Corrib
natural gas

Corrib Onshore Pipeline

Environmental Impact Statement

Volume 2

Book 6 of 6 – Appendix Q – T

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MAY 2010

Appendix Q

Pipeline Design and Safety Information

Appendix Q1

Introduction to Appendix Q

SHELL E&P IRELAND LIMITED

CORRIB GAS FIELD DEVELOPMENT PROJECT

Corrib
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Q1 – INTRODUCTION TO APPENDIX Q

DOCUMENT No: COR-25-SH-0010

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1 EXECUTIVE SUMMARY

The purpose of Appendix Q of the Corrib Onshore Pipeline Environmental Impact Statement (EIS) is to demonstrate that the Corrib Onshore Pipeline does not pose an unacceptable risk to the general public and meets all relevant international and Irish safety criteria. The Appendix has been prepared following detailed technical analysis of the issues highlighted by An Bord Pleanála in their request dated 2nd November for further information in respect of the design of the Corrib onshore pipeline and subsequent correspondence (29th January 2010). Modifications to the design and operation of the pipeline have been proposed in response to the issues raised, and Appendix Q demonstrates that the Onshore Pipeline as now proposed satisfies the new criteria specified by An Bord Pleanála.

The detailed information provided in Appendix Q reflects An Bord Pleanála's stated objective in terms of assessing worst-case scenarios in terms of safety. While SEPIL remains of the opinion that the designs and routes previously proposed for the Onshore Pipeline were safe and fully in accordance with the Codes and Standards designated by the Regulator (Minister for Communications, Energy and Natural Resources), SEPIL has now made further key revisions to its proposals. The route of the pipeline has been modified so that a large proportion of the pipeline will be routed in a tunnel under Sruwaddacon Bay. This has the effect of optimising the distance to occupied dwellings. SEPIL has also reduced the Maximum Allowable Operating Pressure (MAOP) in the Offshore and Onshore Pipeline sections to 150 barg and 100 barg respectively. The pressure in the Onshore Pipeline is now significantly less than the maximum pressure recommended following the Independent Safety Review carried out by Advantica in 2006. The Onshore Pipeline has, over the last number of years, been the subject of several independent safety reviews and reports commissioned by the Minister for Communications, Energy and Natural Resources ("The Minister"), who has statutory responsibility for the upstream oil and gas safety regime in Ireland. The Onshore Pipeline design meets all of the appropriate recommendations arising from these Reviews.

The Onshore Pipeline complies with those pipeline Codes and Standards designated for the Onshore Pipeline by the Technical Advisory Group (TAG) to the Minister. The application of these Codes and Standards for the design, construction and operation of the Onshore Pipeline will ensure that the risk levels associated with the pipeline are extremely low as demonstrated in analyses included in this Appendix Q.

An Bord Pleanála's correspondence specified both risk and consequence based criteria that should apply to the Onshore Pipeline. The risk criteria specified reflect international norms, but the consequence or hazard criterion specified appears to imply that 'hazard distance', taken in isolation from the associated risk, should be applied so as to define proximity distances for the Onshore Pipeline. Such an approach is not required by the designated Codes and Standards and SEPIL and their advisers are not aware of such an approach having been applied to any other gas pipelines in Ireland or Western Europe. It should also be noted that the recently enacted safety legislation (the Petroleum (Exploration and Extraction) Safety Act 2010) makes specific reference to a 'risk-based' safety framework, more specifically a safety case regime, which implies that the application of 'risk' is central in such matters. SEPIL does not consider that the principle of the application of consequence based criteria, without having regard to the extremely low likelihood of a worst-case event, should be applied as the sole criterion in determining the proximity of gas pipelines to dwellings. Nevertheless, this Appendix Q provides the detailed analysis which demonstrates that the exacting requirements regarding An Bord Pleanála's adoption of *"the appropriate hazard distance for the pipeline in the event of a pipeline failure"* are met in full.

The implementation of Petroleum (Exploration and Extraction) Safety Act 2010 will transfer statutory responsibility for the regulation of safety for upstream petroleum infrastructure such as the Corrib pipeline from the Minister for Communications Energy and Natural Resources to the Commission for Energy Regulation. This legislation provides for ongoing safety regulation and certification of designated upstream petroleum activities through a safety case regime, similar to that in place for the downstream gas industry in Ireland, including the Irish gas transmission network as well as gas storage and LNG facilities.

Appendix Q provides detailed information on all of the technical and safety issues raised by An Bord Pleanála in their correspondence.

Attachment Q1A tabulates the queries raised, and provides a cross-reference to the individual responses included within Appendix Q.

Attachment Q1B provides an overview of additional information presented at the request of An Bord Pleanála, to cover the incidental and individual documents presented at the 2009 Oral Hearing.

2 BACKGROUND

2.1 OBJECTIVE OF APPENDIX Q

Appendix Q of the Environmental Impact Statement has been prepared to provide a transparent and adequate demonstration that the Onshore Pipeline meets applicable Irish and international requirements relating to public safety, and also meets the additional requirements set out in correspondence by An Bord Pleanála.

2.2 SCOPE OF APPENDIX Q

The scope of Appendix Q is to provide a detailed overview of how all issues affecting the safety in design and the future integrity of the Onshore Pipeline have been and will be managed in future.

It should be noted that this Appendix Q includes greater detail than would normally be included in an EIS, so as to respond appropriately to the various safety concerns raised by An Bord Pleanála.

Appendix Q also provides information relevant to the offshore sub-sea wells and manifold at the Corrib Field. While these facilities are outside the scope of the proposed Onshore Pipeline Development and the Onshore Pipeline EIS, and are the subject of other regulatory approvals and consents, this additional information is provided because the offshore facilities have a direct bearing on the gas pipeline pressure regime upstream of the Landfall Valve Installation (LVI) at Glengad.

It should be noted that a significant degree of geotechnical analysis has also been completed in respect of the proposed route of the Onshore Pipeline. This information is contained in Appendix M of this Environmental Impact Statement. The outputs from the analysis contained within Appendix M have been used in the relevant pipeline design, risk and integrity analyses contained within Appendix Q.

2.3 STRUCTURE OF APPENDIX Q

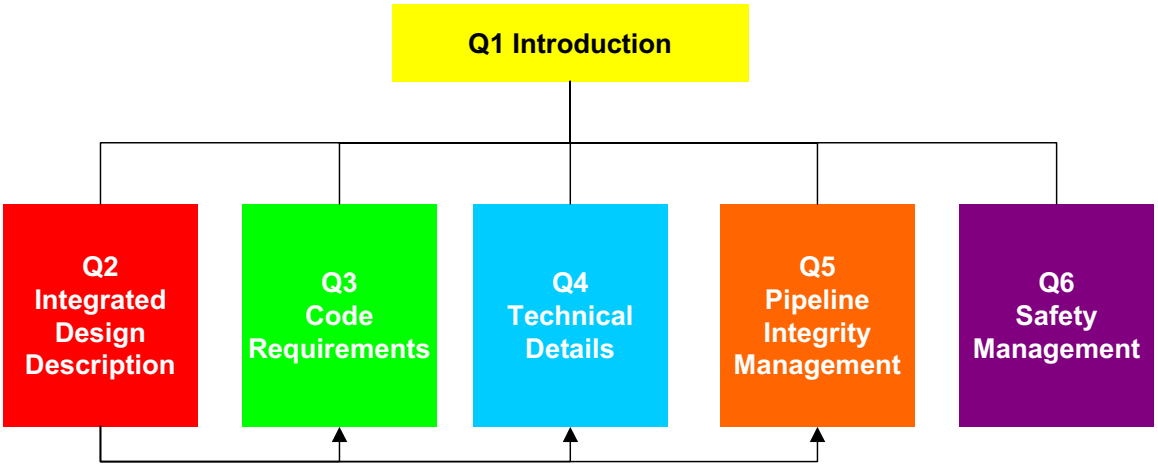
An Bord Pleanála has requested that SEPIL *"provide an integrated set of design documentation in the form of a revised Appendix Q. The documentation should integrate the analysis provided in the incidental and individual documents at the oral hearing".*

Appendix Q therefore provides an integrated set of documentation that draws together the individual documents that have been produced by different specialists and technical experts.

2.3.1 Schematic Summary

A schematic summary of Appendix Q is provided in Figure 2.1 below.

Figure 2.1: Appendix Q Structure



Section Q2 summarises the design approach.

Section Q3 describes the Codes and Standards that are applicable.

Section Q4 provides an overview of the design and includes a review of issues such as settlement of the stone road, the safety shutdown and over-pressure protection systems, corrosion and other 'unprocessed gas' issues.

Section Q5 discusses the pipeline integrity management system.

Section Q6 discusses the safety-specific aspects of the Onshore Pipeline and includes the Qualitative and Quantitative Risk Assessments, along with the analysis requested by An Bord Pleanála in Section 3(b) of their 2nd November 2009 letter. An outline of the approach to Emergency Response Planning is also included.

3 INTEGRATED DESIGN DESCRIPTION

3.1 PIPELINE ROUTE

The route of the Onshore Pipeline is discussed in the EIS (see Chapter 4). A large proportion of the onshore pipeline will be installed in a 4.9 km tunnel between Glengad and Aghoos, under Sruwaddacon Bay.

3.2 DESCRIPTION OF THE PIPELINE

Chapters 4 and 5 of the EIS describe the Onshore Pipeline and summarise the key construction matters.

The Onshore Pipeline is a 20” diameter, 27.1 mm nominal wall thickness carbon steel pipeline.

Installed parallel to the Onshore Pipeline will be a number of supplementary services, including:

- A fibre optic cable and a signal cable
- An umbilical, which will provide electrical and hydraulic power, communications as well as methanol and treated produced water from the Bellanaboy Bridge Gas Terminal through to the Subsea facilities. The onshore umbilical will comprise three individual multi-core cables.
- An outfall pipeline to transport treated surface water from the Gas Terminal to a diffuser at a permitted outfall point north of Erris Head outside Broadhaven Bay cSAC.

The above details are discussed in Appendix Q4.1.

4 LEGAL AND CODE REQUIREMENTS

4.1 REGULATORY CONTROL

The Minister for Communications, Energy and Natural Resources ('the Minister') has responsibility for the regulation of petroleum exploration and production activity in Ireland. This responsibility includes responsibility for the safe design, construction and operation of the Corrib offshore and onshore pipeline.

The onshore pipeline design and route, as approved in 2002, were subject to comprehensive technical and safety review by the Minister's advisers, and the associated consents provided for a process of independent third party verification of the design and construction of the Corrib facilities including the onshore pipeline. A Quantitative Risk Assessment was prepared by SEPIL's consultants to demonstrate that the risk levels associated with the pipeline met normally accepted levels in the gas pipeline industry.

In 2005 the statutory control and supervision aspects of the safety and integrity of the Corrib pipeline were further strengthened by the Minister's appointment of the Technical Advisory Group, specifically tasked with regulating the safety of the Corrib project.

4.2 IMPLICATIONS OF THE PETROLEUM (EXPLORATION AND EXTRACTION) SAFETY ACT 2010

Following the recent enactment of the Petroleum (Exploration and Extraction) Safety Act 2010 the statutory responsibility for the regulation of upstream oil and gas safety (which includes the Onshore Pipeline) will transfer from the Minister to the Commission for Energy Regulation, ("the Commission"). The Commission is already responsible for regulating safety relating to downstream gas infrastructure.

Under the new legislation the Commission is empowered to establish a safety framework, to monitor and to enforce safety compliance, and to issue safety permits for upstream petroleum activities.

The Act provides for a prohibition on all petroleum undertakings from carrying out designated petroleum activities, unless a safety permit from the Commission is in force in respect of the designated petroleum activity concerned. There is a prescribed time frame within which established petroleum undertakings must obtain a safety permit.

The new risk-based legislative requirements include the following provisions:

- Petroleum activities are to be carried out in a manner to reduce any risk to safety to a level that is As Low As Reasonably Practicable (ALARP);
- Petroleum infrastructure is to be designed, constructed, installed, maintained, modified, operated and decommissioned in such a manner as to reduce any risk to safety to a level that is ALARP;
- The construction and installation of petroleum infrastructure is to be sound and fit for the purpose for which it has been designed;
- Safe operating limits are to be established;
- The standards of safety and training of personnel are to be such that personnel are competent;

- Procedures are to be prepared and implemented so as to ensure that the risk of an incident is as low as is reasonably practicable;
- Emergency plans must be in place;
- Incidents are to be reported.

Under the new legislation, a Safety Case will be required for all designated petroleum activities. The Safety Case will have to demonstrate that risks are properly assessed and effectively controlled to ALARP levels.

The Commission will be empowered to issue safety permits where, having reviewed the Safety Case, it is satisfied that the petroleum undertaking involved has a proper safety management system. The Commission will also have the power to refuse to issue a safety permit, or to revoke a safety permit, in circumstances associated with non-compliance, and in such cases, the infrastructure concerned cannot be operated.

The passing of the new legislation implements an important recommendation of the Advantica Independent Safety Review, 2006 (see Section 7 Final Remarks and Recommendations, p. 57).

The Minister for Communications, Energy and Natural Resources is and will continue to be responsible for the upstream oil and gas safety regime until the relevant order(s) to be issued in relation to the Petroleum (Exploration and Extraction) Safety Act are made.

4.3 REGULATORY REVIEW OF THE PIPELINE DESIGN

The design of the onshore pipeline incorporated in this application by SEPIL for the consent to construct the Onshore Pipeline complies with the requirements arising from a number of detailed and independent regulatory reviews, which are briefly discussed below.

4.3.1 Review by Mr. Andrew Johnston

In March 2002, on behalf of the Department of Marine and Natural Resources, Mr. Andrew Johnston, an independent consultant, carried out a review of the pipeline design and concluded that the pipeline would meet public safety requirements as outlined in the selected design code, provided his recommendations were applied. The Minister granted consent for the pipeline subject to the implementation of Mr Johnston's recommendations.

4.3.2 Review by AEA Technology

In 2005, again on behalf of the Department of Marine and Natural Resources, an independent review of the Quantitative Risk Assessment (QRA) of the Onshore Pipeline was conducted by AEA Technology (an independent science and engineering services company operating in a range of market sectors, including Safety and Risk). AEA Technology commented on the QRA Report and agreed with its overall findings, concluding that the prediction of risks to the public resulting from the operation of the Onshore Pipeline indicated that the risks were tolerable when compared with International criteria.

4.3.3 The Advantica Independent Safety Review

In 2005 the Minister for Communications, Marine & Natural Resources appointed Advantica to carry-out a detailed safety review of the proposed Onshore Pipeline. Advantica is one of the world's leading specialist gas engineering companies.

The Advantica report was published on the 3rd of May 2006 following two separate rounds of public consultation. The review concluded *inter alia* that *"there will be a substantial safety margin in the pipeline design … and that the pipeline design and proposed route should be accepted as meeting or exceeding international standards in terms of acceptability of risk",* provided that certain recommendations were followed. These recommendations included the modification of the beach valve above ground installation so as to ensure that the pressure in the onshore section of the pipeline would be limited to 144 barg although the pipeline was originally designed to withstand the maximum pressure from the Corrib gas reservoir. The Advantica Independent Safety Review continues to be relevant to the current design of the Onshore Pipeline. The design complies with the recommendations made by Advantica in their report and Appendix Q3.1 contains a table that shows how SEPIL has met these recommendations.

4.3.4 The Technical Advisory Group

The work of Advantica was supervised by a Technical Advisory Group appointed by the (then) Minister for Communications, Marine and Natural Resources (who *inter alia* has statutory responsibility for establishing the safety standards applicable to the upstream oil and gas developments such as the Corrib project).

Following the publication of the Advantica report, the Technical Advisory Group published three reports during 2006 as follows:

- Report of the Corrib Technical Advisory Group to Minister Dempsey.
- Report of the Corrib Technical Advisory Group to Minister Dempsey on an appropriate Inspection and Monitoring Regime for the Corrib Project.
- Corrib Gas Pipeline Safety Issues.

The reports of the Technical Advisory Group established the technical criteria to be applied to the Corrib Gas Pipeline design, and SEPIL's 2009 and current design comply with their requirements.

A statement of how SEPIL has complied with the recommendations of the Technical Advisory Group is provided in Appendix Q3.1.

4.3.5 Review by Mr. Peter Cassells

Mr. Peter Cassells was appointed as Mediator by the (then) Minister for Communications, Marine and Natural Resources in 2005. Mr. Cassells issued his report (Proposed Corrib Gas Pipeline, Report and Recommendations from Mediation) in July, 2006.

His report contains several recommendations, one of which is particularly relevant to this application; namely the modification of the route of the pipeline in the vicinity of Rossport to address community concerns regarding proximity to housing. SEPIL' s applications for consent for the modified Corrib Onshore Pipeline as lodged in 2009 address this recommendation, as does the revised pipeline route described in this (revised) EIS and arising from the invitation of An Bord Pleanála in their letter of 2nd November 2009 for SEPIL to further modify the route.

4.4 CODES AND STANDARDS

The applicable Codes and Standards for the design, construction and operation of the Corrib Onshore Pipeline were set out by the Technical Advisory Group (see reports listed in Section 4.3.4). The designated Codes and Standards are consistent with the Standards applicable to the design, construction and operation of other gas pipelines in Ireland and generally in Western Europe.

The applicable Codes are summarised below, and are discussed in more detail in Appendix Q3.2.

4.4.1 Recommendation of the Technical Advisory Group to the Minister regarding Onshore Pipeline Codes and Standards

The Codes and Standards applicable to the design, construction, operation and maintenance of the Onshore Pipeline are as follows:

- I.S. EN 14161:2004 (Petroleum and Natural Gas Industries – Pipeline Transportation Systems);
- I.S. 328: 2003 (Code of Practice for Gas Transmission Pipelines and Pipeline Installations (Edition 3.1));
- BS PD 8010-1: 2004 (Code of Practice for Pipelines, Part 1: Steel pipelines on land)).

The application of the above Standards complies fully with a key recommendation of the January 2006 Report of the Corrib Technical Advisory Group to the Minister for Communications, Marine and Natural Resources, which recommended that *"The primary pipeline design code is hereby designated by TAG to be IS EN 14161; however IS 328 and PD 8010 shall apply where they exceed IS EN 14161".*

In the subsequent Report to the Minister in March 2006, the Technical Advisory Group (TAG) also recommended: *To be specific, TAG recommends that, while the overall design code for the upstream, onshore section of the Corrib project shall be IS EN 14161, construction, installation, operation and maintenance of the onshore section of the pipeline shall be generally in accordance with IS 328, and the inspection and monitoring regime that will be applied to this section of the project will be as per the relevant provisions of IS 328.*

Where a case is made by the developer and accepted by TAG, specific provisions of PD 8010 may apply in lieu of the relevant provisions of IS 328".

A Design Code Review for the Onshore Pipeline has been carried out and the associated report, which has been approved by TAG, is included in Appendix Q3.3. This review establishes the basis for compliance with the designated Codes and Standards, and is summarised below.

4.4.2 Details of the Pipeline Codes

- **I.S. EN 14161:2004 (Petroleum and Natural Gas Industries – Pipeline Transportation Systems)**

  This is a European Code first published by CEN (Comité Européen de Normalisation – European Committee for Standardisation) in November 2003. It takes into European Standards the international standard ISO 13623:2000 which gives recommendations for the design, materials, construction, testing, operation and maintenance of pipeline systems in the petroleum and natural gas industries, on land and offshore. The standard is applicable to unprocessed natural gas. As a member of CEN, the National Standards Authority of Ireland published this Code as an Irish Standard in April, 2004.

- **I.S. 328: 2003 (Code of Practice for Gas Transmission Pipelines and Pipeline Installations (Edition 3.1))**

  This Code is published by the National Standards Authority of Ireland. In 1987 NSAI published the first edition of Irish Standard 328. It should be noted from the Foreword to the Code that the *"Code of Practice defines minimum and adequate standards and procedures to be used for steel pipelines for the transmission of gas at maximum operating pressure over 16 bar. The upper pressure limit is not defined but in general practice this ranges up to 100 bar".*

  I.S. 328 was originally modelled on the U.K. onshore gas transmission pipeline Standard - IGEM/TD/1 – Steel Pipelines and Associated Installations for High Pressure Gas Transmission, and is analogous to this U.K. Standard. Since it was introduced I.S. 328 has provided the technical basis for the design, construction and operation for gas transmission pipelines in Ireland. This Code is applicable to processed natural gas. The Technical Advisory Group to the Minister stated in 2006:

  "The relevant provisions in IS 328 have been examined and found to be generally appropriate for the upstream, onshore section of the Corrib project. They deliver a coherent philosophy and sufficient guidance to allow developers and monitoring authorities to agree specific actions.

  A further point in their favour is that, as noted above, BGE follows IS 328 for operations and maintenance purposes for onshore gas transmission pipelines.

  To be specific, TAG recommends that, while the overall design code for the upstream, onshore section of the Corrib project shall be IS EN 14161, construction, installation, operation and maintenance of the onshore section of the pipeline shall be generally in accordance with IS 328, and the inspection and monitoring regime that will be applied to this section of the project will be as per the relevant provisions of IS 328.

  Where a case is made by the developer and accepted by TAG, specific provisions of PD 8010 may apply in lieu of the relevant provisions of IS 328".

- **BS PD 8010-1: 2004 (Code of Practice for Pipelines)**

  BS PD 8010 is published by the British Standards Institute; it has three parts:

  - Part 1 applies to steel pipelines on land;
  - Part 2 applies to subsea pipelines;
  - Part 3 provides guidance to the application of pipeline risk assessment.

  The Code is widely used by the UK pipeline industry. It is applicable to the unprocessed gas conveyed by the Onshore Pipeline (unprocessed natural gas) and, as BS 8010, was the Code on which the original Corrib onshore pipeline, approved by the Minister in 2002, was based.

4.4.2.1 Design Code for the Offshore Pipeline and Landfall Installation (LVI) at Glengad

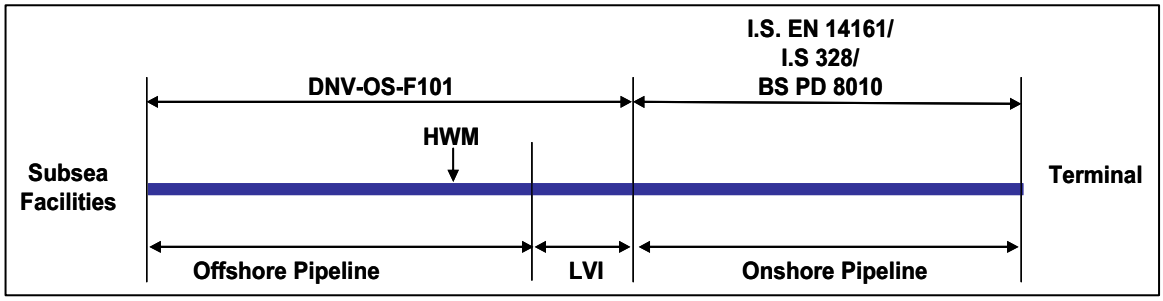
- **<u>DNV-OS-F101 (Offshore Standard – Submarine pipeline Systems)</u>**

  The design code for the offshore pipeline is DNV-OS-F101.

  At the landfall an interface arises between the onshore and offshore pipeline standards, insofar as a different standard is applicable for the offshore section compared to the onshore pipeline. In accordance with the relevant requirements set out in DNV-OS-F101 this interface is the weld between the downstream tee of the Landfall Valve Installation (LVI) and the

onshore pipeline. The Landfall Valve Installation is designed therefore to DNV-OS-F101. This is discussed in more detail in Appendices Q3.2 and Q4.3.

Figure 4.1: Application for Pipeline Design Codes



5 TECHNICAL ISSUES

5.1 GAS PRESSURE

The pipeline design pressure originally selected was 345 barg. This resulted in a pipeline with a thick wall, which greatly contributes to the integrity of the pipeline.

The Advantica Independent Safety Review queried the use of this design pressure for the onshore section, citing concerns associated with the level of uncertainty with the risk modelling which had been carried out for the relevant pressures, the extrapolation of onshore pipeline design codes pressure range, along with societal concerns. Advantica recommended that the pressure in the Onshore Pipeline should be limited to 144 barg. SEPIL accepted this recommendation. Modifications were made to the system and an Onshore Pipeline design pressure of 144 barg was included in SEPIL's planning application to An Bord Pleanála in February 2009.

An Bord Pleanála, in its letter of 2nd November 2009, requested that *"the maximum allowable operating pressure (MAOP) for the pipeline should be stated."*

SEPIL has established the minimum required offshore and onshore pipeline MAOP to maintain a sufficient operating envelope to meet the contractual and technical requirements of the already approved and constructed Gas Terminal. These MAOPs are 150barg and 100barg for the offshore and onshore pipelines respectively.

5.1.1 Definitions of Pressure in the designated Codes

The designated Codes include the following definitions for gas pressure:

- IS EN 14161:2004 defines:
  - The Maximum Allowable Operating Pressure (MAOP) of a pipeline as *"the maximum pressure at which a pipeline system, or parts thereof, is allowed to be operated"*. The corresponding definition in I.S. 328 is MOP or Maximum Operating Pressure, and BS PD 8010 also utilises the term MAOP. For simplicity, the term MAOP is used throughout this Appendix.
  - The Internal Design Pressure as the *'maximum internal pressure at which the pipeline or section thereof is designed in compliance with this European Standard'.* There are comparable definitions in I.S. 328 and BS PD 8010.

5.1.2 Design and Operating Pressures

In this response to An Bord Pleanála's request for further information, SEPIL confirms that the design pressure of the Onshore Pipeline will be limited to 144 barg in accordance with the recommendations in the Advantica Independent Safety Review. The pipeline system test hydrostatic pressures will be 504 barg in accordance with the Standards (see Appendix Q5.3).

SEPIL have set the MAOP of the Offshore Pipeline to 150 barg. This includes the Landfall Valve Installation (LVI) at Glengad. The MAOP of the Onshore Pipeline between the Landfall Valve Installation and the Gas Terminal has been set at 100 barg.

The following table summarises the relevant pressures that will be applicable.

Table 5.1: Applicable Pressures

Location	Design Pressure, Barg	MAOP, Barg
Corrib Offshore Pipeline (up to and including the Landfall Valve Installation)	345	150
Corrib Onshore Pipeline (between the Landfall Valve Installation and the Gas Terminal)	144	100

5.1.3 Operating Pressures and Safeguarding in the pipeline system

The setting of the MAOP values for both the offshore and onshore pipelines, as outlined in Section 2.1, required a review and updating of the Corrib production system operating philosophy.

As described in Appendices Q2.1, Q4.5 and Q4.6 there are 5 layers of safeguarding provided for the pipeline system. These layers can be initiated either by the operators at the Gas Terminal, or else automatically, to ensure that the Corrib System is kept below the defined Maximum Allowable Operating Pressures (MAOPs).

The normal steady state operating pressure at the inlet to the Gas Terminal will be between 80 to 85 barg. Under these conditions, in the case of an upset at the Gas Terminal, there is sufficient capacity in the pipeline system for the operators at the Gas Terminal to quickly stop production from the wells, without tripping the shutdown systems for the LVI.

In the unlikely event that the pressure in the system continues to rise, at 93 barg facilities at the Terminal will automatically send signals to valves at the offshore wells to close.

If the pressure continues to rise at the LVI to 99 barg an automatic signal is initiated at the Landfall Valve Installation, to shut the valves at the LVI, thus isolating the onshore pipeline from the offshore pipeline. If this happens, then the hydraulic fluid in the umbilical connection to the offshore valves will also be released, and these valves will then also close automatically. It should be noted that there will be a continuous 24 hour operations team to oversee production of Corrib gas. The Operators will have ‘push-button’ capability to immediately shut the relevant valves, and so ensure that the system always remains within the defined Maximum Allowable Operating Pressures. Details of the safeguarding system are provided in Appendix Q4.5.

5.2 UNPROCESSED GAS ISSUES

The gas in the Corrib Field is a high quality natural gas, very similar to that produced at the Kinsale Head gas-field and consists of approximately 96% hydrocarbon gas (Methane, Ethane and Propane) and 3% Nitrogen. Small quantities of water and carbon dioxide are also present. To ensure safe and reliable gas production from the Corrib field internal corrosion and hydrate formation must be managed; these are briefly discussed below.

It should be noted that all tests carried out on the Corrib gas samples to date have found no evidence of the presence of hydrogen sulphide. As described in Appendix Q4.7, there is no expectation that

hydrogen sulphide would occur in the Corrib reservoir in the future. Nevertheless routine analysis of gas samples taken will check for Hydrogen Sulphide. It should also be noted that the Advantica Independent Safety Review discussed the issues associated with the gas properties and commented that ***'Pipeline technology for transporting unprocessed gas is well-established, and appropriate measures have been identified to manage these additional hazards'***.

5.2.1 Composition

Appendix Q4.2 provides a product analysis of the gas from the Corrib Field. The following table summarises the principal constituents of the gas that will be carried in the pipeline:

Table 5.2: Principle Constituents of Pipeline Gas

Parameter	Unit	Quantity
Methane, Ethane and Propane	% Mole	95.57
Butane, Pentane & higher (C5+)	% Mole	0.13
Carbon Dioxide	% Mole	0.25
Nitrogen	% Mole	2.61
Water	% Mole	1.09
Methanol (injected)	% Mole	0.35

SEPIL will inject a mixture of methanol and a chemical corrosion inhibitor into the gas at the wellhead, where they will be carried in the gas stream in the Corrib Pipeline.

The gas stream requires minimal processing at the Gas Terminal before entry to the Bord Gáis Éireann gas transmission network.

5.2.2 Internal Corrosion

The small quantities of CO_2 and organic acids in the gas stream have potential to cause a low level of internal corrosion of the Onshore Pipeline. The addition of the corrosion inhibitor, which forms a protective film on the wall of the pipe, prevents significant corrosion occurring. This approach to corrosion mitigation is common in pipelines carrying unprocessed gas. Shell, for instance, has extensive and successful experience (over 40,000 km-years in Europe) with managing internal corrosion.

It is also accepted practice to add additional thickness of metal to the inner surface (i.e. effectively increasing the wall thickness of the pipeline) to allow for the loss of metal over the life of the system, so that at the end of the pipeline's life there is sufficient wall thickness remaining to satisfy the original design requirements. The effective loss of wall thickness in the Onshore Pipeline is calculated to be a maximum of 0.6mm over its anticipated service life, and the pipe wall thickness has been increased therefore by 1mm to allow for such possible corrosion.

It is proposed to continue to check the pipe wall thickness over the life of the Pipeline system. This will be achieved by continuous corrosion monitoring of a section of pipe close to the Corrib field and by carrying out internal inspection of the pipeline at regular intervals. Internal inspection is an established process whereby a pipe inspection gauge (or 'intelligent pig') fitted with a measurement device and

onboard computer is pushed through a pipeline using gas pressure. The 'intelligent pig' will measure and record the pipe wall thickness along the entire length of the Onshore Pipeline to check the degree of any corrosion thus enabling any necessary corrective action to be taken.

The design implications associated with corrosion are discussed in Appendix Q2.1 and the prevention of internal corrosion is also discussed in detail in Appendix Q4.9.

5.2.3 Hydrate inhibition

The Corrib produced gas contains hydrate-forming components such as methane, ethane, propane and carbon dioxide. At high-pressure and low-temperature, these components form crystalline solids known as "gas hydrates". This can occur in pipelines carrying unprocessed gas with inadequate hydrate inhibition. Thus, the prevention of gas hydrates is an important flow-assurance issue since a hydrate blockage may lead to production losses.

To ensure that hydrates do not form in the Offshore and Onshore Pipeline a hydrate inhibitor (methanol) will be added to the gas at the wellhead. Hydrates only have the potential to form if methanol is not injected in sufficient quantities. The operating strategy for Corrib is to immediately stop production in the unlikely event of offshore methanol injection being unavailable. The detailed approach for dealing with hydrates is discussed in Appendix Q4.5.

6 PIPELINE INTEGRITY MANAGEMENT

Pipeline integrity management has been applied within the design, material specification and manufacture of the component parts of the Corrib Pipeline and has included extensive application of independent verification of quality control and assurance. During construction and commissioning of the pipeline the same rigorous approach will continue with a similar application of independent verification. This is described in Appendix Q5.1.

During the operational phase SEPIL intends to provide a high-quality approach to the management of the Corrib pipeline system, which will be based on the extensive experience that Shell has developed in safely operating pipelines in Europe and elsewhere. SEPIL's intent is described in the Pipelines Integrity Management System (PIMS) that describes the operational processes that will be applicable for all elements of the Corrib pipeline facilities, including the Onshore Pipeline, the umbilical lines and water outfall. These operational processes are designed to ensure that the pipeline system is managed appropriately at all times to ensure integrity over the life of the system. The Pipelines Integrity Management System is described in Appendix Q5.2.

7 PIPELINE SAFETY MANAGEMENT

Appendix Q6 contains documents that address the safety-specific aspects of the Corrib onshore pipeline and LVI design. The relationship between the documents contained in Appendix Q6 and other Sections of Appendix Q is shown in Figure 7.1.

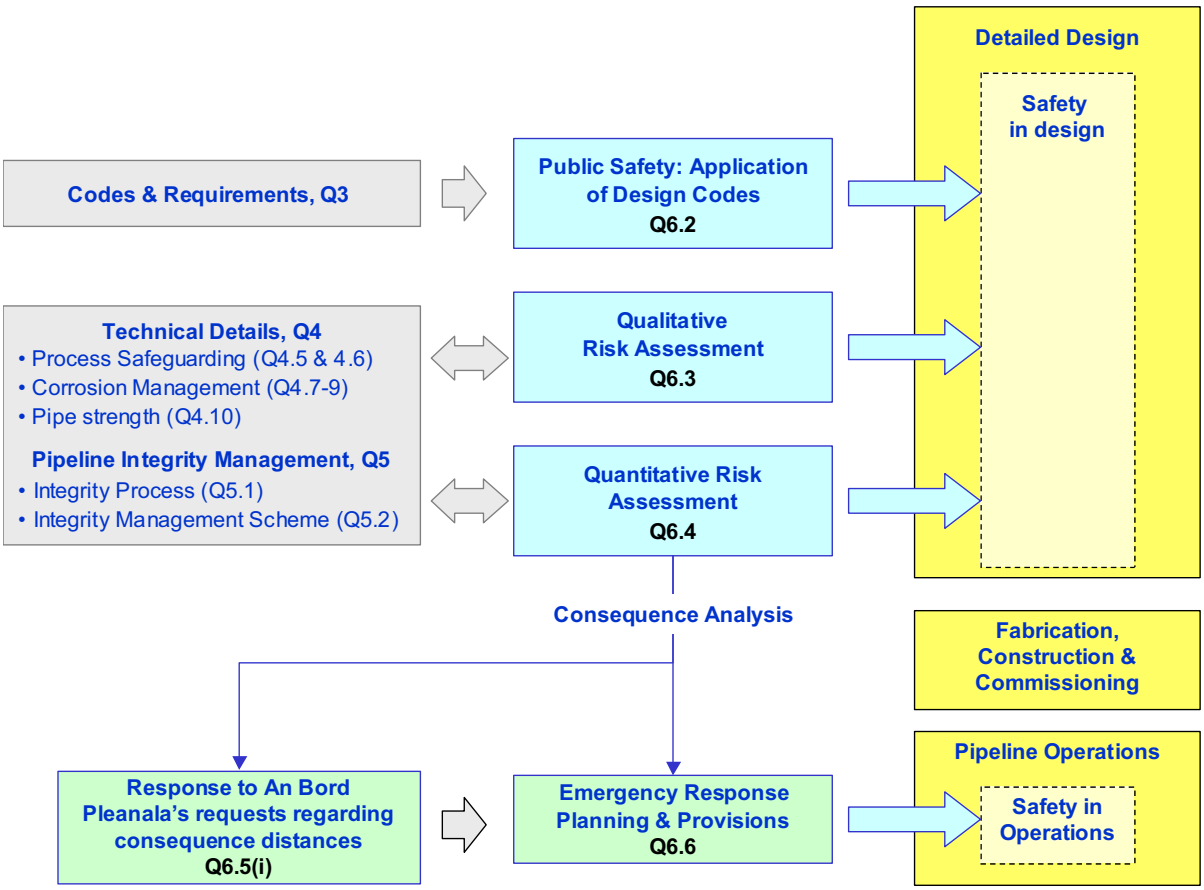


Figure 7.1: Appendix Q6 Document Relationships

7.1 PUBLIC SAFETY: APPLICATION OF DESIGN CODES

The pipeline is designed to be in full conformance with the designated Codes, and will also meet the additional requirements specified by An Bord Pleanála in correspondence. Key issues are discussed below.

7.1.1 Design Factor & Wall Thickness

The designated Codes applicable to the Onshore Pipeline stipulate requirements relating to the route selection of a gas pipeline, the calculation of the pipe wall thickness, as well as the selection of a factor of safety called the Design Factor.

The Corrib Onshore Pipeline originally had a Design Factor of 0.72 which corresponds to the Design Factor required for a pipeline to be located in a rural area. Subsequently a more conservative Design Factor of 0.3 was adopted following a recommendation from Advantica in their Independent Safety Review. It might be noted that the factor of safety of a pipeline is essentially the inverse of the Design Factor, so adopting a Design Factor of 0.3 greatly increases the factor of safety involved, and *inter alia* leads to a pipe with a greatly increased wall thickness. In itself, this contributes significantly to the safety of the Onshore Pipeline.

The calculation of the minimum pipeline wall thickness is described in Appendix Q6.2. The nominal wall thickness is calculated as 27.1mm, which includes a corrosion allowance of 1mm.

7.1.2 Proximity to Normally Occupied Buildings

The Code requirements, and relevant calculations, with respect to proximity to normally occupied buildings, are described in Appendix Q 6.2.

In summary, I.S. 328 and BS PD 8010 prescribe the minimum distance that must separate a gas pipeline from existing normally occupied buildings, which is called the Building Proximity Distance. This distance is either derived from graphs or, in the case of BS PD8010, calculated using a formula that is based on a number of factors such as the Design Factor, the pipe diameter, the pipe wall thickness and the operating pressure of a pipeline.

The Building Proximity Distance for the Onshore Pipeline, based on its pipe-wall thickness of 27.1mm, the MAOP of 100 barg and a Design Factor of 0.3 is 3 metres – as derived in accordance with graphs in I.S. 328 and BS PD 8010 i.e. the two Codes both allow the Onshore Pipeline to be located 3 metres from normally occupied buildings.

If a Design Factor of 0.72 was applied, then the necessary pipe wall thickness would decrease significantly, and the required Building Proximity Distance for an MAOP of 100 barg would then be 63 metres when calculated in accordance with the graph in I.S. 328, and 60.4 metres when calculated by the formula in BS PD 8010.

The Building Proximity Distances calculated in accordance with the Codes reflect the very low probability of any possible incidents occurring, which is derived in the Quantitative Risk Assessment, discussed below.

The closest normally occupied building to the Corrib Pipeline is taken as 234m, which is substantially in excess of the Code minimum requirements.

7.2 QUALITATIVE RISK ASSESSMENT

A Qualitative Risk Assessment is presented in Appendix Q6.3 and provides an overview of the identified risks pertaining to the Onshore Pipeline and assesses those risks in a rigorous fashion.

Given the extremely low levels of public risk associated with the Onshore Pipeline, the scope for determining numerical benefit from further, more detailed, risk reduction measures is limited by the sensitivity of the Quantitative Risk Assessment (QRA). The principal means for assessing the benefit from additional risk reduction measures has therefore been via the qualitative approach. The Qualitative Assessment concludes by demonstrating that the risks associated with the pipeline have been reduced to levels that are As Low As Reasonably Practicable (ALARP).

The output from the qualitative assessment has provided a key input to the QRA in support of the screening and selection of potential failure modes for inclusion in the QRA and in support of the adoption of modifiers to historical data used within the QRA to establish base case failure frequencies.

The qualitative risk assessment presented generally aligns with the Petroleum (Exploration and Extraction) Safety Act and with the published guidance from the Commission for Energy Regulation (CER) for the preparation of Safety Cases.

7.3 QUANTITATIVE RISK ASSESSMENT

A Quantitative Risk Assessment (QRA) of the Onshore Pipeline is presented in Section Q6.4.

The QRA predictions provide a numerical estimate of the residual public safety risks associated with ignited hydrocarbon gas releases from the pipeline and Landfall Valve Installation in terms of:

- Individual risk of receiving a dangerous dose of thermal radiation
- Societal risk
- Distances to the boundaries of Inner, Middle and Outer zones. These zones were specified in the letter of the 2nd November 2009 from An Bord Pleanála, which requested SEPIL to represent the distance from the pipeline at which risk levels of $1x10^{-5}$, $1x10^{-6}$ and $0.3x10^{-6}$ per kilometre of pipeline per year exist

The QRA has been carried out in accordance with the methodology in BS PD 8010 Part 1 and BS PD 8010 Part 3 and applies the risk criteria adopted by An Bord Pleanála as outlined above and described in their letters dated 2nd November 2009 and 29th January 2010.

The overall conclusion from the QRA is that the predicted levels of risk associated with the proposed pipeline and LVI pose an extremely low risk to members of the public and the occupants of dwellings along the route of the pipeline.

In support of this conclusion the results of the QRA are summarised below. Figure 7.2, extracted from the QRA, presents the Risk Transect for the base-case analysis of the pipeline.

Pipeline:

- The predicted level of individual risk of receiving a dangerous dose or more at the nearest dwelling to the pipeline is $1.8x10^{-11}$ per year (i.e. 1.8 chances in every 100,000,000,000 years). This is an extremely low risk and is almost 100,000 times, below the level of risk described by An Bord Pleanála in their correspondence as 'broadly acceptable' ($1x10^{-6}$ per year i.e. one chance in 1,000,000 years)
- The predicted level of individual risk of receiving a dangerous dose or more standing at the pipeline is $2.9x10^{-9}$ per year (i.e. 2.9 chances in every 1,000,000,000 years); this is also well below the aforementioned $1x10^{-6}$ per year level.
- It is not possible to plot the boundaries of the inner, middle and outer zones for the pipeline as requested in An Bord Pleanála's letter of 2nd November 2009 as these levels of risk are not reached.

- The societal risk associated with the pipeline is also very low, being almost six orders of magnitude, or 1,000,000 times, below the criterion line for 'broadly acceptable'.

The above conclusions are drawn based on what is regarded by SEPIL to be the most appropriate application of data, assumptions and rule-sets specific to the Corrib pipeline. However, a number of sensitivity studies using more onerous frequencies and assumptions have been carried out to test the QRA predictions, these sensitivity studies include the inclusion of a frequency for ground movement and variations in parameters used within modelling rule-sets. The outcome of all the sensitivity studies is that the risk levels remain well within the 'broadly acceptable' region.

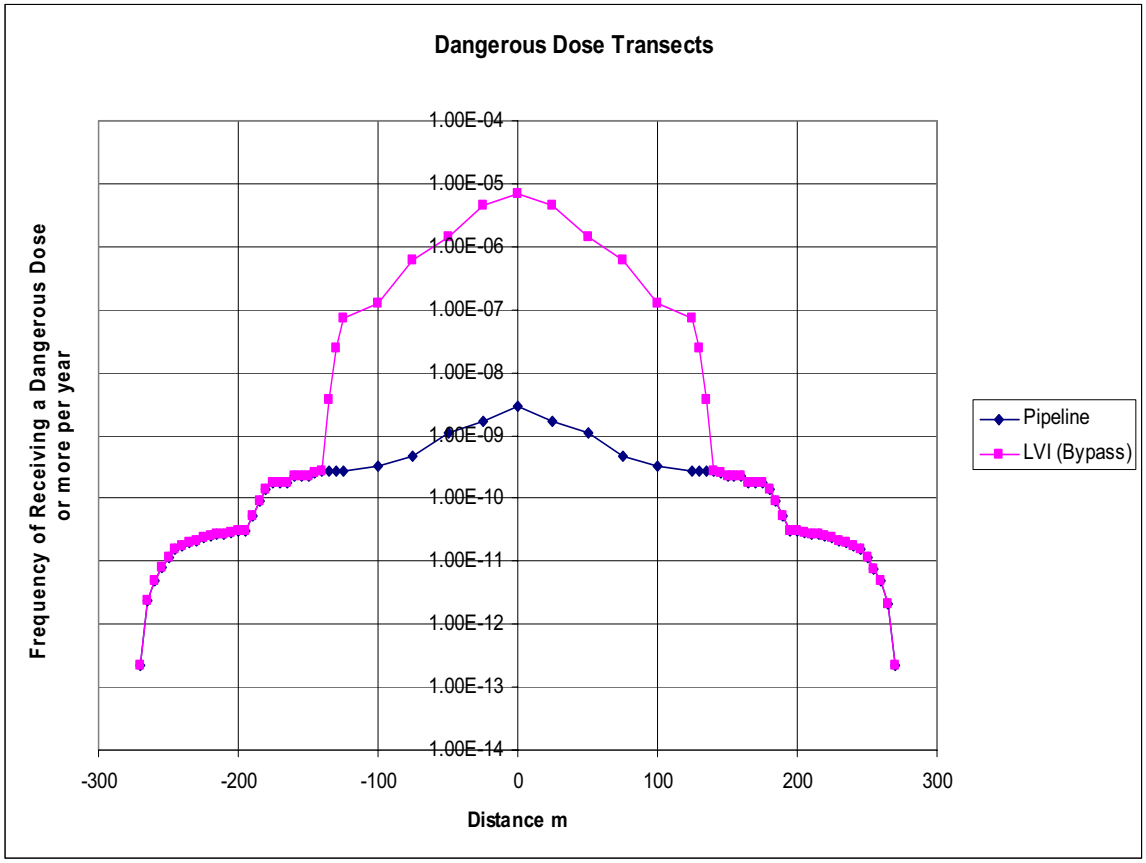
LVI:

- The predicted levels of individual risk of a receiving dangerous dose or more from the LVI are such that the $1x10^{-6}$ per year contour is 63m from the facility. For comparison it should be noted that the nearest dwelling is 280m from the LVI.

- The predicted distances from the LVI to the middle and outer zone outer boundaries are 63m and 91m respectively. The predicted risk level at the LVI is just below $1x10^{-5}$ per year, which is the outer boundary of the inner zone.

Applying a sensitivity analysis to the valve failure frequency in the LVI QRA base case gives predicted distances from the LVI to the outer boundaries of the inner, middle and outer zones of 111m, 124m and 132m respectively.

Figure 7.2: Risk Transect for the Onshore Pipeline



7.4 PROXIMITY DISTANCE DEFINED BY REQUIREMENTS SET BY AN BORD PLEANÁLA

An Bord Pleanála, in its letter dated 2nd November 2009, requested SEPIL to

> *'Adopt a standard for the Corrib upstream untreated gas pipeline that the routing distance for proximity to a dwelling shall not be less than the appropriate hazard distance for the pipeline in the event of a pipeline failure. The appropriate hazard distance shall be calculated for the specific pipeline proposed such that a person at that distance from the pipeline would be safe in the event of a failure of the pipeline.'*

SEPIL sought clarification on the matter, which was provided by An Bord Pleanála, by letter dated 29th January 2010, which stated that:

> *In paragraph (b) (at top of page 2 of the Board's letter of 2nd November, 2009) the intent of the Board is to ensure that persons standing beside the dwellings will not receive a dangerous dose of thermal radiation in the worst case scenario of a "full bore rupture" of the pipeline at maximum pressure.'*

In the Executive Summary of this Introduction, SEPIL commented that it does not consider that the principle of the application of consequence based criteria, in isolation from extremely low likelihood of a worst-case event, should be applied as a criterion in determining the location of gas pipelines. Notwithstanding this, SEPIL has calculated the separation distance, in accordance with the approach specified in the correspondence from An Bord Pleanála. These calculations are presented in Appendix Q6.5, which concludes:

For the worst conceivable full-bore rupture scenario and assuming immediate ignition, then:

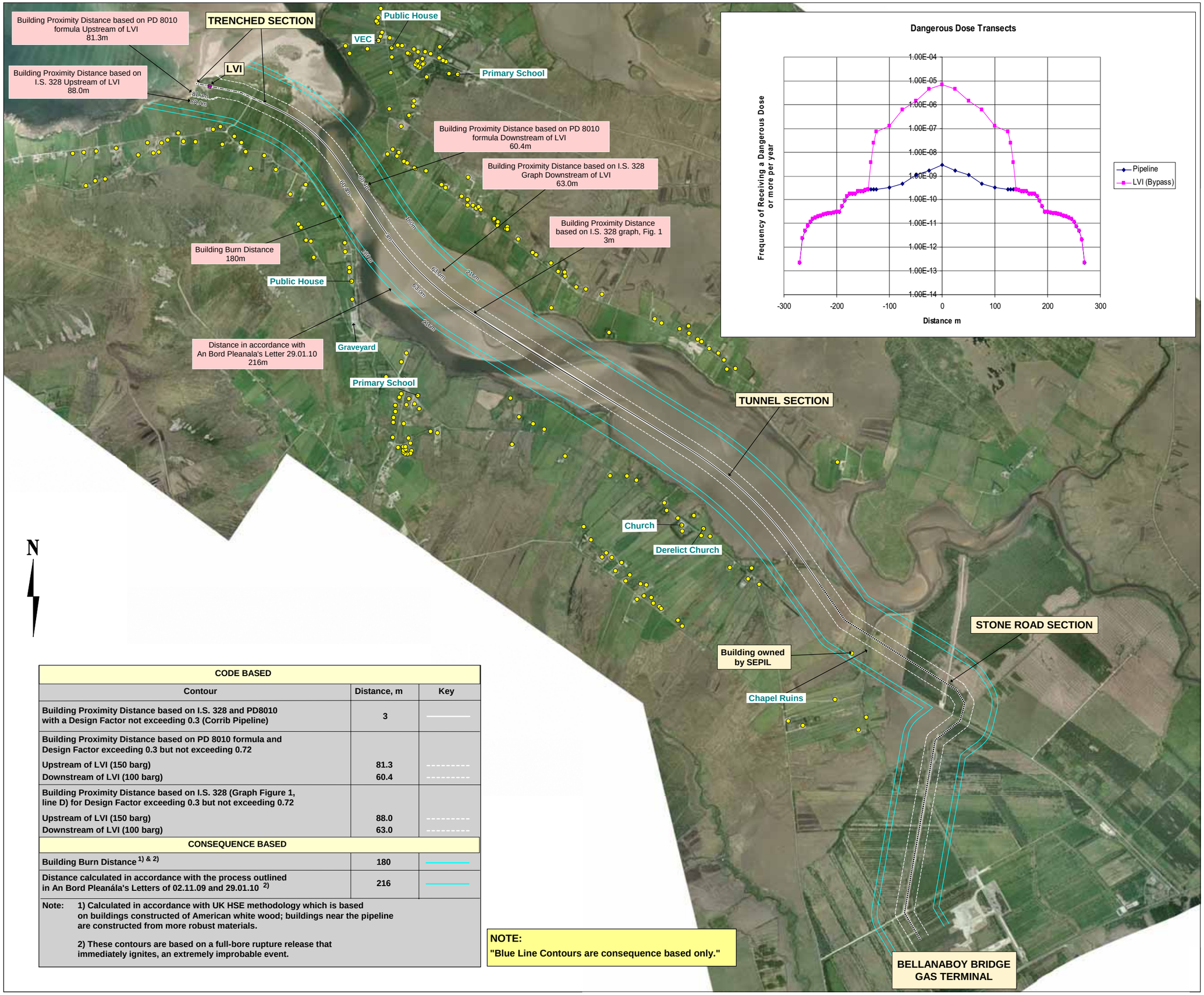
- A person standing beside the nearest dwelling to the pipeline would be safe as they would be able to reach the shelter of that dwelling.
- All existing normally occupied dwellings provide safe shelter.

It can be concluded from the above consequence predictions that the pipeline design meets the defined safety criteria.

A Plot of risk and consequence based contours relative to the Onshore Pipeline and LVI is presented in Figure 7.3. The full set of contour plots is included in Appendix Q6.5(i).

7.5 EMERGENCY RESPONSE PLANNING & PROVISIONS

Appendix Q6.6, Emergency Response Planning and Provisions, documents the initial draft of the emergency response planning and provisions which, whilst a work-in-progress, clearly illustrate the intent with respect to managing emergency response and describes the plans for engaging with, and involving the public and the emergency services.



CODE BASED		
Contour	**Distance, m**	**Key**
Building Proximity Distance based on I.S. 328 and PD8010 with a Design Factor not exceeding 0.3 (Corrib Pipeline)	3	
Building Proximity Distance based on PD 8010 formula and Design Factor exceeding 0.3 but not exceeding 0.72		
Upstream of LVI (150 barg)	81.3	
Downstream of LVI (100 barg)	60.4	
Building Proximity Distance based on I.S. 328 (Graph Figure 1, line D) for Design Factor exceeding 0.3 but not exceeding 0.72		
Upstream of LVI (150 barg)	88.0	
Downstream of LVI (100 barg)	63.0	
CONSEQUENCE BASED		
Building Burn Distance 1) & 2)	180	
Distance calculated in accordance with the process outlined in An Bord Pleanála's Letters of 02.11.09 and 29.01.10 2)	216	

Note: 1) Calculated in accordance with UK HSE methodology which is based on buildings constructed of American white wood; buildings near the pipeline are constructed from more robust materials.

2) These contours are based on a full-bore rupture release that immediately ignites, an extremely improbable event.

NOTE:
"Blue Line Contours are consequence based only."

LEGEND

Proposed Route:

- Trenched Section
- Tunnel Section
- Stone Road Section
- House Location

Consequence and Code Based Contours

Figure 7.3

File Ref: COR25MDR0470Mi2471R04
Date: May 2010

CORRIB ONSHORE PIPELINE

Corrib natural gas

RPS

ATTACHMENT Q1A

Cross-reference to responses made to items raised by An Bord Pleanála in their correspondence

Table A1: Issues and requests for Further information raised by An Bord Pleanála in their correspondence and cross-reference to SEPIL's Responses

Item No.	An Bord Pleanála Request for Further Information items (2nd November 2009)	EIS section
Top of page 2	…the Board should, therefore, (a) adopt the UK HSE risk thresholds for assessment of the individual risk level associated with the Corrib Gas Pipeline, individual risk level above $1x10^{-5}$ – intolerable, individual risk level between $1x10^{-5}$ and $1x10^{-6}$ – tolerable if ALARP (As low as reasonably practicable) is demonstrated, individual risk level below $1x10^{-6}$ broadly acceptable, and	App Q6.4 (Section 8.3 and Fig. 13)
Top of page 2	(b) adopt a standard for the Corrib upstream untreated gas pipeline that the routing distance for proximity to a dwelling shall not be less than the appropriate hazard distance for the pipeline in the event of a pipeline failure. The appropriate hazard distance shall be calculated for the specific pipeline proposed such that a person at that distance from the pipeline would be safe in the event of a failure of the pipeline.	App Q6.5(i)
(a)	Clarify the code requirements and pressure test requirements for the pipeline from chainage 83+390 (HWM) approx. to chainage 83+470 (downstream weld at LVI)	App Q2.1 (Section 3 & Section 5.4)
(b)	Provide confirmation that the design of this section of the pipeline meets the requirements set down by the Technical Advisory Group (TAG).	App Q2.1 (Section 3)
(c)	Provide an integrated set of design documentation in the form of a revised Appendix Q.	App Q
(c)1	The documentation should integrate the analysis provided in the incidental and individual documents at the oral hearing.	App Q & App Q1 (Attachment Q1B, Table B1)
(c)2	The whole set should provide a transparency of the design for the complete pipeline from the HWM to the terminal. This transparency should relate to the different site and design conditions along the pipeline and should relate to the codes.	App Q2.1 & App Q3.2
(c)3	The design should include the analysis related to ground stability	App Q4.1 (including Attachment Q4.1A) & App M2
(c)4	and should provide a system for monitoring movement of the pipeline in those areas of deep peat.	App Q4.1, Chapter 15 & App M2 (Section 8.5 & Drawing 001)
(c)5	Furthermore, the maximum allowable operating pressure (MAOP) for the pipeline should be stated.	App Q2.1 (Section 4.5) & App Q4.5 (Section 2)
(d)	Submit a new QRA that presents the analysis of risk at the different operating conditions and different locations along the pipeline route.	App Q6.4 (Table 9 & Section 8)
(d)1	The QRA should be site specific.	App Q6.4 (Table 9 & Section 8) & App M2
(d)2	The QRA should include ground movement and incorporate a database that matches the conditions of the proposed development.	Q6.4 (Section 6.4.5) & App M2/M3
(d)3	A sensitivity of the QRA is required which demonstrates the range of risk that relates to any uncertainty (in the database) of failure frequencies for the various potential failure modes of the pipeline.	App Q6.4 (Sections 7.4 & 8.7)
(d)4	The database should be relevant for an upstream wet gas.	App Q4.9 & Q6.4 (Sections 6.2 & 6.4.3.1)
(d)5	In order to eliminate any doubt please note that all failure modes should be included including the possibility of third party intentional damage at Glengad,	App Q4.10, App Q6.3 (Attachment Q6.3A, p. A5 and Attachment Q6.3B Fig. B4.5, p. B22) and Q6.4 (Section 6.4.7, Attachment B - Figs 18, 19 &

		Table 20)
(d)6	wet gas in the pipeline,	App Q4.7-4.9, App Q6.3 (Attachment Q6.3B, Figs. B3.4-B3.9 & Figs. B5.4-B5.9) & App Q6.4 (Sections 6.4.3 and 6.7.1.2)
(d)7	CO2 in the pipeline and	App Q4.7-4.9, App Q6.3 (Attachment Q6.3B, Figs. B3.4-B3.9 & Figs. B5.4-B5.9) & App Q6.4 (Sections 6.4.3 and 6.7.1.2)
(d)8	potential for Methane Hydrate in the pipeline.	App Q4.5 (Section 6), App Q6.3 (Attachment Q6.3B, Fig. B3.13) & App Q6.4 (Section 6.3.2.3)
(e)	Provide a qualitative assessment of risk. This should be prepared for the different operating conditions and different locations along the pipeline route and should provide a comprehensive assessment to include those events that cannot be easily defined mathematically.	App Q6.3
(f)	Submit an analysis of the condition where the umbilical becomes severed and the control of valves at the wellhead and the subsea manifold is lost. The analysis needs to identify what conditions apply to the onshore pipeline and the risks involved in that circumstance.	App Q4.5 (Section 3.2) & App Q6.3 (Section 4.4 & Attachment Q6.3B, Figs. B6.1-B6.4)
(g)	An examination of the potential for pressure in the offshore pipeline to increase to wellhead pressure levels in the event that all wellhead valves had to be shut in over a prolonged period and in that period incremental leakage past the valves occurred.	App Q4.5 (Section 4)
(g)1	The concept of a vent at Glengad as a measure to protect against pressure at the wellhead side of the pipeline at the landfall rising above the maximum operating pressure should be examined.	App Q4.5 (Section 7)
(g)2	Information should also be provided on the reliability of the subsea shut down valve system proposed for the wellhead and manifold offshore.	App Q4.6
(h)	Provide details of the examination of the potential increase in safety for the population at Glengad by the use of a straight pipe at the landfall and	App Q4.4
(h)1	provide full justification for the proposed design as submitted (and any revised design that may result from the modifications requested herein).	App Q4.3
(i)	Provide details of the hazard distances, building burn distances and escape distances in contours for the entire pipeline.	App Q6.5(i) & (ii)
(i)1	The applicant should indicate the outer hazard line contour which should show the distance from the pipeline at which a person would be safe. A number of these contours were provided at the oral hearing (copies of which are attached to this letter), however, the set of hazard contours should be complete and should include the entire onshore pipeline as far as the terminal.	App Q6.5(i)
(i)2	Please indicate the assumption made in determining these hazard contours and indicate any limitations that apply to these hazard contours.	App Q6.5(i) & (ii)
(j)	Provide details separately of the inner zone, middle zone and outer zone contour lines for the pipeline. These shall represent the distance from the pipeline at which risk levels of $1x10^{-5}$, $1x10^{-6}$ and $0.3x10^{-6}$ per kilometre of pipeline per year exist.	App Q6.4 (Section 8.6 and Fig. 15)
(k)	Provide an assessment of the societal risk for Glengad and the societal risk along the revised route. This should be fully documented.	App Q6.4 (Section 8.5)
(l)	Submit precise section by section details of the proposals for temporary peat turve storage, which take into account the condition of the existing surface layer of the peat and which specifically identify where peat turves or remoulded peat will be stored on bog mats adjacent to the stone road	App M2 (Section 5, Table 2 & Drawing 001)

	(or elsewhere).	
(m)	Submit details of the specific risk mitigation measures that would be proposed for each of the sections within the peat lands (Sections 1 to 18 were the relevant sections in the route as originally proposed and as set out in the qualitative assessment of relative peat failure potential which was presented as additional information at the oral hearing). These details should identify in particular where there would be limits on the storage of peat on bog mats adjacent to the stone road excavation and where a conservative approach would be proposed to the use of design factors and in the assessment of peat stability.	App M2 (Section 5, Table 2 & Drawing 001)
(n)	Submit an assessment of the potential impact of the estimated stone road settlements on the umbilical pipeline and service ducts that will also be constructed within the stone road,	App M2 (Section 8) & App Q4.1 including Attachment Q4.1A
(n)1	including an assessment of the risks associated with failure due to rupture of these umbilicals or services.	App Q4.5 (Section 3), App Q6.3 (Section 4.4 & Figs. B6.1-B6.4) & App Q6.4 (Sections 6.3.2.7, 6.4.5 & 8.1)
Page 4, para 1	Revised drawings should be submitted which fully describe the full extent of the onshore pipeline from the HWM to the terminal site.	Book of drawings & App A
Page 4, para 2	The site of the proposed development has been incorrectly detailed in the EIS between chainage 91.537 and chainage 92.539, i.e., the existing stone road at the Terminal end of the pipeline. The applicant is invited to amend the details of the proposed development at this location.	App M3 (Drawing DG0112R14)

Item No.	An Bord Pleanála Letter (29th January 2010)	EIS section
1	The Board's specific concern is that the undertaker should provide sufficient information and design detail to enable the assessment of whether or not the revised proposed development would give rise to an unacceptable risk to the public, having regard to the very high pressures involved, the site conditions through which the pipeline traverses and the hazards associated with the transport of untreated wet gas. It is a matter for the undertaker to provide sufficient information to enable the Board to assess the proposed development.	App Q
2	The UK HSE risk thresholds which are contained in paragraph (a) of the Board's letter relate to individual risk of receiving a dangerous dose of thermal radiation. It is the Board's understanding that the UK HSE framework for Tolerability of Risk uses 10^{-5}, for gas pipelines, as the boundary between "tolerable [ALARP]" and "intolerable" risk levels. The Board in paragraph (a) (at top of page 2 of the Board's letter of 2nd November, 2009) have set out the standard against which the proposed development will be assessed. In the event that individual risk of the 10^{-6} or higher applies then the undertaker will have to demonstrate ALARP.	App Q6.4 (Section 8.3 and Fig. 13)
3	In paragraph (b) (at top of page 2 of the Board's letter of 2nd November, 2009) the intent of the Board is to ensure that persons standing beside the dwellings will not receive a dangerous dose of thermal radiation in the worst case scenario of a "full bore rupture" of the pipeline at maximum pressure.	App Q6.5(i)
4	In respect of the pipeline at Glengad the undertaker is asked to provide full justification for the design proposed and the undertaker is asked to provide details of a design examination and safety evaluation of the use of an alternate layout at Glengad which would consist of a pipeline without a loop i.e. the alternative gas pipeline configuration should be considered to consist of a straight pipe at Glengad. In the interests of clarity the term straight pipe should be construed to mean a pipe without a loop and does not preclude the normal longitudinal profile from curvature and geometrical pipe layout with gradual bends to match the requirements of ground profile and other local requirements (streams etc).	App Q4.4

ATTACHMENT Q1B

Oral Hearing Analyses

Analyses provided at the Oral Hearing

Table B1 addresses the text highlighted in bold (which is part of point (c) in the letter from An Bord Pleanála (2/11/2009)):

(c) Provide an integrated set of design documentation in the form of a revised Appendix Q. **The documentation should integrate the analysis provided in the incidental and individual documents at the oral hearing.**

All previous analyses provided during the Oral Hearing, 2009 (in relation to Appendix Q) have been reviewed. Where possible the analyses have been incorporated directly. It should be noted that due to the re-routing and reduction in maximum allowable operating pressure that significant amounts of the analyses previously provided have been superseded by current information.

Table B1: Analyses provided at the Oral Hearing which have been integrated into the Appendix Q documentation

Document Title	Appendix Q section
An Bord Pleanála – Oral Hearing – June 4 2009-06-04 [Supplementary Information requested by the Bord from Phil Crossthwaite, DNV, QRA] – [Distances from jet flames & individual risk sensitivity transects]	Q6.4 (Section 8.1, Table 17) and Q6.4 (Section 6.4.5, Table 19, Figs. 16 & 17)
Fact sheet: umbilical leak	Q4.5 (Section 3)
Potential and Effect of Passing Valves in the Corrib Upstream Pipeline	Q4.5 (Section 4)
Qualitative Risk Management	Q6.3
Preservation of Linepipe pictures	Q5.4 (Figures 2.1 and 3.1)
Notes on the flexibility testing of 3LPP Coating at Bodycote, Eccles, on Pipe straps cut from stored pipe from the Shell Corrib Project and COT coating test results	Q5.4 (Attachment Q5.4B)
Fact sheet: Intelligent Pigging	Q2.1 (Section 9.5)
An Bord Pleanála – Oral Hearing – June 9 2009 [Ground movement transects]	Q6.4 (Section 6.4.5, Fig. 12, Table 19, Figs. 16 & 17)
Explanatory Note 1: Consequence Impact Contour Maps	Q6.5(ii)
Additional Information for An Bord Pleanála for the Corrib gas pipeline application (DNV QRA) [Information on dispersion]	Q6.4 (Attachment C)
Onshore Pipeline Stone Road Settlement Analysis	Q4.1 (Attachment Q4.1A)
Maximum length of a single length offshore umbilical	Q4.1 (Section 6)
Pressure Regime: Subsea to BGE and Corrib Key High Pressure Trips	Q4.5 (Section 2)
Proximity of Pipeline Route to Local Housing (Drawing)	Appendix A2 (File ref. COR25MDR0470Mi2132A5)
Summary of Corrosion Management of Wet Gas Pipelines	Q4.9 (Section 2.3)
UPDATED Explanatory Note 1: Consequence Impact Contour Maps	Q6.5(ii)
Additional Information - Inspection of the pipeline within the tunnelling bundle	Q4.7 (Section 4.3.1 & 7.2.3)
An Bord Pleanála - Further Information on Dispersion of gas from a hole in the pipeline	Q6.4 (Attachment C)

Table B2: Other information and reports provided at the Oral Hearing

Document Title
Upstream Pipeline and Facilities Statutory Risk Assessment Regime in the Netherlands
Supplementary information presented to An Bord Pleanala for the Corrib gas pipeline application by Phil Crossthwaite, DNV [Response to question regarding hazard distance from 2004 Bellanaboy Bridge Gas Terminal QRA]
Offshore pipeline system: long range tie-back study (Granherne) (Sept. 2002)
Corrib Gas Pipeline Project – Report on Evaluation of Onshore Pipeline Design Code (by Andrew Johnston) (28/03/2002)
Advantica Independent Safety Review of the Onshore Section of the Proposed Corrib Gas Pipeline (17/01/2006)
Report of the Corrib Technical Advisory Group to Minister Dempsey (27/01/06)

The information and reports shown in Table B2 (above) were also provided at the Oral Hearing, 2009, but as they are not analyses they are not integrated into the current Appendix Q documentation. The above list is included for completeness.

Appendix Q2

Integrated Design Description

SHELL E&P IRELAND LIMITED

CORRIB GAS FIELD DEVELOPMENT PROJECT

Corrib
natural gas

Q2.1 – PIPELINE AND LVI INTEGRATED DESIGN

DOCUMENT No: COR-25-SH-0011

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LIST OF FIGURES

1 INTRODUCTION

1.1 PURPOSE

The purpose of this document is to provide an integrated set of design documentation for the Corrib onshore pipeline and the Landfall Valve Installation as presented in Appendix Q.

The documentation presented in the revised Appendix Q integrates the technical details presented in the Corrib Onshore Pipeline EIS (Feb 2009) together with supplementary information submitted at the Oral Hearing held May/June 2009, into a transparent and comprehensive submission.

Appendix Q relates to the different sites and design conditions along the onshore pipeline and the applicable pipeline design codes from the HWM to the Gas Terminal. Where required for clarity, information is also provided regarding the subsea facilities, the offshore pipeline and the Gas terminal receipt facilities.

Within Appendix Q specific details are included that relate to the points raised in An Bord Pleanála letters dated 2nd November 2009 and the 29th January 2010 seeking clarification regarding a number of technical issues relating to the design of the Corrib pipeline.

1.2 STRUCTURE

Appendix Q has been structured to address the principal issues related to the design of the Corrib pipeline system and in particular the onshore pipeline and the Landfall Valve Installation. The design information is presented within the following structure and provides a guide to the supporting information available within each respective topic.

The principal sections are as follows:

- Appendix Q3 Code Requirements
- Appendix Q4 Technical Details
- Appendix Q5 Pipeline Integrity Management

1.3 DESIGN DEVELOPMENTS

A number of design enhancements have been incorporated into the design since the issue of the EIS in 2009. These are summarised as follows.

As explained in Chapter 4, the alignment of the onshore gas pipeline has been re-routed beneath Sruwaddacon bay. This necessitated the use of a tunnel as explained in Chapter 5. Thus, where necessary, the design of the onshore pipeline and associated services has been adapted to accommodate this new requirement.

As a consequence of An Bord Pleanála's letter of 2nd November 2009 and because of concerns expressed in the Oral Hearing in 2009, the possibility of further reducing pressure in the pipeline system whilst still maintaining the functionality of the Gas Terminal was reviewed. A review of the flow assurance of the Corrib pipeline system and the Gas Terminal was undertaken. As a result of this review, the overall pressure regime of the Gas Terminal was reduced resulting in a reduction of the inlet pressure required at the Gas Terminal inlet while maintaining the maximum design throughput of 350 MMSCFD. As a consequence the operating pressure envelope of the Corrib pipeline could be reduced, resulting in increased margins being established below the Corrib pipeline design pressures.

This enabled maximum allowable operating pressures (MAOP) to be determined for the onshore pipeline section at 100 barg and for the offshore pipeline section at 150 barg.

Based upon the new MAOP's the pressure safeguarding system was re-evaluated to establish the appropriate alarm and trip pressure settings. In addition the integrity of the shutdown system for the subsea facilities was further enhanced by introduction of additional changes within the Gas Terminal control systems. This included devices to release, at the Gas Terminal, the pressure of the hydraulic fluid within the umbilical resulting in closure of all the subsea valves independently of the control signals within the umbilical.

There have been recent developments in utilising the characteristics of fibre optic cables to provide a method for leak detection and identifying 3rd party activity near to a buried pipeline. As this technology is now verifiable, it has been decided to incorporate this feature using the existing fibre optic cable running parallel to the onshore pipeline and installing the additional equipment at the Gas Terminal. This system is considered a secondary independent technique to the primary mass balance leak detection system already incorporated into the Corrib pipeline design. It will provide a method of identifying and locating a potential leak event along the onshore pipeline.

2 PROJECT OVERVIEW

2.1 PROJECT FACILITIES

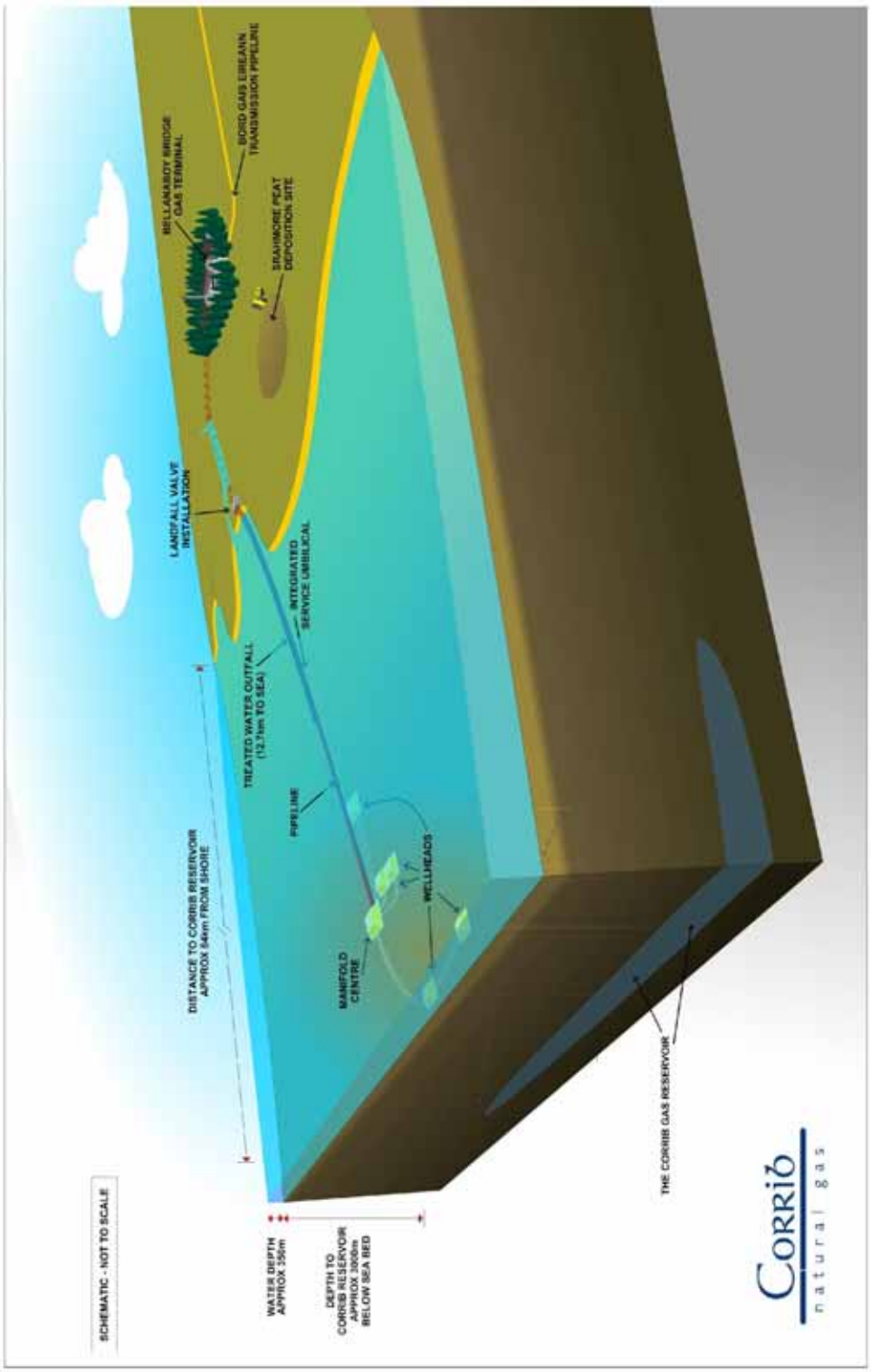
The Corrib Field Development comprises:

- The subsea wells, infield flow lines and manifold
- A Corrib gas pipeline system consisting of offshore and onshore pipeline sections
- Facilities at the Landfall of the offshore pipeline (Landfall Valve Installation)
- Receipt facilities within the Gas Terminal at Bellanaboy
- Supplementary supporting facilities

These are illustrated in Figure 2.1 included on the next page.

Appendix A, Drawing DG103 provides an overview of the offshore and onshore route of the Corrib pipeline system and Chapter 4 presents a detailed description of the route of the onshore pipeline.

Figure 2.1 Overview of Corrib Field Development



2.1.1 Sub-sea Facilities

A brief overview of the subsea facilities is included to provide a comprehensive understanding of the Corrib gas transportation system. Refer Figure 2.2.

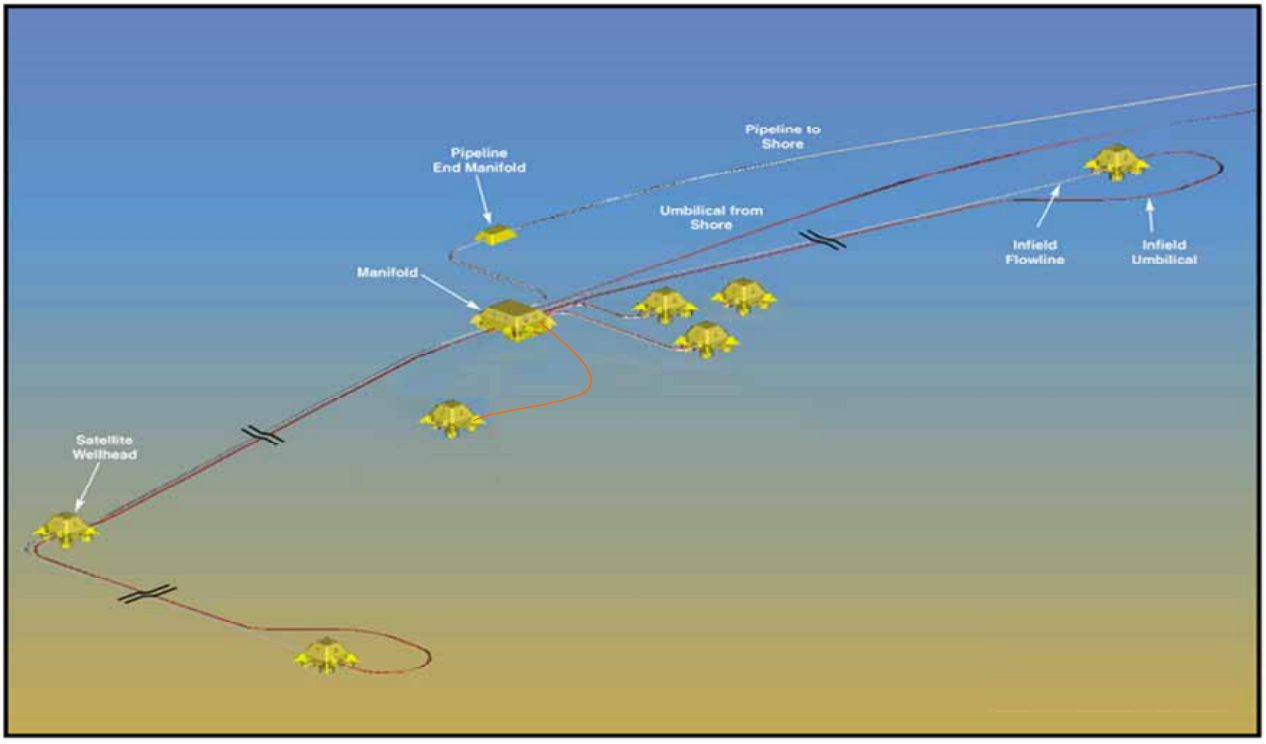


Figure 2.2 Overview of Corrib Subsea Development

The Corrib subsea facilities comprise the wellheads which supply the produced gas from the production wells through to an eight slot gathering manifold. The 20” dia offshore pipeline connects to the subsea manifold via a pipeline end manifold (PLEM). The subsea manifold is equipped with a tie-in point for pig launcher (operated via unmanned Remote Operating Vehicle (ROV))

Three subsea wells (cluster wells) are located adjacent to the manifold (approx 100m) and three (satellite wells) are at remote locations (~1.5 km - 3 km). Two of the satellite wells are connected in series (“daisy chain”), their fluids being commingled into a single flowline from the nearer well to the manifold. Refer Figure 2.2.

A detailed description of the well isolation system is presented in Appendix Q4.5.

2.1.2 Offshore Pipeline

The offshore section of the Corrib pipeline commences from the PLEM through to the landfall at Glengad where it connects into the Landfall Valve Installation.

The 20” dia offshore pipeline is approximately 84 km long and is generally laid on the sea bed. The final ~13 km at the approach to the landfall is provided with additional protection of concrete coating and buried in a trench.

The offshore pipeline will be suitable for the passage of pigs and is externally protected by a factory applied external anti-corrosion coating protection termed a three layer polypropylene system (3LPP)

which provides the toughest, most durable pipe coating solution available. The offshore pipeline is also protected by sacrificial anodes along the length of the pipeline.

The offshore pipeline was installed in 2009. Further details of the offshore pipeline are provided in Appendix Q4.2.

2.1.3 Landfall Valve Installation

The 20" diameter carbon steel onshore pipeline landfall is at Glengad which is an area with protected views. To mitigate the visual impact at Glengad, the Landfall Valve Installation (LVI) will be sited in a dished area. The LVI is the point at which the offshore and onshore sections of pipeline interconnect and its primary function will be to provide over pressurisation protection of the onshore pipeline. The LVI is fully detailed in Appendix Q4.3. The configuration of the LVI is illustrated in Figure 2.3.

A discussion on the alternative mechanical and civil configurations considered for the LVI is presented in Chapter 3. A detailed comparison of the alternative mechanical pipe work arrangements at the LVI is presented in Appendix Q4.4.

An Bord Pleanála have requested SEPIL to examine the potential for cold venting at the LVI to relieve excess pressure in the upstream offshore pipeline (point (g), An Bord Pleanála Letter, 2nd November 2009).

The results of extensive studies of valve leakage from the Corrib wells show that, even on conservative leakage assumptions, the time taken for the pressure in the offshore pipeline to reach the 150 barg MAOP after a Gas Terminal/LVI shutdown is in excess of one year. It is reasonable to expect that normal production would be resumed in that time frame and thus a cold vent at the LVI would be unnecessary.

Hypothetically it could be assumed that isolation of a well did not occur upon shutdown of the Gas Terminal and LVI. To maintain the pressure in the offshore pipeline below the 150 barg MAOP in the case of full well flow would require a substantial cold vent at the LVI, with associated significant negative visual, noise and safety impacts.

It is therefore concluded that provision of a cold vent at the LVI is undesirable and if release of gas is required then this should be performed at the Terminal where provisions have already been made for safe and controlled release of gas under upset conditions.

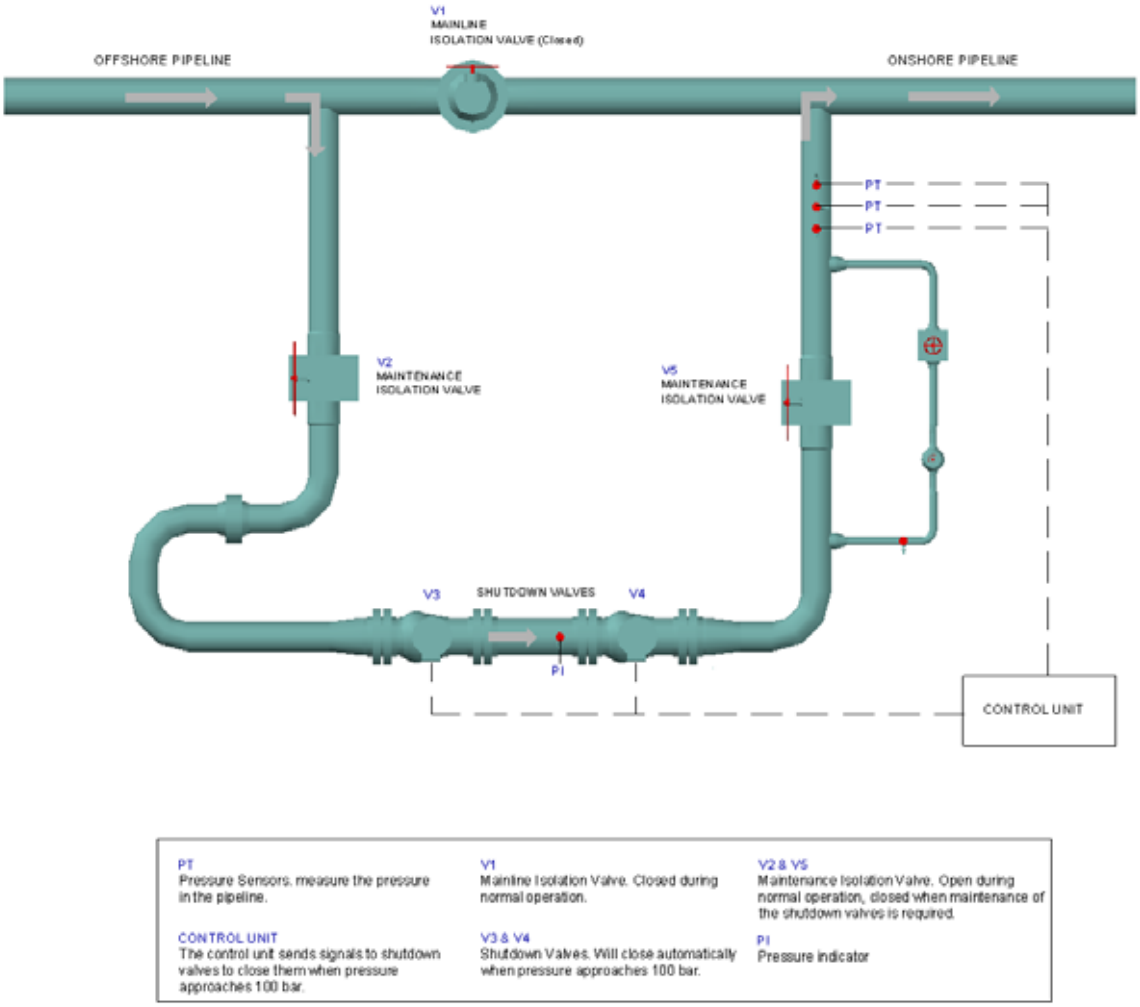


Figure 2.3 Configuration of the LVI

2.1.4 Onshore Pipeline

The 20” diameter, 27.1 mm wall thickness carbon steel onshore pipeline transports the production gas from the LVI through to the Bellanaboy Bridge Gas Terminal. The pipeline route is summarised in Section 2.2 and comprises an overland section at Glengad, through Sruwaddacon Bay via a dedicated tunnel to Aghoos and then onwards through an area of peat/forest to the Gas Terminal. The gas pipeline will be installed within a stone road for this final section. There is one road crossing of the L1202 at Aghoos.

The onshore pipeline will be suitable for the passage of pigs and is externally protected by a factory applied external anti-corrosion coating protection termed a three layer polypropylene system (3LPP). The onshore pipeline is also protected by an impressed current Cathodic Protection system.

The onshore pipeline design is summarised in Appendix Q4.1.

2.1.5 Receipt Facilities at the Gas Terminal

At the Gas Terminal the onshore pipeline receipt facilities will comprise a slug catcher and pipe work connections to the plant. A permanent pig receiver is located at the Gas terminal inlet which is normally isolated by closed valves. An emergency shutdown valve (ESDV) is located up stream of the Gas Terminal inlet facilities for isolation between the Gas Terminal and the onshore pipeline. All the

receipt facilities are located within the confines of the Gas Terminal boundary. A schematic is presented in Figure 2.4

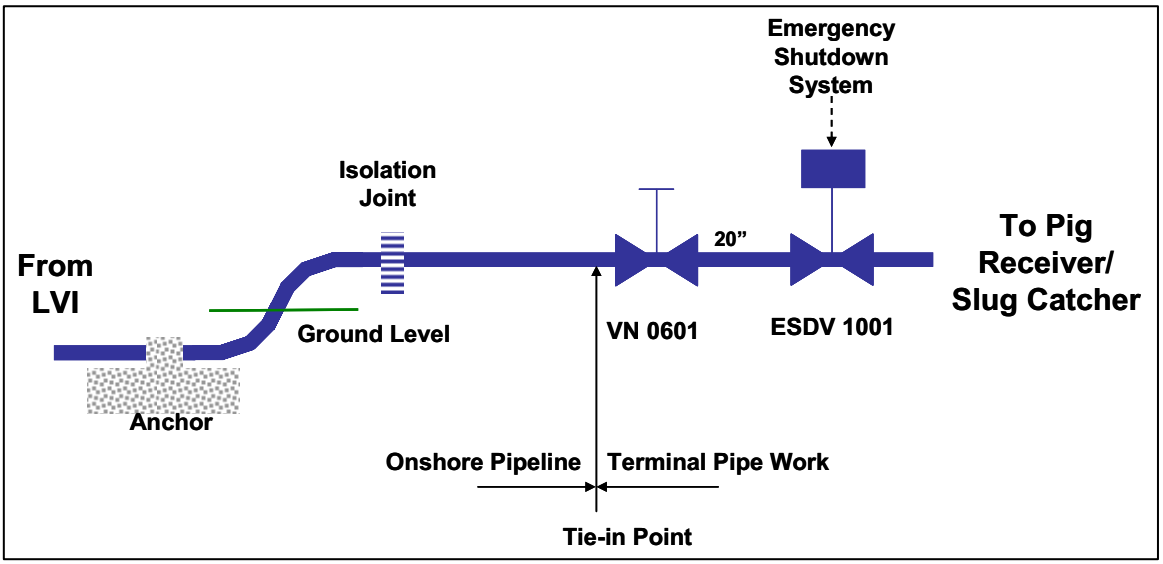


Figure 2.4 Schematic of pipeline tie-in at the Gas Terminal

2.1.6 Supplementary services

These comprise the following:

- An outfall pipe from the Gas Terminal which transports treated surface water from the Gas Terminal which is pumped to a subsea diffuser at a point approximately 13 km offshore in Broadhaven bay.

- A fibre optic cable and a signal cable from the Gas Terminal to the Landfall Valve Installation. The fibre optic cable provides communications and the signal cable facilitates remote closure of the safety shutdown valves at the LVI.

- An umbilical provides communications, electrical and hydraulic power from the Gas Terminal through to the subsea facilities together with methanol for injection in the well streams and treated produced water for disposal at the subsea manifold. The onshore section comprises three individual cables comprising multiple cores. At the LVI these are combined into a single cable which then terminates at the subsea manifold.

All the above service cables and outfall pipe will be buried and routed parallel to the onshore and offshore sections of the Corrib pipeline as appropriate.

The offshore aspects for the above services are detailed in Appendix Q4.2 and the onshore aspects are presented in Appendix Q4.1

2.2 ROUTE OF THE CORRIB PIPELINE

2.2.1 Route overview

The offshore pipeline route is shown in Appendix A, Drawing DG103. The characteristics of the installed offshore pipeline through to the landfall at Km 83.4 are as follows:

- Concrete coated: from Km 26.5 to landfall

- Trenched from Km 70.1 to landfall
- Backfilled from Km 82 to landfall
- Water Outfall Diffuser installed Km 70.65

The overall route of the onshore pipeline and facilities is presented in Appendix A, Drawing DG301.

The offshore pipeline terminates at the Landfall Valve Installation (LVI) which is located approximately 50m east of the landfall at Glengad.

The onshore gas pipeline commences from the tie-in to the downstream barred tee of the LVI. The proposed onshore pipeline route traverses the Glengad headland, in an east-south-easterly direction, for approximately 640m. From here, the pipeline route traverses Sruwaddacon Bay in a south-easterly direction towards Aghoos. The section of the pipeline route from Glengad to Aghoos is approximately 4.8km long and will be tunnelled. Approximately 4.6km of the tunnel will be beneath Sruwaddacon Bay

At Aghoos, the pipeline route turns in an easterly direction for approximately 0.9km, traversing an area of blanket bog within which it crosses an approximately 40m wide estuarine river channel. The route then enters an area of forested bog (approximately 2.2km long) where it turns in a southerly direction, at the crossing of the L1202, and continues to the Gas Terminal.

For the onshore section of the route, the outfall pipeline will be laid parallel to the gas pipeline. For the offshore section the outfall pipe has been piggy backed onto the offshore gas pipeline for approximately 13 km where it will terminate at a subsea diffuser to ensure effective dispersion of the transported water into Broadhaven Bay.

Both the fibre optic cable and the signal cable will be installed parallel to the onshore gas pipeline. Cable jointing will be required along the route.

2.2.2 Tunnel

The Tunnel will be a concrete segment lined construction. The segment lining method is a trenchless tunnelling technique using concrete segments to support the tunnel that has been excavated by a Tunnel Boring Machine (TBM). These segments are assembled to form complete rings and, when connected, act as the tunnel lining.

Segment lining is mainly used for tunnels of larger diameters and / or longer distances. A launch shaft and a reception shaft are needed. Concrete segments are transported to the front of the tunnel on a specialised train that runs on tracks within the tunnel during construction. Further details of the Tunnelling method are provided in Appendix S.

In the case of Sruwaddacon Bay, the tunnel is proposed to be used as an auxiliary construction for the installation of the gas pipeline and services.

The gas pipeline and services will be arranged inside the tunnel in a manner that will facilitate installation of each service. Once the gas pipeline and associated services have been installed within the tunnel, the tunnel will be grouted with a cement grout.

2.2.3 Stone Road

Between Aghoos and the Gas Terminal the onshore pipeline and associated services will be routed through an area of blanket bog. To mitigate the effects of constructing within an area of deep peat, peat with low shear strength and local hydrology effects, the stone road method of construction will be employed.

The stone road method minimises the potential impact on sensitive blanket bog habitats and provides a stable base within the bog to lay the onshore gas pipeline and associated services. Peat will be typically excavated to within approximately 0.5m to 1.0m of the peat base and backfilled with stone. The process of installing the stone road will be a combination of excavation and displacement of peat with stone. The depth of stone varies in line with the depth of peat. The proposed 'stone road' is approximately 12m wide (9m wide in areas where the bog is intact / eroding) and can be turved at its upper surface.

The onshore gas pipeline (and umbilicals etc.) will be installed within the stone road using the methodology adopted for conventional construction (the spread technique).

Potential for movement of the stone road within the area of peat and any potential consequential impact has been assessed with respect to the gas pipeline, the outfall pipeline, the umbilical and both the fibre optic and signal cables. The results of this analysis demonstrated that the stone road would not be subject to any horizontal movement. Should any vertical movement occur, then there was no predicted consequential effect on the gas pipeline, i.e. no loss of containment, and any impact on the umbilicals, the outfall pipe and the fibre optic and signal cables were within their design capacities. Refer Appendix Q4.1.

For further details regarding the Stone Road refer to Chapter 5 together with Appendices M1 and M2.

2.3 ENVIRONMENTAL CONDITIONS - ONSHORE

Environmental data for the pipeline route is listed below:

(Data received from Met Éireann).

Max air temperature:	28 deg C
Monthly mean max temperature range:	8.9 to 18.2 deg C
Min air temperature:	-5.5 deg C
Monthly mean min. temperature range:	3.9 to 12.2 deg C
Mean annual rainfall:	1269 mm
Max daily rainfall:	40 mm
Max hourly rainfall:	25.9 mm
Mean days ≥ 0.2mm rainfall:	254 days/year
Mean monthly wind speed range:	11.7 to 16.2 knots
Wind speed (gust):	93 knots Max

2.4 PROJECT DESIGN LIFE

The pipeline, outfall & umbilical and all sub-sea facilities will have a design life of 30 years. The subsea flowlines have a design life of 20 years.

3 PIPELINE CODES

3.1 ADVANTICA AND TAG INDEPENDENT SAFETY REVIEW

The Corrib Technical Advisory Group (TAG) was established by the Minister for Communications, Marine and Natural Resources in August 2005 to commission an Independent Safety Review of the onshore section of the Corrib gas pipeline between the landfall and the Gas Terminal site, and to design and implement a new inspection and monitoring regime for the project. TAG appointed Advantica to undertake an independent safety review, and the Advantica and TAG recommendations were published by the (then) DCMNR on the 3rd May 2006

SEPIL accepted the findings and recommendations of the Advantica and TAG reports and a point by point statement of implementation is provided in Appendix Q3.1.

3.2 APPLICABLE PIPELINE CODES AND STANDARDS

The design, construction, operation and maintenance of the Corrib pipeline system is in accordance with a series of pipeline codes, which were adopted by SEPIL following the recommendations of the Corrib Technical Advisory Group (TAG).

TAG recommended that the pipeline codes applicable for the **design** of the onshore pipeline were I.S. EN 14161, I.S. 328 and BS PD 8010

The **construction, installation, operation and maintenance** of the onshore section of the Corrib pipeline will be in accordance with I.S. 328, and the **inspection and monitoring regime** that will be applied to the Corrib onshore pipeline will be as per the relevant provisions of I.S. 328.

The **design and construction** of the offshore submarine pipeline was in accordance with DNV-FS-101:2000 as applicable at the time of design.

The break between the offshore and onshore pipeline design codes is defined at the Landfall Valve Installation and is in accordance with DNV-FS-101:2007 Appendix F. The design of the offshore submarine pipeline is in accordance with DNV-FS-101 and conforms to TAG's recommendations. This was confirmed in a letter from TAG dated 13 May 2010.

Appendix Q3.2 sets the above pipeline codes into context within the overall framework of the various Irish and International Pipeline codes and standards. This document also identifies the application of other key pipeline codes in relation to the onshore pipeline.

In the TAG report issued in May 2006, TAG further required that a pipeline code Compliance Document be submitted by SEPIL to demonstrate compliance with designated codes. The application of the codes was then set out in a **Design Code Review**, which was accepted by TAG and is included in Appendix Q3.3. This evaluated the three respective pipeline **design codes** and establishes a basis for **design compliance** with the codes, which avoids potential misunderstanding or misinterpretation. The application of the pipeline design codes is shown in Figure 3.1.

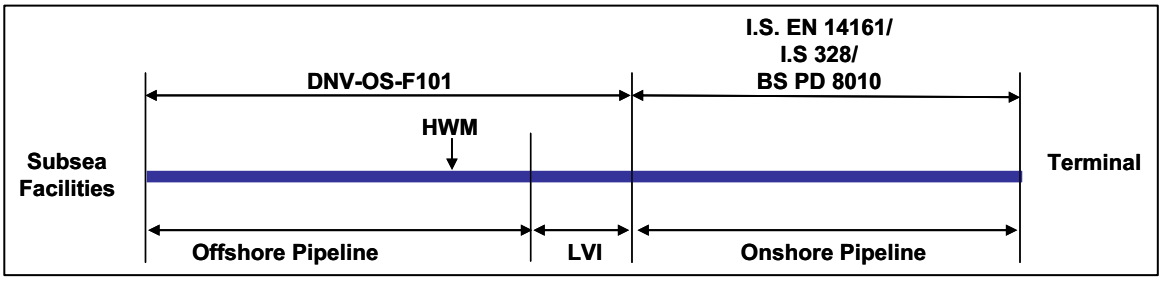


Figure 3.1 Application of Pipeline Design Codes

4 KEY PROCESS DESIGN AND OPERATION ASPECTS

4.1 CORRIB GAS PROPERTIES

For the fluid properties and typical gas composition refer Appendix Q4.2

The typical composition of the fluid transported through the Corrib gas pipeline including the injected methanol is as follows:

Table 4.1 Typical Composition of Corrib Gas Pipeline Fluid

Component	Mole%	Notes
Methane	**92.42**	
Ethane	**2.99**	
Propane	**0.16**	
Butane	**0.08**	
Pentane and higher (C5+)	**0.05**	
Carbon Dioxide	**0.25**	
Nitrogen	**2.61**	
Water	**1.09**	
Methanol	**0.35**	**Injected at wellheads**
Hydrogen Sulphide	**0**	
Total	**100**	

Corrib unprocessed gas contains a very low percentage (0.05%) of hydrocarbons (C5+) that would condense out as hydrocarbon liquid in either the pipeline or in the low temperature separation system in the Gas Terminal. Hence it is referred to as a dry gas in the sense of not containing liquid hydrocarbons. The gas contains water (1.1%) in the vapour phase as it comes out of the reservoir and this water condenses as the gas cools in the pipeline. Methanol is injected into the gas stream at the wells to prevent formation of hydrates in the pipeline. The water and the methanol components in the gas are reduced to very low concentrations in the Gas Terminal to meet the BGE transmission gas quality specification. The percentages of carbon dioxide (0.25%) and nitrogen (2.6%) are relatively low and are within the specification for transmission gas quality and are not removed in the Gas Terminal.

Hydrogen sulphide has not been observed in any gas samples to date, therefore the untreated and treated gas will have zero concentration of this component. A system is in place in the Gas Terminal to monitor H_2S in the incoming gas.

There are traces of other elements such as Mercury and Radon in the gas but these have no impact on the pipeline and are within the transmission gas specification. Both elements will be monitored on a regular basis.

Solids, such as sand and proppant are not expected in the gas. If any are produced, these will be in trace quantities and the subsea manifold has facilities for solids to be detected.

4.2 PRODUCTION PROFILE

Gas production from the Corrib field is expected to steadily decline over a period of 13 to 15 years from an initial maximum flow rate of 350 MMSCFD (dry sales gas). The maximum pressure at the well heads (Closed in Tubing Head Pressure CITHP) will similarly steadily decline from an initial value of around 320 barg to under 70 barg. This is illustrated in Figure 4.1.

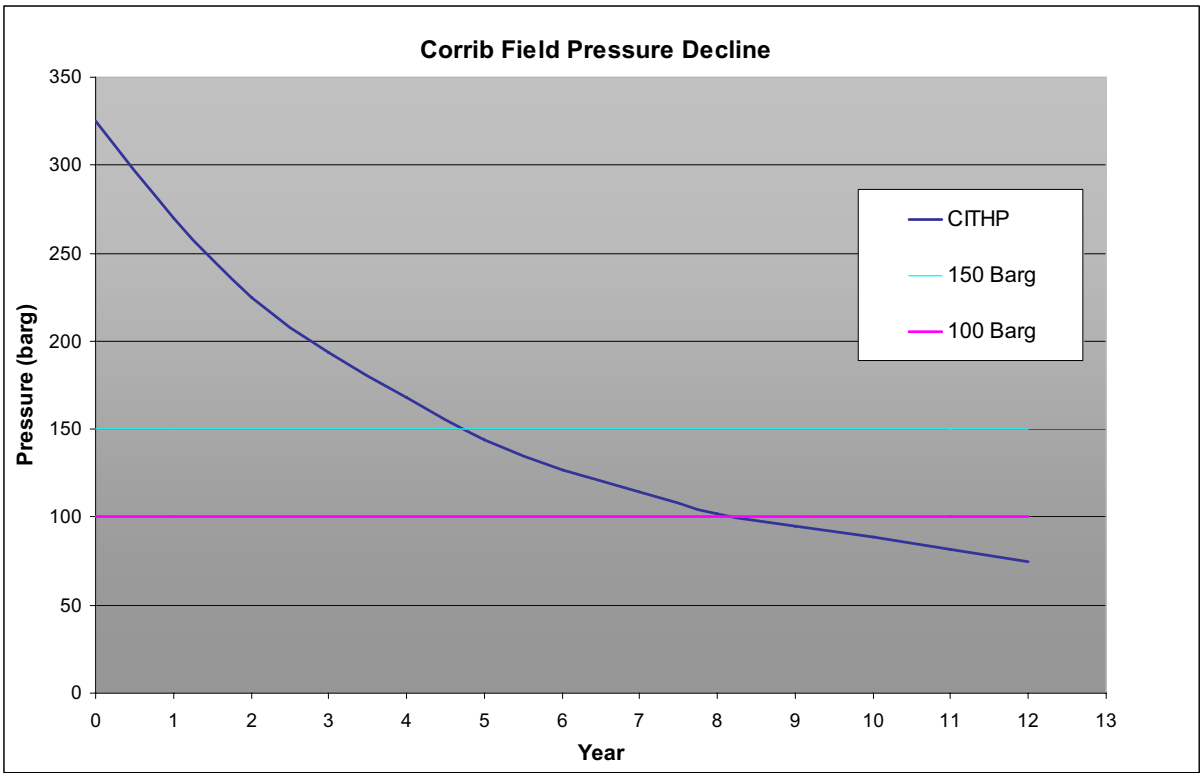


Figure 4.1 Decline in Corrib Field Pressure

For the first ~10km the gas temperature falls from around 50°C to an average seabed temperature of around 4°C to 5°C. This temperature remains almost constant through to the Landfall with a further small decline in temperature through to the Gas Terminal receiving facilities. Refer Figure 4.2 which is based upon year 1 conditions and a throughput of 350 MMSCFD. Over time, lower flow rates and declining well head pressures will change the temperature profile. However the temperature at the landfall will remain at around seabed temperature.

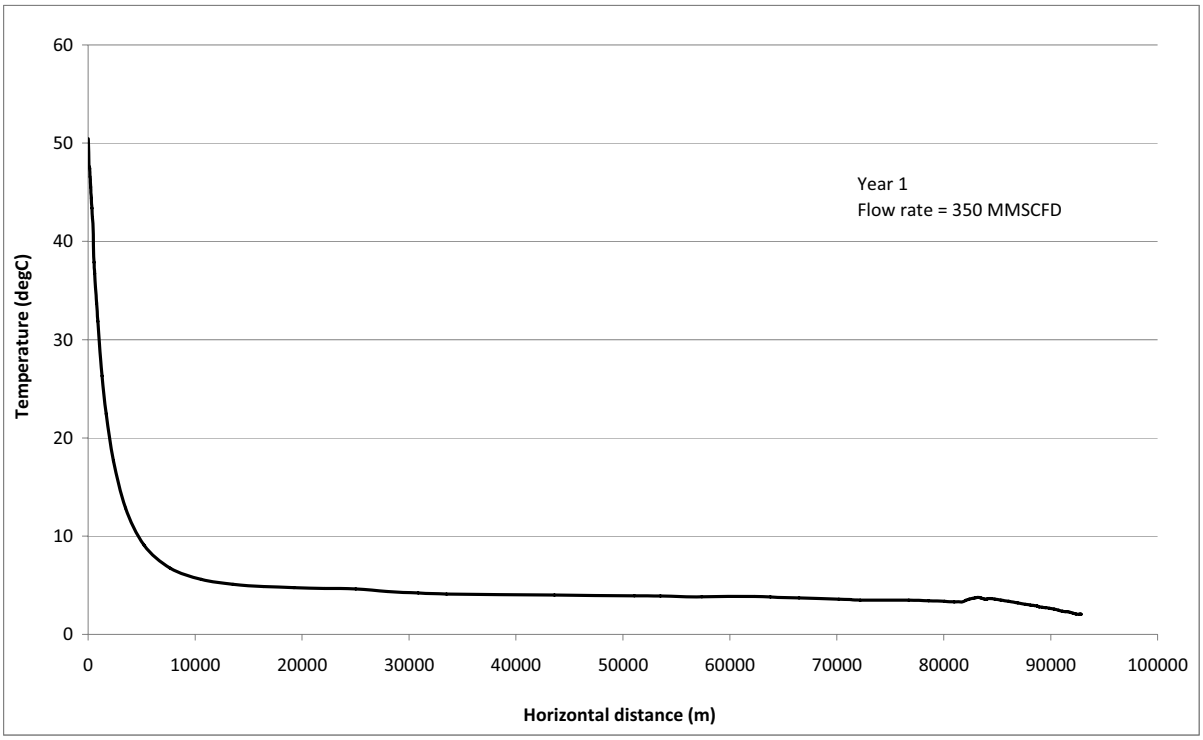


Figure 4.2 Temperature profile along the Corrib Pipeline

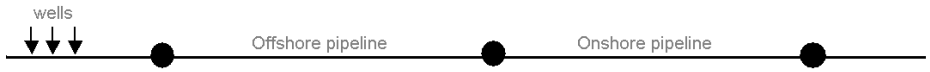
4.3 OPERATING ENVELOPE & PIPELINE FLOW REGIME

Flow through the complete system is planned to be continuous with the actual flow rate depending on gas offtake (sales) required by the Bord Gáis Éireann (BGE) Network. The pressure into the BGE system downstream of the Gas Terminal will be approximately 85 barg (this may vary depending on the pressure in the downstream system).

As gas flows from the subsea manifold towards the Gas Terminal the pressure gradually reduces along the length of the pipeline due to friction resulting in a lower pressure on arrival at the inlet to the Gas Terminal. The normal operating envelope of the Corrib Gas Terminal ranges from a gas arrival pressure of 55 barg to 85 barg.

An illustration of the resulting pressure profiles for the allowable operating envelope of the Corrib pipeline is provided in Figure 4.3.

Figure 4.3 Corrib Pipeline - Operating Pressure Envelope



Pressure Profile	Manifold	LVI	Terminal
Normal Operating Pressure Profile	117 - 122 barg	85 - 90 barg	80 - 85 barg
Lower Operating Pressure	73 barg	58 barg	55 barg

Note: The Normal Operating Pressure Profile data for Year 1 and plateau production at 350 MMSCFD. Lower Operating Pressures for Year 1 and 180MMSCFD

As can be seen from Figure 4.3, the normal operating pressure profile of the Corrib production system will be approximately 80 - 85 barg with a pressure at the subsea Manifold of 117 - 122 barg. This is based on a flow rate of 350 MMSCFD. During steady state production, this pressure may vary gradually by 1 to 3 bar, due to the multiphase flow nature associated with the Corrib production system. The operating pressure range will generally be maintained between 80 to 85 barg to manage this variation. The operating envelope has been designed with a sufficient margin to accommodate instabilities in the production system without having to shut-in production from the field.

In early field life, there will be no issues with liquid slugs and surges during normal operations at steady-state conditions. During initial start-up of production or start-up following a shut-in, liquid surges will be produced at the Gas Terminal. Simulations of the initial start-up scenarios and ramp-up from minimum to maximum production have shown that, given the liquid drainage capacity of the slug catcher, the volume accumulation of these liquid surges is negligible at the Corrib slug catcher. The slug catcher is a gas/liquid separator located at the Terminal that has been designed to handle the largest liquid surge volumes that can be generated in the pipeline during start-up and transient operations.

During late field life (10-40 barg Terminal pressure), annular flow is anticipated for the range of productions expected. For the same reasons explained for early field life, there are no concerns with regards to liquid surge volumes exceeding the slug catcher capabilities.

Further details regarding the above can be found in Appendix Q4.5.

4.4 DESIGN PRESSURES

4.4.1 Offshore Pipeline

The design pressure for the offshore pipeline was principally determined by the CITHP (approximately 320 barg) of the wells and a figure of 345 barg was selected. The pipeline was installed in 2009.

4.4.2 Onshore Pipeline

Following the recommendations of the Technical Advisory Group (TAG) and the Advantica report, the onshore pipeline has been re-classified as a Class 2 (Suburban) pipeline (0.3 design factor) and the design pressure of the onshore pipeline reduced from its original design pressure of 345 barg down to a lower design pressure of 144 barg.

4.4.3 Landfall Valve Installation

At the Landfall Valve Installation (LVI) the offshore pipeline and the onshore pipeline meet and thus there is a change in design codes and design pressures. The LVI is designed to the offshore pipeline code DNV-OS-F101 and the design pressure for the LVI was selected as 345 barg as the LVI pipe work could be subject to the same design pressure as the offshore pipeline. This design pressure was applied through to the downstream barred tee of the LVI.

4.5 MAXIMUM ALLOWABLE OPERATING PRESSURE (MAOP)

For the offshore pipeline the MAOP has been set at 150 barg. This represents the pressure required to achieve the design flowrate of 350 MMSCFD plus a margin for operational variation and pressure trip settings.

For the onshore pipeline the daily operating pressure at the LVI is expected to be typically 90 barg. Allowing a margin for the operational variation and pressure trip settings (including measurement accuracy of instrumentation etc), the onshore pipeline MAOP has been set to 100 barg.

Further details can be found in Appendix Q4.5 and the selected MAOP's are presented in schematic Figure 4.4.

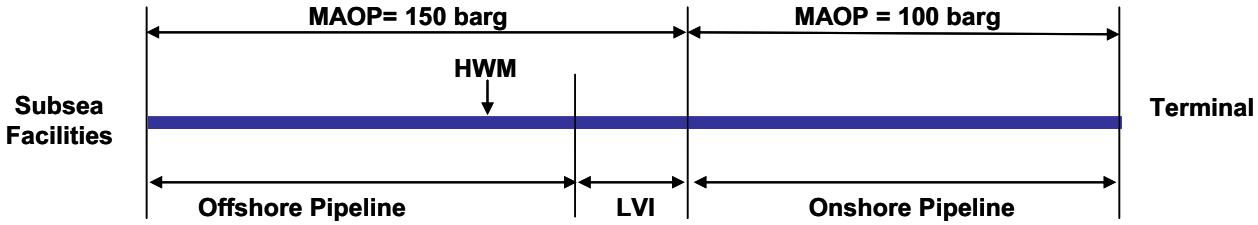


Figure 4.4 Application of MAOP

4.6 TRANSIENT FLOW ASSURANCE

A transient analysis has been performed for the Corrib production system, from the reservoir to the Gas Terminal inlet. This was performed for a number of operating conditions which adequately represents production over the life of the field. This detailed transient analysis was undertaken to determine the physical constraints on the system during normal operation, including turn-down and ramp-up, shut-down and start-up. The main physical constraints examined were with respect to the operability of the system with regard to methanol and liquids management. The analysis covered the following cases:

- Steady state.
- Slug flow.
- Turndown.
- Ramp-up.
- Shutdown.
- Production Restart.
- Start-up.

The results from this analysis indicated that there are no significant liquid handling (total, condensate and aqueous) issues during normal production, turndown, ramp-up, and start-up with respect to slug catcher volumes.

Results also indicate that there are no operational issues with the developed procedures associated with the cases that have been analysed. These procedures will provide the Operators at the Gas Terminal with a detailed step-by-step procedure on how to safely perform each of the above transient operations while remaining with the production system envelope.

4.7 HYDRATE MANAGEMENT

The Corrib produced gas contains hydrate-forming components such as methane, ethane, propane and carbon dioxide. At high-pressure and low-temperature, these components form crystalline solids known as "Gas hydrates". Hydrate blockages must be prevented as they can potentially result in production losses. Further details are provided in Appendix Q4.5.

4.7.1 Corrib Hydrate Management Strategy: Hydrate Inhibition

The Corrib subsea system including the main pipeline operates inside the hydrate region during steady-state flowing conditions. Methanol has been chosen as a primary hydrate inhibitor and it will be continuously injected offshore to prevent hydrate formation in the Corrib production system. A robust hydrate management strategy has been developed for Corrib to cover all foreseeable situations (e.g., Cold well start-up, Normal operating conditions, Planned shut-in, Unplanned shut-in, Hydrate plug remediation, Production restart after a hydrate plug event).

Hydrates will only form in the Corrib subsea facility and pipeline if methanol is not injected in sufficient quantities. The operating strategy for Corrib is to immediately stop production in the unlikely event of offshore methanol injection being unavailable. The methanol system has been designed to meet the reliability required by the system.

4.7.2 Consequence of Hydrate Formation

There is the potential for an unlikely event to occur where a hydrate plug may form in the Corrib production system due to unavailability of the methanol injection system or insufficient methanol injection. In this unlikely event, the formation of a hydrate plug which causes a full bore impermeable blockage in the line will not be sufficient to lead to the pipeline failing because of the layers of safeguarding in place.

4.7.3 Hydrate Remediation

Hydrate remediation procedures have been developed to prevent pipeline failure subsequent to the unlikely event of the formation of a hydrate plug in the Corrib pipeline. Hydrate remediation will be a lengthy operation, and specialist staff will perform this activity

5 CORRIB PIPELINE PROCESS SAFEGUARDING

5.1 BACKGROUND

As a result of the recommendations of the Technical Advisory Group (TAG) based upon the Advantica independent safety review, the design pressure of the onshore pipeline was reduced to 144 barg. Thus there was a change in the onshore design pressures and the introduction of the LVI at Glengad.

Furthermore, SEPIL have modified the design to satisfy the requirements of An Bord Pleanála, as described in their letters of 2nd November 2009 and 29th January 2010. As a result of this requirement, a review was undertaken. The outcome of this review is that SEPIL has established the minimum required offshore and onshore pipeline MAOP to maintain a sufficient operating envelope to meet the contractual and technical requirements of the already approved and constructed Gas Terminal. This review has resulted in the maximum allowable operating pressures (MAOPs) of the pipelines being set to 150barg and 100barg for the offshore and onshore pipelines respectively. Overpressure protection systems are in place for both the offshore and the onshore pipelines. These protection systems will restrict the maximum pressure that can be experienced in these pipelines to their respective Maximum Allowable Operating Pressures (MAOPs).

5.2 SAFEGUARDING OBJECTIVES

The safeguarding system comprises a number of layers of protection which ensure that the MAOP in the offshore and onshore pipeline sections are not exceeded for any credible scenario. The overall system is illustrated in Figure 5.1.

The primary mechanism to ensure the MAOP of the onshore pipeline is not exceeded is to isolate the flow between the offshore and onshore sections at the landfall; that is at the LVI.

The primary mechanism to ensure the MAOP of the offshore pipeline is not exceeded is to isolate all of the wells at the respective wells.

5.3 SAFEGUARDING STRUCTURE

The measurement of pipeline pressure is available from four locations:

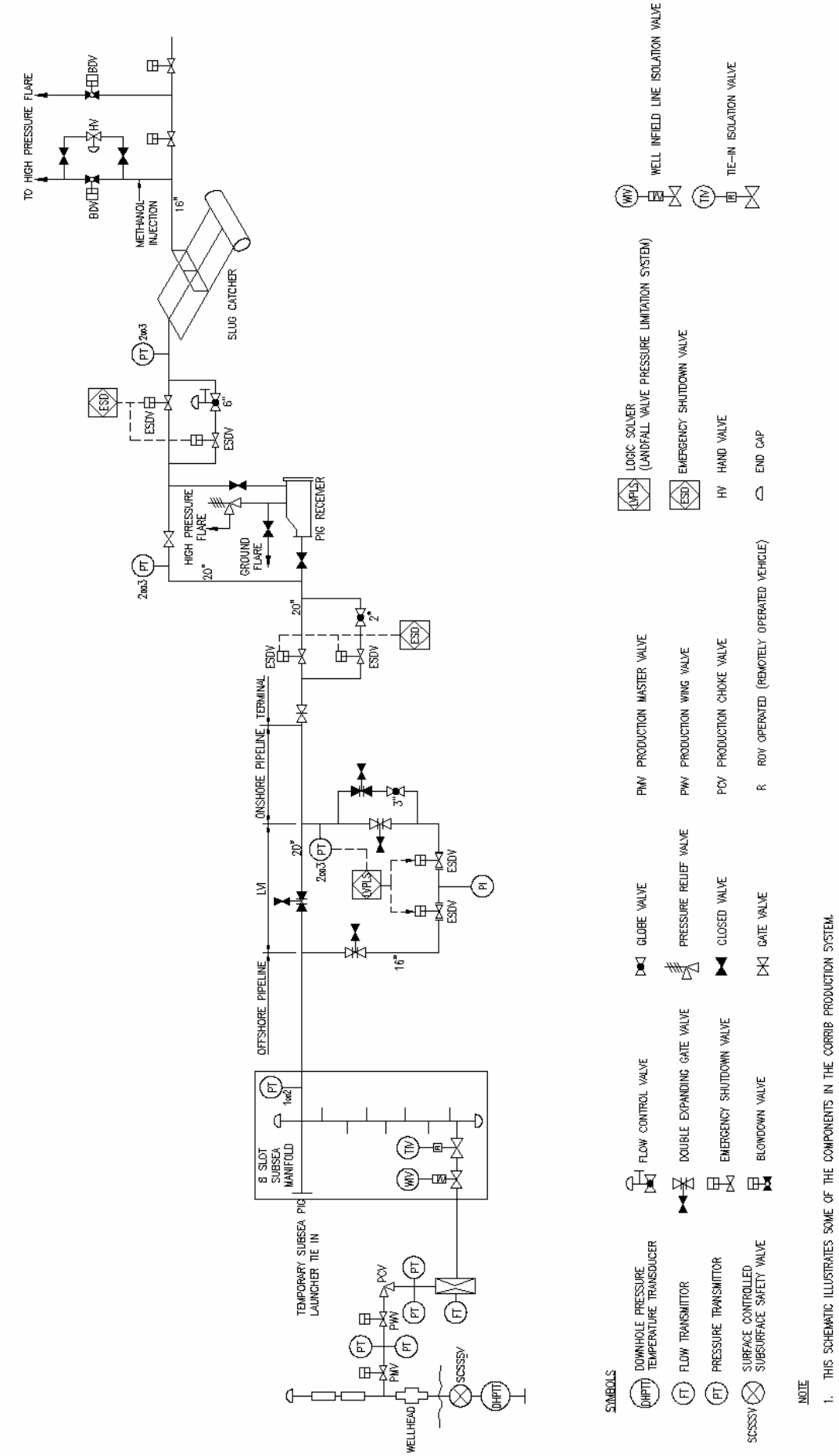
- Subsea wells
- The subsea manifold
- The LVI outlet
- At the Gas Terminal

Communication between the Gas Terminal to the subsea manifold is via the umbilical.

Communication between the LVI to the Gas Terminal is via a fibre optic communications cable.

Hydraulic pressure for operation of the subsea valves is via the umbilical.

Figure 5.1 Overall System Schematic



5.3.1 Subsea Wells and Manifold

There are a number of valves on each subsea tree that can be operated to achieve shutdown of an individual well. These are:

- Close the choke valve
- Close the wing valve
- Close the master valve
- Close the SCSSSV (Surface Controlled Subsurface Safety Valve)

On the manifold there is an individual Well in-field line Isolation Valve (WIV) for each of the wells.

5.3.2 Landfall Valve Installation

The LVI is in a remote location and is a high integrity standalone safety shutdown system to ensure isolation between the onshore and offshore pipelines. This is achieved using two high integrity inline shutdown valves which will be closed when the pressure downstream of the LVI exceeds a pre-set trip value. To ensure high probability to close, three pressure transmitters are installed and both valves are closed should any two out of three pressure readings exceed the trip setting (2oo3 voting).

The signal cable from the Gas Terminal enables the LVI to be closed remotely by the operator at the Gas Terminal

5.3.3 Gas Terminal

At the inlet to the Gas Terminal, the onshore pipeline may be isolated at the incoming ESD valve upstream of the slug catcher.

5.4 OVERPRESSURE PROTECTION OVERVIEW

During initial steady state production, 350MMSCFD of gas will flow through the pipeline and arrive at the Gas Terminal at 80 to 85 barg.

Pressure will begin to rise in the system when there either is a Terminal trip (an Emergency Shutdown (ESD) event) or a flow shut off / flow backing out event. In these events, the operators will reduce production from the wells or shut in some wells to reduce the overall rate of pressure increase in the pipeline, to allow more time for the operator to clear the Terminal trip. If the operator cannot restore the Terminal back to normal operating conditions and the pressure continues to rise, the operator will shut in production from all of the wells.

