigid pipelines.

19.3 Further Use or Re-use of the Pipelines, Umbilicals and Power Cables

There are no other uses for these lines; they are not of use to other operators in adjacent fields and as far as is known are not likely to be of use in the development of future fields. With the exception of some power cables, umbilicals and small diameter lines, it is not feasible to consider re-using lines in other locations even though it may be technically possible to retrieve them in one piece. Consequently, all the lines listed in Table 73 will have to be decommissioned.

[44] KP= kilometre point, the distance along the pipeline from the platform measured in kilometres

Figure 110 Schematic Showing the Present Layout of the Brent Field Pipeline System.

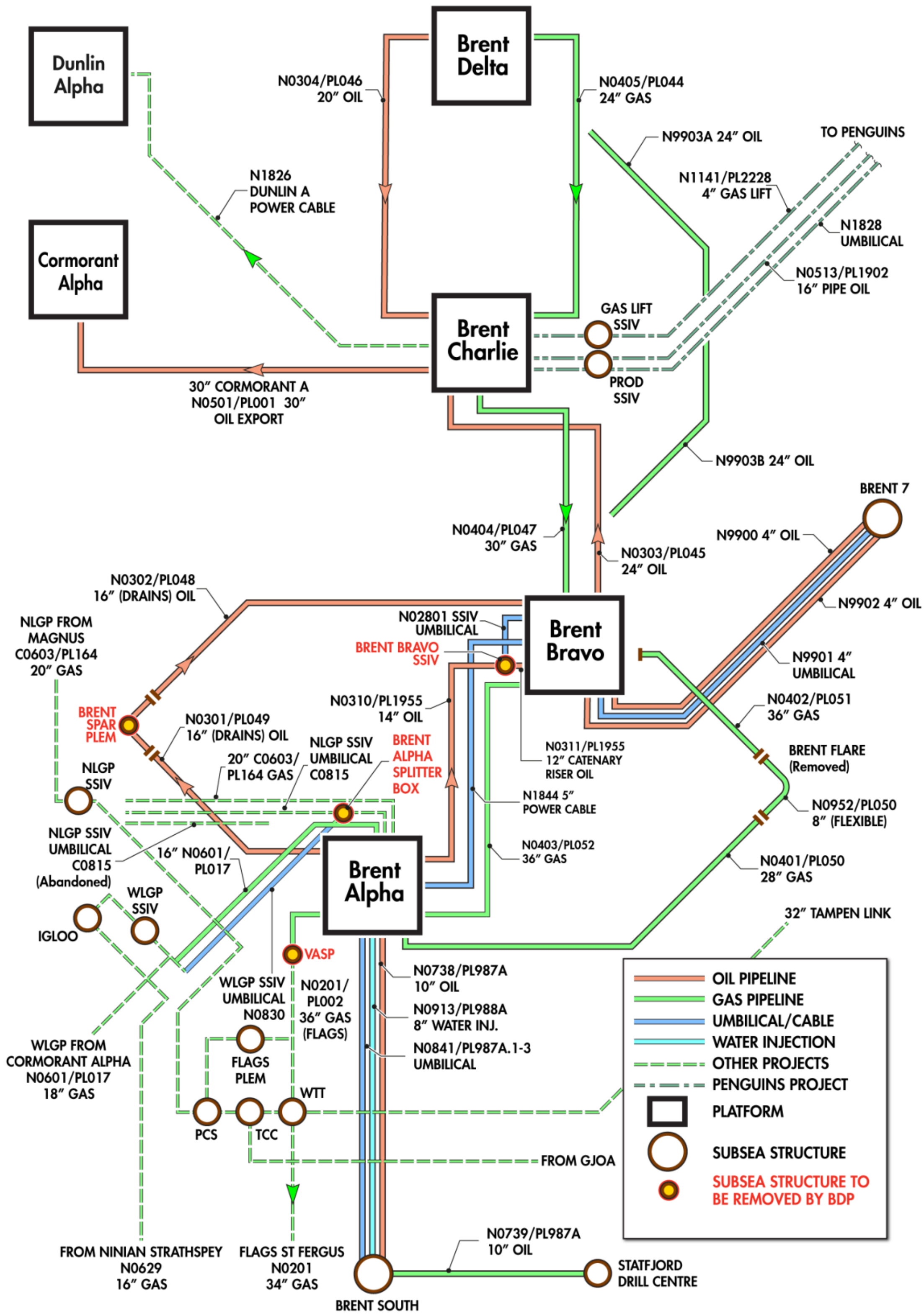


Table 73 Data on the Brent Pipeline System.

PWA Number	Shell Number	Diameter (inches)	Length (km)	Service
PL002	N0201	36	1.3	Gas export Brent A to VASP
PL049	N0301	16	2.8	Oil export, now drains fluids from Brent A to PLEM
PL048	N0302	16	2.3	Oil export, now drains fluids from Brent B to PLEM
PL045	N0303	24	4.6	Oil production Brent B to Brent C
PL046	N0304	20	4	Oil production Brent D to Brent C
PL050	N0401	28	3	Flare gas Brent A to Brent Flare (Note 1)
PL051	N0402	36	2.6	Flare gas Brent B to Brent Flare (Note 2)
PL051	N0402a	36	0.147	Brent B 500 m zone (Note 3)
PL052	N0403	36	2.3	Gas export Brent B to Brent A
PL047	N0404	30	4.4	Gas export Brent C to Brent B
PL044	N0405	24	4.2	Gas export Brent D to Brent C
PL001	N0501	30	35.9	Oil export Brent C to Cormorant Alpha
PL017	N0601	16	0.4	Gas import WGLP SSIV to Brent A
PL987A	N0738	10	5	Oil export Brent South to Brent A (Note 4)
PL987A	N0739	10	1.8	Oil export Brent South to Statfjord drill centre (Note 5)
PL988A	N0913	8	5	Water injection Brent A to Brent South (Note 6)
–	N9903A	24	1.7	Oil production Brent D to Brent B (Note 6)
–	N9903B	24	2.9	
PL1955	N0310	14	2.3	Oil production Brent A to Brent B SSIV
		12	0.36	Oil production Brent A topside to Brent A seabed
PL1955	N0311	12	0.27	Oil production Brent B SSIV to Brent B
PL050	N0952	8	0.03	Brent flare system (Note 5)
–	N9900	4	2.1	Well 211/29-7 to Brent B (Note 6)
–	N9902	4	2.3	Oil production Well 211/29-7 to Brent B (Note 6)
PL987A.1-3	N0841	4.5	5.3	Control and chemical umbilical Brent A to Brent South (Note 6)
–	N1844	5	2.9	Power cable Brent B to Brent A
–	N2801	2.5	0.4	Control umbilical Brent B to Brent B SSIV
–	N9901	4	2.2	Control and chemical umbilical Brent B to Well 211/29-7 (Note 6)
–	N0830	4	0.5	Control umbilical Brent A to WLGP SSIV

Notes:
1. Currently suspended and subject to Interim Pipeline Regime (IPR).
2. Currently suspended and subject to IPR.
3. Disused.
4. Disused and subject to IPR.
5. Never commissioned and subject to IPR.
6. Disused and subject to IPR.

Figure 111 Example of Schematic Layout Drawn for each Pipeline.

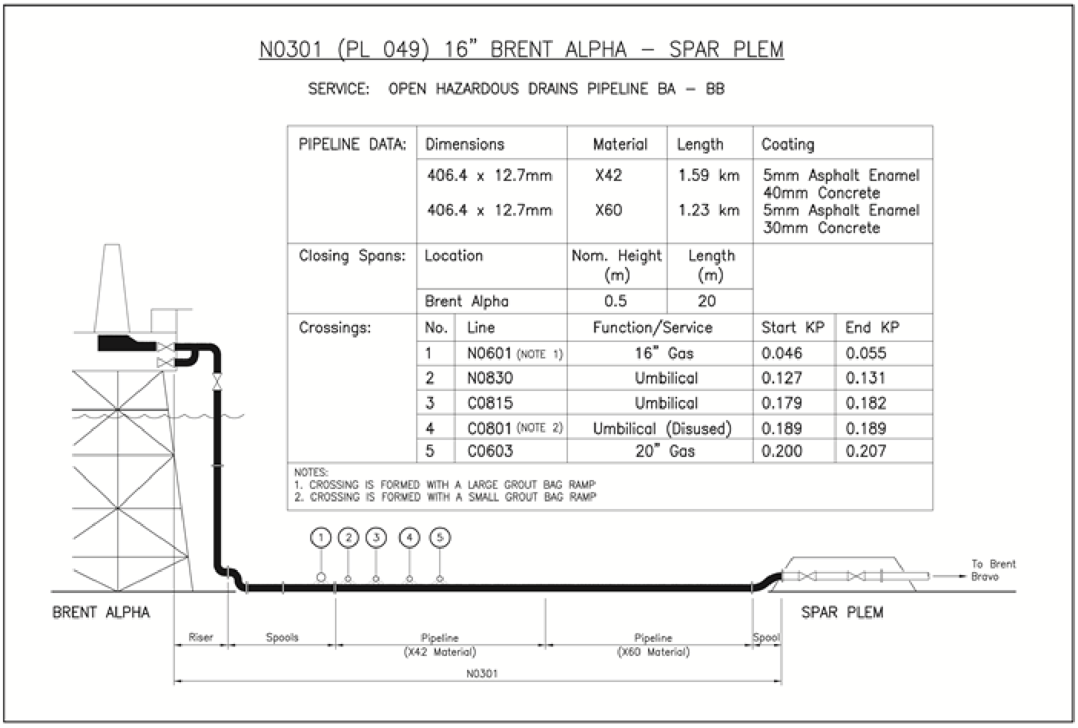
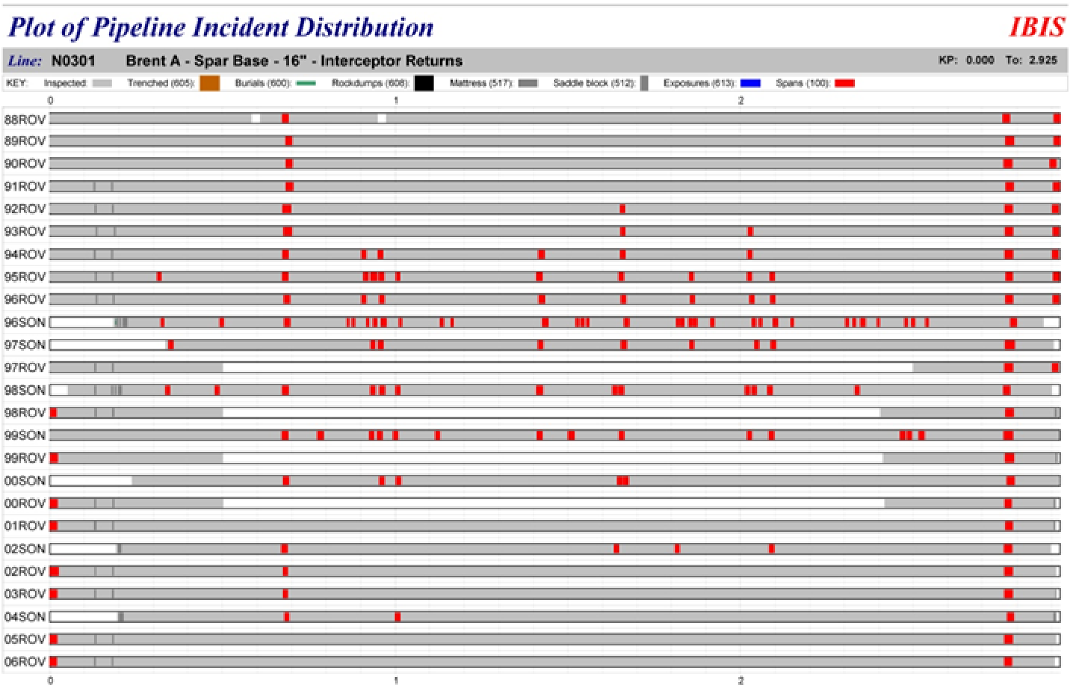


Figure 112 Example of a Spanogram Recording Results of Pipeline Survey.[45]



[45] In Figure 112 each line represents a survey of the whole line in a particular year. The grey zones show the lengths of the line that were covered by the survey. The red bands show the location and lengths of spans.

Table 74 Inventories for each Brent Field Pipeline.

PWA Number	Shell Number	Length (km)	Mass of Materials (tonnes)			
			Steel	Concrete	Coatings	Total
PL002	N0201	1.3	629	600	16	1,246
PL049	N0301	2.8	384	321	25	730
PL048	N0302	2.3	284	296	21	600
PL045	N0303	4.6	1,071	1,085	62	2,218
PL046	N0304	4.0	703	658	46	1,407
PL050	N0401	3.0	1,132	1,075	60	2,267
PL051	N0402	2.6	1,259	1,171	53	2,483
PL051	N0402a	0.147	71	66	3	140
PL052	N0403	2.3	1,114	1,032	18	2,164
PL047	N0404	4.4	1,571	1,465	74	3,110
PL044	N0405	4.2	978	991	57	2,025
PL001	N0501	35.9	12,819	11,983	728	25,529
PL017	N0601	0.4	49	68	4	121
PL987A	N0738	5	776	0	107	883
PL987A	N0739	1.8	279	0	38	317
PL988A	N0913	5.0	361	0	0	361
–	N9903A	1.7	396	401	23	820
–	N9903B	2.9	675	684	39	1,398
PL1955	N0310	2.7	527	0	130	657
PL1955	N0311	0.27	51	0	9	60
PL050	N0952	0.03	6	0	0.2	6
–	N9900	2.1	ND	0	ND	63
–	N9902	2.3	ND	0	ND	69
PL987A.1-3	N0841	5.3	ND	0	ND	133
–	N1844	2.9	55	0	15	96
–	N2801	0.4	ND	0	ND	3
–	N9901	2.2	ND	0	ND	55
–	N0830	0.5	ND	0	ND	13
TOTALS			25,190	21,896	1,528	48,976

ND = No data

Table 75 Mattresses and Grout Bags on the Brent Pipeline System.

Location	Number of Items	
	Mattresses	Grout Bags
Brent Alpha	187	375
Brent Bravo	78	991
Brent Charlie	62	743
Brent Delta	0	1,647
Brent South	125	0
Brent SPAR PLEM	17	200
VASP	20	200
Totals	489	4,156
Estimated Total Mass (tonnes)	1,762	104 (1)

Note 1: Assuming a grout bag weighs 25 kg.

19.4 Options for the Decommissioning of the Pipelines, Umbilicals and Power Cables

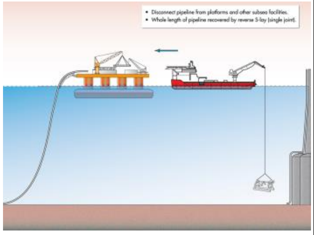
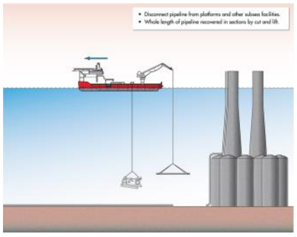
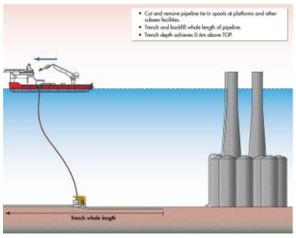
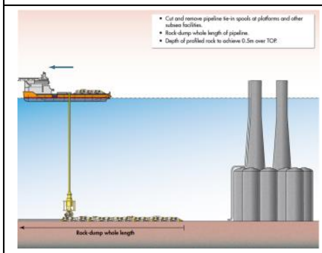
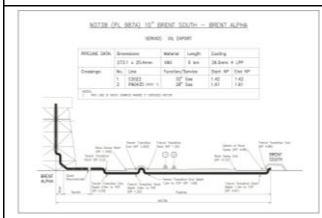
In accordance with the DECC Guidance Notes [3] we have completed CAs of feasible options for each of the 28 Brent Field pipelines that fall within the scope of this DP (Section 19.2). The CAs were informed by our own extensive data on the condition and burial status of each line (described in detail in [17]), engineering studies on removal or burial techniques, the ES [5], Field-specific studies on pipeline degradation and longevity [17], the report on commercial impacts on fisheries [21], and the Anatec study *Assessment of safety risk to fishermen from decommissioned pipelines in the Brent Field* [20].

To permit the continuing export of gas through the Western Leg Gas Pipeline (WLGP) and FLAGS export routes after the decommissioning of the Brent Field, we are reconfiguring the pipeline network in a separate project called the Brent Bypass Project (BBY) (Section 19.7.4). Our assessment of options for the decommissioning of the Brent Field pipelines has taken into account the changes that will be made as a result of the Bypass Project.

For the purpose of assessing options we assumed that all oil and gas lines had been successfully flushed under permit (see Section 19.7.6) to an acceptable standard that would be agreed with BEIS. The main options, and the various techniques or operations that could be performed to complete each type of option for decommissioning pipelines, are summarised in Table 76 and described more fully in [17].

One of our main objectives was to examine ways of reducing or eliminating the potential for a long-term snagging risk to fishermen. This risk arises from the presence of (i) exposed sections of pipeline with or without spans and, (ii) the ‘closing spans’, sections of line that rise from the seabed as they connect with platforms. The presumed higher snagging risk on these sections could be reduced by complete removal, selective partial removal, rock-dumping or trenching. Consequently, we developed various permutations of removal activities and this resulted in the identification of up to nine different options for each of the lines.

Table 76 Main Options for Decommissioning Pipelines.

Option	Methods
Complete or Partial Removal	
	*Reverse S-lay (illustrated):* One end of the line is picked up by a vessel and progressively pulled on board over a 'stinger'. On board the vessel it is cut into sections for recycling onshore. *Reverse reeling:* One end of the line is picked up by a vessel and progressively wound onto a very large reel on board. The line is recycled onshore.
	*Cut and Lift:* After suitable de-burial the line is cut into 12 m long sections on the seabed by ROVs. The sections are lifted by the vessel and taken to shore for recycling.
Trench	
	*Mechanical trenching (illustrated):* A large plough is fitted over one end of the line and pulled or driven along the line to create a trench. A separate backfilling operation is then performed by a specialist backfill plough, to achieve the required depth of burial (usually >0.6 m to top of pipe). *Jet trench:* Jet trenchers work by fluidising the seabed using a combination of high flow/low pressure and low flow/high pressure water jets to cut into sands and gravels and low to medium strength clays. In sands, the pipeline sinks through the slurry that this operation creates, whereas in clay, the jetting process cuts through the material which is carried away by the flow of water.
Rock-dump	
	*Rock-dump:* A specialised vessel deploys a long controllable 'fall pipe' and delivers controlled amounts of graded rock onto and over the line. The rock-dump is carefully designed to provide the required protection and stability to the line.
Leave in Place	
	*Leave in place:* The line would be left in place as it is but there may be operations (such as local trenching or local rock-dumping) to stabilise or protect any exposed ends.

19.5 Issues and Concerns Raised by Stakeholders

For the technically feasible options for the pipelines the main issues and concerns raised by stakeholders during the programme of stakeholder engagement were:

- The long-term snagging risks for towed fishing gear from any lines left exposed on the surface of the seabed.
- Regaining access to grounds for demersal fishing.
- Creation of debris.
- How the lines will be cleaned before decommissioning.
- Release of residual hydrocarbons during removal or from lines left in place.
- Long-term impacts on benthos from the lines and especially from any additional rock-dump.
- Impacts to local communities at onshore dismantling sites caused by noise, dust and odour.

19.6 Comparative Assessment of Options

19.6.1 Introduction

The DECC Guidance Notes [3] provide the following general guidance to help identify (i) pipelines and umbilicals that may be candidates for *in situ* decommissioning and, (ii) pipelines and umbilicals that should normally be entirely removed.

Full removal:

- For small diameter pipelines, including flexible flowlines and umbilicals, which are neither trenched nor buried

Leave under existing rock-dump:

- For lines which are presently completely under stable rock-dump

Leave in place:

- For lines which are adequately buried or trenched and which are not subject to the development of spans, and are expected to remain so
- Lines which are expected to self-bury over a sufficient length within a reasonable time, and remain buried
- Lines where burial or trenching of the exposed sections is undertaken to a sufficient depth and it is expected to be permanent

Using this guidance we screened all 28 lines and determined that for 14 of the lines there was an obvious decommissioning solution and only a small number of pragmatic alternative options [17]. The relatively fewer, simpler decommissioning options for these lines were compared and assessed using a qualitative or narrative-based method. For simplicity these are called 'qualitative lines' and they are listed in Table 77. The remaining 14 lines, listed in Table 80, were subjected to full quantitative CAs and for simplicity these are called the 'quantitative lines'.

19.6.2 Results of Comparative Assessments for Qualitative Pipelines

The results of the assessments for the qualitative lines are presented in Table 77 and discussed in Section 19.6.3. Work at any pipeline crossing is described in Section 19.7.2, and Section 19.7.7 describes how mattresses and grout bags would be dealt with. Individual CAs for each of the lines are presented in the Pipelines TD [17].

Table 77 Recommended Decommissioning Option for Brent Field Pipelines Subject to Qualitative Comparative Assessment.

Pipeline Number		Diam	Length	Service	Status	Recommended Option	Justification
PL1955	N0310	12/14	2.66	Oil production	Laid on the seabed	Remove by reverse reeling	Flexible line, lying on the seabed
PL1955	N0311	12	0.27	Oil production	Laid on the seabed + catenary riser	Remove by reverse reeling	Flexible line, lying on the seabed
PL051	N0402a	36	0.147	Never used	Laid on the seabed	Remove by cut-and-lift	Short exposed rigid line
PL987A	N0738	10	5.0	Oil production (disused and in IPR)	Trenched, one end rock-dumped	Leave in trench, remediate exposed flange with rock-dump	Stable in trench; stable rock-dump cover.
PL987A	N0739	10	1.8	Never used, now in IPR	Trenched, both ends rock-dumped	Leave in trench, remediate one exposed flange with rock-dump	Stable in trench, and under profiled rock-dumps
-	N0830	4 (est)	0.5	Control umbilical	Part of length trenched and part mattressed	Remove by reverse reeling	Short section of umbilical which would be partly exposed on seabed once mattresses removed
PL987A 1-3	N0841	5	5.3	Control umbilical	Trenched (with N0913), one end rock-dumped	Leave in trench, remediate exposed flushing head with rock-dump	Stable in trench, and under profiled rock-dump
PL988A	N0913	8	5.0	Water injection	Trenched (with N0841), one end rock-dumped	Leave in trench, remediate exposed flange with rock-dump	Stable in trench
PL050	N0952	8	0.03	Flushing jumper	Lying beneath profiled rock-dump	Leave under rock-dump	Fully covered by stable, profiled rock-dump
-	N1844	5	2.9	Power cable	Laid on the seabed with mattresses at each end	Remove by reverse reeling	Umbilical, lying on the seabed
-	N2801	2.5	0.4	Control umbilical	Laid on the seabed, largely protected by mattresses	Remove by reverse reeling	Umbilical, lying on the seabed, unprotected when mattresses removed
-	N9900	4	2.1	Oil production	80% exposed on seabed, 20% buried	Remove by cut-and-lift	Small diameter flexible mainly exposed. Lying open to sea for many years. Integrity likely to be compromised
	N9901	4 (est)	2.2	Control umbilical	Mostly exposed on seabed, 14% buried. Cut into sections	Remove by cut-and-lift	Small diameter umbilical mainly exposed and in sections on seabed
	N9902	4	2.3	Oil production	Mostly exposed on seabed, 23% buried. Cut into sections	Remove by cut-and-lift	Small diameter flexible mainly exposed. Lying open to sea for many years. Integrity likely to be compromised

Note: N/D = No data: Diam. = Diameter in inches: Est = Estimated. Length is kilometres: Service = purpose or use of the line: Status = Condition/position of line on or in the seabed.

19.6.3 Discussion of the Recommended Options for the Qualitative Pipelines

Pipelines to be Removed by Reverse Reeling

Lines PL1955/N0310, PL1955/N0311, N0830, N1844 and N2801 are all flexible lines less than 16 inches in diameter. They are therefore ideal candidates for removal by reverse reeling. N0830, N1844 and N2801 have concrete mattresses laid over them, and for the purposes of the CA it was assumed that all these mattresses had been successfully removed.

Reverse reeling is a standard operation which has been successfully undertaken many times in the North Sea. It has well understood risks and mitigations to manage these risks and therefore does not represent a significant risk to offshore personnel. The remaining risk, which might only become apparent once decommissioning work begins, is the structural capacity of the lines to withstand the process of reverse reeling or, for N0830, the loads imposed by the potential over-burden of seabed sediment.

This option will leave a clean seabed and eliminate a potential snagging risk for fishermen and a source of litter and potential environmental impact. For all these lines this option might result in a 'small negative' operational impact to the marine environment but this will be localised and reversible. Removal will result in a 'small positive' effect in terms of long-term environmental impacts. Only a relatively small mass of material would be returned to shore from these lines and the materials can be processed in accordance with waste management practices at suitably licensed onshore sites.

Pipelines to be Removed by Cut-and-lift

Line PL051/N0402a is a very short (147 m) section of 36 inch line lying on the seabed open to the sea after being abandoned in 1976, and the best option is to remove it by cut-and-lift. Because of concerns about its strength and the fact that the concrete coating would probably fall off during removal, we do not believe that this line is suitable for reverse reeling.

