Heather Pipeline Decommissioning Comparative Assessment

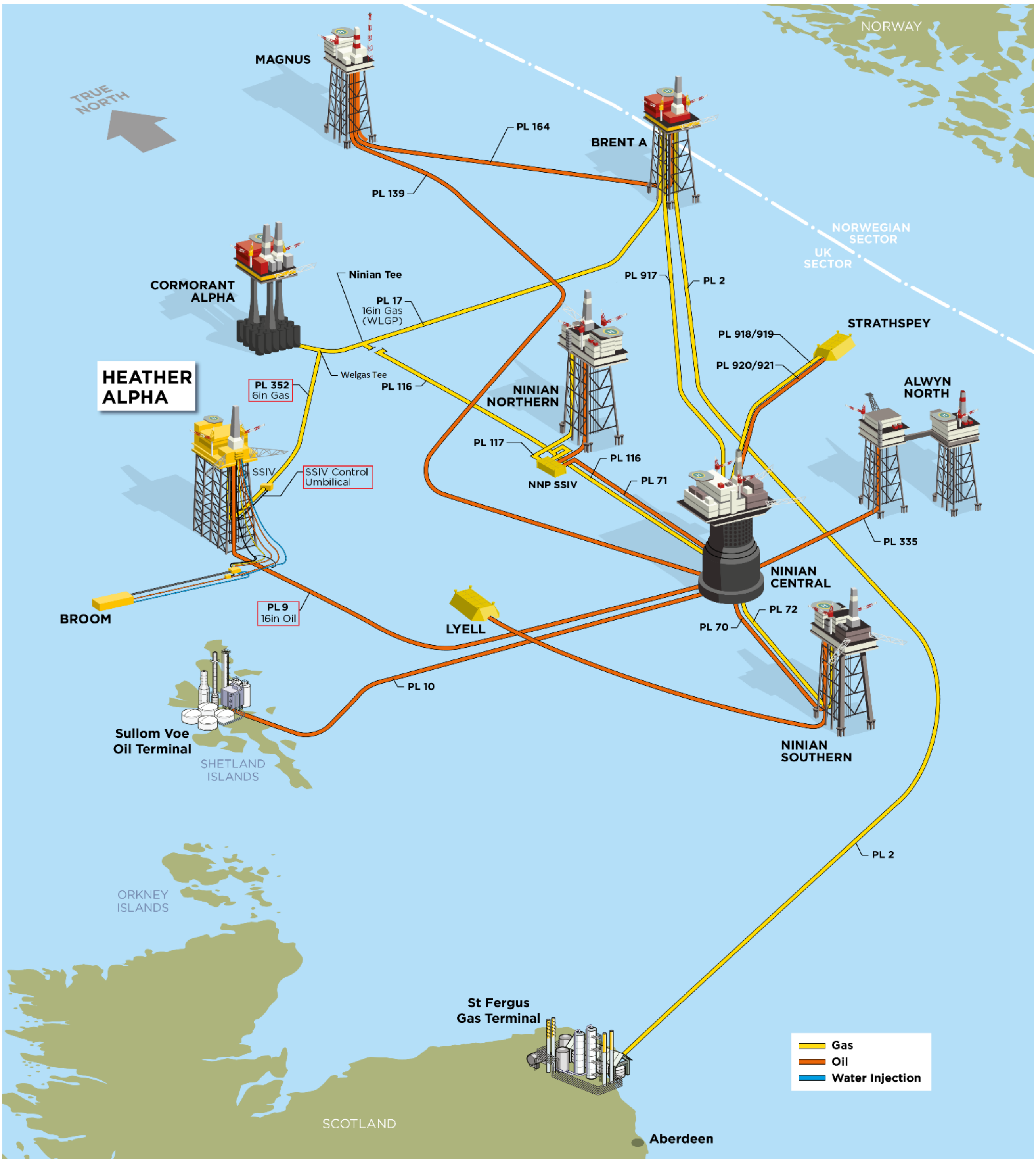

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TABLE OF ABBREVIATIONS

ABBREVIATION	EXPLANATION
~	Approximately
3LPP	3-Layer Polypropylene, coating used for carbon steel pipelines and pipework
ALARP	As Low As Reasonably Practicable
Approach	Initial or final stretch of pipeline (or umbilical) as it leaves its point of origin or reaches its destination
CWC	Concrete Weight Coated (PL9 only)
CSV	Construction Support Vessel
CTE	Coal Tar Epoxy
Cut and lift	The 'cut and lift' method of removing trenched and buried pipelines would involve excavating the pipelines from within the seabed and thereafter cutting the pipeline into recoverable and transportable lengths. This method of removal can be very time-consuming for long pipelines and, would be problematic for concrete coated pipelines. The method is usually only viable for short pipelines
DOL	Depth of Lowering (bottom of pipe in trench)
DP	Decommissioning Programme(s)
EA	Environmental Appraisal
Eductor	An eductor is a simple type of pump which works on the 'venturi effect' to pump out air, gas or liquid from a specified area
EnQuest	EnQuest Heather Limited
ESDV	Emergency Shutdown Valve
Exposure	An exposure occurs when the 'crown' of a pipeline or umbilical can be seen. This does not generally mean it is a hazard
FBE	Fusion Bonded Epoxy
FishSAFE	The FishSAFE database contains a host of oil & gas structures, pipelines, and potential fishing hazards. This includes information and changes as the data are reported for pipelines and cables, suspended wellheads pipeline spans, surface & subsurface structures, safety zones & pipeline gates (www.fishsafe.eu)
HDPE	High Density Polyethylene
HSEQ	Health, Safety, Environment, Quality
ID	Identity (as in tabulated feature)
IRM	Inspection, Repair and Maintenance
", in	Inch; 25.4 millimetres
Km	Kilometre
LAT	Lowest Astronomical Tide
M	Metre(s)
MFE	Mass Flow Excavator
Monel	A nickel alloy, primarily composed of nickel (from 52 to 67%) and copper, with small amounts of iron, manganese, carbon, and silicon
Morgrip connector	Proprietary pipeline connector
MSB	Mean Seabed
N,S,E,W	North, South, East, West
n/a	Not Applicable
N/A	(Data) Not Available
Neoprene	A synthetic rubber
NFFO	National Federation of Fishermen's Organisations
NIFPO	Northern Ireland Fish Producers Organisation Ltd
NORM	Naturally Occurring Radioactive Material
NSTA	North Sea Transition Authority
OD	Outside Diameter (of pipe)
OPRED	Offshore Petroleum Regulator for Environment and Decommissioning

ABBREVIATION	EXPLANATION
Order of Magnitude	Size difference by factor of 10: one (10^1) means 10-times, two (10^2) means 100-times difference
Piggybacked	Clamped or connected to another pipeline along its length
Pipeline	Pipeline or umbilical
PL, PLU	Pipeline, Umbilical Identification numbers (UK)
Post-trenching	Post-trenching involves cutting, ploughing or jetting a trench underneath the pipeline, such that it is lowered into the seabed
PWA	Pipeline Works Authorisation
Q1, Q2, Q3, Q4	Quarter 1, Quarter 2, Quarter 3, or Quarter 4 of any given year
OPRED	Offshore Petroleum Regulator for Environment and Decommissioning
Qualitative	Result determined using judgement and use of risk and impact matrices
Quantitative	Result determined using numerical data and by calculation
RBS	Riser Base Structure
Remediation	For the purposes of this document remediation can mean one of, or a combination of the following: post-trenching, removal of exposures and spans, deposition of additional rock
Reportable span	A reportable span is a significant span which meets set criteria (FishSAFE criteria) of height above the seabed and span length (10m long x 0.8m high)
Reel lay	Using the reel-lay method a flexible pipeline or small diameter rigid pipeline is installed from a large reel mounted on a pipelay barge. A pipe is spooled from a drum (reel) straightened with tension applied and laid over a ramp to the seabed
ROV	Remotely Operated Vehicle
ROVSV	Remotely Operated Vehicle Support Vessel
S-lay	A pipelay method whereby sections of pipe are welded together on a horizontal deck, their transition down to seabed taking the form of an elongated "S"
SAC	Special Area of Conservation
SFF	Scottish Fishermen's Federation
Span	Similar to an exposure except that the whole of the section of pipeline is visible above the seabed rather than just part of it. Once the height and length dimensions meet or exceed certain criteria the spam becomes a reportable span
Splash zone	The wetted area of a riser or structure or riser immediately above and below the mean water level
SSIV	Subsea Isolation Valve
SVT	Sullom Voe Terminal
TOP	Top of Pipe
UK	United Kingdom
UKCS	United Kingdom Continental Shelf
Umbilical	Flexible pipeline manufactured of various materials including steel and plastics typically used to send electrical power, communication signals, chemicals and hydraulic fluid to a manifold or wellhead. An umbilical will include cables and tubes that are covered with an outer sheath to protect them from damage
UNO	Unless Notified Otherwise
UTM	Universal Transverse Mercator (Coordinate System)
Welgas Tee	Manifold Junction for a number of pi-pipelines, including PL17 (Cormorant Alpha to Brent A), PL114 (from North Cormorant), and PL352 (to Heather Alpha). UTM Coordinates: 388738.758 E, 6770510.069 N
WGS84	World Geodetic System 1984
WI	Water Injection
WLGP	Western Leg Gas Pipeline (PL17)
X	Number of (e.g. 16x = 16 in Number)

ASSESSMENT	DESCRIPTION
Broadly Acceptable / Low & least preferred[1]	Risks broadly acceptable but controls shall be subject to continuous improvement through the implementation of the HSEQ Management System and considering changes such as technology improvements; performance in other 'broadly acceptable' options marginally better.
Broadly Acceptable / Low & in-between least & most preferred[1]	As above, but performance of this option is marginally better or marginally worse than others.
Broadly Acceptable / Low & most preferred[1]	As above but performance in other 'broadly acceptable' options marginally worse.
Tolerable / Medium Non-preferred[1]	Risks are tolerable and managed to ALARP. Controls and measures to reduce risks to ALARP require identification, documentation, and approval by responsible leader.
Intolerable / High[1] not acceptable	Impacts are intolerable. Controls and measures to reduce impact to ALARP (at least to Medium) and require identification, documentation, implementation, and approval.

[1] The colour of this highlighted cell is used in the assessment tables – please refer Appendix C and Appendix D.

1. EXECUTIVE SUMMARY

A Comparative Assessment of pipelines is a key consideration within the Decommissioning Programmes submitted to the Offshore Petroleum Regulator for Environment and Decommissioning ('OPRED').

The Heather Field is situated within block 2/5 of the Northern North Sea sector of the United Kingdom Continental Shelf.

Until production ceased in 2020, produced crude oil from the Heather Field was exported to Ninian Central platform using PL9 which is a 16in concrete weight coated ('CWC') pipeline ~33.2km long. The oil is then comingled with production from other facilities and transported from Ninian Central (via PL10, a 36in pipeline) to the Sullom Voe Oil Terminal ('SVT').

Processed gas for the gas turbines used to be imported from the Western Leg Gas Pipeline ('WLGP') using a 6in pipeline (PL352) routed between what is commonly referred to as the Welgas Tee to the Heather Alpha Platform via the Emergency Shutdown Valve ('ESDV') skid. PL352 is ~19.4km long.

The Heather platform is host to a number of risers and umbilicals associated with the Broom development tied back to Heather. These include PL2693 (formerly PL2003), PL2004, PL3758 (formerly PL2005), PL2006, PL2007[2] (and PLU2008). These will be subject to separate Decommissioning Programmes and Comparative Assessment.

Pipeline burial status

This document summarises a comparative assessment of the most feasible options for decommissioning the following pipelines:

- PL9, trenched with multiple exposures, ~33.2km long.
- PL352, trenched with short exposures, ~19.4km long.
- PLU6254 ESDV umbilical, trenched with short exposures, ~570m long (incl. riser section).

Three decommissioning options are considered for the pipelines:

- **Complete removal** – This involves the complete removal of the pipelines by whatever means would be most practicable and acceptable from a technical perspective.
- **Partial removal or remediation** – This would involve removing exposed or potentially unstable sections of pipelines or carrying out remedial work to make the remaining pipeline safe for leaving *in situ*. This option is relevant for those pipelines that are known to have exposures or spans. There will be a need to verify their status via future surveys.
- **Leave *in situ*** – This involves leaving the pipeline(s) *in situ* with no remedial works, but possibly needing to verify their status via future surveys.

Method

The assessment considered five criteria for both the short-term decommissioning activities and the longer-term for 'legacy' related activities. The criteria were: technical feasibility, safety related risks with three sub-criteria, environmental with five sub-criteria, societal effects with three sub-criteria and cost.

Since the decommissioning of the surface laid ends of the pipelines on the final approaches is the same irrespective of which option is pursued, with the exception of cost, the decommissioning of these is not included in this assessment. Any differences are incremental to the decommissioning

[2] PL2007 is incorporated within the PLU2008 umbilical

activities associated with surface laid infrastructure.

Conclusion

From a purely technical perspective, the complete removal option is technically feasible for PL9, PL352 and PLU6254 (ESDV umbilical), using 'cut and lift' for PL9 and reverse reel for both PL352 and the umbilical. Where they are buried the pipelines and umbilical would need to be excavated from the trench or from within rock but technically this is achievable.

The partial removal options would similarly be technically achievable, but in practical terms *in situ* decommissioning would be easier to achieve from a technical perspective.

Several of the exposed sections in PL9 are too short or are interspersed with rock to be post-trenched, which means that they could only be dealt with by the partial removal option or the deposition of additional rock. Therefore, the use of the post-trenching option instead of partial removal is not recommended for PL9.

From a safety perspective, given that the activities and techniques – including the remediation options instead of partial removal are frequently used in the North Sea, the risks from all hazards relating to 'cut and lift' and reverse reel methods of removal as well as excavation would be broadly acceptable. For project personnel, the threat to safety increases with the volume of work and material dealt with, and by inference in the short-term the leave *in situ* option would present the least threat to the safety of offshore and onshore project personnel.

The greatest risk relating to marine users is likely to be concerned with snagging of fishing gear, specifically demersal trawl boards. Demersal trawling is the dominant type of fishing in the area. For demersal (and shellfish) trawling activities there is a potential for snagging on equipment left on the seabed, including spoil mounds and pipelines that remain on the seabed after decommissioning activities have been completed.

By completely removing the infrastructure the risk of snagging would be removed *in perpetuity*. Therefore, the complete removal option would result in lower residual risks to mariners and other users of the sea. Assuming that both pipelines and the umbilical remain buried the partial removal or remediation option also satisfies the requirement to remove snagging hazards.

Outside of the 500m safety zones at Heather and Ninian Central, leave PL9 and PL352 *in situ*, with the accompanying exposures and spans continuing to exist as they are now. Providing the spans are monitored and do not exceed FishSAFE criteria there would be no discernable change to the existing situation. This means, however, that for the leave *in situ* and partial removal or remediation options pipeline inspections, monitoring, and the remediation of any spans would need to continue as done in the past.

The duration that vessels would be are required in the field for the complete removal, partial removal and remediation options would be longer than required for leave *in situ*. and this would be reflected in the use of energy, emissions to air, noise and planned discharges to sea.

While the complete removal option would result in the most short-term disruption, no materials would be left in the seabed. Both the partial removal and leave *in situ* options would result in materials being left in the seabed to degrade naturally but at little detriment to the local marine environment.

If the removal of all of the buried pipelines affects a 10 m wide corridor, the overall area affected would be ~0.54 km^2. This would be a temporary impact and would be considered very small as a percentage of the North Sea. The area of seabed affected by partial removal or either of the remediation operations would also be very small. As a guide, it is estimated that the leave *in situ* option would result in around ~0.27 km^2 of the seabed being permanently affected which is roughly half of the area temporarily affected by complete removal.

While the vessels are present in the field and activities are being undertaken the area would not be accessible for fishing. Therefore, the magnitude of the impact on commercial activities is related to the number and duration of vessels but it can be expected that any impact would be small and managed using vessel management methods.

The main commercial activity in the area is a mixture of demersal fishing. The occurrence of pelagic fishing is much less prominent and has been virtually non-existent for a number of years in two of the three ICES rectangles containing Heather related infrastructure (section 3.3). The potential effects could be loss of fishing revenue due to exclusion from fishing grounds, disturbance of the seabed or loss of, or damage to fishing equipment. Notwithstanding the loss of fishing equipment, historically the average value of fish landed per km^2 in the Heather area - the largest values being obtained in ICES rectangle 50F0, is small.

In pursuing any of the decommissioning options the effect on employment would likely result in the continuation of existing jobs rather than lead to the creation of new employment opportunities.

The effect on communities near the port sites is not considered a significant differentiator between options.

For all three pipelines the leave *in situ* option would be the least costly to achieve. The cost assessment accounts for short-term decommissioning activities as well as surveys over the longer-term.

For PL9 the cost of complete removal would be double the cost of partial removal and much more than the cost of leave *in situ*, options. The deposition of rock would be cheaper than partial removal. Theoretically, the cost of post-trenching the exposures would be more than leave *in situ* and the deposition of rock, but it is not technically viable.

For PL352 the complete removal option would cost ~4x leave *in situ* and slightly more than 2x the partial removal option. The deposition of rock would be about half the cost of complete removal and ~50% more than the partial removal. Theoretically, post-trenching would be the slightly cheaper than deposition of rock, but neither of the remediation options are practical alternatives.

For PLU6254 the costs for complete removal and leave *in situ* are comparable. Neither of the remediation options are practical alternatives because of the inefficiencies involved when dealing with short individual exposures in several different locations.

For the complete removal option once completed, no more costs would be incurred for future pipeline surveys while pipelines - or parts thereof, that are left *in situ* would be subject to future pipeline inspections.

The cost assessment for the pipelines and umbilical accounts for a post-decommissioning survey and assumes that future surveys will be required.

Recommendations

While the exposure and spans for PL352 and PLU62564 have a reasonable chance of disappearing over the next few years the same cannot be stated for PL9 of which approximately one-third remains exposed after decades of service. PL9 will need to continue being surveyed with remedial works likely to be required while the threat of reportable spans continues.

As a result of the foregoing the following recommendations are presented for consideration:

- PL352 & PLU6254 – leave *in situ*. Subject to survey, having removed the surface laid ends, leave PL352 and PLU6254 *in situ* without remediation. This on the basis that the number and extent of exposure and spans will have reduced since 2018 and can be expected to reduce further by the time the next round of survey have been carried out.
- PL9 – leave *in situ* with remedial works involving the deposition of rock on spans only (~2.0 km),

leaving exposures where they are found. Thereafter, the pipeline burial status should continue to be monitored using a Risk Based Inspection regime.

- Surface laid pipeline and umbilical ends should be removed.

For PL9, taking this approach reduces environmental impact on the seabed and need for extensive pipeline remedial works in the short-term and potentially accounts for the pipeline becoming more extensively buried in future from the natural migration of the seabed.

2. INTRODUCTION

2.1 Overview

The Heather installation is in block 2/5 of the United Kingdom Continental Shelf (UKCS) and is a fixed and fully integrated installation consisting of a modular topside providing manned production, drilling, and utilities facilities and a piled steel jacket. It is serviced by two pipelines, and it provides power and controls to the Emergency Shutdown Valve ('ESDV') for the import gas pipeline via an umbilical. The Heather field is located approximately 458 km NNE of Aberdeen in a water depth of ~143 m. Refer Figure 2.2.1 below.

The installation was installed in 1977/78, with first oil being produced on 6th October 1978.

The Heather development comprises:

- The Heather Alpha platform with a topside supported by a steel jacket.
- PL9, trenched with multiple exposures, ~32.8 km long.
- PL9A, part suspended in water column and now partially buried in drill cuttings, 139 m long.
- PL352, trenched and now mostly buried, ~19.4 km long.
- Umbilical for PL352 ESDV, trenched and now mostly buried, ~570 m long.

Until production ceased in 2020 produced crude oil from the Field was exported to Ninian Central platform using PL9 which is a 16 in concrete weight coated ('CWC') pipeline ~33.2km long. The oil is then comingled with production from other facilities and transported via PL10 to the Sullom Voe Terminal ('SVT').

Pipeline PL9A is short section of flexible flowline 139 m long (including the length the 1.5m long Morgrip connectors at each end) and it was installed to replace a compromised 122m long section of PL9 near the Heather platform.

Processed gas used to be imported from the Western Leg Gas Pipeline ('WLGP') using a 6in pipeline (PL352) routed between what is commonly referred to as the Welgas Tee to the Heather Alpha Platform. The pipeline is ~19.4km long.

Heather provides power and controls to the ESDV for PL352 via a 570 m long umbilical.

2.2 Purpose

Following public, stakeholder and regulatory consultation, the Heather pipeline Decommissioning Programme will be submitted in full compliance with the OPRED guidance notes [8]. As per these guidance notes, pipeline decommissioning options require to be comparatively assessed. If the condition of the mattresses or grout bags precludes their safe or efficient removal, then any proposal to leave them in place must also be supported by an appropriate comparative assessment of the options.

The Decommissioning Programme [3] explains the principles of the removal activities and is supported by an Environmental Appraisal [4] and this Comparative Assessment.

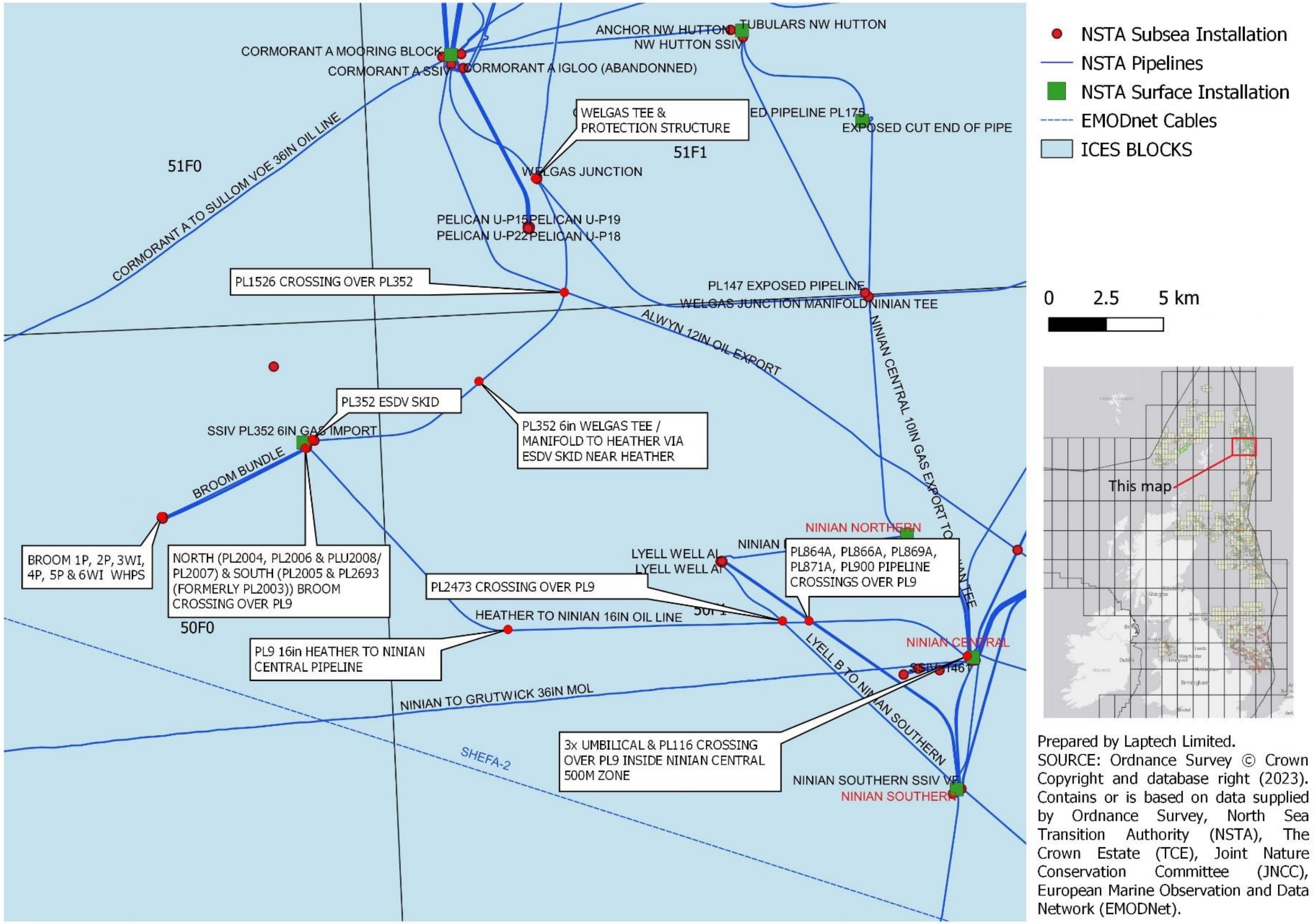


Figure 2.2.1: Locality of Heather in relation to other assets and infrastructure

3. ENVIRONMENTAL SETTING

3.1 Bathymetry and seabed features

The Heather platform is in UKCS Block 2/5 within the East Shetland basin of the northern North Sea, and the local area was subject to an Environmental Baseline Survey in 2020. The general water depth within the survey area showed little variation, ranging from 141.9 m in the southeast to 145.3 m in the northwest with a natural slope of 0.11°. The main feature of the survey was the presence of drill cuttings underneath the platform. The top of the pile is approximately 17 m above the natural seabed. Various features were to be found adjacent to the platform, including debris from construction and fishing activities, exposed infrastructure, and potential pockmarks.

Methane derived authigenic carbonates ('MDAC') are often formed within larger pockmarks and can form bubbling reefs and the EU Habitats Directive Annex I habitat "Submarine structures made by leaking gases". Some 500 m north of the platform there is evidence of a large seabed depression ~60 cm deep and up to 34 m wide containing gravel and empty mussel shells. Two further distinct areas of smaller pockmarks approximately 500 m east and 400 m southeast of the platform were also observed. These seabed depressions were often recorded to contain gravel and/or cobbles and were also frequently inhabited by fish, particularly ling (*Molva molva*). Due to the size and circular shape of these depressions, they appear to be "unit pockmarks". However, the Heather pre-decommissioning environmental survey report [5] confirmed that no Annex 1 habitats were to be found within these depressions in the survey area.