The process safeguarding system has been designed such that the system will automatically stop flow from the wells on detection of high pressure and does not require operator intervention. The following sequence of events will occur, if the operator has failed to take corrective action in the event of a Terminal trip.

If the pressure throughout the Corrib pipeline system (from the wells to the Gas Terminal inlet facilities) is increasing, the safeguarding system will be subject to an overpressure demand unless the operator takes corrective action.

The first high pressure trip is set at 93 barg. This is located at the Gas Terminal inlet and when the pressure has increased from 80 to 85 barg up to 93 barg, this trip will command the subsea valves (master, wing, and choke valves) to close for each well. The second high pressure trip is set at 99

barg. This is located at the LVI. This trip commands the LVI shutdown valves to close. This step represents the onshore pipeline overpressure protection system. The pressure in the onshore pipeline will be 99 barg immediately after the LVI shutdown valves close. This pressure will settle out to approximately 97 barg after 24 hours. The pressure in the onshore pipeline 'settles out' because of the difference between shut-in conditions and normal steady state production conditions. The pipeline will change gradually in temperature when it is shut in for a period. After about 24 hours it will have reached equilibrium with the environment.

When the LVI shutdown valves close there will be another command to close the subsea valves, in the unlikely event that they haven't already closed. This action is more comprehensive, as this trip will close the subsea valves via two routes. Specifically, in addition to the master and wing, valves, this trip will also close the surface controlled subsurface safety valve (SCSSSV) and the well infield line isolation valve (WIV - which is located at the subsea manifold) for each well, due to the releasing of the hydraulic fluid pressure.

Based on the conservative time taken to close the subsea valves (release of hydraulic fluid pressure), the offshore pipeline pressure will be 133 barg immediately after the subsea valves have fully closed. This pressure will settle out to approximately 129 barg after 24 hours. The pressure 'settles out' because of the difference between shut-in conditions and normal steady state production conditions.

Note that there is an inherent mechanical protection in the design of the pipelines to prevent loss of containment. This is the pipeline wall thickness and the hydrostatic testing of the pipelines. For the onshore pipeline the wall thickness is 27.1mm with a design pressure of 144 barg together with the hydrostatic test pressure of 504 barg. Similarly at the offshore pipeline landfall the wall thickness is also 27.1mm with a design pressure of 345 barg and a hydrostatic test pressure of 380 barg.

Further details regarding the above can be found in Appendix Q4.5.

5.5 RELIABILITY OF SHUTDOWN SYSTEMS

5.5.1 General

Overpressure protection systems are in place for both the offshore and the onshore pipelines. These protection systems will restrict the maximum pressure that can be experienced in these pipelines to their respective Maximum Allowable Operating Pressures (MAOPs). The MAOP values have been set based on minimising pressure while maintaining the operability of the Corrib pipeline system and the design throughput. In this document, 'overpressure' will refer to exceeding the set value of MAOP.

The Landfall Valve Installation (LVI) is the overpressure protection system for the onshore pipeline. The Wells Isolation System is the overpressure protection system for the offshore pipeline. The purpose of this section is to demonstrate that the reliability of the overpressure protection systems is sufficient to prevent any credible case of overpressure occurring.

Appendix Q4.6 provides further details that the reliability of the overpressure protection systems is sufficient to prevent any credible case of overpressure occurring.

For high integrity safety shutdown systems the degree of safety is indicated by the probability of failure on demand (PFD). The respective values for the LVI and subsea safety shutdown configurations are given below.

5.5.2 LVI

The reliability analysis for the safety shutdown system at the LVI has been certified by an independent verification authority using validated data from many years of field operation of similar systems. This determined that the probability of failure on demand is $7.4 \times 10^{-4.}$

5.5.3 Well Isolation System

The reliability analysis for the subsea systems has been carried out by using a Failure Mode and Effects Analysis (FMEA) to identify the relevant modes of failure and a Fault Tree Analysis (FTA) to calculate the probability of 'Failure to Isolate One or More Wells'. The analysis is based upon closure of the subsea valves and depressurisation of the hydraulic lines to the subsea valves (i.e. closure of the valves).

All the base data used for calculations within the FMEA are from industry standard auditable sources (e.g. OREDA).

The calculated probability for 'Failure to Isolate One or More Wells' was determined to be 4.5×10^{-4}. This probability of occurrence is for the pressure in the offshore pipeline to reach 150 barg.

5.5.4 Conclusion

In the Industry, the realistic PFD that is attainable for a safety system is a PFD of between 0.0001 to 0.001 which represents a probability of a safety system failing to perform on demand of better than 1 in 1000 occurrences.

Both the offshore pipeline and onshore pipeline over pressurisation protection systems have a PFD which is better than 1 in 1000 occurrences.

6 EFFECT OF PASSING VALVES FOLLOWING SHUTDOWN

In order to assess the potential effect of valve leakage subsequent to a shutdown, it is important to determine the conditions resulting from the shutdown (pressures, temperatures and which valves have closed). This is presented in Appendix Q4.5.

6.1.1 Offshore Pipeline

The subsea valves have been designed to a high specification to ensure that any leakage is minimal. There are also a number of valves in series to provide isolation for each well, therefore even if one valve does leak, there is another valve isolating each well. The subsea valves are periodically tested to ensure that they meet the very low leak rate specification as per the relevant international standards.

For the offshore pipeline, two scenarios were examined:

- A planned shutdown for maintenance,
- An unplanned shutdown due to a high pressure trip,

After each of these shutdowns, the pressure in the offshore pipeline will 'settle out' as the conditions in the pipeline reach equilibrium. From analysis the smallest margin (17 bar) between the MAOP (150 barg) the highest "settle out" pressure (133 barg) was the "unplanned shutdown due to a high pressure trip".

From analysis it was determined that a period of more than 500 days (~71 weeks) would be required for the offshore pipeline pressure to increase from 133 barg to 150 barg at a conservative leakage rate of 14.7 scf/min. This is significantly greater than the time duration of an unplanned shutdown for the Corrib pipeline system.

6.1.2 Onshore Pipeline

The LVI valves have been designed to a high specification to ensure that any leakage is minimal. In the shutdown spool there are four valves in series and thus, if necessary, the two 16" dia isolation valves can be manually closed in addition to the 16" dia safety shutdown valves.

The 20" dia main line valve is not used for operational purposes and is locked closed. The valve is only opened during pigging operation, which will be infrequent, and then tested following closure.

All the valves are periodically tested to ensure that they achieve a tight seal between the onshore and offshore pipelines as per the relevant international standards.

As for the offshore pipeline, two scenarios were examined for the onshore pipeline:

- A planned shutdown for maintenance,
- An unplanned shutdown due to a high pressure trip,

For a planned shutdown there is minimal pressure difference across the LVI (assuming the LVI valves are closed) and thus there is negligible potential for the valves to pass gas into the onshore pipeline. Therefore this is not a credible scenario for pressure in the onshore pipeline to exceed the MAOP of 100 barg.

For an unplanned shutdown due to a high pressure trip, it was determined that a period of more than 4 years would be required for the onshore pipeline pressure to increase to 100 barg at a conservative leakage rate of 0.0000824 MMSCFD (0.057 scf/min) This is significantly greater than the time duration

of an unplanned shutdown for the Corrib pipeline system. To establish the sensitivity of this case a flow rate of more than 3000 times greater than the conservative leakage rate was evaluated and this indicated a period of 10 hours to reach 100 barg. This duration is over double the period needed to align the flare at the Gas Terminal and maintain the pressure in the onshore pipeline below the MAOP.

7 IMPACT OF LOSS OF UMBILICAL ON SHUTDOWN SYSTEMS

Should the umbilical cable be severed either onshore or offshore the consequence would be potential loss of one or more of the following services to the subsea facilities:

- Electrical power cables
- Communication cables
- High Pressure and Low Pressure hydraulic fluid
- Methanol/corrosion inhibitor

Dual redundancy is provided for the electrical power supply cables. However, in the event of loss of electrical power, the production wing valves on all subsea trees will fail closed. This will isolate the wells from producing into the offshore pipeline. This will ensure pipeline pressures remain within their respective MAOPs. The other actuated subsea isolation valves will remain in the position they were before the loss of electrical power occurred.

Dual redundancy is provided for the communications cables. However, in the event of loss of communications, steady state production will continue. Alarms will alert the operators to loss of data communication and subsequent to this the operator will proceed to shut in production from the field, as per the Wells Integrity Management System (WIMS). In the unlikely simultaneous event of an increase in pipeline pressure occurring immediately after the loss of communications, the overpressure protection systems will prevent the MAOP being exceeded in the respective pipelines. Thus, the loss of communications will not result in pipeline MAOPs being exceeded.

On loss of hydraulic fluid pressure a number of actuated valves supplied from the hydraulic fluid core that is severed will move to the closed position i.e. they will fail to a safe position. Thus, the loss of hydraulic fluid pressure will not result in the pipeline pressure exceeding the respective pipeline MAOPs.

Methanol is injected for hydrate inhibition. Severing of the methanol injection cores will not result in pipeline pressures rising above their respective MAOPs.

If the offshore umbilical or all of the onshore umbilicals are severed, the field will shut down on loss of power and hydraulics. If only one onshore umbilical is severed, a number of the wells may automatically shutdown due to loss of hydraulics. The remaining wells will continue to produce at steady state within the operating envelope. Therefore it can be concluded that whether some or all of the umbilicals are severed, the pressures within the onshore and offshore pipelines will remain within their MAOPs.

8 MATERIALS OVERVIEW

Materials selection and corrosion management have been carried out in accordance with the relevant codes and standards. These have been supplemented by Shell standards and practices where necessary. This ensures compliance with I.S. EN 14161.

A number of specific materials issues have been evaluated in detail for the Corrib pipeline. These include:

- Internal corrosion in the context of the "wet gas" (unprocessed) transported to the Gas Terminal
- Erosion in relation to potential production of sand and proppant.
- Brittle and ductile fracture in relation to pipe wall temperature.

The results are summarised in Sections 8.1 and 8.2 below and further details are presented in the following reports:

- Appendix Q4.7 Materials and Corrosion Management Premises
- Appendix Q4.9 Assessment of Wet Gas Operation, Internal Corrosion and Erosion

An assessment has been made regarding the margin of safety with respect to thinning of the pipe wall due to corrosion. These results are summarised in Section 8.3 and presented in Appendix Q4.8 Assessment of Locally Corroded Pipe Wall Area.

The potential effects from third party damage on the Corrib onshore pipeline have been evaluated and this is summarised in Section 8.4 and also presented in Appendix Q4.10 Denting and Puncturing Evaluation.

8.1 CORROSION & EROSION

8.1.1 Corrosion

The Shell Group has extensive experience of successful operation of wet gas pipelines (>40,000 km years in Europe alone). No failures have been experienced with wet gas pipelines and the observed low corrosion rates demonstrate both the validity of the corrosion modelling and the operating methodology adopted.

An assessment of wet gas operation and the related internal corrosion rates for the offshore and onshore sections of the Corrib pipeline from the subsea manifold to the Gas Terminal has been undertaken with the most recent flow assurance data related to the stated MAOPs (Refer Appendix Q4.9). The predicted corrosion rates, based on a field life of 20 years, differ therefore from previous designs.

The integrity assessment of the carbon steel pipeline with respect to corrosion involved a thorough assessment of the corrosivity of the medium transported, degradation threats and mitigation, monitoring and control measures to enable implementation of an effective corrosion management system. The main internal corrosion risks identified are carbon dioxide (CO_2) corrosion and organic acid corrosion.

It should be noted that the CO_2 content of the Corrib gas is relatively low at 0.3% and is not highly corrosive. The acidity (pH) is also an important factor with respect to CO_2 corrosion. CO_2 corrosion results in a corresponding decrease in acidity and hence a significant decrease in corrosivity along the

pipeline from offshore to onshore. There is also a significant temperature drop along the pipeline further decreasing the corrosivity in the onshore section of the pipeline.

The presence of organic acids can increase corrosivity. The organic acid content of the Corrib gas has been found to relatively low at 10ppm. A higher level of 100ppm is possible if formation water is produced.

Internal CO_2 and organic acid corrosion will be mitigated by injecting both corrosion inhibitor and methanol. To ensure that sufficient corrosion mitigation is achieved for the pipeline, a corrosion inhibitor availability capability of >99% has been designed.

The assessment predicts very low corrosion rates for the onshore section of the pipeline (verified by an ongoing corrosion inhibitor test programme).

8.1.2 Erosion

The Corrib reservoir is a tight formation and no sand production is expected. Only one well (18/25-3: P5) has been fractured and treated with a coated ceramic proppant. The design is based on the possibility that some proppant may be produced back to the pipeline during operation, leading to possible wall loss by erosion. However, no significant proppant production has been observed during well clean-up and during a subsequent well test. Thus proppant production is unlikely. An assessment has been made based on 20 year lifetime, the worst-case geometries and assuming proppant production will be up to 2.5kg/day. This conservative assessment gives low erosion predictions (Refer Appendix Q4.9). An acoustic monitoring probe is installed on the subsea manifold and any indication of significant solids production would result in a well intervention or closing-in of the well.

8.1.3 Corrosion & Erosion Allowance

The pipeline wall corrosion allowance provides for potential losses from both corrosion and erosion. The onshore pipeline corrosion rate can conservatively be assumed not to exceed the inhibited corrosion rate that is predicted to be less than 0.05mm/yr. The erosion rate predicted is negligible. The combined losses in the carbon steel pipeline due to corrosion and erosion in the onshore pipeline are therefore unlikely, over the 20 year service life, to exceed the 1mm corrosion allowance provided.

The conservatively predicted erosion rate in the smaller diameter pipe work at the LVI Is within the tolerances of the corrosion resistant materials selected for the LVI pipework. Erosion of the LVI is therefore not expected to be significant and can be monitored by ultrasonic wall thickness measurements to provide additional assurance.

8.2 ONSHORE PIPELINE FRACTURE ANALYSIS

All components of the onshore pipeline system have been designed and fabricated in accordance with I.S. EN 14161 and I.S. 328 to resist brittle or ductile fracture in all operating scenarios.

Under start-up or blow down conditions it is possible that sections of the pipeline system will experience low temperatures due to the Joule-Thomson cooling effect. The most likely low temperature scenarios are equalisation of a pressurised offshore pipeline with a depressurised onshore pipeline, or blow-down of the pipeline system.

The following lower design temperatures apply:

Table 8.1 Lower Design Temperatures

Flexible pipelines*	**-20°C**
Manifold	**-30°C**
Tie-in spool	**-10°C**
PLEM valve	**0°C**
Offshore pipeline	**0°C**
LVI	**-26°C**
First ~1.1 km of onshore pipeline	**-20°C**
Remaining length of onshore pipeline	**-10°C**

* New flexible for P2 to be rated to -50°C

Operating procedures will be developed to ensure that these lower design temperature limits are not exceeded for all credible low temperature scenarios.

Assessments have been carried out to confirm resistance of the linepipe to crack initiation and propagation, and the critical defect length and hole size with respect to leak before break criterion

8.3 MARGIN OF SAFETY DUE TO CORROSION

The recommended practice DNV-RP-F101 for the assessment of corroded pipelines has been used to generate damage assessment lines (graphs of the length versus depth of corrosion that would lead to failure at the Maximum Allowable Operating Pressures) for the evaluation of the potential for failure of a local thinned area of pipe wall due to corrosion. The results show that there is a significant margin of safety with respect to thinning of the pipe wall due to corrosion. This is due to the relatively low maximum allowable operating pressures, 150 barg upstream of the LVI and 100 barg downstream, and the relatively large wall thickness. This is presented in Appendix Q4.8 Assessment of Locally Corroded Pipe Wall Area and the results from this study also provide input to support the selection of corrosion related failure frequencies within the Quantitative Risk Assessment. It also provides input to procedures for damage assessment during the operational phase.

8.4 THIRD PARTY MECHANICAL DAMAGE

The potential for third party mechanical damage on the integrity for the landfall section upstream of the LVI and the 8.3 km onshore pipeline downstream of the LVI to Gas Terminal has been assessed.

The potential for damage leading to loss of containment has been correlated with the puncture and denting resistance for the Corrib pipeline (note that the higher the pressure in the pipeline the more energy is needed to dent the pipe wall). The assessment, as presented in Appendix Q4.10 Denting and Puncturing Evaluation, concluded that:

- In order to puncture the pipe an excavator in excess of 65 tonnes weight would be required (the estimated energy required would be equivalent to that of an excavator of 150 tonnes weight), this is due to the large wall thickness of the pipeline. Puncturing by a smaller excavator is highly unlikely, puncturing by a plough would not occur.

- Denting or gouging of the pipeline that may not immediately lead to loss of containment but may result in subsequent failure should the pressure in the pipeline increase (so-called burst pressure) would require an excavator in excess of 65 tonnes to produce a dent gouge that would fail at a burst pressure less than Maximum Allowable Operating Pressures (MAOP).

The results of this evaluation provides input to the Quantitative Risk Assessment, QRA, in order that a potential frequency, or range of frequencies, of third party damage leading to loss of containment, can be applied that is specifically relevant to the Corrib pipeline. The output of the dent and gouge analysis also provides input to development of an operational phase procedure for follow-up action to be taken in the event that the pipeline should ever suffer such damage.

9 INTEGRITY MANAGEMENT

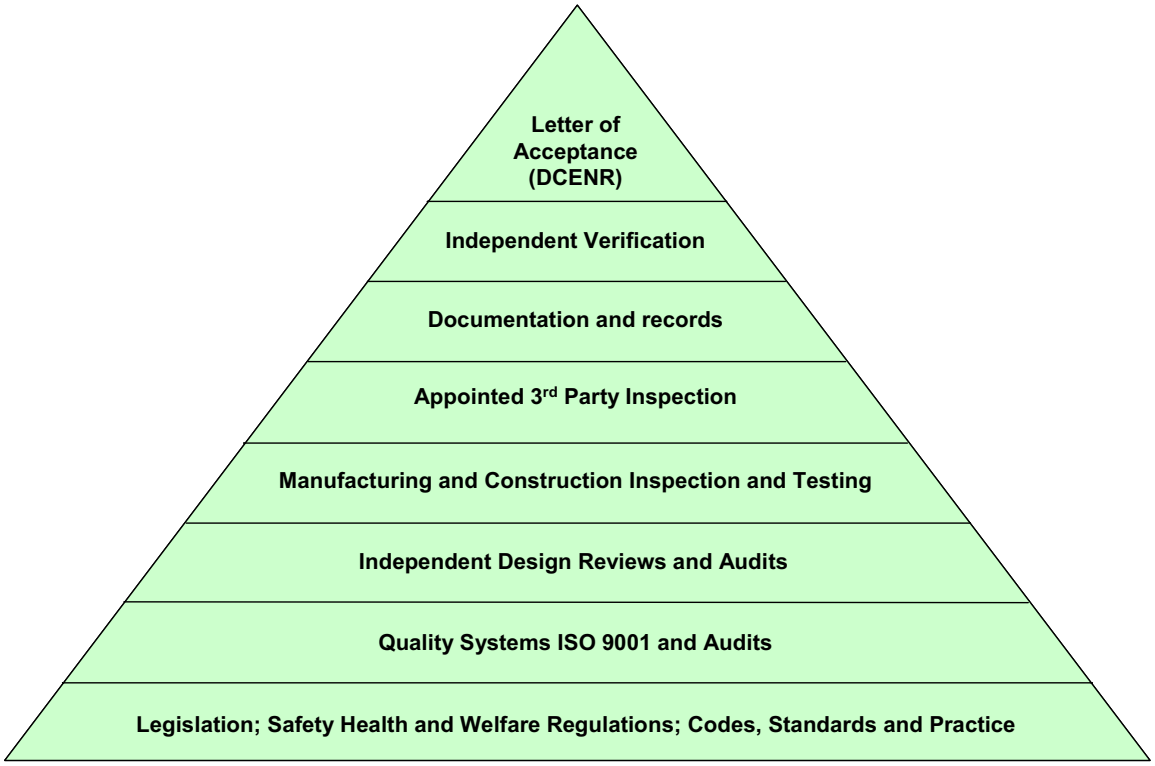
9.1 INTEGRITY PROCESS

To implement the Corrib pipeline system, SEPIL will undertake a range of activities including design, procurement of manufactured equipment and materials together with construction and commissioning. It is essential that, during execution of each of these processes, the integrity of the Corrib pipeline system is defined, achieved and maintained.

The integrity of the Corrib pipeline is established through compliance with Irish legislation, adoption of recognised international codes and standards, SEPIL codes and standards together with incorporation of best practice and procedures.

An overview of the hierarchy of the process of integrity management is illustrated in Figure 9.1. The foundation of the assurance of integrity is formulated in National legislation and the respective codes and standards combined with best practice. This is then supported by the internationally recognised Quality Management systems which require integral process for the integrity of design, manufacture and construction. The integrity system is then verified through inspection and testing during manufacture and construction together with provision of comprehensive documentation. Finally the whole system is independently checked through third party inspection and verification. The Corrib pipeline system will only be allowed to be put into operation on issue of a Letter of Acceptance from the DCENR.

Figure 9.1 Hierarchy for Management of Integrity Process



The integrity process is more fully expanded in document Appendix Q5.1 which provides an overview of the processes that are adopted to assure the integrity of the complete implementation process. The extent and application of the procedures and process adopted take into account the nature of the equipment and materials and in particular their level of importance regarding safety and operation.

9.2 PIPELINES INTEGRITY MANAGEMENT SCHEME

Appendix Q5.2 describes the Pipelines Integrity Management Scheme (PIMS) to efficiently and effectively control and manage the safeguarding of the integrity of the pipeline system in compliance with Irish legislation and conditions of consent, SEPIL's requirements and Shell's corporate policies.

This document describes the Corrib Pipeline System, describes the organisation required for implementation of the integrity management scheme, defines roles, responsibilities and interfaces and outlines the management processes required.

To implement the scheme, SEPIL will use the resources, expertise and common set of policies, procedures and standards of the Royal Dutch Shell group's collective exploration and production operations in Europe, (referred to as 'Shell UIE').

All work is therefore performed in accordance with the 'Shell UIE' integrity cycle for pipelines. This and the 'Shell UIE' implementation process and resources are described in the PIMS.

An overview discussion of the Major Accident and Major Environmental Accident threats, risk barriers and monitoring measures is given for each Safety Critical Element of the pipeline system.

The Integrity Reference Plan, included in the PIMS, provides the details and the performance standards for the risk barriers and monitoring and the immediate action and the longer-term corrective action requirements to be followed during the operation of the pipeline system.

This Pipelines Integrity Management Scheme and its Integrity Reference Plan will be reviewed and improved throughout the pipeline system's operational life to take account of changes in legislation, feedback from experience in implementation, changes to the pipelines and improvements in 'Shell UIE' and industry practice and technology.

9.3 PIPE PRESERVATION

The linepipe for the Corrib pipeline has been in storage, principally at Killybegs, County Donegal, since 2002 and 1150 meters of new pipe stored since 2009. During this period appropriate maintenance operations have been carried out to ensure that the linepipe and its external coating is fit for purpose despite successive delays to the pipe-lay operations.

The delays have resulted in a progressive approach to pipe maintenance. The pipe has been subject to continuous monitoring and appropriate actions have been taken as required.

It is noted that atmospheric corrosion of high strength steel pipe is a relatively slow mechanism provided direct and continuous contact with water is avoided. Thus maintaining the pipe as dry as possible has always been a fundamental premise throughout the period of storage. The regular inspections and subsequent maintenance activities including internal coating have focussed on this aspect.

It has been concluded that the stored linepipe is fit for purpose and the current storage methods ensure that the linepipe is kept relatively dry and protected. This regime of monitoring and maintenance will continue until the linepipe is required for installation.

Refer Appendix Q5.4 for further details of the storage and preservation of the Corrib onshore pipeline.

9.4 HYDROSTATIC TESTING

A key technique to validate the integrity of the gas pipelines, the umbilicals and the outfall pipeline will be hydrostatic testing whereby the line is carefully filled with test water and then raised to a pressure determined by the relevant design code. The pressure is then held for a prescribed period and any variations in pressure must be rationalised with changes in environmental parameters, in particular variations in temperature. The lines are then de-pressurised and the test water removed.

The hydrostatic test pressure for the onshore pipeline is presented in Appendix Q5.3 and has been approved by TAG.

9.4.1 Offshore Pipeline

The offshore pipeline was successfully hydrostatically tested following installation in 2009. The test pressure was 380 barg recorded at Glengad. The pipe remains filled with seawater treated with various additives to prevent internal corrosion until the commissioning phase.

9.4.2 Umbilical Cores

Each of the umbilical cores will be hydrostatically tested to the proof pressures as stated in Appendix Q4.1

9.4.3 Onshore Gas Pipeline, LVI and Outfall Pipeline.

The filling and individually hydrostatic testing of the 20” dia gas pipeline, the LVI and the outfall pipeline will be undertaken as a combined operation to optimise the storage and use of potable water.

The detailed procedure and methodology will be prepared and presented to the relevant Authorities for necessary approvals and permits. The key points for the filling and testing operation will be as follows:

- Temporary storage of water will be established near to the LVI at Glengad and within the Gas Terminal.
- Nitrogen will be used to displace the hydrostatic test water from the installed section of the offshore pipeline which will be discharged at the subsea manifold.
- Once the LVI is completed, the buried pipe work will be filled with potable water and tested to a hydrostatic test pressure of 504 barg. This will include the section of pipe upstream of the LVI for tie-in to the installed section of offshore pipeline.
- A temporary pig launcher will be installed at Glengad on the onshore gas pipeline. The gas pipeline and the outfall pipeline will be filled with potable hydrostatic test water. Where possible the line filling will utilise accumulated rainwater topped up via water tankers.
- The gas pipeline will then be hydrostatically tested from the Gas Terminal to Glengad at 504 barg and the outfall line tested to 20 barg.
- To run any pigs within the onshore gas pipeline, the water will be pumped from the Gas Terminal towards the LVI and returned using the outfall pipeline. This will include the running of the Intelligent Pig in the onshore section of the gas pipeline.
- Following the hydrostatic testing, any surplus potable water will be displaced through the offshore section of the outfall line for discharge subsea at the diffuser. This will be subject to approval from the appropriate Authorities. The onshore section of the outfall pipeline will remain full of potable water.

- The LVI will be tied-in by welds to the offshore and onshore pipeline sections

9.5 INTELLIGENT PIGGING

An initial intelligent pig (IP) run is planned during pre-commissioning of the onshore pipeline. A complete offshore to onshore intelligent pig run is planned, once initial production is established and weather conditions permit, in order to provide a base signature for future IP inspections. Analysis of the IP data will give wall thickness and other feature information along the entire length of the Corrib gas pipeline. The frequency of intelligent pigging is derived from the results of the risk based assessment as part of the annual pipeline integrity review.

9.5.1 Choice of technology

The combination of a high-resolution magnetic flux leakage (MFL) tool with an XGP (eXtended Geometry) module has been selected for the intelligent pigging of the Corrib gas pipeline. The XGP module can also incorporate a SIC (Shallow Internal Corrosion) unit to detect internal features more accurately. The combined MFL/XGP Rosen CDX intelligent pig has been used previously for the base-line inspection of the Ormen-Lange pipeline, and the XGP/SIC tool for the in-service inspection of the Gannet – Fulmar pipeline.

The MFL tool is capable of measuring a range of features including:

- Pipe Wall Anomalies.
    - Pitting and general corrosion.
    - Gouges.
- Girth Weld Anomalies.
    - Mill Features (Metal loss).
    - Non-metallic inclusions.
    - Lap.
- Mechanically induced markings
- Wall Thickness Changes.

The XGP module detects the following types of deformations:

- Internal diameter anomalies
- Dents.
- Buckles.
- Wrinkles.
- Ovality.

- Internal diameter changes.
- Internal metal loss features.

The use of the combined Rosen CDX tool with SIC unit provides a higher level of confidence in measuring internal metal loss. The SIC unit is equipped with small eddy current sensors that can detect internal wall loss features as shallow as 1 mm.

Reasons for preferring Rosen and their advanced combined Rosen MFL & XGP tool over the 'conventional' single MFL tool are the enhanced capabilities of detecting shallow internal corrosion, and having the traditional MFL module and the accurate electronic distance measurement technology of the XGP module in one tool. Typical tools are illustrated in Figure 9.2 and Figure 9.3.

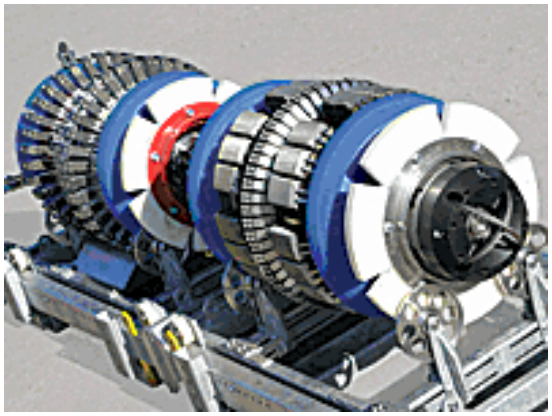


Figure 9.2 Typical Intelligent Pig Tool

Figure 9.3 Typical Intelligent Pig Tool

9.5.2 Accuracy

The baseline survey (a survey at the start of service life) will provide a fingerprint of the as-built pipeline and will function as a calibration run for future in-service IP runs.

The interpretation of IP results of future in-service runs is significantly improved with the availability of a base line survey because it allows accurate classification of all non-corrosion pre-commissioning irregularities, and thus enables any defects that might have developed during operation to be distinguished.

The metal loss depth sizing accuracy of the MFL module is normally ± 10% of the wall thickness within an 80% confidence band. The XGP module can detect internal diameter changes >0.8mm and dents > 2.5mm deep. The SIC module can detect shallow internal metal loss features in the pipe with an accuracy of ± 0.5mm of wall thickness within an 80% confidence band.

9.5.3 Results

The results of the IP inspections will provide information about the condition of the full length of the Corrib pipeline and this will complement the data obtained from the offshore monitoring spool and the ultrasonic measurement mats and corrosion probes installed at the Terminal. These data can be used to provide measurement checks, which can be used to complement the other information available to the pipeline corrosion engineer in the verification of corrosion rate

Appendix Q3

Code Requirements

Q3.1: Compliance with TAG and Advantica Recommendations
Q3.2: Application of Irish and International Pipeline Standards
Q3.3: Design Code Review Onshore Pipeline Section

Shell E & P Ireland Limited CORRIB FIELD DEVELOPMENT PROJECT REPORT	J P KENNY Corrib natural gas

Corrib Onshore Pipeline EIS Appendix Q3.1 COMPLIANCE WITH TAG AND ADVANTICA RECOMMENDATIONS	PROJECT No. 052377.01 REF CTR 349 No OF SHEETS 15

DOCUMENT No	OFFICE CODE	PROJECT No	AREA	DIS	TYPE	NUMBER
	05	2377	01	P	3	042

REV	DATE	DESCRIPTION	BY	CHK	ENG	PM	CLIENT
03	13/05/10	Issued for Planning Application	JG	GSW	GSW	JG	
02	4/05/10	Issued for Comment	JG	GSW	GSW	JG	
01	8/03/10	Issued for IDC	JG	GSW	GSW	JG	

CONTENTS

1 INTRODUCTION

In 2006 Advantica prepared a report [1] which concluded an Independent Safety Review of the onshore section of the Corrib gas pipeline. This review had been commissioned by the Technical Advisory Group (TAG) appointed by the Minister for Communications, Marine and Natural Resources (DCMNR). TAG accepted the Advantica recommendations and incorporated these into a report to the Minister [2]. TAG also prepared a report on inspection and monitoring issues [3] together with a short note which set out in tabular form the recommendations of the Advantica Report, the TAG Report and TAG's recommendations on inspection and monitoring [4]. All four reports were published by the DCMNR (now the Department of Communications, Energy and Natural Resources – DCENR) on the 3rd May 2006.

The purpose of this document is to provide a catalogue of SEPIL responses to the individual recommendations and state how these recommendations will be incorporated into the Corrib pipeline system for the Corrib Field Development. The SEPIL responses are provided in tabular form in Attachment A.

2 CLARIFICATION OF POINTS OF COMPLIANCE

Subsequent to the issue of the TAG/Advantica recommendations, An Bord Pleanála requested in their letter of the 2nd November 2009 that the maximum allowable operating pressures (MAOP) for the Corrib pipeline be defined.

Based upon the designated pipeline codes DNV-OS-F101 (offshore section) and I.S. EN 14161 (onshore section) the respective MAOP's are set at:

Corrib – offshore pipeline	150 barg
Corrib – onshore pipeline	100 barg.

In accordance with the respective pipeline codes the daily operating pressure shall not exceed the respective MAOP in either the offshore or onshore pipelines. Thus the MAOP takes precedence over the requirement to remain within the design pressure of the respective pipelines.

3 REFERENCES

1. Advantica; Independent Safety Review of the Onshore Section of the Proposed Corrib Gas Pipeline: 2006
2. TAG; Report of the Corrib Technical Advisory Group to Minister Dempsey: 2006
3. TAG; Report of the Corrib Technical Advisory Group to Minister Dempsey on an appropriate Inspection and Monitoring Regime for the Corrib Project: 2006
4. TAG; Corrib Gas Pipeline Safety Issues: 2006 (tabular format)

ATTACHMENT A ADVANTICA and TAG Recommendations Compliance Tables

Table A.1 Recommendations arising from Independent Safety Review (Advantica)			
No	**Reference**	**Recommendation**	**Action**
1	4.3.1	Fatigue design and monitoring: The actual fatigue usage of the pipeline should be monitored by carrying out an annual fatigue cycle count.	A robust system has been implemented for recording pressure in the pipeline in the terminal automated control system records. The data will be assessed annually to confirm that the actual pressure cycles are within the allowed design limits. Incorporated in the Pipeline Integrity Management Scheme. Refer Appendix Q5.2.
2	4.3.1	Fatigue design and monitoring: Small bore attachments at the beach valve, such as the bypass, should be checked for flow induced vibration once the pipeline is operating.	Risk of flow induced vibration of buried bypass valving and small bore pipe fittings has been analysed during the design. Vibration will be checked during operation. Mitigation measures recommended will be implemented and incorporated in the Pipeline Integrity Management Scheme.
3	4.3.2	Impact protection: Concrete slabs for road and ditch crossings: It is considered that a site specific design should be produced for each location, to ensure that they are suitable. • The distance between the slab and the top of the pipe is shown as 300 mm. This may not conform to IGE/TD/1 requirements for it to exceed the typical length of a pneumatic drill steel. • For full protection of the pipeline, especially from activities carried out close to the road such as the digging of ditches, the slab should extend to the width of the route. It is understood that this change will be made as a result of earlier safety reviews. • Consideration should be given to supporting the slab from the sub-soil in peat areas, unless the underlying peat is able to support the slab and the peat cover above the slab. If the slab is not supported the full weight of the slab and the cover above the slab may be concentrated on the pipe, increasing the external loads.	Slab details for road and ditch crossings have been shown in the following drawings, which form part of the applications for consent for the pipeline under the Strategic Infrastructure Act and the Gas Act: DG 0701 Typical Road/Track crossings Layout & Sections DG 0702 Typical Small Ditch Crossing Layout & Sections. DG 0703 Typical Open Cut Water Crossing Layout & Section. In peat areas the pipeline will be within a stone road, which is constructed of granular stone fill. Where there is a road/ditch/water crossing of the stone road then material placed under the concrete slab and above the pipe will be selected stone fill, which will be fully capable of supporting the weight of the slab. Alternatively concrete coated linepipe could be utilised.
4	4.3.3.1	Ground movements. Consideration should be given to long	It is proposed to install the pipeline within a stone road in all peat

Table A.1 Recommendations arising from Independent Safety Review (Advantica)			
No	**Reference**	**Recommendation**	**Action**
		term monitoring of the pipeline in areas of peat. (The current construction specification states that where the depth of peat exceeds 4m the pipeline will be placed on top of piles driven through the peat into the subsoil. It is not clear if a landslip is possible in these areas of deep peat. If this is possible, consideration should be given to the possibility of the pipeline being dislodged from the supports by the landslip.)	areas to address concerns in relation to ground movements. This stone road will provide support and stability to the pipeline and to the slabbing (where appropriate). Construction methodologies are described in Chapter 5, and geotechnical stability aspects are outlined in Chapter 15 of the Onshore Pipeline EIS. The movement monitoring programme will involve short term (during construction) and long term (post construction) high accuracy surveys carried out regularly along the pipeline route to identify any indications of movement of the stone road. GPS plates will be installed where appropriate to assist this monitoring. The frequency of monitoring will be tailored based on the results of the ongoing monitoring.
5	4.3.3.2	Ground movements. Results of review of JP Kenny analysis: Finite Element Model: The results of the analyses should be assessed for acceptability to the project design code.	As above and refer to Appendix Q4.1.
6	4.3.3.3	Ground movements. Results of review of JP Kenny analysis: Additional ground movement analysis is required of the sections of the pipeline with bends, and of a landslip parallel to the pipeline.	As above and refer to Appendix Q4.1.
7	4.3.3.4	Ground movements. Results of review of JP Kenny analysis: Additional analysis should be carried out to consider increased depth of cover up to 4m of peat	Comment superseded by inclusion of stone road design in areas of pea
8	4.5.1.1	Coatings: Tests should be carried out on the coatings of a representative sample of the joints strung in summer 2005 and subsequently removed.	Tests carried out on a representative sample of pipe coating in 2007 have confirmed that the coating is suitable for service. Refer Appendix Q5.4
9	4.5.1.1	Coatings: The application of the field joint coatings should be improved and additional inspections made to ensure that disbonding is not occurring.	The pipeline installation contract will specify field joint coating materials and application procedures that have been subject to field tests. Suitably qualified inspectors will supervise installation. Coatings will be ‘holiday’ tested before the pipe is installed in the trench or

Table A.1 Recommendations arising from Independent Safety Review (Advantica)			
No	**Reference**	**Recommendation**	**Action**
			grout is introduced into the Tunnel. (Refer Chapter 4 of the Onshore Pipeline EIS).
10	4.5.1.2	CP system: A factory built insulation joint should be considered at the landfall to separate the offshore and onshore CP systems. Alternatively the detailed CP system design should be revised to take account of the possible effects of the offshore system.	Assessment of the CP system interface at the landfall has confirmed that an isolation joint is not required. The design of the onshore pipeline CP system takes account of the offshore CP system.
11	4.5.1.2	CP system: The general CP system design is supported as well as the design to avoid cable joints in the anode string, however the method of connecting the positive feed cable from the transformer rectifier (T/R) is not specified. We recommend that these cables be connected in a fixed test post to eliminate the risk of premature failure and to facilitate future testing.	The method of connecting the positive feed cable is through a single cable entering the T/R. The cable is then buried and routed to the ground bed. At the ground bed a positive distribution junction box will be installed, in which the anode cable tails will be terminated.
12	4.5.1.2	CP system: It is not clear whether an automatic T/R is required for technical reasons such as variable ground resistivity due to environmental factors (e.g. the effect of tides or seasonal variations). We agree that a manual step controlled T/R unit would be unsuitable, however manual units are available offering extremely good control with 'variac' control. If not really necessary, automatic T/R's add complications with the possibility of compromising reliability. The long term reliability and stability of permanent reference electrodes should also be considered. Maintenance technicians would need to be trained on 'auto' units and to understand their particular requirements when placing them in switching mode for surveys such as the post construction polarised potential survey.	The T/R will be operated in the manual, constant current mode. However, it will have the function to operate in the auto-potential mode. Manufacturers' guarantees are available for up to 20 years operation. Purchase of units will include appropriate operator training and a comprehensive operating manual.
13	4.5.1.2	CP system: It is recommended that a schedule of proposed test facilities with wiring diagrams is prepared. It is important that all temporary anodes are connected via test posts and that facilities are adequate for future survey requirements. All posts should be fitted with a front plate stating ownership, telephone number and a CP test reference number. Black text on yellow	The design recommendations are in accordance with Shell's standard design basis. The marking of the CP test posts will be as agreed with the relevant Authorities.

Table A.1 Recommendations arising from Independent Safety Review (Advantica)			
No	**Reference**	**Recommendation**	**Action**
		plate.	
14	4.5.1.2	CP system: It is agreed that pin brazing is a good technique for CP cable attachment but is more suited to CP remedial, maintenance, or upgrading work where subsequent damage is unlikely. These connections are not as robust as welded steel plates. As welders are available for pipeline construction, welded stud plates are recommended as the preferred method of CP cable attachment. The welding of these plates to the mainline should be carried out by qualified welders using a qualified weld procedure.	It is considered that pin brazing is an appropriate connection for most of the CP connections, producing high-integrity joints. The main negative cable connection will be made with a welded plate.
15	4.5.1.2	CP system: The terminology “Coupon Polarisation Cell” is confusing as it mixes devices commonly known as pipeline corrosion coupons with the completely different polarisation cell. It is recommended that they be termed Pipeline Corrosion Coupons to avoid confusion. The bare coupon area is not specified; for effective use the bare area should simulate a credible coating defect that may be present or arise in service.	The term ‘Pipeline Corrosion Coupon’ has already been used for coupons used to assess internal corrosion levels inside the pipeline. Instead the terminology will be changed to ‘ Coupon Polarisation Probe’. The Coupon area has been specified in the design documentation for the onshore pipeline CP system as recommended.
16	4.5.1.2	CP system: The use of a temporary CP system to protect the pipe during construction is supported including the final choice of 14.5kg-packaged anodes. However, the design for the temporary CP system does not specify whether Grade 'A' anodes, (open circuit potential of –1.5V), or Galvomags with an open circuit potential of –1.7V should be used. In consideration of the superior current characteristics, with minimal commercial implications, the Galvomag option is recommended. All temporary anodes should be connected via a test post with no ‘blind’ connections.	If there is a requirement to use a temporary CP system, this recommendation is noted. Packaged anodes are preferred.
17	4.5.1.3	CP system: Conclusions - See above	See above
18	4.5.2.5	Internal corrosion: The internal corrosion rate prediction should be re-evaluated and the implications of the resulting predicted metal loss on the pipeline integrity assessed.	This has been carried out, and a report issued. Refer Appendix Q4.9

Table A.1 Recommendations arising from Independent Safety Review (Advantica)			
No	**Reference**	**Recommendation**	**Action**
19	4.5.2.5	Internal corrosion: The pipeline integrity management plan should include checks of the actual corrosion rates determined by the internal corrosion monitoring spool and by in line inspection, for comparison with the predicted rates.	This is incorporated in the Pipeline Integrity Management Scheme. Refer Appendix Q5.2.
20	4.7	Testing: The onshore section should be pressure tested using the “high level test” method of section 11.5.2.1 of PD 8010, to a level of 105% SMYS.	As a result of the analysis of code requirements it is recommended to pressure test the onshore pipeline at 504 barg at the lowest point. (Onshore hydrostatic pressure test report). This has been approved by TAG.
21	4.7	Testing: An initial fingerprinting in-line inspection run should be carried out during pipeline commissioning.	An initial fingerprinting in-line inspection run for the onshore pipeline will be carried out and is included in the scope of the pre-commissioning activities. The initial finger printing in-line inspection run for the offshore pipeline is planned during the first year of production.
22	4.8	Integrity Management System: A formal integrity management system should be established for the pipeline before construction is allowed to commence.	SEPIL has developed a Pipeline Integrity Management Scheme (PIMS). This scheme is based on the extensive experience of Shell operating pipelines in Europe over the last 40-50 years, and covers the offshore and onshore pipelines, well flowlines, umbilicals and water outfall. The PIMS addresses the lifetime safeguarding of mechanical integrity through the mitigation of all threats that could compromise pipeline integrity and the monitoring of the effectiveness of risk barriers, and as such considers: • Process safety, e.g. operating procedures, overpressure protection, emergency procedures and leak detection, as well as thorough training and supervision of personnel supported by up to date procedures explaining the work tasks and safe systems of work (permit to work system) to co-ordinate activities and ensure appropriate levels of control; • Mechanical integrity, including general integrity, (e.g. fatigue, overstress, mechanical damage and threats from peat instability and other geotechnical instability), corrosion

Table A.1 Recommendations arising from Independent Safety Review (Advantica)			
No	**Reference**	**Recommendation**	**Action**
			management, (e.g. corrosion and erosion), and flow assurance, (e.g. scaling, surge, slugging and hydrate formation); • Management of change, (e.g. design change, modifications and set points, hot work such as welding or grinding at the landfall installation will be carried out under strict procedural controls and a permit system).
23	4.8.2	Defect assessment and repair: Defect assessment procedures specific to this pipeline should be developed.	A damage assessment methodology has been developed. Repair procedures will be developed before the onshore pipeline is commissioned. Refer Appendix Q4.7.
24	4.8.2	Defect assessment and repair: Repair procedures for non-leaking damage should be developed and, if necessary, tested to take account of the aggressive environment. Appropriate hardware (repair shells etc.) should be obtained and kept available at the terminal.	Repair procedures for non - leaking defects will be developed before pipeline commissioning. As specified in the PIMS, methods will be identified for the repair of damaged pipe. The equipment and materials that may be required will be either held in stock or their acquisition route is identified and assured to meet required timescales. Repair procedures will be tested if required.
25	4.8.3	Presence of Control Umbilical: It is possible that maintenance or repair of the umbilical may be necessary. Working procedures for this case are required. We consider that they should require hand digging to avoid damage to the main pipeline. If the main pipeline has been exposed during work on the umbilical, the procedures should require an inspection to detect and repair any coating damage that may have been inflicted.	During construction, after the pipeline has been lowered and laid in the trench and before backfilling, the exact position of the pipeline (XYZ co-ordinates) will be recorded. If at a later stage the pipeline laid in a trench has to be exposed, the pipeline position will be “set out” on the basis of these coordinates which are logged in the As Built data. Excavation to initially expose the pipeline and umbilicals will only be carried out by hand. Thereafter digging may be supported by mechanical means. Backfilling will only take place after the exposed services have thoroughly been inspected and if necessary coatings have been repaired. Similar excavation precautions will be employed should intervention become necessary for the section within the Tunnel. The above will be described in detail in the dedicated procedures to be associated with the PIMS.
26	5.2	Population density analysis: a more cautious approach should be used in future in calculating population density in any future	The QRA has been carried out using the actual individual locations of houses along the pipeline route and has assumed 4 persons per

Table A.1 Recommendations arising from Independent Safety Review (Advantica)			
No	**Reference**	**Recommendation**	**Action**
		reassessment of the pipeline classification.	house (in line with the methodology to prepare FN curves). Refer to Appendix Q6.4. Appendix Q6.2 outlines the analysis for population density
27	5.3.1	Failure frequency analysis: The measures to protect the pipeline integrity assumed in the QRA must be established for the Corrib pipeline, and maintained throughout its life in order that the risk levels predicted in the QRA remain valid.	The safeguards taken by SEPIL to minimise failure frequencies will be incorporated in pipeline construction (e.g. protective slabs at road crossing, installation of the pipeline in the stone road) and in the procedures associated with the PIMS for operating and maintaining the pipeline.
28	5.3.1	Failure frequency analysis: A procedure should be established for monitoring of the gas for H_2S, specifying the actions to be taken and the threshold concentrations above which action would be required.	Monitoring for H_2S will take place at monthly intervals in accordance with the PIMS. The limits for non-sour service specified in ISO 15156-1/2 for carbon steel are as follows: • At 100 bar: H_2S concentration < 34 ppmv • At 150 bar: H_2S concentration < 23 ppmv Threshold concentrations to trigger appropriate actions have been defined (see Appendix Q4.7). Actions in case the thresholds are exceeded will be included in the PIMS/Pipeline Integrity Reference Plan.
29	5.4	Risk reduction measures and demonstration of ALARP: The proposed arrangements for surveillance and landowner liaison should be specified in the operations and maintenance procedures.	Detailed procedures for pipeline surveillance and landowner liaison will be developed in accordance with the requirements of I.S. 328 (with back-up of BS PD 8010) Part I Chapter 12 Operations and Maintenance. These procedures will form part of the operations and maintenance procedures for the pipeline and will be referenced in the PIMS.
30	5.4	Risk reduction measures and demonstration of ALARP: The pressure in the onshore pipeline should be limited to enable the pipeline to be reclassified as a Class 2 (Suburban) pipeline, with a design factor not exceeding 0.3.	The Maximum Allowable Operating Pressure in the onshore pipeline will be now limited to 100 barg. This is achieved by installation of a safety shutdown system at the Landfall Valve Installation, Glengad. This is described in Chapter 4 of the Onshore Pipeline EIS, and design information is provided in Appendix Q4.3.
31	5.5.2	Options for additional pressure control measures: A full and	This analysis has been carried out and resulted in a reconfiguration

Table A.1 Recommendations arising from Independent Safety Review (Advantica)			
No	**Reference**	**Recommendation**	**Action**
		technically thorough reliability analysis should be carried out of the subsea pressure control and isolation systems specified in the field design to enable appropriate additional pressure control measures to be implemented and the effective limitation of the pressure in the onshore pipeline demonstrated.	of the overall control system for triggering automated shut down offshore on rising pipeline pressure and the installation of a safety shutdown system at the landfall. Refer Appendix Q4.5.
32	6.1.2	Comparison with international codes: If the onshore pipeline is reclassified as a Class 2 (Suburban) pipeline, the pipeline design should be revised in accordance with PD 8010, to ensure that the pipeline is consistent with current best practice, while minimising the change required to the existing design. The alternative approach proposed by Shell, to base the revised pipeline design on the Irish standard IS EN 14161, supplemented by the use of PD 8010 and IS 328, would also be acceptable provided that the more onerous requirements of PD 8010 and IS 328 are adopted where appropriate.	The onshore pipeline design has been revised as recommended, and a code compliance report has been prepared. Refer Appendix Q3.3.
33	6.5.2	Ground stability: The recommendations made by AGEC should be followed in full and the proposed construction methods revised accordingly, in order that the ground stability issues are managed appropriately.	It is proposed to install the pipeline within a stone road in all peat areas to address concerns in relation to ground movements. This stone road will provide support and stability to the pipeline. The stability issues associated with the pipeline have been assessed, and details are presented in Chapter 15 and Appendix M2 and M3 of the Onshore Pipeline EIS. Construction will be overseen by AGEC.
34	6.6	Risk mitigation: Arrangements should be made for an independent audit of construction work and an inspection regime established to confirm safe operation of the pipeline in future.	Independent third party verification will take place throughout the construction of the onshore gas pipeline. SEPIL has appointed an independent verification company that will certify that the pipeline design, specification, manufacture, construction and pre-commissioning is in compliance with the relevant standards and regulations. This company will also independently review safety critical elements of the Corrib project including the onshore pipeline. It is anticipated that the regulator represented by TAG (or CER in the future) will also independently monitor the construction and safe operation of the onshore pipeline.

Table A.2 Recommendations arising from Independent Safety Review (Technical Advisory Group (TAG)).		
Number	**Recommendation**	**Action**
1.	The primary pipeline design code is designated by TAG to be IS EN 14161; however IS 328 and PD 8010 shall apply where they exceed IS EN 14161. Shell should submit a Code Compliance document to TAG demonstrating how the existing proposals comply with the new designation.	A code compliance statement has been prepared which identifies how these codes will be applied to the pipeline. Refer Appendix Q3.3
2	The beachhead isolation valve, as well as being modified to be capable of remote (as well as local) operation, and to be “fail-safe” (i.e. the valve closes in the absence of a control signal keeping it open), should be designed to incorporate a pressure limitation feature set to prevent pressure exceeding 144 bar in the onshore section of the pipeline. Shell should be required to submit proposals for the design, installation and operation of such facilities. TAG should explicitly approve same before further relevant consents are granted.	The Maximum Allowable Operating Pressure in the onshore pipeline will be now limited to 100 barg. This is achieved by installation of a safety shutdown system at the Landfall Valve Installation, Glengad, This is described in Chapter 4 of the Onshore Pipeline EIS, and design information is provided in Appendix Q4.3
3.	It is recommended that the Minister should now require a Pipeline Integrity Management Plan, covering operational and maintenance issues, to be supplied by the company to TAG. Where relevant, this should demonstrate compliance to the appropriate sections of IS 328. A date for receiving this should be agreed with the company before further consents are granted.	SEPIL has developed a Pipeline Integrity Management Scheme (PIMS). This scheme is based on the extensive experience of Shell operating pipelines in Europe over the last 40-50 years, and covers the offshore and onshore pipelines and umbilicals. The PIMS addresses the lifetime safeguarding of mechanical integrity through the mitigation of all threats that could compromise pipeline integrity and the monitoring of the effectiveness of risk barriers, and as such considers: • Process safety, e.g. operating procedures, overpressure protection, emergency procedures and leak detection, as well as thorough training and supervision of personnel supported by up to date procedures explaining the work tasks and safe systems of work (permit to work system) to co-ordinate activities and ensure appropriate levels of control; • Mechanical integrity, including general integrity, (e.g. fatigue, overstress, mechanical damage and threats from peat instability and other geotechnical instability), corrosion management, (e.g. corrosion and erosion), and flow assurance, (e.g. scaling, surge, slugging and hydrate formation); • Management of change, (e.g. design change, modifications and set

Table A.2 Recommendations arising from Independent Safety Review (Technical Advisory Group (TAG)).		
Number	**Recommendation**	**Action**
		points, hot work such as welding or grinding at the landfall installation will be carried out under strict procedural controls and a permit system).
4.	Detailed impact protection design and installation proposals to be submitted.	Detailed impact protection design and installation details have been provided in the applications for consent for the pipeline under the Strategic Infrastructure Act and the Gas Act (see application drawings DG0701, DG0702 and DG0703).
5.	SEPIL to confirm that the distance between slabs (where utilised) and the top of the pipe shall not be less than 500 mm, rather than 300 mm as currently specified	Detailed design and installation details have been provided in the applications for consent for the pipeline under the Strategic Infrastructure Act and the Gas Act (see application drawings DG0701, DG0702 and DG0703).
6.	Where the pipe is laid in peat and slabbing is appropriate, proposals for supporting the slabs from the sub-soil are required.	It is proposed to install the pipeline within a stone road. This stone road will provide support and stability to the pipeline and to the slabbing (where appropriate). Construction methodologies are described in Chapter 5, and geotechnical stability aspects are outlined in Chapter 15 of the Onshore Pipeline EIS and Appendix M2 and M3.
7.	Proposals for assessing pipe wall strain at appropriate sections of the pipe are required.	It is proposed to install the pipeline within a stone road. This stone road will provide support and stability to the pipeline. The proposed construction method mitigates the issue of pipeline stability in peat. The stone road settlement has been assessed. The impact on the pipeline and services stress conditions as a result of these settlements has been calculated and found to be within acceptable limits. Refer Appendix Q4.1. Construction details are provided in drawing no DG0601. To confirm that settlement is within design prediction a movement monitoring programme will be applied which will involve short term (during construction) and long term (post construction) high accuracy surveys carried out regularly along the pipeline route to identify any indications of movement of the stone road. GPS plates will be installed where appropriate to assist this monitoring. The frequency of monitoring will be tailored based on the results of the ongoing monitoring.

Table A.2 Recommendations arising from Independent Safety Review (Technical Advisory Group (TAG)).		
Number	**Recommendation**	**Action**
8.	Proposals for regular inspection of pipe position markers is required.	Detailed operating, inspection and maintenance procedures will be prepared for the pipeline system. These will form part of the system for managing pipeline integrity as described in the Pipeline Integrity Management Scheme.
9.	Proposals for monitoring of settlement and groundwater levels are required.	The construction method of installing the pipeline in the stone road mitigates the requirement for settlement and groundwater monitoring. The movement monitoring programme will involve short term (during construction) and long term (post construction) high accuracy surveys carried out regularly along the pipeline route to identify any indications of movement of the stone road. GPS plates will be installed where appropriate to assist this monitoring. As part of the movement monitoring programme, piezometers will be installed adjacent to the stone road to allow monitoring of groundwater levels. The frequency of monitoring will be tailored based on the results of the ongoing monitoring Monitoring proposals are included in Appendix M2.
10.	Where piling is utilised, proposals for pipeline fixing to the piles are required.	It is proposed to install the pipeline within a stone road. This stone road will provide support and stability to the pipeline and to the slabbing (where appropriate). Construction methodologies are described in Chapter 5, and geotechnical stability aspects are outlined in Chapter 15 and Appendix M2 and M3 of the Onshore Pipeline EIS.
11.	Detailed proposals for repair work on the control umbilical system, with a specific limitation on the use of mechanical diggers for such work once the pipeline has been commissioned are required.	During construction, after the pipeline has been lowered and laid in the trench and before backfilling, the exact position of the pipeline (XYZ co-ordinates) will be recorded. If at a later stage the pipeline laid in a trench has to be exposed, the pipeline position will be “set out” on the basis of these coordinates which are logged in the As Built data. Excavation to initially expose the pipeline and umbilicals will only be carried out by hand. Thereafter digging may be supported by mechanical means. Backfilling will only take place after the exposed services have thoroughly been inspected and if necessary coatings have been repaired. Similar excavation precautions will be employed should intervention become necessary for the pipeline section within the Tunnel The above will be described in detail in the dedicated procedures to be associated

Table A.2 Recommendations arising from Independent Safety Review (Technical Advisory Group (TAG)).		
Number	**Recommendation**	**Action**
		with the PIMS.
12.	Advantica recommends that additional ground movement analysis is required at bends in the pipeline, for modelling a landslip parallel to the pipeline, and for peat cover of 4m depth. TAG recommends that the company should have this work undertaken and submitted to TAG for approval before pipeline installation. In such consideration, TAG will have regard to compliance with IS 328 / PD 8010 rather than DNV OSF101.	It is proposed to install the pipeline within a stone road. This stone road will provide support and stability to the pipeline and to the slabbing (where appropriate). Construction methodologies are described in Chapter 5, and geotechnical stability aspects are outlined in Chapter 15 and Appendix M2 and M3 of the Onshore Pipeline EIS.
13.	TAG recommends that agreed actions to properly preserve the cut sections of pipeline be completed as a matter of urgency.	The cut sections of pipe have been internally cleaned and coated internally, and protected externally.
14.	TAG will design an inspection and monitoring regime for this project, to include supervision of construction. Shell should be asked to indicate their willingness to comply with all reasonable requirements of such a regime (recognising that it does not yet exist).	SEPIL will comply with all reasonable requirements of an inspection and monitoring regime, including supervision of construction.

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Corrib Onshore Pipeline EIS APPENDIX Q3.2 APPLICATION OF IRISH AND INTERNATIONAL PIPELINE STANDARDS	PROJECT No. 052377.01 REF CTR 349 No OF SHEETS 11

DOCUMENT No	OFFICE CODE	PROJECT No	AREA	DIS	TYPE	NUMBER
	05	2377	01	P	3	041

REV	DATE	DESCRIPTION	BY	CHK	ENG	PM	CLIENT
03	13/5/10	Issued for Planning Application	JG	GSW	JSW	JG	
02	4/05/10	Issued for Comment	JG	GSW	GSW	JG	
01	8/03/10	Issued for IDC	JG	GSW	GSW	JG	

CONTENTS

1 INTRODUCTION

The design, construction, operation and maintenance of the Corrib pipeline system is in accordance with a series of pipeline codes, which were adopted by SEPIL following the recommendations of the Corrib Technical Advisory Group (TAG).

This document sets out the context of these pipeline codes within the overall framework of International Codes and specifically in relation to Irish pipeline codes.

The document also identifies the application of other key pipeline codes in relation to the Corrib onshore pipeline.

2 BACKGROUND TO PIPELINE CODES

The applicable code/standard to be applied when designing, constructing, operating or maintaining a pipeline transporting hydrocarbons is subject to a hierarchy of standards applicable across the oil and gas industry. These comprise International Standards, National Standards, Industry Standards and Company Standards as further outlined below. Each standard is regularly reviewed and revised editions issued to reflect ongoing practice. In recent years there has also been a trend to achieve harmonisation across the codes regarding key issues such as design and safety.

It is not unusual to identify and adopt relevant and applicable pipeline codes and standards to be applied to a specific pipeline system. In most cases this is between two to four codes and standards. The key requirement is to clearly nominate the primary code and to set the priority of supplementary codes. For best practice a document is issued to clearly determine which code should be used for a particular aspect of design, construction, operation and maintenance.

2.1 International Standards

These are managed and published by International Organisation for Standardisation (ISO). These standards are written by panels of international experts co-opted via participating national standards bodies for world-wide application and opening up of commercial markets.

2.2 National Standards

These reflect the national practice and legislative requirements of the respective Country. They are managed and published by national standards bodies, written by national panels of experts thus embodying established best practice and specific conditions for that country.

National standards are offered for international use, but historically only USA-ASME and API standards have been widely adopted.

The EU member states also have the CEN – (European Committee for Standardization) based in Brussels. Adoption of CEN standards is mandatory in EU states to facilitate open markets.

The ISO promotes replacement of equivalent national standards with ISO standards and ongoing harmonisation with CEN standards.

2.3 Industry Standards

These are developed by panels of industry experts usually working within their Institutional body. For example: NACE, DNV, Institution of Gas Engineers & Managers (IGEM).

These standards are applicable to the specific industry sector for which the code is written and are often supported by a high level of expertise and research.

2.4 Company Standards

Many of the major oil and gas companies have developed standards, practices and procedures that reflect the application of International and National standards to respective developments. These also reflect industry best practice and corporate practices. Within Shell these standards and practices are defined with a set of documents termed Design Engineering Practices (DEP's).

2.5 Typical Standards

Table 2-1 below highlights various pipeline standards applicable throughout the oil and gas industry. Each of these pipeline codes addresses various aspects for implementation, operation, maintenance and de-commissioning of pipeline systems both onshore and offshore relevant to the location within which the pipeline system is to be installed. In addition some aspects of the codes and standards are in the form of guidance, others are prescriptive and some are silent.

Country	Standard	Gas	Liquid	Notes
International	ISO 13623	Yes	Yes	
USA	ASME B31.8 ASME B31.4	Yes No	No Yes	
European Union	CEN prEN 14161 prEN 1594	 Yes Yes	 Yes No	CEN adopted ISO 13623 for liquids only Non-sour Gas Only
Republic of Ireland	I.S EN 14161 I.S. 328	Yes Yes	Yes No	 Natural gas
United Kingdom	BS EN 14161 BS PD 8010 Part 1 IGEM TD/1	Yes Yes Yes	Yes Yes No	 Supplements CEN Non-sour Gas Only
France	AFNOR NF EN 14161 NF EN 1594	 Yes Yes	 Yes No	Adopted CEN standards.
Netherlands	NEN EN 14161 NEN 3650	Yes Yes	Yes Yes	Supplements CEN Specific local requirements
Germany	DIN EN 14161	Yes	--	
Canada	CSA Z662	Yes	Yes	
Australia	AS 2885	Yes	Yes	

Table 2-1 Typical Pipeline Standards

3 ADVANTICA AND TAG RECOMMENDATIONS

The Advantica report, concluding an Independent Safety Review of the onshore section of the Corrib gas pipeline, was published by the Minister for Communications, Marine and Natural Resources on the 3rd May 2006 [Ref 1]. Three other documents were also published on the 3rd May 2006.

The first was a report to the Minister from The Corrib Technical Advisory Group (TAG) [Ref 2].

The second was TAG's report on inspection and monitoring issues [Ref 3].

The third was a short note by TAG which set out in tabular form the recommendations of the Advantica Report, the TAG Report and TAG's recommendations on inspection and monitoring [Ref 4].

From the first report, TAG's recommendation regarding the application of the appropriate design pipeline codes to be applied to the Corrib onshore gas pipeline was as follows:

The primary pipeline design code is hereby designated by TAG to be I.S. EN 14161; however I.S. 328 and BS PD 8010 shall apply where they exceed I.S. EN 14161.

The second report included TAG's recommended approach which included:

To be specific, TAG recommends that, while the overall design code for the upstream, onshore section of the Corrib project shall be I.S. EN 14161, construction, installation, operation and maintenance of the onshore section of the pipeline shall be generally in accordance with I.S. 328, and the inspection and monitoring regime that will be applied to this section of the project will be as per the relevant provisions of I.S. 328.

Where a case is made by the developer and accepted by TAG, specific provisions of BS PD 8010 may apply in lieu of the relevant provisions of I.S. 328.

For the offshore section of the pipeline, the relevant code for inspection and monitoring purposes shall be DNV-OS-F101. Provisions of BS PD 8010 – 2: 2004 may be substituted by agreement with TAG.

4 CONTEXT OF THE CORRIB PIPELINE CODES

The pipeline codes referenced within the TAG recommendations for the design, construction, testing, commissioning and operation of the onshore section of the Corrib Gas Pipeline are:

I.S. EN 14161:2004	Petroleum and Natural Gas Industries – Pipeline Transportation Systems (ISO 13623:2000 Modified)
I.S. 328:2003	Code of Practice for Gas Transmission Pipelines and Pipeline Installations.
BS PD 8010-1:2004	Code of Practice for Pipelines – Part 1: Steel Pipelines on Land
BS PD 8010-2: 2004	Code of Practice for Pipelines – Part 2: Subsea Pipelines
DNV-OS-F101: 2000:	Submarine Pipeline Systems
DNV-OS-F101: 2007	Submarine Pipeline Systems

There are also other relevant codes applicable to pipeline transmission systems, namely:

ISO 13623:2009	Petroleum and natural gas industries -- Pipeline transportation systems.

I.S. EN 1594	Gas Supply Systems – Pipelines for Maximum Operating Pressures over 16 bar – Functional Requirements.
BS PD 8010-3:2009	Code of practice for pipelines. Steel pipelines on land. Guide to the application of pipeline risk assessment to proposed developments in the vicinity of major accident hazard pipelines containing flammables. Supplement to PD 8010-1:2004
IGEM/TD/1 Edition 5: 2008	Steel Pipelines and Associated Installations for High Pressure Gas Transmission

4.1 International and European Pipeline Codes

The International Standard ISO 13623, Petroleum and natural gas industries -- Pipeline transportation systems was first published in 2000 and was adopted by the International organisations and countries as an overarching standard for pipeline transportation systems.

In Europe, implementation of the ISO code was undertaken within the CEN (European Committee for Standardization). However, significant differences existed between the CEN member countries in the areas of public safety and protection of the environment which could not be reconciled into a single preferred approach to pipeline transportation systems for the petroleum and natural gas industries. Reconciliation was further complicated by the existence in some member countries of legislation which established requirements for public safety and protection of the environment. The ISO technical committee concluded that ISO 13623 should allow individual countries to apply their national requirements for public safety and the protection of the environment.

In 2003 the International Standard ISO 13623 was adopted as a European Standard EN 14161. The CEN members were bound to comply with the CEN regulations, including EN 14161, as the status of a National standard.

Both Ireland and the United Kingdom are members of CEN. The NSAI (National Standards Authority Ireland) adopted the European Standard in 2004 as I.S. EN14161 “ISO 13623: 2000 as modified”. Adoption of EN 14161 code in the UK is discussed in Section 4.3.

4.2 Irish Gas Transmission Codes (I.S. EN 1594 and I.S. 328)

Prior to adopting ISO 13623 in 2004, EN 14161 identified an overlap between the new EN 14161 and an existing European Standard, EN 1594: Gas Supply Systems – Pipelines for Maximum Operating Pressures over 16 bar – Functional Requirements, and by resolution excluded on land supply systems used by the gas supply industry from EN14161. That is, overland national gas transmission systems.

I.S. EN 1594: 2009 describes the general functional requirements for gas supply through pipe systems and covers the pressure range greater than 16 bar maximum operating pressure for steel systems (i.e. transmission pipelines). In preparing EN 1594 it was recognised that the suite of relevant European Standards is incomplete. Therefore EN 1594 allows reference to be made, where appropriate, to international, national or other standards until relevant European Standards are available.

The prevailing Irish Code for gas transmission in Ireland, as adopted by Bord Gáis, is the code of practice I.S. 328. This code applies to on land supply systems for the gas industry in Ireland and states that it should be used in conjunction with the new European standards for gas pipelines and installations. I.S. 328 is to be used for steel pipelines for the transmission of gas at maximum operating pressure over 16 bar.

4.3 Application of EN14161 in the United Kingdom: BS PD 8010 - Part 1

Prior to 2003, the applicable British Standard for pipelines was BS 8010, Code of practice for pipelines and included both onshore and offshore pipelines.

In 2003 EN14161 was adopted as the UK National Standard with the following National Foreword

The UK voted against EN 14161 at the adoption stage but is obliged to publish it as a British Standard. The UK Technical Committee indicated that a more comprehensive approach to the design of pipelines is possible through using BS EN 14161 in association with PD 8010-1:2004.

Code of practice for pipelines, BS 8010, was subsequently withdrawn.

It is noted that BS PD 8010 Part 1 makes reference to the Institute of Gas Engineers and Managers pipeline code IGEM/TD/1 for guidance in a number of areas. Furthermore IGEM/TD/1 Edition 5 states that it can be used to provide detailed requirements to support BS EN 1594.

4.4 Offshore/ Submarine Pipeline Codes

The DNV-OS-F101, Submarine Pipeline systems is widely used within the offshore industry for design of submarine pipelines as it is considered to be a rigorous and established code known throughout the industry. This code was adopted for the design of the offshore section of the Corrib pipeline.

The UK code BS PD 8010 – Part 2 addresses subsea pipelines and is complementary to the onshore code BS PD 8010-Part 1.

4.5 Extent of the Pipeline Codes

The extent of the various pipeline codes can be summarised in Table 4-1.

Code	Offshore/ Submarine	Includes Landfall	Onshore	Notes
I.S.EN14161			Excludes Natural Gas (Transmission)	Implements ISO 13623 in EU
I.S.328			Natural Gas Only (Transmission)	Incorporates I.S. EN 1594
BS PD 8010 Part 1		From HWTL		To supplement EN 14161
DNV-OS-F101				Offshore only
BS PD 8010 Part 2		To HWTL		Offshore only

HWTL = High Water Tide Level APPLICABLE

Table 4-1 Extent of Pipeline Codes

5 OFFSHORE PIPELINE

5.1 Design

Design of the offshore pipeline is in accordance with DNV-OS-F101: 2000.

5.2 Definitions

For the offshore pipeline the definitions as per DNV-OS-F101 are presented in Table 4-1 from the code:

Table 4-1 Pressure terms

Pressure	*Abbreviations*	*Symbol*	*Description*
Mill test	-	P_h	Hydrostatic test pressure at the mill, see Sec.7
System test	-	P_t	The pressure to which the complete submarine pipeline system is tested to prior to commissioning, see Sec.5 B200
Incidental	-	P_{inc}	Maximum pressure the submarine pipeline system is designed for
Maximum allowable incidental	MAIP	-	The trigger level of pressure safety system. Maximum allowable incidental pressure is equal to the incidental pressure minus the pressure safety system operating tolerance
Design	-	P_D	The maximum pressure the pressure protection system requires in order to ensure that incidental pressure is not exceeded with sufficient reliability, typically 10% below the incidental pressure
Maximum allowable operating	MAOP	-	Upper limit of pressure control system. Maximum allowable operating pressure is equal to the design pressure minus the pressure control system operating tolerance

5.3 Construction

Construction of the offshore pipeline will be in accordance with DNV-OS-F101:2000. Therefore the welding of the offshore pipeline and the LVI will be in accordance with DNV-OS-F101:2000 which includes welding of carbon steel and corrosion resistant alloys (as used at the LVI).

5.4 Inspection and Monitoring

For the offshore section of the Corrib pipeline, the relevant code for inspection and monitoring purposes shall be DNV-OS-F101. Provisions of BS PD 8010 – 2: 2004 may be substituted by agreement with TAG.

6 ONSHORE PIPELINE

6.1 Design

As indicated in Section 3, the TAG recommendations for design are:

The primary pipeline design code will be I.S. EN 14161.

I.S. 328 and BS PD 8010 shall apply where they exceed I.S. EN 14161.

To establish the application of the primary and supplementary pipeline codes for the onshore pipeline, a Design Code Review (05-2377-01-P-3-019) was prepared and accepted by TAG. This report considered the respective design clauses in each of the codes with respect to particular aspects of the design and identified where I.S. EN 14161 was applicable and, as appropriate, where I.S. 328 and BS PD 8010- Part 1 should be applied.

6.2 Definitions

As stated in the Design Code Review, the definitions for the onshore pipeline shall be as stated in I.S. EN 14161. Thus the following will be applied:

Internal design pressure

Maximum internal design pressure at which the pipeline or section thereof is designed in compliance with this (*EN 14161*) European Standard.

In addition:

The internal design pressure at any point in the pipeline system shall be equal to or greater than the maximum allowable operating pressure (MAOP). Pressures due to static head of the fluid shall be included in the steady-state pressures.

Maximum Allowable Operating Pressure (MAOP)

Maximum pressure at which a pipeline system, or parts thereof, is allowed to be operated under steady state conditions.

In addition:

MAOP shall be less than or equal to the Internal Design Pressure

For the purposes of clarity when consulting I.S.328 and/or BS PD 8010, the I.S. EN 14161 terminology. Internal Design Pressure and MAOP, shall be applied as follows:

I.S. EN 14161	Internal Design Pressure	MAOP
I.S. 328	Design Pressure	Maximum Operating Pressure (MOP)
BS PD 1010	Design Pressure	MAOP

6.3 Construction

TAG recommended that construction, installation, operation and maintenance of the onshore section of the Corrib pipeline shall be generally in accordance with I.S. 328. Therefore welding of the onshore pipeline will be in accordance with I.S.EN 12732 – refer Section 7 of I.S. 328.

6.4 Inspection and Monitoring

The inspection and monitoring regime that will be applied to the onshore pipeline will be as per the relevant provisions of I.S. 328

7 LANDFALL VALVE INSTALLATION

At the landfall an interface arises between the primary onshore code I.S. EN 14161 and the primary offshore code DNV-OS-F101. To establish this interface the following points were taken into consideration.

Within I.S. EN 14161 Figure 1 - Extent of Pipeline Systems shows that the part of the pipeline system from wellhead to gathering station, treatment plant or process plant is covered by I.S. EN 14161. Therefore this standard is applicable to the Corrib onshore pipeline.

The offshore pipeline has been designed to DNV-OS-F101:2000, Submarine Pipeline Systems. This standard was reissued in 2007 and within DNV-OS-F101: 2007, Appendix F Paragraph A101 specifies the requirements for design, construction and operation of parts of pipeline systems going onshore. The guidance given is that the submarine pipeline system is defined to end at a weld beyond the first flange/valve onshore or to the pigging terminal. Also in Appendix F Other Codes paragraph A 301 further states that Appendix F is fully aligned with the requirements given in ISO 13623 (and thus I.S. EN 14161).

Therefore the design code specification break at the Landfall between the design codes DNV-OS-F101 and I.S. EN 14161 was selected at the weld between the downstream barred tee of the LVI and the onshore pipeline.

8 GAS TERMINAL

Within the Gas Terminal the onshore pipeline code is applicable to the Gas Terminal inline valves and the pig receiver. At a point downstream of the first valve after the receiver the code changes to the Gas Plant code, namely ASME B31.3: 2002 Process Piping.

9 PROXIMITY REQUIREMENTS

The Design Code Review identified that the applicable code to be applied for the determination of proximity requirements was I.S. 328 - Section 6.4. This section further stated that:

"Where it is impractical to comply with the above proximity requirements deviation from these requirements may be permitted provided they can be justified by a Quantitative Risk Assessment carried out in accordance with a recognised standard such as AS 2885.1"

TAG has accepted that BS PD 8010- Part 3; Code of practice for pipelines. Steel pipelines on land. Guide to the application of pipeline risk assessment to proposed developments in the vicinity of major accident hazard pipelines containing flammables, may be used for the purpose of determination of the proximity and Quantitative Risk Assessment for the Corrib pipeline.

10 CONCLUSION

The pipeline codes, I.S. EN 14161, I.S. 328 and BS PD 8010 recommended by TAG and adopted for the Corrib onshore gas pipeline are applicable and relevant to the design of the Corrib onshore pipeline.

The application of the pipeline codes for design is clearly set out in the Design Code Review referred to above.

The construction, installation, operation and maintenance of the onshore section of the onshore pipeline will be in accordance with I.S. 328, and the inspection and monitoring regime that will be applied to the Corrib onshore pipeline will be as per the relevant provisions of I.S. 328.

The design of the offshore submarine pipeline in accordance with DNV-FS-101 conforms to TAG's recommendations.

The break between the offshore and onshore pipeline design codes is defined at the landfall and is in accordance with DNV-FS-101:2007 Appendix F.

11 ABBREVIATIONS

AFNOR	Association Française de Normalisation
API	American Petroleum Institute
ASME	American Society of Mechanical Engineers
BS	British Standard
CEN	European Committee for Standardization
DIN	Deutsches Institut für Normung e.V.

DNV	Det Norske Veritas
IGEM	Institution of Gas Engineers & Managers
I.S.	Irish Standard
ISO	International Organisation for Standardisation
LVI	Landfall Valve Installation
MAOP	Maximum Allowable Operating Pressure
NACE	National Association of Corrosion Engineers
NEN	Netherlands Standardisation Institute
NSAI	National Standards Authority Ireland
TAG	Corrib Technical Advisory Group
QRA	Quantitative Risk Assessment

12 REFERENCES

1. Advantica; Independent Safety Review of the Onshore Section of the Proposed Corrib Gas Pipeline: 2006

2. TAG; Report of the Corrib Technical Advisory Group to Minister Dempsey: 2006

3. TAG; Report of the Corrib Technical Advisory Group to Minister Dempsey on an appropriate Inspection and Monitoring Regime for the Corrib Project: 2006

4. TAG; Corrib Gas Pipeline Safety Issues: 2006 (tabular format)

Shell E&P Ireland Limited CORRIB FIELD DEVELOPMENT PROJECT REPORT	J P KENNY Corrib natural gas

Corrib Onshore Pipeline EIS Appendix Q3.3 DESIGN CODE REVIEW ONSHORE PIPELINE SECTION	PROJECT No. 052377.01 REF CTR 349 No OF SHEETS 15

DOCUMENT No	OFFICE CODE	PROJECT No	AREA	DIS	TYPE	NUMBER
	05	2377	01	P	3	019

REV	DATE	DESCRIPTION	BY	CHK	ENG	PM	CLIENT
04	13.05.10	Appendix format details added for Planning Application	JG	GSW	GSW	JG	
03	26.01.07	Final issue	KJG	DMcK	JG	JG	
02	14.01.07	Revised Draft Issue	KJG	DMcK	JG	JG	
01	16.11.06	Draft Issue	KJG				

Document Comment Sheet				Page 2 of 15
Date of Review:	Reviewed by:	Response by:	Lead Engineer:	Project Engineer:
Areas of Particular Concern:				

	Review Finding	Project Response	

Distribution: Project File, Lead Engineer, Project Engineer Manager, Project Manager

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1 INTRODUCTION

1.1 General

Corrib Field Development Project is being implemented by SEPIL, Shell Exploration and Production Ireland Limited (formerly by Enterprise Energy Ireland Limited).

Corrib is a gas field located in 350m of water some 60 to 65km off the County Mayo coastline in Ireland. The field is being developed as a long-range subsea tieback to an onshore terminal. The gas will then be treated to meet the defined gas specification before onward transportation to the Bord Gais Eireann (BGE) grid via a new cross-country pipeline.

The pipeline system for the Corrib Field Development Project is 83km 20-inch subsea pipeline from the offshore manifold to a valve station at the landfall at Broadhaven Bay in County Mayo, plus further 8.3[1] km onshore to the terminal.

1.2 Objectives

The main objective of this report is to implement the recommendations of the Technical Advisory Group (TAG) with respect to the design code for the onshore section of the pipeline.

TAG has asserted that the overall design code for the upstream, onshore, section of the Corrib project shall be I.S. EN 14161 in accordance with the recommendations of the Independent Safety Review and TAG's consultants, Advantica. However, where the provisions of I.S. 328 and BS PD 8010 exceed those of I.S. EN 14161, then these are to be applied. It is acknowledged that I.S. 328 should be the primary supplementary code.

From the guidance provided by TAG, this report sets out to define areas where exceptions to I.S. EN 14161 are proposed.

2 RESULTS OF THE CODE COMPARISON REVIEW

Table 2-1 lists the areas where it is recommended that the specified elements of I.S. 328 or BS PD 8010 be applied as exceptions to I.S EN 14161.

[1] Onshore pipeline route changed 2010. Previously 9 km.

Table 2-1 Tabular format of exceptions and supplementary inclusions to I.S. EN 14161

The table 1 below shows all the headings given in I.S. EN 14161. It also highlights:

Code to be adopted for designated section
Code to supplement adopted code

I.S. EN 14161	I.S. 328	BS PD 8010
1 Scope		Supplement with Section 7.7.1- reference point of demarcation between pipeline and terminal.
2 Normative references		
3 Terms and definitions		
4 General		
4.1 Health, safety and the environment		Supplement with Section 4.3.1- reference to BS EN 14001 Environmental Management System
4.2 Competence assurance		
4.3 Compliance		
4.4 Records		Supplement with Section 4.4 Design Construction - commissioning assurance flowchart
5 Pipeline system design		
5.1 System definition		
5.2 Categorisation of fluids	Code uniquely dedicated to gas as stated in Section 1	
5.3 Hydraulic analysis		
5.4 Pressure control and over-pressure protection		
5.5 Requirements for operation and maintenance		
5.6 Public safety and protection of the environment	Adopt Section 6.2, 6.3, 6.4 and 6.5	
6 Pipeline design		
6.1 Design principles		
6.2 Route selection		
6.2.1.2 Public Safety	Adopt Section 6.2, 6.3, 6.4 and 6.5	
6.3 Loads		
6.4 Strength requirements		

I.S. EN 14161	I.S. 328	BS PD 8010
6.4.1 Calculation of stresses		
6.4.1.1 Hoop stress due to fluid pressure	Adopt Sections 6.2, 6.3, 6.4, 6.5	Supplement with Section 6.2.2.2 – Straight pipe under external loading
6.4.1.2 Other stresses		Supplement with Section 6.4.2.3 – Longitudinal Stress and Section 6.4.2.4 – Shear Stress
6.4.2 Strength criteria		
6.4.2.1 General		
6.4.2.2 Yielding	Adopt Sections 6.3, 6.5	Supplement with Section 6.4.3.2 - Allowable equivalent stress
6.4.2.3 Buckling		Adopt 6.4.4 Buckling
6.4.2.4 Fatigue		Adopt 6.4.6 Fatigue
6.4.2.5 Ovality		Adopt 6.4.4.2 for ovality calculation
6.5 Stability		
6.6 Pipeline spanning		
6.7 Pressure test requirements	Refer to SEPIL Document (Onshore Hydrostatic Pressure Testing Report, JPK doc nr 05 2377 01 P 3 020)	
6.8 Other Activities		
6.9 Crossings and encroachments	Supplement with Section 6.9 Pipe cover and impact protection - Fig 3 – Acceptable forms of additional protection for pipelines	Supplement with Section 6.10 – Trenchless Technology
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6.11 Section isolation valves		
6.12 Integrity monitoring		
6.13 Design for pigging		
6.14 Fabricated components		
6.15 Attachment of supports or anchors		
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7 Design of stations and terminals		
7.1 Selection of location		

I.S. EN 14161	I.S. 328	BS PD 8010
7.2 Layout		
7.3 Security		
7.4 Safety		
7.5 Environment		
7.6 Buildings		
7.7 Equipment		Adopt Section 7.6 – Equipment as replacement for EN 14161 Section 7.7 - Equipment
7.8 Piping		Adopt Section 7.7.1 – Piping,
7.9 Emergency shutdown system		
7.10 Electrical	Supplement with Section 16.3 - Earthing/equipotential bonding	
7.11 Storage and working tankage		
7.12 Heating and cooling station		
7.13 Metering and pressure control stations		
7.14 Monitoring and communications systems		
8 Materials and coatings		
8.1 General material requirements		
8.2 Linepipe		Supplement this section with reference to BS PD 8010 Section 8.2.6 – Fatigue.
8.3 Components		Supplement with Section 10.12.6 - Factory bends
8.4 Coatings		
9 Corrosion management		
9.1 General		
9.2 Internal corrosivity evaluation		
9.3 Internal corrosion mitigation		
9.4 External corrosion evaluation		
9.5 External corrosion mitigation		
9.6 Monitoring programmes and methods		
9.7 Evaluation of monitoring and inspection results		

I.S. EN 14161	I.S. 328	BS PD 8010
9.8 Corrosion management documentation		
Annex A		
Annex B	Adopt Section 6.2, 6.3, 6.4 and 6.5	
Annex C		
Annex D		

3 COMPARATIVE REVIEW OF I.S. EN 14161 AGAINST I.S.328 AND BS PD 8010

3.1 Introduction

From the guidance provided by TAG, this report sets out to define areas where:

- Exceptions to I.S. EN 14161 are requested due to technical benefits of either I.S. 328 or BS PD 8010
- Supplementary inclusion of I.S. 328 or BS PD 8010 when I.S. EN 14161 is either silent or insubstantial.

The structure shown of I.S. EN 14161 is given below, with the sections of the code in which TAG indicate that I.S. 328 is be adopted shown below the dotted line. Therefore this review only considers Sections 4 to and including Section 9.

- Section 1 - Scope
- Section 2 - Normative reference
- Section 3 – Terms and definitions
- Section 4 - General
- Section 5 - Pipeline System Design
- Section 6 - Pipeline Design
- Section 7 - Design of Stations and terminals
- Section 8 - Materials and Coatings
- Section 9 - Corrosion management

- Section 10 - Construction
- Section 11 - Testing
- Section 12 - Pre-commissioning and commissioning
- Section 13 - Operation, maintenance and abandonment

For each of the specified sections 1 to 9, recommendations have been made to apply I.S. 328 or BS PD 8010 where relevant. A route map is shown in Table 1 indicating which code is to apply to the relevant section of I.S. EN 14161.

3.2 Areas of Exception

There are two key areas within which exception from I.S.EN 14161 is sought, which are:

- Pipeline Design
- Hydrostatic pressure testing

3.3 Pipeline Design

In general terms, the hoop stress formula given in the design codes is influenced directly or indirectly by a number of elements, amongst which are:

- Categorisation of fluids
- Population density
- Location classes
- Design factor
- Design pressure
- Wall thickness of pipe
- Diameter of pipe

These factors are inter-linked with each other and should not be taken in isolation

The key point to note is that the design factors given in I.S.EN 14161 (Appendix B, Table B2) do not address the TAG's stated project objective of 0.3 design factor. Both I.S. 328 (Section 6.3) and BS PD 8010 (Section 6.4.1) do include reference to a design factor of 0.3 in their codes, and their approach to determining the design factor is very similar. In adopting objectives of the TAG recommendations, it is proposed that I.S. 328 be applied for specified aspects of design of the onshore pipeline design.

Additionally, the method of addressing population density within I.S. EN 14161 is not as well defined as in I.S. 328 and BS PD 8010

3.4 Hydrostatic pressure testing

Advantica undertook the Corrib Gas Pipeline Safety Review.

The Technical Advisory Group (TAG) subsequently made additional recommendations.

The SEPIL document addressing the recommendations is:

''Onshore Hydrostatic Pressure Testing Report'' Corrib Document No. 05-2377-01-P-3-020.

3.5 List of sections of I.S.EN 14161, where I.S. 328 or BS PD 8010 should take preference

Below are listed specific areas in I.S. 328 and/or BS PD 8010 codes, where I.S. EN 14161 is either silent or provides passing reference only. It is recommended that these areas be adopted.

NB: The number associated with each paragraph description below is the section referenced in I.S. EN 14161.

(e.g. 5.2 Categorisation of fluids refers to Section 5.2 of I.S. EN 14161 on this subject).

4 GENERAL

4.1 Health, Safety and Environment

Compliance - Environmental aspect of design

I.S. EN 14161 does not address environmental aspects of design.

I.S. 328 does not reference the environmental aspects of design in this code.

In BS PD 8010 Section 4.3.1, "Environmental Management System" BS EN 14001 covers the environmental aspects of design.

It is proposed that BS PD 8010 Section 4.3.1 be adopted specifically for its reference to BS EN 14001, and should supplement the requirements in I.S. EN 14161 Section 4.1 - Health, safety and the environment.

4.2 Records

Design Assurance System

I.S. EN 14161 does not include a design assurance system of the type given in BS PD 8010.

Similarly this is also the case for I.S. 328.

BS PD 8010 shows all aspects of the design process (including the construction and commissioning element) and ensures that the Code requirements are included at all stages of design.

It is proposed that the approach taken in Section 4.4 of BS PD 8010 supplements I.S. EN 14161 Section 4.4 – Records.

4.3 Categorisation of fluids

I.S. EN 14161 lists five categories of fluids that can be referenced in the design.

I.S. 328 Section 1 uniquely refers only to natural gas and in line with acknowledgement of TAG of the suitability of this code for the transmission of Corrib gas; it is therefore recommended that this reference category only be adopted.

4.4 Public safety and protection of the environment

This section of I.S. EN 14161 refers to supplementary requirements for gas carrying pipelines with respect to maximum hoop stresses and pressure testing.

These requirements are detailed in Annex B of the code.

Annex B details:

- location classification,
- population density,
- concentration of people
- and maximum hoop stresses.

Maximum hoop stress design factors given in Table B2 of the Annex B do not reference a design factor of 0.3, which is a TAG requirement.

I.S. 328, through reference to sections 6.2, 6.3, 6.4 and 6.5 addresses:

- location classification (Section 6.2)
- population density (Section 6.2)
- concentration of people (Section 6.2 and 6.4)
- and maximum hoop stress (Section 6.3 and 6.5.) It references the design factor requirement of 0.3. (Section 6.3).

It is recommended that I.S. 328 Sections 6.2, 6.3, 6.4 and 6.5 should be adopted in preference to the following Sections in I.S. EN 14161:

Section 5.6	– Public Safety and Protection of the Environment;
Section 6.2.1.2	– Public Safety
Annex B	– Supplementary requirements for public safety of pipelines for category D and E fluids on land.

4.5 Strength requirements

The following two sections of I.S. EN 14161, with associated sub headings both reference design factors directly or by implication:

4.5.1 Calculation of stresses

4.5.1.1 Hoop Stress due to fluid pressure

I.S. EN 14161 Sections 6.4.1.1 and Section 6.4.1.2 and Appendix B all define the specified minimum wall thickness t_{min}, based on hoop stress design factors that range from 0.83 to 0.45 depending on fluid type and location class.

I.S. 328 Sections 6.2, 6.3, 6.4 and 6.5 define the wall thickness t, based on design factors that range from 0.72 to 0.3 depending on area type classification.

BS PD 8010 Sections 6.2, 6.3 and 6.4 define the minimum wall thickness t_{min}, based on hoop stress design factors ranging from 0.72 to 0.3, depending on fluid type and location class. Design factors greater than 0.72 are permitted in Class 1 locations provided the increase in failure probability and risk can be shown to be not significant. BS PD 8010 Section 6.2.2.2 also gives guidance on prevention of collapse under external loading.

It is recommended that I.S. 328 Sections 6.2, 6.3, 6.4 and 6.5 is adopted for the calculation of hoop stress due to fluid pressure, supplemented with BS PD 8010 Section 6.2.2.2 – straight pipe under external loading. This will satisfy the TAG requirement that the pipeline has a design factor of 0.3 and that the provisions of I.S. 328 and BS PD 8010 are adopted where they exceed I.S. EN 14161.

4.5.1.2 Other stresses

I.S. EN 14161 Section 6.4.1.2 – Other Stresses provides guidance on calculations of equivalent stresses under functional, environmental and construction loads.

I.S. 328 does not reference other stresses in detail.

BS PD 8010 Section 6.4.2 – Calculation of Stresses provides detailed guidance and calculation of longitudinal, shear and equivalent stresses.

It is recommended that BS PD 8010 Section 6.4.2.3 – Longitudinal Stress and Section 6.4.2.4 – Shear Stress, should supplement I.S. EN 14161 Section 6.4.1.2 – Other Stresses.

4.5.2 Strength criteria

4.5.2.1 General

I.S. EN 14161 Section 6.4.2.1 – General, is adequate and recommended for adoption.

4.5.2.2 Yielding

I.S. EN 14161 Section 6.4.2.2 – Yielding, defines the maximum hoop stress but utilises higher design factors greater than the project prescribed 0.3. Allowable equivalent design factors are also defined. The functional plus environmental design factor is 0.9.

I.S. 328 Section 6.3 and 6.5 adequately defines the maximum hoop stress, but does not define the allowable equivalent stress.

BS PD 8010 Section 6.4.3.2 - Allowable equivalent stress, provides clear guidance on this issue. The functional and environmental design factor is 0.9.

It is recommended that BS PD 8010 Section 6.4.3.2 - Allowable equivalent stress should supplement I.S. 328 Section 6.3 and 6.5.

The recommendations for considering Buckling, Fatigue and Ovality are dealt with below:

4.5.2.3 Buckling

I.S.EN14161 - 6.4.2.3 Buckling is referenced but is not detailed.

I.S. 328 is not specific on the issue “Buckling”.

BS PD 8010 - Section 6.4.4 Buckling is more thorough than the relevant section of I.S.EN14161 code.

It is recommended that BS PD 8010 - Section 6.4.4 Buckling should supplement I.S.EN14161 - 6.4.2.3.

4.5.2.4 Fatigue

I.S.EN 14161 - 6.4.2.4 Fatigue is referenced but is not detailed.

Additionally, I.S. 328 Fatigue is not detailed.

BS PD 8010 - Section 6.4.2.4 Fatigue is more thorough than the relevant section of I.S.EN14161 code.

It is recommended that BS PD 8010 - Section 6.4.2.4 Fatigue supplement I.S.EN14161 - 6.4.2.4 Fatigue.

4.5.2.5 Ovality

I.S.EN 14161 - 6.4.2.5 Ovality is referenced but is not detailed.

Additionally I.S. 328 does not specifically address ovality.

BS PD 8010 Section 6.4.4.2 references Annex H for calculating ovality.

It is recommended that BS PD 8010 Section 6.4.4.2 be adopted.

4.6 Pressure test requirements

The SEPIL document addressing the recommendations is ‘’ Onshore Hydrostatic Testing Report, Corrib Document No. 05-2377-01-P-3-020.

4.7 Crossings and Encroachments

Impact Protection

I.S. EN 14161 Section 6.9 does not give any guidance or direction on the issue of impact protection to protect the pipe from third party activity.

I.S. 328 Section 6.9 - Crossings and encroachments Fig 3 gives clear guidance on the requirements for impact protection.

It is recommended that I.S. 328 Section 6.9 - Crossings and encroachments Fig 3, supplement the recommendations given in I.S. EN 14161 Section 6.9.

Trenchless Technologies

I.S. EN 14161 does not consider trenchless technologies.

However, BS PD 8010 (Section 6.10) and I.S. 328 (section 8.20.1.2) cover this in detail, with the former being more comprehensive.

It is recommended that BS PD 8010 Section 6.10 – Trenchless technology supplements I.S. EN 14161 Section 6.9 - Crossings and encroachments, because of its more thorough approach.

5 DESIGN OF STATION AND TERMINALS

5.1 Equipment

I.S. EN 14161 – Section 7 is silent on control equipment associated with isolation valves.

I.S. 328 – Section 15.5 has slightly more detail.

However BS PD 8010 Section 7.6 Equipment, is more detailed and references the integration of high integrity protective system (HIPPS) into the design where appropriate.

It is recommended that BS PD 8010 Section 7.6 – Equipment - be adopted to replace I.S. EN 14161 Section 7.7 - Equipment.

5.2 Primary Piping – Demarcation between Pipeline and Piping system

I.S. EN 14161 Section 1 – Fig 1 is not clear where the point of demarcation between station pipework and the pipeline falls.

I.S. 328 is uniquely for gas systems and is clear on pressure reduction stations, but is not so clear on the interface at pig trap stations.

The clearest and most unequivocal Code on this issue is BS PD 8010 Section 7.7.1. It is for this reason that it is BS PD 8010 is preferred.

It is recommended that BS PD 8010 Section 7.7.1 – Primary piping should supplement I.S.. EN 14161 Section 1 – Fig 1.

5.3 Electrical

I.S. EN 14161 Section 7.10 - Electrical, does not address protection from lightning strikes at above ground facilities.

I.S. 328 Section 16.3 - Earthing/equipotential bonding provides clear guidance on the requirements for lightning protection.

The same applies to BS PD 8010 Section 7.9, which is quite specific on lightning requirements.

It is recommended that I.S. 328 Section 16.3 - Earthing/equipotential bonding, supplements I.S. EN 14161 Section 7.10 Electrical.

5.4 Factory Bends

EN 14161- Section 8.3 –Components, gives no guidance on permitting factory made bends or elbows.

I.S. 328 also gives no guidance on allowing factory bends.

It is recommended that BS PD 8010 Section 10.12.6 - Factory bends, supplements EN 14161- Section 8.3 Components as clear guidance is given on the provision of factory bends.

Appendix Q4

Technical Details

Q4.1: Onshore Pipeline Design Review
Q4.2: Offshore Design Basis and Addendum No 1 to Offshore Design Basis
Q4.3: Landfall Valve Installation Design Justification and Overview
Q4.4: Appraisal of Alternative Configurations for the LVI Safety Shutdown System
Q4.5: Aspects of Process Engineering Design of the Corrib Production System
Q4.6: Reliability of Overpressure Protection Systems for Offshore and Onshore Pipelines
Q4.7: Materials and Corrosion Management Premises
Q4.8: Assessment of Locally Corroded Pipe Wall Area
Q4.9: Assessment of Wet Gas Operation, Internal Corrosion and Erosion
Q4.10: Denting and Puncturing Evaluation

Shell E & P Ireland Limited CORRIB FIELD DEVELOPMENT PROJECT REPORT	J P KENNY Corrib natural gas

Corrib Onshore Pipeline EIS APPENDIX Q4.1 ONSHORE PIPELINE DESIGN OVERVIEW	PROJECT No. 052377.01 REF **CTR 349** No OF SHEETS 18

DOCUMENT No	OFFICE CODE	PROJECT No	AREA	DIS	TYPE	NUMBER
	05	**2377**	**01**	**P**	**3**	**043**

REV	DATE	DESCRIPTION	BY	CHK	ENG	PM	CLIENT
03	17/05/10	Issued for Planning Application	JG	GSW	GSW	JG	
02	4/05/10	Issued for Comment	JG	GSW	GSW	JG	
01	8/03/10	Issued for IDC	JG	GSW	GSW	JG	

CONTENTS

ATTACHMENT Q4.1A

Onshore Pipeline Stone Road Settlement Analysis For Pipelines And Services

1 INTRODUCTION

The purpose of this document is to provide a design overview of the onshore gas pipeline and associated service lines between the Landfall Valve Installation (LVI) at Glengad through to the Bellanaboy Bridge Gas Terminal. The service lines comprise the outfall pipeline, the three umbilicals, the fibre optic cable and the electrical signal cable.

2 GENERAL DESIGN PARAMETERS

2.1 Environmental Data

Environmental data for the pipeline route is listed below, for years 1991 to 2000. Data received from Met Eireann.

Max air temperature:	28 deg C
Monthly mean max temperature range:	8.9 to 18.2 deg C
Min air temperature:	-5.5 deg C
Monthly mean min. temperature range:	3.9 to 12.2 deg C
Mean annual rainfall:	1269 mm
Max daily rainfall:	40 mm
Max hourly rainfall:	25.9 mm
Mean days ≥ 0.2mm rainfall:	254 days/year
Mean monthly wind speed range:	11.7 to 16.2 knots
Max wind speed (gust):	93 knots

2.2 Design Life

The pipeline, outfall pipeline, the umbilical and both the fibre optic and signal cables have a design life of 30 years.

3 PIPELINE ROUTE

3.1 Route Summary

The selected route for the Corrib onshore pipeline is detailed in Chapter 3 and illustrated in Appendix A Drawing DG103.

The onshore gas pipeline commences from the tie-in weld at the downstream barred tee of the LVI. The pipeline then traverses the Glengad headland, in an east-south-easterly direction for approximately 640m. The pipeline then proceeds ~4.9 km within a dedicated tunnel in generally a south easterly direction beneath Sruwaddacon Bay. The end of the Tunnel is situated near Aghoos. At Aghoos, the pipeline route turns in an easterly direction for approximately 0.9km, traversing an area of blanket bog within which it crosses an approximately 40m wide estuarine river channel. The route then enters an area of forested bog (approximately 2.2km long) where it turns in a southerly direction, at the crossing of the L1202, and continues to the Bellanaboy Bridge Gas Terminal site.

3.2 Glengad Headland

The section of route from the LVI to the Tunnel entrance along the Glengad Headland is generally improved grassland and the gas pipeline will be buried with a minimum of 1.2m depth to the top of pipe. This section is traversed by a number of small ditches with run-off from the surrounding terrain. Additional protection will be incorporated to minimise any impact of scour or 3rd party damage.

The cross section of trench for the gas pipeline and the associated services within this section is illustrated in Appendix A, Drawing DG604.

3.3 Tunnel Under Sruwaddacon Bay

A description of the Tunnel through Sruwaddacon Bay is provided in Chapter 5 and. Appendix A, Drawings DG401 to DG404.

The Tunnel is a concrete segment lined construction of some 3.5m internal diameter. The alignment of the Tunnel in Sruwaddacon Bay has been selected to meet the hazard and risk assessment criteria set by the authorities and to minimise the impact on the environment.

The pipeline and associated services will be installed individually in the Tunnel and the cross section is illustrated in Chapter 5 Figure 5.5. On completion the Tunnel will be fully grouted.

3.4 Aghoos to Gas Terminal

From the Tunnel exit near Aghoos, the pipeline transverses a 0.9km section of blanket bog and then crosses the approximately 40m wide Leenamore river channel. From there the route enters forested bog up to the road crossing (RDX1) of the L1202. From the road crossing the route continues with a short section of forested bog and then blanket bog to the boundary of the Gas Terminal.

Throughout this section the pipeline and associated services will be installed within a stone road (refer Section 3.6). At the Leenamore crossing a specific crossing technique will be adopted as detailed in Chapter 5 and illustrated in Appendix A Drawing DG703.

Similarly at RDX1 a specific road crossing method will be adopted as illustrated in Appendix A Drawing DG701.

Throughout this section of the route, the gas pipeline will be buried to a minimum depth of 1.2 m.

The cross section of the gas pipeline and the associated services within the stone road is illustrated in Appendix A, Drawing DG601.

3.5 Tie-in at Gas Terminal

As the pipeline approaches the Gas Terminal boundary fence, the depth of cover will be maintained at a minimum of 1.2m to the top of the gas pipeline. Within the Gas Terminal site the pipeline crosses an internal site access road before rising above ground for interconnection to the Gas Terminal isolation valves and pig receiver. Where the pipeline rises above ground, an specially manufactured Isolation Joint will provide electrical isolation between the Gas Terminal pipe work and the onshore pipeline Cathodic Protection system. To minimise the forces imposed on the Gas Terminal above ground pipe work a buried concrete anchor block will be installed before the onshore pipeline rises above ground. (Refer Section 4.19)

The outfall pipeline, the umbilicals, the fibre optic cable and the signal cable will all terminate at positions close to the gas pipeline pig receiver.

The receipt facilities at the Gas Terminal are illustrated in Figure 3-1.

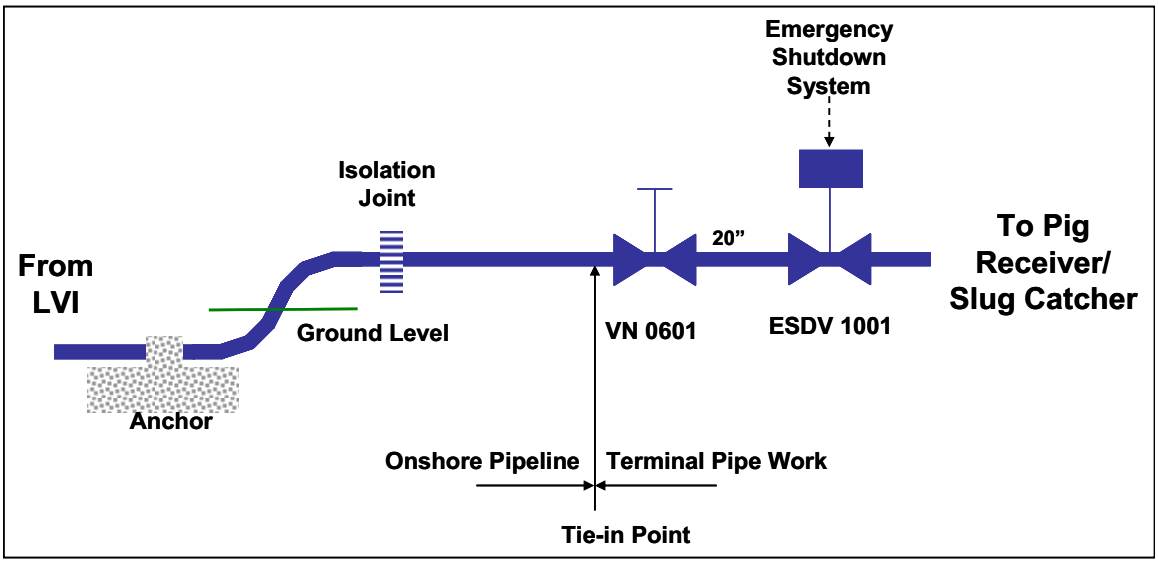


Figure 3-1 Pipeline Facilities at the Gas Terminal

3.6 Stone Road

The method of construction of the stone road is presented in Chapter 5. The top layer of peat turf is stripped and stored. The lower section is excavated and removed from the site. The road is constructed by backfilling with stone to form the stable base within which the onshore gas pipeline and services can be installed with the top of the gas pipeline buried to a minimum depth of 1.2m. The ground surface above the stone road is reinstated using the stored turfs.

As the stone backfill is carefully compacted, no movement of the stone road within the peat is expected. The potential for movement of the stone road has been evaluated and presented in Appendix M. The analysis established that there was no horizontal movement of the stone road in the peat. Small changes in vertical movement may occur and these have been quantified. To ensure that any such vertical movement would not result in loss of containment from the gas pipeline and that the displacements would not affect the services, an analysis was performed taking into consideration the worst case vertical displacements that could be considered along the route of the stone road.

The analysis established that the effects on the services were within the design parameters and thus no consequential effects result from the worst case vertical displacement. For the gas pipeline the calculations established that the resultant pipeline stresses were 408 MPa and within the allowable limits stated by the respective pipeline code. The highest values were identified as occurring during hydrostatic testing of the onshore pipeline. (Refer Attachment Q4.1A for additional details)

To verify the integrity of the gas pipeline, with respect to ground movement within the stone road, a movement monitoring programme will be adopted. This will involve short term (during construction) and long term (post construction) high accuracy surveys carried out regularly along the pipeline route to identify any indications of movement of the stone road. GPS plates will be installed where appropriate to assist this monitoring. As part of the movement monitoring programme, piezometers will be installed adjacent

to the stone road to allow monitoring of groundwater levels. The frequency of monitoring will be tailored based on the results of the ongoing monitoring. The monitoring proposals are included in Appendix M2.

4 ONSHORE GAS PIPELINE DESIGN

4.1 Flow Rates

Design Flow Rate	350 MMSCFD (dry sales gas)
Maximum Flow Rate:	350 MMSCFD (dry sales gas)

4.2 Pressures

Design Pressure:	144 barg
Normal Operating Pressure (onshore section, at start of field life):	90 to 85 barg
Hydrostatic Test Pressure	504 barg

4.3 Temperatures

Maximum Design Temperature:	50°C
Minimum Design Temperature	
20 inch pipeline from LVI to ~1100m downstream of the LVI	-20°C
20 inch pipeline from ~1100 m downstream of the LVI to Gas Terminal	-10°C

For design conditions at the Landfall Valve Installation refer to Appendix Q4.3.

4.4 Fatigue

Normal Diurnal Pressure Range:	90 to 85 barg
Number of Cycles Between Diurnal Pressure Range:	11000
Number of Cycles Between Design Pressure Range:	30

Pressure cycles in the pipeline will be recorded via the DCS at the Gas Terminal. This data will be evaluated on an annual basis and the pressure cycles will be counted. The actual pressure cycles will be compared with the allowable pressure cycles to assess potential fatigue.

4.5 Gas Production

The Corrib field gas will be produced as water saturated gas with small quantities of free water. Early years of production, including start-up, will require use of the wellhead choke valves. Cooling of the gas subsea reduces the temperature to below the hydrate formation point at normal operating pressure. Methanol is used during start-up and in normal operation to prevent hydrate formation.

For information on well product composition, produced water and production profile refer to Appendix Q4.2.

No operational blowdown of the gas pipeline is planned. If required under upset conditions, a pipeline depressurisation procedure at the Gas Terminal will be undertaken in such a manner so as not to induce hydrate formation.

4.6 Design Pressure

TAG recommended, following issue of the Advantica Independent Safety Review, that the pressure in the onshore pipeline should be limited to no greater than 144 barg. This

value of 144 barg was therefore selected as the design pressure for the onshore gas pipeline.

4.7 Selection of MAOP

From the pipeline codes; the maximum allowable operating pressure (MAOP) is the maximum steady state pressure at which a pipeline system is allowed to be continuously operated. The MAOP is the sum of the static head pressure, the pressure required to overcome friction loss and any required backpressure. Furthermore, the MAOP shall not exceed the design pressure. In pipeline code I.S. 328 this is referred to as the maximum operating pressure (MOP).

For the onshore pipeline the highest daily operating pressure at the LVI is expected to be around 90 barg. Allowing a margin for the over-pressurisation protection trip settings an MAOP of 100 barg has been established.

4.8 Hydrostatic Pressure Test

Prior to commissioning, the onshore pipeline will be hydrostatically tested to a defined pressure at the lowest point of the pipeline. The test pressure will be maintained for a period of 24 hours.

The hydrostatic test pressure for the onshore pipeline was established following the recommendation from the Advantica and TAG reports and presented is in Appendix Q5.3. This determined that the onshore pipeline Hydrostatic test pressure will be 504 barg. This is defined in the codes as a High-level hydrostatic strength test. Successful completion of the test at this level demonstrates that any remaining defects are considerably smaller than would fail at the operating pressure. It provides a rigorous demonstration of a quantified safety margin that accommodates an allowance for defect growth during service.

This hydrostatic test pressure is:

- 5.6 times the daily operating pressure (90 barg)
- 5.0 times the MAOP (100 barg)
- 3.5 times the Design Pressure

4.9 Design Location and Design Factor

From the TAG recommendations following issue of the Advantica Independent Safety Review, the classification of design location should be suburban which would be consistent with the design of pipelines passing through more densely populated suburban areas. In I.S. 328 this is defined as a population density exceeding 2.5 persons per hectare but not classified as central areas of highly populated towns and cities. This is more stringent than the rural classification where the population does not exceed 2.5 persons per hectare.

Subsequently the design factor for the onshore pipeline will be 0.3 (as defined in pipeline code I.S. 328). This is further detailed in Appendix Q6.2.

4.10 Corrosion Allowance

From a detailed analysis of the potential for corrosion over the expected field life of the project, an allowance of 1.0 mm was determined for the Onshore Pipeline. Refer to Appendices Q4.7 and Q4.9.

4.11 Selected Wall Thickness

The wall thickness of the onshore pipeline is determined in accordance with pipeline code I.S. 328. It should be noted that each of the codes utilise the same principle of the Barlow formula. However each code applies the formulae with subtle differences.

The factors comprising the Barlow formula are design pressure, pipe diameter, wall thickness of the pipe, design factor and specified minimum yield strength of the pipe (i.e. SMYS or the strength of the pipe material).

It is noted that a lower numerical value of Design Factor increases the wall thickness. Also the higher the design pressure the higher the wall thickness.

By applying the design parameters to the Barlow formula gives a value of wall thickness for pressure containment. Added to this are manufacturing tolerances (1mm) and the corrosion allowance of 1mm giving a nominal pipe wall thickness of 27.1 mm.

4.12 Materials

The line pipe has been manufactured from carbon steel as specified in DNV pipeline code DNV-OS-F101:2000. The specification includes the following main points:

- SMYS: 485 N/mm^2
- Wall thickness manufacturing tolerance: +/- 1mm
- Corrosion allowance: 1mm
- Nominal Wall thickness (onshore section): 27.1mm (inclusive of 1mm corrosion allowance)
- Nominal outside diameter: 20”

4.13 Field Welding

The lengths of 20” dia onshore line pipe will be welded in the field by qualified welders. Welding will be in accordance with the requirements of I.S.328:2003 and in particular I.S. EN 12732.

4.14 External Coating

4.14.1 Linepipe

The factory applied external anti-corrosion coating protection for the onshore line pipe is a three layer polypropylene systems (3LPP). This system comprises a high performance fusion bonded epoxy (FBE) followed by a copolymer adhesive and an outer layer of polypropylene which provides the toughest, most durable pipe coating solution available.

4.14.2 Field joints

Where the line pipe sections are welded together in the field, the section of jointed pipe at the weld is protected by an anti-corrosion coating termed field joint coatings. For the onshore pipeline they take the form of a sleeve or wrap. This shrinks in the circumferential direction under the influence of heat forming an adherent field joint coating. The shrink sleeve consists of a polyolefin based backing with an adhesive layer (mastic or hot melt) on one side. The shrink sleeve will be applied with a primer.

4.15 Cathodic Protection

The onshore pipeline will be primarily protected against external corrosion by a high integrity external coating (Refer Section 4.14). Secondary protection will be provided by cathodic protection. Cathodic protection is maintained in two distinct stages:

- Temporary cathodic protection will be provided for the pipeline during installation. It will also ensure that no part of the pipeline is exposed to the environment unprotected for more than thirty days after backfill.
- The completed onshore pipeline installation will be cathodically protected by a permanent impressed current system from a mains powered transformer rectifier unit located at the Gas Terminal. The system will include test facilities for proper adjustment and monitoring to ensure that it does not interfere with and cause corrosion to third party facilities encountered along the pipeline route. An anode ground bed supported by carbonaceous backfill will be installed near the Gas Terminal.

The Advantica Independent Safety Review recommended that a factory built insulation joint should be considered at the landfall to separate the offshore and onshore CP systems. Alternatively the detailed CP system design should be revised to take account of the possible effects of the offshore section.

An independent review of the inclusion of an isolating joint at the LVI concluded that an isolation joint should not be installed at the interface with the offshore and onshore pipelines. The review noted that the structural integrity of the pipeline system could be compromised. In addition, it would provide a point susceptible to internal corrosion damage. Furthermore burial of the isolation joint at the LVI was not considered best practice.

The review confirmed that validation of the effectiveness of the cathodic protection onshore can be achieved through use of ‘polarisation coupons’ installed at frequent points along the pipeline route. Current drain of the onshore impressed current CP system from the offshore pipeline was considered unlikely but could be mitigated by appropriate design of the onshore CP system. TAG evaluated and accepted this independent review.

Electrical isolation will be provided for any above ground, earthed or bare connections at the LVI or any other metallic connections to the gas pipeline.

Electrical isolation will be provided upstream of the Terminal by means of a monolithic isolation joint.

Cathodic Protection Test Posts will be located along the route of the onshore gas pipeline and at the LVI. These enable the CP voltage potentials to be measured and interpreted to establish the effectiveness of the CP system. Within the Tunnel the test cables will be brought to the Tunnel entrances and connected to the test posts.

4.16 Bends

The minimum bend radius for factory made hot bends shall be 5D. The minimum bend radius for cold field bends shall be 40D.

4.17 Pigging

The onshore pipeline shall be designed to permit intelligent pigging. Pipeline internal diameters shall meet the requirements for the operation of all forms of pigs. There is no normal operational requirement to run pigs.

During operation pigs will be launched from the subsea manifold removable pig trap and received at the pig receiver located in the Gas Terminal. The 20" dia mainline valve at the LVI will be opened during pigging and the LVI will be permanently manned during the pigging operation.

4.18 Crossings

The onshore pipeline route includes estuary, stream, road and track/ditch crossings.

For the tunnel under Sruwaddacon bay, refer to Section 3.3.

The protection of the pipeline at road and track crossings will be as illustrated in Appendix A Drawing DG701.

In addition, road crossings will be in accordance with the requirements of the appropriate regional or local highways agency. Crossings of roads and tracks will generally be open cut.

Ditches and minor waterways will be crossed using the open cut method with cofferdams and the pipe laid under the base of the watercourse and protected where dredging and cleaning of the channels is expected.

Other buried services will be crossed in accordance with the individual owner's requirements but will follow the convention of crossing beneath existing services with protection between them unless indicated otherwise.

Pipeline protection in the form of concrete coating, concrete slabs and marker tape will be incorporated where required against external interference.

4.19 Anchor

A pipeline anchor will be installed in the Gas Terminal site, at a point before the onshore pipeline comes above ground for interconnection to the Gas Terminal pig receiver. The purpose of the anchor is to withstand the forces transferred from the pipeline to the above ground pipe work and thus prevent movement of the pig receiver and above ground pipe work. The forces in the pipeline are generated when there are changes in pressure and/or temperature of the buried onshore pipeline between the installation conditions and the operating or test conditions. At the Gas Terminal, the highest forces occur during hydrostatic testing of the onshore pipeline.

The anchor typically comprises a special carbon steel flange (solid circular plate) and a reinforced concrete foundation. The anchor flange is fully welded in the pipeline and does not include any bolted connection or gasket. The flange extends outside the circumference of the onshore pipeline in order to engage into the concrete foundation. This enables the transfer of load to the reinforced concrete foundation, and then into the ground.

4.20 Leak Detection

The primary Leak Detection System for the Corrib pipeline, which includes the onshore section and the LVI, is achieved by a mass balance system. This compares the pressures and flows at subsea and at the Gas Terminal using various statistical and mass balance techniques. It monitors both the onshore and offshore sections with an interface to the DCS that alerts the operator in the event of a problem.

A secondary independent system for the onshore pipeline utilises the properties of the fibre optic cable and is described in Section 7.2.

5 OUTFALL DESIGN

5.1 General

The outfall pipeline will be designed to carry treated surface drainage water from the Gas Terminal to a diffuser positioned approximately 12.8 km offshore in Broadhaven Bay. The onshore section of the gas pipeline and outfall pipeline will be laid adjacent to each other within a common easement. The outfall pipeline may also be utilised during hydrostatic testing of the onshore gas pipeline between the LVI and the Gas Terminal (Refer Appendix Q2.1 Section 7)]

The outfall will be full of potable water once testing and commissioning has taken place.

5.2 Operational Parameters

The outfall pipeline is designed for the following conditions after commissioning:

Design Maximum Flow Rate:	85 m3/hr
Minimum Pump Flow:	3 m3/hr
Design Pressure:	16 barg
Maximum Operating Pressure:	8.5 barg
Minimum Operating Pressure:	0 barg
Maximum Design temperature:	35^0C
Minimum Design Temperature:	0^0C
Design Life:	30 years

Prior to commissioning, the maximum pressure in the outfall line during pipeline hydrostatic testing will be 20 barg at the low point.

5.3 Codes and Standards

The primary code applicable to the planning, design, construction and commissioning of the onshore section of the outfall pipeline shall be:

I.S. EN 14161 2004 Petroleum and Natural Gas Industries – Pipeline Transportation Systems (ISO 13623:2000 Modified)

The following standards shall also be deemed to apply:

ISO. 4427-2007 Plastic piping systems – Polyethylene (PE) pipes and fittings for water supply.

5.4 Outfall Design

Taking into account pressure losses, velocity limits, installation requirements and flow cycles amongst other considerations the outside diameter selected for the outfall pipeline is 250mm.

The design pressure for the Outfall Pipeline will be 16 barg.

The offshore section of the outfall pipeline has been installed as a piggy-back with the offshore gas pipeline. It has been hydrostatically tested to 6 barg.

The onshore section of the outfall pipeline will be hydrostatically tested to 20 barg.

The 250 mm OD polyethylene (PE) pipe is selected with grade of PE80 SDR17 for the offshore section and PE100 SDR11 for the onshore section.

The subsea diffuser is buried and discharges to sea in a vertical direction.

Along the onshore section of the outfall line, permanently installed vent valves will be required to facilitate commissioning. These will be located at high points and installed below ground. They may be used infrequently during operation should air become entrapped in the outfall line (Refer Appendix A Drawing DG802 for a typical vent valve).

The outfall line ties-in to the Gas Terminal facilities at a point close to the gas pipeline pig receiver.

6 UMBILICAL DESIGN

6.1 General

The umbilicals are utilised to communicate services between the Gas Terminal and the subsea facilities. At the subsea manifold the individual connections are made to the subsea wells via jumpers. The cores within the umbilical are described in Section 6.2.

The offshore section from the landfall to the LVI is constructed as a single umbilical laid parallel to the 20” dia gas pipeline. The limit to the maximum umbilical length that can be installed offshore in a single length depends on the maximum weight & volume of the umbilical that can be accommodated by the installation vessel. The number of functions (tubes & cables) is an important determinant of the weight & volume per unit length and thus of the maximum umbilical length achievable. The installation payload of the latest generation of marine construction vessels, equipped either with reels or hull or deck carousels continuously increases. For the Corrib application the offshore umbilical has been reeled as two equal lengths.

The onshore umbilical system will run a distance in the region of 8.3km between the Landfall Valve Installation at Glengad, where a connection with the offshore umbilical shall be made at an Onshore Termination Unit (OTU), and the gas processing Gas Terminal at an Onshore Terminal Termination Unit (OTTU). The umbilicals will be a composite system containing methanol injection system cores, control system lines (communication signals, electrical and hydraulic power) and produced water. To facilitate handling and installation, the onshore umbilical system comprises three umbilicals with intermediate connections at suitable intervals (~ 1km to 1.5 km).

The typical cross section for the onshore umbilical is presented in Appendix A Drawing DG801 and Chapter 4 Figure 3 and illustrated in Figure 6-1.

