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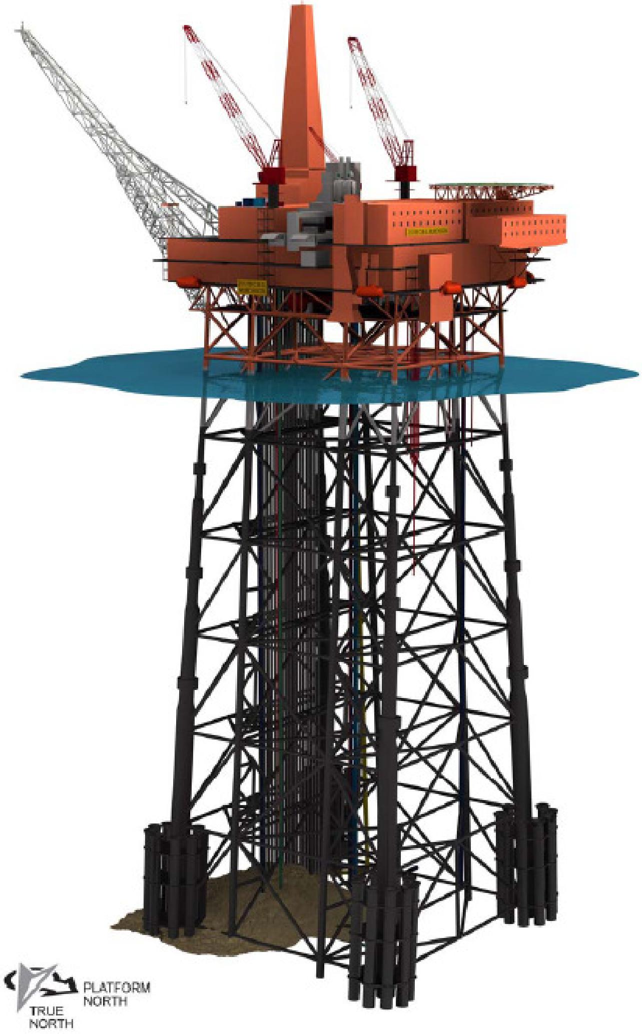


# MURCHISON DECOMMISSIONING

# COMPARATIVE ASSESSMENT REPORT

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**MURDECOM-CNR-PM-REP-00225**

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# Preface

This Comparative Assessment Report is part of a suite of documents that support the Murchison Field Decommissioning Programme. It is issued in support of the Consultation on the Draft Decommissioning Programme.


The Comparative Assessment Report is one of four key documents that support the Decommissioning Programme[1], all of which are available online at www.cnri-northsea-decom.com or on request in CD or hard copy form.

Other supporting documents, listed in section 7 of the Comparative Assessment Report are available for inspection, during normal office hours, at CNRI's Aberdeen offices as part of the statutory consultation. Please contact Carol Barbone on 01224 303102 or carol.barbone@cnrinternational.com for further information.

[1] The other three documents are the Environmental Statement, Independent Review Consultant's Final Verification Report and CNRI's report on Stakeholder Engagement

The Murchison Decommissioning Comparative Assessment Report is arranged in seven sections

| Section | Description |
|---|---|
| 1 | Executive Summary describing the Murchison Field and the rationale behind the selection of the Field's recommended decommissioning options |
| 2 | The Murchison Field Layout, the main facility components, how they were built and installed and their present condition.<br><br>Included is a summary of the environmental setting for Murchison and local marine activities that may impact the assessment of the decommissioning options available |
| 3 | Consideration of the alternate use options following cessation of production from the field and why such options were rejected and not taken further into the comparative assessment process.<br><br>The section also describes the decommissioning technology available and its suitability for Murchison which leads to identifying the decommissioning options available for Murchison's jacket, drill cuttings and pipelines. |
| 4 | Description of the comparative assessment process used on Murchison and details of the methodology used to score and rank the options |
| 5 | The proceedings and conclusions from the formal comparative assessment workshop are reported in this section |
| 6 | Description of the role of the Independent Review Consultant in the comparative assessment verification process is reported |
| 7 | Details of all the supporting studies, surveys and technical assessments used to inform the comparative assessment process and workshop |

# Abbreviations

## A

| | |
|---|---|
| AHP | Analytical Hierarchical Process |
| ALARP | As Low as Reasonably Practicable |

## B

| | |
|---|---|
| BAT | Best Available Techniques |
| BEP | Best Environmental Practice |
| BOP | Blow out preventer (wells) |
| BP | BP plc |
| BTA | Buoyancy Tank Assemblies |

## C

| | |
|---|---|
| CA | Comparative Assessment |
| CCS | Carbon Capture & Storage |
| CFP | Common Fisheries Policy |
| CNR | Canadian Natural Resources |
| $CO_2$ | Carbon Dioxide |
| CoP | Cessation of Production |
| CRI | Cuttings re-injection (well) |
| CSV | Construction Support Vessel |

## D

| | |
|---|---|
| DECC | Department of Energy & Climate Change |
| DPN | Disused Pipeline Notification |
| DWC | Diamond Wire Cutter |

## E

| | |
|---|---|
| EOR | Enhanced Oil Recovery |
| ENVID | Environmental Impact Identification |

## F

| | |
|---|---|
| FLTC | Fishermen’s Legacy Trust Company |

## G

| | |
|---|---|
| GVI | General Visual Inspection |

## Abbreviations (continued)

### H

| | |
|---|---|
| HAZID | Hazard Identification (workshop) |
| HLV | Heavy Lift Vessel |
| HP | High Pressure |
| HSE | Health and Safety Executive |
| HUC | Hook Up and Commissioning |
| HVAC | Heating, Venting and Air Conditioning |
| HVDC | High Voltage Direct Current |

### I

| | |
|---|---|
| ICES | International Council for the Exploration of the Sea |
| ILT | Internal Lifting Tool |
| IRC | Independent Review Consultant |
| IRPA | Individual Risk per Annum |
| ISS | Integrated Subsea Services Ltd |

### J

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|---|---|
| JNCC | Joint Nature Conservation Committee |

### K

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|---|---|
| km | kilometre |
| KV | Kilo Volt |

### L

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|---|---|
| LP | Low Pressure |
| LTOBM | Low Toxic Oil Bases Mud |

### M

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|---|---|
| m | meters |
| MBES | Multi Beam Echo Sounder |
| MMO | Marine Management Organisation |
| MOL | Main Oil Line |
| MSF | Module Support Frame |
| MUR | Murchison |
| MW | Mega Watt |
| MWh | Mega Watt hour |
| MWS | Marine Warranty Surveyor |

### N

| | |
|---|---|
| NLGP | Northern Leg Gas Pipeline |
| NORM | Naturally Occurring Radioactive Material |

## Abbreviations (continued)

### O

| | |
|---|---|
| OBM | Oil Based Mud |
| OSPAR | Oslo Paris convention |

### P

| | |
|---|---|
| P&A | Plug and Abandon (well) |
| pa | Per annum |
| PGB | Production Guide base ( part subsea well completion) |
| PLL | Potential for Loss of Life (safety metric) |
| POB | Personnel on Board |
| PON | Petroleum Offshore Notification |
| PWA | Pipeline Works Authorisation |

### Q

| | |
|---|---|
| QRA | Quantitive Risk Analysis |

### R

| | |
|---|---|
| ROC | Renewable Obligation Certificate |
| ROV | Remotely Operated Vehicle |

### S

| | |
|---|---|
| SBM | Synthetic Based Mud |
| SCV | Small Crane Vessel |
| SEPA | Scottish Environment Protection Agency |
| SFF | Scottish Fishermen’s Federation |
| SHE | Safety Health and Environment |
| SLV | Single Lift Vessel |
| SSCV | Semi-submersible Crane vessel |

### T

| | |
|---|---|
| te | tonne |

### U

| | |
|---|---|
| UKCS | United Kingdom Continental Shelf |
| UPS | Uninterrupted Power Supply |

### W

| | |
|---|---|
| WBM | Water Based Mud |
| WONS | Well Operations Notice System |
| WT | Wall Thickness |
| WTG | Wind Turbine Generator |

# 1. Executive Summary

This document supports a joint draft decommissioning programme for the Murchison Platform and Murchison Pipelines submitted by the Murchison Platform and Pipeline Section 29 Notice Holders to the Department of Energy and Climate Change (DECC).

The Murchison Field lies within UK Block 211/19 and extends into the Norwegian Block 33/9 in the Northern North Sea. The field is approximately 150km northeast of the Shetlands Islands in 156m of water.

The Murchison platform comprises 24,500te topsides supported by an eight leg tubular steel structure (known as the jacket) weighing 27,584 tonnes in total. Oil is exported to the Dunlin platform and then onto the Cormorant A platform and finally to the Sullom Voe terminal on Shetland. Fuel gas is imported from a tie-in into the NLGP network.

Murchison was discovered in 1975 and received Annex B approval in 1978 for a single drilling, production and accommodation facility. The platform was installed and production started in 1980, initially from three subsea wells tied back to the main platform. A Cessation of Production application was submitted to DECC in 2011 and approved in 2012. Actual Cessation of production is expected in or around the first quarter (Q1) of 2014.

A number of studies have been undertaken to assess the viability of alternate uses for the Murchison platform facility. No commercially or technically viable reuse or alternative uses were identified and consequently detailed assessment of decommissioning options has been undertaken, in line with the requirements of the Petroleum Act 1998 and in accordance with the OSPAR decision 98/3.

A comparative assessment (CA) of the jacket, drill cuttings and pipeline decommissioning options was conducted following CNRI's CA procedure which is based on the OSPAR 98/3 framework for jackets and the DECC Decommissioning Guidelines for decommissioning offshore oil and gas installations and pipelines.

### Decommissioning Programme

The Murchison Field decommissioning programme describes the process by which:

1. Production on the Murchison Platform will cease during Q1 2014 approximately three months after the commencement of Well P&A activities.

2. All platform and subsea wells will be plugged and abandoned in accordance with Oil & Gas UK Guidelines.

3. The platform process systems will be progressively shut down, drained and cleaned before being made ready for removal.

4. The topside modules will be removed and returned to shore for reuse, recycling or disposal

5. The process by which the decommissioning options available for the Murchison jacket, drill cuttings pile and pipelines were assessed and the rationale behind the recommended options are described fully in this Comparative Assessment report.

6. On completion of the decommissioning programme a seabed survey will be undertaken to identify oilfield related debris within the platform 500m zone and a 200m wide corridor along each pipeline. All items of oilfield debris will be categorised and in consultation with DECC a management and recovery plan will be agreed. Following completion of the recovery plan, verification of seabed clearance by an independent organisation will be carried out.

The following decommissioning recommendations for the jacket, drill cuttings pile and pipelines are based on legal requirements, the results from specialist studies and surveys, verification by an Independent Review Consultant, stakeholder participation and a detail comparative assessment workshop.

### Recommended Options

1. The jacket will be removed down to the top of footings at 44m above the seabed and returned to shore for reuse, recycling or disposal. The jacket footings will be left in place.

2. The drill cuttings pile located within the jacket footings will be left *in situ* to degrade naturally with time.

3. The short early production pipeline bundles and associated subsea equipment will be removed and returned to shore for recycling or disposal.

4. The main oil export line (PL115) will be left *in situ* with remedial rock placement over exposed sections. The main pipeline tie in spools, at either end, will be removed and returned to shore for recycling or disposal

### Legal Requirements

The decommissioning of disused offshore installations is governed under UK law by the Petroleum Act 1998 as amended by the Energy Act 2008. The Petroleum Act enables the Secretary of State to make regulations as required and advise on complying with the regulations are published as the DECC Guidance Notes. The Petroleum Act also incorporates the UK Government's international obligations relating to the decommissioning of offshore installations that arise from The Oslo Paris Convention for the Protection of the Marine Environment of the North East Atlantic – the 'OSPAR' conventions.

OSPAR Decision 98/3 entered into force in 1999. OSPAR Decision 98/3 requires that the topsides of all installations and jackets weighing less than 10,000 tonnes are removed and returned to shore for reuse, recycling or disposal.

Decision 98/3 recognises that there may be difficulty in removing the footings of the large steel jackets weighing more than 10,000 tonnes that were installed before 1999. As a result there is a provision for derogation from the presumption of total removal for such jackets. The Murchison jacket has a maximum gross weight of 27,584 tonnes and was installed in 1979 and as such is a potential derogation candidate. Nevertheless, there is a presumption that the jacket will be removed entirely and derogation granted only if a detailed comparative assessment of options and consultation with stakeholders demonstrates that there is a better alternate disposal option.

There are no international guidelines covering the decommissioning of disused pipelines. The DECC Guidance Notes have therefore been followed. In particular, following the DECC guidance, the small diameter early production pipeline bundles will be removed completely and returned to shore for recycling or disposal. The main oil export pipeline which is intermittently stabilised by rock placement was, however, subject to comparative assessment of the options for decommissioning.

## Studies and Surveys

68 studies and condition surveys were undertaken for the Murchison Platform and Pipeline Decommissioning Programmes. The studies and surveys were designed to inform the following comparative assessment criteria, conducted by external contractors, consultants and other specialists.

1. Safety risk for all personnel involved in, or affected by, the various decommissioning options both offshore and onshore, including the residual risks to fishermen and marine personnel who will take part in post decommissioning surveys and debris clearance.

2. Environmental impact of all activities at the offshore location and onshore reception site.

3. Technical feasibility of implementing the decommissioning operation and recovery from any unplanned excursion[2] with the level of new technology utilised in each operation.

4. Societal impact on other users of the sea and businesses or communities with the potential to be impacted by the decommissioning activity

5. Economic impacts of the decommissioning works programme.

The studies were broadly categorised into:

1. Surveys of the Murchison platform and pipelines to verify condition and integrity

2. Desk studies of historic documents to determine the original construction methods and outcomes

3. Studies to identify alternatives to decommissioning or other uses for the platform either in the current location or other locations.

4. Removal studies using different methods covering existing and developing technologies to evaluate the full removal of the Murchison platform and all associated material

5. Studies to identify, and incorporate, lessons learnt from other decommissioning projects, and developments in the supply chain capability

6. Impact assessments of the different options being developed covering safety, environmental, societal and economic.

[2] An unplanned excursion is any deviation from a planned operation caused by equipment failure or changes in conditions.

The studies were supplemented by in-house technical expertise, technical authorities with specific Murchison operating experience and meetings with contractors and suppliers to establish the supply chain experience, capabilities and equipment availability.

The results of the option studies and surveys were reviewed, and the relative merits of each option were assessed numerically in seven specialist assessment workshops attended by the CNRI project team specialists, CNRI Technical Authorities, specialist consultants and contractor study teams. The seven specialist workshops separately addressed:

- Safety assessment of jacket and pipeline options
- Environmental assessment of jacket and pipeline options
- Technical assessment of jacket removal options
- Technical assessment of pipeline options
- Drill cuttings pile assessment
- Societal assessment of jacket and pipeline options
- Economic assessment of jacket and pipeline options

Each session was chaired by an independent chairman and secretary. The summary findings from the specialist assessment workshops were reported to the main comparative assessment workshop attended by the full CNRI and Wintershall project teams and Technical Authorities. A list of the output from the seven specialist workshops is given in section 7.8 of this report.

## Verification

DECC's Decommissioning Guidelines define the requirements for independent verification of the comparative assessment process. The purpose of such verification is to confirm that data used are sound and appropriate, the assessment reliable, the comparative assessment process transparent and the chosen decommissioning option supported by credible and verifiable data.

A review was conducted by the Independent Review Consultant (IRC) during 2011/2012 and their verification report is being published alongside this document.

## Stakeholders

An open stakeholder workshop was held in March 2012 at which CNRI as the Murchison Field Section 29 Notice Holders presented the decommissioning options available for Murchison. This was followed by several one to one sessions on specific interest subjects. The results from both the open workshop and the one to one sessions were then reported to the comparative assessment workshops held over the period May 2012 to July 2012.

A follow up open stakeholder workshop was held in November 2012 at which the recommended options were tabled for comment. All comments raised were addressed and have been incorporated into this edition of the Comparative Assessment Report.

Transcripts from both open stakeholder workshops are recorded in section 7.8 of this report and have been published on the website www.cnri-northsea-decom.com

A report on Stakeholder Engagement is also published alongside this document.

## Comparative Assessment Workshops

A comparative assessment (CA) of the jacket, drill cuttings pile and export pipeline removal options was conducted following CNRI's CA procedure (based on the OSPAR 98/3 framework). The CA used quantitative and qualitative data to draw a balanced assessment across the main criteria of safety, technical feasibility, environmental impacts, societal impacts and project cost.

## Jacket Comparative Assessment

The jacket is an eight leg, all welded steel tubular jacket. The legs are stiffened by horizontal and diagonal bracing that provides the overall structural strength. Each of the four corner legs has eight 82inch diameter piles securing it to the seabed. The cluster of piles at each corner leg is referred to as a bottle assembly with each weighing 3,000 tonnes. Each pile is driven into the seabed to a depth of between 40 and 50m.

The section of the jacket from the seabed to the top of the bottle assemblies together with piles is referred to collectively as the footings. The top of the footings is approximately 44m above the seabed and the footings weigh approximately 12,700 tonnes.

The comparative assessment process examined a number of methods for removing the Murchison jacket completely compared with removing the jacket down to top of the footings. Both the full removal and partial removal options require an intensive period of offshore activity involving a large number of specialist vessels, equipment and personnel. The activity is technically challenging as the Murchison jacket will be the largest jacket to be decommissioned in the North Sea to date. CNRI studies included reviews of new and emerging technology to assess whether the new single lift vessel concepts could remove the Murchison jacket as a single lift. The reviews concluded that the Murchison jacket weight was outside the capacity of the new vessel concepts and as a consequence the Murchison jacket will have to be removed in sections.

The number of subsea cuts will depend on the removal method employed. Subsea cutting techniques are prone to operational difficulties resulting from the reliability of cutting equipment used in deep water and the size of equipment required to cut the large structural members (from 4m to 6m in diameter). The difficulties include: handling of the cutting equipment; ensuring that cut sections are securely rigged; positive confirmation of cut around large diameter tubulars; and rigging and handling of the equipment in restricted areas of the jacket. The cut sections of the jacket have to be lifted, back loaded and sea fastened onto cargo barges or crane vessels in open sea operations which are weather sensitive and need to be carefully managed.

Progressive cutting of the jacket members renders the remaining jacket less rigid and potentially unstable. Removal of the jacket's four bottle leg assemblies involve complex operations requiring some support to the bottle legs when they are free standing after the planned horizontal bracing and all the piles are cut. The cutting of the piles requires removal of the debris and soil plug from inside the piles down to -5m below seabed. The drill cuttings pile[3] would have to be disturbed or removed from around the base of the legs to allow safe access to the footings for cutting and confirmation of cutting completion.

[3] During drilling of the initial platform wells, the resulting produced drill cuttings were deposited onto the seabed where they formed what is described as a drill cuttings pile. This is discussed in more detail in s 2.6.2 of this report

The comparative assessment identified the following key issues:

1. Whilst the operational Individual Risk Per Annum (IRPA) for both options is less than the Health and Safety Executive (HSE) tolerable region of 1 in 1000, the full jacket removal would increase the Potential Loss of Life (PLL) by 100% compared to the partial removal option. This increase in risk is unjustifiable as it goes against the principle of reducing risks to as low as reasonably practical.

2. Partial removal creates a long term and persistent risk to fishermen from the potential snagging of their fishing gear on the remaining footings. The PLL for fishermen, directly attributable to the Murchison footings is $1.5 \times 10^{-5}$ per annum or 1 in 65,000 years.

3. The footings are expected to remain for up to 1000 years. If the snagging risk profile and thus the PLL is held constant over the 1000 year life of the footings and then added to the operational PLL to partially remove the jacket then, on comparison, the full jacket removal would have a total PLL 23% higher than the combined partial removal option.

4. While both options cause some environmental disturbance, this is localised and of short duration. There was found to be no significant difference in the energy and emissions in the full compared to partial removal options when the implications of replacing the material left on the seabed are factored in.

5. Full jacket removal is technically more challenging than partial jacket removal. The equipment and techniques required to remove and recover the footings of large steel jackets do not have a demonstrable track record. There is therefore a higher probability of project failure for full jacket removal compared to partial jacket removal particularly when considering innovative removal methods.

6. Partial removal of the Murchison jacket creates a physical obstruction for fishing activity, Murchison is not a major fishing ground in comparison with other areas of the North Sea. The fishing effort in the Murchison area contained within the ICES rectangle 51F1 (approximately 900 $nm^2$) averaged 158 to 230 vessels per annum over the period 2008 to 2010. The obstruction caused by the Murchison footings with a footprint of less than $0.01km^2$ is extremely small in comparison with the size of 51F1.

7. The cost of full jacket removal is approximately 75% higher than for the partial removal option.

In summary, there is a significant increase in operational safety risk, technical complexity and cost associated with the full jacket removal compared to partial jacket removal. For the partial removal case there will be an increase in snagging risk to fishermen which will be mitigated by supporting the programmes set up by the UK Fisheries Offshore Oil and Gas Legacy Trust Fund Limited (FLTC).

The differences between full and partial removal of the Murchison jacket are material and significant. The Murchison Platform Section 29 Notice Holders therefore recommend that the Murchison jacket is partially removed down to the top of footings.

## Drill Cuttings Pile Comparative Assessment

The Murchison cuttings pile was assessed against the OSPAR Management Regime for Offshore Cuttings Piles Recommendation 2006/5. The results shown in Table 1 are significantly below the OSPAR Regime

Stage 1 thresholds, for undisturbed cuttings, and therefore the Murchison drill cutting pile could be left *in situ* to degrade naturally.

| Metric | OSPAR Threshold | Murchison Value |
|---|---|---|
| Rate of oil loss (Tonnes/year) | 10 | 1.2 |
| Persistence over the area of contaminated seabed ($km^2$ years) | 500 | 25.0 |

**Table 1 OSPAR 2006/5 Thresholds & Murchison Values**

The Murchison drill cuttings pile lies within the footprint of the Murchison jacket structure and the options to fully remove the jacket will impact the cuttings pile. The Murchison Field section 29 Notice Holders therefore decided to undertake a Stage 2 assessment to fully characterise the pile and to review the short and long term disturbance impacts in a formal comparative assessment considering the best available techniques (BAT) and best environmental practice (BEP).

The comparative assessment process considered five management options: the first to leave the cuttings pile *in situ*; the second to distribute the cuttings pile over a wider area sufficient to expose the jacket lower bracing members; and a further three options for recovering the cuttings pile from the seabed to the surface with different treatment options at surface. In the recovery options concerns were raised over the availability, within the project timeframe, of proven or even development of, technology for recovery to surface.

On the basis of the difference in consideration of technical feasibility, safety and environmental criteria the management strategy is to leave the cuttings pile *in situ* to degrade and allow the seabed to recover naturally.

## Pipeline PL115 Comparative Assessment

Crude oil processed on the Murchison platform is transported 19.2km through pipeline PL115, south-west to Dunlin Alpha for onward transport to Sullom Voe via Cormorant and the Brent pipeline system.

PL115 consists of a 16 inch diameter steel pipeline with concrete weight coating. The pipeline was laid in 1980. The original Pipeline Works Authorisation specified that the pipeline would lie directly on the seabed as trenching was not required because of the protective concrete weight coating provided on the pipeline.

Between 1983 and 1987, some 63,000 tonnes of rock placement was used as scour protection at 13 intermittent locations along 10.6km of the length of PL115. A general visual survey completed in 2011 found the rock profiles were stable and conformed to the as-built drawing of 1985.

The comparative assessment process examined six options for decommissioning PL115:

1. **Leave the pipeline *in situ*** – this is the minimum work scope leaving the pipeline in its existing configuration. Over time the exposed sections of the pipeline would corrode and break up which would require periodic debris clearance operations to minimise future snagging risk to fishermen.

2. **Leave the pipeline *in situ* with removal of tie-in spools at Murchison and Dunlin.** This is the same as option 1 with the addition of removing the end tie-in spool sections.

3. **Remove the exposed sections of pipeline by cut and lift including the tie-in spool at Murchison and Dunlin.** This option would use proven technology but requires 746 subsea cuts to remove the 17 exposed pipeline lengths in 12m sections. Each section will be cut using one of a number of tools including hydraulic shears, diamond wire cutting (DWC) or abrasive water jet cutting (AWJC). To make the cut using the DWC or AWJC tools, either the pipeline would be lifted off the seabed using a deployed lifting frame with hydraulic operated clamps, or a trench would be excavated to allow tool access. Cutting excavation trenches in the very stiff Murchison boulder clays is problematic. The hydraulic shears do not require the pipeline to be lifted or trenched however the resulting cut is jagged with exposed reinforcing bars creating concern for future snagging and increasing the need for long term monitoring. Approximately 3,000 tonnes of new rock placement would be required to cover all of the pipeline's 34 cut ends in order to provide protection against snagging of fishing nets.

4. **Trench and bury the exposed section of pipeline.** Trenching in the very stiff boulder clays along the PL115 route is problematic, exacerbated by the fact that some of the exposed lengths of pipeline are very short (the shortest is 50m) which would make deployment of the ploughs and burial of the ends challenging. It is estimated that up to 12,000 tonnes of rock will be required to cover the pipeline transition lengths into the trenches.

5. **Remedial rock placement over exposed sections of pipeline.** The rock placement would use graded crushed rock that matches the existing rock material as closely as possible. The graded rock would be placed over the exposed pipeline sections in a carefully controlled operation. Some 53,000 tonnes of material would be required to cover the exposed pipeline sections to match the existing rock profile.

6. **Total removal by cut and lift.** For the total removal option, the existing 63,000 tonnes of crushed rock cover would have to be displaced to permit access to the pipeline cutting locations. There are a number of live pipelines running up and over PL115 such that sections of PL115 will remain *in situ* until the future decommissioning of the live pipelines. To remove the total pipeline in 12m long sections will require 1600 subsea cuts.

The comparative assessment identified the following key issues:

1. Whilst the Individual Risk Per Annum (IRPA) for all options are less than the Health and Safety Executive (HSE) tolerable region of 1 in 1000, the leave i*n situ* option has a lower risk compared to the option of remedial rock placement. The cut and lift of exposed section of pipeline has a PLL of $7.19 \times 10^{-3}$ which is more than five times that for remedial rock placement PLL of $1.33 \times 10^{-3}$. This is a very significant difference.

2. The different decommissioning options have different impacts on the long term snagging risk to fishing. The sections of the pipeline that are currently covered with crushed rock have a rock profile that is designed to be safely over trawl able by fishing gear. The PLL per annum due to snagging risk was highest for the leave *in situ* option because of the long term degradation of the exposed sections of line. There was no significant difference in the PLL per annum (to the fishing industry) for the remedial rock placement option compared with the removal of exposed sections of pipeline by cut and lift option ($3.5 \times 10^{-4}$ compared to $3.3 \times 10^{-4}$). The cut and lift option carries five times the PLL risk (for the removal operations team described in 1. above) compared to that for remedial rock placement, with no discernable benefits to fishermen between the two options.

3. The leave *in situ* options would have very little impact on the environment. At the other extreme total removal and the trench and bury of either the whole pipeline or just the exposed sections of pipeline would have a much greater environmental impact from seabed disturbance. Remedial rock placement over the exposed sections would physically disturb less than approximately $0.045km^2$ of the seabed sediment and will modify the habitat by introducing additional hard substrate into a predominately soft sediment habitat. The presence of naturally occurring hard substrate at Murchison, together with the existing rock cover material, suggests that organisms associated with hard substrates will already be present and not be introduced as a result of additional remedial rock placement. There are no Annex 1 habitats within the length of the PL115 pipeline.

4. Remedial rock placement and the leave *in situ* options are both technically feasible using industry standard operations. The removal of exposed sections by cut and lift also uses standard operations but becomes more complex when considering the large number of cuts required compared to the more conventional single length pipeline repairs. The trench and bury option scored low technically because of concerns over the ability to trench efficiently in the stiff boulder clays at Murchison and the short exposed lengths.

5. Societal criteria were not found to be a driver in the ranking of the PL115 decommissioning options. There would be no long term negative impacts on commercial fisheries from removal operations, or from the remedial rock placement option because it would be designed to be over trawlable. The leave *in situ* options would create small restrictions on fishing access as fishermen took action to avoid the snagging risk of the degraded pipeline.

6. There was a significant difference in the total cost of the options assessed, with the cut and lift options being the most expensive at ten times the cost for the leave *in situ* option.

In summary, there is a significant increase in safety risk, technical complexity and cost associated with the pipeline cut and lift options compared to the remedial rock placement option. There was found to be no discernable difference in residual fishing risk for these two options but there is a significant increase in risk for the leave *in situ* options.