Most of the seabed near Heather consists of muddy sand sediment. It is a mixed sediment type composed primarily of sand, with varying small contributions of fines and gravels outside of the area affected by the drill cuttings. The sediment closer to the platform consists of a mix of cohesive silt, intermixed with coarse sediment and mussel shells with the colour of sediment being nearer to black, most likely due to the presence of drill cuttings.

The sediment within the physical boundary of the drill cuttings pile contains higher proportions of gravelly material. This was typically found on the surface of the drill cuttings with a matrix of fine sedimentary material relating to loose drilling mud derived sediment.

3.2 Habitat sensitivities

The Heather field lies approximately 65 km from any areas of special importance (Figure 3.2.1). The North-east Faroe-Shetland Channel Nature Conservation Marine Protected Area ('NCMPA') and the Pobie Bank Reef SAC are located approximately 123 km northwest and approximately 65 km southwest of the Heather platform respectively. Additionally, the Braemar Pockmarks SAC (Annex I habitat 'Submarine structures made by leaking gases') is approximately 250 km south of the survey area. The most likely sensitive habitats (Annex I, UKBAP and OSPAR) are biogenic reefs formed by the cold-water coral *Lophelia pertusa* or mussels (*Modiolus modiolus* or *Mytilus edulis*), cobble reefs – as a result of glacial deposits, and carbonate mounds or structures produced from leaking gas (i.e. around active pockmarks). Please refer to [9] for an explanation of Annex I Habitats.

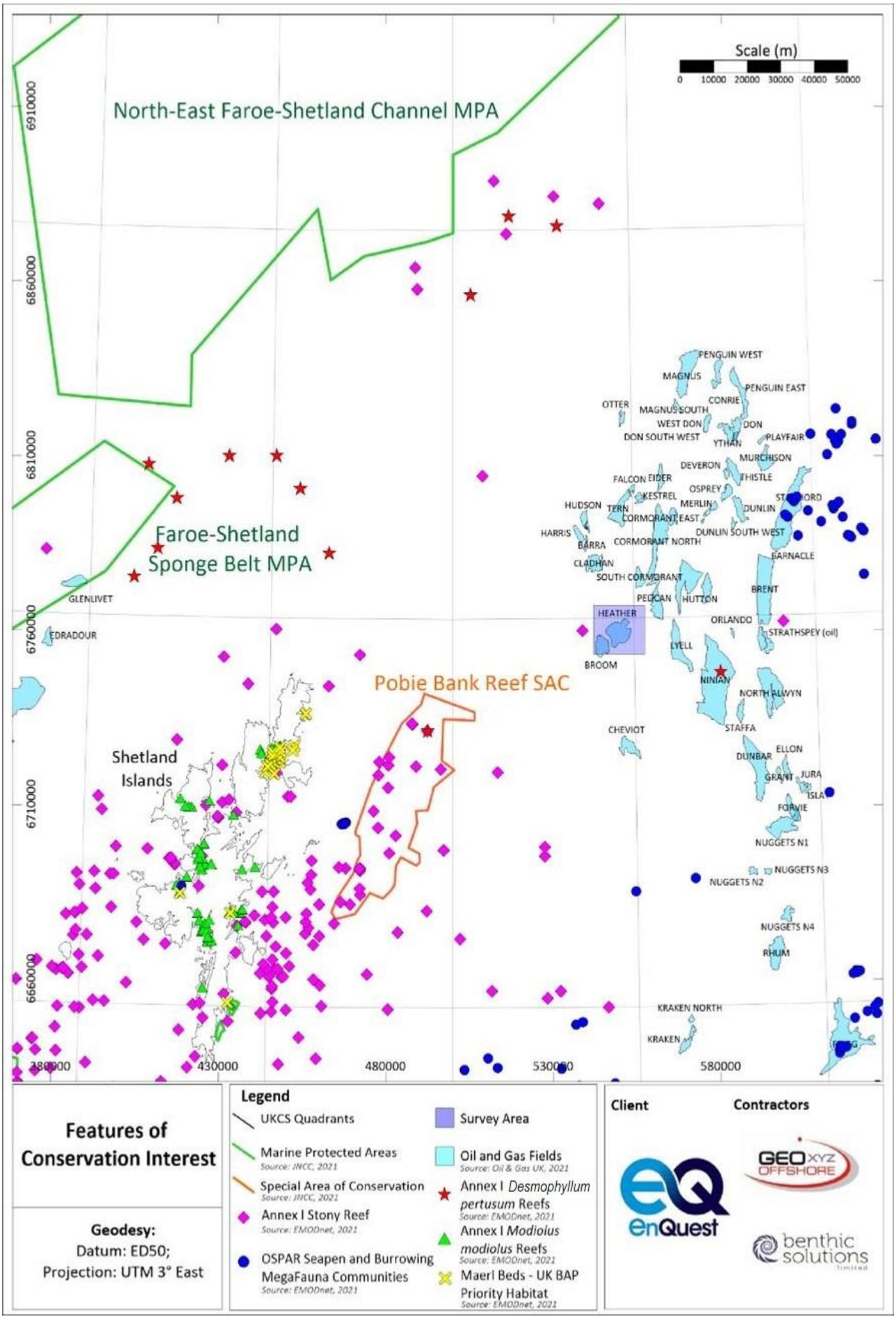


Figure 3.2.1: Features of conservation Interest in relation to Heather

3.3 Commercial fishing

The Heather pipelines are contained within ICES rectangles 50F0, 50F1 and 51F1 (Figure 2.2.1). An analysis of the fishing activity between 2015 and 2020 would suggest that more recently each of the individual ICES areas have contributed little to the overall UK fishing effort [7]. This is indicated in Figure 3.3.1, Figure 3.3.2 and Figure 3.3.3, with demersal fishing being the dominant type of fishing in terms of value. Returns from shellfish landings from the area are so low that they don't register on the graphs. A short length of the pipelines is routed through ICES 50F0 as they depart or arrive at the Heather installation while most of PL9 is routed through ICES 51F0 and most of PL352 is routed through ICES 50F1 and 51F1.

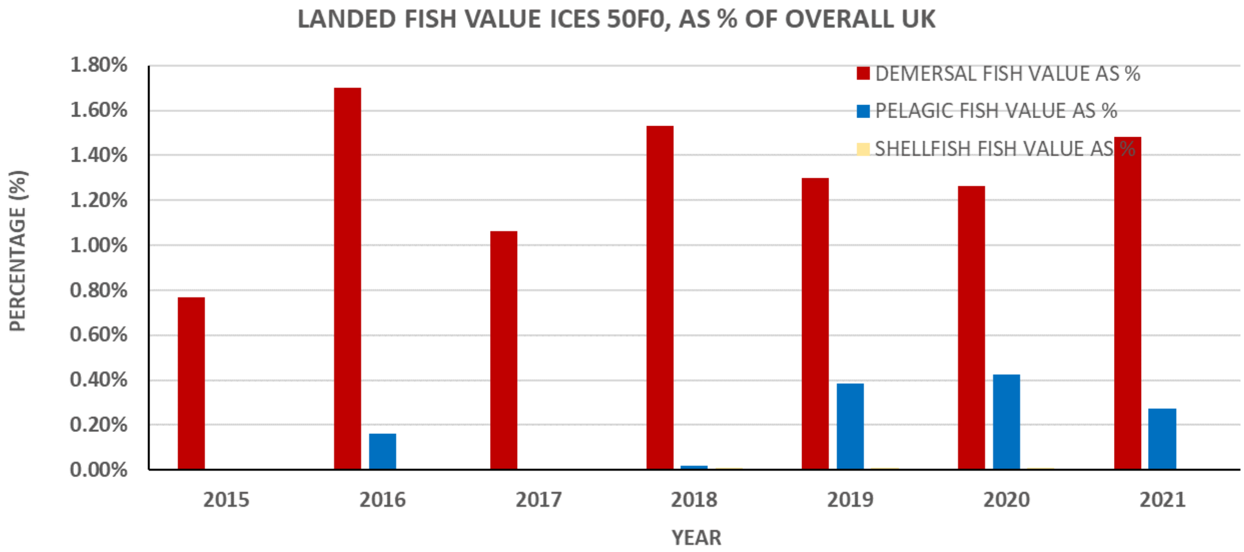


Figure 3.3.1: Value of fish landings from 50F0 as a percentage of UK fishing effort

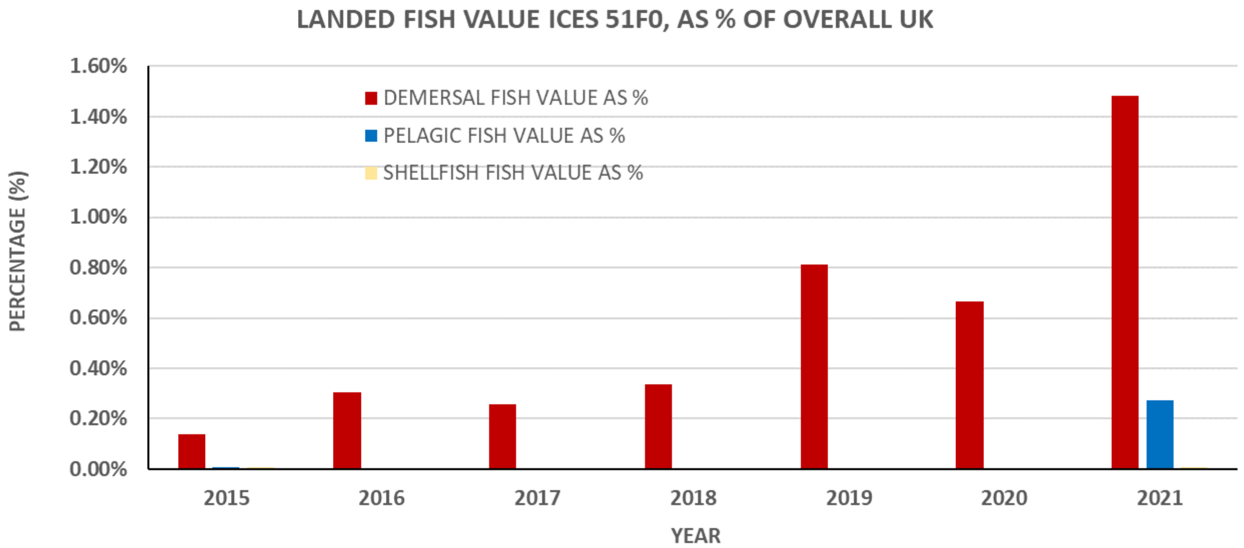


Figure 3.3.2: Value of fish landings from 51F0 as a percentage of UK fishing effort

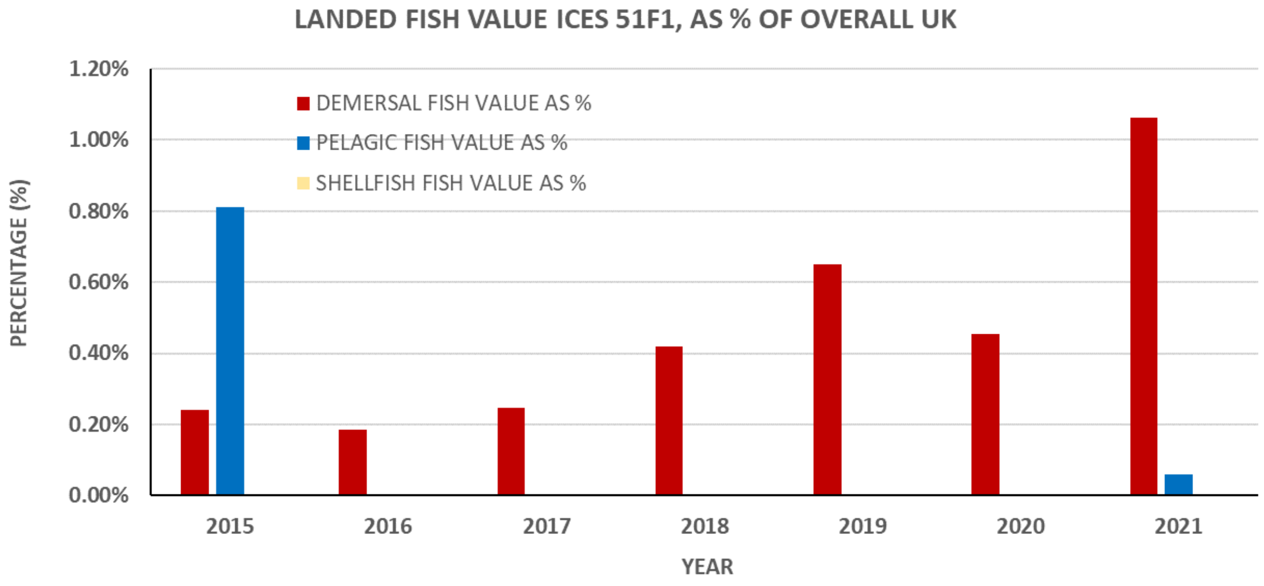


Figure 3.3.3: Value of fish landings from 51F1 as a percentage of UK fishing effort

Landed fish value and average landed fish value per km^2 within ICES rectangle 50F0, 50F1 and 51F1 can be seen in the following graphs between Figure 3.3.4 to Figure 3.3.9.

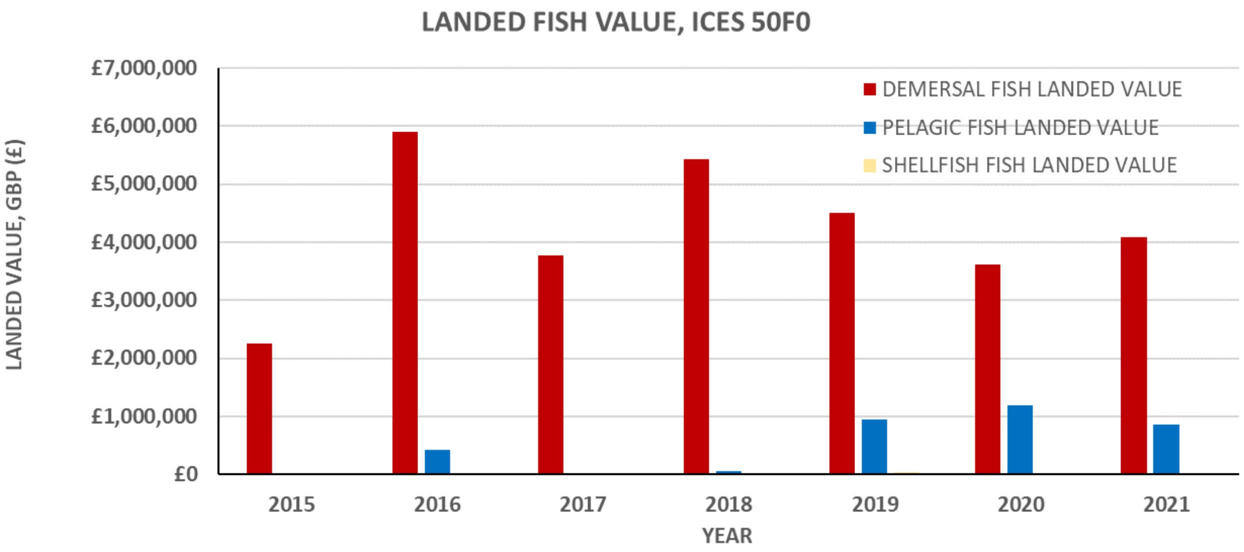


Figure 3.3.4: Landed fish value for ICES 50F0

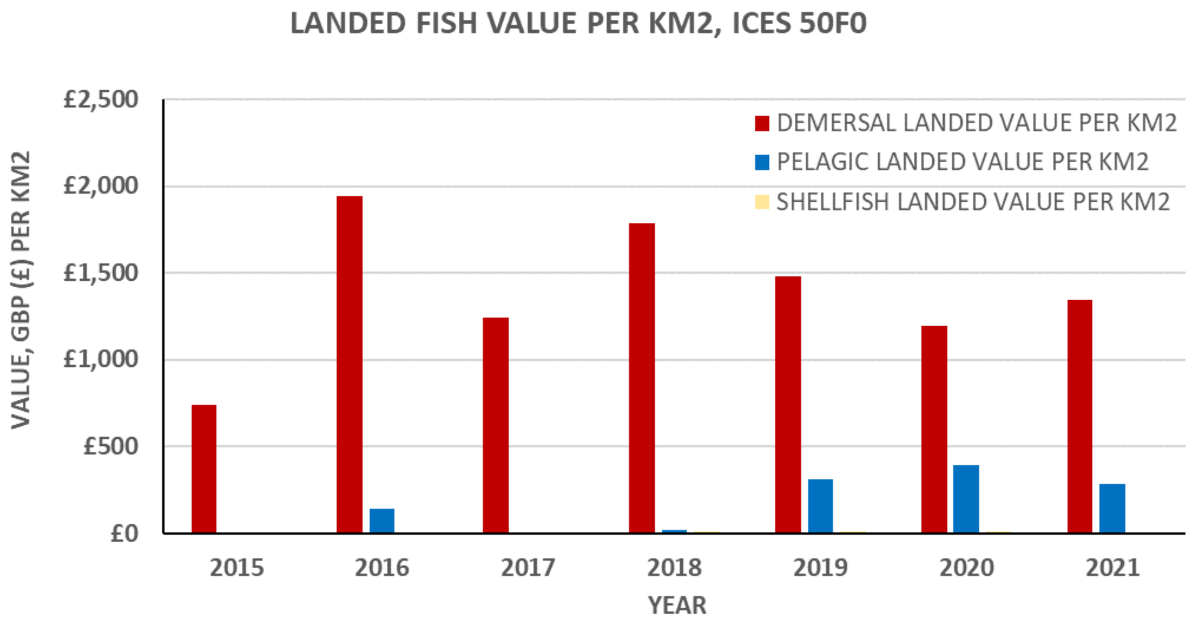


Figure 3.3.5: Value per km² for fish landed from ICES 50F0

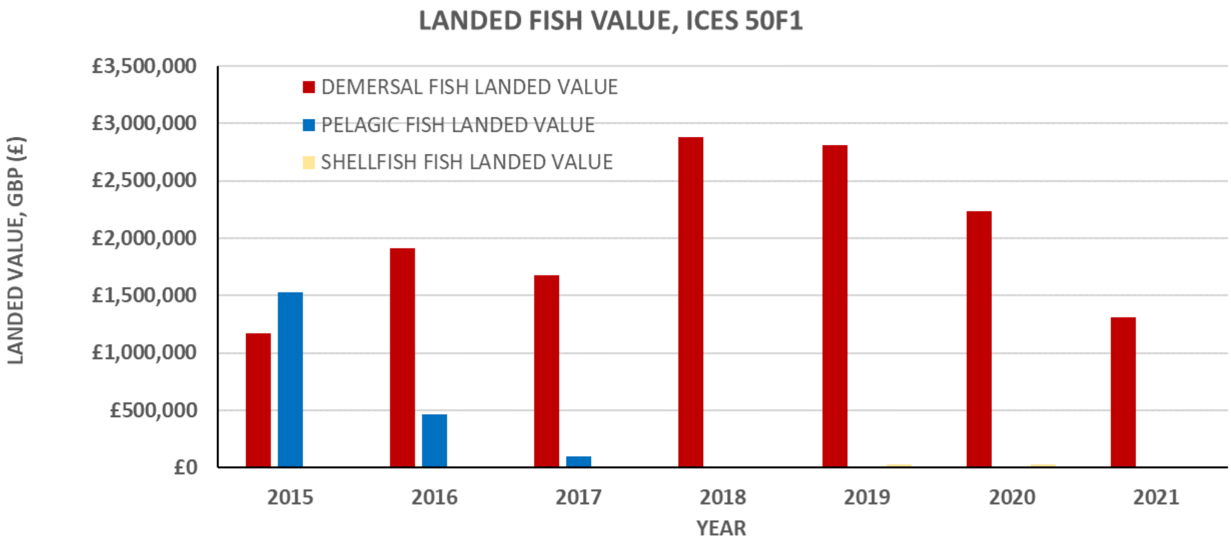


Figure 3.3.6: Landed fish value for ICES 50F1

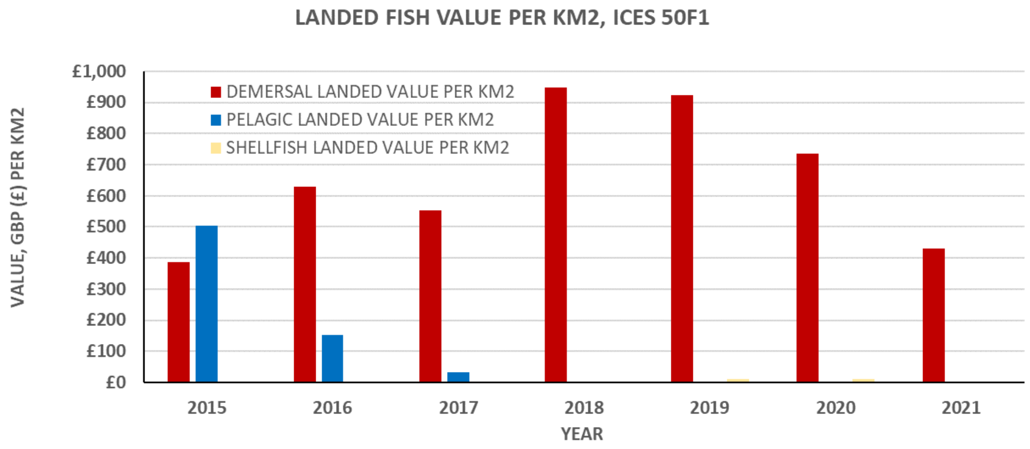


Figure 3.3.7: Value per km^2 for fish landed from ICES 50F1

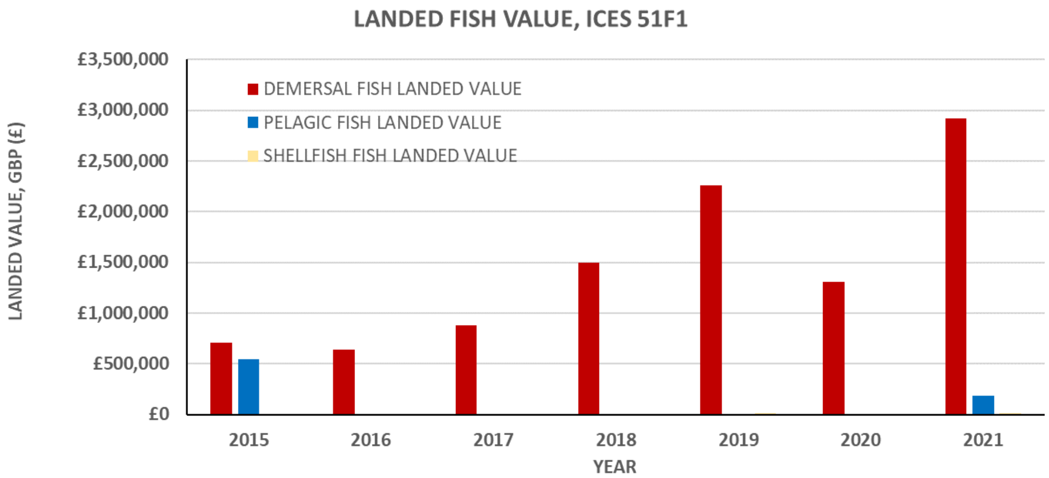


Figure 3.3.8: Landed fish value for ICES 51F1

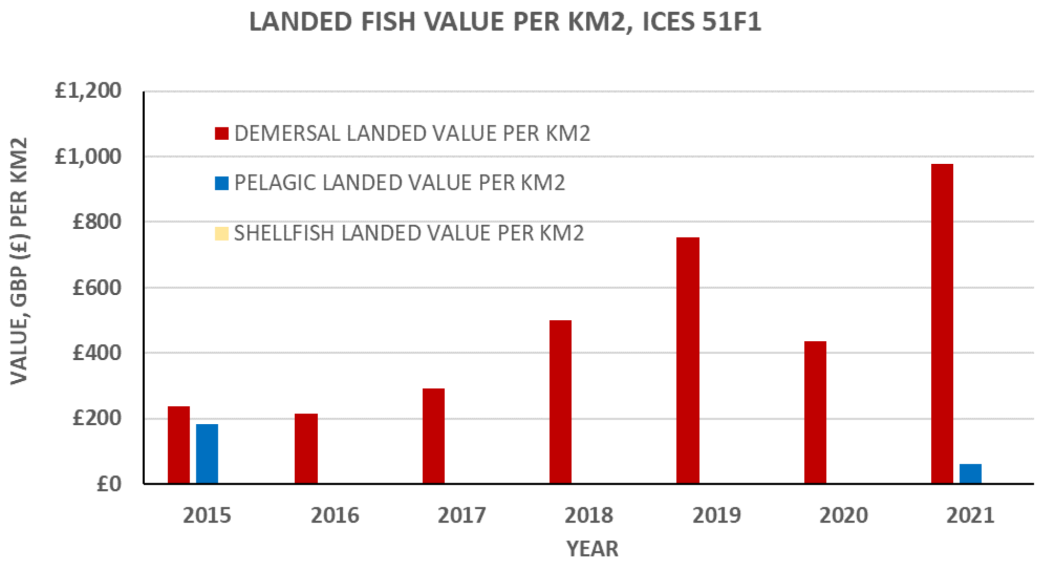


Figure 3.3.9: Value per km^2 for fish landed from ICES 51F1

The foregoing indicates that the area is not significantly important to commercial fisheries, and this is consistently reflected in data from the past six years. This suggests that any fishing that has taken place is likely to be of an exploratory nature rather than the consistent targeting of known fishing grounds.

In the years between 2015 and 2021 the maximum value of demersal, pelagic and shellfish landed per km^2 per annum occurred in ICES Rectangle 50F0 and the average calculated values are £1,939 (2016), £395 (2020) and £12 (2019) respectively. This is calculated by dividing the commercial value of fish landed by the area of ICES Rectangle 50F0 (3,028 km^2). The figures indicate a marked decline in the overall value of fishing in the area.