Lines N9900, N9901 and N9902 are of very small diameter and lie exposed on the seabed open to the sea; all three have some degree (from 18% to 23%) of natural burial over them. As small diameter flexible pipelines they are ideal candidates for reverse reeling but there are concerns over their structural integrity after such a long period lying unprotected on the seabed. On safety and technical grounds it is therefore inadvisable to attempt to remove them by reverse reeling.

The best option is remove these four lines by cut-and-lift. For all these lines the operational safety risk to project personnel is low, and a long-term safety risk to fishermen would be removed. There may be some 'small negative' impacts offshore during operations and onshore during dismantling and recycling, but these will be limited in extent and duration and will be reversible. In all cases removal will result in 'small positive' effects in terms of 'legacy'. None of the alternative options (trenching or rock-dump) offers better performances in terms of either the negative effects of operations or the positive effects of outcomes.

Through this procedure the potential future risk to fishermen can be eliminated without incurring unmanageable levels of risk to offshore personnel. Cutting and lifting operations are likely to disturb the upper layer of the seabed.

Pipelines to be Left in Trench

Lines PL987A/N0738, PL987A/N0739, PL987A1-3/N0841 and PL988A/N0913 are all associated with the now decommissioned Brent South development. They were all laid in trenches and have some degree of natural burial, and all have some mattress cover. When Brent South was decommissioned the mattresses at the ends of these lines were buried beneath over-trawlable rock-dump. The rock-dump and the trenches have remained stable since that time. These lines are thus likely to remain in their trenches as they gradually degrade and collapse, and so would not be likely to become a snagging risk to fishing or a source of seabed litter. There is essentially no safety risk to offshore project personnel and only a small long-term safety risk to fishermen. The impact on commercial fisheries is judged to be 'small negative' because of the long-term presence of a trenched line, but the marine impacts of operations and the legacy environmental impacts are both 'insignificant'.

Pipelines to be Left Under Rock-dump

Line PL050/N0952 is a very short section (30 m) of small diameter line associated with the decommissioned Brent Flare. Profiled rock-dump was deposited during decommissioning operations at the flare site and this has completely buried PL050/N0952. The line therefore lies under an existing stable rock-dump and is not likely to interfere with fishing or create seabed litter as it degrades and collapses; there have been no reported incidents on this line to date. The rock-dump will serve to contain any degradation products and stop or severely restrict the migration of degradation products onto the adjacent seabed. Safety risks to operational personnel would be very low (only from monitoring programmes), as would the long-term risks for fishermen associated with the presence of the over-trawlable rock-dump.

The alternative option would be displace the rock-dump onto the adjacent seabed and remove this line by cut-and-lift. Although technically feasible, displacement of the rock-dump would cause further disturbance to the adjacent seabed and may increase the risk of snagging demersal fishing gear. This alternative option would have some additional negative operational impacts (to seabed and benthos) while not resulting in any better long-term outcome for other users or the environment.

19.6.4 Results of Comparative Assessments for Quantitative Pipelines

We identified a total of nine different options that could be applied to the quantitative lines (Table 78), with 3 to 6 options being applicable to any one line (Table 79).

The results of the assessments for the quantitative lines are presented in Table 80 and discussed in Section 19.6.519.6.5, Section 19.6.6 and Section 19.6.7. Work at any pipeline crossing is described in Section 19.7.2, and Section 19.7.7 describes how mattresses and grout bags would be dealt with. Individual CAs for each of the lines are presented in the Pipelines TD [17].

Table 78 Decommissioning Options for the Quantitative Pipelines.

Option Number	Description
1	Leave tied-in, no further remediation required
2	Leave tied-in at the installation, trench the remote end
3	Leave tied-in at the installation, rock-dump the remote end
4	Disconnect from the installation, trench and backfill the whole length
5	Disconnect from the installation, rock-dump the whole length
6	Remove the whole line by cut and lift
7	Remove the whole line by reverse S-lay (single joint)
8	Partially trench and backfill, with isolated rock-dump
9	Partially rock-dump

Table 79 Decommissioning Options Applicable to each Quantitative Pipeline.

Pipeline Number	Applicable Options								
	1	2	3	4	5	6	7	8	9
PL001/N0501	✓					✓	✓	✓	✓
PL002/N0201		✓	✓	✓	✓	✓	✓		
PL017/N0601		✓	✓		✓	✓			
PL044/N0405	✓			✓	✓	✓	✓		
PL045/N0303	✓			✓	✓	✓	✓		
PL046/N0304	✓			✓	✓	✓	✓		
PL047/N0404	✓			✓	✓	✓	✓		
PL048/N0302		✓	✓	✓	✓	✓	✓		
PL049/N0301		✓	✓	✓	✓	✓	✓		
PL050/N0401	✓			✓	✓	✓	✓		
PL051/N0402	✓			✓	✓	✓	✓		
PL052/N0403	✓			✓	✓	✓	✓		
–/N9903A				✓	✓	✓			
–/N9903B				✓	✓	✓			

Key

Option	Description
1	Leave tied-in, no further remediation required
2	Leave tied-in at the installation, trench the remote end
3	Leave tied-in at the installation, rock-dump the remote end
4	Disconnect from the installation, trench and backfill the whole length
5	Disconnect from the installation, rock-dump the whole length
6	Remove the whole line by cut and lift
7	Remove the whole line by reverse S-lay (single joint)
8	Partially trench and backfill, with isolated rock-dump
9	Partially rock-dump

Table 80 presents an overview of the results for the 14 lines that were subjected to a quantitative CA ('quantitative lines'). Each type of recommended option is then discussed in general terms in Section 19.6.5 to Section 19.6.7 and illustrated with examples of data and results from specific pipelines.

Table 80 Recommended Decommissioning Option for Brent Lines Subject to Quantitative Comparative Assessment.

Pipeline Number		Diam	Length	Service	Status	Recommended Option	Justification
PL002	N0201	36	1.3	Oil export	Laid on the seabed with some mattresses and 71 m of rock-dump	Disconnect, remove the tie-in spools, grout bags and mattresses if present, then trench and backfill to provide at least 0.6 m seabed cover over the top of the pipe. If there is existing rock-dump, trenching will stop just short of the rock-dump and where necessary the existing rock-dump will be extended to cover the cut end(s).	This option provides a clear seabed and reduces the snagging risk for fishermen. It offers most of the benefits of the option 'Complete removal by cut and lift', including lower legacy environmental impacts and lower safety risk to project personnel, but at a significantly lower cost than full removal.
PL049	N0301	16	2.8	Oil export (now drains line)	Laid on the seabed with occasional mattresses		
PL048	N0302	16	2.3	Oil export (now drains line)	Laid on the seabed with mattresses at the PLEM end		
PL045	N0303	24	4.6	Oil production	Laid on the seabed with some mattress at BB end		
PL046	N0304	20	4.0	Oil production	Laid on the seabed		
PL050	N0401	28	3.0	Flare Gas (disused and in IPR)	Laid on the seabed, rock-dump at flare end		
PL051	N0402	36	2.6	Flare Gas (disused and in IPR)	Laid on the seabed, rock-dump at flare end		
PL052	N0403	36	2.3	Gas production	Laid on the seabed with mattresses at BA and 112 m of rock-dump		
PL047	N0404	30	4.4	Gas production	Laid on the seabed with mattresses at BC end		
PL044	N0405	24	4.2	Gas production	Laid on the seabed		
–	N9903A	24	1.7	Oil production (disused)	Laid on the seabed, some buried sections		
–	N9903B	24	1.7	Oil production (disused)	Laid on the seabed, with some buried sections		

Table 80, continued. Recommended Decommission Option for Brent Lines Subject to Quantitative Comparative Assessment.

Pipeline Number		Diam.	Length	Service	Status	Recommended Option	Justification
PL001	N0501	30	35.9	Oil export	Trenched along majority of length	Partially trench and backfill with isolated rock-dump.	The majority of the line lies in a stable trench with the top of the pipe lower than the mean seabed level. Shallower sections of the line will be retrenched or rock-dumped.
PL017	N0601	16	0.4	Gas production	Laid on the seabed with some burial and rock-dump	Remove completely by cut and lift.	This is a short line and the differences between the options are small. It is too short to trench, and a section will have been previously removed by the Brent Bypass Project.

Note: Diam. = Diameter in inches: Length is kilometres. Service = purpose or use of the line. Status = Condition/position of line on or in the seabed.

19.6.5 Discussion of the Recommended Option for the Quantitative Pipelines to be Decommissioned by Trench and Bury

Introduction

The recommended option for twelve of the fourteen quantitative lines (Table 80) is 'Disconnect, remove tie-in spools, trench and backfill'. Three to six options were assessed in the CAs for these lines (Table 81). The results of the CAs for each of the twelve lines to be decommissioned by Option 4 'Disconnect, trench and backfill' are shown in Table 81.

Table 81 Total Weighted Scores of Options for the 12 Quantitative Lines to be Decommissioned by Option 4 'Disconnect, Trench and Backfill'.

Pipeline Number	Total Weighted Score in Options								
	1	2	3	4	5	6	7	8	9
PL002/N0201		82.61	83.83	82.66	85.75	83.07	73.34		
PL044/N0405	82.11			82.37	83.98	83.32	72.82		
PL045/N0303	84.10			82.27	83.86	82.55	72.50		
PL046/N0304	81.41			82.42	84.07	83.42	72.89		
PL047/N0404	83.97			82.27	83.88	83.04	72.58		
PL048/N0302		83.55	84.80	82.33	85.07	83.13	73.23		
PL049/N0301		82.54	83.97	82.24	84.53	83.11	73.21		
PL050/N0401	79.53			81.78	84.01	82.60	72.73		
PL051/N0402	84.11			82.06	84.80	82.35	72.47		
PL052/N0403	82.54			82.77	85.50	83.64	73.17		
–/N9903A				82.45	85.36	82.47			
–/N9903B				82.40	84.72	82.44			

Key

Option	Description
1	Leave tied-in, no further remediation required
2	Leave tied-in at the installation, trench the remote end
3	Leave tied-in at the installation, rock-dump the remote end
4	Disconnect from the installation, trench and backfill the whole length
5	Disconnect from the installation, rock-dump the whole length
6	Remove the whole line by cut and lift
7	Remove the whole line by reverse S-lay (single joint)
8	Partially trench and backfill, with isolated rock-dump
9	Partially rock-dump

Option 7 'Remove whole line by reverse S-lay (single joint)' is a feasible option for ten of these twelve lines, but in every case it clearly had the lowest total weighted score and was never a candidate for the 'CA-recommended option'.

For all of these lines except PL045/N0303 and PL047/N0404 the option with the highest total weighted score (and thus the presumptive CA-recommended option) was Option 5 'Disconnect and rock-dump whole length'. In all cases, however, we have proposed Option 4 'Disconnect, and trench and backfill whole length' as the Recommended Option, an option which for seven of the lines had the lowest total weighted score. Our recommendation is based on a consideration of the relative performances of the options, the raw data and the views of our stakeholders including commercial fishermen. It is worth noting that for these twelve lines the total weighted scores for the other options (excluding Option 7) are very similar. The highest total weighted score is no more than approximately 6% greater than the lowest (Table 82) and this is relevant when considering the illustrative narrative presented below.

Table 82 Highest and Lowest Total Weighted Scores of Options 1 to Option 6 for Quantitative Pipelines Being Trenched and Backfilled.

Pipeline Number	Total Weighted Score Under 'Standard Weighting' (with Option Number)			
	Min	Max	Range	Range as % of Lowest
PL002/N0201	82.61 (2)	85.75 (5)	3.14	3.8
PL044/N0405	82.11 (1)	83.98 (5)	1.87	2.3
PL045/N0303	82.27 (4)	84.10 (1)	1.83	2.2
PL046/N0304	81.41 (1)	84.07 (5)	2.66	3.3
PL047/N0404	82.27 (4)	83.97 (1)	1.70	2.1
PL048/N0302	82.33 (4)	85.07 (5)	2.74	3.3
PL049/N0301	82.24 (4)	84.53 (5)	2.29	2.8
PL050/N0401	79.53 (1)	84.01 (5)	4.48	5.6
PL051/N0402	82.06 (4)	84.80 (5)	2.74	3.3
PL052/N0403	82.54 (1)	85.50 (5)	2.96	3.6
–/N9903A	82.45 (4)	85.36 (5)	2.91	3.5
–/N9903B	82.40 (4)	84.72 (5)	2.32	2.8

Results and Narrative for Example Pipeline

Pipeline PL050/N0401, the 28" 3 km long flare gas line from Brent Alpha to the site of the former Brent Flare, has been selected as an example of the CA results for those lines where the recommended decommissioning option is Option 4 'Disconnect, trench and backfill'.

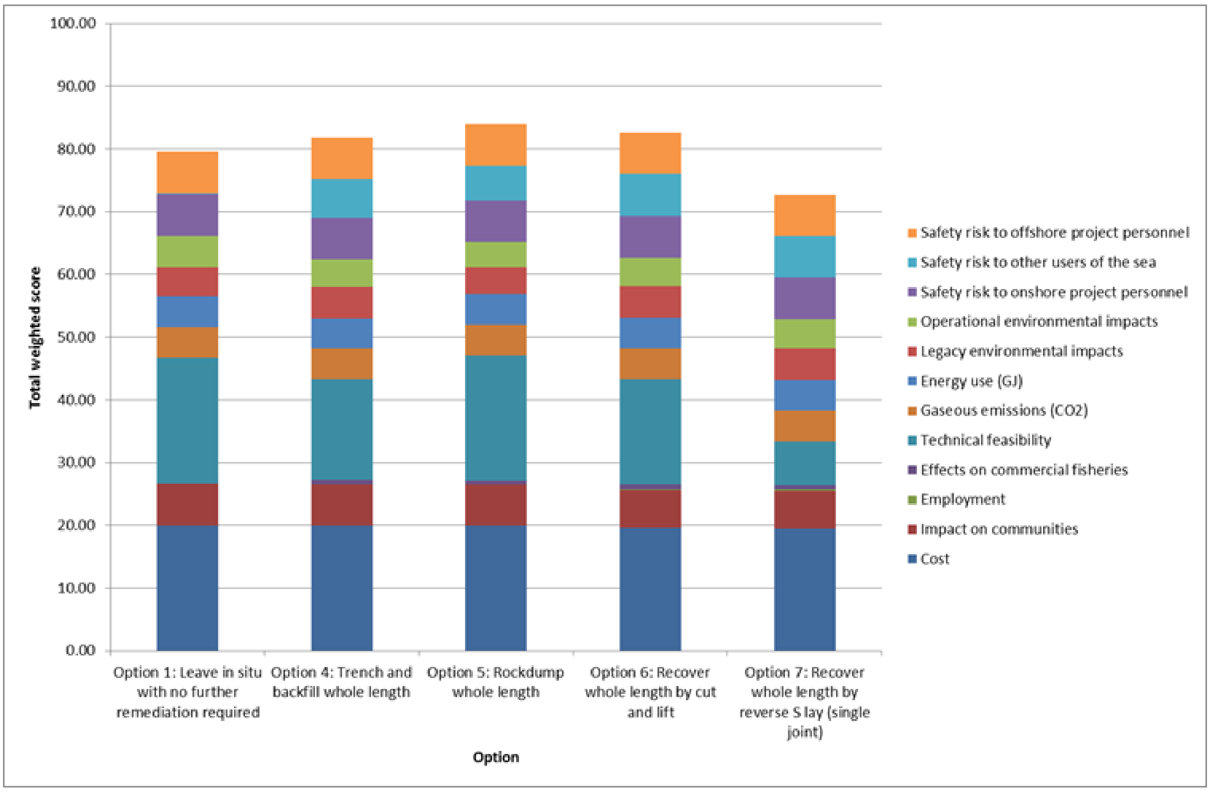
Table 83 shows the total weighted scores of the options for PL050/N0401 and Figure 113 illustrates the results. On the basis of this assessment the 'CA-recommended' option for PL050/N0401 is Option 5 'Disconnect and rock-dump whole length'. It has a total weighted score of 84.01 in contrast to the next best score which is 82.60 for Option 6 'Recover whole length by cut and lift'. However, the narrative below explains why Option 4 was recommended in preference to either Option 5 or Option 6.

Table 83 Transformed and Weighted Sub-criteria Scores for Pipeline PL050/N0401.

Sub-criterion	Option 1	Option 4	Option 5	Option 6	Option 7
Safety risk to offshore project personnel	6.66	6.65	6.66	6.59	6.54
Safety risk to other users of the sea	0.10	6.13	5.59	6.67	6.67
Safety risk to onshore project personnel	6.67	6.67	6.67	6.66	6.66
Operational environmental impacts	5.00	4.30	3.95	4.60	4.65
Legacy environmental impacts	4.65	5.00	4.25	5.00	5.00
Energy use	4.89	4.88	4.87	4.88	4.88
Gaseous emissions	4.90	4.89	4.89	4.91	4.91
Technical feasibility	20.00	16.00	20.00	16.80	7.00
Effects on commercial fisheries	0.00	0.71	0.57	0.71	0.71
Employment	0.01	0.02	0.02	0.12	0.15
Impact on communities	6.67	6.60	6.60	6.00	6.00
Cost	19.97	19.93	19.94	19.65	19.54
Total weighted score	79.53	81.78	84.01	82.60	72.73

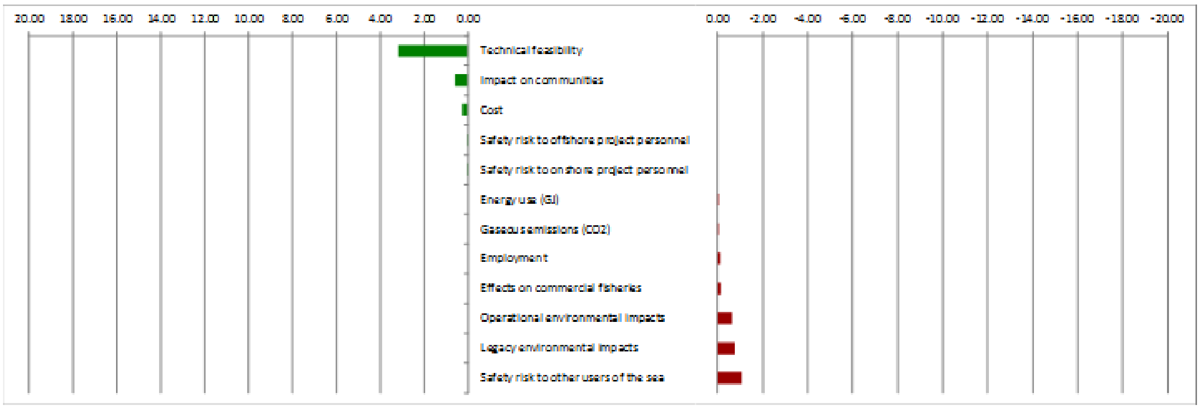
Option 1	Leave *in situ* with no further remediation required
Option 4	Trench and backfill whole length
Option 5	Rock-dump whole length
Option 6	Recover whole length by cut and lift
Option 7	Recover whole length by reverse S-lay (single joint)

Figure 113 The Total Weighted Scores for Options for Pipeline PL050/N0401, and the Contributions of the Sub-criteria.



No strong driver has been identified as the reason for the differences in the total weighted scores under the different weighting scenarios. Option 5 'Rock-dump whole length' is usually ranked first in the sensitivity scenarios though it never scores significantly higher than Option 6 'Recover whole length by cut and lift' or most of the other options. The determination of the recommended option for this pipeline has been based on the comparison between the best full removal option Option 6 'Recover whole length by cut and lift', and the CA-recommended option Option 5 'Rock-dump whole length'. The differences between Option 5 and Option 6 are illustrated in Figure 114. The green bars indicate sub-criteria where Option 5 has the better performance and the red bars indicate sub-criteria where Option 6 has the better performance.

Figure 114 Difference Chart Comparing the Weighted Scores for Each Sub-criterion of Option 5 'Rock-dump Whole Length' with Option 6 'Recover Whole Length by Cut and Lift', under the Standard Weighting, for Pipeline PL050/N0401.



Green bars: Option 5 'Rock-dump whole length' is better than Option 6 'Recover whole length by cut and lift'

Red bars: Option 6 'Recover whole length by cut and lift' is better than Option 5 'Rock-dump whole length'

Option 6 'Recover whole length by cut and lift' is preferable to Option 5 'Rock-dump whole length' in seven sub-criteria: safety risk to other users of the sea, legacy and operational environmental impacts, effects on commercial fisheries, employment and gaseous emissions and energy use. It should be noted that some of these differences are so small that the bars do not appear in Figure 114. Option 5 is preferable to Option 6 in the five remaining sub-criteria: safety risk to onshore and offshore project personnel, cost, impact on communities and technical feasibility; again some of the differences are so small that the bars do not appear on the difference chart.

It is important to examine these differences to see if the differing performance of the options is related to significant and material differences in the raw data in the various sub-criteria. The following sections discuss the performances of the options in each of the sub-criteria in turn as ordered in Figure 114, and determine the extent to which the differences could assist us in reaching a recommendation for PL050/N0401.

Technical Feasibility: The rock-dumping in Option 5 was assessed to be one of the most feasible operations considered by the project (hence the score of 1.0) and to be more feasible than the cut and lift operations in Option 6 (a score of 0.84). Rock-dumping is a routine operation in the industry and there are no concerns about our ability to successfully execute the option. The cutting and lifting of pipeline sections required in Option 6 is a relatively common operation in the industry, but the score was reduced because of the age of the pipeline and some concerns over whether the concrete coating would have sufficient strength to be recovered without spalling off the steel pipeline. Option 6 may require some development of existing technologies and although not insurmountable this will add complexity to the execution of the option. Any problems encountered with the removal of the pipeline in Option 6 are therefore more likely to result in extended operations and hence increased overall cost. As a result, technical feasibility does not, in our view, act as a strong differentiator of the options.

Impact on Communities: In Option 5 and in Option 6 respectively approximately 38 tonnes and 2,180 tonnes of material would be returned to shore. These are relatively small amounts of material and would not be expected to cause any significant onshore impacts, particularly when compared with the amounts of material that will be returned to shore from other scopes of work in the project. Accordingly, both options were scored highly on global scale (0.99 for Option 5 and 0.90 for Option 6). With no significant difference in their scores and relatively small amounts of material being returned to shore, we have concluded that the sub-criterion 'impact on communities' is not a strong differentiator between these options.

Cost: With an estimated cost of approximately £1.6 million, Option 5 'Rock-dump whole length' is approximately 17% of the £9.28 million cost of Option 6 'Recover whole length by cut and lift'. Option 6 therefore represents almost a six-fold increase in the expenditure of Option 5. Cost should therefore be considered further in this assessment.

Safety Risk to Project Personnel: Option 5 has the lowest combined safety risk for project personnel (a PLL of 0.0005) whereas Option 6 has a combined project personnel PLL of 0.0034. The majority of the risk in both options is attributable to offshore project personnel. This means that if Option 5 were performed 2,000 times there might be one fatality among the project personnel and if Option 6 were performed 294 times there might be one fatality among the project personnel.

When compared with the PLL thresholds used in the first step of evaluating E&P projects (an annual PLL of1 $x10^{-3}$), the total PLL for Option 5 (0.5 $x10^{-3}$) falls within the ALARP range. Option 6 is three times higher (3.4 $x10^{-3}$) than the threshold and would require some degree of mitigation prior to execution to confirm it was ALARP.

In all cases the assessments of safety risks are unmitigated assessments made in the absence of any site- or project-specific safety measures. We would never embark on any activity that was unsafe and we always work to reduce all safety risks to a level that is ALARP. Given the conservative (unmitigated) PLLs presented here we are confident that both options could be executed safely and have therefore concluded that the sub-criterion 'safety risk to project personnel' does not act as a differentiator between Option 5 and Option 6.

Energy Use and Gaseous Emissions: Option 5 'Rock-dump whole length' would use more energy (45,171 GJ) than Option 6 (41,386 GJ)(an increase of about 9%) as a result of the vessels used and the penalty for not recycling the steel contained within the pipeline. Even though the steel would be recycled in Option 6 this option would still require 92% of the energy required for Option 5. On the basis of these estimates we have concluded that the sub-criterion 'energy use' does not act as a differentiator between the two options.

Option 5 would also generate more gaseous emissions (3,430 tonnes CO_2) than Option 6 (2,742 CO_2 tonnes)(an increase of about 25%).Both these values are low when compared to the emissions from operating platforms. The total CO_2 emissions from all four Brent platforms in 2011 was 396,000 tonnes, which is approximately 115 times higher than the estimated total CO_2 emissions of Option 5 or approximately 144 times higher than those of Option 6. The estimated emissions from each option are also very low when compared with the total CO_2 emissions from all UKCS oil and gas platforms (which, as reported in the Oil & Gas UK *Environment Report 2013* [62] was 14.22 million tonnes in 2011) and when compared with the UK commitment under the *Climate Change Act* [63] (which implies an average annual reduction of 47.6 million tonnes CO_2 each year from 2013 to 2017). Given the small amounts of emissions associated with Option 5 and Option 6 we have concluded that the sub-criterion 'gaseous emissions' is not a strong differentiator between the options.