The differences between the PL115 decommissioning options are material and significant. The Murchison Platform Section 29 Notice Holders therefore recommend the remedial rock placement over the exposed sections of PL115 as the decommissioning option.

# 2 Project Description

This section describes the Murchison platform and related infrastructure that constitutes the Murchison Decommissioning Project and the environment in which the decommissioning operations will be undertaken.

## 2.1 Murchison Field Development

The Murchison Field is located in UKCS Block 211/19 and the Norwegian Block 33/9 in the Northern North Sea. The field lies approximately 150 km northeast of Shetland in 156m of water and is 2km away from the UK Norway median line. Murchison is among the largest and most northerly of fields in the UK sector of the North Sea.

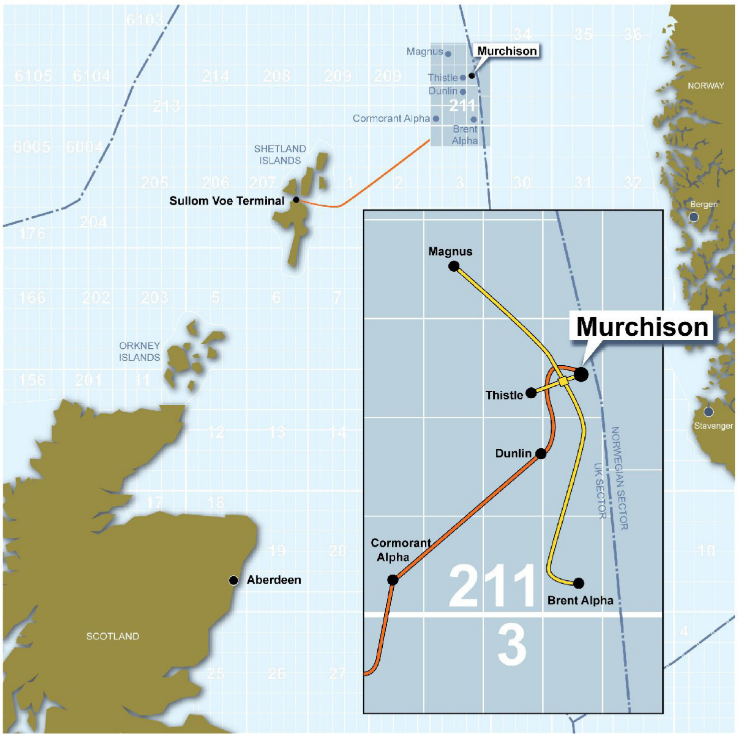


Figure 1: Murchison Field Map

Conoco discovered the Murchison Field in 1975 and submitted a development plan known as an Annex B to the Department of Energy in 1976. The development plan was to develop a single drilling and production platform with wells deviating from it. The platform was to be a steel jacket piled into the seabed which would support a topside modular structure comprising process, utility, drilling and accommodation facilities.

The Murchison development plan envisaged production starting in 1980 and continuing through until 1997. In January 1995 Conoco relinquished operatorship to Oryx. In January 1999, Kerr–McGee acquired the assets of Oryx and assumed the operatorship of Murchison. CNRI subsequently acquired Kerr-McGee's interest in Murchison in 2002 and assumed operatorship.

The current Murchison co-venturers are as follows:

- CNRI International (U.K.) Limited (Operator) 77.8 %
- Wintershall Norge AS 22.2%

Substantial efforts have been made by the Murchison co-venturers over recent years to extend field life beyond the originally anticipated date of 1999 to increase production and ultimate economic recovery from the reservoirs by measures including: well interventions; optimisation of production and injection; plant upgrades and modifications; additional drilling; and, assessing options for third party use, as well as cost management initiatives to improve overall economics. The result is a current forecast for Cessation of Production to be around the first quarter of 2014.

## 2.2 Murchison Field Layout

The Murchison Field Layout is shown in Figure 2.

The Murchison platform is linked to the Dunlin Alpha platform operated by Fairfield by a 19km, 16” oil export line. The Murchison oil is then co-mingled with that from Dunlin and Thistle and transported by a 24” line to Cormorant Alpha and then by a 36” main oil line to the terminal at Sullom Voe.

Murchison is also linked into the Northern Leg Gas Pipeline (NLGP) operated by BP via a 2.6km 6” gas import/export line and an NLGP control umbilical.

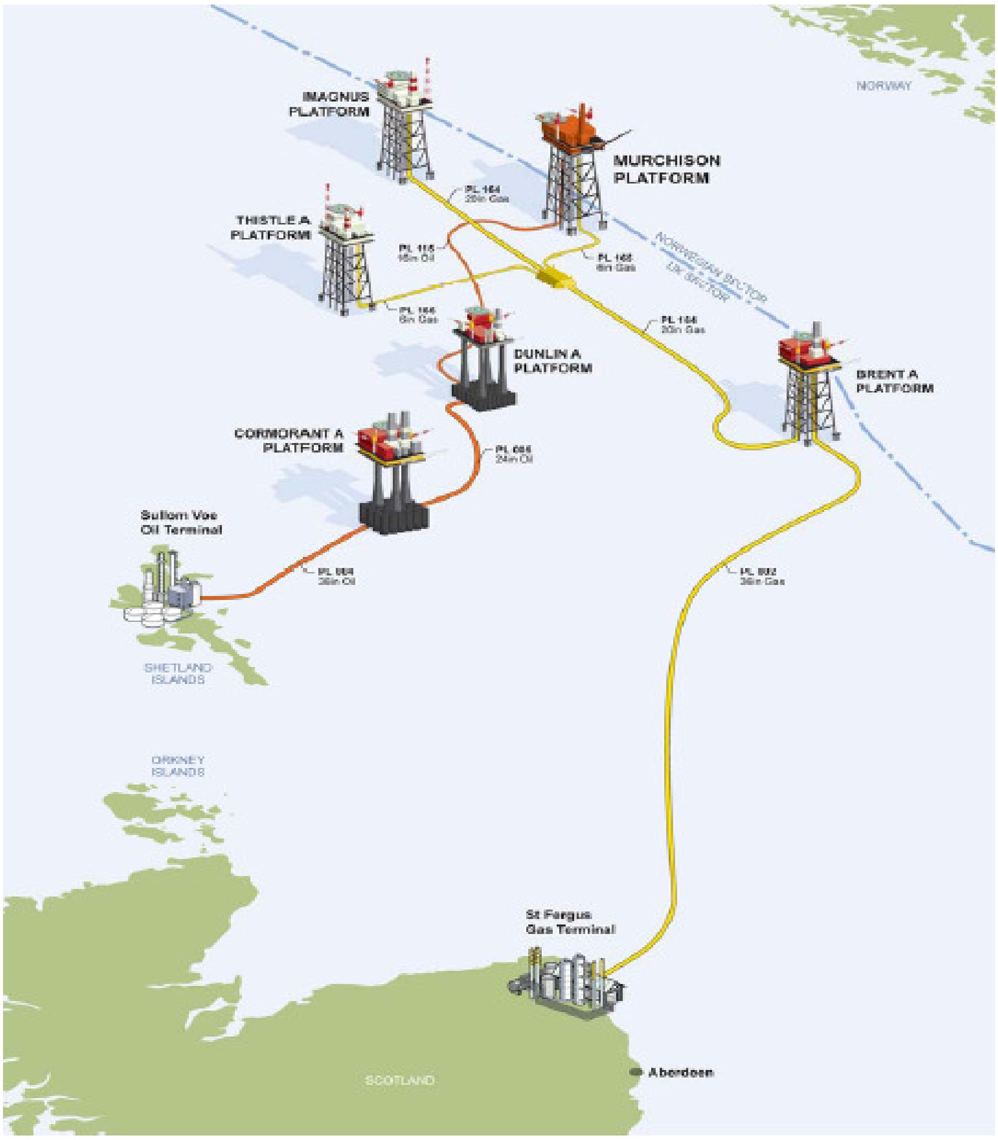


Figure 2: Murchison Field Layout

## 2.3 Description of the Murchison Platform

The Murchison platform, as shown in Figure 3 below, comprises a jacket structure supporting a modular topsides.

### 2.3.1 The Murchison Jacket

The jacket is an eight leg structure of welded steel construction and measuring 75m by 75m at the base and 52.8m by 62.5m at the top. The overall height of the jacket is 188m.

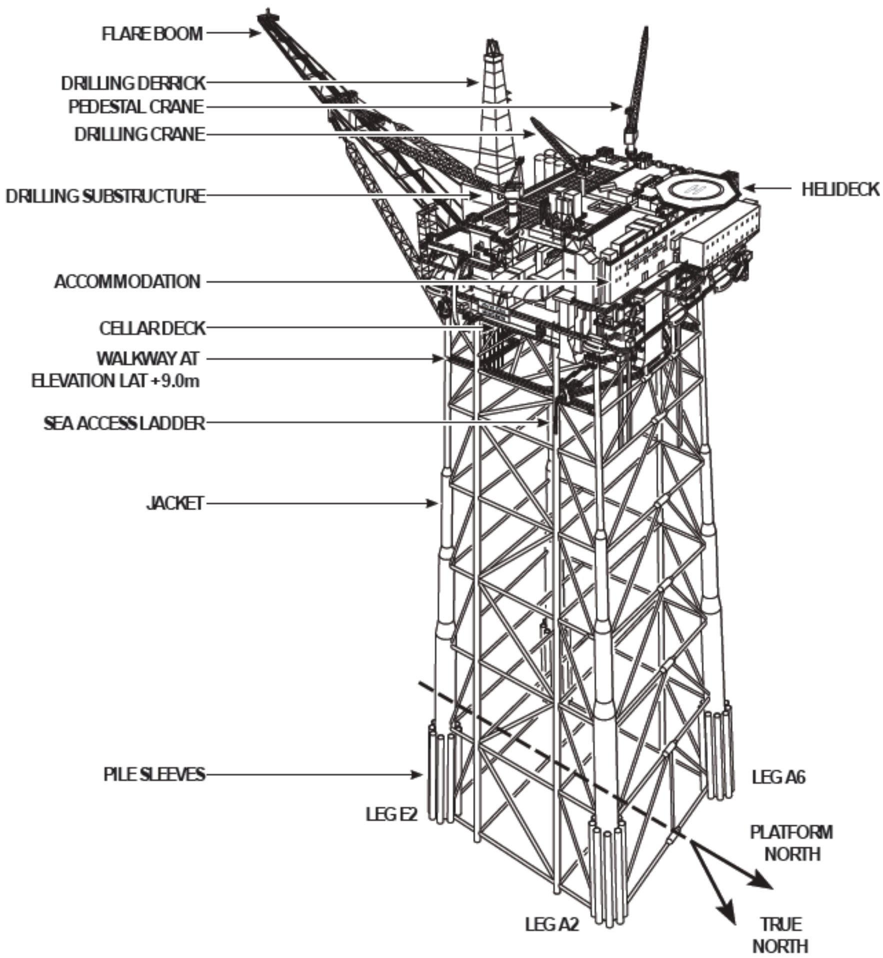


Figure 3: Murchison Platform Components

The jacket foundations consist of 32 piles in groups of 8 around the four corner legs of the jacket. Each pile is 82” in diameter and 80m in length and was designed to be driven some 50m into the seabed. Actual penetrations varied from 40m to 50m.

The piles were driven through pile sleeves which in turn were connected to the jacket by shear plates.

Steel mud mats were attached to the base of the jacket and pile sleeves to provide temporary foundations after the jacket had been installed and before the piles had been driven to the required depth.

The piles, sleeves, mud mats and jacket leg sections are collectively referred to as the `bottle assemblies'. The 'footings' are those parts of jacket which are below the highest point of the piles which connect the jacket to the sea bed. On Murchison, the highest point of the piles is -112m below lowest astronomical tide (LAT) or 44m above the seabed.

The main jacket legs have a diameter of 2m at the water line increasing to 6m diameter at the seabed. Two of the corner legs have been used for diesel storage. The weight of the jacket during installation was 25,000te. The weight of the jacket to be removed, assuming foundation piles are cut 3m below the mud line is as defined in Table 2.[4] [5]

| Jacket Group | Gross dry weight (tonnes) |
|---|---|
| Jacket structure + piles + grout + marine growth + flooded members | **27,584** |
| Jacket structure + piles + grout + marine growth + drained flooded members | **26,131** |
| Jacket + marine growth from surface down to -112m (top of footings) | **14,853** |
| Estimated weight of marine growth | **2,394** |

Table 2 Jacket Summary Weights

### 2.3.2 The Murchison Platform Topsides

The Murchison platform topsides consist of 20 individual modules providing drilling, oil and gas processing plant, produced water processing, water injection facilities, support utilities including power generation and accommodation for 198 operational personnel. There are six additional small packages/lifts.

The topside modules are arranged on two levels along with a drilling derrick to service 33 well slots, flare boom and helideck. The dry weight[6] of the combined topside modules is 24,584te[7].

[4] Further details of weight data is given in document MURDECOM-CNR-PM-TTN-00118, Murchison Platform Weight Alignment Technical Note

[5] See also Murchison Jacket Weight Report MURDECOM-ATK-ST-REP-0253 rev A2 July 2012

[6] Dry weights refer to the basic weight of the models. The Lift weight of the modules will be the dry weight + weight of rigging and lifting temporary items and a further contingency for weight inaccuracies

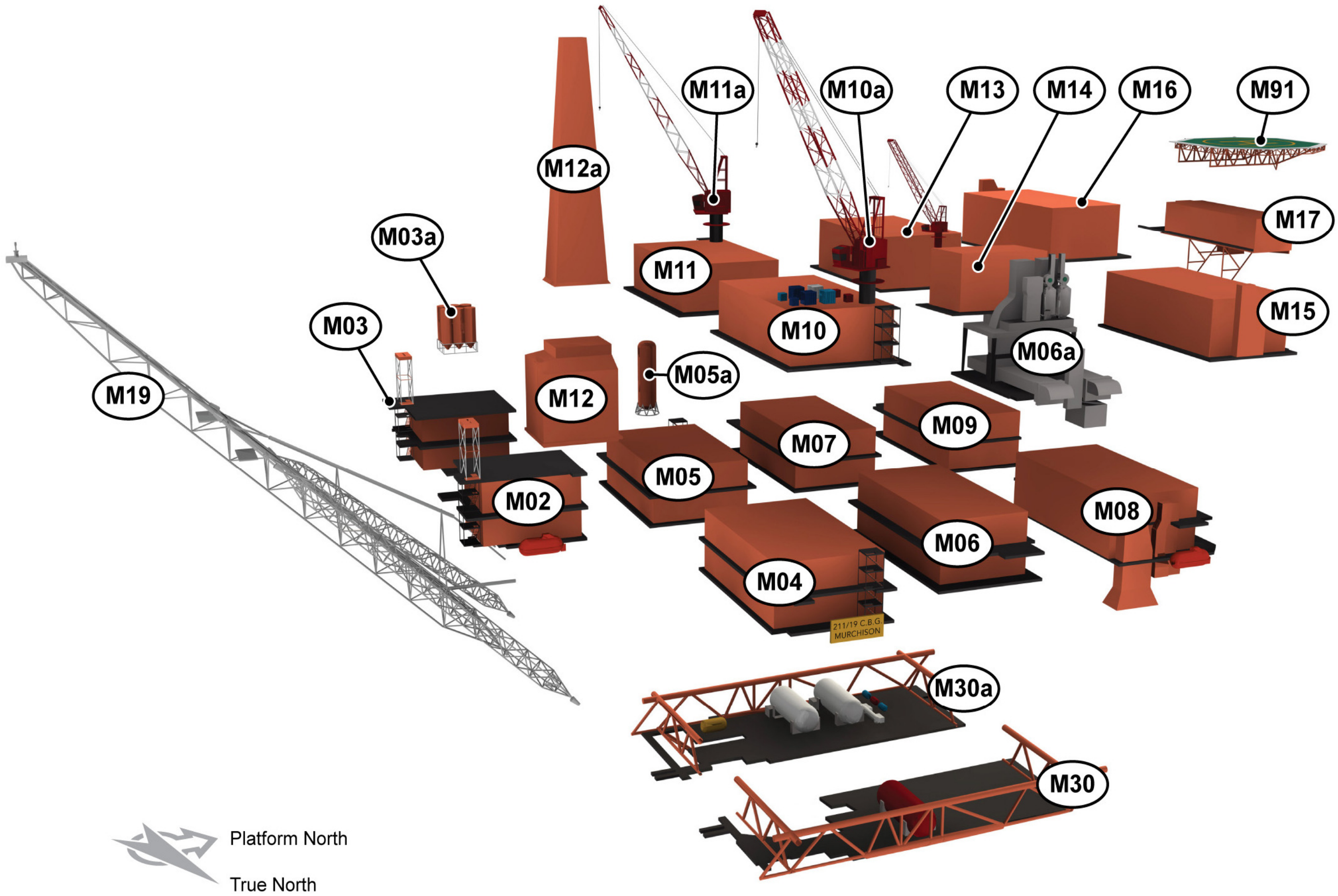


Figure 4: Murchison Topside Configuration

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[7] Further details of weight data is given in document MURDECOM-CNR-PM-TTN-00118, Murchison Platform Weight Alignment Technical Note

| Module | Module Description | Dry Weight [Mt] | Lift Weight [Mt] |
|---|---|---|---|
| **M2** | East Wellbay Module | 1687 | 1940 |
| **M3** | Flare Drums & Wellbay Module | 1772 | 2038 |
| **M4** | Separation Module | 1342 | 1543 |
| **M5** | Pipeline/Meters Module | 1327 | 1526 |
| **M6** | Compression Module | 1681 | 1933 |
| **M7** | Gas Sales Module | 1392 | 1601 |
| **M8** | Utilities Module | 1247 | 1434 |
| **M9** | Utilities Module | 1378 | 1585 |
| **M10** | Drilling Power | 986 | 1134 |
| **M11** | Drilling Mud Module | 978 | 1125 |
| **M12** | Derrick & Substructure Module | 709 | 815 |
| **M13** | Main Control & Workshop Module | 1035 | 1190 |
| **M14** | Main Power Generation Module | 482 | 554 |
| **M15** | Accommodation Module | 1213 | 1395 |
| **M16** | Accommodation Module | 1104 | 1270 |
| **M17** | Accommodation Module | 402 | 462 |
| **M19** | Flare Boom | 213 | 245 |
| **M91** | Helideck | 257 | 296 |
| **M30a** | MSF & Cellar Deck East | 2409 | 2770 |
| **M30b** | MSF & Cellar Deck West | 2345 | 2697 |

**Table 3 Murchison Topside Module - Removal Weights**[8]

Estimated removal weights for the 20 major lifts are shown in Table 3.

Dry weights refer to the basic weight of the models with empty tanks and vessels. The Lift weight of the modules is the dry weight plus the weight of rigging and lifting temporary items and a further contingency for weight inaccuracies.

[8] Topside Weight Review MURDECOM-ATK-ST-REP-00010

## 2.4 Fabrication and Installation of the Murchison Platform

This section of the report describes the process by which the Murchison Platform and associated pipelines were fabricated, installed and commissioned during 1978 - 1980, and their present condition.

### 2.4.1 Fabrication of the Murchison Jacket

The Murchison jacket was fabricated in the McDermott yard at Ardersier on the east coast of Scotland.

**Figure 5: Layout of Jacket in Yard**

The individual frames of the jacket were assembled horizontally at ground level. The inner two jacket frames were strengthened to provide the launch trusses that take the whole jacket load during loadout of the jacket over the quay edge onto the cargo barge and the launch of the jacket when at the offshore location.

**Figure 6: Roll up of Jacket Outer Frame**

As each frame was completed it was rolled up into the vertical using a spread of synchronised crawler cranes. The largest frame to be rolled up into the vertical weighed over 3,000 tonnes.

**Figure 7: Installation of the Bottles Legs**

The bottle leg assemblies comprising the main jacket lower leg, pile sleeves, mud mat and connecting shear plates were assembled in Japan and shipped to Ardersier. Each bottle assembly weighed approximately 3,000 tonnes. It was originally planned to lift the bottles into position using a special built crawler crane.

However, during the initial lift the crane collapsed under the load and a special built portal frame was constructed to lift and hold it in position while final welding was completed.

**Figure 8: The Bottle Leg Assembly**

The bottle leg assembly is shown here in its final position after fitting out. The pile sleeves are 2376mm diameter.

**Figure 9: Jacket Prepared for Loadout**

Figure 9 shows the Murchison jacket after fabrication completed being prepared for loadout onto a sea going cargo barge. Before loadout temporary buoyancy tubes were located in the jacket pile sleeves and the ballast control system installed and commissioned.

The barge was grounded on a purpose built foundation pad in order to transfer the jacket load during loadout.

**Figure 10: Loadout of the Murchison Jacket**

Figure 10 shows the Murchison jacket prior to loadout. The jacket was loaded out using purpose design launch trusses integral with the jacket framing. The launch trusses were fitted with timber runners.

**Figure 11: Jacket Being Towed to Site**

After loadout onto the cargo barge the jacket was towed to the Murchison Platform site.

**Figure 12: Jacket Launch**

On arrival at the Murchison location, the jacket was launched, upended using a system of ballast control lines to execute a controlled flooding of the jacket legs. Once confirmed in its correct position, the final ballasting was undertaken to found the jacket on the seabed.

The mud mats provided temporary foundation for the jacket before the main piles were driven. In its unpiled condition the jacket was capable of withstanding a wave of 10.5m without uplift in a corner leg.[9]

**Figure 13: Jacket Piling**

The temporary buoyancy tanks were removed from the pile sleeves before the piles were installed. Each of the 32 piles was 82 inch diameter and 80m long and driven, using a steam hammer and pile followers, to a design penetration of 50m beneath the seabed. The actual penetrations achieved varied from 40m to 50m.

With two piles driven per leg the jacket was capable of withstanding a wave of 29m which is the 100 year storm wave, without uplift of a corner leg.

After the piling was completed the piles were connected to the jacket by injecting grout between the pile and the pile sleeve. The grouting process was monitored using grout densitometers fitted to each pile sleeve.[10]

After the piling was completed, the upper pile guides were removed leaving only stub connectors.

The jacket installation was carried out by Heerema using the Semi-Submersible Crane Vessel (SSCV) 'Balder' in August 1979.

### 2.4.2 Fabrication of the Murchison Topside Modules

The topside modules described in section 2.3.2 of this report were fabricated in a variety of yards around Europe. On completion the modules were loaded out onto cargo barges, sea fastened and shipped to a marshalling area off Norway.

After the jacket was installed and piled, the modules sailed from Norway to Murchison where they were individually lifted using the semi-submersible crane barge 'Balder' and set atop of the jacket and module support frame.

[9] See the CJB - Earl & Wright report `On Bottom Stability Report' 1978

[10] The radiation emitted from the densitometer Caesium 137 source and received by a detector is attenuated by the material flowing in the pile/sleeve annulus. The degree of attenuation can be calibrated with grout density and hence strength.

**Figure 14: Installation of Topside Modules**

On arrival by barge to the Murchison platform, each module was rigged up, lifted clear of the barge and set onto the module support frame (MSF).

**Figure 15: First Topside Module Installed**

Figure 15 shows the first module to be set down onto the MSF.

**Figure 16: Second Level of Modules Being Installed**

**Figure 17: Hook Up and Commissioning of Modules**

After installing all of the modules, an accommodation vessel was moored alongside the Murchison platform to support the hook up and commissioning (HUC) teams in a 34-week programme.

Hook up and commissioning entails installing all the interconnecting access ways, pipe work, cables and utilities between modules and their final testing and commissioning before hand over to the platform operating teams.

### 2.4.3 Murchison Jacket Condition Survey

The latest jacket condition survey was completed in 2011[11]. The General Visual Inspection (GVI) reported the jacket structure to be in a good condition with no gross damage or significant distortions. Key conclusions for the comparative assessment process were noted as:

a) All 32 piles in four clusters of 8 per leg were inspected. The majority have internal access for cutting the piles below seabed level, after removing internal soil plugs, but 7 were found to have debris located in the pile which would have to be fished out before a cutting tool could be run inside the pile.

b) The height of each of the 32 piles protruding above the pile sleeve, in which they are located, was measured. The level of the highest pile (A2/7) was at an elevation of approximately 112m below sea level. This level sets the datum for the top of footings.

c) All 10 leg ballast control valves, used to control buoyancy during jacket upend, were generally found to be in good condition, although access was restricted due to the extent of the *Lophelia pertusa* marine growth.

d) The 72 grout densitometers fitted to the pile sleeves were found to be in good condition although access was restricted by extensive *Lophelia* marine growth.

e) Flooded member checks were completed, the inner jacket legs being flooded, whilst the corner legs were dry with the exception of the top compartments in legs A2 and E2 which were used for diesel storage.

f) The jacket launch truss timber runners were found to be in good condition with no visible damage.

g) A debris survey within the 500m safety zone identified 345 targets in excess of 1m in length by 1m in width and/or height. The targets were a mixture of 164 oilfield related debris and 181 naturally occurring boulders.

h) Periodic surveys have confirmed details of the extent and type of marine growth on the jacket structure and appurtenances.[12] [13]

### 2.4.4 Murchison Topside Condition Survey[14]

The 2010 topside condition survey found no major defects on the topsides structure and overall the structure appeared to be in an acceptable condition. It was apparent that some fabric maintenance was

[11] For detailed survey results see section 9 of the 2011 Pipeline Inspection and Environmental Survey Report – PLS-ISS-SU-REP-15430
[12] CNR Structural Integrity –Marine Growth NNS-ATK-ST-TEC-0140
[13] Evaluation of the Extent of Colonisation of *Lophelia pertusa* and Marine Growth on the Murchison platform – 2010 ref doc A.INS.001/Murchison
[14] For detail survey results see CNRI Assets Topside Structural Integrity Survey 2011 Report – MUR-ATK-ST-REP-0227

being performed but there remained areas of the structure, particularly the stair towers, showing coating breakdown and/or corrosion.

Further topside condition surveys will be undertaken during the course of the pre-engineering phase of the Murchison decommissioning project.

## 2.5 Murchison Pipeline Infrastructure

The Murchison Platform ties into a pipeline infrastructure as shown below in three principal configurations:

a) The pipeline bundles PL123, PL124 and PL125 which formed part of the early production facilities.

b) The Oil Export Pipeline (OEL) PL115 which exports produced oil to Dunlin and then onto Sullom Voe terminal via the Cormorant Platform.

c) The Murchison Platform imports gas from the BP-operated NLGP network via PL165 and associated control umbilical. These lines will be decommissioned at a later date as part of the NLGP system and are therefore not part of the Murchison Programme.