3.4 Other commercial activity

Although the North Sea has substantial traffic of commercial ships trading between North Sea and Baltic ports, the density of shipping in the Heather area is low, with approximately 0.2 – 0.5 vessels passing each week.

Other commercial activities in the area are related to a number of oil and gas installations but there is no offshore renewable type activity in the area.

3.5 Pipeline stabilisation and protection features

3.5.1 Deposited rock

An examination of the Heather related documentation suggests that ~1,032 m of deposited rock was used to rectify a number of spans on the PL9 pipeline route in 2010. The presence of rock or otherwise is explained in section 4.2 below.

Material that is left in place will preserve the marine habitat that will have established over the time it has been on the seabed, and in this case its presence will not have a negative impact on the environment, nor impact on the safety of other users of the sea.

Methods that could be used to remove the rock include:

- dredging the rock and disposing of the material at an approved offshore location.
- dredging the rock and transporting the material to shore to be disposed of in an appropriate manner.
- lifting the rock using a grab vessel, depositing in a hopper barge, and transporting it to shore for appropriate disposal.

All these proposed methods would impact on the seabed and associated communities, create sediment plumes, and require additional vessel use with the associated environmental impacts, safety risks, impacts on other users of the sea and additional costs.

While it is considered physically possible to remove deposited rock, the decommissioning philosophy in this document is consistent with the guidance notes [8], with all deposited rock being left *in situ*.

Any rock deposited associated with third-party pipeline crossings is out of scope.

3.5.2 Concrete mattresses

There are some concrete mattresses associated with PL9, PL352 and the umbilical that connects to the PL352 ESDV. Details are scant, but the indications are that they are 3.0m x 1.5m x 0.15m 'Linklok' type mattresses. The mattresses are concentrated at the Heather platform, the ESDV skid and on approach to the Welgas Tee at the WLGP connection. A typical Linklok mattress can be seen in Figure 3.5.1 below.

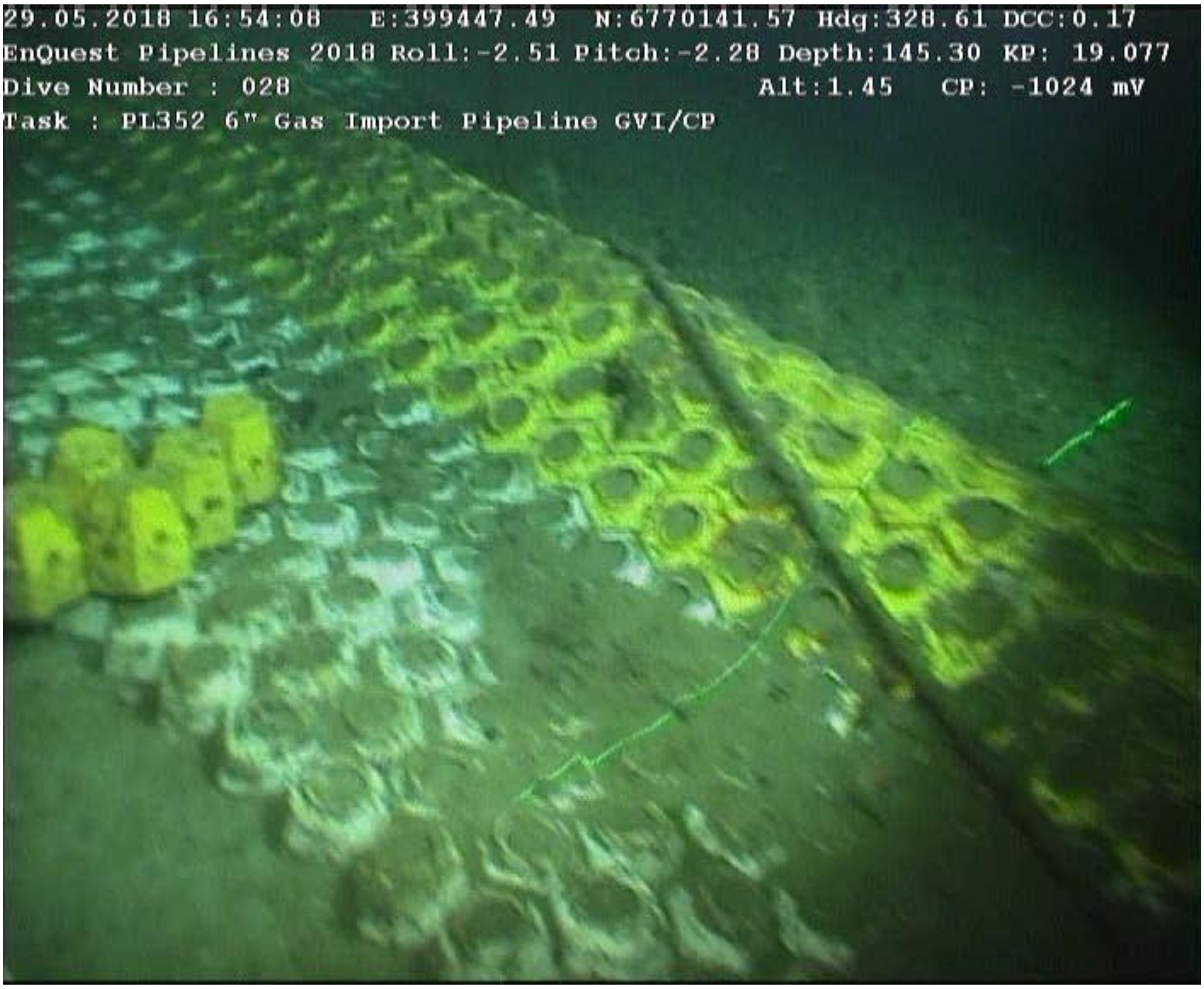


Figure 3.5.1: Linklok mattress on PL352

It is assumed that those concrete mattresses that are found to be exposed will be recovered while those mattresses that are buried will be left *in situ*. The locations and condition of each of the concrete mattresses and proposals for decommissioning are detailed in the Decommissioning Programme [3]. Please also refer to the schematics in Appendix B.

3.5.3 Sand and cement bags

The number of sand and cement bags noted in the Decommissioning Programme has been estimated using engineering judgement based on drawings and design sketches.

Most of the sand and cement bags are associated with remedial works associated with PL9 pipeline spans. The remedial works concern the provision of additional support to the pipeline to reduce the length of the spans to maintain the integrity of the pipeline while it was operating.

The intention will be to leave all the sand and cement bags *in situ* when decommissioning the pipelines unless they are disturbed during the decommissioning works, in which case they will be recovered. Although several different methods could be used to remove the sand and cement bags, from a practical perspective it is not known whether the bag material has remained intact.

3.6 Assumptions, limitations, & gaps in Knowledge

The most significant assumptions, limitations and knowledge gaps relating to the comparative assessment are listed below. In addition, it should be noted that the presentation of the different categories of risks for comparison has required a degree of engineering judgement, which includes the following technical assumptions:

- Complete removal of PLU6254 would be achievable with the overlying sediment being displaced to allow the umbilical to be pulled from the trench
- It is possible that PL352 could be removed using reverse reel assuming that the overlying sediment could be displaced to allow the pipeline to be pulled from the trench
- Technically, removal of PL9 could be achieved using the 'cut and lift' method of removal, assuming that the overlying sediment could be excavated or displaced to allow access, but third-party pipeline crossings over the top of PL9 and PL352 would be left undisturbed as they are out of scope
- EnQuest is not aware of any fishing gear snagging reports. To the companies' knowledge no exposures have been of such a magnitude that they have warranted being recorded as a snagging hazard via Kingfisher Information Services on FishSAFE (www.fishsafe.eu).

The following legacy assumptions have also been made:

- An environmental survey would be required on completion of decommissioning activities irrespective of the decommissioning option implemented so this element is not a differentiator
- Any pipeline being left *in situ* would be subject to at least three legacy burial surveys
- The seabed sediment type is such that any spoil heaps created during any decommissioning operations would not present significant snagging hazards
- In the long term, the deposition of rock over exposed sections or severed pipeline ends would not present snagging hazards
- The impact of the procuring any new materials such as fabricated items or mining of new rock is ignored
- Impact on commercial activities is inversely proportional to vessel activity
- Societal benefits and vessel associated environmental impacts and risks are assumed to be proportional to vessel duration
- Only a high-level comparison of what differentiates the costs is used.

4. THE PIPELINES AND UMBILICAL

4.1 Overview

All the pipelines were laid in trenches that were allowed to backfill naturally.

Description	Route	Burial	Length
PL9 16in pipeline, CWC	Heather to Ninian Central	Trenched, left to backfill naturally, deposited rock along part of its length	32.8 km
PL9A, 15in HDPE flexible pipe	Replaces 65m long section of PL9 near Heather	Part suspended in water column part laid on seabed (drill cuttings)	0.139 km
PL352 6in pipeline	Welgas Tee to Heather	Trenched, left to backfill naturally. Buried	19.4 km
PLU6254 ESDV umbilical	Heather to ESDV skid	As PL352	0.570 km

NOTE

1. PLU6254 shares the same trench as PL352 between the ESDV skid and the Heather platform
2. The length of PL9A includes 2x Morgrip pipe connectors, one at each end.

Table 4.1.1: Heather pipeline and umbilical summary

4.2 Heather pipelines and umbilical

4.2.1 PL9 16in oil export pipeline (Heather to Ninian Central)

PL9 is a 16in carbon steel pipeline ~33.2 km long coated using 5 mm coat tar epoxy ('CTE') and furnished with a 1 in (25.4 mm) thick CWC. The riser at Heather is furnished with a 12 mm thick Neoprene coating, while at Ninian Central in the splash zone the riser is provided with a 3 mm thick Monel coating. The pipeline is routed to Ninian Central and crossed by pipelines associated with the Lyell development, by a pipeline and a few umbilicals: PLU4182, PL116 (not in use), PLU4265 (not in use) and Umbilical UH on the final approach to Ninian Central in the 500 m safety zone. When installed the pipeline was laid in a trench that was left to backfill naturally. Near the Heather platform the pipeline is now buried under drill cuttings (Figure B.1.1).

Over the years the pipeline has been extensively surveyed with remedial works periodically being required to reduce the length of pipeline spans to maintain the operational integrity of the pipeline and to ensure that it remained in a safe condition. The remedial works usually involved the deposition of grout bags and grout mattresses, although in 2010 such remedial works involved the deposition of ~1 km of rock at a number of locations along the pipeline (Figure 4.2.4). Figure 4.2.1, Figure 4.2.2, Figure 4.2.3, Figure 4.2.5, Figure 4.2.6 and Figure 4.2.8 all show that the pipeline has experienced multiple exposures and spans along much of its length. A review of the survey data would suggest that the number and extent of exposures seems to be generally reducing over time, but slowly.

Exposure and span analysis

A summary of the historical data obtained is presented in Table 4.2.1. The exposure data for 2015 appear to be anomalous[3], but nevertheless an assessment of the historical exposures and span data would suggest that although the number of exposures appears to be increasing, the cumulative length of extent of exposures and spans associated with PL9 has been reducing over time, albeit slowly.

[3] This may be because the survey was relatively limited in scope, focussing on specific areas of the pipeline.

YEAR	NO. Of EXPOSURES	∑ LENGTH (M)	MIN EXP LENGTH (M)	MAX EXP LENGTH (M)	NO. Of SPANS	∑ LENGTH (M)	MIN SPAN LENGTH (M)	MAX SPAN LENGTH (M)
1987	n/a	n/a	n/a	n/a	52	1,701m	16m	96.0m
1988	n/a	n/a	n/a	n/a	52	1,636m	11m	98.0m
1989	n/a	n/a	n/a	n/a	48	1,640m	20m	97.0m
1990	n/a	n/a	n/a	n/a	51	1,603m	14m	93.0m
1991	n/a	n/a	n/a	n/a	51	1,582m	15m	86.0m
1992	n/a	n/a	n/a	n/a	52	1,622m	12m	99.0m
1993	n/a	n/a	n/a	n/a	56	1,611m	12m	88.0m
1995	n/a	n/a	n/a	n/a	53	1,451m	12m	100.0m
1997	n/a	n/a	n/a	n/a	54	1,606m	10m	89.0m
2000	n/a	n/a	n/a	n/a	48	1,482m	10m	95.0m
2010	583	18,556m	0.0m	514m	139	1,625m	5m	38.3m
2012	589	17,151m	0.7m	475m	79	772m	5m	19.1m
2015	*5*	*424m*	*23.0m*	*141m*	*5*	*115m*	*16m*	*36.0m*
2018	633	13,609m	0.5m	317m	214	1,772m	0.8m	27.0m
2021	551	13,982m	1.0m	476m	211	2,009m	2m	36m

NOTES

1. n/a – data not available.
2. Limited exposure data available up to 1995.
3. The exposure and span data for 2015 appear to be anomalous; no burial data available for the years prior to 2010 or for 2015.

Table 4.2.1: PL9 historical exposures and span summary

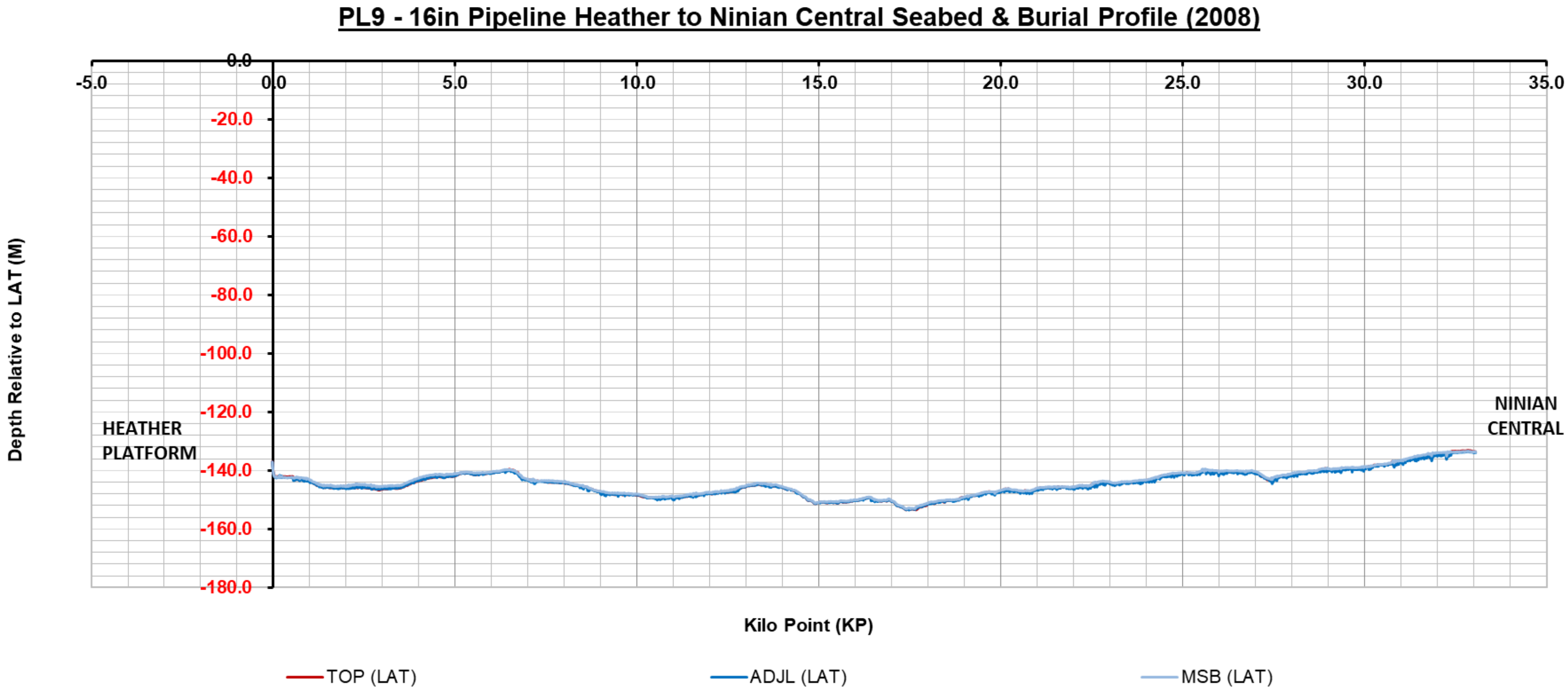


Figure 4.2.1: PL9 seabed & pipeline profile (2008)

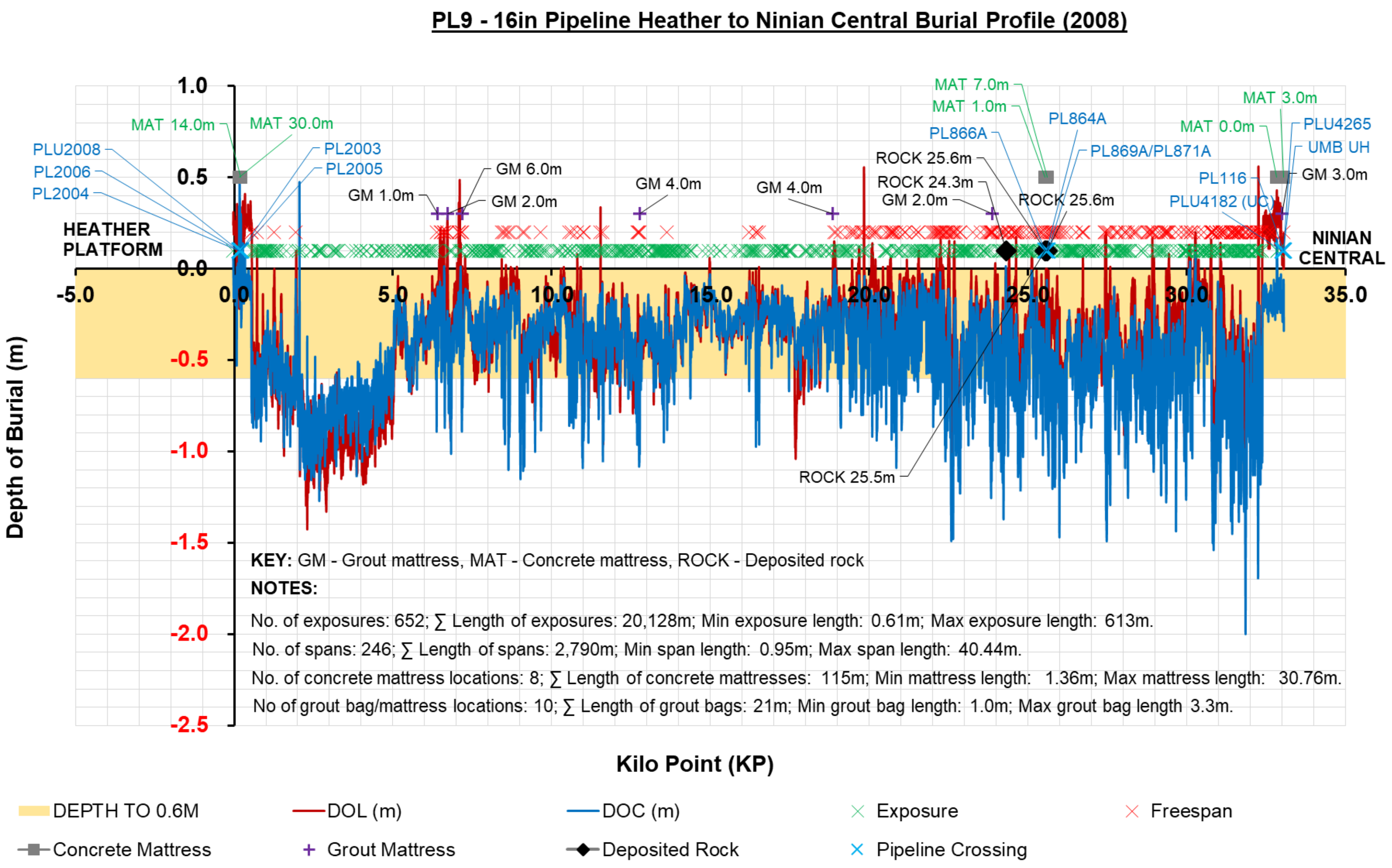


Figure 4.2.2: PL9 pipeline depth of burial profile (2008)[4]

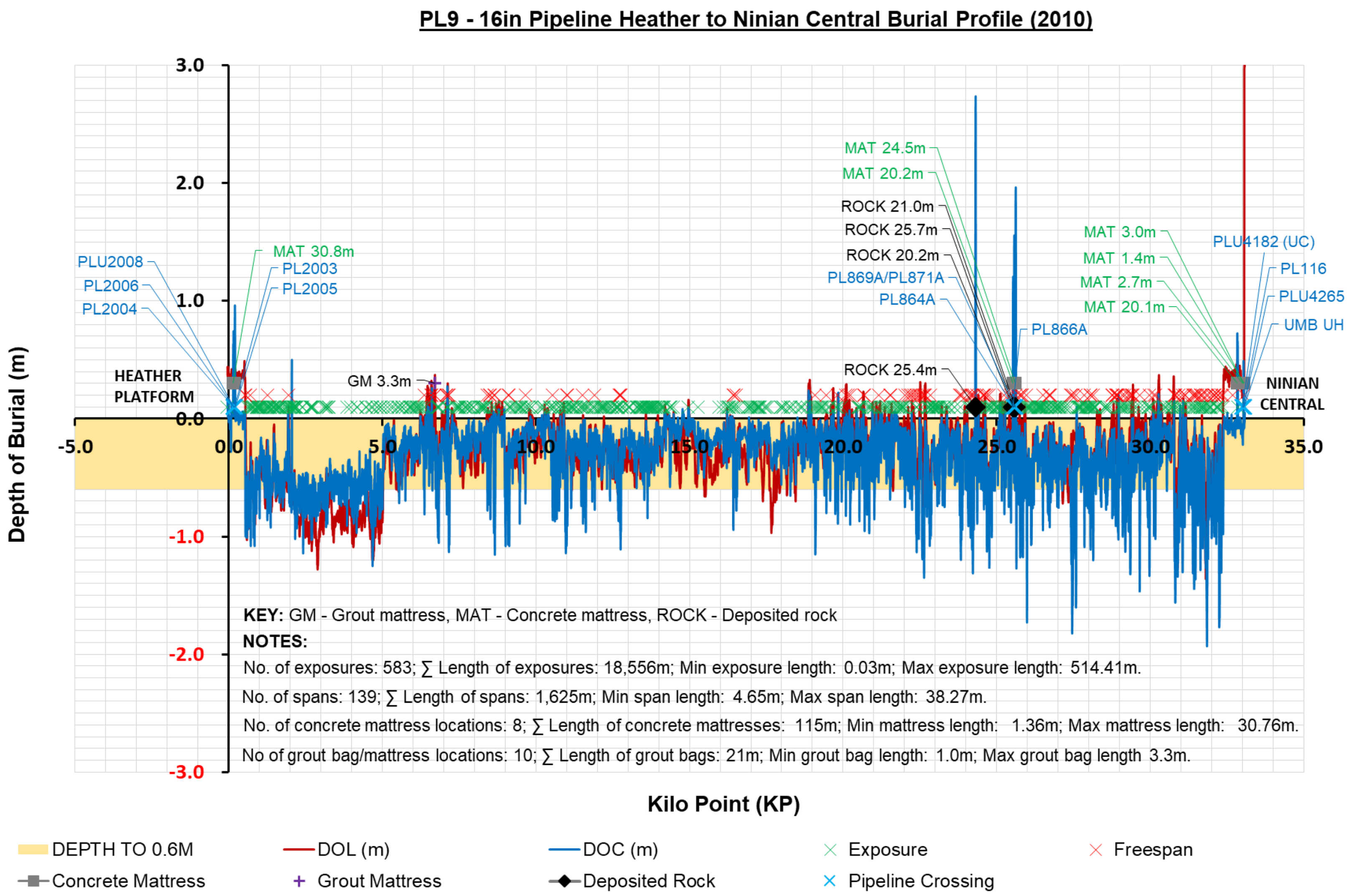
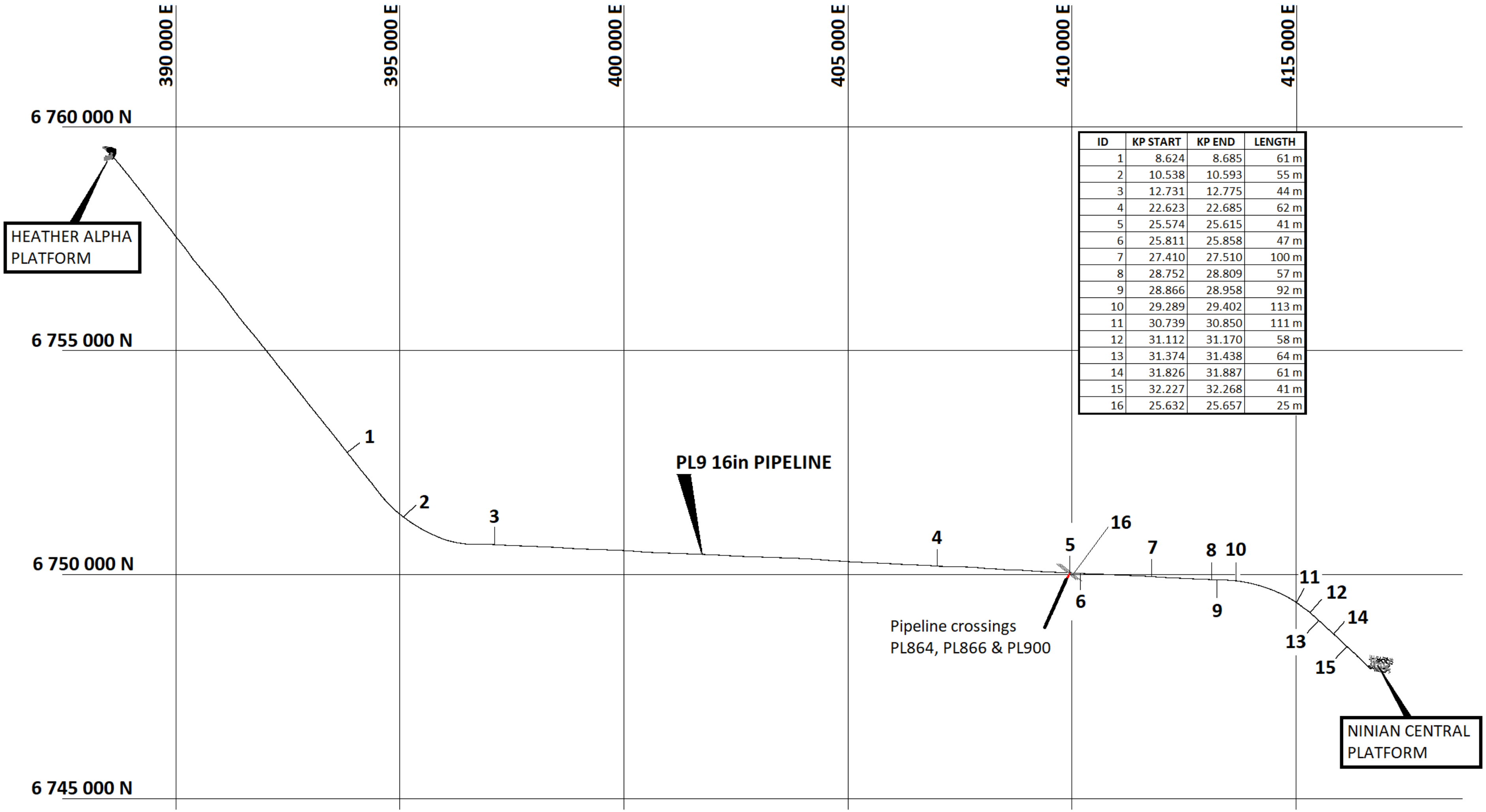