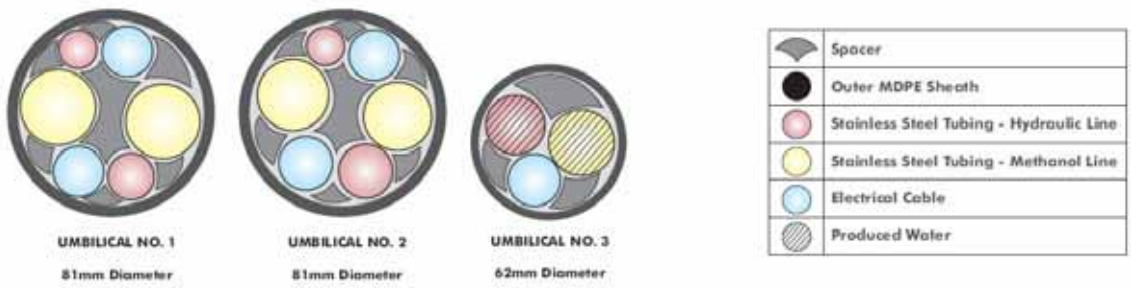


Figure 6-1. A schematic of the Corrib onshore umbilicals

6.2 Umbilical Configuration

The singe offshore umbilical combines all the services into a single multi-element cable.

Onshore, two of the umbilicals (No's 2 and 3) carry the electrical power supply cables, data communications cables, hydraulic fluid pressure lines and methanol lines. The third umbilical (No 1) carries a spare hydraulic fluid pressure line, a supply line for treated produced water disposal, and a spare cable. The duplicated electrical power supply cables, data communication cables and hydraulic fluid pressure lines are carried in different umbilicals.

Details of the elements that comprise the umbilical system are as follows:

6.2.1 Electrical Power and Communications Systems

Duplicated Electrical Power Supply Cables:	Screened Twisted Pairs
Duplicated Data Communications Cables:	Screened Twisted Pairs
One Common Spare Cable:	Screened Twisted Pair

All cables are 16mm^2 CSA.

6.2.2 Hydraulic Fluid Supply Systems

LP Supply Lines

Duplicated 210 barg rated: 19mm ID Steel Tubes (proof test 315 barg)

HP Supply Lines

Duplicated 610 barg rated: 12.7mm ID Steel Tubes (proof test 1007 barg)

6.2.3 Methanol Supply System

The four of the methanol supply lines in the Onshore Umbilical System are 25.4mm ID steel tubes rated to 345 barg (proof test 570 barg). Methanol lines will carry a mixture of methanol, corrosion inhibitor and scale inhibitor.

6.2.4 Produced Water Disposal System

One 610 barg rated: 19mm ID Steel Tube (proof test 1007 barg)

One 345 barg rated: 25.4mm ID Steel Tube (proof test 570 barg)

6.3 Connectors

Only proven fully qualified connector designs and systems within umbilical terminations or in-line connection systems will be used.

6.4 Service Fluids

The umbilical cores shall be designed for use with the following fluids:

6.4.1 Hydraulic Control Fluid

A water-based subsea production control fluid. Castrol Transaqua HT2, is transported within the hydraulic lines.

Castrol Transaqua HT2 is 2007 OSPAR compliant with no substitutable components. It is specifically formulated for use as the control medium in surface and subsea production control systems. The fluid incorporates all the features required for operation in a wide range of equipment, and can therefore be used as the operating medium throughout the control system including subsurface safety valve and well control areas.

Castrol Transaqua HT2 has been developed and qualified under a Quality Management System with ISO 9001:2000 certification and an Environmental Management System with ISO14001:2004 certification for Research and Development.

Qualification testing carried out in accordance with ISO 13628-6 Annex C (2006 E).

6.4.2 Chemical Fluids

The primary fluid is methanol which is transported from the Gas Terminal via the umbilical and injected subsea at the wellheads and manifold to mitigate hydrate formation in the unprocessed gas.

A chemical corrosion inhibitor will be added at the appropriate dosage into the methanol in the Gas Terminal. The methanol and corrosion inhibitor mixture will be chemically scavenged for oxygen. Any potential limitations and/or material compatibility issues associated with the methanol, oxygen scavenger and selected corrosion inhibitor will be identified and tested.

6.4.3 Treated Produced Water

Two cores will be used to transport treated produced water from the onshore Gas Terminal to the offshore subsea manifold, where it will be dispersed subsea.

6.5 Codes and Standards

The primary standards for the umbilical system shall be:

ISO/CD 13628 – 5 Design and Operation of Subsea Production Systems – Subsea Control Umbilicals.

ISO/CD 13628 – 6 Design and Operation of Subsea Production Systems – Subsea Production Control Systems.

The latest editions of all codes including revisions and addenda shall be applied.

6.6 Materials

The materials selected for the Onshore Umbilical System shall be fully compatible with the fluids with which they are to be used. Steel tubes shall comply with the requirements of ISO standard 13628-part 5 or API 17E.

All hydraulic and methanol supply and produced water disposal cores and electrical cables within the Onshore Umbilical System shall be uniquely identified.

6.7 Tubing Material

Steel tubes for the hydraulic, methanol and water supply services shall be seamless ferritic-austenitic (super duplex) stainless steel.

The minimum allowable wall thickness for each of the hydraulic and chemical lines and allowable working pressures given the strength of steel to be used, based on the requirements of ISO 13628 part 5, shall be calculated.

6.8 LVI Offtake

The Onshore Termination Unit (OTU) located at the Landfall Valve Installation will provide the connection between the onshore and offshore umbilicals. At the OTU an offtake will be provided to supply methanol to the Landfall Valve Installation.

6.9 Prevention of Failure

The umbilical will be tested to the proof pressures (Refer Section 6.2) to verify the pressure integrity of the installed umbilicals.

The umbilical tubing is manufactured from super duplex steel to protect them from internal corrosion. Also it has an external sheath of polyethylene to provide mechanical and external corrosion protection during handling, installation and use.

To minimise risk from third party damage, the onshore gas pipeline, services (including the three umbilicals) will be laid in a trench approximately 2-3m wide with a minimum depth of cover of 1.2m to the onshore gas pipeline.

Measures which further reduce the risk of accidental damage include regular line walks, marker posts at field boundaries, marker tape about 1 foot above the top of the buried gas pipeline and services together with regular liaison with landowners and utility services.

Where the onshore pipeline traverses Sruwaddacon Bay, the pipeline and umbilicals are installed in a tunnel and thus protected from third party damage. The offshore umbilical is installed in a trench over its full length to protect against third party damage

6.10 Leak Detection

A leak detection system will monitor the methanol lines. This will measure the inlet and outlet flow and pressure of the methanol umbilical cores at the Gas Terminal and the wellheads. A leak of any significant rate would be detected within a short period of time. The Gas Terminal Operator will be alerted to any changes in the flow/pressure patterns and the individual umbilical core can be isolated.

7 FIBRE OPTIC CABLE DESIGN

The steel wire armoured 24 core fibre optic cable will be compliant to ITU-T Rec. G.652. The fibres are manufactured from high grade silica, doped as necessary to achieve the required light guiding properties and designed with a matched-cladding, step-index profile. The fibre coating is a dual layer structure of ultra-violet cured acrylate resin. The outer layer is optimised for abrasion resistance and fibre processing properties.

7.1 Communications

Seven pairs of cores of the fibre optic cable will be utilised for communication between the LVI and the Gas Terminal. These will transfer data regarding the status of equipment at the LVI, measurements from various instruments, the position of valves etc. together with CCTV and security information.

7.2 Supplementary Leak Detection

Up to three cores within the fibre optic cable will be utilised to monitor for leaks or disturbances along the route of the onshore gas pipeline.

The technology to be utilized is based on fibre optic distributed acoustic sensing (DAS). This technique turns the length of fibre optic cable into a series of “electronic microphones” that listen to sounds around the pipeline and the umbilicals. The system typically separates the fibre optic cable in to 10m lengths as individual microphones. All data will be processed simultaneously by the processing unit located at the Gas Terminal.

The processing unit will have the ability to interpret the acoustic signal data received and generate alarms / warnings for the Operator. The system will be configured to recognise and report leaks in pipeline / umbilicals, excavation near to the pipeline and pipeline pig movements.

8 SIGNAL CABLE DESIGN

The signal cable will be a five pair, 1.5mm^2 cross section, cross layered polyethylene insulated cores overall screen, low smoke zero halogen filler, galvanised steel wire armour, low smoke zero halogen outer sheath.

Two separate circuits are used within the cable to transmit the LVI safety shutdown valve close command from the Operator in the Gas Terminal to the LVI.

Field connections between the discrete lengths of signal cable will be required along the length of the installed cable to facilitate handling and installation.

ATTACHMENT Q4.1 A

Onshore Pipeline Stone Road Settlement Analysis For Pipelines And Services

Shell E&P Ireland Limited CORRIB FIELD DEVELOPMENT PROJECT REPORT	J P KENNY Corrib natural gas

Corrib Onshore Pipeline EIS ATTACHMENT Q4.1A STONE ROAD SETTLEMENT ANALYSIS FOR PIPELINES AND SERVICES	PROJECT No. 052377.01 REF CTR 349 No Of Pages 16

DOCUMENT No	OFFICE CODE	PROJECT No	AREA	DIS	TYPE	NUMBER
	05	2377	01	P	3	051

REV	DATE	DESCRIPTION	BY	CHK	ENG	PM	CLIENT
03	20/05/2010	Issued For Planning Application	GSW	JG	GSW	JG	
02	5/05/2010	Issued for Comment	GSW	JG	GSW	JG	
01	14/04/2010	Issued for IDC	NKM	GSW	GSW	JG	

TABLE OF CONTENTS

1 INTRODUCTION

1.1 General

This report should be read in conjunction with Appendix M2 [1].

This report presents the results from Finite Element Analysis (FEA) modelling for the onshore gas pipeline, umbilicals, outfall pipeline, fibre optic cable and signal cable, when subjected to settlement of the stone road in which they are constructed.

This report supersedes the previous report submitted to the 2009 Oral Hearing, 05-2377-01-P-3-035 Rev 02 Stone Road Settlement Analysis, which assessed the onshore gas pipeline.

1.2 Objective

The objectives of this report are:

1) To assess the effect of settlement in all pipelines and services in the trench and to demonstrate that the design settlement values will not cause loss of containment. The pipelines and services covered in this study includes the onshore gas pipeline, outfall pipeline, umbilicals, fibre optic cable and signal cable;

2) To demonstrate the safety margin inherent in the design by estimating the settlement required to cause loss of containment in the onshore gas pipeline;

3) To assess the stresses developed in the onshore gas pipeline during operation due to an unsupported length occurring within the stone road.

1.3 Abbreviations

FEA	Finite Element Analysis
FOC	Fibre Optic Cable
LVI	Landfall Valve Installation
MRS	Minimum Required Strength (for polyethylene pipe)
SEPIL	Shell E&P Ireland Limited
SMYS	Specified Minimum Yield Strength (for steel pipe)

2 EXECUTIVE SUMMARY

A load-displacement analysis of the onshore pipelines and services has been performed to assess the impact on these when subjected to settlement of the stone road. To ensure that the analysis is conservative, and thereby provide a sufficient margin of safety, the analysis has used the displacement values corresponding to Settlement Case 1 [1]. Note that Settlement Case 1 represents the worst case settlement profile.

The study has shown that all pipelines and services remain within their allowable limits under Design and Hydrostatic test (where appropriate) conditions.

For the design case, the onshore gas pipeline is required by the code to remain under 90% of the material SMYS. With the design temperature and pressure, and the Settlement Case 1 profile applied, the onshore gas pipeline remains below 31% of SMYS (or 34% of the allowable stress).

Furthermore, the analyses performed for the onshore gas pipeline use elastic design (the maximum stress calculated using the Von Mises theory must be less than 90% of SMYS). It is noted that a stress level equal to SMYS does not necessarily cause loss of containment. With the pipe stress at SMYS there is further deformation capacity available. With increased loading, local yielding and strain concentration would occur. A strain based approach would show that a significantly higher load can be applied without loss of containment. With the onshore gas pipeline D/t ratio, local buckling/wrinkling is unlikely to occur.

The study for the onshore gas pipeline was extended to determine the settlement displacements at which the onshore gas pipeline would reach SMYS (which is a conservative predictor for pipe loss of containment). This was then compared to the Settlement Case 1 values to demonstrate an additional margin of safety in the design. This showed that the settlement values would need to be increased by a factor of 10 to cause the onshore gas pipeline to reach its SMYS during operation.

3 OVERVIEW

3.1 The Analysis Methodology

Finite Element Analysis was used to perform load-displacement analysis of the onshore gas pipeline and services while subject to settlement. The analysis has used the maximum displacement values, which correspond to Settlement Case 1 [1].

Settlement Case 1 is summarised in Section 4.1 of this report below, and represents the worst case settlement. For a full description of Settlement Case 1, refer to the referenced report.

The FEA model includes the complete length of the onshore gas pipeline within the peat areas, and the corresponding Settlement Case 1 displacements.

The displacements provided are at various distances along the onshore gas pipeline route. The spacing between data points varies from 29m to 160m. Where the onshore gas pipeline is routed through an area of no peat (and negligible settlement) into an area of peat (potential increase of settlement) it will do so with a gradual change from one settlement condition to another.

The stone road will be installed from Aghoos (approximately KP 88.908) to the Gas Terminal (approximately KP 91.720). The FEA model has been set up to represent this section of the onshore gas pipeline.

The FEA model has been intentionally built conservatively. The model includes changes in settlement which occur over short distances, which result in higher calculated stresses than would occur in a gradual transition from an area of no peat, to a peat area. The FEA included fixed end and free end models to cover the worst cases.

The FEA evaluation considers two load conditions:

- The first is settlement during hydrostatic testing when the onshore gas pipeline is full of pressurised water, and
- The second during the onshore gas pipeline operation when the pipeline is full of gas.

For additional conservatism, the design pressure has been used to represent the operating condition. This uses a higher pressure and contents density than the MAOP, and therefore provides higher calculated stresses.

The onshore gas pipeline assessment for unsupported lengths was assessed by calculation, and verified using Caesar II pipe stressing software.

3.2 Investigated Pipelines/ Services

The following pipelines and services were investigated in this study:

- Onshore gas pipeline
- Outfall pipeline
- Umbilicals (x 3)
- Fibre Optic Cable (in duct)
- Signal Cable (in duct)

The onshore gas pipeline and outfall pipeline have been assessed on Von Mises combined stress criteria. The remainder of the services were assessed on allowable curvature, axial strain, and axial load criteria provided by vendors. This is summarised in Table 3-1:

Table 3-1

Service	Assessment Criteria	Tool
Onshore Gas Pipeline	Von Mises Strength (elastic)	FEA
Outfall Pipeline	Von Mises Strength (elastic and elastic/plastic)	FEA
Umbilicals	Strength (vendor axial tension limit) Bend radius (vendor minimum radius limit)	FEA
FOC and Signal Cable in Duct	Strength (vendor axial tension limit) Bend radius (vendor minimum radius limit) Strain (assessment of available loose cable length in jointing chambers)	FEA (on duct)

4 LOAD CONDITIONS MODELLED

4.1 Key Inputs

For details of the pipelines and services within the trench, refer to Appendix Q4.1 [2].

The following load conditions were analysed:

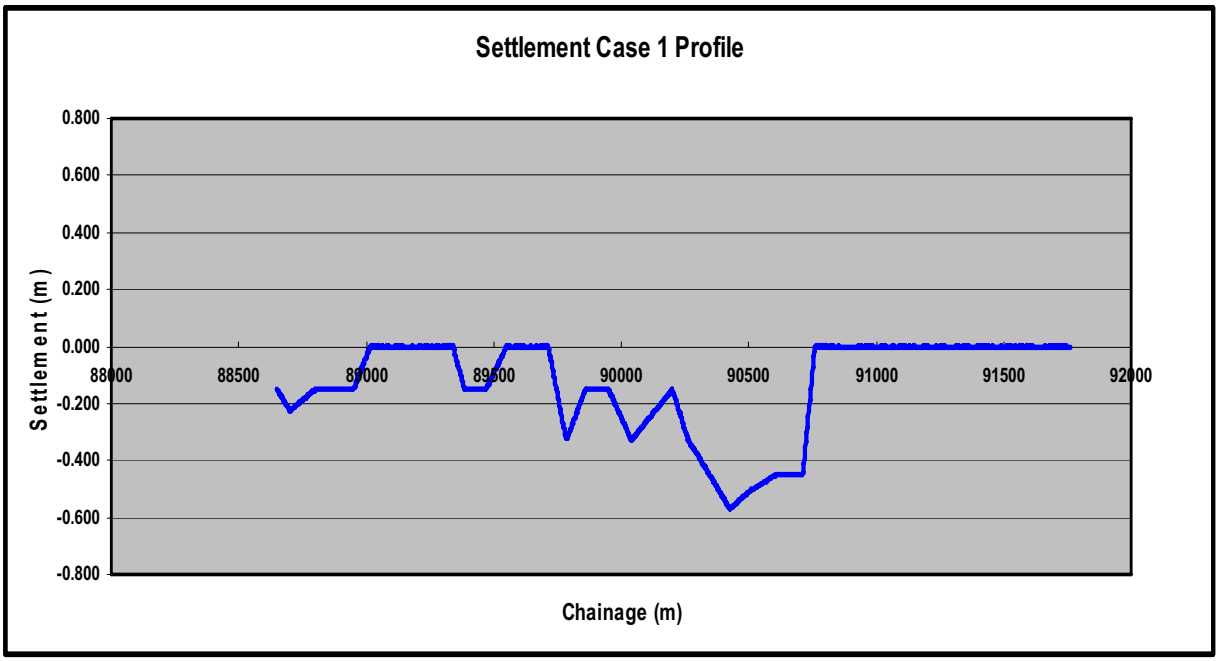
Table 4-1 Load Conditions for 20" Onshore Gas Pipeline

Load Conditions	**1**	**2**
Description	Hydrostatic test (water)	Design (gas)
Pressure (barg)	504	144
Settlement Case[1]	1	1

Note 1: This represents the Settlement Case 1 values [1].

Settlement Case 1, for the second section of peat is summarised in Figure 4-1:

Figure 4-1



A full description of Settlement Case 1 is included in ref. [1].

5 RESULTS

The results of this study are presented below for each pipeline or service. This includes an assessment of the effect of settlement in the particular pipeline or service, for the load conditions as defined in Section 4 of this report.

The results include the calculated and allowable values for the assessment criteria (e.g. stress, tension, bend radius) and the chainage for peak results.

As mentioned above, the onshore gas pipeline assessment was extended to estimate the settlement (in excess of the Settlement Case 1 values) which could lead to loss of containment.

5.1 Onshore Gas Pipeline

The effect of settlement on the onshore gas pipeline was assessed for the load condition as defined in Section 4, and the results are shown below.

5.1.1 Onshore Gas Pipeline - Applied Settlement

The results are presented in Figure 5-1, Figure 5-2 and Table 5-1 below.

In the figures, the following applies:

TOP – represents the stresses at the top of the onshore gas pipeline;

BOT – represents the stresses at the bottom of the onshore gas pipeline.

Figure 5-1

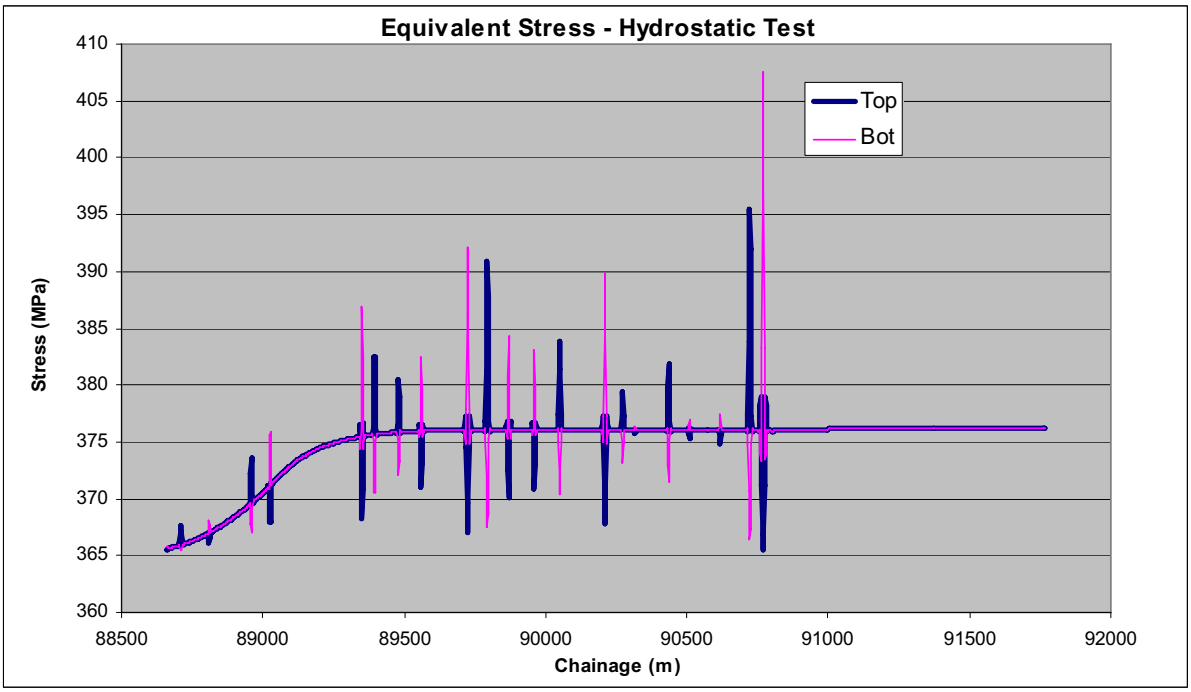


Figure 5-2

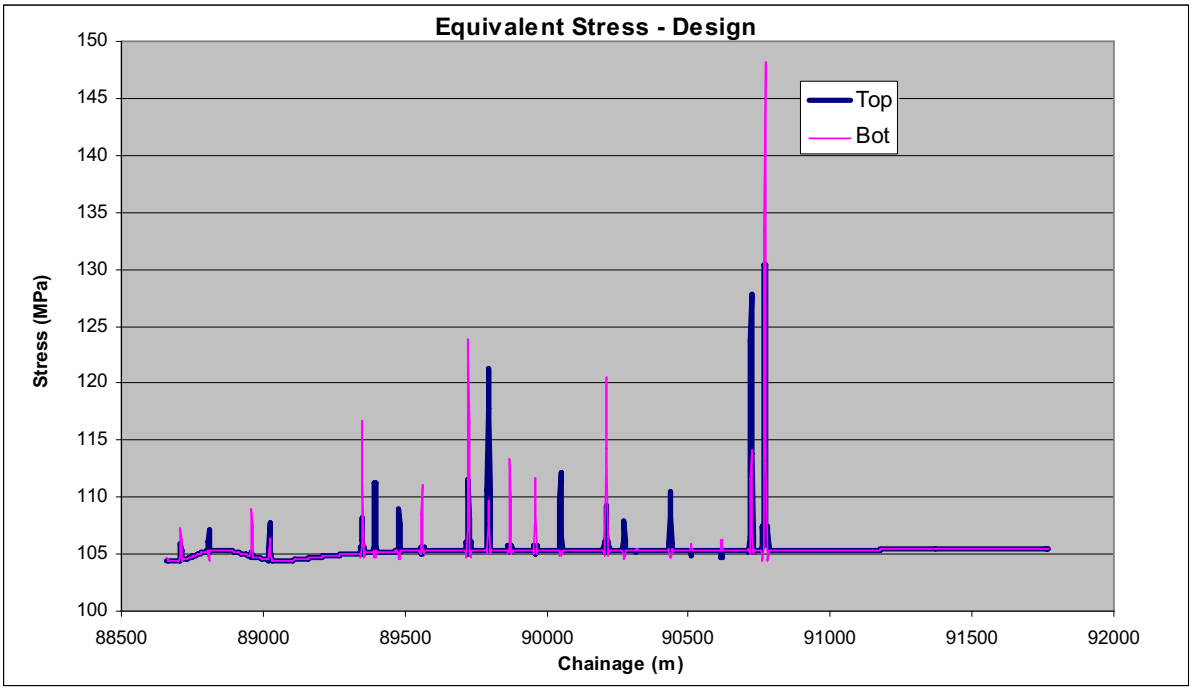


Table 5-1

Onshore Gas Pipeline Settlement Assessment		
Load Condition	**1**	**2**
Description	Hydrostatic Test	Design
Pressure (barg)	504	144
Allowable Stress (MPa) (*)	485	436.5
Maximum FEA Calculated Stress (MPa)	407.6	148.2
Stress Ratio as a percentage of Allowable Stress	84	34

(*) Code I.S. 328, clause 6.4.1 gives the equation for equivalent stress (Von Mises) and 6.4.2 which gives the allowable limits (see Table 3, page 20). These are 1.0 x SMYS for Construction and Environmental load combinations as applied for the Hydrostatic Test case and 0.9 x SMYS for the Functional and Environmental load combinations as applied for the Design case.

For the design case, the onshore gas pipeline remains below 34% of the allowable stress.

The location for maximum stress occurred around chainage 90.770. This is due to the relatively abrupt change in the settlement data at this location in the Settlement Case 1 values, as can be seen in Figure 4-1.

5.1.2 Onshore Gas Pipeline - Settlement Required to Reach SMYS

The required displacements to cause loss of containment have been estimated by applying an increased settlement profile to cause the pipeline material to reach 100% of SMYS during the Design case. This uses the same conservative model used for the FEA reported in 5.1.1 above. This was an iterative process, where the worst case displacement profile (Settlement Case 1) has been multiplied by a factor then assessed using the FEA. The factor required to cause 100% SMYS is greater than 10, i.e. the settlement values need to be more than 10 times the Settlement Case 1 values, in order for the FEA model to show 100% of SMYS. It is noted that after reaching SMYS there remains a significant additional margin of safety for the pipeline before reaching its acceptable limit based on strain criteria.

5.1.3 Onshore Gas Pipeline – Unsupported Span

The stresses developed in the onshore gas pipeline while subjected to a range of unsupported spans within the stone road were calculated and the results verified using Caesar II proprietary stress analysis software.

Table 5-2

Onshore Gas Pipeline Span Assessment (Design Condition)				
Span (m)	2	5	10	40
Equivalent Stress (MPa)	123	123	124	177
% of Allowable	**25**	**25**	**26**	**37**

The calculated equivalent stress was less than 40% of SMYS for all spans considered, including the highly unlikely 40m span. This indicates that during operation, loss of containment from the onshore gas pipeline will not occur as a result of being exposed to an unsupported span within the stone road.

5.2 Outfall Pipeline

The outfall pipeline maximum stress was calculated as 98% of the Minimum Required Strength (MRS) based on the Design case combined with the Settlement Case 1 displacements. MRS is a term used to describe the strength of polyethylene materials, and is similar in concept to SMYS for steel.

Table 5-3

Outfall Pipeline Assessment		
Load Condition	**1**	**2**
Description	Hydrostatic Test	Design
Pressure (barg)	20	16
Allowable Stress (MPa)	10	9.0
Maximum FEA Calculated Stress (MPa)	7.9	8.8
Stress Ratio as a percentage of Allowable Stress	**79**	**98**

It is noted that the above Design case considers a temperature of 35°C. This temperature is highly unlikely and is used as a conservative value for design purposes. Analysis of lower temperatures in the outfall pipeline will result in lower stresses. For example the stress ratio in the pipeline decreases from 98% to 71% if the analysis temperature is reduced to 0°C.

It is further noted that the 50 year MRS for PE100 is 10.0MPa, and this is the basis for the results above. The 30 year MRS has been estimated in consultation with Vendors as greater than 11.0MPa. Using 11.0MPa as the 30 year MRS results in lower stress ratios of 72% and 89% for the Hydrostatic Test and Design cases respectively.

On the above basis, the pipeline satisfies the elastic stress-based assessment criteria.

As discussed in relation to the onshore gas pipeline, there remains capacity for increased loading beyond the point where the pipeline reaches the SMYS (or in the case of polyethylene pipe, the MRS) as calculated by an elastic analysis. With increased loading, local yielding and strain concentration would occur. A strain based approach would show that a significantly higher load can be applied without loss of containment.

5.3 Umbilicals

The umbilicals have limits for bend radius and axial load provided by the manufacturer (see table below).

The calculated curvature and tension are included in Table 5-4 below.

Table 5-4

Umbilical Assessment		
Umbilical Number	**1**	**2 & 3**
INPUT DATA (from Vendor)		
Outer Diameter, mm	62	81
Minimum Allowable Bend Radius (while operating), m	4.3	4.3
Min Allowable BR as max allowable curvature, m^{-1}	0.23	0.23
Maximum Allowable Tension (Bend Radius 10m, Operating), kN	70	100
FEA OUTPUT		
Calculated minimum bend radius, m	349	349
Maximum Calculated curvature, m^{-1}	0.003	0.003
Calculated curvature as a % of allowable	**1.3**	**1.3**
Calculated maximum tension (operating), kN	3.1	4.4
Calculated tension as % of allowable	**4.5**	**4.4**

By comparison of the allowable and calculated values for curvature and tension, it can be seen that the umbilicals will remain well within acceptable limits.

5.4 Fibre Optic Cable & Signal Cable in Duct

The Fibre Optic Cable (FOC) and Signal Cable will each be installed in a duct.

The FEA work performed was to model the duct, and report the response in terms of bend radius and tension. The reported bend radius and tension were then assessed against the allowable values for the FOC and the Signal Cable.

Table 5-5

FOC & Signal Cable Assessment	
INPUT DATA (from Vendors)	
Duct Outer Diameter, mm	46.5
FOC minimum allowable bend radius, mm	195
Signal Cable minimum allowable bend radius, mm	225
FOC minimum allowable bend radius as maximum allowable curvature, m^{-1}	5.13
Signal Cable minimum allowable bend radius as maximum allowable curvature, m^{-1}	4.44
Maximum Allowable Tension FOC, N	1000
Maximum Allowable Tension Signal Cable, N	4000
FEA OUTPUT	
Calculated minimum bend radius, after settlement (FOC and Signal Cable ducts identical), m	354
Calculated minimum bend radius as maximum calculated curvature, m^{-1}	0.003
Maximum calculated curvature as a % of minimum allowable	**0.07**
Calculated Strain for the duct (FOC and Signal Cable identical), %	**<0.0004**
Calculated maximum tension for the duct, N (tension in FOC and Signal Cable will be less than this value)	154
Calculated tension as % of minimum allowable	**15.4**

It is noted that there will be several FOC and Signal Cable splicing chambers along the route where spare cable will be coiled to allow for small amounts of axial displacement. Therefore even though axial load is assessed above, the cable will not be overstressed, as additional cable will be drawn into the ducts from the splicing chambers if required.

The maximum allowable strain (based on e.g. 1.2km sections between splicing chambers, with 0.5m looped cable at each end in the splicing chambers) will be

2 x 0.5/1200 = 0.083%.

The calculated strain over the modelled route length (above) is less than 0.0004% average. Therefore on an average basis, the calculated strain is two orders of magnitude (100 times) lower than the maximum allowable strain.

The maximum calculated local strain is not considered. This is for two reasons:

1. the duct is polyethylene, and suitable for strain greater than 1% meaning that the duct will not rupture, and
2. the duct is ribbed and lubricated to allow the cable to slide inside the duct, thus the cable will slide within the duct instead of developing tension and axial strain.

6 CONCLUSION

The finite element analysis has used the worst case displacements (Settlement Case 1 [1]) for stone road settlement, under two conditions (Hydrostatic Test and Design Pressure) and over the sections of pipeline and services which are routed through significant areas of peat (including the transitions to non-peat areas).

The model has been intentionally built conservatively. The model includes changes in settlement which occur over short distances, which result in higher calculated stresses than would occur in a gradual transition from an area of no peat, to a peat area.

It should be noted that most of the settlement will occur during construction of the stone road, and thus the trench level will be corrected for the majority of the settlement prior to installation of the onshore gas pipeline.

Any further settlement would take place during laying of the onshore gas pipeline and filling of the pipeline with hydrostatic test water. Therefore there would be minimal settlement, if any at all, after gas is introduced into the pipeline.

It is for these reasons that the results of the analysis are considered to be conservative.

The results show that for the onshore gas pipeline, should settlement take place during hydrostatic testing, with the pressure in the pipeline at 504 barg, the calculated stress is within the allowable stress limit.

During operation the pressure will remain below the MAOP. However for conservative calculation purposes the design pressure (144 barg) has been assessed. Should potential settlement occur coincidentally with the design pressure, then the results are also within the allowable stress limit.

It is concluded that the onshore gas pipeline routed through areas of peat and installed in the proposed stone road would not be subject to loss of containment of the linepipe due to the predicted worst case settlement of the stone road.

The effect of settlement on the services such as outfall pipeline, umbilicals, FOC and signal cable was evaluated. These services were assessed on allowable stress, curvature, axial strain, and axial load criteria provided by vendors. The results showed that the design settlement values will not cause failure.

7 REFERENCES

1. Appendix M2, ''Report on Corrib Onshore Pipeline Ground Stability Assessment'
2. Appendix Q4.1 Onshore Pipeline Design Overview (JPK 05-2377-01-P-3-043)

J P KENNY JPK Allseas	**Allseas Construction Contractors SA** **CORRIB FIELD DEVELOPMENT PROJECT**

OFFSHORE DESIGN BASIS	PROJECT No. 052102.01 REF No OF SHEETS 23

DOCUMENT No	OFFICE CODE	PROJECT No	AREA	DIS	TYPE	NUMBER
	05	**2102**	**01**	**P**	**3**	**100**

ALLSEAS DOCUMENT NO.: 8820/D100-01

Corrib natural gas

04	10/05/02	Re-approved for Design	CW	WAB	CW	MG	GD
03	31/01/02	Approved for Design	SMR	CW	CW	SMR	GD
02	24/10/01	Issued for Approval	CW	CS	CW	MG	
01	10/08/01	Issued for Comment	CW	IK	CW	MG	
REV	**DATE**	**DESCRIPTION**	**BY**	**CHK**	**ENG**	**PM**	**CLIENT**

Document Comment Sheet				Page of
Date of Review:	Reviewed by:	Response by:	Lead Engineer:	Project Engineer:
Areas of Particular Concern:				

	Review Finding	Project Response	

Distribution : Project File, Lead Engineer, Project Engineer Manager, Project Manager

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1 INTRODUCTION

1.1 General

JP Kenny Ltd. has been contracted by Allseas Construction Contractors SA to prepare the detailed design of the pipeline system for the Corrib Field development Project.

Corrib, being developed by Enterprise Energy Ireland Ltd, is a gas field located in 350 m of water some 60 to 65 km off the County Mayo coastline. The field will be developed as a long-range subsea tieback to an onshore facility. The gas will then be treated to meet the defined gas specification before onward transportation to the Bord Gais Eireann (BGE) grid via a new cross-country pipeline.

The subsea facilities will consist of a manifold with cluster wells, together with a number of satellite wells. The pipeline system comprises flexible flowlines from the satellite wells to the manifold, and an export line to shore. This 83km 20-inch subsea pipeline from the manifold makes a landfall at Broadhaven Bay in County Mayo, and thence a further 9km onshore pipeline leads to the terminal. An electro-hydraulic umbilical system will run parallel to the pipeline system, and a water outfall pipeline will also run from the terminal to a diffuser some distance offshore.

1.2 Objectives

The purpose of this document is to collate all the basic design data to be used for the detailed design of the offshore section of the Corrib pipeline system, and the approach to be used for each aspect of the work is also briefly outlined. Design data for the infield and onshore elements is covered in separate documents (Refs 8 & 9).

As further data or constraints become available during the project, this document will be revised to incorporate such requirements, but results and conclusions from engineering of the pipeline system will not be addressed.

Note that although the engineering covered by this document covers the offshore pipeline system, work associated with the tie-in spool at the manifold has been subcontracted by Allseas to Stolt Offshore. This is addressed within the infield facilities.

1.3 Abbreviations

BGE	-	Bord Gais Eireann
DTM	-	digital terrain model
EEI	-	Enterprise Energy Ireland Ltd
ETRF	-	European Terrestrial Reference Frame
FEED	-	front end engineering design
JPK	-	JP Kenny Limited
KP	-	kilometre point
LAT	-	lowest astronomical tide
PLEM	-	pipeline end manifold
SWL	-	still water level
WGS	-	World Geodetic System
UTM	-	Universal Transverse Mercator

2 FIELD DEVELOPMENT

2.1 General

The Corrib Field is a Triassic gas reservoir located in the Slyne Basin. It contains a very dry sweet gas with an expected condensate yield of less than 0.5 bbls/ mmscf, 0.3% CO_2 and no H_2S.

Given the water depth and the hostile nature of the environment at Corrib together with the dry nature of the gas and the high well productivity, Corrib will be developed as a long-range subsea tieback to shore. The gas will then be treated to meet the defined gas specification before onward transportation to the Bord Gais Eireann (BGE) grid via a new cross-country pipeline.

Whilst field life is expected to be in the region of 15 to 20 years, the design life for the manifold, main sealine, umbilical, onshore pipeline and terminal will be 30 years.

The Base Case subsea configuration comprises an 8-well manifold providing a commingling facility for five cluster wells and two satellite wells. A spare connection is available for one additional well. The facility for further wells is provided via tie-in to the upstream end of the manifold header.

The system comprises the following main components:

- Wellhead and completion systems
- Subsea tree systems, including flowbases and protection structures
- Manifold with temporary subsea pig launcher
- Subsea production control system, including onshore control equipment, subsea control modules, and subsea distribution unit complete with support and protection structure
- Main umbilical, onshore and offshore, together with umbilical jumpers and infield umbilicals
- Well jumpers and infield flowlines
- Sealine, from PLEM and tie-in spool to manifold, via landfall to Terminal
- Water outfall pipeline from Terminal, via the landfall to a diffuser approximately 6km offshore

The overall pipeline layout is illustrated in Figure 2-1.

2.2 Locations

The location of the Corrib field, 60 to 65 km off the County Mayo coastline, is illustrated in Figure 2-1 and is summarised below. Its general location is classified as West of Ireland, occupying Blocks 18/20 and 18/25. Coordinates are presented in Table 2-1.

Table 2-1 Key Coordinates

	Geographical		Grid			Spheroid
	Latitude	Longitude	Easting	Northing	Projection	
Field centre	54° 20' 20" N	11° 03' 27" W	366 250	6 023 200	UTM zone 29	WGS84
Landfall	54° 17' 01" N	9° 49' 09" W	81 540	338 730	Irish National	Airy Modified

Note that the exact landfall location may be revised during detailed design. Field centre is the approximate location of the well cluster at the Main Drill Centre, and will depend on the final configuration of the cluster.

The offshore engineering work is to be carried out in terms of the ETRF89 geodetic reference frame, which for all practical purposes can be assumed to be based on WGS84. The landfall and onshore parts of the offshore pipelines will be designed using the Irish National Grid (1975), which is based on the Airy Modified Spheroid.

At the landfall, where there is an interface between onshore & offshore systems, co-ordinates will be shown in both systems.

Coordinates of existing wells are listed in Table 2-2. Additional wells are planned at the Main Drill Centre.

Table 2-2 Well Locations

Well ID	Location	UTM coordinate	
		Easting	Northing
18/20-2z	Main Drill Centre	366 242.2	6 023 184.5
18/20-4	Main Drill Centre	366 253.1	6 023 158.8
18/20-3	NE satellite	367 558.5	6 024 112.7
18/25-3	SW daisy chain	365 302.0	6 021 077.0
18/25-1	SE spur	366 753.6	6 020 972.2

2.3 Infield Configuration

At the Main Drill Centre, a total of five wells will be clustered around the manifold, connected by flowline and umbilical jumpers.

Infield flowlines and umbilicals will connect the two satellite wells identified in Table 2-2 to the central manifold. Further infield lines will link the spur well, 18/25-1, in a daisy-chain configuration via the 18/25-3 satellite.

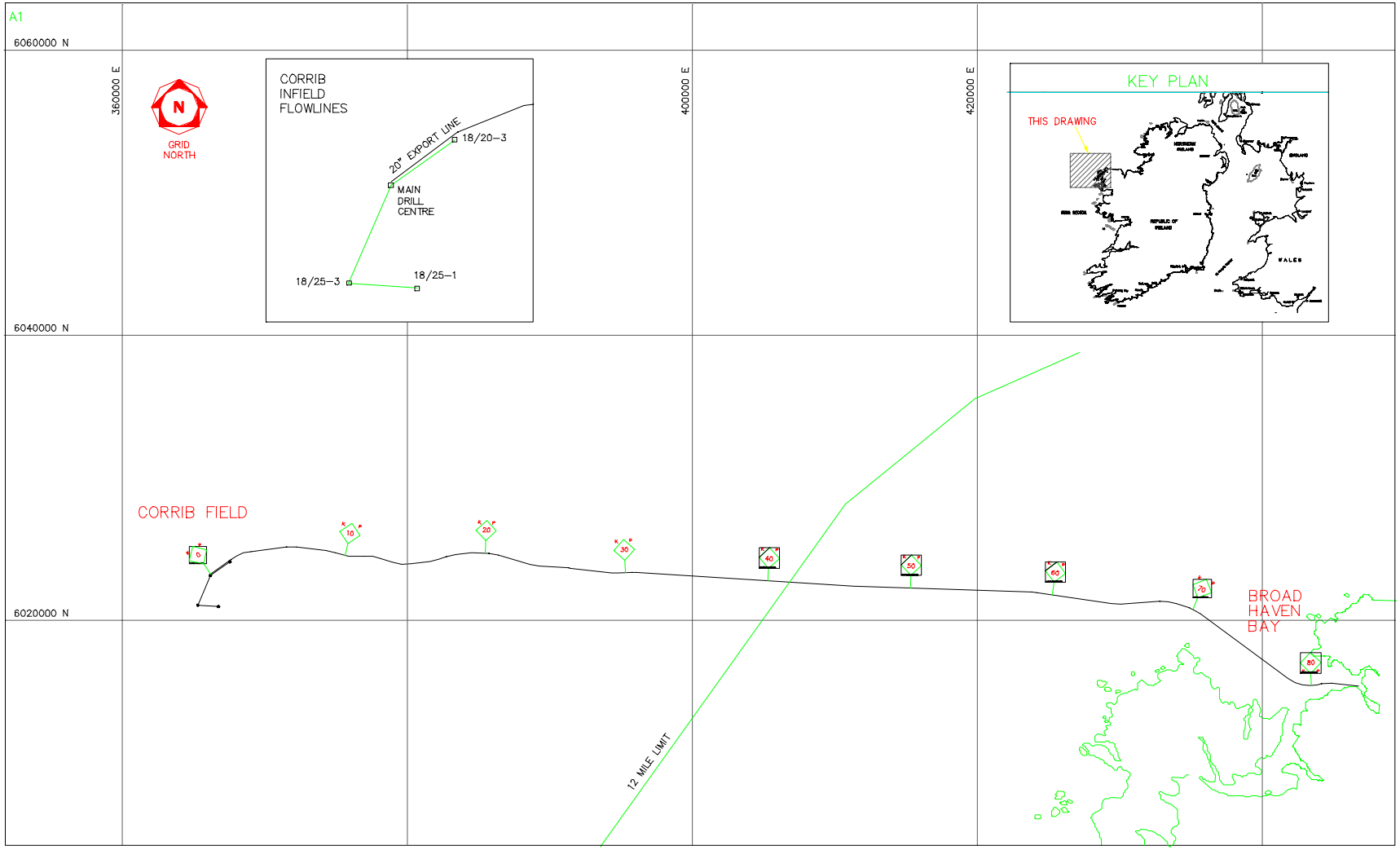

Figure 2-1 Pipeline Route

3 CODES AND STANDARDS

3.1 General

The pipeline system shall comply with the prevailing legislation applicable to the planning, design, construction, testing, commissioning and operation of pipelines in the Republic of Ireland.

The latest editions of all regulations shall be applied, including revisions and addenda.

The pipeline system from the wells to the terminal is to be classified as an upstream pipeline under the Gas (Interim) (Regulation) Act 2001. Enterprise Energy Ireland are applying for consent under section 40 of the Gas Acts 1976 to 2001 (as amended by the Gas (Interim) (Regulation) Act 2001 section 9(1)(b)) from the Department of the Marine and Natural Resources to construct and operate an upstream pipeline, which includes both the offshore and onshore elements.

3.2 Primary Codes

The primary code for the design, construction, testing, commissioning and operation of the offshore pipelines is:

DnV OS-F101, Submarine Pipeline Systems (“DnV 2000”).

Where this primary code is non-specific or ambiguous reference shall be made to relevant alternatives, according to good industry practice.

4 OPERATIONAL PARAMETERS

4.1 General

This section details the operating conditions of the pipeline. Data is all taken from the EEI Project Basis of Design (Ref 7), unless noted otherwise

4.2 Reservoir Conditions

Table 4-1 Initial Reservoir Conditions

Parameter	Value
Mean Depth	3500 m TVDSS
Pressure	401 bara
Temperature	112 °C

4.3 Production Data

Design values for flowrates, pressures and temperatures are given in the following tables.

The facilities shall be capable of the following:

- ramp down by 50% of daily flowrate in six (6) hours
- ramp-up from turn down at 50% to 100 % of daily flowrate in six (6) hours
- ramp-up from shut down to 100% of daily flowrate within 24 hours.
- turn down to 20% of daily flowrate or 25MMSCFD whichever is greater

Design pressures and temperatures are given in Table 4-2 and Table 4-3. During the design life of the field, both flowrates and pressures will decline, and details are given in Table 4-4. These profiles will be used for determination of corrosion allowance, but will not be considered with respect to base wall thickness.

Pipeline design pressure matches wellhead shut-in pressure. Pipeline operating pressure will normally not exceed 150 bara.

Table 4-2 Pressures

Parameter	Pressure
Wellhead Shut-in	345 bara
Flowing Wellhead (max)	272 bara
Pipeline Design Pressure	345 bara

Table 4-3 Temperatures

Parameter	Temperature
Flowing Wellhead (initial)	61 °C
Pipeline Inlet (design)	74 °C

Table 4-4 Sealine Production Profile

Time		Production Rate (mmscfd)	Pressure (barg)	
Yr	Qtr		Manifold *	Terminal
1	2nd	350	223	110
1	3rd	350	211	110
1	4th	350	187	110
2	1st	350	166	110
2	2nd	350	154	110
2	3rd	332	138	110
2	4th	350	161	110
3	1st	350	148	94
3	2nd	332	134	110
3	3rd	311	131	89
4		289	107	66
5		229	94	64
6		185	83	61
7		155	74	57
8		132	67	51
9		114	60	46
10		100	54	39
11		84	47	33
12		74	41	28
13		67	36	22
14		66	27	14
15		48	25	12
16		35	23	10
17		29	22	9
18		25	22	7

Note: Manifold pressure is assumed to be available pressure (eg max FWHP), and not imposed as pipeline inlet condition.

4.4 Product Details

Although test data is available from five Corrib wells, for process simulation and pipeline design purposes, the properties given in the following tables shall be used.

Table 4-5 Product Properties

Parameter	Well		
	18/ 25-1	18/20-3	18/ 20-4
Relative Density (Air=1)	0.587	0.589	0.586
Average MW (g/mole)	17.0	17.0	17.0

Table 4-6 Product Analysis

Component	Well							
	18/25-1		18/20-3		18/20-3		18/20-4	
	Bottom Hole Gas Sample 4594-S1-F		Bottomhole Sample 1439-M1-F		Wellhead Sample 0374-M1-F		Wellhead Sample 4262-M1-F	
	Mole %	Wt %	Mole %	Wt %	Mole %	Wt %	Mole %	Wt %
Hydrogen	0.000	0.000	0.000	0.00	0.00	0.00	0.00	0.00
Hydrogen Sulphide	0.000	0.00	0.000	0.000	0.000	0.000	0.000	0.000
Carbon Dioxide	0.321	0.832	0.258	0.664	0.251	0.646	0.261	0.676
Nitrogen	2.738	4.518	2.644	4.338	2.658	4.359	2.791	4.601
Methane	93.734	88.568	93.706	88.032	93.639	87.951	93.683	88.446
Ethane	2.947	5.219	3.028	5.334	3.072	5.408	2.968	5.253
Propane	0.144	0.374	0.161	0.415	0.159	0.410	0.159	0.412
i-Butane	0.049	0.168	0.057	0.195	0.056	0.190	0.055	0.188
n-Butane	0.021	0.071	0.021	0.073	0.022	0.073	0.022	0.075
i-Pentane	0.020	0.086	0.023	0.098	0.023	0.097	0.022	0.092
n-Pentane	0.002	0.008	0.003	0.011	0.003	0.011	0.003	0.014
Hexanes	0.012	0.062	0.014	0.073	0.015	0.075	0.013	0.066
Me-Cyclo-pentane	0.001	0.005						
Benzene	0.001	0.005						
Cyclo-hexane	0.000	0.002						
Heptanes	0.006	0.029	0.011	0.064	0.031	0.180	0.009	0.053
Me-Cyclo-hexane	0.001	0.004						
Toluene	0.001	0.007						
Octanes	0.000	0.010	0.015	0.102	0.022	0.150	0.005	0.032
Ethyl-benzene	0.000	0.002						
Meta/ Para-xylene	0.000	0.003						
Ortho-xylene	0.000	0.002						
Nonanes	0.000	0.001	0.008	0.063	0.011	0.084	0.003	0.019
Tri-Me-benzene	0.000	0.000						
Decanes	0.001	0.009	0.007	0.058	0.010	0.079	0.002	0.014
Undecanes	0.001	0.015	0.006	0.053	0.008	0.070	0.001	0.013
Dodecane plus			0.039	0.427	0.020	0.218	0.003	0.046
Total	**100.0**	**100.0**	**100.0**	**100.00**	**100.0**	**100.0**	**100.0**	**100.0**

4.5 Produced Water

Water cut will vary during the design life, as detailed in Table 4-7.

Properties of condensing water are as given in Table 4-8 and Table 4-9. No aquifer water was detected in well testing, but properties for the Avonmore (27/5-1) aquifer are given in Table 4-10 and Table 4-11.

Table 4-7 Water Cut

Field Life Stage	Water Content
Early	1.1 bbl/mmscfd
Late	2.6 bbl/mmscfd

Table 4-8 Condensing Water Analysis

	Well 18/20-2z	Well 18/25-1		Well 18/20-2z	Well 18/25-1
Cations (mg/l)			**Additional Elements (mg/l)**		
Sodium	47	1480	Boron	0.43	2.1
Potassium	1.4	58	Aluminium	<0.10	<0.2
Calcium	160	1390	Silicon	0.77	2.8
Magnesium	8.4	155	Phosphorous	0.03	0.11
Barium	2.0	0.22	Lithium	0.02	0.15
Strontium	0.9	2.1			
Dissolved Iron	120	185	**Heavy Metals (mg/l)**		
Total Iron	445	215	Chromium		<0.005
			Manganese		3.1
Anions (mg/l)			Nickel		0.26
Chloride	250	4610	Copper		0.44
Sulphate	3.0	340	Zinc		25
Bicarbonate	125	195	Arsenic		<0.019
Carbonate	Nil	Nil	Selenium		<0.02
Hydroxide	Nil	Nil	Silver		<0.05
Nitrate			Cadmium		<0.005
			Mercury		<0.019
Hydrogen Sulphide	Not Detected	Not detected	Lead		<0.05

Note: Concentrations are all given in mg/litre

Table 4-9 Condensing Water Properties

Property	Well 18/20-2z	Well 18/25-1
pH @ 20^0C	4.56	4.8
Resistivity (ohm.m) @ 60^0F	1.093	1.145
Specific Gravity @ 60^0F	0.996	1.019
Total Dissolved solids (mg/l)	715	8420

Table 4-10 Aquifer Water Analysis

	Well 27/5-1z		Well 27/5-1z
Cations (mg/l)		**Additional Elements (mg/l)**	
Sodium	23050	Boron	4
Potassium	3196	Aluminium	1.3
Calcium	2059	Silicon	4.6
Magnesium	737	Phosphorous	<1
Barium	<0.4	Lithium	2.3
Strontium	46.1		
Dissolved Iron	1	**Heavy Metals (mg/l)**	
Total Iron	76.8	Chromium	<0.1
		Manganese	2.9
Anions (mg/l)		Nickel	15.7
Chloride	41200	Copper	<0.01
Sulphate	4093	Zinc	<0.01
Bicarbonate	127	Arsenic	<0.1
Carbonate		Selenium	<1
Hydroxide		Silver	<0.1
Nitrate		Cadmium	<0.01
		Mercury	3
Hydrogen Sulphide	Not Detected	Lead	<0.05

Note: Concentrations are all given in mg/litre

Table 4-11 Aquifer Water Properties

Property	Well 27/5-1z
pH @ 20^0C	7.4
Resistivity (ohm.m) @ 60^0F	0.099
Specific Gravity @ 60^0F	1.053
Total Dissolved solids (mg/l)	76000

Sand production from the Corrib wells is not expected.

Fracture stimulation may be used on some wells, when the produced fluids will contain proppant. Proppant production could be as high as 320 kg/year per well. The possibility of adding annular screens as part of the well completion to prevent production of proppant is being investigated, but the implementation of such measures should not be assumed.

4.6 Water Outfall Pipeline

A water outfall pipeline will run from the terminal to an offshore diffuser whose location is specified as outside the candidate Special Area of Conservation of Broadhaven Bay. This places it at the 64m depth contour approximately 12.4km from the landfall. The pipeline allows for disposal of run-off water from the terminal as well as water separated from the product. It will be designed for the operational parameters summarised in Table 4-12, which are taken from Reference 8.

Table 4-12 Water Outfall

Parameter	Value
Design Flowrate	85 m^3/hr
Inlet Pressure	TBD
Diffuser Location	64 m water depth

Onshore, the water outfall pipeline will be routed alongside the 20” pipeline, whilst offshore it will be piggybacked onto the sealine. The diffuser at the offshore end will be attached to the 20” pipeline.

4.7 Umbilical Conduit

The main control umbilical will generally be routed alongside the pipeline. For the shore approach, it will be installed within a conduit piggybacked onto the sealine. This conduit will be sized to facilitate the subsequent pull-through.

4.8 Pigging

The pipeline design must facilitate inspection by intelligent pigging and occasional swabbing pigs, but no routine operational pigging is planned.

5 ENVIRONMENTAL DATA

5.1 General

The following environmental data will be applied for design of the sealine. Although some of this data is quoted in the Project Basis of Design (Ref 7), reference will be made directly to the Metoc Report (Ref 11).

5.2 Bathymetry

The water depth at Corrib varies from 334m at well 18/25-1 to 352m at well 18/20. A detailed seabed profile will be derived from the DTM provided as part of the Gardline survey (Ref 10), but a simplified profile is presented in Figure 5-1.

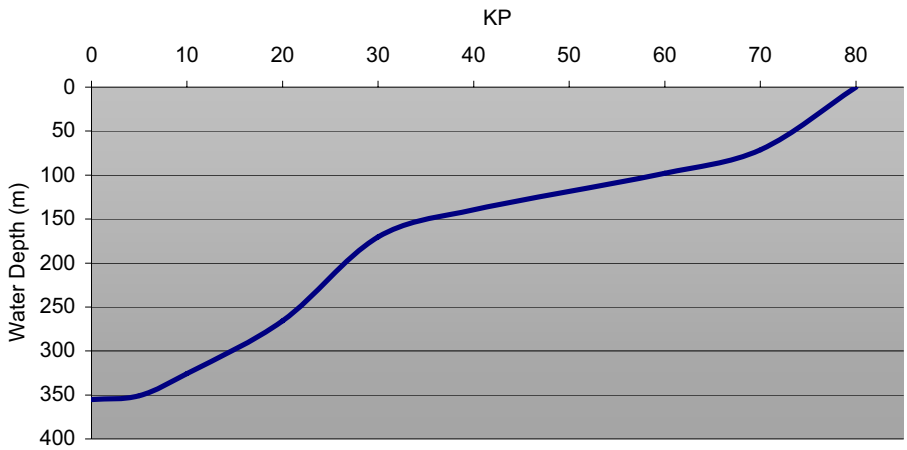

Figure 5-1 Seabed Profile

Tidal heights, extreme still water levels and storm surge data will be taken from Tables 4.1 to 4.3 of Ref 11.

5.3 Waves & Currents

Extreme wave data will be taken from Tables 2.1a to 2.1d of Reference 11, whilst summer data (applicable to the installation case) will be taken from Table 2.2 and 2.1d.

Where wave exceedance data is used, this will be taken from Tables 2.4 and 2.5 of Ref 11.

Extreme and summer seabed currents will be taken from Table 3.1 of Ref 11.

All this data is directional, and the appropriate values will be used for different sections of the line. Where significant variation in value is seen along a section, consideration will be given to either interpolation or use of the more conservative value.

A summary of primary parameters taken from Reference 11 is given in Table 5-1.

Table 5-1 Wave & Current Summary (Corrib Field)

	Return Period (Years)		
	1	**5**	**100**
Significant Wave Height, H_s (m)	15.9	18.1	22.4
Period, T_z (s)	13.5	14.5	16.1
Maximum Wave Height, H_{max} (m)	27.8	31.8	39.2
Period, T_{max} (s)	17.3	18.5	20.6
Current @ 1m above seabed(m/s)	0.42	0.45	0.50

5.4 Seawater

Properties of seawater are given in Table 5-2 below

Table 5-2 Seawater Properties

Parameter	Value
Density	1025 kg/m^3
Viscosity	1.51x10^{-6} m^2/s

Seawater temperatures for both extreme and installation cases will be taken from Table 5.1 of Ref 11. For the Corrib Field location, extremes are as given in Table 5-3

Table 5-3 Extreme Temperatures at Corrib

Temperature	Value
Minimum	6 °C
Maximum	12.7 °C

6 SEABED

6.1 General

The following summary of seabed conditions and soils is taken from the Gardline Route Survey (Ref 10).

KP's run from zero at appraisal well 18/20-2z, to shallow water at KP82.5.

6.2 Overview

The route lies on the Continental shelf and slope. The shelf break occurs at approximately KP15 at a water depth of around 200m and represents the change from the shelf to the steeper slope. The topography of the slope is attributed to many causes, including the volume of sediment transport from the shelves, the angularity of the underlying Tertiary age erosional surfaces, slope instability, current erosion and deposition, and iceberg scouring. The upper slope, to a depth of approximately 500m, shows small scale irregularities due to iceberg scouring, whereas the middle and lower slopes (in deeper water than the proposed development) range from smooth to hummocky, resulting from the actions of mass flow deposits. Scarps, gullies and channels are common. The slope steepens to the west of the Corrib Field, reaching a depth of about 2500m in the Rockall Trough.

The seabed is covered by a patchy veneer of unconsolidated sediments, consisting of a mixture of terrigenous and biogenic derived material. These range in thickness from a few centimetres up to about 2m.

Sandy gravels cover the seabed on the shelf from shallow water down to around 100m depth, beyond which sandy sediments will predominate. Shallow bedrock and glacial till will underlie these, and be exposed locally.

The present-day shelf break is taken to be at approximately 200m water depth, with firm to hard (>40 kPa) Late Pleistocene / Holocene glacial tills above the shelf break. Below the shelf break, very soft to soft (<40 kPa) Late Pleistocene / Holocene mud (>50% mud, <5% gravel). Soft to firm glacial tills may occur immediately below the shelf break. Quaternary deposits are likely to exceed 100m in thickness beyond the shelf break. Gravel and cobble beds, including occasional boulders, have been described in the region of the shelfbreak north of the route, and their possible occurrence along the route should be considered.

Sandy muds should be prevalent on the slope, while muds occupy the deeper waters.

No significant bedforms are anticipated, although localised zones of sand streaks, sand ribbons, and longitudinal sand patches may occur above the shelf break. Where sand ribbons occur on the slope (down to water depths of 600m), they are likely to be approximately 15m apart, up to 1500m long, and less than 1m high. Abundant evidence of iceberg ploughmarks is described in a swathe approximately 25km wide following the shelf break. Sand and clay should partially fill iceberg scour marks and other hollows.

6.3 Pipeline Route

The following is a description of the main route, taken from the SEtech Soils Report forming Appendix N to Volume 7 of the Gardline Survey (Ref 10).

KP0.0 – KP14

A veneer of silty sand, less than 0.5m thick (and locally absent), overlies very soft to soft sandy, occasionally gravelly, clay. Coarse gravel and cobbles occasionally occur locally. Numerous small ploughmarks are described and, during the survey, were attributed to dewatering of the upper sediments. Localised iceberg ploughmarks occur, infilled by soft silty clay. Coarse gravel and cobbles occur on the ploughmark shoulders.

Beyond KP8.5, the clay becomes soft to firm, then firm beyond KP11.5.

KP14 – KP71

A veneer of silty sand, less than 0.5m thick (and locally absent), overlies firm to stiff sandy, occasionally gravelly, clay. Coarse gravel and cobbles occasionally occur locally. Localised iceberg ploughmarks occur, infilled by soft silty clay. Coarse gravel and cobbles occur on the ploughmark shoulders.

Around KP17, thin megarippled sand overlies the clay infill to ploughmarks. Similar megaripples occur within the sand veneer at the seabed from KP19-28. Beyond KP19 the sand veneer becomes predominantly coarse gravel, with local cobbles and small boulders. The sand tends to be present only in depressions.

Beyond KP18, the clay becomes a firm to stiff, locally hard, gravelly sandy clay, becoming stiff to hard beyond KP19.

Beyond KP25.5 the clay is described as a structureless firm to stiff (locally soft to firm) gravelly sandy clay. Up to 0.5m of the upper section of this clay formation comprises a dense gravel layer. A medium dense to dense sand layer, initially less than 1m thick but increasing to in excess of 2m, occurs above this. This sand is locally rippled, gravelly and/or absent.

Beyond KP43, the clay becomes stiff to hard, and very stiff to hard beyond KP52. The sand cover also becomes more patchy between KP52 and KP69.

KP71 – KP82.5

The sand layer continues to increase in thickness, such that any underlying sediments are not identified by sampling or geophysics. They are described as being dense to very dense sands, becoming sands and gravels, exceeding 5m in thickness (>10m by KP73).

Rock is indicated to subcrop at 5-10m depth between KP74.5-75.

The geophysics identified a peat deposit between KP80.7-81.2, although no physical sampling or testing verifies this.

7 FISHING ACTIVITIES

7.1 General

The pipeline system will be designed to withstand expected interactions with fishing gear. These interactions include both the energy resulting from impact of trawl gear and the loads produced during hooking or pullover.

The fishing study provided by EEI (Ref 12) defines trawl types to be expected along the Corrib pipeline and also derives appropriate interaction loadings. Much of this data is also presented within the EEI Basis of Design (Ref 7).

Trawl gear sizes proposed in this study are significantly smaller than those given in GN13 (Ref 5), and it is proposed that the more conservative DnV values be used instead. The methodology will also be as given in GN13.

Where the fishing study gives a loading type not addressed by GN13, this will also be considered. This for example applies in the case of the pelagic clump weight, which is described as commonly in contact with the seabed.

Structures will be designed to prevent groundline hooking, so this type of loading will be ignored.

7.2 Pelagic Trawling

In addition to the loadings given in GN13 (Ref 5), the loading due to pelagic clump weights described in Table 7-1 will also be used.

Table 7-1 Pelagic Trawling Loads

Parameter	Value
Clump Mass	3000 kg
Added Mass Coefficient	1.2
Trawl Velocity	2.6 m/s

8 DESIGN OF SEALINE

8.1 General

This section defines the approaches to be taken to detailed design of the sealine. The extent of the sealine is taken as being from the connection with the tie-in spool at the upstream side of the PLEM to the landward end of the shore pull. The piggy-backed umbilical conduit and outfall pipe are also included.

This work will be performed directly for Allseas.

The primary design code is DnV OS-F101 (Ref 1), but for various elements this code makes reference to a number of other codes and guidelines.

Design life is 30 years.

8.2 Routing

Routing will be based on the “Base Case Route” defined in the FEED, ie the northern option will be ignored. Minor route variations will be addressed in order to optimise span remedial work.

8.3 Wall Thickness

Design of pipe wall thickness to resist internal & external pressures will be made in accordance with DnV OS-F101 (Ref 1). The design pressure specified in Table 4-2 will also be used as the maximum incidental pressure, since it will only actually occur as an upset condition.

A suitable corrosion allowance will be determined, using the operational conditions specified in section 3. Allowance will be given for the decline in pressure through field life.

8.4 Stability

Stabilisation measures for the pipeline will be designed in accordance with DnV RP E305 (Ref 3). Where appropriate, a more detailed, quasi-dynamic analysis will be performed using the AGA stability program.

8.5 Mechanical Protection

Additional protection against mechanical loading, such as results from interaction with fishing gear or dropped objects, will be provided by either concrete coating, trenching, burial or mattresses. Where no such measures are proposed, evaluations will be made of the resistance of the exposed pipe to the appropriate impacts, loadings etc.

8.6 Corrosion Protection & Monitoring

A high integrity anti-corrosion coating will provide primary external corrosion protection. A sacrificial anode system will be designed in accordance with DnV RP B401 (Ref 2).

At the interface with the onshore pipeline, either compatibility of the two CP systems will be ensured, or electrical isolation will be provided. Full compatibility with the subsea facilities will be assumed.

Provision of an internal corrosion monitoring system will be addressed.

8.7 Freespans

Allowable pipeline spans will be calculated in accordance with the methods given in DnV GN14 (Ref 4).

8.8 Landfall

Landfall is made at Dooncarton Point. A conventional shore pull configuration will be assumed.

The interface between onshore and offshore sections of the pipeline is located at the landward end of the landfall. This is represented by the extent of the onshore pull.

At the interface, a welded connection will be made.

8.9 Water Outfall Pipeline

Design of the water outfall pipeline will be addressed as part of the onshore system, as outlined in Ref 8.

Installation of the offshore section of the water outfall pipeline will be addressed, since it will be performed by piggy-backing on the 20” sealine.

Protection of the diffuser at the seaward end of the outfall will be provided by a suitable structure attached to the sealine.

8.10 Umbilical Sleeve

Design of the umbilical is not part of the pipeline scope, but in the shore approach, a sleeve will be pre-installed to allow pull-in to shore of the beginning of the offshore umbilical. This sleeve will be piggybacked to the sealine.

8.11 PLEM

The PLEM near the manifold end of the sealine houses an isolation valve. The structure will be designed to protect this valve from accidental loads in accordance with API RP2A (Ref 6).

Pipeline expansion movement will be accommodated, and due account will be taken of proposed installation methods. Location of the PLEM will be finalised to accommodate diverless connection of the tie-in spool using the Matis system

8.12 Manifold Tie-in Spool

Although forming part of the pipeline, design of the tie-in spool will be addressed under the Subsea Facilities. See section 1.2.

9 REFERENCES

1. DnV OS-F101, Submarine Pipeline Systems ("DnV 2000")
2. DnV, RP-B401, Cathodic Protection Design
3. DnV, RP-E305, On-Bottom Stability Design of Submarine Pipelines
4. DnV, Guideline no.14, Free Spanning Pipelines ("GN14")
5. DnV, Guideline no.13, Interference between Trawl Gear & Pipelines ("GN13")
6. API RP 2A, Recommended Practice for Planning, Designing and Constructing Fixed Offshore Platforms
7. Basis of Design, EEI document no. COR-10-SP-001-6
8. Onshore Design Basis, JPK document no. 05-2102-02-P-3-800
9. Infield Layout, Flowlines, Offshore Umbilcals & Tie-in Spool Design Basis, JPK document no. 05-2199-01-P-3-200
10. Corrib Field Development Pipeline Route Survey, Gardline project ref 5465.1, 06/10/00
11. Metocean Criteria Corrib Field & Sealine Route, Metoc Report No. 978, Oct 2000
12. Corrib Pipeline & Subsea Equipment Design Basis for Fishing Protection, Trevor Jee report, 19/09/00

SHELL E&P IRELAND LIMITED

CORRIB FIELD DEVELOPMENT PROJECT

REPORT

J P KENNY

Corrib natural gas

Corrib Onshore Pipeline EIS

APPENDIX Q4.2

ADDENDUM NO 1 TO OFFSHORE DESIGN BASIS

PROJECT No. 052377

REF CTR 349

No OF SHEETS 4

DOCUMENT No	OFFICE CODE	PROJECT No	AREA	DIS	TYPE	NUMBER
	05	2377	01	P	3	027

REV	DATE	DESCRIPTION	BY	CHK	ENG	PM	CLIENT
04	17/05/10	Revised for Planning Application	JG	GSW		JG	
03	15/01/09	Revised for Planning Application	JG	GSW		JG	
02	07/03/08	For Planning Application	CW	JG		JG	
01	13/02/08	For Review by SEPIL	CW	JG		JG	

Reference Document: OFFSHORE DESIGN BASIS

J P Kenny Document 05-2102-01-P-3-100 Rev 04 dated 10/5/02 issued as Allseas Document No.: 8820/D100-01

ADDENDUM No 1

General

J P Kenny Document 05-2102-01-P-3-100 Rev 04 dated 10/5/02 (also issued as Allseas Document No: 8820/D100-01) presented the Design Basis for the Corrib Offshore Pipeline.

Since that issue a number of statements or items of data have changed and the purpose of this Addendum No 1 is record and document these changes as at May 2010.

The original document remains a valid basis for design of the offshore section of the Corrib export pipeline. None of the changes identified below materially affect the original design basis for the offshore pipeline.

A copy of the original Offshore Design Basis is attached following this Addendum No 1 for reference purposes.

Item	Section	Description
1	1.1	Shell E&P Ireland Ltd has replaced Enterprise Energy Ireland Ltd as the owner of the Corrib Field. Length of onshore section is now 8.3km
2	1.2	Manifold tie-in is no longer part of the Allseas scope. Allseas subcontract with Stolt Offshore is closed.
3	2.1	Distance from landfall to water outfall diffuser is more than 12km. This change has been incorporated in the design (see section 4.6) but the update in this section was omitted in error.
4	2.1	Delete 7th bullet and replace with • *Corrib pipeline, from PLEM and tie-in spool to manifold, via Landfall Valve Installation (LVI) to Terminal*
5	2.2	Landfall location has been revised. Refer drawing 05-2377-01-P-0-007 DG103 Gas Export Pipeline Overall Route Layout, latest revision.
6	3.1	The system for Regulatory Approvals has been substantially changed. The prevailing system for Regulatory Approvals will be applied.
7	3.2	A newer revision of DNV OS F-101 has since been issued (2007), but the offshore pipeline is designed and constructed, as stated, to the 2000 issue.

Item	Section	Description
8	4.2	Delete sentence "Pipeline operating pressure will normally not exceed 150 bara" and replace with *"Offshore pipeline operating pressure will not exceed the stated maximum allowable operating pressure."*
9	4.3	Add to Table 4-2, Maximum Allowable Operating Pressure 150 barg
10	4.3	The data set for Table 4-4 is now superseded as the inlet pressure to the Gas Terminal has been reduced resulting in a corresponding pressure reduction at the manifold.
11	4.5	Last paragraph replaced with; *One well has been hydraulically fractured. Based on production testing to date no significant proppant production is expected. The production system has been designed to tolerate proppant production up to 320kg/year per well. A sand detector has been installed on the production manifold and in the unlikely event that excessive proppant or sand is produced, the individual well will be closed in until it can be repaired. There are no plans to fracture any other wells.*
12	4.6	The water outfall pipeline will only transport treated run-off water from the Terminal. Produced water from the Terminal will be transported via the Umbilical to the subsea facilities
13	8.1	Delete first paragraph and replace with; *This section defines the approaches to be taken to detailed design of the sealine. The extent of the sealine is taken as being from the connection with the tie-in spool at the upstream side of the PLEM to the tie-in weld with the Landfall Valve Installation. The piggy-backed umbilical conduit and outfall pipe are also included.*
14	8.8	Delete second paragraph and replace with following two paragraphs; *The interface between Offshore pipeline and the Onshore pipeline is at the Landfall Valve Installation system.* *The interface between the Onshore pipeline and the Landfall Valve Installation is at the downstream weld of the downstream barred-tee of the LVI.*
		END OF ADDENDUM

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Corrib Onshore Pipeline EIS Appendix Q4.3 LANDFALL VALVE INSTALLATION DESIGN JUSTIFICATION AND OVERVIEW	PROJECT No. 052377.01 REF CTR 349 No OF SHEETS 17

DOCUMENT No	OFFICE CODE	PROJECT No	AREA	DIS	TYPE	NUMBER
	05	2377	01	P	3	045

REV	DATE	DESCRIPTION	BY	CHK	ENG	PM	CLIENT
03	17/05/10	Issued for Planning Application	JG	GSW	GSW	JG	
02	4/05/10	Issued for Comment	JG	GSW	GSW	JG	
01	8/03/10	Issued for IDC	JG	GSW	GSW	JG	

CONTENTS

1 INTRODUCTION

1.1 Purpose

The purpose of this document is to provide an evaluation of the design adopted for the LVI and to provide an overview of the facilities that will be installed at the site.

The Corrib Onshore Pipeline Environmental Impact Statement presents an environmental assessment of the LVI regarding its alternative locations and its impact on the environment. Refer Chapters 3 and 4.

1.2 Background

The original Corrib offshore and onshore proposed pipelines were designed to 345 barg to withstand the highest possible shut-in wellhead pressures. The onshore section of the pipeline traversed mainly an overland route to the Gas Terminal. The previous design comprised a manually operated 20" isolating valve with a bypass located at the landfall.

Following the recommendations of the Corrib Technical Advisory Group (TAG), the Advantica report re-classified the onshore pipeline as a Class 2 (Suburban) pipeline (0.3 design factor) and reduced the design pressure of the onshore pipeline section from its original 345 barg down to a lower design pressure of 144 barg.

Subsequent to the issue of the TAG/Advantica recommendations, maximum allowable operating pressures (MAOP) for the Corrib pipelines were defined. These are:

Corrib – Offshore pipeline and Landfall Valve Installation	150 barg
Corrib – Onshore pipeline	100 barg.

In accordance with the respective pipeline codes the daily operating pressure shall not exceed the stated MAOP in either the offshore on onshore pipelines. Thus the MAOP takes precedence over the requirement to remain within the design pressure of the respective pipelines.

To comply with the relevant design codes, the overall system design required a high reliability over-pressurisation protection system to be installed at the landfall. This facility would limit the pressure in the onshore section to below 100 barg.

In addition TAG required that there were facilities to initiate, from the Gas Terminal, remote isolation between the offshore and the onshore pipelines sections at the landfall.

2 DESIGN STANDARDS

2.1 Applicable Codes and Standards

The principal authorities associated with regulatory codes, standards and legislative compliance, applicable to the aspects of design; construction, installation and commissioning of the LVI are listed below in alphabetical order.

- Det Norske Veritas (DNV)
- European Community Legislative Standards.
- Institute of Petroleum (IP)
- International Organization for Standardization (ISO)
- National Fire Protection Association Codes (NFPA)
- Republic of Ireland National Standards.
- Shell Design and Engineering Practice (DEP)

2.2 Applicable Design Standard

A review of the Codes and Standards recommended by TAG following issue of the Independent Safety Review of the Onshore Section of the proposed Corrib Gas Pipeline by Advantica, and their application to the LVI and the onshore pipeline is presented in Appendix Q3.2.

In summary, TAG has designated that the design of the onshore pipeline shall be in accordance with I.S. EN 14161; however I.S. 328 and BS PD 8010 shall apply where they exceed I.S. EN 14161.

The application of these standards to the design of the onshore pipeline has been evaluated and a Design Code Review issued to TAG (Refer Appendix Q3.3). The Design Code Review sets out the application of the individual standards to the design of the onshore pipelines. TAG subsequently accepted the findings of the design code review.

The DNV-OS-F101 code for submarine pipeline systems is applied to the design of the offshore pipeline (issue 2000) and the LVI (issue 2007).

The break between the two codes, namely DNV-FS-101 and I.S.EN 14161 is at the weld between the downstream barred tee of the LVI and the onshore pipeline.

3 DESIGN AND OPERATING PARAMETERS

3.1 Flow Rate

Design Flow Rate	350 MMSCFD of dry sales gas
Maximum Flow Rate	350 MMSCFD of dry sales gas

3.2 Pressure

Design Pressure (upstream of code break)	345 barg
Design Pressure (downstream of code break)	144 barg
MAOP (upstream of code break)	150 barg
MAOP (downstream of code break)	100 barg

3.3 Temperature

Maximum Design Temperature	50°C
Minimum Design Temperature	
20 inch pipeline from installed offshore line to LVI	0°C
20 inch pipeline at LVI to ~1100 m downstream LVI	-20°C
20 inch pipeline from ~1100 m downstream of the LVI to Gas Terminal	-10°C
16 inch/ 4 inch shutdown/restart spools at LVI	-26°C

3.4 Hydrostatic Test Pressures

LVI linepipe, mainline valve and shutdown loop and valves	504 barg
From installed offshore linepipe to LVI	504 barg

3.5 Design Life

The LVI shall have a design life of 30 years.

3.6 Location

The location of the LVI is presented in drawing number DG2101 Site Plan.

3.7 Environmental Constraints

Presented in the Corrib Onshore Pipeline Environmental Impact Statement.

3.8 Production Flow Rates, Pressures and Composition

Refer to Appendix Q2.1.

3.9 Environmental Data

Environmental data for the pipeline route is listed below, for years 1991 to 2000.

Data received from Met Eireann.

Maximum air temperature	28°C
Monthly mean maximum temperature range	8.9°C to 18.2°C
Minimum air temperature	-5.5°C
Monthly mean minimum temperature range	3.9°C to 12.2°C

Mean annual rainfall	1269mm
Maximum daily rainfall	67.8mm
Maximum hourly rainfall	25.9mm
Mean days ≥ 0.2mm rainfall	254 days/year
Mean monthly wind speed range	11.7 to 16.2 knots
Max wind speed (gust)	93 knots

4 LVI DEVELOPMENT OF DESIGN CONCEPT

4.1 Design Implications

To meet the objectives outlined in Section 1.2, the pipeline design codes require that where there is a change in design pressure or maximum allowable operating pressure, that is from offshore to onshore, then the downstream pipeline must be protected by an over-pressurisation protection system. Thus additional facilities are required at the landfall and these would replace the previous single, manually operated, 20” dia beach valve.

These additional facilities at the landfall would comprise part of an overall Corrib pipeline over-pressurisation protection system (Refer Appendix Q2.1). This requires a high integrity safety shutdown system to be installed at the landfall in a new facility termed the Landfall Valve Installation (LVI). Isolation between the offshore and onshore sections will be initiated should the pressure in the downstream pipeline exceed a pre-set trip value.

4.2 Design Constraints

The constraints influencing the design of the LVI were as follows:

- Selection of the safety shutdown system and the optimum pipe configuration.
- Offshore to onshore pipeline interface at LVI to be suitable for intelligent pigging.
- Maximise safety at the LVI.
- Mitigate visual impact at Glengad.
- Minimise the footprint of the LVI site.
- Site security and lighting.

Each of these constraints are discussed in further detail below.

4.2.1 Pigging Continuity

It is a requirement that the offshore and onshore pipelines be suitable for intelligent pigging which necessitates a continuous connection between the 20” dia offshore and onshore pipeline sections. Consideration was given for provision of temporary receiver and launcher at the LVI, however this was discounted due to extended footprint, visual impact and safety implications.

4.2.2 Selection of the Safety Shutdown System and Pipe Configuration

The safety shutdown system comprises two inline shutdown valves located in the 16” bypass of the locked closed 20” mainline valve. The actuators for the shutdown valves are “spring to close” and hydraulic pressure to maintain open. The tripping of the safety shutdown valves will be achieved by measuring the downstream pipeline pressure via triple transmitters and through a 2 out of 3 voting logic, close the shutdown valves should the measured pressure exceed a prescribed trip value.

Locating the safety shutdown system inline with the 20” dia offshore and onshore pipeline was considered (Refer Appendix Q4.4). However, following evaluation, this configuration was discounted as there were no 20” dia high integrity safety shutdown valve systems available for the given design pressure and having a proven field track record. In addition there was potential consequential reduction in reliability of closing the shutdown valves due to pigging operations. Finally there was no significant improvement in safety at Glengad.

The largest safety shutdown systems with proven track record were up to 16" dia and non-piggable. From flow calculations it was determined that the maximum design flow rate that could be accommodated in a 16" diameter pipe without resulting in excessive gas flow velocities.

Thus it was elected to install a 20" dia mainline isolation valve between the onshore and offshore pipeline sections (normally locked fully closed) and accommodate the two inline safety shutdown valves in a 16" dia bypass of the 20" dia mainline valve.

4.2.3 Maximise Safety at the LVI

To maximise safety at the LVI, it was located as remotely as practicable from normally occupied buildings. All of the pipe work at the LVI below ground will have a minimum cover of 1.2 m. In addition all above ground small bore connections to the buried valves would be capped with a bolted flange. Security cages will be installed over all above ground actuators and instrumentation

4.2.4 Mitigate Visual Impact at Glengad

The location of the LVI at Glengad is in an area of protected views. A number of alternative civil designs were evaluated which included:

- Conventional Above Ground Installation
- Installation on the Cliff Edge
- Underground and Enclosed Installation
- Installation in Excavated Lower Terrain Position

From the evaluation of the alternatives the installation in an excavated lower terrain position (Dished) was elected as the optimum arrangement which mitigated the visual impact of the LVI at Glengad.

4.2.5 Minimise the Footprint of the LVI Site.

Based upon the "dished" arrangement for the LVI, the overall foot print of the LVI was minimised to reduce as far as possible the visual impact at Glengad while maintaining the design requirements for safe working at the installation. The factors that influenced the size of the footprint were:

- Safety distances from the points of potential emissions from the pipe work and valves.
- The size required for a secure enclosure to house the electronic and electrical equipment.
- Access to the buried valves.
- Access to the connection between the onshore and offshore umbilicals.
- Space for the outfall pipeline manual and control valves.
- Vehicle access to the LVI compound area in the dished profile.
- Crane access for maintenance.

4.2.6 Site security and lighting

In accordance with the pipeline design code, access to stations shall be controlled and fenced, with locked gates. Thus the LVI compound area housing the LVI valves and buried pipe work is enclosed in a security fence with a locked main gate and an

emergency gate. As there may be occasions to visit the LVI at night, low-level site lighting is required. All above-ground actuators and instrumentation are protected by security cages.

5 LVI DESIGN DETAILS

5.1 LVI Overview

The location of the LVI at Glengad is presented in Appendix A Drawing DG2101. An illustration of the LVI layout is presented in Chapter 4 Figures 4 and 5. The configuration of the LVI pipe work and valves is presented in Chapter 4 Figure 6 which is reproduced below as Figure 5-1.

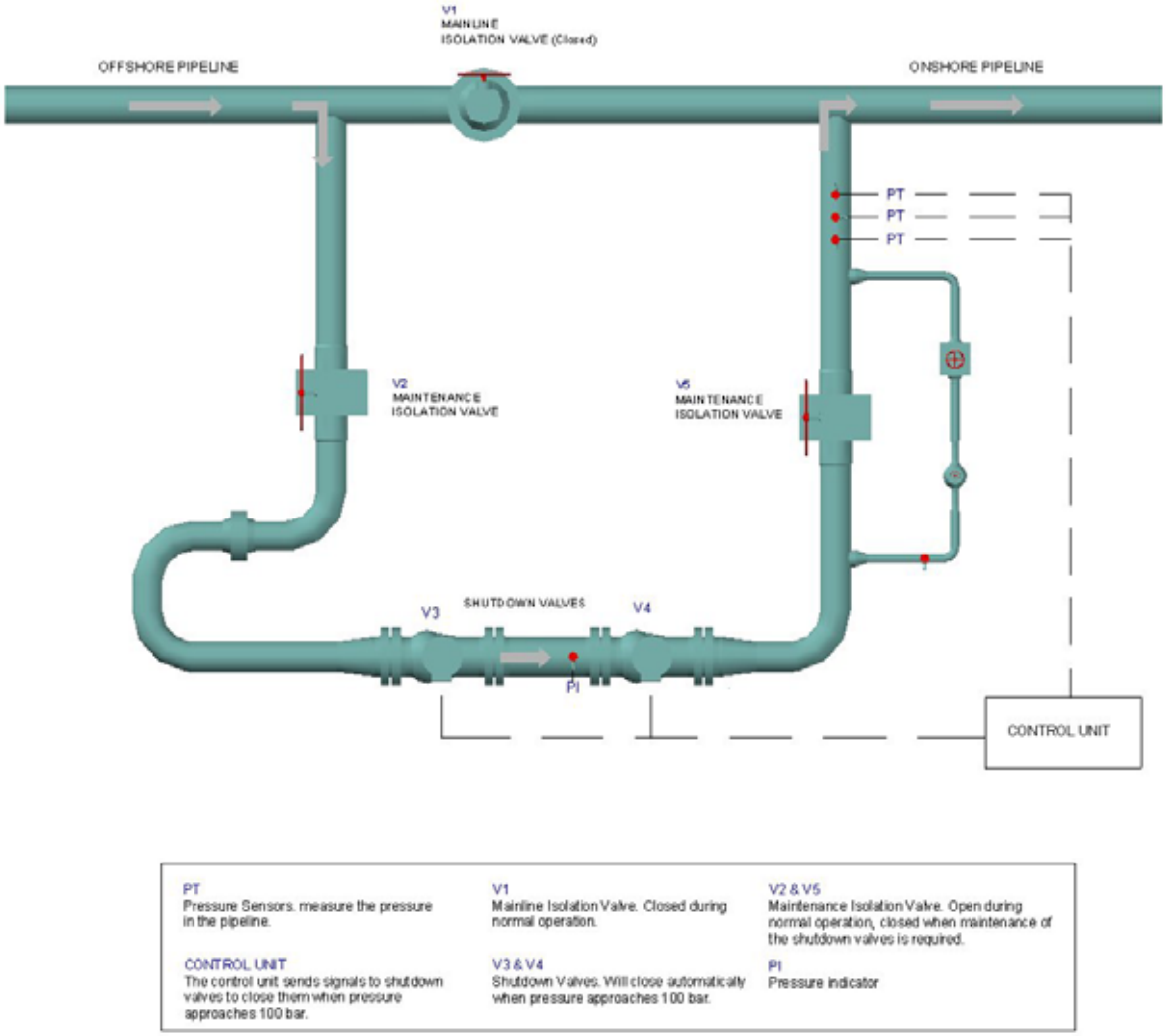

Figure 5-1 LVI Configuration

The primary function of the facilities at the LVI is to provide safety shutdown facilities, as part of the overall over-pressurisation protection system as described Appendix Q2.1. This will ensure that the pressure in the downstream onshore pipeline does not exceed the onshore pipeline maximum allowable operating pressure of 100 barg.

The Mainline Isolation Valve (V1) is a full bore double expanding gate valve which is normally locked closed. This valve will only be opened for pipeline pigging (from subsea manifold to Terminal). The LVI will be permanently manned during opening of this valve

and the pigging operation will be executed under the Gas Terminal permit to work system. A full risk-assessment will be undertaken prior to a pigging operation.

Normal flow is therefore via the 16" diameter Shutdown Spool which is connected to the mainline pipeline via barred tees. This spool comprises two Safety Shutdown Valves (V3 and V4) and upstream and downstream 16" Isolation Valves (V2 and V5). A 4" Restart Spool is installed around isolation valve V5. This spool includes a Restart Control Valve and a 4" Isolation Valve. This spool is used for re-pressurisation of the downstream onshore pipeline following a shutdown of the LVI.

The barred tees and the interconnecting 20" pipe together with V1 will be fabricated with corrosion resistant materials. Also the complete shutdown spool, restart spool and valves will be fabricated with corrosion resistant materials. Both duplex and internally clad carbon steel materials will be used as the corrosion resistant materials.

The actuators on the Safety Shutdown Valves (V3 and V4) will be hydraulically opened, spring closed, i.e. fail-closed. The remaining valves are all operated manually.

The Safety Shutdown Valves will be axial flow type valves and the Isolation Valves (V1, V2, V5 and the restart spool) will be double expanding gate valves which provide an integral double block and bleed isolation.

Three pressure transmitters located downstream of the downstream Isolation Valve V5, prior to the barred tee, will measure the pressure in the onshore pipeline and will be connected to the electronic Logic Solver Unit. The instrument piping connections to the buried pipe work will be heat traced to mitigate potential hydrate formation.

To mitigate hydrate formation during restart following a shutdown, a methanol injection connection is located on the upstream of the Control Valve in the restart spool. The methanol will be obtained via permanent piping from the subsea umbilical line, which is routed through the LVI. The methanol injection connection is isolated during normal operation.

A pressure indicator is located between the Safety Shutdown Valves to facilitate restart and is used when the valve seals are checked during maintenance. The temperature transmitter downstream of the three pressure transmitters is used to monitor the pipe temperature during restart.

5.2 LVI Over-Pressurisation Protection System Functionality

The high integrity safety shutdown facilities at the LVI comprise the duplicated safety shutdown valves (V3 and V4), the triplicate pressure measurement instruments and the electronic control unit termed a Logic Solver.

Under normal operation V3 and V4 are maintained open under hydraulic pressure and the pressure in the onshore pipeline is maintained below its MAOP of 100 barg. The independent readings from the three pressure transmitters are compared using a two–out–of-three (2oo3) voting system within the Logic Solver. Provided that the measured pressure is maintained below a preset trip pressure, valves V3 and V4 remain fully open. However should the measured pressure (2oo3) of the onshore pipeline exceed the preset trip pressure, then the logic solver will immediately release the hydraulic pressure from the actuators on both valve V3 and V4, and their respective spring actuators will promptly close the valves, thus isolating the pressure between the onshore and offshore pipelines.

The system will be designed such valves V3 and V4 will fail to the closed position.

The Logic Solver will also receive the remote close signal from the operator at the Gas Terminal and initiate closure of both V3 and V4 for the purposes of inventory control.

The status of the valves, the logic solver, pipeline pressures etc will be transmitted back to the Gas Terminal, via the fibre optic cable, to keep the Operator informed as to the operational status of the LVI.

5.3 Restart Requirements

As discussed in Section 5.2 the high integrity shutdown system will close should the pressure in the onshore pipeline reach the defined trip value. However provisions at the LVI are required to restart the pipeline system following a shutdown. In this case the thermodynamics of restarting the gas flow, with the upstream pressure being higher than the downstream pressure, results in cooling of the downstream gas (known as the Joule-Thompson effect). To mitigate this effect the restart of the gas flow into the onshore pipeline must be regulated and this is achieved via the restart bypass around the Isolation Valve V5. The restart bypass will be equipped with a globe valve to regulate the flow and a downstream isolation valve to isolate the restart bypass during daily operation.

During restart methanol needs to be injected into the onshore pipeline to mitigate formation of hydrates. This is achieved via a methanol supply line form the umbilical which is normally isolated by a 1” isolation valve. The supply of methanol is discussed in Section 5.18.

5.4 Primary Valve Selection

As a result of the tendering process, the selected valve for the high integrity shutdown system is a 16” axial flow valve with a spring close and hydraulic open actuator with re-pressurisation through a manual hand pump. The fail safe condition is closed. The safety shutdown valves, the actuators, the electronic package and the pressure transmitters were supplied as a complete package with independent certification.

In order for maintenance to be performed on the shutdown spool, positive isolation is required. Because of space restrictions, this has been achieved by the installation of, upstream (V2) and downstream (V5) of the shut down valves, double expanding gate valves (DEGV) which provides a Double Block and Bleed feature in a single valve. This could be achieved by closure of two inline valves with an intermediate bleed valve between the two inline valves (termed a double block and bleed - DBB). However, this arrangement requires additional space and it was decided to select a valve equipped with a double expanding gate valve (DEGV) mechanism. This mechanism provides the DBB feature in a single valve. IN addition the mainline 20” dia valve and the restart bypass isolation valve were all specified as DEGV’s.

5.5 Material Selection

The main section of the onshore and offshore pipeline is piggable through the 20” dia mainline valve. This valve is normally locked closed during daily operation of the Corrib pipeline system. Consequently the short section of 20” dia pipe between the upstream and downstream barred tees is not subject to continuous flow of gas and is not afforded protection via the internal corrosion inhibitors dosed into the gas subsea. Additional corrosion protection is therefore provided on this section of pipe in the form of clad carbon steel pipe. In addition the valve internals of the 20” dia DEGV are also clad carbon steel.

The shutdown spool and the restart spool are non-piggable sections of pipe and thus the materials used are selected to provide additional corrosion resistance. This is achieved by using both duplex stainless steel and clad carbon steel pipe.

5.6 Erosion and Corrosion

All buried and above ground pipe work and fittings will be painted to prevent external corrosion. Additional protection for the below ground section will be provided by the cathodic protection system as described in Section 5.7.

The threat of corrosion for the LVI configuration will be the same as for the onshore pipeline. For the LVI valves and pipe work, Corrosion Resistant Alloys have been selected to mitigate any potential corrosion issues. As indicated by the erosion assessment (Appendix Q4.9), erosion is unlikely to occur with the expected flow rates because of lack of direct impingement of solids on any surfaces. All LVI valves have been specified for proppant service.

5.7 Cathodic Protection

The LVI buried pipe work and valves will be integrated into the onshore pipeline impressed current cathodic protection (ICCP) system. Facilities are provided at the LVI to measure the ICCP system electrical potentials and enable the cathodic protection system to be optimised.

No isolation joint will be installed at the interface between the offshore and onshore pipelines and the cathodic protection systems for the offshore and onshore pipelines will be designed to be balanced at the LVI. This design concept was proposed to and subsequently accepted by TAG.

Appropriate electrical isolation and earthing will be provided between the below-ground and above ground facilities.

5.8 Vibration

Based upon the design adopted for the LVI, any vibration that may occur during operation will be within the design limits of the pipe work and fittings. To verify the design with respect to vibration an independent study was commissioned by SEPIL and this concluded that:

- A vibration induced fatigue failure of the main flow lines of the LVI is considered unlikely due to:
  - (i) flow induced turbulence
  - (ii) flow induced pulsation
  - (iii) pigging and slugging activities
- The small bore connections on the flow lines are also not considered to be at risk of vibration induced fatigue failure

5.9 Noise

As all the pipe work and main valves are located below ground the noise levels due to gas flow will be very low. Refer to Appendix H.

An additional potential source of noise will be on infrequent occasions when use of the standby diesel generator is in use. This will only be required when electrical supply is not available from the ESB. The standby diesel generator is equipped with a silencer and acoustic insulation. The noise level is rated at 55 dBA at 10 metres (Refer Section 5.15).

5.10 Emissions

There is no provision for permanent or temporary venting of gas at the LVI.

Each of the valves with a small bore connection to the body cavity, has connections which are routed above ground and fitted with a blank flange. All of the connections will be checked periodically for fugitive emission during maintenance visits.

5.11 Instrument Cabin

There are a number of items of electronic and electrical equipment at the LVI that must be housed in a custom built cabin. As this Instrument Cabin is located in the compound it must be classified as a safe area to house the electrical/electronic equipment. Therefore the internal pressure within the Instrument Cabin is maintained positive with respect to the external air pressure. This is achieved by the HVAC system installed in the cabin. The Instrument cabin will house:

- A Uninterruptible Power Supply with battery back-up.
- The shutdown logic electronic equipment.
- The controllers for the security systems.
- The DCS safety node (for communication with the Gas Terminal Control Systems).
- The HVAC system.
- The site lighting controls.

5.12 Fire Detection and Protection

The above ground valve actuators for the safety shutdown valves will be fitted with passive fire protection.

Portable fire extinguishers will be located in the Instrument Cabin.

Internal smoke detectors will be provided in the Instrument Cabin

Smoke and gas detection will be provided in the Instrument Cabin and an alarm provided to the Gas Terminal control room.

5.13 Control and Communications

Various data from the LVI will be required for display to the operator in the Gas Terminal Control Room. This data is gathered at the LVI from the shutdown logic, the HVAC system and the smoke and gas detectors via a Distributed Control System (DCS) safety node installed at the LVI. Communication to the Gas Terminal will be via the Fibre Optic cable installed parallel to the onshore gas pipeline.

Facilities to remotely close the safety shutdown valves from the Gas Terminal are achieved via the signal cable installed parallel to the onshore gas pipeline. The signal cable will connect directly to the electronic shutdown logic controller which operates the safety shutdown valves. Multiple cores are assigned within the signal cable for the “LVI close” command. Should the signal cable connection between the LVI and Gas Terminal be lost, then the shutdown logic will automatically close the safety shutdown valves at the LVI.

5.14 Electrical Hazardous Areas

Field instrumentation located within electrical hazardous areas shall be rated accordingly for safe operation within the designated zone in general accordance with I.S. EN 60079 and Institute of Petroleum, Model Code of Safety Practice Part 15.

Instrumentation shall be rated suitable for a Zone 1 Group II B T3 area.

The Zone 2 area will extend to the upper edge of the lowered area within which the LVI compound is installed.

5.15 Security of Electrical Supply

Electrical Power will be required at the LVI for the electronic instrumentation and control systems together with the site lighting, CCTV and intruder detection systems.

The supply of electricity to the LVI will be via the Electricity Supply Board (ESB) local overhead electrical supply system. As there are potential periods of outage from this supply, provisions are included in the LVI design to maintain essential loads from a battery system which will provide more than 4 hours electrical back-up. In the event of prolonged electrical supply outage, a standby diesel generator will be brought to the site from the Gas Terminal and this will provide a source of electrical power until the main ESB electrical supply is restored.

5.16 Lighting

Security lighting will be installed at the LVI to illuminate the compound perimeter. Under normal conditions the LVI will not be illuminated at night. Lighting will also be installed to illuminate the Instrument Cabin and valve controls and be adequate for both operational and security purposes.

The LVI site will be illuminated for required site attendance such as maintenance or for security purposes and on detection of unauthorised entry. The site lighting can be controlled from the Gas Terminal control room.

5.17 Lightning and Earthing

The level of lightning strikes in the Glengad area is rated as low and thus no specific provisions are needed to manage lightning. There will be a site earth at the LVI to ensure all metal structures are correctly bonded to earth for personnel safety and to protect the electrical/electronic equipment.

5.18 Umbilical and Methanol Supply

At the LVI the three onshore umbilical cables inter-connect into the single offshore umbilical cable via an Onshore Termination Unit (OTU). At this point methanol is piped from one of the umbilical cores through to the restart bypass pipe work. The methanol pressure is measured within the methanol off-take piping. Facilities are provided to control the methanol injection flow rate and valves are provided to isolate the methanol off-take.

5.19 Outfall Line

The outfall line transporting treated surface water from the Gas Terminal though to disposal subsea in Broadhaven Bay will be routed through the LVI compound. At the LVI a backpressure control valve will ensure that the outfall pipe is maintained at a positive pressure to avoid slack line operation and water surges.

5.20 Access for Maintenance

During maintenance various elements of the LVI facilities will require access.

The safety shutdown valves will require removal and refurbishment after a prescribed period of time to ensure their high integrity to close when demanded. Thus these valves are flanged and are installed in a chamber, which is normally sand filled, to facilitate access for maintenance. In addition the buried pipe work upstream of these valves is arranged to facilitate removal and re-installation of the valves and includes an additional

buried flange. This arrangement also provides a method of access to the LVI bypass pipe work for internal visual inspection or external verification of the pipe work wall thickness.

Controlled access will also be provided to the Onshore Termination Unit (OTU).

5.21 Drainage

As the LVI compound is located at the bottom of the dished area specific provisions are included to manage surface water drainage and changes in the water table level. The drainage system is around the boundary of the compound area and drains to a designated surface water drain with an outfall through the cliff onto the beach area. The construction of the surface water outfall will be subject to further optimisation to reduce potential impacts where possible.

Should the water level in the compound rise above a prescribed threshold then an alarm is alerted to the Operator in the Gas Terminal.

5.22 Site Security

As the location of the LVI is some distance from the Gas Terminal, provisions are included at the LVI for site security. These comprise:

- Locked fenced compound
- CCTV (covers only the dished area of LVI)
- Intruder Detection
- Security cages over above ground valve actuators etc.

All authorised access to the LVI site will be controlled and in accordance with Gas Terminal work permit procedures.

6 LVI OPERATION AND MAINTENANCE

6.1 Operation

There are no specific operation actions to be undertaken at the LVI which will function as an unmanned location. Daily monitoring of the LVI will be undertaken from the Gas Terminal Control Room where operational and alarm data, obtained via the LVI DCS safety node and communication system, is displayed and alerted to the Operator.

Visits to the LVI site will be conducted on at least a weekly frequency to monitor overall equipment condition and perform the associated task instructions. The Operator will also attend the LVI on an as needed basis in response to any alarms.

In the event of outage of the electrical supply to the LVI the Operator will determine the need to mobilise the standby diesel generator from the Gas Terminal to the LVI. While the standby generator supply is at the LVI, the site will be manned.

6.2 Maintenance Strategy

The LVI equipment is subject to the same Risk Reliability Management (RRM) analysis adopted for the Gas Terminal. Every item of equipment is identified and analysed using Shell's RRM analysis tool. From the analysis, preventative maintenance routines are established together with the maintenance frequencies needed to mitigate potential failures. The maintenance plans are controlled by a computerised maintenance management system CMMS-SAP. The maintenance scheduler will ensure that work orders for the preventative maintenance routines (PMR's) are planned and executed in a timely manner by competent and trained technicians.

Examples of Preventative Maintenance Routines are;

- Annual ESDV testing to prove that valve closes and does not pass (performance standard criteria and test results verified by independent assessor).
- Major overhaul by the original equipment manufacturer of the safety shutdown valves to replace seals (not greater than every 5 years).
- Pressure, Temperature, Level Transmitter calibration checks to ensure specified measurement accuracies are achieved.
- HVAC checks on dampers. Monthly handheld vibration measurements of all rotating equipment and the above ground process pipe work.
- Electrical checks for ATEX compliance on all equipment.
- Motor/Switchgear/UPS/Battery electrical inspections for contactors and ancillaries.
- Inspections of fencing, drainage and security systems.

Examples of Corrective Maintenance are;

- Replacement of failed electrical component (e.g. light fittings)
- Replacement of broken V belt in fan
- Rectification of a seized HVAC damper

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Corrib Onshore Pipeline EIS Appendix Q4.4 Appraisal of Alternative Configurations for the LVI Safety Shutdown System	PROJECT No. 052377.01 REF **CTR 349** No OF SHEETS 12

DOCUMENT No	OFFICE CODE	PROJECT No	AREA	DIS	TYPE	NUMBER
	05	**2377**	**01**	**P**	**3**	**046**

REV	DATE	DESCRIPTION	BY	CHK	ENG	PM	CLIENT
03	13/05/10	Issued for Planning Application	JG	GSW	GSW	JG	
02	4/05/10	Issued for Comment	JG	GSW	GSW	JG	
01	8/03/10	Issued for IDC	JG	GSW	GSW	JG	

CONTENTS

1 INTRODUCTION

1.1 Background

Following the issue of the Corrib Technical Advisory Group (TAG) and Advantica Independent Safety Review recommendations in 2006, the design of the Landfall Valve Installation (LVI) was initiated to provide a safety shutdown system at the landfall to prevent the pressure in the onshore pipeline section exceeding the new, lower, design pressure. At the time of design, the maximum size of field proven high integrity safety shutdown valves available from the market was 16" dia. These valves were not suitable for the passage of pipeline pigs. Thus the design of the LVI as previously presented was based upon a configuration with the safety shutdown valves located in a 16" dia bypass around a 20" dia full bore mainline valve which facilitated pipeline pigging.

An Bord Pleanála letter dated 2nd November 2009 and subsequent clarification in their letter dated 29th January 2010 requested that further consideration be given to adopting a straight pipe configuration for the LVI with a potential for increase in safety at Glengad. This has been interpreted as locating the safety shutdown valves in the 20" dia pipeline.

A high integrity safety shutdown system remains a requirement at the Glengad Landfall in order to limit the pressure in the onshore section of the upstream pipeline to a Maximum Allowable Operating Pressure (MAOP) of 100 barg.

1.2 Purpose

The purpose of this report is to re-evaluate the potential configurations of the safety shutdown system at the LVI, taking into consideration any developments available in the market, any impacts on the functionality of the LVI and determine any increase in safety to the population in the Glengad area.

2 SYSTEM REQUIREMENTS

2.1 Over Pressurisation Protection

The over pressurisation protection evaluation, initiated following issue of the TAG and Advantica recommendations, determined that a high integrity safety shutdown system was required at the LVI. This would comprise dual fail safe inline safety shutdown valves (hydraulic open, spring close) and valve closure would be initiated when the pressure of the onshore pipeline at the LVI attains a preset trip value which would not exceed the designated MAOP for the onshore pipeline. The initiation system would be via triple individual pressure transmitters with a two out of three (2oo3) voting logic. That is, if two of the three pressure transmitters exceed a pressure higher than a preset trip value, then the two safety shutdown valves will close.

2.2 Restart

The over pressurisation protection system evaluation also identified that restarting the onshore pipeline following closure of the safety shutdown valves would require use of a manually operated control valve. This would enable controlled re-pressurisation of the onshore pipeline and ensure that the downstream temperature in the onshore pipeline was maintained within the pipeline material design limits.

2.3 Testing of the Shutdown Systems

The safety shutdown system would require periodic testing to validate the operation of the system and to ensure that the valves were maintaining a gas tight seal.

2.4 Pipeline Pigging

When the onshore and offshore pipelines are being pigged, the pig will be launched from the subsea manifold and run through to the Gas Terminal. The pigs will pass through the Glengad Landfall and therefore any configuration adopted must accommodate internal pipeline pigging. This means that any valve inline with the pipeline must be the same internal diameter as the adjacent pipe (full bore) and be suitable for the passage of pigs.

Pigging of the offshore and onshore pipelines is an integral part of verifying the integrity of the complete pipeline system. Thus the ability to pig the pipelines is a fundamental requirement for the design of the LVI

It is recognised as best practise within Shell that high integrity safety shutdown valves should not be pigged to avoid any potential for damage to the valve seals which may affect the ability and reliability of the valve to close on demand.

2.5 Potential Configurations

There are two potential configurations for the high integrity safety shutdown system at the Glengad landfall. These are the Bypass arrangement (as proposed) and the straight Pipe arrangement as indicated in the An Bord Pleanála correspondence. These can be summarised as follows:

Straight Pipe – The two safety shutdown valves are mounted inline with the onshore and offshore pipelines and thus the straight pipe configuration requires piggable safety shutdown valves (Refer Section 4).

Bypass – The two safety shutdown valves are mounted in a non-piggable bypass (Refer Section 5).

3 AVAILABILITY OF SAFETY SHUTDOWN VALVES

3.1 Potential Suppliers

While there are many companies that supply valves to the oil and gas industry, there are a limited number having experience of supplying valves suitable for installation into high integrity safety shutdown systems. In addition, the potential companies must be suitably established and qualified as accepted suppliers to Shell.

Within the present market there are four primary potential international suppliers of safety shutdown valves and systems that are considered acceptable to Shell. These are (in alphabetical order):

- BEL Valves (a division of British Engines Ltd)
- Cameron International Corporation ("Cameron")
- Mokveld Valves BV
- Petrolvalves Srl

3.2 Industry Track-Record

High integrity safety shutdown valves are used in many applications throughout the oil and gas industry. They are to be found in subsea facilities, processing plants, topside facilities and at receipt and intermediate pumping/compressor stations for onshore transmission pipelines. In the majority of applications these valves are in process piping and thus are reduced bore ball, gate and axial flow valves with typical sizes ranging from 4” dia to 12” dia.

Larger diameter safety shutdown valves, i.e. greater than 14” and pressure class 2500, are not as readily available in the market due to the fewer applications and resultant lower demand.

A range of the larger diameter valves supplied to the industry are given in Table 3-1.

Supplier	Dia	Type	Year	Pressure	Application	Client	Project
BEL Valves	18" max	Gate	2008	830 bar	Topside	AGIP (KCO)	Kashaghan
Petrolvalves	10" max	Ball	2004	Rating ASME 2500	Topside	AMEC Service Ltd	Venture-Annabel Development UK
Cameron	20”	Ball	2008	301 bar	Plant	Shell	Pearl Development
Cameron	24”	Ball	2006/08	294/301 bar	Topside	QatarGas	Qatar North Field
Cameron	28" max	Ball	2006/08	345 bar	Topside	RazGas	Qatar North Field

Table 3-1 Typical larger valve diameters

Mokveld BV manufacture axial flow valves up to a maximum 16” dia. These valves are not piggable but have many years of service in high integrity safety shutdown applications.

From the information supplied from the above companies, all valves supplied in Table 3-1 are reduced bore i.e. non-piggable. No piggable safety shutdown valves have been identified. Petrolvalves advised that pigging would have an effect on the reliability of the safety shutdown valves as there would be a definite risk with the inclusion of pigs in the system.

The conclusion from the above is that field proven, full bore 20” diameter safety shutdown valves at the required pressure rating are not available and if considered, they would be

one-off specials. SEPIL do not consider one-off specials with no proven track record are appropriate for the Corrib project.

4 SHUTDOWN CONFIGURATION – STRAIGHT PIPE

4.1 Pipe Configuration

The straight pipe arrangement, which is a potential alternative to the design previously presented, is illustrated in schematic form in Figure 4-1.

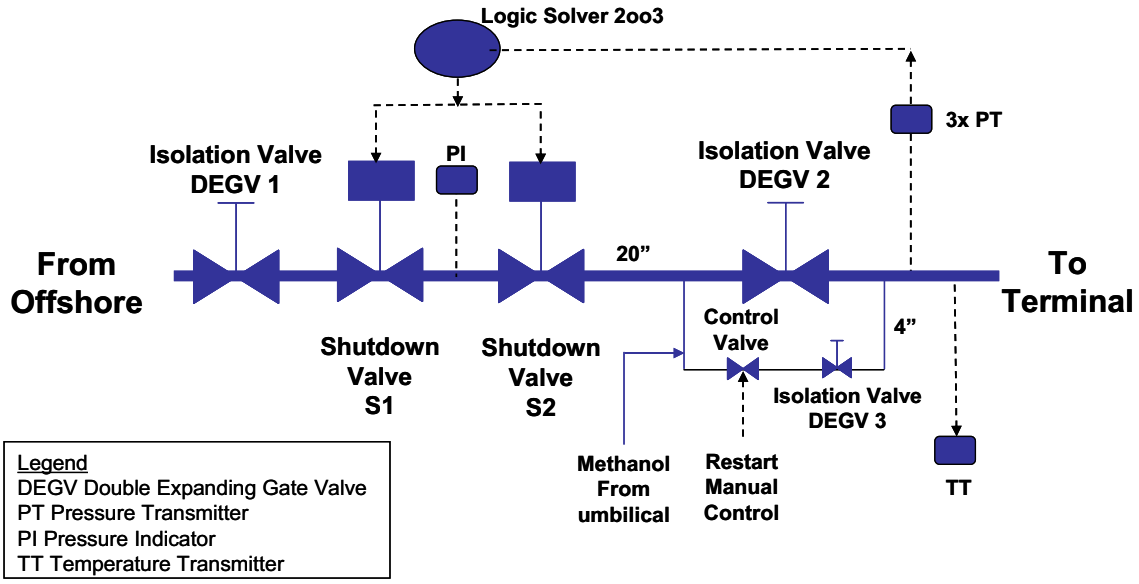

Figure 4-1 Straight pipe configuration

The two safety shutdown valves (S1 and S2) are normally fully open. These valves will automatically close if the pressure readings from the three pressure measurements (3xPT) exceed the preset trip pressure on a two out of three (2oo3) basis. The Logic Solver then releases the hydraulic pressure in the actuators of the two safety shutdown valves and they close under the force of the compressed springs in the valve actuators. To isolate the section for maintenance an upstream and downstream double expanding gate valve (DEGV1 and 2) would be installed in the pipeline. To facilitate the restart a small 4" dia bypass equipped with the manual restart valve and the third isolation valve DEGV 3 would be installed around the downstream DEGV2. Methanol from the umbilical would be injected into the pipeline at restart (Methanol line from the umbilical).

For this configuration all the valves will need to be full bore to allow pigging of the pipeline. It is expected that valves S1 and S2 would be top entry ball valves.

4.2 Corrosion/ Erosion

The threat of corrosion for the straight pipe configuration will be the same as for the onshore pipeline. For the 20" valve sealing surfaces and the small bypass around DEGV2, Corrosion Resistant Alloys would be selected to mitigate any potential corrosion issues. As indicated by the erosion assessment (Appendix Q4.9), erosion is unlikely to occur with the expected flow rates and lack of direct impingement of solids on any surfaces.

4.3 Layout Arrangement

The straight line configuration could be accommodated within the compound area of the proposed LVI. There may be some re-arrangement of the facilities however it is not expected to significantly change the visual impact of the LVI.

4.4 Testing of the Shutdown Systems

In this configuration two top entry ball valves could be used to maintain the safety shutdown valves without removal from the pipeline. The two safety shutdown valves would be isolated by DEGV 1 and DEGV 2 to facilitate maintenance.

5 SHUTDOWN CONFIGURATION- BYPASS

5.1 Pipe Configuration

The bypass arrangement, which is the design previously presented, remains the currently proposed design. This is illustrated in schematic form in Figure 5-1.

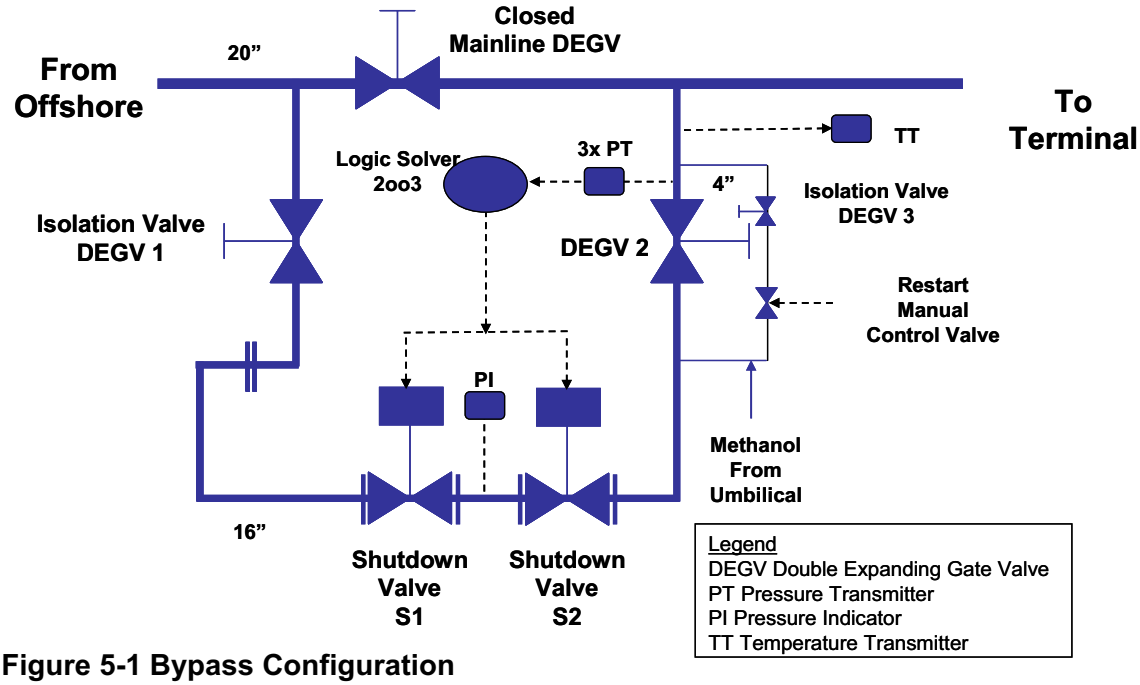

Figure 5-1 Bypass Configuration

The full bore mainline double expanding gate valve is positioned in the 20" dia pipeline and is normally locked closed. This valve will only be opened during a pigging operation when the facilities will be manned fulltime. This valve will be locked closed once the pig has passed the LVI and the valve leak tightness confirmed.

The two safety shutdown valves (S1 and S2) are located in a shutdown bypass and are normally fully open. The valves will automatically close if the pressure readings from the three pressure measurements (3xPT) exceed the preset trip pressure on a 2oo3 basis. The Logic Solver then releases the hydraulic pressure in the actuators of the two safety shutdown valves and they close under the force of the compressed springs in the valve actuators. To isolate the shutdown valves for maintenance, an upstream and downstream double expanding gate valve (DEGV1 and 2) would be installed in the bypass. To facilitate the restart a small 4" dia bypass equipped with the manual restart valve and the third isolation valve DEGV 3 are installed around the downstream DEGV2. Methanol (MeOH) from the umbilical would be injected into the pipeline during restart.

For this configuration DEGV 1, 2 and 3 will be reduced bore. The selected valve for the Shutdown valves S1 and S2 are Mokveld axial flow valves, 16" dia.

5.2 Corrosion/ Erosion

Corrosion Resistant Alloys will be selected for the barred tees, the 20" dia pipeline, the 20" dia mainline valve together with the bypass pipe work and associated valves. This will mitigate any potential corrosion issues caused by the more geometric configuration.

The changes in direction at the Tees and bends within the bypass configuration compared to the straight pipe increase the sensitivity to erosion by solids should they be produced.

However, as indicated by the erosion assessment (Appendix Q4.9), erosion is not likely to be significant and is within the design parameters.

The likelihood of liquid slugs in the pipeline is considered to be negligible and thus no design issues for either configuration are expected with respect to slugging (Refer Appendix Q 4.5).

5.3 Layout Arrangement

The LVI compound area has been sized to accommodate the bypass configuration.

5.4 Testing of the Shutdown Systems

In this configuration the safety shutdown valves are axial flow types and require to be removed from the pipeline for full maintenance after a prescribed period of time. This is to ensure the high reliability of these valves. Consequently the valves are flanged. To facilitate removal of these two valves, an additional flange and a U shaped pipe section is included immediately upstream of shutdown valve S1. This work will be coordinated within the period assigned for a planned shutdown of the Gas Terminal and pipeline system.

6 SAFETY

To establish any potential difference in the inherent safety of the alternative LVI configurations, a Quantitative Risk Assessment (QRA) was performed for both the straight pipe and bypass alternatives. The methodology used is described in Appendix Q6.4.

In order to compare relative risk, the individual risk of fatality per year as a result of a loss of containment event at the LVI has been calculated. The results of this comparative QRA are illustrated in Figure 6-1 (based upon a pressure of 100 barg in the gas pipeline at the LVI.)

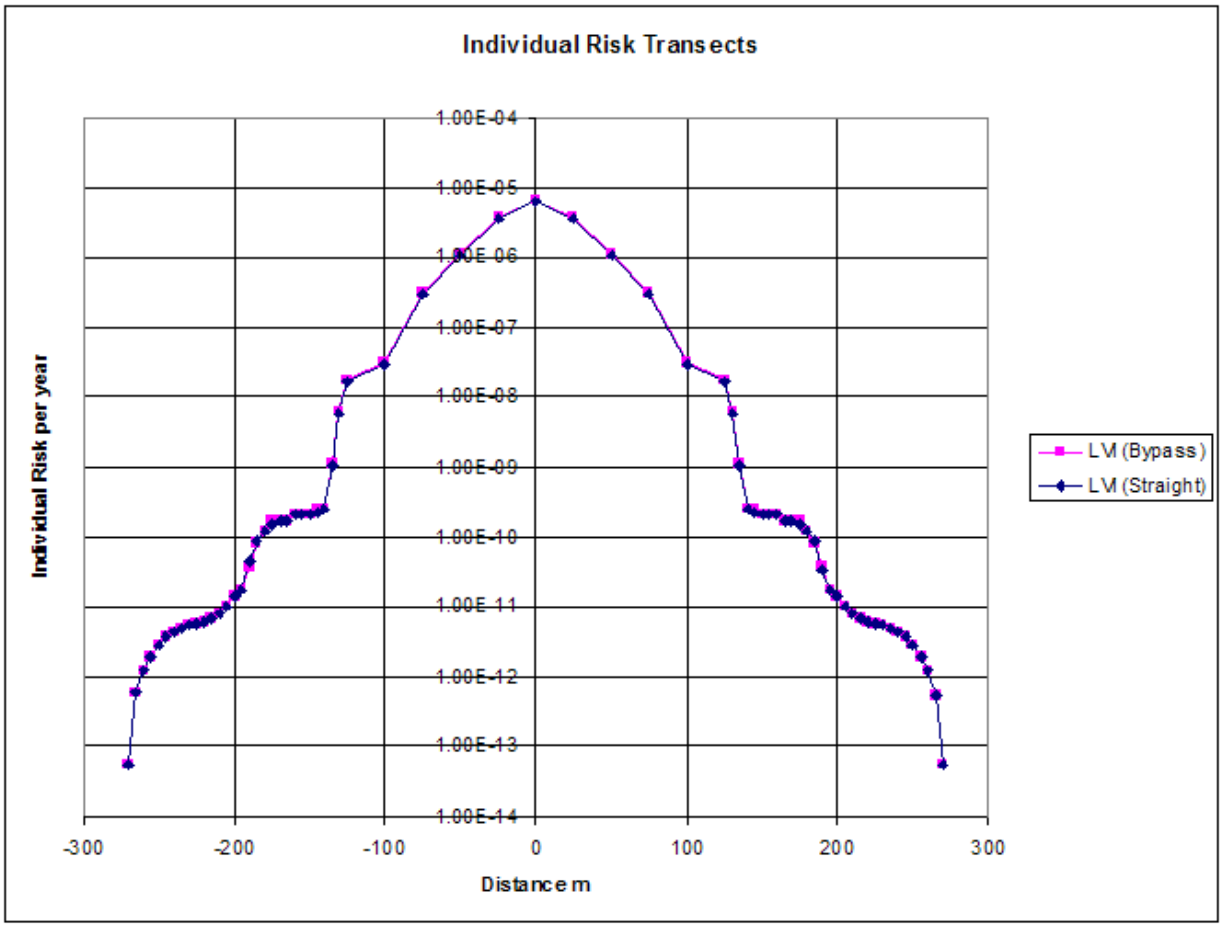

Figure 6 -1 Comparison of Individual Risk per Year

The Figure presents individual risk (of fatality) transects for the base case "bypass" configuration and "straight pipe" alternative for the LVI at Glengad. The horizontal axis represents the distance from the LVI and the vertical axis represents the likelihood (risk) that a person will be fatally injured in a year as a result of release from the LVI. The smaller the number, the lower the risk. While the bypass arrangement has more items of equipment than the straight pipe arrangement, the straight pipe arrangement has more pipe and valves at the larger 20" dia. However in terms of individual risk, there is minimal difference between the two configurations for the LVI as the two risk transects are virtually identical.

It is therefore concluded that adoption of a straight pipe configuration at the LVI would not result in increased safety at Glengad.

7 SUMMARY AND CONCLUSION

A comparison of the factors relevant to the selection between the two alternative configurations is presented in Figure 7-1.

From this comparison the proposed bypass arrangement for the LVI is clearly preferred.