Employment: Option 6 is more expensive than Option 5 and therefore supports a higher level of employment (37 man-years as opposed to 6 man-years). The employment supported in Option 5 would only be in offshore roles during the rock-dumping operations; the employment in Option 6 would be split between offshore (cut and lift operations) and onshore (recycling of the material). In absolute terms these levels of employment are not significant; the employment would not be continuous and would not support roles full-time. The level of employment supported by Option 5 and Option 6 is equivalent to less than 1% of the estimated 3,800 man-years of employment Brent Decommissioning well abandonment programme. Consequently we have concluded that the sub-criterion 'employment' is not a strong differentiator between the options.

Effects on Commercial Fisheries: If the lines were covered with rock-dump (Option 5) or removed completely (Option 6) a small additional area of seabed would be available for demersal fishing. Based on information in [21] this would amount to a net benefit over the 280 year predicted lifetime of the pipeline of £197,230 and £246,538 for Option 5 and Option 6 respectively. On an annual basis this represents a very small increase (£704 and £880 each year respectively) so in absolute terms of benefit to commercial fishermen and in relative terms between the options, this is a small benefit. This sub-criterion is therefore not considered to be a strong differentiator between Option 5 and Option 6.

Operational Environmental Impacts: Option 6 would result in the minor disturbance of seabed sediments as the pipeline is cut into sections and removed. It is expected that the short and limited nature of the disturbance would allow the rapid recovery of the seabed and benthic fauna, hence Option 6 scored highly on the global scale (0.92). The seabed would also be disturbed in Option 5 by the deposition of the new rock-dump. This would probably result in a larger area of disturbance in order to create the over-trawlable profile of the deposited rock and so for pipeline PL050/N0401 this option had the lowest score of all the options in this sub-criterion (0.79). Neither option is expected to result in significant environmental impacts nor is the difference in the assessment of such impacts for the options very great, so this sub-criterion is not considered to act as a strong differentiator between the options.

Legacy Environmental Impacts: The full removal of the pipeline in Option 6 will completely eliminate the legacy environmental impacts which might occur as the pipeline degrades and disintegrates. It was therefore accorded the highest score on the global scale (1.00). In Option 5 the pipeline and any disintegration products and hence environment impacts, including seabed litter, would be contained within the rock-dump and the effects would therefore be limited. The addition of the rock in Option 5 would have the potential to cause environmental changes as a result of the local change in habitat and colonisation by different species more typical of rocky substrates. DNV GL did not consider this impact to be significant, however, because areas of hard substrate are already present in the Field; the Brent seabed is known to be littered with rocks and boulders in various places.. The score for Option 5 has been reduced to 0.85 because of the amount of rock to be used in this option (51,000 tonnes). Overall, no significant environmental impacts are expected to occur and we have concluded that the sub-criterion 'legacy environmental impacts' is not a strong differentiator between the options.

Safety Risks to Other Users of the Sea: The other users of the sea who would be exposed to safety risks from the pipelines are fishermen who might trawl over the pipelines and snag their fishing gear. We commissioned Anatec to assess the potential safety risks to fishermen for the decommissioning options [20]). These assessments assumed that all the safety zones around subsea infrastructure had been removed and as such were a worst case assessment. In Option 6, the pipeline would be removed and any risk to the fishermen would be eliminated. The total PLL for fishermen in Option 5 was calculated to be 0.0428 which means that if pipeline PL050/N0401 were to be decommissioned 23 times by covering in rock-dump, there might be one fisherman fatality over the predicted lifetime of the pipeline (280 years). Anatec estimated that the annual PLL in Option 5 for this pipeline was 7.14×10^{-5} which, when compared to the annualised PLL threshold for oil and gas industry E&P projects (1×10^{-3}), is well within the tolerable range.

There have been no reported incidents of fishing gear interactions or accidents during the time this pipeline has been in place. We will remain responsible for any section pipeline which remains *in situ* and we will ensure that any section of any pipeline which remains above the mean seabed level is marked on navigational charts and is registered in the FishSAFE database used by commercial fishing vessels. Although the sub-criterion 'safety risks to other users of the sea' is a differentiator between Option 5 and Option 6, the potential risk to fishermen in Option 5 is considered to be acceptable.

Conclusion: Following the assessment of the weighted scores for each sub-criterion and an examination of the data informing those scores we have concluded that there are no strong drivers that differentiate the two best-performing options, Option 5 and Option 6. The supporting data do show differences, however, particularly in the sub-criterion 'safety risk to other users of the sea' (fishermen), although the risk to fishermen in both options is low or eliminated. Estimating the long-term safety risk for fishermen is complex and uncertain. In addition, the assessment of safety risk used in the CA assumed that the 500 m safety zone around the Brent Alpha platform would no longer be in place. In reality, if derogation from the OSPAR 98/3 Decision were granted for the Brent Alpha jacket footings, we would apply to the HSE for the 500 m safety zone to remain in place. Overwhelmingly, the assumptions used in the calculations of safety risk to other users of the sea have been conservative, and we believe that their individual and combined effects have been to over-estimate the likelihood that fishing gear will snag on degrading pipelines on the seabed and that snaggings will lead to accidents and that accidents will lead to fatalities. However, the risks to fishermen are less amenable to mitigation than those to project personnel. They are not under the control of the project and would be reduced mainly by the application of good navigation practice and seamanship, by the use of present and future aids to navigation and by the use and maintenance of systems such as FishSAFE.

Option 6 would completely eliminate any future safety risk to fishermen but this would require an expenditure of £9.28 million which is a significant increase in expenditure when compared with either Option 5 'Rock-dump whole length' or Option 4 'Trench and backfill whole length', which is the remaining affordable option that would significantly reduce the long-term safety risk to other users of the sea. When the performances in all other sub-criteria show no significant differences, cost can be considered to be a driver. Mindful of the views expressed by the SFF during informal discussions, however, we wished to investigate if a more cost efficient compromise could be achieved between reducing safety risk to other users (fishermen) and project expenditure. To this end, the data for Option 4 'Trench and backfill whole length' were re-examined because this option would result in a halving of the potential safety risk to fishermen.

In Option 4 the potential safety risk to fishermen over the predicted lifetime of the pipeline is half that estimated for Option 5 (PLLs of 0.0214 and 0.0428 respectively). This reduction in the PLL would be accompanied by a slight increase in the safety risk to project personnel (from a PLL of 0.0005 in Option 5 to a PLL of 0.0009 in Option 4, but this is not a significant increase and we are confident that the risk to project personnel in Option 4 could be demonstrated to be ALARP. Trenching and backfilling the pipeline would have an increased operational environmental impact when compared to Option 6 because there would be greater disturbance of the seabed sediments, but Option 4 would have less of an operational impact compared with Option 5. Once operations were completed the pipeline would be entirely buried and this would minimise the legacy impacts of the degrading pipeline (as rock-dumping would in Option 5) but without the potential for altering the seabed habitat by the use of a large volume of additional rock. Option 4 therefore performs better than Option 5 in the sub-criterion 'legacy environmental impact', achieving the highest possible score (1.0) on the global scale. This is the same score as Option 6 'Recover whole length by cut and lift', but it is noted that there is a difference between a negligible impact in Option 4 and the absence of an impact in Option 6.

In Option 4 the trenching of the pipeline would use slightly more energy and generate slightly more gaseous emissions than Option 6 because the pipeline material would not be returned to shore, but it would use less energy and generate less gaseous emissions than Option 5. These differences in the calculated values are, however, small.

Because of the changeable and difficult seabed conditions known to exist in the Brent Field, trenching the pipeline is thought to be slightly more difficult than removing it by cut and lift or rock-dumping the whole length. The difference in feasibility is not great, however, and Option 4 still scores relatively highly on the global scale in this sub-criterion (0.80).

Recommendation for Pipeline PL050/N0401: Option 4 presents what we believe to be a balanced recommendation in which the concerns of our stakeholders can be addressed with only a minimal increase in the safety risk to our own project personnel, which remains at a level within the tolerable range. Although Option 4 would not completely remove the legacy environmental impact as in Option 6, it would result in less of an impact than Option 5. This more desirable outcome can be achieved with a marginally greater operational environmental impact than Option 6 and a smaller operational impact than Option 5. Once the pipeline is trenched, the additional area available for fishing would be the same as would be available if the pipeline had been removed. These benefits can be achieved with a very minor increase in project expenditure when compared with Option 5 (approximately £15,000) as opposed to the significant cost required to remove the pipeline completely. We have therefore concluded that the recommended decommissioning option for PL050/N0401 is Option 4 'Trench and backfill whole length'.

19.6.6 Discussion of the Recommended Option for the Quantitative Pipeline to be Left Partially Trenched and Backfilled with Isolated Rock-dump.

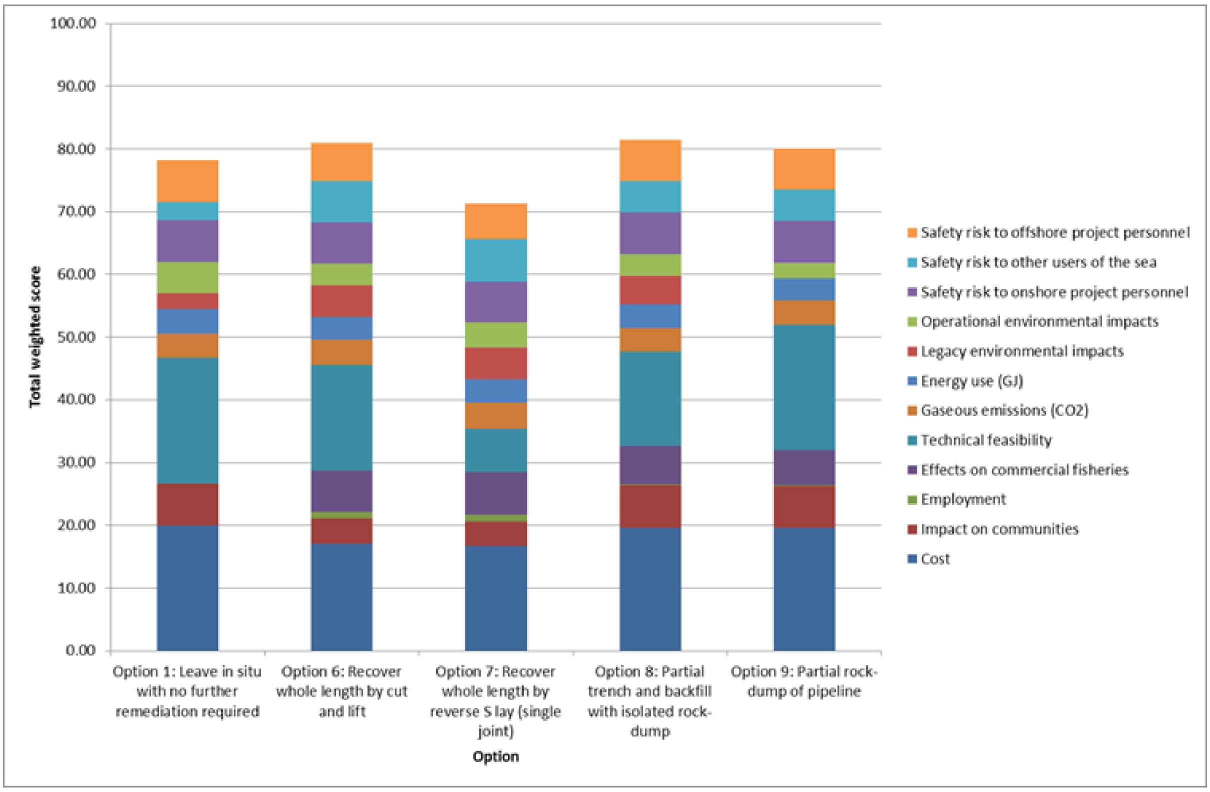
Results: This is the recommended option for one line PL001/N0501, the 30" 35.9 km export line. Five options were consider for this line (Table 79). Table 84 shows the total weighted scores of the options for this line and Figure 115 illustrates the results. On the basis of this assessment the 'CA-recommended' option for PL001/N0501 is Option 8 'Partially trench and backfill, with isolated rock-dump'. It has a total weighted score of 81.42 in contrast to the next best score which is 80.89 for Option 6 'Recover whole length by cut and lift'.

Table 84 Transformed and Weighted Sub-criteria Scores for Pipeline PL001/N0501.

Sub-criterion	Option 1	Option 6	Option 7	Option 8	Option 9
Safety risk to offshore project personnel	6.64	5.91	5.64	6.54	6.56
Safety risk to other users of the sea	2.88	6.67	6.67	5.02	4.94
Safety risk to onshore project personnel	6.67	6.61	6.61	6.67	6.67
Operational environmental impacts	5.00	3.50	4.00	3.50	2.50
Legacy environmental impacts	2.50	5.00	5.00	4.50	0.00
Energy use	3.82	3.66	3.79	3.67	3.59
Gaseous emissions	3.97	3.98	4.08	3.86	3.81
Technical feasibility	20.00	16.80	7.00	15.00	20.00
Effects on commercial fisheries	0.00	6.67	6.67	6.23	5.60
Employment	0.01	0.96	1.12	0.12	0.15
Impact on communities	6.67	4.00	4.00	6.67	6.67
Cost	19.97	17.13	16.65	19.64	19.56
Total weighted score	**78.13**	**80.89**	**71.22**	**81.42**	**80.04**

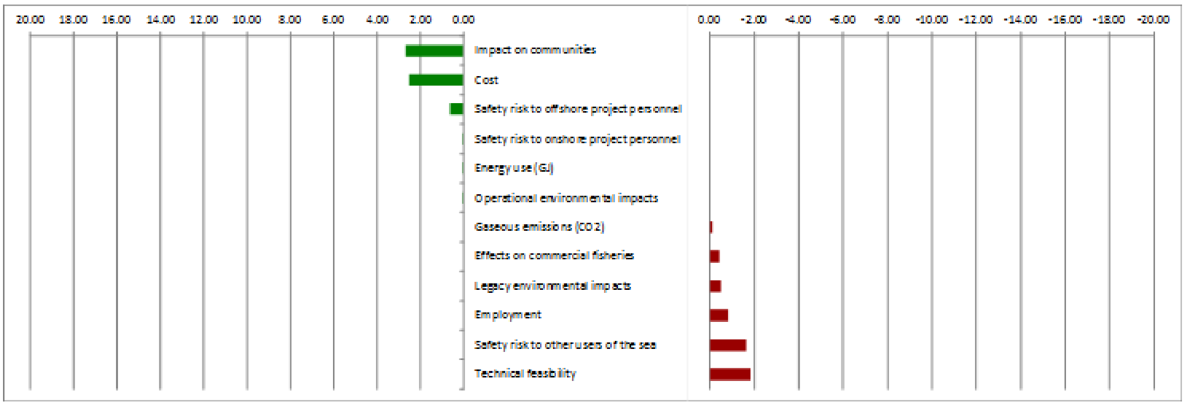
Option 1	Leave *in situ* with no further remediation required
Option 6	Remove whole length by cut and lift
Option 7	Remove whole length by reverse S-lay (single joint)
Option 8	Partial trench and backfill with isolated rock-dump
Option 9	Partial rock-dump of pipeline

Figure 115 The Total Weighted Scores for Options for Pipeline PL001/N0501, and the Contributions of the Sub-criteria.



No strong drivers have been identified under any of the weighting scenarios. Option 6 'Recover whole length by cut and lift' is often ranked first under the six weighting scenarios but it never scores significantly higher than Option 8 'Partial trench and backfill with isolated rock-dump'. This is illustrated in Figure 116 which shows that Option 6 performs marginally better than Option 8 across a number of sub-criteria rather than there being any strong drivers for the performance of either option. The green bars indicate sub-criteria where Option 8 has the better performance and the red bars indicate sub-criteria where Option 6 has the better performance.

Figure 116 Difference Chart Comparing the Weighted Scores for Each Sub-criterion of Option 6 'Remove Whole Length by Cut and Lift' with Option 8 'Partial Trench and Backfill with Isolated Rock-dump', under the Standard Weighting, for Pipeline PL001/N0501.



Green bars: Option 8 'Partial trench and backfill with isolated rock-dump' is better than Option 6 'Remove whole length by cut and lift'

Red bars: Option 6 'Remove whole length by cut and lift' is better than Option 8'Partial trench and backfill with isolated rock-dump'

Conclusion: Following the assessment of the weighted scores for each sub-criterion and an examination of the data informing those scores we have concluded that there are no strong drivers that differentiate Option 6 and Option 8. PL001/N0501 is the longest pipeline in the Brent Field, however, and the implications of the pipeline to commercial fishermen must be considered. Estimating the long-term safety risk for fishermen is complex and uncertain. Particularly in respect to commercial fishing activity and pipeline degradation, several important assumptions had to be accepted, and forecasts made going hundreds of years into the future. These assumptions have been intended to be conservative, and we believe that their individual and combined effects have been to over-estimate the likelihood that fishing gear will snag on degrading pipelines on the seabed and that snaggings will lead to accidents and that accidents will lead to fatalities. The risks to fishermen, however, are less amenable to mitigation than those to project personnel. They are not under the control of the project and would be reduced mainly by the application of good navigation practice and seamanship, by the use of present and future aids to navigation, and by the use and maintenance of systems such as FishSAFE. Despite the fact that there have been no incidents involving this pipeline during its lifetime we would prefer to take steps to reduce even a theoretical risk to third parties, and by trenching and rock-dumping the pipeline we would reduce the risk currently associated with this pipeline. Although the risks could be completely eliminated by removing the pipeline by, for example, cut and lift, this would incur an increase in cost of £67 million which is a disproportionate expenditure to reduce a theoretical risk.

Recommendation for pipeline PL001/N0501: There have been no incidents involving this pipeline in its current configuration, but we have limited influence on the future activities in the vicinity of the pipeline. The cost of completely removing this pipeline is, however, substantial. We therefore intend to complete extensive operations to reduce the theoretical future risk to fishermen by trenching and rock-dumping the shallow-trenched sections of this pipeline. The recommended decommissioning option for PL001/N0501 is Option 8 'Partial trench and backfill with isolated rock-dump'.

19.6.7 Discussion of the Recommended Option for the Quantitative Pipeline to be Removed Completely by Cut and Lift.

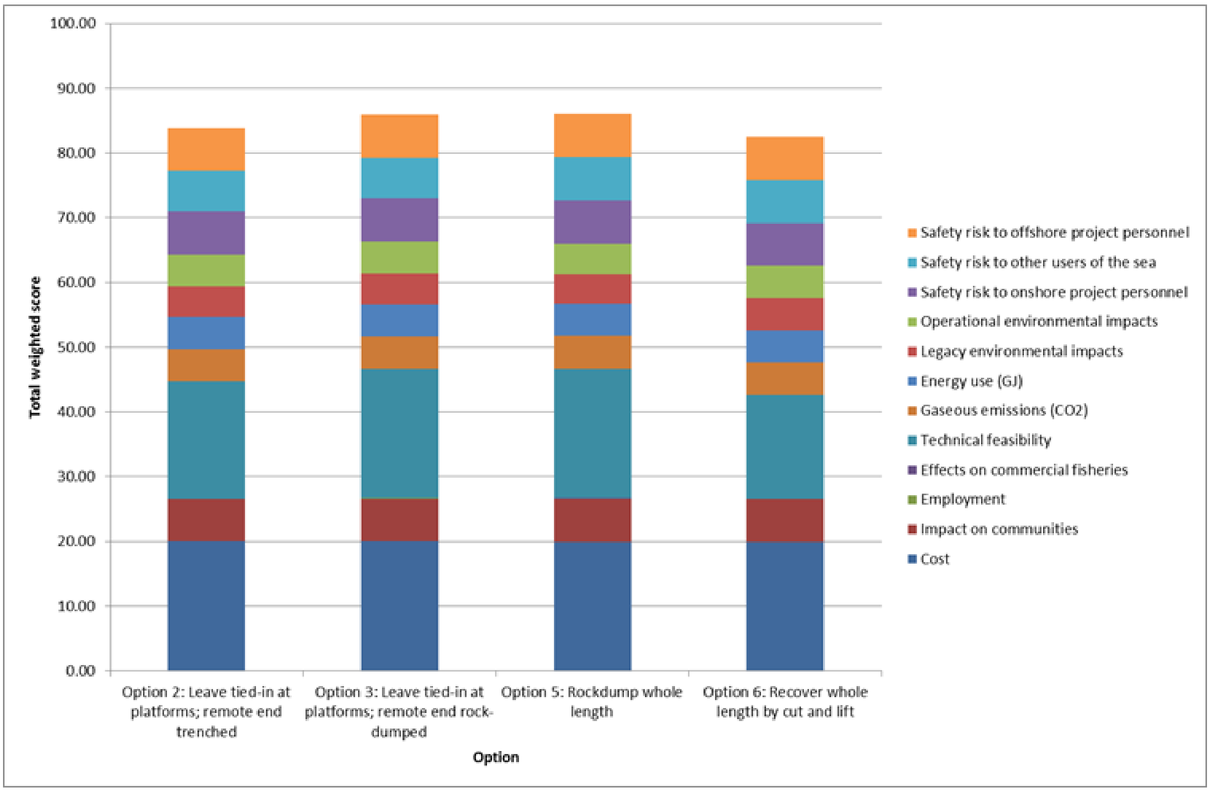
Results: This is the recommended option for PL017/N0601 the short length (0.4 km) of 16" gas export lying exposed on the seabed at Brent Bravo. Four options were considered for this line (Table 79). Table 85 shows the total weighted scores of the options for this line and Figure 117 illustrates the results. On the basis of this assessment the 'CA-recommended option' for PL017/N0601 is Option 5 'Rock-dump whole length'. The total weighted score for this option is 86.03. The next best performing option is Option 3 'Leave tied-in at platform, remote end rock-dumped' with a total weighted score of 85.89.

Table 85 Transformed and Weighted Sub-criteria Scores for Pipeline PL017/N0601.

Sub-criterion	Option 2	Option 3	Option 5	Option 6
Safety risk to offshore project personnel	6.66	6.66	6.66	6.66
Safety risk to other users of the sea	6.23	6.23	6.67	6.67
Safety risk to onshore project personnel	6.67	6.67	6.67	6.67
Operational environmental impacts	4.95	4.95	4.75	4.90
Legacy environmental impacts	4.75	4.75	4.60	5.00
Energy use	4.98	4.98	4.98	4.98
Gaseous emissions	4.99	4.99	4.99	4.99
Technical feasibility	18.00	20.00	20.00	16.00
Effects on commercial fisheries	0.00	0.00	0.06	0.08
Employment	0.01	0.01	0.01	0.02
Impact on communities	6.67	6.67	6.67	6.60
Cost	19.97	19.97	19.96	19.94
Total weighted score	83.89	85.89	86.03	82.51

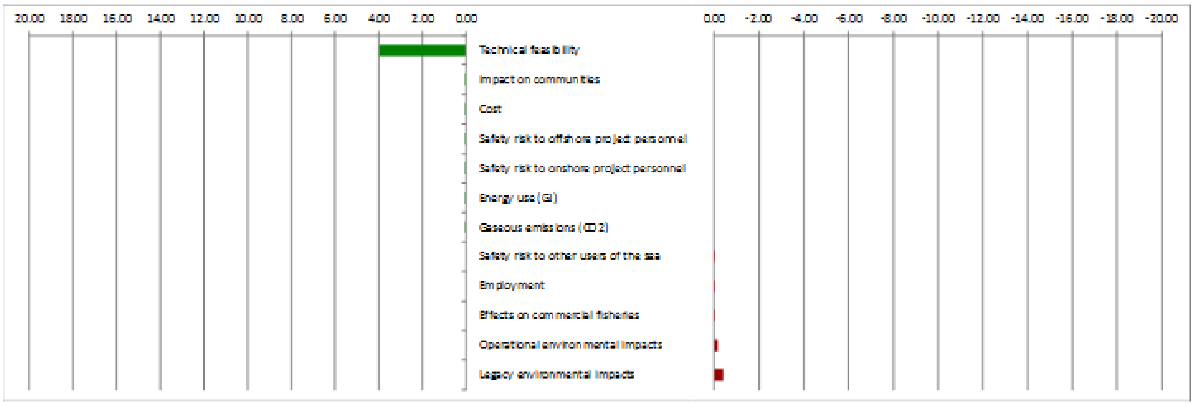
Option 2	Leave tied-in at platform; remote end trenched
Option 3	Leave tied-in at platform; remote end rock-dumped
Option 5	Rock-dump whole length
Option 6	Recover whole length by cut and lift

Figure 117 The Total Weighted Scores for Options for Pipeline PL017/N0601, and the Contributions of the Sub-criteria.



No strong driver has been identified as the cause of the difference in the total weighted scores under the different weighting scenarios. Option 5 'Rock-dump whole length' is usually ranked first, though it never scores significantly higher than Option 3 'Leave tied-in at platform; remote end rock-dumped' or the other options. The determination of the recommended option for PL017/N0601 has been based on the comparison of the best full removal option (Option 6 'Recover whole length by cut and lift' which is the only full removal option for this line) and the best-performing option based on the CA data (Option 5 'Rock-dump whole length'). The differences between Option 5 and Option 6 are illustrated in Figure 118. The green bars indicate sub-criteria where Option 5 has the better performance and the red bars indicate sub-criteria where Option 6 has the better performance. The difference chart shows that there are hardly any differences between the options except in terms of Technical Feasibility, where Option 5 'Rockdump whole length' has a better performance than Option 6 'Recover whole length by cut and lift'.