Figure 4.2.3: PL9 pipeline depth of burial profile (2010)[4]



ID	KP START	KP END	LENGTH
1	8.624	8.685	61 m
2	10.538	10.593	55 m
3	12.731	12.775	44 m
4	22.623	22.685	62 m
5	25.574	25.615	41 m
6	25.811	25.858	47 m
7	27.410	27.510	100 m
8	28.752	28.809	57 m
9	28.866	28.958	92 m
10	29.289	29.402	113 m
11	30.739	30.850	111 m
12	31.112	31.170	58 m
13	31.374	31.438	64 m
14	31.826	31.887	61 m
15	32.227	32.268	41 m
16	25.632	25.657	25 m

Figure 4.2.4: PL9 deposited rock for remediation of spans in 2010[4]

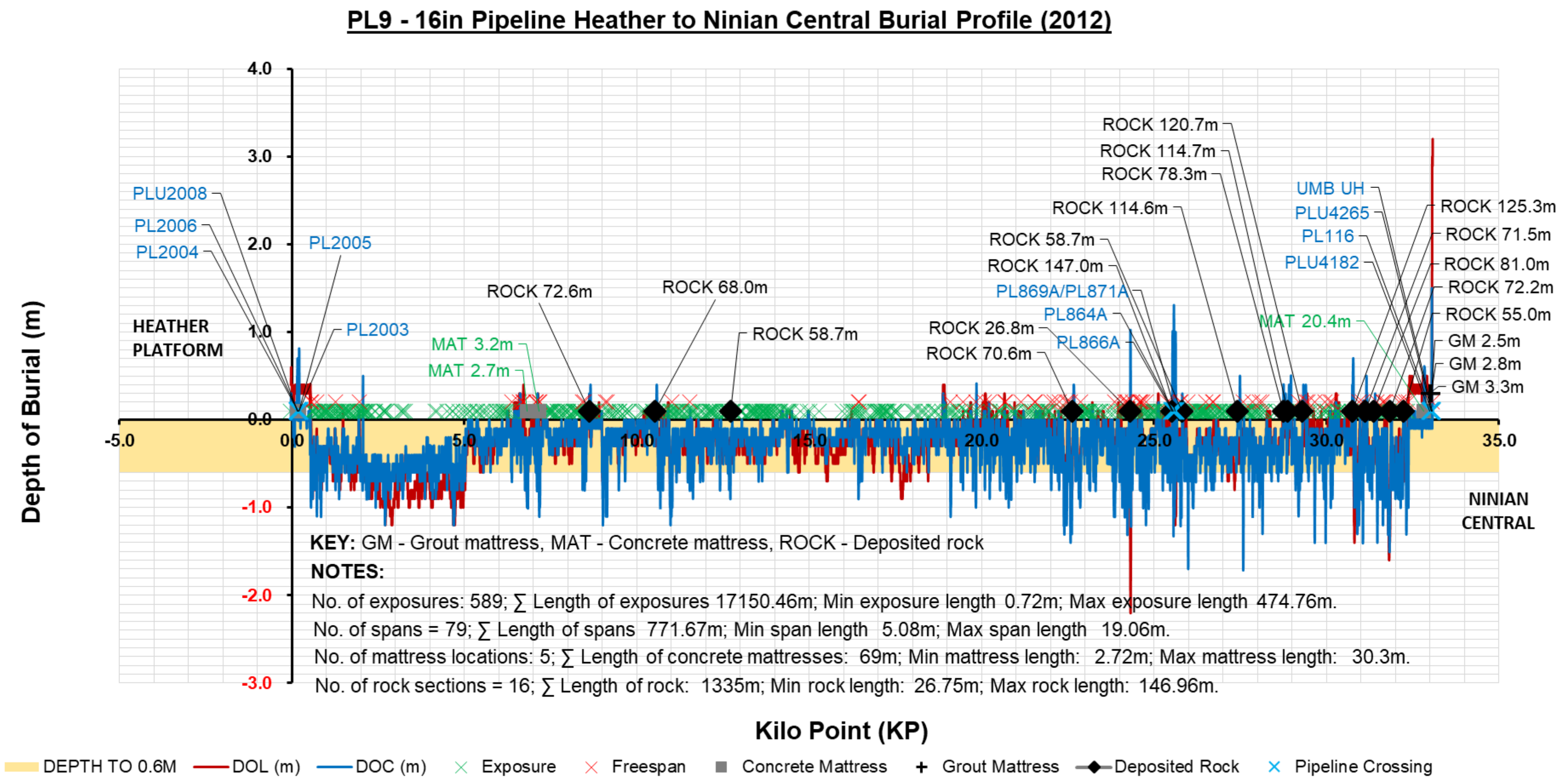


Figure 4.2.5: PL9 pipeline depth of burial profile (2012)[4]

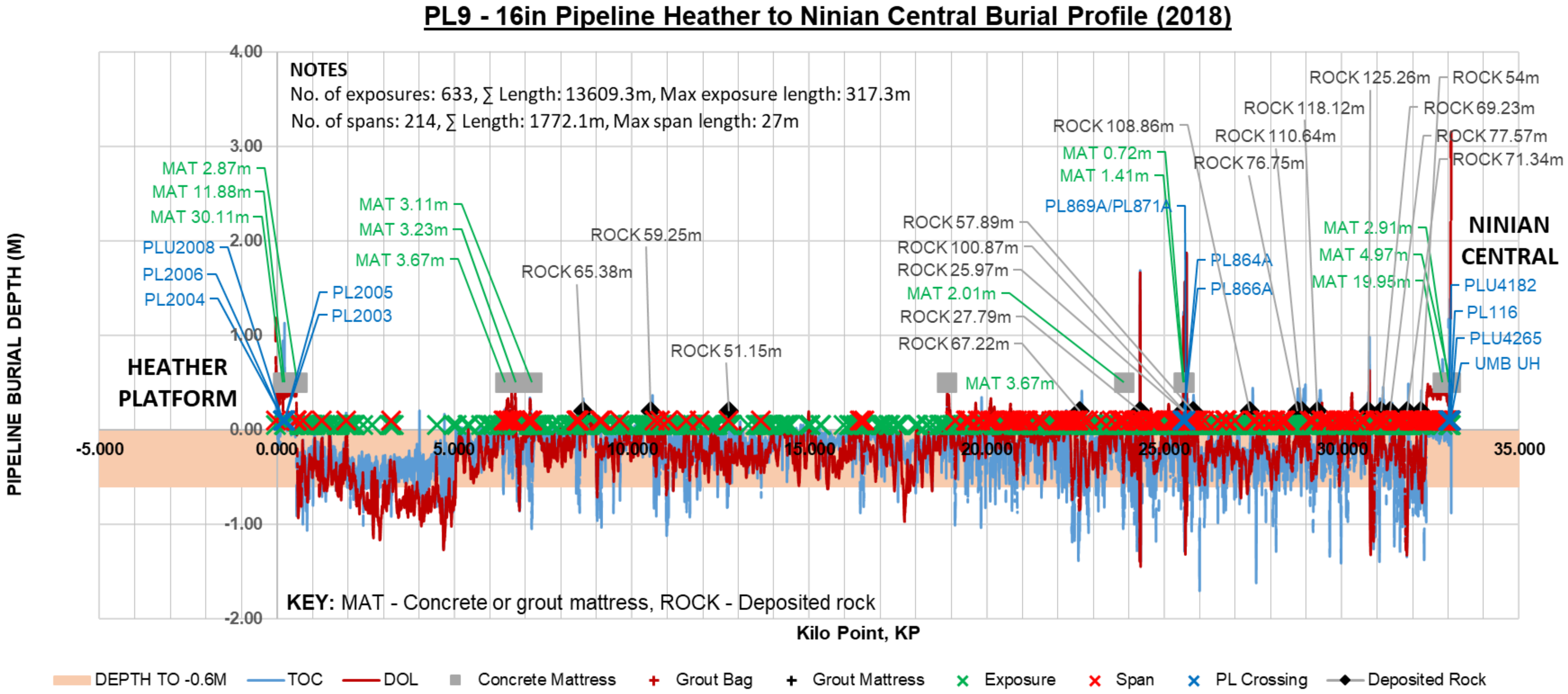


Figure 4.2.6: PL9 pipeline depth of burial profile (2018)[4,5]

[5] Lyell pipeline crossings were not noted in the survey records.

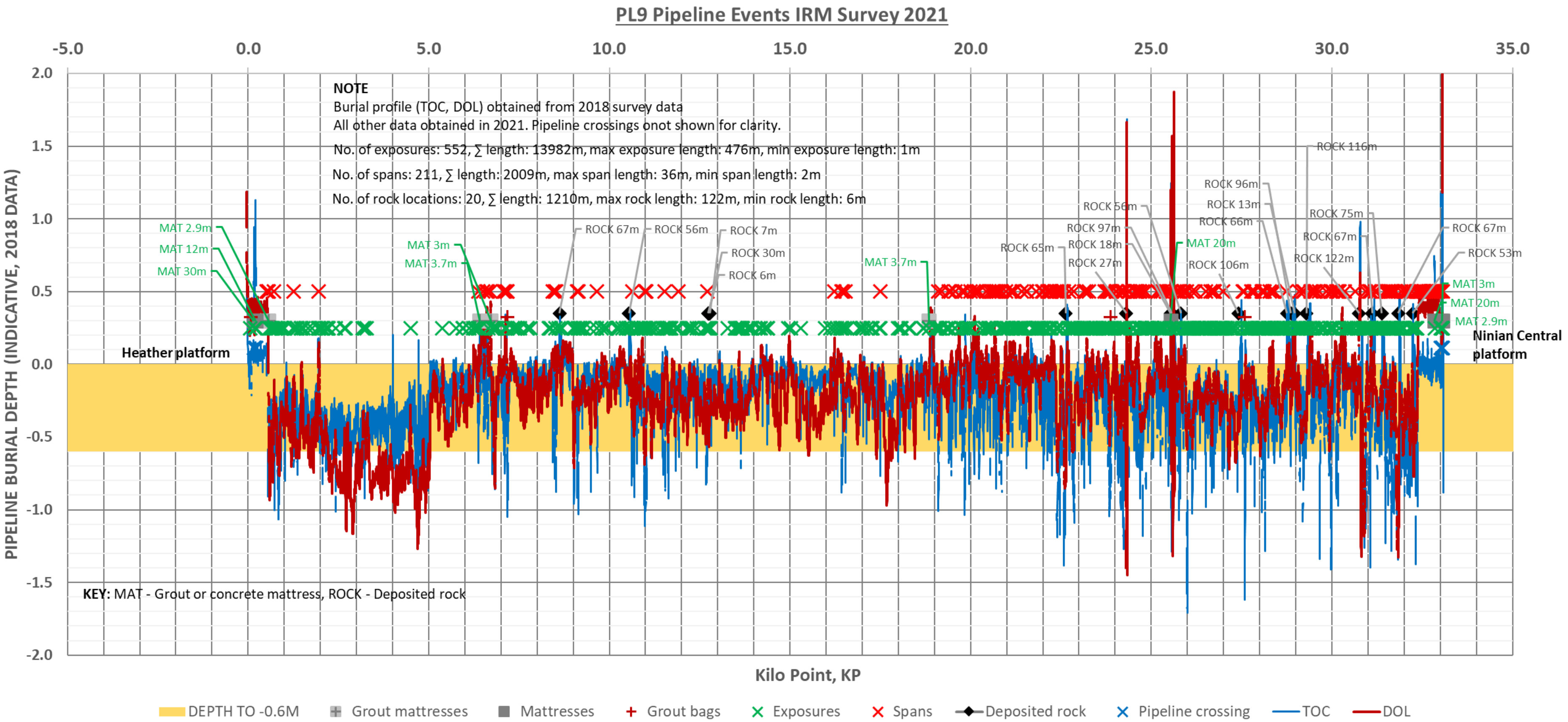


Figure 4.2.7: PL9 pipeline exposures, spans, mattresses, rock, etc. (2021)[5]

4.2.2 PL9A 15in Flexible flowline replacement section

PL9A is a 15 in flexible flowline manufactured from high density polyethylene ('HDPE') that was installed to replace a section of PL9 where the integrity had been compromised. The section is 139 m long including the length the 1.5 m long Morgrip connectors at each end. The replacement section was installed in 2004.

It is part suspended in the water column where it connects to the PL9 riser at the Heather platform, and was part laid on the drill cuttings. It is now partly buried in the drill cuttings.

Some details are presented in Figure 4.2.8 and Figure 4.2.9 below.

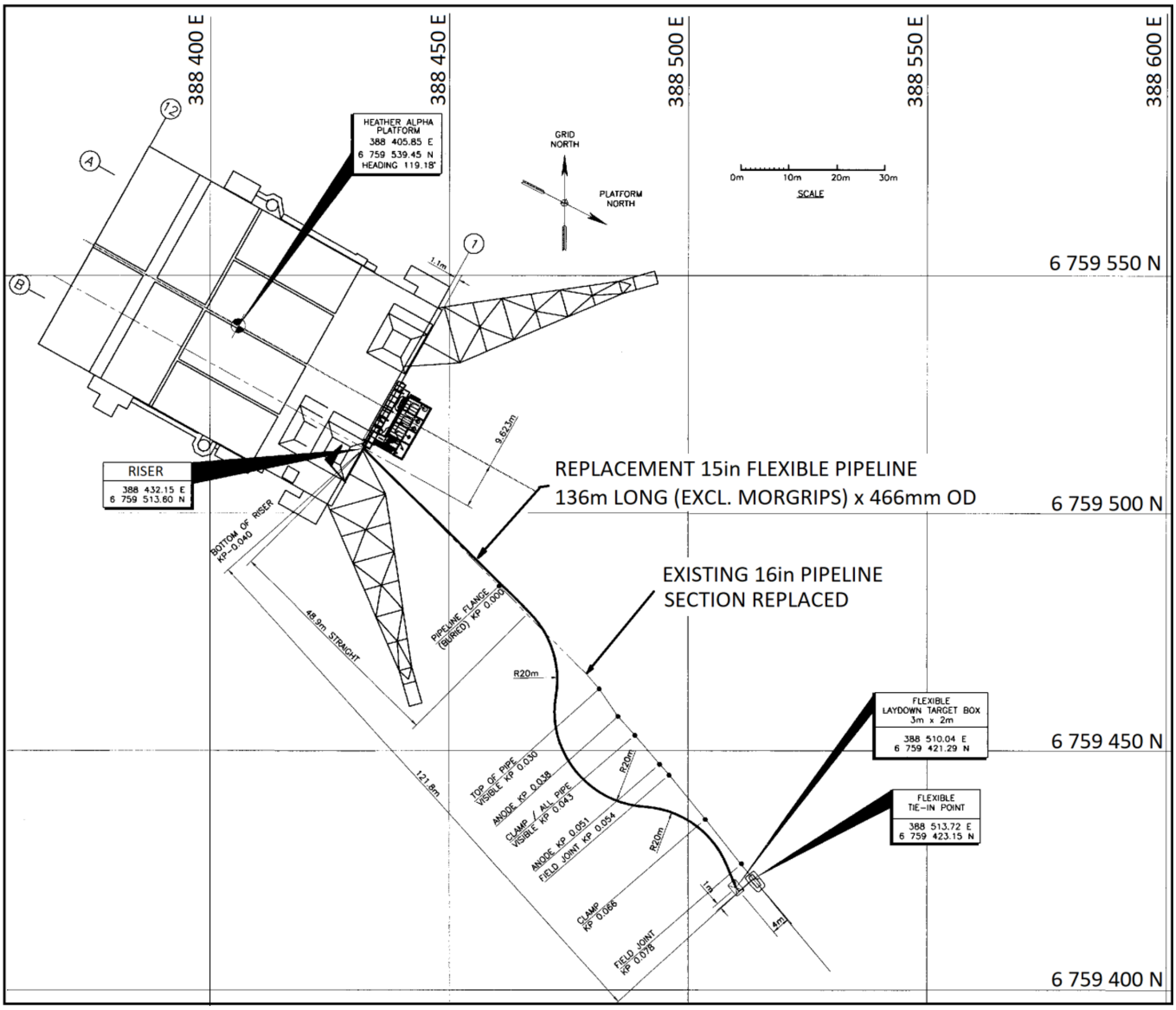


Figure 4.2.8: Plan of PL9A connected to PL9 at Heather

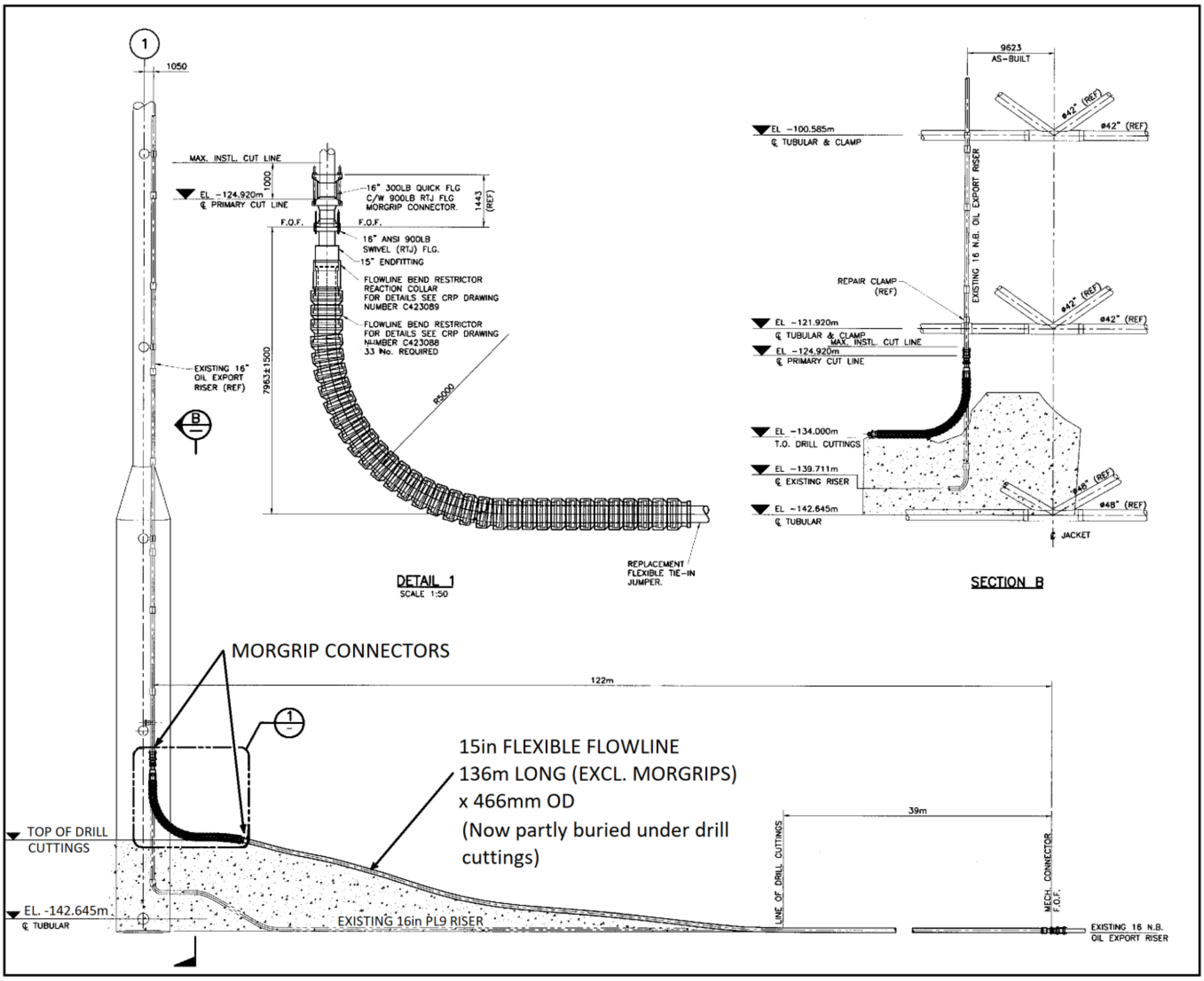


Figure 4.2.9: Elevation & section of PL9A connected to PL9 at Heather

PL9A is not subject to a comparative assessment but the final decommissioning proposals will be discussed and agreed with the appropriate stakeholders.

4.2.3 PL352 6in gas import pipeline (Welgas tee to Heather)

PL352 is an 6in carbon steel pipeline ~19.4 km long coated along most of its length using fusion bonded epoxy ('FBE') with the riser section at Heather being provided with a 3 mm thick Monel coating in the splash zone. The pipeline is routed from the Welgas tee to the Heather platform via a dedicated ESDV skid about 320 m from Heather. The design intent was that the pipeline be trenched with a 1 m minimum cover with the trench being left to backfill naturally. Figure 4.2.11, Figure 4.2.12, and Figure 4.2.13 show that most of the pipeline generally has a good depth of cover although over the years it has experienced multiple exposures and occasional spans along its length. Near the Heather platform the pipeline is buried under drill cuttings (Figure B.1.1).

Exposure and span analysis

A summary of the historical data obtained is presented in Table 4.2.2. The exposure data for 2015 appear to be anomalous[6], but nevertheless an assessment of the historical exposures and span data would suggest that the number and extent of exposures and spans associated with PL352 has been reducing over time, albeit slowly. The approach to decommissioning might either be to remediate the exposures or spans as they are at the time of decommissioning or continue to monitor the pipeline on the assumption that the exposures and spans will eventually disappear.

YEAR	NO. Of EXPOSURES	∑ LENGTH (M)	MIN EXP LENGTH (M)	MAX EXP LENGTH (M)	NO. Of SPANS	∑ LENGTH (M)	MIN SPAN LENGTH (M)	MAX SPAN LENGTH (M)
1987	n/a	n/a	n/a	n/a	8	214.0m	13.0m	46.0m
1988	n/a	n/a	n/a	n/a	8	202.0m	13.0m	36.0m
1989	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
1990	n/a	n/a	n/a	n/a	8	160.0m	15.0m	31.0m
1991	n/a	n/a	n/a	n/a	8	155.0m	12.0m	27.0m
1992	n/a	n/a	n/a	n/a	6	102.0m	8.0m	26.0m
1993	n/a	n/a	n/a	n/a	6	95.0m	3.0m	26.0m
1995	n/a	n/a	n/a	n/a	5	84.0m	7.0m	25.0m
2010	37	288.5m	n/a	30.0m	7	78.2m	5.8m	24.2m
2014	28	221.0m	0.9m	54.9m	11	61.1m	1.3m	15.7m
2015	*3*	*58.2m*	*13.2m*	*29.0m*	*4*	*41.5m*	*6.7m*	*16.0m*
2018	29	106.9m	n/a	27.1m	8	30.4m	0.0m	13.3m

NOTES

1. n/a – data not available.
2. Limited exposure data available up to 1995.
3. The exposure and span data for 2015 appear to be anomalous; no burial data available for the years prior to 2010 or for 2015.

Table 4.2.2: PL352 historical exposures and span summary

[6] This may be because the survey was relatively limited in scope, focussing on specific areas of the pipeline.