The principle drivers in forming this selection are as follows:

- Requirement for pigging of the offshore and onshore pipelines is an integral part of verifying the integrity of the overall pipeline system.
- Lack of field proven and piggable 20" dia high integrity safety shutdown valve.
- The difference in effect on safety at Glengad is negligible.

Option Comparison	Straight Line 20"	With Bypass 16"
Valve dia available	Very limited source	16" readily available
Full bore valve required and available	Required but not available	Not required
Change on Visual Impact	None	None
Change in LVI footprint	Minimal	None
Complies with Shell standards	No	Yes
Proven track record in field	No	Yes
Reliability and rating certification available	Will need specific qualification – not guaranteed	High
Impact on safety at Glengad	No difference in risk level	No difference in risk level
Corrosion Issues	Mitigated with CRA materials	Mitigated with CRA materials
Erosion Issues	Not significant	Not significant
Methanol Injection available	Yes	Yes
Testing is achievable	Yes	Yes

Key

Significant problems	
Issue identified would require further investigation	
Acceptable no significant problem identified	

Figure 7-1 Summary of Options

SHELL E&P IRELAND LIMITED

CORRIB GAS FIELD DEVELOPMENT PROJECT

Corrib
natural gas

Q4.5- ASPECTS OF PROCESS ENGINEERING DESIGN OF THE CORRIB PRODUCTION SYSTEM

DOCUMENT No: COR-25-SH-0012

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1 INTRODUCTION

The purpose of this document is to provide detailed information relating to key process engineering design aspects of the Corrib production system. These aspects have been previously discussed at the Oral Hearing in 2009, or further information was requested in relation to these topics through subsequent letters received from An Bord Pleanála on 2nd November 2009 and 29th January 2010. A comprehensive but high-level summary of all the topics in this document is provided in Appendix Q2.1.

Table 1.1: displays queries that have been previously raised and the corresponding section of this document which addresses each query

Query	Relevant section in this Appendix Q4.5 document
Furthermore, the maximum allowable operating pressure (MAOP) for the pipeline should be stated Furthermore, the board has asked that "*…..the routing distance for the proximity to a dwelling shall not be less than the appropriate hazard distance for the pipeline in the event of a pipeline failure".* (Letters from An Bord Pleanála of 2nd November 2009 and 29th January 2010)	Section 2: Pipeline Process Safeguarding & MAOP
The Boards specific concern is that the undertaker should provide sufficient information and design detail to enable assessment of whether or not the revised proposed development would give rise to an unacceptable risk to the public, having regard to the very high pressures involved, the site conditions through which the site traverses and the hazards associated with the transport of untreated wet gas. (Point 1, An Bord Pleanála Letter, 29th Jan 2010).	Section 2: Pipeline Process Safeguarding & MAOP
Submit an analysis of the condition where the umbilical becomes severed and the control of the valves at the wellhead and the subsea manifold is lost. The analysis needs to identify what conditions apply to the onshore pipeline and the risks involves in that circumstance. (Point (f), An Bord Pleanála Letter, 2nd November 2009).	Section 3: Severing of the Umbilical
"*An examination of the potential for pressure in the offshore pipeline to increase to wellhead pressure levels in the event that all wellhead valves had to be shut in over a prolonged period and in that period incremental leakage past the valves occurred*". (Point (2), An Bord Pleanála Letter, 2nd November 2009).	Section 4: Potential and Effect of Passing ('Leaking') Valves in the Corrib Pipeline

Submit a new QRA that presents the analysis of risk at the different operating conditions and different locations along the pipeline route. The QRA should be site specific. The QRA should include ground movement and incorporate a database that matches the conditions of the proposed development. A sensitivity of the QRA is required which demonstrates the range of risk that relates to any uncertainty (in the database) of failure frequencies for the various potential failure modes of the pipeline. The database should be relevant for an upstream wet gas. In order to eliminate any doubt please note that all failure modes should be included including the possibility of third party intentional damage at Glengad, wet gas in the pipeline, CO2 in the pipeline and potential for ***Methane Hydrate*** *in the pipeline.* (Point (d), An Bord Pleanála Letter, 2nd November 2009).	Section 6: Hydrates
The concept of a vent at Glengad as a measure to protect against pressure at the wellhead side of the pipeline at the landfall rising above the maximum operating pressure should be examined" (Point (g), An Bord Pleanála Letter, 2nd November 2009).	Section 7: Cold Venting at Glengad (The LVI Compound)

2 PIPELINE PROCESS SAFEGUARDING DESIGN & MAOP

2.1 MAXIMUM ALLOWABLE OPERATING PRESSURE (MAOP)

In the letters received on 2nd November 2009 and 29th January 2010, An Bord Pleanála requested the setting of both an onshore and an offshore MAOP. Furthermore, An Bord Pleanála asked that "*…..the routing distance for the proximity to a dwelling shall not be less than the appropriate hazard distance for the pipeline in the event of a pipeline failure".* An Bord Pleanála have also indicated how the hazard distance should be calculated, in which MAOP is a key input.

Although hazard distance is not a standard measure for pipeline safety, in order to comply with the An Bord Pleanála request, SEPIL has undertaken a review of the required MAOPs.

The outcome of this review is that SEPIL has established the minimum required offshore and onshore pipeline MAOP to maintain a sufficient operating envelope to meet the contractual and technical requirements of the already approved and constructed Gas Terminal. This review has resulted in the maximum allowable operating pressures (MAOPs) of the pipelines being set to 150barg and 100barg for the offshore and onshore pipelines respectively.

SEPIL have modified the design to satisfy the requirements of An Bord Pleanála, as described in their letters of 2nd November 2009 and 29th January 2010. Note that further lowering of the pipeline MAOP would not allow for the Gas Terminal to operate within its operating envelope, as per the basis upon which approval has been granted for the Gas Terminal.

2.2 SUPERSEDED PIPELINE PROCESS SAFEGUARDING PHILOSOPHY

This section presents the development of the Corrib Pipeline Process Safeguarding Philosophy from 2002 to 2009.

The Corrib pipeline system between the Corrib subsea wells and the Gas Terminal is divided into two sections:

- An offshore pipeline from the subsea manifold to the inlet of the beach valve (a valve located at the beach serving as an isolation valve, no overpressure protection function)
- An onshore pipeline from the beach valve to the Gas Terminal

The Corrib pipeline was originally designed and has been procured for a design pressure of 345 barg, equal to the maximum pressure from the Corrib wells plus some margin. Thus the original pipeline system was designed as a "fully rated" system.

With respect to the operating envelope, the operating pressure was limited to approximately 150 barg based on various constraints within the system (methanol injection capabilities).

In 2006 the Technical Advisory Group (TAG) Independent Safety Review, prepared by Advantica recommended re-classification of the onshore pipeline as a Class 2 (Suburban) pipeline with a design factor reduced to 0.3. SEPIL acted upon these recommendations and the design pressure of the onshore section was reduced from 345 barg to 144 barg. Due to the change in design pressure (that is the offshore pipeline having a design pressure of 345 barg, and the onshore pipeline having a design pressure of 144 barg), the pipeline codes required an overpressure protection system at the landfall.

To achieve overpressure protection, an Instrumented Protective Function (IPF) option was selected. This option may be applied where a dedicated pressure relief system is not practical for safety or environmental reasons. IPFs consist of fail closed valves activated to close at the set pressure by a redundant and highly reliable instrumented pressure sensing and transmitting system. This IPF is known as the Landfall Valve Installation (LVI), located at Glengad, and further details can be found in Appendix Q4.3.

2.3 CURRENT PIPELINE PROCESS SAFEGUARDING PHILOSOPHY

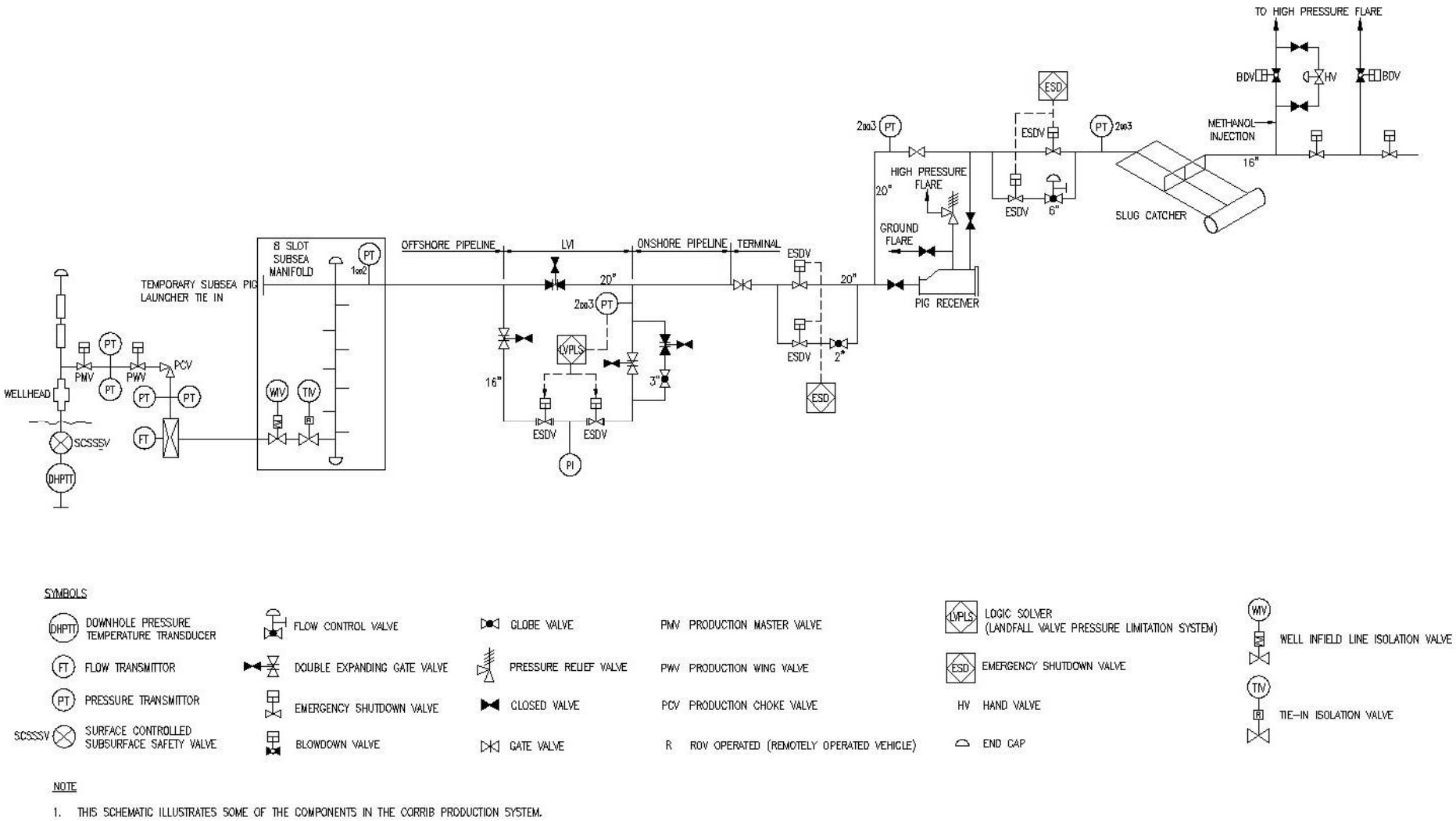
The setting of lower MAOP values for both the offshore and onshore pipelines (section 2.1) required a review and update of the Corrib production system operating and safeguarding philosophy. An integrated flow assurance review, spanning the offshore wells to the export from the Gas Terminal into the BGE network, was conducted. This concluded that it would be possible to reduce the normal operating pressure at the inlet to the Gas Terminal to 80-85 barg, whilst maintaining adequate operating margins between the normal operating pressure and the trip pressure of the Terminal inlet and Pipeline instrumented safeguarding systems.

As a result of the changes to the MAOP's the following design changes have been incorporated into the instrumented safeguarding systems:

- An additional means of shutting down all subsea actuated valves has been implemented by fitting a high reliability automatic subsea hydraulic pressure release system in the Bellanaboy Bridge Gas Terminal (BBGT). All actuated valves subsea are fail safe (i.e. they close on loss of their motive power – hydraulic fluid). By releasing the pressure of the hydraulic lines in the umbilical the following valves will automatically close on each well:
    - Surface controlled subsurface safety valve (SCSSSV) located in the production tubing of each well
    - Master valves
    - Wing valves
    - Well isolation valves (located on the manifold)
- Thus for each well 4 valves in series will be closed to isolate the pipeline system from the well. The signal to initiate this releasing of hydraulic fluid pressure will be taken from the LVI high integrity trip system. This additional shutdown configuration results in an increase of the reliability of the wells isolation system. The set point for the existing Terminal inlet high pressure trip, otherwise known as the 'SS3' trip, will be set at 93 barg with no change to the system reliability.
- The set point for the LVI high integrity trip will be set at 99 barg with no change to the system reliability.

Figure 2.1 illustrates a schematic of some of the main elements of the pipeline process safeguarding system. See Table 2.2 in section 2.5 Pipeline Process Safeguarding In Detail, for further details of the updated layers of protection as described above.

Figure 2.1: A schematic of some of the main elements of the pipeline process safeguarding system



2.4 NORMAL OPERATING PIPELINE PRESSURE PHILOSOPHY

This section provides a description of the operating envelope limits.

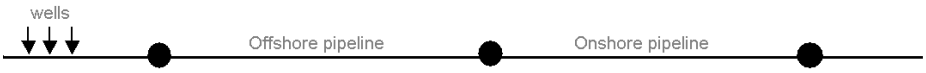
There will be a continuous 24 hour operations team to oversee production of Corrib gas and to ensure that operations remain within the limits of the operating envelope.

The normal operating envelope of the Corrib production facilities is from approximately 55 barg to 85 barg Terminal arrival pressure.

The normal steady state operating pressure at the inlet to the Gas Terminal is between 80 to 85 barg at the rated throughput of 350 MMSCFD. Under these conditions, in the case of upset at the Gas Terminal, there is ullage in the pipeline system for the operator to close in production from the wells without tripping the shutdown systems for the LVI.

The minimum pressure limit has been set at 55 barg Terminal arrival pressure. In the unlikely event of an unplanned system shutdown occurring while operating at 55 barg, trips will be automatically initiated to command valves to close to ensure that the resultant settle out pipeline pressure at the wells is above the minimum required pressure for system restart. An illustration of the resulting pressure profiles for the operating envelope of the pipeline is provided below.

Figure 2.2: The pipeline pressure operating envelope (Normal Operating Pressure Profile data for Year 1 and plateau production at 350 MMSCFD. Lower Operating Pressure data for Year 1 and 180MMSCFD)



Pressure Profile	Manifold	LVI	Terminal
Normal Operating Pressure Profile	117 - 122 barg	85 - 90 barg	80 - 85 barg
Lower Operating Pressure	73 barg	58 barg	55 barg

As can be seen from the above figure, the normal operating pressure of the Corrib production system at the Terminal inlet will be in the range up to approximately 85 barg. During steady state production, this may vary gradually by 1 to 3 bar, due to the nature of multiphase flow associated with the Corrib production system. The operating envelope has been designed with a sufficient margin to accommodate instabilities in the production system without having to shut-in production from the field.

There are many barriers in place, both hardware and activity based (i.e. trained operators), to ensure that the production facilities remain within the operating envelope. These barriers are varied and introduced throughout all the phases of the project, including design, construct, commission and operate phases.

Certain barriers associated with process safeguarding can be categorised as Safety Critical Elements (SCEs) and safety critical activities. Hardware identified as SCEs are assigned mandatory operational performance standards and undergo rigorous certification checks during fabrication, installation and

commissioning. Safety critical activities are given special attention within operator and maintenance task assignments and competency development. The bow tie assessments that form part of the Qualitative Risk Assessment, see Appendix Q6.3, provide the means of identifying safety critical elements and activities.

2.5 PIPELINE PROCESS SAFEGUARDING IN DETAIL

This section provides details of the process safeguarding philosophy.

In the unlikely event of an excursion beyond the operating envelope, there are additional barriers in place to ensure shut-in of production in a safe manner. These additional barriers are collectively known as process safeguarding.

The intent of this section is to provide a transparent description of the Corrib pipeline process safeguarding to prevent the pressure rising above the MAOP. As previously described, there are numerous layers of protection in the system. A number of these layers form the offshore pipeline overpressure protection system, while another layer forms the onshore pipeline overpressure protection system. The major layers of protection in the system to prevent the pressure rising above the MAOP are detailed in the table 2.2 in section 2.5.2. However, in order to provide context for some of the terms used in describing the layers of protection, section 2.5.1 has been added to provide an explanation of the subsea trips in the system and the associated nomenclature.

2.5.1 Subsea Tripping Nomenclature

There are a number of subsea (SS) trips in the Corrib production system to ensure operations remain within the design envelope of the facilities. Once these subsea trips are initiated an action will be performed to shut in production from the wells. There are various initiators (e.g. different pressure transmitter locations and settings) which can cause the trips to be activated. Also, the initiators can either be manual (i.e. intervention from operations) or automatic. Furthermore, the process and valves by which the trip shuts in production from the wells vary depending on the trip. As such, the following tables provide an explanation, both simplified and detailed, of each subsea trip.

Table 2.1A: Simplified Subsea Trips and Explanations

Sub Sea Trip Level	Initiated by	PMV	PWV	PCV	SCSSSV	WIV
SS3	Automatic Refer 2.5.2	Close	Close	Close	No Action	No Action
SS2	Automatic Refer 2.5.2	Close	Close	No Action	Close	Close
SS1	Operator Push button	Close	Close	Close	No Action	No Action
SS0	Operator Push button	Close	Close	Close	Close	No Action

Note1: SS3 uses the signal lines via the umbilical to close the subsea valves. SS2 releases hydraulic pressure in the umbilical at the Terminal which consequently closes the subsea valves.

Note2: Abbreviations are explained in the Glossary

Table 2.1B: Detailed Subsea Trips and Explanations

Subsea Trip	Explanation
SS3	SS3 is Subsea Shutdown Level 3. This trip closes the (1) Production Master Valve, (2) Production Wing Valve and (3) Production Choke Valve located on each well. This trip is similar to SS1, but is **automatically initiated when the terminal inlet pressure rises to 93 barg (or falls below 55 barg).** **It is also automatically initiated from a number of other sources (e.g. for a terminal ESD)**.
SS2	SS2 is Subsea Shutdown Level 2. This trip closes the (1) Production Master Valve, (2) Production Wing Valve, (3) Surface Controlled Subsurface Safety Valve and (4) Well Infield Line Isolation Valve at the subsea manifold This trip is **automatically activated** when the pressure at the **LVI reaches 99 barg**, or if either of the shutdown valves at the LVI is less then 95% open.
SS1	SS1 is Subsea Shutdown Level 1. This trip closes the (1) Production Master Valve, (2) Production Wing Valve and (3) Production Choke Valve located on each well. The SS1 trip is **manually initiated** by use of a control room push button by the CRO (control room operator).
SS0	SS0 is Subsea Shutdown Level 0. This trip closes the (1) Production Master Valve, (2) Production Wing Valve, (3) Production Choke Valve and (4) Surface Controlled Subsurface Safety Valve on each well. The SS0 trip is **manually initiated** by use of a control room push button by the CRO (control room operator).

2.5.2 Safeguarding Layers of Protection

The major layers of protection in the system to prevent the pressure rising above the MAOP are detailed in the table below.

The set points for the various trips have been selected based upon detailed simulation of pressure build-up curves in the pipeline using OLGA software. The curves illustrate the increase in pressure along the length of the pipeline with respect to time for various scenarios. This, combined with other data, allows for identification of set points for the various trips. OLGA is a dynamic pipeline simulator for engineering the flow of oil, water and gas in wells, pipelines and receiving facilities, and is recognised and widely used in the international oil and gas industry.

Table 2.2: The major layers of protection in the Corrib production system to prevent overpressurisation

Layer	Applicable to pipelines	Trip/Protection	Set Point	Description
Layer 1	Offshore & Onshore	Normal operating procedures	n/a	Normal pipeline operating procedures to control pressure within the selected operating pressure range of 80 to 85 barg in initial years, to minimise the risk of triggering the over-pressurisation protection system due to an upset in the Terminal.
Layer 2	Offshore & Onshore	Terminal inlet high pressure trip (SS3)	93barg terminal inlet	Initiates trip **SS3**: Closes well subsea tree wing, master and choke valves
Layer 3a	Offshore & Onshore	LVI pressure trip	99barg,	Closes **LVI** valves and initiates SS3 and SS2 trips. **SS2** releases hydraulic pressure from HP and LP hydraulic lines to subsea valves and thus closes actuated subsea valves (surface controlled subsurface safety valve (SCSSSVs), master valves, wing valves, well infield line isolation valves)
Layer 3b	Offshore & Onshore	Spurious closure of the LVI shutdown valves	Either LVI valve less than 95% open	Initiate **SS2** trip which releases hydraulic pressure from HP and LP hydraulic lines to subsea valves and thus closes actuated subsea valves (surface controlled subsurface safety valve (SCSSSVs), master valves, wing valves, well infield line isolation valves)
Layer 4	Offshore	Subsea manifold pressure trip	145barg subsea manifold pressure	Initiates an **SS3** trip which closes well subsea tree wing, master and choke valves.
Layer 5	Offshore &	Manual trip, SS0 or	Manual	Initiates an SS0 or SS1 trip.

	Onshore	SS1	operation	**SS1** Closes production master valves, choke valves and wing valves, **SS0** closes the same as SS1 and closes SCSSSV

Layer 1 of protection is provided by normal operating procedures. This ensures that pressure changes under normal operating conditions allow time for operator intervention. The normal steady state operating pressure at the inlet to the Gas Terminal is between 80 to 85 barg at the rated throughput of 350 MMSCFD. Under these conditions, even in the case of upset at the Gas Terminal, there is ullage in the pipeline system for the operator to close in production from the wells without tripping the shutdown system at the LVI. The maximum operating pressure for the Terminal inlet will be limited to below the first Terminal inlet high pressure trip, which is set at 93 barg.

Layers 2 to 5 combine to form the overall shutdown sequence in the event of the pressure rising. These layers protect the system if excursions occur beyond the normal operating envelope. They do not take account of all barriers previously mentioned (e.g. proficiently trained operators that can intervene). These layers, with the exception of Layer 5, are designed to be automatic without any operator intervention.

Layer 2. This is the Terminal inlet trip designated SS3 with a set point of 93barg and is triggered to prevent a further increase in pipeline pressure. The signal from the Terminal pressure transmitters that detect rising pressure is processed via the Terminal Emergency Shutdown (ESD) system and closes the well master valve and wing valve for each well via the Master Control Station (MCS) located at the terminal. The choke valves will also be commanded closed on this trip. The wing and master valves are immediately commanded closed and do not wait for the production choke valves to close first. Due to the pressure gradient in the pipeline (subsea manifold pressure is approximately 117 – 122 barg) prior to the trip, the resulting settle out pressure at the LVI will increase towards 99 barg (the set point of the next trip). This will cause the subsequent layer, Layer 3a, to automatically trip whenever Layer 2 is initiated. Note: The automatic SS3 trip causes the same valves to close as the control room manual subsea shutdown, designated SS1.

The pressure transmitters used for the Terminal inlet trip are located inboard of the Terminal boundary ESD valve. Closure of this ESD valve isolates the pressure transmitters from the onshore pipeline and impairs this trip function. Thus, to cover spurious closure of the ESD valve, SS3 is tripped if the valve limit switches indicate that the valve is not fully open.

Layer 3a is the ultimate layer to prevent the pressure within both the onshore and offshore pipelines from rising above their MAOP. Pressure is measured at the LVI and the trip pressure is set at 99 barg. Note that this will automatically initiate if Layer 2, as described above, has tripped due to high pressure at the Gas Terminal inlet. This initiates closure of the LVI shutdown valves (2 in series) at the landfall location; this layer also initiates a subsea shutdown via the SS3 and SS2 trips. The LVI is equipped with two in-line ESD valves (i.e. the 'LVI shutdown valves'), two out of three voting (2oo3) pressure transmitters and a high reliability logic solver; this configuration achieves a very high reliability. A facility to remotely close the LVI valves from the Terminal control room for inventory isolation purposes with high reliability has been provided. LVI pressure transmitter readings, LVI trip status and LVI valve open/closed status are continuously transmitted back to the Terminal and displayed in the control room.

The SS2 trip will initiate four electrically latched solenoid valves at the onshore Terminal HPU to bleed both the LP and HP hydraulic fluids from both 'A' and 'B' hydraulic rails that provide hydraulic pressure to the subsea valves. The solenoids will act on command signals (hard wired) directly from the Terminal ESD panel which will get its signal from the LVI solid state logic solver (LVPLS). The time taken to release hydraulic fluid pressure in a 92km subsea tie-back is significant. The control system hydraulic analysis indicates that the pressure in both the High Pressure (HP) and Low

Pressure (LP) supplies reduces to either the valve closing pressure or the solenoid drop out pressure within approximately two hours. This time to release hydraulic fluid pressure has been taken into account in the design and setting of the offshore pipeline MAOP.

Layer 3b is also provided to protect the offshore pipeline from exceeding MAOP in the event of spurious closure of either of the LVI valves. If either valve is less than 95% open this initiates both SS3 and SS2 trips as per paragraph 2.5.1.

Layer 4 is the sub-sea pipeline manifold High Pressure trip. Its main purpose is to limit upstream line packing in the offshore pipeline and hence limit the differential pressure over the LVI following an LVI trip. The trip will be taken from the subsea manifold pressure transducers PT-001 & PT-002 (i.e. designed with a redundant spare) and will activate when the pressure rises to 145 barg. The output of this trip, processed via the Master Control Station (MCS), shall close all wing and master valves, in addition to all production choke valves.

Layer 5 provides a pushbutton for the Control Room Operator (CRO) to command closed all subsea actuated valves via the MCS. This includes closing all SCSSSVs.

The above layers of protection form the instrumented protection to maintain the offshore and onshore pipeline within the respective MAOP. There is also inherent mechanical protection in the design of the pipelines to prevent loss of containment. This is the pipeline wall thickness and the hydrostatic testing of the pipelines. For the onshore pipeline the wall thickness is 27.1mm with a design pressure of 144 barg together with the hydrostatic test pressure of 504 barg. Similarly at the offshore pipeline landfall the wall thickness is also 27.1mm with a design pressure of 345 barg and a hydrostatic test pressure of 380 barg.

3 SEVERING OF THE UMBILICAL

An Bord Pleanála have raised a query with regards potential severing of the umbilical. This was raised in point (f) of their letter dated 2nd November 2009:

(d) *Submit an analysis of the condition where the umbilical becomes severed and the control of the valves at the wellhead and the subsea manifold is lost. The analysis needs to identify what conditions apply to the onshore pipeline and the risks involves in that circumstance.*

The following analysis is a synthesis of a note ("Fact Sheet: Umbilical Leak" which was submitted during the 2009 oral hearing) and a description of the bowtie for the umbilical from Appendix Q6.3 and supersedes the earlier information.

3.1 UMBILICAL DESCRIPTION

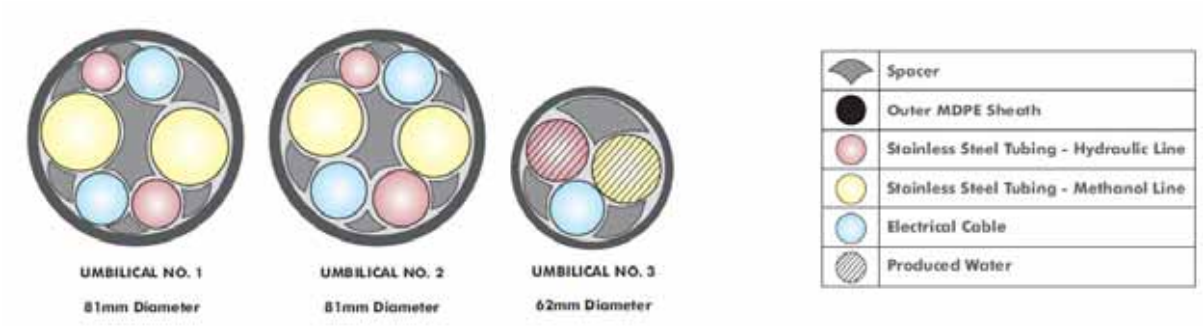
The control of the subsea facilities will be achieved using a composite system containing methanol injection system cores and control system lines (communication signals, electrical and hydraulic power). The umbilical will run from the Terminal through to the subsea manifold. Within the subsea facilities there are local umbilicals to control the individual wells.

Table 3.1 provides the main functions of the services provided by the umbilical, and Figure 3.1 illustrates a schematic of the onshore umbilicals. Further details of the umbilical can be found in section Q4.1. Further information can also be found here in relations to the barriers that act to prevent failure of the umbilical and also a description of the leak detection system (for the methanol lines).

Table 3.1: Functions of services provided by umbilical

Supply	Function
Electrical Power	Electrical power is required for the operation of the Subsea Control Modules (SCM) and for operation of the Directional Control Valves (DCV's).
Communication cable	The communication cable allows the operator to operate all DCV's via the SCM and to read the available instrumentation, for example pressure and temperature indicators.
HP Hydraulic	HP hydraulics is used to keep the Surface Controlled Sub Surface Safety Valve (SCSSSV) open
LP Hydraulic	LP hydraulics is used to keep all other actuated valves open and is used to drive all actuated valves open. (Note: upon release of LP hydraulic fluid pressure choke valves will fail in their last position).
Methanol	Methanol injection at LVI, Manifold and Wells to prevent hydrates. Also contains corrosion inhibition liquid.

Figure 3.1: A schematic of the Corrib onshore umbilicals



3.2 ASSESSMENT OF SEVERED UMBILICALS IMPACT ON PIPELINE PRESSURES

3.2.1 Introduction

Pipelines pressures will remain within their respective onshore and offshore MAOPs in the event of umbilical failure, as the pipeline safeguarding system is designed to deal with such an event. A detailed analysis for severing each of the individual components in the umbilical is provided in the subsequent sections.

3.2.2 Electrical Power Cables

Dual redundant electrical power cables supply electrical power to:

1. The solenoid valves (Directional control valves) located on each subsea well's Subsea Control Module (SCM) and on the subsea manifold SCM.

2. The Subsea Electronics Modules (SEMs) on each subsea wells' SCM and on the subsea manifold's SCM. The SEMs provide power to all instrumentation.

The solenoid valves for the production wing valve on all subsea trees are electrically latched and on loss of electrical power they will move to their fail safe position and vent hydraulic fluid to sea causing the production wing valve to move to the closed position. The solenoid valves for all other actuated subsea isolation valves, the surface controlled subsurface safety valves (SCSSSVs), the production masters valves and the well isolation valves are electrically driven and hydraulically latched. On loss of electrical power they will remain in the position they were before the loss of electrical power occurred (normally the fully open position).

Loss of electrical power to the SEMs and instrumentation will prevent the operator from monitoring the conditions within the subsea wells, well subsea trees and pipelines. The operators will not be able to control any of the actuated subsea valves, other than by releasing the hydraulic fluid pressure at the onshore Terminal and thereby closing all actuated subsea isolation valves. Line insulation monitors in the Electrical Power Unit (EPU) will initiate alarms within the control room, alerting the operators of the loss of electrical power.

Should the pressure in the pipeline rise, the pressure transmitters at the LVI station will detect the rise in pressure and close the LVI isolation valves, preventing the onshore pipeline from rising above its MAOP. Simultaneously, these same pressure transmitters will also send a signal to the Terminal to release the subsea hydraulic fluid pressure, thus closing all actuated subsea isolation valves and preventing the pressure within the offshore pipeline from rising above its MAOP.

As there are dual redundant electrical cables, both cables will need to be severed to lose electrical power to the subsea manifold and wells.

In the event of severance of the electrical power cables, production will be stopped and the pressure in the pipeline will not exceed MAOP.

3.2.3 Communication Cables

Dual redundant communication cables send data between the MCS on the onshore Terminal and the SEMs on the subsea well subsea trees and the subsea manifold. Severing the cables will prevent the operator from monitoring the conditions within the subsea wells, well subsea trees and pipelines and prevent the operators from controlling any of the actuated subsea valves, other than by releasing the hydraulic fluid pressure from within the onshore Terminal and closing all actuated subsea isolation valves. Alarms on the MCS will alert the operators of the loss of data communication.

On loss of signal all subsea isolation valves and the subsea choke valves will remain in the position they were in before loss of communication. Should the pressure in the pipeline rise, the pressure transmitters at the LVI station will detect the rise in pressure and close the LVI isolation valves, preventing the onshore pipeline from rising above its MAOP. Simultaneously, these same pressure transmitters will also send a signal to the Terminal to release the subsea hydraulic fluid pressure, thus closing all actuated subsea isolation valves and preventing the pressure within the offshore pipeline from rising above its MAOP.

The integrity of the communication system between the LVI and the Gas Terminal is monitored, and should the communications be severed, the system will detect this and initiate releasing of the subsea hydraulic fluid pressure, closing all subsea actuated valves.

As there are dual redundant communication cables, both cables will need to be severed to lose communications to the subsea manifold and wells.

In the event of severance of the communications cables, production will be stopped and the pressure in the pipeline will not exceed MAOP

3.2.4 HP Hydraulic Fluid

There are two hydraulic cores (A and B) for the High Pressure (HP) hydraulic supply. Hydraulic fluid is used to energise subsea actuated valves and keep then in the open position.

The HP Hydraulic Fluid supply is used to keep the SCSSSV on each well open. In the event that the HP Hydraulic supply lines are severed the HP pressure will decrease and the relevant SCSSSV's will close which will stop flow into the pipeline and therefore will prevent the pipeline pressure from rising.

In the event of severance of the HP hydraulic fluid line production will be stopped and the pressure in the pipeline will not exceed MAOP.

3.2.5 LP Hydraulic Fluid

On loss of hydraulic fluid pressure all actuated valves supplied from the hydraulic fluid core that is severed will move to the closed position, which will stop further inflow and therefore will prevent the pipeline pressure from rising.

There are two hydraulic cores (A and B) for the Low Pressure (LP) hydraulic supply. Hydraulic fluid is used to energise subsea actuated valves and keep them in the open position.

The LP supply is used for all actuated valves apart from the SCSSSV. In the event that the LP Hydraulic supply lines are severed the LP pressure will decrease and the relevant master valves and wing valves will close. The production chokes will be left in the as-is position.

The Subsea Control Modules (SCMs) at the subsea manifold and the SCMs at each of the subsea well subsea trees can be supplied from either the A or the B supply. A typical arrangement will be for some SCMs to be supplied with hydraulic fluid from the A supply and the remaining from the B supply.

In the event of severance of the LP hydraulic fluid line production will be stopped and the pressure in the pipeline will not exceed MAOP.

3.2.6 Methanol/Corrosion Inhibitor

Methanol is injected into the pipeline as a hydrate inhibitor, along with a corrosion inhibitor to prevent corrosion. Severing of these cores will not be a cause for the pressure in the pipelines to rise above their MAOPs.

The pressure in the pipeline will not exceed MAOP in the event of severance of the methanol cores**.**

3.2.7 Conclusions

The umbilicals provide a number of services to the subsea facilities. Each of these services was analysed to determine the potential impact on the control of subsea facilities.

If the offshore umbilical or all of the onshore umbilicals are severed, the field will shut down on loss of power and hydraulics. If only one onshore umbilical is severed, a number of the wells may automatically shutdown due to loss of hydraulics. The remaining wells will continue to produce at steady state within the operating envelope. Therefore it can be concluded that whether some or all of the umbilicals are severed, the pressures within the onshore and offshore pipelines will remain within their MAOPs.

3.3 HEALTH, SAFETY AND PIPELINE INTEGRITY CONSEQUENCES OF ONSHORE UMBILICAL FAILURE

See Appendix Q6.4 Quantitative Risk Assessment for further details in relation to consequences associated with the release of methanol from the umbilical as a result of onshore umbilical failure. This section also concludes that the presence of the umbilical adjacent to the onshore pipeline does not present a credible risk of pipeline failure due to umbilical loss of containment.

3.4 SPILL VOLUMES AND POTENTIAL FOR ENVIRONMENTAL IMPACT

The failure of an umbilical core is an unlikely event. However, in the extremely unlikely event that all three umbilicals were ruptured at the same time, a total liquid release of 18.2m3 is estimated. This will consist of approximately 3,000 litres of treated produced water, approximately 8,800 litres of methanol (including very small volumes of corrosion/scale inhibitor) and 6,400 litres of water based hydraulic fluid. These quantities are based on a very conservative response time of 1 hr to detect the leak in the control room and isolate the umbilical. In most cases of a major failure alarm signals in the control room would give rise to prompt operator intervention. Leak detection would be followed by a visual survey along the onshore pipeline route.

Once the spill/leakage has been located, mitigation measures will be activated. This will include applying measures to contain and clean up any liquids which may have escaped into the environment.

Depending on the location of the spillage, liquids could enter soils, surface water or groundwater at that location. The potential impact of this is outlined in the following:

1. The treated produced water is effectively clean water and would not pose an environmental threat to water or soils in the volumes that might be released.

2. The hydraulic fluid is a water/glycol based fluid known as Castrol Transaqua HT2. There is potential for localised temporary impact to soils and surface water/ground water. However, this fluid is readily biodegradable and the product is not expected to bioaccumulate through food chains in the environment. Its eco-toxicity is not classified as dangerous.

3. The potential impact of a methanol spill is as follows: Methanol degrades readily in the environment under both aerobic and anaerobic conditions, in soils (and sediments) and in the aquatic (freshwater and sea water) environment. Methanol degrades totally into carbon dioxide and water. Methanol is of low toxicity to aquatic and terrestrial organisms and is not bioaccumulated, but in the event of a large spill there may be localised effects. A spill in a water body will result in immediate dilution, which increases the rate of biodegradation and reduces its toxicity.

The water catchments of the route primarily discharge to the marine environment, either directly or via surface water bodies such as drains, streams or rivers. A spill of methanol to the marine environment has limited potential impact – methanol is classified by OSPAR to be a PLONOR substance, i.e. a substance which Poses Little or No Risk to the marine environment.

If such a spillage were to occur in an area which could present a risk of contamination of a private groundwater well, then measures would be put in place to monitor this well and provide an alternative water source if necessary until the contamination dissipates.

The corrosion/scale inhibitor present in the methanol will exist in such low concentrations that it is not expected to result in a significant impact on the receiving environment.

4 POTENTIAL AND EFFECT OF PASSING ('LEAKING') VALVES IN THE CORRIB PIPELINE

4.1 SUMMARY

An Bord Pleanála have raised a query with regard to the potential for valve leakage, subsequent to a shutdown, leading to an increase in pipeline pressure. This was raised in point (g) of their letter dated 2nd November 2009: "*An examination of the potential for pressure in the offshore pipeline to increase to wellhead pressure levels in the event that all wellhead valves had to be shut in over a prolonged period and in that period incremental leakage past the valves occurred*".

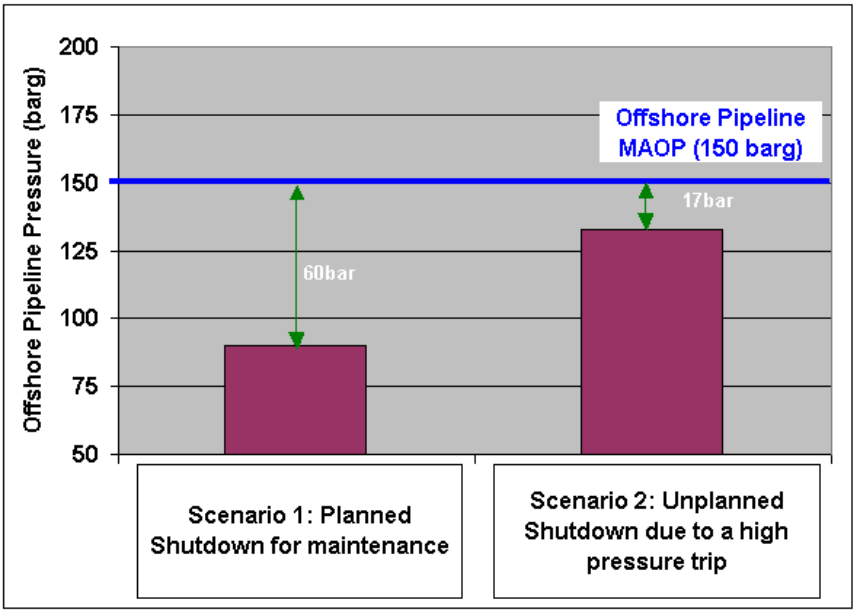
In order to assess the potential effect of valve leakage subsequent to a shutdown, it is important to determine the conditions resulting from the shutdown (pressures, temperatures and which valves have closed). Therefore, two scenarios have been examined as these represent the critical shutdowns:

(1) A planned shutdown for maintenance,

(2) An unplanned shutdown due to a high pressure trip

After each of these shutdowns, the pressure in the offshore pipeline will 'settle out' as the conditions in the pipeline reach equilibrium. The settle out pressures in the offshore pipeline and the associated margin to the offshore pipeline MAOP for the two scenarios can be seen in Figure 4.1.

<u>Figure 4.1:</u> Pressure margin available for 'valve leakage' in the offshore pipeline for various scenarios.

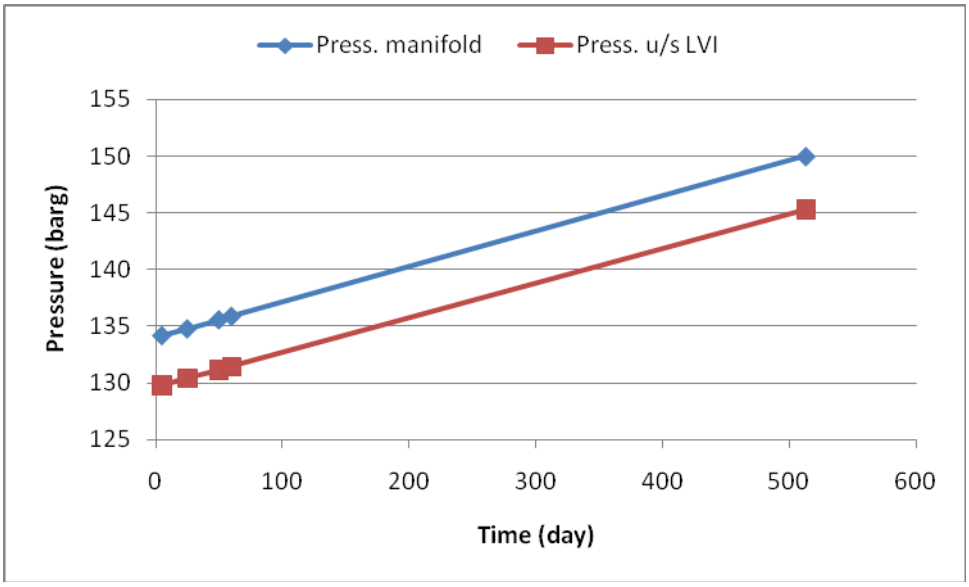


The subsea valves have been designed to a high specification to ensure that any leakage is minimal. There are also a number of valves in series to provide isolation for each well, therefore even if one valve does leak, there is another valve isolating each well. The subsea valves are periodically tested

to ensure that they meet the very low leak rate specification as per the relevant international standards. Should the valves fail to meet the test criteria set out within the Well Integrity Management system, corrective action will be carried out as per the standards contained within the Well Integrity Management system.

There is significant operational experience using these types of subsea valves in many locations around the world. It would be expected that two valves in series per well, as is the case for Corrib, provide a leak tight seal. Therefore it is conservative to assume that two valves in series will both have leakage rates at the uppermost limit of the allowable leakage rate as per the testing requirement. The subsea valves must meet the 14.7 scf/min testing requirement defined by the Wells Integrity Management System (WIMS). From analysis, it has been predicted that it would take more than 500 days for the offshore pipeline pressure to increase from 133 barg to 150 barg for a leakage rate of 14.7 scf/min. This is illustrated in Figure 4.2. 500 days (approximately 71 weeks) is significantly greater than the time duration of an unplanned shutdown for the Corrib system.

Figure 4.2: Pressure trends at the manifold and upstream (u/s) of the LVI after an offshore pipeline unplanned shutdown due to a high pressure trip.



Therefore, in conclusion, exceeding the offshore pipeline MAOP due to leakage across the subsea valves is not a credible scenario. This is mainly due to a combination of

- **(A) there will be a large margin between the settle out pressure and the MAOP even for an unplanned shutdown (because of the subsea valves closing to ensure the pressure is below 150barg in the offshore pipeline),**
- **(B) even the conservative cumulative leakage rate for subsea valves is relatively small, and**
- **(C) the large capacity of the offshore pipeline.**

In the event of an unplanned shutdown occurring due to a high pressure trip, a total leakage rate occurring past the subsea valves at the upper limit of the allowable leakage rate as per the testing requirement (14.7 scf/min), and the gas Terminal being shutdown for more than 500 days, the operations team can reduce, or vent, the pressure in the offshore pipeline in a staged operation using the blowdown system at the Terminal via the onshore pipeline.

Note that the overpressure protection systems have been designed to ensure that pipeline pressures remain within their respective MAOPs. As such, the overpressure protection systems have been designed such that the reliability of these systems is sufficient to ensure that valves will close to limit the pressure when required to do so. Further information on the reliability of the overpressure protection systems can be found in Appendix Q4.6.

In addition to the above, the potential effect of valve leakage at the LVI was also examined. Details of this examination, and further details of well subsea tree valve leakage can be found in the remainder of this section.

4.2 BACKGROUND

4.2.1 Introduction

The Oral Hearing in 2009 considered the possibility of the well subsea tree valves offshore and/or the LVI valves passing fluid (gas and any condensate, water, etc.) and thereby increasing the pressures in the Corrib offshore and onshore pipelines.

In response to this a note was submitted during the 2009 oral hearing, entitled “Potential and effect of passing valves in the Corrib upstream pipeline”. Information from this note has been included in this section of Appendix Q and additional information has been added to further explain this topic.

In their letter dated 2nd November 2009, An Bord Pleanála have requested SEPIL to provide an examination of the potential for pressure in the offshore pipeline to increase to wellhead pressure levels in the event that all wellhead valves had to be shut in over a prolonged period and in that period incremental leakage past the valves occurred.

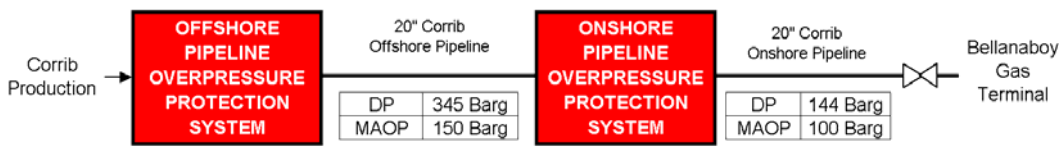
This note sets out details of the respective valves both subsea and at the Landfall Valve Installation (LVI) in order to place into context the potential for valve leakage and the scenarios regarding increasing pressure in the respective pipelines.

It is set out that an increase in pressure due to fluid passing through the closed valves is very small. Furthermore pressurisation of the offshore and onshore pipelines over their respective Maximum Allowable Operating Pressures (MAOP) due to leakage is not foreseen.

4.2.2 Basis of Analysis

The parameters for the Corrib production system are shown below.

Figure 4.3: Pipeline Overpressure Protection System



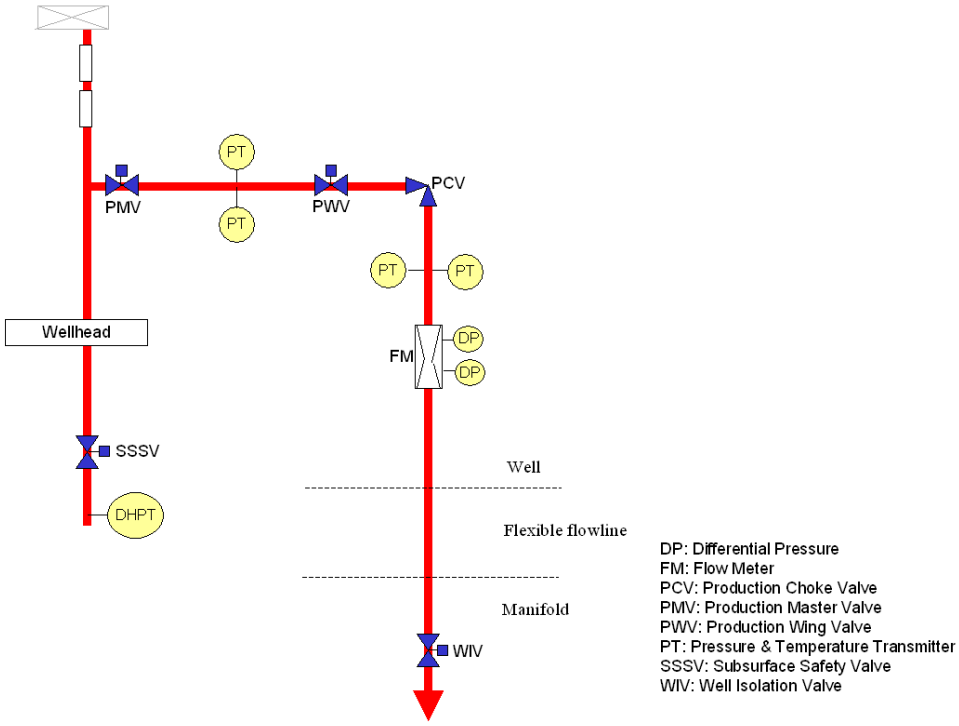
The design pressure (DP) for the Corrib offshore pipeline is 345 barg. The MAOP for the Corrib offshore pipeline is 150 barg.

During daily operation the subsea pressure at the manifold will normally range between 73 barg and 122 barg, depending on the production rate and the Terminal arrival pressure.

The offshore overpressure protection system is a highly reliable system (see Appendix Q4.6: 'Reliability of overpressure protection systems for offshore and onshore pipelines'). This prevents pressure excursions beyond the offshore pipeline MAOP (150 barg) by ensuring that the subsea valves close, stopping production into the offshore pipeline, and hence limiting the offshore pipeline pressure.

Each subsea well has a master valve and a wing valve for isolation and a choke valve to regulate flow. In addition, each well has a downhole safety isolation valve located approximately 900m below the seabed. This is called the surface controlled subsurface safety valve (SCSSSV). There will be a total of six producing wells at the start of field life.

<u>Figure 4.4:</u> Some of the main elements of a typical Corrib well and subsea tree tied into the manifold



The design pressure for the Corrib onshore pipeline is 144 barg. The MAOP for the Corrib onshore pipeline is 100 barg.

During daily operation the pipeline receiving pressure at the Terminal will normally range between 55 barg and 85 barg.

The onshore overpressure protection system is a highly reliable system. (See Appendix Q4.6: 'Reliability of overpressure protection systems for offshore and onshore pipelines'). This prevents pressure excursions beyond the onshore pipeline MAOP (100 barg).

4.2.3 Trip and Alarm Settings & Sequence

The pressures referred to throughout this section have been calculated using the OLGA software. OLGA is a dynamic pipeline simulator for engineering the flow of oil, water and gas in wells, pipelines and receiving facilities, and is recognised and widely used in the international oil and gas industry.

During initial steady state production, 350MMSCFD of gas will flow through the pipeline and arrive at the Gas Terminal at 80 to 85 barg.

Pressure will begin to rise in the system when there either is a Terminal trip (an Emergency Shutdown (ESD) event) or a flow shut off / flow backing out event. In these events, the operators will reduce production from the wells or shut in some wells to reduce the overall rate of pressure increase in the pipeline, to allow more time for the operator to clear the Terminal trip. If the operator cannot restore the Terminal back to normal operating conditions and the pressure continues to rise, the operator will shut in production from all of the wells.

The process safeguarding system has been designed such that the system will automatically stop flow from the wells on detection of high pressure and does not require operator intervention. The following sequence of events will occur, if the operator has failed to take corrective action in the event of a Terminal trip.

On the assumption that the pressure throughout the Corrib pipeline system (from the wells to the Gas Terminal inlet facilities) is increasing, the safeguarding system will be subject to an overpressure demand.

The first high pressure trip is set at 93 barg. This is located at the Gas Terminal inlet and when the pressure has increased from 80 to 85 barg up to 93 barg, this trip will command the subsea valves (master, wing, and choke valves) to close for each well. The resulting settle out pressure at the LVI will increase towards 99 barg (the set point of the next trip). This will cause the subsequent trip, the second high pressure trip set at 99 barg, to automatically trip whenever the first high pressure trip is initiated.

The second high pressure trip is set at 99 barg. This is located at the LVI. This trip commands the LVI shutdown valves to close. This step represents the onshore pipeline overpressure protection system. (Note: for this scenario, 99 barg at the landfall equates to approximately 98.5 barg at the Terminal inlet and 120.5 barg at the subsea manifold).

The pressure in the onshore pipeline will be 99 barg immediately after the LVI shutdown valves close. This pressure will settle out to approximately 97 barg after 24 hours. The pressure in the onshore pipeline 'settles out' because of the difference between shut-in conditions and normal steady state production conditions. Generally, the pipeline will change gradually in temperature when it is shut in for a period. After about 24 hours it will have reached equilibrium with the environment.

When the LVI shutdown valves close there will be another command to close the subsea valves, in the unlikely event that they haven't already closed. This action is more comprehensive, as this trip will close the subsea valves via two routes. Specifically, in addition to the master and wing, valves, this trip will also close the surface controlled subsurface safety valve (SCSSSV) and the well infield line isolation valve (WIV - which is located at the subsea manifold) for each well, due to the releasing of the hydraulic fluid pressure.

The offshore pipeline overpressure protection system is composed of tripping sequence as detailed in the preceding four paragraphs. The design of the system (the logic, automated actions, redundancy in the system, reliability of the equipment involved, etc.) provides a high reliability that offshore pipeline pressure will be prevented from increasing further due to the closure of subsea valves.

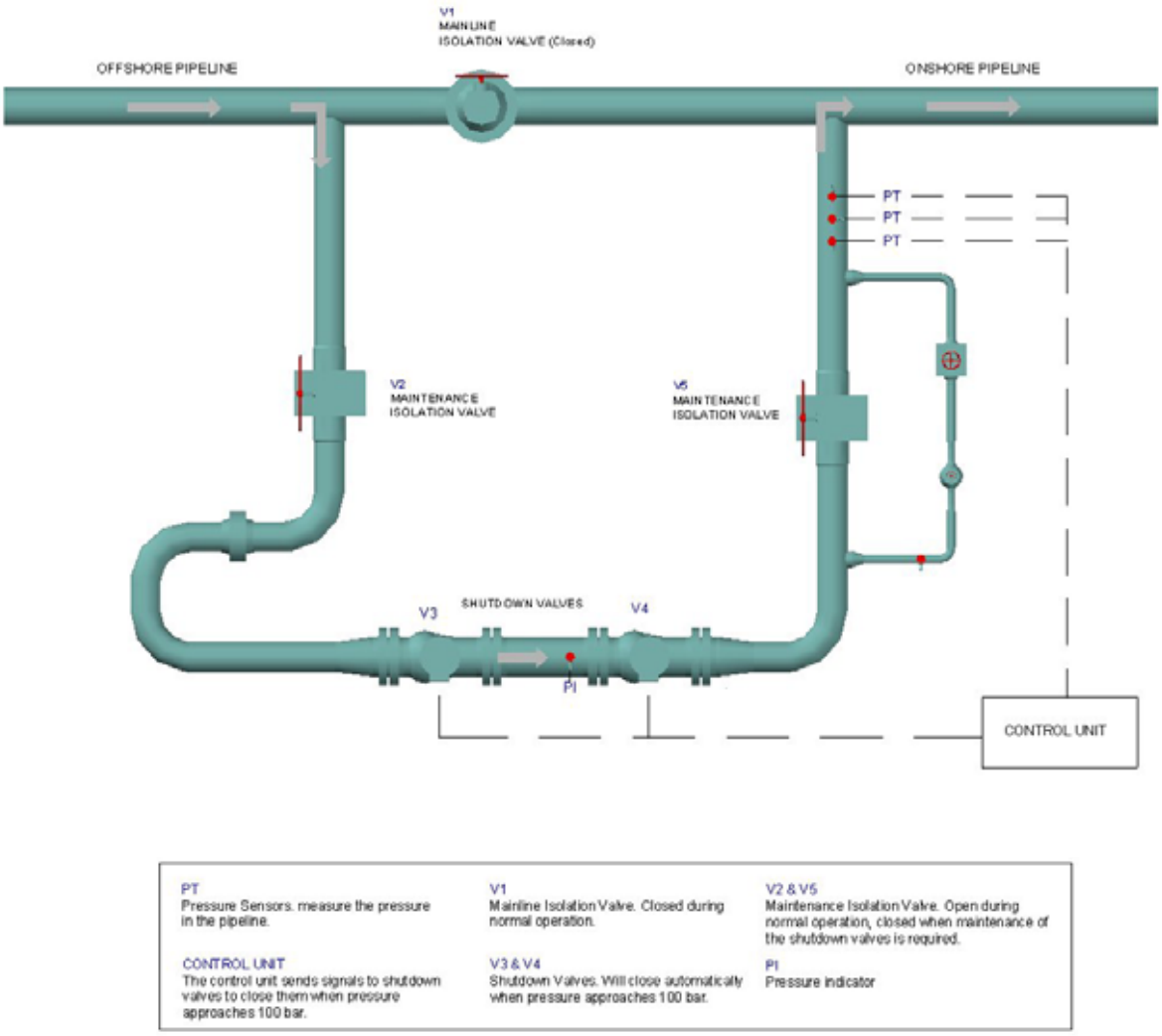
High reliability is provided by the offshore pipeline overpressure protection system due to the ability to close the subsea valves via two routes and redundancy within the system. This reduces the potential for common cause failure. Both routes will be automatically activated once the overpressure protection system is initiated.

One of the routes (or 'systems') is fast acting and will close the subsea valves almost instantly, while the other route is slower acting. In order to be conservative, it has been assumed that only the second slower acting system functions. Even in this circumstance, with the increased time to close the valves, the pressure in the offshore line will be limited below 150 barg.

Based on the conservative time taken to close the subsea valves (release of hydraulic fluid pressure), the offshore pipeline pressure will be 133 barg immediately after the subsea valves have fully closed. This pressure will settle out to approximately 129 barg after 24 hours. The pressure 'settles out' because of the difference between shut-in conditions and normal steady state production conditions.

4.2.4 The LVI Valves

Figure 4.5: The configuration of the LVI pipework and valves



All valves at the LVI have a design pressure of 345 barg.

The following valves are double expanding gate valves (DEGV) with manual operation:

- LMIV 20” Landfall Mainline Isolation Valve (full bore)
- LSSIV 16” Landfall Shutdown Spool Isolation Valves
- LRSIV 4” Landfall Restart Spool Isolation Valve

The dual inline Safety Shutdown Valves (otherwise known as Landfall Pressure Limitation Valves – LPLVs) are axial flow isolation valves with hydraulic open, spring to close, actuators.

4.2.4.1 Double Expanding Gate Valves

The DEGV's at the LVI are designed to operate with a 345 bar differential pressure across the valve. The valves have a zero leak rate (ISO 5028:2008 Rate A).

The sealing components of the double expanding gate valves are coated in an extremely hard tungsten carbide layer which is fused into the surfaces by a specialised process. This coating protects the tight shut faces of the gate and seats from deterioration from erosion, friction and debris.

This type of valve was selected for Corrib based on the good operating performance of this valve and its ability to provide tight shut off over a long life. Unlike the more common soft seated valves, hard coated metal seated valves generally do not have a deteriorating sealing performance in service, and in the case of the DEGV the sealing parts are not in contact during opening and closing – they do not slide across each other, they are separated - thus avoiding wear on the sealing faces. Additionally, the DEGV has two seal rings in series, both of which independently provide tight shut off at full gas pressure in both directions, as has been tested on each Corrib valve at the manufacturers.

This type of valve from the same manufacturer and with the same materials specification is in service with Shell at 845 bar in very corrosive and abrasive duty (Shearwater flowline isolation and other locations) and was tested for 600 open-close-open cycles in dry gas and demonstrated zero seat leakage at 845 barg gas differential pressure at the end of the tests.

4.2.4.2 Axial Flow Valves

The closure mechanism of an axial flow valve (open/closed type) is a balanced movement which seals against both metal seats and soft seats. The design of this valve means the sealing element is out of the flow path so that damage during operation is extremely unlikely.

There are many hundreds of axial flow type valves in service and it has become the industry norm for this duty having demonstrated in service high durability and reliability. This is the reason this type of valve, and the specific manufacturer, was selected for safety shutdown at the LVI. The sealing capability can be tested and demonstrated both in situ and in service.

Both the safety shutdown valves have a zero leak rate (ISO 5028:2008 Rate A).

4.2.4.3 Subsea Valves

Although there will be up to 5 valves in series per well to shut in production, account is only taken for up to 3 valves in series: the surface controlled subsurface safety valve (SCSSSV), the master valve and the wing valve for each well. The purpose of these valves is to provide isolation of the well from the offshore pipeline, and as such they have been designed and tested to a high standard. Further details are provided here for the valves (master and wing valves) on the Horizontal Tree (VG 300 Series) and Tree Valve cavities.

The gate valves (5 1/8" and 2 1/16") are of the Vetco Gray VG 300 series and have been tested in accordance to API 6A Appendix F PR2 to 10,000 psig Maximum Working Pressure (MWP) over the full temperature range of -35 to +350 F.

The VG 300 series valves are very well established in the industry and are used in every key region of the world. The VG 300 series is a slab gate valve with floating/fixed seats. A tee slot style drive

bushing connects the stem to the gate, this allows the gate to float freely giving a better gate to seat interface. Wave springs, set behind the seats, keep the seats in constant contact with the slab gate, this contact being important to keep the valve body free of contaminants. This provides a sanitary cavity in both the open and closed positions. The slab gate is designed for low operating torque, a low initial breakout torque means less wear on the valve bearings, stem and drive bushing.

The hydraulic actuator requires hydraulic pressure to hold it in its normally operating position, on loss of hydraulic supply pressure the actuator will drive the gate valve to its failsafe close position.

Metal to Metal (MTM) sealing is provided between gate / seat and seat / body. The contact faces of the gate / seat are carbide coated.

Valve Cavities: materials selection for the tree equipment has been made to ensure fitness for purpose with regard to structural integrity and corrosion resistance. Additionally, Inconel 625 corrosion resistance alloy has been used in the valve cavities of the tree, and on seal interfaces on the wellhead components, in order to reduce the effects from corrosion, pitting attack and general metal loss, for a design life of twenty (20) years

4.2.5 Valve In Situ Testing Regime

The subsea tree valves will be leak tested twice per year in line with the well integrity management system (WIMS). This entails shutting in the flowing well and systematically testing each valve in turn. A subsea horizontal xmas tree is an assembly which is locked to the subsea wellhead and contains valves to provide production control for each well. The closed in tubing pressure will be present upstream of the subsea horizontal tree and downstream of the tree this pressure will be equalised to the pipeline pressure. The results will be recorded within the well integrity management system (WIMS). Should the valves fail to meet the test criteria (the subsea valves must meet the 14.7scf/min testing requirement defined by WIMS) set out within the well integrity management system, corrective action will be carried out as per the standards contained within the well integrity management system.

The shutdown valves at the LVI are leak tested on an annual basis. The bypass spool is isolated via the two DEGV's. Methanol is used to increase the pressure within the short upstream section of pipework to 345 barg. The downstream pipework is then equalised with the onshore pipeline pressure. This allows the valve leakage rate (if any) to be calculated in the normal direction of flow.

The shutdown valves at the LVI are leak tested at least every 12 months. These in situ tests positively verify if the zero leakage rates have been maintained. No release of gas is incurred when undertaking these verification tests.

4.3 VALVE LEAKAGE SCENARIOS

Even with the high confidence of zero leakage of the LVI valves and subsea valves, prudent design still recognizes that there is a possibility that a valve or valves may leak during the course of the lifetime of the Corrib project. Such a situation is managed in accordance with the Pipeline Integrity Management System (PIMS) and Well Integrity Management System (WIMS), and actions taken to mitigate the level of leakage and a program established to undertake rectification measures.

There are three scenarios which this report analyses in order to comprehensively assess the potential effect of passing valves on pipeline pressure. This is due to the different conditions which will arise for each scenario.

Two locations are assessed for valve leakage for each scenario: leakage at the subsea valves, and leakage at the LVI valves.

4.3.1 Valve Leakage Scenario 1: Planned Shutdown for Maintenance

This section provides the assessment of the potential for the pipeline pressure to increase due to valves passing subsequent to commencement of a planned shutdown.

It also presents the information as requested by the An Bord Pleanála query (as per the 2nd November 2009 letter) with regards to providing “an examination of the potential for pressure in the offshore pipeline to increase to wellhead pressure levels in the event that all well subsea tree valves had to be shut in over a prolonged period and in that period incremental leakage past the valves occurred”.

A planned shutdown for maintenance represents the only likely scenario during which all well subsea tree valves will be shut in for a period of 14 – 21 days every 4 years (i.e. “over a prolonged period”).

There is a planned maintenance activity which will occur annually (up to 1 day), which will result in a requirement to shut in the Terminal, pipeline and all the wells.

The pipeline will be shut in with a settle out pressure (at the Terminal inlet valve) of 85 barg approximately.

This creates a margin of approximately 15 bar between the settle out pressure and the onshore pipeline MAOP (100 barg).

The settle out pressure in the offshore pipeline will be approximately 90barg. Thus there will be a 60 bar margin approximately between the offshore pipeline settle out pressure and the offshore pipeline MAOP (150 barg).

Note that for a planned shutdown, the LVI will not be used to initiate the shutdown and it will not be initially closed during the planned maintenance period. Therefore the resulting offshore and onshore pipeline shut-in pressure will be very close – the only difference being due to the static head in the pipeline.

4.3.1.1 Valve Leakage Scenario 1: Leakage across the Subsea Valves

For each well there are two valves in series that are closed to isolate a well (the master valve and wing valve) for a planned shutdown. The choke valve is not considered to be tight shutoff. If closing both these valves does not fully isolate the well, or the shutdown is planned to be more than 24hrs, then the operator can also close the surface controlled subsurface safety valve (SCSSSV).

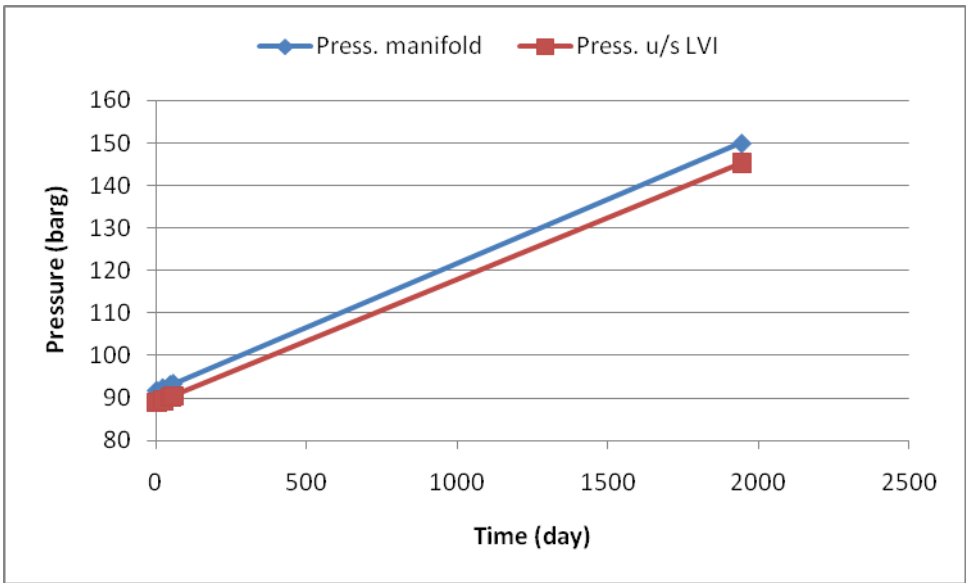
The offshore pipeline pressure will be monitored at the subsea manifold (and at the individual pressure transmitters located on each well subsea tree) for a pre-determined period after the wells have been shut-in to ensure all of the well valves have closed.

This will ensure that production from all of the wells has ceased, and that the subsea valves have properly closed and are not leaking.

Both the potential for a leak to occur, and the magnitude of such a leak were it to occur, will be minimised due to the requirement of having closed two or three isolation valves in series per well.

A worst case scenario would be to assume a leak rate of 0.022 MMSCFD across the subsea valves. It would take more than 1500 days for the offshore pipeline pressure to increase from 90 barg (settle out pressure in the offshore pipeline) to 150 barg (offshore pipeline MAOP). A planned shutdown for maintenance, during which all well subsea tree valves will be shut in for a period of 14 – 21 days, will occur approximately every 4 years. Thus, 1500 days is significantly greater than the length of any planned shutdown for Corrib.

Figure 4.6: Pressure trends at the manifold and upstream (u/s) of the LVI after an offshore pipeline planned shutdown. The operators will command close subsea valves. However, subsequent to shutting in production, it has been assumed that gas leakage may occur through the subsea valves at a rate of 0.022 MMSCFD (equivalent to 14.7 scf/min). The resulting pressure rise, at the subsea manifold and at the LVI, can be seen in the figure below.

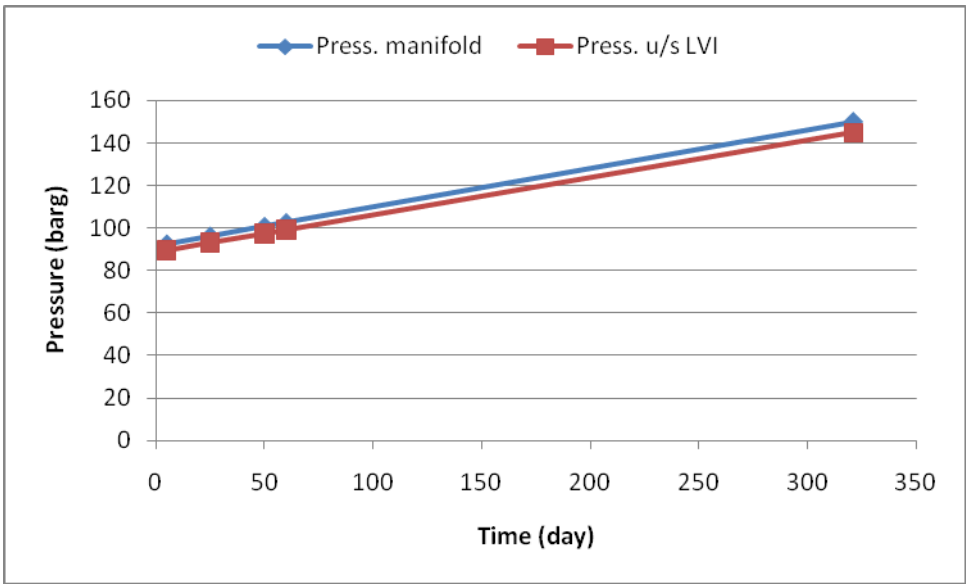


Conclusion: **when xmas tree valves are shut in for planned maintenance (i.e. over a prolonged period), leakage across the subsea valves leading to an increase in offshore pipeline pressure above its MAOP of 150 barg is not a credible scenario**. This is mainly due to a combination of (A) the measures taken prior to a planned shutdown to provide a large margin between the settle out pressure and the MAOP, (B) even the conservative cumulative leakage rate for subsea valves is relatively small, and (C) the large capacity of the offshore pipeline.

The subsea valves must meet the 14.7scf/min testing requirement defined by WIMS, which is equivalent to 0.022 MMSCFD. With significant operational experience using these types of subsea valves in many locations around the world, it would be expected that 2 valves in series provide a leak tight seal. Therefore it is conservative to assume that two valves in series will both have leakage rates at the most upper limit of the allowable leakage rate as per the testing requirement. If the valves do not meet the testing requirement, remedial action will be taken as prescribed in the Wells Integrity Management System (WIMS).

A sensitivity test has been performed to determine the worst case scenario where all of the subsea valves are leaking at the maximum allowable leak rate as defined in the WIMS testing requirement. This is a highly unlikely scenario and equates to a cumulative subsea valves leakage rate of 0.132 MMSCFD (i.e. the maximum leak rate for 6 wells). It would take a period of greater than 300 days (42 weeks) for the offshore pipeline pressure to increase from 90 barg (settle out pressure in the offshore pipeline) to 150 barg (offshore pipeline MAOP). 300 days is also significantly greater than the length of a planned shutdown for Corrib.

Figure 4.7: Pressure trends at the manifold and upstream (u/s) of the LVI after an offshore pipeline planned shutdown. The operators will command close subsea valves. However, subsequent to shutting in production, it has been assumed that gas leakage may occur through the subsea valves at a rate of 0.132 MMSCFD. The resulting pressure rise, at the subsea manifold and at the LVI, can be seen in the figure below.



4.3.1.2 Valve Leakage Scenario 1: Leakage across the LVI Valves

During the initial phase of a planned shutdown, the LVI valves will not be closed. Following the initial phase, the LVI valves will be closed for testing.

In order for leakage to occur across the LVI, the pressure upstream of the LVI must be greater than downstream. As described previously, for a planned shutdown there will be a very minimal pressure drop across the LVI. The only pressure drop from the subsea manifold to the outlet of the onshore pipeline will be due to static head. Therefore when the LVI valves are closed for testing, there will be no pressure drop across the valves, and therefore there will be no driving force for a leak to occur past the LVI valves.

Conclusion: **when the LVI valves are closed for testing during a planned maintenance activity, leakage across the LVI valves leading to an increase in onshore pipeline pressure above its MAOP of 100 barg is not a credible scenario**. This is because there is no pressure difference across the LVI to create a driving force for a leak to occur.

4.3.2 Valve Leakage Scenario 2: Unplanned Shutdown due to a High Pressure Trip

This section provides the assessment of the potential for the pipeline pressure to increase due to valves passing subsequent to a high pressure trip.

Subsequent to a high pressure trip, the pressure in the offshore pipeline will be 133 barg approximately. The pressure in the onshore pipeline will be 99 barg approximately.

As set out previously, the subsea valves and the LVI safety shutdown valves have zero leak rates.

Therefore the pressure will gradually decrease during the 24 hours after the high pressure trip. The pressure in the offshore pipeline will settle out at 129 barg approximately, while the pressure in the onshore pipeline will settle out at 97 barg approximately.

The pressure decreases because of the ‘settling out’ effect.

It is prudent to consider the potential effect of valves leaking subsequent to a high pressure trip i.e. an unplanned shutdown. In the event that a leak does occur, there is a potential for pressure in the pipeline to increase. The pipeline pressure will only increase if there is a leakage rate which is significant enough to counteract the ‘settling out’ effect described above.

This section provides an analysis of the effect a conservative (large) leakage rate has on pipeline pressure. It also provides details of the procedure that is available to the operators to ensure that the pipeline pressure remains within its MAOP limit.

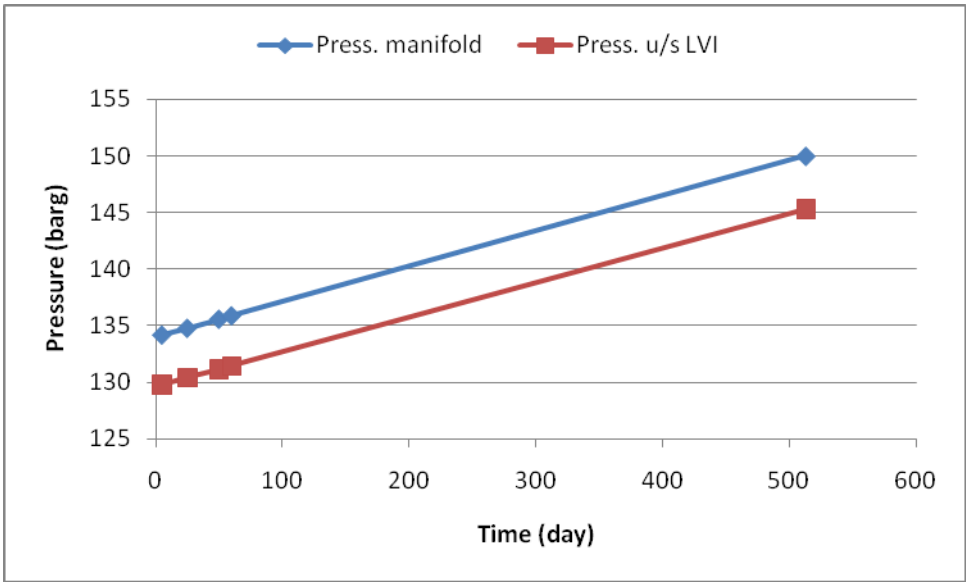
4.3.2.1 Valve Leakage Scenario 2: Leakage across the Subsea Valves

Subsequent to a high pressure trip, the pressure in the offshore pipeline will be 133 barg approximately.

A conservative approach would be to assume a cumulative leakage rate of 0.022 MMSCFD across the subsea valves.

It would take a period greater than 500 days for the offshore pipeline pressure to increase from 133 barg to 150 barg (offshore pipeline MAOP). 500 days is significantly greater than the foreseeable length of an unplanned shutdown for Corrib.

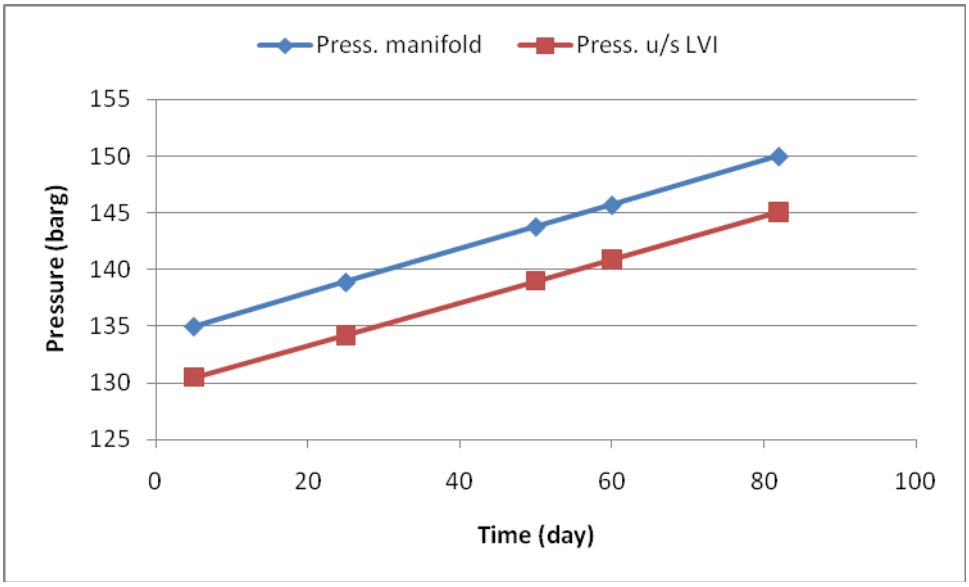
Figure 4.8: Pressure trends at the manifold and upstream (u/s) of the LVI after an offshore pipeline unplanned shutdown due to a high pressure trip. This high pressure trip will command close all subsea valves. However, subsequent to shutting in production, it has been assumed that gas leakage may occur through the subsea valves at a rate of 0.022 MMSCFD. The resulting pressure rise, at the subsea manifold and at the LVI, can be seen in the figure below.



Conclusion: **when well subsea tree valves are shut in due to a high pressure trip (i.e. unplanned shutdown), leakage across the subsea valves leading to an increase in offshore pipeline pressure above its MAOP of 150 barg is not a credible scenario**. This is mainly due to a combination of (A) there will be a large margin between the settle out pressure and the MAOP even for an unplanned shutdown (because of the subsea valves closing to ensure the pressure is below 150 barg in the offshore pipeline), (B) even the conservative cumulative leakage rate for subsea valves is relatively small, and (C) the large capacity of the offshore pipeline.

A sensitivity test has been performed to determine the worst case scenario where all of the subsea valves are leaking at the maximum allowable leakage rate as per the testing requirement. This is a highly unlikely scenario and equates to a cumulative subsea valves leakage rate of 0.132 MMSCFD. It would take a period of greater than 80 days for the offshore pipeline pressure to increase from 133 barg to 150 barg (offshore pipeline MAOP). 80 days is significantly greater than the length of an unplanned shutdown for Corrib.

Figure 4.9: Pressure trends at the manifold and upstream (u/s) of the LVI after an offshore pipeline unplanned shutdown due to a high pressure trip. This high pressure trip will command close all subsea valves. However, subsequent to shutting in production, it has been assumed that gas leakage may occur through the subsea valves at a rate of 0.132 MMSCFD. The resulting pressure rise, at the subsea manifold and at the LVI, can be seen in the figure below.



4.3.2.2 Valve Leakage Scenario 2: Leakage across the LVI Valves

Subsequent to a high pressure trip, the pressure in the onshore pipeline will be 99 barg approximately.

At the LVI there are two potential flow paths. These are via the 20” mainline valve (otherwise known as the Landfall Mainline Isolation Valve (LMIV)) and via the two inline safety shutdown valves (otherwise known as the Landfall Pressure Limitation Valves (LPLVs)).

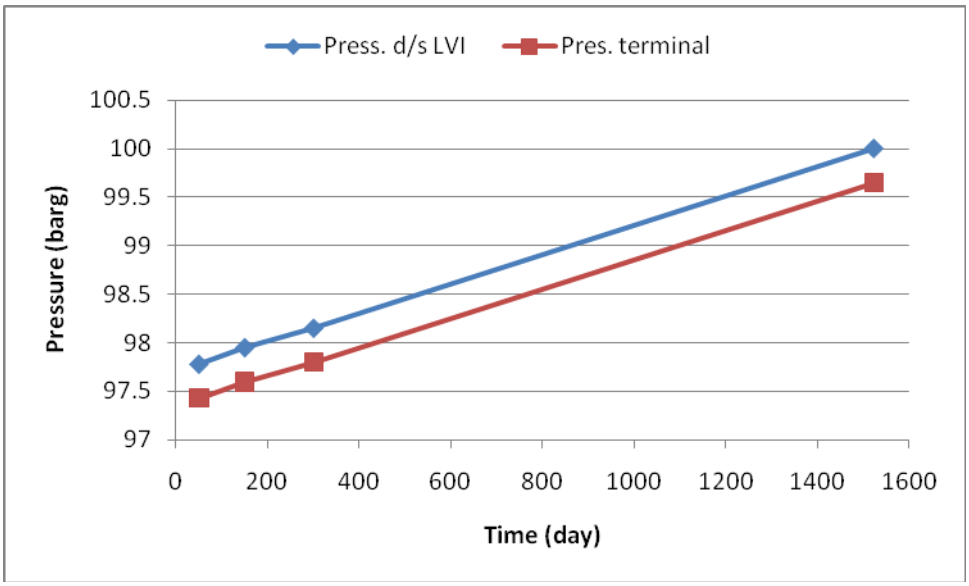
Following a trip of the LVI at 99 barg then potentially, either or both flow paths could pass fluid due to valve leakage. While the two safety shutdown valves could be isolated by the upstream and downstream isolation valves, this is omitted from this evaluation.

It has been conservatively assumed that either the 20” DEGV or both safety shutdown valves leak at a combined rate based upon ISO 5028 Rate D. This is conservative as both the 20” DEGV and the safety shutdown valves have been tested and accepted with criteria Rate A – no visible leakage/bubbles.

Conservatively assuming that the valves only meet Rate D criteria, this equates to a leakage rate of approximately 0.0000824 MMSCFD.

At this leakage rate, it takes greater than 4 years to reach 100 barg from the moment the LVI has been closed and the onshore pipeline pressure is 99 barg.

Figure 4.10: Pressure trends downstream (d/s) of the LVI and at the pipeline outlet (located at the Terminal) after an onshore pipeline unplanned shutdown due to a high pressure trip. This high pressure trip will command close the LVI valves and all subsea valves. However, subsequent to shutting in production, it has been assumed that gas leakage may occur through the LVI valves at a rate of 0.0000824 MMSCFD.



Conclusion: **when the LVI valves are shut in due to a high pressure trip (i.e. unplanned shutdown), leakage across the valves leading to an increase in onshore pipeline pressure above its MAOP of 100 barg is not a credible scenario**. This is mainly due to a combination of (A) there will be a sufficient margin between the settle out pressure and the MAOP even for an unplanned shutdown (because the pressure settles out below 100barg in the onshore pipeline), (B) even the conservative (large) leakage rate for LVI valves is relatively small, and (C) the large capacity of the onshore pipeline.

As highlighted above, even assuming a cumulative leakage rate of 0.0000824 MMSCFD is conservative due to the high specification of the LVI valves. However, a further sensitivity has been performed using a leakage rate of 0.25 MMSCFD. This leakage rate is more than three orders of magnitude greater than the design specification of the LVI valves.

The pipeline pressure could reach 100 barg approximately 10 hours after the high pressure trip with a leakage rate of 0.25 MMSCFD.

However, within this time the operator can vent an amount of the gas from the onshore pipeline through the flare at the Terminal. The operator can line up the onshore pipeline to the flare just downstream of the slugcatcher. The operator can perform this procedure within approximately 4 hours subsequent to the high pressure trip. This is well within the time it would take for the pipeline pressure to reach 100 barg (onshore pipeline MAOP).

5 CORRIB PIPELINE FLOW REGIME

This section has been included to demonstrate that sufficient analysis has been performed and that slugging in the Corrib pipeline will not be an issue.

The term multiphase flow in pipelines refers to the simultaneous flow of different phases such as gas and liquid. In the case of Corrib, there are two liquid phases which are condensate and water and one gas phase. When a gas-liquid mixture flows in a pipe, the interface between the gas and liquid phases can assume different configurations depending on variables such as inlet flowrates, fluid properties, pipe geometry and orientation of the flow. To simplify the description, a limited number of typical multiphase flow configurations of the gas-liquid interface are distinguished, the so-called “flow patterns”. The offshore and onshore pipelines of Corrib fall into the horizontal flow pattern map classification as they are prevalently horizontal and slightly inclined. Figure 6.1 shows the flow patterns that are distinguished in horizontal pipelines while Figure 6.2a shows a typical flow pattern map plotted as a function of the superficial gas and liquid velocities.

Figure 6.1: Flow patterns in horizontal pipelines

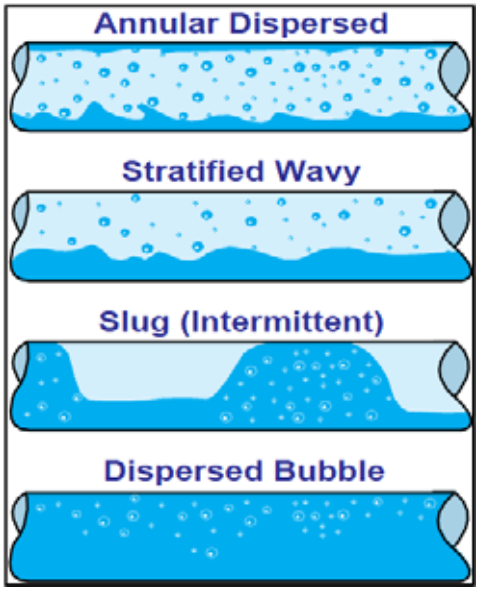
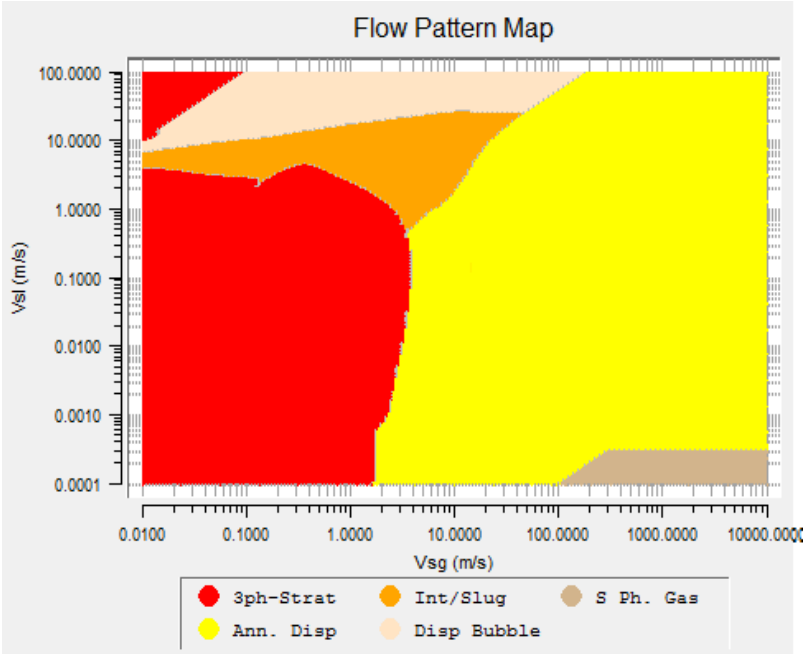


Figure 6.2a: Typical flow pattern map.



Key:

Red area: 3 phase stratified flow

Orange area: intermittent / slug flow

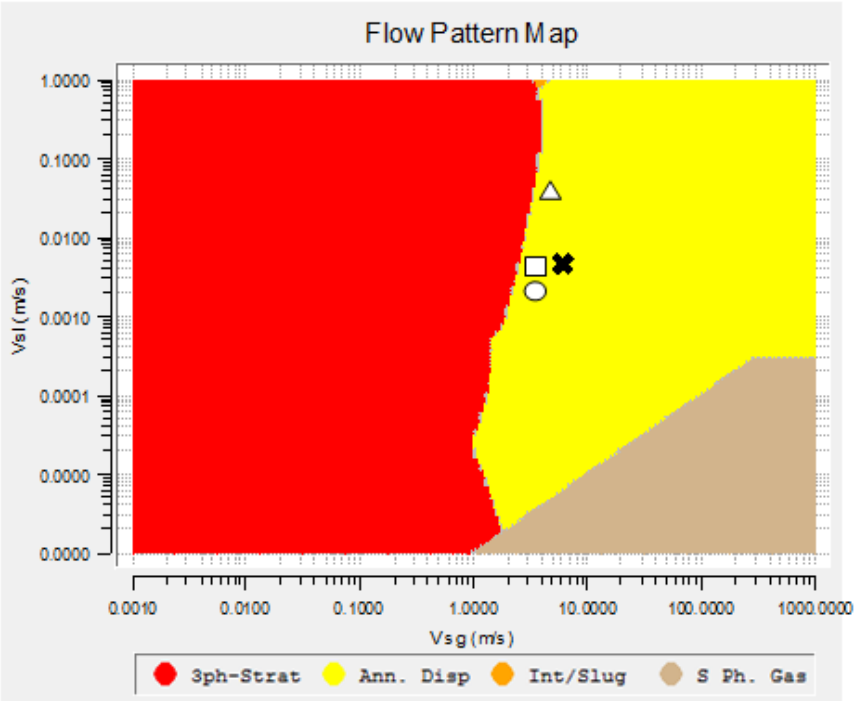
Dark brown area: Single phase gas flow

Yellow area: Annular dispersed flow

Light brown area: Dispersed bubbled flow

For the Corrib production pipeline system, annular flow has been predicted in the early field life for the entire range of productions expected with a Terminal pressure between 60-90 barg, Figure 6.2b. In annular flow, the gas and the entrained liquid droplets flow in the centre of the pipe while the liquid flows as a film along the pipe wall. Therefore, a good wall wetting can be assured with this flow pattern in the Corrib pipeline. Moreover, during normal production the risk of water settling at the bottom of the pipeline is low. Note that also stratified flow, in which the liquid settles at the bottom of the pipeline and the gas flows on top, near the transition region of stratified to annular dispersed flow would result in a good wall wetting of the Corrib pipeline. Sensitivity calculations have shown that the liquid droplets entrainment in the gas phase in stratified flow in this transition region would be the same as shown in annular flow. This liquid entrainment would result in wall wetting in the upper part of the pipeline.

Figure 6.2b: Flow pattern map for early and late field life of Corrib



Key:

Cross: early life – 350 MMscf/d with 85 barg Terminal pressure

Circle: early life – 160 MMscf/d with 60 barg Terminal pressure

Triangle: late life – 100 MMscf/d with 40 barg Terminal pressure

Square: late life – 30 MMscf/d with 10 barg Terminal pressure

In early field life, there will be no issues with liquid slugs and surges during normal operations at steady-state conditions. During initial start-up of production or start-up following a shut-in, liquid surges will be produced at the Gas Terminal. Simulations of the initial start-up scenarios and ramp-up from minimum to maximum production have shown that, given the liquid drainage capacity of the slug catcher, the volume accumulation of these liquid surges is negligible at the Corrib slug catcher. The slug catcher is a gas/liquid separator located at the Terminal that has been designed to handle the largest liquid surge volumes that can be generated in the pipeline during start-up and transient operations.

During late field life (10-40 barg Terminal pressure), annular flow is anticipated for the range of productions expected, Figure 6.2b. For the same reasons explained for early field life, there are no concerns with regards to liquid surge volumes exceeding the slug catcher capabilities.

6 HYDRATES

This section addresses the concern of the potential for hydrate formation in the Corrib pipeline. An Bord Pleanála have raised a query with regards the potential for a "Methane Hydrate in the pipeline" to be a potential failure mode for the pipeline. This was raised in point (d) of their letter dated 2nd November 2009:

(d)*…. In order to eliminate any doubt please note that all failure modes should be included including the possibility of third party intentional damage at Glengad, wet gas in the pipeline, CO2 in the pipeline and potential for* ***Methane Hydrate*** *in the pipeline.*

6.1 INTRODUCTION

The Corrib produced gas contains hydrate forming components such as methane, ethane, propane and small quantities of carbon-dioxide. At high-pressure and low-temperature, these components along with water form crystalline solids known as "Gas hydrates". The prevention of gas hydrates is generally recognized as the most important flow-assurance issue for projects such as Corrib because should a hydrate blockage occur, this can then cause large production losses.

6.2 CORRIB HYDRATE MANAGEMENT STRATEGY: HYDRATE INHIBITION

The Corrib subsea system including the main pipeline operates inside the hydrate region during steady-state flowing conditions. Methanol has been chosen as a primary hydrate inhibitor and it will be continuously injected offshore to prevent hydrate formation in the Corrib production system. Methanol is a thermodynamic hydrate inhibitor (similar to Mono-Ethylene Glycol and salt), which mostly dissolves in water but some amount, also dissolves/evaporates in condensate and gas. Depending on the methanol concentration in water, the hydrate formation temperature decreases at a given pressure. Therefore, methanol injection quantities are calculated using thermodynamic PVT software to ensure that sufficient quantities of methanol are injected so that the entire system operates outside the hydrate region.

A robust hydrate management strategy has been developed for Corrib to cover all circumstances and not just the most prevalent (i.e. operating at steady state for the life of the field). Thus, the hydrate management strategy and methanol injection system has been designed and will be managed such that sufficient methanol will be injected and correct operational procedure will be used to prevent hydrate formation during all foreseeable situations (e.g., Cold well start-up, Normal operating conditions, Planned shut-in, Unplanned shut-in, Hydrate plug remediation, Production restart after a hydrate plug event).

Hydrates will only form in the Corrib subsea facility and pipeline if methanol is not injected in sufficient quantities. The operating strategy for Corrib is to immediately stop production in the unlikely event of offshore methanol injection being unavailable. The methanol system has been designed to meet the reliability required by the system.

6.3 CONSEQUENCE OF HYDRATE FORMATION

There is the potential for an unlikely event to occur whereby a hydrate plug forms in the Corrib production system due to unavailability of the methanol injection system or insufficient methanol injection. This section summarises that in this unlikely event, the formation of a hydrate plug which causes a full bore impermeable blockage in the line will not be sufficient to lead to the pipeline failing.

Subsequent to the formation of a hydrate plug in the Corrib pipeline, operating conditions would begin to change throughout the production system. A surveillance and monitoring plan will be in place and the operators will be trained to detect the formation of hydrates from identification of changes in key operating parameters. The operator would shut down production from the wells on identification of hydrates as per the Corrib hydrate management strategy. However, the hydrate inhibition system has been developed (e.g. sparing for methanol injection equipment, overdosing of methanol volumes) such that the demand for a shutdown due to hydrate formation would be extremely infrequent if at all.

However, in the unlikely event where there has been no manual intervention after the formation of a hydrate plug, the pressure will continue to increase upstream of the plug and decrease downstream of the plug. The following analysis is provided to describe how hydrate formation in 3 locations throughout the Corrib production system has been considered.

(1) Within the Corrib onshore pipeline. In the event of a full bore blockage occurring in the onshore pipeline due to the formation of a hydrate, the pressure upstream of the hydrate blockage (in the onshore section) can only rise to the onshore pipeline MAOP (100 barg). The Landfall Valve Installation (LVI) at Glengad will ensure that the MAOP is not exceeded in the onshore pipeline.

(2) Within the 10km Corrib offshore pipeline section (upstream of LVI). If the hydrate blockage forms in the Corrib offshore pipeline near to Glengad, for example within the 10km section upstream of the LVI, the pressure will decrease downstream of the plug at a faster rate than the increase in pressure upstream of the hydrate blockage. By definition pressure in the 10km section downstream of the full bore hydrate blockage, will not increase beyond the pressure at which the hydrate plug formed. Therefore there will be no exceedance of the offshore pipeline MAOP for this 10km section. In addition to this, due to the location of the blockage, there is a greater volume upstream of the blockage in comparison to downstream of the blockage. As it has been hypothetically assumed that there is no manual intervention, production will continue from the subsea wells into the pipeline at the rate gas is produced from the pipeline into the Gas Terminal. However, due to the blockage, pressure at the Gas Terminal inlet will begin to decrease such that the low pressure terminal trip will be initiated. This will cause the Gas Terminal inlet valve and the subsea valves to close. This will ensure that the offshore pipeline MAOP is not exceeded.

(3) Within the Corrib offshore pipeline section – from subsea manifold to 10km point upstream of LVI. At some point greater than 10km (e.g. approximately half way between the subsea manifold and the Gas Terminal), it is assumed for this analysis, that a hydrate blockage will form. This, by the definition of a full bore blockage, will prevent a pressure increase in the (approximately) 40km section immediately upstream of the LVI. There will be no increase in pressure beyond the pressure at which the hydrate plug formed. Therefore there will be no exceedance of the offshore pipeline MAOP for this 40km section. The rate of pressure increase upstream of the blockage will be equal, or greater, than the decrease in pressure downstream of the blockage. When the pressure upstream of the hydrate blockage reaches 145 barg at the subsea manifold, the safeguarding system will automatically shut down production from the wells (as described in layer 4 of section 2.5.2). This will prevent pressures exceeding the MAOP in the offshore pipeline.

6.4 HYDRATE REMEDIATION

Hydrate remediation procedures have been developed to prevent pipeline failure subsequent to the unlikely event of the formation of a hydrate plug in the Corrib pipeline. Hydrate remediation will be a lengthy operation, and specialist staff will perform this activity.

Depending on the hydrate plug characteristics (incomplete or complete blockage) and location of a hydrate plug, depressurization and methanol injection are methods to melt a hydrate plug. If possible and feasible, methanol injection is the preferred method to melt a hydrate plug. To prevent hydrate plug movement while applying the depressurization method, necessary steps (such as gradual pressure-reduction in maximum 2-3 bar step) will be taken to avoid large pressure difference across a hydrate plug. From the facilities integrity and safety perspective, this is a very important step as it has been observed in a field test that a hydrate plug can accelerate to high velocity when a large pressure difference exists across a hydrate plug. Therefore, two-sided depressurization is the recommended method to dissociate a completely blocked (full bore) hydrate plug that is close to the production facilities.

In the event of a full bore pipeline hydrate blockage it may be possible to perform a one-sided depressurisation. This will be predicated on the condition of the hydrate plug being located at such a distance that the depressurisation will not result in the plug travelling at high velocities in the proximity of the Terminal or LVI. Because of this requirement (for the depressurisation procedure to specify a method which will not result in pipeline failure arising from a hydrate plug travelling at high velocities), the hydrate plug remediation strategy will be classified as an SCE (Safety Critical Element). Detailed procedures prepared by specialist engineers in this field of expertise and appropriately peer reviewed, will provide a step by step procedure to dissociate a hydrate plug in a safe manner irrespective of location or extent of plug.

7 COLD VENTING AT GLENGAD (THE LVI COMPOUND)

7.1 OBJECTIVE

Consider An Bord Pleanála request to examine cold venting at the LVI to reduce pressure in the upstream offshore pipeline.

"The concept of a vent at Glengad as a measure to protect against pressure at the wellhead side of the pipeline at the landfall rising above the maximum operating pressure should be examined" (Point (g), An Bord Pleanála Letter, 2nd November 2009).

7.2 PRESENT ARRANGEMENT

At present there is no provision for cold venting at the LVI and to date public statements have been made by SEPIL that there will be no venting or flaring of gas at the LVI.

Some small fugitive discharges will occur during maintenance and instrument calibrations / function tests, and if the two safety shutdown valves are removed for maintenance.

7.3 COLD VENT SIZING

A cold vent at the LVI would only be of use should the pressure in the offshore pipeline continue to rise following shut down of the subsea wells and valves. As previously described in section 4: Potential and Effect of Passing ('Leaking') Valves in the Corrib Pipeline, exceeding the pipeline MAOPs due to leakage across the valves is not a credible scenario.

In order to explain the usage of a cold vent at the LVI, it requires the use of a hypothetical assumption, which would allow for the potential of pipeline overpressure to occur. Otherwise, there is no requirement for an assessment of a cold vent at Glengad.

Therefore, it has been assumed that in the event of a high pressure occurring in the pipeline, there is no operator intervention, and the wells isolation system fails, such that production from one well continues into the offshore pipeline. It is extremely unlikely for such an event to occur. See Appendix Q4.6 with regards details of the reliability of the wells isolation system (i.e. details the probability of the wells isolation system <u>or</u> the LVI failing to function on demand).

If a cold vent was considered at the LVI for this scenario, then to maintain the pressure in the offshore pipeline below 150 barg will require a substantial cold vent of similar proportions to the flare at the Terminal.

Typically this would be 200mm to 300mm diameter with a stack height of approximately 30m to ensure sufficient and safe dispersion.

Provision would be required for utilities and auxiliary systems such as knock-out vessels and storage tanks.

7.4 VENT LOCATION

The LVI is situated in protected views and the LVI itself has been positioned in a dished area. Due to the parameters of the Cold Vent, a permanent installation would be required outside the dished area with appropriate foundations and guides.

To connect the Cold Vent to the LVI pipework it is envisaged that a valved connection would be made downstream of Valve V2 to enable isolation of the vent. The vent pipework would be routed up the slope of the dished LVI to the vent foundation.

The Cold Vent would be located down-wind of the prevailing wind at the LVI. A suitable wind sock will be required to verify the prevailing wind.

From the design codes an area of around 150 metres radius around the Vent Stack would be temporary fenced off during venting.

7.5 CONSEQUENCES

Provision of a Cold Vent at the LVI would result in:

- High visual impact.
- High noise levels during venting.
- Release of large gas volumes to atmosphere.
- Increased safety risk during venting.
- Potential for uncontrolled ignition.

7.6 CONCLUSION

It is concluded that provision of a cold vent at the LVI is not a viable option and if release of gas is required then this should be performed at the Terminal where provisions have already been made for safe and controlled release of gas under upset conditions.

GLOSSARY

Term	*Explanation*
2oo3 voting	Two out of three (2oo3) voting means that an action will be initiated once two out of three transmitters register a certain value. For example, there are three pressure transmitters provided at the LVI to monitor the onshore pipeline pressure. Once two of these three pressure transmitters register a pressure of 99 barg the LVI shutdown valves will close.
Landfall Valve Pressure Limitation System (LVPLS)	The Landfall Valve Pressure Limitation System (LVPLS) is the system used to ensure the onshore pipeline MAOP is not exceeded. It is comprised of the safety shutdown valves, the logic solver, the pressure transmitters and the solenoid valves, which were supplied as a complete package with independent certification.
Master Control Station (MCS)	The Master Control Station (MCS) provides communications and logic processing for the control and monitoring of the SPCS (Subsea Production Control System). It will use dual redundant industrial PC's operating in an active/hot standby mode.
Overpressure Protection System	An Overpressure Protection System is a system which functions to protect against exceedance of a predetermined pressure. For the offshore pipeline, the wells isolation system serves as the overpressure protection system. For the onshore pipeline, the LVI serves as the overpressure protection system.
Production Choke Valve (PCV)	There is a production choke valve (PCV) located on every xmas tree, which sits on each Corrib well. The PCV, or choke valve as it is commonly known, is used to regulate the flow of produced gas from each of the Corrib wells.
Production Master Valve (PMV)	There is a production master valve (PMV) located on every xmas tree, which sits on each Corrib well. The PMV, or master valve as it is commonly known, is used to isolate wells from the Corrib offshore pipeline.
Production Wing Valve (PWV)	There is a production wing valve (PWV) located on every xmas tree, which sits on each Corrib well. The PWV, or wing valve as it is commonly known, is used to isolate wells from the Corrib offshore pipeline.

Subsea Valves	This is a collective term, which has been used throughout and refers to the xmas tree valves and the surface controlled subsurface safety valve (SCSSSV).
Surface controlled subsurface safety valve (SCSSSV)	In addition to the master and flow wing valves each well also has a surface controlled downhole safety valve installed approximately 900m below the seabed. This valve is designed to be an independent back up for the primary xmas tree valves.
Subsea Tree (or Subsea Xmas Tree)	A structure which sits at the top of each Corrib well and is composed of a series of valves and instruments that can be used to safely manage the Corrib gas production. The main function of the xmas tree is to direct the gas from the well into the flow line and to provide the means to safely and reliably shut in or stop gas production. The primary valves on the xmas tree are the master valve and flow wing valves. These two valves are used to ensure that gas production can be safely shut in either by the operator or, automatically by the control system, should an unexpected event occur. The xmas tree also contains valves to allow methanol and other chemicals to be injected into the well if required. Each xmas tree has a choke valve that the control room operator can use to accurately control the rate and pressure at which the gas flows from the wells into the subsea pipeline.
Tree Valves (or Xmas Tree Valves)	Main valves of interest located on the xmas tree include the production master valve (PMV), the production wing valve (PWV) and the production choke valve (PCV). See Figure 4.4 in section 4.4.2 for a schematic of a typical Corrib xmas tree.
Well Infield Line Isolation Valve (WIV)	Isolation valve located at the subsea manifold. It is included in the design to allow for isolation of each infield flow line that is tied into the subsea manifold.

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Q4.6 – RELIABILITY OF OVERPRESSURE PROTECTION SYSTEMS FOR OFFSHORE AND ONSHORE PIPELINES

DOCUMENT No: COR-25-SH-0013

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PREAMBLE

Note: Appendix Q4.5 should be read prior to Appendix Q4.6, as references to information and explanation of terminology has been provided in Appendix Q4.5. However, a selection of relevant figures have been reproduced below.

Figure 1: Pipeline Overpressure Protection System

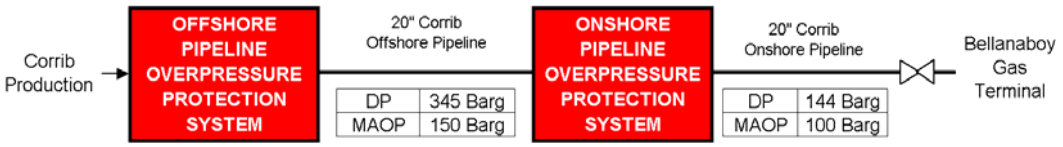
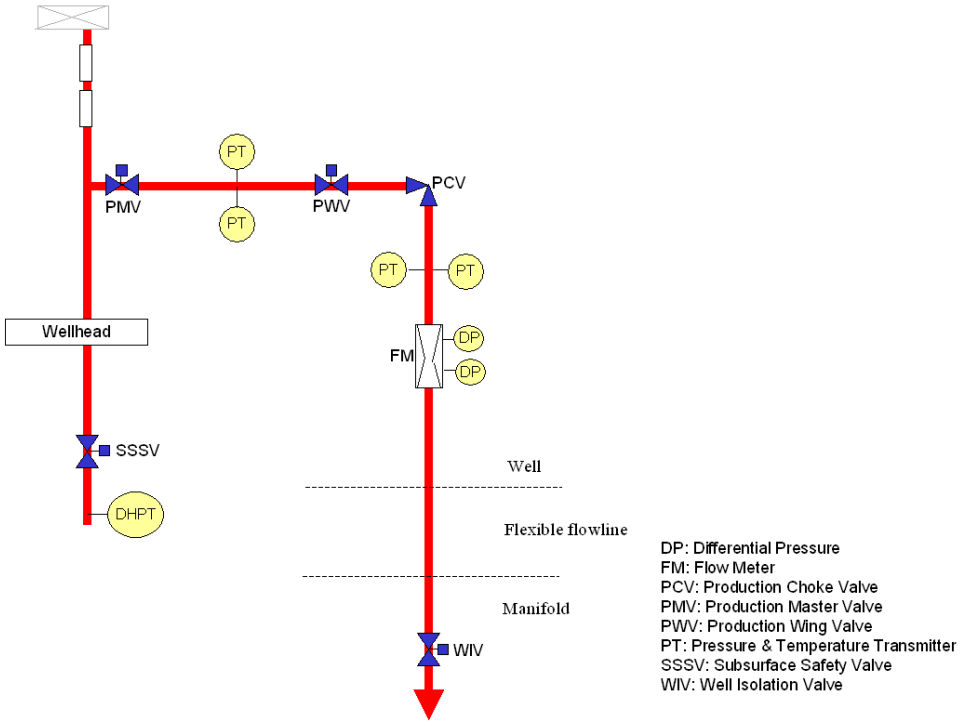
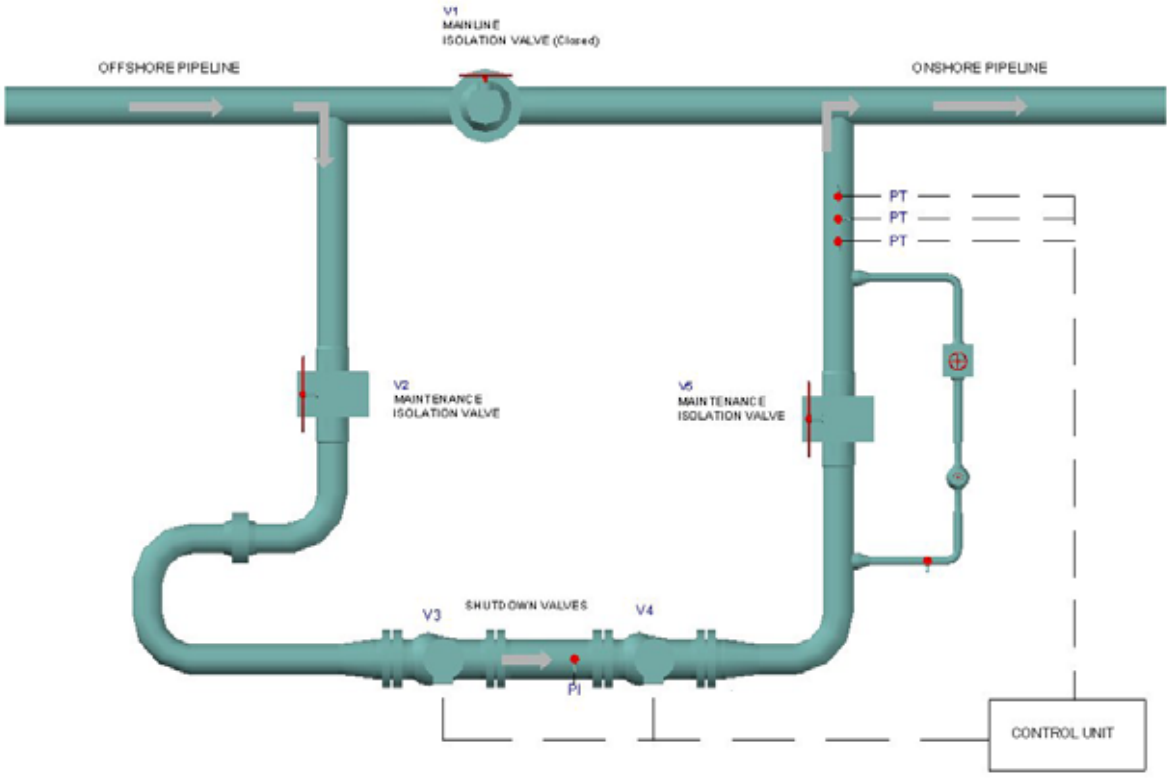


Figure 2: Some of the main elements of a typical Corrib well and subsea tree tied into the manifold



<u>Figure 3:</u> The configuration of the LVI pipework and valves



PT Pressure Sensors. measure the pressure in the pipeline.	V1 Mainline Isolation Valve. Closed during normal operation.	V2 & V5 Maintenance Isolation Valve. Open during normal operation, closed when maintenance of the shutdown valves is required.
CONTROL UNIT The control unit sends signals to shutdown valves to close them when pressure approaches 100 bar.	V3 & V4 Shutdown Valves. Will close automatically when pressure approaches 100 bar.	PI Pressure indicator

1 RELIABILITY OF OVERPRESSURE PROTECTION SYSTEMS

Overpressure protection systems are in place for both the offshore and the onshore pipelines. These protection systems will restrict the maximum pressure that can be experienced in these pipelines to their respective Maximum Allowable Operating Pressures (MAOPs). The MAOP values have been set based on minimising pressure while maintaining the operability of the Corrib pipeline system and the design throughput. In this document, 'overpressure' will refer to exceeding the set value of MAOP.

The Landfall Valve Installation (LVI) is the overpressure protection system for the onshore pipeline. The Wells Isolation System is the overpressure protection system for the offshore pipeline. **The purpose of this document is to demonstrate that the reliability of the overpressure protection systems is sufficient to prevent any credible case of overpressure occurring.**

This document summarises the reliability calculations of the respective overpressure protection systems.

1.1 ONSHORE PIPELINE (THE LANDFALL VALVE INSTALLATION)

The onshore section of the pipeline is protected from overpressure by a high reliability overpressure protection system at the Land Valve Installation (LVI). This is located at the landfall at Glengad and forms the interface between the onshore and offshore pipelines.

The LVI safety shutdown system comprises the following components:-

- Three pressure transmitters.
- An electronic high integrity logic solver, configured so that when any two of the three (2oo3) transmitters detect a pressure of 99 barg or more the safety shutdown valves are closed.
- Two safety shutdown valves that fail to the closed position. These are configured so that either of the valves can isolate the offshore pipeline from the onshore pipeline.
- Two solenoid valves per isolation valve. These are configured so that either of the two solenoid valves can close the respective safety shutdown valve.

The safety shutdown valves selected for the high integrity shutdown system are two inline 16" diameter axial flow valves each equipped with a spring to close and hydraulic pressure to open actuators. Pressurisation of the actuators is via a manual hand pump. The fail safe condition for both shutdown valves is closed. The safety shutdown valves, the actuators, the electronic logic solver and the three pressure transmitters were supplied as a complete package with independent certification. For further design details of the LVI see Appendix Q4.3

Signals from the three pressure transmitters will be processed through the LVI logic solver and the solenoid valves for each safety shutdown valve will be de-energised which results in depressurising the hydraulic fluid in the actuator. Loss of hydraulic fluid pressure will cause the safety shutdown valves to move to the closed position. Closure of any one of the two safety shutdown valves stops flow into the onshore pipeline. The safety shutdown system will be regularly tested with a full closure test every 12 months and a planned overhaul of the safety shutdown valves within 5 years.

The total probability of failure on demand (PFD) of the LVI shutdown system has been calculated to be 7.4×10^{-4} (0.00074). This has been certified by an independent verification authority in accordance with international standards IEC 61508 and IEC 61511. This is within the recognised industry probability integrity level of 0.0001 to 0.001

1.2 OFFSHORE PIPELINE (THE WELLS ISOLATION SYSTEM)

The subsea gate valves used for isolation, of the Vetco Gray VG 300 series, are very well established in the industry and are used in every key region of the world. The subsea tree valves will be leak tested twice per year in line with the well integrity management system (WIMS). Further details can be found in Appendix Q4.5.

The Wells Isolation System has two sub-systems. These are:

- Sub-System 1 This system utilises the command signals from the Gas Terminal via the umbilical to close the subsea valves.
- Sub-System 2 This system utilise the release, at the Gas Terminal, of hydraulic pressure in the umbilical and thus resulting in closure of the subsea wellhead valves.

1.2.1 Sub-System 1

This is the first sub-system that is initiated to prevent pressure exceeding the offshore pipeline MAOP. It is initiated if the pressure transmitters at the outlet of the onshore pipeline (i.e. located at the Gas Terminal inlet) rise to 93 barg. This sub-system, otherwise known as the SS3 trip, will prevent the offshore pipeline MAOP being exceeded by closing the master, wing and choke valves for each well. The master and wing valves will close in less than approximately 1 minute.

This sub-system comprises the following components:

- Three pressure transmitters at the terminal inlet configured so that when any two of the transmitters detect a pressure of 93 barg or more the subsea trip SS3 is initiated.
- High Integrity ESD logic Solver at the Terminal.
- Master Control Station (MCS) logic solver in the Terminal.
- Wing valves located on each Subsea Well which fail closed on loss of electrical or hydraulic power.
- Master valves located on each Subsea Well which fail close on loss of hydraulic power.

If the pressure at the terminal inlet rises to 93 barg, signals from the pressure transmitters will be processed through the ESD logic solver in the terminal and the Master Control Station (MCS) located in the terminal. The solenoids for each subsea well wing and master valve will be commanded to vent hydraulic fluid pressure at the Subsea Control Modules (SCMs) on each well. Thus, the subsea well wing and master valves will be commanded closed.

Loss of hydraulic pressure will cause the wing and master valves to move to the closed position. Closure of either the Master Valve or the Wing Valve at each wellhead will stop the flow from that well.

This sub-system is also initiated if the pressure at the LVI pressure transmitters rises to 99 barg, or on closure of either of the LVI shutdown valves.

1.2.2 Sub-System 2

This is the second sub-system that is initiated to prevent pressure exceeding the offshore pipeline MAOP. It is initiated on closure of the LVI safety shutdown valves. Sub-system 2, otherwise known as the SS2 trip, will prevent the offshore pipeline MAOP being exceeded by closing well isolation valves using a different route to local releasing of hydraulic fluid pressure described in Sub-system 1 (thereby reducing the potential for common cause failure). Sub-system 2 will also close well infield line isolation valve (WIVs situated in the subsea manifold), in addition to the surface controlled subsurface safety valve, the master valve and wing valve for each well.

This sub-system comprises the following components:

- Three pressure transmitters at the LVI configured so that when any two of the transmitters detect a pressure of 99 barg or more the LVI safety shutdown valves are closed and subsea trip SS2 is initiated.
- Limit switches located on each LVI shutdown valve which initiate the subsea shutdown if either valve moves from its fully open position.
- High Integrity Logic Solver at the LVI.
- High Integrity ESD logic Solver at the Gas Terminal.
- Communication / Distributed Control System from the LVI to the Master Control Station panel
- Solenoid valves located in the Gas Terminal which release the hydraulic fluid pressure in the umbilicals which supply hydraulic pressure to the subsea facilities (High pressure and Low pressure hydraulic lines).
- Wing valves located on each subsea well which fail closed on loss of electrical or hydraulic power.
- Master valves and Surface Controlled Subsurface Safety Valves (SCSSSVs) located on each subsea well which fail closed on loss of hydraulic power.

If the pressure at the LVI pressure transmitters rise to 99 barg the subsea high pressure (HP) and low pressure (LP) umbilical hydraulic lines (that control the subsea valves) are vented (depressurised) at the Gas Terminal. Signals from the LVI pressure transmitters will be processed through the LVI logic solver and the ESD logic solver in the Gas Terminal. Solenoid valves located within the Gas Terminal on each of the A and B LP hydraulic supplies and the A and B HP hydraulic supplies will be commanded to vent hydraulic fluid. The hydraulic pressure in the umbilical at the well will start to depressurise and within 2 hours the wing, master and the surface controlled subsurface safety valve (SCSSSV) will close. At the sub-sea manifold, the well in-field isolation valves (WIV) on each subsea well flowline will also close. However, no account has been taken for these in the reliability calculations, as they are not regularly tested. In total three valves on each well, which are tested at 6-month intervals, will be closed. The closure of any one of the three valves stops flow from the individual well. Should the LVI safety shutdown valve(s) spuriously close, limit switches on the LVI safety shutdown valve(s) will detect each valve moving from its open position and initiate a subsea SS2 trip. Should both circuits of the LVI signal cable fail, (this cable provides the operator with the ability to remotely close the LVI from the Gas Terminal) then the LVI safety shutdown valves will close and also initiate a subsea SS2 trip.

1.2.3 Analysis

An independent analysis has been performed of the Well Isolation System. The method used a Failure Mode and Effects Analysis (FMEA) to identify the relevant modes of failure and a Fault Tree Analysis (FTA) to calculate the probability of 'Failure to Isolate One or More Wells', with the associated consequence to exceed the MAOP.

The analysis has been performed by use of the following analytical techniques:

Failure Mode and Effects Analysis (Bottom-Up Approach)

- List all equipments within the Isolation System
- Determine the failure modes of each equipment
- Determine what effect each failure mode has on the operation of the Isolation System
- Assign probabilities to Failure Modes

All the base data used for calculations within the FMEA are from industry standard auditable sources (e.g. OREDA) and the references are provided in the FMEA worksheets.

Fault Tree Analysis (Top-Down Approach)

- Establish the 'TOP' Event (Failure to Isolate One or More Wells)
- Determine which failure modes affect the operation of the Isolation System
- Determine at what level each failure mode impacts on the safe operation of the Isolation System
- Use the fault tree logic to calculate the probability of unsafe operation

The calculated probability for 'Failure to Isolate One or More Wells' is 4.5 x 10-4 (0.00045), which is within the recognised industry probability integrity level of 0.0001 to 0.001.

1.3 SUMMARY

The Landfall Valve Installation (LVI) is the overpressure protection system for the onshore pipeline. The Wells Isolation System is the overpressure protection system for the offshore pipeline.

The calculation of the likelihood of failure of a safety protection system at the moment it is demanded to act is known as the Probability of Failure on Demand (PFD). In the industry, the realistic PFD that is attainable for a safety system is a PFD of between 0.0001 to 0.001 which represents a probability of a safety system failing to perform on demand of better than 1 in 1000 occurrences.