Figure 118 Difference Chart Comparing the Weighted Scores for Each Sub-criterion of Option 5 'Rock-dump Whole Length' with Option 6 'Recover Whole Length by Cut and Lift', under the Standard Weighting, for Pipeline PL017/N0601



Green bars: Option 5 'Rock-dump whole length' is better than Option 6 'Remove whole length by cut and lift'

Red bars: Option 6 'Remove whole length by cut and lift' is better than Option 5 'Rock-dump whole length'

Conclusion: Following the assessment of the weighted scores for each sub-criterion and an examination of the data informing those scores, we have concluded that there are no strong drivers that differentiate Option 5 the best-performing option, and Option 6 the best full removal option. Bearing in mind the preference of the Scottish Fishermen's' Federation (SFF) and the small difference in cost between Option 5 and Option 6 (approximately £500,000), we propose that this pipeline should be completely removed from the seabed.

Recommendation for pipeline PL017/N0601: The recommended decommissioning option for PL017/N0601 is Option 6 'Recover whole length by cut and lift'.

19.7 Recommended Programme of Work for Decommissioning the Brent Field Pipeline System

19.7.1 Introduction

The decommissioning of the Brent Field lines comprises the completion of seven different options across the Field (Table 77 and Table 80), which between them involve one or more of the following activities:

- Reverse reeling
- Cutting and lifting
- Trenching and backfilling
- Rock-dumping

This section describes, in general terms, the operations that would be carried out and the results that would be achieved on successful completion of each type of decommissioning activity. The operations that would be performed during these activities are likely to be broadly similar regardless of whether we categorised the line as 'qualitative' or 'quantitative'. Detailed programmes of work for each pipeline and for each pipeline crossing are presented in the Pipelines TD [17].

19.7.2 Third-party Pipeline Crossings

The recommended decommissioning option takes account of the presence of pipeline crossings ,where one of our lines goes over or under one of our active operational lines or a line belonging to another operator. Thirteen of the Brent Field pipelines cross or are crossed by pipelines or umbilicals owned by Shell or third party operators.

PL052/N0402 is crossed by N9900, N9901 and N9902. We propose to trench and backfill PL052/N0402 and to recover N9900, N9901 and N9902 by cut and lift. During these operations the two small metal bridges supporting N9900 and N9902 will also be recovered.

PL987A/N0738, PL987A.1-3/N0841 and PL988A/N0913 are all situated within trenches to a depth of burial of 0.6 m or more and are all crossed by third party pipelines. The recommendation from our CAs is to leave our pipelines in place. The crossings therefore do not need to be dismantled.

The crossings of the five remaining Shell pipelines are more complex and the details and proposed programmes of are presented in Table 86.

Where we intend to remove the pipeline on either side of a pipeline crossing that cannot be dismantled by the BDP, we will sever the pipeline at an appropriate distance from the crossing to ensure that we do not disturb the crossing or risk adversely affecting the live pipelines. If the owners of the third party pipelines choose to remove the pipelines which cross over the Brent pipelines, we will return at a later date to collect the severed section of each pipeline for recycling or disposal onshore. Should the third party owners choose to leave their pipelines in place, we will consult with BEIS on the best course of action regarding the lengths of Brent pipelines remaining in place.

Table 86 Pipeline Crossings to be Decommissioned after the Brent Field Pipelines Decommissioning Programme of Work.

Proposed Decommissioning Option	Pipeline Crossings				
	Crossing 1	Crossing 2	Crossing 3	Crossing 4	Crossing 5
PIPELINE PL049/N0301					
Trench and backfill whole length	Crosses under Shell 16 inch gas line PL017/N0601 at KP 0.046 to KP 0.055. Crossing is formed with a large grout bag ramp. PL017/N0601 will be removed by cut and lift, so the crossing will be dismantled and the material removed.	Crosses under Shell umbilical N0830 at KP 0.127 to KP 0.131. Crossing is mattressed. During the reverse reeling of N0830 the four mattresses at the crossing will be recovered (Note 1).	Crosses under BP umbilical C0815 at KP 0.179 to KP 0.182. Crossing comprises two mattresses. Decommissioning of C0815 is the responsibility of BP. Before PL049/N0301 can be trenched the crossing and C0815 must be removed (Note 2).	Crosses under disused BP umbilical C0801 at KP 0.189. Crossing is formed by a small grout bag ramp. Decommissioning of C0801 is the responsibility of BP. Before PL049/N0301 can be trenched, the crossing and C0801 must be removed (Note 2).	Crosses under 20 inch BP NLGP pipeline C0603 at KP 0.20 to KP 0.207. Crossing comprises eight mattresses. Decommissioning of C0603 is the responsibility of BP. Before PL049/N0301 can be trenched the crossing and C0603 must be removed (Note 2).
PIPELINE PL045/N0303					
Trench and backfill whole length	Crosses under Shell 4 inch gas lift line PL2228/N1141 at KP 4.48. Decommissioning of PL2228/N1141 is the responsibility of Shell but not the BDP. Before PL045/N0303 can be trenched PL2228/N1141 must be removed (Note 3).	Crosses under Shell 30 inch gas line PL047/N0404 at KP4.56. PL047/N0404 will also be trenched and backfilled so this crossing must be removed (Note 4).	Crosses under Shell umbilical N1845 at KP4.55. Crossing is mattressed. Decommissioning of PLU2232/N1845 is the responsibility of Shell but not the BDP. Before PL045/N0303 can be trenched PLU2232/N1845 and the crossing must be removed (Note 4).	Crosses under Shell 4 inch gas lift line N1141 at KP 4.52. Crossing is mattressed. Decommissioning of PL2228/N1141 is the responsibility of Shell but not the BDP. Before PL045/N0303 can be trenched PL2228/N1141 and the crossing must be removed (Note 4).	Crosses under Shell umbilical N1845 at KP 4.48. Crossing is mattressed. Decommissioning of PLU2232/N1845 is the responsibility of Shell but not the BDP. Before PL045/N0303 can be trenched, PLU2232/N1845 and the crossing must be removed (Note 4).

Table 86, continued Pipeline Crossings to be Decommissioned after the Brent Field Pipelines decommissioning Programme of Work

Proposed Decommissioning Option	Crossing 1	Crossing 2	Crossing 3
PIPELINE PL017/N0601			
Recover whole length by cut and lift	Crosses under BP 20 inch NLGP gas pipeline C0603, from Magnus to Brent A at KP 41.2. N0601 is mattressed. Decommissioning of C0603 is the responsibility of BP. Before PL017/N0601 can be removed, C0603 and the associated crossing must be removed (Note 2).	Crosses under Shell umbilical N0830 from Brent A to SSIV at KP 41.15. Crossing formed with concrete saddle and mattresses. The BDP will recover the concrete saddle and mattresses which form the crossing during the reverse-reeling of N0830 (Note 1).	Crosses over Shell hazardous drains line N0301 from Brent A to Brent SPAR PLEM at KP 41.10. Crossing formed with large grout bag ramp. N0301 will be trenched and backfilled; therefore the crossing will be removed during the recovery of PL017/N0601 (Note 1).
PIPELINE PL047/N0404			
Trench and backfill whole length	Crosses over PL045/N0303 at KP0.010. PL045/N0303 will also be trenched and backfilled; therefore the crossing must be removed (Note 4).	Crosses under PL2228/N1141 at KP 0.050. Decommissioning of PL2228/N1141 is the responsibility of Shell but not the BDP. Before PL047/N0404 can be trenched PL2228/N1141 and the mattresses at the crossing must be removed (Note 3).	

Table 86, concluded Pipeline Crossings to be Decommissioned after the Brent Field Pipelines decommissioning Programme of Work

Proposed Decommissioning Option	Crossing 1	Crossing 2	Crossing 3	Crossing 4	Crossing 5	Crossing 6	Crossing 7
PIPELINE PL001/N0501							
Partial trench and backfill	Crosses under Fairfield Energy power cable N1826 from Brent Charlie to Dunlin at KP 0.15. Crossing is mattressed (Note 2).	Crosses under BP 20 inch NLGP gas pipeline PL164/C0603 from Magnus to Brent Alpha at KP 5.46. Crossing is rock-dumped (Note 2).	Crosses under BP 24 inch oil line PL139/C0503 from Magnus to Ninian Central at KP 8.56. Crossing is rock-dumped (Note 2).	Crosses under TAQA Bratani Ltd.10 inch gas line PL114/N0602 from North Cormorant to Welgas Junction at KP 30.98. Crossing is rock-dumped (Note 2).	Crosses under TAQA Bratani Ltd. umbilical N0801B from Cormorant A to Satellite well P1 at KP 34.42. Crossing is rock-dumped. (N0801B is listed in Shell imaps[46] as decommissioned). (Note 2).	Crosses under TAQA Bratani Ltd. 2 x 3" flexible flowlines N0701B from Cormorant Alpha to Cormorant Satellite well P1 at KP34.6. Crossing is rock-dumped. (N0701B is listed in Shell imaps as decommissioned). (Note 2).	Crosses under TAQA Bratani Ltd. umbilical PL169/N0803 from Cormorant A to Cormorant UMC at KP 35.9. (PL169/N0803 is listed in Shell imaps as decommissioned and as being with line N0802). (Note 2).

Notes:
1. This work is the responsibility of the Brent Decommissioning Project (BDP).
2. These Brent pipelines run underneath these third party pipelines; the third party pipelines must be taken out of use or removed before the Brent pipelines can be fully decommissioned.
3. This crossing is the responsibility of Shell U.K. Limited but not the Brent Decommissioning Project.
4. The crossings of these pipelines may be covered by a significant amount of drill cuttings. Should this be the case the crossings and the associated lengths of pipeline will remain in place to prevent disturbance of the drill cuttings. Full details are presented in the programme of work descriptions for these pipelines.

[46] Imaps is Shell's Geographical Information System (GIS) for recording the status of all of its facilities

19.7.3 Span Remediation

Ten of the twenty-eight Brent Field pipelines will be completely removed, thus removing any spans that are present. One pipeline is completely buried under rock-dump and therefore is not expected to span. Ten pipelines will be trenched and backfilled. Four of the pipelines will remain in their existing trenches. The shallow trenched sections of PL001/N0501 will be remediated with trenching and rock-dump, and the FishSAFE spans thought to be present on PL001/N0501 will be removed by cut and lift if they still exist. If any spans are found on the eighteen pipelines that remain in the Field after the decommissioning operations we will discuss possible remediation options with BEIS and agree the most appropriate action on a case-by-case basis.

19.7.4 Brent Bypass Project

In order to allow the continuing export of gas through the WLGP and FLAGS export routes a separate project is being undertaken by Shell to reconfigure the pipeline network. This project is referred to as the Brent Bypass Project (BBY) and some of the activities of this project will affect pipelines in the BDP. The BBY project is being executed in two phases. In Phase 1 the Northern Leg Gas Pipeline (NLGP) (from the Magnus platform) and WLGP (from the Ninian Central platform) will be disconnected from the Brent Alpha platform. The gas from the NLGP and WLGP will be commingled at a new subsea NL-WL PLEM structure. In Phase 2 the FLAGS pipeline will be disconnected from the Brent Alpha platform and existing VASP structure with the fluids and associated gas routed to a new FLAGS PLEM before onward transmission to shore via the remaining length of the FLAGS pipeline (PL002/N0201). Phase 1 work is due to commence in 2016 and be completed in 2017. It is anticipated that Phase 2 work will be completed in 2019.

19.7.5 Phases of Work

The Brent pipeline system will be decommissioned in a programme of work extending over several years. Initial phases will be carried out before the topsides are decommissioned because fluids and residues flushed from the pipes will be transported to shore via the topsides. Once flushed, however, some lines may be left on the seabed for a time until they can be decommissioned in a cost-effective ‘campaign’.

19.7.6 Subsea Cleaning and Preparatory Work

Each of the Brent pipelines will be cleaned prior to decommissioning. The cleaning operations will be completed under the appropriate permits and reporting requirements. For those pipelines already submitted to the Interim Pipeline Regime (IPR), which have already been cleaned, we will confirm that the previous cleaning is sufficient under the present legislation. If so, no further cleaning will be undertaken.

Cleaning operations will include pigging operations, and chemical and seawater flushing, as determined by the content and configuration of the pipeline. Some pipelines are not connected to any pigging facilities and would require temporary pipework to be fitted or alternative arrangements to be made.

The intention is to clean the pipelines from one platform to another using the existing connections to push the pipeline contents through the system. Depending on the function of the pipeline and the nature of the contaminants found within the cleaning fluids, the waste at the receiving platform will either be stored in tanks and transported to shore for treatment and disposal, or discharged to sea under permit.

In cleaning the pipelines, we are required to demonstrate that BAT has been employed, and tothis end we will de-oil or de-gas the pipeline before commencing cleaning operations. In 2016 we had the opportunity to trial our cleaning methodology with PL046/N0304 (the oil export line from Brent Delta to Brent Charlie) and PL044/N0405 (the gas export line from Brent Delta to Brent Charlie). Cleaning of these pipelines was required so that we could sever the pipelines at Brent Delta to allow the Brent Delta topside to be lifted away. At the time of the cleaning operation the final decommissioning recommendation for these pipelines had not been confirmed; we therefore intended to leave both these pipelines in such a condition that either a leave in place or full removal option was possible.

Full details of the proposed flushing operations on each Brent Field pipeline are presented in the Pipelines TD [17]. In summary, our proposed programmes for the three types of line are as follows

- Oil pipelines will be treated using a mixture of seawater flushes and mechanical pigging runs. If flushing operations are insufficient we may consider using chemicals to assist in the removal of waxy deposits. When repeated sampling of the flush water indicates that a plateau in the concentration of oil-in-water (OIW) has been reached we will confirm with BEIS that flushing operations can stop. Any solids will be collected and returned to shore for treatment and disposal.
- Gas pipelines will be flushed. No heavy deposits are expected in these pipelines and so it is likely that flushing will successfully remove any free hydrocarbons from the pipeline. As with the oil pipelines, samples will be taken and when no further improvement in OIW concentrations are found a report will be sent to BEIS to confirm that flushing operations can be stopped.
- Umbilicals will flushed before being severed, capped and removed.

19.7.7 Removal of Subsea Mattresses and Grout Bags

Mattresses and grout bags will be removed from the seabed to effect the decommissioning of the structures and pipelines, as determined by their proposed programmes of work. Should any problems be encountered with the removal of the mattresses we will consult with BEIS on the most appropriate course of action. Some mattresses will be intentionally left in place on the seabed if this is required by the recommended decommissioning option for the pipeline. All retrieved mattresses will be taken to shore for recycling or disposal.

The mattresses at Brent South which are already covered with rock-dump will remain in place. All concrete mattresses and grout bags associated with subsea structures and pipelines which are to be removed will also be removed. If any problems are encountered with these operations we will contact BEIS for guidance.

The intention is to recover the mattresses using speed-loaders or lifting baskets because it is likely that the ropes which form the lifting points have degraded, and may not be strong enough to bear the full weight of the mattresses when lifted. On the seabed, the mattresses will be loaded into the speed-loader or basket using a lifting frame (which would require divers) or a mattress grab. The mechanical mattress grab is unlikely to be able to lift those mattresses that are closely associated with seabed structures, and these mattresses will either have to be dragged clear or lifted clear using a frame. Five mattresses can be lifted at a time in a lifting basket; speed-loaders can recover up to six mattresses in each load and use less deck space than lifting baskets.

Grout bags set and harden when immersed in water, and when packed close together they may adhere to each other, forming large heavy masses on the seabed. In such circumstances the grout bags cannot be removed by ROV and the safest and most efficient method is to use a mattress grab. Once lifted from the seafloor the grout bags will be recovered to the vessels in debris baskets and disposed of onshore.

The removal of concrete mattresses and grout bags will cause very minor, localised and short-lived disturbances to the seabed and benthic communities in the immediate vicinity. Recovery of the seabed should begin as soon as the seabed activities have been completed.

19.7.8 Operations for Reverse Reeling

These operations will be performed on PL1955/N0310, PL1955/N0311, N0830, N1844 and N2801, a total of approximately 6.8 km of line. It is likely that the removal and recovery operations will be conducted from an MSV with a carousel. After the line has been cut or detached from any platform or subsea structure an anchor ‘head’ will be fitted at one end to fix it to the seabed. A lifting head will be fitted at the other end of the line, which will then be pulled up to the MSV. The line will then be wound under tension onto a large reel and transported to shore where it will be unspooled for treatment and recycling or disposal.

19.7.9 Operations for Removal by Cut-and-lift

These operations would be performed on PL051/N0402a, N9900, N9901, N9002 and PL017/N0601, a total of approximately 7km of line. The pipelines will be cut into sections approximately

25m long using an ROV fitted with a cold-cutting tool such as a diamond wire system or shear cutters. It is likely that the operations will be conducted from an ROV Support Vessel (ROVSV) or DSV. The sections will be lifted to the vessel and transported to shore for dismantling and recycling. Some excavation may be required for those lines which are partially covered or in a trench and this would probably be carried out by water-jetting.

Cut-and-lift is a standard operation in the North Sea and can be completed without excessive safety risks to offshore personnel. The cuts would be made using an ROV, which reduces the need for divers. Should the lines be so weak that the 'standard' lengths of cut lines could not be lifted safely the lines would either be cut into shorter lengths or recovered to the surface in a debris basket.

19.7.10 Operations to Disconnect, Trench and Backfill

This operation will be performed on PL002/N0201, PL049/N0301, PL048/N0302, PL045/N0303, PL046/N0304, PL050/N0401, PL051/N0402, PL052/N0403, PL047/0404, PL044/N0405, N9903A and N9903B, a total of approximately 34.9km of pipeline.

The pipelines would be disconnected from the platform or subsea structures at each end, and the tie-in spools removed by cut and lift for onshore recycling or disposal. The main section of the pipeline would be trenched and back-filled over the whole length to a depth of 0.6m to top of pipe (TOP). On pipelines with a diameter greater than 24 inches, a mechanical trenching tool would be used followed by back-filling by another tool. For lines with a diameter of less than 24 inches, trenching and back-filling would be achieved simultaneously using a water-jet trenching tool. Should any problems be encountered with achieving a 0.6m depth of trench to TOP we would consult with BEIS regarding the options for appropriate remediation. Such options might include re-trenching the pipeline such that the TOP was at least below the mean seabed level, removal of the section of the pipeline, or the addition of material to the seabed to mitigate any snagging risk to fishing gear.

19.7.11 Operations to Partial Trench and Backfill with Isolated Rock-dump

This operation would be performed on the 35.9 km long line N0501. An ROVSV will perform preparatory works including spool piece recovery, recovery of the 62 mattresses already over the pipeline, and boulder clearance in the areas to be trenched. The trenching and backfilling operations will probably require the use of a mechanical trencher and separate backfilling tool. As with all rock-dumping operations in the Brent decommissioning programme of work, the rock-dump will be deposited by a flexible fallpipe vessel (FFPV).

All shallow-trenched sections (<0.6 m below mean seabed level) will be remediated. Where possible, we will trench all the sections that are long enough to allow the deployment of the trenching and backfilling equipment. Where the sections are too short or where trenching does not reach the required depth of 0.6 m to TOP rock will be used to provide sufficient cover over the pipeline to mitigate the snagging risks to fishermen. Trenching will not be possible at the seven crossings over this pipeline if they remain in place. As necessary at these locations, we will stop trenching operations and may add more rock cover on either side of the crossings to prevent snagging. All of the seven pipelines are operated by third parties; four of them are still in operation and three are disused. We will liaise with the owners of these pipelines to coordinate the decommissioning works. Details of how we will deal with each crossing on this line are presented in the Pipelines TD [17].

19.7.12 Operations for Rock-dumping

Four pipelines, PL987A/N0738, PL987A/N0739, PL987A 1-3/N0841 and PL988A/N0913, a total of approximately 17.1km of line, will be remediated by the placement of approximately 30m of rock-dump at the cut ends (total length of rock-dump approximately 120m). This will ensure that the cut ends are covered by at least 0.5m to TOP. The general procedure for rock-dumping operations was summarised in Section 19.7.11.

19.7.13 Onshore Dismantling, Treatment and Disposal of Retrieved Material

Retrieved lines or sections of line will be treated and disposed of at suitably licensed onshore sites.

They may have to be cut into shorter sections for handling and treatment onshore, and this could be done using hot or cold cutting techniques. Further internal cleaning of lines may be required either before or after this operation, depending on the diameter, length and cleanliness of the retrieved line.

Sections of line will then be separated into their component materials for recycling or disposal as appropriate. Concrete-coated lines will, if practicable, be treated by a concrete-crushing machine to shatter and remove the concrete coating; the steel would then be recycled and the concrete would probably have to be disposed of to landfill.

19.7.14 Final Condition of the Brent Field Pipeline System

If these recommendations were adopted 10 of the 28 Brent lines would be removed or partially removed. The final disposition of the pipelines and their materials would be as shown in Table 87 and Table 88, and the final layout of the pipelines in the Field would be as show in Figure 119.

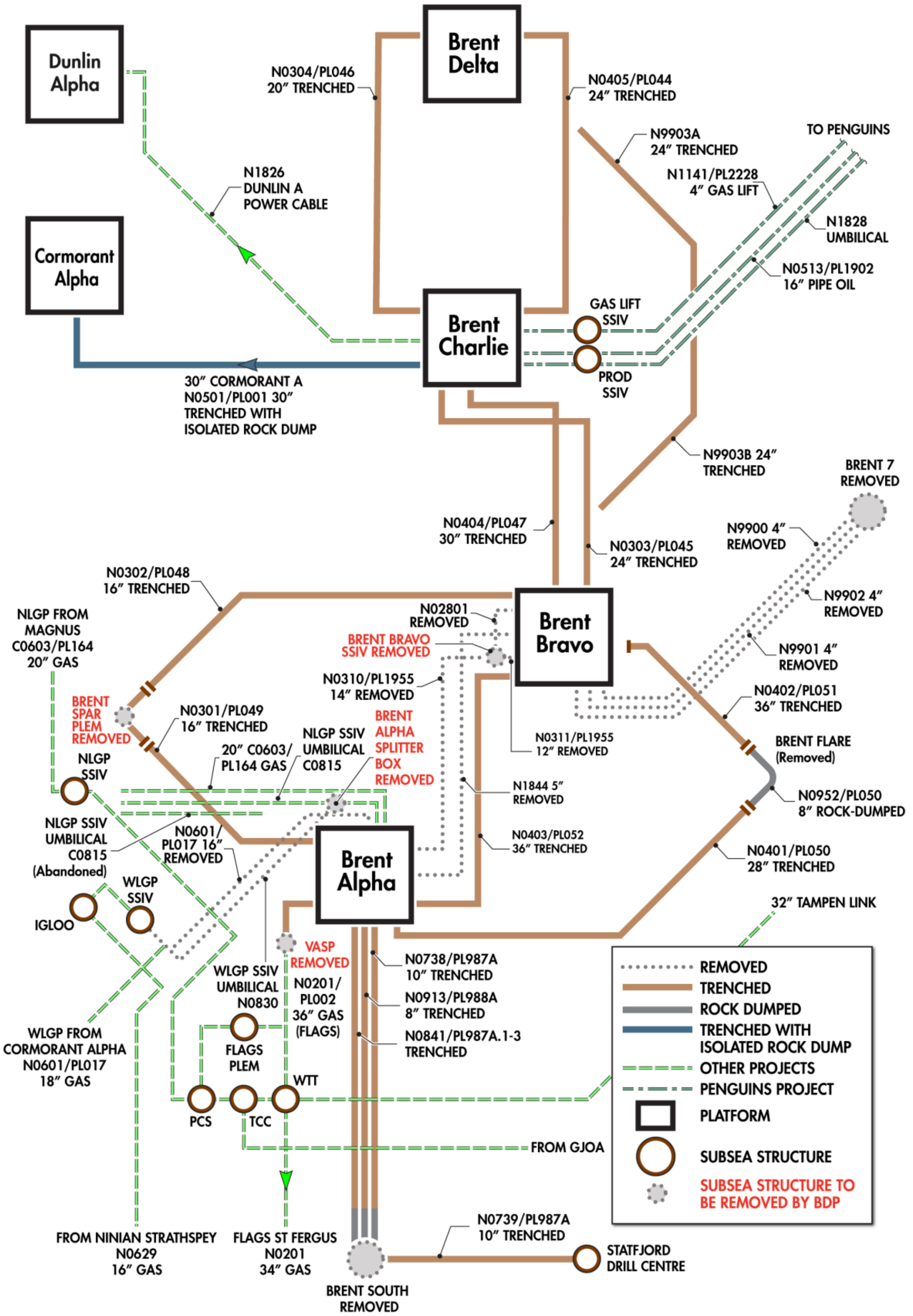
Table 87 Present and Proposed Condition of Brent Field Pipelines.

Condition	Present Pipeline System		On Completion of Proposed Decommissioning Programme		
	Length (km)	Proportion (%)	Length (km)	Proportion (%)	Change (km)
Laid on seabed	47.2	46.3	0	0.0	-47.2
Trenched	54.6	53.6	78.9	77.5	+24.3
Rock-dumped	0.03	0.03	9.03	8.9	+9.0
Removed to shore	0.00	0.0	13.9	13.6	+13.9
Totals	101.8	100	101.8	100	0.0

Table 88 Final Disposition of Main Materials in the Brent Pipeline System.