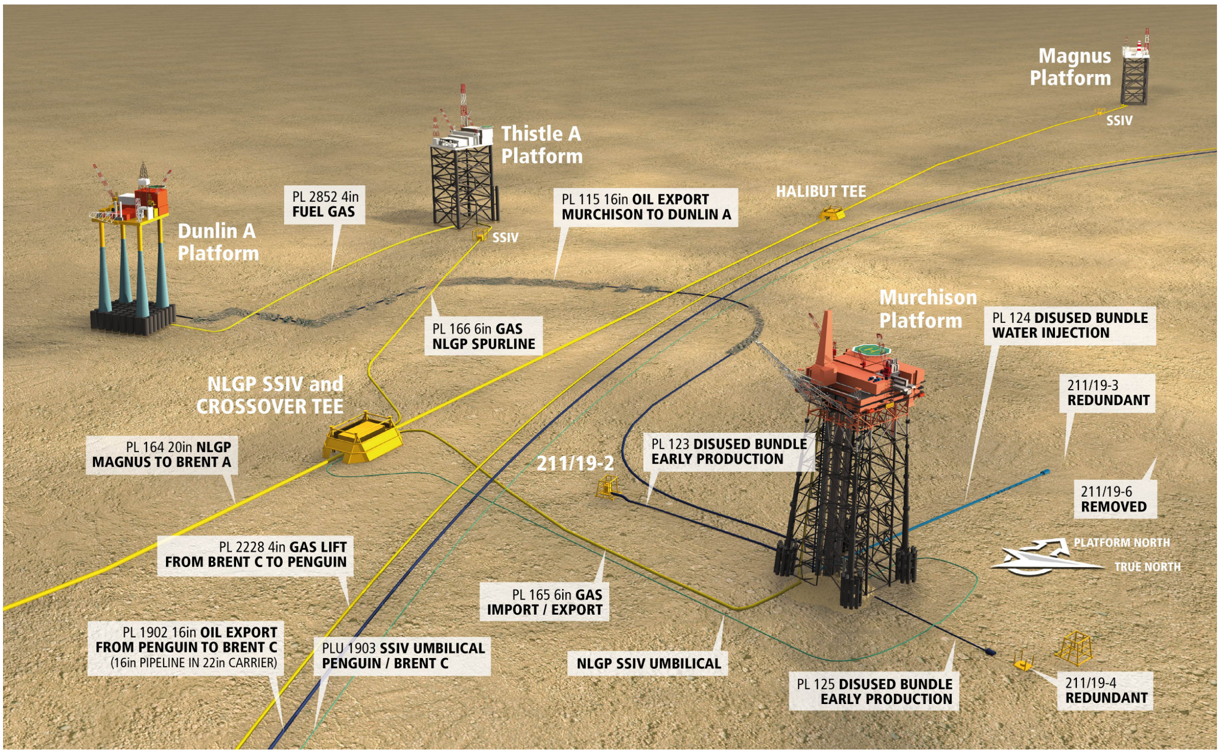



**Figure 18: Murchison Subsea Infrastructure**

The PL115 oil export line (OEL) runs under[15] a number of existing pipelines, including:

[15] For crossing details see NLGP Handover Documents – 'As Built drawings – Vol 1 1984 and for the Penguin lines see Shell Penguin Gas Lift Project doc ref PENGL/25/UK006524/402/)F-3/004

a) The 20 inch diameter PL164 from Magnus to Brent operated by BP

b) The 16 inch diameter PL1902 from Penguins to Brent operated by Shell

c) The 4 inch diameter PL2228 from Penguins to Brent operated by Shell

d) The 6 inch diameter PL 166 Spur to Thistle operated by BP and associated umbilical

e) The 4 inch diameter PL2852 gas line from Thistle to Dunlin operated by Fairfield

f) The Penguin/Brent C PLU1903 SSIV control umbilical

It is anticipated that at the time of decommissioning of the PL115 line, all of the pipelines noted above will continue in operation. As a consequence, any decommissioning work on PL115 will need the prior agreement of BP, Shell and Fairfield as operators of the crossing lines. As PL115 ties into the Dunlin Platform, any decommissioning work within the Dunlin 500m safety zone will require the agreement of Fairfield as the Dunlin operator. There are well established protocols for negotiating Proximity Agreements.

### 2.5.1 Murchison Pipeline Bundles[16]

The Murchison Pipeline Bundles[17] were conceived as part of an early production concept of tying in subsea appraisal wells to the platform to produce oil while the main drilling programme commenced using the platform facilities.

| Pipeline | Description | From | To | Diameter | Wall Thickness | Length |
|---|---|---|---|---|---|---|
| **PL 123** | Early production flow line, with 2 x 3.5" dia flowlines and 4 control umbilicals in a carrier pipe | Well 211/19-2 | MUR | 324mm | 6.35mm | 792.5m |
| **PL 124** | Early Water Injection flow line, with 2 x 3.5" dia flowlines and 4 control umbilicals in a carrier pipe | Well 211/19-3 | MUR | 324mm | 6.35mm | 2,012.0m |
| **PL 125** | Early Production flow line, with 2 x 3.5" dia flowlines and 4 control umbilicals in a carrier pipe | Well 211/19-4 | MUR | 324mm | 6.35mm | 1,237.5m |

Table 4 Pipeline Bundle Summary Details

Figure 19: Tow Out of Flowline Bundle

Each of the pipeline bundles was fabricated in a single length at a special onshore yard at Wick.

The completed bundles were pulled out from the yard and towed at a controlled depth by Smit - Lloyd in 1980. The depth of tow was controlled by using anchor chains at various positions along the pipe length.

[16] For Further details of the Murchison pipeline bundles see `Murchison Subsea Pipeline Assets – Decommissioning Report MURDECOM –ATK_PI-REP-00027

[17] For details of the Flowline riser bundles and control lines see drg number EM-307-9 rev 4

On arrival at the Murchison platform, the bundles were flooded down onto the seabed and tied into the platform by Subsea Offshore in 1980.

The early production wells were shut-in in 1982 and the pipeline bundles registered under the disused pipeline notification scheme.

The bundles PL124 and PL 125 were disconnected from their subsea wells in 1982 using divers and left open to the sea. PL123 remains connected to the well 211/19-2 and will require pressure and fluid monitoring ahead of any disconnection.

Recent surveys indicate all three Murchison bundles are exposed on the seabed with some spanning[18] and local damage[19] to the bundle carrier pipes.

### 2.5.2 Murchison Pipeline PL115

PL115 is the main oil export line (OEL) that runs 19.2 km from the Murchison platform to Dunlin.

Crude oil processed on the Murchison platform is transported 19.2km south-west to Dunlin Alpha (Fairfield Energy-operated) where the flow combines with that of Thistle (Enquest-operated) and Dunlin Alpha production before passing into a 24 inch pipeline to Cormorant Alpha (Taqa-operated). From Cormorant Alpha, the oil is transported through the Brent Pipeline System to the BP-operated Sullom Voe Terminal on the Shetland Islands via the 36 inch MOL (Main Oil Line).

PL115 consists of a 16 inch (406mm) diameter by 0.625 inch (15.9mm) wall thickness (WT) pipe made from 5LX Grade X60 steel. The pipeline is weight coated with 2.25 inches (57.2mm) of concrete which is reinforced with 8mm diameter circumferential steel bars and 5mm longitudinal steel bars (rebar).

The coated pipe was shipped out to the Brown and Root lay barge – 'Semac 1' – in 12m lengths. The individual lengths were joined and run out over the stinger in a lazy-S configuration to lie on the seabed.

**Figure 20: Laying the 16" OEL to Dunlin**

Figure 20 shows laying the oil export line from the Semac 1 vessel in 1980. The stinger is shown in white, partly submerged.

The Pipeline Works Authorisation (PWA) issued in 1980 specified that the pipeline would lie directly on the seabed; trenching was not required as the pipeline was properly protected with concrete.

Between 1983 and 1987 rock placement was used as scour protection at intermittent locations along the length of PL115[20], as shown in Table 5 The rock was placed using the Seaway vessel 'Seaway Sandpiper' or the ACZ vessel the 'Trollnes'.

[18] Spans are lengths of unsupported pipeline arising from seabed erosion by scouring from under the pipeline
[19] For more detail see the 2011 Pipeline Inspection Report PLS-ISS-SU-REP-15430

Figure 21 shows the transition between exposed section of pipeline and pipeline under rock cover. Full survey results of PL115 are available in the 2011 ISS Pipeline Survey Report PLS-ISS-SU-REP-15430.

The survey reported 73 areas of damage to the pipeline which included 15 areas of exposed rebar and 56 area showing areas of concrete spalling. Portions of PL115 have shown depleted anodes with consequential internal and external corrosion.

| start km | finish km | exposed length m | rock dumped length m | |
|---|---|---|---|---|
| 0 | 1.45 | 1450 | | **Murchison 500 m zone** |
| 1.45 | 1.6 | | 150 | |
| 1.6 | 1.78 | 180 | | |
| 1.78 | 1.81 | | 30 | |
| 1.81 | 3.77 | 1960 | | |
| 3.77 | 4.4 | 630 | | |
| 4.4 | 4.75 | | 350 | |
| 4.73 | 5.35 | 620 | | |
| 5.35 | 7 | | 1650 | |
| 7 | 7.075 | 75 | | |
| 7.1 | 7.2 | 100 | | |
| 7.2 | 7.73 | | 530 | |
| 7.73 | 8.2 | 470 | | |
| 8.2 | 8.95 | | 750 | |
| 8.95 | 9.5 | 550 | | |
| 9.5 | 11.65 | | 2150 | |
| 11.65 | 11.8 | 150 | | |
| 11.8 | 11.95 | 150 | | |
| 11.95 | 12.3 | | 350 | |
| 12.3 | 12.7 | 400 | | |
| 12.7 | 14.28 | | 1580 | |
| 14.28 | 14.45 | 170 | | |
| 14.45 | 14.68 | | 230 | |
| 14.68 | 14.73 | 50 | | |
| 14.73 | 14.8 | | 70 | |
| 14.8 | 15.35 | 550 | | |
| 15.35 | 15.55 | | 200 | |
| 15.55 | 15.75 | 200 | | |
| 15.75 | 18.26 | | 2510 | |
| 18.26 | 19.2 | 940 | | **Dunlin 500 m zone** |
| | | **8645** | **10550** | |
| | | **19195** | | |

Table 5 Extent of Rock Placement during 1985 to 1987

[20] For detail information on the scour protection see Technical Note: Murchison Comparative Assessment, Post Workshop Actions - PL115 MURDECOM-CNR-PM-GTN-00226

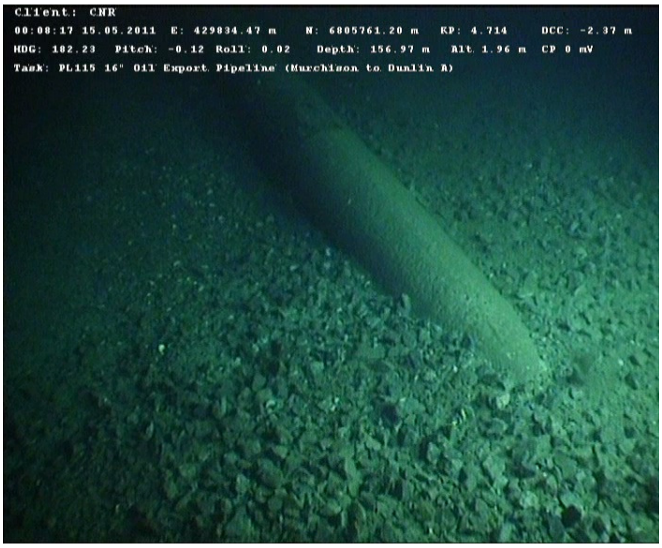



**Figure 21: Transition exposed pipeline and rock profile**

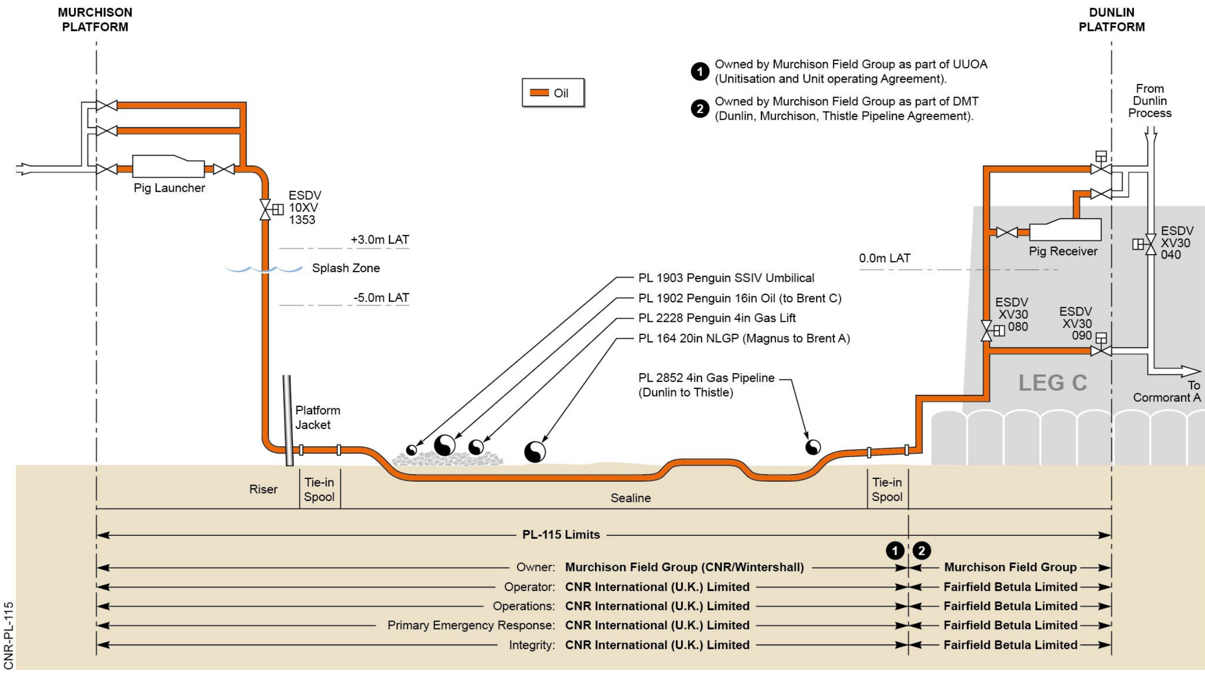



**Figure 22: PL115 Schematic**

### 2.5.3 Murchison Gas Import Riser to the NLGP - PL165

The Murchison gas import riser, shown in Figure 23 below, is connected to the main PL165 at the subsea riser tie-in spool. The riser will have to be disconnected from the main pipeline when Murchison is decommissioned in preparation for the decommissioning of the main PL165 which will be undertaken by the NLGP owners at some future time.

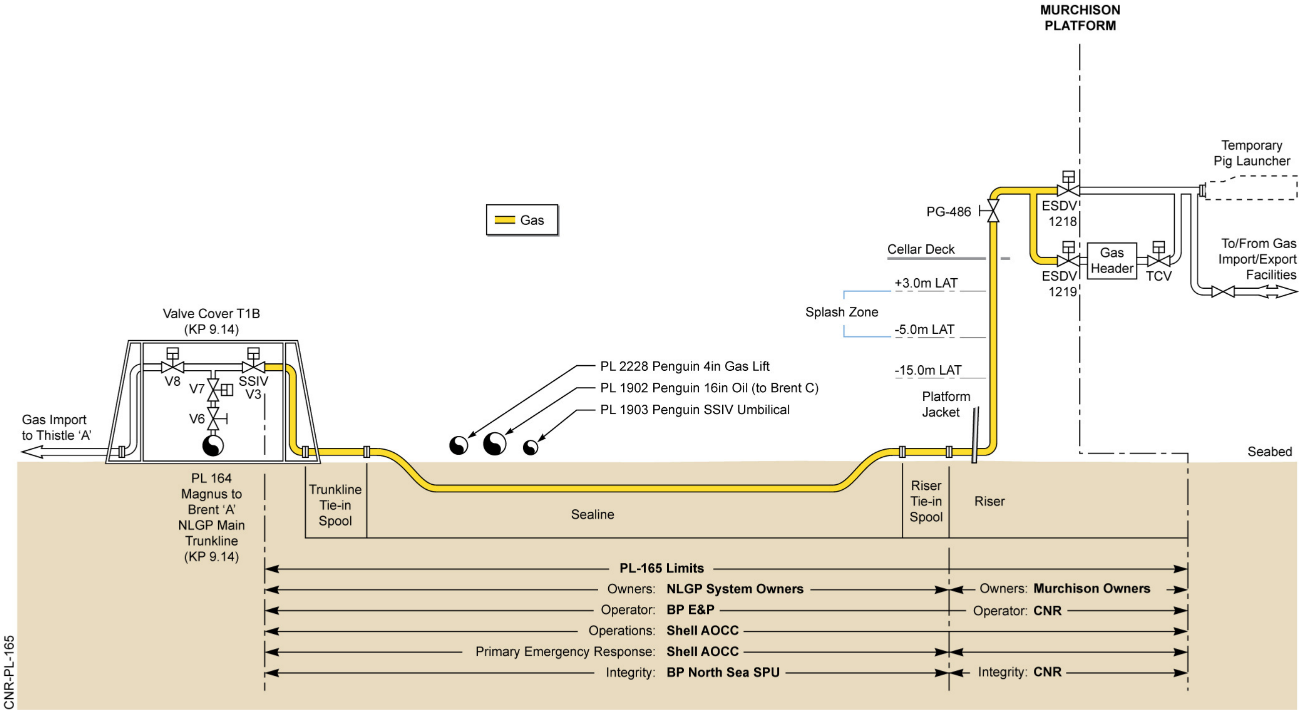



**Figure 23: PL165 Schematic**

## 2.6 Murchison Operations and Drilling

Murchison was developed using:

a) Re-entry into three subsea Exploration and Appraisal (E&A) wells and completion as two producers and one water injection as part of an early production plan

b) Drilling of production and water injection wells from the Murchison platform.

### 2.6.1 Murchison Subsea Wells

Between 1974 and 1977 six exploration wells were drilled in the Murchison Block 211/19. Three of the six wells were suspended plugged and abandoned almost immediately. The remaining three wells, identified as 211/19-2; 211/19-3 and 211/19-4, were re-entered and completed as satellite subsea completions by the semi-submersible drill rig 'Dundee Kingsnorth'. The three subsea completions were tied back to the Murchison platform in 1980 using the three bundles described in section 2.5.1.

The three subsea completions constituted an early production initiative and produced oil through Murchison whilst the platform drilled wells were completed[21].

[21] CNRI Technical Note on Murchison Subsea Satellite Well Status MURDECOM-CNR-PM-WTN-00001

The survey of the subsea wells conducted in 2011[22] confirmed the following:

**211/19-2** – Subsea, the pipeline end remains connected to wellhead. Wellhead protection cover remains *in situ*. At the platform, the riser / flowline subsea connector remains *in situ*. On the platform topsides, the Cameron tree has been removed leaving the outer casing and 4-off control lines terminating at +24m level and the Cameron hub with flowlines terminating at +33m level.

**211/19-3** – Subsea, the end connections of each flowline at wellhead have been removed, with the bundle-end lying on seabed. Two bends/associated buckles have been observed at the wellhead end of the bundle. At the platform, the riser / flowline subsea connector remains *in situ*. On the platform topsides, the termination to the Cameron tree remains *in situ*, with pipe work removed downstream. The subsea tree and structure have been removed and a 1m section of casing remains above the seabed.

**211/19-4** – Subsea, the flowline has been cut just short of the wellhead, with the bundle-end lying undisturbed on seabed. It should be noted that whilst the wellhead tree has been removed, the production guide base (PGB) remains in place and the protection structure is located to the east of the structure. At the platform, the riser/flowline subsea connector remains *in situ*. On the platform topsides, the termination to the Cameron tree remains *in situ*, with pipe work removed downstream of the tree.

A schematic of the wellhead protection structure is shown in Figure 24.

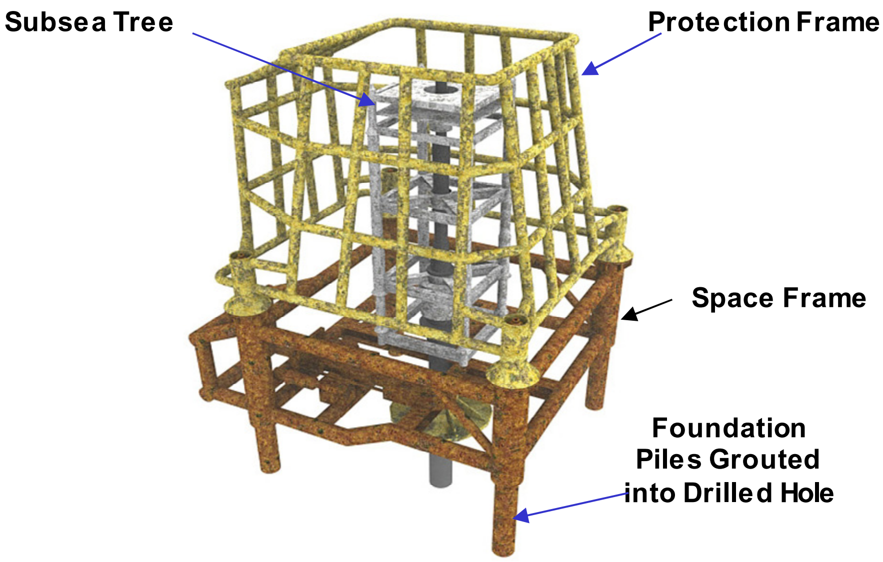



Figure 24: 211/19-2 Subsea Installation

The subsea installation 211/19-4 is similar, but the protection frame is set on the seabed beside the space frame and subsea tree.

[22] Survey results are reported in ISS Pipeline and Subsea Survey – Phase 2 Report PLS-ISS-SU-REP-15430

### 2.6.2 Murchison Platform Wells and Characteristics of the Drill Cuttings Pile

The total number of development wells drilled to date on Murchison is through the existing 33 slots, which includes the satellite wells drilled to Playfair (M71) and the Delta area (M75 series – Norwegian sector).

Currently, 18 slots are active producers and 13 slots are injectors, with two slots (M16 and M50) which are abandoned due to integrity issues with the wellbores. The layout and designation of wells is shown in Figure 25.

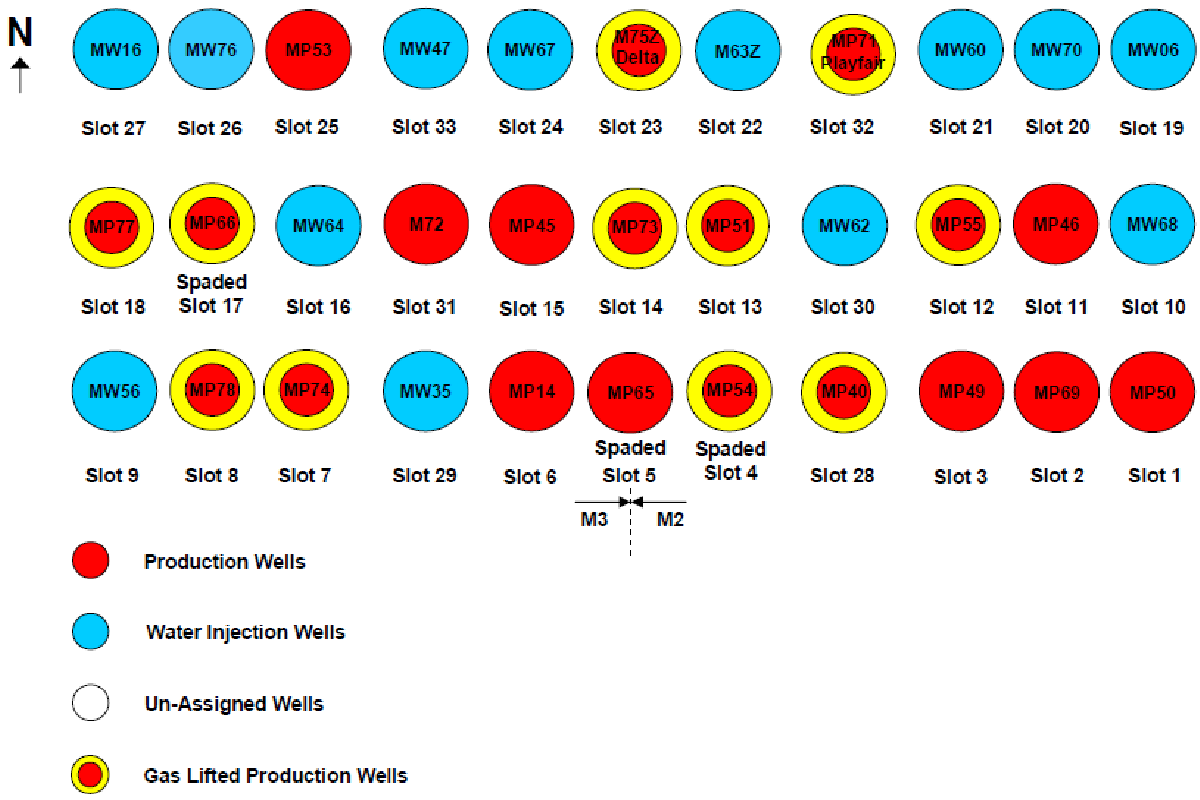



Figure 25: Murchison Well Slot Diagram

The history of individual wells and their current status is described in MURDECOM-CNR-PM-REP-00015.

Figure 26: Drilling Production Wells on Murchison

During the life of the platform, approximately 22,545m$^3$ of cuttings have been discharged to the sea. Of the 33 well slots drilled in this field, oil based mud (OBM) was used and discharged with drill cuttings at half of the wells[23] .

[23] Technical Review of Data from CNR's North Sea Assets with regards to OSPAR recommendations 2006/5 – ERT report 1881-2008

A proportion of these discharged drill cuttings and drilling mud now exist as a pile on the seabed immediately below the jacket, covering the bottom bracing.

The top hole sections (36 and 26 inch) of all 33 platform wells were batch drilled in 1980 using water based mud, with mud and drill cuttings discharged directly to the seabed and forming the base of the pile.

The lower hole sections (17.5 - 8.5 inches) were primarily drilled with oil based mud (OBM) the composition of which has changed over time due to advances in the mud technologies used and changes in the regulatory regime.

The discharge of OBM was normal practice in the first two decades of offshore drilling in the North Sea, normally using diesel as the oil, but concerns over its environmental impacts led to restrictions on its discharge. The use of diesel in discharges of drilling mud was prohibited from 1984 onwards and in its place alternative oils were used that had similar properties but with a lower content of aromatic compounds. These muds were known as low-toxicity oil-based muds (LTOBM). They were used for around a decade, but still contained a significant aromatic content including polycyclic aromatic hydrocarbons (PAH) which are relatively toxic.

Up to 1996 the discharge of such muds was phased out and they were replaced with oils that were entirely synthetic in origin (synthetic based mud, SBM) with lower levels of aromatic hydrocarbons (virtually zero). Finally the discharge of SBMs was phased out and banned from 2001 onwards, with some exceptions that do not apply to Murchison. Since 2001 all OBM and OBM-contaminated cuttings have either been re-injected or returned to shore for disposal.

For the purposes of the Murchison comparative assessment process, the following assumptions have been made on the mud types used in modelling the drill cuttings pile:

| | Period assumed | No wells drilled incl side tracks |
|---|---|---|
| WBM top-hole sections | <1980 | 33 |
| Early WBM | 1980-1984 | 3 |
| Diesel OBM | 1980-1983 | 20 |
| LTOBM | 1984-1996 | 15 |
| SBM | 1996-2001 | 19 |
| OBM | retained 2001-present | 22 |

Table 6 Assumed History of Murchison Drilling Muds

During the pre-decommissioning environmental baseline survey in 2011 the Murchison drill cuttings pile was surveyed using MBES (Multi-Beam Echo Sounder) to map the topography of the pile, and six ROV-operated push cores were collected. Three cores were used for faunal analysis, and three were used to characterise the physical and chemical composition of the pile[24] .

The results of the MBES survey indicate that the pile is located under and to the southeast of the Murchison platform extending in a south-easterly direction following the main residual current. The pile

[24] 2011 Pipeline Inspection and Environmental Survey Report PLS-ISS-SU-REP-15430

is located against and around the eastern leg of the Murchison jacket and covers the lower horizontal and vertical braces of the jacket.