Both the offshore pipeline and onshore pipeline over pressurisation protection systems have a PFD which is better than 1 in 1000 occurrences.

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Q4.7 – MATERIALS AND CORROSION MANAGEMENT PREMISES

DOCUMENT No: COR-39-SH-0002

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1 PURPOSE AND SCOPE

This document is intended to describe the materials and corrosion management requirements for the design and installation of the Corrib pipeline. It is a “live” document and will be updated during the project execution phase to reflect any changes that affect materials or corrosion management.

It forms the basis for the corrosion management strategy during the operations phase. It also describes erosion and mechanical degradation threats including fracture.

It covers all elements of the pipeline system from the wellheads to the inlet of the Terminal.

This document covers the requirements of the following deliverables defined in the Shell Discipline Controls & Assurance Framework:

- Materials Selection Report
- Corrosion Inhibition System Design
- MCI Failure Modes and Effects Analysis Report

This document also provides the basis for compliance with Section 9 of I.S. EN 14161, Corrosion Management.

2 GENERAL FACILITIES AND MATERIALS DESCRIPTION

The Corrib reservoir will be produced from an 8 slot subsea manifold via an 83.5km 20” pipeline to the landfall (at Broadhaven Bay), through a Landfall Valve Installation (LVI) and 8.3km onshore pipeline to the Terminal (at Bellanaboy Bridge). There are currently 3 cluster wells P101, P4 and P6 (close to the manifold) and 3 more satellite wells P3, P2 & P5 (1.7km, 2.3km and 2.4km away from the manifold respectively). Well flows will be commingled at the main subsea manifold. There is also a smaller subsea manifold at the P5 satellite well to which P2 is connected.

The in-field flexible jumpers and flowlines (6” & 8”) between the wells and manifolds have a 316L carcass and a Coflon (Polyvinylidene Fluoride) pressure sheath which is not degraded by methanol. The subsea manifold pipework, valves and fittings have been fabricated from 22%Cr duplex stainless steel. The subsea connection hubs are 25%Cr super-duplex stainless steel except for the 16” connection hub for the pig launcher which is AISI8360 overlay clad with corrosion resistant Alloy 625, and the production hub which is F65 overlay clad with Alloy 625. The small bore methanol supply and hydraulic pipework is fabricated from 316L.

The pipeline tie-in spool is fabricated from a small section of 22%Cr duplex stainless steel and 27.1mm X-70 grade carbon steel to DNV OS F-101:2000 (SAWL 485 II FD). The first two bends of the tie-in spool after the 22%Cr duplex stainless steel section have been internally clad with a 3.5mm layer of Alloy 625. The FSM corrosion monitoring spool will be welded into the tie-in spool.

The pipeline (both on- and offshore sections) is X-70 carbon steel to DNV OS F-101 (SAWL 485 II FD). Corrosion mitigation of carbon steel pipeline will be achieved with corrosion inhibitor and a corrosion allowance that varies along the length (minimum of 1mm). The pipeline has not been specified to sour service standards [1]. The pipeline is coated with either a three-layer polypropylene coating, or asphalt enamel and concrete coating, depending on the location in the pipeline route.

The offshore pipeline has an internal coating (girth weld areas excepted) from approximately 5.5km from the Corrib field to the landfall. The Pipeguard P-100 flow coating was applied for preservation purposes during storage and was removed from the first 5.5km prior to installation to avoid the coating blistering during service at elevated temperatures in this section. Testing showed the coating to be suitable at ambient temperature. All onshore linepipe is internally coated with the same system. No benefit is taken for the internal coating with respect to corrosion because of the exposed weld areas.

The LVI comprises a 16” loop with pressure protection and isolation valves with a 4” bypass and associated valves. The 16” isolation valves are carbon steel overlay welded with corrosion resistant Alloy 625, and the 16” pressure protection valves and bypass valves are 22%Cr duplex stainless steel. The 16” loop and 4” bypass pipework will be fabricated with 22%Cr duplex stainless steel. The main 20” pipeline and valve within the LVI are carbon steel overlay welded with corrosion resistant Alloy 625.

The onshore pipeline will be routed under the estuary via a 4.8km long 4.2m maximum diameter tunnel. The tunnel will be backfilled with cementatious grout.

The subsea facilities are controlled by means of a multiplex electro-hydraulic system served by three umbilicals originating at the onshore terminal. At the LVI location, these are combined in a single umbilical to the Corrib field. The umbilical also transports methanol (for hydrate inhibition) and corrosion inhibitor from the Terminal to the subsea facilities. Two spare cores of the umbilical will be used for the disposal of treated produced water from the Terminal to the Corrib field. All umbilical cores are 25%Cr super-duplex stainless steel which is resistant to internal corrosion for the Corrib fluids and operating conditions and to external corrosion by seawater/ground-water. For the umbilical tubes which are exposed to aerated produced water, 25%Cr super-duplex stainless steel is also resistant to crevice corrosion up to 20°C and higher if biocidal control is applied as intended. 316L is not suitable for exposure to aerated produced water and any 316L components in the produced water return system have been replaced with 25%Cr super-duplex stainless steel. The umbilical core

connections will be welded with an orbital welding system to avoid crevices and to allow full radiographic inspection.

Facilities are provided to inject methanol at each tree, at the subsea manifold, and at the LVI. Corrosion inhibitor will be added to methanol for transport via the umbilical for injection at wellheads and at the manifold to mitigate corrosion.

Determination of the corrosion allowances for the pipeline were based on the original design corrosion assessment in 2002 together with the relative position in the pipeline route from the subsea manifold as follows:

Table 2.1: Corrosion Allowances and Relative Position in the Pipeline Route from the Subsea Manifold

Distance (km)	Corrosion Allowance (mm)
0.0	**6.4**
0.4	**3.6**
0.8	**2.3**
1.6	**1.4**
2.5	**1.0**
92	**1.0**

The operational field life is expected to be 20 years. The base case design life of the pipeline, umbilical, manifold and wellheads is 30 years. The other subsea facilities have a minimum design life of 20 years.

3 DESIGN PREMISES

The maximum CO_2 content from the Corrib reservoir is 0.32%. No H_2S has been observed in the test wells and is not expected. The organic acid concentration of the condensed water is expected to be maximum 10 mg/l.

The formation water chemistry analyses of the Corrib reservoir show a relatively high chloride content (197,158 mg/l), an organic acid concentration of 100 mg/l and a low bicarbonate concentration of <5 mg/l.

Production is not expected to vary significantly (Corrib is not a swing producer).

The pressures of the pipeline system are:

- Wellhead shut-in: 345 barg
- Flowing wellhead (max): 272 barg
- Offshore Pipeline design pressure: 345 barg
- Offshore MAOP: 150 barg
- Onshore Pipeline design pressure: 144 barg
- Onshore MAOP: 100 barg
- Normal operating pressure at Terminal inlet: 85 barg

The temperatures of the pipeline system are:

- Upper design offshore pipeline inlet: 74°C
- Flowing wellhead (initial): 61°C
- Flowing onshore pipeline inlet: 2 to 10°C
- Lower design temperatures are given in Table 4.3

4 CORROSION AND OTHER MATERIALS THREATS

4.1 FAILURE MODES

A Failure Modes and Effects Analysis (FMEA) has been carried out for the Corrib pipeline system. The objectives of an FMEA are to identify the potential pipeline and LVI failure modes with respect to materials threats, determine the required mitigation and controls, and assess the criticality. Based on this analysis the most critical failure modes are:

Table 4.1: Critical failure modes

Section	Failure Mode	Control
Manifold/Satellite Manifold	External Corrosion	External polymeric coating and cathodic protection applied. Regular ROV surveys to check for damage. Additional anodes retro-fitted if required.
Offshore pipeline	Low temperature cracking	Flow regulation during depressurisation as per operating procedures. Materials suitable to lower design temperature
	Excessive corrosion	Continuous (>99%) injection of corrosion inhibitor. Corrosion monitoring. Intelligent pig inspection.
Landfall Valve Installation (LVI)	Low temperature cracking	Flow regulation during depressurisation as per operating procedures. Materials suitable to lower design temperature
	Hydrogen induced stress cracking	Control through design to avoid HISC Stress levels below HISC threshold during manufacture and installation.
Onshore Pipeline	Low temperature cracking	Flow regulation during depressurisation as per operating procedures. Materials suitable to lower design temperature
	Excessive internal corrosion	Continuous (>99%) injection of corrosion inhibitor. Corrosion monitoring. Intelligent pig inspection.

The relevant corrosion, erosion and mechanical threats and mitigations identified during the FMEA for the Corrib pipeline system are explained in more detail below.

4.2 INTERNAL THREATS

4.2.1 CO_2 and Organic acid corrosion

The primary corrosion threat to the carbon steel pipeline is CO_2 acid corrosion which can occur when carbon dioxide dissolves in water to form carbonic acid. The gas is non-corrosive until it cools below the water dew point at which point it is at its most corrosive. As the temperature and pressure change some water will condense upstream in the well bores and/or flowlines and it continues to condense in the pipeline until the gas reaches ambient temperature at sea bed conditions. Alternatively formation water may be produced from the reservoir in which the CO_2 can also dissolve. The corrosivity of the fluids reduces along the pipeline as the temperature decreases and the pH increases due to saturation of ferrous ions.

The presence of organic acids can increase the corrosivity especially in systems with a relatively low CO_2 partial pressure. The organic acid content for the condensed water case is low (10 ppm) but increases significantly (100 ppm) should formation water be produced.

The carbon dioxide content of the Corrib gas is relatively low. The corrosion assessment (see Appendix Q4.9) predicts that the maximum uninhibited corrosion rate is 1.3mm/yr at a point near the manifold. After year 3 the corrosion rate will decrease with time as the wellhead pressures decline. The expected flow regime is annular dispersed for the full field life so corrosion can occur at any point around the circumference of the pipe and not just at the bottom of the line (BOL). Should formation water be produced the maximum predicted uninhibited corrosion rate is 9.9mm/yr, but is generally 2.5 to 6 mm/yr. This reflects the greater corrosivity of the higher organic acid content.

The maximum predicted uninhibited corrosion rate for the onshore pipeline is initially 0.12mm/yr for the condensed water case and 0.2mm/yr should formation water be produced. The predicted internal CO_2 corrosion rates are described in detail in Appendix Q4.9. It should be noted that if significant formation water is produced the relevant well will be subject to intervention or shut-in.

To mitigate internal CO_2 and organic acid corrosion it is common practice to inject corrosion inhibitor which forms a barrier against the corrosive fluids. Another method is to inject glycol or methanol which are miscible with the corrosive water and further reduce the corrosivity. For the Corrib pipeline the threat of carbon dioxide corrosion will be mitigated primarily by injecting corrosion inhibitor but will also benefit from the presence of methanol. The maximum predicted inhibited corrosion rate for the onshore pipeline is <0.05mm/yr and this has been verified by initial corrosion inhibitor testing.

The annular dispersed flow regime for the full field life means that water accumulation at low points in the pipeline is unlikely to occur. There are no significant low points in the offshore pipeline but there will be a low point in the onshore pipeline where it passes through the tunnel. In the unlikely event that pockets of fluid collect in this low point the water soluble corrosion inhibitor and methanol will protect the pipe from corrosion.

Testing has shown that the corrosion rate can be adversely affected by the presence of oxygen in the methanol. The oxygen content in the methanol is maintained at a low level by nitrogen blanketing of the methanol storage tanks and will be reduced to a negligible level (<20 ppb) with application of oxygen scavenger in the Terminal.

For sections of the pipeline system where protection of the carbon steel pipe by the film forming corrosion inhibitor cannot be assured, e.g. due to insufficient length to establish the film or where there is turbulent flow, corrosion resistant materials have been used. This includes the flexible pipelines from the satellite wellheads, the subsea manifold pipework & valves and the LVI pipework & valves. The

section of onshore pipeline and 20” valve within the LVI has also been overlay welded with Alloy 625 because of the potential for turbulent flow and the presence of stagnant conditions during normal operation.

A computational fluid dynamics (CFD) analysis has shown that the tie-in spool from the subsea manifold to the PLEM requires additional protection to the first bend to allow full circumferential protection of the pipe by the corrosion inhibitor. The pipe from the manifold to the first bend is therefore 22%Cr duplex stainless steel and both the first and second bends have been overlay welded with Alloy 625.

4.2.2 Top of the Line (TOL) Corrosion

CO_2 or organic acid corrosion can occur in pipelines where the flow regime is stratified and condensation occurs at the top of the line. This is particularly acute where the hot gas contacts a relatively cool (uninsulated) area of the pipeline typically at the inlet or at cold spots close to the inlet. The corrosion inhibitor does not protect the top of the line but mitigation is provided by the co-condensing methanol.

The expected flow regime over the full length of the Corrib pipeline is annular dispersed for the 20 year field life which precludes TOL corrosion as a mechanism.

However, TOL corrosion tests carried out at IFE (Institute for Energy Technology, Norway) for simulated Corrib conditions at the pipeline inlet showed that TOL rates were significantly lower in the presence of methanol. TOL corrosion rate without methanol at 60ºC was 0.2mm/yr while with methanol the rates were well below 0.1mm/yr. No pitting or other localised corrosion was observed in any of the tests.

Based on the TOL corrosion testing there is sufficient corrosion allowance at pipeline inlet (6.4mm) to mitigate this mechanism should stratified flow conditions occur. Similarly, should stratified flow occur in the onshore pipeline no TOL corrosion is expected because of the negligible condensation rate and presence of methanol.

4.2.3 Preferential weld corrosion

Pipelines in wet gas/condensate service are known to be susceptible to preferential weld CO_2 corrosion (PWC) especially when low conductivity fluids such as condensed water are present. Elements such as nickel in the weld can exacerbate PWC. Although avoidance of deliberate nickel additions to welding consumables can reduce the risk of PWC, mitigation is best provided by corrosion inhibition. To ensure that the selected corrosion inhibitor is capable of mitigating PWC, offshore production welds have been included in the corrosion inhibitor test programme. Initial results indicate no significant PWC problem.

4.2.4 Galvanic corrosion

Galvanic corrosion can occur as a result of differences in electrochemical potential between metals, such as the interface between the internal CRA clad layer of the tie-in spool and the adjacent carbon steel pipe, or the duplex stainless steel T-piece and the adjacent steel pipe at the LVI. This type of corrosion has not generally been observed in producing oil and gas systems [2]. This is because effective inhibition limits the anodic reaction on the steel and the absence of oxygen prevents a strong cathodic reaction at the CRA surface.

Mitigation at the offshore tie-in spool and T-pieces will be provided by the corrosion allowance, and at the LVI wall thickness checks can be carried out to confirm the absence of this mechanism.

4.2.5 H_2S corrosion

Sour corrosion mechanisms including sulphide stress cracking and hydrogen induced cracking are not expected for the Corrib gas pipeline because there is no indication that any measurable level of hydrogen sulphide (H_2S) is present in the Corrib field. Well tests have shown no H_2S in the reservoir and with no requirement for water injection there is no credible mechanism for H_2S to occur. Increase in H_2S due to well souring is a relatively slow process and H_2S measurements will be routinely made on gas samples at the Terminal to ensure early detection.

Although the subsea facilities, pipeline and LVI have not been specified for sour service it is likely that an acceptable (but low) level of H_2S with respect to the materials could be determined. Samples of offshore and onshore welds will be retained to allow testing to be performed if required. H_2S scavenging could also be considered as mitigation to reduce the level of H_2S.

The limits for sour service are derived from the requirements of ISO 15156 [1] as follows:

Table 4.2: Sour Service Limits

Material	Pressure	H_2S limit
Carbon steel	345 barg	10ppm
	150 barg	23ppm
	144 barg	24ppm
	100 barg	34ppm
22%Cr duplex stainless steel	345 barg	30ppm
	144 barg	70ppm

Exceeding these limits does not mean that sulphide stress cracking will occur but a detailed assessment of the risk is required. Using the duplex stainless steel limit for the subsea manifold and the carbon steel 150 bar (MAOP) limit for the pipeline, an H_2S threshold of 20ppm will be defined to trigger such an assessment. Closure of the field may be required whilst the assessment is done.

Acidic H_2S corrosion is lower than CO_2 corrosion (typically 5 times lower) and therefore will not significantly influence the corrosion assessment for the pipeline for conditions associated with well souring where the level of H_2S is relatively low. The high corrosion rates associated with very high H_2S containing fluids (e.g. in Canada) are more related to pitting and the presence of free sulphur which would not occur with Corrib should well souring occur.

4.2.6 Microbial induced corrosion

Bacterial related corrosion is unusual in gas/condensate production systems and with no requirement for water injection there is no expectation that this mechanism will occur in the Corrib pipeline during operation.

4.2.7 Corrosion by hydrotest water

The water used for hydrotesting can cause corrosion either by the oxygen dissolved in the water (oxygen corrosion) or the presence of microbes and sufficient nutrient (microbial induced corrosion).

Microbial induced corrosion is a particular threat if the hydrotest water is left in the pipeline for extended periods (typically >2 weeks) without treatment.

Following hydrotesting the offshore pipeline was filled and sealed with filtered seawater treated with a cocktail of oxygen scavenger, biocide and corrosion inhibitor. Provided the pipeline remains sealed then oxygen corrosion and microbial corrosion are not expected.

The onshore pipeline and LVI will likely be hydrotested with potable water. The exact procedure is still to be defined but is likely to involve filtering and pH control with sodium bicarbonate to mitigate corrosion. It is unlikely that the onshore pipeline will be left for an extended period with hydrotest water.

4.2.8 Erosion

Internal erosion could potentially occur as a result of the presence of contaminants such as sand, liquids or proppant. The Corrib reservoir is a tight formation and is not expected to produce sand. One of the wells (P5) has been fractured and contains a hard ceramic proppant which may be produced back from the well. However, no significant proppant production was observed during clean-up of the well in 2001 and no proppant production was observed during a subsequent well test in 2008. An assessment of erosion by proppant indicated no significant erosion (see Appendix Q4.9).

Should solids production occur likely areas of erosion damage would be at the wellhead choke in the field, the bends in the pipeline spool just downstream of the manifold, and at the T-piece and first bend of the LVI. Should solids production occur monitoring of the performance of the subsea chokes will give an early indication if there is a significant problem in the early years of production. In addition an acoustic monitor is fitted to the subsea manifold which will provide an alert of any significant solids production. If monitoring indicates solids production then the T-piece and bends of the LVI can be subject to wall thickness monitoring to check for erosion damage. Production of solids would result in a well intervention or shut-in of the well.

Furthermore, the flow velocities in the pipeline are well below the threshold values required to cause flow induced erosion-corrosion or liquid droplet induced erosion (typically 20m/s and 38m/s respectively for carbon steel).

4.2.9 Mercury embrittlement

Levels of mercury are relatively low and the materials used in the pipeline are not susceptible to this mechanism.

4.2.10 Stress Corrosion Cracking (SCC)

There are no credible internal stress corrosion cracking mechanisms for carbon steel with the Corrib production conditions. The stress corrosion cracking mechanism observed in town gas pipelines as reported in the UKOPA database [3] will not occur in the Corrib system. In addition to CO_2 this mechanism requires the presence of carbon monoxide and is enhanced by oxygen. Carbon monoxide and oxygen are not present in the Corrib gas.

Chloride stress corrosion cracking of stainless steels can occur in aqueous chloride solutions especially if oxygen is present. For oxygenated systems chloride SCC can occur in stressed components above 60°C for AISI316L stainless steel, 90°C for 22%Cr duplex stainless steel and 120°C for 25%Cr super-duplex stainless steels. For oxygen free conditions these temperatures are higher depending on the chloride content. No chloride SCC is expected for the Corrib production conditions. Alloy 625 is immune to chloride SCC.

4.2.11 Stray current corrosion

Stray current corrosion can occur when an isolation joint in the pipeline system fails due to bridging or short-circuiting, typically by internal conductive fluids. This mechanism has been observed in many wet gas pipelines in the Netherlands. Rate of metal loss can be high and in this case is normally internal.

Following a specialist review by an independent consultant an isolation joint was not installed at the beach to isolate the offshore and onshore cathodic protection systems. This is covered in more detail in section 7.2.3 of this document. However, there is an isolation joint at the interface with the Terminal and this will require periodic monitoring for this mechanism.

4.2.12 Overall assessment of internal corrosion

The threat from internal corrosion is primarily CO_2 and organic acid corrosion but for the onshore section of the pipeline it is relatively benign. For normal operating conditions the maximum predicted corrosion rate is 0.12mm/yr without corrosion inhibition and <0.05mm/yr with corrosion inhibition. This inhibited corrosion rate is slightly higher than the rate that might be expected for a dry gas line, and is significantly less than might be expected for a pipeline producing oil where additional threats such as under-deposit corrosion and microbial induced corrosion can also affect the degradation rate. This assessment has been used in relation to the selection of pipeline failure databases for the QRA (see Appendix Q6.4).

4.3 EXTERNAL THREATS

4.3.1 External corrosion

External corrosion of the pipeline system and subsea facilities can occur as a result of the corrosivity of seawater and/or groundwater. For buried sections of the pipeline where anaerobic conditions may exist, microbial action can increase the corrosion rate. External corrosion is potentially most severe where the pipe temperature is highest.

External corrosion of the pipeline system (offshore pipeline, LVI, and onshore pipeline) and the subsea facilities (X-trees, end fittings of flexibles, subsea manifold structure and pipework) is mitigated by high performance coatings and the application of an electrically continuous cathodic protection system.

The design and installation of the tunnel section of the onshore pipeline will ensure mitigation of potential corrosion during service. A thorough inspection of the coating system will be carried out following installation and any damage will be repaired. Once installation is complete the tunnel will be filled with a cementatious grouting compound. The grout typically has shrinkage of 2 to 5% and normally takes over 24 hours to harden. As it shrinks on to the pipe it will not damage the coating and will form a protective layer which should exclude free water and oxygen. The grout also has a pH of 12 which is alkaline and would effectively passivate the steel against corrosion if exposed to water. The grout is conductive which will allow the pipeline cathodic protection system to protect any exposed steel should water penetrate the grout.

4.3.2 Pitting corrosion

Stainless steels are susceptible to pitting corrosion at relatively low temperatures in a damp saline environment. AISI 316L stainless steel can suffer pitting at ambient temperatures and 22%Cr duplex stainless steel at temperatures above 20°C. Mitigation can be achieved with an external coating and application of cathodic protection will prevent pitting occurring. All AISI 316L and 22%Cr duplex stainless steel components in the Corrib pipeline system and subsea facilities are protected by external coating and/or cathodic protection if subsea or buried.

4.3.3 Stress Corrosion Cracking (SCC)

External stress corrosion cracking of the carbon steel onshore pipeline by high pH (carbonate) or near neutral pH mechanisms is not expected. High pH stress corrosion by carbonate-bicarbonate ions requires disbondment of the coating, cyclic loading and a temperature greater than 40°C. The mechanism has not been observed with 3 layer polypropylene coatings. Near neutral pH stress corrosion requires coating disbondment and cyclic loading. The Corrib pipeline is protected with a robust 3 layer polypropylene coating, there is no significant cyclic loading, and the operating temperature will be below 10°C, which precludes these mechanisms.

External chloride stress corrosion cracking can occur in stainless steels if exposed to seawater or ground water but is dependent on the temperature. Chloride SCC can occur in stressed components above 60°C for AISI316L stainless steel, 90°C for 22%Cr duplex stainless steel and 120°C for 25%Cr super-duplex stainless steels. For the Corrib pipeline system the only possible threat would be to AISI316L stainless steel components in the production system of the subsea manifold. These components are protected by the cathodic protection system which removes this threat.

4.3.4 Stray current corrosion

External stray current corrosion of a pipeline can occur either due to interference between the cathodic protection system and another nearby current path in earth provided by a low resistance metallic object such as another pipeline, or from alternating current sources such as overhead high voltage power supply lines (also referred to as AC corrosion).

Mitigation can be achieved by thorough review of underground facilities in the vicinity of the onshore pipeline to identify possible sources of stray current and to accommodate these in the cathodic protection system design and installation. There are no overhead high voltage power lines in the vicinity of the Corrib pipeline.

Interference with the cathodic protection system by induced current from the umbilical is negligible because of the low voltage (1kV) and screening of the power cables.

4.3.5 Hydrogen Induced Stress Cracking

Duplex stainless steels are vulnerable to failure by hydrogen induced stress cracking (HISC) caused by hydrogen uptake when the duplex stainless steel is exposed directly to the cathodic protection and subject to high strain. Mitigation can be provided by following the DNV F-112 guideline [4] to avoid HISC, and the risk can be reduced by applying a high performance coating.

All the duplex stainless steel components of the manifolds and LVI have been assessed against DNV F-112. As a result some minor modifications (grinding of the weld caps) were required for the P5 manifold pipework. For the LVI the weld caps of the duplex components will be provided with a nickel hydrogen barrier to reduce the risk further. Procedures have been/will be implemented to ensure high stresses are not created during fabrication or installation, such as imposed loads at the flexible/manifold connections.

A similar hydrogen embrittlement mechanism can occur at the interface between Alloy 625 cladding and a high strength steel substrate if subject to high stress and exposed to cathodic protection. This mechanism can be mitigated through design of the component, avoidance of PWHT following cladding, and control of the welding procedure. Application of a coating can reduce the risk but often susceptible clad components such as hubs are left bare or the coating is damaged during installation. The only component in the Corrib pipeline system at risk to this mechanism is the hub for the pig launcher connection. Review of the welding procedure indicated that the risk of this mechanism is negligible.

4.4 MECHANICAL THREATS

4.4.1 Fracture

4.4.1.1 Basis for Fracture Control Plan

All components of the pipeline system have been designed and fabricated in accordance with I.S. EN 14161 and I.S. 328 to resist brittle or ductile fracture in all operating scenarios.

Under start-up or blowdown conditions it is possible that sections of the pipeline system will experience low temperatures due to the Joule-Thomson cooling effect. The most likely low temperature scenarios are opening up cold wells to a depressurised pipeline, equalisation of a pressurised offshore pipeline with a depressurised onshore pipeline, or blow-down of the pipeline system.

The following lower design temperatures apply:

Table 4.3: Lower Design Temperatures

Flexible pipelines*	**-20°C**
Manifold	**-30°C**
Tie-in spool	**-10°C**
PLEM valve	**0°C**
Offshore pipeline	**0°C**
LVI	**-26°C**
First 1.15 km of onshore pipeline	**-20°C**
Remaining length of onshore pipeline	**-10°C**

* New flexible for P2 to be rated to -50°C

Operating procedures will be developed to ensure that these lower design temperature limits are not exceeded for all credible low temperature scenarios. Should pressure equalization of the onshore pipeline be required, operational procedures will ensure that adiabatic cooling of the pipeline will be limited such that the lowest temperature in the pipeline at the LVI will be -10°C.

Assessments have been carried out to determine the resistance of the pipe to crack initiation, the critical defect length and hole size with respect to leak before break criterion, and to confirm resistance of the pipeline steel to crack propagation. These form the basis of the fracture control plan and input to the QRA and are summarised below.

4.4.1.2 Fracture Initiation

This assessment determined resistance of the pipe to fracture initiation from a planar defect. The calculation method relates the three main variables affecting defect tolerance which are defect size, stress and toughness (CTOD value). If two of these variables are known, a safe level for the third can be calculated for avoidance of failure through crack initiation and plastic collapse. The assessment used the fracture mechanics Level 2 approach in BS 7910 [5].

Based on the knowledge of detectable defect sizes and applied stresses in the pipeline the required minimum CTOD (crack tip opening displacement) values for the longitudinal seam weld were conservatively calculated as follows:

Table 4.4: CTOD Values for the Longitudinal Seam Weld

Defect case in longitudinal seam weld	Required CTOD Values mm
Axial defects & minimum specified tensile properties	**0.08**
Axial defects & maximum specified tensile properties	**0.014**
Transverse defects & minimum specified tensile properties	**0.08**

The lowest recorded CTOD value for the longitudinal seam welds tests for the Eisenbau Krämer linepipe at -20ºC was 0.18mm with a mean of 0.37mm, and for the Corus linepipe at -0ºC was 0.83 with a mean of 0.93mm. The Corus and Eisenbau Krämer linepipe were also tested at -30ºC. All values exceeded the minimum required value of 0.08mm and this confirms the resistance to crack initiation at the lower design temperatures for the Corrib pipeline.

An engineering criticality assessment was also performed for the offshore girth welds by the pipe-lay contractor. A minimum CTOD requirement of 0.2mm was derived for the girth welds. Fracture testing at 0ºC and -30ºC in accordance with BS7448-2 [6] gave a minimum allowable value of 0.2mm. This meets the minimum required value of 0.2mm.

A similar assessment will be performed for the girth welds for the onshore pipeline when the welding procedures are qualified.

4.4.1.3 Leak Before Break (LBB)

This assessment covered a leak-before-break (LBB) evaluation for the landfall and onshore section of the Corrib pipeline with respect to planar defects, and determines estimates of the defect lengths associated with the LBB criterion, for use in conjunction with consideration of the likely effective hole size in the event that a defect penetrates through wall.

Potential defects in the wall of a pipeline introduced during manufacturing or welding may result in a leak. The size of such a leak would depend on the size of the defect. The nature of the leak could be a stable hole or, at a critical point dependent on the size and nature of the defect, could become a sudden disruptive break. A LBB assessment determines the critical size of potential defects in the pipe wall where the transition from a stable hole to sudden disruptive break is predicted to take place.

The results of the LBB assessment can be used to provide an indication of the criticality of the sizes of different potential defects, as well as providing a basis for assessing the likelihood of stable holes being formed as part of a consequence analysis of loss of containment due to material defects within a Quantitative Risk Assessment.

The following conclusions were drawn on the basis of the work:

1. Upper bound through-wall defect lengths of 623mm (100 barg) and 425mm (150 barg) are defined for the limiting length of a stable defect for the purposes of hole size estimates and leak rate calculations.

2. For the purposes of integrity assessment with respect to planar defects, lower bound limiting through wall defect lengths of 196mm (100 barg) and 147mm (150 barg) are defined for the assessment of LBB response.
3. Surface breaking defect analysis has been undertaken to define an envelope of allowable defect dimensions (length and depth) for simplified screening assessment purposes and to understand the general defect tolerance of the pipeline materials.
4. An estimate of the crack opening area has been made for a range of defect lengths, assuming a leak-type failure mode. Of the cases considered the upper bound crack opening area is estimated to be 1410mm^2 for 100 barg MAOP and 327mm^2 for 150 barg MAOP.
5. Insufficient data have been found in the open literature from which to estimate the crack opening area in the event of a burst-type failure mode.
6. These defect sizes are less conservative but consistent with the assessment carried out by PIE (see Appendix Q6.4).

The results summarised above would indicate that substantial defects would need to be present within the pipe wall for a related loss of containment to become a disruptive break rather than a stable leak through a hole.

4.4.1.4 Running Fracture

This assessment compared the material properties of the onshore section of the Corrib pipeline with the code requirements for running brittle or running ductile fracture.

Running brittle fracture describes the propagation of a crack initiated from a flaw in the pipe steel that then runs in a brittle fracture mode extremely rapidly leading to pipeline failure. The initial failure would most likely be prompted by a combination of low temperature and high pressure condition.

Running ductile fracture describes the propagation of a crack initiated from a flaw in the pipe steel that then runs in a ductile fracture mode at a constant speed corresponding to a balance between the local (decompression) pressure level and the steel fracture resistance. If the metal fracture resistance is adequate no steady state fracture propagation can be reached and the fracture will arrest.

It was assessed that running brittle fracture will not occur since, in accordance with I.S. 328 (which exceeds the requirement of I.S. EN 14161), both the Corus linepipe and the Eisenbau Krämer linepipe meet the minimum Drop Weight Tear Test shear area requirement of 75% shear area at 0°C.

It was assessed that running ductile fracture will not occur since, in accordance with I.S. 328 (which exceeds the requirement of I.S. EN 14161) and I.S. EN 10208-2, the minimum required Charpy impact energy is 46 Joule average and 35 Joule minimum for line pipe with a wall thickness up to 25mm and a design factor of 0.72. The Corrib 27.1 mm nominal wall thickness pipe has a design wall thickness of 25.1 mm and a measured Charpy impact energy of average 236 Joule and minimum 145 Joule at -20°C for the Corus linepipe, and average 250 Joule and minimum 171 Joule for the Eisenbau Krämer linepipe at -40°C to -50°C. No criterion is given for a design factor of 0.3, however, taking the 0.72 design factor as a conservative basis the requirements of I.S. 328 and I.S. EN 10208-2 are also easily fulfilled.

Therefore, it was concluded that the Corrib linepipe steel satisfies the code requirements of I.S. EN 14161 and I.S. 328, and a running fracture will not occur in the Corrib pipeline.

4.4.1.5 Effect of cooling at a gas release

The possible effect of a drop in temperature by adiabatic cooling (Joule-Thomson effect) caused by rapid release of gas through a small hole has been considered. It has been postulated that this could cause sufficient cooling that the pipe material makes a transition from ductile to brittle regime increasing risk of crack propagation ultimately to full-bore failure.

Assuming a hole size of 10mm initial calculations have shown that a temperature drop of -20°C from the initial fluid temperature in the pipe to the temperature of the gas exiting the hole, bounds all of the simulated blow-down releases for the Corrib pipeline. The effects of this temperature drop only affect the hole close to the outer pipe wall and the temperature of the pipe wall will have recovered to the internal gas temperature within approximately 50mm from the hole perimeter. Ongoing modelling work based on computational fluid dynamics will provide a more accurate, less conservative estimate of this temperature drop.

The typical gas temperature in the onshore pipeline will be 6°C which means a temperature drop at a hole perimeter in these circumstances to -14°C (lowest value). During blow-down or pressure equalization operational procedures will be applied to ensure that adiabatic cooling of the pipeline will be limited such that the lowest value at the LVI will be -10°C. This means a worst case temperature at this location in these circumstances of -30°C, although it is expected that the additional modelling work will predict a higher temperature than this.

Testing has shown that the pipeline steel has good resistance to crack initiation and propagation at low temperature. In the highly unlikely event that crack initiation would occur at a hole, the adjacent steel has the capability to arrest the crack especially as it extends into the higher ductility region associated with the warmer areas of the pipe. Furthermore such an event has never been experienced in practice and is thus generally regarded as hypothetical. It is concluded that failure of the pipe by this mechanism is a non-credible scenario.

4.4.2 Fatigue

The likely operating mode of the pipeline and the normal operating pressures make it unlikely that the pipeline will accumulate any significant amount of fatigue damage through stress fluctuations over its service life. The number of significant pressure fluctuations will be monitored on an annual basis from pressure records in the DCS (distributed control system).

Fatigue failure of pipework and small-bore fittings at the LVI is also a threat. This has been assessed on an item-by-item basis using Industry guidelines, and the necessary supports and modifications will be implemented when the LVI is constructed.

4.4.3 Pressure sheath failure

The PVDF (Polyvinylidene Fluoride) pressure sheath material of the flexible pipelines can pull out from the end fitting due to leaching of the plasticizer during service. In accordance with current industry practice to avoid this type of failure, the PVDF in the pipe at the end fittings has been subject to a deplasticizing operation prior to assembly. The end fittings and flexible pipe have been designed and manufactured for the full design temperature range.

5 CORROSION MITIGATION

5.1 INTERNAL BARRIERS

To mitigate internal corrosion of the pipeline the primary barrier is corrosion inhibitor delivered continuously in the methanol to the injection points in the subsea wellheads and manifold via the umbilical. The methanol also provides a degree of corrosion protection. Corrosion resistant materials have been selected for all areas where protection by corrosion inhibitor cannot be assured.

As a secondary barrier the carbon steel pipeline has been provided with a corrosion allowance which varies along the length. Should this corrosion allowance be consumed, a corrosion damage assessment will be carried out to confirm the continued technical integrity of the pipeline. A procedure for corrosion damage assessment has been developed using the DNV RP F-101 methodology (see Appendix Q4.8). Corrective actions for sections of corroded pipeline will be included in the Pipeline Integrity Management Scheme (PIMS - see Appendix Q5.2).

5.2 EXTERNAL BARRIERS

To mitigate external corrosion of the pipeline the primary barrier is a robust coating of either, a combination of asphalt enamel and concrete weight coating, or a 3 layer polypropylene coating. The field joints use a standard shrink sleeve system. For the onshore pipeline an additional epoxy primer will be used under the shrink sleeve.

As a secondary barrier to external corrosion should the coating be damaged, the pipeline is protected by a cathodic protection system. The offshore pipeline is protected by sacrificial aluminium anodes. The LVI and onshore pipeline are protected by an impressed current system. A cathodic potential of –850mV versus $Ag/AgCl_2$ reference electrode is required to ensure protection of carbon steel for aerobic conditions and –950mV for anaerobic conditions.

Assessment of external corrosion damage and corrective actions will be covered by the same procedures as above.

6 CORROSION INHIBITION

Corrosion inhibition is the primary internal barrier for the carbon steel pipeline. A robust and effective corrosion inhibitor and application regime is essential in order to meet the pipeline design life and maximise life cycle value.

6.1 CORROSION INHIBITOR SELECTION

The selected corrosion inhibitor will be carried by the methanol and needs to be fully compatible.

Enterprise Ireland originally ranked a number of different products from vendors but following a Shell review, a new qualification criteria matrix was developed to capture issues not considered previously, including aromatic accumulation in the regenerated methanol, presence of formation water, and presence of oxygen scavenger.

Corrosion inhibitor qualification work will address functional performance (ability to inhibit corrosion) at the specific operating conditions of the Corrib production system, and compatibility with all aspects of the production system including the onshore produced water treatment process. Qualification work is ongoing and a suitable inhibitor has been identified. Testing will be completed by Q3 2010.

6.2 CORROSION INHIBITOR AVAILABILITY

A corrosion inhibitor availability of 99% is required to ensure that the design life of the pipeline is met. A spare pump has been provided at the Terminal to ensure that this availability target is achievable.

The specified corrosion inhibitor availability of 99% allows a cumulative inhibitor downtime of 4 days per year. Additional qualification work is underway to determine the persistency of the chosen inhibitor to assess how long it will be able to protect the pipeline after an interruption in corrosion inhibitor application. Extended periods with low inhibitor levels could lead to inhibitor breakdown and potential for higher corrosion rates, especially at the offshore pipeline inlet. This will be reflected in the guidelines for the inhibitor application that will be included in the Corrib pipeline operating manual which will be available prior to commissioning. This will clearly state what action to take if corrosion inhibitor is not available at the required level.

The Production Chemist will define the corrosion inhibitor injection rates based on the corrosion inhibitor test results. The corrosion inhibitor will be applied continuously from the beginning of production to ensure good filming of the inhibitor in the pipeline during start-up.

7 PIPELINE CORROSION MONITORING REQUIREMENTS

It has been shown that corrosion threats can be successfully mitigated. Corrosion monitoring is also required to verify that these mitigations are effective.

7.1 INTERNAL

7.1.1 Corrosion monitoring philosophy

As previously discussed the effective application of corrosion inhibitor is essential to reduce and manage corrosion of a carbon steel pipeline. To monitor the effectiveness of this application a comprehensive corrosion monitoring system is required. The aim of this monitoring system is two-fold:

1. To flag the breakdown of the inhibitor application in the pipeline; and
2. To provide corrosion rate data.

The primary means of corrosion monitoring is a subsea FSM spool welded into the pipeline tie-in spool at the Corrib field. This will be supplemented by additional corrosion monitoring, chemical sampling and wall thickness measurements at the onshore Terminal and LVI, as part of a coordinated approach to corrosion management.

A high confidence in the corrosion monitoring data will allow more flexibility in determining requirements for intelligent pigging.

7.1.2 Field Signature Monitor (FSM) spool

The deepwater FSM is powered with a hard-wired link from the subsea control module (SSCM), which is powered from the umbilical electrical supply.

The FSM will detect sudden changes in corrosivity due to breakdown of the corrosion inhibitor application, by providing corrosion rate data around the circumference of the pipe over a length of circa 1 metre. The sensitivity of the system can be determined by setting the time between measurements, in accordance with operational requirements. This will be set initially to one set of measurements per hour.

The FSM will be located in the longest section of the 20” pipeline tie-in spool. This location has been chosen because it is sufficiently downstream of the inhibitor injection point to have steady state flow conditions, and it is at the warm end of the pipeline and is therefore likely to experience a higher corrosion rate than the rest of the pipeline.

The required heat transfer coefficient (U) value for the FSM is 70 W/m^2K. This matches the maximum U value for the first 28 km of the pipeline at the Corrib end. Therefore the conditions at the FSM will replicate those in the pipeline.

7.1.3 FSM Corrosion data handling

Once installed and commissioned, the FSM will have analogue and digital output. The analogue output will consist of spool temperature, maximum corrosion rate, average corrosion rate, and accumulated metal loss. The digital output will consist of the individual FSM pin-pair corrosion measurements and associated data.

A direct link will be installed from the MCS (Master Control Station) to the Plant Instrumentation (PI) system to allow remote real time interrogation. The digital data will be downloaded each month and sent to the FSM contractor for analysis and reporting.

The Terminal Control Room will advise the asset corrosion engineer of any corrosion rate alarms. The corrosion rate alarms will initially be set at 0.2mm/yr (H) and 0.4mm/yr (HH) and will be reviewed if instrument noise causes erroneous alarm events. Each of these alarms will have an individual Tag number.

7.1.4 Onshore corrosion monitoring

An ultrasonic “fleximat” which allows continuous monitoring of the wall thickness around the circumference of the pipe will be installed on the 20” pipeline upstream of the pigging tee at the Terminal. In addition an electrical resistance probe will be installed in the 20” pipe downstream of the pigging tee before the slugcatcher. The conditions at these points with respect to pressure, temperature, flow rate and acidity will be identical to those in the onshore pipeline and will therefore give a representative indication of the corrosivity of the fluids in the onshore pipeline.

Additional wall thickness measurements on the above ground section of 20” pipeline at the Terminal will be defined and included in the PIMS.

7.1.5 Sand monitoring

A ‘Clamp-on’ acoustic sand-monitoring device has been mounted on the subsea manifold. It will monitor gross flow from all wells and detect any solids production. The device will provide a 4-20mA signal which will be calibrated and captured in the PI system. An alarm setting will be defined during commissioning of the pipeline system.

7.2 EXTERNAL

7.2.1 Coating condition

The integrity of offshore coating systems will be monitored for the non-buried sections of the pipeline by regular ROV (remote operated vehicle) surveys as defined in the PIMS (see Appendix Q5.2). For buried sections of the offshore line and for the onshore pipeline any coating breakdown will be detected through the cathodic protection monitoring surveys.

7.2.2 Offshore cathodic protection system

Monitoring of the cathodic protection of the offshore pipeline can be achieved for the non-buried sections by ROV inspection of anode consumption, stabbing of the anodes to measure potential, and measurement of potential at any exposed sections (manifold and PLEM), although inspection which disturbs the carbonaceous deposits created by cathodic protection will be avoided where possible. Potential surveys (e.g. trailing wire) will be carried out for both buried and non-buried sections to assess the performance of the cathodic protection system and to identify any anomalies. An offshore cathodic protection inspection and maintenance plan will be defined in the PIMS.

7.2.3 Onshore cathodic protection system

The onshore impressed current system will be monitored through checks on the transformer/rectifier up-time and output, standard test posts and coupon polarisation probes, close interval potential surveys (CIPS) and direct voltage current gradient (DCVG) surveys. The cathodic protection design for the section of onshore pipeline in the tunnel will include cathodic protection monitoring facilities.

Particular attention is required for the interface between the offshore and onshore pipelines to ensure that there is no current drain from the offshore pipeline anodes to onshore. Following a detailed assessment it was concluded that the installation of an isolation joint between the offshore and onshore pipeline was not necessary, but potential monitoring coupons/probes will be installed close to the LVI to allow potentials to be accurately measured. This satisfies the recommendation of the Advantica Independent Safety Review (see Appendix Q3.1). An isolation spool is fitted between the onshore pipeline and the Terminal facilities and this will be subject to monitoring to assure isolation and absence of any degradation.

An onshore cathodic protection inspection and maintenance plan will be defined in PIMS.

7.3 SAMPLING

Facilities have been provided at the onshore Terminal to permit regular sampling of the residual inhibitor concentrations. These samples should be taken on a frequent basis during the first 30 days of production and at monthly intervals thereafter. The feasibility of this sampling is dependent on the actual water cut and will be determined by the Asset Production Chemist. The derivation of the field partitioning of corrosion inhibitor during the initial phase of operation will provide useful information concerning the dosage rate. Ferrous ion, bicarbonate, chloride concentrations and pH is normally determined on a monthly basis. Monitoring of CO_2 and H_2S will be done on regular basis. The actual frequency of this sampling will be defined by the Asset Production Chemist and subsequently included in the PIMS.

8 OTHER PIPELINE REQUIREMENTS

8.1 PIPELINE PRE-COMMISSIONING & COMMISSIONING

To minimise the possibility of debris remaining after construction, the pipeline will be cleaned prior to commissioning by successively pushing several cleaning pigs with steel brushes through the pipeline.

It is likely that the offshore and onshore pipelines will be commissioned separately.

8.2 OPERATIONAL PIGGING

The requirement for running cleaning pigs through pipelines to remove deposits such as wax, corrosion products, scale or sand is dependent on the likelihood of accumulation of such deposits at the bottom of the pipeline that can cause localised shielding of the corrosion inhibitor and possible CO_2 corrosion.

Pipelines operated at velocities above ~1.5m/s have a low likelihood of suffering from sand and debris accumulation because the sand and debris stay in suspension. The mixture velocities for the 20" pipeline are predicted to remain above 4m/s and therefore the accumulation of deposits including proppant is unlikely. Wax and scale formation are not expected in the Corrib fluids. Sand and proppant production is not expected, but will be monitored.

There is no requirement to run a pig through the pipeline to distribute the corrosion inhibitor because it will be well dispersed by the flow.

Based on these premises operational pigging is not expected to be required for corrosion control reasons during the current field life of the pipeline.

A subsea temporary pig launcher has been fabricated and can be connected to the subsea manifold in case operational pigging becomes necessary for any reason. The Terminal has a pig receiver.

8.3 INTELLIGENT PIGGING

The Corrib pipeline will be inspected with an intelligent pig during commissioning (onshore pipeline) and at subsequent intervals as determined by Risk Based Assessment as defined within the PIMS (see Appendix Q5.2). The intelligent pig will likely be a combination of a magnetic flux leakage module (MFL) and a high resolution geometry (XGP) module with a shallow internal corrosion (SIC) detection unit. This type of intelligent pig system has been run in the Ormen Lange 30"x35mm pipelines in Norway. The XGP/SIC pig has been run in the Gannet-Fulmar pipeline in the U.K.

9 DESIGN RE-ASSESSMENT

In addition to the periodic pipeline integrity assessments a formal re-assessment of the design premises with respect to the effect of actual operating conditions on corrosion management will be conducted after three to six months operation and again if significant formation water occurs. This assessment will confirm whether there are any significant divergences between design and actual data in terms of fluid compositions, corrosion inhibitor performance, corrosion monitoring data, and process conditions.

10 REFERENCES

1. ISO 15156 Petroleum and natural gas industries - Materials for use in H2S containing environments in oil and gas production.

2. ISO/FDIS 21457 Petroleum, petrochemical and natural gas industries - Materials selection and corrosion control for oil and gas production systems.

3. UKOPA Pipeline Fault Database – Pipeline Product Loss Incidents 1962 – 2004. April 2005.

4. DNV RP F-112: Design of duplex stainless steel subsea equipment exposed to cathodic protection.

5. BS 7910 Guide to methods for assessing the acceptability of flaws in metallic structures, 2007.

6. BS 7448-2 Fracture mechanics toughness tests Part 2, 2007.

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Q4.8 - Corrib onshore pipeline - assessment of locally corroded pipe wall area

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Corrib onshore pipeline - assessment of locally corroded pipe wall area

by

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M. Church

Summary

The recommended practice DNV RP F101 for the assessment of corroded pipelines has been used to generate damage assessment lines (graphs of the length versus depth of corrosion that would lead to failure at the Maximum Allowable Operating Pressures (MAOP)) for the evaluation of the potential for failure of local thinned area of pipe wall due to corrosion.

The results show that there is a significant margin of safety with respect to thinning of the pipe wall due to corrosion. This is due to the relatively low maximum allowable operating pressures, 150 barg upstream of the LVI and 100 barg downstream, and relatively large wall thickness.

The output from this study also provides input to support the selection of corrosion related failure frequencies within the Quantitative Risk Assessment

Amsterdam, May 2010

Table of contents

1. Introduction

This report describes the results of an evaluation of localised corrosion on the integrity for the landfall section upstream of the LVI and the 8.3 km downstream of the LVI to the onshore terminal.

2. Objective

Corrosion inhibitor will be injected at the subsea manifold and wellheads to control the corrosion in the pipeline, negligible corrosion is expected in the onshore section. The pipeline will be protected externally with a coating and cathodic protection system. The pipeline has a 1 mm corrosion allowance.

The objective of this study is to assess the influence of localised wall thinning due to corrosion on the integrity of the pipeline and determine the margin of thinning to the point where pipeline failure would lead to loss of containment (at MAOP).

The output from this study provides input to support the selection of corrosion related failure frequencies within the Quantitative Risk Assessment

3. Design conditions and operating conditions

The primary design code is I.S. EN 14161 [1] with I.S. 328 [2] and BS PD 8010 [3] as the back-up codes (I.S. 328 has priority over PD 8010).

The landfall section of the offshore pipeline and the onshore section (8.3 km) are designed with a nominal outside diameter of 508 mm (20”) and a nominal wall thickness of 27.1 mm. The line pipe was delivered to DNV OS-F101 SAWL 485 II FD. The pipes have a Submerged Arc Welded Longitudinal seam weld.

The nominal wall thickness of 27.1 mm comprises 25.1 mm for pressure containment, 1 mm mill tolerance and 1 mm corrosion allowance.

The design and operating conditions are listed in Table 1.

Table 1 *Design and operating conditions*

		Design & Maximum Allowable Operating Pressure (MAOP) condition	Operating condition (based on 350 mmscf/d & 85 barg terminal arrival pressure)
Upstream LVI (offshore pipeline)	Pressure	Design: 345 barg MAOP: 150 barg	122 barg at the pipeline inlet (subsea manifold).
	Temperature	0 °C upstream of the LVI	60 °C at the pipeline inlet located downstream of subsea manifold. 2 to 10 °C landfall section.
LVI	Pressure	Design: 345 barg MAOP: 150 barg	90 barg at the LVI
	Temperature	Landfall shutdown spool (16” pipeline section): -26 °C Landfall mainline section (20” pipeline section): -20 °C	2 to 10 °C
Downstream LVI (onshore pipeline)	Pressure	Design: 144 barg MAOP: 100 barg	90 barg at the LVI. 85 barg at the terminal inlet.
	Temperature	-20 °C from LVI to 1150m downstream of the LVI. -10 °C from 1150m downstream of the LVI to the terminal.	2 to 10 °C

4. Material properties

The pipes for the pipeline were purchased in two batches. The major part of the line pipe was fabricated in 2002 by the Corus 42" mill in Hartlepool. The 27.1 mm line pipe is fabricated using Dillinger Hutte (DH) plate. An additional 1150 m of pipes was fabricated in 2009 by Eisenbau Krämer. To distinguish between the two batches these are referred to as '2002 line pipe' and '2009 line pipe' in this report.

The line pipe specified minimum yield strength is 485 MPa (605 MPa maximum) and the specified minimum tensile strength is 570 MPa (760 MPa maximum).

5. Assessment of corroded areas

The maximum allowable size of a local area of wall thinning due to corrosion is calculated on the basis of recommended practice DNV-RP-F101 [4] for the assessment of corroded pipelines.

5.1 Approach

DNV-RP-F101 gives a procedure to determine the safe working pressure (P_{sw}) for a pipe containing a Local Thinned Area (LTA) e.g. due to corrosion. The procedure is used to construct an assessment diagram to assess the significance of a local thinned area. The method to construct the damage assessment diagram is given below. First the failure line will be constructed and secondly a safe working line will be constructed.

5.1.1 Construction failure line

The operating pressure ($P_{operating}$) can be written as follows:

$$P_{operating} = f_{operating} \frac{2t(SMYS)}{(D-t)}$$

$f_{operating}$ = Operating factor
D = Outer diameter pipe (mm)
t = Nominal wall thickness pipe (mm)
$SMYS$ = Specified Minimum Yield Strength (MPa)

Note:
When the operating pressure is equal to the design pressure the factor $f_{operating}$ is equal to the pipeline design factor.

The failure pressure (P_{fail}) of a pipe containing an LTA is given by:

$$P_{fail} = \frac{2t(0.9)(SMTS)}{(D-t)} \frac{\left(1-\frac{d}{t}\right)}{\left(1-\frac{d}{Qt}\right)}$$

$$Q = \sqrt{1+0.31\left(\frac{l}{\sqrt{Dt}}\right)^2}$$

D = Outer diameter pipe (mm)
t = Nominal wall thickness pipe (mm)
l = Axial length of the LTA (mm)
$SMTS$ = Specified Minimum Tensile Strength (MPa)

Failure is predicted when the operating pressure is equal to the failure pressure,

$$P_{operating} = P_{fail}$$

or

$$\frac{\left(1 - \frac{d}{t}\right)}{\left(1 - \frac{d}{Qt}\right)} = f_{operating} \frac{SMYS}{(0.9)(SMTS)}$$

5.1.2 Construction safe working line

The safe working pressure (P_{sw}) of a pipe containing an LTA is given by:

$$P_{sw} = f \frac{2t(0.9)(SMTS)}{(D - t)} \frac{\left(1 - \frac{d}{t}\right)}{\left(1 - \frac{d}{Qt}\right)}$$

$$Q = \sqrt{1 + 0.31 \left(\frac{l}{\sqrt{Dt}}\right)^2}$$

f = Design factor (-)
D = Outer diameter pipe (mm)
t = Nominal wall thickness pipe (mm)
l = Axial length of the LTA (mm)
$SMTS$ = Specified Minimum Tensile Strength (MPa)

The safe working condition is determined when the operating pressure is equal to the failure pressure,

$$P_{operating} = P_{sw}$$

or

$$\frac{\left(1 - \frac{d}{t}\right)}{\left(1 - \frac{d}{Qt}\right)} = \left(\frac{f_{operating}}{f}\right) \frac{SMYS}{(0.9)(SMTS)}$$

Note: The operating factor $f_{operating}$ is less than or equal to the design factor f.

5.2 Results

Assessment lines have been constructed for the following conditions.

- Operating at a MAOP.
- Design pressure conditions.
- To show the margin to failure, the failure lines are also plotted.

Table 2 *Design and maximum allowable pipeline operating conditions*

Location	Design pressure	MAOP
Upstream including LVI	345 barg	150 barg
Downstream LVI	144 barg	100 barg

The assessment line for the section upstream to the LVI is plotted in Figure 1 and for the section downstream of the LVI in Figure 2.

The assessment lines for the design pressure are shown in Figures 3 and 4. Comparison with assessment lines for operation at the MAOP shows that the margin before corrosion would become critical is significantly increased by lowering the MAOP.

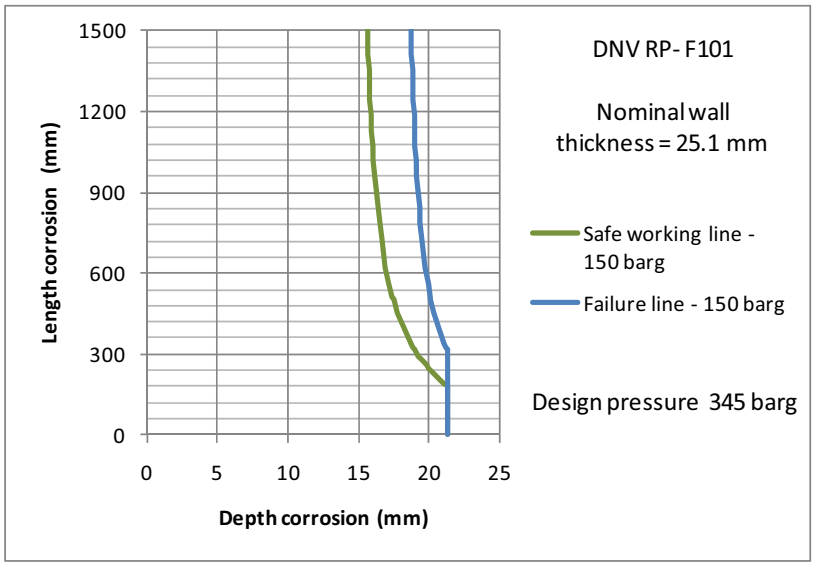

Figure 1 *Upstream LVI: 150 barg MAOP*

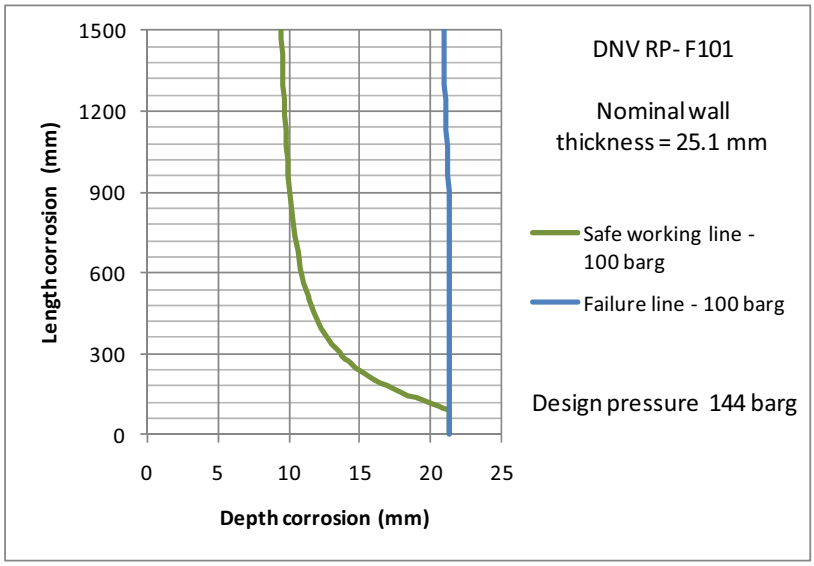

Figure 2 *Downstream LVI: 100 barg MAOP*

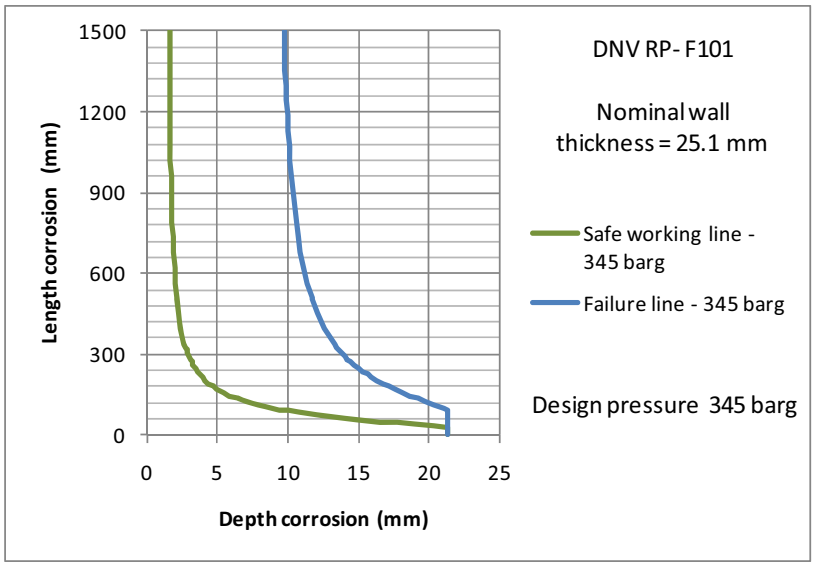

Figure 3 *Upstream LVI: Design pressure of 345 barg*

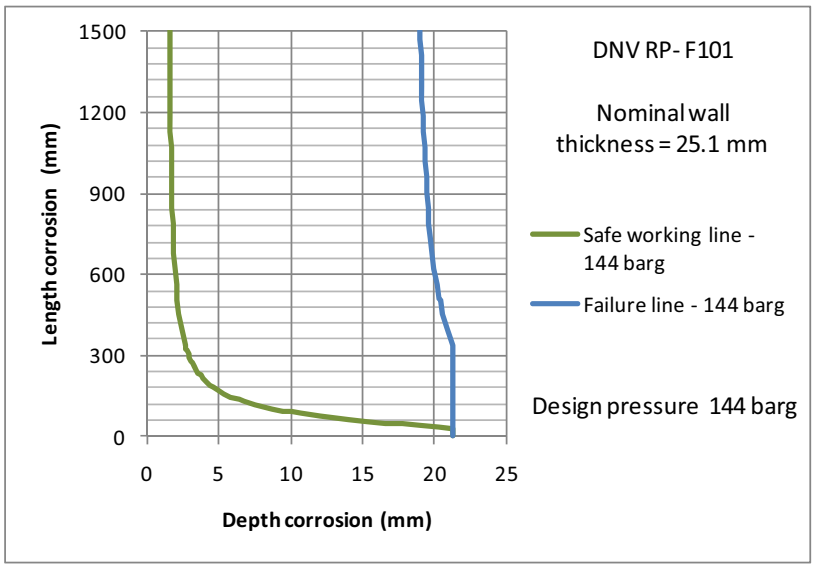

Figure 4 *Downstream LVI: Design pressure of 144 barg*

6. Discussion

6.1 Conservatism of the assessment

Assessment lines have been developed for the assessment of local thinned areas. The assessment lines have been determined using the minimum specified tensile properties. This is conservative since a higher tensile strength would increase the failure stress and, therefore, the margin for corrosion.

The ultimate tensile strength values taken from the material test certificates have been plotted in Figure 5, which confirms that the actual Ultimate Tensile Strength (UTS) is much higher than the specified minimum.

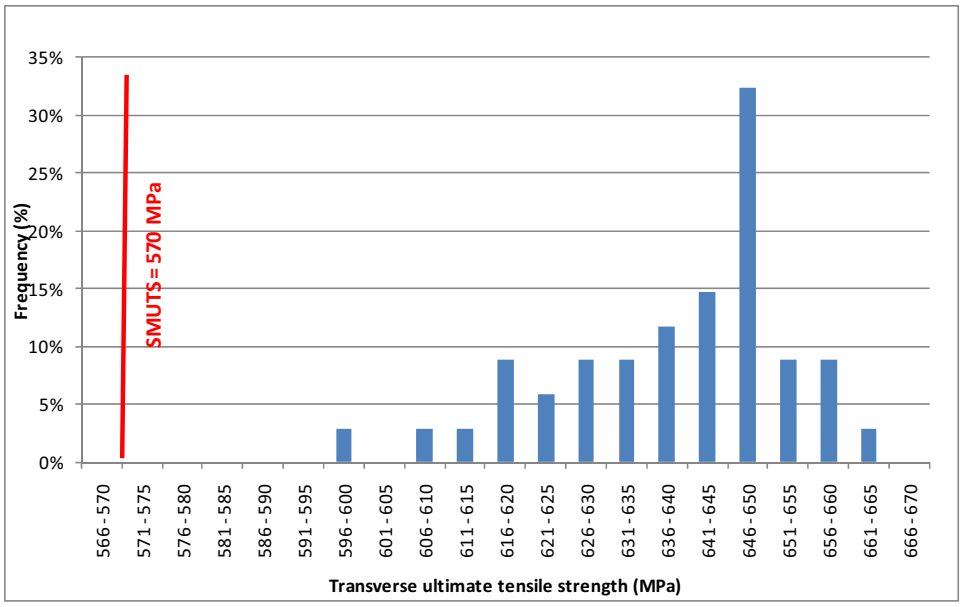

Figure 5 *Ultimate tensile strength distribution*

The assessment lines have been calculated for the maximum allowable operating pressures. The actual operating pressures are 122 barg at the pipeline inlet (versus MAOP of 150 barg) upstream of the LVI and 85-90 barg (versus MAOP of 100 barg) downstream of the LVI. This gives an additional margin of safety.

6.2 Explanation of the damage assessment diagrams

The corrosion assessment lines are plotted in Figures 1 to 4. A local thinned area due to corrosion that is below/left of the green line would be acceptable. A local thinned area that is above/right of the blue line is not acceptable because failure is predicted. A local thinned area that is in between the green and the red line is not acceptable, although failure is not yet predicted. A remedial action would be required in such a case, e.g. reduction of pressure or repair.

7. Conclusions

The recommended practice DNV-RP-F101 for the assessment of corroded pipelines has been used to generate damage assessment lines for the evaluation of a local thinned area due to corrosion.

The results show that the margin before corrosion would become critical is very significant. This is due to the relatively low maximum allowable operating pressures, 150 barg upstream of the LVI and 100 barg downstream, and relatively large wall thickness.

8. References

1 I.S. EN 14161:2004 Petroleum and Natural Gas Industries – Pipeline Transportation Systems.
2 I.S. 328:2003 Code of practice for gas transmission pipelines and pipeline installations.
3 BS PD 8010-1:2004 Code of Practice for Pipelines – Part 1: Steel Pipelines on Land.
4 Recommended practice DNV-RP-F101, Corroded pipelines, October 2004.

Amsterdam, May 2010
qts

SHELL E&P IRELAND LIMITED

CORRIB GAS FIELD DEVELOPMENT PROJECT

Corrib
natural gas

Q4.9 Assessment of Wet Gas Operation, Internal Corrosion and Erosion

DOCUMENT No: COR-39-SH-0011

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ATTACHMENTS

1 PURPOSE AND SCOPE

This document provides an assessment of wet gas operation and the related internal corrosion and erosion rates for the offshore and onshore sections of the Corrib pipeline from the subsea manifold to the Terminal. This assessment has been undertaken with the most recent flow assurance data related to the lower maximum allowable operating pressures and therefore the predicted corrosion rates differ from previous versions of this document. The corrosion assessment is based on a field life of 20 years.

2 FUNDAMENTALS OF WET GAS OPERATION

2.1 MECHANISMS

The integrity of a carbon steel pipeline with respect to corrosion requires a thorough assessment of the corrosivity of the medium transported and the implementation of an effective corrosion management system. This involves identifying all possible degradation threats and defining mitigation, monitoring and control measures to manage the risk during operation. The main internal corrosion risks identified in the assessment of the Corrib pipeline system are carbon dioxide (CO_2) corrosion and organic acid corrosion associated with unprocessed (wet) gas (see Appendix Q4.7).

CO_2 corrosion can occur when carbon dioxide dissolves in water to form carbonic acid which is corrosive to steel. Water will be present in the pipeline either through condensation from the gas or it may be produced as formation water from the reservoir. The higher the content of CO_2, the greater is the corrosivity of the water. It should be noted that the CO_2 content of the Corrib gas is relatively low at 0.3%. Other key factors that increase CO_2 corrosivity are increases in pressure, temperature, flow rate or acidity.

The acidity (pH) is an important factor with respect to CO_2 corrosion. Modelling, testing and experience has shown that CO_2 corrosion increases the tendency for saturation of iron carbonate in condensed water. This results in a corresponding decrease in acidity and a significant decrease in corrosivity along the pipeline from offshore to onshore. There is also a significant temperature drop along the pipeline further decreasing the corrosivity in the onshore section of the pipeline.

Organic acids such as acetic acid can be present in the produced fluids potentially increasing corrosivity. The organic acid content of the Corrib gas has been found to relatively low (maximum 10ppm) although 100ppm is expected should formation water be produced.

2.2 CORROSION MITIGATION

In order to mitigate internal CO_2 and organic acid corrosion of steel it is common practice to inject corrosion inhibitor which forms a barrier against the corrosive liquids. Another method is to inject glycol or methanol which are miscible with the corrosive water and further reduce the corrosivity. For the Corrib pipeline the risk of CO_2 and organic corrosion will be mitigated by injecting both corrosion inhibitor and methanol (which is also used to prevent formation of hydrates in the pipeline). To ensure that sufficient corrosion mitigation is achieved for the pipeline, a corrosion inhibitor availability capability of >99% has been designed for the Corrib system.

2.3 WET GAS EXPERIENCE

The current approach taken by Shell to the design and operation of carbon steel pipelines in wet gas service was defined in the late 90's following an extensive review of operating experience of wet gas pipelines [1]. The methodology ensures that key factors are taken into account during design and that corrosion control is properly applied during operation. It adopts the concept of inhibitor availability based on inhibited corrosion rate rather than inhibitor efficiency as previously applied by the industry.

The availability concept was derived from the comparison of actual field corrosion rate data from intelligent pig runs in inhibited wet gas pipelines compared to that predicted by the Shell proprietary corrosion model at the time using inhibitor efficiency. The results (Table 2.1 and Figure 2.1) show that significantly lower corrosion rates than predicted were observed in these wet gas pipelines, which are operated at relatively high temperatures and highly corrosive conditions.

This philosophy was originally implemented using a 90 to 95% inhibitor availability (which is reflected by slightly higher measured corrosion rates than would be expected today), but with increasing experience and improved reliability of injection equipment, a 99% inhibitor availability with even lower corrosion rates is now achievable.

Table 2.1: Data for operating conditions and corrosion rates (CR) for inhibited wet gas pipelines (1998)

Pipeline	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**
Service	Onshore Wet Gas	Onshore Wet Gas	Offshore Wet Gas	Offshore Wet Gas	Offshore Wet Gas	Offshore Wet Gas	Offshore Wet Gas	Offshore Wet Gas	Offshore Wet Gas
Start-up date	1989	1989	1990	1987	1991	1978	1969	1970	1971
Inspection date	1994	1993	1993	1994	1994	1990	1984	1981	1982
Pressure bar	148	80	60	62	100				
CO2 mole%	0.46	1	0.46	0.6	3				
CO2 pressure, bar	0.7	0.8	0.28	0.37	3	0.7	0.6	2.5	1.8
Temp °C	65	50	50	53	80	60	49	57	103
Predicted uninhibited CR, mm/yr	1.98	2.27	1.89	2.54	11.8	3.2	1.8	6.3	8.9
CR with 85% inhibition, mm/yr	0.3	0.34	0.28	0.38	1.7	0.48	0.27	0.95	1.34
Measured CR, mm/yr	0.2	0.2	0.64	0.35	0.13	0.25	0.27	0.27	0.27

Note that the high value of 0.64 is related to the intelligent pig accuracy at the time and has since been shown to be <0.2mm/yr

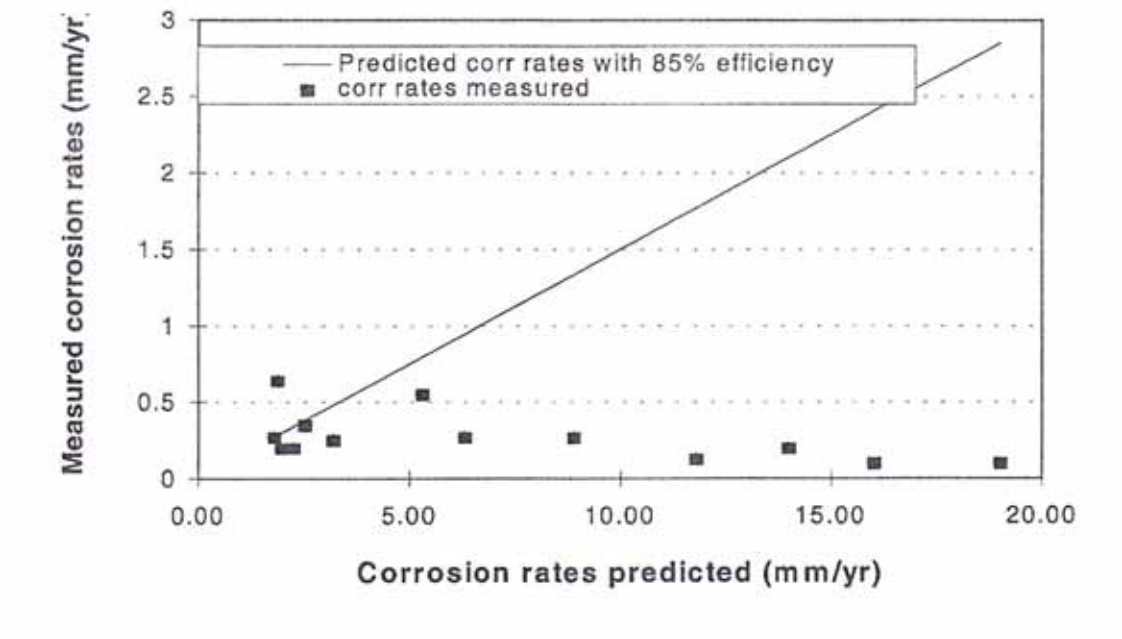

Figure 2.1: Comparison of predicted corrosion rate with 85% inhibitor efficiency versus field inspection data for inhibited wet gas pipelines

A more recent overview of wet gas pipelines operated in the Shell Group is given in Attachment Q4.9A. This shows extensive experience of successful operation of wet gas pipelines. In many cases the performance of the inhibited pipeline systems with respect to corrosion has been verified by internal intelligent pig inspection or external ultrasonic examination. No failures of wet gas pipelines have been experienced with these pipelines, and the observed low corrosion rates demonstrate both the validity of the corrosion modelling and the methodology adopted for the operation of wet gas pipelines. The total Shell experience with operation of wet gas pipelines in Europe without a loss of containment incident amounts to 40,384 km years, which provides a high degree of confidence in Shell's capability with this type of operation.

It should also be recognised that the Corrib onshore pipeline operating conditions are inherently less corrosive than many of the pipelines in the overview due to the low temperature and lower acidity. In addition the inhibitor availability is designed for >99% compared to 95% that has been used in the past, and mitigation will be enhanced by the complementary inhibitive effect of methanol.

3 CORROSION ASSESSMENT

The corrosion assessment for the Corrib pipeline has used the Shell HYDROCOR (version 6.00) corrosion modelling software which has been enhanced over many years of development [2-6] from the original De Waard-Milliams relationship for CO_2 corrosion [2] which is used as the basis for industry standards. For the Corrib conditions with relatively low water throughput the model tends to over-predict the corrosion by as much as 25%.

The production profiles used in the assessment have been derived from the most recent flow assurance calculations undertaken by the Shell process discipline Technical Authority related to the lower maximum operating pressure, and a 20-year production scenario.

3.1 KEY ASSUMPTIONS

The following are the key assumptions used in the corrosion assessment:

1. Water rate = Water Gas Ratio (WGR) × Gas Rate. The water that condenses in the sub-sea equipment prior to the pipeline inlet is included in the aqueous phase input.

2. The peak methanol injection rate required is 2.2 m^3/h (or 53 m^3/d). This occurs in year 3. The minimum rate is 0.5 m^3/h. This analysis has assumed the peak methanol injection rate for all years. The actual amount of methanol will vary from this amount depending on operational analyses. The methanol will be injected at the wellheads and will mix with any water.

3. Aqueous rate = Water rate + Methanol rate.

4. Condensate flow = Condensate Gas Ratio (CGR) × Gas Rate.

5. The highest expected pipeline inlet temperature is 75°C. This is the assumption used as the base case. The pipeline inlet temperature has also been modelled at 60°C as a less conservative sensitivity case.

6. It is assumed there will be no oxygen in the methanol as a result of removal in the Terminal.

3.2 PRODUCTION PROFILE

The production profile from the latest flow assurance review is given in Table 3.1 below.

Table 3.1: Production Profiles for pipeline inlet conditions

	Pipeline Inlet Pressure	Peak Gas Flow	Condensate Flow	Aqueous Flow (incl. 53 m^3/d MeOH)
Year	barg	mln Sm3/d	m^3/d	m^3/d
1	122	10.19	3.1	103.0
2	122	10.19	3.1	103.0
3	120	10.19	3.1	142
4	88	7.62	2.07	118.8
5	78	5.89	0.32	93.1
6	72	4.70	0.32	90.5
7	63	3.96	0.32	88.3
8	54	3.37	0.32	88.0
9	48	2.89	0.32	87.0
10	42	2.52	0.32	86.9
11	36	2.24	0.32	87.5
12	29	1.98	0.32	87.7
13	24	1.73	0.32	88.5

Years 14 to 20 are assumed to be the same as Year 13.

3.3 DESIGN LIFE

The pipeline has an overall design life of 30 years. The operating field life is anticipated to be approximately 20 years. This corrosion assessment is based on a field life of 20 years but it is anticipated that the design life is achievable if required.

3.4 HYDROCOR INPUT DATA

The following input data were used with HYDROCOR for the assessment to predict the internal corrosion rates:

- CO_2 content of the gas = 0.3 mole%
- H_2S (hydrogen sulphide) content of the gas is 0.1 ppm v/v (no effect on corrosion in the pipeline)
- Pipeline inlet temperature = 75ºC with 60ºC used as a sensitivity calculation
- Ambient Temperature = 10ºC
- Condensed water properties:

    100 ppm chlorides

    5 ppm bicarbonates

    10 ppm organic acids

- Formation water properties for the sensitivity study

    197,000 ppm chloride

    5 ppm bicarbonates

    100 ppm organic acids

- Corrosion inhibitor availability (three cases considered were 0%, 95% and 99%).
- Alcohol types = methanol
- Alcohol concentration = 87%.
- Pipeline internal diameter = 0.457m
- Total pipeline length = 92.3 km
- Pipeline elevation is shown in Attachment Q4.9E.

4 CALCULATED CORROSION RATES

4.1 OFFSHORE PIPELINE BASE CASE

The following assumptions were used for the base case calculations:

(i) Pipeline inlet temperature is 75ºC.

(ii) No formation water is produced (this is a reasonable assumption because operation with formation water could lead to water handling issues, and would be mitigated by well control or re-completion).

The predicted corrosion rates are given in Table 4.1 and Figure 4.1 below. The expected flow regime is annular dispersed for the full field life so BOL (Bottom of the Line) corrosion can occur at any point around the circumference.

Table 4.1: Maximum CO_2 Corrosion rate (mm/yr) for Corrib Offshore Pipeline: Bottom of the Line (BOL) and Top of the Line (TOL) for 0%, 95% and 99% corrosion inhibitor availabilities

Corrosion rate	Year												
mm/yr	1	2	3	4	5	6	7	8	9	10	11	12	13+
BOL CI 0%	0.77	0.77	1.33	0.84	0.45	0.39	0.33	0.29	0.26	0.24	0.22	0.2	0.18
TOL CI 0%	0	0	0	0	0	0	0	0	0	0	0	0	0
BOL CI 95%	0.09	0.09	0.11	0.09	0.07	0.07	0.06	0.06	0.06	0.06	0.06	0.06	0.06
TOL CI 95%	0	0	0	0	0	0	0	0	0	0	0	0	0
BOL CI 99%	0.06	0.06	0.06	0.06	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
TOL CI 99%	0	0	0	0	0	0	0	0	0	0	0	0	0

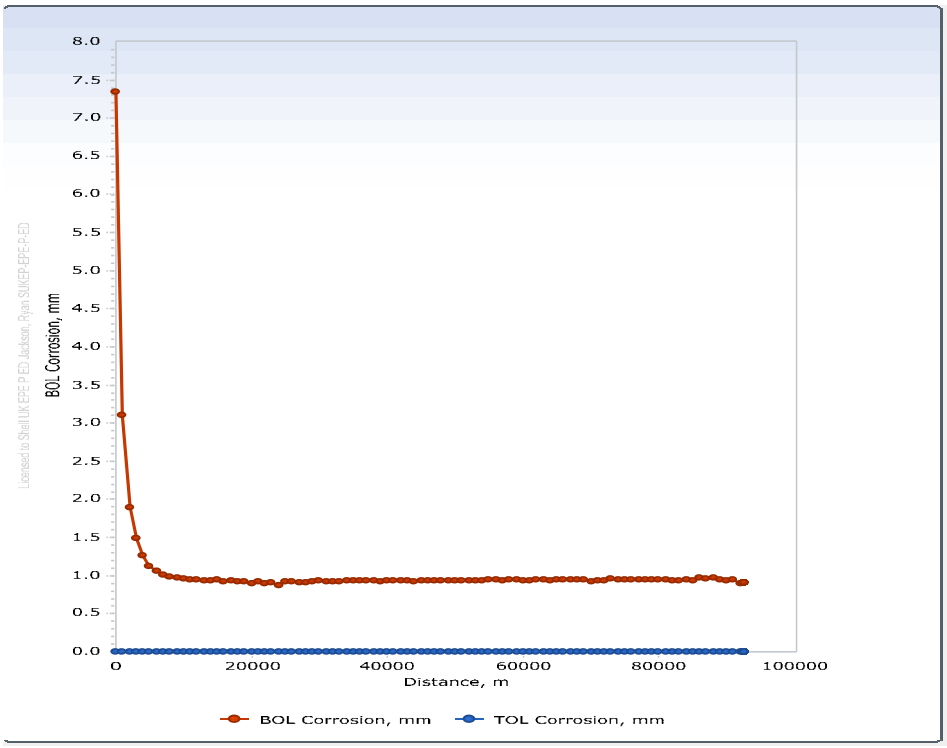

Figure 4.1: Accumulated uninhibited CO_2 Corrosion (mm) for the Corrib Pipeline for 20 year field life: Bottom of the Line (BOL) and Top of the Line (TOL)

Typical output screens are given in Attachments Q4.9B – Q4.9D. It can be seen that the predicted corrosion rates decrease with:

(i) decreasing fluid temperature along the pipeline away from Corrib towards the Terminal

(ii) decreasing production in later years.

The maximum uninhibited corrosion rate of the offshore pipeline occurs in year 3 and is approximately 1.3 mm/yr. The increase in corrosion rate in year 3 is related to the higher liquid loading. The cumulative uninhibited wall loss over 20 years is approximately 7.5 mm. The location of the maximum corrosion will be within the first 400 metres from the pipeline inlet where additional wall thickness in the design provides a greater corrosion allowance (refer Table 4.2). However, this corrosion allowance will not be exceeded because the pipeline will be operated with corrosion inhibitor. Similarly, the corrosion allowance around 2.5km is insufficient for the uninhibited corrosion rate at this point but will not be exceeded because of the corrosion inhibition.

Table 4.2: Corrib Pipeline Corrosion Allowance

Distance from Corrib (km)	Corrosion Allowance (mm)
0.0	6.4
0.4	3.6
0.8	2.3
1.6	1.4
2.5	1.0
93.0	1.0

The application of corrosion inhibitor results in a significant reduction in corrosion rate to <0.1 mm/year at the pipeline inlet assuming 99% inhibitor availability (Table 4.1). The maximum cumulative inhibited corrosion over the 20-year field life at the pipeline inlet reduces to approximately 1 mm, which is well within the design corrosion allowance at this location. The predicted cumulative inhibited corrosion for the remainder of the pipeline is also within the given corrosion allowances for the 20 year field life.

The calculated flow regime for the Corrib pipeline is annular dispersed for the full field life. This means that top of the line (TOL) corrosion is not expected because significant condensation will not occur and the full circumference is protected by corrosion inhibitor. In the unlikely event of stratified flow conditions occurring in the pipeline the corrosion rate would be low because of the effect of co-condensing methanol and low condensation rates. Any TOL corrosion would only occur close to the manifold.

TOL corrosion tests carried out at IFE (Institute for Energy Technology, Norway) for simulated Corrib conditions confirmed that TOL rates were significantly lower in the presence of methanol. TOL corrosion rate without methanol at 60ºC was 0.2 mm/yr while with methanol the rates were well below 0.1 mm/yr. No pitting or other localised corrosion was observed in any of the tests.

In order to ensure that the pipeline is suitable for the 20 year field life, and possibly longer, the required corrosion inhibitor availability for the Corrib pipeline has been set to 99% for the base case.

4.2 OFFSHORE PIPELINE SENSITIVITY CASES

Three sensitivity cases have been examined:

1. Pipeline inlet temperature of 60ºC;
2. Production of formation water containing 100 ppm organic acids;
3. Lower inhibited corrosion inhibitor rates.

4.2.1 Pipeline Inlet Temperature

It is possible that the offshore pipeline will operate at a lower temperature than the original design temperature of 75ºC. Decreasing the pipeline inlet temperature to 60ºC reduces the corrosion rate, principally at the pipeline inlet (Table 4.3). This shows that for the 20 year field life the cumulative uninhibited wall loss due to corrosion close to the pipeline inlet is reduced from 7.5 mm to 4.9 mm. The remainder of the pipeline is relatively unaffected by the lower inlet temperature.

Table 4.3: Maximum CO_2 Corrosion rate (mm/yr) for Corrib Offshore Pipeline: (BOL) with 60ºC pipeline inlet temperature

Corrosion rate	Year												
mm/yr	1	2	3	4	5	6	7	8	9	10	11	12	13+
BOL Cl 0%	0.52	0.52	0.9	0.56	0.3	0.25	0.21	0.19	0.17	0.15	0.14	0.13	0.11

4.2.2 Formation Water

The results presented above have assumed only condensed water is present in the pipeline. It is unlikely that formation water will be produced because of the possible liquid handling problems, which means that any well producing significant formation water will be shut in. However, if some formation water is produced due to production control issues then this will influence the potential for corrosion. The formation water is estimated to have an organic acid content of 100 ppm (10 times that of the condensed water). Sensitivity analysis calculations have been made in which the water entering the pipeline is assumed to be 100% formation water with an organic acid content of 100 ppm, and a bicarbonate content of 5 ppm. The results of these calculations are given in Table 4.4. Uninhibited corrosion rates close to the pipeline inlet increase to 3 to 5 mm/yr with a high of approximately 10 mm/yr in year 3. However, these corrosion rates will be mitigated by the corrosion inhibitor and are predicted to be approximately 0.1 mm/yr at the offshore pipeline inlet.

Table 4.4: Maximum CO_2 Corrosion rate (mm/yr) for Corrib Offshore Pipeline with Formation Water

Corrosion rate	Year												
mm/yr	1	2	3	4	5	6	7	8	9	10	11	12	13+
BOL Cl 0%	5.7	5.7	9.88	7.25	3.85	3.16	2.78	2.65	2.42	2.34	2.45	2.52	2.59

4.2.3 Lower Inhibited Corrosion Rates

The corrosion calculations have assumed a standard inhibited corrosion rate of 0.1 mm/year and the overall corrosion rate has been derived from the following relationship:

$CR = (0.1 \times f) + (CR_u \times (1-f))$ *where:*

CR = Overall corrosion rate
f = Availability of corrosion inhibitor as a fraction
CR_u = Predicted uninhibited corrosion rate

Current laboratory testing of the corrosion inhibitor to determine the required dose rate to achieve the inhibited corrosion rate indicates that a lower inhibited corrosion rate of 0.02 - 0.04 mm/yr is possible. This would extend the effective service life with respect to corrosion assuming 99% corrosion inhibitor availability and taking into account the inhibitive effect of methanol.

4.3 ONSHORE PIPELINE

The corrosion assessment for the Corrib pipeline shows that corrosion rates in the onshore section will be an order of magnitude lower. This is related to three factors:

(i) Ambient temperature (10ºC)

(ii) Higher pH

(iii) Higher dissolved $Fe^{2+/3+}$ ion content.

The output from the HYDROCOR corrosion modelling indicates that the uninhibited corrosion rates assuming condensed water are initially 0.12 mm/yr at the BOL position declining to 0.02 mm/yr in later life. The predicted corrosion rate at the TOL position should stratified conditions occur is zero mm/yr. The predicted inhibited corrosion rate is <0.05mm/yr with an accumulated corrosion over 20 years of 0.6mm.

The uninhibited corrosion rates assuming formation water production (which will be limited by well control) are approximately 0.2 mm/yr at the BOL position (declining in later life) and zero mm/yr at the TOL position should stratified conditions occur. The predicted inhibited corrosion rate is <0.05mm/yr.

Initial results from the inhibitor selection programme indicate uninhibited corrosion rates at 10ºC of 0.006 to 0.02 mm/yr in condensed water and 0.007 to 0.04 mm/yr in formation water.

Inhibited corrosion rates will therefore be below 0.05 mm/yr and the 1 mm corrosion allowance will be more than sufficient to mitigate the internal corrosion threat to the onshore pipeline for the anticipated operating field life of 20 years.

In summary, very limited corrosion is expected in the onshore line and this is confirmed by the current ongoing corrosion inhibitor test programme.

4.4 CORROSION ALLOWANCE

On the basis of current Shell corrosion rate calculations and ongoing corrosion inhibitor testing, the 1 mm corrosion allowance is considered to be sufficient for the design life.

Shell does not use the generic fixed value corrosion allowance approach as practised by other operators because a specific assessment using the highly developed Shell CO_2 corrosion prediction modelling coupled with a detailed flow assurance analysis is preferred. The corrosion allowance can then be tailored to the application. This is in accordance with the design considerations outlined in the EFC publication [7] on this subject:

"When evaluating a system's corrosivity, carbon steel is normally the first choice material. Based on the estimated corrosion rate (mm/year) for the system, the required corrosion allowance (mm) can be defined by summing the corrosion rate for the specified design lifetime. The corrosion allowance for topside equipment is often 0, 1.5, 3.0, 4.5 or 6 mm."

The predicted inhibited corrosion rate of <0.05 mm/yr supports the selection of a 1 mm corrosion allowance to mitigate the internal corrosion threat to the onshore pipeline for the anticipated operating field life of 20 years. The ongoing corrosion inhibitor testing indicates much lower corrosion rates than 0.05 mm/yr for the onshore pipeline conditions. Taken together with corrosion monitoring and assessment during service this should allow further operation to meet the design life of 30 years if required. Benefit could also be taken for any gradual decrease in operating pressure over the years because less wall thickness would be required for pressure containment. However, this would also be influenced by any future tie-ins to the Corrib system.

5 EROSION ASSESSMENT

5.1 METHOD

The Corrib reservoir is a tight formation and no sand production is expected. Only one well 18/25-3: P5) has been fractured and treated with a coated ceramic proppant. It is possible that some proppant may be produced back to the pipeline during operation, although only limited proppant was observed during the original well test in 2001 and no proppant production was observed during a subsequent well test in 2008.

To consider this scenario with respect to possible wall loss by erosion an assessment has been made using the Tulsa SPPS prediction tool (version 3.4). This is recognised as an industry standard for prediction of erosion by solids and reflects the current Shell approach for assessment of sand or solids erosion.

The assessment assumed that all solids are proppant and that proppant production will be up to 2.5kg/day as a conservative estimate. The assessment considered the following worst-case geometries with respect to erosion:

- Tee configurations at the Landfall Valve Installation (LVI): 20”x16”
- 16” bends (1.5D elbow) at the LVI
- 20” 5D bends at the manifold and Terminal ends of the pipeline.

Erosion rate estimates were generated for Years 1-20 and summed for a cumulative loss.

It is assumed that significant erosion will not occur in straight sections of the pipeline or those with bends of radius greater than, r=5xD, where D = nominal diameter, because of limited impingement of solids on the steel surface.

5.2 PREDICTIONS

The results from the prediction spreadsheet are as follows:

Table 5.1: Erosion predictions for LVI & onshore pipeline for 2.5 kg/day proppant

Feature	**Cumulative Erosion for 20 years mm**
LVI – 20/16” tee	0.04*
LVI - 16” short radius bend (r/D = 1.5)	0.1
Pipeline – 20” long radius bend (r/D = 5)	0.03*
** Predicted losses at this level should be taken as negligible.*	

5.3 DISCUSSION

The prediction method should not be taken as providing an exact forecast but gives a reasonable indication of the erosion that may occur if proppant was produced over the full 20 year period. However, there is a finite amount of proppant in the well and the back-production, should it occur, will likely decrease with time. There is an acoustic monitoring probe installed on the subsea manifold and any indication of significant solids production would likely result in a well intervention or closing-in of the well.

The corrosion allowance needs to provide for losses from both corrosion and erosion. As discussed above the amount of corrosion allowance likely to be consumed by corrosion will depend on the effectiveness of the corrosion inhibitor. The carbon steel onshore pipeline corrosion rate can conservatively be assumed not to exceed the uninhibited rate that is predicted to be less than 0.05 mm/yr.

As the erosion rate predicted for the long radius bends of the pipeline is negligible, the combined losses due to corrosion and erosion in the onshore pipeline are therefore unlikely to exceed the 1mm corrosion allowance over the 20 year service life. This assumes that there are no significant synergistic effects, which is realistic because the corrosion rate here is governed by temperature rather than by protective scale formation.

However, the erosion rate will be greater in the smaller diameter pipework at the LVI, but the predicted worst case mean values are within the tolerances of the corrosion resistant materials selected for the LVI pipework. It can be concluded that erosion of the LVI is not expected to be significant and can be monitored by ultrasonic wall thickness measurements to provide additional assurance.

6 CONCLUSIONS

The assessment indicates that the expected corrosion and erosion rates in both the offshore and onshore sections of the Corrib pipeline are within the design corrosion allowances for a service life of 20 years provided corrosion mitigation with corrosion inhibitor and methanol is correctly applied. This assessment is supported by the extensive and successful Shell experience with operating wet gas pipelines.

The assessment predicts very low corrosion rates for the onshore section of the pipeline and this has been verified by the ongoing corrosion inhibitor test programme. Should corrosion occur it is more likely in the offshore pipeline close to the subsea manifold.

7 REFERENCES

1. S. Kapusta, B. Pots & R. Connell, NACE Corrosion/99, Paper 045.
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7. European Federation of Corrosion (EFC) Publication 23: CO_2 Corrosion Control in Oil and Gas Production - Design Considerations.

ATTACHMENT Q4.9A

OVERVIEW OF SHELL WET GAS PIPELINES

This list comprises an overview of wet gas pipelines that are operated primarily by Shell. There are a small number of pipelines included for which Shell is a partner. The list has been updated from 2003 to reflect new developments and is intended for internal use to demonstrate the validity of the Shell wet gas corrosion management philosophy and methodology.

The identity of the pipelines has been kept anonymous to respect individual Operating Company confidentiality. Pipelines with the identifier A, B, C, D & L are European pipelines and the remainder are global pipelines including the Americas, Middle East, and Asia. The list of European pipelines is comprehensive and is believed to include all Shell operated wet gas pipelines. The global list is less complete but represents a high proportion (>80%) of Shell operated wet gas pipelines. Note that pipelines where the mitigation is gas dehydration and inhibitor indicates that there is significant liquid carry-over which requires inhibiting.

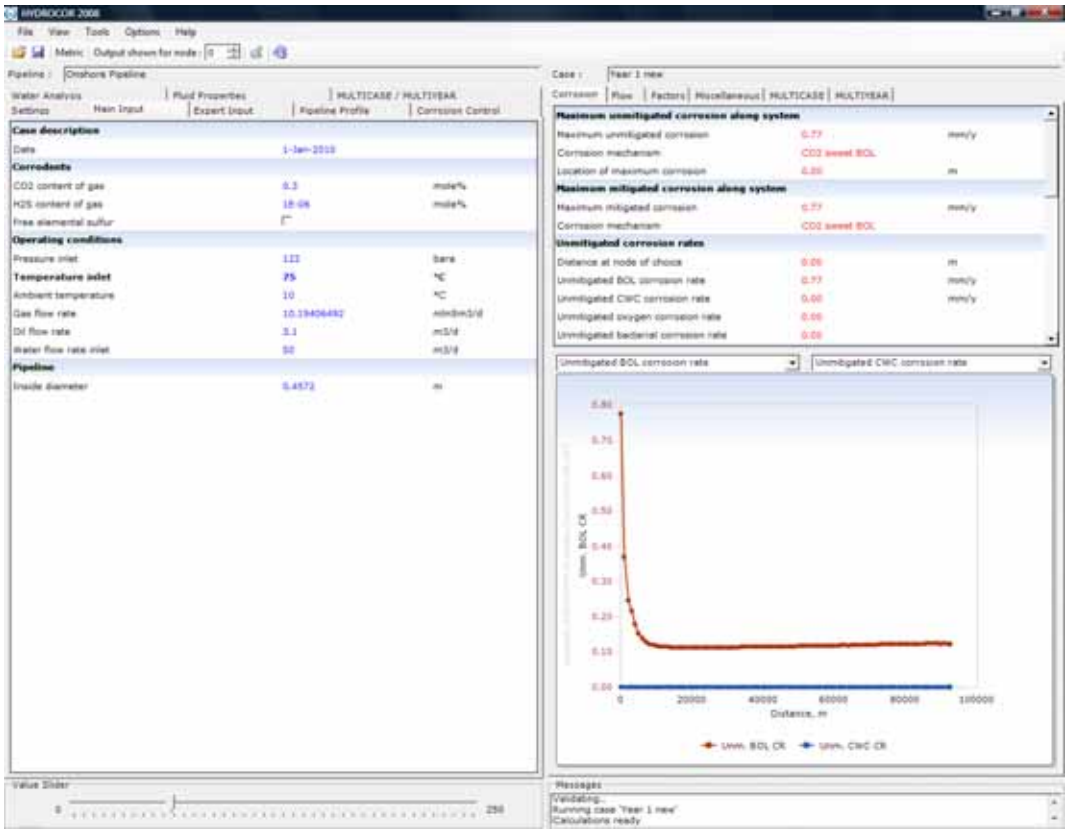
The total Shell experience with operation of wet gas pipelines in Europe without a loss of containment incident amounts to 40,384 km years.

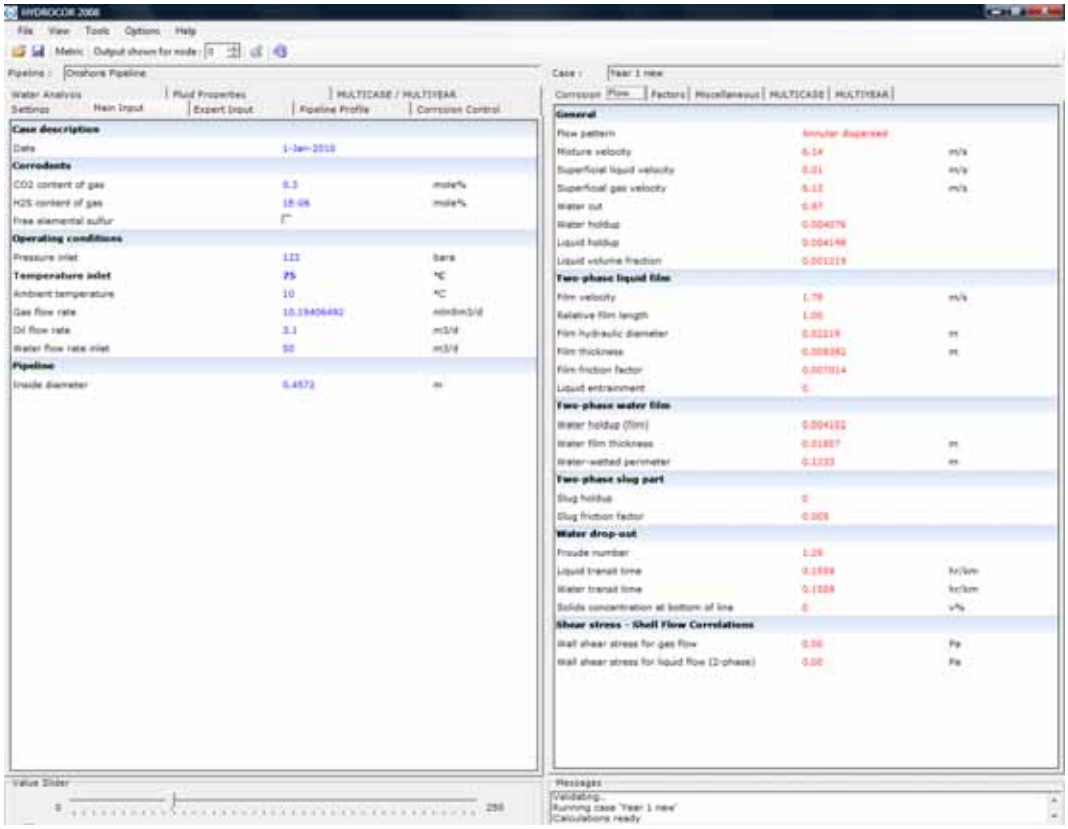
Identifier	Operating Temperature	pCO2	pH_2S	Length (Km)	Status	Corrosion control (actual or proposed)	Years in Service	Uninhibited corrosion Rate	Assessed Corrosion rate	Number of Inspections
	°C	bar	mbar					mm/y		
A01	30	-	-	0.2	Operating	Inhibition	37	0.8	0.1	2
A02	70	0.1302	-	9.5	Operating	Inhibition	11	2	0.1	3
A03	60	0.504	-	6.1	Operating	Inhibition	26	3.6	0.1	3
A04	70	-	-	20.7	Operating	Uninhibited	24	0.2	0.2	5
A05	50	0.444	-	0.6	Operating	Inhibition	18	7.0	0.2	4
A06	50	-	-	10.5	Operating	Inhibition	16	1.3	0.1	-
A07	70	0.651	-	6.9	Operating	Inhibition	10	0.6	0.1	5
A08	70	0.651	-	0.2	Operating	Inhibition	10	0.6	0.1	4
A09	65	-	-	2.8	Operating	Inhibition	20	1.0	0.1	4
A10	70	0.00255	-	4.4	Operating	Inhibition	36	2.0	0.1	8
A11	100	-	-	1.7	Operating	Inhibition	23	3.8	0.1	3
A12	50	0.45	-	9.3	Operating	Inhibition	25	1.0	0.1	4
A13	50	0.44	-	6.8	Operating	Inhibition	24	1.2	0.2	9
A14	70	0.638	-	6.8	Operating	Inhibition	20	1.0	0.1	5
A15	70	-	-	3.6	Operating	Inhibition	11	1.4	0.1	5
A16	55	-	-	22.1	Operating	Inhibition	35	-	0.2	5
A17	70	0.2	0	3.9	Operating	Inhibition	-	2.9	0.1	-
A18	65	0.29	-	5.0	Operating	Inhibition	21	2.9	0.1	7
A19	85	0.693	-	5.8	Operating	Inhibition	7	0.8	0.1	4
A20	70	0.2	0	-	Operating	Inhibition	14	2.9	0.1	-
A21	55	0.341	-	7.9	Not Operating	Inhibition	30	2.5	0.1	2
A22	70	0.0715	-	11.2	Operating	Inhibition	11	1.0	0.1	5
A23	50	-	-	5.2	Operating	Uninhibited	25	0.2	0.2	5
A24	50	-	-	2.2	Not Operating	Preserved w/ N2	23	<0.05	<0.05	4
A25	50	-	-	0.9	Not Operating	Preserved w/ N2	24	<0.05	<0.05	6
A26	50	-	-	2.3	Not Operating	Preserved w/ N2	23	<0.05	<0.05	5
A27	50	-	-	2.8	Not Operating	Preserved w/ N2	21	<0.05	<0.05	3
A28	50	-	-	74.2	Operating	Preserved w/ N2	23	<0.05	<0.05	5
A29	50	-	-	2.6	Operating	Uninhibited	25	0.2	0.2	1
A30	50	-	-	2.3	Operating	Uninhibited	23	-	0.2	2
A31	50	0.2016	-	6.1	Operating	Inhibition	27	0.6	0.1	3
A32	50	0.0836	-	2.4	Operating	Inhibition	29	0.2	0.1	1
A33	50	0.0968	-	3.1	Operating	Inhibition	28	0.1	0.1	5
A34	50	0.028	-	2.4	Operating	Inhibition	28	0.1	0.1	5
A35	50	-	-	0.1	Operating	Uninhibited	22	0.2	0.2	10
A36	50	-	-	0.1	Not Operating	Preserved w/ N2	35	<0.05	<0.05	2
A37	50	0.0168	-	2.1	Operating	Uninhibited	20	0.2	0.2	6
A38	50	0.0662	-	3.4	Operating	Uninhibited	20	0.2	0.2	5
A39	50	-	-	3.4	Operating	Uninhibited	14	0.2	0.2	4
A40	50	-	-	3.4	Operating	Uninhibited	22	0.2	0.2	3
A41	50	-	-	6.8	Operating	Uninhibited	20	0.2	0.2	6
A42	70	0.0396	-	1.8	Operating	Inhibition	37	0.6	0.1	4
A43	50	0.0168	-	9.9	Operating	Uninhibited	35	0.2	0.2	5
A44	50	-	-	6.5	Operating	Uninhibited	22	0.2	0.2	6
A45	50	0.01134	-	3.1	Operating	Uninhibited	21	0.2	0.2	4
A46	50	0.015	-	3.1	Operating	Uninhibited	14	0.2	0.2	3
A47	50	0.0143	-	6.3	Operating	Uninhibited	21	0.2	0.2	5
A48	50	0.0143	-	2.1	Operating	Uninhibited	21	0.2	0.2	5
A49	50	0.0192	-	3.8	Operating	Uninhibited	21	0.2	0.2	2
A50	50	0.0496	-	3.8	Operating	Uninhibited	41	0.2	0.2	4
A51	50	-	-	2.2	Operating	Uninhibited	41	0.2	0.2	5
A52	30	0.0525	-	2.3	Operating	Inhibition	37	0.75	0.1	1
A53	50	0.0288	-	2.9	Operating	Inhibition	31	0.7	0.1	4
A54	30	0.048	-	2.6	Operating	Inhibition	35	0.8	0.1	1
B01	70	0.406	-	5.5	Operating	Inhibition	18	3.9	0.2	-
B02	70	0.406	-	5.0	Operating	Inhibition	18	3.9	0.5	-
B03	70	0.406	-	2.0	Operating	Inhibition	18	3.9	0.27	-
B04	60	0.476	-	102.6	Operating	Glycol	6	3.1	0.15	-
B05	104	3	-	23.0	Proposal	Inhibition	-	12	-	-
B06	125	2.55	-	3.8	Operating	Inhibition	4	16.4	0.2	-
B07	95	3.234	-	11.9	Operating	Inhibition	7	17	0.2	-
B08	95	2.52	-	34.0	Operating	Inhibition	2	15	0.2	-
C01	68	0.4509	0	242.4	Operating	Glycol + pH Control + Inhibition	3	2.6	0.1	0
D01	50	0.7273	0	14.6	Operating	Inhibition	4	17.3	0.2	-
D02	30	0.1573	0	9.4	Operating	Inhibition	28	2.08	0.2	4
D03	40	0.23	0	17.0	Operating	Inhibition	7	9.64	0.1	-
D04	50	3.0495	0	19.6	Operating	Inhibition	1	8.84	0.0001	-
D05	50	0.589	0	0.1	Operating	Inhibition	1	2.92	0.0001	-
D06	27.2	0.07091	0	24.4	Operating	Inhibition	19	1.56	0.1	3
D07	33.7	0.07758	0	15.3	Operating	Inhibition	15	2.52	0.3	1
D08	49.3	0.50819	0	18.0	Operating	Glycol + Inhibition	4	3.55	0.2	-
D09	41.5	0.46814	0	81.5	Operating	Glycol + Inhibition	7	10.9	0.3	-
D10	27.2	0.36262	0	73.0	Operating	Glycol + Inhibition	20	2.72	0.3	2
D11	11.2	0.64428	0	36.6	Operating	Glycol + Inhibition	12	0.61	0.1	-
D12	29.1	0.08318	0	8.9	Operating	Inhibition	12	2.3	0.4	1
D13	11.7	0.10216	0	12.2	Operating	Inhibition	16	2.57	0.3	2
D14	50	0.2193	0	55.7	Operating	Glycol + Inhibition	43	1.92	0.3	2
D15	10.7	0.00561	0	0.6	Operating	Uninhibited	39	0.53	0.1	-
D16	13.8	0.00583	0	3.5	Operating	Uninhibited	39	0.81	0.1	-
D17	15	0.00605	0	2.0	Operating	Uninhibited	39	0.64	0.1	-
D18	14.2	0.00385	0	8.0	Operating	Uninhibited	37	0.74	0.1	-
D19	15	0.00638	0	3.0	Operating	Uninhibited	28	0.3	0.1	-
D20	14.3	0.00693	0	4.8	Operating	Uninhibited	23	0.44	0.1	-
D21	11.9	0.00627	0	2.5	Operating	Uninhibited	23	0.28	0.1	-
D22	14.6	0.85424	0	108.0	Operating	Dehydration	24	7.83	0.01	3
D23	30	0.06797	0	11.0	Operating	Glycol + Inhibition	10	1.84	0.2	-

Identifier	Operating Temperature	pCO2	pH_2S	Length (Km)	Status	Corrosion control (actual or proposed)	Years in Service	Uninhibited corrosion Rate	Assessed Corrosion rate	Number of Inspections
	°C	bar	mbar					mm/y		
E01	Up to 100	0.8	0	45.0	operating	Inhibition	11	0.15	0.15	1+
E02	60	0.23	0	-	operating	Inhibition	13	0.1	0.1	1+
E03	up to 80	0.056	0	44.0	operating	Inhibition	2	0.1	0.1	1+
E04	up to 80	0.056	0	14.0	operating	Inhibition	2	0.1	0.1	1+
E05	up to 80	0.384	0	9.0	operating	Inhibition	2	0.1	0.1	1+
E06	up to 80	0.384	0	27.0	operating	Inhibition	2	0.1	0.1	1+
F01	86	2.8	300	6.0	Operating	Inhibition	12	23	0.1	-
F02	85	4.8	4200	40.0	Proposal	Glycol + Inhibition	4	13	0.1	-
F03	100	2.38	2380	64.0	Construction	Inhibition	-	10	0.1	-
F04	100	2.38	2380	52.0	Construction	Inhibition	-	10	0.1	-
G01	30	0.67	5	21.0	Construction	Inhibition	3	0.37	0.1	-
H01	60	0.34	0	17.3	Operating	Glycol + pH control	13	1.2	0.1	-
H02	60	0.34	0	16.3	Operating	Glycol + pH control	13	1.2	0.1	-
H03	60	0.34	0	161.0	Operating	Glycol + pH control	13	1.2	0.1	-
H04	27	0.15	0	75.5	Operating	Inhibition	15	0.3	0.1	-
H05	77	0.96	0	-	Pre-unloading	Inhibition	7	4.1	0.1	-
H06	49	1.0192	2	-	Operating	Inhibition	-	2.2	0.1	1
H07	71	0.5	0	77.8	Operating	Inhibition	15	5	0.1	-
H08	71	0.5	0	117.5	Operating	Inhibition	15	5	0.1	-
I01	100	3	0	-	Operating	Glycol + Inhibition	11	27	-	-
I02	34	10.3	7200	-	Operating	Inhibition	37	-	-	-
I03	41	2.5	12400	2.4	Operating	Inhibition	17	4.17	0.18	-
I04	41	3.5	17500	2.4	Operating	Inhibition	17	4.1	0.18	-
I05	60	7.8	9000	-	Operating	Inhibition	57	-	-	-
I06	48	8.3	9800	42.0	Operating	Inhibition	31	-	-	-
I07	46	4.8	18700	-	Operating	Inhibition	43	-	-	-
I08	55	4.4	12000	-	Operating	Inhibition	43	-	-	-
I09	20	3.528	0	2.0	Operating	Glycol	5	0.03	0	1
I10	-	3.4	0	40.0	Operating	Inhibition	3	0.26	-	1
I11	-	3.4	0	16.0	Operating	Inhibition	3	0.26	-	1
I12	-	-	-	9.4	Operating	Inhibition	33	51.5	0.05	2
I13	-	-	-	3.3	Operating	Inhibition	51	0.18	0.1	2+
I14	-	-	-	1.2	Operating	Inhibition	51	0.56	0.12	2+
I15	-	-	-	2.0	Operating	Inhibition	51	0.59	0.12	2+
I16	-	-	-	16.7	Operating	Inhibition	26	4.87	0.34	2+
I17	-	-	-	2.3	Operating	Inhibition	21	0.58	0.19	2+
I18	-	-	-	1.8	Operating	Inhibition	27	2.81	0.36	2+
I19	-	-	-	21.0	Operating	Inhibition	30	29.6	0.39	2+
I20	-	-	-	27.6	Operating	Inhibition	30	35.1	1.85	2+
J01	-	-	0	11.7	Operating	Inhibition	5	-	0.21	-
J02	-	-	0	10.7	Operating	Inhibition	5	-	0.16	-
J03	-	-	0	8.5	Operating	Inhibition	5	-	0.8	-
J04	40	0.92	0	1.0	Operating	Inhibition	13	7	0.1	-
J05	32	0.6	0	1.0	Operating	Inhibition	13	-	0.09	-
J06	30	1.8	0	2.6	Operating	Inhibition	16	10	0.28	-
J07	38	1.1	0	0.7	Operating	Inhibition	14	8.4	0.03	-
J08	45	1.1	0	0.7	Operating	Inhibition	14	9.4	0.08	-
J09	45	1.1	0	0.7	Operating	Inhibition	14	9.4	0.04	-
J10	35	12.5	0	0.7	Operating	Inhibition	21	41	0.15	-
J11	46	4.5	0	0.6	Operating	Inhibition	21	24	0.18	-
J12	49	4.6	0	0.6	Operating	Inhibition	21	26.5	0.08	-
J13	40	8.4	0	0.6	Operating	Inhibition	21	34.5	0.11	-
J14	45	3	0	0.6	Operating	Inhibition	21	18	0.32	-
J15	43	1.68	0	0.6	Operating	Inhibition	5	12	-	0
J16	35	8.5	0	0.7	Operating	Inhibition	21	31	0.35	-
K01	82	10.8	1.2	10.0	Operating	Inhibition	5	>12	0.1	-
K02	54	0.1	0	31.0	Operating	Inhibition	12	1.5	0.1	-
K03	50	0.1	0	31.7	operating	inhibition	13	3.9	0.2	1+
K04	23.3	4.455	35.64	35.5	operating	Gas Dehydration + inhibition	7	4.02	1	1+
K05	50	10.3785	0	14.2	operating	inhibition	5	19.65	0.1	-
K06	34	1.5051	9.57	43.0	operating	Inhibition	4	4.1	0.1	-
K07	40	6.1056	0	124.9	operating	Gas Dehydration + inhibition	28	10.9	0.17	1+
K08	40	1.7493	266.56	44.7	operating	Gas Dehydration + inhibition	27	3.3	0.28	1+
K09	37	1.978	0	52.0	operating	Gas Dehydration + inhibition	23	3.6	0.38	1+
L01	50	0.4	0	70.0	Operating	Glycol + pH control	14	2	0.2	-
M01	60	4	0	36.0	Proposal	Inhibition	-	7	-	-
N01	70	4	0	140.0	Proposal	Inhibition	-	14	-	-
O01	45	0.15 to 0.35	0	33.0	Operating	Inhibition	8	2-4	0.1	0
O02	45	0.15 to 0.35	0	33.0	Operating	Inhibition	9	2-4	0.1	0
O03	45	0.35 - 0.45	0	70.0	Operating	Inhibition	7	4	0.1	0
P01	106	14	46200	10.0	Proposal	Inhibition	-	-	-	-

ATTACHMENT Q4.9B

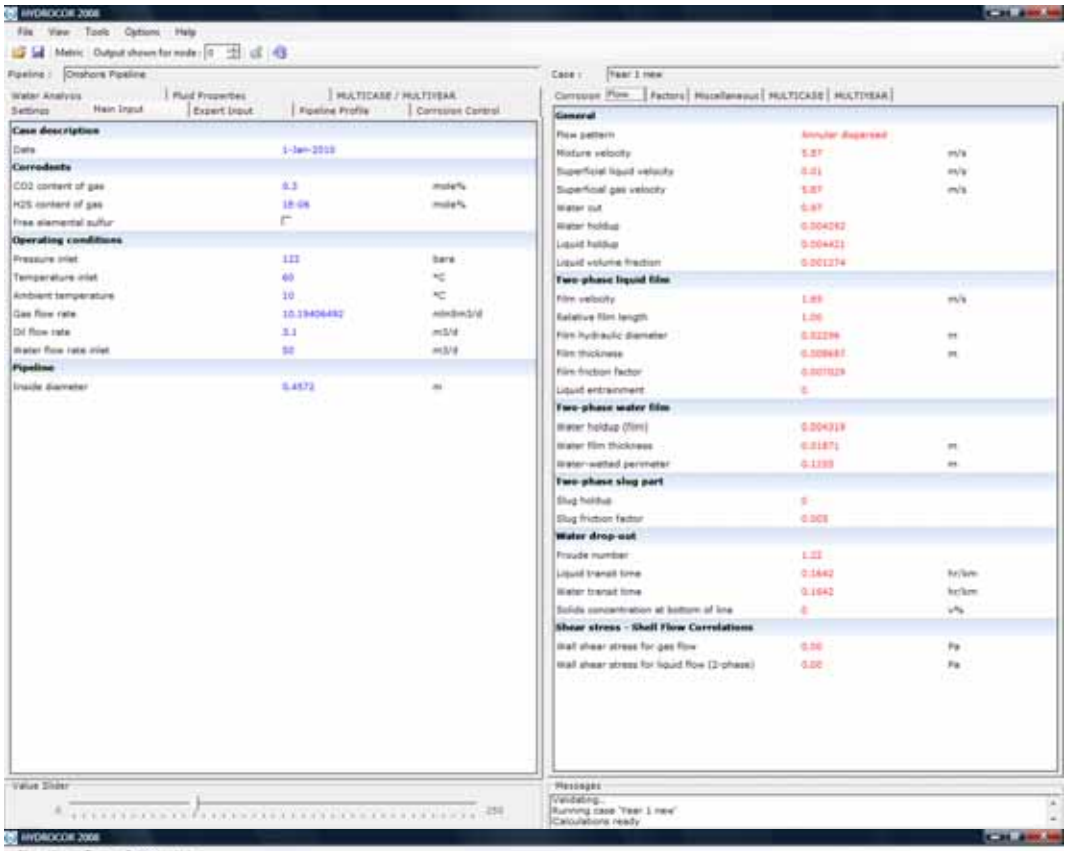
HYDROCOR OUTPUT FOR YEAR 1: CO_2 CORROSION PROFILE (mm/yr) FOR CORRIB PIPELINE BOTTOM OF THE LINE (BOL) AND TOP OF THE LINE (TOL) AT 75ºC

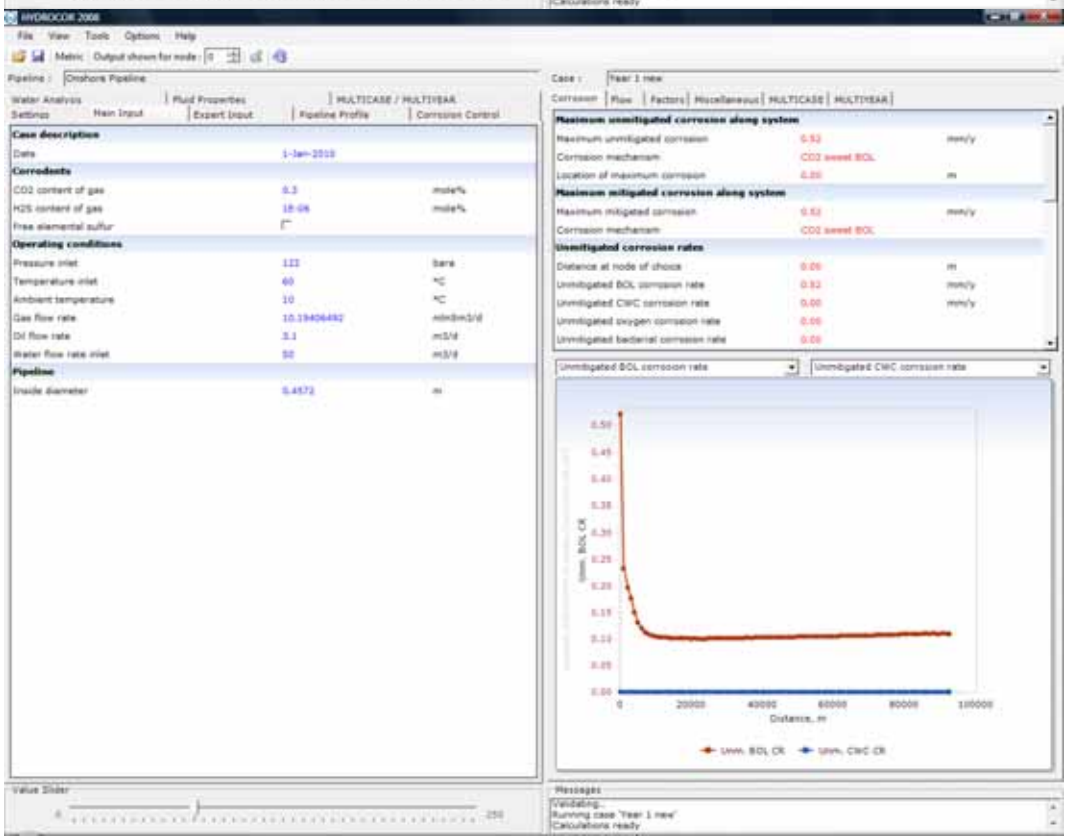

HYDROCOR 2008
File View Tools Options Help
Pipeline : Onshore Pipeline
Case : Year 1 new
Water Analysis
Fluid Properties
MULTICASE / MULTIYEAR
Settings
Main Input
Expert Input
Pipeline Profile
Corrosion Control
Corrosion Flow Factors Miscellaneous MULTICASE MULTIYEAR
Case description
Date 1-Jan-2010
Corrodants
CO2 content of gas 0.3 mole%
H2S content of gas 18.06 mole%
Free elemental sulfur
Operating conditions
Pressure inlet 122 bara
Temperature inlet 75 °C
Ambient temperature 10 °C
Gas flow rate 10.19406492 mln0m3/d
Oil flow rate 3.1 m3/d
Water flow rate inlet 50 m3/d
Pipeline
Inside diameter 0.4572 m
Maximum unmitigated corrosion along system
Maximum unmitigated corrosion 0.77 mm/y
Corrosion mechanism CO2 sweet BOL
Location of maximum corrosion 0.00 m
Maximum mitigated corrosion along system
Maximum mitigated corrosion 0.77 mm/y
Corrosion mechanism CO2 sweet BOL
Unmitigated corrosion rates
Distance at node of choice 0.00 m
Unmitigated BOL corrosion rate 0.77 mm/y
Unmitigated CWC corrosion rate 0.00 mm/y
Unmitigated oxygen corrosion rate 0.00
Unmitigated bacterial corrosion rate 0.00
Unmitigated BOL corrosion rate
Unmitigated CWC corrosion rate
Unm. BOL CR
Distance, m
Unm. BOL CR
Unm. CWC CR
Value Slider
Messages
Validating...
Running case 'Year 1 new'
Calculations ready