Material	Material Weight (tonnes)	Material Removed to Shore (tonnes)	Material Left in Field (tonnes)
Steel	25,129	1,125	24,004
Concrete (excluding mattresses)	21,896	542	21,353
Concrete mattresses	1,762	1,055	707
Protective coatings and plastics	1,513	165	1,348
Total	50,300	2,887	47,412

Figure 119 Final Status of Pipelines in the Brent Field.



19.8 Environmental Impacts of Decommissioning the Pipeline System

19.8.1 Stakeholder Environmental Concerns

For the suite of recommended options for the Brent Field pipelines, the specific environmental concerns or issues raised by our stakeholders were:

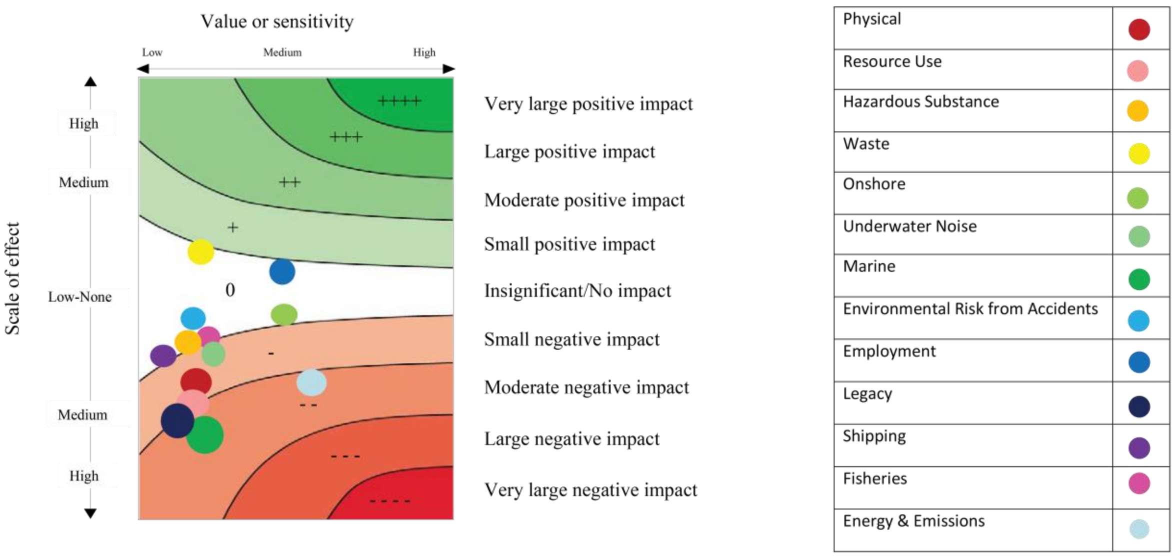
- Continued loss of access to fishing grounds.
- Potential for presence of long-term snagging risk for bottom-towed fishing gear.
- Accidental discharges or releases of hydrocarbons or chemicals to sea.
- Disturbance to seabed and benthic fauna, especially from additional rock-dump.
- Impacts to local communities at onshore dismantling sites caused by noise, dust and odour.

19.8.2 Potentially Significant Impacts in ES

DNV GL have undertaken a detailed assessment of the potential environmental impacts of the proposed decommissioning options for each of the 28 lines in the Field and this is fully reported in the ES [5]. This section summarises their findings, concentrating only on those impacts that were worse than 'small negative' or better than 'small positive'.

Figure 120 presents DNV GL's assessment of the impacts of the whole pipeline decommissioning programme. The most significant negative impacts are in the 'marine' category which was assessed as 'moderate negative, and in the 'resource use', 'legacy' and 'energy and emissions' categories which were all assessed as being 'small-moderate negative'.

Figure 120 Environmental Impacts of Completing the Whole Proposed Programme of Work for the Brent Field Pipeline System.



Marine Impacts from operations

Decommissioning the pipelines would result in marine impacts associated with the disturbance of benthic fauna and habitats caused by operations such as cut and lift, reverse reeling and trenching and rock-dumping, and with disturbance caused by noise generated by vessels and operations such as underwater cutting. When viewed in isolation these impacts are generally small for the individual pipelines (except PL001/N0501) because:

- The total rock-dump for the programme (excluding PL001/N0501) is only approximately 2,000 tonnes.

- Removal by cut and lift will cause only very local, transient and fully-reversible impacts on benthic communities within a few metres along the 13.9km of line to be removed, as a result of the disturbance of sediments and/or smothering by sediments. Locally, noise levels may be elevated for a time during the offshore operations. The combined impact to the marine environment would, however, be small, because the impacts are temporary and reversible.
- With the exception of PL001/N0501, only short lengths of new rock-dump will be created, impacting a very small proportion of the ICES rectangle, and all new rock-dumps will be verified as being over-trawlable. Although areas of rock-dump can be a concern for demersal trawlers, DNV GL estimated that the long-term effect of these short sections would be small.

The main contribution to the assessment of impacts in the category "marine" is the decommissioning of the 35.9 km long 30 inch export line PL001/N0501, which will involve both trenching and rock dumping. We estimate that the isolated areas of rock-dump on this line would require a total of approximately 147,000 tonnes of rock-dump. As well as causing a permanent change to the seabed (see "legacy" below) rock-dumping on such a scale will cause direct impacts by smothering the benthic fauna under and adjacent to the areas of rock-dump.

Viewed together, the various proposed operational activities in the whole pipelines programme of work would result in impacts in the "marine" category that were assessed by DNV GL as being "moderate negative". The main sources of impact were rock-dumping, trenching and the noise from vessels, and there was a major contribution to the overall impact from work on the long export line PL001/N0501.

Legacy impacts from pipelines left in place

Approximately 47km (46%) of the 103km of line covered in DP2 is presently laid on the surface of the seabed and 55km (54%) is trenched (Table 87). On completion of the proposed programme of work no pipeline, umbilical or cable will remain uncovered on the surface of the seabed; all 47km of such line will be removed to shore. The main legacy impacts of the proposed programme therefore arise from the trenching and rock-dumping of approximately 33km of line (comprising 24km of new trenching and 9km of new rock-dump). In particular, we have assumed that of the estimated 29km of PL001/N0501 that requires remediation (because the top of the pipe is less than 0.6m below the level of the seabed), 30% (approximately 8.6km) will require rock-dumping because further trenching will not be completely successful. The creation of new areas of rock-dump along a total of approximately 9km of line will result in a permanent change to the nature of the seabed, although it is noted that the areas of rock-dump, including on PL001/N0501, are not necessarily continuous. If the rock-dump is 10m wide on either side of the line the total area of seabed covered would be approximately 0.2km^2, about 0.007% of the ICES rectangle. The new rock-dump will permanently change the character of the seabed and provide a new and different type of surface and habitat for marine life.

Overall, DNV GL assessed the potential legacy impacts from the proposed programme of work as being "small-moderate negative", primarily as a result of the extensive new rock-dumping that may be required on PL001/N0501.

We estimate that the trenched or rock-dumped lines on the seabed will remain extant for 150-600 years (depending on the line) before they essentially disappear and are incorporated into the seabed sediment. On concrete-coated lines the light steel reinforcing mesh will corrode and expand, causing the spalling of the outer shell of the coating. Seawater will then penetrate to the steel below and surface corrosion will begin. At the same time seawater inside the line will initiate corrosion of the inner face, although this will be very slow to begin with because of the lack of oxygen within stretches of intact line that are distant from holes and openings to the sea. Pinhole corrosion of the outer face of the line and corrosion of the inner face by sulphate reducing bacteria will eventually create holes which will allow oxygenated seawater inside the line. Double-sided corrosion may then take place, and this will accelerate the rate of degradation. Within the trench or under the rock-dump, the remains of the concrete coating will spall and the line may begin to break into shorter lengths. In the final stages of degradation the steel line will corrode completely and crumble, and the remains of the concrete coating will collapse. The degraded remains of the line will lie within the trench or under the rock-dump.

19.8.3 Energy Use and Gaseous Emissions

We estimate that the whole proposed programme of work for the Brent Field pipeline system would use about 1,003,500 GJ of energy and have total emissions of about 78,000 tonnes CO_2 (Table 89). These estimates include the energy and emissions associated with the 'replacement' by new manufacture of otherwise recyclable material that was left in the sea. For the recommended programme this accounts for some 94% of the total estimated energy use and gaseous emissions. The total estimated 'direct' use of energy and 'direct' CO_2 emissions would be approximately 62,000 GJ and 5,000 tonnes respectively.

Table 89 Total Energy Use and Gaseous Emissions from Programme of Work to Decommission Brent Pipeline System.

Operations	Energy (GJ)	Emissions to Atmosphere (tonnes)		
		CO_2	NO_X	SO_2
Direct				
In marine operations, onshore dismantling, and recycling	62,016	4,761	83	63
Recycling				
Replacement of material left at sea	941,495	72,870	310	125
Total	1,003,511	77,631	393	188

19.9 Mitigation Measures for Pipelines Programme of Work

- All oil and gas lines will be depressurised, de-oiled and flushed with seawater to reduce the amounts of residual hydrocarbons they contain.
- The campaign(s) to remove or treat offshore pipelines and umbilicals will be conducted under all necessary permits.
- Appropriate Notices to Mariners will be issued to alert other users of the sea to proposed offshore operations.
- The size, extent and profile of each area of rock-dump will be carefully planned. Suitably graded rock will be accurately placed around the line(s) using a dedicated specialist rock-dump vessel with a fall pipe.
- Where pipelines or umbilicals have been removed an over-trawling survey will be conducted by an independent organisation to ensure that the area is free of debris.
- On completion of offshore operations other users of the sea will be advised of the changed status or condition of each line and the information will be entered into the FishSAFE system.
- Pipelines and umbilicals retrieved to shore will be treated, recycled or disposed of through suitably-licensed onshore sites.
- As far as practicable all the different materials in the lines and umbilicals will be segregated into different waste streams to maximise the amount of recycling. It is impracticable, however, to strip down some composite umbilicals and a small proportion of the mass of lines removed will have to be disposed of to landfill.

20 PROGRAMME OF WORK FOR DEBRIS CLEARANCE

20.1 Introduction

On completion of all the approved offshore decommissioning operations we will locate and remove all visible items of oil and gas debris within a 500 m radius of each installation and the centre of the former Brent South site, and along a 200 m wide corridor centred on each pipeline. If we know of any exceptional or large Brent-related items in the Field at greater distances from the facilities we will remove these as well.

20.2 Description of Debris Items

In 2006 and 2012 we carried out detailed surveys of the extent and nature of the seabed debris around the four installations, the Brent South subsea site, and the routes of all the pipelines; the findings of these surveys are presented in the Pipelines TD [17]. We found that within 500 m of each platform and along the 200 m wide corridor centred on each pipeline there is a total of approximately 5,000 items of debris more than 0.5 m in size, which together may weigh approximately 109 tonnes. The vast majority of this material is steel scaffolding poles; a very large quantity of scaffolding has been used in the 40 year history of the Field during platform upgrades, inspections and routine maintenance operations. Scaffolding erected around legs and the lower parts of offshore platforms is easily damaged or dislodged by wave action, even in summer.

Figure 121 shows an example of the debris items we identified in our 2006 debris survey, in this case at Brent Charlie. Figure 122 illustrates the typical debris that has accumulated on the top of the GBS cells and Figure 123 shows the same cell after removal of the debris.

Figure 121 Debris Around the Brent Charlie Platform, 2006.

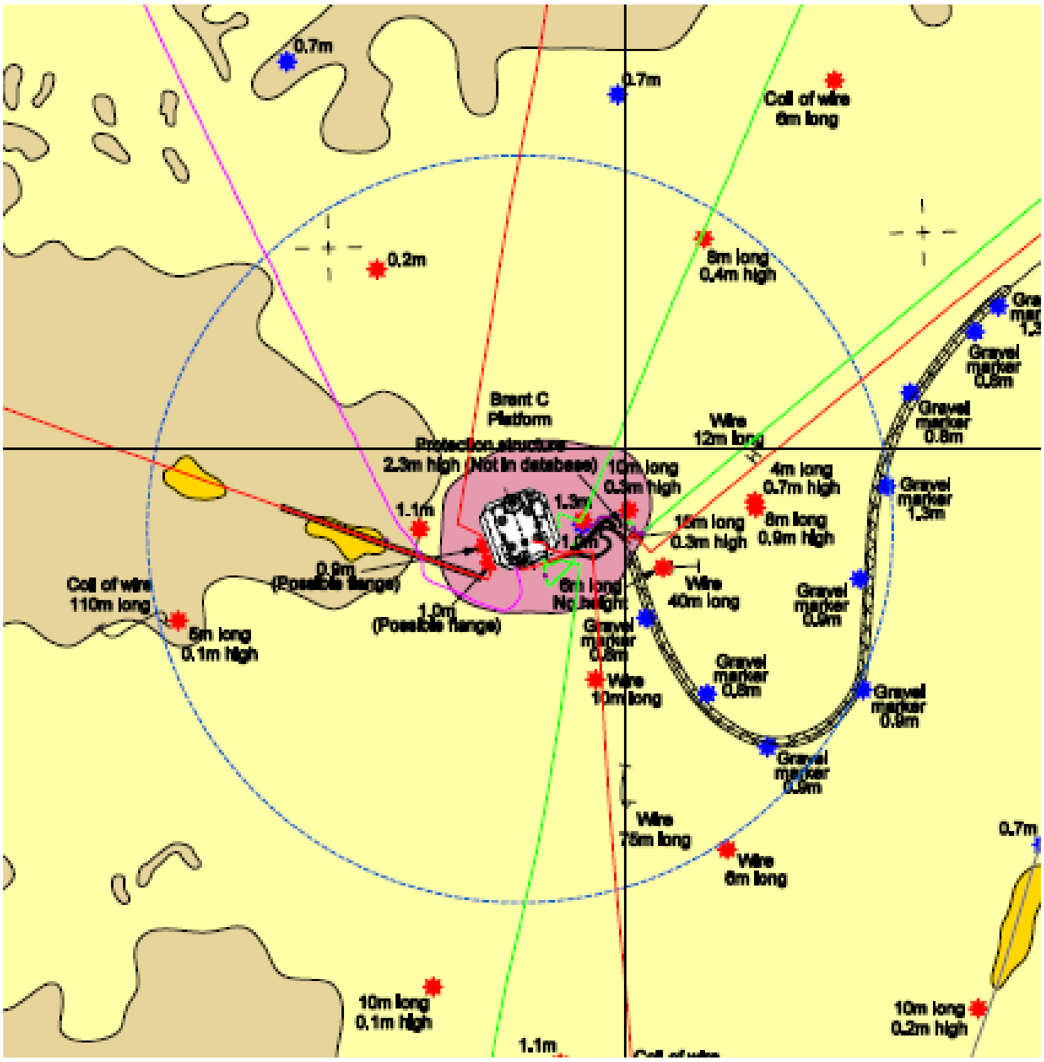


Figure 122 Debris on Top of a Brent Delta GBS Cell.

Figure 123 A Brent Delta GBS Cell-Top after Removal of Debris.

20.3 Removal of Debris

We will locate and remove all visible items of oil and gas debris within a 500 m radius of each platform (and the centre of the former Brent South site) and along a 200 m wide corridor centred on each pipeline. We anticipate that the majority of these items will be historical items of debris already surveyed and mapped, but we will also remove any items of debris that have accidentally arisen as a result of the permitted decommissioning operations. If we know of any exceptional or large Brent-related items in the Field at greater distances from the facilities we will remove these as well. As part of the debris programme, we will remove the drill guide base at the Brent 7 site (Figure 110) which is the only subsea structure remaining at the site of this former well.

We have started to remove all the exposed debris from the tops of the GBS caissons, using a platform-based ROV, and we will continue this programme for as long as it is practicable, efficient and safe to do so. Thereafter, all operations to remove debris will be performed from vessels. It is most likely that all the vessel-based operations to remove debris will be conducted in one or more 'campaigns' when the proposed decommissioning programmes for the platforms and the pipelines have been completed.

Debris items will probably be removed using a combination of ROVs, baskets and vessel cranes, and the programme may extend over more than one season (Section 21, Schedule). All the recovered debris will be returned to shore for recycling or disposal as appropriate.

20.4 Seabed Clearance Survey

Once we have completed the programme to remove debris originating from oil and gas operations we will engage an independent contractor to carry out a comprehensive sweep of the 500 m radius zones and the 200 m wide corridors, to determine if they are now free of items that could snag on bottom-towed fishing gear. The contractor will produce an independent report of their findings and we will submit this to BEIS and publish it on our website.

20.5 Final Condition of the Offshore Site

On completion of the above programme it is our intention that, within the 500 m zone around each of the five sites and along the 200 m corridor centred on the route of each pipeline, there will be no items of debris capable of snagging bottom-towed fishing gear.

20.6 Environmental Impacts of Debris Clearance

20.6.1 Stakeholder Environmental Concerns

For the proposed programme of work for the removal of debris, the specific environmental concerns or issues raised by our stakeholders were:

- Accidental discharges or releases of hydrocarbons to sea.
- Accidental loss of debris items to sea during their recovery.
- Disturbance of drill cuttings piles.
- Disturbance to the benthos.

20.6.2 Impacts of Offshore Operations

The potential impacts of the programme to remove debris are associated with (i) the disturbance of the natural seabed and the local turbidity caused by resuspended material and, (ii) the possible disturbance of historic drill cuttings piles. The impacts of the programme to remove debris are included and discussed in Section 18.4 describing the impacts of the removal of the four sub-sea structures.

Debris will be removed by ROV in one or more 'campaigns' each lasting several weeks. Some natural sediment and some OBM cuttings may be disturbed as visible items are extracted, but no excavation of natural sediment or drill cuttings will take place. Any impacts on the benthos or water column will thus be very small, of very limited extent and duration, and fully reversible. The ES found that the most significant negative impact from these activities, collectively, was disturbance to the seabed and benthos which was rated 'small-moderate negative'. There were no positive impacts.

After decommissioning the pipelines and umbilicals, removing the seabed structures, and removing all items of debris, the areas around each site and along each line will be swept to verify that they are free of obstructions to bottom-towed fishing gear. An area of about 25 km^2 (about 0.8% of ICES rectangle 51F1) would be swept by a strong steel net. Like trawling, this activity will physically disturb the upper 5-10 cm of the seabed, re-suspending natural sediment into the water column which will then resettle. Care will be taken to ensure that the visible drill cuttings piles at the five Brent sites are not disturbed by the debris sweep.

20.6.3 Onshore Impacts

Retrieved material will be recycled in established licenced sites. There will be no negative effects from these onshore operations.

20.6.4 Legacy Environmental Impacts

If the majority of identified debris items are removed and recycled (most of the debris is metallic) there will be no negative legacy impacts offshore or onshore.

Some items of debris might remain completely buried in undisturbed drill cuttings piles. These will very gradually corrode or degrade, and will not be likely to cause any impacts to the benthic or pelagic ecosystems.

20.6.5 Energy and Emissions

DNV GL estimate that the programmes of work to remove debris and then complete the seabed sweep would use approximately 215,000 GJ of energy and produce approximately 16,000 tonnes of CO_2 (Table 90).

Table 90 Total Energy Use and Gaseous Emissions from Programme of Work to Remove Subsea Debris.

Operations	Energy (GJ)	Emissions to Atmosphere (tonnes)		
		CO_2	NO_X	SO_2
Direct				
Marine operations	209,764	15,472	321	263
Onshore dismantling	258	19	0	0
Onshore transport	199	15	0	0
Sum	*210,221*	*15,506*	*322*	*263*
Recycling				
Material recycling	4,893	221	1	2
Total	215,114	15,727	323	265

20.7 Mitigation Measures for Programme of Work to Remove Subsea Debris

- The campaign(s) to remove and dispose of offshore debris will be conducted under all necessary permits.
- Impacts to the marine environment will be minimised by not disturbing drill cuttings piles; we will not attempt to retrieve items of debris that are largely or wholly buried in drill cuttings piles.
- Underwater explosives will not be used.
- When the campaign(s) have been completed, an over-trawling survey will be conducted by an independent organisation to ensure that the area is free of debris and that no items that might pose a snagging risk to fishermen are present in the 500 m safety zones or along the 200 m wide pipeline corridors.
- Materials will be treated, recycled or disposed of through suitably-licensed onshore sites.

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PART FOUR
PROGRAMME MANAGEMENT

These sections present:

1. A high level timetable for the completion of the whole Brent Field Decommissioning programmes of work.
2. A description of the potential environmental impacts of these programmes and how we will mitigate and manage them.
3. A description of the way in which we will manage the decommissioning operations and verify that the proposed programmes of work are undertaken as described in this DP document.
4. A description of our proposed approach to the monitoring of structures left in the Brent Field.

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21 SCHEDULE

21.1 Introduction

Planning for the Brent Decommissioning Project began in 2006, the lengthy programme to plug and abandon the wells started in 2008, and preparatory work offshore on topsides modules and systems began in 2009. All this work was and is being done under all necessary permits and licences to prepare for decommissioning, and can be carried out in advance of the submission and approval of the Decommissioning Programmes. None of the preparatory work would or will foreclose or eliminate any feasible option for the decommissioning of the facilities.

21.2 Proposed Programmes of Work

Figure 124 outlines the main phases of work in the decommissioning programmes and their approximate duration. This schedule has been developed with reference to:

- The agreed CoP dates for the installations.
- The requirement to plug and abandon the wells safely and efficiently.
- The operational and logistical interactions between the four installations, the Brent Field pipeline system, the export system, third-party pipelines (Section 19.7.2) and platforms, and the Brent Bypass Project (Section 19.7.4).
- The time required to prepare and obtain approval for the necessary licences and consents.
- The programme of work for removing the attic oil from the GBS oil storage cells.

The exact timing and durations of activities will depend on many factors including the contractors selected, the equipment, vessels or procedures they propose to use, and the possibility of devising 'campaigns' to complete common or repeated operations in the most cost-effective way. We will continue to review and learn from our ongoing activities. We will subsequently discuss and agree with BEIS any changes to the proposed methods of execution outlined in these DPs.

There are no licence conditions or environmental sensitivities (Section 3 and Section 22) that might influence the time of year when certain activities should be undertaken. We plan to complete all the offshore operations and submit verification and close-out reports (Section 23) by 2026.

21.3 Industrial Implications

We have striven to identify safe, efficient and cost-effective methods and procedures for decommissioning the different types of structures and facilities in the Brent Field. Many contractors and consultancies have contributed to the numerous studies and assessments that have been prepared since 2006 to inform our plans and support our decision-making processes.

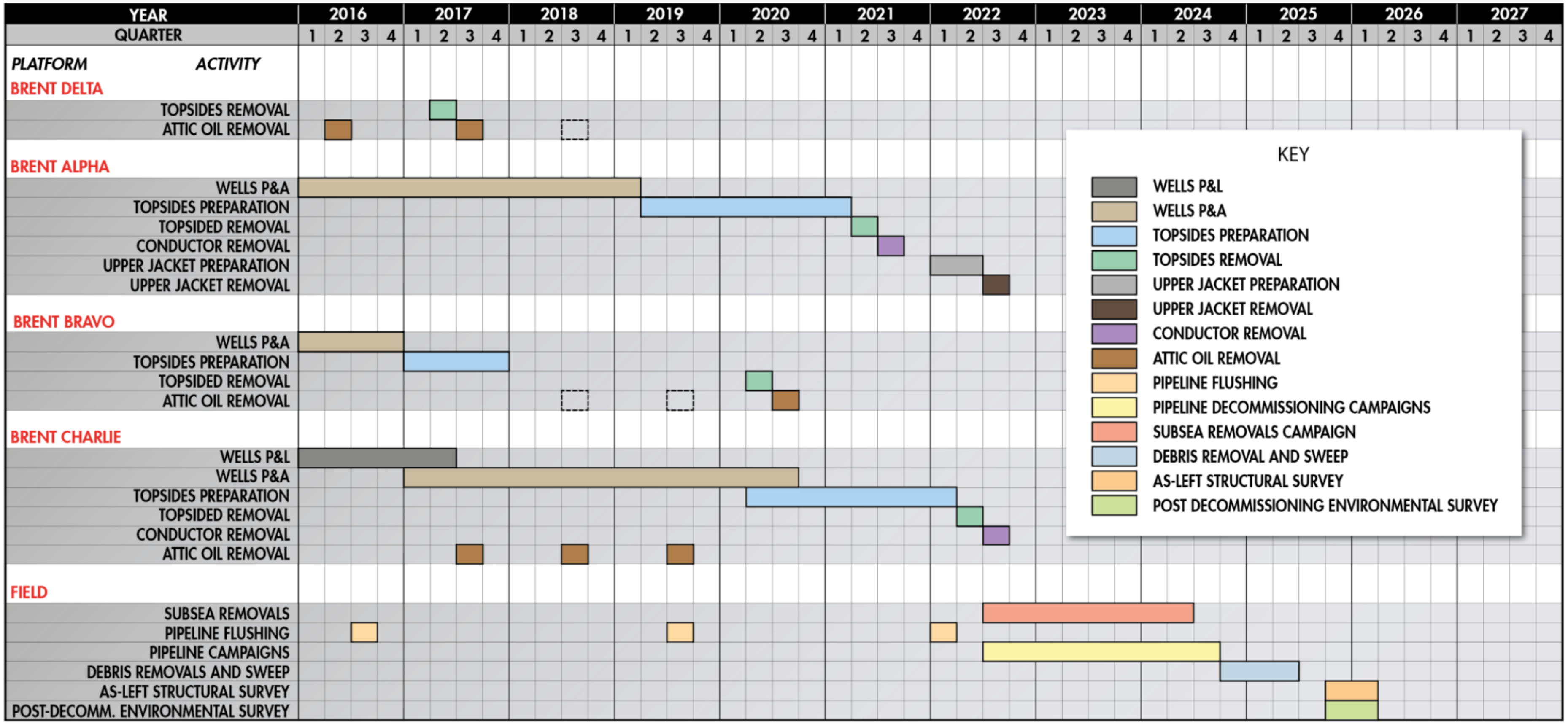
During the 'Concept Select' phase of our work, leading international contractors and engineering companies prepared FEED studies describing how different technologies and programmes of work might be used to decommission the Brent structures.