The footprint area and volume of the Murchison cuttings pile were calculated as 6,840m$^2$ and 22,545m$^3$ respectively, shown below.[25]

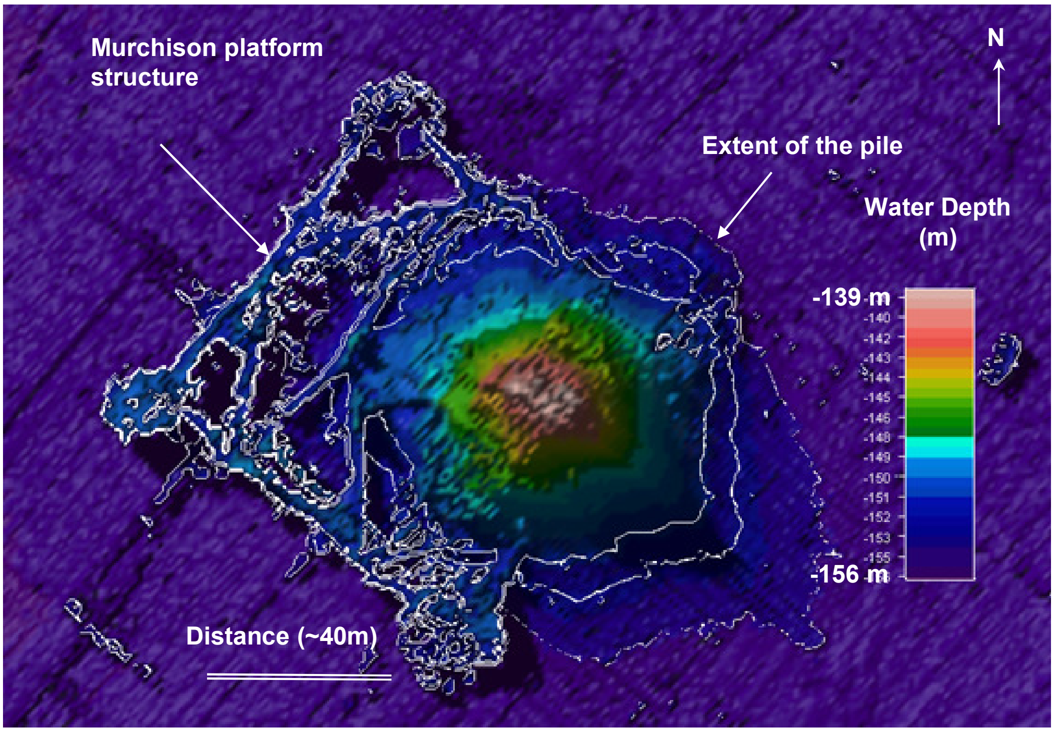



Figure 27: MBES Survey Data of the Murchison Drill Cuttings Pile

[25] For details of the drill cutting pile see the Environmental Assessment of Options for the Management of the Murchison Drill Cuttings Pile MURDECOM-BMT-EN-STU-00132

## 2.7 The Murchison Environmental Setting[26]

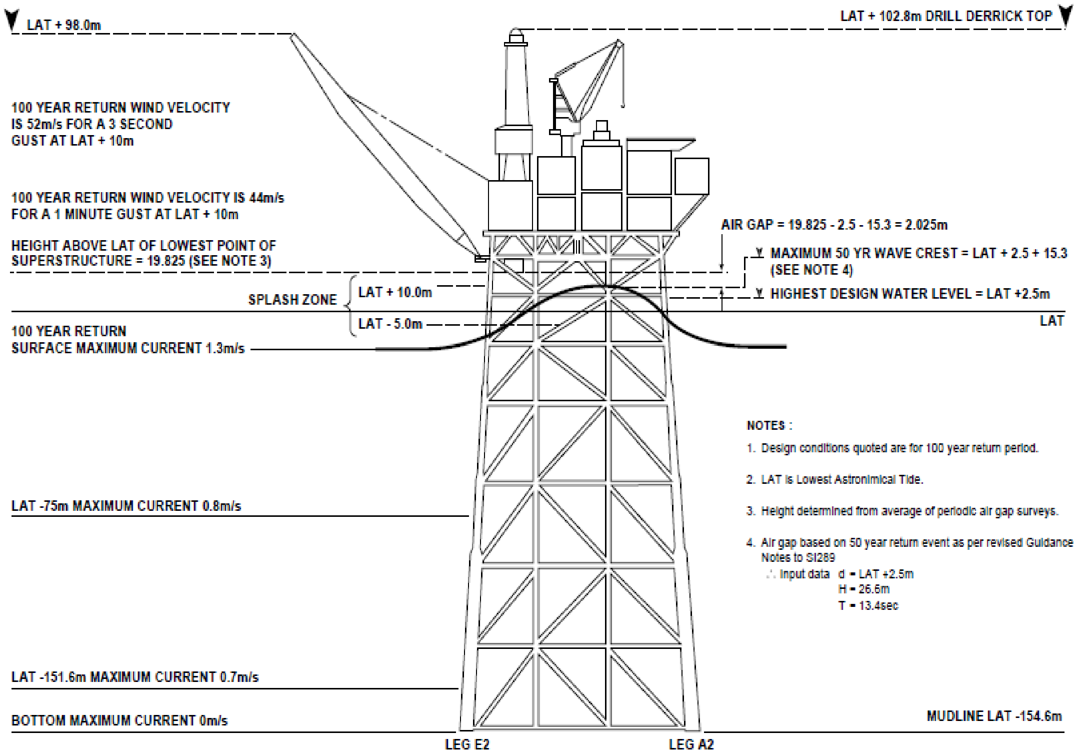



Figure 28: Murchison Environmental Setting

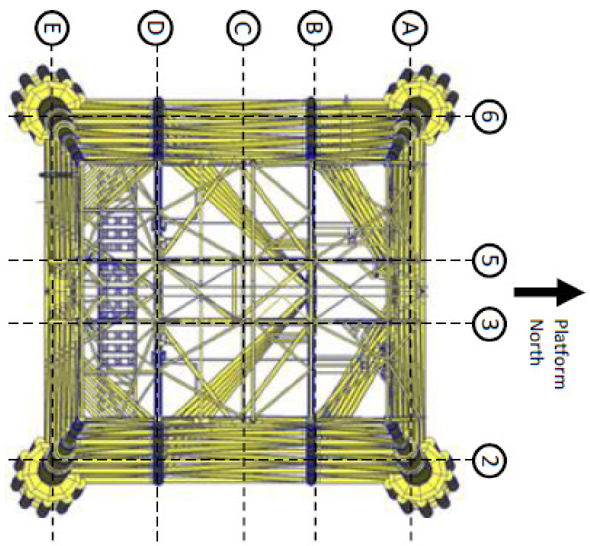



Figure 29: Jacket Key Plan

[26] For more detailed information see Environmental Statement for the Decommissioning of the Murchison Facilities – Environmental Description MURDECOM-BMT-EN-REP-00126

### 2.7.1 Bathymetry

Water depth at the Murchison field is approximately 156m. The seabed in the vicinity of Murchison is mainly flat with a northwards gentle slope from about 150m to 200m.

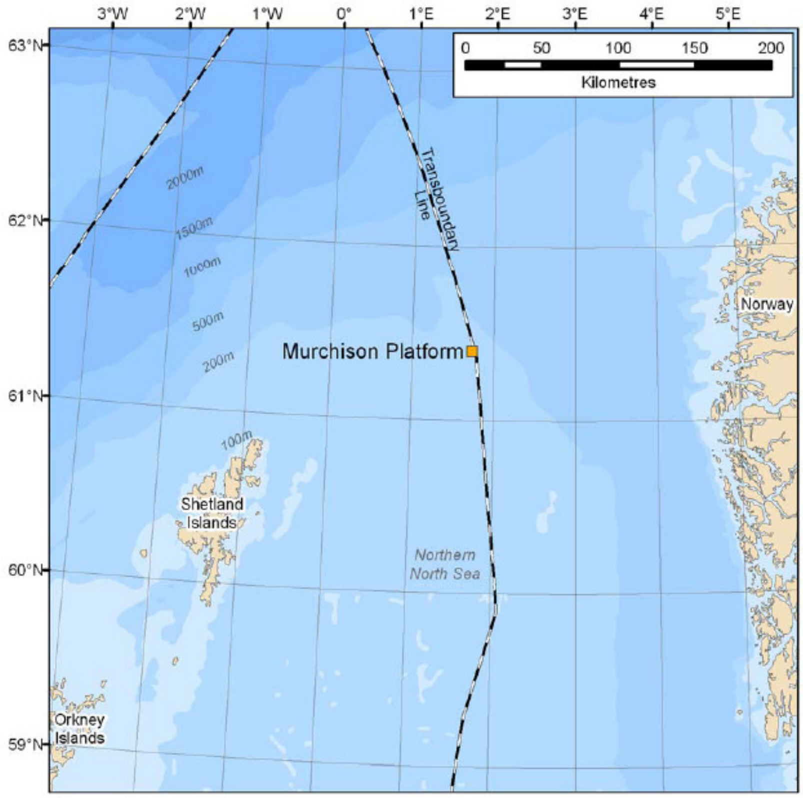



Figure 30: Bathymetry Map of the Murchison Area

### 2.7.2 Seabed Sediments

Table 7 gives average soils data across the Murchison Area used in the assessment of the jacket footings integrity for different removal options, and for the technical assessment of pipeline trenching options.

| Depth | Description | Wet Density t/m$^3$ | Shear Strength Kn/m$^2$ |
|---|---|---|---|
| 0-1m (varies) | Grey medium to fine sands with some coarse sand and gravel. Large number of surface boulders | 2.21 | |
| 1 - 2.7m | Stiff finally laminated grey sandy very silty clay (boulder clay) with occasional shell fragments | 2.06 | 126 |
| 2.7 - 3.8m | Very stiff laminated very dark grey sandy very silty clay | 2.08 | 75 -285 |
| 3.8 - 4.7m | Very stiff laminated very dark grey sandy very silty clay with occasional chalk fragments | 2.08 | 150 - 260 |

Table 7 Average Values across Boreholes[27]

[27] Report on Laboratory Testing – Murchison Field -1977 Fugro

### 2.7.3 Extreme Metocean Criteria[28]

Table 8 summarises the extreme Metocean conditions used in the technical and risk assessments of the Murchison jacket removal options.

| WINDS | 1-Year | 10-Year | 50-Year | 100-Year | 1,000-Year | 10K-Year |
|---|---|---|---|---|---|---|
| *Wind Speeds at 10m asl [m/s]* | | | | | | |
| **V ( 1-hr )** | **30.1** | **34.4** | **37.2** | **38.4** | **42.0** | **45.5** |
| V ( 10-min ) | 33.1 | 38.2 | 41.5 | 42.9 | 47.2 | 51.4 |
| V ( 1-min ) | 37.1 | 43.0 | 46.9 | 48.7 | 53.9 | 59.0 |
| Gust ( 3-sec ) | 42.1 | 49.3 | 54.1 | 56.2 | 62.6 | 69.0 |
| **WAVES** | **1-Year** | **10-Year** | **50-Year** | **100-Year** | **1,000-Year** | **10K-Year** |
| *Wave Heights [m]* | | | | | | |
| Hs | 10.9 | 13.2 | 14.8 | 15.5 | 17.8 | 20.1 |
| Hmax *(3 hr)* | 20.0 | 24.0 | 27.1 | 28.3 | 32.5 | 36.7 |
| Crest *(rel mean sample level)* | 12.1 | 14.6 | 16.4 | 17.2 | 19.8 | 22.3 |
| **CURRENTS** | | **1-Year** | **10-Year** | **50-Year** | **100-Year** | |
| *Total Current Profile [m/s]* | | | | | | |
| Surface | | 0.51 | 0.58 | 0.62 | 0.64 | |
| 75% of water depth | | 0.51 | 0.58 | 0.62 | 0.64 | |
| 50% of water depth | | 0.51 | 0.58 | 0.62 | 0.64 | |
| 20% of water depth | | 0.44 | 0.50 | 0.54 | 0.56 | |
| 5% of water depth | | 0.36 | 0.41 | 0.45 | 0.46 | |
| 0.01% (near seabed) | | 0.30 | 0.34 | 0.37 | 0.38 | |
| **WATER LEVELS** | **The following parameters do not vary with return period** | | | | | |
| *Tidal Height (LAT) [m]* | | | | | | |
| HAT | 2.00 | | | | | |
| MHWS | 1.67 | | | | | |
| MHWN | 1.30 | | | | | |
| MSL | 0.99 | | | | | |
| MLWN | 0.68 | | | | | |
| MLWS | 0.31 | | | | | |
| LAT | 0.00 | | | | | |
| | **1-Year** | **10-Year** | **50-Year** | **100-Year** | **1,000-Year** | **10K-Year** |
| *Positive Surge Levels (MSL) [m]* | 0.52 | 0.65 | 0.73 | 0.76 | 0.84 | 0.90 |
| *Still Water Level (LAT) [m]* | 2.30 | 2.40 | 2.45 | 2.47 | 2.51 | 2.53 |
| *Extreme Water Level (LAT) [m] (Crest + associated SWL)* | 13.8 | 16.3 | 18.1 | 18.9 | 21.4 | 24.0 |

Table 8 Extreme Metocean Data[29]

[28] For full Metocean data see report Metocean Criteria For Murchison-Design Criteria doc ref C319-R413-10
[29] Metocean Criteria For Murchison Vol 1- Design Criteria - 2010 doc ref PhysE Re C319-R-413-10

## 2.8 Marine Activity around Murchison[30]

### 2.8.1 Adjacent Oil and Gas Infrastructure

Oil and gas developments in the area adjacent to Murchison are relatively intense, as described in section 2.2 above. The interdependence within the local oil and gas infrastructure has been addressed particularly with regard to the export of oil product from Murchison to Dunlin; the import of fuel gas from the NLGP system and the numerous pipeline crossings which will impact the available options for decommissioning of PL115.

### 2.8.2 Shipping[31]

The Murchison Field is located in an area of moderate to low shipping activity. There are four shipping lanes in the vicinity of Block 211/19 with an average shipping density of 0.5 to 10 vessels per day. The shipping lanes are used primarily by shuttle tankers, supply and standby vessels serving the offshore industry.

### 2.8.3 Defence

There is no known military activity in the vicinity of the Murchison Field, nor any recorded munitions dumping grounds.

### 2.8.4 Telecommunications and Cables

There are no known submarine telecommunication and power cables within the vicinity of the Murchison Field.

### 2.8.5 Wrecks

There are no recorded wrecks in the vicinity of the Murchison Field.

### 2.8.6 Fishing

The relative UK fishing effort in the Murchison area (ICES rectangles 51F1 and 52F1) in 2010 was very low in comparison with other areas of the North Sea.

A detailed analysis of the fishing effort around Murchison is reported in the Commercial Fisheries – Socioeconomic Impact Study – document ref MURDECOM –SFF–EN–ST-00131.

The commercial fishing industry is subject to frequent changes in legislation and policy and, as a result, it is difficult to predict future levels, patterns and practices, over the timescale of the decommissioning project particularly where an assessment of long term residual impacts is being considered.

It is likely that there will also be changes to fisheries management policies on international, national and regional levels that will impact fishing activities in the area. Of particular importance is the proposed reform of the Common Fisheries Policy (CFP), which could potentially bring in a change to the way commercial fisheries are managed.

[30] For details of Marine Activity data in the vicinity of Murchison see the DTI - Strategic Environmental Assessment of the Mature Area of the North Sea SEA2 - 2001

[31] Ref Murchison Shipping Traffic Survey – Anatec - MURDECOM-ATC-EN-STU-00199

### 2.8.7 Annex 1 Habitats

Although specimens of the cold water, reef building coral *Lophelia pertusa* were evident on parts of the Murchison jacket, no evidence of sub tidal reefs, submarine structures or any other potential Annex I Habitats were found across the rest of the survey area of the platform or along the length of PL115.

# 3 Murchison Decommissioning Options

This section provides a description of the process by which decommissioning options were identified, screened and taken forward for assessment.

## 3.1 Post CoP Alternate Use Options

During the Murchison Life of Field strategic planning, a number of initiatives to extend the field operating life were examined by CNRI including enhanced oil production technology, drilling to reach stranded reserves and potential third party tie backs. None of the initiatives examined was found to be commercially viable and consequently a Cessation of Production (CoP) Application was submitted to DECC in 2011, approved in 2012, and decommissioning planning commenced.

Three key strategic options were assessed, namely:

a) Could the Murchison platform be relocated to a new oil/gas exploration and production area?

   If not, then

b) Could an alternate use be found for the Murchison Platform in its present location?

   If not, then

c) What were the decommissioning options?

### 3.1.1 Relocation and Reuse of Murchison Platform[32]

The Murchison platform was installed in 1978 in UKCS Block 211/19 and lies approximately 150km northeast of Shetland in 156m water depth. It was originally designed for a service life of 20 years with an anticipated decommissioning date of 1998.

The main issue with reuse of the Murchison platform as an oil and gas production facility is the high cost of maintaining the fabric and structural integrity of the platform and its operating components which are subject to fatigue damage and degradation caused by corrosion.

The platform process systems were designed using 1970's technology which has moved on significantly since that time, so major replacement of process and utility systems would be required in a re-use scenario. This would be unviable.

Relocation of the platform to another site for re-use as an oil and gas producing platform was therefore considered impractical because of the condition size and age of the platform and hence was not considered further.

[32] A detailed study was undertaken to review re-use of the Murchison platform, the results from which are reported in the document `Post CoP Alternate Use Appraisal' – DECOM-GLD-PM-STU-00048

With no viable reuse options identified, three main alternate use options were identified:

1. Alternate use for wind energy
2. Alternate use for wave and tidal energy
3. Alternate use for carbon capture and storage.

### 3.1.2 Potential Alternate Reuse for Wind Energy

One option investigated[33] was to remove the Murchison topsides to shore and then use the jacket structure as a support for one or more wind turbine generators (WTGs).

**Figure 31: Concept for a 10MW Vertical Axis Turbine**

The largest WTGs to date have a rotor diameter of up to 150m with a generating potential of 6MW, although there are development projects in hand for the design of 10MW WTGs. The other factor to take into account is the capacity factor of the WTG. This is a function of wind strength and is location dependent. The Murchison platform is in an exposed offshore location and would have a capacity factor of around 0.45. On this basis it is estimated that Murchison could generate up to 39,420MWh per annum for up to 25 years.

It would require laying over 150km of high voltage direct current (HVDC) subsea cable for transmission of power to shore, with a substation located on the jacket.

A simple economic model was created to assess the commercial viability of converting Murchison to wind generation. This was based on the following assumptions:

Energy generated 39, 420 MWh pa
Transmission efficiency 0.9
Basic Power price £55.00/MWh
Renewable Obligation Certificate (ROC)[34] £50.00/MWh
ROC band 1.5
Levy Exemption Certificate (LEC)[35] £4.30

[33] For details see Post CoP Alternate Use Appraisal – DECOM-GLD-PM-STU-00048

[34] Renewable Obligation Certificates (ROCs) are green certificates issued by Ofgem to operators of accredited renewable generating stations for the eligible renewable electricity they generate

[35] Renewable Levy Exemption Certificates (Renewable LECs) are electronic certificates issued by Ofgem to accredited generating stations for each Megawatt/hour (MWh) of renewable source electricity generated. LECs identify renewable source electricity produced by accredited renewable generating stations

On this basis:

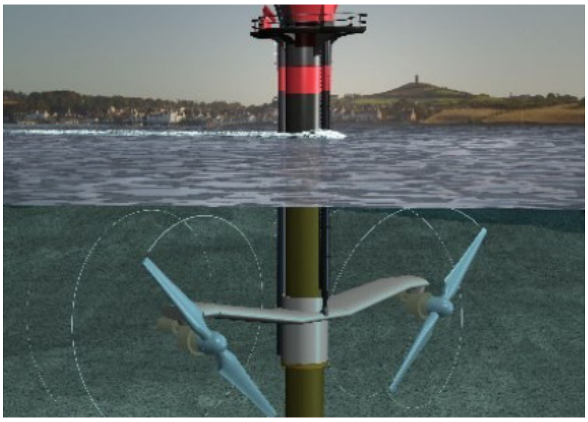
1. Total income is then 39420 * 0.9* (£55 + £50*1.5 +£4.3) = £4,765,000 pa
2. The capital cost for procurement of the WTG, support equipment, transmission cable including installation is approximately £55,000,000
3. The annual running costs, including maintenance of the jacket is estimated at £3,060,000pa
4. The operating life of the WTG is estimated at 25 years. Over this period of time the annual maintenance costs will escalate at around 5% pa reflecting the age of the jacket and the need for more extensive and more costly repairs.

Entering this data into an economic model and discounting at 10% gave a Net Present Value[36] of minus £36.5m, which is a not a commercially sound proposition, at least in the near future and consequently was not considered further.

### 3.1.3 Potential for Wave & Tidal Energy

The potential for converting the Murchison Platform to wave and or tidal energy generation was also assessed[37].

Figure 32: Seagen Drive



There are two principal ways of harnessing tidal energy either by converting the kinetic energy of tidal currents or by converting the potential energy in the water level tidal variations. The kinetic energy of tidal currents is converted using S-turbine type devices such as the Seagen device.

The Murchison platform is in a location of negligible tidal power resource and for this reason the use of the existing structure for tidal energy is discounted.

The methods of converting wave energy to electrical energy are diverse, but in deep water the devices tend to be floating or tethered to the seabed such as the Pelamis Wave Energy Converter.

Figure 33: Pelamis Device Prototype

[36] NPV can be described as the “Difference Amount” between the sums of discounted cash inflows and cash outflows. It compares the present value of money today to the present value of money in future, taking inflation and returns into account

[37] For details see ‘Post CoP Alternate Use Appraisal’ – DECOM-GLD-PM-STU-00048

Pelamis is a semi-submerged articulated structure linked by hinge joints. The wave induced motion of the joints is resisted by hydraulic rams which pump high pressure fluid through hydraulic motors. The hydraulic motors in turn drive electrical generators to produce electricity.

Assuming a device, similar to Pelamis could be attached to the Murchison jacket, the maximum wave crest width from which the energy is extracted would be around 60m long, being a function of the jacket dimensions.

In the area around Murchison the annual mean wave power would be approximately 40kW/m wave crest. This equates to 60* 40kW/m or 2400kW (2.4MW) Applying a wave to electrical energy conversion efficiency of 50% and 8760 hours pa (365 *24) gives an expected annual energy generated of = 2.4 * 50% * 8760 = 10,512 MWh pa.

Again using a simple economic model, assuming:

1. Energy generated 10,512 MWh pa
2. Basic Power price £55.00/MWh
3. Renewable Obligation Certificate (ROC)[38] £50.00/MWh
4. ROC band 2.0
5. Levy Exemption Certificate (LEC)[39] £4.30

Then:

1. Total income is £10,512* (£55 + £50*2.0 +£4.3) = £1,675,000 pa

2. The capital cost for procurement of the WTG, support equipment, transmission cable including installation is approximately £55,000,000, similar to that for wind energy

3. Likewise, the annual running costs, including maintenance of the jacket is estimated at £3,000,000pa

The annual operating costs alone are more than double the annual income from wave energy generation. Therefore the use of the existing Murchison platform for wave generation is not considered to be a commercially viable option, and was not considered further.

### 3.1.4 Potential for Carbon Capture

Concerns regarding the impact of rising carbon dioxide ($CO_2$) levels on the climate have resulted in a number of initiatives directed towards the stabilisation and eventual reduction of $CO_2$.

Carbon Capture and Storage (CCS) is a process involving the capture of carbon dioxide from the burning of fossil fuels and its transportation and storage in secure spaces, such as geological formations, under the seabed. Primary aspects of CCS for Murchison addressed the following issues:

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[38] Renewable Obligation Certificates (ROCs) are green certificates issued by Ofgem to operators of accredited renewable generating stations for the eligible renewable electricity they generate.

[39] Renewable Levy Exemption Certificates (Renewable LECs) are electronic certificates issued by Ofgem, to accredited generating stations, for each Megawatt/hour (MWh) of renewable source electricity generated.. LECs identify renewable source electricity produced by accredited renewable generating stations

- To avoid corrosion problems in the processing equipment, well completions and pipelines, the imported $CO_2$ would need to be dried
- It is anticipated that existing process and drilling facilities would have to be removed and a new CCS injection module built and installed together with a new riser
- Transportation of the $CO_2$ from participating fields would require a new pipeline system capable of carrying dense phase gas at approximately 200bar
- Fuel gas would have to be continually imported from the existing NLGP supply
- Delivery of the $CO_2$ into the reservoir may require workover and/or replacement of the existing well downhole equipment
- Further reservoir studies would be required to assess the impact of the fields past water injection programme on the viability for $CO_2$ storage.

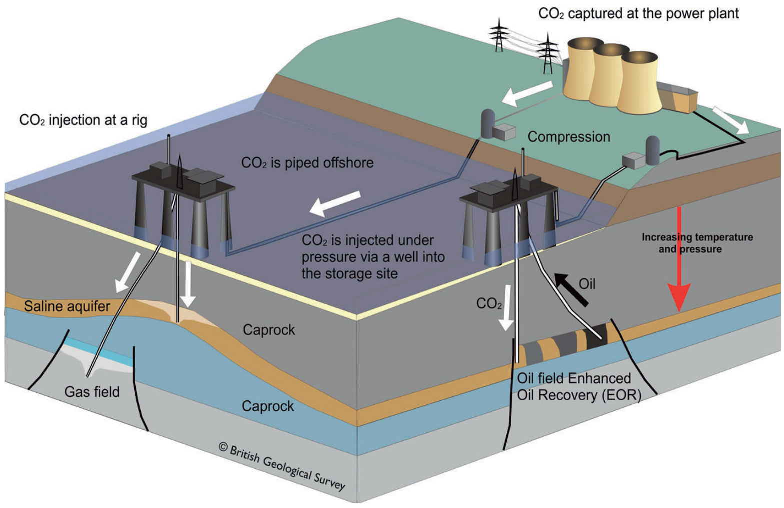


**Figure 34: CCS Schematic**

Figure 34 is a schematic showing elements of a CCS infrastructure in relation to the required geological sub surface structure[40].

Based on an initial commercial assessment and compared with other published economic studies[41], it is concluded that the costs associated with modification of Murchison facilities for CCS, together with the on-going maintenance costs, the cost of a new pipeline system and modification to well architecture will not be commercially viable. Accordingly this alternative use was not considered further.

[40] Taken from Carbon Capture & Storage -Options for Scotland published by Scottish Enterprise.
[41] See for example Fairfield Energy Ltd –Dunlin Alpha Decommissioning Concrete Gravity Base Re-use – Appendix C – $CO_2$ Opportunities for Dunlin Alpha 2010

### 3.1.5 Alternate Non Energy Uses for the Murchison Platform

Studies into alternate use opportunities outside the energy sector were carried out and reported in the document DECOM-GLND-PM-STU-00048. The alternate use opportunities evaluated included:

- Marine research
- Diver training centre
- Fish farm
- Offshore infrastructure hub

None of the alternate use options was found to be commercially viable and hence none were taken forward.

### 3.1.6 Conclusion from Alternate Use Appraisal

No viable reuse or alternate use has been identified and consequently the option to reuse the platform was not taken forward into the detailed comparative assessment process.

## 3.2 Platform Removal Technology – Available Options

The Murchison Field owners commissioned a report entitled `Platform Removal Technology Study (DECOM-GLND-PM-STU-00042), the purpose of which was to summarise the oil industry's experience, both in the Gulf of Mexico and the North Sea, in decommissioning methods and available equipment.

The results of the study were used to identify the potential options for decommissioning the Murchison Platform and associated pipelines.

### 3.2.1 Murchison Platform Vessel Selection

In the North Sea decommissioning activities have been dominated by Seaway using single hull Heavy Lift Vessels (HLVs) with Heerema and Saipem operating the larger Semi-Submersible Crane Vessels (SSCVs). McDermott have not operated a marine fleet of SSCVs and HLVs in the North Sea since about 1996 but are believed to be considering a return. Subsea 7 took delivery of the new-build Borealis in July 2012.

| Operator | Vessel | Type | Capacity (tonnes) |
|---|---|---|---|
| Saipem | S7000 | SSCV | 2 x 7,000 (te) |
| Heerema | Thialf | SSCV | 2 x 7,100 te |
| | Hermod | SSCV | 1 x 4,500 + 1 x 3,600 te |
| | Balder | SSCV | 1 x 3,600 + 1 x 3175 te |
| Seaway | Oleg Strashnov | HLV | 1 x 5,000te |
| McDermott | DB101 | SSCV | 1 x 3,175 te |
| | DB50 | HLV | 1 x 4,000te |
| Subsea 7 | Borealis | HLV/Pipelay | 1 x 5,000te |

Table 9 Heavy Lift Vessel Capability

All the larger SSCV vessels listed in Table 9 could remove the Murchison topside and jacket structure in whole or in sections. The smaller SSCVs and HLVs could remove the topside and parts of the jacket structure only.

There is a large fleet of shear leg cranes operating in the North Sea but their operational use is restricted to shallow water operations and they are not suitable for the Murchison decommissioning project.

A number of new design Single Lift Vessels (SLVs) have been proposed over the years. There is only one SLV being built at present with any realistic prospect of being commercially available in a time frame that meets the CNRI schedule. This was the Allseas vessel the Pieter Schelte due for delivery in 2014 and therefore was considered further in the CA process.

Although not a vessel, Aker Kverner has developed a jacket removal method which uses external Buoyancy Tank Assemblies (BTAs) to refloat the jacket at a predetermined draft. The BTAs were successfully used during the summer of 2008 to remove the 12,000te Frigg DP2 jacket. With some modification the BTA's potentially could provide an alternate decommissioning option for the Murchison jacket and was therefore considered further in the CA process.

### 3.2.2 Pipeline Vessel Selection

A pipeline decommissioning technology review[42] was completed to define the vessel and equipment options available for the Murchison decommissioning project. This covered the following issues:

1. Cutting and removing sections of pipeline
2. Trenching and burial of pipelines
3. Recovery of wellhead equipment and protection structures
4. Recovery of pipeline spools

Vessels capable of undertaking this scope include the following (Table 10):

| Operator | Vessel | Type | Capacity (tonnes) |
|---|---|---|---|
| Acergy | Havila | DSV[43] | 1 x 250te with AHC[44] |
| | Osprey | DSV | 1 x 150te + AHC |
| | Skandi Acergy | CSV | 1 x 400te |
| | Toisa Proteus | CSV | 1 x 390te |
| Bibby | Bibby Sapphire | DSV | 1 x 150te + AHC |
| Saipem | Normand Cutter | CSV | 1 x 300te + AHC |
| | SEMAC | Pipelay | 1 x 380te |
| | Far Samson | CSV | 1 x 250 + AHC |
| Seaway | Oleg Strashnov | HLV | 1 x 5,000te |
| Subsea7 | Seven Oceans | Reelship | 1 x 350te |
| | Seven Seas | Pipelay | 1 x 400te |
| Technip | CSO Constructor | | 1 x 200te +AHC |

Table 10 Pipeline Vessel Capacities

[42] See Decommissioning Technology Review ATK/PDi doc C200-TN-0001
[43] DSV – Diving Support Vessel
[44] AHC – Active Heave Compensated crane

Given the weight and size of the subsea structures and infrastructure to be removed it is expected that they could all be recovered by DSV or CSV.