HYDROCOR 2008
File View Tools Options Help
Pipeline : Onshore Pipeline
Case : Year 1 new
Water Analysis
Fluid Properties
MULTICASE / MULTIYEAR
Settings
Main Input
Expert Input
Pipeline Profile
Corrosion Control
Corrosion Flow Factors Miscellaneous MULTICASE MULTIYEAR
Case description
Date 1-Jan-2010
Corrodants
CO2 content of gas 0.3 mole%
H2S content of gas 18.06 mole%
Free elemental sulfur
Operating conditions
Pressure inlet 122 bara
Temperature inlet 75 °C
Ambient temperature 10 °C
Gas flow rate 10.19406492 mln0m3/d
Oil flow rate 3.1 m3/d
Water flow rate inlet 50 m3/d
Pipeline
Inside diameter 0.4572 m
General
Flow pattern Annular dispersed
Mixture velocity 6.14 m/s
Superficial liquid velocity 0.01 m/s
Superficial gas velocity 6.13 m/s
Water cut 0.87
Water holdup 0.004076
Liquid holdup 0.004198
Liquid volume fraction 0.001219
Two-phase liquid film
Film velocity 1.79 m/s
Relative film length 1.00
Film hydraulic diameter 0.02219 m
Film thickness 0.008382 m
Film friction factor 0.007014
Liquid entrainment 0
Two-phase water film
Water holdup (film) 0.004102
Water film thickness 0.01807 m
Water-wetted perimeter 0.1233 m
Two-phase slug part
Slug holdup 0
Slug friction factor 0.003
Water drop-out
Froude number 1.26
Liquid transit time 0.1559 hr/km
Water transit time 0.1588 hr/km
Solids concentration at bottom of line 0 v%
Shear stress - Shell Flow Correlations
Wall shear stress for gas flow 0.00 Pa
Wall shear stress for liquid flow (2-phase) 0.00 Pa
Value Slider
Messages
Validating...
Running case 'Year 1 new'
Calculations ready

ATTACHMENT Q4.9C

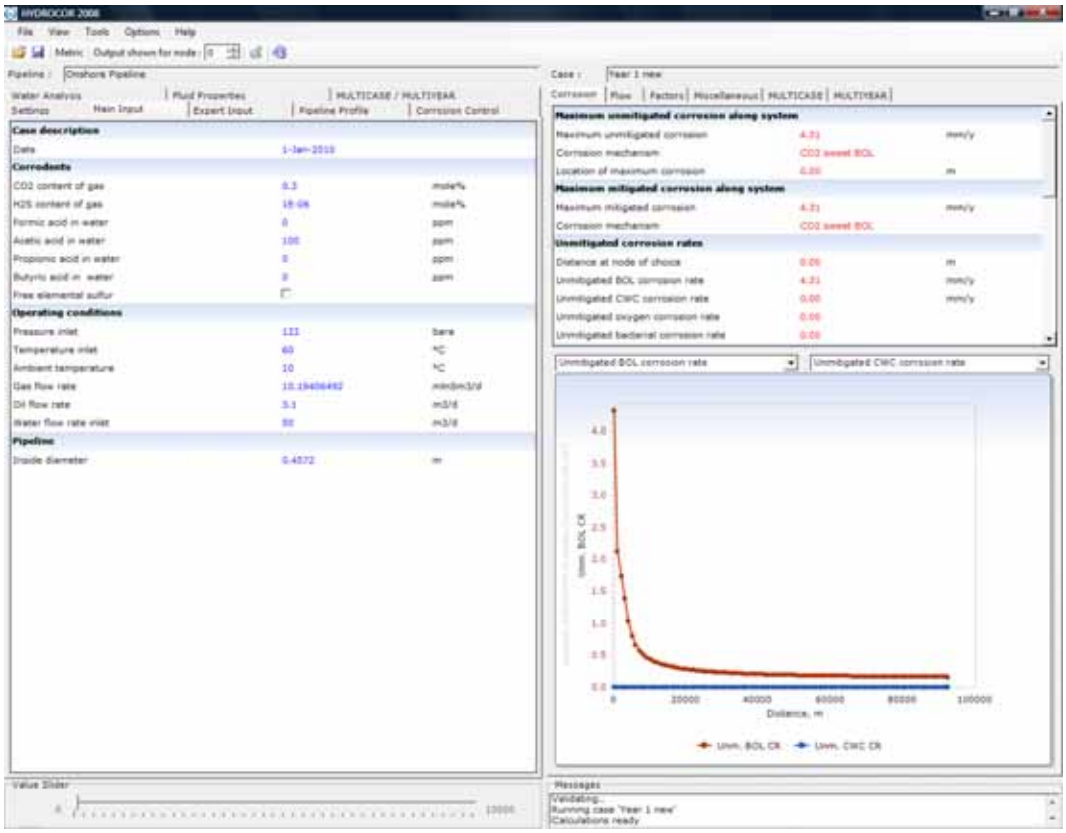
HYDROCOR OUTPUT:
CO_2 CORROSION PROFILE (mm/yr)
FOR CORRIB PIPELINE
BOTTOM OF THE LINE (BOL)
AND TOP OF THE LINE (TOL) AT 60ºC

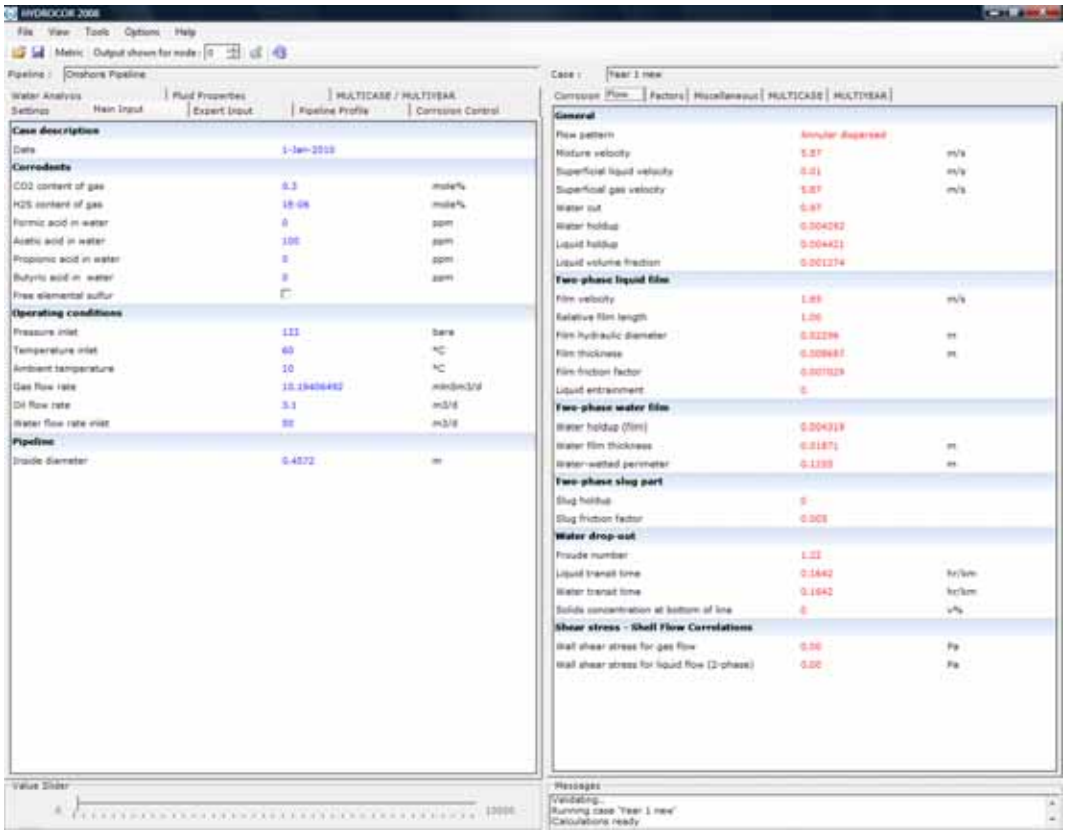

HYDROCOR 2008
File View Tools Options Help
Metric Output shown for node
Pipeline : Onshore Pipeline
Case : Year 1 new
Water Analysis
Fluid Properties
MULTICASE / MULTIYEAR
Settings
Main Input
Expert Input
Pipeline Profile
Corrosion Control
Corrosion Flow Factors Miscellaneous MULTICASE MULTIYEAR
Case description
Date 1-Jan-2010
Corrodants
CO2 content of gas 0.3 mole%
H2S content of gas 18.06 mole%
Free elemental sulfur
Operating conditions
Pressure inlet 122 bara
Temperature inlet 60 °C
Ambient temperature 10 °C
Gas flow rate 10.19406492 mln0m3/d
Oil flow rate 3.1 m3/d
Water flow rate inlet 50 m3/d
Pipeline
Inside diameter 0.4572 m
General
Flow pattern Annular dispersed
Mixture velocity 5.87 m/s
Superficial liquid velocity 0.01 m/s
Superficial gas velocity 5.87 m/s
Water cut 0.97
Water holdup 0.004262
Liquid holdup 0.004421
Liquid volume fraction 0.001274
Two-phase liquid film
Film velocity 1.89 m/s
Relative film length 1.00
Film hydraulic diameter 0.02294 m
Film thickness 0.009687 m
Film friction factor 0.007029
Liquid entrainment 0
Two-phase water film
Water holdup (film) 0.004319
Water film thickness 0.01871 m
Water-wetted perimeter 0.1203 m
Two-phase slug part
Slug holdup 0
Slug friction factor 0.005
Water drop-out
Froude number 1.22
Liquid transit time 0.1642 hr/km
Water transit time 0.1642 hr/km
Solids concentration at bottom of line 0 v%
Shear stress - Shell Flow Correlations
Wall shear stress for gas flow 0.00 Pa
Wall shear stress for liquid flow (2-phase) 0.00 Pa
Value Slider
Messages
Validating...
Running case 'Year 1 new'
Calculations ready


HYDROCOR 2008
File View Tools Options Help
Metric Output shown for node
Pipeline : Onshore Pipeline
Case : Year 1 new
Water Analysis
Fluid Properties
MULTICASE / MULTIYEAR
Settings
Main Input
Expert Input
Pipeline Profile
Corrosion Control
Corrosion Flow Factors Miscellaneous MULTICASE MULTIYEAR
Case description
Date 1-Jan-2010
Corrodants
CO2 content of gas 0.3 mole%
H2S content of gas 18.06 mole%
Free elemental sulfur
Operating conditions
Pressure inlet 122 bara
Temperature inlet 60 °C
Ambient temperature 10 °C
Gas flow rate 10.19406492 mln0m3/d
Oil flow rate 3.1 m3/d
Water flow rate inlet 50 m3/d
Pipeline
Inside diameter 0.4572 m
Maximum unmitigated corrosion along system
Maximum unmitigated corrosion 0.52 mm/y
Corrosion mechanism CO2 sweet BOL
Location of maximum corrosion 0.00 m
Maximum mitigated corrosion along system
Maximum mitigated corrosion 0.52 mm/y
Corrosion mechanism CO2 sweet BOL
Unmitigated corrosion rates
Distance at node of choice 0.00 m
Unmitigated BOL corrosion rate 0.52 mm/y
Unmitigated CWC corrosion rate 0.00 mm/y
Unmitigated oxygen corrosion rate 0.00
Unmitigated bacterial corrosion rate 0.00
Unmitigated BOL corrosion rate
Unmitigated CWC corrosion rate
Unm. BOL CR
Unm. CWC CR
Distance, m
Value Slider
Messages
Validating...
Running case 'Year 1 new'
Calculations ready

ATTACHMENT Q4.9D

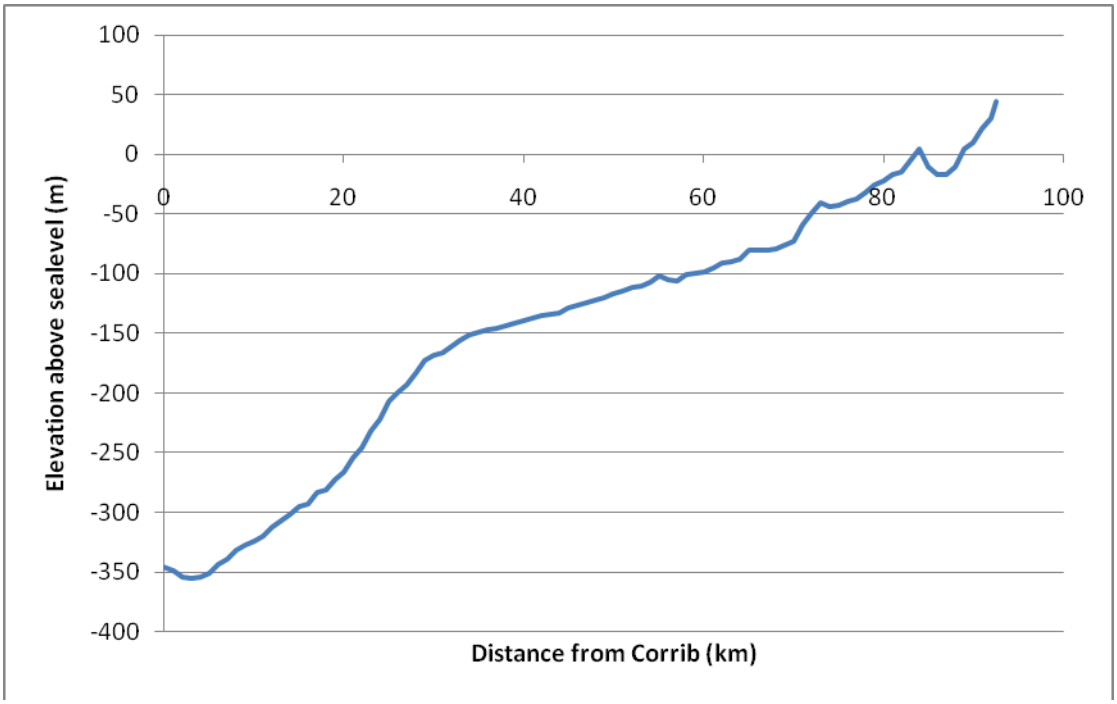
HYDROCOR OUTPUT:
CO_2 CORROSION PROFILE (mm/yr)
FOR CORRIB PIPELINE
BOTTOM OF THE LINE (BOL) AND TOP OF THE LINE (TOL)
WITH FORMATION WATER AT 60ºC


HYDROCOR 2008
File View Tools Options Help
Metric Output shown for node :
Pipeline : Onshore Pipeline
Case : Year 1 new
Water Analysis
Fluid Properties
MULTICASE / MULTIYEAR
Settings
Main Input
Expert Input
Pipeline Profile
Corrosion Control
Corrosion Flow Factors Miscellaneous MULTICASE MULTIYEAR
Case description
Date 1-Jan-2010
Corrodants
CO2 content of gas 0.3 mole%
H2S content of gas 18.06 mole%
Formic acid in water 0 ppm
Acetic acid in water 100 ppm
Propionic acid in water 0 ppm
Butyric acid in water 0 ppm
Free elemental sulfur
Operating conditions
Pressure inlet 111 bara
Temperature inlet 60 °C
Ambient temperature 10 °C
Gas flow rate 10.19406492 mln0m3/d
Oil flow rate 3.1 m3/d
Water flow rate inlet 30 m3/d
Pipeline
Inside diameter 0.4572 m
Maximum unmitigated corrosion along system
Maximum unmitigated corrosion 4.21 mm/y
Corrosion mechanism CO2 sweet BOL
Location of maximum corrosion 0.00 m
Maximum mitigated corrosion along system
Maximum mitigated corrosion 4.21 mm/y
Corrosion mechanism CO2 sweet BOL
Unmitigated corrosion rates
Distance at node of choice 0.00 m
Unmitigated BOL corrosion rate 4.21 mm/y
Unmitigated CWC corrosion rate 0.00 mm/y
Unmitigated oxygen corrosion rate 0.00
Unmitigated bacterial corrosion rate 0.00
Unmitigated BOL corrosion rate
Unmitigated CWC corrosion rate
Unm. BOL CR
Unm. CWC CR
Distance, m
Value Slider
Messages
Validating...
Running case 'Year 1 new'
Calculations ready


HYDROCOR 2008
File View Tools Options Help
Metric Output shown for node :
Pipeline : Onshore Pipeline
Case : Year 1 new
Water Analysis
Fluid Properties
MULTICASE / MULTIYEAR
Settings
Main Input
Expert Input
Pipeline Profile
Corrosion Control
Corrosion Flow Factors Miscellaneous MULTICASE MULTIYEAR
Case description
Date 1-Jan-2010
Corrodants
CO2 content of gas 0.3 mole%
H2S content of gas 18.06 mole%
Formic acid in water 0 ppm
Acetic acid in water 100 ppm
Propionic acid in water 0 ppm
Butyric acid in water 0 ppm
Free elemental sulfur
Operating conditions
Pressure inlet 111 bara
Temperature inlet 60 °C
Ambient temperature 10 °C
Gas flow rate 10.19406492 mln0m3/d
Oil flow rate 3.1 m3/d
Water flow rate inlet 30 m3/d
Pipeline
Inside diameter 0.4572 m
General
Flow pattern Annular dispersed
Mixture velocity 5.87 m/s
Superficial liquid velocity 0.01 m/s
Superficial gas velocity 5.87 m/s
Water cut 0.97
Water holdup 0.004292
Liquid holdup 0.004421
Liquid volume fraction 0.001274
Two-phase liquid film
Film velocity 1.89 m/s
Relative film length 1.00
Film hydraulic diameter 0.02294 m
Film thickness 0.009687 m
Film friction factor 0.007029
Liquid entrainment 0
Two-phase water film
Water holdup (film) 0.004319
Water film thickness 0.01871 m
Water-wetted perimeter 0.1333 m
Two-phase slug part
Slug holdup 0
Slug friction factor 0.005
Water drop-out
Froude number 1.22
Liquid transit time 0.1642 hr/km
Water transit time 0.1642 hr/km
Solids concentration at bottom of line 0 v%
Shear stress - Shell Flow Correlations
Wall shear stress for gas flow 0.00 Pa
Wall shear stress for liquid flow (2-phase) 0.00 Pa
Value Slider
Messages
Validating...
Running case 'Year 1 new'
Calculations ready

ATTACHMENT Q4.9E

ELEVATION PROFILE OF CORRIB PIPELINE


100
50
0
-50
-100
-150
-200
-250
-300
-350
-400
0
20
40
60
80
100
Elevation above sealevel (m)
Distance from Corrib (km)

Shell Global Solutions

GS.10.50885
UNRESTRICTED

Q4.10 - Corrib onshore pipeline - denting and puncturing evaluation

Shell Global Solutions

GS.10.50885
UNRESTRICTED

Corrib onshore pipeline - denting and puncturing evaluation

by

R.W.J. Koers
M. Church

Summary

The objective of the technical studies covered by this report is to evaluate the potential for mechanical damage of the Corrib onshore pipeline by third party activities (which may include those of contractors working near the pipeline on SEPIL's behalf) that may lead to loss of containment.

This report describes the results of an evaluation of the effect of third party mechanical damage on the integrity for the landfall section upstream of the LVI and the 8.3 km downstream of the LVI to the onshore terminal.

The potential for damage leading to loss of containment has been correlated with the puncture and denting resistance for the Corrib pipeline (note that the higher the pressure in the pipeline the more energy is needed to dent the pipe wall). It is concluded that:

- In order to puncture the pipe an excavator in excess of 65 tonnes weight would be required (the estimated energy required would be equivalent to that of an excavator of 150 tonnes weight), this is due to the large wall thickness of the pipeline. Puncturing by a smaller excavator is highly unlikely, puncturing by a plough would not occur.
- Denting or gouging of the pipeline that may not immediately lead to loss of containment but may result in subsequent failure should the pressure in the pipeline increase (so-called burst pressure) would require an excavator in excess of 65 tonnes to produce a dent gouge that would fail at a burst pressure less than Maximum Allowable Operating Pressures (MAOP).

The output of this evaluation and conclusions drawn provide input to the Quantitative Risk Assessment, QRA, in order that a potential frequency, or range of frequencies, of third party damage leading to loss of containment, can be applied that is specifically relevant to the Corrib pipeline. The output of the dent and gouge analysis also provides input to development of an operational phase procedure for follow-up action to be taken in the event that the pipeline should ever suffer such damage.

Amsterdam, May 2010

Table of contents

1. Introduction

This report describes the results of an evaluation of the effect of potential third party mechanical damage on the integrity for the landfall section upstream of the LVI and the 8.3 km downstream of the LVI to the onshore terminal.

2. Objective

The objective of the technical studies covered by this report is to evaluate the potential for mechanical damage of the Corrib onshore pipeline by third party activities (which may include those of contractors working near the pipeline on SEPIL's behalf) that may lead to loss of containment.

This report describes the results of an evaluation of the effect of third party mechanical damage on the integrity for the landfall section upstream of the LVI and the 8.3 km downstream of the LVI to the onshore terminal. The potential for damage takes account of:

- Immediate puncture leading to loss of containment.
- Denting or gouging that may not immediately lead to loss of containment but may result in subsequent failure should the pressure in the pipeline increase (so-called burst pressure).

Note that although activities around the pipeline such as construction using mechanical excavators or a farmer using a plough are a possible threat, operational phase controls, for example through the application of a Permit to Work (for construction activities), and ongoing surveillance of the pipeline right of way will be established to counter this threat.

3. Design conditions and operating conditions

The primary design code is I.S. EN 14161 [11] with I.S. 328 [12] and BS PD 8010-1 [13] as the back-up codes (I.S. 328 has priority over PD 8010).

The landfall section of the offshore pipeline and the onshore section (8.3 km) are designed with a nominal outside diameter of 508 mm (20") and a nominal wall thickness of 27.1 mm. The line pipe was delivered to DNV OS-F101 SAWL 485 II FD. The pipes have a Submerged Arc Welded Longitudinal seam weld.

The nominal wall thickness of 27.1 mm comprises 25.1 mm for pressure containment, 1 mm mill tolerance and 1 mm corrosion allowance.

The design and operating conditions are listed in Table 1.

Table 1 *Design and operating conditions*

		Design and Maximum Allowable Operating Pressure (MAOP) condition	Operating condition (based on 350 mmscf/d & 85 barg terminal arrival pressure)
Upstream LVI (offshore pipeline)	Pressure	Design: 345 barg MAOP: 150 barg	122 barg at the pipeline inlet (subsea manifold).
	Temperature	0 °C upstream of the LVI	60 °C at the pipeline inlet located downstream of subsea manifold. 2 to 10 °C landfall section.
LVI	Pressure	Design: 345 barg MAOP: 150 barg	90 barg at the LVI
	Temperature	Landfall shutdown spool (16" pipeline section): -26 °C Landfall mainline section (20" pipeline section): -20 °C	2 to 10 °C
Downstream LVI (onshore pipeline)	Pressure	Design: 144 barg MAOP: 100 barg	90 barg at the LVI. 85 barg at the terminal inlet.
	Temperature	-20 °C from LVI to 1150m downstream of the LVI. -10 °C from 1150m downstream of the LVI to the terminal.	2 to 10 °C

4. Material properties

The pipes for the pipeline were purchased in two batches. The major part of the line pipe was fabricated in 2002 by the Corus 42" mill in Hartlepool. The 27.1 mm line pipe is fabricated using Dillinger Hutte (DH) plate. An additional 1150 m of pipes was fabricated in 2009 by Eisenbau Krämer. To distinguish between the two batches these are referred to as '2002 line pipe' and '2009 line pipe' in this report.

The line pipe specified minimum yield strength is 485 MPa (605 MPa maximum) and the specified minimum tensile strength is 570 MPa (760 MPa maximum).

5. Punctures, dents and gouges (third party interference)

During operation, pipelines are exposed to potential damage by third parties. EPRG [1] studied the damage caused by the most common type of ground working equipment, i.e. excavators. To estimate the damage capacity of pipelines by excavators and to quantify the effect of the damage on the burst strength the following approach has been followed:

Step 1: Determine the damage capacity as a function excavator weight (Section 5.1).

Step 2: Determine the resistance of the pipeline to damage.
Puncture resistance (Section 5.2.1).
Denting resistance (Section 5.2.2).

Step 3: Estimate the damage due to an excavator by correlating the damage resistance (Step 2) with the excavator damage capacity (Step 1) (Section 5.3).

Step 4: Determine the burst pressure for damage possibly produced by an excavator. (Section 5.4).

5.1 Damage capacity of excavators

EPRG determined the maximum force that an excavator could produce for a population of 18 excavators from four manufactures with different fittings (24 cases) and checked the derived correlation on a wider population of 44 machines of four different manufactures.

A number of correlations were derived. The first correlation relates the maximum force with the mass of the excavator (Figure 1):

Correlation 1: $F_{max} = 14.2 m_{ex}^{0.928}$

F_{max} = Maximum excavator static force at tooth tip (kN);

m_{ex} = Excavator mass (tonnes).

The maximum force is 1.85 times the force produced by the bucket jack, and 2.32 times the force produced by the stick jack.

The second correlation correlates the standard tooth length with the mass of the excavator (Figure 2):

Correlation 2: $(L)_{standard} = 24.6 m_{ex}^{0.420}$

L = Tooth length (mm);

W = Tooth width (mm).

The validity range of the correlations is $7.8\ tonnes \leq m_{ex} \leq 65.5\ tonnes$.

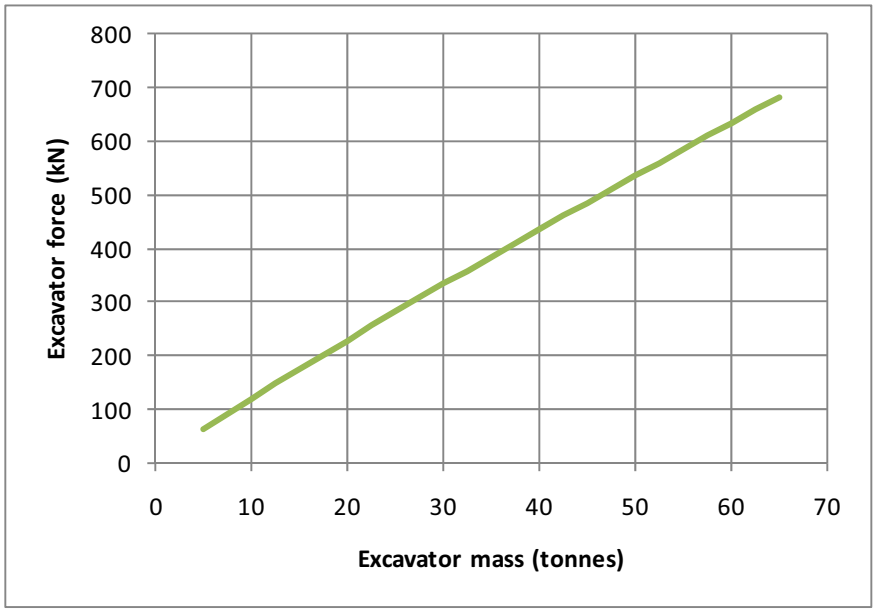


Figure 1 *Excavator force on pipeline as a function of excavator mass*

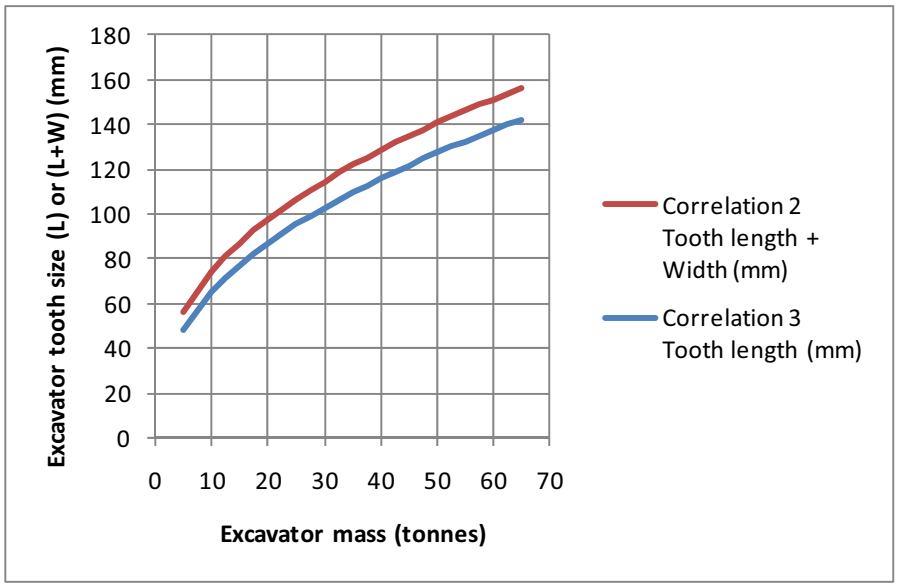


Figure 2 *Standard tooth size as a function of excavator mass*

5.2 Pipeline resistance to mechanical damage

5.2.1 Resistance to denting

EPRG has performed 82 static and dynamic full scale pipe denting test. The range of the denting test data is listed in Table 2 [1].

Empirical relations have been established that allow calculation of the dent depth corresponding to an excavator force. The excavator force is calculated using the following equations:

$$R_d = 7(10)^{-3} P_r \sqrt{H} \quad if \quad P_r \leq 2000\ mm\sqrt{N} \qquad \text{(Static denting)}$$

$$R_d = 0.31\sqrt{P_r}\sqrt{H} \quad if \quad P_r > 2000\ mm\sqrt{N} \qquad \text{(Dynamic denting)}$$

Where:

$$P_r = \sqrt{t^3 \cdot UTS \cdot L}\left(1 + 0.7\frac{P_{op} \cdot D}{t \cdot UTS}\right)$$

R_d = Denting resistance force (kN)
H = Dent depth measured after damage under pressure (mm)
P_r = Parameter describing the resistance of the pipeline to denting (mm√N)
P_{op} = Operating pressure (MPa)
D = Pipe outer diameter (mm)
t = Pipe wall thickness (mm)
L = Tooth length (mm)
UTS = Ultimate tensile strength (MPa)

Table 2 *Range of values tested for the static and dynamic resistance to denting [1]*

Parameter	Range of values
Pipe outside diameter (mm)	168.3-1220
Pipe thickness (mm)	3.2-18.6
Hoop stress level	0-72 % SMYS
Ultimate tensile strength (MPa)	413-665 MPa

Based on these equations the denting resistance as a function of tooth length and dent depth for the Corrib line pipe dimensions is plotted in Figure 3 for the minimum operating pressure of 85 bar. A higher pressure would increase the resistance to denting. The interpretation of Figure 3 is as follows. An excavator with a tooth length of 80 mm requires a force equal to 282 kN to produce a dent with depth of 5 % of the outer diameter.

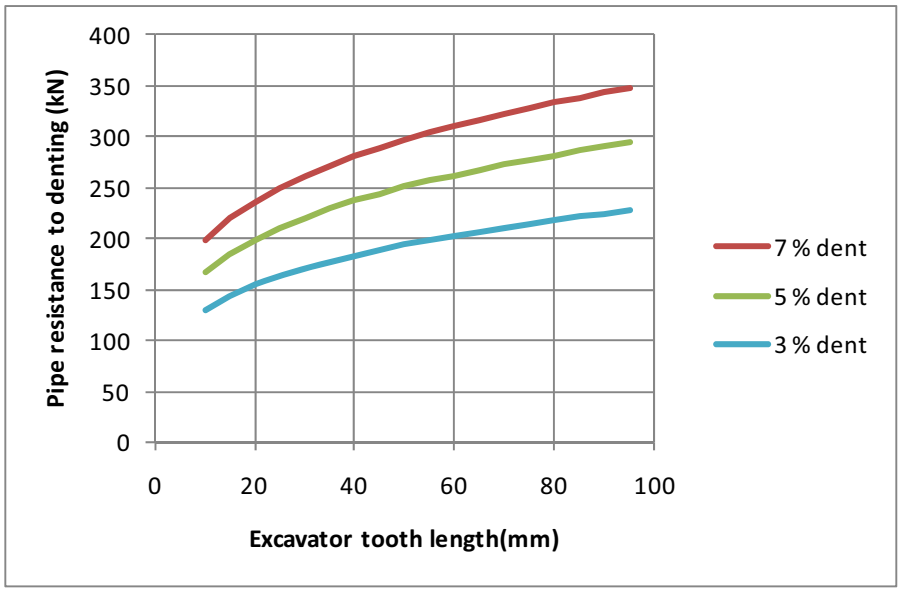


Figure 3 *Pipe resistance to denting as a function of the excavator tooth length (85 barg)*

5.2.2 Resistance to puncture

The resistance of line pipe against puncture has been a topic of several studies. The different models have been evaluated against experimental data. The range of values tested for static and dynamic puncturing are summarised in Table 3.

Table 3 *Range of values tested for the static and dynamic resistance to puncturing*

Parameter	Range of values
Pipe outside diameter (mm)	168.3-914,4
Pipe thickness (mm)	3.2-12.5
Hoop stress level	0-86 % SMYS
Ultimate tensile strength (MPa)	402-728 MPa
Tooth half perimeter (length + width) (mm)	15-75

In Reference [5] different puncture resistance models have been compared against experimental data from EPRG and Battelle, and a new model has been proposed. For this report the verification has been extended with the model presented in [6, 7] and using additional experimental data from the University of Western Australia [7]. The test data is

limited to relatively thin pipe walls. This is because pipelines with a wall thickness up to around 12.5 mm are most vulnerable to puncturing.

Puncture model 1 (Spiekhout 1987), [2]:

$$R_p = \frac{2.3\sigma_y t^2}{D - 0.7W}\left(0.4D\sqrt{\frac{D}{t}} + L\right)$$

Puncture model 2 (Spiekhout 1995), [3]:

$$R_p = c\sigma_y t^2$$

Puncture model 3 (Corbin and Vogt), [4]:

$$R_p = 0.711(L + W)(t\sigma_u)^{1.04}$$

Puncture model 4 (Driver and Zimmerman), [5]:

$$R_p = \left[1.17 - 0.0029\left(\frac{D}{t}\right)\right](L + W)t\sigma_u$$

Puncture model 5 (EPRG - mean), [1]:

$$R_p = 0.464(L + W)(t\sigma_u)^{1.087}$$

Puncture model 6 (EPRG – lower bound), [1] :

$$R_p = 0.232(L + W)(t\sigma_u)^{1.087}$$

Puncture model 7 (Brooker), [6]:

$$R_p = 7.0074(10)^{-4}t(\sigma_u + 410.4)(L + 22.41)\frac{W}{(3.142 + W)}$$

R_p = Puncture resistance force (kN)
D = Pipe outside diameter (mm)
t = Pipe wall thickness (mm)
L = Tooth length (mm)
W = Tooth width (mm)
σ_y = Material yield stress (0.5% strain) (MPa)
σ_u = Material ultimate tensile strength (MPa)
c = 4.8 for quasi-static loads
4.0 for dynamic loads

The different puncture models have been verified against in total 55 experiments from Battelle, EPRG and the University of Western Australia. The results are plotted in Figures 4 to 10 and summarised in Table 4. The ratio of the measured puncture load and the predicted puncture load is used to describe the scatter for each model. A value larger than 1.0 means that the puncture load is predicted to be conservative. All models have a mean value larger than 1.0. The least scatter is obtained for model number 7 and therefore this has been used to estimate the puncturing resistance for the Corrib pipeline.

Table 4 *Summary puncture resistance models*

Model	Mean	Standard deviation	95% confidence lower bound	Plot
1 - Spiekhout et al 1987	1.84	0.71	0.66	Figure 4
2 - Spiekhout 1995	1.92	0.70	0.78	Figure 5
3 - Corbin and Vogt 1997	1.06	0.33	0.51	Figure 6
4 - Driver and Zimmerman 1998	1.04	0.32	0.52	Figure 7
5 - EPRG 2000 (mean)	1.09	0.35	0.51	Figure 8
6 - EPRG 2000 (lower bound)	2.18	0.71	1.02	Figure 9
7 - Brooker 2003	1.08	0.16	0.82	Figure 10

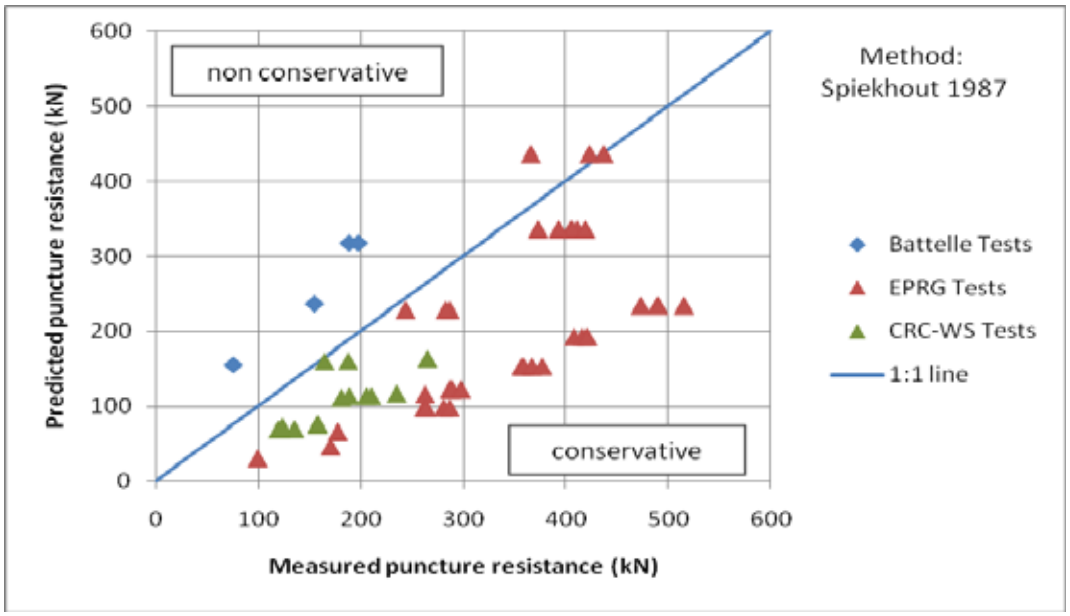


Figure 4 *Puncture resistance: Verification model 1 (Spiekhout 1987)*

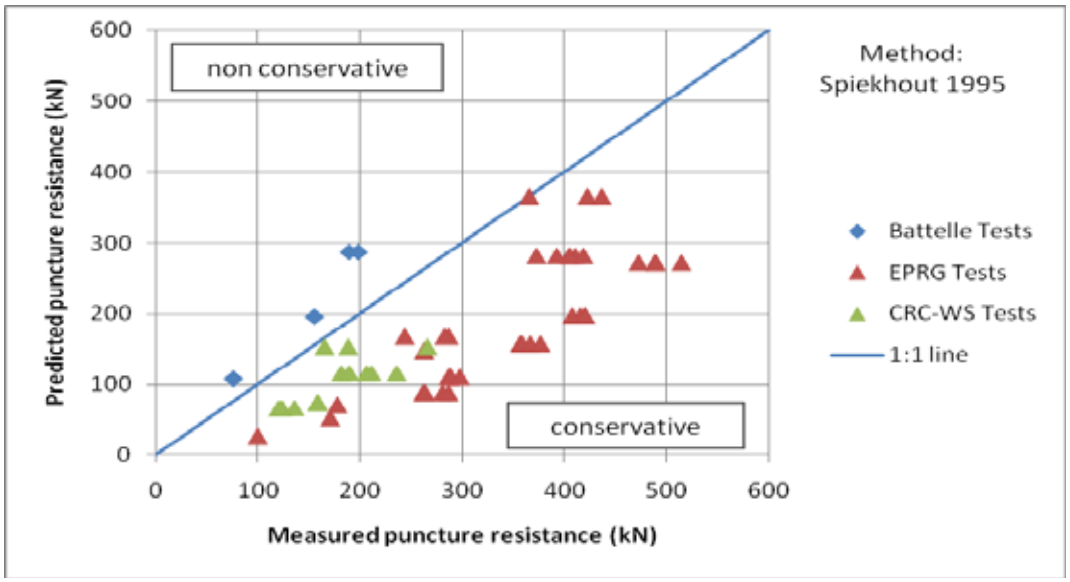


Figure 5 *Puncture resistance: Verification model 2 (Spiekhout 1995)*

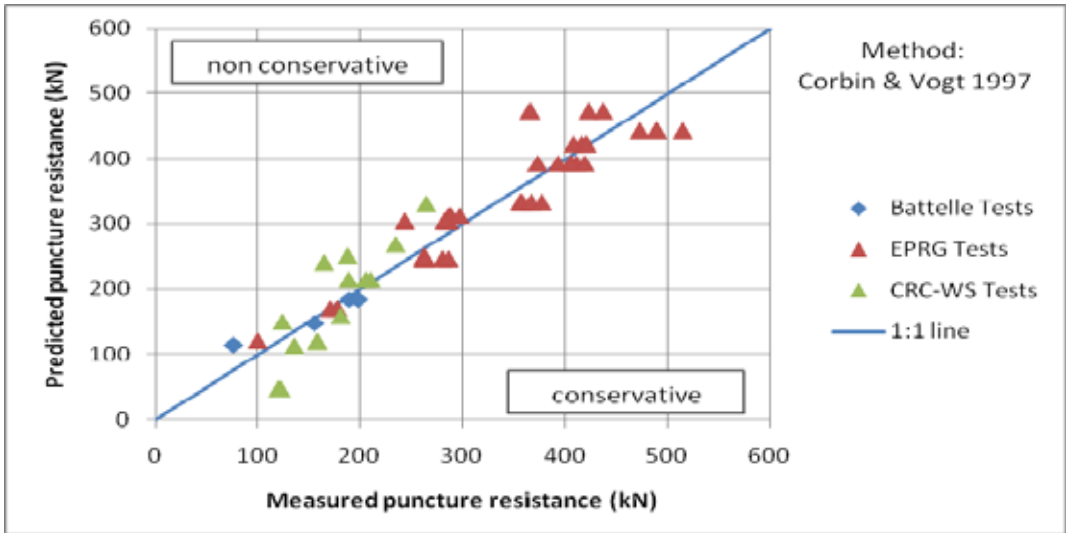


Figure 6 *Puncture resistance: Verification model 3 (Corbin and Vogt)*

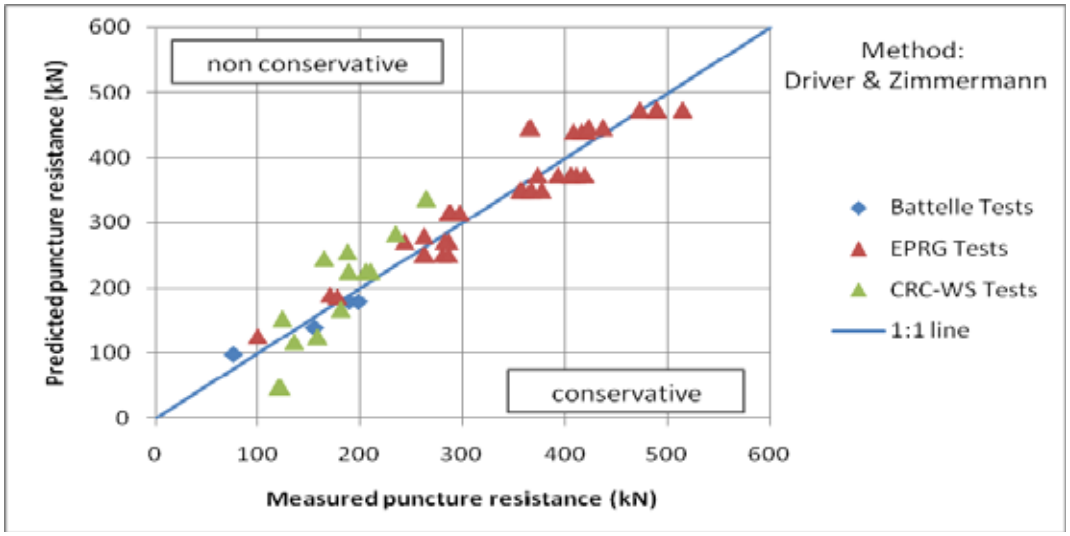


Figure 7 *Puncture resistance: Verification model 4 (Driver and Zimmerman)*

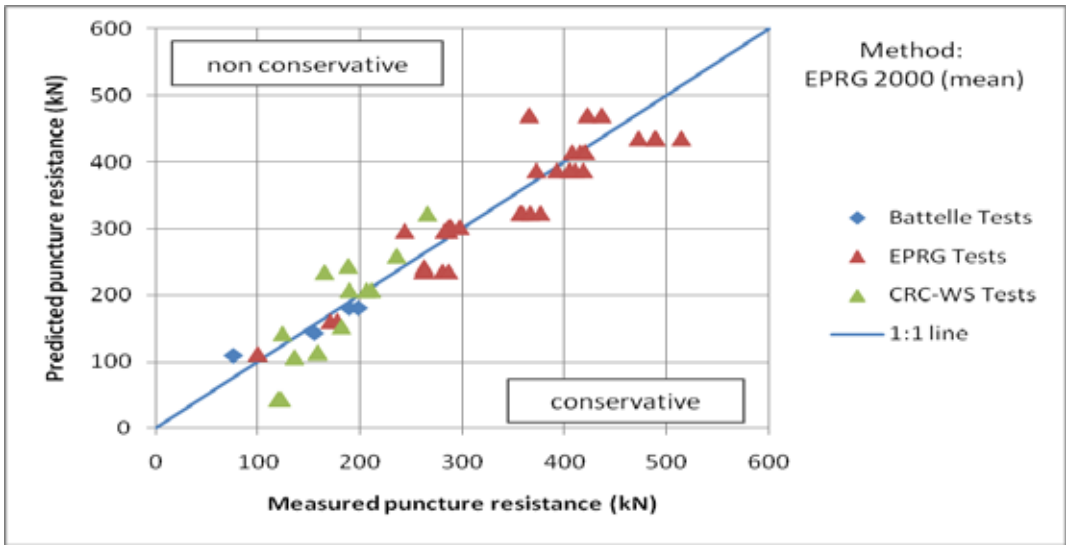


Figure 8 *Puncture resistance: Verification model 5 (EPRG – mean)*

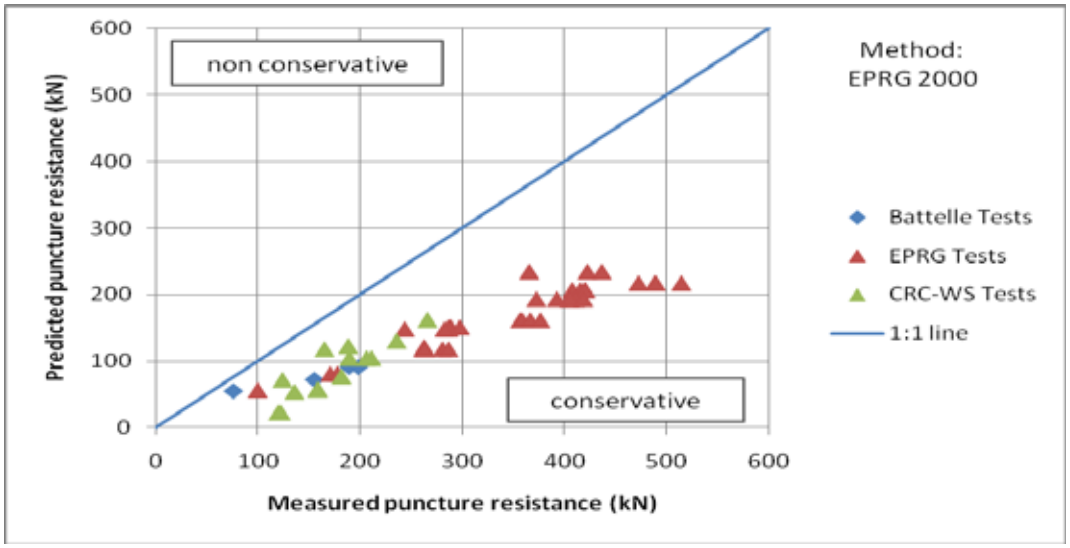


Figure 9 *Puncture resistance: Verification model 6 (EPRG – lower bound)*

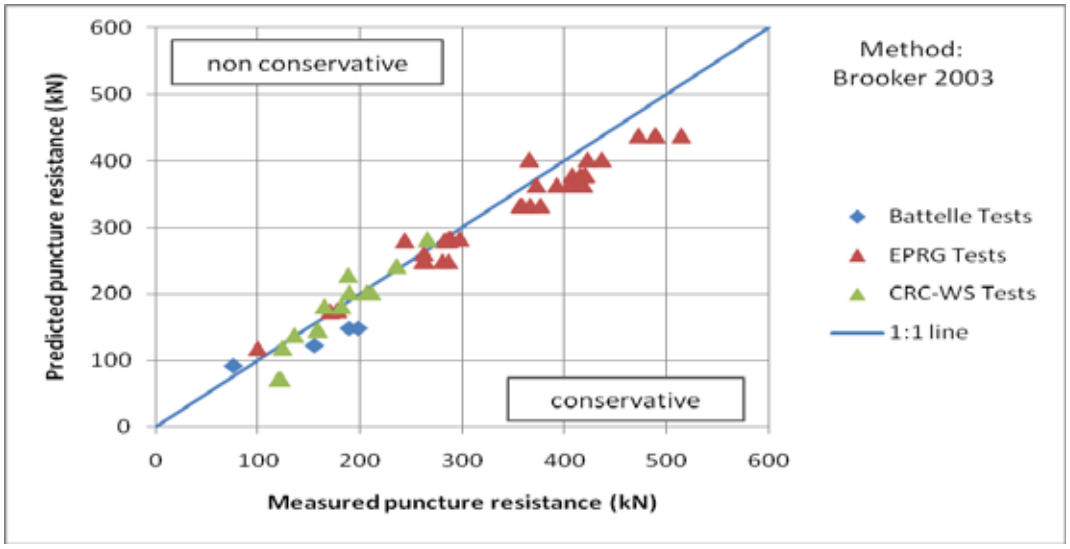


Figure 10 *Puncture resistance: Verification model 7 (Brooker)*

5.3 Possible damage due to an excavator

In Section 5.1 the damage capacity (force) of excavator has been described as a function of the excavator mass, and in Section 5.2 the resistance (required force) of the pipeline against mechanical damage has been described. In this section the damage capacity and the resistance to mechanical damage has been combined to estimate the excavator mass to produce a certain level of damage.

5.3.1 Denting

Combining the damage capacity (Figures 1 and 2) with the pipeline resistance to denting (Figure 3) the possible dent depth, should an excavator hit the pipeline, can be estimated. The result is given in Figure 11 which shows that a 40 tonnes excavator could produce a dent depth of 10% of the pipeline outer diameter (OD = 508 mm) during operation of the pipeline (i.e. pressurised).

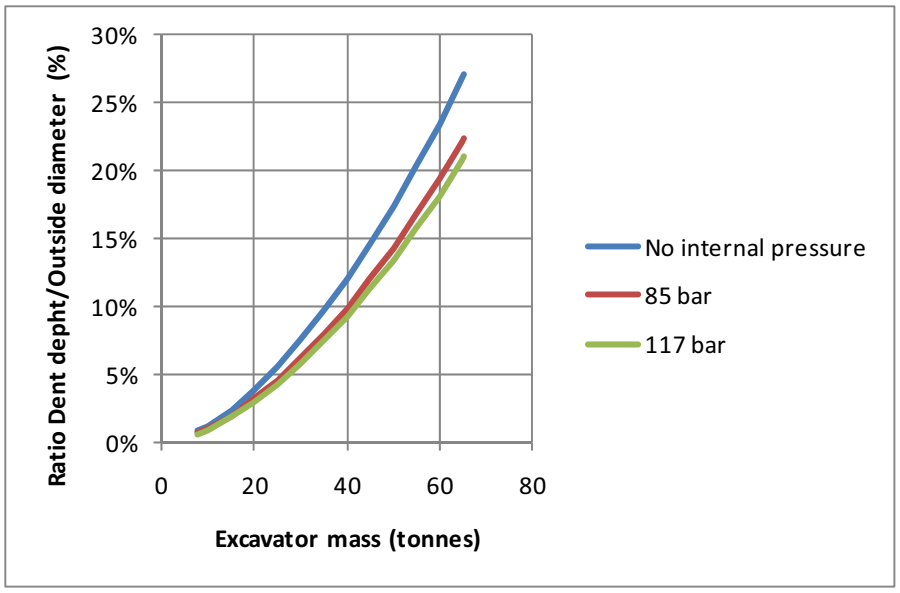


Figure 11
Excavator denting capacity unpressurised pipe, 85 barg and 117 barg internal pressure

5.3.2 Puncturing

Combining the damage capacity (Figures 1 and 2) with the pipeline resistance to puncture (Figure 10) the required excavator mass to puncture through the pipe wall can be estimated. Puncture model 7 has been used since this model produced the best correlation with experimental data. Nevertheless, a 95% confidence correction factor of 0.82 on the puncture model 7 equation has been applied to ensure conservative predictions. The resulting excavator puncturing capacity is plotted in Figure 12.

For an excavator size up to 65 tonnes the curves (solid lines) are generated using the mass versus standard tooth length correlation. Beyond 65 tonnes the curves (dotted lines) are based on a tooth length of 142 mm corresponding to the standard tooth length for an excavator size of 65 tonnes. The excavator damage capacity correlations where developed for excavators up to 65 tonnes.

The interpretation of Figure 12 is as follows. To puncture through a 10 mm wall a 65 tonnes excavator is required. To puncture through a 25 mm wall an excavator of more than 150 tonnes would be required. Therefore, puncturing through the 27.1 mm thick Corrib pipeline is unlikely with the type of mechanical equipment that would normally be used in the Glengad-Aghoos area.

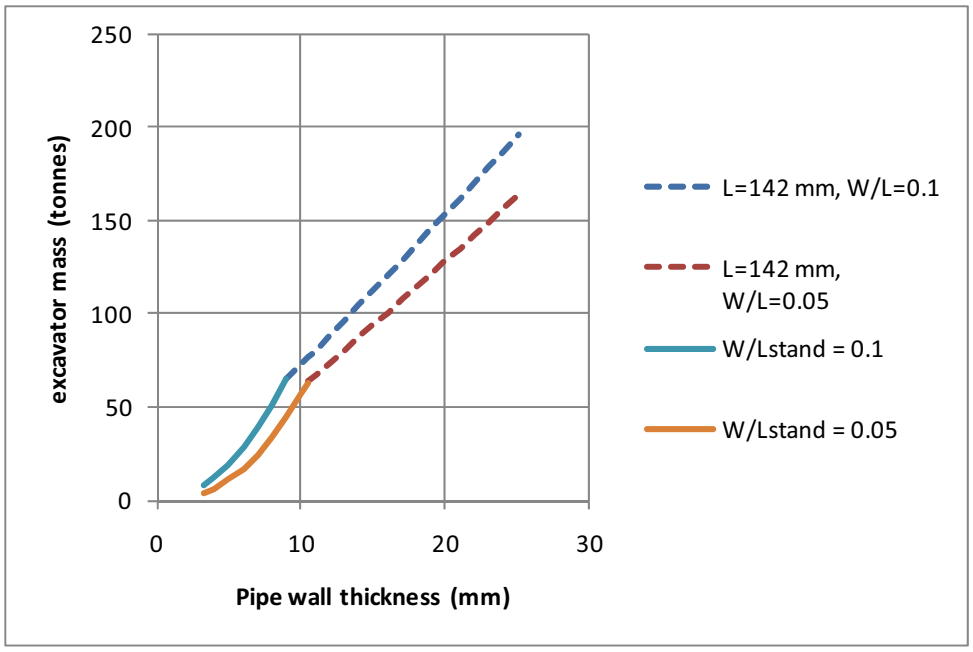


Figure 12 *Excavator puncture capacity*

5.4 Burst strength pipe dented pipe

In this section the burst strength of a pipe containing a dent or a dent with a gouge has been determined.

5.4.1 Burst strength pipe containing a plain dent

An empirical limit for a plain dent under static internal pressure loading had been derived from the results of full scale testing [8]. The results of the pressure of the tests, carried out by various organisations, of plain dents have been plotted in Figures 13 and 14. Figure 13 contains data of unconstrained dents only and Figure 14 also contains data of constrained dents.

A plain dent is a dent which causes smooth changes in curvature of the pipe wall and contains no wall thickness reductions (such as a gouge or a crack) and does not change the curvature of an adjacent girth weld or seam weld.
An unconstrained dent is a dent that is free to rebound elastically (spring back) when the indenter is removed, and is free to re-round as the internal pressure changes.
A constrained dent is not free to rebound or re-round, because the indenter is not removed. A dent caused by a rock is an example of a constrained dent.

Only four tests failed in the dented area and had a dent depth greater than 10 % of the outer diameter. The remainder of the tests were terminated prior to failure. No failure occurred in the tests for a dent depth of up to 10% of the outer diameter (measured after spring back and measured at zero pressure). This corresponds to a depth of 7% measured at full pressure [8].

Full scale tests on dents containing welds can exhibit lower burst pressure. Therefore, dented welds are usually repaired or removed if found in a pipeline. In addition specific construction methods are applied to reduce the risk of local denting at welds.

Table 5 *Test data range burst tests plain dents*

Parameter	Range
Pipe diameter (D), mm	168 - 914.4
Wall thickness (t), mm	4.78 - 12.7
D/t ratio	23.6 - 80.0
Grade (API 5L)	X42 - X60
Yield strength, MPa	371.6 - 485.4
Tensile strength, MPa	483.3 - 639.2
yield to tensile ratio	0.70 - 0.85
2/3 Charpy Impact Energy, Joule	20.3 - 43.4
Dent depth (H), mm	2.72 - 327.7
H/D	0.005 - 0.43
Maximum pressure, MPa	2.76 - 46.0
Maximum stress (percent SMYS)	30.8 - 175.1

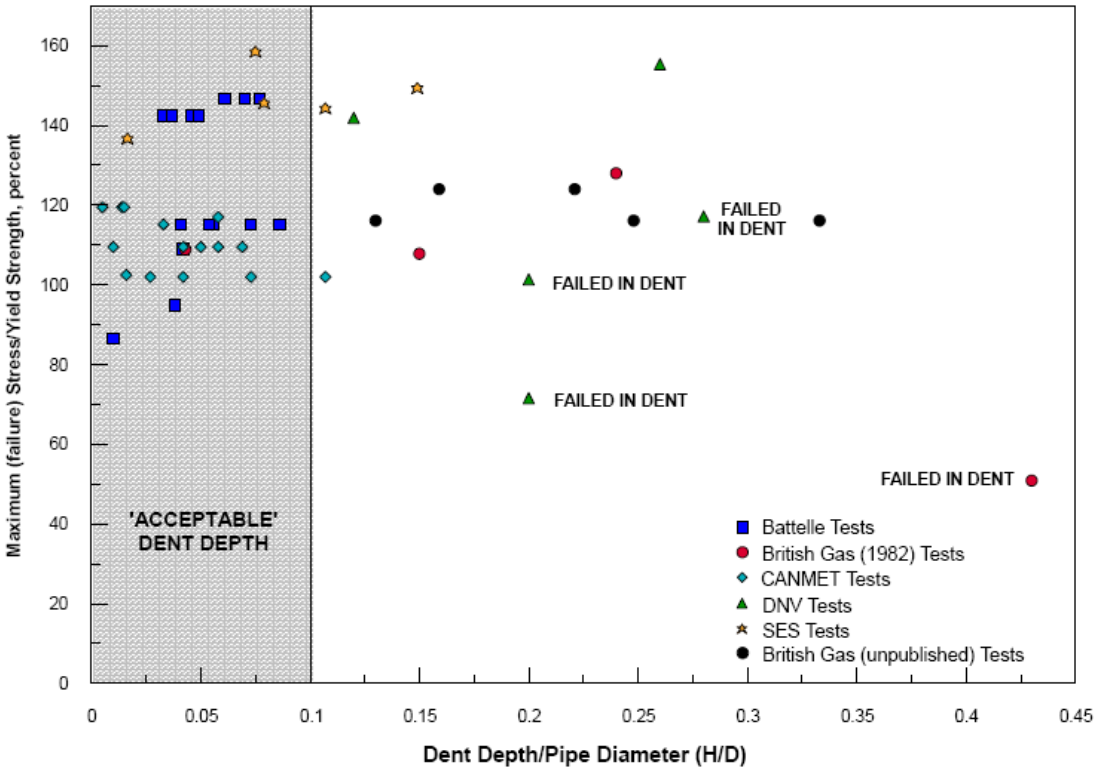


Figure 13
Maximum (failure) stress of unconstrained plain dents, normalised by yield strength (dent depth after spring back and measured at zero pressure)

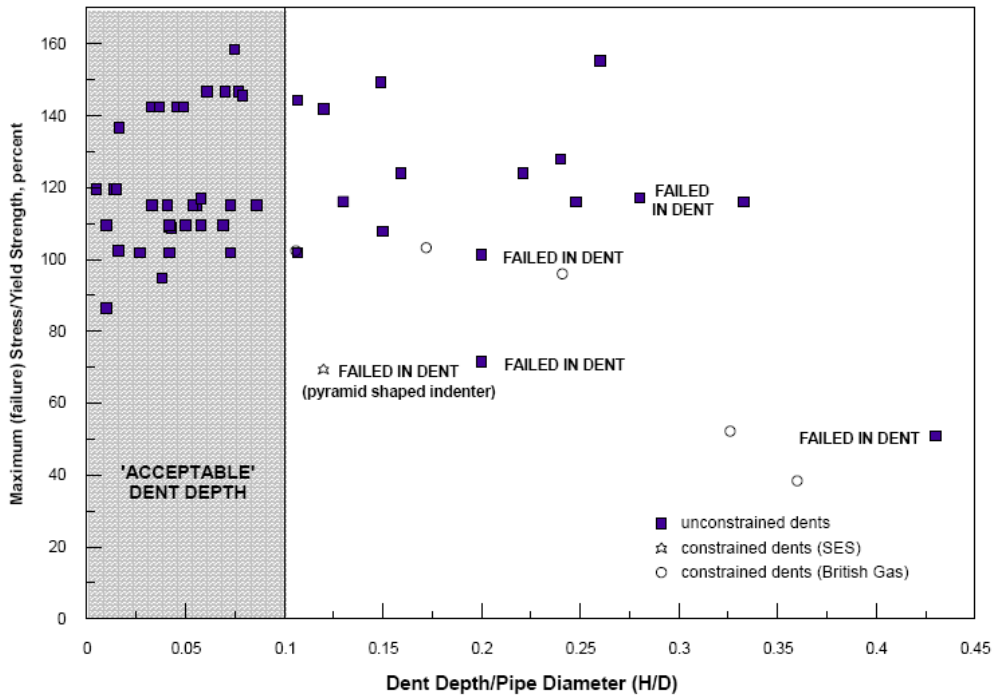


Figure 14
Maximum (failure) stress of constrained and unconstrained plain dents, normalised by yield strength (dent depth after spring back and measured at zero pressure)

5.4.2 Burst strength pipe containing a dent with a gouge

Several models to predict the failure stress of a smooth dent containing a gouge have been compared and the best correlation with the experimental data was obtained with the following semi-empirical fracture model [9]. The failure (circumferential) stress is given by:

$$\frac{\sigma_\theta}{\bar{\sigma}} = \frac{2}{\pi}\cos^{-1}\left[\exp - \left\{113\frac{1.5\pi E}{\bar{\sigma}^2 A d}\left[Y_1\left(1 - 1.8\frac{H_o}{D}\right) + Y_2\left(10.2\frac{R}{t}\frac{H_o}{D}\right)\right]^{-2}\exp\left[\frac{\ln(0.736C_{v2/3}) - K_1}{K_2}\right]\right\}\right]$$

$$\bar{\sigma} = 1.15\sigma_y\left(1 - \frac{d}{t}\right)$$

$$Y_1 = 1.12 - 0.23\left(\frac{d}{t}\right) + 10.6\left(\frac{d}{t}\right)^2 - 21.7\left(\frac{d}{t}\right)^3 + 30.4\left(\frac{d}{t}\right)^4$$

$$Y_2 = 1.12 - 1.39\left(\frac{d}{t}\right) + 7.32\left(\frac{d}{t}\right)^2 - 13.1\left(\frac{d}{t}\right)^3 + 14.0\left(\frac{d}{t}\right)^4$$

$$K_1 = 1.9$$

$$K_2 = 0.57$$

Where:

σ_θ = circumferential stress (MPa)
σ_y = material yield strength (MPa)
d = gouge depth (mm)
t = wall thickness (mm)
R = outside radius of pipe (mm)
D = outside diameter of pipe (mm)
H_o = dent depth measured at zero pressure (mm)
$C_{v2/3}$ = 2/3 Charpy impact energy (Joule)
A = ligament area 2/3 Charpy specimen (mm^2)
E = Young's modulus (MPa)

A comparison between the predictions and data from full scale tests on rings and vessels containing smooth dents and gouges is shown in Figure 15. When a point is above the solid line, the failure pressure is predicted unconservative (predicted failure pressure greater than measured failure pressure). When a point is below the solid line, the failure pressure is predicted conservative (predicted failure pressure less than the measured failure pressure).

There is a relatively large scatter between the predictions and the experimental results. Therefore, it is proposed to use a 95% confidence level to the data. The result is shown in Figure 16. Using the 95% confidence as the failure prediction the predicted failure pressure is generally predicted conservative (predicted failure pressure less than the measured failure pressure).

A summary of the test data is given in Table 6.

Table 6 *Test data range burst tests dent with gouge*

Parameter	Range
Pipe diameter (D), mm	216.3 – 1066.8
Wall thickness (t), mm	4.8 – 20.0
D/t ratio	33.6 – 107.7
Yield strength, MPa	279.2 – 543.3
Tensile strength, MPa	475.0 – 701.2
Yield to tensile ratio	0.61 - 0.87
2/3 Charpy Impact Energy, Joule	16.3 – 130.7
Dent depth (H), mm	1.5 – 146.5
H/D	0.0042 - 0.18
Defect depth (d), mm	0.18 – 6.1
d/t	0.014 – 0.51
Defect length (2c), mm	50.8 – 810.0
Burst pressure, MPa	0.972 – 25.24
Burst stress (percent SMYS)	7.05 - 151.5

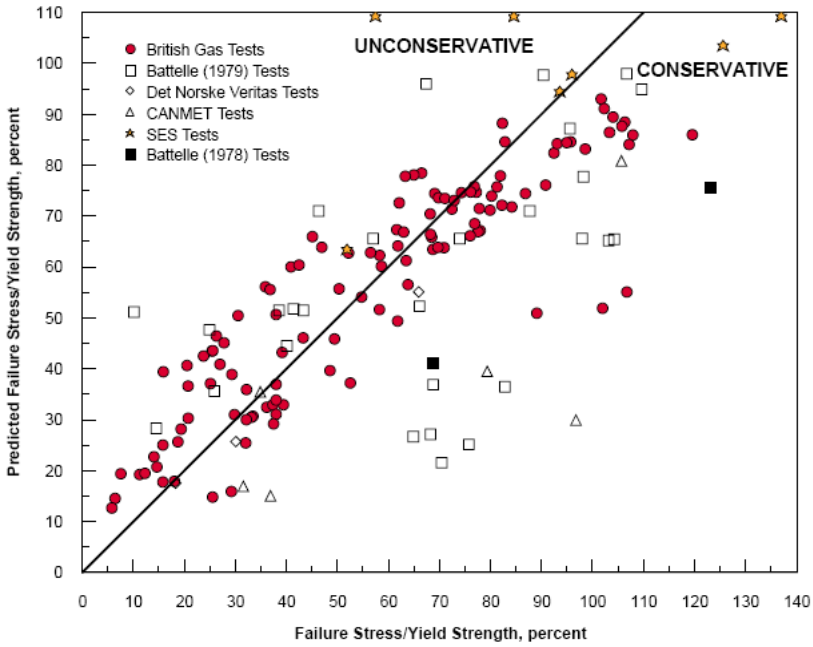


Figure 15 *Predictions of the failure stress compared with the experimental stress*

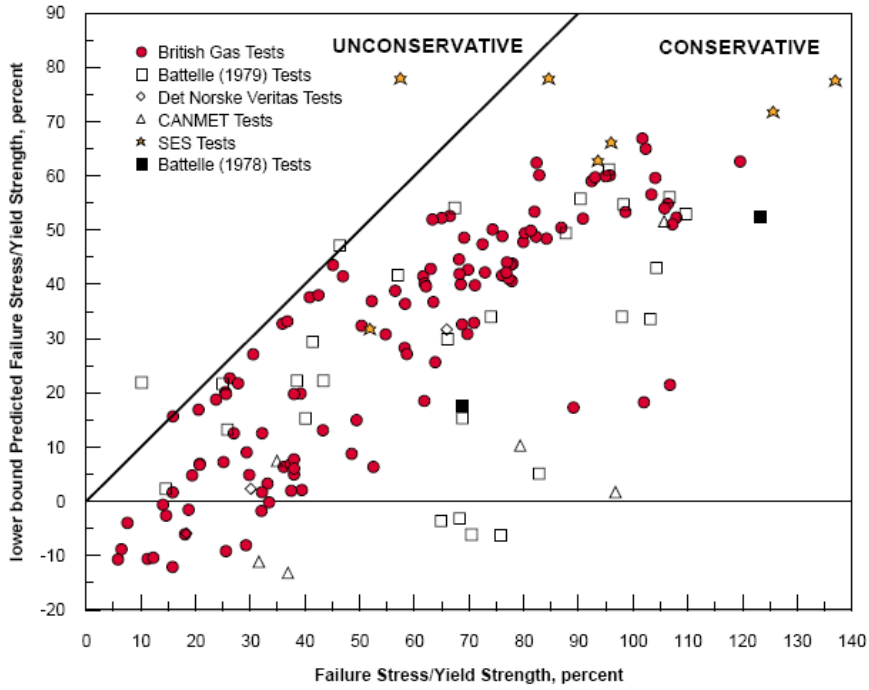


Figure 16
Predictions of the failure stress and applying a 95% confidence with the experimental stress

5.4.3 Results burst strength predictions

A dent which causes smooth changes in curvature of the pipe wall and contains no wall thickness reductions (such as a gouge or a crack) and does not change the curvature of an adjacent girth weld or seam weld is acceptable up to a depth of 10% of the outer diameter.

Dents with a gouge do limit the burst pressure. The burst pressure and 95% confidence safe working pressure have been determined using the Charpy impact data from the material certificates. The Charpy impact data (transverse full size specimens) has been summarised in Table 7.

Table 7 *Charpy impact data (full size specimen)*

Pipe	Corus 2002 line pipe	Krämer 2009 line pipe
Test temperature	(-20 °C)	(-20 °C)
Average	236 Joule	265 Joule
Standard deviation	34 Joule	30 Joule
Lower 95 % confidence	180 Joule	214 Joule

The result is plotted in Figure 17 for a Charpy impact energy of 180 Joule (full size specimen).

Assuming that an excavator of 40 tonnes has generated a dent, downstream of the LVI, with a depth equal to 10% of the outer diameter (refer Figure 11) and the operating pressure downstream of the LVI is 89 barg, the safe working pressure for a 10% dent with a 3 mm gouge is 122 barg. This exceeds the MAOP of 100 barg.

In reference [10] cumulative Weibull probability distribution functions are given for gouge depth and dent depth based on historical data. Using the 90% probability values it follows that, 90% of the dents had a depth less than 20.8 mm and 90% of the gouges had a depth less than 3.7 mm.

It is unclear from reference [10] whether the dent depths were measured at zero pressure or while the pipe was at pressure. Therefore, it has conservatively assumed that the quoted dent depths were measured while the pipe was at pressure.

A dent depth of 20.8 mm would correspond to a 4.1% dent depth for the Corrib line. Using Figure 17 for a dent depth of 4.1% and a gouge depth of 3.7 mm the safe working pressure is 177 barg. This exceeds the MAOP of 100 barg.

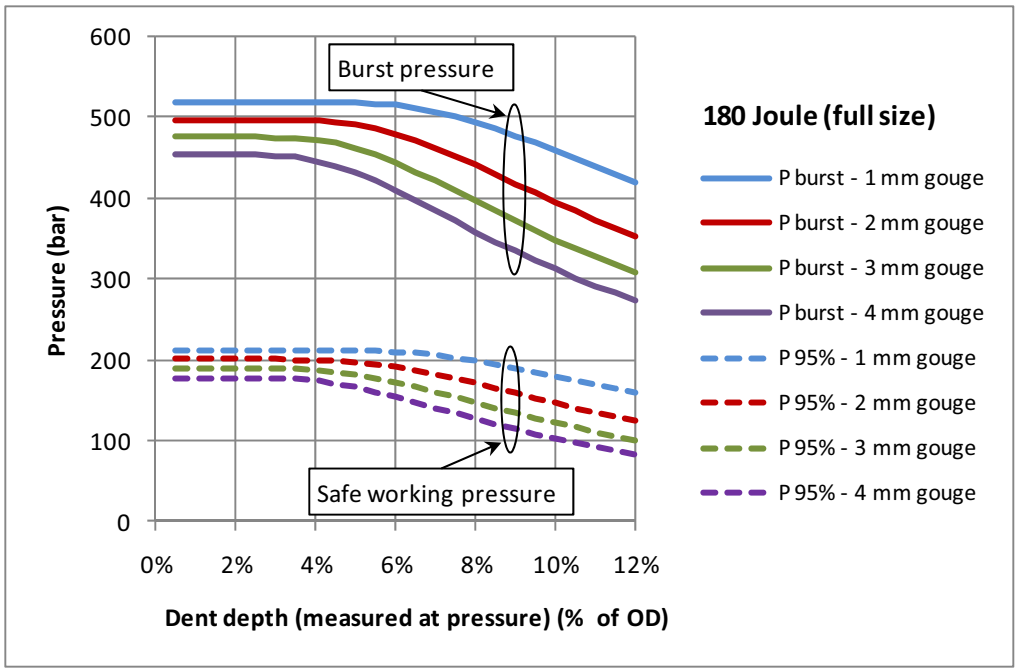


Figure 17 *Predictions Corrib line pipe (25.1 mm wall thickness)*

6. Mitigation of mechanical damage

Note that although activities around the pipeline such as construction using mechanical excavators or a farmer using a plough are a possible threat, operational phase controls, for example through the application of a Permit to Work (for construction activities), and ongoing surveillance of the pipeline right of way will be established to counter this threat.

The trench padding and backfill material will be selected such that the risk of rock dents or other damage will be reduced to a minimum.

7. Conclusions

The damage capacity has been correlated with the puncture and denting resistance for the Corrib pipeline.

In order to puncture the pipe an excavator in excess of 65 tonnes weight would be required (the estimated energy required would be equivalent to that of an excavator of 150 tonnes weight), this is due to the large wall thickness of the pipeline.
Puncturing by a smaller excavator is highly unlikely, puncturing by a plough would not occur.

Denting due to an excavator cannot be excluded. However, an excavator in excess of 65 tonnes is required to produce a dent gouge that would fail at a burst pressure less than MAOP.

This compares with excavators in use in the area which are normally of the size of 15-20 tonnes.

Figure 18 *Example of a 20 tonnes excavator (weight 20,600 kg) (www.newholland.com)*

Figure 19 *Example 63 tonnes excavator (weight 63,200 kg) (www.newholland.com)*

8. References

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Amsterdam, May 2010
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Appendix Q5

Pipeline Integrity Management

Q5.1: Integrity Process
Q5.2: Pipelines Integrity Management Scheme
Q5.3: Onshore Hydrostatic Pressure Testing Report
Q5.4: Summary of Preservation of Linepipe

Shell E & P Ireland Limited CORRIB FIELD DEVELOPMENT PROJECT REPORT	J P KENNY Corrib natural gas

Corrib Onshore Pipeline EIS Appendix Q5.1 INTEGRITY PROCESS	PROJECT No. 052377.01 REF **CTR 349** No OF SHEETS 19

DOCUMENT No	OFFICE CODE	PROJECT No	AREA	DIS	TYPE	NUMBER
	05	**2377**	**01**	**P**	**3**	**047**

REV	DATE	DESCRIPTION	BY	CHK	ENG	PM	CLIENT
03	13/05/10	Issued for Planning Application	JG	GSW	GSW	JG	
02	4/05/10	Issued for Comment	JG	GSW	GSW	JG	
01	8/03/10	Issued for IDC	JG	GSW	GSW	JG	

CONTENTS

1 INTRODUCTION

1.1 Purpose

In the development of the Corrib pipeline system, SEPIL will undertake a range of activities including design, procurement of manufactured equipment and materials together with construction and commissioning. It is essential that during execution of each of theses process the integrity of the Corrib pipeline system is defined, achieved and maintained.

Integrity of the Corrib pipeline is established through compliance with the Irish legislation, adoption of recognised international codes and standards together with incorporation of best practice and procedures.

This document provides an overview of the processes adopted to assure the integrity of the complete development process. The extent and application of the procedures and process adopted take into account the nature of the equipment and materials and in particular their level of importance regarding safety and operation.

1.2 Integrity Overview

An overview of the hierarchy of the process of integrity management is illustrated in Figure 1-1. The foundation of the assurance of integrity is formulated in National legislation and the respective codes and standards combined with best practice. This is then supported by internationally recognised Quality Management systems which require integral process for the integrity of design, manufacture and construction. The integrity of the system is then verified through inspection and testing during manufacture and construction together with provision of comprehensive documentation. Finally the whole system is independently checked through third party inspection and independent verification.

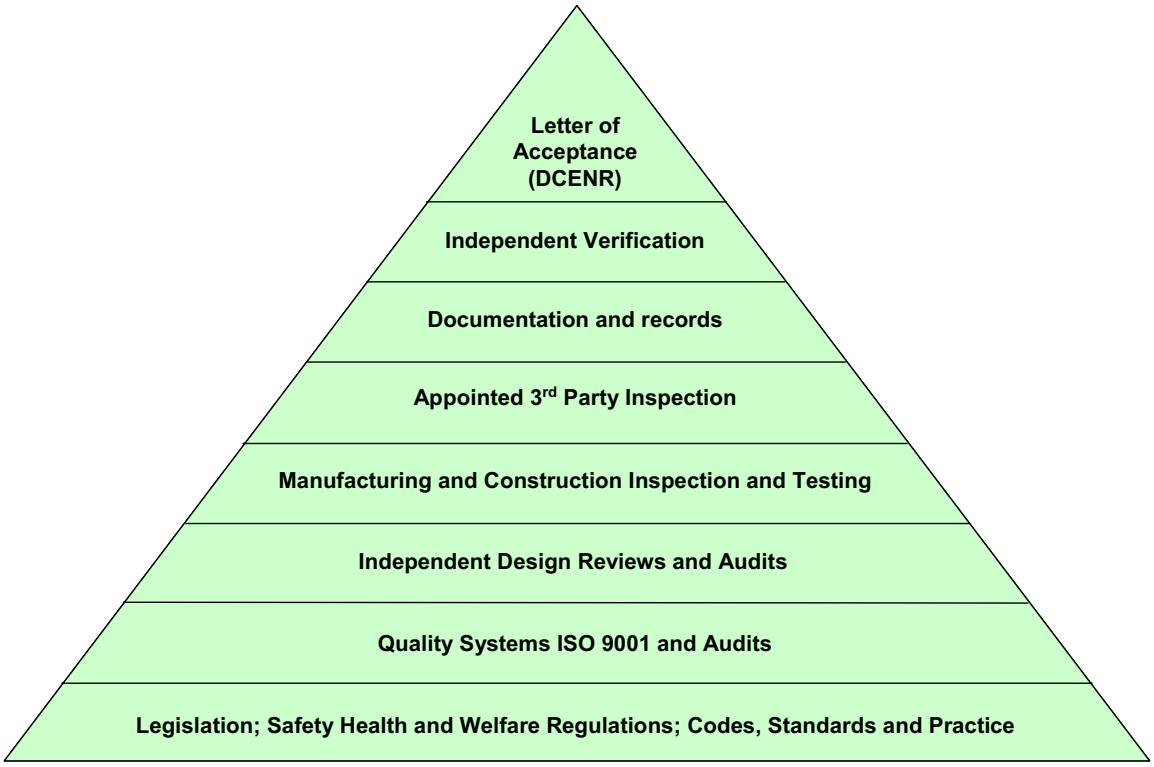

Figure 1-1 Hierarchy for Management of Integrity Process

1.3 Project Activities

The principal processes undertaken for project implementation are:

- Design
- Manufacturing
- Construction
- Pre-commissioning

Each of these processes comprises a series of key activities, as summarised below, which establishes and manage integrity. This ensures that the implemented system is safe and fit for purpose.

1.3.1 The Design Process

This includes:

- Establishment of Codes, Standards and procedures
- Establish Quality System and Audits
- Prepare the Basis of Design
- Prepare key design documents
- Perform safety studies (e.g. HAZID, HAZOP etc)
- Prepare technical specifications, data sheets and material take-offs
- Prepare Engineering Requisitions for procurement
- Prepare detailed design drawings
- Perform design reviews and approval procedures
- Prepare scope of work packages and bills of quantity
- Prepare Design Package Dossier including documents Approved for Design

1.3.2 Manufacturing Process

This includes:

- Establishment of plans and procedures
- Manufacturing design (if required)
- Placement of orders and appointment of sub-contractors
- Fabrication
- Assembly
- Testing
- Acceptance Tests
- Documentation

1.3.3 Construction Activities

This includes:

- Establishment of plans and procedures

- Preparation of Method Statements.
- Placement of material orders and appointment of sub-contractors
- Materials Storage and Handling
- Supervision and Inspection
- Fabrication
- Excavation
- Erection of structures
- Installation
- Back-filling
- Mechanical Completion
- As-Built Documentation

1.3.4 Pre-commissioning Activities

- Testing and Inspection
- Acceptance Testing
- Handover for Commissioning

1.4 Safety, Health and Welfare at Work

The Safety, Health and Welfare at Work (Construction) Regulations 2006 where Regulations 1 to 29 are concerned with the duties on promoters, designers, project supervisors, and the general duties of contractors. SEPIL will ensure compliance with all the Regulations, including the duties 30 to 105. The Regulations are aimed at protecting workers from accidents and ill heath in the construction industry. They apply to all forms of construction work undertaken in the course of trade, business, or other undertaking. SEPIL will ensure the competence of all appointees as required by the Regulations.

To comply with the Regulations, SEPIL has appointed a Project Supervisor Design Process (PSDP) who will:

- Identify hazards arising from the design or from the technical, organisational, planning, or time related aspects of the project.
- Where possible, assist the designers to eliminate the hazards or reduce the risk.
- Communicate necessary control measures, design assumptions, or remaining risks to the PSCS so they can be dealt with in the Safety and Health Plan.
- Ensure that the work of designers is co-ordinated to ensure safety.
- Organise co-operation between designers.
- Prepare a written safety and health plan.
- Prepare a safety file for the completed structure.
- Notify the Authority and SEPIL of non-compliance with any written directions issued.

In addition SEPIL has appointed a Project Supervisor Construction Stage (PSCS) who will:

- Co-ordinate the implementation of the construction regulations by contractors.

- Organise co-operation between contractors and the provision of information.
- Co-ordinate the reporting of accidents to the Authority.
- Notify the Authority before construction commences.
- Provide information to the site safety representative.
- Co-ordinate the checking of safe working procedures.
- Co-ordinate measures to restrict entry on to the site.
- Co-ordinate the provision and maintenance of welfare facilities.
- Co-ordinate arrangements to ensure that craft, general construction workers, and security workers have a Safety Awareness card, e.g. Safe Pass and a Construction Skills card where required.
- Co-ordinate the appointment of a site safety representative on site.
- Appoint a safety adviser.
- Provide all necessary safety file information to the PSDP.
- Monitor the compliance of contractors on the construction site and take corrective action where necessary.
- Notify the Authority and SEPIL of non-compliance with any written directions issued.

2 QUALITY SYSTEM

2.1 Quality Management and Control

The key driver to the quality and thus assurance as to the integrity of the supplied product is compliance with ISO 9001:2008 Quality Management Systems. All SEPIL Contractors are audited against ISO 9001 standard which is the accepted industry benchmark. This standard is applied to both Suppliers and Contractors and all major or key sub-suppliers and sub-contractors.

Each Contractor is required to establish a Quality Assurance and Control management systems and procedures in accordance with the Contractors Quality Plan. This will be undertaken by a dedicated team within the Contractor's organisation and will report directly to the Contractors corporate management. The established review and approval procedures will be monitored by the Quality Team which will include qualified and competent auditors.

SEPIL undertakes audits of Contractor's quality system and any non-conformances are required to be rectified.

2.2 Codes and Standards

All work is undertaken in accordance with the applicable codes and practices defined for the project which are identified in the contract documents and the scope of work, specifications and drawings.

2.3 Company Selection

The tender process is the first stage in selecting a preferred Contractor. The list of companies selected for tendering is usually limited to around five. Thus the selected companies will either be already approved by Shell from previous work, tendering or qualification procedures, or the identified companies will be specifically prequalified for the specific project. In this instance a separate exercise is undertaken prior to tendering when the track record, financial stability, competence, design process, HSE management and Quality Systems will be evaluated against strict criteria.

In certain cases the procurement process may be subject to European Union procurement rules and thus these are also followed during the pre-qualification and/or tender selection process.

The principle steps in the tendering process are:

- Issue of Tender Documents.
- Respond to tenderers questions.
- Receive the individual tenders.
- Technically and commercially evaluate the submissions.
- Clarify any points within the submitted tender.
- Make a recommendation to senior management.
- Obtain approval from senior management.

2.4 Competence Management

In order to achieve safe and high quality design the personnel assigned by the Contractor must have the necessary qualifications and competences for the role and duties assign within the Contractor's team. The Contractor will prepare a job description for each position within the design team and will nominate personnel to fulfil the

designated role. SEPIL will check the qualifications and experience of the proposed individuals by initial reference to the personnel career resume and for more senior positions will conduct interviews of the personnel. Once assigned to a position, the Contractor will be required to advise SEPIL of any proposed changes in personnel and will replace them with a suitable person with equivalent or better qualifications and experience; as approved by SEPIL.

SEPIL will have the authority to require the Contractor to replace any person in the Contractor's design team who SEPIL considers does not attain the level of competence required.

2.5 Change Management

During the design, manufacturing and construction process there may arise occasions when a change has to be implemented while part way through a particular process. Management of such changes is a critical element in assuring the integrity of the overall system design. In addition to internally undertaking the change control procedure, the Contractor is required to formally notify the PSDP/ SEPIL of any such changes and to await formal approval before proceeding with the work. In some cases SEPIL may require additional checking and verification to be performed prior to approval of the proposed change. This ensures that the final system fully meets it specified purpose without comprising safety or performance.

2.6 Documentation

A key aspect to the management of integrity during each of the processes is concise and complete documentation and records that fully define the design, manufacture, construction and pre-commissioning of the complete system.

Each Contractor is required to co-operate with the PSDP and PSCS to implement a formal control of documents to ensure the correct revision is used and that each document is duly checked and authorised for use. At the conclusion of the work, each Contractor is required to formally hand-over comprehensive documentation which records and reflects the integrity process undertaken during the individual stage of the development. In particular these include:

- Design Dossiers including calculations and safety engineering.
- Manufacturers record books including certificates, manuals and lists of spares
- Construction as-built documents reflecting the actual as installed status and inspection documentation.
- Testing records and approved certificates following pre-commissioning.
- Verification audits and letters of release

3 DESIGN

3.1 Design Integrity Process

The integrity of the design process is achieved through a variety of tools as follows:

- Design Management co-ordinated by the PSDP
- SEPIL Discipline Control Assurance Framework Process
- Design Development and Checking
- Safety and Constructability Engineering
- Design Reviews
- Design Approval

3.2 Design Management

The methods and process adopted by the PSDP in conjunction with the Design Contractors and approved by SEPIL are established once the contract is awarded.

These include:

- Design Team Organisation (roles and responsibilities)
- Design plan/schedule/procedures
- Design element integration procedures
- Identification of applicable codes, standards and practices
- Procedure and content of Basis of Design
- Design Procedures
- Materials Procurement Plan
- Subcontracting Plan (as applicable)
- HAZID and HAZOP reviews
- HSE plan
- Quality Assurance and Control Plan (including prescribed Quality audits)
- Design Reviews and Approvals
- Documentation Control Procedure
- Input to the Safety File prepared by the PSDP

3.3 SEPIL Discipline Control Assurance Framework Process

Shell operates a quality assurance process framework covering all areas of all exploration and production projects and the Group standardises Quality Control and Quality Assurance across all technical disciplines.

The quality assurance process framework addresses both the project's execution deliverables (the "Controls") and the quality and technical soundness of those deliverables. Assurance is achieved via Shell experts known as "Technical Authorities (TA's)"

3.4 Design Development and checking

During the design process the individual engineers and designers develop the underlying design including respective calculations and supporting documents. These are then internally reviewed between the various disciplines and subsequently issued to SEPIL for comment. SEPIL checks the design documents and where appropriate obtain reviews by the internal Shell Technical Authority. Once all comments are received and verified, the document is issued for approval.

3.5 Safety and Constructability

As part of the design process PSDP, in conjunction with the Design Contractors, holds internal design review meetings to establish the basis and methodology for the design taking into consideration HSE and constructability aspects.

More formal reviews are held to identify hazards (HAZID) and to evaluate hazard and operability issues (HAZOP). Qualitative risk assessments are used to identify and document the safety risks and mitigation measures. Also formal constructability reviews are held prior to issue of the design and documents as Approved for Construction.

The residual risks that remain and the proposed mitigation measures assumed by the Design Contractors are included in the Preliminary Health and Safety Plan prepared by the PSDP for further development by the PSCS in conjunction with the Construction Contractors Method Statements.

3.6 Design Reviews

Once the design is firmly established, SEPIL conduct internal design reviews attended by relevant Technical Authorities and internal independent representatives from within the Shell organisation.

SEPIL has appointed an independent company to undertake 3rd party review and approval of the critical aspects of the work during the design process. This entails review of the associated design information, calculations, specifications etc to verify compliance to the defined codes, standards and practices.

3.7 Design Approval/ Documentation

Prior to commencement of the onsite works the complete design packages will be reviewed by the Design Contractor and SEPIL to assure that the work can commence against the approved design.

At this stage all comments form the previous reviews, HAZOP etc will be checked to ensure that they are formally closed out.

The documents and drawings are then issued as “approved for construction” and all subsequent changes will be in accordance with the on-site change control procedure verified as required via an Engineering Site Request procedure.

4 MANUFACTURE

4.1 Manufacturing Integrity Process

The integrity of the manufacturing process is achieved through a variety of tools as follows:

- Suppliers Management
- Suppliers Design
- Materials and sub-orders
- Manufacturing Inspection
- Factory Acceptance Tests
- Manufacturing Documentation

4.2 Suppliers Management

The methods and process adopted by the Supplier and approved by SEPIL are established once the contract is awarded.

These include:

- Design Plan (as applicable)
- Subcontracting Plan (as applicable)
- Manufacturing plan/schedule
- HSE plan
- Inspection and Test Plans (including Hold and witness points)
- Documentation Control Procedure
- Manufacturing Procedures (e.g. welding, testing etc)
- Factory Acceptance Test Plan

4.3 Suppliers Design

In some instances the Supplier is required to undertake a manufacturing design process. These are usually focused on the customisation of a supplier's standard designs or products to meet the specific requirements stated in the SEPIL drawings and specifications. These designs are reviewed and approved by SEPIL prior to acceptance for manufacturing to proceed.

4.4 Materials and sub-orders

Within the scope of supply there may be some materials and sub-systems that are critical to the safety and operation of the product to be supplied. In such cases SEPIL ensures that full access is available to the sub-suppliers and the same level of rigorous control is applied. The Supplier is also required to perform supervisory management and inspection of the sub-suppliers.

4.5 Manufacturing Inspection

The inspection regime applied is multi level and sets out the Inspection and Test Plans prepared by the Supplier and approved by SEPIL. These are:

4.5.1 Supplier Inspection and Testing

This is usually conducted by the supplier's internal quality control and inspection department with the objective to check and verify that the work performed meets the supplier's internal acceptance criteria. The supplier's inspection and testing steps are set out in the approved Inspection and Test Plan.

4.5.2 3rd Party Inspection

SEPIL has appointed an independent company to undertake 3rd party inspections of the work at critical points in the manufacturing process. This entails visits to the manufacturing sites to verify compliance to the specifications and to check that the supplier's internal inspection has been conducted in accordance with the stated procedures.

4.5.3 System tests

Once the product (or component) is complete, the Supplier will conduct system tests to verify that the product meets its performance standards. These include hydrostatic tests, start-up tests etc. In some cases these tests are witnessed by the 3rd party inspector and if required also by SEPIL.

4.6 Factory Acceptance Tests

Once the package or product is completed, a Factory Acceptance (performance) Test is jointly conducted by the Supplier and SEPIL. The FAT will be undertaken to a predefined plan which sets out the tests, the expected criteria for acceptance and the result of the test. If the requirements of a particular test are not met then a non-compliance is noted and the Supplier is required to rectify the problem and submit a plan for a re-test. If the number of non-compliance items is significant then SEPIL will require the Supplier to submit a formal report identifying the nature and cause of the failure and a remediation plan/procedure. In such cases a complete FAT is repeated. Shipment is not permitted until satisfactory completion of the FAT and all non-compliance items are corrected and accepted by SEPIL.

4.7 Manufacturing Documentation

Records of the manufacturing process such as 3rd party inspection, certificates, release notes, manufacturing data books etc are compiled into a complete package and handed over to SEPIL.

5 CONSTRUCTION

5.1 Construction Integrity Process

The integrity of the construction process is achieved through a variety of tools as follows:

- Appointment of Competent Project Supervisor for Construction Stage (PSCS)
- Contractors management
- Work methods and qualification
- Procedure qualification
- Materials storage and handling
- Construction supervision
- Inspection

The construction stage will be planned and managed by the PSCS in conjunction with SEPIL and the Construction Contractors.

5.2 Construction Management

The methods and process adopted by the PSCS and the Contractors are approved by SEPIL and established in detail once the contract is awarded.

These include:

- Construction Team Organisation (roles and responsibilities)
- Construction plan/schedule
- Procedure and content of Method Statements
- Materials Procurement Plan
- Subcontracting Plan (as applicable)
- HSE plan
- Quality Assurance and Control Plan (including prescribed Quality audits)
- Inspection and Test Plans (including Hold and witness points)
- Change Control Procedure
- Documentation Control Procedure
- Construction Procedures (e.g. welding, testing etc)
- Site Acceptance Test Plans
- As-Built procedure

5.3 Work Methods and Qualification

The work undertaken on the site during construction can be divided into a series of individual activities. For each such activity the PSCS and Contractors will prepare a Work Method Statement which sets out:

- The safety issues and the actions to ensure safe working practices.
- The personnel, equipment and materials required.
- The method of working.

- Testing and inspection requirement.
- Environmental issues and mitigation.

Each method statement will be reviewed in detail by SEPIL and no work will commence until the Method Statement is approved.

5.4 Procedure Qualification

In performing the work during construction various technical procedures will be implemented to ensure the requirements of the specifications and standards are attained. Each of these procedures will be technically reviewed and as required tested for compliance. In some cases the personnel who will undertake the activity will also be tested and specifically qualified to undertake the specific procedure.

An example is welding of the pipeline where the procedure for the welding is defined and qualified by using sample pieces of linepipe which are tested to verify the procedure. In addition each of the welders are required to perform the qualified procedure and the results tested and only those welders meeting the requirements of the test are certified as a qualified pipeline welder.

5.5 Materials Storage and Handling

The Contractor will be responsible for the correct receipt, storage, handling and transportation of the equipment and materials required for construction of the system.

The associated plans and procedures will be co-ordinated by the PSCS, reviewed and approved by SEPIL. SEPIL will monitor and audit the work to ensure the integrity of the materials and equipment is assured at all times. Key aspects will include the following:

- Establishment of required controlled environment for storage
- Identification, inspection and tagging of all materials, equipment and associated documentation on receipt
- Strict quarantine of all damaged or non-conforming items
- Controlled and documented release for inclusion in the construction
- Approved handling and stacking procedures relevant to the materials and equipment
- Appropriate transport vehicles and movement plans
- Approved lifting and placement procedures at the specific location for installation.

5.6 Construction Supervision

The first line of assurance of the integrity of the construction activities is the construction team which will undertake the various activities in accordance wit the various method statements and procedures. The work undertaken will be carefully planned on a daily basis. The need to arrange the correct personnel, plant, materials and equipment to be available to perform the work to the highest standards is critical to the assurance of construction integrity. The PSCS and Contractors construction management will be responsible for delivering the construction process and SEPIL site team will work closely with the PSCS, Contactor's management and field supervisors to ensure the work is undertaken in the designated manner. A system of notifying the PSCS and Contractors of any deficiencies or potential incidents will be used by SEPIL to daily notify the PSCS and Contractor's construction management where an issue has arisen or attention is required.

5.7 Inspection

The inspection regime applied is multi level and is set out in the Inspection and Test Plans prepared by the Contractor and approved by SEPIL. These are:

5.7.1 Contractor Inspection and Testing

This is usually conducted by the Contractors quality control and inspection department assigned to the project. This is performed on a daily basis to check and verify that the work performed meets the Contractors internal acceptance criteria and the requirements of the specifications, codes and standards are met. The Contractor's inspection and testing steps are set out in the approved Inspection and Test Plan.

5.7.2 3rd Party Inspection

SEPIL has appointed an independent company to undertake 3rd party inspections of the work at key points in the construction process. This entails presence on site to verify compliance to the specifications and to check that the Contractor's internal inspection has been conducted in accordance with the stated procedures.

6 PRE-COMMISSIONING

Pre-commissioning is conducted to verify that the manufacturing has been carried out as specified and that the system is ready for commissioning, introduction of hydrocarbons.

6.1 Pre-Commissioning Integrity Process

Following mechanical completion of the installation and construction activities on site, the integrity of the pre-commissioning process is achieved through a variety of tools as follows:

- Pre-Commissioning management
- System Testing
- Hydrostatic Pressure Testing
- Site Acceptance Testing
- Handover for Commissioning

6.2 Contractors Management

The methods and process adopted by the Contractor are reviewed and approved by SEPIL.

These include:

- Pre-commissioning Team Organisation (roles and responsibilities)
- Pre-commissioning plan/schedule
- Pre-commissioning Procedures
- Subcontracting Plan (as applicable)
- HSE plan
- Inspection and Test Plans (including Hold and witness points)
- Documentation Control Procedure
- Site Acceptance Test Plans

6.3 System tests

Once the product (or component) is complete, the Contractor will conduct system tests to verify that the constructed package performs as required e.g. electrical start-up tests, control system tests etc. In some cases these test are witnessed by the 3rd party inspector and as required also by SEPIL.

6.4 Hydrostatic Pressure Testing

The pipeline and mechanical equipment and pipe work will be subject to hydrostatic pressure tests which involve raising the pressure of the test water contained within the pipe etc to a prescribed test pressure as defined by the pipeline codes. This will be a 24 hour hold test and is only accepted once the pressure test is validated against stated criteria.

6.5 Site Acceptance Tests

Once the complete package or product is completed a Site Acceptance Tests (SAT) is jointly conducted by the Contractor and SEPIL. The SAT will be undertaken to a predefined plan which sets out the tests, the expected criteria for acceptance and the result of the test. If the requirements of a particular test are not met then a non-

compliance is noted and the Contractor is required to rectify the problem and submit a plan for a re-test. If the number of non-compliance items is significant then SEPIL will require the Contractor to submit a formal report identifying the nature and cause of the failure and a remediation plan/procedure. In such cases a complete SAT is repeated. Shipment is not permitted until satisfactory completion of the SAT and all non-compliance items are corrected and properly documented.

6.6 Commissioning and Handover to Operations

Following satisfactory pre-commissioning the pipeline system is ready for introduction of Corrib gas which will be undertaken by SEPIL operations supported by the respective contractors.

During commissioning the integrity of the pipeline will be established by running an Intelligent Pig though the complete Corrib pipeline.

7 INDEPENDENT VERIFICATION

Independent third party verification of a system provides assurance that it is designed, constructed and installed in accordance with relevant statutory regulations, stated codes and standards and project objectives.

SEPIL has implemented a system of independent third party verification for the entire Corrib development including subsea facilities, pipelines and the gas terminal.

The verification scheme includes a combination of document review(s), simplified or advanced independent analysis, audits, inspections and quality control, and witnessing of tests. The appointed independent verification body for the Corrib development project is Det Norske Veritas (DNV).

The verification approach requires the identification of Safety Critical Elements (SCEs) within systems and the preparation of Performance Standards (PSs) for each. This approach mirrors the examination requirements of the UK Sector's Offshore Installations (Safety Case) Regulations (SCR) as amended by "Design and Construction Regulations" [DCR] and Regulation 19 of UK Sector "Prevention of Fire and Explosion and Emergency Response Regulations [PFEER]". Shell's internal Technical Standards have also been used as a reference for the selection of SCEs.

The April 2002 approval of the Corrib Plan of Development states that the production of Gas from the Corrib Field (for commissioning or sales purposes) can only commence once a Letter of Acceptance has been issued for the facilities. This Letter of Acceptance will be a confirmation by the Minister's (DCENR) auditor that independent 3rd party verification of the Corrib Development has been carried out and completed satisfactorily.

New legislation in respect of upstream petroleum activities is currently being implemented. The *Petroleum (Exploration and Extraction) Safety Act* (hereinafter, PEES Act) was passed recently, and it establishes the Commission for Energy Regulation (CER) as the administrative body with statutory authority to regulate safety with regard to upstream petroleum undertakings in Ireland.

The PEES Act creates a new administrative process whereby the developer of a designated upstream petroleum project is required to submit a safety case to the CER which will then issue a safety permit to the developer. In determining whether or not to grant the safety permit the CER refers to the risk-based petroleum safety framework that it is required to establish and implement through new regulation. The legislation requires the CER to prepare safety case guidelines in relation to the preparation of and the appropriate contents of a safety case applicable to petroleum activities. This will include the standards and codes of practice applicable to designated petroleum activities together with relevant standards and codes of practices that have been formulated or recommended by the National Standards Authority of Ireland and the relevant performance indicators according to which safety performance in respect of each designated petroleum activity will be assessed.

8 ABBREVIATIONS

DCENR	Department of Communications, Energy and Natural Resources
DNV	Det Norske Veritas
FAT	Factory Acceptance Test
HAZID	Hazard Identification
HAZOP	Hazard and Operability
HSE	Health, Safety and Environment
ISO	International Standards Organisation
LVI	Landfall Valve Installation
PFEER	Prevention of Fire and Explosion and Emergency Response Regulations
PSCS	Project Supervisor Construction Stage
PSDP	Project Supervisor Design Process
SAT	Site Acceptance Test
SCE	Safety Critical Element
SCR	Safety Case Regulations
SEPIL	Shell E&P Ireland Ltd
TA	Technical Authority
UK	United Kingdom

SHELL E&P IRELAND LIMITED

CORRIB GAS FIELD DEVELOPMENT PROJECT

Corrib
natural gas

Q5.2 – Pipelines Integrity Management Scheme

DOCUMENT No: COR-52-SH-009

PIPELINES INTEGRITY MANAGEMENT SCHEME

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EXECUTIVE SUMMARY

This document defines the integrity safeguarding system for the Shell E&P Ireland Limited (SEPIL) Corrib Natural Gas Pipeline System covering the 20" offshore and onshore pipelines, the gathering lines from the wells to, and including, the manifold, the power, control, methanol and chemical supply umbilical, the signal cable and fibre optic cable and the water outfall.

It describes the Pipeline Integrity Management Scheme (PIMS) to efficiently and effectively control and manage the safeguarding of the integrity of the pipeline system in compliance with Irish legislation and conditions of consent, SEPIL's requirements and Shell's corporate policies.

This document describes the Corrib Natural Gas Pipeline System, describes the organisation required for implementation of the integrity management scheme, defines roles, responsibilities and interfaces and outlines the management processes required.

To implement the scheme, SEPIL will use the resources, expertise and common set of policies, procedures and standards of the Royal Dutch Shell group's collective exploration and production operations in Europe, (referred to in this document as 'Shell UIE').

All work is, therefore, performed in accordance with the 'Shell UIE' integrity cycle for pipelines. This and the 'Shell UIE' implementation process and resources are described in this document.

An overview discussion of the Major Accident and Major Environmental Accident threats, risk barriers and monitoring measures is given for each Safety Critical Element of the pipeline system.

The Integrity Reference Plan, in Attachment A, provides the details and the performance standards for the risk barriers and monitoring and the immediate action and the longer-term corrective action requirements to be followed during the operation of the pipeline system. This Pipeline Integrity Management Scheme and its Integrity Reference Plan will be reviewed and improved throughout the pipeline system's operational life to take account of changes in legislation, feedback from experience in implementation, changes to the pipelines and improvements in 'Shell UIE' and industry practice and technology.

1 INTRODUCTION

1.1 OBJECTIVES

The objective of this scheme is to provide a management system for safeguarding the integrity of the Corrib Natural Gas Pipeline system, and so ensure its availability for safe operations in line with the SEPIL Policy on Health, Safety and the Environment. In particular the management of integrity is assured in accordance with the requirements of:

Irish Legislation [References 1, 2, 3, 4, 11] and Consent Conditions.

Irish Standards:

- I.S. EN 14161 2004 Petroleum and natural gas industries - Pipeline Transportation Systems (ISO 13623:2000 Modified) [9],

- I.S. 328 2003 Code of Practice for Gas Transmission Pipeline and Pipeline Installations (Edition 3.1) [5]

International Standards:

- BS PD 8010-1:2004 Code of Practice for Pipelines – Part 1: Steel Pipelines on Land

- DNV-OS-F101: 2000. Offshore Standard, Submarine Pipeline Systems

- DNV-OS-F101: 2007. Offshore Standard, Submarine Pipeline Systems

1.2 POLICY

It is Shell's policy that the risk of failure, which would endanger people, the environment, or asset value, is reduced to a level that is as low as reasonably practicable (ALARP). To achieve this, effective and systematic safety and integrity management is put in place.

Failure resulting in loss of containment of any pipeline within the system could have significant consequences. Therefore, all elements that comprise the Corrib pipeline system, including process control elements, are regarded as Safety Critical Elements (SCE). The performance criteria that need to be met periodically in order to assure the effectiveness of each barrier to the failure of each SCE is identified as a Performance Standard. Pipeline integrity requires that SCE performance is monitored or measured for the ongoing verification of its effectiveness. Also critical to safety and integrity is the management of aspects such as procedures, roles and responsibilities and performance reviews. This requires an effective pipeline integrity management process and supporting scheme.

The pipeline integrity management scheme (PIMS), therefore, addresses the safeguarding of technical integrity through the barriers to all threats that can compromise pipeline integrity and the monitoring of the effectiveness of risk barriers, and as such considers:

- Process Safety, e.g. operating procedures, overpressure protection, emergency procedures and leak detection.

- Mechanical Integrity, including fatigue, overstress, mechanical damage and threats from peat instability and other geotechnical instability, Corrosion Management, e.g. corrosion and erosion, and Flow Assurance, e.g. scaling, surge, slugging and hydrate formation.

- Management of Change, e.g. design change, modifications and set points

1.3 PIPELINE SYSTEM SCOPE

This document describes the Pipeline Integrity Management Scheme (PIMS) for all the elements of the SEPIL operated Corrib pipelines:

- The gathering lines & jumpers (N1171/2/3/4/5, N1199 and N2101) from the Corrib Field wells to the manifold.

  This includes the gathering lines/jumpers from the well production wing valves to the manifold, the manifold itself and the connecting hubs and the ICARUS assemblies.

- 20” Natural Gas offshore pipeline (N0211) from the Corrib Field Manifold to the Landfall Valve Installation (LVI).

  This includes the pipeline, the tie in spool, the pipeline end termination (PLET) and the pipeline end manifold (PLEM).

- 20” Natural Gas onshore pipeline (L0011) from, and including, the Landfall Valve Installation to the Bellanaboy Bridge Gas Terminal.

  This includes the LVI, the pipeline from the LVI to the terminal pig receiver bypass valve, the terminal pig receiver and all associated pipework up to and including the first valve on any branch line.

- The Power, Control, Methanol, Chemical supply and produced water discharge umbilicals from the Bellanaboy Bridge Gas Terminal to the Corrib Field manifold (N2823) and from the manifold to the wells (N2824/5/6/7/8 and N2879).

  This includes the pressure containing cores in the umbilicals and associated tie in pipework from the isolation valves in the onshore terminal termination unit (OTTU) to the isolation valves at the wells and manifold together with subsea distribution unit (SDU) and all underwater termination assemblies (UTAs) and the onshore termination unit (OTU) and onshore joints

- Water Outfall (N1004) from the Bellanaboy Bridge Gas Terminal to a point approximately 12.5 km offshore from the landfall.

  This includes the water outfall from the terminal isolation valve, via the backpressure-regulating valve at the LVI to the diffuser on the seabed.

- Plus all control systems and protective devices, that are part of the pipeline system elements above, that control flow and pressure in the pipeline system, prevent overpressure, detect leakage and isolate the pipeline system in an emergency.

A schematic view of the pipeline system is presented in Figure 1.1 below.

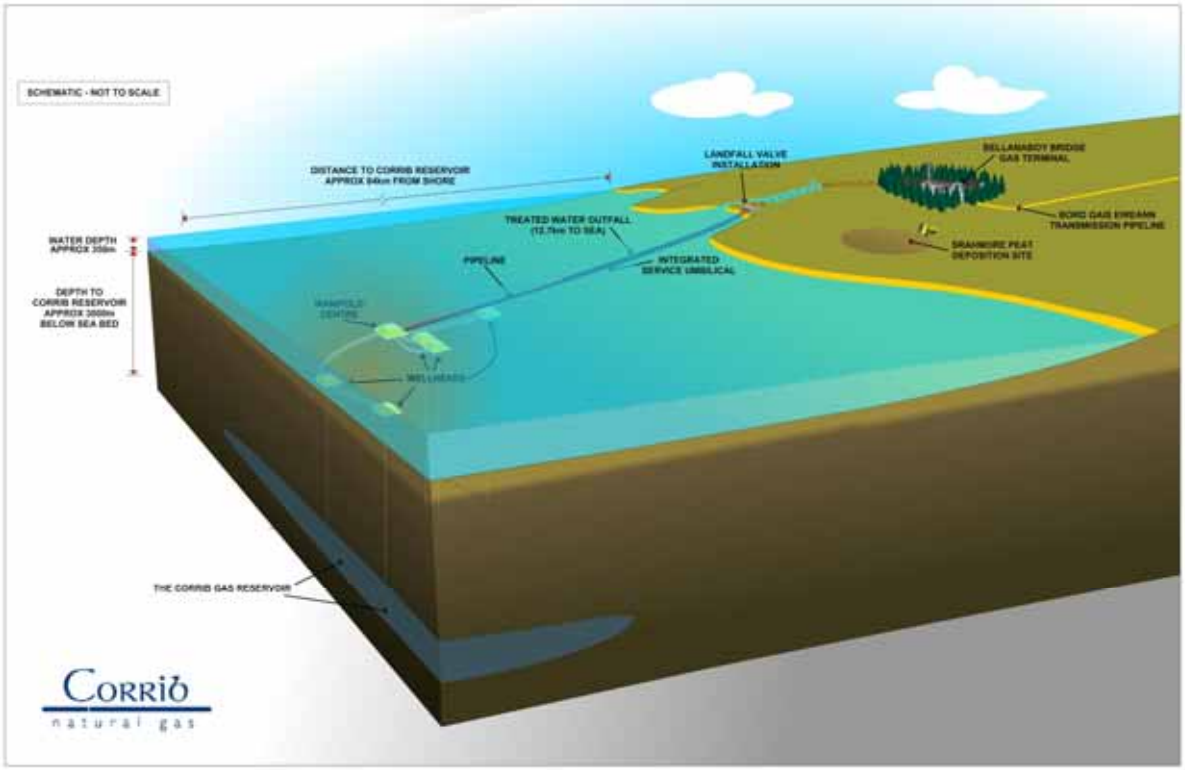


Figure 1.1: System Schematic

A more detailed description of the elements of the system and a description of measures necessary to assure ongoing integrity of the pipeline system is provide in Attachment A of this document.

1.4 PIMS STRUCTURE AND KEY PROCESSES

The Pipeline Integrity Management Scheme (PIMS) consists of the following elements:

- Definition of policy, objectives and the scope of application. (Section 1)
- A description of the Statutory Regulations and Corporate Standards. (Section 2)
- Definition of organisation and the allocation of responsibilities. (Section 3)
- Identification of the implementation processes that deliver the plan. (Section 4)
- Definition of the Integrity Reference Plan. (Attachment A)
- Continuous assurance and the management of change. (Section 3)

The physical limits of the system are described in Section 1.2 and described in more detail in Attachment A.

Section 4 of this document describes the way the PIMS is delivered though five processes:

1. **Review of the Pipeline System.** Definition of system limits and identification of design and operating parameters.

2. **Strategy.** Risk assessment and the identification of Safety Critical Elements and Performance Standards. Development and update of the Integrity Reference Plan for the monitoring of performance.

3. **Implementation.** Incorporation of requirements into inspection plans, operating and maintenance routines, etc. Delivery of the plans, routines, etc.

4. **Records, Reporting and Review.** Reporting and assessment of results. Status reporting. Action definition. Peer review. Routine review of system performance through Key Performance Indicators (KPIs).

5. **Corrective and Improvement Action.** Implementation of Corrective Action. Revision of risk assessments. Update of the Integrity Reference Plan. Improvement of the PIMS. Audit of the PIMS execution.

1.5 PIMS DOCUMENTATION

The Pipeline Integrity Management Scheme documentation consists of:

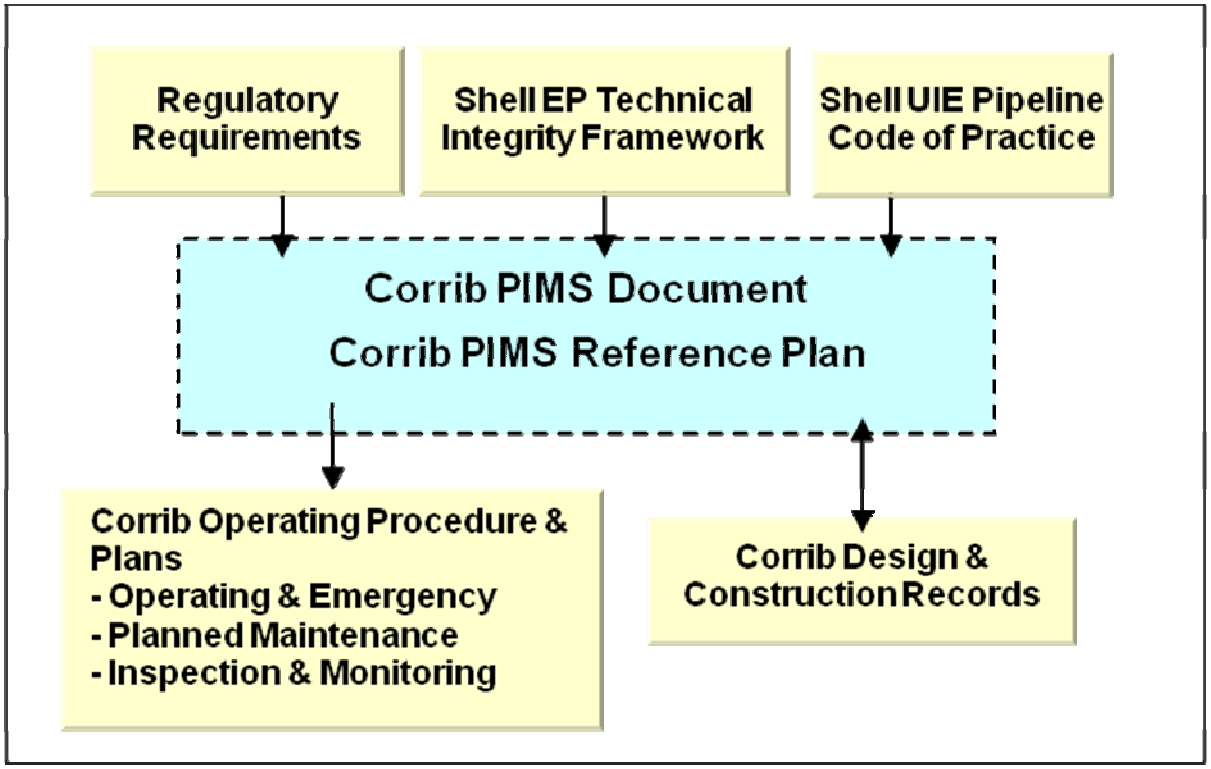
- This document, which defines the management structure, processes and responsibilities for integrity management and the functions accountable for the threat assessment, risk barriers and monitoring activities. It also contains a summary of the threats for each element of the pipeline system together with the steps taken to mitigate and monitor those threats.

- The Integrity Reference Plan, in Attachment A, which identifies the Safety Critical Elements and provides the detail of the risk barriers and monitoring for each threat together with the Performance Standards and the immediate and corrective action requirements for when those Performance Standards are not met.

The documents have been developed to conform to the Irish Regulatory Requirements [1, 2, 3, 4, 10, 11] and conditions of permits and consents and requirements of SEPIL, as shown in Figure 1.2 PIMS Documentation below.

The PIMS documents reference the Corrib Operating Procedures and the Design and Construction documentation.

Figure 1.2: PIMS Documentation



As soon as the Regulatory Requirements resulting from the recently passed Petroleum (Exploration and Extraction) Safety Act 2010 are fully established during the pipeline pre-commissioning phase, the PIMS documentation and Integrity Reference Plan will be updated.

2 STATUTORY REGULATIONS AND CORPORATE STANDARDS

Design, construction and operation of hydrocarbon pipelines are governed both by *Irish legislation* and *Shell Corporate Requirements*.

Various levels of applicable legislation and documentation govern the integrity management and safe operation of the Corrib Natural Gas Pipeline System and are required to ensure ongoing *legislative* and *corporate compliance*. This may be divided into the following categories:

- Legislation - Acts, etc., which must be adhered to. Failure to do so could result in a legal requirement to remedy the omission, withdrawal of consent to operate or prosecution.

- Legal Consents and Permissions – The Operator of the pipeline must have a consent in order to legally construct and operate a pipeline (see Table 2.1).

- New legislation may require consents, licences from additional Government Agencies. These will be obtained as necessary at the time.

- In addition conditions may be imposed by the SIA consent, Gas Act Section 40 consent and the Foreshore licence.

- Legally Required Documentation – These documents are required by the legislation previously identified and should be reviewed annually or as required.

- Safety/Integrity/Operating Procedures – These documents are necessary to ensure the ongoing pipeline integrity is assured, safe operation of the pipeline maintained and that all aspects of risk are understood and addressed.

- Operational Records – Full historical records shall be maintained and logged from design through to ongoing operational and inspection data.

Statutory regulations and corporate standards relating to the Corrib Pipeline are detailed in Table 2.1.

Table 2.1: Corrib Natural Gas Pipeline - Applicable Petroleum/Planning Legislation, Consents and Documentation Required

TYPE	DESCRIPTION
Legislation	*Petroleum and Other Minerals Development Act, 1960, as amended* *Gas Act, 1976, as amended* *Foreshore Acts, 1933 to 2009, as amended* *Planning and Development (Strategic Infrastructure)(SIA) Act, 2006* *Petroleum (Exploration and Extraction) Safety Act 2010* *Continental Shelf Act 1968*
Administrative Requirements	*Rules & Procedures Manual for Offshore Petroleum Operations* *Report of the Corrib Technical Advisory Group to Minister Dempsey, January 2006 ("TAG Report")*
Statutory Consents/ Permissions	*Consent to Construct and associated phased consents* *Plan of Development Approval and associated Permissions/ Consents* *Consent under SIA 2006* *Foreshore Licence* *IPPC licence*
Compliance Documentation	*Pipelines Integrity Management Scheme*
Irish Standard	*I.S. 328: 2003, Code of Practice for Gas Transmission Pipelines and Pipeline Installations* *I.S. EN 14161:2004, Petroleum and natural gas industries. Pipeline transportation systems*
International Standards	*BS PD 8010 Code of Practice for Pipeline, Part 1 Steel Pipelines on Land* *DNV-OS-F101 Submarine pipeline systems (DNV 2000, 2007)*
Corporate Requirements	*HSE Group Policy and SEPIL HSE Policy* *Standard EP Technical Integrity Framework*
Safety/Integrity /Operating Procedures	*Corrib Project Design, Fabrication & Installation Dossiers* *Corrib Pipeline Emergency Response Planning & Procedures* *Corrib Pipeline Operating Procedures* *Corrib Inspection & Maintenance Routines*
Operational Records	*Inspection Data, Analysis, Integrity Statements (in IBIS, Common Pipeline Database and PIPE-RBA)* *Corrib Project Design, Construction and Testing Records*

3 ORGANISATION AND ACTIVITIES

3.1 ORGANISATION

The organisation for the safeguarding of pipeline technical integrity combines roles from both the operating and the technical functions.

The Asset Operations Management has responsibility for implementing the Pipeline Integrity Management Scheme and is accountable for safeguarding asset integrity.

The Nominated Responsible Person (NRP) has overall responsibility for the standard setting of pipeline integrity management activities and compliance assurance via audit and review.

The interfaces are shown in Figure 3.2 and described in Tables 3.1 to 3.6, below.

3.1.1 Shell E&P Ireland Ltd., Corrib Natural Gas Operating Organisation

The Shell E&P Ireland Limited (SEPIL) Organisation is shown in Figure 3.1.