We plan to use the SLV *Pioneering Spirit* to remove the Alpha, Bravo and Delta topsides and the Alpha upper jacket. This unique vessel is capable of lifting topsides of up to 48,000 tonnes quickly and efficiently in one piece for onshore dismantling. It is anticipated that this will reduce the duration, risk and cost of decommissioning the topsides of large production platforms, which to date have usually been dismantled module by module at the offshore location.

At the same time we have assessed how our topsides could be dismantled and recycled, and this has included a detailed review of the dismantling capabilities and capacities of a large number of sites in the UK and across Europe. After a comprehensive commercial tendering exercise we identified the Able UK Limited ASP facility at Teesside as having the necessary facilities, space and experience to deal with the topsides that would be delivered by the SLV, and have now placed a contract with them for the dismantling of three Brent topsides (Alpha, Bravo and Delta) and the Alpha upper jacket. We are now working with Able to upgrade their onshore facilities, including the construction of a new quay and the strengthening of the lay-down area for topsides. The investment that has been made on Teesside will support employment now and in the future as Able enlarge their capabilities, broaden their services, provide additional training to their workforce and increase their experience in large-scale decommissioning.

The scopes of work for the Brent Charlie topside, the pipelines and the removal of debris will be subject to separate tender evaluations at a later date.

Figure 124 Indicative Timing and Duration of the Proposed Brent Field Decommissioning Programmes of Work.



22 ENVIRONMENTAL IMPACT ASSESSMENT

22.1 Introduction

DNV GL prepared an Environmental Statement on behalf of and as endorsed by Shell U.K. Limited and Esso Exploration and Production UK Limited, as the Brent Field owners, under the responsibility of the Brent Field owners to provide an Environmental Impact Assessment in support of the Brent Field Decommissioning Programme.

DNV GL completed a comprehensive EIA for both of the Brent DPs, including assessments of the potential impacts of the technically-feasible options considered in the CAs [5]. Their assessments of the main impacts of the recommended options for each facility were summarised in Section 11 to Section 20 and are not repeated here.

This section presents our appreciation of the potential environmental impacts of the proposed programmes of work to decommission the Brent Field, using the assessments and results from the Brent Field Decommissioning ES [5]. It gives an overview of effects over the whole course of the proposed decommissioning programmes, taking into consideration the project- and site-specific mitigation measures that have been identified in the preceding sections. Finally, it estimates the possible cumulative effects both of our operations offshore and in combination with other potential concurrent operations in the area.

22.2 Overview of Impacts from Offshore Operations

22.2.1 Societal Impacts

With the exception of sections of pipeline N0501 and short sections of the intra-field lines, all the proposed offshore operations would occur within the 500 m safety zones around the installations and consequently will not result in any impacts to fishermen or other users of the sea.

The transportation of topsides on the SLV will be a normal marine operation that will not impact other users of the sea. Each operation to transfer a topside to the cargo barge will take one or two days at the designated nearshore transfer location off Teesside, and will be suitably notified to mariners and fishermen and is not expected to have any effect on other users of the sea.

22.2.2 Seabed and Benthos

In years 1 to 3, the possible displacement of some of the cell-top drill cuttings on Bravo and Delta and their subsequent resettlement on the adjacent seabed might result in an increase in the area of seabed around the platforms which exhibits THC of >50 mg/kg. This will reverse the present trend of seabed recovery. Recovery is expected to resume, however, within a few years since the newly settled layer will be quite thin and largely aerobic, such that physical, chemical and biological degradation of the hydrocarbons are likely to be rapid.

At a later date, perhaps in years 8 to 10 of the combined Brent decommissioning programmes, areas of seabed will be impacted by the decommissioning of pipelines and subsea structures, and then the debris sweep. In both cases the areas that will be impacted are very small in relation to the existing adjacent seabed and benthos, and disturbed areas are likely to recover within 1 year to 3 years.

22.2.3 Water Column

In years 1 to 3, displacement of small amounts of cell-top drill cuttings at Bravo and Delta will cause some historic OBM cuttings to be re-suspended into the water column. This will result in local, transient and fully recoverable increases in turbidity and THC loading.

At a later date, perhaps in years 8 to 10 of the combined Brent decommissioning programmes, clean sediment and some drill cuttings will be re-suspended into the water column during the decommissioning of pipelines and subsea structures and the debris sweep. The impacts of these events will be quite small, localised and temporary.

22.2.4 Marine Mammals

In years 1 to 3 (topsides and jacket), years 3 to 6 (cell contents management) and years 8 to 10 (decommissioning of pipelines and subsea structures and debris sweep), various vessel spreads will be working around the platforms and along the pipelines. While it is not possible to be precise about the numbers of vessels operating at any one time or indeed of the exact source noise levels and frequencies they will create, modelling of likely scenarios shows that no marine mammal would be likely to experience noises of a character that would be likely to cause 'temporary threshold shift' in hearing ability. None of the vessel noises emanating from the decommissioning programmes will be percussive and none is likely to start suddenly or unexpectedly; noises will vary in intensity and location only gradually and mobile creatures should be able to avoid them if they are disturbed. The areas of sea likely to experience intermittent noise from our decommissioning operations are small in comparison with the known ranges of marine mammals in the North Sea, and there is no evidence to suggest that the Brent Field is of particular importance or significance to any species in terms of migration, feeding or reproduction.

22.3 Overview of Impacts from Offshore Legacy

22.3.1 Introduction

All of the potential legacy impacts are likely to occur long after all the decommissioning operations have ceased and there is no possibility that these two sources of impact would overlap.

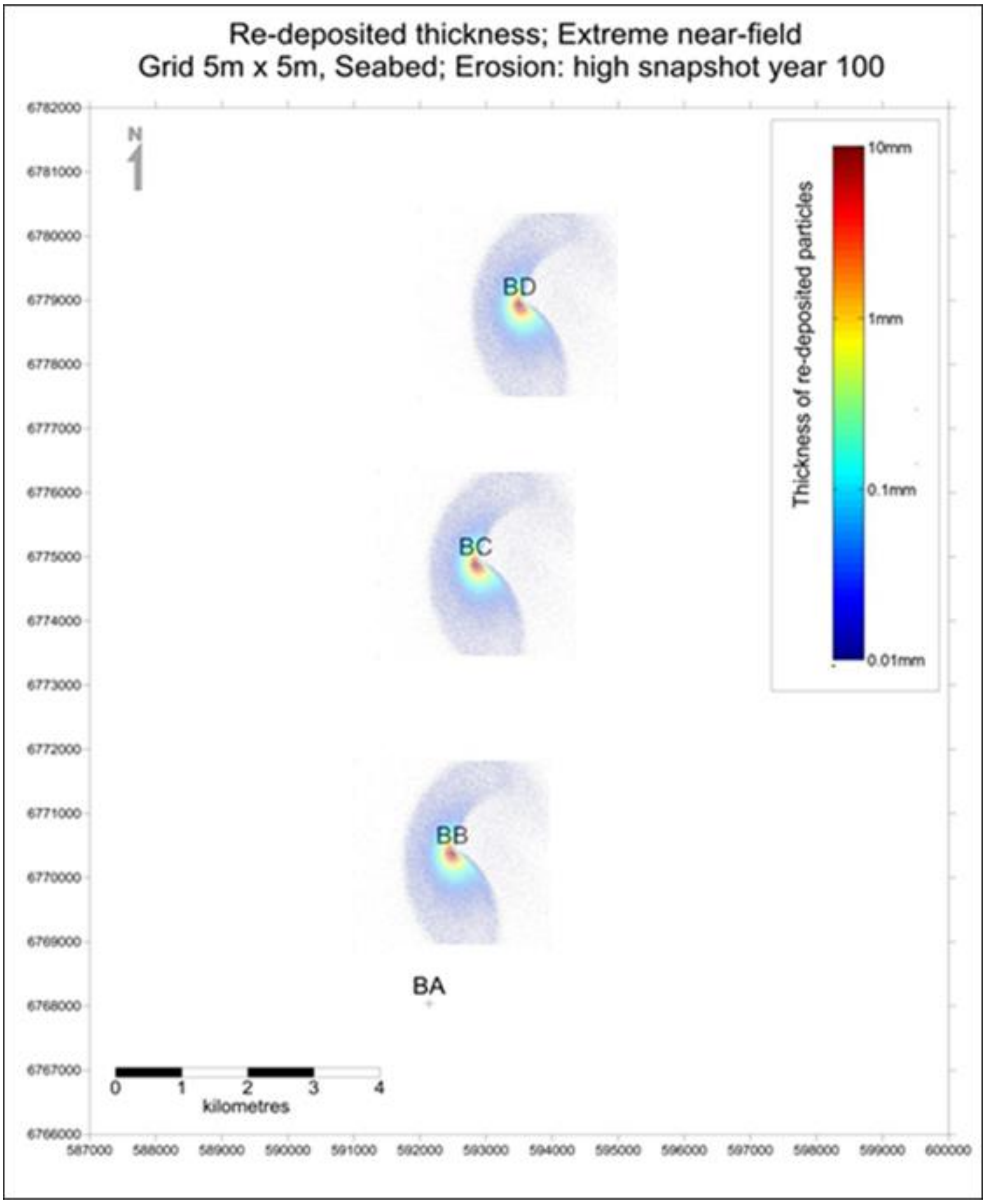
22.3.2 Seabed and Benthos

The footprints of the GBSs — singly and together – will be very small and will have no effect on the benthic communities in the area. They will cover a tiny fraction of the seabed in ICES rectangle 51F1 and will have no effect on commercial fisheries. The degradation of the steel and concrete will have no impact on the benthos. Likewise, the degradation and collapse of the jacket footings, in themselves, will have no impact.

The eventual exposure of some of the cells contents may result in the very slow release of, or migration of, cell sediment onto the adjacent seabed. This is likely to occur at a time when the seabed adjacent to the GBS has, to a large extent, recovered from the impacts of the historic discharges of OBM. The inputs of cell sediment will therefore reverse this process, over an area extending to perhaps 50 m to 100 m from each GBS. It is extremely difficult to model the possible extent of the movement of this material over long timescales. The impacts of this gradual, long-term exposure of sediments on the benthos will, however, be limited. The area of seabed that might be affected will be small, perhaps up to 0.06 km^2 at each site with contaminated sediment thickness exceeding 10 mm, and 0.34 km^2 at each site with contaminated sediment thickness ranging from 1 mm to 10 mm. These areas of impact are of a similar size to those already observed around North Sea installations impacted by the historic discharge of drill cuttings. As an example, in Region 1 of the Norwegian Shelf the area exceeding 50 mg/kg THC around each platform varied from 0.1 km^2 to 2 km^2 in 2014. The Brent Field does not contain any rare or protected benthic species or habitats. The main contaminant in the cell sediment, hydrocarbons, will only very slowly escape into the water column and even locally concentrations of hydrocarbons in the sediment or water column would not be of concern.

Figure 125 shows how cell sediment may spread and then settle on the seabed after some hypothetical event that results in the worst case scenario of the simultaneous exposure of the sediments in all three GBSs. The plumes do not overlap. Modelling showed that after 1,000 years of erosion the redeposited pile would be less than 5mm thick at a distance of approximately 112m from the GBS.

Figure 125 Representation of the Deposition of Cell Sediment Material 100 Years after Hypothetical Simultaneous Exposure of Cell Sediment at all Three Brent GBSs.



The drill cuttings piles on the seabed and on the cell-tops which are left undisturbed will gradually degrade and erode under the influence of currents, wave action, leaching and biodegradation. The amount of oil being released into the marine environment will decrease with time [60], and the area of seabed and benthos impacted by elevated concentrations of hydrocarbons and heavy metal will gradually decrease in size, as evidenced by the trend already discerned in our previous benthic surveys [57] [58]. The drill cuttings that may be present in the tri-cells of Bravo and Delta could be equivalent to the total mapped external volumes of cuttings at each of these sites. As with the GBS cell sediments, however, it is likely that they would only be gradually exposed to the marine environment as the main body of the caisson slowly degraded and collapsed over a period of many hundreds of years. (Cuttings in each tri-cell are contained by the three walls of the adjacent cells. For some of the tri-cells, at least two walls would have to be breached to create a lateral pathway from the tri-cell to the seabed. For remaining tri-cells, three or sometime four walls would have to have failed.) On exposure, the tri-cell drill cuttings would be subject to erosion from the currents on or near the seabed although it is likely that the crumbled remains of walls would continue to partially shield cuttings and reduce resuspension. Some cuttings would, however, be re-suspended into the water column both from the forces of cell wall collapse and natural erosion. This material would drift in the current before settling on the seabed. This perhaps low-level but long-term input would re-contaminate areas of seabed immediately adjacent to the GBS that had already been contaminated with cuttings and might partially reverse, or delay, the long-term recovery of these areas from the historic discharges. Section 17.12.3 describes the impacts of the long-term presence of the cuttings piles.

22.4 Overview of Impacts from Onshore Operations

22.4.1 Societal Impacts

The bulk of the material that will be removed to shore will be received, dismantled, treated and disposed of through the ASP facility on Teesside. The separate ESHIA assessment by AECOM for the activities at this existing, active, licensed site [35] has shown that there will be no significant impacts to the communities living close to the dismantlement site. All the sources of impact have been identified and understood and there are, or will be, specific measures in place to minimise or eliminate each type of potential impact.

22.4.2 Onshore Decommissioning Sites

We plan to dismantle the topsides and the upper part of the Brent Alpha steel jacket at the ASP facility on Teesside. This is an existing industrial facility and as such the planned programmes of work will have no impact on this site.

22.4.3 Landfill Sites

We plan to recycle at least 97% by weight of the material returned to shore and consequently it is likely that only a relatively small amount of non-recyclable material, predominantly hazardous waste and inert solids, will have to be disposed of to landfill. Most of this will be disposed of in the existing Able-operated landfill adjacent to the ASP facility over a period of 3-4 years as the topsides are dismantled individually. It is not expected that these operations will have any impact on landfill sites.

22.5 Overview of Impacts from Onshore Legacy

22.5.1 Landfill Sites

Small amounts of specific types of waste material will be disposed of to landfill sites that are licensed to receive and dispose of such types of material. The contributions from the Brent Decommissioning programmes of work will be small in comparison to other sources and are not likely to impact the long-term operation or viability of the site(s).

22.6 Overview of Energy Use and Gaseous Emissions

We estimate that in total the proposed Brent decommissioning programmes of work would result in the direct use of approximately 5 million GJ of energy and the emission of approximately 350,000 tonnes of CO_2, that is, without taking into account any use of energy or emissions of CO_2 that would be associated with the new manufacture theoretically required to replace otherwise recyclable material that was left at sea or not recycled [5]. Table 91 presents a summary of these usages and emissions, which would arise mainly from the programme to plug and make safe the wells, offshore vessel operations, and onshore dismantling and recycling operations for the topsides.

Energy usage and gaseous emissions would occur over a period of approximately the next 8-10 years (see Schedule, Section 21) and probably fluctuate during each year, particularly in response to seasonal changes in activity offshore. The overall annual average level of gaseous emissions of approximately 35,000 tonnes CO_2/year is approximately 10% of the annual emissions of running the whole Brent Field when it was operational (396,000 tonnes in 2011), and it is very small in comparison to the total emissions from the UKCS in 2011 (14.2 million tonnes CO_2).

Table 91 Estimated Direct Use of Energy and Emission of CO_2 from the Proposed Decommissioning Programmes.

Source or Activity	Energy Use (GJ)	Gaseous Emissions (Te CO_2)
Plug and make safe all wells	3,256,728	233,330
Removing the Topsides	1,157,008	63,045
Removing the Upper Jacket	238,900	15,600
Decommissioning the 3 GBSs	13,965	1,029
Decommissioning the GBS Cell Contents	69,435	5,121
Decommissioning BA cuttings pile	30,687	2,263
Decommissioning BB and BD cuttings pile	5,732	423
Decommissioning BC cuttings pile	30,687	2,263
Removing the four subsea structures	32,436	2,282
Decommissioning the pipeline system	62,016	4,761
Removing debris	215,114	15,727
Total for whole proposed programmes of work	5,112,708	345,844

22.7 Potential Cumulative Impacts

22.7.1 Introduction

The potential impacts of the proposed programme of work have been assessed for each of the installations or facilities individually and the main types of impact identified by the ES are as follows:

- Effects in or on the marine environment from offshore operations including physical disturbance to the seabed, contamination of the seabed by resuspended drill cuttings and underwater noise from vessels.
- Effects to local communities onshore from the dismantling, treatment and final disposal of the topsides and upper jacket including the potential impacts of noise, odour and traffic.
- Legacy effects on the marine environment from permanent changes to the character of the seabed (especially by rock-dumping), contamination or recontamination of the seabed from disturbed drill cuttings piles (including from the eventual exposure or ejection of drill cuttings in the tri-cells), the escape of oily water from the storage cells, and the exposure of oily sediment from the oil storage cells.

Although few cumulative impacts were identified, mainly because of the distance between the installations and the length of the decommissioning programme, there is the potential for cumulative impacts or effects to arise from these and other impacts as a result of one or more of the following events or situations:

i. Interactions of the same effect occurring at more than one Brent facility.

ii. Interactions of the same effect occurring at a Brent facility and a nearby facility belonging to another operator.

iii. Interactions of different types of effect either at one Brent facility, or between several Brent facilities, or between a Brent facility and a third party facility.

iv. Additive effects on individual organisms or local marine communities as a result of the sequential exposure over a period of time to one or more effects or types of effect that, cumulatively, have a progressively detrimental effect on the individual or the viability of the local population.

For each of the receptor categories identified in the ES, DNV GL examined the combined impacts of the proposed programmes of work for all the facilities. The results were displayed in a series of diagrams showing the relative severity of the impacts from each of the proposed options.

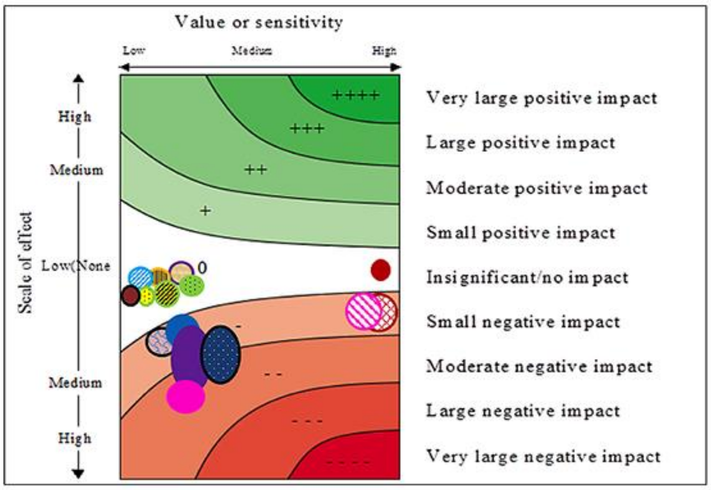
With respect to potential cumulative impacts to local communities onshore, DNV GL assessed the most likely sources of impact at the onshore dismantling facility would arise from noise, dust and odour. These would be small, localised, amenable to management and fully reversible, and DNV GL determined that individually they would not to be significant. It is likely that only one topsides would be taken ashore in any year and so it is not likely that there would be significant cumulative negative effects onshore.

DEN GL found that the categories "marine" and "legacy" were the most negatively impacted, and Figure 126 and Figure 127 show DNV GL's assessment of the combined impacts from all facility programmes to these two receptors. The main cumulative impacts are discussed below.

22.7.2 Cumulative effects in the "marine" category from operations

Figure 126 shows DNV GL's assessment of the cumulative impacts in the "marine" category. The decommissioning programmes of work giving rise to the most significant potential impacts were the pipelines which was assessed as 'moderate negative', and the subsea structures and debris (including the debris sweep), and the *possible* programme to remove all the Brent Charlie cell-top cuttings pile, which were both assessed as 'small-moderate negative'.

Figure 126 Combined impacts in "marine" category from proposed option for each Brent facility.



Note: some impact points have been moved slightly on the x-axis to facilitate visibility (without changing the impact).

Key to the proposed option that would be completed for each of the facilities (shown overleaf):

Topsides Option 1: Complete removal	
Brent A Upper Jacket Option 1: Complete removal	
Brent A Jacket Footings Option 3: Leave *in situ*	
GBS Option 2: Leave *in situ*	
GBS Attic Oil Option 1: Complete removal	
GBS Cell Contents Option 5: Leave *in situ*	
GBS Drilling Legs Option 5: Leave *in situ*	
GBS Minicell Annulus Option 5: Leave *in situ*	
Seabed Drill Cuttings Option 1: Leave *in situ*	
Brent B and D Cell Top Drill Cuttings Option 1: Partial removal by water jetting	
Brent C Cell Top Drill Cuttings Option 3: Dredge and transport slurry to shore for treatment	
Tri-cell Drill Cuttings Option 1: Leave *in situ*	
Pipelines: Proposed Programme of works	
Subsea Structures and Debris Option 1: Complete removal	
Wells Option 1: Plugging and Abandonment	

Physical disturbance to seabed from operations

Impacts would arise from (i) the cutting and removal of subsea structures, (ii) the water-jetting of small amounts of cell-top drill cuttings and, (iii) from different types of operations on pipelines including cut and lift, trenching and rock-dumping. These would disturb natural sediment and some amounts of historic drill cuttings which would then drift and settle on the adjacent seabed. This might affect individual benthic organisms and populations of benthic invertebrates within <1km of the disturbed site but recovery would begin as soon as seabed sediments and/or cuttings had settled. Apart from rock-dumping on PL001/N0501, each impact is judged by DNV GL to be small and localised and reversible. Some work on pipelines may affect areas previously affected by the resettlement of drill cuttings displaced to permit cell access for the removal of attic oil and interphase material, but these two operations will be separated in time. Some work on individual pipelines that were close together might affect the same area on more than one occasion, but such areas are likely to be very small in relation to the area of benthos in the Field. Rock-dumping on the long export line PL001/N0501 may affect other areas impacted by other lines close to Brent Charlie, but since the export line runs away and out of the Field work on more distant sections of this line will not be likely to affect areas of benthos close to the Brent platforms. It is not likely that the physical effects of operations in the Brent Field would add to any physical effects from the decommissioning of adjacent platforms and pipelines, even if these were to occur at the same time, because the nearest third-party platform is 9.6km away from any Brent platform (Figure 9).

Effects of underwater noise on marine mammals

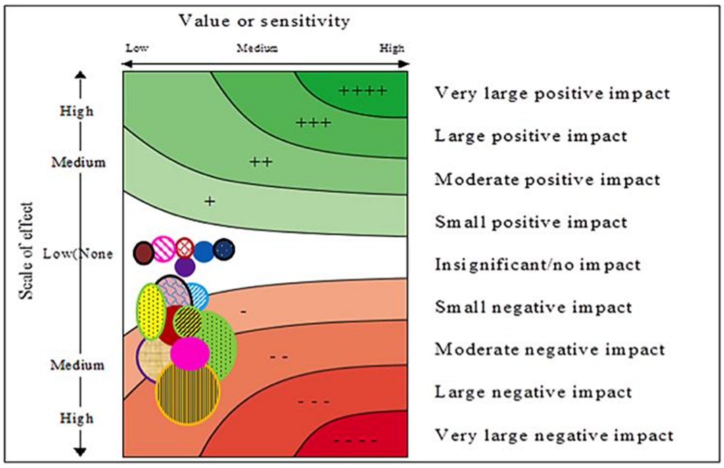
The separate noise report by DNV GL [5] shows that some combinations of vessels may produce noise of frequencies and levels that can be detected by marine mammals. If marine mammals are close to such sources they may experience a temporary threshold shift (TTS) in hearing ability. DNV GL noted that the numbers of marine mammals that might be so exposed is likely to be very small, and that the impacts are reversible. Most vessel activity will be around the platforms during the removal of the topsides. DNV GL assessed that the noise impact from each such operation was 'insignificant-small negative'. Only one topside will be removed in any one season, so it is not likely that there would be cumulative noise impacts. Operations on the pipelines are likely to be conducted by a single vessel during a campaign lasting one or more seasons and so there is little likelihood of cumulative impacts from this source. It is not likely that underwater noise from operations in the Brent Field would add to underwater noise impacts from the decommissioning of adjacent platforms and pipelines, even if these were to occur at the same time, because the effects would not be likely to extend more than 1km at most from the Brent facilities and the nearest third-party facility is 9.6km away from any Brent platform.

There is not likely to be any additive or synergistic effect from the combined effects of underwater noise and seabed disturbance because these impacts affect separate aspects of the environment (marine mammals and the benthos respectively).