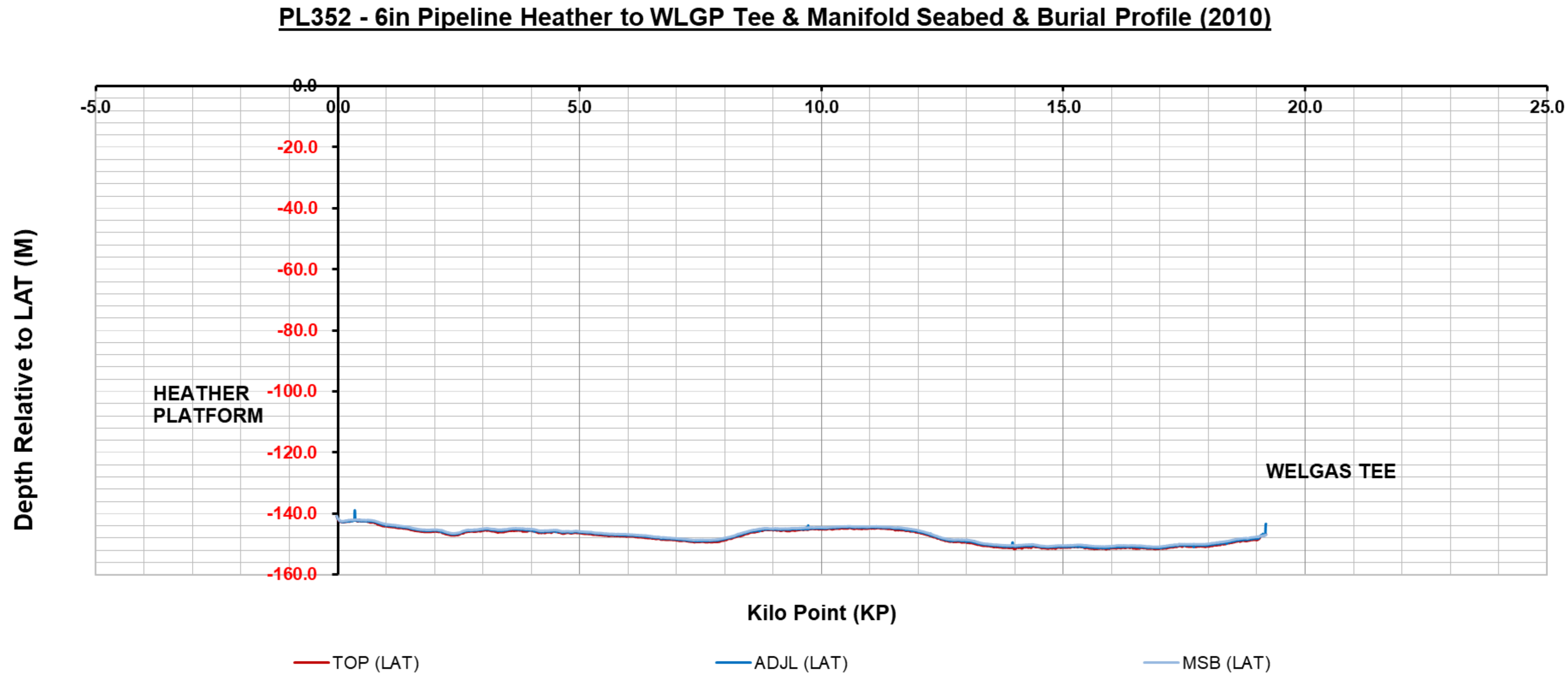


Figure 4.2.10: PL352 seabed & burial profile (2010)

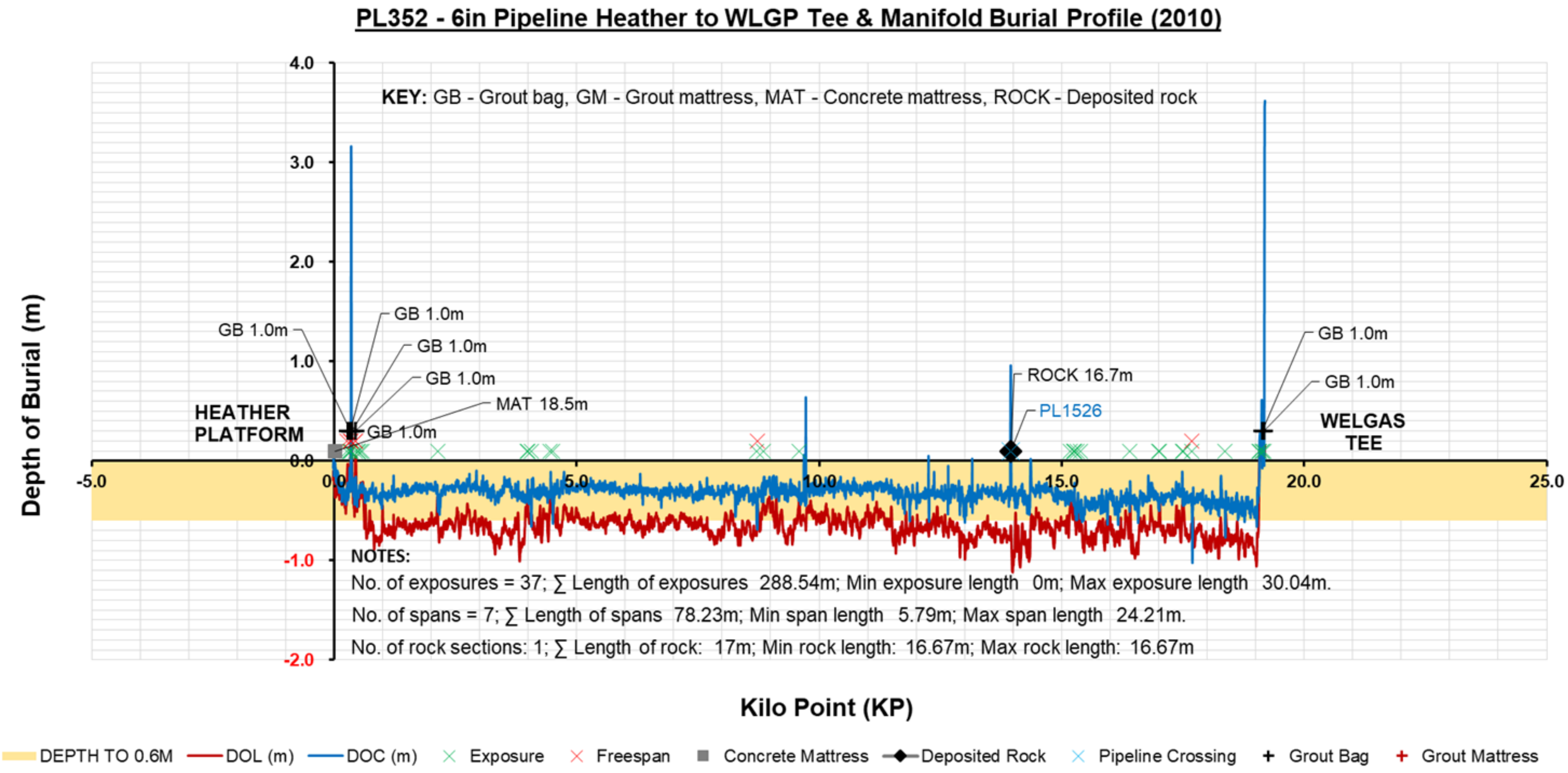


Figure 4.2.11: PL352 pipeline depth of burial profile (2010)

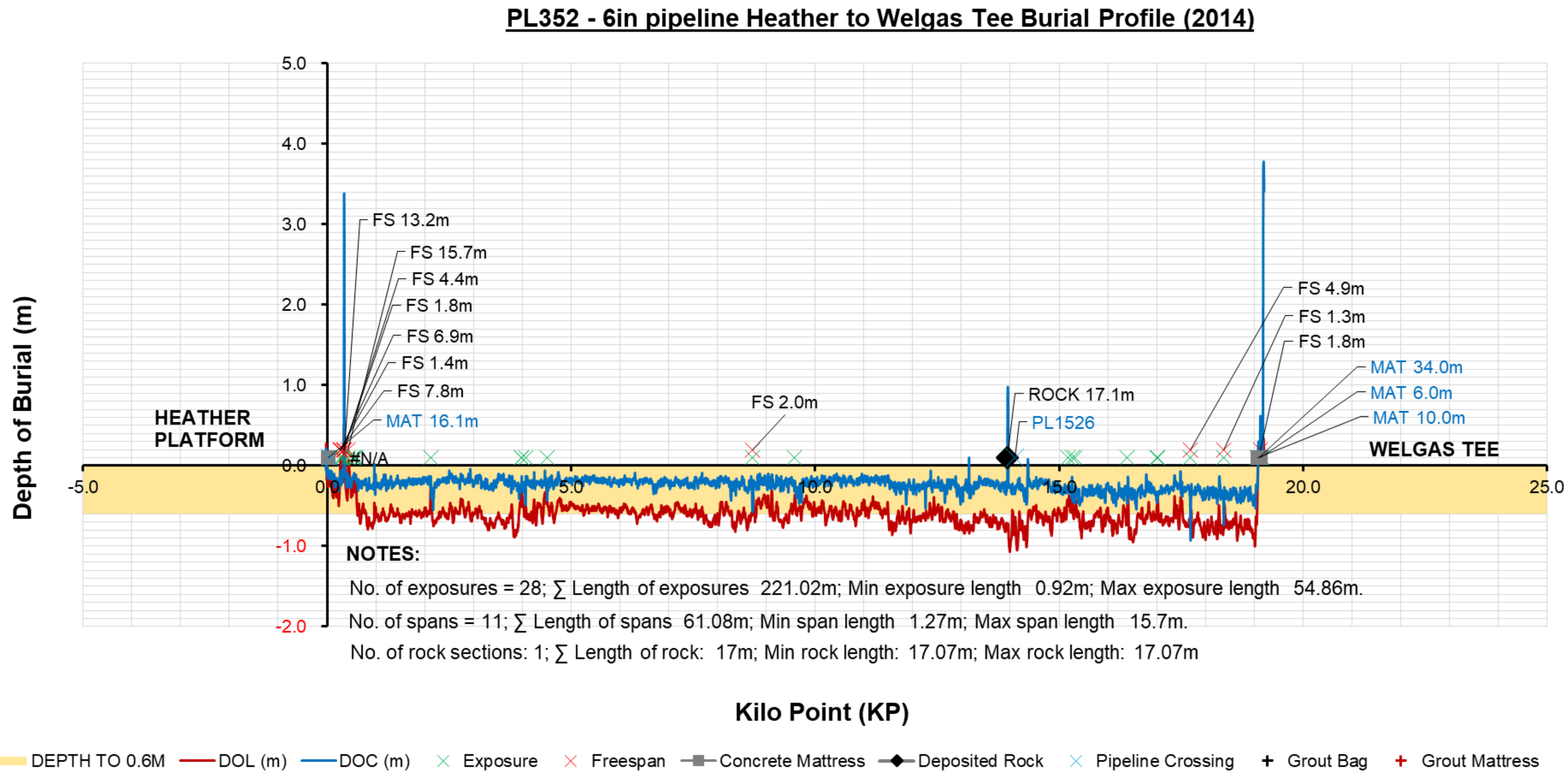


Figure 4.2.12: PL352 pipeline depth of burial profile (2014)

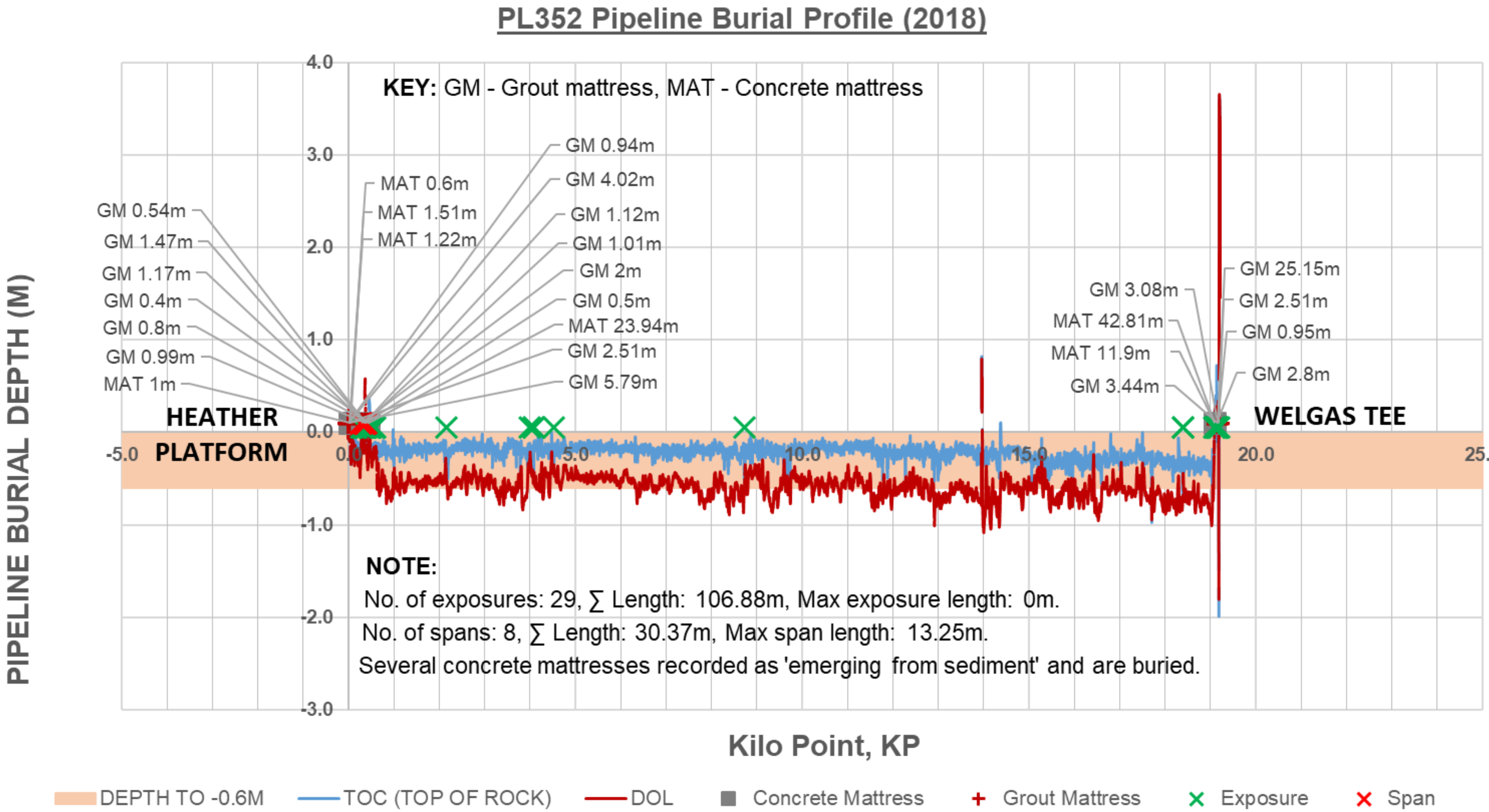


Figure 4.2.13: PL352 pipeline depth of burial profile (2018)

4.2.4 PLU6254 ESDV umbilical (Heather to ESDV skid)

PLU6254, the ESDV umbilical is an 81 mm OD umbilical ~570 m long and it is routed from the Heather topsides to the PL352 ESDV skid located approx. 350 m away from the platform. The umbilical is installed inside a caisson that was retrospectively installed between EL +22.5 m and EL -68.0 m n the Heather jacket. Below the caisson the umbilical is clamped to the jacket at EL. -79 m, EL. -101 m, EL -122m levels before being routed onto the seabed onwards to where it is laid a trench. Near the jacket the umbilical is buried in drill cuttings. The umbilical is manufactured using a variety of materials including steel and plastics. It is laid in the same trench as PL352 although in 2010 for some reason it was subject to its own survey (Figure 4.2.14). As per PL352 the umbilical has experienced exposures and spans over the years although survey data for PL352 would suggest that the number and extent of exposures has been reducing over time.

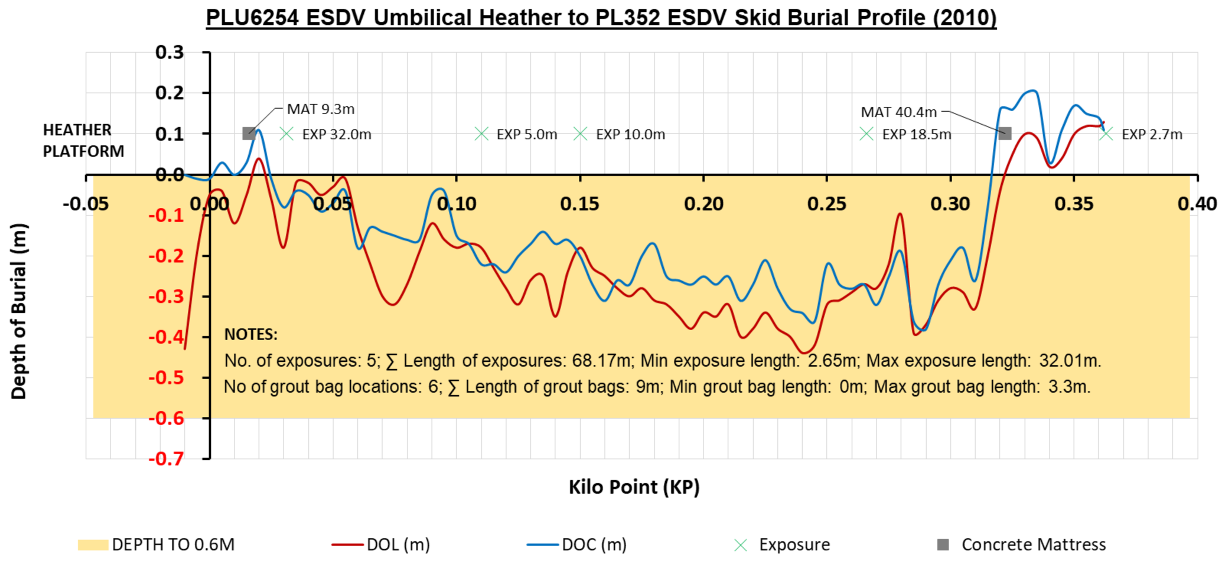


Figure 4.2.14: PLU6254 ESDV Umbilical burial profile (2010)

As PL352 and PLU6254 are laid in the same trench, for the purposes of this assessment it is assumed that the occurrence of exposures and spans between Heather and the ESDV skid and protection frame are the same for both PL352 and the ESDV umbilical.

Using the 2018 survey data for PL352 (Figure 4.2.13), PLU6254 experienced a total of 4 exposures with a total length of 45 m (c.f. 70 m in 2010), the longest exposure was <1 m (c.f. 32 m in 2010). At the same time, 5 spans were recorded with a cumulative length of 20 m, the longest of which was <1 m.

4.3 Pipeline crossings

Both PL9 and PL352 are crossed over by third party pipelines, most of which are operational.

For oil and gas related infrastructure, this can usually be determined by the pipeline number. The higher pipeline number crosses over the top of a pipeline with a lower identification number, so for example, PL1526 crosses over PL352. This is illustrated in Figure 4.3.1.

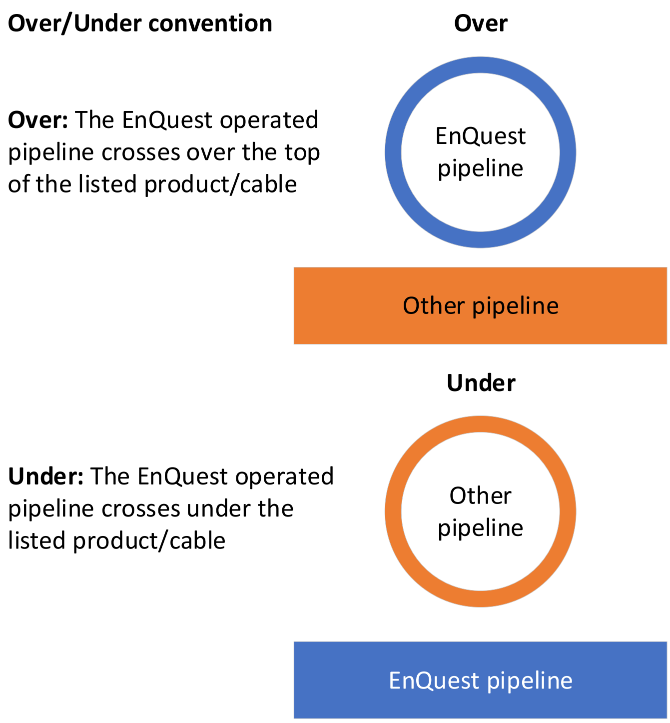


Figure 4.3.1: Over/under convention for pipeline crossings

4.4 Dealing with pipeline crossings

The various pipeline and cable crossings will impact or be impacted by the decommissioning options described in section 5.1. The potential impacts are summarised in Table 4.4.1 and illustrated in Figure 4.4.1, although we have not considered this level of detail in the comparative assessments.

Decommissioning option	Newer pipeline on top	Older pipeline underneath[7]
Full removal	Cut the EnQuest pipeline either side of third-party pipeline crossing.	No impact on option
Partial removal or remedial work	No impact on option as none of the partial removal options would involve removing pipelines from underneath; leave the EnQuest pipeline *in situ*.	No impact on option
Leave *in situ*	No impact on option as none of the leave *in situ* options would involve removing a pipeline from underneath another pipeline; leave the EnQuest pipeline *in situ*.	No impact on option
NOTE 1. PL9 is crossed over by a number of pipelines on the final approach to the Ninian Central platform. These would need to be removed or at the very least be out of use and cleaned before the surface laid section of PL9 could be removed in its entirety. This aspect is out of scope for this comparative assessment.		

Table 4.4.1: Impact of pipeline crossings on pipeline decommissioning options

[7] Although it is noted here that there would be no discernible impact on the decommissioning option, permission would need to be granted from the owner of the older pipeline to carry out any works in the vicinity.

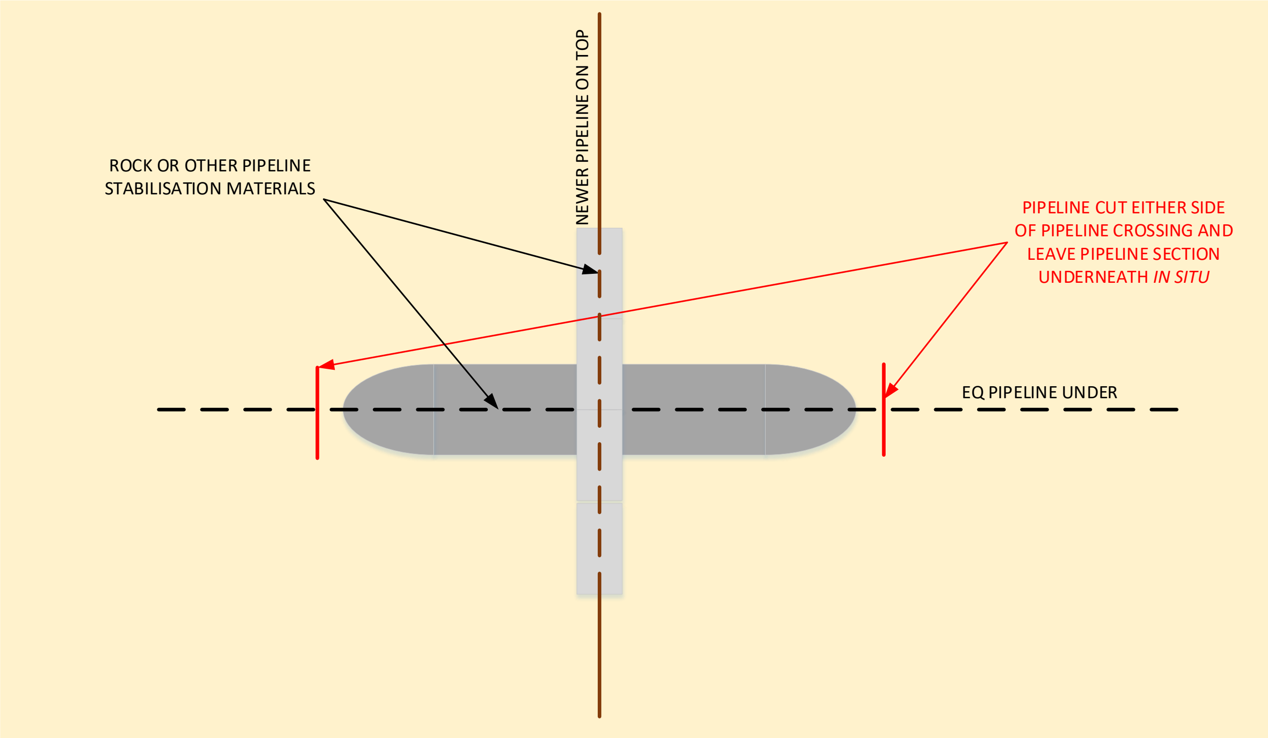


Figure 4.4.1: Pipeline underneath being removed

5. DECOMMISSIONING OPTIONS

5.1 Pipeline decommissioning

There is an implicit assumption that options for re-use of the pipelines have been exhausted prior to the facilities and infrastructure moving into the decommissioning phase and associated comparative assessment. Therefore, this option has been excluded from the assessment. The three decommissioning options considered are:

- **Complete removal** – This involves the complete removal of the pipelines by whatever means would be most practicable and acceptable from a technical perspective
- **Partial removal or remediation** – This would involve removing exposed or potentially unstable sections of pipelines or carrying out remedial work to make the remaining pipeline safe for leaving *in situ*. This option is relevant for those pipelines that are known to have exposures or spans. There will be a need to verify their status via future surveys.
- **Leave *in situ*** – This involves leaving the pipeline(s) *in situ* with no remedial works, but likely needing to verify their status via future surveys.