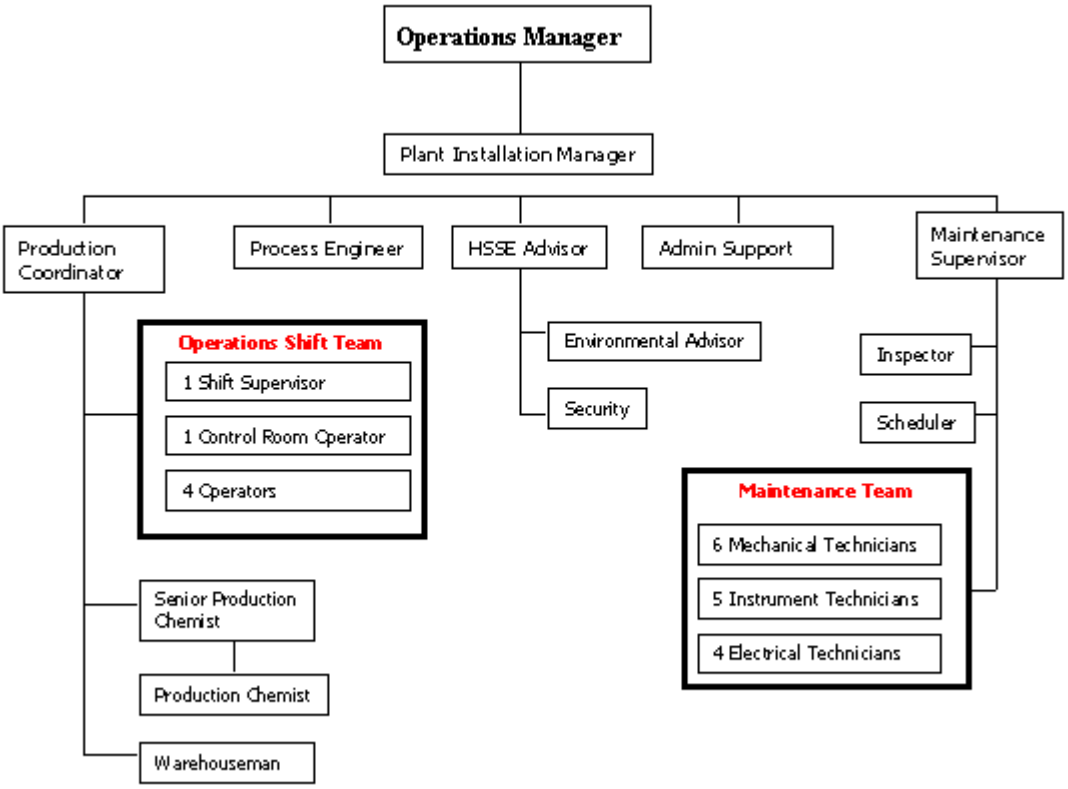


Figure 3.1: SEPIL Operations Organisation

3.1.2 Pipeline Integrity Organisation

SEPIL, on behalf of the Corrib partners, is the Owner and Operator of the pipeline and SEPIL's Asset Owner has assigned responsibility and accountability for:

- Implementing the safeguarding of the technical integrity of the Corrib pipeline system, to the SEPIL Operations Manager, and,

- Assuring the technical integrity of the pipelines, to the Nominated Responsible Person (NRP).

It is the responsibility of the SEPIL Operations Manager to maintain in place the systems and manpower and material resources needed to safeguard technical integrity at a level of effectiveness agreed by the NRP. This includes the engagement and funding of resources from other functions of 'Shell UIE' to include the necessary skills and competencies that are not included in SEPIL's line organisation.

The NRP liaises with the Asset Owner and assists in reporting the integrity status of the pipelines to the Ireland Country Chairman and, where appropriate, the Statutory Authorities.

The Pipeline Competent Person (PCP) is appointed to the role by the NRP to coordinate the operation of the Pipeline Integrity Management Scheme.

To facilitate effective maintenance of risk barriers and the control of the inspection, testing and monitoring activities, the pipeline integrity safeguarding activities are identified and divided into areas of activity.

Each of the areas of activity is allocated to an activity Focal Point who has responsibility for ensuring that all of the activities in the integrity assurance process are performed in respect of their allocated area. Each Focal Point is functionally accountable to the Pipeline Competent Person (PCP) who coordinates their activity.

Focal Point roles are assigned to the Plant Installation Manager, Process Engineer and Maintenance Engineer who are in a reporting line to the Operations Manager. The other Focal Points, including the Pipeline Engineer and Material & Corrosion Engineer, are engaged from other parts of 'Shell UIE'.

The PCP, NRP and those Focal Points that are employed by other parts of 'Shell UIE' have, in the context of this Scheme, authority to act on behalf of, and accountable to, SEPIL.

To safeguard integrity it is critical that a clear path for communications is established between all Focal Points and between each Focal Point and the PCP. The 'Shell UIE' pipeline integrity processes enable this. The management process for the safeguarding of the pipeline integrity is described in Section 4.

The organisation and relationships for integrity management safeguarding are shown diagrammatically in Figure 3.2 and the areas of activity are shown in Figure 3.3.

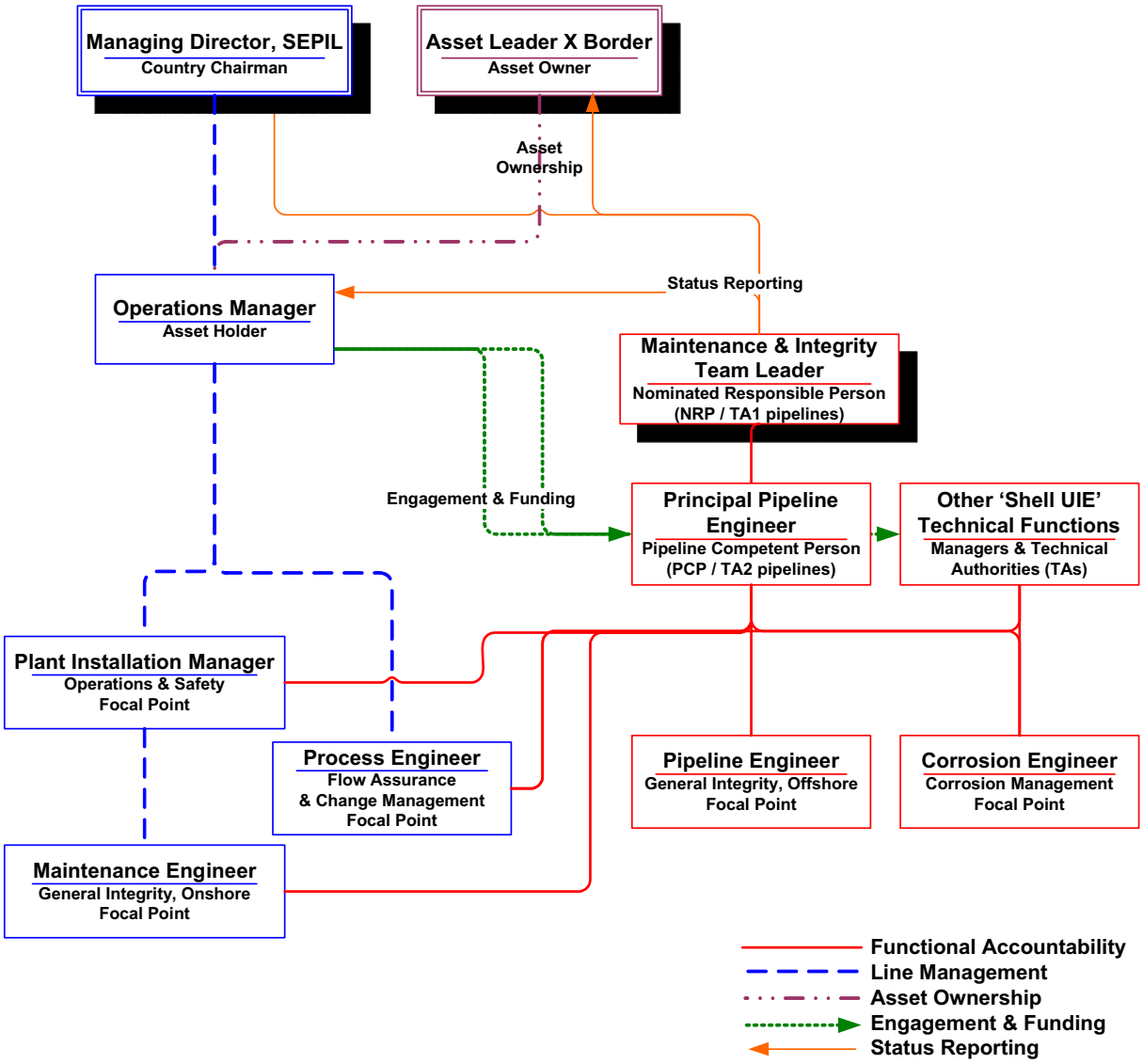


Figure 3.2: Pipeline Integrity Organisation

3.2 KEY AREAS OF INTEGRITY SAFEGUARDING ACTIVITY

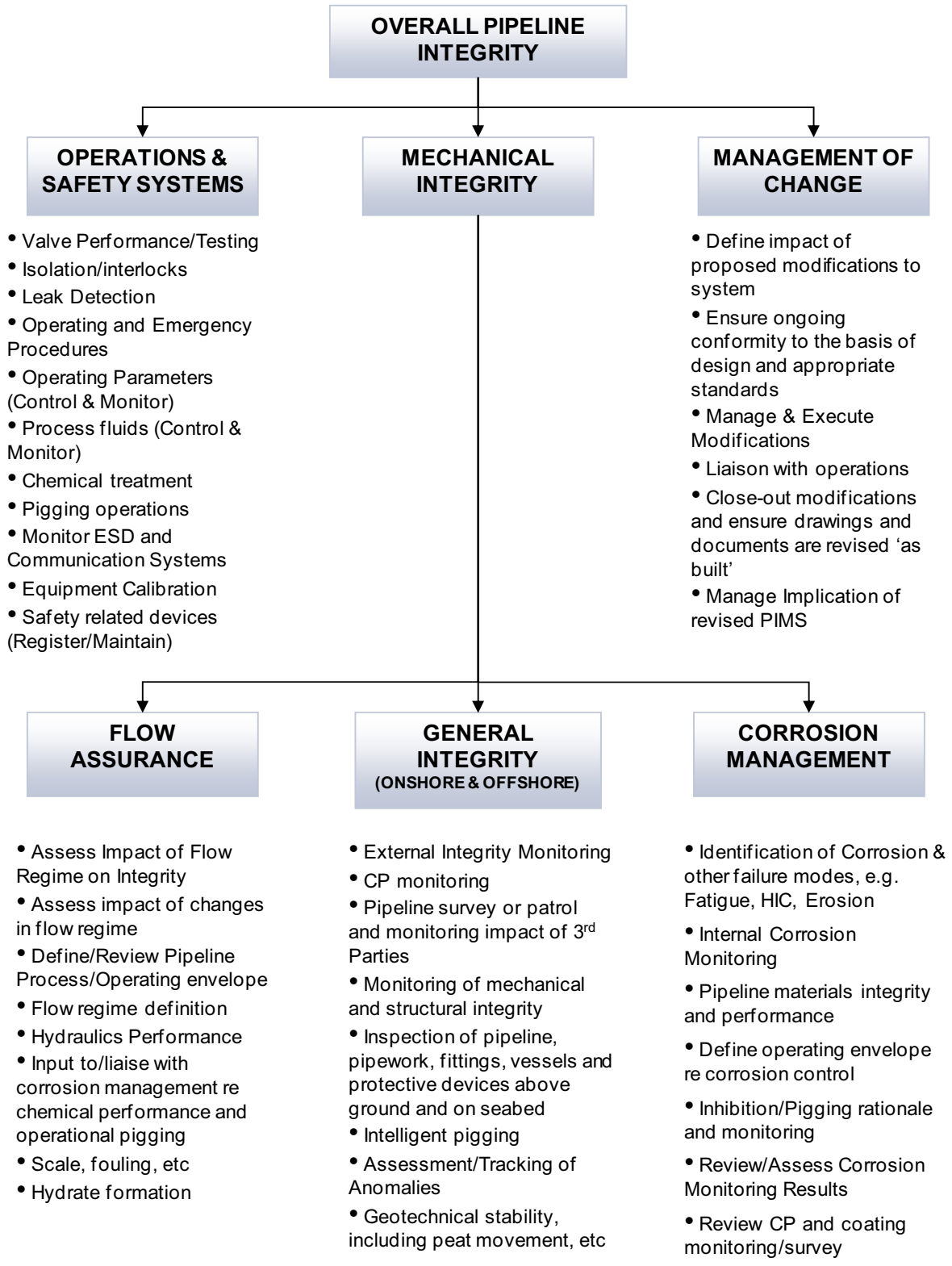
3.2.1 Area Activities

The three distinct integrity activity areas are:

- Operations and Safety management Systems
- Technical Integrity (subdivided into General Integrity Onshore & Offshore, Corrosion Management & Flow Assurance)
- Management of Change

These key areas of activity are shown in Figure 3.3 below. Each management role and Focal point has roles and responsibilities, as described in following section.

Figure 3.3: Structure of Integrity Management Activities



3.2.2 Area Roles and Responsibilities

Tables 3.1 to 3.6 present the limits, scope of responsibility and necessary interfaces for each Manager and Focal Point involved with the integrity safeguarding activities.

Others may be delegated the responsibility to carry out specific activities but it is the Focal Point who remains accountable for their completion and is shown as such in the 'Shell UIE' Common Pipeline Database (CPD), as described in Section 4, below.

A key part of the set up of the system is the requirement for each Focal Point to liaise across the other areas. The role of the PCP includes co-ordination, monitoring and control across all the areas.

3.2.3 Contact Names, Addresses and Telephone Numbers

Included in Attachment B is a listing of the contact names, addresses and telephone numbers for the relevant personnel within the SEPIL asset, Shell Pipeline Integrity Group and the Focal Points who have a role or responsibility defined under the PIMS. Names and contact details to be provided prior to commissioning the system.

3.3 INTERFACES

The integrity management organisation interfaces with a number of external bodies, including:

- Department of Communications, Energy and Natural Resources
- Commission for Energy Regulation
- Mayo County Council
- Environmental Protection Agency
- Health & Safety Authority
- Land Owners and other stake holders

Specific responsibility for external liaison is detailed in Tables 3.1 to 3.6

3.4 TECHNICAL AUTHORITY

The 'Shell UIE' system of Technical Authority applies, without exception, to the SEPIL management of the Corrib assets. Technical Authorities are listed in the TA Register of the 'Shell UIE' Facilities Status Report System (FSR).

The ‘Shell UIE’ Level 1 Pipeline discipline Technical Authority (TA) gives Level 2 Technical Authority to the PCP for the Corrib assets.

Only a Pipeline discipline TA has the authority to approve deviations from ‘Shell UIE’ pipeline technical standards and deviations from the design standards for the Corrib pipelines. The Operation Manager has the authority to approve deviations from the performance standards and the Integrity Reference Plan after acknowledgement of the Pipeline Discipline TA Level 2.

Technical Authorities in the other disciplines have the authority in matters relating to the other disciplines (Subsea; Materials/Corrosion; Instrumentation/Control). They shall cooperate with the Operations Manager in ensuring that Technical Authority is properly applied to the management of the Corrib assets.

3.5 COMPETENCE

The PCP and the Focal Points shall all meet a standard of competence approved by the discipline Technical Authority and shall only be appointed to their roles if their appointment is agreed by the relevant discipline Technical Authority.

Table 3.1: SEPIL Operations Manager Scope

LIMITS

• Whole Corrib Natural Gas pipeline system:
  • 20” Natural Gas offshore pipeline
  • 20” Natural Gas onshore pipeline
  • The Power, Control, Signal, Monitoring, Methanol, Chemical supply and produced water umbilicals.
  • Water Outfall.
  • The manifold, gathering lines and jumpers

SCOPE OF RESPONSIBILITY AND ACCOUNTABILITY
• The Operations Manager is responsible for operating within the operating integrity boundaries and for providing the systems and resources for safeguarding the integrity of the Corrib Natural Gas pipelines including: a) Provide SEPIL personnel resources. b) Provide systems and materials. c) Agree service levels for and funding for supporting resources provided by other parts of the ‘Shell UIE’ organisation. d) Contract and fund the services of 3rd parties for specialist support. e) Maintain a system of reporting against KPIs to demonstrate the ongoing effectiveness of pipeline integrity safeguarding f) Liaison with regulatory authorities and point of contact for external interfaces with 3rd parties g) Emergency response organisation h) Incident investigation, reporting and follow-up i) Approval of maintenance and modification proposals • Operations Manager is accountable for a) Maintaining the level and competence of resources as agreed with the NRP b) The ongoing effective implementation of integrity safeguarding. c) Corrective action in the event that performance standards are not met or that safeguarding is not carried out as required. d) Keeping the HSE case up to date. e) Complying with all regulatory requirements including permissions, permits, incident reporting, etc.
INTERFACES
• Shell Ireland Country Chairman • Irish Regulatory Authorities • Corrib Natural Gas Pipeline Asset Owner • NRP and PCP

Table 3.2: Pipeline Nominated Responsible Person (NRP) Scope

LIMITS

• Whole Corrib Natural Gas pipeline system:
  • 20” Natural Gas offshore pipeline
  • 20” Natural Gas onshore pipeline
  • The Power, Control, Methanol, Signal, Monitoring, Chemical supply and produced water umbilicals.
  • The Water Outfall
  • The manifold, gathering lines and jumpers

SCOPE OF RESPONSIBILITY AND ACCOUNTABILITY

• NRP is responsible for all aspects of safeguarding the technical integrity of the Corrib Natural Gas pipelines including:
  a) Approval, review, distribution and custodianship of the PIMS document
  b) Update and approval of Integrity Reference Plan
  c) Assuring the competence of personnel within the integrity management process
  d) Approval and distribution of Annual Integrity Statement
  e) Reporting the status of the pipeline to the Asset Owner and Ireland Country Chairman
  f) Audit & review compliance with PIMS document
• NRP is accountable for
  a) Ensuring the PIMS is consistent with legislation/legislation updates and relevant ‘Shell UIE’ operating and engineering standards and guidelines.
  b) Ensuring records of all activities on, or changes to, the pipelines are maintained

INTERFACES
• Shell Ireland Country Chairman • Irish Regulatory Authorities (when and where agreed with the Operations Manager) • Corrib Natural Gas Pipeline Asset Owner/SEPIL Operations Manager • PCP

Table 3.3: Pipeline Competent Persons (PCP) Scope

LIMITS

• Whole Corrib Natural Gas pipeline system:
  • 20” Natural Gas offshore pipeline
  • 20” Natural Gas onshore pipeline
  • The Power, Control, Methanol, Signal, Monitoring, Chemical supply and produced water umbilicals
  • The Water Outfall
  • The manifold, gathering lines and jumpers

SCOPE OF RESPONSIBILITY AND ACCOUNTABILITY
• Overall technical assessment of the pipeline system, using the results and assessments received from each of the Focal Points, to ensure fitness for purpose on an ongoing basis. • Approval of fitness for purpose conclusions and repair or operational modifications following damage or deterioration. • Review and approval of the inspection, monitoring and testing scheme developed by each of the Focal Points, including performance standards and operating limits. • Coordination of peer review of annual reports of the inspection, monitoring and testing scheme results and interpretation. • Review and approval of maintenance and modification proposals. • Co-ordination of the integrity management process as implemented by each of the Focal Points. • Preparation of presentations for Business Unit management and Regulatory Bodies as required. • Identification of change and initiating change process. • Reporting the status of the pipelines to the NRP and Operations Manager. • Pipeline Discipline Technical Authority, level 2
INTERFACES
• NRP • All Focal Points • ‘Shell UIE’ Pipeline Group • Corrib Natural Gas Pipeline Asset Owner/SEPIL Operations Manager

Table 3.4: Focal Point Scope – Operations and Safety Systems

LIMITS

• Whole Corrib Natural Gas pipeline system:
  • 20” Natural Gas offshore pipeline
  • 20” Natural Gas onshore pipeline
  • The Power, Control, Methanol, Signal, Monitoring, Chemical supply and produced water umbilicals
  • The Water Outfall
  • The manifold, gathering lines and jumpers

SCOPE OF RESPONSIBILITY AND ACCOUNTABILITY
OPERATIONS • Develop and maintain Operations and Emergency Manuals • Ensure operation within operating integrity envelope • Provide clear direction and instruction for the Operators of the control rooms with the appropriate manuals and training including: a) Monitor process fluid quality b) Monitor pipeline operating pressures and temperatures and other relevant parameters c) Ensure process fluid quality and operating parameters remain within PIMS Performance Standards d) Record process upsets • Maintain and monitor pipeline leak detection system • Maintain and monitor chemical treatment for corrosion control and flow assurance. • Maintain and calibrate measuring devices and instruments. **SAFETY** • Review assurance against performance standards for all safety critical elements • Implement valve testing regime (timing/seal/full closure) – all pipeline valves • Monitor, test, calibrate and maintain protective and ESD devices and systems • Annual Summary Integrity Statement • Test emergency response organisation
INTERFACES
• All other Focal Points • PCP

Table 3.5: Focal Point Scopes – Mechanical Integrity (General Integrity (Offshore & Onshore), Corrosion Management, Flow Assurance)

LIMITS

• Corrib Natural Gas pipeline system elements relevant to each specific focal point onshore, offshore respectively:
  • 20” Natural Gas offshore pipeline.
  • 20” Natural Gas onshore pipeline.
  • The Power, Control, Methanol, Signal, Monitoring, Chemical supply and produced water umbilicals.
  • The Water Outfall
  • The manifold, gathering lines and jumpers.

SCOPE OF RESPONSIBILITY AND ACCOUNTABILITY
• Maintain corrosion risk assessments and manage implementation of requirements. • Inspections to include, but not limited to, external damage, coating integrity, debris, movement, condition of supports, condition of connections. • Review impact of Process/Flow Assurance on Corrosion Management Strategy as required. • Manage implementation of Integrity Management Strategy to define corrosion monitoring/control and inspection requirements. Ensure schedules maintained up to date. • Manage performance and reporting of routine corrosion monitoring activities (e.g. production chemist for product composition analysis). Ensure requirements are reviewed at suitable intervals. • Ensure that all activities are successfully implemented according to the schedule. • Appointment of competent contractors/specialists as required. • Maintain Inhibition strategy. • Review incoming data regarding effectiveness of strategies. • Review impact of 3rd party changes. • Collate internal inspection data, review, assess, report and maintain details on a suitable corrosion management database. • Manage CP/external corrosion monitoring Strategy. • Annual Summary Integrity Statement. • Provide the limiting operating process parameters (flow velocities, pressures, temperatures, product composition), identifying critical process/flow upset conditions that may threaten integrity. • Review/report the impact of significant changes in flow or process conditions. • Maintain the anomaly tracking database. • Maintain relationship with landowners
INTERFACES
• All other Focal Points • PCP, NRP • Shell Pipeline Integrity Group Specialists

Table 3.6: Focal Point Scope – Management of Change

LIMITS

• Whole Corrib Natural Gas pipeline system:
  • 20” Natural Gas offshore pipeline
  • 20” Natural Gas onshore pipeline
  • The Power, Control, Methanol, Signal, Monitoring, Chemical supply and produced water umbilicals
  • The Water Outfall
  • The manifold, gathering lines and jumpers

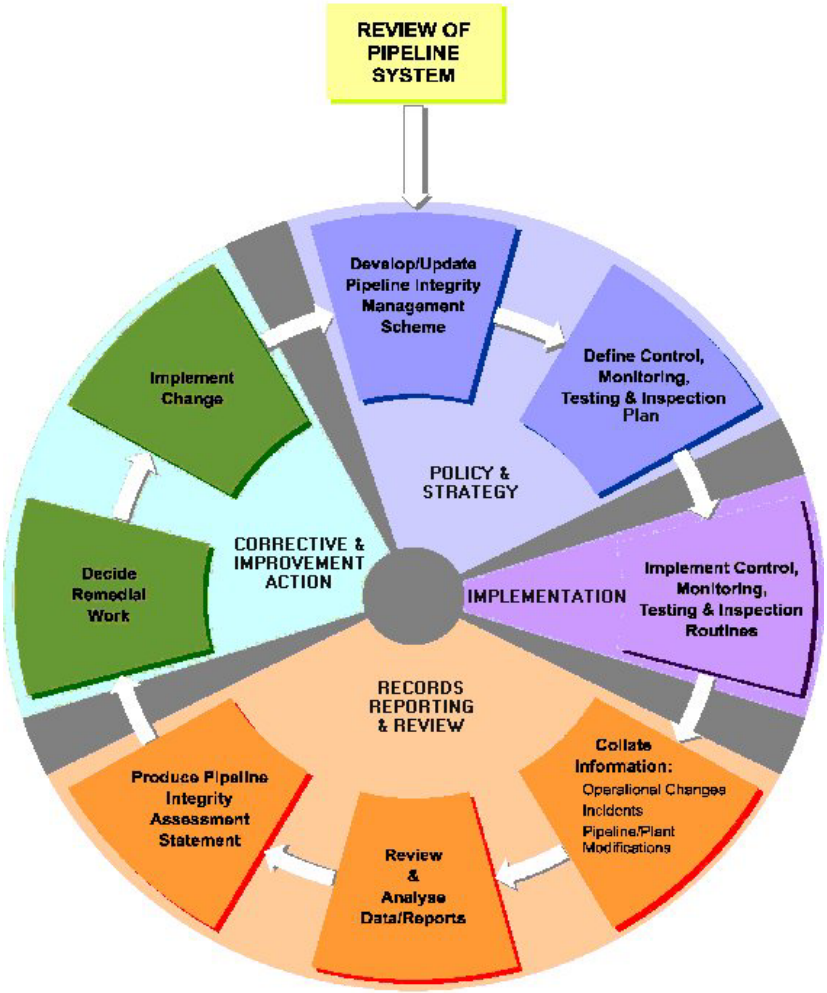
SCOPE OF RESPONSIBILITY AND ACCOUNTABILITY
• Scoping and identification of proposed modifications • Perform Risk Assessment and risk management of proposed modifications • Manage new build and modification works on behalf of SEPIL • Provision of Corrib Gas Pipeline data required for work • Identify and manage interfaces – internal and external • Review and approval of basis for design with PCP (TA role) • Co-ordination/implementation of modifications with operations • Provision of data for other Focal Points, NRP to up-to-date systems databases/ drawings, manuals etc. • Develop Bridging Documents • Assist with liaison with regulatory authorities
INTERFACES
• All other Focal Points • PRP, PCP • 3rd Parties (as required) • Contractors

4 INTEGRITY MANAGEMENT PROCESS

4.1 THE OUTLINE PROCESS

The process for assuring the integrity of the SEPIL pipelines is based on the Integrity Assurance Cycle as shown in Figure 4.1 (i.e. Policy & Strategy – Implementation – Records, Reporting & Review – Corrective & Improvement Action).

Figure 4.1: Integrity Assurance Cycle



The process comprises of the following basic activities:

- Review of Pipeline System and the Safety Critical Elements
  - Define physical limits for each pipeline/Safety Critical Element
  - Identify operating and design basis for each pipeline

- Policy & Strategy
    - Identify health, safety, environmental and integrity policy
    - Identify the major safety & environmental risks
    - Identify the barriers for the threats and against escalation
    - Define the Performance Standards for the risk barriers
    - Define the assurance activities for the Performance Standards
    - Define the Integrity Reference Plan of integrity safeguarding activities
    - Develop risk based inspection schemes
    - Define immediate and corrective action requirements
- Implementation
    - Operating instructions for routine operation, treatment, testing and analysis
    - Planned maintenance routines for testing and maintenance and assurance activities
    - Development of pipeline annual inspection and review scheme
    - Implementation of barriers, monitoring, inspection and testing schemes
- Records, Reporting & Review
    - Information recording in relevant reports, logs and online data systems
    - Integrity assessment based on findings
    - Peer review
    - Recommendation of corrective and remedial actions
    - Report pipeline status to NRP& Asset Owner and to Country Chairman
    - Monitor the performance of implementation of activities against Key Performance Indicators (KPIs)
- Corrective & Improvement Action
    - Review and revise risk based inspection schemes

- Identify improvements to operating and maintenance procedures and routines
- Recommend improvements to the Integrity Management Scheme
- Define, plan and execute corrective and remedial actions
- Revise Integrity Management Scheme and update Integrity Reference Plan
- Audit implementation of this scheme
- Review implementation against KPIs
- Improve implementation

4.2 REVIEW OF THE PIPELINE SYSTEM

The pipeline system limits and components and their basis of design and operation are set out in the initial plan. The physical limits of the pipeline system are described in more detail in Attachment A1 of this document. The Change Management Focal Point updates this when changes are made.

4.3 POLICY & STRATEGY

The threats to pipeline integrity and associated risk barriers are captured in the HSE case. For significant risks, and where the regulatory authorities mandate prescriptive requirements, the risk barriers, performance standards, monitoring activities and corrective action provisions are identified. All in accordance with the health, safety, environmental and integrity policy set by legislation and the Company. The HSE case is updated periodically including re-evaluation of the integrity threats and risk barriers.

The related integrity management strategy is documented in detail in the Integrity Reference Plan (Attachment A) and the elements are transferred for implementation into the Common Pipeline Database (CPD), the 'SAP PM' planned maintenance database and the Operating Instructions, as appropriate to each.

Furthermore each Focal Point routinely reviews the threats to pipeline integrity in his area of responsibility and expertise Attachment

4.3.1 Safety Critical Elements and Performance Standards

Each pipeline in the system of Corrib pipelines is a Safety Critical Element safeguarded against loss of containment by its mechanical design, materials selection, protective devices, chemical treatment of the process fluids, coatings and cathodic protection and the operating procedures to prevent damage to the environment, by the fluids conveyed and by external parties.

The Performance Standards are the operating limits and targets developed for each pipeline Safety Critical Element, based upon appropriate design codes, the specific design of each pipeline system, its current condition and operational requirements and the risk barriers put in place to prevent failure by the identified Major Accident/Major Environmental Accident (MA/MEA) threats.

Threat assessment identifies the MA/MEA threats to the Safety Critical Elements of the pipeline system that may lead to operation outside of the operating integrity boundary defined by the Performance Standards. Each threat requires a risk barrier(s), which is (are) identified in this document and detailed in its reference document, which will be: -

- A design report,
- The operating procedure, or
- The operations and maintenance philosophy,

or, possibly, a combination of these.

Control activities monitor the operating parameters of the pipelines or the mitigating activities to ensure that the pipeline is not operated beyond its safe operating limits and to ensure that the mitigating activities are effective.

Each of the Focal Points is responsible for developing and maintaining their respective schemes, including the barrier control activities for the sections of the pipeline allocated to them and the acceptance or rejection criteria (Performance Standards) against which the condition of the pipeline is monitored.

The barrier control and monitoring activities are based on one or more of the following:

- Risk Assessment
- Industry practice
- Company practice
- Specific development for the Corrib Pipelines (e.g. the peat stability study)

The MA/MEA threats, risk barriers and performance standards are reviewed at least annually by the Focal Point.

Change to key parameters of the pipeline, physical or operational, are subject to the SEPIL Management of Change process, to ensure the associated risks are reviewed and addressed.

The MA/MEA threats, risk barriers and Performance Standards are discussed in Attachment A.

4.3.2 Performance Monitoring

Control activities require a Performance Monitor relevant to the Performance Standard and the Risk Barrier and include inspection, monitoring, testing and maintenance as appropriate. These activities will be performed to identify: -

- Deviations from the Performance Standards,
- Deterioration in risk barrier effectiveness,

- Trends in pipeline system deterioration, and,

- The development of nascent defects.

All the Performance Monitors have a Monitoring Frequency set to ensure that the pipelines are maintained in efficient working order and good repair, as required by legislation and to comply with SEPIL requirements.

The Monitoring Frequencies can either be time based or be risk based. Time based frequencies are usually set for control activities relating to fixed operating parameters (e.g. Cathodic Protection) and continuous barriers (e.g. corrosion inhibitor injection), whilst risk based frequencies are set for inspection and monitoring of gradual deterioration processes, (e.g. inspection for internal corrosion). It is the responsibility of the respective Technical Authorities to choose the appropriate method for determining the Monitoring Frequency. At annual review the method may be changed if considered appropriate.

Annual review of the developed schemes is performed to confirm the continuing appropriateness of the Performance Standards and the adequacy and relevance of the control activities.

4.3.3 Time based Monitoring

Time based monitoring frequencies stated in this document are either mandated by the statutory consents or are embedded in the pipeline control system, operating procedures or maintenance routines. They are set with due regard to the rate of change of the performance parameter that is being monitored.

4.3.4 Risk Based Monitoring

Risk based frequencies are used to monitor those gradual deterioration mechanisms and outside influences where the likelihood and the consequences of occurrence can be assessed.

Three established and verified methodologies are used: -

- PIPE-RBA, (Pipeline – Risk Based Assessment), is used for the life prediction and internal inspection of the infield pipelines and the Natural Gas Pipeline both offshore (N0211) and onshore (L0011), (except for the Terminal Pipework and the Pig Receiver).

- Subsea Facilities RBA is used for external inspection of the subsea pipelines, manifold, umbilicals, and SDU, UTAs, PLEM, PLET and outfall diffuser.

- RRM (Risk and Reliability Management) is used for the Pig Receiver and Terminal Pipework.

4.4 IMPLEMENTATION

4.4.1 Planning

The monitoring and inspection scheme is updated annually and recorded in the Common Pipeline Database (CPD). The CPD includes a register that defines the scheme of activities to be carried out and the Focal Points responsible for each of them. The PCP approves the scheme and is responsible for ensuring that the scheme is compiled and distributed to the relevant Focal Points.

Each Focal Point ensures that the required control activities (Risk Barriers and Monitoring) are performed as required by the reference document and Common Pipeline Database (CPD) listing. They are translated into an on-line inspection plan, a subsea inspection plan, a monitoring plan, maintenance routines, plant operators' duties or a sampling and analysis plan.

If the activity is carried out less frequently than annually or if it is necessary to 'book' resources well in advance (e.g. intelligent pigs) it is the responsibility of the Focal Point to maintain a long-term plan within CPD. If resources are shared with other Shell companies the PCP maintains that plan in collaboration with the Focal Point.

All activities will need budget, orders, inclusion in resource plans and other financial and administrative approvals. It is the responsibility of the Focal Point to ensure that these are initiated and obtained from the Asset management. In the event that approval is not forthcoming this is referred to the NRP for resolution with the Asset Owner.

4.4.2 Scheduling and Execution

Maintenance and inspection activities are planned and scheduled in the SAP PM (Plant Maintenance) database. It is the responsibility of the Focal Point to add routines to the SAP PM system, develop work packs, issue work orders, etc. in order to ensure that activities are triggered and instructions are available. The Focal Point should ensure that the activity is incorporated in the Integrated Activity Plan for execution.

The continuously implemented activities are carried out repetitively in accordance with their controlling procedure and the requirements of this document. The CPD monitoring and inspection scheme includes appropriate annual review of these activities.

The Focal Point ensures that reports of the Risk Barrier activity (where appropriate) and the results of the Monitoring activity are accurate and are transmitted and stored in a secure manner.

The Focal Point ensures that the results are captured in a way that highlights any breach of the Performance Standard in a timely manner (e.g. control room alarm, anomaly criteria in work packs).

4.4.3 Immediate Action

The spreadsheet tabulation that is part of Attachment A of this document and which is to be finalised prior to commencing commissioning will identify the Immediate Action that is taken in the event that a Performance Standard is breached and will reference the procedure that is followed.

Immediate Action is part of Operating and Emergency Procedures [7] where the threat to integrity is immediate (e.g. corrosion loss in excess of corrosion allowance, unauthorised excavation in the right of way), and the appropriate response is detailed in emergency operating procedures.

Alternatively Immediate Action may be a response to an 'alarm' that warns of increased degradation rate, (e.g. corrosion inhibitor injection stopped), or an approach to non-conformity, (e.g. corrosion monitoring losses at alarm point). In this case it is the Focal Point's responsibility to ensure that action is taken to review and instigate corrective action in a sufficiently timely manner.

All incidence of Immediate Action is reported to the PCP who maintains an overview and monitors progress towards resolution.

4.4.4 Deviations and Corrective Action

Where Immediate Action leaves the pipeline in a temporary state that does not conform to the design or to 'Shell UIE' standards a deviation is created that must be approved by the appropriate Technical Authority.

Requirements for physical work to restore the pipeline state are entered into the SAP PM database by the Focal Point as a Notification to allow a preventive or corrective work order to be raised.

The status of deviations and SAP work orders are tracked by the Facility Status Reporting system. Status in the system is monitored by the Focal Point Operations & Safety Systems to ensure that action is taken.

4.5 RECORDS, REPORTING AND REVIEW

4.5.1 Records

All Inspection and Monitoring is recorded in the way that is appropriate to the organisational unit carrying out the task and the data acquisition methods used. In general it is one of the following:

- Data from instrumented system in PI, (the SCADA data historian)
- Records of operator surveillance in operations logs
- Records of maintenance activity in SAP PM,
- Terminal inspection activity in inspection reports, for vessels, a database for pipework, and the test records, for protective devices.
- Monitoring data in spreadsheets maintained by the Corrosion Engineer or reports provided by the service contractor.
- Subsea pipeline and manifold inspection data in the Inspection Based Information System, (IBIS).

- Specialist subsea and onshore pipeline survey data, including cathodic protection surveys, in the service contractor's reports and, for subsea data, in IBIS.

IBIS is used, in particular, for data linked to locations identified by kilometre point (KP).

4.5.2 Analysis

The results of the inspection, monitoring and control activities are assessed to determine trends and identify breaches of the Performance Standards that require Immediate Action. The responsible Focal Points carry this out within their allocated responsibility, and maintain a record of the results together with their assessment.

The full set of results are reviewed and assessed on an annual basis to ensure the continuing fitness for purpose of the pipeline. This annual analysis addresses all the items listed in the CPD generated inspection plan. The relevant Focal Points ensure that the analysis is carried out for each assigned item in the plan and is signed off by the person carrying out the analysis.

The Corrosion Management Focal Point analyses results relating to corrosion and material degradation (e.g. fatigue), including corrosion and erosion monitoring, fluids analysis and corrosion barriers, for the production pipelines using PIPE-RBA. The PIPE-RBA analysis delivers a revised inspection due date (IDD) for intelligent pig inspection and a report giving:

- A summary of key data including operating data, risk assessment parameters, integrity 'traffic light' status and inspection due date.
- A summary of deterioration and barrier status including corrosion inhibition, cathodic protection and coatings.
- A statement regarding current integrity status and any outstanding issues that may affect that status if not corrected
- Recommendations for changes to inspection and monitoring, if required, or a recommendation to continue the existing scheme.
- A summary of outstanding corrective action.

The Technical Integrity Focal Points review the last 12 months operation, including:

- Maintenance work carried out (if any).
- Summary of significant Inspection and Survey records in the year including a comparison of trends with those of previous years where applicable.
- Identification of anomalies and anomaly tracking requirements.
- Modifications made (if any).
- Significant recommendations from audits carried out.

The General Integrity (Onshore) Focal Point arranges a review and update of the vessel and pipework (RRM) risk based inspection schemes and inspection frequencies. The General Integrity (Offshore) Focal Point arranges a review and update of the Subsea Facilities RBA scheme and the associated inspection and survey frequencies.

Subsea facility anomalies are recorded and tracked in IBIS. Onshore anomalies are recorded in the PIPE-RBA report. All significant anomalies and required corrective action are included in the CPD summary report.

The Operations & Safety Focal Point reviews the last 12 months operation, including:

- Integrity related operating data
- Security incidents (if any)
- Testing of safeguarding systems
- Communications systems
- Emergency preparedness and exercises

The PIMS is reviewed on an annual basis following the technical assessment and provision of recommendations. The PCP is responsible for the review of the PIMS and ensures it remains appropriate in the light of each year's findings. The results of the review shall be included in the summary integrity report as a formal record of the review.

The Focal Points annually review the risk assessment, control activities and schedules, and if appropriate recommend revision of the Integrity Reference Plan accordingly. The results of these reviews are included in the summary reports as a formal record of the review.

When complete, the PCP convenes a peer review of the PIPE-RBA results, the Subsea Facilities RBA and RRM results and the Pipeline Annual Report before they are finally published. The review team includes:

- The PCP, who shall chair the review
- The Focal Points
- 'Shell UIE' Pipeline Group specialists as required by the PCP
- 'Shell UIE' Materials & Corrosion Technical Authority, or representative
- A representative of the Production Chemistry Team

The Peer Review considers: -

- Validity of the analysis of the results including the integrity status and the ongoing issues.
- Appropriateness of the corrective action recommended.
- Appropriateness of the monitoring and inspection plan for the next year.
- Amendments to the Integrity Reference Plan and CPD Monitoring/Inspection plan
- Improvement to the Integrity Management Scheme

4.5.3 Pipeline Annual Report

The Pipeline Annual Report is finalised incorporating the findings of the review.

The PIPE-RBA results, together with the assessment of other operating results and sub sea survey results are further summarised and presented in a Pipeline Annual Report summary within CPD. The PCP takes responsibility for this.

The Pipeline Annual Report also gives the status of the annual monitoring and inspection plan and the plan for the following year. The report also gives an overall 'traffic light' status for the pipeline. The status colour will signify: -

- **RED:** The short term integrity of the pipeline cannot be assured and immediate management action is required.
- **AMBER:** The medium to long-term integrity of the pipeline cannot be assured and action to mitigate risk and/or degradation is required.
- **GREEN:** The long-term integrity of the pipeline is assured, no remedial action is required.

Where the status is Amber or Red a corrective action recommendation must be made via SAP PM or FSR. Where the status is Red this must include a recommendation to cease operation or to immediately adopt an operating mode that avoids the potential for failure (e.g. a reduction in operating pressure). The PCP must approve a change in operating mode.

The finalised Pipeline Annual Report, and any findings requiring rectifications / modifications, is presented to the NRP, the Operations Manager and the Asset Owner who sign off the report.

The NRP presents the report to the Ireland Country Chairman and assists the Asset Owner in reporting to the statutory authorities, as required.

4.6 CORRECTIVE AND IMPROVEMENT ACTION

4.6.1 Performance Measurement and Review

Each Focal Point has a set of Key Performance Indicators that measure performance in the Focal Point's set of activities. These are measures of success and effectiveness in completion of mitigation and monitoring activities - leading indicators – and measures of outcome – lagging indicators.

The Focal Point Operations & Safety Systems and the PCP are responsible for agreeing target values and reporting frequency for KPIs. The KPIs must incorporate the requirements of the performance standards as a minimum.

4.6.2 Corrective and Remedial Action

Recommendations for corrective action may include a procedural change, a change to the inspection programme or modification to the plant. The scope of any work is defined by the relevant Focal Point and full justification provided to the PCP with an assessment of the impact of such works. The Operations Manager is ultimately responsible for ensuring that the recommendations are adopted and implemented, if required and appropriate.

The NRP and Operations Manager decide how rectification works shall be managed. This also applies to the selection of contractors for the work. The Focal Point may be given the management task depending upon the scale of the work.

However, regardless of whether the Focal Point takes management responsibility or not, he shall be responsible for acceptance of the completed work and participates in engineering reviews and associated risk assessments.

Changes are developed, reviewed and approved in accordance with the Corrib Change Management Procedure.

4.6.3 Revision of the Integrity Reference Plan

Where the Pipeline Annual Report recommends changes to the Integrity Reference Plan the NRP requires the PCP, in collaboration with the Focal Point, to make the required changes.

This may require studies or test work to determine and validate changes in Performance Standards, in which case the PCP in collaboration with the relevant Focal Point makes recommendation to the Asset Owner for the necessary funding of supporting work.

Changes may also be made to operating procedures, design documents, instrument settings, maintenance routines, etc. which are referenced in the revised Integrity Reference Plan. Where appropriate changes are developed, reviewed and approved in accordance with the asset Change Management Procedure.

4.6.4 Audit

The NRP is responsible for arranging audits by persons not involved in the day-to-day pipeline integrity management process. Audit is an important aspect of the pipeline integrity management scheme and is arranged at regular intervals as a means of:

- Confirming compliance of PIMS with legislative and company requirements;
- Confirming that the PIMS is effectively implemented;
- Providing a basis for continuous improvement.

4.6.5 Action Tracking

The NRP and the Asset Holder review the outcomes of the Pipeline Annual Report and Audits. All recommendations or actions that have been raised in relation to the SEPIL pipeline systems are tracked using either the 'Shell UIE' Facility Status Reporting system (FRS), where the requirement is for physical work on the pipeline system, or the Fountain Assurance System, where the requirement is for the change of a documented procedure.

5 REFERENCES

Note: References relating to the content of Attachment A are included at the end of each of the Attachment sections, A1 to A6. References relating to the content of the tabulation are included in the tabulation itself.

1. Petroleum and Other Minerals Development Act, 1960

2. Gas Act, 1976

3. Planning and Development (Strategic Infrastructure) Act, 2006

4. Rules & Procedures Manual for Offshore Petroleum Operations (Draft), 2004

5. Irish Standard I.S. 328: 2003, Code of Practice for Gas Transmission Pipelines and Pipeline Installations (Edition 3.1)

6. Report of the Corrib Technical Advisory Group to Minister Dempsey, January 2006 ("TAG Report")

7. Corrib Pipelines Operating & Emergency Procedures (in preparation)

8. Corrib Change Management Procedure

9. I.S. EN 14161: 2004 Petroleum and natural gas industries – Pipeline transportation systems (ISO/360:2000 Modified)

10. Foreshore Acts 1933 to 2009

11. Petroleum (Exploration and Extraction) Safety Act, No.4/2010

6 LIST OF ABBREVIATIONS

API	American Petroleum Institute
ASTM	American Society for the Testing of Materials
CER	Commission for Energy Regulation
CIPS	Close Interval (CP) Potential Survey
CMS	('Shell UIE') Corporate Management System
CO_2	Carbon Dioxide
CP	Cathodic Protection
CPD	('Shell UIE') Common Pipeline Database
DCS	Distributed Control System
DEP	('Shell UIE') Design & Engineering Practice
DCENR	Department of Communications, Energy and Natural Resources
DCVG	Direct Current Voltage Gradient
DNV	Det Norske Veritas
UIE	(Shell) Upstream International Europe
ER	Electrical Resistance
ERD	('Shell UIE') Engineering Reference Document
ESD	Emergency Shutdown
ESDV	Emergency Shutdown Valve
FSM	Field Signature Method
GRP	Glass Reinforced Polyester
HE	Hydrogen Embrittlement
HDPE	High Density Polyethylene
HP	High Pressure
H_2S	Hydrogen Sulphide
HS&E	Health, Safety & Environment
IDD	Inspection Due Date
IBIS	('Shell UIE') Inspection Based Information System
IPPC	Integrated Pollution Prevention Control
I.S.	Irish Standard
KP	Kilometre Point
KPI	Key Performance Indicator
LP	Low Pressure
LVI	Landfall Valve Installation
MAOP	Maximum Allowable Operating Pressure
MA	Major Accident (threat)
MEA	Major Environmental Accident (threat)
MDPE	Medium Density Polyethylene
MOP	Maximum Operating Pressure

MTD	Marine Technology Directorate
NRP	(‘Shell UIE’) Nominated Responsible Person, TA1 Pipelines
OCOP	(‘Shell UIE’) Operating Code of Practice
OTU	Onshore (Umbilical) Termination Unit
OTTU	Onshore Terminal (Umbilical) Termination Unit
P&ID	Process & Instrumentation Drawing
PAG	Pipeline Above Ground
PE	Polyethylene
PFP	Passive Fire Protection
PCP	(‘Shell UIE’) Pipeline Competent Person, TA2 Pipelines
PIMM	Shell EP Pipeline Integrity Management Manual
PIMS	Pipeline Integrity Management Scheme
PIPE-RBA	(‘Shell UIE’) Pipeline Risk Based Assessment
PLEM	Pipeline End Manifold
PLET	Pipeline End Termination
PP	Polypropylene
PTW	Permit To Work
PVDF	Polyvinylidine Fluoride
RBA	Risk Based Assessment
RBI	Risk Based Inspection
ROV	Remotely Operated (Underwater) Vehicle
RRM	(‘Shell UIE’) Risk and Reliability Management
SAP PM	SAP Planned Maintenance
SCADA	Supervisory, Control and Data Acquisition
SCE	Safety Critical Element
SDR	Standard Dimension Ratio (of Polyethylene pipe)
SDSS	Super Duplex Stainless Steel
SDU	Subsea Distribution Unit
SEPIL	Shell E&P Ireland Limited
SIA	Strategic Infrastructure Act
SS	Stainless Steel
TA	(‘Shell UIE’) Technical Authority
TAG	(DCENR) Technical Advisory Group
TIF	Shell EP Technical Integrity Framework
UNS	Unified Numbering Scheme (for materials)
UT	Ultrasonic
UTA	Underwater (Umbilical) Termination Assembly

ATTACHMENT A

[INTEGRITY REFERENCE PLAN]

NOTE: The design and process data provided in this Attachment is for Information Only as the system has not been constructed yet. Reference must be made to the design documentation and operating manuals for authoritative data.

The Integrity Reference Plan provides a catalogue of activities necessary to assure the ongoing integrity of the pipeline system. As appropriate, activity items are included in the Common Pipeline Database (CPD) for the annual pipeline inspection/monitoring scheme, the subsea maintenance plan and the planned maintenance scheme, etc.

The detailed plan will be published in spreadsheet form prior to commissioning. Barriers against operational threats, generally, are discussed below and those that are actioned during fabrication and construction should be detailed in the relevant quality plans.

ATTACHMENT A1 – OVERALL SYSTEM DESCRIPTION

The Corrib Natural Gas Pipeline system comprises pipeline Safety Critical Elements (SCEs), which are divided into sections, as follows:

Table A1.1: Pipeline System Elements and Sections

Line No	SCE/ Pipeline	SCE Section	Section Description	Limits
N0211	20" Natural Gas offshore	Tie in	Tie in spool	Corrib Field Manifold to the Pipeline End Termination (PLET).
		PLET Tie in	PLET/PLEM Tie in spool	Spool between PLET and PLEM
		PLEM	PLEM	Pipeline End Manifold (PLEM)
		Deep Water	Pipeline, Deep Water	PLEM to the KP 82.9
		Inshore	Pipeline, Inshore	KP 82.9 to Landfall Valve Installation.
L0011	20" Natural Gas onshore	LVI	Landfall Valve Installation	Landfall Valve Installation
		Onshore	Pipeline, buried onshore	Landfall Valve Installation to burial point within the Bellanaboy Bridge Gas Terminal.
		Terminal PAG	Pipeline above ground at Terminal	Burial point Bellanaboy Bridge Gas Terminal to ESDV 1001
		Terminal Pipework	Terminal pipework	Pipework from ESDV 1001 and Pig Receiver to Pipeline limit
		Pig Receiver	Pig Receiver	Pig Receiver D-1001 and PSV1001
N1171	6" Flexible Jumper	Flexible	Flexible Pipe	Well P1 End Fitting to Manifold End Fitting
		Ends	End Fittings	Outboard hubs, ICARUS assemblies and bend restrictors
N1172	8" Flexible Jumper	Flexible	Flexible Pipe	Well P3 End Fitting to Manifold End Fitting

Line No	SCE/ Pipeline	SCE Section	Section Description	Limits
		Ends	End Fittings	Outboard hubs, ICARUS assemblies and bend restrictors
N1173	6” Flexible Jumper	Flexible	Flexible Pipe	Well P4 End Fitting to Manifold End Fitting
		Ends	End Fittings	Outboard hubs, ICARUS assemblies and bend restrictors
N1174	8” Flexible Jumper	Flexible	Flexible Pipe (Two lengths)	Well P5 WHPS End Fitting to Manifold End Fitting
		Ends	End Fittings	Outboard hubs, ICARUS assemblies, mid point joint fittings and bend restrictors
N1175	6” Flexible Jumper	Flexible	Flexible Pipe	Well P2 End Fitting to Well P5 WHPS End Fitting
		Ends	End Fittings	Outboard hubs, ICARUS assemblies and bend restrictors
N2101	6” Flexible Jumper	Flexible	Flexible Pipe	Well P6 WHPS End Fitting to Manifold End Fitting
		Ends	End Fittings	Outboard hubs, ICARUS assemblies and bend restrictors
N1199	6” Flexible Jumper	Flexible	Flexible Pipe	Well P5 Tree End Fitting to P5 WHPS End Fitting
		Ends	End Fittings	Outboard hubs, ICARUS assemblies and bend restrictors
N2823 (Onshore)	Onshore Umbilicals	OTTU	Onshore Terminal Termination Unit	OTTU at Bellanaboy Bridge Gas Terminal
		Onshore	Onshore Umbilicals	Umbilical from Bellanaboy Bridge OTTU to OTU
		Joint	Onshore Joint	Joints in Onshore Umbilicals
		OTU	Onshore Termination Unit	OTU at the Landfall Valve Installation
		Onshore	Signal Cable	LVI to Terminal

Line No	SCE/ Pipeline	SCE Section	Section Description	Limits
		Onshore	Monitoring Cable	LVI to Terminal
N2823 (Offshore)	Offshore Main Umbilical	Offshore	Offshore Main Umbilical	Umbilical from the Landfall Valve Installation OTU to the Manifold Subsea Termination
		UTA	Underwater Termination Assembly	UTA and Subsea Termination at SDU
		SDU	Subsea Distribution Unit	Subsea Distribution Unit mounted on top of the Manifold
N2824	Umbilical	Infield	Infield Umbilical	SDU to Well P1
		UTA	Underwater Termination Assemblies	UTAs and Subsea Terminations at SDU and Well
N2825	Umbilical	Infield	Infield Umbilical	SDU to Well P3
		UTA	Underwater Termination Assemblies	UTAs and Subsea Terminations at SDU and Well
N2826	Umbilical	Infield	Infield Umbilical	SDU to Well P4
		UTA	Underwater Termination Assemblies	UTAs and Subsea Terminations at SDU and Well
N2827	Umbilical	Infield	Infield Umbilical	SDU to Well P5
		UTA	Underwater Termination Assemblies	UTAs and Subsea Terminations at SDU and Well
N2828	Umbilical	Infield	Infield Umbilical	Well P2 to Well P5
		UTA	Underwater Termination Assemblies	UTAs and Subsea Terminations at Wells
N2879	Umbilical	Infield	Infield Umbilical	SDU to Well P6

Line No	SCE/ Pipeline	SCE Section	Section Description	Limits
		UTA	Underwater Termination Assemblies	UTAs and Subsea Terminations at SDU and Well
N1004 (Onshore)	Water Outfall	Onshore Outfall	Water outfall buried onshore	Bellanaboy Bridge Gas Terminal to Landfall Valve Installation
		Valve	Back Pressure Valve	Back pressure regulating valve buried at Landfall Valve Installation
N1004 (Offshore)	Water Outfall	Offshore Outfall	Water outfall offshore	Landfall Valve Installation to Diffuser
		Diffuser	Diffuser Assembly	Diffuser assembly at offshore end of outfall

A schematic overview of the pipeline system was shown earlier in Figure 1.1.

ATTACHMENT A2 – 20" OFFSHORE GAS PIPELINE (N0211), CORRIB FIELD TO SHORE

A2.1 PHYSICAL DESCRIPTION

The pipeline runs for 83.4km from the Corrib Field Manifold to the Landfall Valve Installation. The pipeline is routed partly on the seabed (0-70.1km) and partly trenched (70.1km to shore) with terrain varying from sands and gravels to clays and muds.

The main parameters for the pipeline are:

Table A2.1: Sealine parameters

Sealine		**PLET to Landfall Valve Installation**	
Length		**83.4km**	
External Diameter		**508mm (20inch)**	
Material		**DNV OS-F101 Gr 485**	
Design Pressure		**345 barg**	
MAOP		**150 barg**	
Section	**Wall Thickness**	**Design Corrosion Allowance (see note)**	**Coating**
KP0-0.4	**27.1mm**	**6.4mm**	**2.5mm 3 layer PP**
KP0.4-0.8	**27.1mm**	**3.6mm**	**2.5mm 3 layer PP**
KP0.8-1.6	**27.1mm**	**2.3mm**	**2.5mm 3 layer PP**
KP1.6-2.5	**27.1mm**	**1.4mm**	**2.5mm 3 layer PP**
KP2.5-4.1	**27.1mm**	**1.0mm**	**2.5mm 3 layer PP**
KP4.1-12.0	**21.0mm**	**1.0mm**	**2.5mm 3 layer PP**
KP12.0-17.7	**22.5mm**	**1.0mm**	**2.5mm 3 layer PP**
KP17.7-26.4	**24.7mm**	**1.0mm**	**2.5mm 3 layer PP**
KP26.4-65.7	**22.0mm**	**1.0mm**	**4mm Asphalt + Concrete**
KP65.7-81.9	**22.5mm**	**1.0mm**	**4mm Asphalt + Concrete**
KP81.9-83.0	**27.1mm**	**1.0mm**	**4mm PP**
KP83.0-83.4	**27.1mm**	**1.0mm**	**4mm PP + Concrete**

Table A2.2: Spoolpiece parameters

Spoolpiece		Manifold to PLET	
Length		75m approx.	
External Diameter		508mm (20inch)	
MAOP		150barg	
Material		Approx. 5m pipe, Duplex Stainless Steel, UNS S31803 4 bends DNV OS-F101 Gr 485 , 3 layer PP coated 2.5mm 2 bends DNV OS-F101 Gr 485 internally 3.5mm Alloy 625 clad, polyurethane coated, Remainder of pipe, DNV OS-F101 Gr 485, 2.5 mm 3 layer PP Hubs ASTM A694 F65, internally 3mm Alloy 625 clad, coated with Xylan 1400.	
Section	Wall Thickness	Design Corrosion Allowance (see note)	Coating
Duplex Pipe	38.1mm	None	Epoxy NORSOK M-501 System 7
Pipeline end hub			Xylan 1400
Clad Bends	31.8mm DNV OS-F101 Gr 485 mm + 3.5mmcladding with Alloy 625	None	Polyurethane coated
Carbon Steel	27.1mm	6.4mm	2.5mm Polyurethane coated

Note: The Design Corrosion Allowances quoted has been set by the initial wellhead closed in tubing head pressure of 345barg.

A2.2 PROCESS PARAMETERS

The pipeline has a design pressure of 345barg.

The MAOP of the offshore pipeline is 150barg. Maximum design throughput is 350mmscf/day. The maximum design temperature is 74ºC (75ºC is used in the corrosion prediction) and the minimum is 0ºC for the line pipe and 0ºC for the PLEM valve.

The gas entering the pipeline comprises hydrocarbon gas (mainly methane), water vapour and condensed water, carbon dioxide and traces of other gases together with methanol containing a corrosion inhibitor. Methanol is added to prevent the formation of gas hydrates as the water condenses. Significant amounts of formation water will not be produced.

The pipeline is designed for non-sour service. There is no indication that any measurable quantity of hydrogen sulphide is present in the Corrib field. Nor is there any reason to believe that any hydrogen sulphide will be produced in the future.

Leak detection is achieved by two dedicated independent systems:

- The mass balance system, which is comparing the pressures and flows from subsea and the terminal using various statistical and mass balance techniques. It monitors both the onshore and offshore sections with an interface to the DCS that alerts the operator in the event of a problem.

- A second system installed along the onshore pipeline, which is based on very sensitive vibration monitoring, using the fibre optic cable.

Automatic Emergency Shutdown initiates closure of the wells in the field offshore and shuts the Terminal pipeline ESDV.

High pressure protection levels are established in order to limit the pressure to a MAOP = 150barg.

Pigging is not considered to be a requirement for normal operations. Velocities in the pipeline are predicted to remain above 4m/s, which is above the rate whereby sand or proppant particles if present would be expected to settle out. Wax or scale formation is not anticipated. There is no requirement to run a pig through the pipeline to distribute the corrosion inhibitor because the flow will ensure good mixing. However, facilities exist to launch pigs from the subsea manifold for special operations, (e.g. commissioning, on-line inspection).

A2.3 INTEGRITY CONTROL ACTIVITIES

The spreadsheet of Attachment A2, that will be finalised before the pipeline system is commissioned, will give details of the threats, barriers and monitoring which are assured through control action during operation together with details of reference documents, and corrective action requirements.

The threats and their control measures can be summarised as follows:

A2.3.1 Internal Corrosion

Internal corrosion caused by carbon dioxide and organic acid in the gas dissolving in the water condensed from the gas is the main threat. The corrosivity of the fluids varies along the line. The gas is non-corrosive until it cools below the water dew point at which point it is at its most corrosive. Depending on temperature and pressure changes some water may condense upstream in the well bores and/or flowlines and it continues to condense in the pipeline until the gas reaches ambient temperature at sea bed conditions.

The base case maximum predicted uninhibited corrosion rate of 1.3 mm/yr occurs in Year 3 at a point near the manifold. This rate will decrease with time as the wellhead pressures decline.

Internal corrosion is, therefore, controlled by the injection of a corrosion inhibitor (conveyed in the methanol added for hydrate control). The predicted inhibited rate at the point of maximum corrosion is <0.1mm/yr assuming 99% inhibitor availability. This sets the performance standard for inhibitor injection availability.

The incorporation of corrosion allowances into the pipeline design, varying as shown in Table A2.1 above, allows for the residual corrosivity of the inhibited fluids. The maximum corrosion rates occur at the start of the line where the corrosion allowance is 6.4mm.

The gas cools as it flows along the pipeline and the corrosivity decreases reaching a steady uninhibited value of 0.1mm/yr from around KP 10 onwards. The inhibited corrosion rate will be less.

The corrosion inhibitor injection is monitored by the measurement of injection rate and logging of inhibitor injection up time. Residual inhibitor is analysed in the aqueous phase separated at the Terminal.

The effect of the treatment is assessed by a corrosion monitoring device – a Field Signature Method (FSM) Spool incorporated in the Tie In Spool near the manifold which records the wall thickness on a continuous basis. Intelligent pig inspection, at intervals set by a risk-based assessment, is used to measure and trend actual wall thickness loss along the entire pipeline.

The corrosion rate would be adversely affected by oxygenation of the methanol injected into the pipeline system offshore. The oxygen content in the methanol is relatively low but is reduced to negligible levels with oxygen scavenger in the terminal. This is monitored at the terminal.

The CO2 corrosion rate and life prediction is revisited on an annual basis and monitoring and inspection results are used to validate them.

Sour corrosion mechanisms are not expected to be a problem for the Corrib gas pipeline as there is no indication that any measurable level of hydrogen sulphide is present in the Corrib field. However, hydrogen sulphide measurement is routinely made on gas samples in the terminal to ensure that this remains the case.

A2.3.2 External Corrosion

External corrosion can occur to the pipeline due to the corrosivity of seawater, and this will be higher where the pipe temperature is highest. To combat this, the pipeline is coated to a high standard and equipped with sacrificial anodes to cathodically protect the pipe at any point where the coating is damaged. The sacrificial system covers the manifold, jumpers, wellheads and offshore pipeline in one electrically continuous system

The combination of coating and cathodic protection (CP) system will be monitored for ongoing effectiveness with estimates of remaining anode mass and potential measurements (at points of access on the PLEM and Manifold) and by potential gradient surveys along the pipeline. Performance targets are set for potential measurements and remaining anode mass. The results are analysed on a routine basis. Changes and impacts brought about by the activities of other parties are assessed and surveyed as necessary.

A2.3.3 Mechanical Damage

The likelihood that the submarine pipeline could experience impact associated with the activities of outside parties is, in common with other pipelines, high. However, the thick walled construction of the line and/or the concrete weight coating make the pipe resistant to pullover buckling, hooking and denting damage from fishing operations using trawl gear equivalent to N Sea weight. In view of this the line is only buried at the inshore end from KP 70 to the shore at KP 83.

The weight coating protects the anticorrosion coating from damage. The sacrificial anode bracelet shape is designed to prevent trawl board snagging.

The residual risk of damage from the activities of outside parties including anchor damage and dropped object impacts is mitigated by marking pipeline on charts and notifying location in notices to mariners. In the vicinity of the field these threats are mitigated by the management of works by Shell and by liaison with contractors deploying vessels using anchors and vessels positioning over the line. Other parties are prohibited from undertaking fishing, etc., in the safety zone around the well and manifold locations (Ref Statutory Instrument (S.I.) no 395 of 2006 Continental Shelf (Protection of Installations) (Corrib Field) Order 2006). The PLEM is provided with a protection structure.

The type of trawlers fishing in the area is monitored and the results are factored into the risk-based determination of survey intervals.

The risk from Shell maintenance and engineering activities is controlled though standard procedures for risk assessment and approval to work in accordance with the Shell Subsea Engineering Maintenance & Inspection Procedures. This applies to any work on the umbilicals, outfall pipe, manifold and wellheads that run alongside the pipeline or are in the vicinity.

The line is inspected for damage with side scan sonar and visually at intervals determined by risk based assessment for the deepwater and inshore sections. Any damage is assessed and, if necessary, pressure limitation and/or repair actioned. Exposure of the buried inshore section is rectified if significant. The significance of weight coating damage is also assessed and substitute protection provided if necessary.

A2.3.4 Fatigue

The likely operating mode of the pipeline and the normal operating pressures make it unlikely that the pipeline will accumulate, if any, a significant amount of fatigue damage through internal pressure fluctuations over its service life. However, the number of significant pressure fluctuations, if any, is counted on an annual basis from pressure records held in the SCADA/DCS historian.

Fatigue failure of the pipeline through seawater flow-induced turbulence over lengths of free span is the main initiator of fatigue failure threat. Free spans are identified by routine side scan sonar surveys and further assessed visually if necessary. Some free spans may exist on the route as laid. Remedial action is taken where an existing or new span's length exceeds the maximum free span length that can be tolerated without rectification. This has been assessed in the design of the pipeline.

A2.3.5 Brittle Fracture

The pipeline has been manufactured to resist low temperature brittle fracture at all normal operating temperatures and all possible temperatures that may be encountered during planned start up and blow down.

A2.3.6 Overstress

The pipeline has been designed for the maximum wellhead shut in pressure of 345barg.

High-pressure protection levels are established in order to limit the pressure to a MAOP = 150barg. To ensure it remains appropriate the MAOP is reviewed periodically. It will also be reviewed if the pipeline sustains any corrosion or mechanical damage in the interim.

The unburied parts of the pipeline are at risk from deflection by trawl fishing, vessel anchors and other heavy marine operations. Design analysis has, however, shown that the pipe will survive a lateral pull from the trawl fishing operations using trawl gear equivalent to N Sea weight at all design conditions of pressure and temperature and in an otherwise undamaged condition. The residual risk of deflection from the activities of outside parties using anchors, etc., will be mitigated by marking on charts and notices to mariners and, in the vicinity of the field, the management of works by Shell and liaison with contractors deploying vessels using anchors, etc.

The type of trawlers fishing in the area is monitored and the results are factored into the risk-based determination of survey intervals.

The risk from Shell maintenance and engineering activities is controlled though standard procedures for risk assessment and approval to work in accordance with the Shell Subsea Engineering Maintenance & Inspection Procedures. This will apply to any work on the umbilical, outfall pipe, manifold and wellheads that run alongside the pipeline or are in the vicinity.

Thermally induced overstress by buckling has been addressed in the design and temperatures that are within the operating and shut in values used in the design do not cause overstress to an otherwise undamaged pipe. The wellhead temperatures are monitored to ensure the line remains within these constraints.

The line is inspected for deflections or upheaval with side scan sonar, and visually, at intervals assessed by risk-based analysis to be appropriate to the deepwater and inshore sections. Any deflections are assessed and, if necessary, pressure limitation and/or repair actioned.

A2.3.7 Integrity Reference Plan and Action

The detail identification of threats and barriers, together with performance standards, immediate action requirements and corrective action requirements are given in the tabular Integrity Reference Plan.

Where actual or suspected damage or deterioration requires Immediate Action then the pressure in the line will not be allowed to exceed 80% of the operating pressure at the time that the damage was found. A Shell defect assessment process and methods will be used to assess any defect. If indicated by initial assessment, the operating pressure may need to be restricted till remedial actions have been completed.

Methods will be identified for the repair of damaged pipe. The equipment and materials that may be required will be either held in stock or their acquisition route is identified and assured to meet required timescales.

ATTACHMENT A3 – 20" ONSHORE GAS PIPELINE (L0011), SHORE TO GAS TERMINAL

A3.1 PHYSICAL DESCRIPTION

The onshore gas pipeline runs for approx. 8.3 km from the Landfall Valve Installation (LVI) to the Bellanaboy Bridge Gas Terminal. At Glengad the pipeline is routed over a short distance across farmland. There after the pipeline is installed in a tunnel, which runs from Glengad to Aghoos underneath the Sruwaddacon bay over a distance of 4.8km. The final part of the route is through terrain generally consisting of soft peaty soils and subsequently through woodland where the soil is very soft peat bog to the terminal.

The main parameters for the pipeline are:

Table A3.1: Onshore Pipeline parameters [Ref A1]

Onshore Pipeline		**Landfall Valve Installation to Bellanaboy Bridge Gas Terminal**	
Length		**8.3km**	
External Diameter		**508mm (20inch)**	
Design Pressure		**144 barg**	
MAOP (see Note)		**100barg (see note)**	
Steel Grade		**DNV OS-F101 Gr 485**	
Section	**Wall Thickness**	**Design Corrosion Allowance**	**Coating**
All	**27.1mm**	**1.0mm**	**3 layer PP**

Note: The MAOP is reviewed at least every four years in accordance with I.S. 328. (Regulatory requirements). [Ref A2]

A3.2 PROCESS PARAMETERS

The pipeline has a design pressure of 144barg with a maximum throughput of 350mmscf/day.

The MAOP of the onshore pipeline has been set at 100barg, which is established by appropriated pressure limit settings at both the offshore manifold and the pressure limiting system in the LVI.

The arrival pressure at the terminal is in the order of 85barg initially. The temperature of the gas in the pipeline will be approximately 2 - 10°C, (having been cooled to the sea bed temperature in the offshore pipeline).

The gas entering the pipeline is the well fluid from the offshore section comprising hydrocarbon gas (mainly methane), water vapour, carbon dioxide and traces of other gases together with condensed hydrocarbons and water. The aqueous phase includes the Methanol and Corrosion Inhibitor, injected offshore to prevent the formation of gas hydrates and to mitigate corrosion.

The pipeline is designed for non-sour service. There is no indication that any measurable quantity of hydrogen sulphide is present in the Corrib field. Nor is there any reason to believe that any hydrogen sulphide will be produced in the future.

Leak detection is achieved by two dedicated independent systems:

- The mass balance system, which is comparing the pressures and flows from subsea and the terminal using various statistical and mass balance techniques. It monitors both the onshore and offshore sections with an interface to the DCS that alerts the operator in the event of a problem.

- A second system installed along the onshore pipeline, which is based on very sensitive vibration monitoring, using the fibre optic cable.

Automatic Emergency Shutdown initiates closure of the wells in the field offshore and shuts the Terminal pipeline ESDV.

A High Integrity Pressure Protection System in the Landfall Valve Installation provides overpressure protection. The valves will automatically close to prevent the onshore pipeline pressure from exceeding its Maximum Allowable Operating Pressure (MAOP).

Pigging is not considered to be a requirement for normal operations. Velocities in the pipeline are predicted to remain above 4 m/s, which is above the rate whereby sand and proppant particles would be expected to settle out. Wax or Scale formation is not anticipated. There is no requirement to run a pig through the pipeline to distribute the corrosion inhibitor because the flow will ensure good mixing. However, facilities exist to launch pigs from the subsea manifold for special operations, (e.g. commissioning, on-line inspection).

A3.3 INTEGRITY CONTROL ACTIVITIES

The spreadsheet tabulation gives details of the threats, barriers and monitoring spreadsheet to be checked against new set of bow-ties, which are assured through control action during operation together with details of reference documents, and corrective action requirements.

Many of these integrity control activities are subject to a mandatory requirement of the DCENR (and in the future it is anticipated the CER) either by a direct requirement in the Report of the Corrib Technical Advisory Group to Minister Dempsey, January 2006 (“TAG Report”), or through their requirement for the integrity management scheme to follow Irish Standard, I.S. 328. These regulatory requirements are indicated below. The final requirements will be included in spreadsheet form prior to commissioning.

The threats and their control measures can be summarised as follows:

A3.3.1 Internal Corrosion

Internal corrosion caused by carbon dioxide and organic acid in the gas dissolving in the water condensed from the gas is the main threat. It is controlled and reduced by the injection of a corrosion inhibitor (conveyed in the methanol added for hydrate control). The incorporation of a 1mm corrosion allowance into the pipeline design allows for the residual corrosivity of the inhibited fluids.

The injection is monitored by the measurement of injection rate and logging of inhibitor injection up time. Residual inhibitor is analysed in the aqueous phase separated at the Terminal. Intelligent pig inspection, at intervals set by a risk-based assessment, is used to measure and trend actual wall thickness loss. The base line survey provides measurement of wall thickness and pre-existing features against which later intelligent pig inspections may be compared. (Regulatory requirement).

Taking all the influences into consideration a prediction has been made of the expected corrosion rate. The prediction has been made using the Shell Hydrocor methodology to determine the basic CO2 and organic acid corrosion rate.

As the fluid composition, temperature, pressure and flow rate is essentially the same throughout the onshore pipeline, the corrosion rate will not vary significantly along the section. The predicted uninhibited corrosion rate is initially 0.12 mm/yr and drops as the pressure declines through time. If formation water is produced the predicted uninhibited corrosion rate increases to 0.20mm/yr, at initial conditions, but also drops as pressure declines. Inhibition will reduce the actual corrosion rate to <0.05mm/yr, which is sufficient to achieve the field life of 20 years.

The CO_2 corrosion rate and life prediction is revisited and updated on an annual basis and monitoring and inspection (corrosion monitoring at the terminal, UT of the above ground pipeline or intelligent pig) results are used to validate them.

Sour corrosion mechanisms are not expected to be a problem for the Corrib gas pipeline as there is no indication that any measurable quantity of hydrogen sulphide is present in the Corrib field. However, hydrogen sulphide measurement is routinely made on gas samples to ensure that this remains the case. (Regulatory requirement).

Damage by erosion by solids is not expected. One of the wells has been treated with proppant in 2001. This well was cleaned-up in 2001 and re-tested in 2008, but no proppant production was detected.

The reservoir consists of extremely tight rock and no formation sand production is expected. However as a precaution a clamp-on sand detector has been installed on the subsea manifold. This tool will allow assessment of solids production and subsequent corrective action to be undertaken in the unlikely event of sand or proppant production.

A3.3.2 External Corrosion

External corrosion can occur to a buried pipeline. To combat this, the Corrib pipeline is coated to a high standard and cathodically protected to prevent corrosion of the pipe at any point where the coating is damaged.

The CP system is monitored for ongoing effectiveness with checks on the transformer/rectifier up time and output together with ‘pipe/soil’ potential measurements at test posts and close interval potential surveys and DCVG surveys. Measurements close to the LVI should demonstrate that there is no current drain from the offshore anodes. The monitoring measurements include checks on isolation

joint effectiveness at the terminal. Frequencies for these checks conform to I.S. 328. (Regulatory requirement) [Ref A2].

The requirements for the cathodic protection (CP) system for the pipeline in the tunnel will be addressed during the detailed design.

The transformer/rectifier output required for protective levels of potential are initially determined on system commissioning. Performance targets are set for transformer/rectifier up time and output and measured 'pipe/soil' potentials.

The results of checks and surveys are analysed on a routine basis. Changes and impacts brought about by the activities of utilities and other parties are assessed and surveyed as necessary.

A3.3.3 Mechanical Damage

Buried pipelines, where not installed in the tunnel, are at risk from third party interference, especially unauthorised excavation. However, the thick walled construction of the line makes it resistant to damage from most agricultural and earth moving equipment. Also the minimum 1.2m cover and use of concrete slab protection, at crossings and ditches put the line out of reach of most routine farming and fishing activity and protect it from live vehicle loads, etc.

The residual risk of damage from the activities of outside parties is mitigated through line patrols and liaison with landowners and utilities. Patrol scope includes the main water crossings as well as the buried line.

The risk from Shell maintenance and engineering activities is controlled though standard procedures for risk assessment and permit to work, and for work within pipeline rights of way. This applies also to any work on the umbilicals and outfall pipe, which run alongside the pipeline. (Regulatory requirement).

A3.3.4 Fatigue

The likely operating mode of the pipeline and the normal operating pressures make it unlikely that the pipeline will accumulate any significant fatigue damage through stress fluctuations over its service life. However, the number of significant pressure fluctuations, if any, is counted on an annual basis from pressure records in the SCADA/DCS historian. (Regulatory requirement).

Fatigue failure of pipework and small-bore fittings at the Landfall Valve Installation and the Terminal end of the pipeline is also a threat. This has been assessed on an item-by-item basis and vulnerable items are surveyed, and, if necessary, modified, when the plant is constructed. (Regulatory requirement for LVI).

A3.3.5 Brittle Fracture

The first 1150 metres of the buried onshore pipeline, just downstream of the LVI, has good fracture toughness at temperatures down to -20ºC. The remainder of the buried onshore pipeline to the Terminal is suitable for temperatures down to -10ºC.

The LVI shutdown spool (16” bypass with valves) is specified for low temperature service down to -26ºC. The 20” gas pipeline section in the LVI is specified for service down to -20ºC.

Operating procedures require temperature monitoring and flow adjustment to prevent temperatures lower than -20ºC at the LVI and -10ºC from the point 1150m downstream of the LVI to the terminal, when the flow is restarted after valve closure at the LVI.

A3.3.6 Overstress

It is possible for the pressure in the offshore pipeline to rise beyond the onshore pipeline’s Maximum Allowable Operating Pressure (MAOP). To prevent the pressure in the onshore pipeline exceeding its MAOP a High Integrity Pressure Protection System is installed at the Landfall Valve Installation. This is tested for closure function, remote operation and valve leak tightness at an interval of not longer than one year. The hydraulic system for valve actuation is visually inspected every month for leakage. The valves are internally inspected for degradation due to corrosion or erosion at risk based intervals. The intervals for closure testing and hydraulic system inspection conform to I.S. 328. (Regulatory requirement). [Ref A2]

To ensure it remains appropriate the MAOP is reviewed at least every 4 years. It will also be reviewed if the pipeline sustains any corrosion or mechanical damage in the interim. The frequency for this check conforms to I.S. 328. (Regulatory requirement). [Ref A2]

Parts of the pipeline are laid through peat bog that has little capability to support the line and the peat could move to cause lateral displacement of the line. To avoid this problem, stone roads will be constructed in the bog areas and the pipeline buried within the stone roads thus providing support to the pipeline. Pipeline patrols watch for signs of settlements and, if any occurs, measurement of deflection (marker plates) is carried out and an assessment made to ensure that the original analysis remains valid. (Regulatory requirement).

The onshore pipeline line is protected at vehicle crossings of the way leave with a protection slab designed to protect from the maximum legal axle weight of 10.5tonne. Pipeline patrol and landowner liaison are used to ensure this is understood and observed and that the line is not crossed at unprotected points or by heavy off-road plant.

Since for the long bay crossing the pipeline will be installed in a tunnel, unsupported spans and differential settlement are highly unlikely to occur due to scour. The crossing is surveyed on a maximum 2-year interval to detect any problems. Frequencies for these checks conform to I.S. 328. (Regulatory requirement).

A3.3.7 Integrity Reference Plan and Action

The detail identification of threats and barriers, together with performance standards, immediate action requirements and corrective action requirements will be given in the tabular Integrity Reference Plan which will be prepared prior to commissioning.

Where actual or suspected damage or deterioration requires Immediate Action then the pressure in the line will not be allowed to exceed 80% of the operating pressure at the time that the damage was found. A defect assessment process will be used to assess any defect. If indicated by initial assessment, the operating pressure may need to be restricted till remedial actions have been completed.

Methods will be identified for the repair of damaged pipe. The equipment and materials that may be required will be either held in stock or their acquisition route is identified and assured to meet required timescales.

A3.4 REFERENCES

A1 Basis of Design, COR-39-SH-0018-09.

A2 Irish Standard I.S. 328: 2003, Code of Practice for Gas Transmission Pipelines and Pipeline Installations (Edition 3.1).

A3 Landfall Valve Installation Design Justification and Overview, JPK 05 2377 01 P 3 045 Rev 3 (Appendix Q4.3).

A4 Corrib Pipeline: Assessment of Wet Gas Operation, Internal Corrosion and Erosion, COR-39-SH-0011 rev 5 (Appendix Q4.9).

A5 Guidelines for the Avoidance of Vibration Induced Fatigue in Process Pipework, MTD Publication 99/100.

ATTACHMENT A4 - GATHERING LINES & MANIFOLD

A4.1 PHYSICAL DESCRIPTION

The main parameters for the Gathering system are:

Table A4.1: Gathering system parameters

Line/Item	Dimensions		Flexible Pipe Construction	
	Dia-meter	Length	Layer	Material
N1171	6”	98.1m	Interlocked Carcass	316L Stainless Steel
N1173	6”	108.4m	Pressure Sheath	PVDF
N1174	8”	2468.9 m	Zeta Spiral	FM 35 Carbon Steel
N1199	6”	200m	Two Armour Layers	FM 72 Carbon Steel
N2101	6”	100m (approx)	External Sheath	HDPE
N1172	8”	1724.4 m	Interlocked Carcass	316L Stainless Steel
N1175	6”	1515.2 m	Pressure Sheath	PVDF
			Zeta Spiral	FM 35 Carbon Steel
			Two Armour Layers	FM 72 Carbon Steel
			External Sheath	HDPE
			Connection Construction	
			Component	Material
Pipeline End	6” & 8”		Outboard Hub	UNS S32760
Fitting and Icarus			Outboard Hub Flange	UNS S31803

Termination			**End Fitting (Body, Neck & Flange)**	**ASTM A694 F60 Carbon Steel External Electroless Nickel Coating Internal UNS N06625 Clad**
			Connection Construction	
			Component	**Material**
			Termination Barrel, Front Lid & Rear Lid	**ST52-3N Carbon Steel, Coating NORSOK M-501 System 7 (Epoxy)**
			Bend Restrictor	**Carbon Steel**
Intermediate Connection (Grayloc Hub) N1174 Only			**End Fittings**	**ASTM A694 F60 Carbon Steel External Electroless Nickel Coating Internal Inconel 625 Cladding**
			Manifold Construction	
			Component	**Material**
Pipework & Fittings	**1" to 16"**		**Pipe & Fittings**	**UNS S31803**
			Valves	**UNS S31803**
			Hubs	**UNS S32760**
			Coating	**NORSOK M-501 System 7 (Epoxy)**
	20"		**Pig Launcher Hub**	**ASTM A694, F 65, 3 mm alloy 625 overlay.**

A4.2 PROCESS PARAMETERS

The flowlines and jumpers and manifold have a design pressure of 345barg. The gas entering the flowlines and jumpers is well fluids comprising hydrocarbon gas (mainly methane), water vapour and condensed water, carbon dioxide and traces of other gases to which Methanol containing a Corrosion Inhibitor is added at the wellhead to prevent the formation of gas hydrates and mitigate corrosion as the water condenses.

The flowlines and jumpers are designed for non-sour service.

A4.3 INTEGRITY CONTROL ACTIVITIES

The spreadsheet tabulation gives details of the threats, barriers and monitoring which are assured through control action during operation together with details of reference documents, and corrective action requirements.

Many threats have been eliminated by design but in some cases the assurance of barriers cannot be monitored visually because the manifold layout and protection structure prevents it.

The threats and their control measures can be summarised as follows:

A4.3.1 Internal Corrosion

Internal corrosion is controlled by the use of corrosion resistant materials in the flexible pipelines and manifold pipework and by the use of corrosion resistant cladding of low alloy steels and corrosion resistant materials in the flexible pipeline end fittings. These alloys are resistant to CO2 and organic acid corrosion corrosion for all Corrib production conditions.

The inner carcass of the flexibles is low carbon austenitic stainless steel (UNS S31603), which would be susceptible to pitting and crevice corrosion should formation water be produced. However there will be sufficient dilution by the methanol to mitigate this risk. Aqueous methanol is injected in sufficient quantity to dilute the chloride by 30% down to an acceptable level, less than 150,000ppm chloride. Also the oxygen content of the produced liquids/methanol mixture is not allowed to exceed 20ppb. Control to this level at the terminal, ensures that significant pitting damage will not occur.

The duplex stainless steel manifold pipework is not vulnerable to pitting, for the Corrib conditions.

The pressure sheath is a polyvinylidine fluoride (PVDF) thermoplastic that is resistant to chemical action by both the produced fluids and the methanol at the design operating temperatures. The carcass liner will protect it from erosion.

Wells that are chemically treated for fracturing, etc., will be cleaned up with backflow to the treating rig and not into the pipeline system to prevent damage to the carcass and pressure sheath materials.

As the pressure sheath material is gas permeable, components of the gas including carbon dioxide will migrate to the annulus containing the carbon steel armour layers. Consequently there is a risk of corrosion if this annulus becomes water flooded following damage to the outer sheath. A prediction has been made of the expected corrosion rate using Technip in-house methodology to determine the carbon dioxide permeation rate and the resulting CO2 corrosion rate. The armouring thickness has been manufactured to include the required corrosion allowance, conservatively assuming a flooded annulus for the whole 20-year field life.

Sulphide stress corrosion cracking of the armour wire is not expected to be a problem for the Corrib gas pipeline as there is no measurable amount of hydrogen sulphide in the produced gas. However, hydrogen sulphide measurement is routinely made on gas samples to ensure that this remains the case.

A4.3.2 External Corrosion

External corrosion could occur to the flexibles and end fittings due to the corrosivity of seawater, particularly at the operating temperatures. To combat this, the flexibles have an extruded high-density polyethylene (HDPE) outer sheath. Sacrificial anodes attached to the end fittings will afford some protection to the armour layers of the flexibles at any point where the sheath is damaged.

The end fittings of the flexibles are carbon steel externally protected with an electroless nickel coating and the hubs to which they attached are super duplex stainless steel. The end fittings and parts of the hubs contained within the Icarus termination assemblies, which are flooded, are coated and cathodically protected by sacrificial aluminium anodes. The end fittings and barrels are bonded together to share this protection and prevent galvanic corrosion.

The sacrificial anode system covers the manifold, flexibles and wellheads in one electrically continuous system. All the manifold structure and pipework - both carbon steel and alloy components – is coated with an epoxy coating system (NORSOK M-501 System 7) to reduce the current demand and extend the life of the anodes.

The cathodic protection (CP) system is monitored for ongoing effectiveness with estimates of remaining anode mass and potential measurements at points of access on the wellheads, flexible end fittings/termination sleeves and the manifold. All components are bonded together and tested for electrical continuity during assembly so the protection of inaccessible items is inferred from the measurements that are possible on other parts. Performance targets are set for potential measurements and remaining anode mass. The results are analysed on a routine basis.

Duplex stainless steels are vulnerable to failure by cracking (Hydrogen Induced Stress Cracking, HISC) caused by hydrogen uptake when cathodically protected and there is no protective coating. For pipework this mechanism can be mitigated by following the DNV F-112 guideline to avoid HISC. The manifold pipework and connecting hubs have been assessed against this guideline and fabricated to ensure overstressing does not occur due to thermal effects or imposed loads at the flexible/manifold connections. The manifold has a protection cover and the flexibles are partly covered or buried to protect from accidental overload, e.g. from fishing operations. Inspection ensures that this cover and burial remains in place and effective.

A4.3.3 Mechanical Damage

The likelihood that the activities of outside parties could cause impact damage to exposed flexible lines is, in common with other pipelines, high. Therefore, the flexible flow lines are mostly buried to avoid impact damage by trawl gear and help prevent damage by anchors. To avoid damage by trawl gear and dropped objects close to the structures, where the burial equipment cannot be used, the lines will be protected, in sequence by:

- A GRP tunnel attached to the structure,
- Mattresses from the tunnel end out to a point where rock dumping is no hazard to the structure, and then,
- Rock dump cover out to a point where full depth trenching is possible.

The Manifold is provided with a protection structure that will allow trawl boards to pass over it without snagging or causing damage.

The residual risk of damage from the activities of outside parties including anchor damage and dropped object impacts is mitigated by the declaration of a safety zone, marking on charts and notices to mariners and by the management of works by Shell including liaison with contractors deploying vessels using anchors and positioning vessels over the lines and manifold.

The risk from Shell maintenance and engineering activities is controlled though standard procedures for risk assessment and approval to work in accordance with the Shell Subsea Engineering Maintenance & Inspection Procedures.

The flexible flow lines, around the wellheads and at the manifold, and the manifold itself are inspected visually for damage and loss of cover at intervals determined by risk-based assessment. Any damage is assessed and, if necessary, pressure limitation and/or repair actioned. Exposure of the protected lines is rectified if significant.

A4.3.4 Fatigue

Fatigue is not a problem for the flexible pipes, as they remain static through burial, etc. The piping on the manifold will not be at risk from fatigue if it remains fully supported by attachment to the structure.

A4.3.5 Brittle Fracture

The flexible pipe end fittings and the manifold piping have been manufactured to resist low temperature brittle fracture at normal operating temperatures down to -20°C.

The Manifold piping design temperature is -30°C.

Brittle cracking can also occur if duplex stainless steel pipe and fittings on the manifold have inappropriate microstructures, generally caused by poor control of welding or heat treatment. These problems have been mitigated by strict controls during manufacturing.

A4.3.6 Connection Failure

The PVDF pressure sheath material of the flexibles can pull out from the end fitting due to leaching of the plasticizer during service. In accordance with current industry practice to avoid this type of failure, the PVDF in the pipe at the end fittings has been subject to a deplasticizing operation prior to assembly. The end fittings and flexible pipe have been designed and manufactured for the full design temperature range.

A4.3.7 Overstress

The flexibles and manifold piping have been designed for the maximum wellhead shut in pressure.

The flexibles are installed in a side bend configuration and in tension in 2m deep trenches. This ensures that the maximum temperature induced upheaval cannot expose the pipe above the trench, thus protecting it from trawl damage.

The risk from Shell maintenance and engineering activities is controlled though standard procedures for risk assessment and approval to work in accordance with the Shell Subsea Engineering Maintenance & Inspection Procedures.

Thermally induced overstress by buckling has been addressed in the design of the flexible. Temperatures that are within the operating values used in the design do not cause overstress to an otherwise undamaged pipe. The wellhead temperatures are monitored to ensure the line remains within these constraints.

The flexibles are inspected for deflections or upheaval with side scan sonar, and, along with the manifold, visually, at intervals assessed by risk-based analysis to be appropriate. Any damage is assessed and, if necessary, pressure limitation and/or repair actioned.

A4.3.8 Integrity Reference Plan and Action

The detail identification of threats and barriers, together with performance standards, immediate action requirements and corrective action requirements will be given in the tabular Integrity Reference Plan, which will be prepared before commissioning.

ATTACHMENT A5 - UMBILICALS

A5.1 PHYSICAL DESCRIPTION

The main parameters for the Umbilicals, Termination Units and Connectors are:

Table A5.1: Umbilical section parameters

Umbilical Sections	Key Parameters
Onshore Umbilical No1	**Bellanaboy Terminal OTTU to Landfall Valve Installation OTU**
Treated Production Water	**2 Lines**
Electrical	**1 Element**
Overall Diameter	**62mm**
Overall Length (approx)	**8.3 km (in c.9 sections)**
Outer Sheath Material	**MDPE**
Ducting	**PE**
Onshore Umbilicals Nos 2 & 3	**Bellanaboy Terminal OTTU to Landfall Valve Installation OTU**
Methanol	**2 Lines**
HP Hydraulic Supply	**1 Line**
LP Hydraulic Supply	**1 Line**
Electrical	**2 Elements**
Overall Diameter	**81mm**
Overall Length (approx)	**8.3 km (in c.9 sections)**
Outer Sheath Material	**MDPE**
Ducting	**PE**
Landfall Valve Installation **Control cables**	**Bellanaboy Terminal OTTU to Landfall Valve Installation OTU**
Fibre Optic Cable	**12 fibres (subject to procurement)**
Electrical	**6 cores (subject to procurement)**

Umbilical Sections	Key Parameters
Offshore Main Umbilical	**Landfall Valve Installation OTU to Corrib Manifold SDU**
Methanol	**4 lines**
HP Supply	**2 Lines**
LP Supply	**2 Lines**
Treated Production Water	**2 Lines**
Electrical	**5 Elements**
Overall Diameter	**129mm**
Overall Length (approx)	**84km**
Outer Sheath Material	**MDPE**
Offshore Infield Umbilicals	**Corrib Manifold SDU to Wells P1, P3, P4, P5 & P6 and Well P5 to Well P2**
Methanol	**3 Lines**
HP Supply	**2 Lines**
LP Supply	**2 Lines**
Electrical	**3 Elements**
Overall Diameter	**117mm**
Overall Lengths (approx)	**1.114km SDU to Well P1** **1.217km SDU to Well P4** **1.0km (approx) SDU to Well P6** **1.752km SDU to P3** **2.465km SDU to P5** **1.517km Well P5 to Well P2**
Outer Sheath Material	**MDPE**

Table A5.2: Umbilical core parameters

Umbilical Cores	Key Parameters
Methanol	4 Lines
Outside Diameter	28.2mm
Wall thickness	1.40mm
Pressure Rating	345barg
Material	Super Duplex SS UNS S39274
HP Hydraulic Supply	2 Lines
Outside Diameter	14.98mm
Wall thickness	1.14mm
Pressure Rating	610barg
Material	Super Duplex SS UNS S32750
LP Hydraulic Supply	2 Lines
Outside Diameter	21.25mm
Wall thickness	1.10mm
Pressure Rating	210barg
Material	Super Duplex SS UNS S39274
Treated Production Water	2 Lines
Outside Diameter	22.67mm/28.20mm
Wall thickness	1.81mm/1.40mm
Pressure Rating	610barg/345barg
Material	Super Duplex SS UNS S39274
Electric Elements	5 Elements
Outside Diameter	22.5mm
Outer Sheath wall thickness	1.5mm
Outer Sheath Material	LLDPE

Table A5.3: Termination Unit & Connector parameters

Termination Units & Connectors	Key Parameters
Subsea Distribution Unit (SDU)	1 Unit, 10 Lines (2 spare)
Location	On top of manifold
Form	Steel structure protecting distribution pipework and providing stab plate connectors
Dimensions	11.4m x 6.7m x 1.35m high
Material	Carbon Steel structure with coating and sacrificial cathodic protection, Duplex SS UNS 31803 Methanol piping SDSS hydraulic piping
Offshore Termination Assemblies (UTAs)/ Terminations	13 Units, 10 Lines or 8 Lines
Location	Subsea, entering and leaving SDU and Well packages
Form	D shaped Main Barrel and tubular Front Barrel
Dimensions	Infield, 610mm dia x 3.131m overall length Main, 610mm dia x 3.631m overall length
Material	Carbon Steel, epoxy coated (NORSOK M-501 No 7) with Aluminium anodes Duplex SS UNS 31803 Methanol piping SDSS hydraulic piping
Onshore Termination Unit (OTU)	1 Unit, 10 Lines (1 spare)
Location	Landfall Valve Installation, below ground
Form	Split tube with flat ends, located in concrete 'protection slab' box
Dimensions	600mm dia x 2.37m long
Material	Carbon Steel, epoxy coated (NORSOK M-501 No 7) with Magnesium anodes
Onshore Joints	Approx 24 Units, 2 or 4 Lines
Location	Onshore way leave, below ground, in ducting
Form	Tube with flat ends. Polyurethane filled
Outside Diameter	280mm

Termination Units & Connectors	Key Parameters
Wall thickness	10.7mm
Tube Material	HDPE
Onshore Terminal Termination Unit (OTTU)	1 Unit, 10 Lines (2 spare),
Location	Bellanaboy Terminal, above ground
Form	Rectangular Cabinet
Signal Cable	1 Unit, 5 pairs 1.5mm2, Plain annealed copper conductors (Cross Linked Polyethylene/Steel Wire Armr.)
Outside Diameter	33.5 mm
Weight	1.9 kg/m
Fibre Optic Cable (FOC)	Details part of ongoing tendering work

A5.2 PROCESS PARAMETERS

The three liquids, conveyed in the umbilicals, are:

- Product Methanol containing the Corrosion and Scale Inhibitors that controls corrosion in the pipeline,
- Aqueous Ethylene Glycol based hydraulic fluid, Castrol 'Transaqua HT', which contains a corrosion inhibitor, bactericide, dye and other chemicals.
- Treated Production Water from the terminal to be disposed at the manifold.

The Methanol solution is transported out to the field to be injected into the produced fluid for the suppression of gas hydrate formation. A Corrosion Inhibitor designed to reduce the corrosivity of the produced fluid is mixed into it. It is provided at pressures up to 345barg.

The hydraulic fluid is provided to power actuated valves at the wellheads and manifold and is supplied at two maximum pressures 610barg (HP) and 210barg (LP). The operating pressures are reduced to match the closed in wellhead pressure and will therefore decrease over the field life.

The fluids will mostly be at ambient seabed temperature, between 6ºC and 12ºC.

The treated production water from the terminal will be transported via the umbilical lines to the manifold where it will be disposed.

A5.3 INTEGRITY CONTROL ACTIVITIES

The spreadsheet tabulation will provide details of the threats, barriers and monitoring which are assured through control action during operation together with details of reference documents, and corrective action requirements.

The consequences of damage to the umbilicals are not restricted to loss of containment, although spillage of methanol or glycol in any quantity is environmentally detrimental. The main threat is the loss of function, i.e. the loss of hydrate control, the loss of wellhead valve actuation, the loss of inhibition or the loss of instrument signals. The first two of these would result in immediate loss of production and the latter two could result in serious production restrictions.

The leak detection system being developed for the offshore and onshore pipelines will also be configured to trend the relevant parameters for umbilical flows and pressures.

Most components of the system have been designed and constructed to be inherently resistant to corrosion, and other threats, as they are mostly inaccessible for condition monitoring

The direct threats and their control measures can be summarised as follows:

A5.3.1 Internal Corrosion

Internal corrosion by the aqueous fluids is controlled by the use of corrosion resistant Super Duplex Stainless Steel for both chemicals in the umbilical, and type 316L stainless steel for the hydraulic fluid in the Subsea Distribution Unit (SDU). At the ambient operating temperature these will resist general corrosion, pitting and crevice corrosion.

For the umbilical tubes, which are exposed to aerated produced water, the Super Duplex Stainless Steel selected is resistant to crevice corrosion up to 20°C. The biocidal control of the produced water will allow higher temperatures. 316L is not suitable for exposure to aerated produced water and any 316L components in the produced water return system have been replaced with Super Duplex Stainless Steel. The umbilical core connections will be welded with an orbital welding system to avoid crevices and to allow full radiographic inspection.

The 316L stainless steel hydraulic piping on the SDU is at risk from microbiologically induced corrosion if the fluid becomes badly contaminated with seawater. This is mitigated by a bactericide in the fluid and appropriate design of connectors.

There are no opportunities to monitor the internal condition of the umbilical cores and the SDU piping.

A5.3.2 External Corrosion

The umbilicals are sheathed in Medium Density Polyethylene (MDPE). However the sheath is not guaranteed to survive pipe lay and operation without damage and water entry, and the offshore umbilical will be deliberately allowed to flood so the corrosion protection of the tubing cores depends on the corrosion resistance of the Super Duplex Stainless Steel. At the ambient operating temperatures this will resist general corrosion, pitting and crevice corrosion in ground water or in seawater. The type 316L stainless steel tubing in the SDU is susceptible to crevice corrosion but this will be mitigated by the cathodic protection and the design requires it to be fully electrically bonded to ensure this.

The subsea terminations and underwater termination assemblies (UTAs) joining the umbilicals to the SDU and the well assemblies are designed to flood. They are fabricated in carbon steel and protected by a coating and an aluminium alloy sacrificial anode system both externally and internally. The internal anodes also prevent galvanic corrosion of the UTA bodies that are connected to the Super Duplex material of the tubes.

The onshore termination unit (OTU) is also a coated carbon steel unit and is protected externally and internally by Aluminium sacrificial anodes.

The sacrificial cathodic protection has a design life of 30 years.

The metal components are all electrically bonded to each other and, at the manifold and in the SDU, to the manifold structure to share external cathodic protection (CP). This is monitored generally for ongoing effectiveness with estimates of remaining anode mass (where visible) and potential measurements. Performance targets are set for potential measurements. The results are analysed on a routine basis.

Duplex stainless steels are vulnerable to failure by hydrogen induced stress cracking caused by hydrogen uptake at bare surfaces when cathodically protected. This mechanism has been mitigated by following the DNV F-112 guideline to avoid HISC and is less likely to occur in fine grain microstructures associated with umbilical tubes. The 316L stainless steel hydraulic tubing in the SDU

is vulnerable to chloride stress corrosion cracking, pitting and crevice corrosion. This is fully mitigated by the cathodic protection system which is fully electrically bonded together to protect all tubing.

The cathodic protection will also prevent galvanic corrosion between the stainless steel and carbon steel components of the various connectors and the SDU. For that purpose the individual elements are bonded

A5.3.3 Mechanical Damage

Umbilicals laid on the sea bed are at risk from third party interference. However, the offshore umbilicals and termination units are covered, rock dumped or trenched to avoid damage by trawl gear and to reduce the potential for damage by dropped objects and anchors.

The residual risk of damage from the activities of outside parties including anchor damage and dropped object impacts is mitigated by the declaration of an exclusion zone, marking on charts and notices to mariners and by the management of works by Shell and liaison with contractors deploying vessels using anchors and positioning vessels over the lines and manifold. The SDU is protected by the Manifold protection structure.

The risk from Shell maintenance and engineering activities is controlled though standard procedures for risk assessment and approval to work in accordance with the Shell Subsea Engineering Maintenance & Inspection Procedures.

The ends of the subsea umbilicals at the wells and manifold are visually inspected for damage along with those structures at intervals determined by risk based assessment. Any damage is assessed and, if necessary, repair actioned. Exposure of the buried umbilicals is rectified if significant.

Onshore, except where installed in the tunnel, the buried umbilicals are at risk from third party interference, especially unauthorised excavation. However, it is buried with a minimum of 1.2m cover and with concrete slab protection at vehicle crossings and ditches. These put the umbilical out of reach of most routine farming and fishing activity and protect it from live loads, etc.

The residual risk of damage onshore from the activities of outside parties is mitigated through pipeline patrols and liaison with landowners and utilities. This includes the main water crossing as well as along the buried line.

The risk from Shell maintenance and engineering activities is controlled though standard procedures for risk assessment and permit to work, and for work within pipeline rights of way. This applies also to any work on the gas pipeline and outfall that run alongside the umbilicals.

A5.3.4 Fatigue

Fatigue is not a problem for the umbilicals as they remain static through burial, etc., and the cores are at a constant temperature and pressure. The small bore tubing on the SDU will not be at risk from fatigue if it remains fully supported by attachment to the structure.

A5.3.5 Brittle Fracture

All umbilical components are fabricated in materials resistant to brittle fracture at ambient temperature so the risk is not significant.

A5.3.6 Overstress

The cores are protected from over pressure by relief devices at the terminal associated with the pumping equipment.

The subsea umbilicals are covered or trenched to avoid overstress through trawl gear pullover.

The risk from Shell maintenance and engineering activities is controlled though standard procedures for risk assessment and approval to work in accordance with the Shell Subsea Engineering Maintenance & Inspection Procedures.

The umbilicals are inspected for deflections with side scan sonar, and, along with the terminations and SDU, are visually, at intervals assessed to be appropriate by risk-based analysis. Any damage is assessed and, if necessary repair actioned.

A5.3.7 Joint Integrity

Loss of containment can occur if couplings are not properly made up, particularly in Methanol service. Wherever possible, integrity is proved by pressure test.

Visual inspection by ROV is used to detect leaks of the dyed hydraulic fluid, offshore, and pipeline patrols will look for any signs of leakage onshore. The liquid inventories of the umbilical system are also monitored to detect sign of loss.

A5.3.8 Blockage

Blockage can be caused by the degradation of chemicals or by bacterial action. The chemicals have been selected to prevent bacterial action and are tested on a regular basis to mitigate this threat. Blockage, should it occur, will be detected as a loss of flow by the wellhead flow meters.

A5.3.9 Integrity Reference Plan and Action

Details of the threats, barriers and monitoring which require control action during operation together with details of reference documents, and corrective action requirements will be given in the tabular Integrity Reference Plan, which will be prepared prior to commissioning.

ATTACHMENT A6 – WATER OUTFALL

A6.1 PHYSICAL DESCRIPTION

The main parameters for the pipeline are:

Table A6.1: Water Outfall parameters

Parameter	Details
	Onshore Section
Length	**8.3km**
Outside Diameter	**250mm**
Wall thickness	**13.25mm (PE100 SDR11)**
Max Head	**10barg**
Material Grade	**PE 100 (HDPE)**
	Offshore Section
Length	**12.5km**
Outside Diameter	**250mm**
Wall thickness	**14.7mm (PE80 SDR 17)**
Max Head	**6barg**
Material Grade	**PE 80 (MDPE)**

A6.2 PROCESS PARAMETERS

The Water Outfall has a minimum design pressure of 20barg onshore and 6barg offshore. Flow in the onshore section is maintained at the Landfall Valve Installation by a self-regulating backpressure control valve. The offshore end of the Outfall line is connected to the diffuser. The water from the terminal will enter the outfall line at a maximum temperature of 35ºC.

Pump performance will be monitored for anomalous trends including the possibility of leaks.

A6.3 INTEGRITY CONTROL ACTIVITIES

The spreadsheet tabulation gives details of the threats, barriers and monitoring which are assured through control action during operation together with details of reference documents, and corrective action requirements.

The consequences of damage to the Water Outfall and loss of containment are essentially restricted to environmental impacts. Remedial and corrective actions will be given in the tabular Integrity Reference Plan, which will be prepared prior to commissioning.

The direct threats and their control measures can be summarised as follows:

A6.3.1 Internal Deterioration

Internal deterioration caused by the aqueous fluids is controlled by the use of High and Medium Density Polyethylene (HDPE and MDPE) pipe material as long as there is no significant and ongoing organic contamination. The design and operation of the wastewater treatment facilities mitigates against this happening.

A6.3.2 External Deterioration

The High and Medium Density Polyethylene (MDPE) outfall pipe material is resistant to deterioration from ground water and seawater.

Onshore, ground contamination from leaks, spillages and disposal of fuels and other organic material can cause deterioration and this is managed by pipeline patrol and landowner liaison.

Polyethylene is vulnerable to deterioration in sunlight but this will not affect the buried pipeline and the black pigment mitigates the risk for aboveground connections at the terminal.

A6.3.3 Mechanical Damage

The offshore underwater and the buried onshore sections of the outfall line are, in common with the other pipelines, at risk from third party interference.

The offshore section is piggybacked on the gas pipeline and both are trenched to avoid damage by fishing gear and to reduce the potential for damage by dropped objects and anchors. The offshore end of the water outfall will be designed to mitigate the effect of trawling impact loads.

The residual risk of damage from the activities of outside parties including anchor damage and dropped object impacts is mitigated by marking on charts and notices to mariners.

The risk from Shell maintenance and engineering activities is controlled though standard procedures for risk assessment and approval to work in accordance with the Shell Subsea Engineering Maintenance & Inspection Procedures.

Depending on water depth the offshore trenched lines are inspected for damage with side scan sonar and visually at intervals determined by risk based assessment. Any damage is assessed and, if necessary repair actioned. Exposure of the buried pipe is rectified if significant.

The potential for damage to the onshore, buried outfall is mitigated by a minimum 1.2m cover and concrete slab protection at vehicle crossings and ditches. These keep it out of reach of most routine farming and fishing activity and protect it from live loads, etc.

The residual risk of damage from the activities of outside parties is mitigated through line patrols and liaison with landowners and utilities. This includes the main water crossings as well as along the buried line.

The risk from Shell maintenance and engineering activities on adjacent lines is controlled though standard procedures for risk assessment and permit to work. This applies also to any work on the gas pipeline and outfall that run alongside the umbilicals.

A6.3.4 Overstress

The offshore outfall is buried to avoid snagging by inshore fishing gear. In the onshore, buried section the pipe is sufficiently flexible to be tolerant to small deflections but may not resist damage from significant settlement or landslip. The movement monitoring of the gas line is also be used to monitor movement of the outfall.

The risk from Shell maintenance and engineering activities is controlled though standard procedures for risk assessment and approval to work in accordance with the Shell Subsea Engineering Maintenance & Inspection Procedures.

Depending on water depth the offshore trenched lines are inspected for damage with side scan sonar and visually at intervals determined by risk based assessment. Any damage is assessed and, if necessary repair actioned. Exposure of the buried pipe is rectified if significant.

A6.3.5 Blockage, Etc.

Blockage could be caused by marine growth around and inside the diffuser and upstream pipe. Blockage, should it occur, will be detected as a loss of flow and the cause will be investigated visually by ROV.

Malfunction of the self-regulating valve at the Landfall Valve Installation is a potential source of blockage or mal-operation. In the event the valve would be exposed for repair

A6.3.6 Integrity Reference Plan and Action

The detail identification of threats and barriers, together with performance standards, immediate action requirements and corrective action requirements will be given in the tabular Integrity Reference Plan, which will be prepared prior to commissioning.

ATTACHMENT B

[ROLES & POST HOLDERS]

PIMS Role	Organisational Function, Reference Indicator & Current Post Holder	TEL NO.	LOCATION
Asset Owner	Asset Transition Manager, NORSKE-UIE-P-S		
Nominated Responsible Person (NRP)	TA-1 Pipelines UIE/P/SDP		
Pipeline Competent Person (PCP)	TA-2 Pipelines UIE/P/SDP		
Operations Manager	Operations Manager, SEPIL-UIE/T/IO		
Operations and Safety Systems Focal Point	Plant Installation Manager, SEPIL UIE/T/IO		
General Integrity (Offshore) Focal Point	Pipeline Engineer, UIE/P/SDP		
General Integrity (Onshore) Focal Point	Maintenance Engineer, SEPIL- UIE/T/IO		
Corrosion Management Focal Point	Corrosion Engineer, UIE/P/SDD		
Flow Assurance Focal Point	Process Engineer, SEPIL- UIE/T/IO		
Change Management Focal Point	Process Engineer, SEPIL- UIE/T/IO		

Shell E&P Ireland Limited CORRIB FIELD DEVELOPMENT PROJECT REPORT	J P KENNY Corrib natural gas

Corrib Onshore Pipeline EIS APPENDIX Q5.3 ONSHORE HYDROSTATIC PRESSURE TESTING REPORT	PROJECT No. 052377.01 REF CTR 349 No OF SHEETS 20

DOCUMENT No	OFFICE CODE	PROJECT No	AREA	DIS	TYPE	NUMBER
	05	2377	01	P	3	020

REV	DATE	DESCRIPTION	BY	CHK	ENG	PM	CLIENT
04	13/05/10	Appendix format details added for Planning Application	JG	GSW	GSW	JG	
03	23/05/07	SEPIL Comments Included	KJG	BD	JG	JG	
02	25/04/07	Second Draft	KJG	FEB	JG	JG	
01	17/11/06	First Draft	KJG	POC	JG	JG	

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Date of Review:	Reviewed by:	Response by:	Lead Engineer:	Project Engineer:
Areas of Particular Concern:				

No.	Review Finding	Project Response	LE

Distribution: Project File, Lead Engineer, Project Engineer Manager, Project Manager

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1 INTRODUCTION

1.1 Overview

Shell Exploration and Production Ireland Limited have requested J P Kenny Limited to evaluate and develop a basis for independent hydrostatic pressure testing of the 8.3[1] km onshore pipeline section from the landfall to the gas treatment terminal.

A Corrib Gas Pipeline Safety Review was undertaken by Advantica on behalf of the Minister for Communications, Marine and National Resources. TAG (Technical Advisory Group) subsequently made additional recommendations to these findings. The study has been based principally on these additional recommendations, which are specifically:

- The onshore section should be pressure tested in accordance with I.S. 328 – Code of Practice for Gas Transmission Pipelines and Pipeline Installations.
- Limit the design pressure to 144 barg and use a design factor of 0.3.

This document also sets out to consider the hydrostatic test pressure requirements of TAG when compared to other relevant codes and standards.

1.2 Purpose of Document

The purpose of this document is to:

- Review test pressures defined by TAG when compared with recognised codes and Shell practice.

1.3 Abbreviations

API	American Petroleum Institute
ASME	American Society of Mechanical Engineers
BS	British Standard
BGE	Bord Gais Eireann
EEI	Enterprise Energy Ireland Limited
EN	European Norms
ESD	Emergency Shutdown
JPK	J P Kenny Limited
I.S.	Irish Standard
LAT	Lowest Astronomical Tide
MAOP	Maximum Allowable Operating Pressure
NPTC	Non Pressure Tested Closure
SEPIL	Shell Exploration and Production Ireland Limited
SMYS	Specified Minimum Yield Strength
TAG	Technical Advisory Group
w.t.	wall thickness

[1] Onshore pipeline route changed 2010. Previously 9 km.

2 HYDROSTATIC TEST PRESSURES ASSOCIATED WITH THE PIPELINE

2.1 Original Pipeline Design Pressure and Wall Thickness

The original basis for the design of the pipeline was carried out in accordance with BS 8010 Part 2. Pipelines on land: design, construction and installation, Section 2.8 Steel for oil and gas. The design pressure was 345 barg, the diameter was 20 inch and steel grade was API 5L X70. The wall thickness resulting from the hoop stress was 25.1mm plus 1 mm corrosion allowance plus 1mm manufacturing tolerance giving a total of 27.1 mm.

2.2 TAG Requirement

Advantica undertook an Independent Safety Review of the Onshore Section of the proposed Corrib Gas Pipeline. TAG reviewed the recommendations of Advantica, with respect to hydrostatic pressure testing and stated that I.S.328: 2003 should be followed**.** This code differentiates between pipelines designed to operate above or equal/below a design factor of 0.3. The nominal wall thickness derived by applying a design pressure of 144 barg and design factor of 0.3 to this code is 26.1mm. This is inclusive of 1mm allowance (Code requirement) to compensate for pipe manufacturers under-thickness tolerance. An additional 1mm is added to provide corrosion allowance. Hence total required wall thickness is 27.1mm.

As a result of the above TAG recommendations, hydrostatic test pressure calculations were undertaken. These results are outlined below.

2.3 Pipeline Design Code Comparison

The following codes were evaluated:

- Onshore Standard DNV OS-F-101, 2000. This was the standard to which the pipe was originally supplied.
- I.S. EN 14161 Petroleum and Natural Gas Industries – Pipeline and Transportation Systems (ISO 13623:2000 Modified)
- I.S.328: 2003 Code of Practice for Gas Transmission Pipelines and Pipeline Installations (Edition 3.1)
- BS PD 8010-1:2004 Code of Practice for Pipelines – Part 1: Steel Pipelines on Land.
- BS 8010 Part 2. Pipelines on land: design, construction and installation, Section 2.8 Steel for oil and gas

The requirements stated in each code are repeated in Appendix 1 for information.

The results of applying each of these codes on hydrostatic test calculations are shown in Table 2-2 Comparative Code Results for Hydrostatic Test Pressures and discussed below.

2.4 Discussion of Results of Code Calculations

2.4.1 Original Hydrostatic Pressure Test Codes

a) Offshore Section – DNV OS-F-101, 2000

The test pressure that satisfies the system pressure test requirement based on the referenced DNV code is 360.25 barg measured at LAT, where the lowest wall thickness is 21 mm. (For the system test pressure an allowable hoop stress of 96% SMYS is allowed).

Table 2-1 below shows the wall thickness selected for KP ranges along the route.

Table 2-1 - Selected Nominal Wall Thickness over length of Offshore Pipeline

KP Range	Selected Nominal Wall Thickness (mm)
0 to 4.1	27.1
4.1 to 12	21.0
12 to 17.7	22.5
17.7 to 26.4	24.7
26.4 to 65.7	22.0
65.7 to 81.9	22.5
81.9 to 83.4	27.1

b) Onshore Section – BS 8010

The onshore test pressure for this section was based on a nominal wall thickness of 25.1mm (calculated for 0.72 design factor). The calculated system test pressure was 435.4 barg based on 90% SMYS at a LAT of –2.5m.
The nominated wall thickness for the onshore section is 27.1mm (KP range 83.4 to 93 km).

2.4.2 I.S.328:2003

Reference was made to Section 9 - Testing, and in particular 9.4.4 - Test Limits.

The "Testing" section of the code differentiates between pipelines designed to operate at a design factor (f) not exceeding 0.3 and pipelines designed to operate at a design factor exceeding 0.3. The nominal wall thickness is greater than the required thickness for a design factor of 0.3 and hence in accordance with the code, the *minimum* pipeline test pressure required is 1.5 times the design pressure. This results in a minimum test pressure of 216 barg. For this condition, the pre-test pressure is an additional 10% of this value, which is 238 barg.

The *maximum* pipeline test pressure outlined in the code is based on pipelines designated to operate at a design factor exceeding 0.3.

The code provides guidance for limiting the *maximum* pipeline test pressure in the event that the calculated test pressure results in overstressing of valves and other fittings. In these circumstances, it is recommended that the test pressure should not exceed twice the design pressure that in this instance is 288 barg.

Otherwise, the maximum mainline hydrostatic test pressure of 523 barg (105% of SMYS) has been derived for this code, and a value of 575 barg (10% of hydrostatic test pressure) for pre-tested pipes (which is equivalent to 111% SMYS).

These test pressures have been derived using the nominal wall thickness (26.1mm), as required by the code. The nominal wall thickness is the design wall thickness (25.1mm) plus an allowance for pipe manufacturers underthickness (1mm).

TAG has recommended that this code be adopted when determining hydrostatic test values.

2.4.3 I.S. EN 14161:2004

The relevant section of this code is Section 11 - Testing, which refers in turn to Section 6.7 – Pressure Test Requirements. The pipeline hydrostatic test pressure of 187 barg is the result of a

factor of 1.25 being applied to functions of design pressure, wall thickness and corrosion allowance.

These test pressures have been derived using the specified minimum wall thickness 25.1mm and is not inclusive of allowances for pipe manufacturers underthickness or corrosion.

This hydrostatic test pressure is the lowest value compared to the other Codes.

2.4.4 BS PD 8010-1:2004

Reference was made in this code to Section 11.5.2 – Hydrostatic Strength Test.

The "standard hydrostatic strength test" was based on the lower of a pressure of not less than 150% of the MAOP or a pressure that produces a hoop stress level of equivalent to 90% SMYS. In this case the former condition applied, resulting in a test pressure of 216 barg (based on a worst case, where MAOP equals the design pressure of 144 barg. The code recommends the "standard hydrostatic strength test" be used in cases where significant cyclic pressures and/or increases in the pipeline MAOP are not anticipated in the future operation of the pipeline.

The "high-level hydrostatic strength test" for the mainline pipeline is 431 to 503 barg (90% to 105% of SMYS respectively).

For "pre-tested pipes", the pre-test pressure should be at least 1.05 times the test pressure appropriate to the section into which the pipe is to be installed. Hence if the "standard hydrostatic strength test" is adopted then the pre-test pressure is 227 barg. If the "high-level hydrostatic strength test" is adopted then the pre-test pressure is in the range of 453 to 528 barg

The wall thickness taken for these calculations is the minimum wall thickness (25.1mm), which in accordance with the code excludes corrosion allowance and mill tolerance.

When compared to all of other codes, these are the most onerous values for hydrostatic testing.

2.4.5 Mill Hydrostatic Test Pressure

The line pipe was purchased to DNV OS –F-101, 2000. The project was supplied by the Client with the results of the hydrostatic test, a copy of which is shown in Appendix 2. The formula used for determining the hydrostatic pressure test is stated in DNV OS-F101 Section 6.0 Clause E1100, Formula 6.2. The mill hydrostatic test pressure results show that for a nominal wall thickness of 27.1mm the hydrostatic test pressure was 504 barg minimum and 511 barg maximum.

Table 2-2 – Comparative Code Results for Hydrostatic Test Pressures

Code	Test Type	% Factor of SMYS	Pressure Barg	Wall thickness used in calculation (mm)
Linepipe was designed and procured to DNV OS-F-101, 2000	Actual Mill Test Pressure for purchased pipe	Note 1	504 (min) to 511 (max)	27.1
Offshore Section – DNV OS –F-101, 2000	System test pressure for offshore section	96	360.25	21.0 (Note 6)
Onshore Design Wall Thickness to BS 8010	System test pressure for onshore section	90	435.4	25.1 (Note 7)
I.S. EN 14161:2004	Design Pressure		144	25.1 (Note 7)
	Pipeline Test Pressure	Note 2	187	
I.S.328: 2003 (Note 3)	Minimum Test Pressure (MinTP)	Note 4	216	26.1 (Note 8)
	Maximum Test Pressure (MaxTP)	105	523	
	Pre-tested Pipes (for MinTP)	Note 9	238	
	Pre-tested Pipes (for MaxTP)	Note 9	575	
BS PD 8010-1:2004 (Note 3)	Standard Level test	Note 4	216	25.1(Note 7)
	High Level Test	90-105	431-503	
	Pre-tested pipes standard strength test	Note 5	227	
	Pre-tested pipes high level strength test	Note 5	453-528	

Note 1 - Refer to Appendix 2 for actual mill test pressure details.
Note 2 - Hydrostatic test pressure = 1.25x function of (Design pressure, wall thickness and corrosion allowance).
Note 3 - Differences in method of calculation between I.S. 328 and BS PD 8010.
Note 4 – 150% MAOP as per code.
Note 5 – 1.05 times test pressure for section.
Note 6 – Offshore System Pressure Test Requirement, measured at LAT, where the wall thickness is 21mm.
Note 7 – Specified Minimum Wall thickness (25.1mm) and is not inclusive of allowance for pipe manufacturers under thickness or corrosion.
Note 8 - Nominal Wall thickness (26.1) = design pressure wall thickness (25.1mm)+allowance for pipe manufacturers under thickness (1mm).
Note 9 – Pre-test pressure. This is based on the pre-test pressure exceeding the main test pressure by 10%.

2.5 Code for Hydrostatic Testing

2.5.1 Introduction

The application of a suitable design code for undertaking a hydrostatic test is recommended from reports undertaken by Advantica (Ref 1) and TAG (Ref 2). The recommendations from each of the reports are outlined below. However, to put the test requirements in context, details of the mill hydrostatic test results are shown in Appendix 2. It was shown that the lowest value for the Mill test pressure was 504barg.

2.5.2 Mill Test Pressure

The pipe had been designed and purchased to DNV OS-F-101 2000. The results showed that for a nominal wall thickness of 27.1mm, the minimum recorded hydrostatic pressure test pressure was 504 barg.

2.5.3 Advantica Recommendations

Advantica's report in relation to hydrostatic pressure testing stated that hydrostatic pressure testing should be undertaken in accordance with their recommended code, BS PD 8010. This makes provision for testing to be carried out to either "standard" or "high level" testing. The details are outlined in Table 2-2 and discussed in Section 2.4.4.

2.5.4 TAG Recommendations

TAG undertook a review of the Advantica report and further recommended that I.S. 328 be adopted for hydrostatic pressure testing.