22.7.3 Cumulative legacy effects

Figure 127 shows DNV GL's assessment of the cumulative impacts in the "legacy" category. The circumstances giving rise to the most severe potential impacts were the long-term presence of the GBSs, the eventual exposure or release of the GBS cell contents, the eventual exposure of the tri-cell drill cuttings, and the long-term presence of the remaining pipelines.

Figure 127 Combined impacts in "legacy" category from proposed option for each Brent facility



Note: some impact points have been moved slightly on the x-axis to facilitate visibility (without changing the impact).

Key to the proposed option that would be completed for each of the facilities:

Topsides Option 1: Complete removal	
Brent A Upper Jacket Option 1: Complete removal	
Brent A Jacket Footings Option 3: Leave *in situ*	
GBS Option 2: Leave *in situ*	
GBS Attic Oil Option 1: Complete removal	
GBS Cell Contents Option 5: Leave *in situ*	
GBS Drilling Legs Option 5: Leave *in situ*	
GBS Minicell Annulus Option 5: Leave *in situ*	
Seabed Drill Cuttings Option 1: Leave *in situ*	
Brent B and D Cell Top Drill Cuttings Option 1: Partial removal by water jetting	
Brent C Cell Top Drill Cuttings Option 3: Dredge and transport slurry to shore for treatment	
Tri-cell Drill Cuttings Option 1: Leave *in situ*	
Pipelines: Proposed Programme of works	
Subsea Structures and Debris Option 1: Complete removal	
Wells Option 1: Plugging and Abandonment	

DNV GL determined that the most likely causes of cumulative impacts would be the legacy effects to the marine environment that will arise when the GBS have suffered considerable degradation that leads to structural failure and collapse of legs and then cell walls. Hydrocarbons will be released into the marine environment as a result of (i) the exposure of the cell contents, (ii) the disturbance of seabed and cell-top drill cuttings and, (iii) the exposure of the materials in the drilling legs and minicell annulus. Any overlap in the timing of the exposure/release of these materials is difficult to predict, however, because of the uncertain nature and rate of GBS degradation. In Figure 128 in Section 24 we have attempted to show a possible timescale for the various *events* (falling debris, degradation, structural collapse) that would trigger or lead to possible exposure, release or ejection of contaminated material into the sea and this gives a view of which events and impacts might overlap temporally.

Despite the difficulty in predicting the timing of these events on each of the four Brent structures DNV GL states:

> "Some cumulative legacy impacts to the marine environment will take place, particularly at each GBS due to the combination of the hydrocarbons contained within the cell contents, the minicell and drilling legs contents, and the tri-cell drill cuttings" [5].

Together, these contents amount to an estimated 70,000m^3 of material, with an estimated hydrocarbon content of approximately 16,000 tonnes. When exposed into the marine environment, these materials would add to the existing hydrocarbon burden in the seabed and cell-top drill cuttings piles. The amount of oil in these cuttings is gradually decreasing through physical and chemical degradation, and at present is estimated to amount to about 5,642 tonnes. The total estimated *additional* amount of hydrocarbons that might thus be exposed is between two and three times the amount currently exposed in the present external cuttings piles.

Effects of escape of water phase from GBS cells

Modelling by BMT suggests that there may be impacts in the water column from large escapes or releases of oily water from the GBS cells. Potential impacts may occur up to 17 km from the source GBS and thus there is the potential for physical overlap in effects from more than one Brent GBS. Although the three GBSs will degrade in the same approximate timeframe (in excess of 500 years), there could be decades even centuries between each GBS being sufficiently degraded for its contents to be exposed to the marine environment. It is therefore unlikely that such releases would occur at exactly the same time, and given that the elevated concentrations of THC and H_2S would exist in the water column for only a short period of time (up to 5-10 days) such an overlap is unlikely. After the contaminants have dispersed further and/or biodegraded or reacted the potential for impacts will disappear. The release of cell water will occur long after all the proposed offshore operations have been completed and there will be no possibility of spatial or temporal overlap with any impacts from operations. The Brent GBSs are more than 15 km from the nearest third party GBS with comparable sources of oily water (Dunlin). An overlap in space and time between these two sources of oily water would only occur if there were very large volumes of very oily water on Dunlin and in the very unlikely event that loss of containment occurred on both structures at essentially the same time.

Finally, it is also likely that a large proportion (if not all) of the oily water phase in the cells will have escaped to, or been released into, the marine environment well before any appreciable amount of cell sediment has been exposed in a way that would provide a quick, direct pathway for hydrocarbons to reach the open sea.

Degradation of drill cuttings piles on seabed, cell-top and tri-cells

Desk-top studies have shown that all the seabed drill cuttings piles and all the cell-top drill cuttings piles except Brent Charlie fall below both of the thresholds in OSPAR 98/3. The oil release rate from the combined Charlie drill cuttings pile may be of the order 16 tonnes per year for perhaps 30 years; the oil release rate from the other piles ranges from approximately 0.3 tonnes per year to 2 tonnes per year. Individually these inputs of oil are assessed as giving rise to 'insignificant -small negative' impacts in the marine environment. A total of approximately 20 tonnes per year of oil may thus be entering the body of water around the five sites at present (the total distance from Brent Delta in the north to Brent South is 15.9km) where it is dispersed and undergoes chemical and biological degradation. Although the oil inputs to the water column from the drill cuttings piles at the five sites may overlap in space and in time for several years, the concentrations of oil in the overlapped areas will be very low and any areas of potential impact will remain confined to the immediate water column around each individual pile. The nearest known historic drill cuttings pile belonging to a third party is the 20,000m^3 pile at Statfjord B. This is approximately 10km away and thus there is very little likelihood of spatial overlap of any area (around a Brent installation and Statfjord B) where a potential effect may be experienced by marine organisms.

Modelling has shown that as the drill cuttings piles are eroded by the seabed currents and wave action, cuttings will be resuspended then drift and settle on the adjacent seabed. These new thin layers of cuttings, exposed to oxygenated seawater and bioturbation from benthic animals, will then experience more rapid chemical and biological degradation than cuttings deep with a pile. Modelling shows that the maximum area persistence[47] of any cuttings pile in the Brent Field (the combined Brent Charlie seabed and cell-top pile) is 5.5km^{2}years after 1,000 years. If 5.5km^2 is assumed to be the maximum likely extent of area impacted by a sediment THC of >50mg/kg, the area of seabed so impacted would extend to approximately 1 km around the site. The value of 5.5km^{2}years is an aggregate of the size of the impacted area each year and the actual area exhibiting a sediment THC of >50mg/kg at any one time is less than this. For example, sampling has shown that the THC of seabed sediments has fallen to a value of <50mg/kg at distances of between 350 m and 500 m from any of the Brent piles. Since the minimum distance between Brent piles is 2.4 km (Brent Alpha to Brent Brent) it is therefore not likely that as the piles erode and spread the area exhibiting THC above this threshold will overlap. Likewise, since the nearest third party cuttings pile is at least 10km away from any Brent drill cuttings pile, there is no likelihood of overlap in the physical or chemical impacts from these two sources.

Drill cuttings in the tri-cells in Bravo and Delta are likely to be partially exposed in the marine environment when the GBS caisson has substantially degraded or been severely damaged by large items of falling debris from the legs. Such extensive damage to the walls of the cells that enclose the tri-cell spaces is not likely to occur for perhaps 500 years. By this time some of the existing seabed and cell-top drill cuttings piles will have eroded and degraded and the area of seabed experiencing physical and chemical impacts from drill cuttings will have decreased in size. Exposure of the tri-cell cuttings may be both passive (through collapse of cell walls) and active (through ejection into the water column by the force of falling debris). It is therefore likely that at some time in the future some amount of tri-cell cuttings will be exposed in the marine environment and add to the burden of cuttings already present around these two platforms. In broad terms the estimated volume of tri-cell cuttings on Bravo and Delta is about the same as the original mapped volume of seabed cuttings at each site. In the very worst case, therefore, the addition of this material might further impact an area of seabed as large as the area originally impacted by the permitted discharge of cuttings. The extent of any such new layer of cuttings is likely to be smaller than this, however, because the cuttings released from the tri-cells will be dispersed from a depth about half-way down the water column, rather than from the sea surface as in the original discharge of cuttings. It is very unlikely, however, that the whole volume of tri-cell cuttings would ever be exposed because some would always remain buried under the large amount of concrete rubble that will be created when the cell domes and cell walls collapsed, which is a necessary condition for the exposure or ejection of the bulk of tri-cell cuttings. In summary, tri-cell cuttings may be exposed on the seabed before the existing seabed cuttings have disappeared and this co-exposure in time and space may delay the recovery of the seabed around Bravo and Delta or even perhaps enlarge the decreasing area of impact somewhat. It is not likely, however, that an area of seabed larger than that originally impacted would be affected. Once the tri-cell cuttings had been exposed, erosion and chemical and biological degradation would begin and the gradual recovery of the local seabed would recommence.

Exposure of sediments in GBS storage cells

When the domes of the cells collapse (as a result of impacts from falling leg debris and/or the long-term degradation of the domes) and then again, later, when the wall of the cells themselves are damaged or degrade, the sediment in the GBS cells will become exposed, and may also be ejected, into the marine environment. Because both events will be associated with (indeed a consequence of) the creation of large amounts of concrete debris, it is unlikely that the whole volume of cell sediment would ever be ejected or exposed in the sea. Nonetheless, a proportion of the sediment will eventually become exposed. In the ES, DNV GL state [5]:

> "There will be a cumulative legacy impact from the hydrocarbons on the marine environment, and DNV GL considers it to be one of the most important cumulative environmental impacts of the decommissioning programme. The main driver of the impact is the cell contents, as this provides the bulk of the hydrocarbon load, although the tri-cells contribution is also significant, particularly as it is

[47] The area of seabed exhibiting a THC of more than 50mg/kg.

> likely to be released in a dynamic disturbed state and at a higher location than the cell contents. There will be localised pollution to the marine environment around each platform, and although it will naturally degrade over time, this localised pollution will be present for decades, and will affect local benthic fauna. The cumulative contaminated area at Brent Bravo and Brent Charlie has not been modelled but will be similar, but larger, than that predicted in the DNV GL toxicological study [53] for a 'static' cell contents release (0.05km^2 based on analytical results, to a distance of 250m), when taking the tri-cells drill cuttings into account. Because the contaminated area will be localised around the platforms, there is not expected to be any measurable effect upon marine or benthic populations/ecosystems. The impact will be smaller at Brent Charlie because the volume of cell contents is smaller and also because there are no tri-cell drill cuttings present."

When discussing the effects of the combined release of cell sediment and tri-cell drill cuttings from the GBSs, DNV GL state [5]:

> "It is reasonable to assume that a proportion of the hydrocarbons in the GBS may be released in a dynamic disturbed state as a result of GBS degradation (particularly the tri-cells drill cuttings, most of which are located at a higher level than the cell sediment). The likelihood of some disturbed release of material is higher for 'Leave GBS legs in place', where a GBS leg collapse will have more destructive energy to damage the GBS caisson than the GBS legs down option. Although dynamic release scenarios would result in larger areas of the seafloor being contaminated (modelling has shown that the PEC:PNEC>1 covers much wider areas), the vast majority of the areas have a sediment thickness of less than 1mm, and hence are not expected to have any harmful impacts on biota once bioturbation and biodegradation effects are taken into account."

Modelling has shown that passively exposed cell sediments are likely to erode and spread over the adjacent seabed only very slowly. As they erode they will be subject to chemical and biological degradation which will gradually reduce the THC of the surface layers. Modelling of a theoretical, unshielded exposure has indicated that if the whole amount of sediment in each GBS were exposed the impacted area of each such "mound" of material may eventually extend up to 250m from the GBS, and then slowly decrease in size. It is therefore very likely that on the seabed within approximately 250m of the GBSs there will be co-exposure of the seabed and cell-top drill cuttings, the tri-cell drill cuttings and the cell sediment. This will result in a continuation of the physical and chemical contamination of the local seabed (principally by THC) at Bravo, Charlie and Delta for many years. The areas of impact around the GBSs will not overlap because the minimum distance between any of the Brent GBSs is 4.1km. They will not overlap with the smaller and possibly shorter-lived area of impact at Alpha (2.4km from Bravo) or the even smaller and shorter-lived area of impact at Brent South (4.9km from Alpha). None of these areas of physical or chemical impact will overlap with any similar area of impact from any other nearby third party installation.

Ejected cell sediment (a dynamic release as a result of GBS degradation) will drift and then settle onto the adjacent seabed, most likely onto areas that were previously affected by, and are still recovering from, the permitted discharge of drill cuttings. Modelling shows that the major proportion of newly settled layers will be thin and as such will experience ready and rapid chemical and biological degradation. The areas of seabed exhibiting a THC of >50mg/kg will therefore rapidly decrease in size and it is not expected that there would be any harmful impact on biota. Ejected cell sediment will be co-exposed on the seabed with historic drill cuttings piles and may delay or set-back the recovery of part of the seabed for a time. Ejected material is not likely, however, to increase the size of area originally impacted by cuttings. In addition, it is likely that the majority of the seabed freshly affected by a newly settled layer of ejected cell sediment will have recovered, or largely recovered, well before passively exposed cell sediment has spread any distance from the GBS. The sediment will spread only slowly and so it is not likely that cell sediment would spread onto all the area previously impacted by historic cuttings or re-impacted by ejected cuttings or ejected cell sediment.

Resuspension of drill cuttings

The drill cuttings on the GBS cell-tops and on the seabed around the GBS will be disturbed by falling debris as the GBSs degrade and collapse. DNV GL state [5]:

"If it took approximately 500 years before loss of containment of the cell contents occurred, the seabed and cell-top drill cuttings that are currently exposed on the seabed will have degraded further between 30-50%, hence they will still retain some hydrocarbons. The future disturbance of the existing drill cuttings is likely to occur in stages as the GBS degrades over time, and the impacts are likely to be similar to those [arising from] the disturbance of the drill cuttings from various activities such as trawling and dredging, with between 493m^3 and 775m^3 of drill cuttings released in to the water column (as described in more detail in [16]). The distribution of the released cuttings on the seabed was largest for the release of 775m^3 of the Brent Charlie cell-top cuttings (this is logical because the cuttings were released at the cell tops approximately 60m above the seabed, resulting in a thinner layer and larger dispersal on the seabed compared to the seabed release). The cuttings from the cell-tops generated a layer of less than 1cm thick (the average and maximum thickness of the re-deposited cuttings is 0.2 and 0.6mm respectively), and redeposition with a layer thickness of more than 1mm was restricted to an area of about 0.07km^2. Where the sediment thickness is less than 1mm there is not expected to be any harmful impact on biota. Regardless, the disturbance of the drill cuttings will add to the cumulative impact described above [from the release of the cell sediment], but the environmental impact will remain localised (to several hundred metres) around the platforms and will reduce over time, particularly where the sedimentis less than 1cm thick, as aerobic degradation will break down the organic material. The cumulative area with potentially harmful impact due to THC contamination will be similar to what is currently observed on the seafloor around many North Sea oil and gas installations."

Conclusion on cumulative impacts

Hydrocarbons from different sources in the Brent Field may be released into the marine environment at the same time. In the water column, because of the effects of dispersion and degradation, these inputs are very unlikely to increase the severity or extent of the short-lived and localised impacts on pelagic organisms.

In the benthos, although the concentrations of hydrocarbons in seabed sediments may increase for a time, the area impacted is not likely to be significantly greater than that already impacted by the historic discharge of drill cuttings.

None of the potential impacts from Brent offshore operations or legacy will act cumulatively with any existing or future known operations or legacy at fixed installations belonging to other operators.

23 PROJECT MANAGEMENT AND VERIFICATION

23.1 Strategy

The strategy for this project is to maximise the use of our in-house resources and existing contracts for the preparatory work, and to award lump sum contracts to pre-qualified prime contractors for the main decommissioning activities such as topsides removal and disposal.

23.2 Project Management

The project will be managed in accordance with applicable regulatory requirements and to Shell's Global Project Management standards. The project will be led by a Shell Project Director with sub-project managers, project engineers and support functions including, but not limited, to Health, Safety and Environment, Quality, and Project Services. The project will be divided into a series of sub-projects and tendered to the open market as appropriate. Synergies will be sought with other Shell project activities (and in principle other decommissioning activities) where they make economic and business sense.

The approved DPs will be subject to strict change management, with any significant change to scope being agreed with BEIS prior to implementation.

23.3 Preparatory Work

We will work closely with our contracting partners to prepare the topsides and other facilities for decommissioning. This work will include topside and pipeline flushing, equipment isolation, engineering-down and making safe for handover to decommissioning contractors.

23.4 Notifying Other Users of the Sea

At least 6 weeks before any vessel-based offshore decommissioning work begins we will notify the UK Hydrographic Office so that appropriate Notices to Mariners can be distributed. At the same time an advisory notice about the planned programme of work will be placed on the Sea Fish Industry Authority's Kingfisher Bulletin.

23.5 Verification

At significant milestones in the planning and execution of the project, work will be subject to internal peer reviews by Shell and by Esso. Major technical decisions will also be subject to approval from Shell's internal 'technical authorities'.

23.6 Reporting Progress

We will report progress to BEIS throughout the offshore and onshore programmes of work. Given the multi-faceted and prolonged nature of the Brent Field decommissioning programmes, the frequency and content of these reports may vary (see Section 23.8) but this will be discussed and agreed with BEIS.

23.7 Duty of Care for Waste Materials

In planning and managing the responsible disposal of our materials we will follow the 'waste hierarchy', which states that re-use is preferred to recycling, and recycling is preferred to disposal to landfill. In order of decreasing preference, the hierarchy of how material from the Brent Field will be disposed of is therefore as follows:

- Refurbishment for re-use as a unit
- Removal of equipment for re-use
- Segregation of pipes for re-use (recovered end sections)
- Segregation of steelwork and other materials for re-use
- Segregation of materials for recycling

- Segregation of materials (including hazardous materials) for disposal

Table 92 presents a summary of how the main waste streams will be dealt with. All hazardous materials will be appropriately handled and disposed of in accordance with the relevant legislation. We expect that the bulk of the recovered platform material will be recycled but some compound items that are difficult to separate into their component materials may have to be scrapped and sent to licensed landfill sites.

Once on the quayside, any components with marine fouling will be cleaned and the organic fouling material disposed of to landfill. Any large components scheduled for re-use or possible re-use will be stored in a designated area of the facility for refurbishment or preservation until final decisions have been made about their disposal or fate.

Other components that are not viable for re-use as single units will be stripped and any equipment and/or materials suitable for re-use will be stored and preserved in suitable warehouses or designated storage areas.

Anodes will be removed from all the recovered sections of the jacket and pipelines, and collected for recycling. Where it is deemed practical, the concrete coating on all the recovered sections of pipeline will be removed and collected for use as hardcore, leaving the steel pipes in a condition suitable for recycling.

Other materials will be collected by type and stored in separate areas for shipment to smelters or other recycling facilities.

Materials not suitable for any of the above treatments (including hazardous materials such as asbestos, LSA-contaminated materials, and heavy metals) will be collected and then removed for disposal in landfill and/or other approved disposal facilities. All wastes will be dealt with in accordance with the appropriate legislation, including if applicable, the Transfrontier Shipment of Waste Regulations.

The project has set a target to recycle and re-use at least 97% by weight of the equipment and materials retrieved. We will comply with our legal duties with respect to the management, treatment and disposal of all waste equipment and materials retrieved during the decommissioning programmes.

Table 92 Summary of Methods for Managing Waste Streams.

Waste Stream	Removal and Disposal Method
Steel	Steel will be removed by dismantling or by hot (oxy-propane flame) or cold (hydraulic shears) cutting. Processed material will be stored adjacent to the processing area or loaded into dump trucks and delivered to the processed scrap storage area on the ASP facility. Scrap metals will be transported by road, rail or sea to suitably-licensed facilities for processing.
Hydrocarbons	Any petroleum hydrocarbons discovered within the pipework, equipment, vessels or tanks will be drained into suitable receptacles and sent to a licensed facility for recycling or disposal.
NORM/LSA Scale	During the dismantling operations, radiation monitoring will be undertaken on any module or structure that is known or suspected to contain naturally-occurring radioactive materials (NORM). If monitoring reveals the presence of LSA scale a detailed method statement for the removal of the component or pipe will be prepared. This may involve encapsulating any open ends and transferring the item to the Hazardous Waste Store at the ASP facility, pending off-site disposal or further processing. All NORM will be handled, stored and treated in accordance with RSA 1993.
Asbestos	Following a period of onshore survey, all asbestos will be removed by specialist contractors wearing appropriate protective clothing and respiratory equipment. This will be completed as part of a ‘soft strip’ programme that will be undertaken before dismantling of the topside begins. All asbestos will be disposed of in sealed containers at the adjacent licensed landfill site owned and operated by Able.
Other hazardous wastes	All such wastes will be disposed of under appropriate permit(s).

23.8 Close-out Report

The proposed programmes of work to decommission the Brent Field facilities are complex and will take about nine or ten years to complete (Figure 124). We envisage that we will issue several interim Close-Out Reports during this time, for example (i) after the removal of each topside, (ii) after the removal of the Brent Alpha upper jacket and, (iii) after the removal of attic oil and interphase material. These interim reports will be updated when their respective onshore dismantling and waste management programmes have been completed.

When all the decommissioning work has been completed we will submit a final project close-out report that will comply with BEIS's requirements. We envisage that this would be a single report covering both DPs and would only be produced when:

- All the offshore decommissioning and remediation work is finished
- All the retrieved material has been returned to shore and disposed of
- The debris sweeps have been performed and signed-off
- The 'as-left' structural surveys of any remains have been completed

Given the complexity of the Brent decommissioning programmes and the need to present 'as-left' data for any remains on the seabed, it is likely that the final Close-Out report would be available approximately 12 months after completion of all offshore work and onshore work.

23.9 Management of Residual Liability

In accordance with the Petroleum Act 1998 (as amended) ('the Act') [1], the responsibility for the subsequent management of on-going residual liabilities including managing and reporting the results of the agreed post-decommissioning monitoring (described in Section 24), evaluation and any remedial programme, will remain with the owners. The owners will also be the contact point for any third party claims arising from damage caused by any remaining infrastructure or materials left in place under the approved Brent Decommissioning Programmes. All the structures and pipelines which are proposed to be left in place remain the property and responsibility of the owners, even if they were to exit the UKCS.

23.10 Costs

An estimate of the overall cost of the combined proposed programmes of work has been provided separately to BEIS and OGA.

24 PRE- AND POST-DECOMMISSIONING MONITORING

24.1 Introduction

If the proposed Decommissioning Programmes are approved it is possible that there will be short-term and long-term effects in the environment of the Brent Field. The offshore decommissioning operations themselves may cause generally localised and short-term effects for various environmental receptors which would disappear in time after the activities stop. The resultant end-points of those operations (i.e. the state and condition of any items left in the sea) and in particular the long-term presence of the remains of the footings, the GBSs and the GBS contents, may cause delayed, intermittent or chronic impacts in the future. Our proposed programmes have therefore been designed to monitor two types of event (i) environmental effects and, (ii) the physical degradation and collapse of remains. Figure 128 presents a visualistion of the possible timing and sequence of the events or operations and the associated targetted surveys that might be performed around these times to monitor the disturbance or release of contaminants. This shows that after the local disturbance that may be caused by decommissioning activities over the next 5-10 years there are not likely to be any potential impacts to monitor for perhaps 100-200 years.

24.2 Pre-decommissioning Environmental Surveys

We completed a pre-decommissioning baseline environmental survey in 2007 to provide essential information for the EIA and our CAs, and repeated this survey in 2015. Together, these surveys provide a detailed assessment of the status of the seabed around each site before offshore operations begin. They add to our time-series of data showing how the character of the benthic community and the concentrations of oil and other contaminants in the seabed immediately adjacent to historic cuttings piles have changed over time, especially since the discharge of oil-based drill cuttings ceased in 1998.

24.3 Post-decommissioning Environmental Surveys

A post-decommissioning environmental survey will be conducted when all offshore work has been completed, debris removed and the debris sweep successfully carried out. The survey will re-visit all the stations sampled in the two pre-decommissioning baseline surveys, to obtain a directly comparable set of data which would allow us to determine with a high degree of certainty if the offshore operations have had any impacts on the local environment.

24.4 Future Environmental Monitoring

We propose to carry out a second post-decommissioning environmental survey about 5 years after the first one, again re-visiting the previous sampling stations. This would be the fourth in a time series of comprehensive and comparable surveys and should provide a good assessment of the extent of any perturbation caused by the offshore operations, and more data on the general character and state of the seabed in the Field.

If the post-decommissioning surveys show that there have been impacts from our operations we will continue the environmental surveys at about 5-year intervals until such time as there is a clear trend showing that recovery is taking place and will occur within a reasonable time-scale.

Thereafter, we will discuss the need for further environmental surveys with BEIS. As Figure 128 shows, once the seabed has recovered from any operational impacts it is for many years unlikely to experience any further perturbation, either from residual contaminants in remains or from the physical presence of degraded remains. Future environmental surveys therefore have to be targeted to anticipated events or milestones in the slow degradation of remains when there will be a heightened risk that some residual contaminants might be exposed to the sea or escape into it.