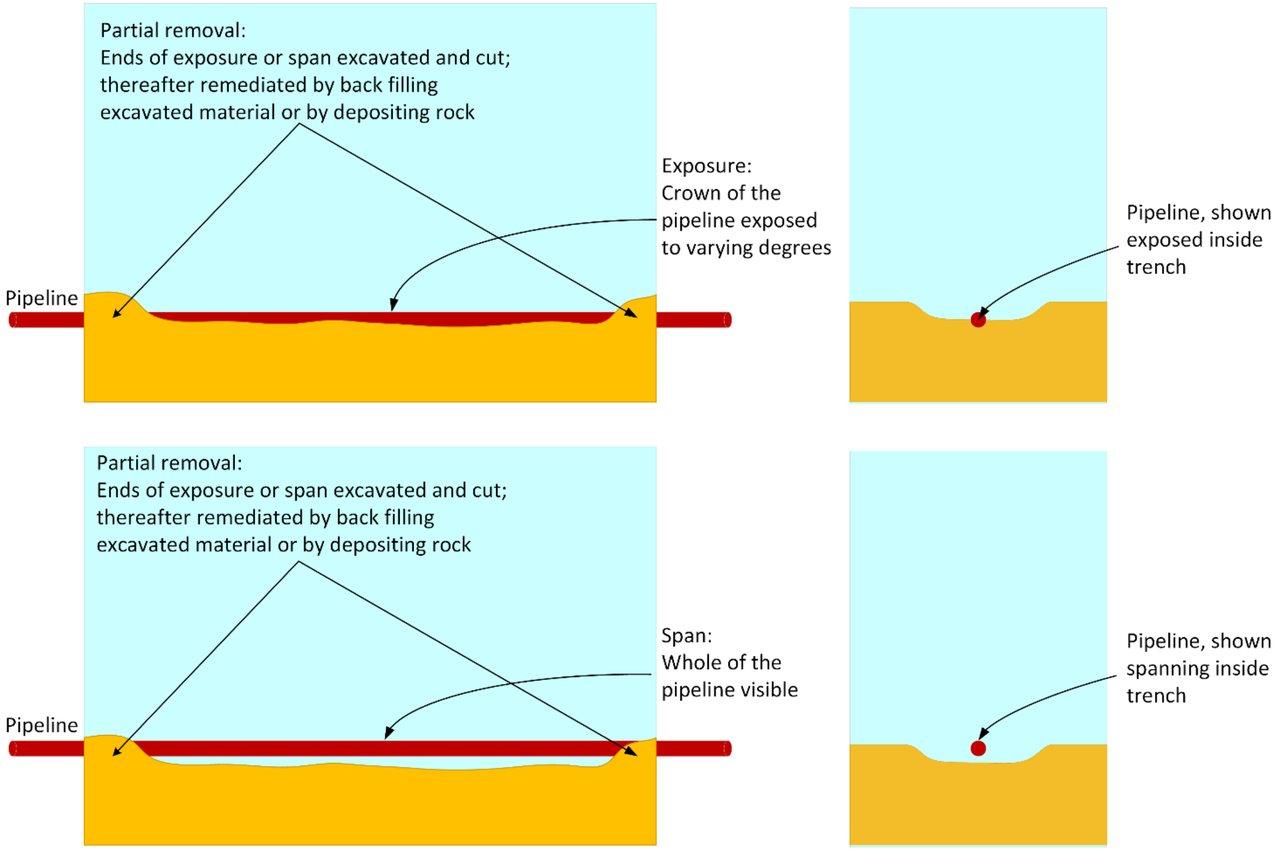


Figure 5.1.1: Exposures, spans & partial removal

The method for decommissioning of the risers or surface laid sections of pipelines and pipeline approaches is the same irrespective of which option is pursued. Therefore, decommissioning of these parts of the pipelines are not included in the assessment. All options include removal of features such as pipespools, surface laid pipelines, jumpers, concrete mattresses, and grout bags in accordance with mandatory guidelines.

Following an assessment of the quality of burial, the decommissioning options considered for the pipelines are summarised as follows:

Pipeline ID	Complete removal	Partial removal	Leave *in situ*	Comments
PL9	X	X	X	Variable depth of cover, exposures & spans exist
PL9A	X		X	Surface laid but part buried under drill cuttings, adjacent to Heather jacket
PL352	X	X	X	Reasonable depth of cover, number and extent of exposures & spans have reduced over the years
PLU6254	X	X	X	Refer note 1. Comments as per PL352

NOTES

1. As it is part suspended in the water column and partly buried in the drill cuttings and seabed, PL9A is not subject to a comparative assessment but final decommissioning proposals will be discussed and agreed with the appropriate stakeholders.
2. PL9, PL352 and the PLU6254 (ESDV umbilical) were trenched into the seabed and left to backfill naturally. That is, PL352 and PLU6254 share the same trench.

Table 5.1.1: Pipeline decommissioning options

Further details of the decommissioning options for the pipelines and umbilical are described in Table 5.1.2 below. The activities in these sections could be undertaken using a variety of vessel type. Vessel type might include a construction support vessel (CSV), an ROV support vessel (ROVSV), or a pipelay vessel, a rock discharge vessel, or a mixture of all of them, depending on the activities being undertaken.

ID	Item Description	Complete removal	Partial removal or remediation	Leave *in situ*
1	Riser sections of pipeline PL9, PL352, PLU6254	Remove upper section of PL9 and PL352 risers along with upper jacket. Leave lower sections of PL9, PL352 risers and PLU6254 connected to the lower jacket (note 1).	Remove upper section of PL9 and PL352 risers along with upper jacket Leave lower section of PL9, PL352 risers and PLU6254 connected to the lower jacket, otherwise remove (note 1).	Remove upper section of PL9 and PL352 risers along with upper jacket Leave lower section of PL9, PL352 risers and PLU6254 connected to the lower jacket otherwise remove (note 1).
2	PL9A	Remove.	n/a	Leave *in situ*.
2	Trenched and buried section of PL9, PL352, PLU6254	Uncover the pipeline(s) using mass flow excavator ('MFE'). Completely remove rigid pipelines either using reverse reel (PL352) or the 'cut and lift' method (PL9). Completely remove PL:U6254 using reverse reel method.	Either remove exposed sections of pipelines and remediate the remaining pipeline ends or rebury the exposed sections by post-trenching or by the deposition of additional rock.	Leave *in situ* with no remedial work being carried out.
3	Surface laid section of pipe spools and umbilical jumpers protected and stabilised with concrete mattresses on approach to ESDV (PL352, PLU6254) or Ninian Central (PL9).	Remove. Remove all surface laid pipespools and associated sand and cement bags and concrete mattresses.	Leave *in situ*.	Leave *in situ*.

NOTES

1. Recognising that the fate of the lower jacket has yet to be determined. The long-term solution will be the same as any decommissioning proposals for the lower jacket.
2. PL9A which is 139m long and part riser and partly laid on top of drill cuttings is not subject to a comparative assessment.
3. PL352 and PLU6254 share the same trench and emerge from the trench near the ESDV and on approach to Heather.

Table 5.1.2: Options for decommissioning pipelines and umbilicals

6. COMPARATIVE ASSESSMENT

6.1 Method

PL9, PL352 and PLU6254 are subjected to the comparative assessment. The approach to the comparative assessment is largely qualitative and carried out at a level that is sufficient to differentiate between the options. However, in some cases, for example such as cost, it can be necessary to examine the differences in more detail and quantitatively to provide clarity. The comparative assessment considers the following generic evaluation criteria and specific sub-criteria in line with OPRED guidance notes [8]. These elements are considered for short-term work as the assets are decommissioned as well as over the longer-term as 'legacy' impacts and risks. Please refer Table 6.1.1.

No scores have been determined. However, risk matrices have been used to determine if the planned and unplanned impacts would be for example broadly acceptable, possibly acceptable, unlikely to be acceptable or not acceptable. Cells coloured red indicate high risk, high impact, and less desirable outcomes. Green coloured cells indicate less risk, less impact, and more desirable outcomes. Cells coloured orange sit in-between red and green and may or may not be less, or more, desirable. High costs also attract a 'less desirable outcome' but cost differences are compared relative to each other. A relatively high cost therefore would be coloured red whereas a relatively low cost would be coloured green. All costs are assessed in relation to the cheapest cost. It should be noted that societal score looked at beneficial outcomes as well as detrimental outcomes. Where a comparison of options varies by shades of green rather than by red or orange it means there is little to choose between the options.

It is proposed to decommission the approaches and surface laid sections for each pipeline in the same way irrespective of the decommissioning option chosen. Therefore, the approaches are not included in this assessment.

CRITERIA	DEFINITION	SUB-CRITERIA (Short-term & Legacy, UNO)	COMMENTS
Technical	A technical evaluation of the complexity of a job that can be expected to proceed without major consequence or failure if it is adequately planned and executed.	Risk of project failure.	The risk of project failure given the technical and technological challenges.
		Technological challenge.	The technical challenge considers the viability of a task should the technology be available.
		Technical challenge (legacy).	The technological challenge concerns the availability of specific technologies to perform a task and the extent of research & development that may be required. Technically, complete removal of the pipelines would most likely be achievable, but significant complications could arise because the pipelines are buried. The 'cut and lift' method of removal is tried and tested for relatively short pipelines but would be avoided for longer pipelines several km long. Reverse reeling of pipelines has been achieved for small diameter pipelines and surface laid umbilicals but not for pipelines with significant depth of cover. The technical aspects of post-trenching and the deposition of rock are a consideration.
Safety	An assessment of the potential health and safety risk to people directly or indirectly involved in the programme of work offshore and onshore, or who may be exposed to risk as the work is carried out.	Health and safety risks for project personnel carrying out decommissioning activities offshore.	Typical offshore hazards might include loss of dynamic positioning, sudden movements during pipeline recovery works, dropped objects, collision between vessels, dealing with residual quantities of hazardous materials.
		Residual risks to marine users on successful completion of decommissioning.	Typical diving hazards might include, loss of heat or air supply, trapped cables and hoses, trapped limbs. After decommissioning has been completed typical hazards could relate to exposed pipelines or sections of umbilicals leading to possibility of fishing net snagging.
		Safety risks for project personnel engaged in carrying out decommissioning activities onshore.	Typical onshore hazards might include dealing with residual hazardous materials, onshore cutting, sudden movements or dropped objects.

CRITERIA	DEFINITION	SUB-CRITERIA (Short-term & Legacy, UNO)	COMMENTS
Environmental	An assessment of the significance of the risks / impacts to the environmental receptors because of operational activities or the legacy aspects.	Energy and emissions to atmosphere. Effect on seabed: Seabed disturbance and area affected. Effect on water column: • Liquid discharges to sea • Liquid discharges to surface water • Noise. Waste creation and use of resources such as landfill. Recycling and replacement of materials.	The assets are located outside of environmentally sensitive areas, so the dominant environmental criteria would likely be the effect on the seabed, the amount and type of waste recovered, or replacement materials needing to be manufactured to compensate for materials left *in situ*.
Socio-economic	An assessment of the significance of the impacts on societal activities, including offshore and onshore activities associated with the complete programme of work for each option and the associated legacy impact. This includes all the "direct" societal effects (e.g. employment on vessels undertaking the work) as well as "indirect" societal effects (e.g. employment associated with services in the locality to onshore work scope, accommodation, etc.).	Effects on commercial activities e.g. fishing Employment. Communities or impact on amenities.	Decommissioning of pipelines on individual projects involves work that is generally temporary in nature. On its own this type of work might typically lead to an extension of employment rather than new employment. Any impact on commercial fishing offshore is temporary and of relatively short duration.
Economics or Cost	Difference in cost.	Difference in cost compared for like-for-like activities; pipeline ends included in the comparison on the basis that they would incur mobilisation and demobilisation activities. This means that activities such as partial removal and complete removal, would incur incremental cost increases should the same vessels be used. Normalised to demonstrate a sense of scale.	In the short-term it is cheaper to do nothing, but this needs to be compared with the need for future surveys and potential remedial work.

Table 6.1.1: Comparative Assessment method – criteria & sub-criteria

6.2 Comparative Assessment for pipelines

The 'complete removal', 'partial removal' and 'leave *in situ*' decommissioning options are compared for pipelines PL9, PL352 and PLU6254.

6.2.1 Technical considerations

All three decommissioning options are technically feasible, although post-trenching can be problematic for pipelines whose coatings have degraded and for areas where rock or boulders are present. Rock or boulders would need to be cleared from the locality before any post-trenching could be achieved.

It would be technically feasible to recover all of the pipelines or parts thereof. The method used would depend in size, the material of manufacture, and whether a pipeline is concrete weight coated. The most likely method that would be used would be 'cut and lift' for PL9, the larger concrete weight coated pipeline and reverse reel for PL352 which is a smaller 6 in pipeline, and the shorter PLU6254. While the 'cut and lift' method of removal has been used for relatively short lengths, it could be used as a fall-back should it not be considered viable to use the reverse reel method. There is limited experience in reverse reeling individual trenched and buried pipelines or pipelines buried in rock and for this method it is likely that any overlying sediment (or rock) would need to be removed or displaced to uncover the pipelines or umbilical before they could be recovered. The removal or displacement of sediment or rock would be typically done using an MFE.

The Heather PL9 16in pipeline is concrete weight coated and would be a candidate for recovery using the 'cut and lift' method. This is because reverse reeling is not generally considered viable for concrete coated pipelines as they cannot be reeled onto the reel without the coating cracking and falling off the pipeline. The concrete coated pipe is not designed to develop the bending stresses expected with reverse reeling when taking account of the weight of concrete coating. Reverse S-lay is also unlikely to be feasible for concrete coated pipelines so these would need to be recovered in sections using 'cut and lift'. There are also potential issues with the deterioration of the concrete coating over time which may result in sections falling off during recovery. There could also be uncertainties over the condition and structural integrity of the pipeline which could lead to failure during recovery. To the author's knowledge reverse S-lay has not been used for recovering pipelines in the industry.

Although repetitive, the 'cut and lift' method would be feasible but would take a significant amount of time to achieve. Should the pipeline be recovered in road transportable lengths between 10m and 12m long this would mean between 80 and 100 sections being recovered per km of pipeline. For the PL9 pipeline which is ~33.2km long, recovery using the 'cut and lift' method would be a significant undertaking and probably an unrealistic prospect.

The 6in pipeline (PL352) and ESDV umbilical (PLU6254, ~570m, long including the riser section) would both likely be candidates for recovery using the reverse reel. As the pipeline would be deformed as it is recovered onto a reel, it would not be available for reuse, but it could be recycled when recovered to shore. The structural integrity of the steel pipelines would need to be assured before commencing the removal works but should any issues arise the contingency method of removal would involve using 'cut and lift'.

From a technical perspective the partial removal and leave *in situ* decommissioning options are also feasible.

Technically, instead of partial removal should there be a case to be made for post-trenching the exposed sections or for the deposition of additional rock. No specific difficulties appear to have been recorded in the original pipeline trenching documentation, but the subsequent installation of rock and the fragmentation of the concrete weight coating along the pipeline (PL9) mean that operations to post-trench of the pipeline would be compromised and the successful outcome of such an operation cannot be assured. Furthermore, several of the exposed sections are too short or are interspersed with rock, which means that they could only be dealt with by the partial removal option or the deposition of additional rock.

The diameter of PL9 (>16 in outside diameter) is such that a plough rather than self-propelled trenching machine[8] would need to be used to post-trenching the pipeline. At each post-trenching location a section of pipeline would need to be removed at the start and end of the section being trenched to allow the pipeline to pass through the plough and to allow the plough to transition down to a new trench depth. To backfill a pipeline after it is lowered to a specified depth in a trench, the plough is either modified to 'backfill' – which may mean a trip back to port, or a second backfill plough is then pulled over the pipeline which then directs the mounds of trenching spoil back into the trench to cover the pipeline.

Note that PL352 and PLU6254 lie in the same trench, so it can be assumed that any disturbance to one will affect the other. This means that post-trenching activities would likely be required between Heather and the ESDV skid remaining *in situ* if the other is removed. However, the proximity of the pipeline and umbilical to each other could render the post-trenching option unviable.

For this reason it is reasonable to discount the feasibility of post-trenching PL9.

6.2.2 Safety considerations

The difference in potential safety risk between the options is sufficiently large that a HAZID was not considered necessary at this stage. A HAZID would ordinarily be carried out as part of the preparatory activities.

Safety risk to offshore project personnel

The key differences between the options are as follows.

- Should divers be required, the risk to divers and personnel on the vessel from hydrocarbon or hazardous substance releases from recovered pipelines will be greater for complete removal than for either partial removal or leave *in situ* due to the larger volume of material that would be recovered.
- Risk associated with 'cut and lift' operations. Assuming the pipeline(s) could successfully be excavated from a technical perspective the operation should be relatively straightforward. However, to ensure road transportable lengths, the 'cut and lift'; operations would require between ~80 to ~100 sections or pipe to be removed *per km* of pipeline. Arguably, from a safety perspective this would likely be manageable, but the associated risks would increase with the number of operations needing to be performed, and the amount of material needing to be transferred and handled on the vessel; No such project risks would be incurred for the leave *in situ* decommissioning option.
- Risk associated with reverse reeling operations for complete removal and partial removal, with PL352 and PLU6254 needing to be spooled onto a reel on a subsea support vessel being attached to the pipeline or umbilical. The risk to personnel and assets would therefore be greater for complete removal option than for partial removal and leave *in situ* although a potential issue with the partial removal option would be the stop-start nature of the recovery operations.
- Increased risk to all activities due to adverse weather is greater for complete removal than for

[8] Self-propelled trenching machines are more typically used for smaller pipelines and power cables.

partial removal and leave *in situ* as the vessels would be in the field for longer.

- Remediation option instead of partial removal option. Risk associated with deposition of rock either along part or all of the pipeline. The operational risks would increase with the amount of material involved but can be expected to be low. To have to carry out the operation at all would present more of a risk than doing nothing.
- Remediation option instead of partial removal option only. Risk associated with post-trenching along part of the pipelines. The operational risks are such that any safety concerns would be low, but to have to carry out the operation at all would present more of a risk than doing nothing.
- Risk associated with legacy survey activities that is, the risks associated with vessels being used are greater for the leave *in situ* option than for complete removal. Typically, in the UK a minimum of three legacy surveys would be required to confirm the condition of subsea pipelines left *in situ*.

Given that the activities and techniques are frequently used in the North Sea, the risks from all hazards relating to 'cut and lift' and reverse reel methods of removal would be broadly acceptable. It is acknowledged that there is relatively little experience of reverse reeling a trenched and buried pipeline and therefore this risk could be higher but still tolerable if sufficient mitigation and control measures are adopted. This risk relates to the complete removal and partial removal (or remediation) options depending on the individual lengths recovered.

Short-term safety risk to fishermen and other marine users

The risk to mariners in the short-term is aligned with the duration the activities would be undertaken in the field. While decommissioning operations are underway the duration of vessels in the field would be longer for either the complete removal or partial removal (or remediation) options than for leave *in situ*. Reverse reel and to an extent 'cut and lift' would mean that the vessel is attached to a pipeline and could not move out of the way quickly. However, a vessel management plan would address the mitigations required.

For the leave *in situ* option at most only the pipeline ends would be dealt with and the duration of the vessels in the field would be much shorter for this option.

Therefore, while decommissioning activities are occurring, the risk to fishermen and other marine users would be least for the leave *in situ* option. It could be expected that any interference would take the form of minor alterations to normal operating practices. Such deviations would be so small as to not be significant. On this basis the potential impact associated with any of the decommissioning options can be considered low.

Residual safety risk to fishermen and other marine users

The greatest risk relating to marine users was likely to be concerned with snagging of fishing gear, specifically demersal trawl boards. As explained in section 3.3, demersal trawling is the dominant type of fishing in the area. For demersal (and shellfish) trawling activities there is a potential for snagging on equipment left on the seabed, including spoil mounds and pipelines that remain on the seabed after decommissioning activities have been completed.

By completely removing the pipelines and umbilical the risk of snagging would be removed in perpetuity. Therefore, the complete removal option results in lower residual risks to mariners and other users of the sea.

The pipelines and umbilical were installed in open trenches that were left to backfill naturally. Historical data would indicate that the pipelines PL9 and PL352 and PLU6254 have suffered from exposures and spans since they were originally installed, but the frequency and combined length of exposures (and spans) has been decreasing over time. Albeit very slowly. This suggests the possibility that the exposures and spans would eventually disappear without any remedial work having been carried out, but for PL9 this would likely take decades to achieve. Outside of the 500m safety zones at Heather and Ninian Central, leaving PL9 and PL352 *in situ* as they are with exposures and spans continuing to exist there would be no discernable change to the existing situation. Any spans would continue to require remediation. This means, however, that pipeline inspections and monitoring and the remediation of any spans would need to continue.

For the partial removal (or remediation) and leave *in situ* options once any surface laid pipelines or pipeline exposures have been dealt with, the remaining pipelines can be expected to remain buried with no exposures.

From this it can be reasoned that decommissioning activities that minimise the disturbance to the seabed, reduce the likelihood of creating snag hazards / spoil mounds and that leave the seabed free of equipment will minimise the impact on local fishing activities; this will be no different from the current situation. All three decommissioning options would leave the seabed free of potential snagging hazards as long as span management activities continue for the leave *in situ* decommissioning option. Although the complete removal option and to a lesser extent partial removal has the potential to leave spoil mounds that present snagging hazards, it is possible that with extra effort these could be dispersed, or they would disappear over time.

Health & safety risk to onshore project personnel

The key differences between the options are as followed:

- Risks associated with cutting the pipeline(s) resulting in injury would be greater for complete removal due to the higher quantity of material returned to shore compared with the partial removal and leave *in situ* options.
- Risks associated with lifting and handling pipeline sections are also greater for complete removal and to a lesser extent partial removal due to larger quantities of material being returned to shore.
- For the remediation option involving the deposition of rock would require rock to be quarried. To do this at all would incur risks that would otherwise not occur.

Many of the hazards described in the foregoing safety assessment are common to both decommissioning options. Based on the differences, the leave *in situ* option gives rise to lower risks to onshore personnel for the following reasons:

- Less offshore work.
- Less onshore handling.
- Unloading pipespools from a vessel has been done before, but to do this at all for the complete removal and partial removal options would increase the risk to onshore personnel as compared to the leave *in situ* option.
- Unspooling of pipelines and umbilicals from a reel has been done before, but to have to do this at all increases the risk for onshore personnel compared to the leave *in situ* option.

6.2.3 Environmental considerations

Planned energy use, emissions, and discharges

The duration that vessels would be are required in the field for the complete removal and partial removal (or remediation) would be longer than required for leave *in situ*. For PL9 ('cut and lift'), PL352 ('reverse reel') and PLU6254 (reverse reel), vessels would be in the field longer. Vessels would be in the field a comparable time for complete or partial removal of PLU6254 and in both instances the time in the field would be longer than for the leave *in situ* option.

The deposition of rock on exposures and post-trenching would both take less vessel time than the removal of exposed sections for the partial removal option.

Vessel times would be reflected in the liquid discharges to sea, noise, energy requirements and resulting missions to air. Conversely, the legacy survey requirements for partial removal (or remediation) and leave *in situ* would be greater than for complete removal, and in the case of partial removal (or post trenching) the possibility of remedial works could increase with the number of cut pipeline ends.

The amount of cutting, lifting and disposal requirements are related to the length of pipeline recovered. Therefore, the discharge to sea, discharges to surface water, noise in water from cutting, seabed disturbance from excavation and lifting, and the potential use of landfill space would all be greater for the complete and partial removal options than for leave *in situ*.

Energy requirements and emissions to air would be such that there would be a difference between options. However, the gap between complete removal and leave *in situ* narrows when indirect energy requirements and emissions required for replacement of unrecovered material are accounted for.

Planned and unplanned impacts on the seabed sediments

The complete removal option would result in no materials left in the seabed, although during removal operations the likelihood of concrete spalling or breaking off from sections of PL9 (a CWC coated pipeline) during cutting and lifting operations would be greatest, and some of this material – despite best intentions, may be left *in situ*.

While the complete removal option would result in no materials left in the seabed, the partial removal and leave *in situ* options would result in materials being left *in situ* to degrade naturally. As the pipelines are predominantly manufactured from steel (PL352) or steel and concrete (PL9) this would not be detrimental to the local environment. PLU6254 has a higher content of composite materials (~10%) and so would take so would take much longer than steel to decompose. The deposition of the composite materials into the marine environment would likely occur very gradually over hundreds of years, and so would be at little detriment to the local marine environment. Any raw material not recovered would need to be replaced by newly manufactured material for any new products.

If it can be assumed that the removal of all of the buried pipelines would affect a 10 m wide corridor, the overall area affected would be ~0.54 km^2 which is equivalent to ~0.02% of the area (2,991 km^2) of the smallest ICES rectangle (51F0) that contains Heather related infrastructure. This can be considered very small as a percentage. Removal (or remediation) of part of the pipelines (PL9 ~14 km and PL352 ~0.1 km, equivalent area ~0.14 km^2) would also be considered very small as a percentage of the area of ICES rectangle 51F0).

If it can be assumed that leaving all of the buried pipelines *in situ* would affect a 5 m wide corridor, the overall area affected would be half of the area affected by removal operations and can also be considered very small. The area affected by the partial removal operations would fit in between these two calculated values.

Waste management

Material for pipelines and umbilicals that are recovered as part of a decommissioning programme. can theoretically be reused but in practice the materials would have suffered deformation during the recovery process. Proving that the integrity of the complex multi-layered structure of components such as an umbilical has not been compromised during the handling and operational process is difficult. Often recycling is the only realistic option.

Such materials can be split into their component parts with materials such as steel and copper being readily recycled as the base material with synthetic components being recycled as recovered energy.

The amount of material made available for reuse, recycling or destined for landfill would be directly related to the quantity recovered. However, experience would suggest that very little material would be destined for landfill once recovered. The concrete weight coating would likely be crushed and recycled along with the steel material. Conversely, any material left *in situ* would need to be replaced by the manufacture of new material.

In adopting a remediation option rather than partial removal, the deposition of newly quarried rock would mean that new material would be deposited on the seabed while at the same time no materials would be recovered for reuse of recycling. Theoretically, the post-trenching remediation option would not require any additional materials but in practical terms the deposition of rock would need to be needed to bury any cut pipeline ends.

6.2.4 Societal considerations

Commercial

While the vessels are present in the field and activities are being undertaken the area would not be accessible for fishing. Therefore, the magnitude of the impact on commercial activities is related to the number and duration of vessels.

Activities which involve removal or reburial would implicitly disturb the seabed. Therefore, since complete removal would require more activities on the seabed it will have a higher short-term impact on commercial fishing.

The main commercial activity in the area is demersal fishing. The occurrence of pelagic fishing is much less prominent and has been virtually non-existent in two of the three ICES rectangles containing Heather related infrastructure for a few years (section 3.3). The potential effects could be loss of fishing revenue due to exclusion from fishing grounds, disturbance of the seabed or loss of, or damage to fishing equipment. Notwithstanding the loss of fishing equipment, historically the average value of fish landed per km^2 in the Heather area - the largest values being obtained in ICES rectangle 50F0) is relatively small (Figure 3.3.5).

In the years between 2015 and 2020 the maximum value of demersal, pelagic and shellfish landed per km^2 per annum occurred in ICES Rectangle 50F0 and the average calculated values are £1,939 (2016), £395 (2020) and £12 (2019) respectively (section 3.3). This is calculated by dividing the commercial value of fish landed by the area of ICES Rectangle 50F0 (3,028 km^2).

The combined length of pipelines PL9, PL352 and PLU6254 is 53.14 km. If, simplistically, it can be assumed that their continued presence would mean that a 250 m corridor along the pipelines was not accessible for fishing, the equivalent area would be 13.28 km^2. Conservatively this would mean the loss of revenue 13.28 km^2 x £1,939 = £25,760 per annum, although this calculation is based on 2016 figures.