Some examples of the type of equipment available for cutting pipelines are reported in Table 11. For cutting the bundles, hydraulic shears may be preferred because the act of cutting crimps the pipe and prevents the inner pipes from moving during recovery.

The range of cutting machines available for pipeline recovery includes:

| Manufacturer | Equipment | Cut Range |
|---|---|---|
| EOT Cutting Services | Guillotine Saw | 2" – 32" |
| CUT | Standard Diamond Wire | 10" – 150" |
| CUT | ROV Diamond Wire | 18"- 64" |
| UCS | Dual Cut band Saw | 4"- 30" |
| Proserv | Jet Cut | 6" – 180" |
| Genesis | Hydraulic Shears | Up to 46" |

**Table 11 Subsea Cutting Equipment Capability**

Dependent on the situation, dredging may be required to provide access for cutting equipment. There is a range of dredging equipment available but in the stiff boulder clays there are two problems to consider:

1. High pressure water jetting may be required to break up the soil to assist the dredger
2. The dredging equipment can handle maximum debris size of up to 250mm in diameter but the naturally occurring sediment boulders may be considerably larger.

For the trench and burial operations, the selection of tool will depend on the soil conditions. For the stiff clays along the pipeline route cutting equipment will probably be the only practicable alternative, as shown in Figure 35.

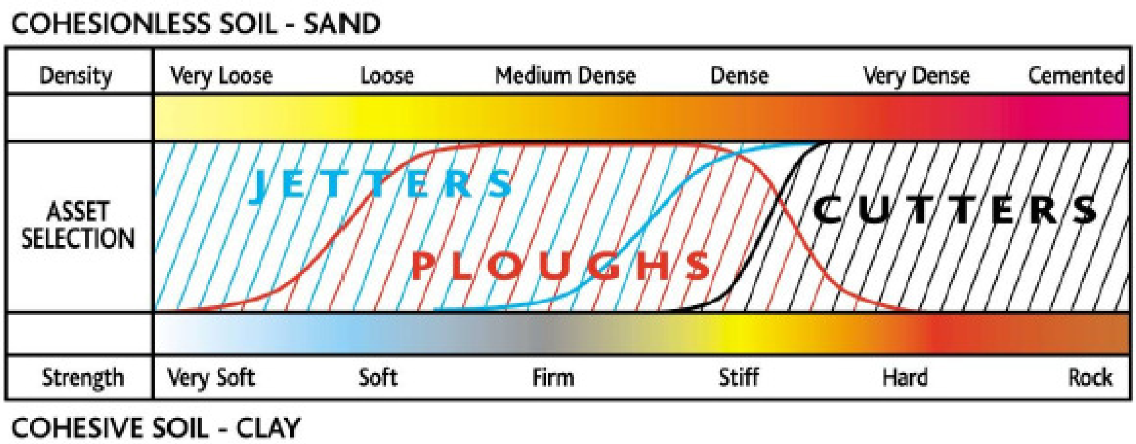


**Figure 35: Trenching Equipment V Soil Type**

Mechanical trenchers use chain cutters or wheels to create an open trench. The trench may then be backfilled by the natural movement of sediments by seabed currents or by controlled placement of graded rock.

## 3.3 Murchison Decommissioning Options

The Murchison decommissioning phases include:

a) The Cessation of Production which includes well plug and abandonment that results in isolating the platform from the producing reservoir and the subsequent engineering down and cleaning which leaves the topsides effectively free from hydrocarbons

b) Removal of the Murchison topside structures, after cleaning, and transportation to shore for reuse, recycling and final disposal

c) Removal of the Murchison jacket and transportation to shore for recycling and disposal

d) The drill cuttings management

e) Decommissioning of the main export pipeline PL115

f) Decommissioning of the early production flowline bundles PL123, PL124 and PL125.

g) Clearance of seabed debris after completion of the decommissioning programme.

h) On-going post decommissioning surveys and monitoring of any material left on the seabed in the Murchison area.

The options appropriate to each phase of the decommissioning programme are described in the following sections.

### 3.3.1 Well Plug and Abandon (P&A) Procedures

All 33 platform wells will be abandoned in accordance with CNRI drilling and operations policy DCWS-POL-101 Policies & Standards. Consent for Suspension or Abandonment of a well will be sought from Department of Energy & Climate Change (DECC) through the Well Operations and Notification System (WONS) by completing a PON5.

In consideration of options, each of the Murchison Wells to be abandoned has been categorized in compliance with UK Oil & Gas Guidelines for the Suspension and Abandonment of Wells July 2012 version 4.

The offshore work will be phased into four parts; this strategy is seen as best practice from other major abandonment projects.

#### Phase 1: Bull Heading and Circulation

This technique will be considered for all suitable wells and would be the preferred option. The approach maximises the amount of completion materials, fluids and accessories to be left in hole. If successful manning levels and costs would be minimized, if unsuccessful due to poor integrity or difficult well conditions these wells could be abandoned either during phase 2 or, if sufficiently complex, could be deferred for Phase 3 rig driven abandonment.

It is assumed that bullhead and through tubing abandonment can be attempted in 15 wells.

**Phase 2: Coil Tubing;**

Coiled tubing is used to place cement. The technique is regularly used to conduct well abandonment's where tubing integrity is poor or tubing blockages require removal for depth access. It has been assumed at this stage that all 11 water injection wells will require abandonment using this technique due to the anticipated poor condition of the tubing.

**Phase 3: Conventional Abandonment;**

Conventional abandonment involves a complete or partial work-over of the well utilising full well control (BOP's). This approach is required due to the presence of deep set down hole gauges and chemical injection lines that cannot be allowed to form any part of the required permanent barriers.

Five wells require partial or complete tubular removal; two wells have already been partially abandoned at the reservoir interval and require intermediate and surface barriers to be installed.

The upgraded Murchison rig will be used to carry out reservoir abandonment operations for these wells.

**Phase 4: Tubing, Casing, Upper Barrier Placement and Conductor Recoveries**

Reverse installation of tubing, casing and conductors would be recommended as the base case option. All 33 slots require some form of lifting system to support tubing, upper barrier setting, casing and conductor removal. The platform rig and crews used in phase 3 will perform this function with the support of a specialist conductor cutting contractor.

Two options exist for removing the platform conductors[45];

a) If the Murchison jacket is to be removed completely, the conductor/casing strings would be removed to a minimum of 3.0m below the seabed, in order to accommodate fishing activities.

b) If the Murchison jacket is removed down to the top of footings then the conductor/casing strings could be removed down to approximately the -124m LAT bracing level which is below the top of footings[46]. This option is alignment with the Oil & Gas Guidelines for the suspension and abandonment of wells –July 2012 (section 7.20)

The final well P&A Programme will be determined during detailed engineering with the nominated well P&A contractors and as such is not considered further in the formal comparative option assessment.

### 3.3.2 Platform Topsides Decommissioning Procedures

All of the topside structures will be removed and returned to shore for reuse, recycling, demolition and disposal. Topsides are defined as those parts of the offshore installation which are not part of the substructure and includes modular support frames and decks where their removal would not endanger compromise the structural stability of the substructure[47]

[45] For further information see section 7.20 of the Oil & Gas UK – Guidelines for the suspension and abandonment of wells.

[46] For comparative assessment of options see CNRI Technical Notes on Murchison Conductor String Removal – doc MURDECOM-CNR-WS-TFN-00001

[47] See section 7.7 of DECC Guidance Notes version 6

Two methods are being considered for removing the topside structures, the first being to remove the individual modules, described in section 2.3.2 The Murchison Platform Topsides using a conventional semi-submersible crane vessel (SSCV)[48] or smaller heavy lift vessel (HLV). The method is the reverse of the installation sequence described in section 2.4.2 Fabrication of the Murchison Topside Modules

The second option[49] is to demolish the topside structures in the field and return the salvaged elements to shore in containers, a process known as piece small decommissioning.

A third option to remove the topside structure as a single lift was assessed but initially discounted because the Murchison jacket size was not compatible with the new single lift vessel (SLV) geometry. However, it has since been decided by the vessel developer to modify the geometry of the vessel which may facilitate the ability to remove the topside structure in a single lift.

**Figure 36: SSCV Lifts off Topside Module**

After removal individual modules and components will be shipped to shore and unloaded at a licensed reception facility[50]. The reception facility will be nominated by the removal contractor at the appropriate time and will be subject to CNRI approval.

**Figure 37: Demolition of Topside Modules *In Situ***

The Murchison topside modules will be removed completely and returned to shore. The exact programme of work will be finalised during detailed engineering with the nominated removal contractor and as such is not considered in the formal comparative option assessment.

[48] The majority of topside removals have used either a SSCV or HLV see report `Platform Removal Study' DECOM-GLND-PM-STU-00042

[49] The piece-small or demolish *in situ* option has been used on the Ekofisk 2/4 Tank decommissioning and on the smaller Inde Kilo gas platform

[50] For details of potential reception yards refer to Facilities for Onshore Receipt of Decommissioning Structures Survey - 2011 DECOM-GLND-PM-REP-00043

### 3.3.3 Platform Jacket Decommissioning Options

OSPAR Decision 98/3 prohibits the dumping and leaving wholly or partly in place of disused offshore installations.

OSPAR recognises there may be difficulties in removing the footings of large steel jackets weighing over 10,000te and installed prior to 9th February 1999. As a result there is a facility for derogation from the main rule for such installations.

The Murchison jacket qualifies for consideration of derogation from OSPAR Decision 98/3 because the jacket weighs 27,584te and it was installed in 1979.[51]

The presumption of total removal is the starting point for the comparative assessment (CA) process.[52] By way of derogation a CA process has to be undertaken in accordance with OSPAR Annex 2 that requires there to be significant reasons why a partial removal option is preferable to full removal for re-use, recycling or disposal on land.

Two jacket decommissioning options were identified as being compliant with the OSPAR Decision 98/3 and DECC Guidelines and thereby assessed within a formal CA process (see section 4 of this report):

1. Full removal, with foundation piles cut 3m below the mudline. The total weight of jacket removed would be approximately 27,580te

2. Partial removal of the jacket down to the top of footings, defined as the top of the highest pile[53]. The total weight of jacket removed would be approximately 14,850te.

The two options are illustrated overleaf.

[51] It was intended in OSPAR that jackets installed after 1999 were to be designed to be fully removed regardless of weight
[52] See section 7.10 of DECC Guidance Notes version 6
[53] See section 7.11 DECC Guidance Notes version 6

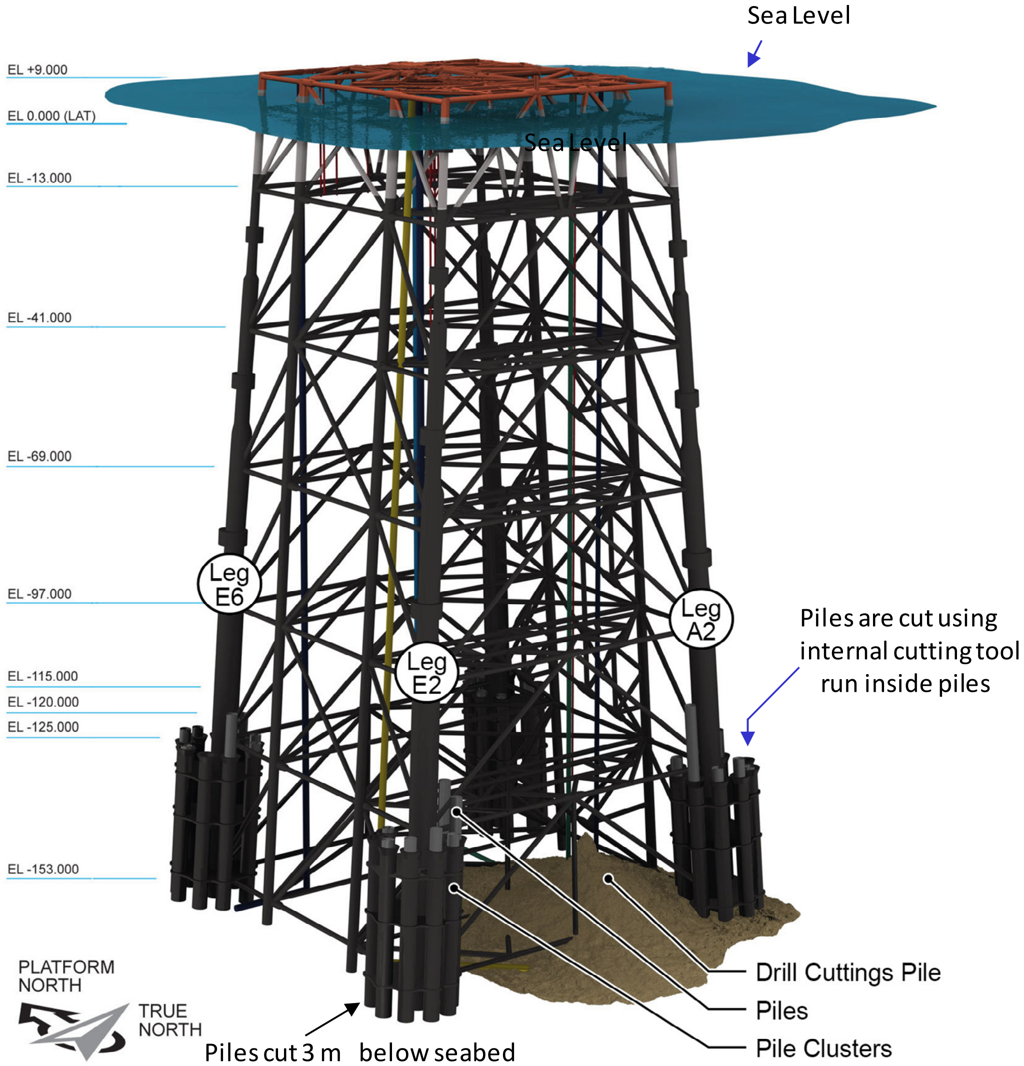


**Figure 38: Option 1 -Murchison Jacket Full removal**

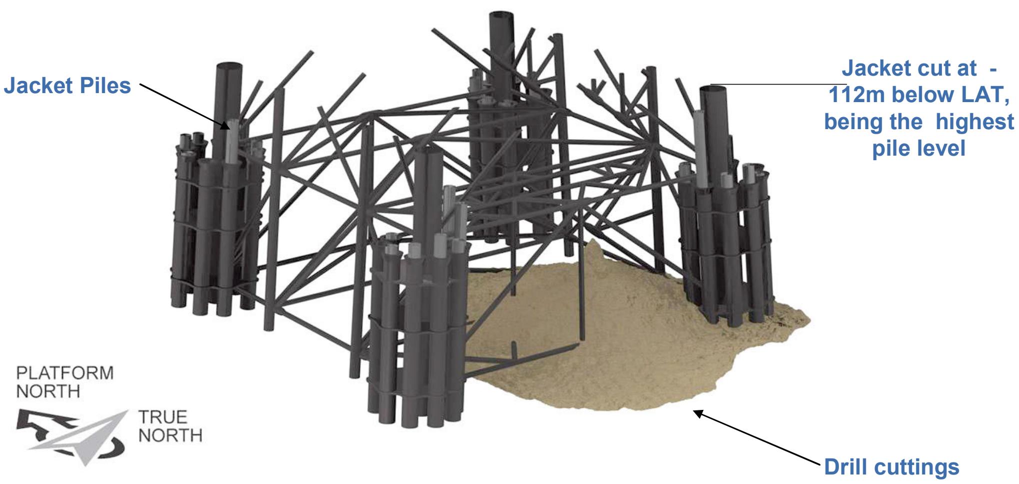


**Figure 39: Option 2 - Murchison Jacket Partial Removed**

### 3.3.3.1 Jacket Footings Life Expectancy

If the jacket footings are left in place the most significant degradation mechanism will be long term corrosion. After decommissioning the Murchison topsides and removing the top section of jacket the remaining sacrificial anodes will deplete eventually offering no protection and allowing the remaining structure to corrode freely. Once the structural members have lost sufficient wall thickness they will no longer be able to support the self-weight loading and the structure will progressively fail, collapsing into the jacket footprint.

The most important factors which affect the corrosion of metals immersed in unpolluted sea water are dissolved oxygen and temperature. These factors were addressed in a study predicting the life expectancy of the footings left in place, over time.[54]

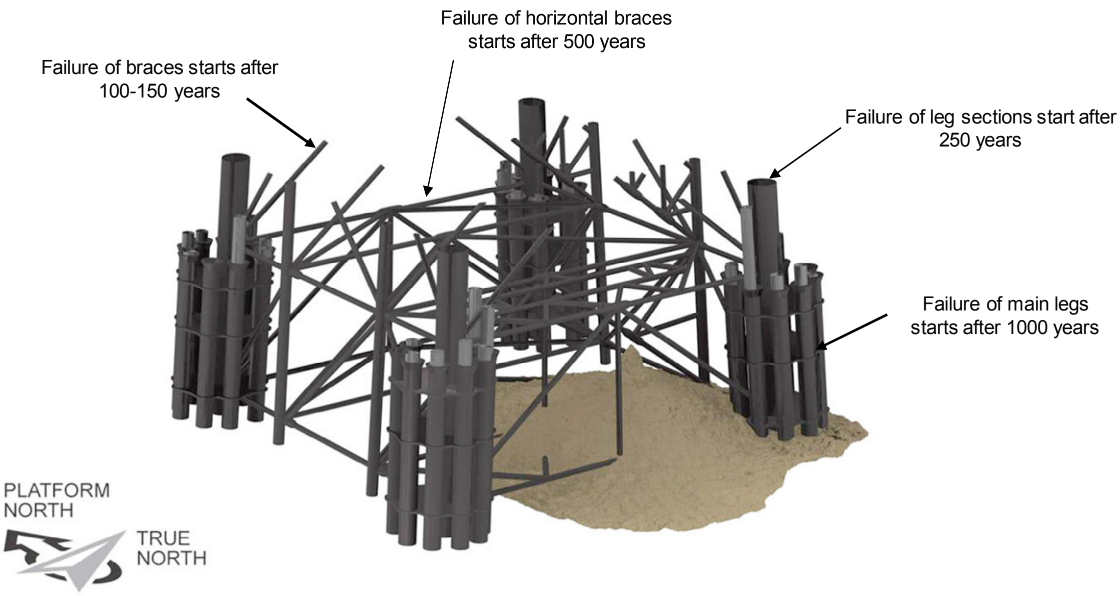


Figure 40: Predicted Degradation Rate of Footings

During the stakeholder consultation process, the question was raised as to whether it was feasible to accelerate the corrosion rate of the remaining structure to mitigate any long term snagging risk to fishing.

Two options were considered. The first entailed installing a cathodic protection (CP) system whereby the footings acted as the sacrificial anode. This was concluded as being unviable due to the significant amount of anode material required[55].

The second option was to utilise the potential impact of microbial induced corrosion (MIC). MIC is typically localised and patchy in distribution, forming under marine growth e.g. barnacles, or under biofilms, and results in areas of pitting. It was concluded that bacteria tend to be active in warmer

[54] Further details on the Jacket degradation rates are given in the Murchison Decommissioning Study –Preliminary Footings Life Expectancy - report no DECOM-ATK-ST-REP_00080
[55] Email JEE to CNRI Dec 2012 subject re Corrosion engineering query

environments and that a decommissioned structure that is no longer producing heated fluids through the sub-sea infrastructure may present a colder environment and perhaps reduced bacterial growth.

Providing predictions for increased corrosion rates resulting from MIC was unlikely to be robust, however, it is likely that MIC could increase the overall corrosion of a subsea structure above the predicted electrochemical corrosion rates, and that localised pitting may reduce the structural integrity of any structure left on the seabed but the effects may not be significant.[56]

#### 3.3.3.2 Jacket Densitometers

As described in section 2.4.2, after piling was completed, the piles were connected to the jacket by injecting grout between the pile and sleeve. The grouting process was monitored using two grout densitometers fitted to each of 36 pile sleeves. Each densitometer consists of a Caesium 137 source and a detector.[57] Each densitometer is housed inside a lead shield which is further housed inside an outer steel container welded to the pile sleeve surface on the sleeve surface closest to the jacket leg in order to provide protection during jacket launch.

An outline method statement for the removal and recovery of the densitometers using divers, operating within the confined space of the jacket footings, was completed to inform a hazard identification and risk assessment (HIRA) of the operation[58] . A dose assessment was conducted to assess the worst case exposure in the event that the sources leaked to the environment. The assessment concluded that there is no adverse impact on the general public either through direct exposure to a source or through exposure within the food chain should the sources remain *in situ* [59]

Based on the safety risk and dose assessments undertaken, an application has been submitted to SEPA to reclassify the densitometers as irretrievably lost in that the safety risk to divers in attempting to recover the sources from the deep water confined spaces of the jacket footings is significantly greater than the environmental risk of leaving the densitometers in place to decay naturally over time.

#### 3.3.3.3 Jacket Decommissioning Methods

Four methods were investigated for removing all or part the Murchison jacket. The four methods included:

a) Using a semi-submersible crane vessel (SSCV) for removing the Murchison jacket in large sections and individual components
b) Using a heavy lift vessel (HLV) for removing the Murchison jacket in small sections
c) Using a single lift vessel (SLV) to remove the Murchison jacket in a single piece
d) Using buoyancy tank assemblies to refloat the Murchison jacket in a single piece

See Table 9 Heavy Lift Vessel Capability for details of each of the vessels considered in the alternate methods described above.

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[56] Internal email re Degradation rates of Jacket footings April 2011
[57] For details see Technical note on Murchison Densitometers MURDECOM-CNR-EN-ETN-00001
[58] Assessment of Murchison Densitometer Sources HIRA Report MURDECOM-CNR-EN-REP-00001
[59] Full details in Application for Leaving the Murchison Densitometers in Place MURDECOM-CNR-EN-REP-0002

The following section describes the operations involved in each of the decommissioning method that were the subject of specialist studies undertaken in support of the CA process.

### (a) & (b) Removing the Jacket Using a SSCV or a HLV

Figure 41 shows a jacket being removed using a semi-submersible dual crane vessel (SSCV). The SSCV with a crane capacity of 14,000te is able to remove the jacket in large sections.

Three[60] technical studies were undertaken, to assess the feasibility of full removal and partial removal of the Murchison jacket:

a) Two studies were based on using the 14,000te capacity SSCV's, removing the jackets in large sections

b) One study was undertaken using a smaller 5,000te capacity Heavy Lift Vessels (HLV) removing the jacket in individual and small sections.

Figure 41: Jacket Removal Using a Heavy Lift Vessel

As shown in Figure 42 the jacket members would be cut into sub-assemblies appropriate to the capacity of the lift vessel using a mix of hydraulic cutters or shears, diamond wire cutting (DWC), or abrasive water jet cutting.[61]

[60] For details see the three reports Saipem 979978/KMUK/Removal 2002; MURDECOM-HMC-ST-PRO-00033 and MURDECOM-SHL-PM-REP-00067
[61] For an assessment of cutting tools see Technology for Subsea Cutting of Jacket Members DECOM_GLND-ST-REP-00045

The larger SSCVs could remove the jacket in sections weighing up to 4,000te, as shown in Figure 42.

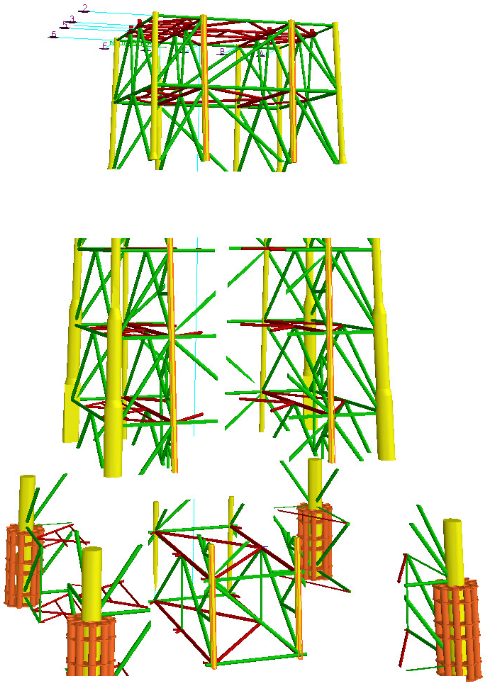

Figure 42: Jacket Removal in Large Sections

The stability of each section as it is cut away from the remaining structure would need to be verified. The more complex operation will be the cutting of the pile foundation at each of the four bottle leg assemblies, whilst maintaining the stability of the remaining structure prior to lifting clear[62].

The piles would be cut using internal pile cutters. If that were not possible the pile would be cut using external cutters after excavating beneath the mud mats. This would increase the problems of ensuring the stability of the bottle leg assemblies after cutting piles just prior to lifting clear of the seabed.

The smaller HLV with a crane rated for underwater working of 2,500te would have to lift the jacket in much smaller components of up to 2,000te. This would present problems for the removal of the final bottle leg assemblies with each weighing 3,000te.

### c) Removing the Jacket Using a SLV

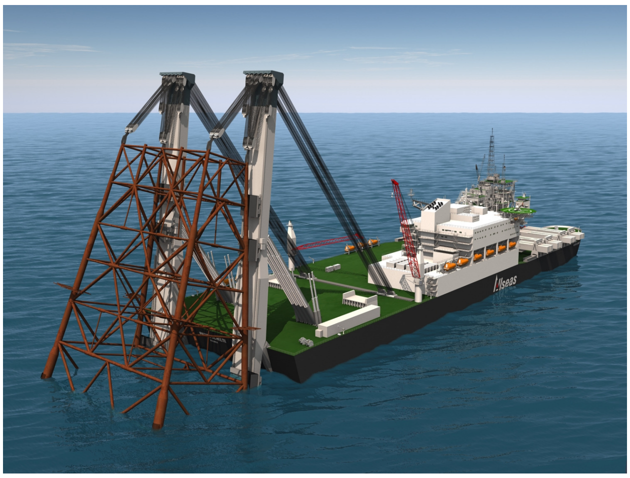

Figure 43: Jacket Removal Using a Single Lift Vessel

Figure 43 shows a jacket being removed using the new single lift vessel (SLV) the *Pieter Schelte*, currently under construction. The single lift vessel has a jacket lift system capacity of 25,000te whereas the Murchison jacket has a total lift weight of 26,131te.[63]

The concept is based on cutting the jacket piles below the mudline, attaching rigging to the top of jacket and simultaneously lifting and tilting the jacket until it bears on the tilting lifting beam assemblies. The lifting beams are then pulled down onto the deck and the jacket sea fastened for tow to shore.

Because the Murchison jacket weight exceeds the SLV lift capacity it was concluded that full removal of the Murchison jacket was not feasible with the present SLV jacket lift system (JLS) design.[64]

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[62] See TN-Murchison Comparative Assessment Post Workshop Actions MURDECOM-CNR-PM-GTN-00210 for more details

[63] Weight assumes drain holes will be drilled in flooded members before removing the jacket

[64] See updated Murchison Jacket Removal Method Statement MURDECOM-ALS-ST-PRO-00219 – July 2012

A further technical study[65] was undertaken to assess the feasibility of full removal and partial removal of the Murchison jacket in two operations:

a) The first operation studied was to assess the feasibility of removing the jacket down to -102m below LAT in a single lift of 13,376te using the existing vessel's JLS design

b) The second operation studied was to assess the removal of jacket sections below the -102 level using the construction support vessel Lorelay by cutting and removing the jacket individual members. The Lorelay has a crane capacity of 300te so could remove individual bracing members down to -112m, but could not remove any of the four 3,000te bottle leg assemblies.

For both the heavy lift vessel and single lift vessel methods described above, the removed jacket or jacket sections would be transported from the offshore location to either a designated onshore reception facility or to a sheltered site where recovered structures would be transferred to cargo barges for onward shipping to the designated onshore reception facility.

The returned sections would be offloaded from the lift vessel or transportation barge across the quay side onto temporary foundations where they would be demolished and the component material recycled.