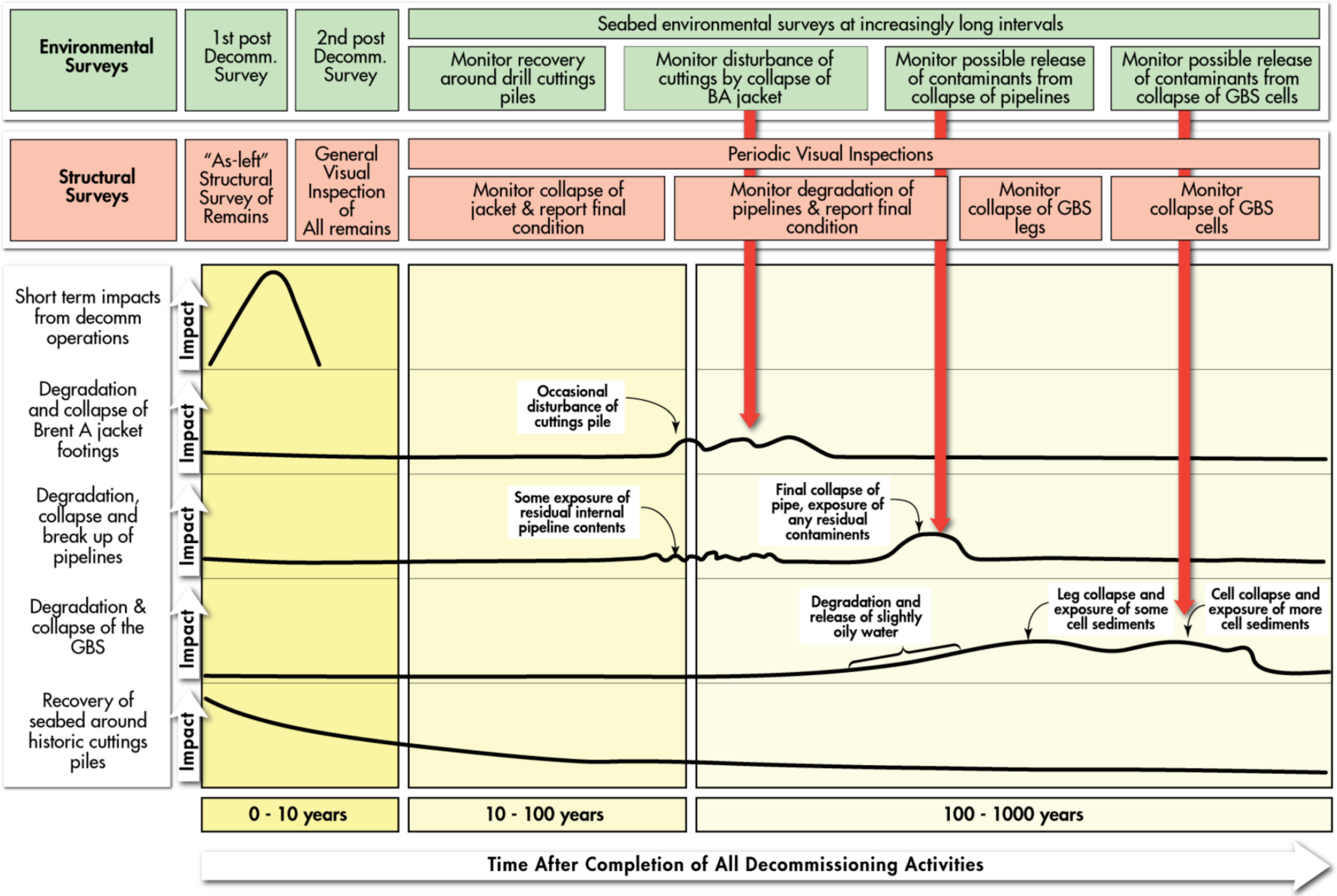
24.5 Monitoring Degradation and Collapse of Remains

We will be responsible for all the structures and materials which are permitted to remain on the seabed on completion of the Decommissioning Programmes; as described in Section 13.13, Section 14.15, Section 15.11.5, Section 16.15.1, Section 17.13 and Section 19.7.14 these will slowly degrade. Once we have performed the proposed detailed 'as-left' structural surveys after completion of the proposed Decommissioning Programmes, it is unlikely that any noticeable structural degradation would occur for 20-50 years. Our programme of post-decommissioning structural monitoring therefore needs to be targeted and 'risk-based' since routine annual surveys will be very wasteful. Rather than repetitive, unproductive structural surveys, we propose to minimise the small risks to the environment and to other users of the sea that may occur as structures deteriorate by leaving the remains in a good structural condition. This means, for example, removing light-weight components such as external piping and caissons.

In addition, we propose to re-assess the safety risk to other users of the sea from the derogated GBSs in a "rolling" programme as described in Section 14.17.1. Based on updated information of commercial fishing activity and shipping traffic, and in light of the latest information on the condition of the GBS legs, this will provide an accurate estimate of safety risk that can be regularly refreshed into the long-term future.

The post-decommissioning as-left structural survey will provide detailed information on the Brent Alpha footings, the Bravo, Charlie and Delta GBSs, and any sections of pipeline that may be left in the Field. Informed by this survey, we will enter into discussions with BEIS to plan and agree the content and frequency of a risk-based long-term structural monitoring programme.

Figure 128 Relative Timescales of Impacts from Offshore Operations and Some of the Long-term Consequences of Leaving Material on the Seabed.



PART FIVE
SUPPORTING MATERIAL

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25 SUPPORTING MATERIAL

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26 ACRONYMS AND GLOSSARY

ABS	Acrylonitrile Butadiene Styrene
Ac	Actinium
Al	Aluminium
AIS	Automatic Identification System
ALARP	As Low As Reasonably Practicable
APE	Alkylphenolpolyethoxlyate: a group of chemicals of possible concern as endocrine disruptors
ARPS	Aberdeen Radiation Protection Services
ASP	Able Seaton Port
AtoN	Aid to Navigation
Attic oil	Crude oil that is physically or hydro-dynamically trapped just below the GBS cell dome.
AWJ	Abrasive Water Jet
BAT	Best Available Technique
BBY	Brent Bypass Project
BDP	Brent Decommissioning Project
BEIS	Department for Business, Energy and Industrial Strategy
BEP	Best Environmental Practice
BHA	Bottom Hole Assembly
billion	One thousand million (109)
Bq	Becquerel, the SI unit measuring the activity of a quantity of radioactive material
BTA	Buoyancy Tank Assemblies
BTEX	Benzene, Toluene, Ethylbenzene, Xylene
CA	Comparative Assessment
Caisson	The term used to describe the lower part of the GBS, containing the storage cells.
CCS	Carbon Capture and Storage
Cell sediment	Fine particles of sand from the reservoir fluids that have settled to the bottom of the cells
CFC	Chlorofluorocarbon
CHARM	Chemical Hazard and Risk Management
CMSTG	Cell Management Stakeholder Task Group
CO_2	Carbon Dioxide
CO_2E	CO_2 equivalent sum of GWP of all gases
Conductor	A large diameter pipe that links the well bore hole to the topsides
CoP	Cessation of Production
CRI	Cuttings Re-injection
CSP	Cell Sampling Project
DE	Doris Engineering
DECC	Department of Energy and Climate Change
DNV	Det Norske Veritas
dowel	A vertical steel and concrete 'pin' on the base of the GBS that penetrates the seabed and prevents the structure sliding sideways
DP	Decommissioning Programme
Drawdown	The system and process which maintains a difference in pressure between the fluids inside the cells and the surrounding sea. The cell fluids are kept at a lower pressure and the resultant compression force on the caisson enhances its strength and integrity
Drill cuttings	The fragments of rock generated during the process of drilling a well
DSC	Decommissioning Services Contractor
DSV	Diving Support Vessel
DTI	Department of Trade and Industry
DTOO	Dr techn. Olav Olsen
DWC	Diamond Wire Cutting
DyP	Dynamic Positioning
EIA	Environmental Impact Assessment
EoFL	End of Field Life
EMS	European Marie Site
E&P	Exploration and Production
EPDM	Ethylene propylene diene monomer (a type of rubber)
ESP	Emergency Shut-Down Procedure
ESP	Electrical Submersible Pump
ES	Environmental Statement
ESHIA	Environmental, Social and Health Impact Assessment
EV	Enhanced Voidage

FAR	Fatal Accident Rate
FEED	Front End Engineering and Development
FFDP	Final Field Development Plan
FFPV	Flexible FallPipe Vessel
FishSAFE	An electronic means of alerting vessels to the proximity of a structure in the sea. FishSAFE is a commercial fishing industry driven safety program. (www.fishsafe.eu)
FLAGS	Far North Liquids and Associated Gas System
FLTC	Fisheries Offshore Oil and Gas Industry Legacy Trust Fund Limited
FTE	Full-time Equivalent
GBS	Gravity Base Structure
GJ	Gigajoule (10^9 joules)
Grout	A general term for usually light, pumpable cement that can be introduced into pipes or complex and/or confined spaces.
GRP	Glass-reinforced plastic
GWP	Global Warming Potential
HAZID	Hazard Identification
HC	Hydrocarbon
HLV	Heavy Lift Vessel
HSE	Health and Safety Executive
H_2S	Hydrogen Sulphide
IALA	International Association of Lighthouse Authorities
ICES	International Council for the Exploration of the Sea
IMO	International Maritime Organisation
IMPACT	A Shell project undertaken from 2004 to 2008 to change the Brent Field from mainly oil production to mainly gas production
Interphase	A term for the viscous emulsion of oil and water that has formed at the interface between crude oil and sea water in the GBS oil storage cells
IoP	Institute of Petroleum
IPR	Interim Pipeline Regime
IRG	Independent Review Group

ISO	International Standards Organisation
JLS	Jacket Lifting System
JNCC	Joint Nature Conservation Committee
kg	kilogramme
km	kilometre
KP	Kilometre Point
LAT	Lowest Astronomical Tide
LSA	Low Specific Activity (scale)
LTD	Low-temperature Thermal Desorption
LTFD	Long Term Field Development
LTOBM	Low Toxicity Oil-based Mud
LWIV	Light Well Intervention Vessel
MAH	Major Accident Hazards
MBES	Multi-Beam Echo Sounder
MCDA	Multi-Criteria Decision Analysis
MCZ	Marine Conservation Zone
MEG	Mono-ethylene Glycol
MNA	Monitored Natural Attenuation
MOD	Ministry of Defence
MSF	Module Support Frame
MSV	Multi Support Vessel
NGO	Non-governmental Organisation
NLGP	Northern Leg Gas Pipeline
Nm	Nautical mile
NNR	National Nature Reserve
NORM	Naturally-Occurring Radioactive Material
NOx	Nitrous Oxides
NPF	Norske Petroleumsforening
NRG	NRG Well Examination Ltd
OBM	Oil-based Mud
OCNS	Offshore Chemicals Notification Scheme
ODCP	Offshore Decommissioning Communications Project
ODE	Offshore Design and Engineering
OGA	Oil and Gas Authority

OGUK	Oil and Gas UK Limited
OIW	Oil in Water
OPEP	Oil Pollution Emergency Plan
OPF	Organic Phase Fluid
OSDR	Offshore Safety Directive Regulator
OSPAR	Oslo Paris Commission
OSRL	Oil Spill Response Limited
P&A	Plug and Abandon
Pb	Lead
PCB	Polychlorinated Biphenyls
PGDS	Plate Girder Deck Support
Piles	Hollow steel tubes that fix a steel jacket to the seabed. The piles are inserted through pile guides and bonded to the guides by grout
PLEM	Pipeline End Manifold
PLL	Potential Loss of Life. A comparative measure of the safety risk of an option or programme of work
POBM	Pseudo Oil-based Mud
PON	Petroleum Operations Notice
PPE	Personal Protection Equipment
ppm	parts per million
PTE	Principal Technical Expert
PTFE	Polytretrafluoroethylene
PVC	Polyvinylchloride
PWA	Pipeline Works Authorisation
QRA	Quantitative Risk Assessment
Ra	Radium
Riser	A steel tube that links a pipeline on the seabed to the topside. They are fixed to the outside of steel jackets but may run inside the legs of GBSs
ROV	Remotely Operated Vehicle
RSA	Radioactive Substances Act
R4C	Resources for Change
SAC	Special Area of Conservation
SCE	Safety Critical Elements
SEPA	Scottish Environment Protection Agency
SFF	Scottish Fishermen's Federation
Skirt	Short vertical walls of concrete and steel fixed to the bases of the GBS. They divide the under-surface into compartments that are filled with grout and help to fix the GBS to the seabed
SLV	Single Lift Vessel
SOPEP	Shipboard Oil Pollution Emergency Plan
SOx	Sulphur Oxides
SPA	Special Protection Area
SSCV	Semi-Submersible Crane Vessel
SSIV	Subsea Isolation Valve
STASCO	Shell Trading and Shipping Company
TAC	Total Allowable Catch
TBT	Tri-Butyl Tin
TD	Technical Document
te	metric tonne (1000 kg)
TEC	The Environment Council
TF	Technical Feasibility
THC	Total Hydrocarbon Concentration
TOP	Top of Pipe
TPF	Technical Project Failure
Tri-cell	A tall thin vertical space with a triangular cross-section, formed when three circular GBS storage cells meet
trillion	one million million (10^{12})
TTS	Temporary Threshold Shift
UKCS	United Kingdom Continental Shelf
UKHO	UK Hydrographic Office
UKOOA	United Kingdom Offshore Operators Association
VASP	Valve Assembly Spool-Piece
WBM	Water-based Mud
WGS84	World Geodetic System
WLGP	Western Leg Gas Pipeline
WONS	Well Offshore Notification Scheme
Zn	Zinc

Table 93 Status of P&A on Brent Alpha Wells at 1st February 2017.

No	Side-track	OGA Number	Well Type	Status
BA01	S8	211/29-A56U	Producer	To be Abandoned
BA02	S2	211/29-A59Z	Water Injector	Barriers Installed
BA03	S1	211/29-A47	Producer	Barriers Installed
BA04	S2	211/29-A54	Producer	To be Abandoned
BA05	S1	211/29-A55	Water Injector	To be Abandoned
BA06	S1	211/29-A41	Producer	Barriers Installed
BA07	S1	211/29-A53	Gas Lift Producer	To be Abandoned
BA08	S3	211/29-A48	Gas Lift Producer	To be Abandoned
BA09	S1	211/29-A44	Producer	To be Abandoned
BA10	/	211/29-A28	Producer	To be Abandoned
BA11	S1	211/29-A49	Water Injector	To be Abandoned
BA12	S2	211/29-A32	Producer	Barriers Installed
BA13	S3	211/29-A57Y	Gas Lift Producer	To be Abandoned
BA14	/	211/29-A34	Gas Lift Producer	To be Abandoned
BA15	S4	211/29-A51	Gas Lift Producer	To be Abandoned
BA16	S5	211/29-A40Z	Water Injector	To be Abandoned
BA17	S4	211/29-A58Y	Producer	To be Abandoned
BA18	S2	211/29-A14	Gas Lift Producer	To be Abandoned
BA19	/	211/29-A04	Gas Lift Producer	To be Abandoned
BA20	S4	211/29-A42	Producer	To be Abandoned
BA21	S1	211/29-A22Z	Producer	To be Abandoned
BA22	S2	211/29-A30	Producer – not completed	Barriers Installed
BA23	S2	211/29-A45	Producer	To be Abandoned
BA24	S1	211/29-A26Z	Producer	To be Abandoned
BA25	S1	211/29-A43	Gas Lift Producer	To be Abandoned
BA26	S2	211/29-A05	Producer	To be Abandoned
BA27	S5	211/29-A52	Producer	To be Abandoned
BA28	S2	211/29-A50	CRI	To be Abandoned

Table 94 Status of P&A on Brent Bravo Wells at 1st February 2017.

No	Side-track	OGA Number	Well Type	Status
BB01	S3	211/29-B52Y	Gas Lift Producer	Barriers Installed
BB02	S1	211/29-B48	Gas Lift Producer	Barriers Installed
BB03	S2	211/29-B30A	EV Water Producer	Barriers Installed
BB04	S2	211/29-B63Z	Gas Lift Producer	Barriers Installed
BB05	S2	211/29-B60Z	Producer	Barriers Installed
BB06	S2	211/29-B72	EV Water Producer	Barriers Installed
BB07	S1	211/29-B64	Gas Lift Producer	Barriers Installed
BB08	S2	211/29-B55	Producer	Barriers Installed
BB09	S4	211/29-B71	EV Water Producer	To be Abandoned
BB10	S1	211/29-B75	EV Water Producer	Barriers Installed
BB11	/	211/29-B11	Water Injector	Barriers Installed
BB12	S1	211/29-B76	EV Water Producer	Barriers Installed
BB13	/	211/29-B20	Gas Lift Producer	Barriers Installed
BB14	S5	211/29-B70X	Gas Lift Producer	Barriers Installed
BB15	S5	211/29-B67	Gas Lift Producer	Barriers Installed
BB16	S1	211/29-B45	Gas Lift Producer	Barriers Installed
BB17	S1	211/29-B65	Gas Lift Producer	Barriers Installed
BB18	/	211/29-B38	Producer	Barriers Installed
BB19	S2	211/29-B51	Producer	Barriers Installed
BB20	S2	211/29-B61	Producer	Barriers Installed
BB21	/	211/29-B09	Gas Injector	Barriers Installed
BB22	S4	211/29-B46	Gas Lift Producer	Barriers Installed
BB23	S1	211/29-B73	Producer	Barriers Installed
BB24	S1	211/29-B54	Gas Lift Producer	Barriers Installed
BB25	S1	211/29-B57	Producer	Barriers Installed
BB26	/	211/29-B07	Gas Injector	Barriers Installed
BB27	S1	211/29-B56	Gas Lift Producer	Barriers Installed
BB28	S2	211/29-B44	Gas Lift Producer	Barriers Installed
BB29	S2	211/29-B68Z	Gas Lift Producer	Barriers Installed

Table 94, continued Status of P&A on Brent Bravo Wells at 1st February 2017.

No	Side-track	OGA Number	Well Type	Status
BB30	S4	211/29-B69X	Gas Lift Producer	Barriers Installed
BB31	/	211/29-B08	Gas Lift Producer	Barriers Installed
BB32	S4	211/29-B62	Gas Lift Producer	Barriers Installed
BB33	/	211/29-B06	Producer	Barriers Installed
BB34	/	211/29-B26	Gas Lift Producer	Barriers Installed
BB35	S1	211/29-B59	Gas Lift Producer	Barriers Installed
BB36	S2	211/29-B47	Gas Lift Producer	Barriers Installed
BB37	S2	211/29-B74	EV Water Producer	Barriers Installed
BB38	/		Conductor Only	Conductor Only

Table 95 Status of P&A on Brent Charlie Wells at 1st February 2017.

No	Side-track	OGA Number	Well Type	Status
BC01	S3	211/29-C51Z	Gas Lift Producer	To be Abandoned
BC02	/	211/29-C12	Water Injector	To be Abandoned
BC03	S2	211/29-C47	Gas Lift Producer	To be Abandoned
BC04	S2	211/29-C53	Gas Lift Producer	To be Abandoned
BC05	S2	211/29-C60	Gas Lift Producer	To be Abandoned
BC06	/	211/29-C04	Water Injector	To be Abandoned
BC07	S2	211/29-C61Z	Gas Lift Producer	To be Abandoned
BC08	/	211/29-C26	Gas Lift Producer	To be Abandoned
BC09	/	211/29-C30	Producer	To be Abandoned
BC10	/	211/29-C29	Producer	To be Abandoned
BC11	S1	211/29-C55	Gas Lift Producer	To be Abandoned
BC12	S1	211/29-C41	Gas Lift Producer	To be Abandoned
BC13	S1	211/29-C57	Gas Lift Producer	To be Abandoned
BC14	S2	211/29-C63	Gas Lift Producer	To be Abandoned
BC15	S2	211/29-C52Z	Gas Lift Producer	To be Abandoned
BC16	S1	211/29-C50	EV Water Producer	To be Abandoned
BC17	/		Conductor Only	Conductor Only
BC18	S1	211/29-C17	Water Injector	To be Abandoned
BC19	/	211/29-C20	Gas Lift Producer	To be Abandoned
BC20	S2	211/29-C42	Water Injector	To be Abandoned
BC21	S4	211/29-C46Y	Gas Lift Producer	To be Abandoned
BC22	S1	211/29-C16	Producer	To be Abandoned
BC23	S1	211/29-C32	Gas Lift Producer	To be Abandoned
BC24	S2	211/29-C48	Producer	To be Abandoned
BC25	/	211/29-C18	Gas Lift Producer	To be Abandoned
BC26	S1	211/29-C45	Gas Lift Producer	To be Abandoned
BC27	/	211/29-C10	Gas Lift Producer	To be Abandoned
BC28	S1	211/29-C35	Water Injector	To be Abandoned
BC29	S1	211/29-C25	Gas Lift Producer	To be Abandoned

Table 95, continued Status of P&A on Brent Charlie Wells at 1st February 2017.

No	Side-track	OGA Number	Well Type	Status
BC30	/		Conductor Only	Conductor Only
BC31	S4	211/29-C56Z	Gas Lift Producer	To be Abandoned
BC32	S1	211/29-C07	Gas Lift Producer	To be Abandoned
BC33	S1	211/29-C64	Gas Lift Producer	To be Abandoned
BC34	/	211/29-C13	Producer	To be Abandoned
BC35	S1	211/29-C65	EV Water Producer	To be Abandoned
BC36	S1	211/29-C59	Gas Lift Producer	To be Abandoned
BC37	S1	211/29-C62	Gas Lift Producer	To be Abandoned
BC38	S1	211/29-C49	Gas Lift Producer	To be Abandoned
BC39	S4	211/29-C58	Gas Lift Producer	To be Abandoned
BC40	S1	211/29-C54	Gas Lift Producer	To be Abandoned

Table 96 Status of P&A on Brent Delta Wells at 1st February 2017.

No	Side-track	OGA Number	Well Type	Status
BD01	S1	211/29-D72	CRI	Abandoned
BD02	S1	211/29-D71	CRI	Abandoned
BD03	S1	211/29-D55	EV Water Producer	Abandoned
BD04	S2	211/29-D45Z	Water Injector	Abandoned
BD05	S1	211/29-D38	Gas Lift Producer	Abandoned
BD06	S5	211/29-D57Z	Water Injector	Abandoned
BD07	S1	211/29-D34	Gas Lift Producer	Abandoned
BD08	S2	211/29-D39Y	Gas Lift Producer	Abandoned
BD09	/		Conductor Only	Abandoned
BD10	S1	211/29-D44	Producer	Abandoned
BD11	S1	211/29-D62	Gas Lift Producer	Abandoned
BD12	S5	211/29-D66Z	Gas Lift Producer	Abandoned
BD13	/	211/29-D12	Water Injector	Abandoned
BD14	/	211/29-D10	Water Injector	Abandoned
BD15	S3	211/29-D32	Water Injector	Abandoned
BD16	S3	211/29-D59Z	CRI	Abandoned
BD17	S2	211/29-D69Z	EV Water Producer	Abandoned
BD18	S2	211/29-D52	Gas Lift Producer	Abandoned
BD19	S1	211/29-D60	Gas Lift Producer	Abandoned
BD20	S2	211/29-D50Z	Producer	Abandoned
BD21	/		Conductor Only	Abandoned
BD22	S3	211/29-D51	Gas Lift Producer	Abandoned
BD23	/		Conductor Only	Abandoned
BD24	/		Conductor Only	Abandoned
BD25	/	211/29-D04	Gas Lift Producer	Abandoned
BD26	/	211/29-D01	Gas Lift Producer	Abandoned
BD27	/	211/29-D03	Gas Injector	Abandoned
BD28	/	211/29-D05	Gas Lift Producer	Abandoned
BD29	/	211/29-D31	Gas Lift Producer	Abandoned

Table 96, continued Status of P&A on Brent Delta Wells at 1st February 2017.

No	Side-track	OGA Number	Well Type	Status
BD30	S1	211/29-D70	Gas Lift Producer	Abandoned
BD31	S1	211/29-36Z	Producer	Abandoned
BD32	/		Conductor Only	Abandoned
BD33	/		Conductor Only	Abandoned
BD34	/	211/29-D16	Producer	Abandoned
BD35	/	211/29-D42	Gas Lift Producer	Abandoned
BD36	S2	211/29-D43Z	Gas Lift Producer	Abandoned
BD37	S6	211/29-D65Z	Gas Lift Producer	Abandoned
BD38	S2	211/29-D63	Gas Lift Producer	Abandoned
BD39	S2	211/29-D64	Gas Lift Producer	Abandoned
BD40	S1	211/29-D54	Gas Lift Producer	Abandoned
BD41	S4	211/29-D61Z	Gas Lift Producer	Abandoned
BD42	S4	211/29-D68Y	Gas Lift Producer	Abandoned
BD43	S2	211/29-D67Z	Gas Lift Producer	Abandoned
BD44	S1	211/29-D41	Gas Lift Producer	Abandoned
BD45	S2	211/29-D25Z	Producer	Abandoned
BD46	S7	211/29-D73Z	Gas Lift Producer	Abandoned
BD47	/		Conductor Only	Abandoned
BD48	/		Conductor Only	Abandoned

Table 97 Status of P&A on Brent South Wells at 1st February 2017.

No	Side-track	OGA Number	Well Type	Status
BS1	S3	3/4A-BS1	Producer	Abandoned
BS2	S1	3/4A-BS2	Producer	Abandoned
BS3	/	3/4A-BS3	Water Injector	Abandoned

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