Therefore, during decommissioning activities the complete removal option can be expected to have a greater impact on fishing activities as it would have the longest duration and the greatest amount of activity disturbing the seabed. Leave *in situ* and to a large extent partial removal (or remedial works) would involve leaving the pipelines (and umbilical) where they are, and this could result in residual snag hazards and result in damage to fishing gear. Surveys may need to be undertaken to confirm that the pipelines and umbilical remain buried. While these surveys are being undertaken fishing activity may be disrupted for a short time, but the impact can be expected to be minimal. Typically, at least three post decommissioning surveys would be required; the exact magnitude of the impact will be dependent on the type, frequency and duration of the surveys required.

Employment

The complete removal and partial removal (or remediation) options would require a longer vessel duration and more waste management requirements. These options would therefore impact more positively on employment than leave *in situ*. However, the effect on employment would likely result in the continuation of existing jobs, rather than lead to the creation of new employment opportunities. The significance of the positive impact has therefore been assessed as low.

Communities

The port and the disposal site have yet to be established. However, they will be existing sites which are used for oil and gas activities and hold the permits required for the management of waste. The communities around the port and the waste disposal sites can therefore be expected to have adapted to the types of activities required, and the decommissioning activities associated with this project would be an extension of the existing situation. Therefore, the effect on communities is not considered a significant differentiator between options.

6.2.5 Cost considerations

More details of the cost assessment for the pipelines are presented in Appendix D, Table D.3.1 and it accounts for the post-decommissioning surveys and assumes that future surveys will be required.

For the purpose of assessing for PL9, based on 2018 survey data the partial removal option assumes that ~14 km of exposures would be recovered to shore or be subject to remediation measures. Complete removal of PL9 would be the most expensive option, costing twice as much as the partial removal option and costing much more than the leave *in situ*. The cost of the deposition of rock would be less than partial removal but more than twice the leave *in situ* option. The cost of post-trenching would cost more than the deposition of rock and it is not a viable alternative.

For the purpose of the assessing for PL352, based on 2018 survey data it is assumed that ~120m of exposures would be removed to shore for the partial removal option or be subject to remediation measures. Complete removal of PL352 would cost more than both the partial removal and leave *in situ* options.

For PLU6254, once exposed in the trench the reverse reel method of recovery would be more efficient than 'cut and lift', so the cost of complete removal would be ~20% more than the cost associated with dealing with just the umbilical ends at Heather and at the ESDV skid (i.e. leave *in situ*) and slightly more than the cost of partial removal. Partial removal of PLU6254 (~70 m based on 2010 data - likely to be conservative) would cost ~10% more than leave *in situ*.

The remediation options for PL352 and PLU6254 are not practical alternatives because of the inefficiencies involved when dealing with short individual exposures in several different locations.

Note that PL352 and PLU6254 lie in the same trench, so it can be assumed that any disturbance to one will affect the other. This means that post-trenching activities would likely be required for either of the pipelines between Heather and the ESDV skid remaining *in situ* if the other is removed. This is accounted for in the cost assessment.

The assessment assumes 1x post decommissioning survey would be required irrespective of the decommissioning options, and 3x legacy surveys would be required for any pipelines or umbilical being left i*n situ*.

7. CONCLUSIONS

7.1 Overview

PL9 is a 16in concrete weight coated pipeline ~33.2 km long. PL352 is a steel FBE coated pipeline ~19.4 km long. PLU6254 is 81 mm OD and is ~570 m long although part of this length is the riser section that hangs off the Heather topsides and is thus partly suspended in the water column and part surface laid and part buried in the seabed sediment.

All pipelines were trenched, with the trenches being left to backfill naturally. PLU6254 was laid in the same trench as PL352 between Heather and the ESDV skid. Historically both PL9 and PL352 as well as PLU6254 have experienced exposures and spans, although in the decades since the pipelines were installed the number and cumulative length of exposures and spans has reduced, although about a third of the length of PL9 remains exposed with spans making up ~1.8km of this length. Historically both PL9 and PL352 have remedial works to rectify spans and for PL9 in particular, this requirement can be expected to continue. A few of the spans in PL9 remain reportable to FishSAFE. PL352 still experiences a few exposures with spans making up above half of the exposed length; none are reportable to FishSAFE, and the indications are that over a long time - decades, the exposures (and spans) will disappear.

The comparative assessment was undertaken with a focus on the three decommissioning options for the pipelines associated with the Heather field. The pipelines are PL9, PL352 and PLU6254. Two remediation options were also considered in lieu of the partial removal option – post-trenching and the deposition of rock on exposed sections of pipelines.

The assessments considered five criteria for both the short-term decommissioning activities and the longer-term for 'legacy' related activities. The criteria were: technical feasibility, safety related risks with three sub-criteria, environmental with four sub-criteria, societal effects with three sub-criteria and cost.

Since the decommissioning of the surface laid ends at Heather (PL9, PL352, PLU6254), the Welgas tee (PL352) and at Ninian Central (PL9) is the same irrespective of which option is pursued, decommissioning of these is not included in the assessment. Therefore, any differences are incremental to the activities associated with surface laid infrastructure.

7.2 Conclusion

Technical aspects

From a purely technical perspective, the complete removal option is technically feasible for PL9, PL352 and PLU625. The 'cut and lift' method would likely be the most viable method for PL9 whereas the reverse reel could probably be used to recover PL352 and PLU6254. As a contingency, 'cut and lift' could be used for both pipelines and the umbilical, and although the operations would be repetitive, complete removal would be achievable. Where they are buried, the pipelines would need to be excavated from the trench or from within rock but technically this is achievable.

The partial removal options would similarly be technically achievable, and in practical terms leave *in situ* decommissioning would be easier to achieve technically.

Several of the exposed sections in PL9 are too short to be post-trenched or are interspersed with rock, which means that they could only be dealt with by the partial removal option or the deposition of additional rock. The post-trenching option instead of partial removal is not recommended for PL9.

Safety aspects

From a safety perspective, given that the activities and techniques – including the remediation options instead of partial removal, are frequently used in the North Sea it is assumed that the risks from all hazards relating to 'cut and lift' and reverse reel methods of removal as well as excavation would be broadly acceptable. It is acknowledged that there is relatively little experience of reverse reeling a trenched and buried pipeline and therefore this risk could be higher but still tolerable if sufficient mitigation and control measures are adopted. This risk relates to the complete removal and partial removal options depending on the individual lengths recovered. The individual lengths recovered would need to be of sufficient length to make it practical for using the reverse reel method. For project personnel, the threat to safety increases with the volume of work and materials dealt with, and by inference in the short-term the leave *in situ* option would present the least threat to the safety of offshore and onshore project personnel.

While decommissioning activities are underway, the risk to fishermen and other marine users would be least for the leave *in situ* option. It can be expected that any interference would take the form of minor alterations to normal operating practices. Such deviations would be so small as to not be significant. On this basis the potential impact associated with any of the decommissioning options can be considered small.

The greatest risk relating to marine users is likely to be concerned with snagging of fishing gear, specifically demersal trawl boards. Demersal trawling is the dominant type of fishing in the area. For demersal (and shellfish) trawling activities there is a potential for snagging on equipment left on the seabed, including spoil mounds and pipelines (particularly where pipeline spans are evident) that remain on the seabed after decommissioning activities have been completed.

By completely removing the pipelines and umbilical the risk of snagging would be removed in perpetuity. Therefore, the complete removal option results in lower residual risks to mariners and other users of the sea. Assuming that both pipelines and the umbilical remain buried the partial removal option would also satisfy the requirement to remove snagging hazards as would either of the remediation options.

Outside of the 500m safety zones at Heather and Ninian Central, leaving PL9 and PL352 *in situ* as they are with exposures and spans continuing to exist and providing the spans continue to be monitored (and remediated where they exceed FishSAFE criteria) there would be no discernable change to the existing situation. This means, however, that for the leave *in situ* and partial removal or remediation options, pipeline inspections, monitoring, and the remediation of any spans would need to continue.

Environmental aspects

The duration that vessels would be are required in the field for the complete removal and partial removal would be longer than required for leave *in situ*. and this would be reflected in the use of energy, emissions to air, noise and planned discharges to sea.

While the complete removal option would result in no materials left in the seabed, the partial removal and leave *in situ* options would result in materials being left *in situ* to degrade naturally. As the pipelines are predominantly manufactured from steel (PL352) or steel and concrete (PL9) this would not be detrimental to the local environment. PLU6254 has a higher content of composite materials (~10%) and so would take so would take much longer than steel to decompose. The deposition of the composite materials into the marine environment would likely occur very gradually over hundreds of years, and so would be at little detriment to the local marine environment. Any raw material not recovered would need to be replaced by newly manufactured material for any new products.

If the removal of all of the buried pipelines would affect a 10 m wide corridor, the overall area affected would be ~0.54 km^2. This would be a temporary impact and would be considered very small as a percentage of the North Sea. The area of seabed affected by partial removal or either of the remediation operations would also be very small. As a guide it is estimated that the leave *in situ* option would result in around ~0.14 km^2 of the seabed being affected.

Societal aspects

While the vessels are present in the field and activities are being undertaken the area would not be accessible for fishing. Therefore, the magnitude of the impact on commercial activities is related to the number and duration of vessels.

The main commercial activity in the area is a mixture of demersal fishing. The occurrence of pelagic fishing is much less prominent and has been virtually non-existent in two of the three ICES rectangles containing Heather related infrastructure for a number of years (section 3.3). The potential effects could be loss of fishing revenue due to exclusion from fishing grounds, disturbance of the seabed or loss of, or damage to fishing equipment. Notwithstanding the loss of fishing equipment, historically the average value of fish landed per km^2 in the Heather area - the largest values being obtained in ICES rectangle 50F0, is small.

The combined length of pipelines PL9, PL352 and PLU6254 is 53.14 km. If their continued presence means that a 250 m corridor along the pipelines would not be accessible for fishing, the equivalent area would be 13.28 km^2. Conservatively based on 2016 figures this would mean the loss of revenue 13.28 km^2 x £1,939 = £25,760 per annum although it should be noted that fishing effort in more recent times has been much less.

In pursuing any of the decommissioning options the effect on employment would likely result in the continuation of existing jobs, rather than lead to the creation of new employment opportunities.

The effect on communities near the port sites is not considered a significant differentiator between options.

Cost aspects

The cost assessment for the pipelines and umbilical accounts for a post-decommissioning survey and assumes that future surveys will be required.

For PL9 and PL352 the complete removal option would cost more than the leave *in situ* option. Partial removal and either of the remediation options (deposition of rock or post trenching) would also be more expensive than leave *in situ*. For PLU6254, the cost for complete removal is slightly more than for leave *in situ*. For both pipelines and the ESDV umbilical the partial removal option and either of the remediation options would also cost more than leave *in situ*.

Note that the remediation options for PL352 and PLU6254 are not practical alternatives because of the inefficiencies involved when dealing with short individual exposures in several different locations.

For the complete removal option once completed, no more costs would be incurred for future pipeline surveys while pipelines - or parts thereof, that are left *in situ* would be subject to future pipeline inspections.

Pipeline ID	Leave *in situ* (end removal)	Partial removal (incl. ends)	Remove ends, remediation, rock	Remove ends, remediation, post Trench	Complete removal
PL9 (16in)	0.3	2.4	0.9	1.0	5.00
PL352 (6in)	1.4	1.7	2.6 (n/a)	2.3 (n/a)	5.00
PLU6254 (81 mm)	1.6	1.8	5.0 (n/a)	2.7 (n/a)	1.9

NOTES

1. Partial removal or remediation: PL9 ~14.0 km (2018), PL352 ~120m (2018), PLU6254 ~70m (2010).
2. All partial removal lengths subject to verification.
3. The remediation options for PL352 and PLU6254 are not practical alternatives because of the inefficiencies involved when dealing with short individual exposures in several different locations.

Table 7.2.1: Summary of cost assessment

7.3 Recommendations

While the exposure and spans for PL352 and PLU6254 have a reasonable chance of disappearing over the next few years the same cannot be stated for PL9 of which approximately one-third remains exposed. PL9 will need to continue being surveyed with remedial works likely to be required while the threat of reportable spans continues.

As a result of the foregoing the following recommendations are presented for consideration:

- PL352 & PLU6254 – leave *in situ*. Subject to survey, having removed the surface laid ends, leave PL352 and the umbilical *in situ* without remediation. This on the basis that the number and extent of exposure and spans will have reduced since 2018 and can be expected to reduce further by the time the next round of IRM surveys have been carried out.
- PL9 – leave *in situ* with remedial works involving the deposition of rock on spans only (total ~2.0 km long), leaving exposures (total ~14 km long) where they are found, Thereafter, the pipeline burial status should continue to be monitored using a Risk Based Inspection regime.
- Surface laid pipeline and umbilical ends should be removed.

For PL9, taking this approach reduces environmental impact on the seabed and need for extensive pipeline remedial works in the short-term and potentially accounts for the pipeline likely becoming more extensively buried in future from the natural migration of the seabed.

8. REFERENCES

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[9] The Council of the European Communities (1992) The Habitats Directive, Council Directive 92/43/EEC. Weblink last accessed 29 Sept 2021: Habitats Directive

[9] The data are only available for a rolling 5-yearly sequence. The 2015 data was obtained prior to the 2016 to 2020 update.

APPENDIX A ROCK VS. EXPOSURES (2018)

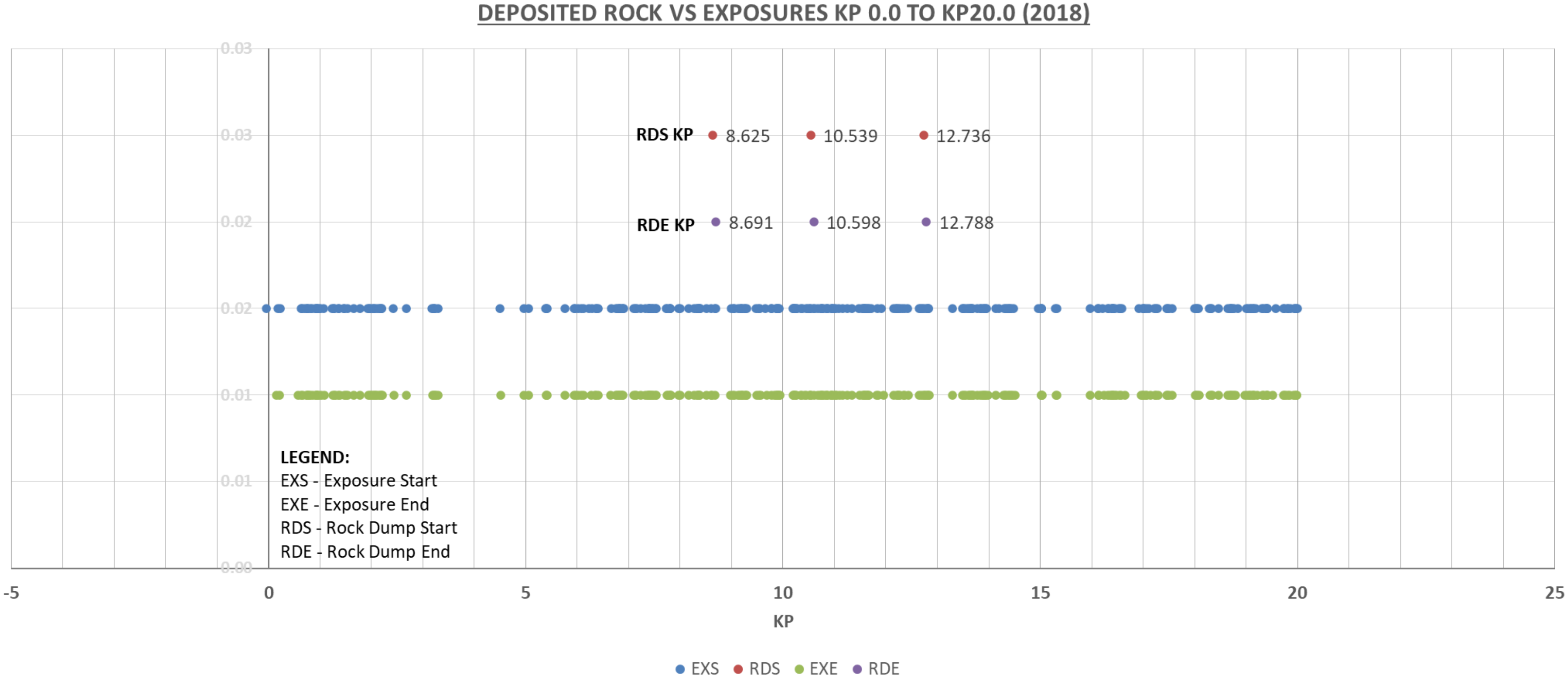

Figure B.1.1: PL9 rock vs. exposures plot KP0.0 to KP20.0 (2018 data)

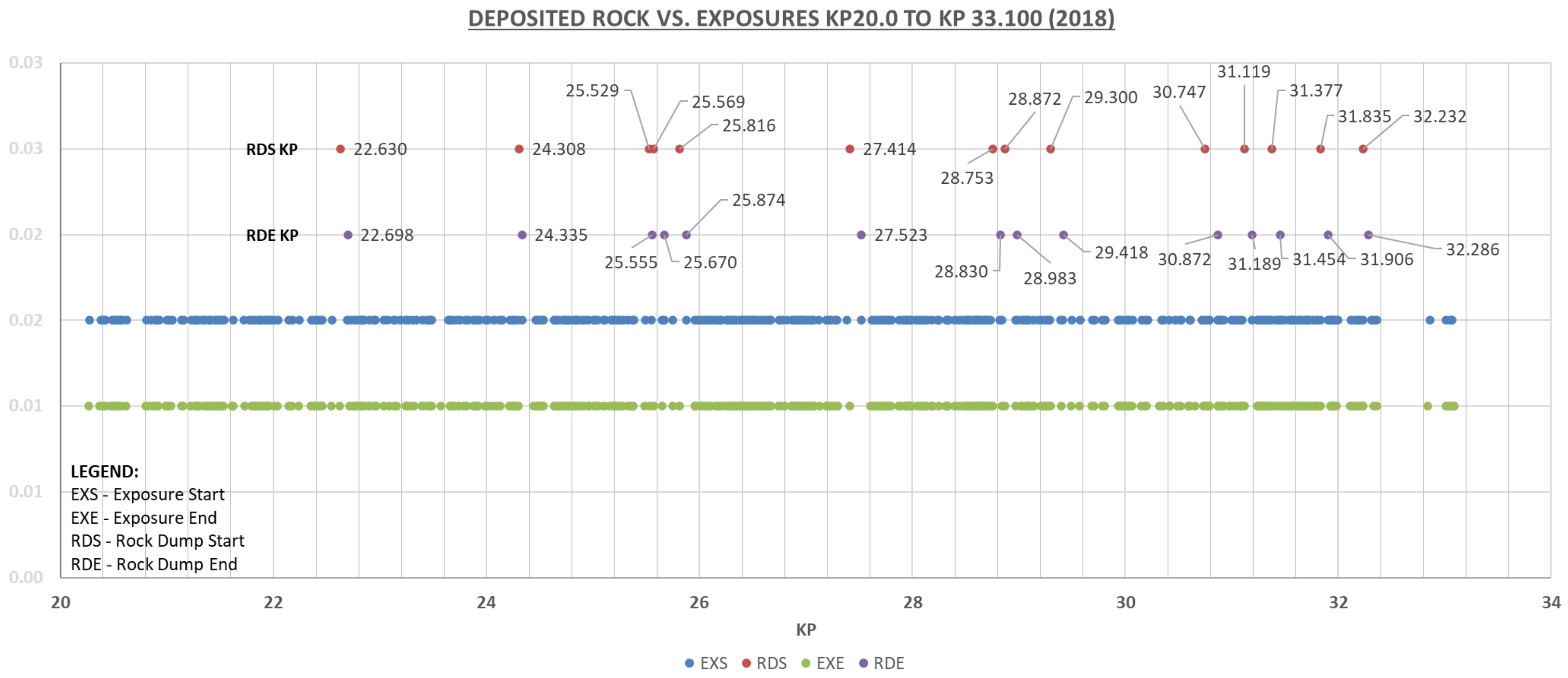

Figure B.1.1: PL9 rock vs. exposures plot KP20.0 to KP33.100 (2018 data)