### d) Refloating the Jacket using a BTA's

Figure 44[66] illustrates a different removal concept which is based on reusing the buoyancy tank assemblies (BTA's) that were used to refloat the 12,000te Frigg DP2 jacket.

The four tanks, each weighing 1,025te, would be modified to suit the Murchison jacket configuration. Each tank would be towed to the Murchison site, mated and attached to the jacket using preinstalled anchor points.

To provide additional buoyancy the four corner jacket legs would have to be made airtight after removing the module support frame, and a new buoyancy control system installed for each leg.

The jacket foundation piles would be cut using internal pile cutting, or excavated beneath mudmats for an external cut should debris prevents access for the internal pile cutting tools.

**Figure 44: Refloat of jacket using added buoyancy tanks**

The point during the operation at which the buoyancy tanks are attached to the jacket and the foundation piles are cut would introduce new temporary hydrodynamic loading conditions for which the jacket has not been designed.

[65] For details see the report Method Statement Murchison Jacket Removal MURDECOM-ALS-ST-PRO-00024
[66] Murchison Jacket BTA Removal Study Report MURDECOM-AKER-ST-REP-00025

The BTAs and corner legs would be deballasted to lift the jacket off the seabed. The ballast control system would run from an attendant vessel rather than the jacket mounted control module used during its original installation.

Tow lines would be attached and the jacket towed along a deep-water route to a fjord in Norway, where the jacket would be grounded and dismantled *in situ* using shear leg cranes. A series of tow analysis for both the intact and damaged condition[67] would need to be undertaken to verify the jacket structural integrity would be maintained during the tow.

### 3.3.4 Murchison Drill Cuttings Management Options

The undisturbed Murchison drill cuttings pile is predicted to be significantly below the OSPAR thresholds for both total rate of oil release into the water column and persistence over the area of seabed contaminated. Under these circumstances OSPAR 2005/6 recommends that the best management option is to leave the pile to degrade naturally.[68] [69]

However some or all of the pile would have to be removed in order to undertake the full removal of the jacket if this option were adopted. Accordingly alternative options for the management of the Murchison drill cuttings pile were assessed in order to understand the implications of having to remove the cuttings pile to facilitate full removal of the jacket structure.

The five options considered were:

a) Leave the cuttings pile *in situ* to degrade naturally

b) Recover cuttings slurry to surface separate, treat liquids for discharge overboard, ship solids to shore in containers for further treatment and disposal or re-use.

c) Recover cuttings slurry to surface and ship to shore for processing, separation and treatment and disposal

d) Recover cuttings slurry to surface, grind cutting to a maximum diameter of 300 microns and inject the slurry into a nominated cuttings reinjection (CRI) well

e) Disperse and distribute over the seabed sediments surrounding the Murchison platform.

Two questions relating to the cuttings pile management options were raised by stakeholders during the comparative assessment process. The first questioned the viability of re-injecting the recovered cuttings into a CRI well and the second asked if there was a platform based treatment option that could be an alternative to CRI.**[70]**

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[67] Intact and damaged condition analysis are standard floating/tow analysis requirements that model the consequence of loss of buoyancy in one of the BTA's or other members providing buoyancy caused by damage or failure.

[68] See report Environmental Assessment of Options for the Management of the Murchison Drill Cuttings Pile MURDECOM-BMT-EN-STU-00132

[69] See section 11.0 DECC Guidance Notes version 6

[70] For a full response see Murchison Comparative Assessment – Post Workshop Actions MURDECOM-CNR-PM-GTN-00210

For both of these options the first activity would be to recover the cuttings pile from the seabed.[71] There is no industry experience of recovering large volumes of drill cuttings from the seabed.[72] A test on the NW Hutton platform recovered 14m$^3$ of drill cuttings to the surface over a 2 day trial period which is not comparable to the volume of the Murchison pile (22,545m$^3$ )[73]. It is thus uncertain whether a viable system could be developed and tested within the Murchison project timeframe.

A number of problems have been reported[74] within closed drilling and CRI systems including:

a) Plugging of CRI wells due to improper slurry rheology and/or inappropriate operating procedures

b) Excessive erosion wear from the high volume of reinjection slurry causing well integrity failures

c) Hydraulic fracturing – uncontrolled induced fractures to surface

d) Interaction of new or future well with fractures containing cuttings slurry

e) Local faults/fractures

Because no recovery of drill cuttings from the seabed for re-injection has previously been proposed, there is no legislative framework in place which permits the reinjection of solid and liquid residues from lifted cuttings and the legislative/compliance requirements have not been tested[75]. OSPAR is still considering the best way to deal with existing drill cuttings piles. Further it is not clear whether the reinjection of recovered drill cuttings would be classified as waste under the Marine Scotland Act.

There were thus three issues relating to the CRI option that were addressed in the comparative assessment process, namely:

1. If there is no existing system/process for recovering the large volume of the Murchison drill cuttings pile, could such a system be developed within the project timeframe?

2. Can the CRI technical problems be resolved with certainty?

3. What are the implications for regulatory compliance?

A further question asked if there was a platform-based treatment option that could be an alternative to CRI. In particular could a thermal desorption unit be used[76].

[71] Further details are given in Murchison Drill Cuttings Pile Removal Methods DECOM-CNR-EN-ETN-00102
[72] See Oil & Gas UK Cutting Study 2011 for a review of developments in drill cutting recovery equipment since 2002
[73] UKOOA 2002 Drill Cuttings JIP Task 6 Drill Cuttings Recovery project. Final Report
[74] OSPAR Commission 2001 - Environmental Aspects of On-site Injection of Drill Cuttings
[75] Ref DECC “Offsite injection of drill cuttings “ Guidance for Operators
[76] See also Oil & Gas UK Cutting Study 2011 which concluded that technologies for the treatment of recovered drill cuttings were not established or proven for offshore use

In the thermal desorption unit, drill cuttings slurry recovered from the seabed is fed into a hopper before passing into either a Hammermill or Rotary Kiln unit in which the volatile components in the slurry are vaporised. Cleaned drill cuttings are returned to shore and the vapours are passed through condensers to recover the oil and water.

Both the Hammermill or Rotary Kiln units would have difficulty processing the very large amounts of water that would be entrained in the recovered cuttings slurry. To recover the estimated 25,000te of drill cuttings under Murchison would result in some 375,000te of recovered slurry at a water/solid ratio of 15. At the treatment rates of 1.5- 3.0te/hour achievable at these water/solid rates, it would take 10 years to treat the recovered slurry.

It may be possible to install additional water settling tanks with separate treatment of produced water and multiple thermal absorption units. In our studies, however no evidence was found of the, actual or planned use of such a large and complex system, on offshore platforms and this raised serious doubts as to the viability of such an approach. It was therefore concluded that no commercially effective thermal desorption unit could be put in place for the recovery of the Murchison drill cuttings pile and would not be considered further in the comparative assessment process.

### 3.3.5 Jacket and Drill Cuttings Option Interdependence

The Murchison drill cuttings pile covers part of the jacket bottom framing, so for jacket full removal options the drill cuttings will have to be removed and recovered to the surface or moved from their present location beneath the jacket.

| | | Jacket Options | |
|---|---|---|---|
| | | Full removal | Removal to top of Footings |
| Drill Cutting Options | Leave Pile *in situ* to degrade naturally | ✗ | ✓ |
| | Recover to surface, treat liquids and ship solids to shore | ✓ | ✓ |
| | Recover to surface and ship slurry to shore | ✓ | ✓ |
| | Recover to surface and re-inject down CRI well | ✓ | ✓ |
| | Distribute drill cuttings over surrounding sediments | ✓ | ✓ |

Table 12 Jacket Drill Cutting Options Interdependence

### 3.3.6 Export Pipeline PL115 Decommissioning Options

The six options considered for the PL115 pipeline described in section 2.5.2 Murchison Pipeline PL115 were:

1. Leave *in situ*

2. Minimal removal i.e. remove the Murchison and Dunlin tie-in spools only

3. Recover end tie-in spools and exposed sections of the pipeline either by reverse S-lay or by cut and lift

4. Recover end tie-in spools and trench and bury the exposed lengths of pipeline

5. Recover end tie-in spools and place rock over exposed lengths of pipeline to match the existing rock profile

6. Remove the pipeline completely by either reverse S-lay or by cut and lift after displacing the existing rock cover

#### (a) & (b) Leave Pipeline *In Situ* and the Minimal Removal Options

The options (a) and (b) would be the minimum work scopes leaving the pipeline in its existing condition, with only the tie-in spool connections being removed at Dunlin and Murchison for the minimal removal, option (b). It is anticipated that some remedial works may be necessary at the time of decommissioning and in the future where such a need is justified following periodic surveys undertaken to verify the pipeline condition. Over time the exposed sections of the pipeline will deteriorate and break up and this will require periodic debris clearance operations to minimise the snagging risk to fishermen.

#### (c) Remove Exposed Sections of Pipeline by S-Lay or by Cut and Lift

Option (c) is the option to remove the exposed sections of pipeline by S-Lay or by cutting and lifting in sections.

The S-lay option was eliminated as impractical because of the large number of short exposed lengths and the condition of the pipeline. Refer to section 2.5.2 Murchison Pipeline PL115 for details.

The cut and lift option is a proven operational procedure used in pipeline repair where a damaged section of pipeline is cut, recovered to surface and replaced with a new pipeline section. To remove the 17 exposed lengths of PL 115 in 12m long sections would require 746 cuts and the lifting and handling of 720 x 12m long sections.[77]

[77] The pipeline with concrete weight coat weighs 377kg/m, so a 12m length would weigh approx 4.55 tonnes. 12m is a standard pipe length to suit road transport. Longer section could be lifted depending on the vessel used and crane capacity, but further cuts would be required to be completed onboard before offloading at an onshore quay.

Each section would be cut using hydraulic shears, diamond wire cutting (DWC), abrasive water jet cutting (AWJC) or chop saws as appropriate. To make the cut, using DWC or AWJC cutters, either the pipeline would have to be lifted off the seabed using a deployed lifting frame with hydraulic operated clamps, or a short trench would have to be excavated to allow the tool access. Cutting excavation trenches in the very stiff Murchison clays is problematic. In 2006 CNRI took 40 hours to excavate a single 5.4m long x 2m wide x 800mm deep trench along PL115.[78] [79] Using the hydraulic shears for cutting does not require lifting or excavation. The location of the cut line from the edge of the rock cover is shown in Figure 45 and will be determined to suit the cutting tool selected.

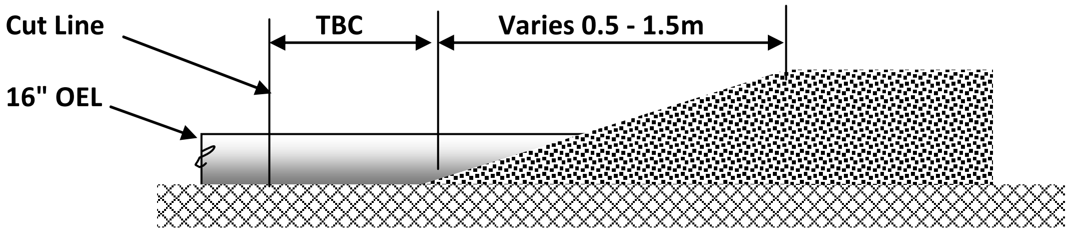


**Figure 45: Location of Cut Lines in PL115**

Approximately 2,500 – 3,000 tonnes of new rock placement would be required to cover the pipeline's 34 cut ends in order to provide protection against future fishing snagging. The exact quantity will depend on the method used to cut the pipeline and the existing rock profile.

### (c) Trench and Bury Exposed Sections of Pipeline

On PL115, any trench and burial operation would have to deal with the following two particular problems:

1. Trenching in the very stiff boulder clays around Murchison would require use of a tool similar to the Canyon Offshore iTrencher. This cuts a vertical sided trench without generating a spoils heap which means that once laid in the trench the pipeline would have to be covered by additional backfill material and or imported rock cover.

2. PL115 has 17 separate exposed sections, each of which would have to be trenched and buried. The exposed sections vary in length from 50m up to 1,900m. On shorter sections there might be problems attaining the appropriate transition lengths at each end, from the pipe protruding from the rock placement down to placement in the bottom of the trench.

   There are seven spans less than 175m long. To accommodate a transition length at the ends plus the exposed section of 2 x 1.5m transition out of the rock profile, three of the spans of less than 100m could not accommodate the required transition length and the remaining four would have pipe touch down length in trench of less than 50m.

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[78] For details see Murchison Pipeline Repair Clamp Works- 2006 doc ref MUR-ACE-SUR-REP-02793

[79] Similar problems were reported by BP for PL 148, where it took 19 hours to excavate a trench to facilitate the abrasive water cutting tool used – see email J Blacklaws to R Sinclair dated 26th July 2012

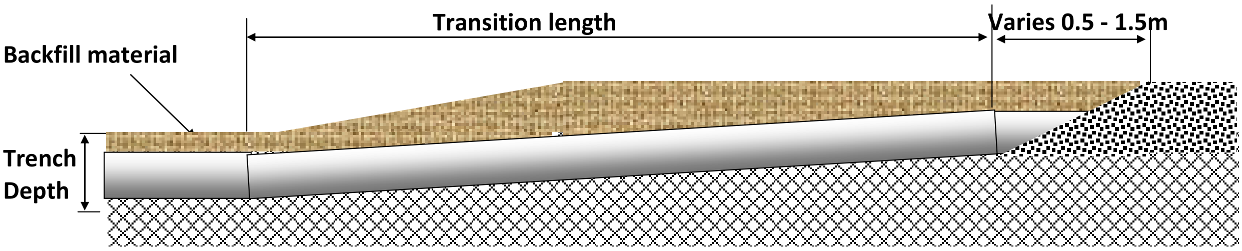


Figure 46: Transition from Rock Placement to Trench[80]

The transition length would be covered by rock placement to match existing profile. It has been estimated that between 6,000 and 12,000[81] tonnes of crushed rock would have to be placed to cover the 17 exposed transition lengths.

### (d) Rock Placement over Exposed Sections of Pipeline

Rock placement would use graded crushed rock that matches the existing rock material specification. The graded rock would be placed onto the seabed in a carefully controlled operation using a dedicated rock placement vessel equipped with a dynamically positioned fall pipe.

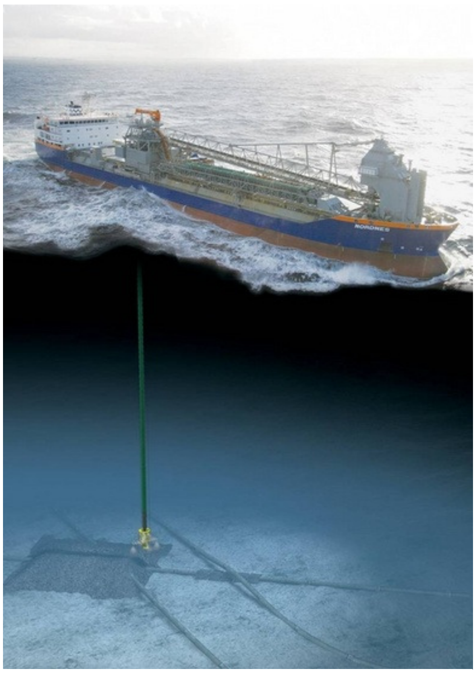

Figure 47: Typical Rock Placement Vessel

The graded rock would be fed into the fall pipe at a controlled rate using a hopper system. The length of the fall pipe would be adjusted for variation in water depth along the route to keep the fallpipe end within 5m of the seabed. This would ensure that the material was placed accurately at the required location and to the specified profile.

The operation would be monitored by an ROV during placement and after completion to confirm the material is deposited in the correct position on the seabed. On completion of the rock placement, over-trawl verification will be undertaken and any remedial works completed before demobilisation of the rock placement vessel.

Post decommissioning surveys of the pipeline would be undertaken at intervals agreed with DECC to verify the stability of the rock placement.

It is estimated that up to 52,000 tonnes of graded rock would be required to cover the exposed sections of pipeline. For comparison, an estimated 63,000 tonnes of rock material was placed during the 1985 to 1987 rock placement operations.

[80] Transition length could be up to 50m+ for a 16" weight coated pipeline
[81] Estimate is based on 50m length with average cover 2.2m rock density 2.2kg/m3 and 17 transition lengths

The area of the seabed directly impacted by the rock placement would be approximately 8,500m by 5m which is equivalent to 0.043km$^2$.

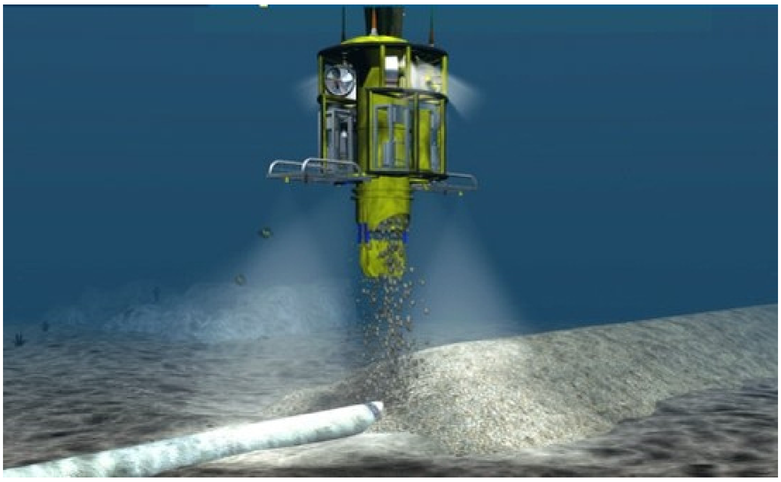

Figure 48: ROV Control of Rock Placement

#### (f) Total Removal of Pipeline by S-Lay or by Cut and Lift

The S-lay option was eliminated as impractical because of the condition of the pipeline. Refer to section 2.5.2 Murchison Pipeline PL115 for details.

For the pipeline total removal option, the existing estimated 63,000 tonnes of crushed rock would have to be displaced to permit access to the pipeline for cutting. PL115 pipeline runs under the live pipelines described in Section 1, consequently a length of PL115 must be left in place until the remaining live pipelines are decommissioned. The length of PL115 remaining under the live pipelines will be subject to Proximity Agreements[82] with each of the respective pipeline owners.

To remove the total pipeline, excluding pipeline cross over corridors, would then require 1600 subsea cuts to facilitate the lifting and handling of 1600 x 12m long sections.[83]

### 3.3.7 Pipeline Bundles PL123, PL124, PL125 Decommissioning Options

The pipeline bundles are as described in section 2.5.1. The carrier pipe has a diameter of 324mm and a wall thickness of 6.35mm and weighs 145kg/m. The bundles are neither trenched nor buried.

Initially five decommissioning options were identified for the pipeline bundles:

1. Leave *in situ* – this was rejected because the bundles were showing signs of damage and were expected to further degrade and become an increasing fishing snagging risk

[82] For Guidance Note see O&GUK Pipeline Proximity Agreements – 2009. Proximity Agreements will define the work to be done in decommissioning PL115, and conditions attached to that work when working within a specified control area of third party live pipelines. The control area has been defined as 300m by the operators of the other pipelines subject to negotiation

[83] Pipeline sections are nominally 12m in length. It may be possible to lift double sections of 24m depending on the condition of the pipeline, the available vessel capacity and the design of the pipe handling frame. This would result in less subsea cuts but more cuts completed on surface.

2. Reverse installation – original installation was by submerged depth tow (see***2.5.1 Murchison Pipeline Bundles***) this was rejected, for removal, due to concerns over the technical feasibility of bundle and towhead structural integrity

3. Trench and Bury – concerns were expressed over the feasibility of trenching the short bundle lengths in the stiff boulder clays around Murchison. The original ballast chains remain attached to the bundles and were a further constraint on trenching operations

4. Cover with rock material – remained a viable option

5. Full removal by cut and lift – was a viable option with removal operation considered as part of the recovery programme of subsea equipment and protection frames (see 2.6.1 Murchison Subsea Wells)

The DECC Guidelines suggest that small diameter pipelines, including flexible flowlines and umbilicals which are neither trenched nor buried should normally be entirely removed[84].

The pipeline bundles PL123, PL124 and PL125 will therefore be removed completely and returned to shore in lengths of approximately 12m, each length weighing 1,740kg.[85] Consequently the pipeline bundles were not considered further in the formal comparative assessment process.

### 3.3.8 Seabed Debris Options

Sub-sea installations include well heads, protective structures, anchor blocks, anchor points and anchor chains used for bundle buoyancy control during installation. All such items will be completely removed for re-use or recycling or final disposal on land.[86] As such subsea equipment and debris will not be considered further in the formal comparative assessment process.

A MBES survey of the Murchison 500m zone was undertaken in 2011 and an as-found debris map produced (see drg CH-ASA-3956-003). The debris included both oil field related debris and naturally occurring boulders and rocks. A further post decommissioning debris survey will be undertaken and a plan for recovery of the oil field debris completed.

### 3.3.9 Summary of Options Carried Forward to the Comparative Assessment

The following options were carried forward to the Comparative Assessment Workshop:

**For the Murchison Jacket**:

1. Full removal of the jacket to 3m below seabed
2. Partial removal of jacket down to top of footings at 44m above seabed (EL -112m LAT)

Each option was assessed for each of the removal methods considered, namely:

[84] See section 10.8 DECC Guidance Notes version 6
[85] Bundle dry weights 145kg/m
[86] See section 7.21 DECC Guidance Notes version 6

a) Removal using a SSCV
b) Removal using a HLV
c) Removal using a SLV
d) Removal by refloating using BTAs

### For the Murchison Drill Cuttings Pile:

1. Leave the drill cuttings pile *in situ* to degrade naturally
2. Recover cuttings slurry to surface separate, treat liquids for discharge overboard, ship solids to shore in containers for further treatment and disposal or re-use
3. Recover cuttings slurry to surface and ship to shore for processing, separation and treatment
4. Recover cuttings slurry to surface, grind cutting to a maximum diameter of 300 microns and inject the slurry into a nominated cuttings reinjection (CRI) well
5. Disperse and distribute over the sediments surrounding the Murchison platform.

### Combined Jacket and Drill Cuttings Pile Options

1. Full removal of jacket with each of the drill cuttings pile options
2. Partial removals of jacket with each of the drill cuttings pile options.

### For the Murchison Export Pipeline PL115

1. Leave *in situ*
2. Minimal removal i.e. removal the Murchison and Dunlin tie-in spools only
3. Recover end tie-in spools and exposed sections of the pipeline by cut and lift
4. Recover end tie-in spools and trench & bury the exposed lengths of pipeline
5. Recover end tie-in spools and place rock cover over exposed lengths of pipeline to match the existing rock profile
6. Remove the pipeline completely by cut and lift after displacing the existing rock cover

# 4 The Comparative Assessment Process

## 4.1 Purpose of the Comparative Assessment

A formal Comparative Assessment (CA) is required under OSPAR Decision 98/3 for facilities which fall within any category of structures that may be considered as a candidate for derogation from the general rule of "total removal"; and for pipelines which are candidates for *in situ* decommissioning as described in the Petroleum Act 1998 and the DECC Guidance Notes.

Screening of the Murchison drill cuttings pile indicates that it falls well below both the OSPAR oil release rate (10 tonnes/yr.) and area persistence (500 $km^2$ years) and as such would not be subject to a formal stage 2 assessment. However, as the drill cuttings pile must be removed in order to access the jacket footings CNRI conducted a CA to determine the best option for the drill cuttings pile.

## 4.2 CNRI CA Method Statement

CNRI developed a CA method statement to outline a framework for conducting detailed CA's for the evaluation of alternative disposal options during the decommissioning planning process. The CNRI framework is based on the high-level framework outlined in the OSPAR Decision 98/3 and the DECC Guidance Notes. It adopts the five main assessment criteria prescribed in these guidelines – Safety, Environment, Technical, Societal and Economic – and appropriate sub-criteria chosen in light of the specific Murchison facilities and CNRI's SHE Policy and CNRI's mission statements.

The CNRI CA methods are covered in detail in the following documents, and are summarised in this chapter:

- Comparative Assessment Method Statement DECOM-CNR-PM-PRO-00081
- Comparative Assessment Procedure MURDECOM-CNR-PM-PRO-00136

## 4.3 CA Criteria and Scoring

Table 13 details the five main criteria, sub-criteria and the assessment method for each sub-criterion. Sub-criteria were assessed and then scored on a scale of 0-1, where 1 represents the best performance or outcome, using either quantitative or qualitative measures as described in Table 13.

A series of score guides were developed for the sub-criterion that was assessed on a qualitative basis. These score guides provided a framework for scoring the qualitative measures on a range of 0-1. Qualitative assessments were made by suitably experienced experts and based on the results of supporting decommissioning studies.

Quantitative estimates for sub-criteria were based on the data presented supporting decommissioning studies the values for each option within sub-criteria were transformed onto the 0-1 scale by proportional normalisation of the raw data.

CNRI developed a set of weightings for each of the five main selection criteria, which were subsequently split equally amongst the sub-criteria. The weightings were determined using Analytical Hierarchical Process (AHP) followed by an internal workshop to discuss the AHP results and ensure the weightings aligned with CNRI's SHE Policy, CNRI's vision and mission statements.

The scores for the option in each of the sub-criteria were then multiplied by the weightings that CNRI has determined for each sub-criterion, and the individual weighted scores summed to give a total weighted score for each option. The total weighted scores were then examined and discussed to determine the recommended option for that facility.

A sensitivity analysis was conducted to test whether the results of the Comparative Assessment would be any different if CNRI had selected different weightings. The results of the sensitivity analysis confirmed that CNRI CA results are robust and would not change with different weightings.

**Table 13 The Criteria and sub criteria used in the CNRI Comparative Assessments**

| Criterion | Sub-criteria | Description of sub-criteria | Assessment of sub-criteria |
|---|---|---|---|
| **SAFETY** | Risk to project personnel offshore | Safety risk to project personnel working offshore. | Quantitative estimate of total PLL for project personnel. |
| | Risk to project personnel onshore | Safety risk to project personnel working onshore. | Quantitative estimate of total PLL for project personnel. |
| | Residual risk to other users of the sea | The combined safety risk to the crews of commercial fishing vessels, the crews of military vessels and the crew and passengers of commercial shipping vessels. | [87]Independent quantitative assessment of the snagging risk for commercial fisheries, and consequent risk to life and limb, as a result of the option's end-point. Provides values for likelihood of "serious injury" and "fatality". |
| **ENVIRONMENT** | Impacts of operations | The impacts of offshore and nearshore operations on any aspect of the marine environment. The impacts of onshore operations (e.g. dismantling, transporting, treating, recycling) on any ecological aspect of the terrestrial environment. | Qualitative assessment based on the results of the EIA process, where impacts are assessed and the significance categorised according to a pre-defined Risk Assessment Matrix. |
| | Impacts of end-points[88] | The impacts of offshore and nearshore end-points on any aspect of the marine environment. The impacts of onshore end-points (e.g. land filling, secondary use) on any ecological aspect of the terrestrial environment. | |
| | Total energy consumption and $CO_2$ emissions | Total energy consumption (GJ) and $CO_2$ emissions (tonnes). | Quantitative estimate of total energy consumption (GJ) and $CO_2$ emissions (tonnes) that would arise as a result of the successful completion of the option, including theoretical energy use and gaseous emissions that would arise if otherwise recyclable materials were left in the sea. Scores of both measures were averaged to provide an overall score for energy and emissions. |

[87] The other users of the sea in the area of the project will be identified, and the potential for any project end points (e.g. jacket footings, or pipelines left *in situ*) to interact with other users will be identified. Only jacket footings and pipelines are candidates to remain *in situ*; therefore, it is highly unlikely that there will be any interactions with commercial shipping or the MOD. Consequently, the safety risk to other users of the sea shall be assessed by quantifying safety risk to fishermen.