APPENDIX B FIELD LAYOUTS

Appendix B.1 Heather Alpha approaches

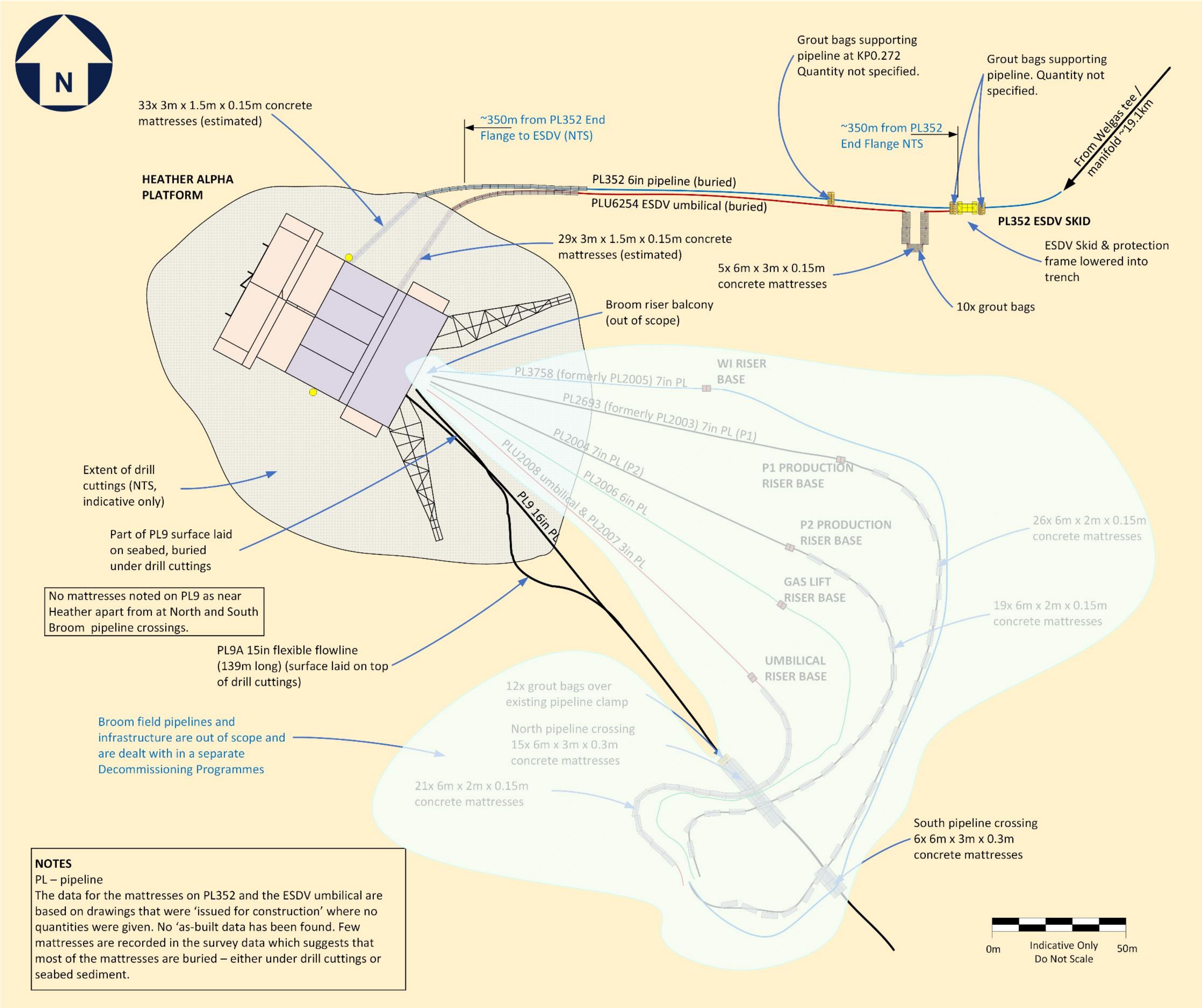

Figure B.1.1: Heather platform approaches

Appendix B.2 Welgas tee approaches

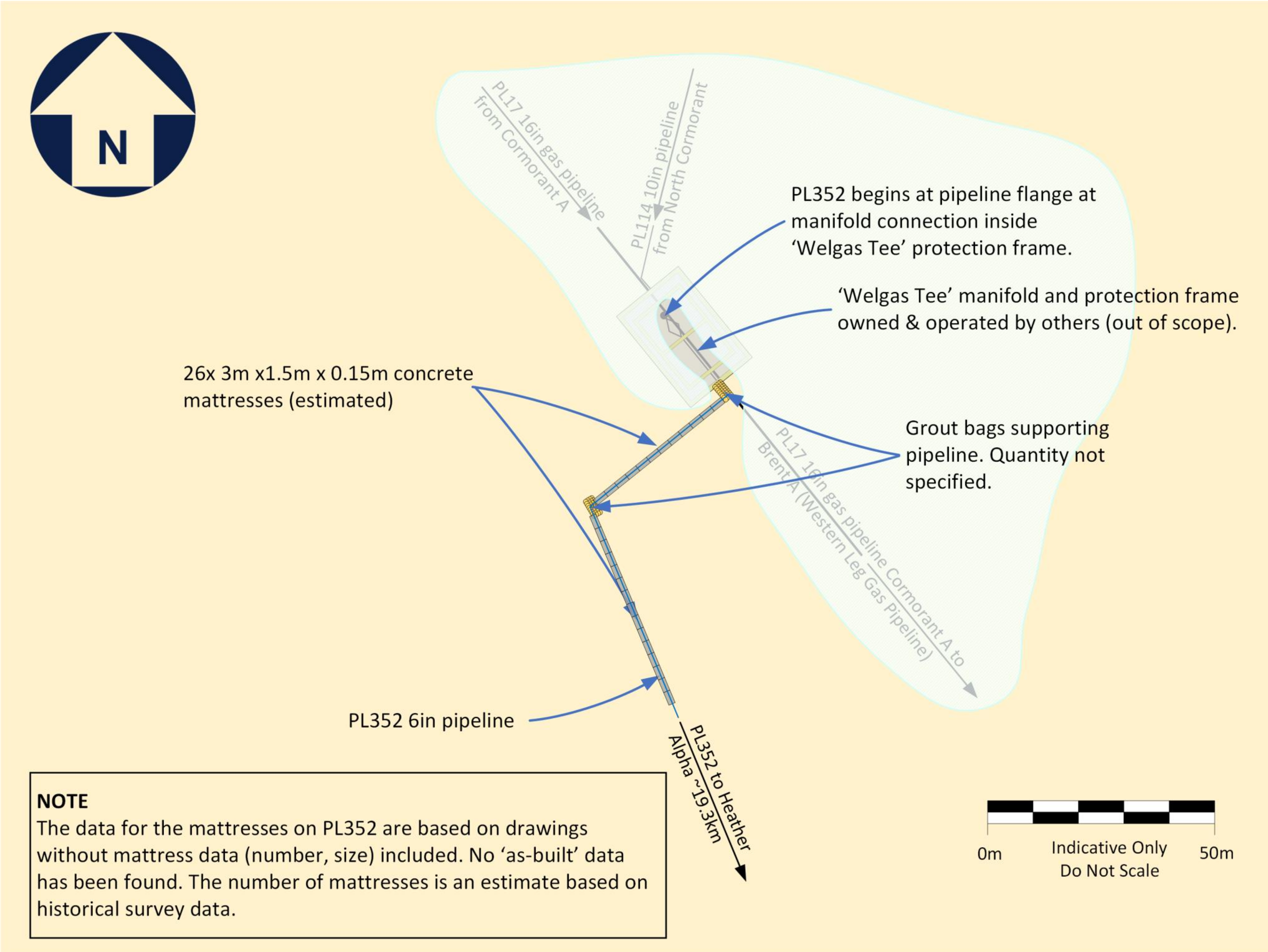

Figure B.2.1: Welgas tee / manifold approaches

Appendix B.3 Ninian Central approaches

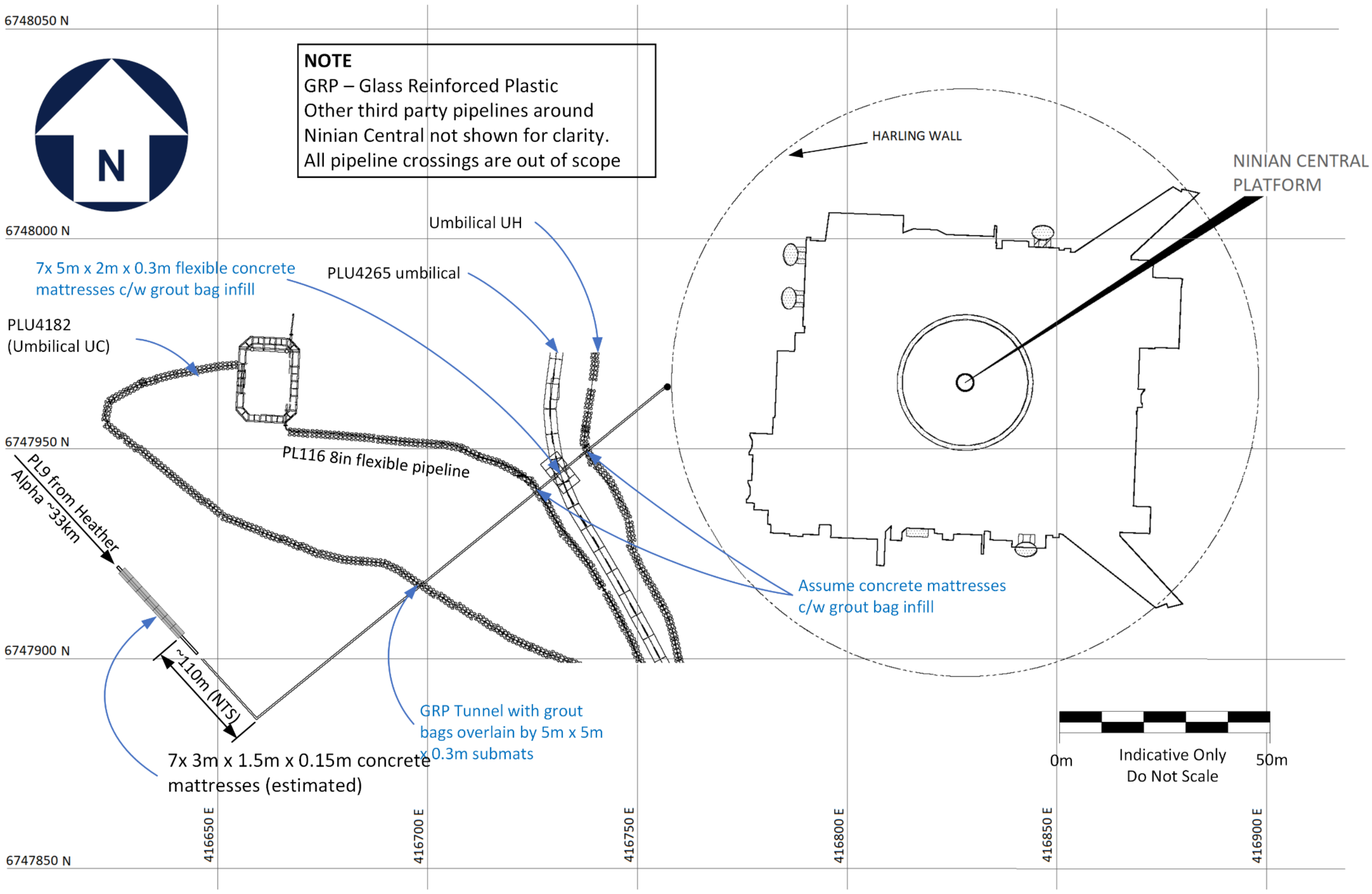

Figure B.3.1: Ninian Central approaches

APPENDIX C SUMMARY COMPARATIVE ASSESSMENT TABLES

Appendix C.1 Technical assessment

CRITERIA	ASPECT	SUB-CRITERIA	COMPLETE REMOVAL	PARTIAL REMOVAL OR REMEDIATION	LEAVE *IN SITU*
Technical	**Offshore Execution**	Risk of project failure	Technically, complete removal of the pipelines and umbilical would be achievable with little chance of project failure. PL9 using 'cut and lift' and PL352 and PLU6254 using reverse reel. There is relatively little experience in UKCS with reverse reeling slightly larger pipelines, but it would be achievable. Total length of buried pipelines is ~53 km.	Technically, partial removal of the exposed sections of PL9, PL352 and PLU6254 would be achievable with little chance of project failure. PL9 using 'cut and lift' (~14 km) and PL352 (~110 m) and the ESDV umbilical (~70 m based on 2010 data) using 'cut and lift'.	Technically, the pipelines and umbilicals could be left *in situ*.
			As above.	PL9 only. The PL9 CWC will have suffered from spalling which renders post-trenching unviable. Furthermore, several exposures are too short to be post-trenched or are interspersed with rock which means that there would be a high chance of project failure.	
			As above.	PL9 only. Technically it would be possible to deposit rock on the exposed sections of pipeline; this has been done before with no risk of project failure.	
		Technological challenge	Technology is currently available to excavate, cut and recover the pipelines to shore as well as to remediate the pipelines (post-trenching, deposition of rock)		N/A
		Technical challenge	Technically there is equipment available to remove the pipelines.	Technically there is equipment available to conduct partial removal activities.	Stable and buried pipeline(s) and umbilicals with exposures have been left *in situ* before so this approach would be achievable.
				PL9 only. Technically there is equipment available for post trenching activities. However, the short length of many of the exposures, the presence of rock and spalling CWC reduces the efficiency and viability of the post-trenching option for all exposed sections of pipeline.	
				PL9 only. A fall pipe vessel could be used for deposition of rock and has been used before in the field.	
Technical	**Legacy**	Risk of project failure	No pipeline surveys would be required in future.	Pipeline surveys have been undertaken in the past, so this is achievable with no complications.	
		Technological challenge	No pipeline surveys would be required in future.	The technology is currently available for carrying out pipeline surveys.	
		Technical challenge	No pipeline surveys would be required in future.	There would be no technical issues associated with carrying out pipeline surveys in future.	

BACKGROUND NOTES – POST-TRENCHING

Conventional trenching methods include the use of ploughs, mechanical cutters or jetting sleds. All of them can be deployed after the pipeline has been laid. Trenching using these methods is the most effective way on cohesionless soils or soft clay, when the seabed is relatively soft. Generally trenching is not a practical option when rock – either loose or solid, is present in the seabed of a pipeline route. The stiffness of a pipeline is also a consideration, and a transition from seabed to trench depth would be required remembering that the pipeline was originally installed into a 1.0 m deep trench.

Pipeline plough and pipeline backfill ploughs: These are pulled along the seabed using a surface vessel and require a transition from seabed down to the depth of burial. The ploughing method can be limited when the seabed is too fluid and lacks load bearing capacity to support the plough's weight or conversely when the seabed is too hard to "cut", in instances where coral, rock or boulders are prevalent as would be the case for a spalling pipeline or where deposited rock is present. In other words, given that the pipeline CWC is spalling the plough would likely be jammed or damaged as it encounters parts of the spalled concrete weight coating or where deposited rock is present either at or overlapping areas of the pipeline that are exposed, this method would not be suitable for 'post-trenching' the pipeline. Ploughs can be suitable for large pipelines.

Pipeline trencher: Pipeline trenchers are typically furnished with tracks and are self-propelled. That is, they are not towed. Typically they can be furnished with rock and clay chains, cutter, jetters, dredges, eductors and backfill tools. When cutting tools are used, spoil is removed from the trench by water eduction using high pressure water jetting and by air lifting.

Typically when cutting the pipeline or cable passes through the trencher and over the cutting chain using a roller cradle before existing the rear of the machine through jetting swords, or when dredging using water the pipeline (or cable) passes underneath the trencher between the tracks before passing though jet legs into a fluidised trench. Pipeline trenchers are typically used for smaller pipelines or cables.

Pipeline trench jetting sleds: An alternative mechanical dredging method is the 'pumping' or 'blowing' of sediment. The pumping is primarily performed using a hydraulic submersible pump fitted with an agitator head and jetting ring. Pumping can be effective in isolated shallow areas or when there are shorter lengths of pipe to cover. The pumping method is generally slow, less efficient and can have limitations depending on the 'depth of cover' requirements.

The blowing of soils is performed by Mass Flow Excavation ('MFE') tools using a high volume and a high flow rate of water directed through a wide diameter nozzle. This method is limited to sandy and softer seabeds when high pressure jetting is not required. Mass Flow Excavators have difficulty 'cutting' consolidated soils.

The jetting method is limited to favourable soil compositions which can be fluidised and pass through the eductor system. Jetting as a burial method is only commercially feasible when the backfill can occur via a natural seabed backfill process. Due to the soil fluidization during the jetting process, the trenched spoil is placed into the water column and generally 'swept away' by the current and is therefore not able to be placed back in the trench on top of the pipeline. In other words this method would not be suitable for 'post-trenching' the pipeline.

Table C.1.1: Technical assessment

Appendix C.2 Safety assessment

CRITERIA	ASPECT	SUB-CRITERIA	COMPLETE REMOVAL	PARTIAL REMOVAL OR REMEDIATION	LEAVE *IN SITU*
Safety	**Offshore Execution**	Health & safety risk offshore project personnel	More offshore work than partial removal or leave *in situ*. Excavation of the pipelines and recovery, either using 'cut and lift' or reverse reel for smaller pipelines. The work associated with 'cut and lift' would be repetitive (typically ~80 to ~100 lengths of pipe per km) but manageable from an HSE perspective. With appropriate engineering and pipeline integrity checks and planning reverse reel method would also be manageable from an HSE perspective. Most of the work could be done using equipment operated remotely and achieved without using divers. Material handling on vessel decks could be automated given the right resources and focus. 'Tolerable' rather than 'preferred' owing to the quantity of cuts and material transfers from seabed to vessel involved.	Less work than complete remove but more work than leave *in situ*. Little to choose for PL9 between complete removal and partial removal. Deposition of rock and post-trenching activities are performed using remotely operated equipment.	Only the pipeline ends would be dealt with; Less offshore work than for complete removal. Experience in the UKCS a of removal of pipeline sections. Significantly less work and therefore a shorter duration of activities than for complete removal.
		Health & safety risk to mariners	The risk to mariners in the short term would be aligned with the duration the activities would be undertaken in the field. Duration of vessels in the field would be longer than for leave *in situ*. Using the reverse reel method would mean that the vessel would be attached to a pipeline and could not move out of the way quickly. Using the 'cut and lift' method would also restrict the ability of a vessel to move out of the way, but for a relatively short time.	The risk to mariners in the short term would be aligned with the duration the activities would be undertaken in the field. Duration of vessels in the field would be longer than for leave *in situ* but less than for complete removal. Using the reverse reel method would restrict the ability of a vessel to move out of the way, but for a relatively short time.	Only the pipeline ends would be dealt with; duration of vessels in the field would be shorter than for complete removal.
		Safety risk onshore project personnel	Significantly more off-loading, off-reeling, onshore cutting, lifting, and material handling associated with disposal of the pipelines; presents an increased safety risk to personnel. The work would all be manageable from an HSE perspective.	Significantly less off-loading, onshore cutting, lifting, and material handling associated with disposal of the pipelines than for the complete removal option and so would present less of a safety risk to personnel than for complete removal but more of a safety risk than for leave in situ. The work would all be manageable from an HSE perspective.	No onshore work except for that possibly associated with the pipeline ends, which would be required for any of the decommissioning options.
Safety	**Legacy**	Health & safety risk offshore project personnel	No pipeline surveys or remediation related activities.	Pipeline surveys would be required, but this activity is considered routine with well managed risks and would be of short duration.	
		Health & safety risk to mariners	No infrastructure left therefore no residual snag hazards. Lower risk as potential snag hazards completely removed. Although bottom dredging, demersal fishing nets should not adversely interact with the temporary excavations.	Post decommissioning surveys and existing data provide evidence that any pipeline spans or exposures are limited, and therefore the risk to mariners from snagging would be low. Degradation of the pipeline if it remains buried, would not change the risk. If exposures occur the degradation could change the risk, but the risks of snagging individual exposures would remain low.	
		Safety risk onshore project personnel	Nothing to differentiate the options.		

Table C.2.1: Safety assessment

Appendix C.3 Environmental assessment

CRITERIA	ASPECT	SUB-CRITERIA	COMPLETE REMOVAL	PARTIAL REMOVAL OR REMEDIATION	LEAVE *IN SITU*
Environmental	**Offshore Execution**	Energy & emissions	Energy use and resulting emissions for this option would be higher than for leave *in situ*, but no energy and emissions would be needed to create new steel material.	Energy use and resulting emissions for this option slightly more than needed for leave *in situ*, but no energy and emissions would be needed to create new material. Significantly less energy use than needed for complete removal.	Least amount of energy used, and least emissions generated in the short term, although any gains would be offset by the energy and emissions required to create new material to replace that which would be left *in situ*.
		Seabed disturbance, area affected	The amount of seabed disturbed would be directly related to the length of pipeline being removed. The area affected (0.54 km^2) would be largest for this option.	The amount of seabed disturbed would be directly related to the length of pipeline being removed. The area affected by the removal of (Exposure lengths PL9 ~14 km and PL352 ~0.1 km), equivalent area ~0.14 km^2) would be much less than affected by the complete removal of all of the pipelines (0.54 km^2). Should deposited rock or post-trenching be the preferred option the area of seabed affected would be similar to that affected by the removal of just the exposed sections.	The smallest area of seabed would be disturbed in the short-term with the leave *in situ* option.
		Disturbance to Protected Area	The Heather pipelines do not currently reside within Special Conservation Area or a Marine Protected Area, so there is nothing to differentiate the options.		
		Effect on Water Column: • Liquid discharges to sea • Liquid discharges to surface water • Noise.	Discharges and releases to the water column are related to the duration of activities being undertaken and would therefore be greatest for the complete removal option.	Discharges and releases to the water column are related to the duration of activities being undertaken and would be less than for complete removal.	Discharges and releases would be least for the leave *in situ* option, particularly in the short-term.
		Waste creation and use of resources such as landfill. Recycling and replacement of materials	This option would result in the largest quantity of material being returned to shore. No material would be lost as no material would be left *in situ*.	This option would result in less material being brought to shore than for complete removal but more than for leave *in situ*.	No material would be returned to shore for recycling and therefore the material would be lost. Newly manufactured material would be needed to replace the material not recovered to shore.
Environmental	**Legacy**	Energy & emissions	No pipeline burial surveys or remedial would be required as the pipelines would have been completed removed.	Pipeline surveys would be required.	Pipeline surveys will be required, and remedial works will likely be required in future.
		Seabed disturbance, area affected	No pipeline burial surveys or remedial would be required as the pipelines would have been completed removed.	It is assumed that no pipeline related remedial activities would be required once partial removal or remedial activities have been carried out.	Pipeline burial surveys do not usually involve disturbance to the seabed, although remedial works would. However the areas affected would be relatively insignificant and measured in fractions of a km^2 in terms of area.
		Disturbance to Protected Area	The Heather pipelines do not currently reside within Special Conservation Area or a Marine Protected Area, so there is nothing to differentiate the options.		
		Effect on Water Column: • Liquid discharges to sea • Liquid discharges to surface water • Noise.	No pipeline burial surveys or remedial would be required as the pipelines would have been completed removed.	Pipeline surveys would be required.	Pipeline surveys would be required, and remedial works will probably be required in future.
		Waste creation and use of resources such as landfill. Recycling and replacement of materials	As the pipeline(s) would have been removed, no further waste would be created.	Pipeline surveys would be required, and remedial works may be required in future.	

Table C.3.1: Environmental assessment

Appendix C.4 Societal assessment

CRITERIA	ASPECT	SUB-CRITERIA	COMPLETE REMOVAL	PARTIAL REMOVAL OR REMEDIATION	LEAVE *IN SITU*
Societal	**Offshore Execution**	Effect on commercial activities	The impact of decommissioning vessel traffic on local commercial activities such as fishing would be greatest for complete removal.	The impact of decommissioning vessel traffic on local commercial activities such as fishing would be less than for complete removal but more than for the leave *in situ* option. The impact of remedial activities such deposition of rock or post trenching vessel traffic on local commercial activities such as fishing would be less than for complete removal.	The impact of decommissioning vessel traffic on local commercial activities such as fishing would be least for leave *in situ*.
		Employment	Decommissioning activities associated with the complete removal of pipelines would contribute greatest to the continuity of employment.	Employment opportunities would be less than for complete removal but more that leave *in situ*.	Decommissioning activities associated with leave *in situ* would contribute the least to continuity of employment.
		Communities or impact on amenities	Once the pipelines have been removed there would be few opportunities for continuity of work in ports and disposal sites.	Decommissioning activities would contribute to continuity of work in ports and disposal sites less than for complete removal but more than for leave *in situ* option.	Decommissioning activities associated with leave *in situ* would contribute the least to continuity of work in ports and disposal sites.
Societal	**Legacy**	Effect on commercial activities	No impact as no legacy related activities would be required.	Impact of survey vessel traffic on local commercial activities such as fishing would be more less than complete removal but there would be little to differentiate partial removal and leave in situ.	
		Employment	No future opportunities for continuation of employment.	Survey related work, little or no difference between partial removal and leave *in situ*.	
		Communities or impact on amenities	No opportunities for continuity of work in ports and disposal sites.	Few opportunities for continuity of work in ports and disposal sites other than associated with survey related. Little difference between partial removal and leave *in situ*.	

Table C.4.1: Societal assessment

Appendix C.5 Cost assessment

CRITERIA	ASPECT	COMPLETE REMOVAL	PARTIAL REMOVAL OR REMEDIATION		LEAVE *IN SITU*	
Cost	**Offshore Execution**	Using the assumption that PL9 would be removed using the 'cut and lift' method, the cost of complete removal would cost an order of magnitude more than the cost of leave *in situ*.	Partial removal. More than 2x leave *in situ*.	Rock. Approx. 2x leave *in situ*.	Post-trench. Approx. 2x leave *in situ*.	The cost of leave *in situ* would be the least expensive of the options.
		Using the assumption that PL352 would be removed using the 'reverse reel' method, the cost of complete removal would cost an order of magnitude more than the cost of leave *in situ*.	Partial removal. More than 2x leave *in situ*.	Rock. More than 2x leave *in situ*.	Post-trench. More than 2x leave *in situ*.	The cost of leave *in situ* would be the least expensive of the options
		Using the assumption that the ESDV umbilical would be removed using the 'reverse reel' method, the cost of complete removal would be comparable to the cost of leave *in situ*.	Partial removal. Less than 2x complete removal or leave *in situ*.	Rock. More than 2x complete removal or leave *in situ*.	Post-trench. Comparable to complete removal or leave *in situ*.	The cost of leave *in situ* would be slightly less but comparable to the cost of complete removal.
Cost	**Legacy**	Should the pipeline(s) have been completely removed no pipeline burial surveys would be required in future.	Future burial surveys would be required. The premise is that if two successive surveys demonstrate that the pipeline remains stable no more surveys would be required.			

NOTE:

1. By inspection the length of exposures for PL352 and the ESDV umbilical (~0.1 km) would be such that remediation activities such as deposition of rock or post trenching could not really be justified unless expedited as part of a broader campaign of work.

Table C.5.1: Cost assessment

APPENDIX D COST AS A DIFFERENTIATOR

Appendix D.1 Overview

The following section details the qualitative comparative assessment made to distinguish the decommissioning options. Note that the figures quoted do not account for the overall costs of decommissioning the pipelines – they only account for the difference in cost once activities common to both options have been discounted.

The costs have been normalised and categorised as indicated in Table D.1.1.

High / Intolerable & not acceptable	Medium / Tolerable non-preferred	Low/Broadly acceptable & most preferred	Low/Broadly acceptable but least preferred
More than 10x least cost	More than 2x least cost	Cheapest cost	Less than 2x more than cheapest cost

Table D.1.1: Categories of impact – cost assessment

Appendix D.2 Assumptions

The following key assumptions have been used in the cost by difference assessment:

- Operator and contractor management and engineering costs are excluded on the basis that this cost would be incurred whichever decommissioning option would be pursued.
- Any pipelines being removed would need to be excavated.
- Mobilisation and demobilisation cost of construction vessels are *excluded* for two reasons: The first is because mobilisation and demobilisation costs would be incurred for the overall decommissioning activity, not just for one pipeline, and the other is that for the purposes of this assessment it has been assumed that the same type of vessel – an anchor handling vessel, furnished with reels, ROV equipment, excavation equipment and hydraulic cutting spread.
- Mobilisation costs for a fall pipe rock installation vessel are *included*. The reason for this is that while construction vessels would be used for most if not all of the decommissioning operations, the fall pipe rock installation vessels would be used specifically for installing rock on the affected areas.
- For surveys it has been assumed that one post-decommissioning pipeline survey would be required for each pipeline, and (at least) three legacy pipeline surveys for those instances where a pipeline or part thereof would be left *in situ* following completion of decommissioning activities.
- The costs associated with mobilisation and demobilisation of survey vessels is *excluded* since it is not a differentiator, and because mobilisation and demobilisation costs would be incurred for the overall survey activity, not just for one pipeline.
- The removal of mattresses is accounted for in the assessment and assumes that for all decommissioning options they would be removed.
- It is assumed that individual rigid pipelines such as PL9 would be removed using 'cut and lift.
- It is assumed that PL352 and PLU6254 would be reverse reeled separately onto a subsea support vessel.

- Trench backfilling costs are accounted for the partial removal options and for the complete removal of PLU6254. The reason for this is that PLU6254 shares the same trench as PL352.
- Leave *in situ* assumes a length of surface laid pipelines and umbilicals being removed to burial depth at the end of transition either at the bottom of the trench or in deposited rock. This is likely to be conservative meaning that if the length of pipeline recovered is less, the cost by difference between complete removal and partial removal would increase.

Appendix D.3 Pipeline decommissioning cost by difference

Pipeline ID	Pipeline types	End removal length	Partial removal length (incl. ends)	Complete removal length	Mattresses	Leave *in situ* (remove ends)	Partial removal (incl. ends)	Remove ends, remediation, rock	Remove ends, remediation, post-trench	Complete removal
PL9	16"CWC	470m	14,470m	33,176m	0	£1.249	£9.644	£3.567	£4.228	£20.401
PL352	6"	244m	364m	19,394m	59	£0.636	£0.735	£1.152	£1.032	£2.225
PLU6254	81mm	109m	179m	570m	33	£0.157	£0.180	£0.490	£0.266	£0.185

NOTES:

1. The leave *in situ* options assume that the surface laid ends have been removed to burial depth, and that the protection and stabilisation features have also been removed. The 'end removal length' is based on the total length of mattresses that would need to be removed.
2. The assessment assumes 1x post decommissioning survey would be required irrespective of the decommissioning options, and 3x legacy surveys would be required for any pipelines being left *in situ*.
3. Post-trenching is not a viable alternative from a technical perspective for any of the pipelines. The remediation options for PL352 and PLU6254 are not practical alternatives because of the inefficiencies involved when dealing with short individual exposures in several different locations.
4. Broad metrics: full removal: PL9 – 'cut & lift' (200m/day), PL352 & PLU6254 – 'reverse reel' (5 km/day), surface laid end sections - 'cut & lift'; post-trenching & backfill 2.3 km/day; rock fall pipe vessel 1,500 to 2,000 Te/day = ~1.5 km/day.
5. The combined end lengths are measured to the riser and include lengths buried under drill cuttings so they may not match those quoted in the Decommissioning Programme.

Table D.3.1: Pipeline decommissioning – dimensions for cost assessment

Pipeline ID	Pipeline types	Leave *in situ* (remove ends)	Partial removal (incl. ends)	Remove ends, remediation, rock	Remove ends, remediation, post-trench	Complete removal
PL9	16"CWC	0.3	2.4	0.9	1.0 (n/a)	5.0
PL352	6"	1.4	1.7	2.6	2.3 (n/a)	5.0
Umbilical	81mm	1.6	1.8	5.0 (n/a)	2.7 (n/a)	1.9

Table D.3.2: Pipeline decommissioning –cost assessment normalised