[88] End Points addresses the consequence of an operation that describes the final condition of the material or components covered in the option

Table 13, **continued. The criteria and sub-criteria used in the CNRI Comparative Assessments.**

| Criterion | Sub-criteria | Description of sub-criteria | Assessment of sub-criteria |
|---|---|---|---|
| **TECHNICAL** | Technical feasibility | Assessment of the technical feasibility of each option. | Qualitative assessment by expert judgement which was based on the range of engineering and technical studies carried out by the CNRI decommissioning team and their independent consultants. |
| | Ease of recovery from excursion | Assessment of the ability to recover from unplanned excursions and complete the planned decommissioning option. | |
| | Use of proven technology and equipment | Assessment of the extent to which the option requires the use of proven technology. | |
| **SOCIETAL** | Commercial impact on fisheries | Impacts of both the operations and the end-points on the present commercial fisheries in and around the Field. (NB Safety risks were considered under “safety” above). | Qualitative assessment based on information in the EIA process on the level of fishing activity in the area, the type of gear used, the value of the fishery, and the value of the ground that may or may not be available for fishing on completion of the options. |
| | Socio-economic impacts – amenities | The risks from any near-shore and onshore operations and end-points (dismantling, transporting, treating, recycling, land filling) on any aspect of the amenity or infrastructure of the environment. | Qualitative assessment based on the results of the EIA process, where impacts are assessed and the significance categorised according to a pre-defined Risk Assessment Matrix. Also informed by feedback from stakeholder dialogue. |
| | Socio-economic impacts – communities | The risks from any near-shore and onshore operations and end-points (dismantling, transporting, treating, recycling, land filling) on the health, well-being, standard of living, structure or coherence of communities. | Qualitative assessment based on the results of the EIA process, where impacts are assessed and the significance categorised according to a pre-defined Risk Assessment Matrix. Also informed by feedback from stakeholder dialogue. |
| **ECONOMIC** | Total project cost | The estimated total CAPEX cost plus a Net Present Value (NPV) estimate of the cost of any ongoing liability. | Quantitative estimate by CNRI based on the programmes and schedules being prepared for the “Select” phase of the project. |

## 4.4 CA Process

CNRI ran a series of specialist workshops (January to May 2012) to assess and score the decommissioning options within each sub-criteria for the jacket, pipelines and drill cuttings pile. Assessments were made on the basis of relevant study material which was issued as pre-read material for each workshop. The workshops were run[89] and recorded by an independent chair and secretary and the discussions and outcomes from the individual workshops were recorded in formal minutes, which formed the pre-read material for the overall CA workshop.

Results from all of the individual assessment workshops were collated and presented at an overall CA workshop attended by all project personnel, field equity partners and the IRC (Independent Review Consultants).

This workshop, held in May 2012, examined the results and the original raw data behind the weighted scores to:

- Review the scores for each of the options
- Summarise and take into consideration stakeholder's views
- Determine if there were any differences in the performance of the different options
- Determine the extent to which any observed differences in the weighted scores were significant.
- Identify and explain the cause(s)of any differences between options
- Identify the best decommissioning option for each of the facilities under assessment.

A number of actions were identified during the overall workshop in May to validate certain aspects of the raw data before a final recommendation could be made. CNRI reconvened two further follow-up CA meetings in June and July 2012[90] to review the validated data and to determine the recommended options for decommissioning.

[89] Minutes for all the assessment workshops are listed in section 7.8 of this report
[90] Minutes for the two follow up CA assessment workshops are listed in section 7.8 of this report

# 5 – The Comparative Assessment Workshop

This section of the report summarises the main conclusions from the comparative assessment workshop held on the 10th May 2012[91] and follow up meetings with conclusions from sensitivity studies leading to definition of the preferred option for the Murchison jacket, drill cuttings and pipeline PL115.

The pipeline bundles PL123, PL124 and PL125 and the associated subsea equipment will all be completely removed and hence are not considered further in the Comparative Assessment process.

## 5.1 Introduction

The results and total weighted scores from the individual technical assessment workshops were presented to the Comparative Assessment (CA) team, including representatives from CNRI's Murchison partners Wintershall and observers from the IRC, at a workshop held on the 10th May 2012.

The workshop considered options for the following facilities

a) Murchison jacket

b) Murchison drill cuttings pile

c) The Interdependence of jacket and drill cutting options

d) Pipeline PL115

The workshop was split into separate sessions in which each facility in turn was described, the possible decommissioning options summarised and the scores from the relevant technical assessment workshops presented and discussed.

Results of a sensitivity analysis of the weightings applied to the total weighted scores, as defined in the CNRI comparative assessment method (DECOM-CNR-PM-PRO-00081) were presented. This analysis indicates the level of robustness of the recommended option by examining how the results would be affected if the relative importance of the criteria were altered. Following the presentation of this analysis a recommended option for the facility was identified.

This section describes the currently recommended option for each facility and the justifications supporting the recommendation. These justifications are based on the evidence provided by the numerous technical studies and information provided by the previous technical assessment workshops. Several items of further work identified during the 10th May workshop was completed, reported in Post Workshop Action Technical Notes (TNs) and considered in reconvened workshops held in June and July 2012. The relevant TNs and minutes of the reconvened workshops are listed in section 7.8 of this report.

[91] For the Workshop minutes of meeting see doc ref MURDECOM-CNR-PM-MOM-0204

## 5.2 Murchison Jacket – Results of Comparative Assessment

The jacket options were

a) Full removal of jacket with foundation piles cut 3m below mudline

b) Partial removal with the jacket removed down to top of footings, with footings left in place.

Each option was considered for the four removal methods described in
As described in section 2.4.2, after piling was completed, the piles were connected to the jacket by injecting grout between the pile and sleeve. The grouting process was monitored using two grout densitometers fitted to each of 36 pile sleeves. Each densitometer consists of a Caesium 137 source and a detector. Each densitometer is housed inside a lead shield which is further housed inside an outer steel container welded to the pile sleeve surface on the sleeve surface closest to the jacket leg in order to provide protection during jacket launch.

An outline method statement for the removal and recovery of the densitometers using divers, operating within the confined space of the jacket footings, was completed to inform a hazard identification and risk assessment (HIRA) of the operation . A dose assessment was conducted to assess the worst case exposure in the event that the sources leaked to the environment. The assessment concluded that there is no adverse impact on the general public either through direct exposure to a source or through exposure within the food chain should the sources remain *in situ*

Based on the safety risk and dose assessments undertaken, an application has been submitted to SEPA to reclassify the densitometers as irretrievably lost in that the safety risk to divers in attempting to recover the sources from the deep water confined spaces of the jacket footings is significantly greater than the environmental risk of leaving the densitometers in place to decay naturally over time.

**Jacket Decommissioning Methods** where the four removal methods reflected the spectrum of existing and developing technologies.

The options are ranked for full or partial removal for each of the decommissioning and removal methods.

### 5.2.1 Jacket Options scoring for sub criteria

The following option scores were derived by specialist teams independently assessing each criterion. The overall scores were then reviewed by the CA workshop. The sub criteria scores compare the full removal and partial removal options utilising each of the four removal methods and are not intended as a comparison between methods.

| Criteria | Subcriteria | Removal Methods | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | SSCV | | SLV | | HLV | | BTA | |
| | | Full | Partial | Full | Partial | Full | Partial | Full | Partial |
| Safety | Personnel offshore | 0.3 | 0.7 | 0.4 | 1.0 | | 0.8 | 0.3 | 0.5 |
| | Personnel onshore | 0.3 | 1.0 | 0.3 | 1.0 | | 1.0 | 0.3 | 1.0 |
| | Fishermen | 1.0 | 0.3 | 1.0 | 0.3 | | 0.3 | 1.0 | 0.3 |
| Environment | Operations | 0.7 | 0.7 | 0.7 | 0.8 | | 0.6 | 0.5 | 0.6 |
| | End points | 0.7 | 0.9 | 1.0 | 0.9 | | 0.9 | 0.8 | 0.9 |
| | Energy | 1.0 | 1.0 | 1.0 | 1.0 | | 0.9 | 0.8 | 0.8 |
| | Emissions | 1.0 | 1.0 | 1.0 | 1.0 | | 0.9 | 0.7 | 0.7 |
| Technical Feasibili | Technical feasibility | 0.4 | 0.8 | 0.3 | 0.6 | 0.0 | 0.8 | 0.2 | 0.3 |
| | Recovery | 0.7 | 0.8 | 0.3 | 0.4 | 0.0 | 0.7 | 0.2 | 0.2 |
| | Proven technology | 0.5 | 0.9 | 0.3 | 0.5 | 0.0 | 0.8 | 0.3 | 0.6 |
| Societal | Fisheries | 0.9 | 0.6 | 0.9 | 0.6 | | 0.6 | 0.9 | 0.6 |
| | Amenities | 1.0 | 1.0 | 1.0 | 1.0 | | 1.0 | 0.8 | 0.8 |
| | Communities | 1.0 | 1.0 | 1.0 | 1.0 | | 1.0 | 1.0 | 1.0 |
| Cost | Capex | | | | | | | | |

| | |
|---|---|
| Low | Worst performance/outcome |
| Medium | |
| High | Best performance/outcome |

**Table 14 Jacket Options- Sub-criteria Score**

The HLV full removal option scored low in all categories because the heavy lift contractor advised that after studying the option they concluded it was not feasible with their vessel

### 5.2.2 Jacket Safety Comparative Assessment

Safety risks were assessed for:

a) Operational risks, being risks to personnel directly involved in the decommissioning and removal operations

b) Onshore risks, being risks to personnel involved in the fabrication and preparation for offshore decommissioning operations and in the receipt, demolition and disposal of returned items from the offshore operations

c) The residual risk to fishermen arising from fatal snagging incidents related to any jacket remains left on the seabed.

Whilst the operational Individual Risk Per Annum (IRPA) for both full and partial removal options are less than the Health and Safety Executive (HSE) tolerable region of 1 in 1000, the full jacket removal has a PLL of 4.5 x $10^{-2}$ compared to the partial removal option PLL of 2.3 x $10^{-2}$. The full removal option has a PLL 100% greater than that for partial removal This increase in risk was considered as unjustifiable as it goes against the principal of reducing risks to as low as reasonably practical.

PLL figures are driven by the number of people involved and the duration of the offshore operations; hence longer operations or those with a greater number of personnel result in higher PLL values and therefore lower overall scores in this criterion.

The potential risk to onshore personnel consistently had higher PLL values and scored lower for the full removal options than the partial removal counterparts, based on the larger amounts of material that will be returned to shore for demolition, processing, recycling and disposal.

Partial removal creates a long term and persistent risk to fishermen from the potential snagging of their fishing gear on the remaining footings. The footings are expected to remain for up to 1000 years. The PLL for fishermen, directly attributable to the Murchison footings is 1.5 x $10^{-5}$ per annum or 1 in 65,000 years.

During the Comparative Assessment workshop a question was raised as to how to combine the short term operational risk with the long term residual risk to fishermen.[92] The jacket footings will degrade and disintegrate slowly over approximately 1000 years after which the snagging risk to fishermen will decrease. If the annual risk to fishermen reported to the CA workshop is multiplied by the 1000 years and then added to the offshore and onshore operational risk to personnel, the result will represent a total project risk. It was found that the resulting total project risk for full removal was 16% to 23% higher than for partial removal depending on the removal methods considered. [93]

### 5.2.3 Jacket Environmental Comparative Assessment

Environmental impacts associated with the different removal options did not differ significantly such that this criterion did not act as a driver between options.

Environmental impacts were considered in terms of operational impacts and long-term end point impacts associated with any infrastructure decommissioned *in situ*. The full jacket removal options were scored slightly higher in terms of environmental impacts of end-points as the entire infrastructure and potential contaminants would be removed although this was only considered to be of low significance.

The recovery of the footings would also mean that the steel and concrete within the footings could be recycled which is preferable to new manufacture of this material and is reflected in the lower energy and emissions calculated for the full removal option, despite the increased duration and level of vessel activity. However, the total energy use and atmospheric emissions estimated for all removal options were well below the energy emissions arising from one year's operation of the Murchison platform and were consequently considered to be of low significance and therefore did not act as a decision driver.

The level of underwater noise created by vessels and cutting operations was found to be similar for both full and partial removal options. While the duration of the noise would be shorter for the partial removal options and hence these options were scored slightly higher than the full removal options this was not considered to be of significance to act as a decision diver between removal options.

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[92] For a full response to the question see Technical Note: Murchison Comparative Assessment Post Workshop Actions MURDECOM-CNR-PM-GTN-00210

[93] The results were reported to a Workshop Follow up session held on the 11th June 2012 ref MURDECOM-CNR-PM-MOM-00203

It is important to note that the assessment of the environmental impacts of jacket operations and end-points did not consider the potential impacts of having to recover or relocate all or part of the cuttings pile. This is assessed in section 5.3 and the interdependence of jacket and cuttings pile is assessed in section 5.4.

### 5.2.4 Jacket Technical Comparative Assessment

The main criterion which separated the full and partial removal options was technical feasibility. Two issues were raised at the CA and follow-up workshop of 10th May 2012[94]:

a) The technical feasibility of full removal for each method assessed

b) The technical complexity of cutting piled foundations for full removal.

#### Technical Feasibility

a) Using a conventional semi-submersible crane vessel, (SSCV) full jacket removal is within the vessel capacity, albeit with the complex issues of cutting free the foundation pile assemblies whilst maintaining structural integrity.

b) The new single lift vessel (SLV) could not remove the jacket down to mudline in a single lift as the full weight of the jacket exceeds the capacity of the vessel systems (actual dry weight after draining flooded members + marine growth of 26,130te against a capacity of 25,000te). Further studies were undertaken[95] to assess the feasibility of changing the operating mode of the vessel, firstly, to separate and remove the top half of the jacket in a single lift and then to change the jacket lift beams into a shear leg configuration to remove the footings of the jacket. These studies were inconclusive being dependent on the final design of the vessel's jacket lift beams and the capacity of the auxiliary blocks, when rated for deep water application, which has not currently been determined. Consequently full removal using a SLV was scored significantly lower than that for partial removal.

c) The smaller heavy lift vessels (HLV) cannot remove the footings of the jacket because of crane block capacity restraints when re-rigged for deep-water operation. The nominal 5000te capacity main blocks are rated for less than 2,500te when operating in 156m of water. The weight of a single Murchison bottle leg is in excess of 3,000te and consequently the HLV option scored zero for the full removal option. Cutting of the bottle legs into smaller sections was not considered viable.

d) The buoyancy tank assembly (BTA) option would be operating at close to its absolute capacity, and would require the reinstatement of the jacket ballast control system in the four corner legs. The current buoyancy capacity is 23,660te in comparison to the jacket weight of 27,500te which includes actual dry weight with flooded members and marine growth. Even with further modifications to the existing BTAs the risk of failure for the full removal case was considered to be unacceptably high and hence full removal scored lower than partial removal.

[94] See MOM MURDECOM-CNR-PM-MOM-00204 and Technical MURDECOM=CNR-PM-GTN-00210
[95] See MURDECOM-ALS-ST-PRO-00024

Based on the capacities of the removal methods assessed, all four methods are capable of removing the Murchison jacket down to the top of footings but only the SSCV's method could potentially fully remove the platform with any level of confidence.

**The Technical Complexity involved in cutting the Foundation Piles.**
Full removal of the jacket would require the cutting of the footings below the seabed surface.

This could be achieved with two options:

a) Internal pile cutting
b) External pile cutting

For internal pile cutting any debris inside the pile would have to be removed to allow access for a dredging tool to remove the soil plug inside the pile before the cutting tool could be run in. With at least 6 of the 32 piles known to have substantial internal debris, specialist fishing tools would be required to remove the debris, before the dredger and cutting tools could be run in.[96] The internal debris consists of scaffold poles, caisson sections, ladders and wire rope. Although the piles are 84 inch diameter, they are 44m long and hence diver access into piles is not possible[97,98].

If the debris from inside the piles could not be removed, or the soil plug excavated down to 5m[99] below seabed, then external cutting would be required. This would involve the excavation of a large volume of stiff seabed sediment to gain access to the footings. Tools exist in the industry to excavate large volumes of seabed sediment, but they have not been fully tested for large volumes of the type of stiff, boulder-strewn sediment found at Murchison.

Based on currently available excavation techniques, if this operation were possible, it is likely to be a lengthy operation. If excavation is successful the jacket piles would then need to be severed: cutting technologies again exist but do not have a consistent track record for successfully cutting pile groups with restricted access. Both the excavation and cutting tools would represent proven technology being used in a new way and as such would require extensive engineering and testing to prove.

Based on the capacities of the equipment and vessels currently available, full removal of the jacket footings would require multiple cutting and lift operations, the heaviest components being the four bottle leg assemblies each weighing in excess of 3,000te. The feasibility of the excavation, cutting and lifting operations has not been proved and is likely to require significant engineering development before work could commence.

Cutting free the bottle legs from the connecting plan bracing and cutting the foundation piles below mudline introduces stability problems which would be exacerbated if excavation under the mud mats is required.

[96] Removing debris from pile internals was a problem encountered on the Hutton foundation pile removal, internal cutting of piles was changed to external cutting (personal communication S Etherson to project team)
[97] See industry Diver Excursion Limit Tables
[98] See Excursion Tables in Saturation Diving – HSE- Research Report 44
[99] Soil plug is removed to -5m below seabed to allow cutting tool to be run into the pile to make a cut at -3m below seabed

The partial removal options, which leave the jacket footings *in situ*, score higher than the full removal options for two reasons, firstly because the concerns detailed above do not exist or are present to a much smaller degree, and secondly, partial removal of comparable jacket structures has been successfully completed before.

The partial removal option does not carry the same concerns as the full removal options about the feasibility of the excavation, and the cutting and lifting capacity of existing equipment and vessels and therefore is considered to be more technically feasible with a higher probability of success.

### 5.2.5 Jacket Societal Comparative Assessment

Societal considerations were not found to be a great differentiator between options.

There was considered to be a limited impact to onshore amenities and communities because recovered items would be returned to existing specialist onshore facilities for processing under the necessary management and control procedures. The one exception was the BTA option where the refloated jacket would be towed to, and grounded at, a near-shore location in a Norwegian fjord for final demolition. This was considered to impact the amenity value of the local area, albeit to a low level and for a temporary duration.

The societal impact on fishing was assessed both for loss of access in the partial removal case and the loss of fishing time due to snagged or damaged nets. As a consequence full removal scored higher than partial removal in this case.

### 5.2.6 Jacket Economic Comparative Assessment

Costs were assessed for both full and partial removal of the Murchison jacket. Costs included the direct operational costs for each option and the long term residual costs arising from future survey and remedial work commitments, discounted to today's money.

The full removal options cost approximately 75% more than the partial removal options, the cost driver being the increased schedule for the full removal options. The one exception was the refloat option where the cost difference between full and partial removal was not significant.

### 5.2.7 Stakeholder Concerns on Jacket Removal Options.

Stakeholder concerns as raised in the March 2012 Stakeholder Workshop[100] facilitated by the Environmental Council, were largely addressed within the CA Societal and Environmental technical workshops[101].

One issue raised by stakeholders was that cost should not be a main driver in selecting a decommissioning option. This is the reason for reporting the option rankings both with and without costs included.

### 5.2.8 Recommended option for Decommissioning the Murchison Jacket

[100] See CA Stakeholder Workshop – Transcript Report (March 2012) ref doc MURDECOM-TEC-PM-REP-00184
[101] See doc ref MURDECOM-CNR-PM-MOM-00179 and MURDECOM-CNR-PM-MOM-00185

The overall recommended option for the Murchison jacket was determined to be partial removal of the structure down to the top of footings at 44m above seabed (EL-112m LAT).

It was found that the main drivers for this conclusion were the safety and technical feasibility criteria.

The option ranking was determined by applying criteria weightings to the sub-criteria scores reported in Table 15 and discussed during the CA workshop.

| Rank | Including cost criteria |
|---|---|
| 2 | Full Removal SSCV |
| 1 | Partial removal SSCV |
| 2 | Full Removal SLV |
| 1 | Partial Removal SLV |
| NA[102] | Full removal HLV |
| 1 | Partial Removal HLV |
| 1 | Full removal BTA |
| 1 | Partial removal BTA |

| Rank | Excluding cost criteria |
|---|---|
| 2 | Full Removal SSCV |
| 1 | Partial removal SSCV |
| 2 | Full Removal SLV |
| 1 | Partial Removal SLV |
| NA | Full removal HLV |
| 1 | Partial Removal HLV |
| 2 | Full removal BTA |
| 1 | Partial removal BTA |

**Table 15: Ranked Decommissioning Options for the Murchison Jacket[103]**

### 5.2.9 Jacket Sensitivity Analysis of Options' Performance

A sensitivity analysis was run in which the individual comparative assessment weightings were randomly varied to check whether CNRI's weighting of assessment criteria was a significant factor in determining the option rankings. The results showed that for 99% of possible weightings, partial removal of the jacket would be the recommended option, though the method of partial removal, e.g. by a heavy lift vessel, or a single lift vessel may change.

## 5.3 Murchison drill cuttings pile – Results of Comparative Assessment

Five options were assessed for the drill cuttings pile

a) Leave the pile *in situ* to degrade naturally

b) Distribute the pile onto the adjacent seabed, beyond the jacket footprint

c) Recover the drill cuttings to surface and inject down a designated well

d) Recover the drill cuttings to surface and ship to shore for separation treatment and disposal

e) Recover the drill cuttings to surface, separate treat and dispose of liquids and ship solids to shore for treatment and disposal

[102] The small crane vessel (SCV) has a 5,000te capacity block which is de-rated to 2,500te for underwater operations. A single jacket bottle leg assembly weighs 3,000te which is greater than the SCV capacity.
[103] Abbreviations SLV = single lift vessel, HLV = Heavy lift vessel, SCV = small crane vessel and BTA = buoyancy tank assembly for re-floating the jacket

### 5.3.1 Drill Cuttings Pile sub criteria scores

The following option scores were derived by specialist teams independently assessing each criterion. The overall scores were then reviewed by the CA workshop.

| Criteria | Subcriteria | Decommissioning Options | | | | |
|---|---|---|---|---|---|---|
| | | Leave Insitu | Treat liquids offshore + solids onshore | Recover liquids & solids to shore | Recover to surface and inject slurry | Distribute over surrounding sediments |
| **Safety** | Personnel offshore | 0.8 | 0.4 | 0.4 | 0.2 | 0.6 |
| | Personnel onshore | 1.0 | 0.4 | 0.4 | 1.0 | 1.0 |
| | Fishermen | 1.0 | 1.0 | 1.0 | 1.0 | 1.0 |
| **Environment** | Operations | 1.0 | 0.6 | 0.6 | 0.6 | 0.2 |
| | End points | 0.9 | 0.9 | 0.9 | 0.9 | 0.6 |
| | Energy | 1.0 | 0.9 | 0.9 | 0.9 | 0.9 |
| | Emmissions | 1.0 | 0.9 | 0.9 | 0.9 | 0.9 |
| **Technical Feasibili** | Technical feasibility | 1.0 | 0.2 | 0.3 | 0.4 | 0.7 |
| | Recovery | 1.0 | 0.5 | 0.5 | 0.7 | 0.8 |
| | Proven technology | 1.0 | 0.2 | 0.3 | 0.8 | 1.0 |
| **Societal** | Fisheries | 0.6 | 0.8 | 0.8 | 0.9 | 0.8 |
| | Amenities | 1.0 | 0.9 | 0.8 | 1.0 | 1.0 |
| | Communities | 1.0 | 0.9 | 0.9 | 1.0 | 1.0 |
| **Cost** | Capex | 1.0 | 0.3 | 0.3 | 0.3 | 0.7 |

| | |
|---|---|
| Low | Worst performance/outcome |
| Medium | |
| High | Best performance/outcome |

Table 16 Drill Cuttings Pile - Sub-criteria Scores

### 5.3.2 Drill Cuttings Safety Comparative Assessment

In terms of safety, those options which involve the least amount of offshore work e.g. leaving the pile *in situ* or the ROV-based redistribution of the cuttings across the seabed were scored higher than those which would require a greater number of offshore personnel or longer time to complete the offshore operations. The PLL figures for the recovery to surface options were 100% greater than the leave *in-situ* option.

### 5.3.3 Drill Cuttings Environmental Comparative Assessment

The Murchison drill cuttings pile was assessed to fall below the OSPAR thresholds for stage 1 screening.

All management options were considered to have an environmental impact associated with disturbing the cuttings pile sediments, either directly as a result of the removal method or indirectly as a result of the eventual collapse of the jacket footings onto the pile if left in situ. However, disturbance by removal methods was considered to have a more significant impact than the disturbance of the drill cuttings pile by the collapse of the jacket footings if both the footings and the drill cuttings pile were left in situ, as the impacts associated with the collapse would be within already contaminated sediments and of a similar magnitude to currently permitted discharges and predicted recovery within 20 years

The distribution of the cuttings across the seabed for the pile redistribution option scored particularly low under this criterion due to the potential contamination of uncontaminated seabed sediments across a wide area and the long duration of persistence of the impact with recovery predicted within 40 years.

It was noted that the cuttings distribution option has been used for other projects, though severe difficulties were encountered such that the time to complete the operation was significantly longer than estimated. These projects also redistributed a smaller volume of water based mud cuttings material compared to the larger volumes of oil based mud's that currently exists at Murchison.

### 5.3.4 Drill Cuttings Technical Comparative Assessment

The technical feasibility of both the leave *in situ* option and the redistribution of cuttings option scored highly as a result of high technical feasibility and use of proven technology for the redistribution option.

All the other options require the drill cuttings pile to be recovered from the seabed to the surface for treatment, reinjection or store and return to shore for treatment. There is no industry experience of recovering volumes of the size of Murchison and hence these options scored low on technical feasibility and development of available technology.[104]

The offshore reinjection of the cuttings into existing Murchison wells is feasible as this operation is carried out in some fields during drilling operations; however, the two wells which could be used for disposal of the cuttings material cannot be fully tested until production from the field has ceased. Further, current offshore reinjection of cuttings is a proven operation for much smaller volumes of material than the estimated 375,000m$^3$ of cuttings slurry that would be produced from recovering the Murchison cuttings pile. There are concerns that the reinjection of this volume of material may fracture the Murchison reservoir resulting in very real environmental and safety hazards, such as craters developing in the seabed surface or well integrity being compromised. Although a second well would be identified for cuttings injection as a redundancy, the loss of integrity of the primary well may require the abandonment of this operation all together.

The options that require the recovery and either onshore or offshore separation, cleaning and disposal of the cuttings solids and waste liquid were scored the lowest of all options. This is because the volume of material to be recovered from the seabed and brought to shore under either option would be significantly greater than any volumes which are currently brought onshore for treatment and disposal e.g. from drilling operations. In addition, the characteristics of the recovered drill cuttings material may be sufficiently different from drill cuttings produced during drilling operations to require significant alteration to the processing technology. If required, this bespoke process could be viewed as new technology and require significant engineering to complete and prove the system. The technology to complete these operations and the onshore facilities to store and process this volume of material do not currently exist.

[104] See studies cited in Oil & Gas Cuttings Study 2011

### 5.3.5 Drill Cuttings Societal Comparative Assessment

Societal criteria were not found to be a significant differentiator between the options.

The option to leave the drill cuttings pile *in situ* scored lower than remaining options because of the potential loss of fishing grounds, albeit a very small area of 0.007km$^2$ (see section 2.6.2) compared to the 3,000km$^2$ area of ICES rectangle 51F1.

Amenity and community scores were lower for those options which involved large volumes of material being transported back to shore for treatment.

### 5.3.6 Drill Cuttings Cost Comparative Assessment

There is a very significant difference in the cost of leaving the drill cuttings pile *in situ* to degrade naturally compared with all the other options. The main reasons for the difference are the long durations and the extensive equipment spreads required, in all options, to recover the drill cuttings from the seabed and return to surface for treatment or re-injection.

### 5.3.7 Stakeholder Concerns on Drill Cutting management Options

Stakeholders expressed competing concerns between achieving a clean seabed to minimise risks to fishermen and avoid any long term contamination and the environmental disturbance and possible contamination during the recovery and removal from the seabed.

Stakeholders acknowledged that CNRI had used the best available technologies to conduct the sampling of the drill cutting pile but there remained some concern that the material deep within the 15m deep pile had not been characterised. CNRI reported[105] to the 11$^{th}$ June CA workshop the results of further reviews or methods that could be used to obtain deep core samples from the pile which could provide information for the long term management of the cuttings pile.

CNRI initially reviewed the option for sampling during the conductor recovery stage and concluded that there would be some level of disturbance to the pile during pulling of conductors, the result of which would compromise the integrity of any samples subsequently taken, even if practically possible.

CNRI then looked at alternate means of sampling from the platform. Firstly using the original 24 inch diameter drill cuttings chute over which a compact drilling unit would be mounted on the top deck and a drill corer run through the full depth of the cutting pile. The drill cutting chutes are ideally located with respect to the cutting pile centre but are offset in the vertical making it difficult to run a corer down the chute. Other caisson positions were checked but rejected because of their offset from the cutting pile centre.

A final option was examined, that being to use the diving stations located on the cellar deck. Of the five diving stations, stations 3 and 4 could be suitable for accessing the cuttings pile. The operation would require modifications to the cellar deck, installing temporary steel and plated supports for a diesel hydraulic skid mounted drilling rig that would run the drill corer. A similar unit was used on the Murchison platform to mill out and pull in the NLGP umbilical riser.

[105] See MURDECOM-CNR-PM-MOM-00203 and MURDECOM-CNR-PM-GTN-00210

CNRI concluded that even if sampling of the drill cuttings pile through the diving hatches could be achieved, the results were unlikely to change the ranking of the drill cuttings pile management options. The sampling results might however, help validate the modelling tool used to predict the long term fate of the cuttings material and disturbance effects.

### 5.3.8 Recommended Option for Decommissioning the Murchison Drill Cuttings Pile

The option identified as the recommended option for the drill cuttings pile is to leave it *in situ* to degrade naturally.

This is on the basis of the differences in the weighted scores for the safety, environmental and technical feasibility criteria.

The option ranking was determined by applying criteria weightings to the sub-criteria scores reported in Table 16 and discussed during the CA workshop.

| Rank | Including cost criteria |
|---|---|
| 1 | Leave pile *in situ* |
| 2 | Distribute offshore |
| 3 | Offshore injection |
| 4 | Onshore separation and disposal |
| 5 | Offshore separation and liquid disposal; onshore disposal of solids |

| Rank | Excluding cost criteria |
|---|---|
| 1 | Leave pile *in situ* |
| 2 | Distribute offshore |
| 3 | Offshore injection |
| 4 | Onshore separation and disposal |
| 5 | Offshore separation and liquid disposal; onshore disposal of solids |

**Table 17: Ranked Decommissioning Options for the Murchison Drill Cuttings Pile**

### 5.3.9 Sensitivity analysis of options' performance

Sensitivity analysis of the effect of changing the weighting percentages for the criteria showed that for the range of random combinations assessed, there was a 100% probability that the leave *in situ* option would be the recommended option for the drill cuttings pile.

## 5.4 Combined Jacket and Drill Cuttings Pile

The possible decommissioning options for the Murchison jacket and drill cuttings pile have been assessed separately on the individual merits and disadvantages of the options.

As the drill cuttings are located directly below and around the jacket and footings, the possible combined impacts of disturbing the drill cuttings pile to access or fully remove the jacket has also been considered.

For drill cuttings, when the leave *in situ* option is discounted the best performing option is to redistribute over the adjacent seabed. The weighted score for this option was then combined with the weighted scores for each of the jacket options to determine if the inclusion of cuttings pile considerations would have any effect on the ranking of the jacket options. The results are shown in Table 18.

The inclusion of the drill cuttings scores supports the recommended option for partial removal of the jacket and increases the difference between the full and partial jacket removal total weighted scores.

The combined recommendation is therefore for partial removal of the Murchison jacket, allowing the cuttings pile to remain *in situ* to degrade naturally.

**Table 18: Combined Ranked Decommissioning Options for the Murchison Jacket and Drill Cuttings Pile**

| Rank | Including cost criteria |
|---|---|
| 1 | Partial removal of jacket; drill cuttings left *in situ* |
| 2 | Full removal of jacket; drill cuttings redistributed offshore |

| Rank | Excluding cost criteria |
|---|---|
| 1 | Partial removal of jacket; drill cuttings left *in situ* |
| 2 | Full removal of jacket; drill cuttings redistributed offshore |

## 5.5 Murchison Pipeline PL115 Results of Comparative Assessment

Six options were considered for decommissioning the PL115 pipeline:

a) **Leave the pipeline *in situ***, intermittently exposed on the seabed and with existing rock cover
b) **Minimal removal** – remove Dunlin and Murchison tie-in spools, leave the remainder *in situ*
c) **Partial removal** of the exposed lengths by cut and lift
d) **Trench and bury** the exposed lengths
e) **Remedial rock placement** over the exposed lengths
f) **Total removal** of the pipeline by cut and lift after dispersing existing rock cover

### 5.5.1 PL115 sub criteria scores

The following option scores were derived by specialist teams independently assessing each criterion. The overall scores were then reviewed by the CA workshop.

| Criteria | Subcriteria | Decommissioning Options | | | | | |
|---|---|---|---|---|---|---|---|
| | | Leave Insitu | Minimal Removal | Partial removal by cut and lift | Trench and bury exposed sections | Remedial Rock placement | Total removal by cut and lift |
| Safety | Personnel offshore | 1.0 | 0.8 | 0.4 | 0.7 | 0.8 | 0.3 |
| | Personnel onshore | 1.0 | 1.0 | 0.5 | 1.0 | 1.0 | 0.3 |
| | Fishermen | 0.3 | 0.3 | 0.8 | 1.0 | 0.7 | 1.0 |
| Environment | Operations | 1.0 | 0.9 | 0.8 | 0.6 | 0.8 | 0.6 |
| | End points | 1.0 | 1.0 | 0.9 | 0.9 | 1.0 | 0.9 |
| | Energy | 1.0 | 1.0 | 0.9 | 1.0 | 1.0 | 0.8 |
| | Emmissions | 1.0 | 1.0 | 0.9 | 1.0 | 1.0 | 0.8 |
| Technical Feasibili | Technical feasibility | 1.0 | 1.0 | 0.8 | 0.6 | 1.0 | 0.7 |
| | Recovery | 1.0 | 1.0 | 0.8 | 0.5 | 1.0 | 0.8 |
| | Proven technology | 1.0 | 1.0 | 1.0 | 0.3 | 1.0 | 1.0 |
| Societal | Fisheries | 0.6 | 0.6 | 0.6 | 0.7 | 0.8 | 0.8 |
| | Amenities | 1.0 | 1.0 | 0.8 | 1.0 | 1.0 | 0.8 |
| | Communities | 1.0 | 1.0 | 1.0 | 1.0 | 1.0 | 1.0 |
| Cost | Capex | 1.0 | 0.9 | 0.4 | 0.9 | 1.0 | 0.3 |

| | |
|---|---|
| Low | Worst performance/outcome |
| Medium | |
| High | Best performance/outcome |

**Table 19 PL115 Decommissioning Options - Sub-criteria Scoring**

### 5.5.2 PL115 Safety Comparative Assessment

Full removal of PL115 by cut and lift will take the longest time and involve the greatest number of offshore personnel and has a resulting PLL of 1.29 x $10^{-2}$. Partial removal by cut and lift also involves a significant offshore spread, albeit for a shorter duration than full removal with a resulting PLL of 7.19 x $10^{-3}$.

The trench and bury option also requires a significant offshore spread and has a consequential PLL of 1.86 x $10^{-3}$.

The leave *in situ* option is the safest option with a PLL of 2.89 x $10^{-4}$ by virtue of the very small amount of offshore work involved. The remedial rock placement has a PLL of 1.33 x $10^{-3}$ because of the relatively small specialist offshore spread required.

Whilst the leave *in situ* option has the lowest operational PLL it poses an increasing snagging risk for fishermen. The exposed pipeline sections will begin to break up between 169 and 400 years after decommissioning. This will result in an increasing snagging frequency and a PLL of 1.7 x $10^{-3}$ pa for the fishermen.

Since the 10th May CA workshop additional work has been undertaken[106] to model the snagging risk to fishermen. Firstly modelling the effect of the remedial rock placement option resulted in a PLL of 3.5 x $10^{-4}$ pa. This is a significant improvement over the leave *in situ* option.

[106] For full results see Technical Note- Murchison Comparative Assessment – Post Workshop Actions _PL115 doc ref MURDECOM-CNR-PM-GTN-00226

A second post partial removal model was generated. This assumed that the existing exposed sections of pipeline had been removed by cut and lift and the resulting exposed cut ends protected by a rock cover. This left a series of separate rock covered berms for which a fishing risk of 3.3 x $10^{-4}$ pa was calculated.

Rock has already been used to protect some sections of the pipeline and historical surveys demonstrate that this rock has remained stable and over-trawlable by fishing gear. The use of rock to cover the remaining exposed section would reduce the risk of snagging fishing gear and is also, in terms of offshore operations, the option with the lowest risk to offshore personnel.

When comparing the partial removal by cut and lift with the remedial rock placement over exposed sections, the former has an operation PLL five times greater than the later, for no reduction in the residual snagging risk to fishermen i.e. for fishing risk partial removal has a fishing PL or 3.3 x $10^{-4}$ compared to 3.5 x $10^{-4}$ for remedial rock placement.

### 5.5.3 PL115 Environmental Comparative Assessment

When considering environmental impacts, the trench and bury option was found to have the greatest impact on the seabed and the longest recovery time due to the amount of disturbance to the sediments to ensure the exposed sections were buried to a minimum depth of 0.6m.

The total removal of the pipeline would require some excavation of the sediments in order to position some types of cutting equipment. The existing rock cover would have to be removed from the pipeline to provide access for cutting and lifting of the pipeline. The existing rock cover would most likely be moved using a form of mass flow jetting tool which would scatter the rock across the adjacent seabed. The long-term impact of this scattered rock would not be significant as the Murchison sediments are known to be strewn with surface and sub-surface rocks and boulders.

In terms of risk to fishing activities, this natural condition of the seabed would usually require the use of hard-bottom or rock-hopping demersal gear and so the scattered rock material would be unlikely to require a change of the type of gear used in the area.

The partial removal option would have less of an impact on the seabed sediments than total removal, as any disturbance associated with excavation of the sediment to position the cutting gear would be confined to a smaller area and would not be related to the relocated existing rock cover, though the cut ends would have to be buried or covered with rock.

Extending the rock-placement to cover the exposed sections would physically disturb the seabed but the level of disturbance would be less than for the trenching option. Rock placement would utilise an ROV controlled fall pipe equipped with cameras, profilers and other sensors to ensure rock is only placed within the planned footprint with minimal spread over adjacent sediment, thereby minimising seabed disturbance.

The remedial rock placement option would also replace some of the existing soft sediment with an additional modified hard substrate. Surveys around the Murchison platform show that the seabed exhibits areas of cobbles and boulders with small amounts of gravel with shell debris. The presence of this naturally occurring hard substrate together with the existing rock placement material suggests that organisms associated with hard substrates will already be present in the area and will not be introduced as a result of any new rock placed within the area. The area of modified substrate would be kept to a minimum by the accurate placement and profiling of rock. There are no Annex 1 habitats along the route of PL115.

As no operations would be undertaken for the leave *in situ* option there would be little impact to the environment: the long-term degradation of the pipeline was considered and the impact of any released contaminants is expected to be of low significance because the line would have been flushed and cleaned before decommissioning. The concrete coating of this pipeline would also prevent significant movement of the pipeline across the seabed as it degrades.

### 5.5.4 PL115 Technical Comparative Assessment

The use of rock placement and the recovery of spool-pieces from pipelines are all standard operations within the oil and gas industry.

The total removal and partial removal options for the pipeline by cut and lift are also standard operations though these are more complex when dealing with aging concrete-coated pipelines.

As with the excavation of the jacket footings, there are some concerns over the ability of current trenching equipment to successfully and efficiently complete the operation in sediments which are stiff and contain numerous boulders as at Murchison. Further, some of the exposed sections are too short to deploy the equipment and accommodate the necessary trench transitions of the equipment – these sections would have to be buried by rock cover. For this reason the feasibility of the trench and bury option for the PL115 pipeline is in question and was scored low.

### 5.5.5 PL115 Societal Comparative Assessment

All options scored similarly for the amenities and communities sub-criteria. The effects of processing of any returned material were not considered to be significantly higher than those resulting from normal operations.

Differences in the options were primarily driven by the impact on commercial fisheries particularly related to loss of access for those options in which exposed sections of the pipeline would be left on the seabed.

### 5.5.6 PL115 Cost Comparative Assessment

Costs were assessed for all six PL115 decommissioning options. Costs included the direct operational costs for each option together with the long term residual costs arising from future survey and remedial work commitments, discounted to today's money.

The options total removal, and partial removal, both by cut and lift, scored considerably lower than the remaining options because of the difference in the length of the operations involved.

### 5.5.7 PL115 Stakeholder Concerns

Stakeholder concerns as raised in the March Stakeholder Workshop[107] facilitated by the Environmental Council were largely addressed within the CA Sociatel and Environmental technical workshops[108].

One issue raised by stakeholders was that cost should not be a main driver in selecting decommissioning options. This is the reason for reporting the options ranking with and without costs included.

Stakeholder concerns were primarily with safety risks associated with the pipeline or sections of the pipeline remaining *in situ.* Follow up sessions were held separately with the SFF and JNCC during which concerns were raised relating to the change in habitat for the PL115 remedial rock placement option and the risk to fishermen of the rock placement option compared to the cut and lift options.[109]

### 5.5.8 Recommended Option for Decommissioning the Murchison Pipeline PL115

The oil export pipeline PL115 is 19km long and is constructed of steel with concrete weight coating. Approximately 11km of the pipeline is covered by graded rock, leaving 17 uncovered sections varying from 1.96km to 50m in length.

Two options were identified as comparable options based on the overall weighted scores: **leave *in situ*** and **remedial rock placement** with the latter scoring marginally higher overall based on the lower risk to fishermen. These scores were driven by safety and technical feasibility concerns.

The option ranking was determined by applying criteria weightings to the sub-criteria scores reported in Table 19 and discussed during the CA workshop.

| Rank | Including cost criteria |
|---|---|
| 1 | Remedial rock placement |
| 2 | Leave *in situ* |
| 3 | Trench and bury |
| 4 | Minimal removal |
| 5 | Total removal |
| 6 | Partial removal |

| Rank | Excluding cost criteria |
|---|---|
| 1 | Remedial rock placement |
| 2 | Leave *in situ* |
| 3 | Trench and bury |
| 4 | Minimal removal |
| 5 | Total removal |
| 6 | Partial removal |

**Table 20: Ranked decommissioning options for the pipeline PL115**

### 5.5.9 PL115 Sensitivity analysis of options' performance

The sensitivity analysis of the overall weighted scores for the decommissioning options for PL115 indicated that the leave *in situ* option and rock placement options would always be ranked as the top two options despite any changes to the weighting percentages.

[107] See CA Stakeholder Workshop – Transcript Report (March 2012) ref doc MURDECOM-TEC-PM-REP-00184
[108] See doc ref MURDECOM-CNR-PM-MOM-00170 and MURDECOM-CNR-PM-MOM-00185
[109] These concerns were further studied and the results reported in the PL115- Post Workshop Actions MURDECOM-CNR-PM-GTN-00226

There is also an 82% probability that leave *in situ* would be the recommended option. However, when stakeholder concerns and CNRI core values are considered, the leave *in situ* option, which does not include any immediate action to mitigate future risks to the fishing industry from the presence of the pipeline, is unacceptable.

The recommended option for the PL115 pipeline is therefore to extend the present rock cover over the exposed sections.

## 6 Independent Review Consultants – Verification Certificate

The requirement for independent verification of the comparative assessment process is defined in DECC's Decommissioning Guidelines.

The DECC Decommissioning Guidelines define the purpose of such verification being to confirm that the data used is sound and appropriate, the assessment reliable, the comparative assessment process transparent and the chosen decommissioning option supported by credible and verifiable data.

CNRI appointed Xodus Group Ltd (Xodus) as the expert Independent Review Consultant (IRC) to undertake the verification process in support of the Murchison Decommissioning Programme.

The specific role of the IRC was to ensure that an appropriate range of decommissioning options was being assessed in sufficient depth and quality so that the resultant information available was adequate for a rational decision to be reached by CNRI in the Comparative Assessment Process (CA).

This was achieved by ensuring that the IRC maintained an independence from CNRI's Comparative Assessment decision making process. The verification process then included

1. Review and comment on the studies and technical reports used to inform the CA process
2. Review and comment on the CNRI's Comparative Assessment Method Statement
3. Attend the pre-assessment workshop to witness the briefing of the CA participants
4. Review the Minutes of Meeting from the pre-assessment workshop and technical scoring meetings
5. Review Minutes of Meeting and notes of individual stakeholder meetings.
6. Attend stakeholder open session to witness the briefing and handling of questions from stakeholders
7. Review the Minutes of Meeting notes, finding and conclusions from the CA workshop
8. Review the means by which the results from the CA workshop are reported back to stakeholders

At the conclusion of the CA process, the IRC provided its report, published alongside this document in support of the Decommissioning Programme, summarizing their findings for individual studies used in support of the CA and a separate statement on the process that CNRI employed to manage the comparative assessment process. See Murchison Decommissioning Comparative Assessment – Final IRC Report MURDECOM-XDS_PM-REP-00062.

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26 June 2012

# Expert Verification Statement

## Murchison – Comparative Assessment Procedure

This statement has been prepared by Xodus Group Ltd (Xodus) in compliance with the UK Department of Energy and Climate Change (DECC) Decommissioning Guidance Notes on independent expert verification (Ref. 1).

Xodus has been appointed by CNR International (U.K.) Limited (CNRI), on behalf of the Murchison field partners CNRI and Wintershall Norge AS, to independently verify that a reliable Comparative Assessment (CA) procedure has been established in relation to the Murchison Asset for the following:-

> Jacket and footings
> Drill cuttings pile
> Pipelines and bundles

Xodus has reviewed the Comparative Assessment Method Statement (Ref. 2) and the Comparative Assessment Procedure (Ref.3). These reports are available for viewing at http://www.cnri-northsea-decom.com.

Xodus verifies that the processes described in the Method Statement and the Procedure will deliver robust, scientifically based CA's based on the five main criteria of:-

1. Safety
2. Environmental
3. Technical
4. Societal
5. Economic

**Issued:** ML Taylor

**Checked:** T Cairns

**Approved:** ML Taylor

1. DECC. Guidance Notes. Decommissioning of Offshore Oil and Gas Installations and Pipelines under the Petroleum Act 1998. Version 6. March 2011 (p64)

2. CNRI. Comparative Assessment Method Statement. Doc No DECOM-CNR-PM-PRO-00081 Rev B1.

3. CNRI. Comparative Assessment Procedure. Doc No MURDECOM-CNR-PM-PRO-00136 Rev A2.

# 7 Reference Documents

This section of the report list all reference documents, studies and regulatory procedures referred to in the Comparative Assessment process.

## 7.1 Regulations and Procedures

DECC Guidance Notes Version 6

OSPAR 2006. Recommendation 2006/5 on a Management Regime of Offshore Cuttings Piles

Oil & Gas UK Guidelines for the Suspension & Abandonment of Wells – Issue 4 2012

Comparative Assessment Method Statement
DECOM-CNR-PM-PRO-00081

Comparative Assessment Procedure
MURDECOM-CNR-PM-PRO-00136

Murchison Decommissioning Comparative Assessment – Final IRC Report
MURDECOM-XDS-PM-REP-00062

## 7.2 Surveys

Murchison Pre-Decommissioning Environmental Baseline Survey
MURDECOM – ERT-EN-REP-00056

ISS Pipeline Inspection and Jacket Survey 2011
PLS-ISS-SU-REP-15430

Murchison Asset Inventory Study Report
MURDECOM-PSN-PM-REP-00037

Murchison Platform – 2010 ROV Structural Inspection Report
MUR-ISS-SU-REP-15406

Murchison Shipping Traffic Survey
MURDECOM-ATC-EN-STU-00199

CNRI Assets- Topside Structural Integrity Surveys 2011
MUR-ATK-ST-REP-0227

Murchison Field – Subsea Inspection of 16” oil export line, flowlines and wellheads – 1983
(Report by Sub Sea Survey Ltd- CNR075646)

Soils Survey Report – 1977
Fugro- U0170-2/1

Facilities for Onshore Receipt of Decommissioning Structures Survey -2011
DECOM-GLND-PM-REP-00043

Refurbishment /Demolition Asbestos Survey – Murchison Platform April 2012-09-26
MURDECOM-RPS-EN-REP-00200

CNRI Technical Note on Murchison Subsea Satellite Well Status
MURDECOM-CNR-PM-WTN-00001

## 7.3 Removal Studies

Murchison –Post CoP Alternate Use Appraisal
DECOM-GLND-PM-STU-00048

Murchison Platform Removal Technology Study
DECOM-GLND-PM-STU-00042

Murchison Jacket Weight Report
MURDECOM-ATK-ST-REP-00253 revA2 July 2012

Murchison Topside Weight Review
MURDECOM-ATK-ST-REP-00010

Murchison Jacket Weight Calculations
MURDECOM-ATK-ST-REP-00254

Murchison Field 2002 Decommissioning Study
Saipem Doc 979978/KMUK/Removal 2002-CNR096810

Murchison Topside & Jacket Removal Study-Method Statement
MURDECOM-HMC-ST-PRO- 00033

Method Statement Murchison Jacket Removal
MURDECOM-ALS-ST-PRO- 00024

Murchison Jacket Removal Method Statement
MURDECOM-ALS-ST-PRO-00219 – July 2012

Provision of Topside and Jacket Removal Studies decommissioning of the Murchison Platform
MURDECOM-SHL-PM-REP- 00067

Murchison Jacket BTA Removal Study Report
MURDECOM-AKER-ST-REP- 00025

CNRI Technical Note on Murchison Anchor Pile Cutting
MURDECOM-CNR-PM-GTN-00137

Evaluation of Removal Options for the Murchison Jacket
MURDECOM-GLND-PM-REP-00008

Murchison Platform Structural Analysis Model Development
MUR-ATK-ST-REP-0157

Limitation to Marine Operations during Platform Removal
DECOM-GLND-MA-REP-00044

Technology for Subsea Cutting of Jacket members
DECOM-GLND-ST-REP-00045

Murchison Topside Separation Study Report
MURDECOM-PSN-ST-REP-00043

Technical Notes on Murchison Densitometers
MURDECOM-CNR-EN-ETN-00001

PL115-16” Oil Export Pipeline, Lifetime Expectancy Study
CNR32-r01c

Ninian North and Murchison Preliminary Footings Life Assessment
DECOM-ATK-ST-REP-00080

CNRI Technical Note on Murchison Conductor String Removal
MURDECOM-CNR-WS-TFN-00001

## 7.4 Drill Cuttings

CNRI Technical Note on Murchison Drill Cuttings Pile Removal Methods
DECOM-CNR-EN-ETN-00102

Murchison Drill Cuttings Pile – Environmental Impact Study
MURDECOM-BMT-EN-STU- 00132

Murchison Drill Cuttings Pile Long-Term Cuttings Pile Characteristics
MURDECOM-GEN-EN-REP- 00133

Murchison Drill Cuttings Pile Modelling the Effects of Human Disturbance of the Cuttings Pile
MURDECOM-GEN-EN-REP- 00135

Oil & Gas UK Cutting Study 2011
MURDECOM-FSS-PM-STU-00001

## 7.5 Environment

Environmental Statement for the Decommissioning of the Murchison Facilities
MURDECOM-BMT-EN-REP-00198

Underwater Noise Impact Assessment for the Murchison Field Decommissioning
MURDECOM-BMT-EN-REP- 00122

Energy and Emissions Report for the Decommissioning of Murchison
MURDECOM-BMT-EN-REP- 00125

Environmental Statement for the Decommissioning of the Murchison Facilities – Risk Assessment and Environmental Assessment Workshop Report
MURDECOM-BMT-EN-REP- 00127

Murchison Decommissioning - Commercial Fisheries - Socioeconomic Impact Study
MURDECOM-SFF-EN-STU- 00131

Evaluation of the Extent of Colonisation of *Lophilia pertusa* and Marine Growth on the Murchison Platform
A.INS.001/Murchison 2010-CNR0105209

Assessment of Marine Growth levels on Murchison
NNP-ATK-ST-TEC-0140

Environmental Conditions in the Northern North Sea – Marex report
(no document number)

Wave Characteristics Model
DECOM-PHYSE-EN-STU-00063

Metocean Criteria for Murchison
Physe Ltd document reference C319-R413-10

Application for Assessing the Removal of the Murchison Densitometers
MURDECOM-CNR-EN-REP-0002

## 7.6 Pipeline

Murchison Subsea and Pipeline Assets – Decommissioning Report
MURDECOM ATK-PI-REP- 00027

Murchison Subsea and Pipeline Assets Register
MURDECOM ATK-PI-DAB- 00028

2011 Pipeline Inspection & Environmental Survey Phase 2 Report…
PLS-ISS-SU-REP-15430

Subsea Ultrasonic Inspection of selected areas on the 16” Murchison Oil export pipeline
C42666/01 Issue 01
MUR-ACE-SU-REP-02796

Technical Integrity Assessment 2010 – North Sea Pipelines
CNR0106254

Final Inline Inspection Report – PL115 -2010
CNR080046

PL115-16” Oil Export Pipeline Lifetime Expectancy Study
MURDECOM-JEE-PM-STU-00233

## 7.7 Safety

Decommissioning Project - General Hazid Jacket Removal Report
DECOM-WHF-SA-HAZ-00094

Decommissioning Project - Major Hazard Workshop Identification Report - Woodhill Frontier
DECOM-WHF-SA-REP-00106

Murchison Platform - Perpetuity Liability Hazid - Hazid Report
MURDECOM-WHF-SA-HAZ- 00103

Decommissioning Project – Safety Support – Murchison Topsides and Jacket Decommissioning Hazid - Heerema Option
MURDECOM-WHF-SA-REP- 00071

Decommissioning Project – Safety Support – Murchison Jacket Decommissioning Hazid - Aker Marine Option
MURDECOM-WHF-SA-REP- 00074

Decommissioning Project – Safety Support – Murchison Topsides and Jacket Decommissioning Hazid - Allseas Option
MURDECOM-WHF-SA-REP- 00076

Decommissioning Project – Safety Support – Murchison Pipeline Decommissioning Hazid - Atkins Option
MURDECOM-WHF-SA-REP- 00080

Decommissioning Project – Safety Support - Murchison - Topsides and Jacket Decommissioning Hazid - SHL Option
MURDECOM-WHF-SA-REP- 00087

Decommissioning Project – Safety Support – Murchison Onshore Disposal - Hazid/Envid Report
MURDECOM-WHF-SA-REP- 00113

Decommissioning Project - QRA Report - Murchison Jacket Decommissioning Options – Woodhill Frontier
MURDECOM-WHF-SA-REP- 00115

Decommissioning Project- QRA Report – Murchison Pipeline Decommissioning Option
MURDECOM- WHF-SA-REP-00089

Decommissioning Project- QRA Report – Murchison Topsides Decommissioning Options
MURDECOM-WHF-SA-REP-00114

Decommissioning Project – Safety Support – Murchison Topsides Decommissioning Hazid - AFDO Marine Option
MURDECOM-WHF-SA-REP- 00072

Decommissioning Project – Murchison Platform – Murchison Pipelines and Platform Fishing Risk Analysis - Technical Note
DECOM-ATC-EN-TN-00098

Murchison Decommissioning Study – Preliminary Footings Life Assessment
DECOM-ATK-ST-REP-00080

Ship Collision Risk – Management Review
A1204-CNR-TN-1

Assessment of Murchison Densitometer Sources HIRA
MURDECOM-CNR-EN-REP-00001

## 7.8 Comparative Assessment & Stakeholder Workshops

CA Workshop – Pre-Assessment Introduction Workshop
MURDECOM-CNR-PM-MOM- 00151

CA Workshop – Technical Assessment Murchison Jacket
MURDECOM-CNR-PM-MOM- 00156

CA Workshop – Economic Assessment Murchison Jacket & Pipelines
MURDECOM-CNR-PM-MOM- 00161

CA Workshop – Technical Assessment Murchison Pipelines
MURDECOM-CNR-PM-MOM- 00162

CA Workshop – Safety Assessment Murchison Jacket & Pipelines
MURDECOM-CNR-PM-MOM- 00176

CA Workshop – Societal Assessment Murchison Jacket & Pipelines
MURDECOM-CNR-PM-MOM- 00179

CA Stakeholder Workshop – Transcript Report (March 2012)
MURDECOM-TEC-PM-REP-00184

CA Workshop – Environmental Assessment Murchison Jacket & Pipelines
MURDECOM-CNR-PM-MOM- 00185

CA Workshop – Drill Cuttings Pile Assessment
MURDECOM-CNR-PM-MOM- 00186

CA Workshop – Murchison 10th May 2012
MURDECOM-CNR-PM-MOM- 00204

CA Workshop – Follow up Murchison Workshop 11th June 2012
MURDECOM-CNR-PM-MOM- 00203

Technical Note – Murchison Comparative Assessment – Post Workshop Action
MURDECOM-CNR-PM-GTN-00210

Technical Note- Murchison Comparative Assessment – Post Workshop Action – PL115
MURDECOM-CNR-PM-GTN-00226

Murchison Decommissioning Stakeholder Workshop 8th Nov 2012 – Summary Report
MURDECOM – CNR-PM-REP-00236

Murchison Decommissioning Stakeholder Workshop 8th Nov 2012 – Transcript Report
MURDECOM – CNR-PM-REP-00237