As can be seen from Table 2-2, (and discussed in Section 2.4.2), the code offers a minimum to maximum range of pressures, from 216 barg to 523 barg respectively.

The key point to note is that for a design factor of 0.3 (which has been adopted for the project) the test pressure requirement in accordance with I.S. 328 is 216 barg.

3 CONCLUSIONS

The recommendations of TAG require that I.S.328 be adopted for hydrostatic pressure testing.

The maximum potential test pressure when applying pressure limits for the main hydrostatic pressure test in accordance with I.S.328 code is based on designing the pipeline with a design factor of 0.72. This results in a maximum hydrostatic test pressure of 523 barg. However, it is not proposed to test to this level since it falls outside the design factor of 0.3 determined by the project.

It is the intention to obtain the benefits of high level testing as outlined in the Advantica Report through adopting as rigorous a test of the pipeline as possible. To this end it is concluded that the mill test pressure value of 504 barg is taken as the maximum test pressure for this hydrostatic pressure test.

This test pressure is to be taken at the lowest point in the pipeline.

The benefits of this approach are:

- It satisfies I.S.328 code requirements
- The mill test has proved the pipe against a verifiable code under test conditions.
- By testing to 101% SMYS (I.S.328) it will ensure that any remaining defects are considerably smaller than would fail at operating pressures.
- The potential for the pipe to yield and undergo plastic deformation is greatly reduced for testing at 101% SMYS, when compared to the upper limit of 105% SMYS (I.S.328). This is because tolerances on high strength steel wall thickness are now much tighter than in the past and therefore the margin of safety when pressure tests exceed the SMYS is reduced.
- Testing to 101% SMYS is significantly greater than I.S.328 Code requirements for 0.3 design factor, and consequently provides a high degree of confidence in the integrity of the pipeline.

At all crossings, the same test pressure as for the mainline onshore pipeline will be adopted. The crossing section will be tested prior to installation. Subsequently, once the section has been welded in the mainline, the installation will form part of the main test.

4 RECOMMENDATIONS

As a result of thorough consideration of the hydrostatic pressure testing requirements outlined in relevant Pipeline Design Codes and by following the recommendations of TAG, it is recommended that:

- Following pipeline construction, the maximum hydrostatic test pressure for the onshore mainline section of the pipeline should be 504 barg at the lowest point.
- Prior to installation of crossings, the line pipe section be pre-tested to 504 barg for a 4 hour period.

5 REFERENCES

1. Advantica Report – Independent Safety Review of the Onshore Section of the Proposed Corrib Gas Pipeline – Report Number R 8391.
2. TAG – "Report of the Corrib Technical Advisory Group to Minister Dempsey on an appropriate Inspection and Monitoring Regime for the Corrib Project".

APPENDIX 1 EXTRACTS FROM REFERENCED CODES AND STANDARDS FOR TESTING LIMITS

1-1	DNV-OS-F101:2000	SUBMARINE PIPELINE SYSTEMS. SECTION 6, E1100.
1-2	BS 8010 PART 2	PIPELINES ON LAND:DESIGN CONSTRUCTION AND INSTALLATION, SECTION 2.8 STEEL FOR OIL AND GAS
1-3	I.S. 328:2003	IRISH STANDARD - CODE OF PRACTICE FOR GAS TRANSMISSION PIPELINES AND PIPELINE INSTALLATIONS – SECTION 9.4.4.
1-4	I.S. EN 14161:2004	IRISH STANDARD – PETROLEUM AND NATURAL GAS INDUSTRIES - PIPELINE TRANSPORTATION SYSTEMS (ISO13623:2000 MODIFIED).
1-5	BS PD 8010-1:2004	BRITISH STANDARD PUBLISHED DOCUMENT - CODE OF PRACTICE FOR PIPELINES – PART 1:STEEL PIPELINES ON LAND.

1-1 DNV-OS-F101:2000 SUBMARINE PIPELINE SYSTEMS. SECTION 6, E1100

E 1100 Mill pressure test

1101 Each length of linepipe shall be hydrostatically tested, unless the alternative approach described in 1108 is used.

1102 For pipes with reduced utilisation of the wall thickness, the test pressure (P_h) may be reduced as permitted in Section 5D 400.

1103 The test pressure (P_h) for all other pipes shall, in situations where the seal is made on the inside or the outside of the linepipe surface, be conducted at the lowest value obtained by utilising the following formulae:

$$P_h = \frac{2 \cdot t_{min}}{D - t_{min}} \cdot \min [SYMS \cdot 0.96; SMTS \cdot 0.84] \qquad \textbf{(6.2)}$$

1-2 BS 8010 PART 2 PIPELINES ON LAND:DESIGN CONSTRUCTION AND INSTALLATION, SECTION 2.8 STEEL FOR OIL AND GAS

8.4 Test pressure

8.4.1 Hydrostatic pressure test

The hydrostatic test pressure in any part of the system under test should be not less than the lower of:

a) 150% of the maximum operating; or

b) that pressure which will induce a hoop stress as defined in 2.9.2 of 90% of the specified minimum yield stress of the pipeline material in the system under test.

NOTE Provided that in no case should the hydrostatic test pressure be less than the sum of the maximum operating pressure plus any allowances for surge pressure and other variations likely to be experienced by the pipeline system during normal operation.

The pressure at the point of application should be such that the test pressure as calculated in this clause is generated at the highest point in the section under test. The additional static head at any point in the section should not cause a hoop stress in excess of the specified minimum yield stress of the material at that point.

1-3 I.S. 328:2003 IRISH STANDARD - CODE OF PRACTICE FOR GAS TRANSMISSION PIPELINES AND PIPELINE INSTALLATIONS – SECTION 9.4.4

9.4.4 Test limits

Where reference is made to a test limit being a percentage of specified minimum yield strength, the required pressure is calculated from the following formula:

$$P_t = \frac{2 t_n s f_1}{10\ D}$$

Where:

P_t	is the test pressure required in bar
t_n	is the normal wall thickness in mm
s	is the specified minimum yield strength (smys) in N/mm²
D	is the outside diameter of pipe in mm
f_1	is the percentage of smys as specified in 9.4.4.1 and 9.4.4.2

9.4.4.1 Pressure limits for main test

9.4.4.1.1 Pipelines designed to operate at a design factor f not exceeding 0,30

Minimum test pressure shall be one and a half times design pressure. Maximum test pressures shall be as specified for pipelines designed to operate at a design factor exceeding 0,30.

9.4.4.1.2 Pipelines designated to operate at a design factor f exceeding 0,30

Test pressure shall be as specified below for seam welded, seamless and electric resistance welded (ERW) pipe. In some circumstances however, this may result in excessively high test pressures, particularly in smaller diameter pipelines which may result in over stressing of valves and other fittings. In these circumstances it is recommended that the test pressure should not exceed twice the design pressure.

9.4.4.1.2.1 Seam welded pipe

Pressures shall be raised so that the measured or computed value at the lowest point of the section of pipeline being tested reaches the value at which the first occurring of one of the following three conditions is achieved:

a) 105% smys;

b) half slope (see 9.4.5.2);

c) the lowest of the maximum pressure levels attained in the pre-installation testing of any pipe length included in the section.

If half slope occurs before 100% smys the test shall be stopped for investigation, which should include a detailed check of test procedure and measuring equipment to ensure accuracy, followed by check on pipe mechanical properties. Should no defect or leak be found the results should be considered acceptable provided that the computed or measured pressure at the highest point on the line shall not be lower than the pressure required to produce 100% smys at the lowest point on the line less 5,8 bar.

9.4.4.2 Pressure limits for pre-installation testing

For operation at a design factor not exceeding 0,30

The test pressure chosen shall exceed by 10% the test pressure selected for the main test (in accordance with 9.4.4.1).

1-4 I.S. EN 14161:2004 **IRISH STANDARD – PETROLEUM AND NATURAL GAS INDUSTRIES - PIPELINE TRANSPORTATION SYSTEMS (ISO13623:2000 MODIFIED)**

6.7 Pressure test requirements

6.7.3 Pressure levels and test durations

The pipeline system shall be strength-tested, after stabilization of temperatures and surges from pressurizing operations, for a minimum period of 1 h with a pressure at any point in the system of at least:

- 1,25 x MAOP for pipelines on land; and
- 1,25 x (MAOP minus the external hydrostatic pressure) for offshore pipelines.

If applicable, the strength test pressure shall be multiplied by the following ratios:

- the ratio of σ_y at test temperature divided by the derated value for σ_y at the design temperature in case of a lower specified minimum yield strength σ_y at the design temperature than exists during testing; and
- the ratio of t_{min} plus corrosion allowance divided by t_{min} in case of corrosion allowance.

The strength test pressure for pipelines conveying category C and D fluids at locations subject to infrequent human activity and without permanent habitation may be reduced to a pressure of not less than 1,20 times MAOP, provided the maximum incidental pressure cannot exceed 1,05 times MAOP.

1-5 BS PD 8010-1:2004 BRITISH STANDARD PUBLISHED DOCUMENT - CODE OF PRACTICE FOR PIPELINES – PART 1:STEEL PIPELINES ON LAND

11.5 Type and level of test

11.5.2 Hydrostatic strength test

NOTE It is essential that the hydrostatic test pressure is not less than the sum of the MAOP plus any allowance for surge pressure and other variations likely to be experienced by the pipeline system during normal operation.

11.5.2.1 Hi-level hydrostatic strength test

A high-level pressure test involves testing to a pressure that generates a hoop stress 90% to 105% SMYS of the pipeline material. Successful completion of the test at this level demonstrates that any remaining defects are considerably smaller than would fail at the operating pressure.

It provides a rigorous demonstration of a quantified safety margin that accommodates an allowance for defect growth during service, and is therefore recommended in cases where operational requirements could involve significant cyclic pressures, or where increases in the MAOP to design factors exceeding 0.72 are likely to be considered.

NOTE 1 Requirements for high-level testing are given in IGE/TD/1 Edition 4:2001, Section 8 and Appendix 5.

NOTE 2 Where limit state design has been used for natural gas pipelines, see BS EN 1594 for guidance on maximum hydrostatic test pressures.

11.5.2.2 Standard hydrostatic strength test

A standard pressure test involves testing to the lower of a pressure of not less than 150% of the MAOP or a pressure that produces a hoop stress level equivalent to 90% SMYS. This test level is intended to determine whether the quality of the pipeline materials and construction is adequate for future operation of the pipeline. It is recommended in cases where significant cyclic pressures and/or increases in the pipeline MAOP are not anticipated in the future operation of the pipeline.

11.11 Pre-testing

11.11.1 General

Pipe and fittings should be pre-tested in the following circumstances:

a) when they cannot be tested after installation in subassemblies to be incorporated into an existing installation;

b) when they are to be installed in close proximity to operating plant which cannot be protected against test failure;

c) when it is considered that the potential consequences of a test failure justify pre-testing.

Road and rail crossings classified as major crossings, river crossings, canal crossings and bridge crossings (see **10.13**) should be fabricated from pre-tested pipe or should be pre-tested after fabrication but before installation and final test. Pre-testing of pipe or fabrications should be carried out in accordance with **11.4, 11.5** and **11.6** except that:

the pre-test pressure should be at least 1.05 times the test pressure appropriate to the section into which the crossing is to be installed, taking into account the elevation of the crossing within the test section; and the duration of the final hold period should be not less than 3 h.

APPENDIX 2 RANGE OF MILL TEST PRESSURES

Contract Code BHA,BHB,BHC,BHD,BHE **Corrib Field Development Project**

508mm OD Grade SAW L II 485 F U

MECHANICAL EXPANSION

(OS-F101 Sect 6. E803, P.Spec Sect 6. E803)

Maximum expansion ratio permitted - 1.5%.
Expansion ratio shall be measured and recorded on 10 pipes for each item. If expansion ratios of 0.15% above that recorded at this time are experienced, additional Strain Aged Charpy's will be conducted one pipe to establish a new level. i.e.Threshold control

HYDROSTATIC TEST PRESSURE

(OS-F101 Sect. E1100. Formula 6.2)

$$\left[\frac{2.t_{min}}{D - t_{min}}\right] \times 0.96.SMYS$$

Item No.	BHA	BHB	BHC	BHD	BHE
Wall Thickness	27.1mm	24.7mm	22.5mm	22.0mm	21.0mm
Minimum Pressure	504 Bar	456 Bar	412 Bar	402 Bar	382 Bar
Maximum Pressure	511 Bar	463 Bar	419 Bar	409 Bar	389 Bar
Minimum Duration	10 sec.	10 sec.	10 sec.	10 sec.	10 sec.
Bolling Die Size	1422mm	1438mm	1452mm	1455mm	1461mm

PIPE NUMBERING REQUIREMENTS

(Allseas Communication 368820/AE/CT/E/017)

Prefix	Diameter	W/T	No.Pipes	Pipe Number Range
BHA	508mm	27.1mm	1,400	9000 - 10400
BHB	508mm	24.7mm	743	8000 - 8743
BHC	508mm	22.5mm	1,858	6000 - 7858
BHD	508mm	22.0mm	5,301	2000 - 5301
BHE	508mm	21.0mm	677	0001 - 0677

SHELL E&P IRELAND LIMITED

CORRIB GAS FIELD DEVELOPMENT PROJECT

Corrib
natural gas

Q5.4 SUMMARY OF PRESERVATION OF LINEPIPE

DOCUMENT No: COR-39-SH-0025

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ATTACHMENTS

1 PIPE STORAGE

Following manufacture at Corus in mid-2002, the 20” diameter pipe for the Corrib pipeline was delivered to Killybegs, County Donegal and stored in two locations. The pipe was stacked on (uncovered) berms to keep them off the ground and inclined to prevent accumulation of water. No other protection was provided at this stage because the storage was considered to be temporary.

The pipe was delivered with either an external asphalt enamel/concrete coating or a 3-layer polypropylene coating. The pipe for the onshore pipeline is predominantly polypropylene coated. There was no internal coating applied in the coating mill. Approximately 40 cm of the ends of the pipe are not coated externally to allow welding of the pipeline during installation.

Since 2005 the pipe has been stored at various sites in Killybegs, although 219 pipes were transported in 2005 to County Mayo in preparation for the onshore pipeline installation. Approximately 1.5 km of pipe was welded together. Following the cancellation of the pipe-lay the welded pipe was cut and all 219 pipes were stored in single or double stacks on the way-leave close to the Terminal until they were returned to Killybegs in 2007.

An additional 1.15 km of 27.1 mm thick pipe was ordered from Eisenbau Krämer for the onshore pipeline and delivered to Killybegs in 2009.

In May 2009 the pipe for the offshore pipeline was transferred to the Allseas Solitaire for the offshore pipe-lay. A total of 110 unused 27.1 mm thick pipes were returned to Killybegs.

All of the pipe for the onshore pipeline and the remaining offshore pipe are now stacked on protected berms and covered at the Artic site in Killybegs.

A small number of pipes (16) intended for the tie-in of the subsea manifold to the offshore pipeline were stored in a single row at Corus in Hartlepool in 2002. No protection was applied to these pipes.

2 PRESERVATION OPERATIONS

The pipe has been subject to several preservation operations since 2002 depending on the anticipated timing of the pipe-lay.

In early 2005 all the pipes were internally cleaned by high pressure water jetting and the external steel surfaces cleaned by rotary wire brushing. The pipes were air dried and then sealed with VPI (vapour phase inhibitor) film. Recessed end caps were fitted and the non-coated area and end cap were sealed with petroleum tape. During transfer of the pipe back to the storage site a number of end caps were damaged by the lifting arm allowing water ingress to the inside of the pipe. On discovery of this damage, the lower end cap of every pipe was either drilled with a hole or slit with a knife to allow any water inside to drain out.

At this stage it was decided to blast and internally coat the pipes on site to prevent internal corrosion as a result of water accumulation or water condensation in the humid conditions, and to replace the recessed end caps with more robust flat end caps. The internal blasting and coating operation required significant development and trialling to ensure that a high quality coating could be applied and this was implemented in 2007.

The VPI film and petroleum tape which was applied to the external exposed steel ends of the pipe was removed and since 2007 the pipe ends have been left bare because the pipe ends are kept dry with corrugated sheeting (Figure 2.1).

Figure 2.1: Current storage of Corrib line pipe

The site applied internal coating was removed from the whole of the internal surface of 565 of the polypropylene coated pipes for the offshore pipeline prior to offshore pipe-lay. All other pipes for the offshore pipe-lay had 300mm of the internal coating removed at each end to facilitate welding. The opportunity was also taken to clean the bare external steel surfaces of all pipes including the onshore pipe that was returned from Mayo. The site applied internal coating of the onshore pipe from the original (2002) order was not removed.

The returned offshore pipes and the new (2009) onshore pipes are to be internally coated in Spring 2010.

3 PIPE INSPECTION

During the period of storage the pipes have been subject to regular visual inspection by the project materials & corrosion engineer. Most pipe ends have suffered some superficial rusting as shown in the photo (Figure 3.1) but there is no significant corrosion.

Figure 3.1: Photo showing light corrosion of stored 27.1mm pipe

Some 10 pipes suffered noticeable pitting at the external pipe ends because they sank into the mud early in the storage period before proper berm protection was installed. These pipes, which were all offshore pipes, have been quarantined and will not be used.

In addition to visual inspection, ultrasonic wall thickness checks have been carried out at regular intervals over the period of storage on a sample of pipes to confirm that there is no significant wall loss.

This is illustrated in Figure 3.2 which shows that the trended wall thickness measurements for 27.1mm thick pipe are well above the 26.1mm minimum allowable wall thickness excluding the mill tolerances, and there is no significant wall loss trend.

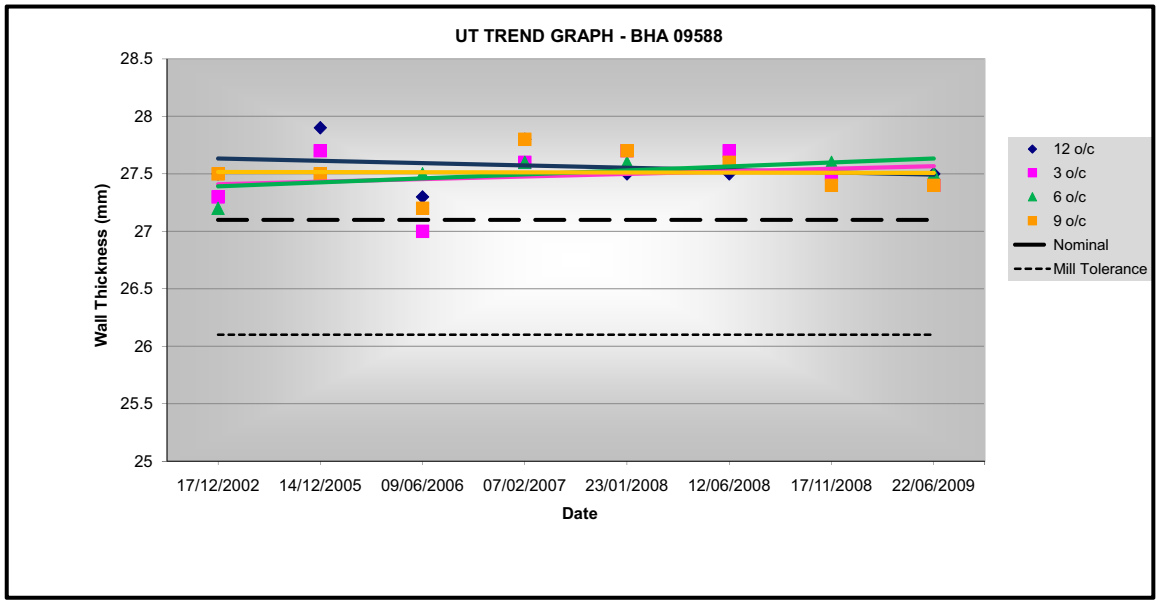

Figure 3.2: Trended ultrasonic wall thickness measurements for 27.1mm pipe

4 COATING CONDITION

4.1 GENERAL COMMENTS

The external polypropylene coating comprises of 3 layers:

- fusion bonded epoxy which is the anti-corrosion layer
- adhesive layer which enables the polypropylene to stick to the FBE
- polypropylene which is a robust layer to protect the FBE from mechanical damage and to exclude water especially at elevated temperature.

The coating was applied by BSR Pipeline Services, Hartlepool in accordance with the French specification NF A 49-711.

The polypropylene coating has been exposed to ultraviolet light (UV) during the period of storage. The supplier of the coating guaranteed resistance to UV for a period of 3 to 4 years. Following cancellation of the installation in 2005, a UV resistant paint (acrylic-urethane) was applied to the exposed areas of the coating. Since 2008 the pipes have been protected with a double layer of special covering (Fosroc) to exclude UV light.

In accordance with the recommendation by Advantica, testing has been carried out on the coating to check whether there has been any significant change in the properties of the coating during the storage. These tests showed that the external coating of the pipe is still fit for purpose.

4.2 DSC TESTS

Differential scanning calorimetry (DSC) testing provides a measure of the degree of curing of the fusion bonded epoxy (FBE) layer and confirms the suitability of the application parameters for a given coating system. This type of testing cannot be done on a finished 3 layer polypropylene coating and needs to be done during application of the FBE layer. This is not a requirement of the French specification that was used for the coating application and was therefore not done for the Corrib pipe from Corus. However, Shell has DSC test results for the same system as that applied at the BSR factory for the Corrib pipe which confirms the application parameters of the system as suitable.

4.3 REPEAT COATING TESTING TO NF A 49-711

Testing was done in 2007 to confirm the integrity of the polypropylene coating on the stored pipe (Attachment Q5.4A) as requested by Advantica. Overall the results show good conformance with the requirements of the French specification and also Shell requirements. The good adhesion of the anti-corrosion FBE layer to the steel is demonstrated by both the adhesion tests and the cathodic disbondment tests and is the most important parameter for the long term performance of the coating. The elongation at break test shows a high degree of scatter of results. This test is an extremely difficult test to do with a coated pipe because the polypropylene coating has to be removed from the pipe. In the factory the polypropylene coating is extruded onto a bare test pipe without the FBE and adhesive to allow this particular test to be done properly. Removal of the full coating system from a pipe invariably causes nicks and tears that affect the actual result. However taking into account the scatter there is an overall increase in the elongation with ageing. Also note that the coating performed well in the hot water soak test and there is no evidence of yellowing which is an early indication of coating degradation.

4.4 FLEXIBILITY TESTING

In order to demonstrate that major cracking would not happen as a result of the strain induced during installation, a series of flexibility tests were carried out. Samples of 3LPP coating from areas with and without the acrylic-urethane UV protection were subjected to flexibility tests in accordance with draft ISO standard ISO/CD 21808-1. The samples with no acrylic-urethane UV protection were considered to represent the likely UV exposure of any individual pipe, taking into account the pipe mixing that

would have occurred during pipe movements. Flexibility testing was also carried out on samples of the pipes that were stored in Hartlepool, which represent the very worst-case conditions possible, (i.e. constant UV exposure because they had not been moved). All flexibility results met the requirements of ISO/CD 21809-1 with the exception of those from pipes under constant UV exposure stored at Hartlepool.

4.5 SPECIALIST REVIEW

Shell requested a renowned coating specialist (David Norman), who sits on ISO standards committees for pipeline coatings, to inspect the coating and review the results. His conclusion is that the coating should be fit for purpose assuming no further deterioration (Attachment Q5.4B). The condition of the coating will continue to be monitored during storage to confirm that deterioration has not occurred.

5 DISCUSSION AND CONCLUSION

Although the pipe for the Corrib pipeline has been in storage since 2002, appropriate maintenance operations have been carried out during this period to ensure that the pipe and coating is fit for purpose despite successive delays to the pipe-lay operations.

The delays have resulted in a progressive approach to pipe maintenance which at times may have given the appearance that the pipe was not being maintained. However, the pipe has been subject to continuous monitoring and appropriate actions have been taken when necessary.

It should be realised that atmospheric corrosion of high strength steel pipe is a relatively slow mechanism provided that direct and continuous contact with water is avoided. Keeping the pipe as dry as possible has always been a fundamental premise throughout the storage. Regular inspections and subsequent maintenance activities including internal coating have focussed on this aspect.

Pipe which may appear to be corroded will have actually suffered very little wall loss because the oxide scale is 5 to 10 times thicker than steel. This lack of significant corrosion has been demonstrated by the wall thickness measurements that have been taken over the period of storage.

It can be concluded that the pipe is fit for purpose. Furthermore, the current storage method ensures that the pipe is kept relatively dry and protected, such that it will be suitable for installation when required.

ATTACHMENT Q5.4A

POLYPROPYLENE COATING TEST DATA FOR ONSHORE PIPE (MAYO)

CDT07-0680-REP

Table 3: results coated pipe "Mayo"

Coated pipe "Mayo" (COT sample number: 21-09-06/722)			
Test	**Results**	**Requirement**	
		Shell DEP 31.40.30.31	**NF A 49-711**
Elongation	68 ± 40% (initial) 83 ± 19% (after weathering)	> 50% of initial value	> 75% of initial value
Brittleness / Impact	no defects	min. 25 J	min. 25 J
Adhesion at 20 ± 2°C	> 78N/10 mm		78N/10 mm
Adhesion at 80 ± 2°C	> 235 N/10 mm (rupture of coating)	> 40N/10 mm	
Adhesion after water immersion	> 216 N/10 mm	-	-
Cathodic Disbondment	2 mm at 23°C 6 mm at 80°C	max. 5 mm max. 7 mm	max. 3 mm max. 7 mm
Penetration	0.080 mm at 23°C 0.105 mm at 80°C	≤ 0.2 mm ≤ 0.4 mm	≤ 0.1 mm ≤ 0.3 mm
Yellowing of the coating	no yellowing on both areas	-	-
Cracking	no cracking (before weathering) no cracking (after weathering)	-	no cracking
Hot water soak test	no defects and no change in adhesion (qualitative)	-	no defects

ATTACHMENT Q5.4B

COATING SPECIALIST'S REPORT ON FLEXIBILITY TESTING

Notes on the Flexibility Testing of 3LPP Coating at Bodycote, Eccles, on Pipe Straps Cut from Stored Pipe from the Shell Corrib Project.

30th January 2009

by

David Norman

David Norman Corrosion Control

Present: Geoff Duck - Shell, John Jones – Barrier, Terry Haynes – Bodycote, and David Norman – Pipeline Coating Consultant to Shell.

1. Introduction

Flexibility testing to the requirements of the draft ISO 21809-1 3LPO standard have previously been undertaken on Shell Corrib, 3LPP coated, pipe.

The first set of tests were undertaken, (on 14/08/07), at Bodycote on pipe that had been protected with an anti-UV paint on the top segment of the pipe, but no anti-UV paint on the remainder. The pipe had been stored in Killybegs on the West coast of Ireland. All the flexibility tests undertaken passed the requirements of the ISO 21809-1 testing regime.

The second set of testing was undertaken, (on 13/11/07), at Bodycote on pipe that had been stored at BSR, Hartlepool, England, where no anti-UV paint had been applied. This PP coating had degraded, cracked and crazed. All the flexibility tests undertaken failed the requirements of ISO 21809-1.

A third set of flexibility tests were undertaken, (on 07/01/08), on straps cut from pipe pups taken from randomly selected 3LPP coated pipes from the centre of the stacks at Killybegs, with no application of an anti-UV coating.

Shell decided to undertake a fourth set of coating flexibility tests on straps taken from pipe pups from the same pipes as tested in January 2008. During the intervening storage period (January 2008 to January 2009), these pipes were not stacked, covered or provided with any other anti-UV protection. They should therefore represent worst case pipe storage during the extended period to January 2009.

2. 3LPP Coated Pipe Chosen for 4th Series of Flexibility Testing at Bodycote

0.9m pups were cut from 4 coated pipe and sent to Bodycote for cutting into straps and for preparation prior to testing. The thickness of the 3LPP coatings on the straps tested varied between a minimum of 2.09mm and a maximum of 4.75mm.

The 4 pipes utilised were the same as those used in the third series of flexibility testing on 07/01/08:

BHE 00366; 20" diameter, 21mm wt; for offshore use.

Bodycote code N950301, straps 299, 300, 301 from 12 o'clock and straps 302, 303, 304 from 6 o'clock position on pipe as stored.

The thickness of the coating on the straps was 2.51mm min. / 4.28mm max. on ring 1 and 2.09mm min. / 4.69mm max. on ring 2.

Under 40X magnification the coating on items 01, 02 and 03 from the 12 o'clock position exhibited no signs of cracking; however the surface was covered in adhesive from tape that had been removed.

The PP on items 04, 05 and 06 exhibited no cracking but scratch marks were evident.

All 6 flexibility tests passed the requirements of ISO 21809-1.

BHC 06712; 20" diameter, 22.5mm wt; for offshore use.

Bodycote code N950302, straps 318, 319, 320 from 12 o'clock and straps 321, 322, 333 from 6 o'clock position on pipe as stored.

The thickness of the coating on the straps from the 12 o'clock position was 3.46mm min. / 4.75mm max. on ring 1 and from the 6 o'clock position between 3.72mm min. / 4.70mm max. on ring 2.

Under 40X magnification the coating from items 01, 02 from the 12 o'clock position exhibited fine mud cracking and item 03 exhibited fine radial cracking. Items 04, 05 and 06 from the 6 o'clock position exhibited numerous small particles of PP under 40X magnification.

All 6 flexibility tests passed the requirements of ISO 21809-1.

BHA 10272; 20" diameter, 27.1mm wt; for offshore use

Bodycote code N050300, straps 280, 281, 282 from 12 o'clock and straps 283, 284, 285 from 6 o'clock position on pipe as stored.

The coating was 3.02mm min. / 3.51mm max. in thickness on ring 1, and 2.67mm min. / 3.83mm max. in thickness on ring 2.

Under 40X magnification the coating at the 12 o'clock position exhibited radial cracks and marks on items 01 and 02, and fine mud and radial cracks on item 03. On items 04, 05 and 06 from the 6 o'clock position mud and radial cracks could be seen under 40X magnification.

All 6 of the flexibility tests passed the requirements of ISO 21809-1.

BHA 09433; 20" diameter 27.1mm wt; for onshore use.

Bodycote code N950299, straps 261, 262, 263 from 12 o'clock and straps 264, 265, 266 from 6 o'clock position on pipe as stored.

The thickness of the coating was 3.50mm min. / 4.70mm max. on ring 1 and 3.66mm min. / 4.65 mm max. on ring 2.

The coating at the 12 o'clock and 6 o'clock positions exhibited 'mud type surface cracking' and some radial cracks on items 01, 02, 03, 04, 05, but no visible cracking on item 06 when examined under 40X magnification. Items 04 and 06 exhibited a small lump of PP.

All 6 flexibility tests passed the requirements of ISO 21809-1.

<u>Note on Pipe Selections:</u>

- Pipe BHA 10272 selected from "Section A" offshore pipe;
- Pipe BHE 00366 selected from "Section B" offshore pipe;
- Pipe BHC 06712 selected from "Section C" offshore pipe;
- Pipe BHA 09433 selected from onshore pipe.

Random tears in, and lifting of areas of the internal coating on the tested straps was apparent.

Photographs of all the samples are available, after testing. They are not included in this report as they do not show anything of note to the naked eye.

3. Comments on the Testing Results

3.1 The 3LPP coating on the 6 straps from each of the 4 pipe pups (24 total) passed the flexibility requirements of ISO 21809-1.

3.2 Intermittent cracking and crazing of the 3LPP coating could be seen on many of the straps under 40X illuminated magnification.

3.3 The worst cracking and crazing could be seen on pipe BHA 10272 (Bodycote N950300, straps 280 to 285).

4.0 Bodycote Report

Bodycote were asked to undertake some further testing using 40X illuminated magnification on sample N950300, BHA 10272 at the 3, 6, 9 and 12 o'clock positions. This is the sample that had shown the worst cracking and crazing of all the samples during flexibility testing.

Intermittent surface cracking and crazing, of most of the areas examined, could be seen, especially where black markings were on the surface of the 'white' polypropylene.

5.0 Conclusion

As no loss of adhesion of the 3LPP coating system to the substrate was apparent before or after flexibility testing, and cracking and crazing of the coating system was a surface 'phenomenon', the 3LPP pipe coating should still be fit for purpose – even after nearly 7 years since application at BSR Hartlepool.

David Norman

David Norman Corrosion Control

dn/gd/sc/030

Appendix Q6

Safety Management

Q6.1: Introduction to Safety Management
Q6.2: Public Safety - Application of Design Codes
Q6.3: Qualitative Risk Assessment
Q6.4: Quantitative Risk Assessment (QRA)
Q6.5(i): Response to An Bord Pleanála regarding the query raised in Section 3b of letter dated 2nd November 2009
Q6.5(ii): Response to An Bord Pleanála regarding the request for further information, item (i) of letter 2nd November
Q6.6: Emergency Response Planning and Provisions

SHELL E&P IRELAND LIMITED

CORRIB GAS FIELD DEVELOPMENT PROJECT

Corrib
natural gas

Q6.1 - INTRODUCTION TO SAFETY MANAGEMENT

DOCUMENT No: COR-14-SH-0075

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1 PURPOSE OF THIS APPENDIX

This document introduces Appendix Q6 with the aim of setting the scene and providing the reader with a clear picture of how Q6 documents relate to each other and to other documents in Appendix Q.

Appendix Q6 focuses on the safety of the Corrib pipeline in so far as this relates to the community living and working in the vicinity of the pipeline. It explains why the pipeline is safe and provides a written demonstration that the pipeline is safe – in other words it presents a 'case for safety'.

2 SUMMARY OF APPENDIX Q6 DOCUMENTS

Pipeline safety hinges on the quality of the design, fabrication, construction, commissioning and, thereafter, management of pipeline operations and maintenance such that physical integrity is safeguarded and the design intent is not compromised.

2.1 PUBLIC SAFETY: APPLICATION OF DESIGN CODES

Development of a pipeline design is primarily governed by the diligent application of standards and codes of practice, which prescribe certain safety features. However, design also involves a substantial element of option analysis and selection and, in addition, the physical environment that hosts the pipeline often introduces special demands. Therefore, as not everything can be prescribed, it is necessary to combine use of design standards and codes of practice with professional expertise and practical experience in order to assure a safe design.

To test the safety of a design, code compliance is therefore coupled with an assessment of the risks.

Appendix Q6.2 (Public Safety: Application of Design Codes) provides a code compliance overview with respect to designing for public safety and demonstrates how the Corrib pipeline complies with the safety requirements relating to the proximity of the pipeline to existing buildings.

2.2 QUALITATIVE RISK ASSESSMENT

Put simply, risk is a function of the likelihood of something happening and the consequences should it happen. The approach to risk adopted here is that risk is used to reflect unwanted events as illustrated in Figure 2.1.

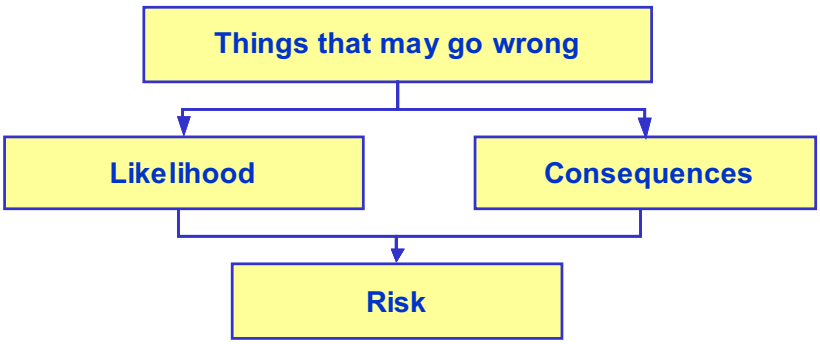

Figure 2.1: Risk

Levels of risk are assessed in order to help improve, and assure, safety in the design and to provide input into operational control of any remaining (or residual) risk,

Risk is assessed qualitatively (i.e. without the use of numbers) for each potential thing that may go wrong using a matrix to enable the potential likelihood and consequence severity to be judged and, from this, the risk is classed as ‘high’, ‘medium’ or ‘low’.

Classification in this way allows two things to be done:

1. Determine the level to which each discrete risk is analysed with the aim of reducing the residual risk to acceptable levels – the higher the risk, the more effort we put into analysing it; and

2. Determine the level to which we document the measures in place to control the risk and demonstrate that the risk is being managed – the higher the risk, the more detailed the documentation and demonstration.

Appendix Q6.3 (Qualitative Risk Assessment) provides an overview of the qualitative risk assessments that have been undertaken for the Corrib Pipeline and presents the results of some detailed qualitative (bowtie) risk analysis. It concludes by demonstrating that the risks associated with the pipeline have been reduced to As Low As Reasonably Practicable (ALARP) levels.

2.3 QUANTITATIVE RISK ASSESSMENT

Where the consequences of an unwanted event have the potential to impact the public as well as workers, then a Quantitative Risk Assessment (QRA) is carried out. Here the aim is to calculate the risk such that it can be presented numerically and compared with numerical risk tolerance criteria.

Appendix Q6.4 (Quantitative Risk Assessment) presents the latest QRA for the Corrib Pipeline, including detailed results showing how risk varies with distance along and away from the pipeline. The QRA results are compared against relevant criteria and are shown to lie in the "broadly acceptable" risk region.

2.4 CONSEQUENCE ANALYSIS

At the request of An Bord Pleanála, the consequences associated with a full-bore failure of the pipeline are analysed based on An Bord Pleanála's prescribed requirements. The likelihood of a full-bore failure is extremely low, as reflected within the QRA. Nevertheless, **Appendix Q6.5(i)** presents a documented response to An Bord Pleanála's request.

Appendix Q6.5 (ii) presents information specifically requested by An Bord Pleanála in order to complete the presentation of contours presented at the 2009 Oral Hearing (escape and building burn distances). This information has been superseded by that in Appendix Q6.5(i).

2.5 EMERGENCY RESPONSE PLANNING & PROVISIONS

Operating procedures, of which emergency response plans form a part, are not normally produced until nearer start up of operations. However **Appendix Q6.6** (Emergency Response Planning and Provisions) documents the current emergency response planning and provisions which, whilst a work-in-progress, clearly illustrate the intent with respect to managing emergency response and describes the plans for engaging with, and involving the public and the emergency services.

3 APPENDIX Q6 DOCUMENT RELATIONSHIPS

The relationship between the documents contained in Appendix Q6 and other Sections of Appendix Q is shown in Figure 3.1.

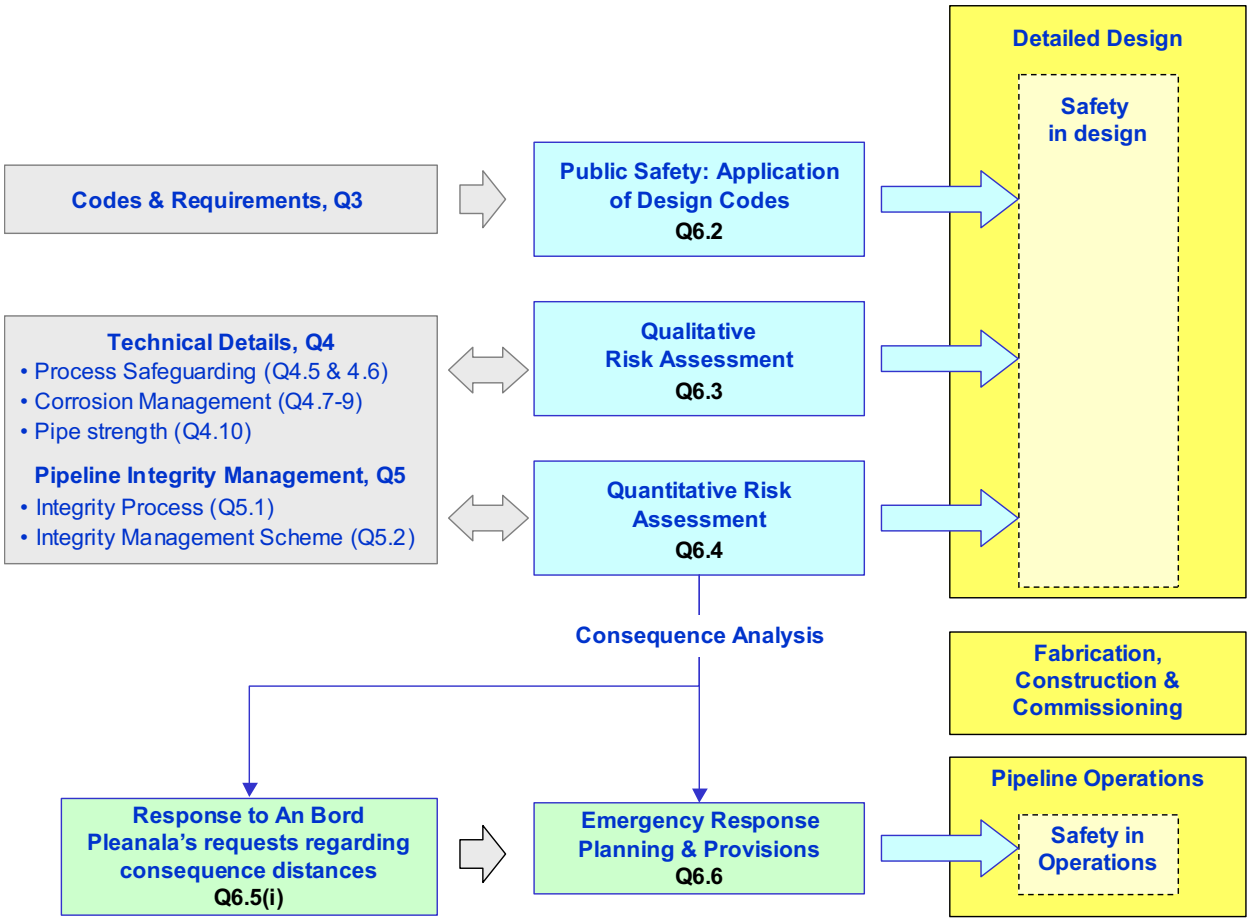

Figure 3.1: Appendix 6 Document Relationships

4 NEXT STEPS FOR SAFETY MANAGEMENT

Looking to the future, the work presented here in Appendix Q6 which has been carried out during the design stage will continue up to start-up and into the operations phase.

Much of the risk assessment work will be incorporated into, and developed further within, a 'Safety Case' document, which is a legislative requirement under the recently enacted Petroleum (Exploration and Extraction) Safety Act. Figure 4.1 illustrates this and further details about the Safety Case are given in Appendix Q6.3.

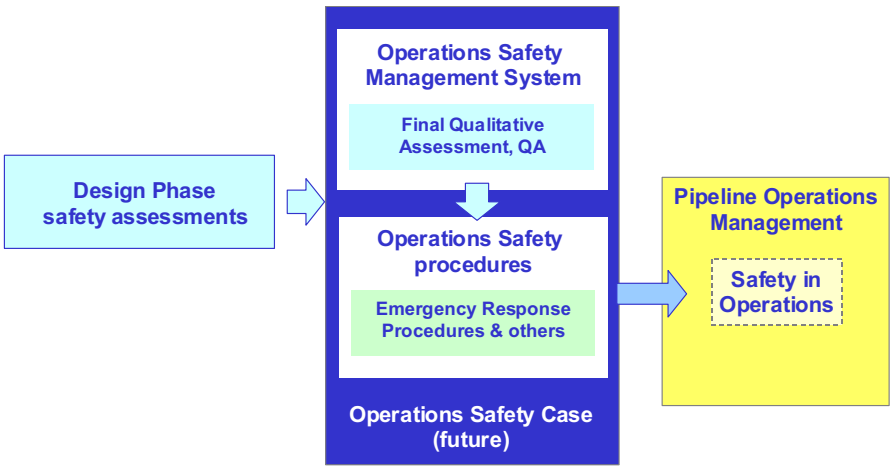

Figure 4.1: Design Phase inputs to Pipeline Safety

SHELL E&P IRELAND LIMITED

CORRIB GAS FIELD DEVELOPMENT PROJECT

Corrib
natural gas

Q6.2 – PUBLIC SAFETY - APPLICATION OF DESIGN CODES

DOCUMENT No: COR-14-SH-0076

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1 CONCLUSIVE SUMMARY

1.1 INTRODUCTION

This document provides a demonstration of compliance with applicable Design Standards and Codes (referred to simply as Codes) with respect to onshore pipeline routing and design and potential safety impact on the public.

Described are the relevant Codes, the process adopted to route the pipeline, the key factors that govern the selection of a safe route and an appropriately designed pipeline. An assessment is made of Code-based proximity distance to buildings.

1.2 CONCLUSIONS

It is concluded that the inherent level of safety of the currently proposed pipeline continues to be significantly greater than the minimum required by the Codes.

The outcome of this Code-based assessment is:

- The Corrib onshore pipeline originally had a Design (safety) Factor of 0.72 with wall thickness determined by design pressure of 345 barg. Subsequently a Design Factor of 0.3 has been adopted based on a lower design pressure of 144 barg as required by the Technical Advisory Group (TAG) to the Department of Communications, Energy and Natural Resources. Compared with 0.72, a Design Factor of 0.3 requires a stronger and thicker walled pipe. Having now been routed through Sruwaddacon Bay the Corrib onshore Pipeline could be classified as traversing a low-density location, Type R (rural) area, in accordance with I.S. 328, in which case a Design Factor of 0.72 would be used. By retaining the Design Factor of 0.3 the Corrib onshore pipeline represents a higher level of safety than would normally be required by the Code in an area of low population density.

- The individual risk levels for persons standing at the pipeline centreline as predicted in the QRA, see Appendix Q6.4, are lower than the level that enables risk-contour based building proximity distance criteria to be applied.

- The graph in I.S. 328 relevant for Corrib pipeline Design Factor of 0.3 (Figure 4.1 in this document) specifies that the nearest dwelling should be no closer than 3m at the MAOP of 100 barg.

- The graph in I.S. 328 relevant to a Design Factor exceeding 0.3 but not exceeding 0.72 (Figure 4.2 in this document) specifies that the nearest building should be no closer than 63m at MAOP of 100 barg. The formula in BS PD 8010 relevant to a Design Factor up to 0.72 specifies no closer than 60.38m.

The nearest house to the Corrib pipeline is 234m.

2 RELEVANT SAFETY RELATED DESIGN STANDARDS & CODES

As instructed by TAG on behalf of the Department of Communications, Energy and Natural Resources and in support of the Advantica recommendations the Codes critical to achieving a safe pipeline are:

Primary: I.S. EN 14161: Petroleum and Natural Gas Industries - Pipeline Transportation Systems

Supplementary: I.S. 328: Code of Practice for Gas Transmission Pipelines and Pipeline Installations

BS PD 8010 Code of Practice for Pipelines:

Part 1: Steel Pipelines on Land

Part 3: Steel Pipelines on Land – Guide to the Application of Pipeline Risk Assessment to Proposed Developments in the Vicinity of High Pressure Natural Gas Pipelines.

Note that BS PD 8010 makes reference to IGEM/TD/1: Steel Pipelines and Associated Installations for High Pressure Gas Transmission, for establishing initial routing and population density requirements. Although this document was not explicitly included in TAG's statement .

A full description of Codes and Standards applied for onshore Corrib pipeline design, manufacturing, construction and pre-commissioning are described in Appendix Q 3.3.

The principles and processes applied with respect to safety in pipeline design contained in each of these Codes are very similar, and are described in the next Section. The above Codes cover the onshore pipeline from the Landfall Valve Installation (LVI) to downstream of the pig receiver at Bellanaboy Bridge Gas Terminal (BBGT). For the purposes of assessing risk to the public the details regarding the offshore pipeline upstream of the LVI are also discussed and assessed on the same basis as the onshore line downstream of the LVI.

Where details vary, for instance with respect to metrics of location classification and population density, the most stringent Code requirement is adopted.

3 PROCESS FOR ROUTING OF AN ONSHORE PIPELINE

This Section summarises the key activities associated with routing the pipeline in accordance with the designated Codes and Standards.

3.1 INTRODUCTION

A key objective of Codes for the design, installation, operation, testing & maintenance of pipelines is to minimise safety risks to the public.

The consequences of failure are minimised by:

- As far as is practical, routing the pipeline through areas of minimum population and infrastructure.
- Maintaining as great a distance as is practical between the pipeline and normally occupied buildings and infrastructure such as main roads. (Here the concept of building proximity distance (BPD) is relevant and minimum BPDs are specified within Codes)
- Reducing operating pressures as far as is practical consistent with the required system functionality

The likelihood of failure is minimised by:

- Ensuring that the design of the pipeline takes account of the actual population and infrastructure within the area through which the pipeline is to be routed. This is done by:
    - Classifying the area according to population and infrastructure and assigning a Design Location classification
    - Based on the Design Location classification, assign the appropriate Design Factor. The higher the density of occupied dwellings and infrastructure the lower the Design Factor. Using a lower Design Factor means that the pipe design is even stronger and more resistant to damage.
- Reducing the likelihood of material/construction defects through the use of material and inspection specifications which control material quality, fabrication and installation standards, and pre commissioning testing requirements
- Minimising the likelihood of pipe wall fracture propagation through use of materials with a fracture toughness that is sufficiently high to control crack initiation, and prevent brittle fracture propagation
- Ensuring controls are in place to minimise material degradation through the use of high quality coatings and the design, installation and maintenance of corrosion protection systems
- Ensuring the pipeline is resistant to impact damage caused by external interference through use of increased pipe wall thickness and installation of additional pipeline protection at potentially vulnerable locations

3.2 PIPELINE ROUTING PROCESS

In parallel with the fundamental design of the pipeline (e.g. diameter, flowrate, hydraulic analysis, pressure control and protection, see Appendix Q 4.1) the options for routing the pipeline are studied such that current and, as far as is possible, foreseen future public presence is taken into account. This tends to be an iterative process with the objective of complying with code requirements as a minimum.

The selection of a pipeline route also takes account of factors not all specifically relating to public safety; these include, for example, construction safety, environmental impact assessments, geotechnical constraints, and stakeholder consultations.

The Codes require that the following basic steps be taken in order to determine the route:

1. Categorise fluids
2. Classify the Design Location through which the pipeline is proposed to be routed
3. Establish the Design Factor
4. Establish the minimum distance a normally occupied building can be to the pipeline (through Quantified Risk Assessment (QRA) or, if no QRA carried out, through Code minimum proximity distances)
5. Route the pipeline to take account of:
    a. Normally occupied buildings
    b. Any known future development plans in the vicinity of the pipeline (as advised by the local planning authority)
6. Carry out a QRA to confirm that the pipeline satisfies risk acceptance criteria
7. Based on the outcome of the QRA adjust the route if necessary
8. Finalise the routing proposal

For onshore pipelines with an MAOP in excess of 100 barg, a safety evaluation is required; this involves a systematic study of a pipeline and its associated installations, covering design, construction and operation, for the purpose of demonstrating that all reasonably practicable measures to ensure safety have been taken.

The safety evaluation must include:

- A full quantified risk assessment
- Specific consideration of material requirements
- Specific consideration of pressure boundaries and the control regime

- Assessment of additional maintenance and risk management requirements

3.3 RISK CRITERIA

Two criteria have to be satisfied to be in compliance with Codes, these are:

- Individual Risk
- Societal Risk

Both are described in full within the QRA, see Appendix Q 6.4.

If predicted risk levels are higher than the defined 'broadly acceptable' level then it must be demonstrated that residual risks are as low as reasonably practicable (ALARP).

3.4 LAND USE PLANNING

As noted above, route selection should take account of any potential future use of the land as, over the lifetime of the pipeline, plans for the actual use of adjacent land may involve extensive development. For the Corrib pipeline SEPIL have been requested by An Bord Pleanála to provide details of the inner, middle and outer zones, this has been included as an aspect of the QRA, see Appendix Q 6.4.

4 KEY FACTORS FOR PUBLIC SAFETY WITH RESPECT TO GAS PIPELINES

Before addressing the specifics of the Corrib pipeline this Section describes the key factors that determine an appropriate level of pipeline safety.

4.1 CATEGORISATION OF FLUIDS

Fluids in a pipeline are categorised and the assigned category then defines the action to be taken to ensure public safety.

4.2 CLASSIFICATION OF DESIGN LOCATIONS

The number of normally occupied buildings within a defined area each side of the proposed pipeline route is counted, and, based on an assumed occupancy level, the population density for that area calculated. The population density then determines the design location classification. This classification then determines the pipeline Design Factor and minimum depth of burial.

4.3 DESIGN FACTOR AND WALL THICKNESS

The minimum wall thickness required by the Code (not including manufacturing tolerance and corrosion allowance) is inversely proportional to the Design Factor. The lower the Design Factor, generally, the greater the wall thickness, and hence the lower the likelihood of pipeline failure. The Barlow formula below (I.S. 328, 6.5.1) is applied

$$t = \frac{PD}{20fs}$$

t = Wall thickness excluding corrosion & manufacturing allowances
P = Design pressure, barg
D = Outer pipe diameter, mm
f = Design Factor
s = min yield stress at design temperature

4.4 PROXIMITY TO NORMALLY OCCUPIED BUILDINGS

The nearest a pipeline can be from a normally occupied building, the Building Proximity Distance (BPD) is calculated based on:

- A defined Individual Risk level predicted through Quantitative Risk Assessment
- An empirical basis (graphical or formula based)
  - **Graphical based:** Figure 4.1 is extracted from I.S. 328 and is the graph relevant for natural gas pipelines but are presented here for comparison
  - **Empirical formula based:** BS PD 8010: Pt 1 states that 'where individual risk contours are not available the limiting proximity distance for routing purposes, Y, should be in accordance with the formula':

$$Y=Q\left[\frac{D_o^2}{32{,}000}+\frac{D_o}{160}+11\right]\left[\frac{P}{32}+1.4\right]$$

Y=Minimum BPD, m
Q= Substance factor for fluid transported in the pipeline
D_o = Outer pipe diameter, mm
P=Pressure (maximum), barg

Figure 4.1: Extract from I.S. 328 for Design Factor not exceeding 0.3[1]

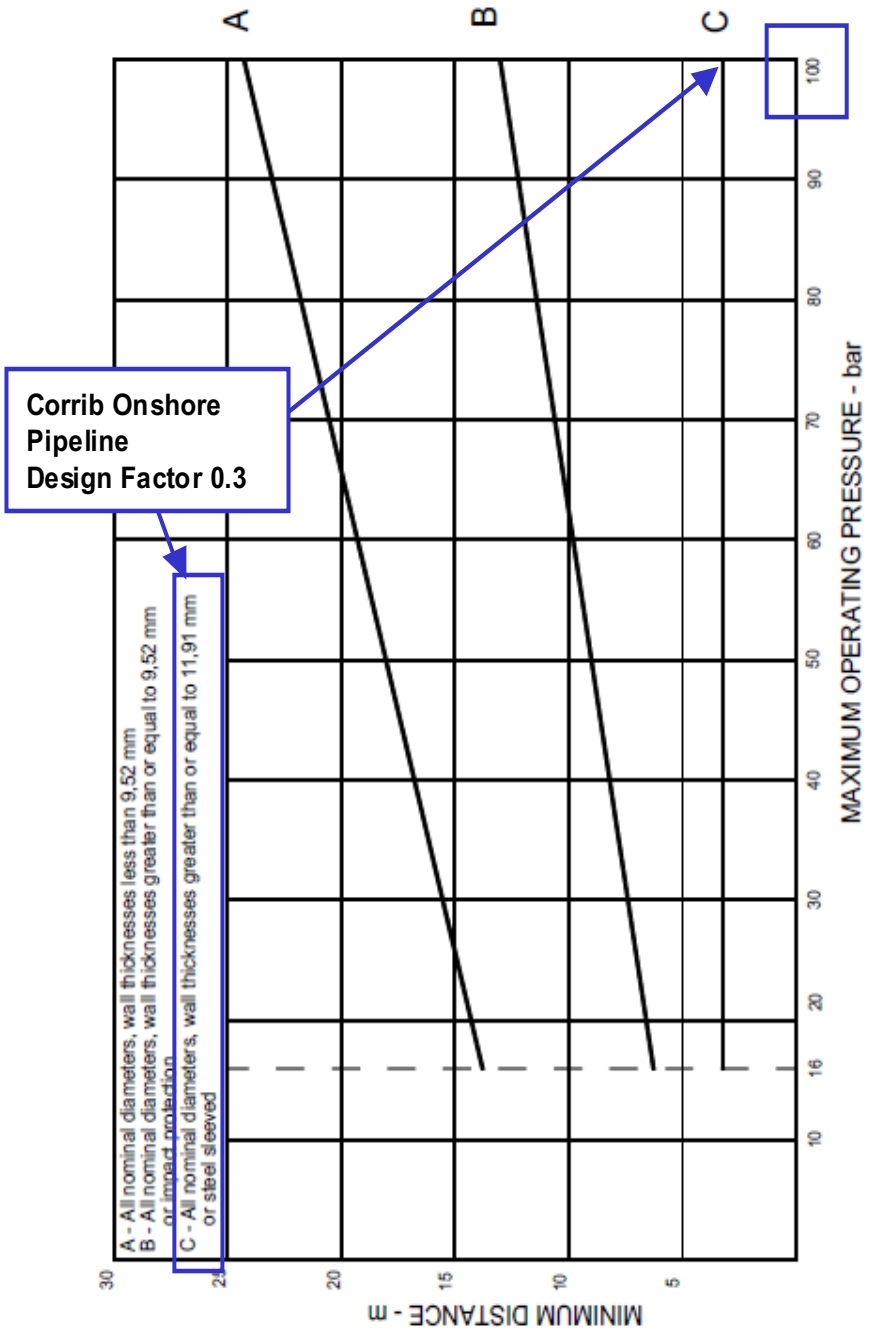


Figure 2 — Minimum distance from normally occupied buildings of pipelines generally designed to operate at a design factor f not exceeding 0,30 or steel sleeved.

[1] Acknowledgements to the National Standards Authority of Ireland for permission to use this Figure.

Figure 4.2: Extract from I.S. 328 for Design Factor exceeding 0.3 but not exceeding 0.72[2]

I.S. 328:2003

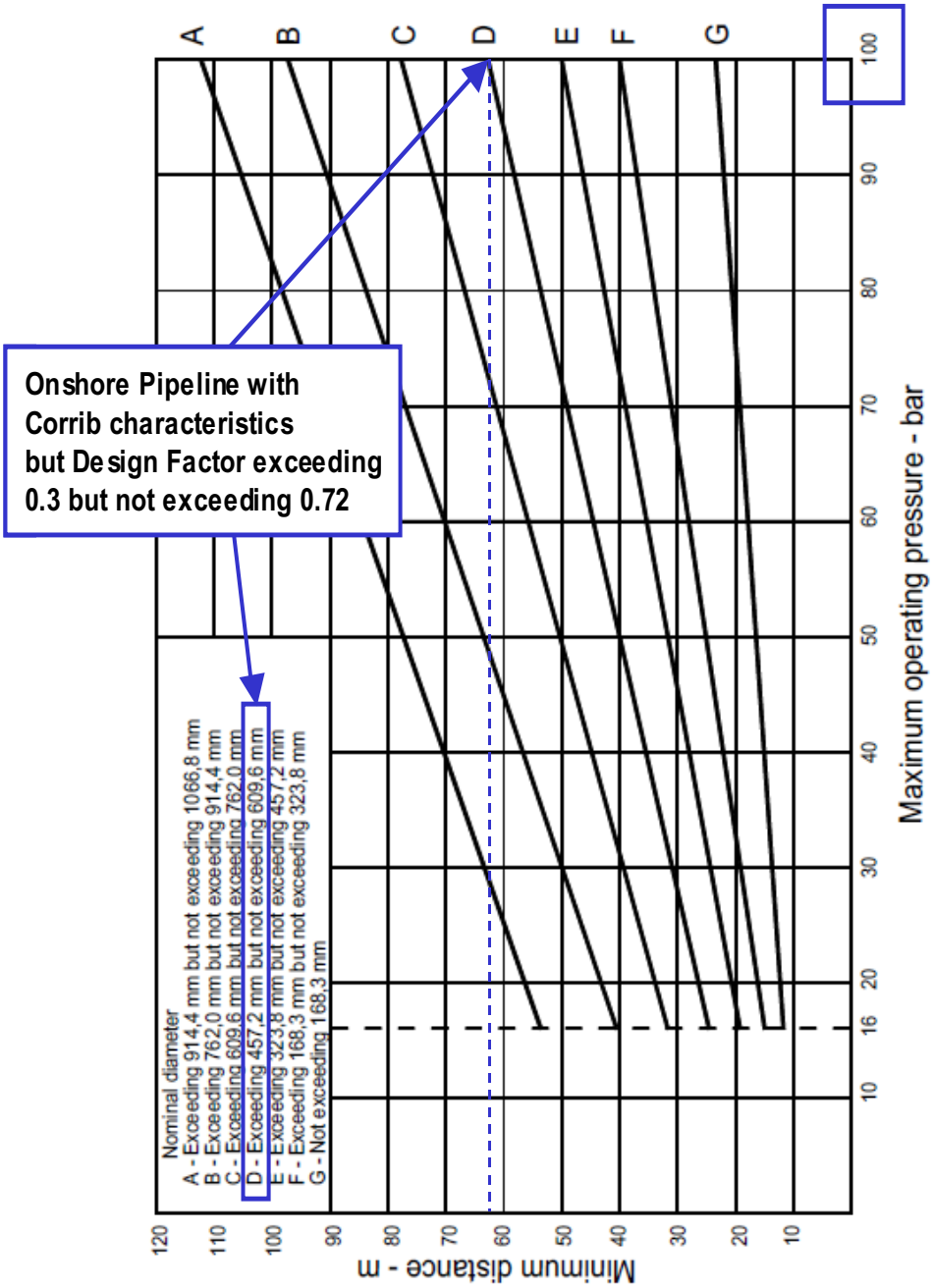


Figure 1 — Minimum distance from normally occupied buildings of pipelines generally designed to operate at a design factor f exceeding 0,30 but not exceeding 0,72.

NOTE Linear extrapolation should be used for higher pressures

A1

[2] Acknowledgements to the National Standards Authority of Ireland for permission to use this Figure.

4.5 ASSESSMENT OF FINAL ROUTE

The final proposed route is then subject to QRA to generate:

- Risk transects along the pipeline length that can be converted to risk contours and compared with proximity to normally occupied buildings criteria

- Societal Risk plots (frequency of n or more casualties) that can be compared with acceptance criteria

And, as specifically requested in An Bord Pleanála's letter of 2nd November 2009, page 3, item (j):

- Inner, Middle and Outer zone contour lines

5 CORRIB PIPELINE COMPLIANCE ASSESSMENT

5.1 HISTORY

For the route first proposed the applicable design code was BS 8010 and the design pressure of 345 barg used as the basis for the design location classification and the consequent selection of Design Factor. The location classification was assessed as Location Class 1 and a Design Factor of 0.72 applied.

Based on their analysis of the above calculations Advantica recommended (see Appendix Q 3.1) that a more conservative approach should be applied as the housing was ribbon type development and had the bay to one side. They recommended a suburban classification that resulted in the pipeline being classified as Class 2, and therefore a Design Factor of 0.3 (design pressure 144 barg).

TAG supported the Advantica recommendations and added the following requirements:

> The primary pipeline design code is hereby designated by TAG to be I.S. EN 14161; however I.S. 328 and BS [now BS PD] 8010 shall apply where they exceed I.S. EN 14161. Shell should submit a Code Compliance document to TAG demonstrating how the existing proposals comply with the new designation.

A Code Compliance Report was then prepared and submitted to TAG. For the design of the pipeline (wall thickness etc) it was not practical to split the series of design calculations over the three Codes thus the compliance report adopted I.S. 328 sections (6.2 Classification of Design Locations, 6.3 Design Factor, 6.4 proximity Requirements, 6.5 Pipe Wall Thickness). This resulted in an I.S. 328 Suburban (S) Location Classification and an assigned Design Factor limit of 0.3.

TAG subsequently accepted this Compliance Report and a copy was included in Appendix Q of the EIS that was originally submitted with this application in 2009 (see Appendix Q3.3).

Thus any new analysis should use I.S. 328 as the basis for any design calculations including design with respect to public safety. However, in the information that follows comparison has also been made with the BS PD 8010 proximity distance formula.

5.2 CURRENT DESIGN COMPLIANCE

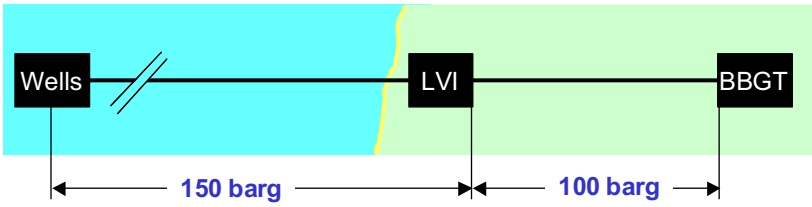
5.2.1 Design Changes

The pipeline diameter and material have not changed (20” pipe, external 508mm, wall thickness 27.1mm, corrosion allowance 1mm, manufacturing tolerance 1mm). The design pressure remains at 345barg offshore – 144 barg onshore.

The current design results in the following key changes:

- Routing beneath Sruwaddacon Bay
- Maximum Allowable Operating Pressures (MAOP) have been established (refer Fig. 5.1)

Figure 5.1: Maximum Allowable Operating Pressures, MAOP



Taking these changes into account and re-visiting the Codes the following is concluded.

5.2.2 Classification of Design Locations

The population density has been re-calculated as Type R (rural areas with a population density not exceeding 2.5 persons per hectare) to take account of the new route and reduction in onshore pipeline MAOP. Refer **Attachment 1A**.

5.3 DESIGN FACTOR

Based on the population density the limiting Design Factor is 0.72, however the 0.3 Design Factor is retained based on the requirements of TAG. A Design Factor of 0.3 and design pressure of 144 barg results in a design wall thickness (I.S. 328, 6.5.1) of 25.1mm (i.e. 27.1 including corrosion and manufacturing allowance).

5.3.1 Building Proximity Distance

5.3.1.1 QRA

I.S. 328 and BS PD 8010 state that the graph (I.S. 328) or formula (BS PD 8010) should be used if a QRA has not been done.

Whilst a QRA has been carried out for the Corrib pipeline the base case predicted individual risk of receiving a dangerous dose for a person standing at the pipeline is 2.9x 10^{-9} per year (i.e. 2.9 chances in every 1,000,000,000 years). Given that this risk is so low the prescribed minimum distances contained in the Codes would be applied.

5.3.1.2 I.S. 328

Application of section 6.4, Proximity Requirements of I.S. 328 for the Corrib pipeline Design Factor less than or equal to 0.3 specifies the use of Figure 4.1 above. Since the design wall thickness is greater than 11.91mm then line C applies thus giving a minimum distance to an occupied building of 3m. It is noted that this is the minimum distance advised by the recommended Codes but, as mentioned above, I.S. 328 is drawn up for treated gas.

For comparison, I.S. 328, Fig. 4.2 above for a pipeline with Corrib characteristics and at MAOP of 100barg but a Design Factor of 0.72 gives a minimum distance to an occupied building of 63m, i.e. the separation distance required would be greater due to the reduction in required pipeline strength (thickness).

5.3.1.3 BS PD 8010

BS PD 8010-1:2004 section 5.5.3.2 refers to IGEM/TD/1. Figure 6 of IGEM/TD/1 also gives a minimum proximity distance of 3m for single-phase natural gas pipelines having a Design Factor that is no greater than 0.3 and a wall thickness of at least 11.91mm.

However if a Design Factor up to 0.72 is again conservatively assumed, and a value of Q, substance factor, of 0.6 taken, then applying the formula:

$$Y=Q\left[\frac{D_o^2}{32{,}000}+\frac{D_o}{160}+11\right]\left[\frac{P}{32}+1.4\right]$$

The results are:

Applying BS PD 8010 Formula with Conservative Design Factor of 0.72		
Maximum Operating Pressure	**Min Building Proximity**	**Nearest building**
100 barg (downstream of LVI)[3]	60.38m	234m
150 barg (upstream of LVI)*	81.23m	

* Note: As stated in the Introduction to this Section, the offshore pipeline falls under the offshore Code

Table 5.1: Application of BS PD8010 Formula

5.3.1.4 Safety Evaluation

The Safety Evaluation requirement has been fulfilled through the preparation of the Qualitative Assessment and QRA, see Appendix Q6.3 and Q6.4 respectively.

[3] Note that the previous design pressure of 144 barg led to a minimum Building Proximity Distance of 78.72m

ATTACHMENT Q6.2A

CLASSIFICATION OF DESIGN LOCATION

A1.1. Introduction

The purpose of this Appendix is to classify the currently proposed pipeline route in terms of Design Location in accordance with I.S. 328.

It is demonstrated that all locations along the modified pipeline route can be classified as Type R areas – Rural area with a population density not exceeding 2.5 persons per hectare.

A1.2. Codes of Practice

A1.2.1.1. Area Density

Area density is a term used to describe and quantify the population density in an area through which a pipeline is routed. Area density calculations are relevant to the classification of Design Locations on pipelines that pass through open or rural areas and through more populated areas including towns and cities. Area density is defined in different ways depending on the Code of Practice consulted. The relevant design codes for the Corrib /Onshore Pipeline are:

- I.S. EN 14161:2003 – Petroleum and Natural Gas Industries – Pipeline Transportation Systems
- I.S. 328, 2003, Edition 3.1, Code of Practice for Gas Transmission Pipelines and Pipeline Installations.
- BS PD 8010-1:2004 Code of Practice – Part 1:Steel Pipelines on Land

In the case of area density calculations, I.S. 328 is most stringent and is therefore applied

A1.2.1.2. I.S. 328

Section 6.2 of I.S. 328 defines the means for calculating population densities and hence classification of areas.

Classification of Design Location is used to determine the selection of the Design Factor (the ratio of hoop stress and specified minimum yield stress). The lower the Design Factor the safer the pipeline. A Design Factor of 0.72 is acceptable where the population density is less than 2.5 persons per hectare.

The area considered in population density calculations is defined as that of a 1.6km length of pipeline in a strip centred on the pipeline and of width 10 times the minimum building proximity distance (determined in accordance with I.S. 328, Section 6.2, Refer Figure 1 and Figure 2).

Population numbers included in density calculations are based on the number of buildings within the defined area that are normally occupied premises including non-residential buildings where people may congregate. Houses are assumed to be occupied by four persons as allowed by the Code.

The population density is thus the defined area divided by the population.

A1.3. Assessment of Currently Proposed Pipeline Route

A1.3.1.1. Modified Pipeline Route

Figure A1.3.1 below shows the currently proposed pipeline route

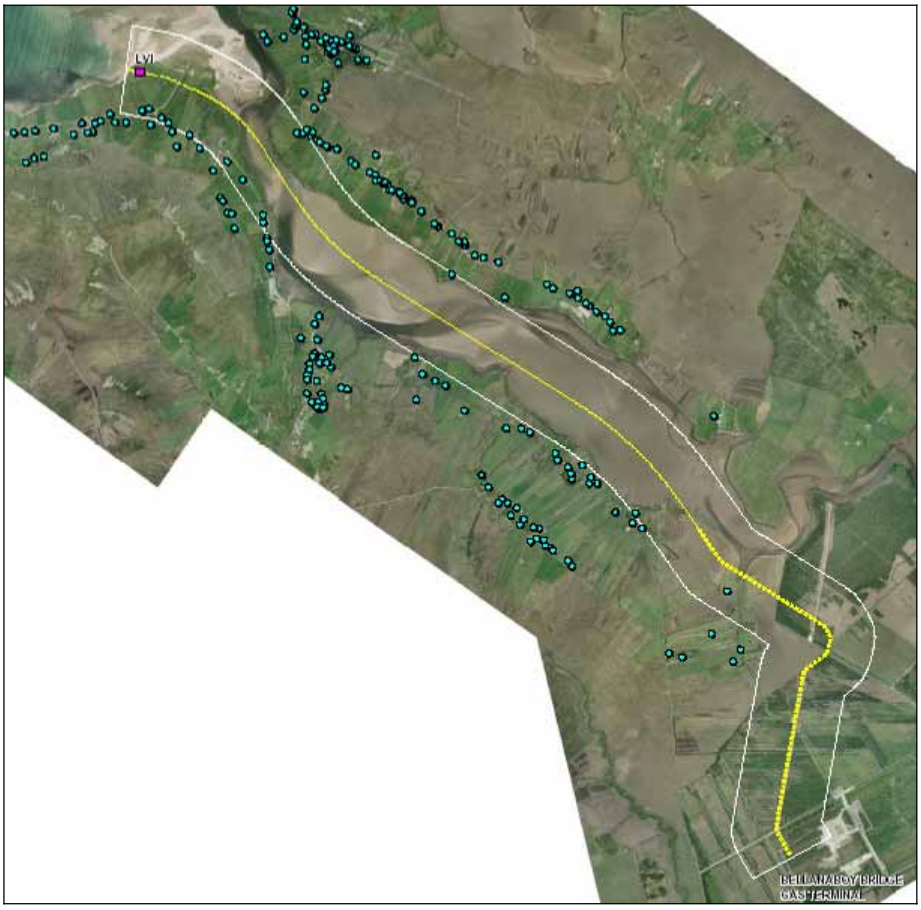


Figure A1.3.1: Proposed Pipeline Route with Houses Identified (blue dots)

Population densities along the route have been assessed in the following sections using Aerial photography and *MapInfo GIS* Software (Version 5.5 PC) based software, the An Post GeoDirectory and site survey information.

A1.4. Population Density for 100barg MAOP

The Maximum Allowable Operating Pressure of the pipeline downstream of the LVI is 100barg.

MAOP	Design Factor	I.S. 328	Building Proximity Distance
100 barg	0.72	Fig. 1 applies	63m
	0.30	Fig 2 applies	3m

Table A1.4.1: BPD's based on I.S. 328 Graphs

Although the Design Factor for the Corrib pipeline is 0.3 the following population density assessment is carried out conservatively based on 0.72.

A 'window' 1.6km in length and 630m in width (10 times the minimum building proximity distance at 100 barg) is moved along the pipeline route, centred on the pipeline's centerline. The area of greatest population density is located at the point where this 'window' encompasses the greatest number of houses.

The most densely populated area is shown on Figure A1.4.1 below, with the 'window' used for assessing the population density also indicated.

For the MAOP of 100 barg there are 11 dwellings within the window (the threshold level is 64 houses). Under the Code, this means the population density is 44 people in an area of 102.3 ha and 0.43 people per ha. This area is considered a Type R / low density area.

The area of the window is 102.3 hectares. Within this area there are 11 dwellings, which, at 4 persons per dwelling, gives 44 persons, a population density of 0.43 persons per hectare. Under the Code the Type R / low-density area covers a population density from zero to 2.5 persons per hectare which equates to a threshold level of 64 dwellings. The appropriate Area type for the Corrib pipeline, even when adopting the conservative 0.72 Design Factor, is thus Type R.

Figure A1.4.1: Proposed Route Centre-Line with Distance of 315m Either Side (MAOP of 100bar)

SHELL E&P IRELAND LIMITED

CORRIB GAS FIELD DEVELOPMENT PROJECT

Corrib
natural gas

Q6.3 - QUALITATIVE RISK ASSESSMENT

DOCUMENT No: COR-14-SH-0056

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1 INTRODUCTION

Qualitative risk assessment allows for assessment of risks and identification of risk reduction measures for a project independently of detailed numerical calculations and data. This document, Appendix Q6.3 to the EIS, presents the qualitative risk assessment for the Corrib pipeline facilities.

It introduces the qualitative risk assessment process adopted for the Corrib pipeline facilities and goes on to describe how these assessments have been applied during the design of the facilities and will continue to be applied through their operation.

One output from the qualitative risk assessment process is an inventory of all the hazards associated with operation of the Corrib pipeline facilities (the 'Risk Register') which is also presented in this section. The major risks arising from operation of the pipeline are described in detail, together with the measures in place to mitigate the risks.

The major risks present for Corrib pipeline facilities have been assessed using bowtie analysis, which is an internationally accepted form of qualitative risk assessment; this section describes the bowtie method and how it has been applied for the Corrib pipeline.

A qualitative risk assessment process requires demonstration that the risks from major risks have been reduced to a level that is As Low As Reasonably Practicable (ALARP); this section explains what is meant by ALARP and provides such a demonstration.

The document concludes that all risks associated with the Corrib pipeline have been identified and assessed, and are effectively managed such that no further risk reduction measures could practicably be implemented.

This section was prepared by Risktec Solutions Ltd.

Throughout this section, the following definitions (taken from International Standard ISO17776 - Guidelines of Tools and Techniques for Hazard Identification and Risk Assessment) have been adopted**:**

Hazard - potential source of harm.

Risk - combination of the probability of an event and the consequences of that event.

1.1 OBJECTIVES OF THE QUALITATIVE RISK ASSESSMENT

The objectives of a qualitative risk assessment are to ensure that all the risks are known and assessed, are effectively managed and that suitable and sufficient control measures are in place such that the risks are reduced to ALARP levels. Essentially this can be simplified to the following questions:

Figure 1.1: Qualitative Risk Assessment Process

In its letter of 2nd November 2009 (Page 3 (e)), An Bord Pleanála requested that SEPIL "*Provide a qualitative assessment of risk. This should be prepared for the different operating conditions and different locations along the pipeline route and should provide a comprehensive assessment to include those events that cannot be easily defined mathematically".*

This Appendix Q6.3 describes the qualitative risk assessments that have been undertaken by SEPIL and therefore addresses this specific An Bord Pleanála request.

In addition to this, it should also be noted that Shell's own internal standards require that every Upstream International (UI) Company is required to conduct a qualitative health, safety and environmental (HSE) risk assessment which feeds into a documented demonstration that the major risks are being managed effectively and have been reduced to ALARP levels.

1.2 SCOPE

The scope of the qualitative risk assessments reported here includes those elements of the Corrib facilities directly associated with the pipeline:

- Offshore seabed installations (subsea wells, wellheads, flexible flowlines and manifold) in so far as they are relevant to the operation and safety of the onshore pipeline;
- Offshore gas pipeline (between the manifold and landfall at Glengad);
- Landfall Valve Installation (LVI) at Glengad;
- Onshore gas pipeline between landfall and Bellanaboy Bridge Gas Terminal; and
- The control umbilical from the Gas Terminal to the wells.

Separate risk assessments have been undertaken for the Gas Terminal, which is outside the scope of this document.

This document focuses on the risks associated with the Corrib pipeline design and operation. Construction risks are covered in Chapter 5 and Appendix M of the EIS.

1.3 COMPLIANCE WITH CODES AND LEGISLATION FOR QUALITATIVE RISK ASSESSMENT

The Corrib pipeline has been designed to comply with a number of codes of practice, as demonstrated in Appendix Q3 of the EIS.

This section considers specifically the requirement for qualitative risk assessment as specified in the codes and demonstrates that the qualitative risk assessment process applied to the Corrib pipeline meets the principles identified in the following codes (as summarised in Table 1.1).

1.3.1 I.S. EN 14161:2004 Petroleum and Natural Gas Industries - Pipeline Transportation Systems (ISO 13623:2000 Modified)

I.S. EN 14161 requires that a 'Safety Evaluation' is performed for all Category E fluids (Category E fluids include unprocessed / untreated gas, as transported by the Corrib pipeline).

I.S. EN 14161 states that the safety evaluation can be qualitative or quantitative and includes the standard stages of hazard identification; hazard estimation; consideration of risk control measures; and evaluation of the acceptability of the results. In other words 'safety evaluation' is just another term for risk assessment.

1.3.2 I.S. 328:2003 Code of Practice for Gas Transmission Pipelines and Pipeline Installations (Edition 3.1)

I.S. 328 predominantly uses prescribed separation distances based on pipeline operating pressure, wall thickness and population density rather than a risk-based approach to pipeline safety. However it refers to the use of Quantitative Risk Assessment (QRA) as a means of justifying pipeline designs where it is impractical to comply with the prescribed distances.

I.S. 328 does not explicitly refer to the use of qualitative risk assessment, although it references Australian Standard AS 2885.1-2007 Pipelines - Gas and Liquid Petroleum - Design and Construction which provides guidance on qualitative risk assessment.

1.3.3 BS PD 8010:2004 Code of Practice for Pipelines

BS PD 8010 does not explicitly require the use of risk assessment but gives guidance on how a risk assessment should be conducted *"where a safety evaluation is required"*. This guidance is more focussed towards numerical risk assessment rather than qualitative risk assessment, although the overall process presented is largely identical to that of I.S. EN 14161.

1.3.4 Petroleum (Exploration and Extraction) Safety Act

The recently passed Petroleum (Exploration and Extraction) Safety Act (No. 4/2010) requires petroleum undertakings to implement a Safety Management System (SMS) and prepare a Safety Case (see Section 2.1). As part of this Safety Case work, the undertaking must demonstrate that it has the ability to properly assess and effectively control risks i.e. risk assessment is a principal requirement of the Petroleum (Exploration and Extraction) Safety Act.

In anticipation of Petroleum (Exploration and Extraction) Safety Act, SEPIL has ensured that its Safety Case, including risk assessments, (currently in preparation) aligns with the published guidance, in preparation for submission of the Safety Case to the Commission for Energy Regulation (CER).

Table 1.1: Compliance of Corrib Qualitative Risk Assessment with Code Requirements

I.S. EN 14161 Safety Evaluation	AS 2885.1-2007 Qualitative Risk Assessment (referenced by I.S. 328)	BS PD 8010 Safety Evaluation	Corrib Compliance
Scope definition		Define extent of assessment	See Section 1.2
Hazard identification and initial evaluation	General	Identify credible failure modes	Captured in the Corrib Risk Register. See Section 3
Hazard estimation (qualitative or quantitative)	Consequence Analysis, Frequency Analysis, Risk Ranking (qualitative)	Evaluate failure frequencies, consequences, evaluate risk levels and screen hazards (quantitative)	Qualitative – Risk Register (Section 3), bowtie analyses (Section 5) Quantitative – QRA (see Appendix Q6.4)

I.S. EN 14161 Safety Evaluation	AS 2885.1-2007 Qualitative Risk Assessment (referenced by I.S. 328)	BS PD 8010 Safety Evaluation	Corrib Compliance
Measures	Risk Treatment	Implement risk measures as necessary	The qualitative and quantitative risk assessments described in Section 3, Section 5 and Appendix Q6.4 take account of preventive and mitigation controls in place. Additional risk reduction measures have been considered as part of the assessment process. Actions have been taken to reduce risk and Section 6 provides a documented record of that process.
Review results / acceptability	ALARP	Assess acceptability / tolerability of risk levels	See demonstration that risks are ALARP (Section 6)
Documentation		Document the analysis	Qualitative risk assessment process and findings are documented in this Appendix Q6.3. Entirety of risk assessments, for whole Corrib facilities including gas terminal, is documented in Corrib HSE Case.

1.4 THE QUALITATIVE RISK ASSESSMENT PROCESS

As noted above, the objectives of a qualitative risk assessment are to ensure that all the risks are known and assessed, are effectively managed and that suitable and sufficient control measures are in place such that no further risk reduction measures could be practicably implemented. To achieve these objectives, the following process has been used for the assessment of the Corrib pipeline facilities:

1. **Hazard Identification** - the hazards (i.e. those attributes of the Corrib pipeline with the potential to cause harm) have been systematically identified (see Section 3).

2. **Risk Assessment** - each event scenario identified has been qualitatively assessed for its likelihood and severity of its consequences using a risk assessment matrix (see Section 3).

The results of these two stages are recorded in the Risk Register (see Section 3).

3. **Risk Control** - suitable and sufficient controls for each scenario have been identified proportional to the scenario's level of risk and are recorded in the risk register. Scenarios with the potential to result in major consequences (see Section 4) have been subject to detailed analysis using 'bowties' (see Section 5) to ensure that an appropriate level of control is, and will be, maintained.

4. **Risk Reduction** - using the bowtie diagrams, the major risks have been further challenged to consider whether any additional risk reduction measures could be identified, and if yes, whether they are practicable to be implemented (see Section 6).

The risk management process summarised above and described in this document has been supported by more than 60 individual risk assessment studies and reviews for the Corrib pipeline conducted throughout the lifetime of the project (see Section 2).

1.5 INTERFACE WITH QUANTITATIVE RISK ASSESSMENT (QRA)

The major risks associated with the Corrib pipeline have also been subject to QRA, which is described in Appendix Q6.4. QRA provides a numerical estimate of the risk, whereas qualitative risk assessment presents the risk in non-numerical terms (e.g. such as 'high', 'medium' and 'low'). Nevertheless, there is a link between the two forms of assessment and qualitative risk assessment provides input into the QRA.

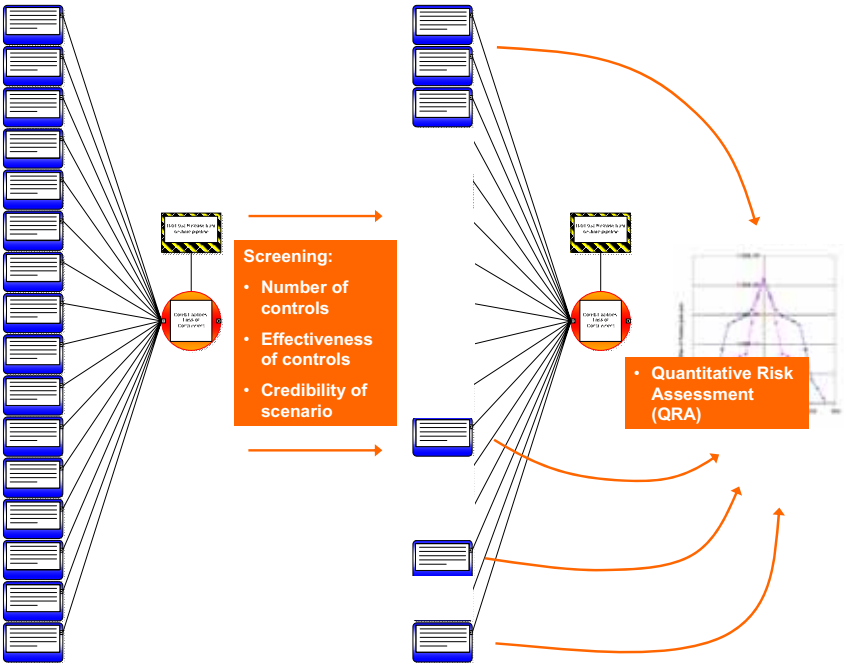
For the Corrib pipeline risk assessments, the specialist consultancy responsible for the QRA participated in qualitative risk assessment (bowtie) workshops and the QRA reports were reviewed to

provide input to the bowtie workshop. The aim was to ensure consistency between, and completeness of, both types of assessment.

The detailed qualitative risk assessment captured in the bowtie analysis (as described in Section 5) considers the effectiveness of each control measure and the potential ways in which it can fail. This allowed the generic, historical industry data used for the QRA leak frequency and failure probability values to be adjusted where possible (as described in Appendix Q6.4) to better reflect the actual conditions for the Corrib onshore pipeline.

The qualitative bowtie analysis considers all mechanisms which were suggested by the bowtie workshop team as might possibly be capable of leading to a failure with major consequences, however unlikely. For example, for the release of gas from the onshore pipeline, thirty two potential causes of pipeline failure were suggested. Each of these causes was then subject to scrutiny during the bowtie analysis workshops whereby the team identified and evaluated all the controls in place to prevent each scenario from occurring. On the basis of this information, the team made a judgement as to whether each scenario could result in a gas release or whether, given the controls in place, the scenario was no longer credible or could only occur with an extremely low frequency (Figure 1.2). This judgement was used by the QRA consultancy, as described in Appendix Q6.4, to screen out those causes which did not require further consideration in the QRA.

Figure 1.2: Relationship Between Qualitative Risk Assessment and QRA



1.6 STRUCTURE OF THIS DOCUMENT

This Appendix Q6.3 of the Onshore Pipeline EIS summarises the qualitative risk assessments that have been carried out since the very early stages of the project and describes in detail those studies which form the core of the qualitative risk assessment work.

Individual studies may be completed but qualitative risk assessment is an ongoing process and further qualitative risk assessments continue to be carried out. This document concludes by setting out how SEPIL anticipates the qualitative risk assessment results to be embodied into future operation of the pipeline.

The remainder of this document is structured as follows:

- **Section 2** provides an overview of the various types of qualitative risk assessment studies which have been carried out to date for the Corrib pipeline;

- **Section 3** describes the hazard identification process undertaken for the Corrib facilities and includes an inventory of all the hazards identified and evaluated (the Risk Register);

- **Section 4** defines and summarises the major risks associated with the pipeline;

- **Section 5** describes in detail the qualitative risk assessment of the major risk scenarios, which has been carried out using 'bowtie analysis';

- **Section 6** demonstrates that the risks associated with the Corrib pipeline have been reduced to ALARP levels;

- **Section 7** outlines how the results of the qualitative risk assessments conducted so far will be carried forward and how risks will continue to be managed during operation of the pipeline; and

- **Section 8** presents the conclusions of this qualitative risk assessment Section Q6.3.

2 QUALITATIVE RISK ASSESSMENT SINCE THE START OF THE PROJECT

More than 60 individual risk assessment reviews and workshops have been carried out so far during the design stages of the Corrib project, including:

- Hazard IDentification (HAZID) reviews;
- Hazard and Operability (HAZOP) studies;
- Operability reviews;
- Bowtie analysis workshops; and
- Reliability studies.

HAZID: Several HAZID workshops have been carried out for various parts of the Corrib facilities, the earliest being in 2000. HAZID reviews can be applied to equipment or to planned activities and use checklists of typical hazards to systematically identify whether those hazards are relevant to the system or activity being reviewed. The HAZID is carried out by a team of people with relevant experience. Where significant risks are identified, the review team makes recommendations or initiates further assessment to ensure that solutions are included in the system's design or planned activity.

HAZOP: These have been carried out to assess the adequacy and operability of the pipeline process control and safeguarding. HAZOP workshops have been held during the Corrib facilities' design stages, including coarse HAZOPs of early designs and detailed HAZOPs once designs are more defined. HAZOP studies are also team based and the outputs are incorporated into the design and operations plans and procedures.

Operability Reviews: These are conducted to confirm that the as-designed system is suitable to safely deliver its objectives without causing operational problems. The review involves both the project design team and operations team to make sure that the interface between design and operations is addressed. Operability review workshops were held in 2007 for the Corrib offshore and onshore pipelines. Outputs from the workshops are incorporated into the design and operations plans and procedures.

Bowtie Analysis: This is a specific form of qualitative risk assessment widely used in a range of industries and standards worldwide. The workshop team members evaluate the risk in terms of its causes, potential consequences and the controls in place to prevent the event from occurring or to reduce the extent of the consequences. The output is recorded in a 'bowtie diagram'. Several bowtie workshops have been undertaken for the Corrib facilities. Recommendations from the Corrib bowtie workshops have been incorporated into the system design, subject to further assessment if necessary, or carried forward for inclusion in operating procedures. The bowtie analysis process and the Corrib bowtie workshops are described in more detail in Section 5.

Reliability Studies: A number of reliability studies have been carried out during the course of the Corrib project and the recommendations incorporated into the design. Reliability studies involve application of qualitative risk assessment and include Failure Modes and Effects Analyses and Safety Integrity Level reviews focussing on a specific piece of equipment or control system. The output from the study are incorporated into the design to improve the equipment or system reliability.

In 2003 the main risk assessment studies which had been carried out to date, by various teams responsible for different elements of the system design and construction, were brought together in the form of Formal Safety Assessments. Similarly, the Corrib HSE Case which is currently being developed (see Section 2.1) describes the findings of the various Corrib risk assessments.

2.1 THE HSE CASE

A Health, Safety and Environment (HSE) Case is a formal, detailed document which demonstrates that controls are in place such that risks to people and the environment are reduced to ALARP levels. A Safety Case is a similar document but is concerned purely with the risk to people and not to the environment.

For the Corrib project, Shell standards independently require development of an HSE Case, while the recently enacted Petroleum (Exploration and Extraction) Safety Act requires submission of a Safety Case for approval to the CER.

SEPIL has therefore taken the approach of developing a Shell-compliant Corrib HSE Case and, as far as possible, proactively aligning the case with the Petroleum (Exploration and Extraction) Safety Act requirements. It is anticipated that a Petroleum (Exploration and Extraction) Safety Act-compliant Corrib Safety Case, based largely on the HSE Case, will be submitted to CER should permission be granted.

The Corrib HSE Case development process started in 2006 and the case has been subject to several updates during the design phase involving teams of personnel across Corrib project design, HSE, operations and maintenance. It is a 'work in progress' and is a live document which will continue to be used and updated throughout operations.

The HSE Case structure is summarised in Table 2.1.

Table 2.1: HSE Case Structure

1. Introduction	2. Facility & Operation Description	3. People & HSE MS	4. HEMP	5. Risk Control	6. Action Plan
▪ Summary of HSE Case objectives & scope ▪ Outline of major risks, bowtie analysis and QRA ▪ Overview of ALARP demonstration ▪ Arrangements for document control, review & update ▪ Statement of fitness – written approval that the HSE Case meets Shell standards ▪ Regulatory checklist – demonstrating compliance with Petroleum (Exploration and Extraction) Safety Act ▪ Abbreviations ▪ Holds	▪ Corrib development history ▪ Asset description including – safety systems – locality – environment	▪ HSE Policy and objectives ▪ Corrib organisation and manning ▪ HSE competencies & training ▪ Workforce involvement (in the HSE Case) ▪ HSE critical activities ▪ Processes and standards ▪ Operating, maintenance and security procedures ▪ Document control procedures ▪ Monitoring legal compliance ▪ Planning work activities, planning for emergencies ▪ Management of change ▪ Monitoring, reporting, audit and review arrangements	▪ Introduction to HEMP and ALARP ▪ Hazards and Effects Register ▪ Summary of formal risk assessments and results including: – Bowtie assessments – Quantitative Risk Assessment (QRA) ▪ Summary of major risks – Causes – Consequences – Controls – Additional risk reduction measures ▪ Risk reduction philosophies ▪ ALARP demonstration	▪ HSE critical elements and verification scheme ▪ Manual of Permitted Operations (MOPO) ▪ Operating and maintenance procedures ▪ Permit to Work (PTW) / Integrated Safe Systems of Work (ISSOW) ▪ Job Safety Assessment (JSA) ▪ Asset integrity management ▪ Change control ▪ Maintenance, testing and inspection ▪ Emergency response	▪ Plan for further development of the HSE Case ▪ Actions identified during preparation of the HSE Case

The Corrib HSE Case has been developed in order to demonstrate that there has been, and continues to be, systematic hazard identification and risk assessment and that risks are actively and systematically reduced to ALARP levels. Qualitative risk assessment forms a core component of the HSE Case document and is described in detail in Part 4 of the HSE Case.

This Appendix Q6.3 of the EIS describes the qualitative risk assessment carried out for the Corrib pipeline and therefore draws heavily on information currently contained in Part 4 of the Corrib HSE Case.

3 CORRIB RISK REGISTER

The Risk Register is a key part of the qualitative risk assessment process, providing a Quality Record and proving that a systematic process was followed to consider and document all hazards associated with operation of the facilities, the risk levels associated with each hazard and the controls in place to manage the risk.

A Corrib Risk Register was first produced in 2002, compiled from the various design HAZID workshops, and has subsequently been further developed and maintained, in particular at workshops in 2005 and 2008.

The current Risk Register and the background to its development are presented in Attachment Q6.3A at the end of this Section Q6.3.

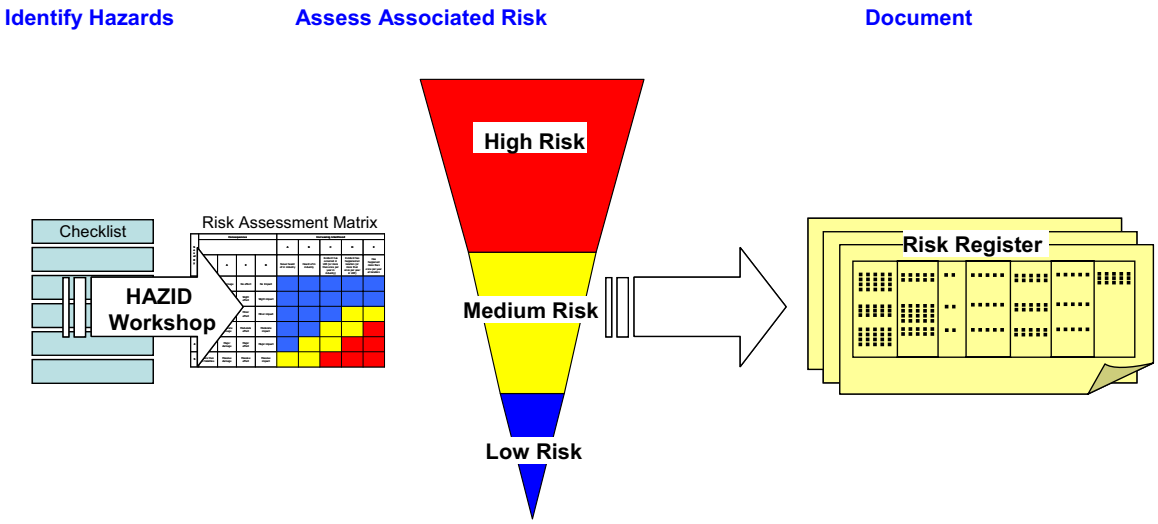
The Corrib Risk Register is subject to periodic review and update as part of the review and update process for the HSE Case (see Section 2.1).

The process for developing the risk register is illustrated in Figure 3.1. The potential risks associated with each relevant scenario are evaluated using a Risk Assessment Matrix (see Attachment Q6.3A at the end of this document). This segregates the risks into high, medium and low categories so that the highest potential risks can be subject to more detailed assessment and an appropriate level of control (Figure 3.2). Lower risks are still controlled, by implementation of the Corrib Safety Management System (see Section 5.2.5), as documented in the Risk Register.

Note that the risk is assessed assuming control of the hazard has been lost i.e. no credit is assumed for correct functioning of the controls planned to be in place. This means that the risk value recorded in the risk register is actually the *potential risk* rather than the residual risk which remains once the controls have been implemented and are working correctly.

The reason for assessing the risk in this way is to highlight which risks have the inherent potential to be high, so that commensurate levels of control can be identified, implemented and enforced. The higher the level of potential risk, the greater the level of control needed.

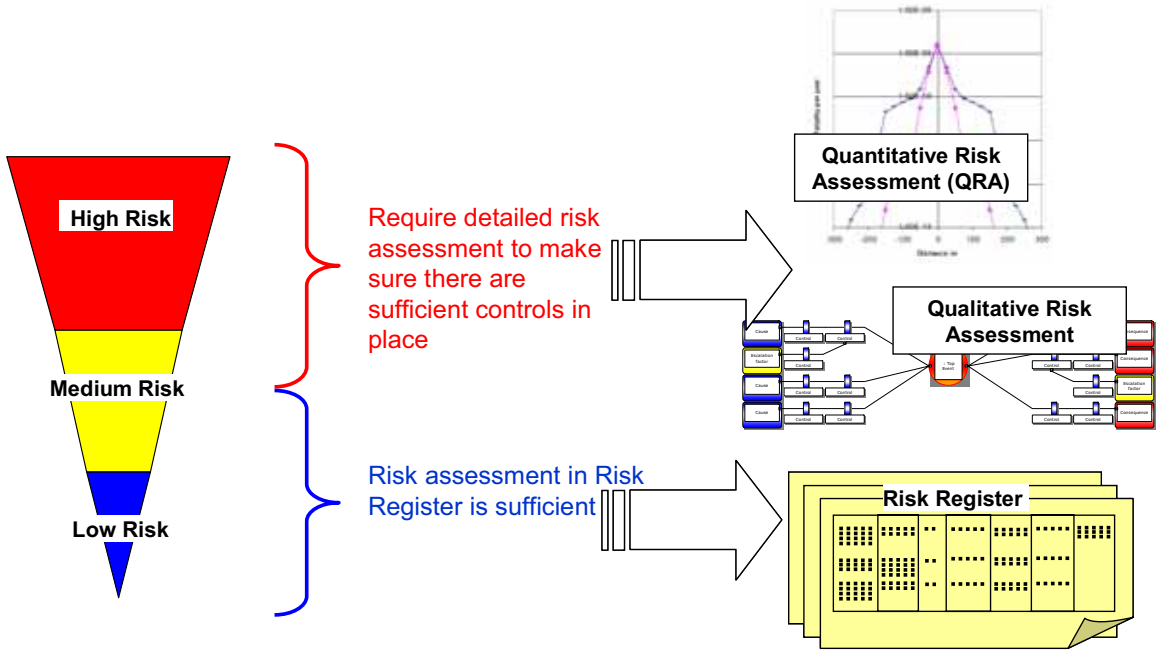
Figure 3.1: Risk Register Development



'Major risks' are defined as those classified as high risk on the Risk Assessment Matrix, or those with high consequence regardless of likelihood.

The Corrib HAZID workshop identified four major risks associated with operation of the Corrib pipeline facilities. These are itemised in the Corrib Risk Register and are described further in Section 4 below. They were carried forward for more detailed qualitative risk assessment as explained in Section 5.

Figure 3.2: Level of Risk Assessment Commensurate with Level of Risk



4 CORRIB PIPELINE MAJOR RISK SCENARIOS

The definition of a major risk is given in Section 3 above and in Attachment Q6.3A at the end of this Section Q6.3. This section describes the major risk scenarios identified for the Corrib pipeline operations and the key measures in place to manage those risks.

The major risks are also described briefly in the Corrib Risk Register (see Attachment Q6.3A), and have been subject to detailed qualitative risk assessment in the major risk bowties (see Section 5).

Four major risks associated with the Corrib pipeline facilities have been identified:

- Hydrocarbon release from subsea facilities (wells, flexible flowlines, manifold or offshore pipeline);
- Hydrocarbon release from LVI;
- Hydrocarbon release from onshore pipeline; and
- Dropped objects at LVI*.

* see note in Section 4.2.

Failure of the control umbilical was not, in itself, identified during the HAZID as a major risk. However, it was subject to detailed assessment as the umbilical is recognised as being important to pipeline integrity and process control, and also in line with the request of An Bord Pleanála (page 3, item (f) of its letter of 2nd November) which required that SEPIL *"submit an analysis of the condition where the umbilical becomes severed and the control of valves at the wellhead and subsea manifold is lost".*

Thus, whilst failure of the umbilical would not, in itself, lead to a major accident, it is nevertheless subject to detailed qualitative risk assessment:

- Umbilical failure

4.1 RELEASE FROM WELLS, FLEXIBLE LINES AND OFFSHORE PIPELINE

The safety risk of an unignited release happening was judged by the HAZID team to be medium. If the released vapour encountered an ignition source, the team judged that the risk to people was still medium but was increased from B4 to B5 (see Attachment Q6.3A). The B5 risk rating means that the scenario was judged to have the potential to result in multiple fatalities, albeit at a very low frequency of occurrence, so this scenario was subject to detailed risk assessment in the form of bowtie analysis (see Section 5).

The potential causes of a release from the subsea system include:

- corrosion;
- erosion;
- fatigue / fracture / material degradation;
- high or low pressures or temperatures inside the system;
- hydrate formation;
- human error during design, manufacturing, construction, installation or operation / maintenance;
- accidental impact (e.g. dropped object, anchor snagging);
- intentional damage; and
- ground instability (e.g. seabed landslide, scouring / subsidence of the seabed, seismic event).

The bowtie for this scenario illustrates the numerous controls in place to prevent these threats from leading to a hydrocarbon release. Particular preventive measures of note include:

- design takes account of corrosion and erosion potential associated with Corrib gas composition which reflects the wet gas nature and other operating conditions (e.g. pipeline wall thickness, corrosion allowance, appropriate material selection, cathodic protection, real-time corrosion monitoring);
- continuous injection of methanol and corrosion inhibitor;
- design for pressure / temperature extremes plus safety margin, with operational monitoring of pressure and temperature and controlled rate of re-pressurisation, in line with start-up procedures, to maintain temperature above minimum allowable value;
- overpressure protection systems linked to subsea valves offshore and LVI valves onshore;
- design, manufacturing and construction reviews, Quality Assurance/Quality Control (QA/QC) procedures, design assurance process, acceptance tests and independent 3rd party audits and inspections;
- robust design with well / manifold protective covers and pipeline concrete coated / buried for first 12km from shore; and
- subsea inspections and pipeline pre- and post-lay surveys.

Should the preventive measures fail and one of the potential causes result in a hydrocarbon release, the outcome could possibly take the form of:

- an unignited, relatively small leak of hydrocarbons;
- an unignited large hydrocarbon release or rupture; and / or
- an ignited release with associated jet / sea surface pool fire effects.

The bowtie analysis considered the effects of a release located out to sea and also a release from the subsea pipeline on approach to the landfall.

The controls which will mitigate the effects and help recover the situation are illustrated on the right side of the bowtie and include:

- process monitoring and leak detection systems;
- terminal control room staffed 24 hours per day, 7 days per week;
- isolation valves (three in series on each wellhead and at manifold); and
- emergency response plans and training, including liaison with emergency services.

4.2 RELEASE FROM LANDFALL VALVE INSTALLATION (LVI)

The HAZID workshop determined that the safety risk to people from an unignited release from the LVI was low. However, for an ignited gas jet fire the risk to people was rated potentially high and hence this scenario was subject to detailed risk assessment as described in Section 5.

The HAZID team identified a major risk of hydrocarbon release from either the LVI or the onshore pipeline. Early bowtie workshops assessed these scenarios in a single bowtie and subsequently they have been separated into two, although there remains significant commonality in terms of potential threats and control measures.

The potential causes of a release from the LVI include:

- corrosion;
- erosion;
- low temperature (from de- or re-pressurisation) resulting in brittle failure or hydrate formation;
- fatigue / fracture / stress cracking;
- human error during design, manufacturing, construction, installation or operation / maintenance;
- fire at the LVI;
- dropped object impact*;
- ground instability (e.g. cliff erosion, landslide, seismic event);
- intentional damage (as specifically referenced to by An Bord Pleanála in its letter of 2nd November 2009); and
- extreme weather (e.g. flooding, lightning strike).

* dropped object impact was identified during the HAZID workshop as a major risk in its own right, and is assessed for both the LVI and the gas terminal in a separate bowtie in the Corrib HSE Case. For the purposes of this Section Q6.3, dropped object at the LVI is assessed as part of the bowtie for Hydrocarbon Release from the LVI.

The bowtie for this scenario illustrates the controls in place to prevent these causes from resulting in a hydrocarbon release. Key preventive measures include:

- design takes account of corrosion, stress cracking and erosion potential (e.g. corrosion allowance, appropriate material selection, stresses, cathodic protection);
- continuous injection of methanol and corrosion inhibitor;
- design for pressure / temperature extremes plus safety margin, with operational monitoring of pressure and temperature and controlled rate of re-pressurisation, in line with start-up procedures, to maintain temperature above minimum allowable value;
- design, manufacturing and construction reviews, QA/QC procedures, design assurance process, acceptance tests and independent 3rd party audits and inspections;
- housekeeping and Integrated Safe Systems Of Work (ISSOW) controls on hot work, lifting activities, etc;
- regular inspections of equipment / condition; and
- security measures (e.g. fencing, locked equipment cages, CCTV, intruder detection, lighting).

Should the preventive measures fail and one of the potential causes result in a hydrocarbon release, the consequences may possibly include:

- an unignited, relatively small leak of hydrocarbons;
- an unignited large hydrocarbon release or rupture; and / or
- an ignited release with associated fire effects.

The controls which will mitigate the effects of these consequences are shown on the right side of the bowtie and include:

- process monitoring and leak detection systems to identify leaks and enable shut-in and prevention of large releases;
- isolation valves (two in series at the LVI) enable shutdown of pipeline to prevent large releases and repair leak;
- control of ignition sources (hazardous area classification, ISSOW for hot work), fire and blast rating of instrument cabins;
- drainage and spill containment systems; and
- emergency response plans and training, including support from emergency services.

4.3 RELEASE FROM ONSHORE PIPELINE

The HAZID team determined that the risk to people from an unignited release from the onshore pipeline was low. For an ignited gas release the risk to people was rated high and so was subject to detailed qualitative risk assessment.

As explained in Section 4.2, early bowtie workshops assessed this scenario in a single bowtie together with the scenario of hydrocarbon release at the LVI but, for improved clarity, the December 2009 / January 2010 workshops created a separate bowtie for hydrocarbon releases from the onshore pipeline.

The potential causes of a release from the onshore pipeline include:

- corrosion;
- erosion;
- low temperature (from de- or re-pressurisation) resulting in brittle failure or hydrate formation and blockage;
- overpressurisation;
- fire at terminal threatens pipeline;

- fatigue;
- human error during design, manufacturing, construction, installation or operation / maintenance;
- accidental impact (e.g. during excavation work, or from boats where pipeline runs beneath water);
- intentional damage;
- ground instability where pipeline runs on land (e.g. peat slide, landslide, seismic event, settlement of stone road above pipeline, settlement at public road / pipeline crossing);
- wash out / erosion of river bed where pipeline runs beneath river crossings; and
- extreme weather (e.g. flooding / wash out of land around pipeline, lightning strike).

The controls in place to prevent these causes from resulting in a hydrocarbon release are shown on the left side of the bowtie diagram. Preventive measures of particular note include:

- design takes account of corrosion and erosion potential (e.g. wall thickness, corrosion allowance, appropriate material selection, cathodic protection, real-time corrosion monitoring offshore and at terminal end of pipeline);
- continuous injection of methanol and corrosion inhibitor;
- design for pressure / temperature extremes plus safety margin, with operational monitoring of pressure and temperature and controlled rate of re-pressurisation, in line with start-up procedures, to maintain temperature above minimum allowable value;
- overpressure protection systems and LVI maintaining Maximum Allowable Operating Pressure (MAOP) of 100barg;
- passive fire protection of above ground section of pipeline at terminal;
- design, manufacturing and construction reviews, QA/QC procedures, design assurance process, acceptance tests and independent 3rd party audits and inspections;
- pipeline buried, route / location marked, intruder detection system and significant wall thickness reduce risk of accidental impact resulting in a release;
- pipeline installed within concrete lined, fully grouted tunnel under Sruwaddacon Bay and buried to minimum cover depth in accordance with codes and standards;
- geotechnical / peat stability assessments and stone road design and construction reduce risk of ground movement adversely affecting pipeline; and
- Pipeline Integrity Management Scheme including: regular pipeline inspections (2 weekly patrols, cathodic protection and coating inspections, GPS movement monitoring, periodic intelligent pigging) to identify any potential problems well before they develop to such an extent that they could result in a release.

Should the preventive measures fail and one of the potential causes lead to a hydrocarbon release, the consequences may possibly include:

- an unignited, relatively small leak of hydrocarbons;
- an unignited large hydrocarbon release or rupture; and / or
- an ignited release with associated fire.

The bowtie diagram illustrates the controls in place to mitigate these consequences and help recover from the event. Key right-side bowtie controls include:

- process monitoring and leak detection systems (including fibre optic);
- LVI isolation valves (two in series); and
- emergency response plans and training, including liaison with emergency services.

4.4 UMBILICAL FAILURE

The risk associated with umbilical failure was directly assessed in the HAZID in terms of a release of hydraulic fluid or methanol and is recorded in the Corrib Risk Register against both of these hazards. The HAZID team determined that the potential for asset loss (e.g. in terms of shut down of operations) was medium risk, as was the safety risk to people from an onshore release of hydraulic fluid or an ignited release of methanol. All other scenarios were assessed as low risk.

Failure of the control umbilical is not, in itself, a major risk but it may contribute to the other major risks described above and so has been subject to detailed qualitative risk assessment.

Possible causes of umbilical failure include:

- corrosion;
- overpressurisation;
- material incompatibilities / reactions leading to blockage;
- accidental impact;
- intentional damage;
- ground instability where umbilical runs on land (e.g. peat slide, landslide, seismic event, settlement of stone road, settlement at public road crossing, flooding / washout);
- ground instability where umbilical runs beneath water (e.g. erosion of river bed, ground movement);
- human error during design, manufacturing, construction, installation or operation / maintenance; and
- adjacent pipeline failure.

The bowtie illustrates the preventive measures in place to avoid umbilical failure. Preventive measures of note include:

- design takes account of potential for corrosion, material compatibilities, etc;
- design, manufacturing and construction reviews, QA/QC procedures, design assurance process, acceptance tests and independent 3rd party audits and inspections;
- subsea pipeline pre- and post-lay surveys and burial of umbilical protect offshore sections against damage from ground movement or impact;
- umbilical buried, route / location marked reduce risk of accidental impact of onshore sections;
- umbilical installed within tunnel under Sruwaddacon Bay and buried to minimum cover depth in accordance with codes and standards;
- geotechnical / peat stability assessments and stone road design and construction reduce risk of ground movement adversely affecting onshore sections of umbilical; and
- regular pipeline inspections (2 weekly patrols) may also identify problems with umbilical.

The following consequences of umbilical failure were assessed:

- potential pollution effects of liquid releases to sea;
- potential pollution effects of liquid releases to land;
- ignited methanol release potentially affects pipeline;
- loss of hydraulics to Subsea Distribution Unit (SDU);
- loss of electrical power to SDU;
- loss of data communication;
- loss of methanol / corrosion inhibitor to a single injection point; and
- total loss of methanol / corrosion inhibitor (to all injection points).

The measures in place to mitigate the effects of these consequences are illustrated on the right side of the bowtie diagram and include:

- process monitoring and leak detection systems;
- low environmental impact of liquids involved;
- redundancy of control systems to reduce risk of total loss of control;
- fail close control systems – safe shutdown in the event of total loss of hydraulics or electrics; and
- emergency response plans and training, including liaison with emergency services.

5 BOWTIE ANALYSIS

The benefits of using bowtie analysis for risk management have been realised by organisations world-wide across a variety of business sectors and the method has been in widespread use since the mid-1990s. It provides a readily understandable visualisation of the relationships between the causes of accidents, the escalation of such events to a range of possible outcomes, the controls preventing the event from occurring and, should the event nevertheless occur, the preparedness measures in place to limit the consequences.

When the analysis is carried through to an operating facility, the preventive and mitigation controls are linked to activities, procedures, responsible individuals and competencies, thereby demonstrating the crucial connection between risk controls and a Safety Management System for assuring their ongoing effectiveness. This ensures critical roles are identified (i.e. individuals know what is expected of them), procedures are complete and effective and critical equipment is identified as such, with defined performance standards.

Illustrating the risk controls against their respective causes and consequences in such a structured way demonstrates that risks are understood and are being controlled and can highlight gaps in risk control which should be a focus for remedial action.

The bowtie diagram also provides a simple visual demonstration of the way in which risks are managed, allowing widespread understanding at all levels, including non-risk specialists, and giving everyone the opportunity to review the existing controls in place, their specific responsibilities and to identify any potential improvements.

Section 5.1 below explains the bowtie analysis method in detail and Section 5.2 describes the bowtie analyses which have been undertaken for the Corrib pipeline.

The bowties developed for the Corrib pipeline are illustrated in Attachment Q6.3B at the end of this document.

5.1 BOWTIE ANALYSIS METHOD

The bowtie analysis method entails building a bowtie diagram, step-by-step, to produce a structured, qualitative assessment of the risks associated with the hazard under consideration.

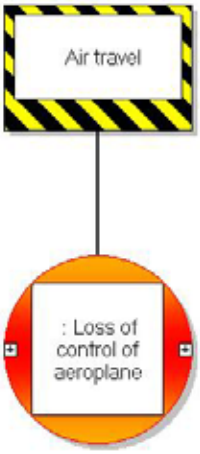
5.1.1 Bowtie Diagrams

A hazard is defined as something which has the potential to cause injury, damage or loss. Examples of hazards are air travel, electricity, alcohol, working on a ladder.

Hazards normally do not cause harm because they are kept under control. For example, electricity is ‘contained’ in properly rated and installed wiring and equipment.

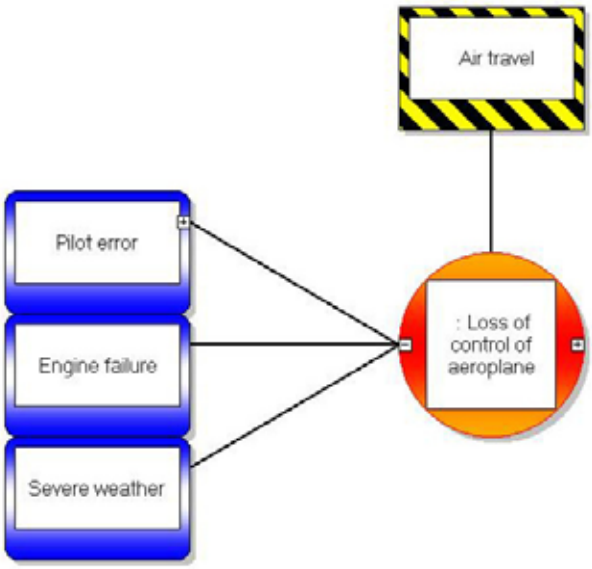
However, if control of the hazard is lost, an initial incident will occur – this is the top event and is shown at the centre of the bowtie diagram.

Figure 5.1: Hazard and Top Event Example



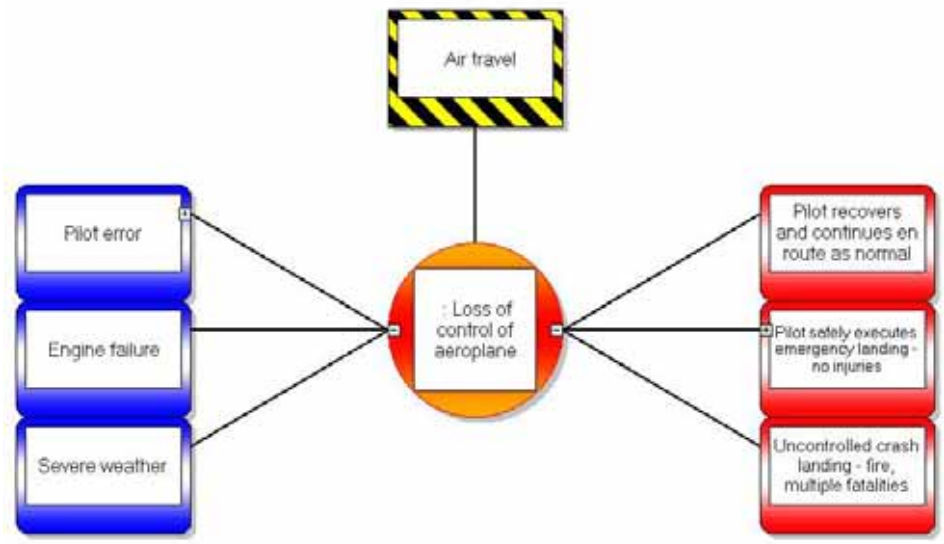
The causes (sometimes called “threats”) illustrate the various ways in which the hazard could be released i.e. what could cause loss of control of the hazard?

Figure 5.2: Causes Example



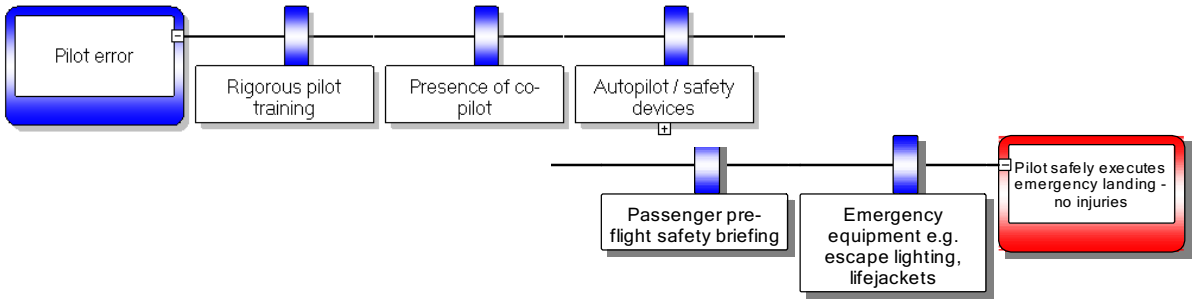
Once control is lost and the top event occurs, there may be a number of ways in which the event can develop to the ultimate consequence. Each consequence will result in a specific extent of harm i.e. severity of impact. The impact might be to people, the environment, physical assets or the reputation of the company involved, or all of these.

Figure 5.3: Consequence Example



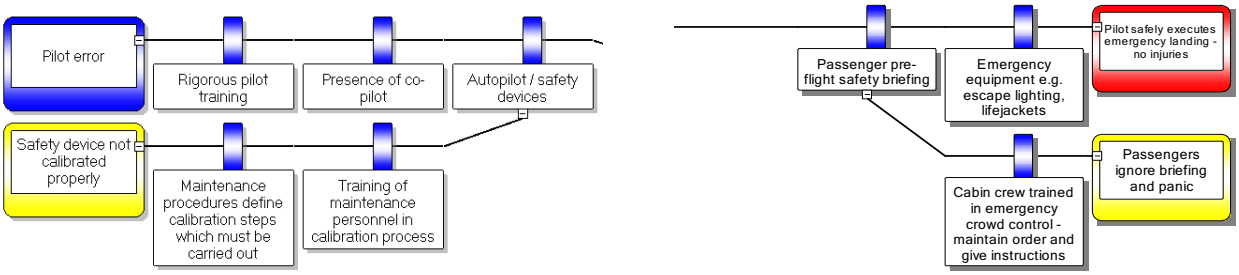
There are controls in place to prevent the release of the hazard (i.e. prevent the threat leading to the top event). These controls are shown on the left side of the bowtie and can be items of equipment or actions taken in accordance with training and procedures. No control can be 100% effective, so if the preventive controls on the left side of the bowtie fail to maintain control and the top event occurs, further controls can be implemented to interrupt development of the scenario and mitigate or recover from the consequences.

Figure 5.4: Controls Example



Circumstances may arise which undermine a control measure and reduce its effectiveness; these are recorded on the diagram by means of escalation factors (i.e. they allow the scenario to escalate). Escalation factors are, in turn, managed by further controls.

Figure 5.5: Escalation Factor Example



5.1.2 Safety Critical Activities

The bowtie analysis identifies activities which, if carried out, support the controls and make sure they are functioning correctly and remain effective (Figure 5.6). These activities are termed 'Safety Critical Activities' as they support controls which reduce the potential risks (Figure 5.6).

An example Safety Crititical Activity would be the regular checking and calibration of a piece of safety equipment. If this activity was not carried out, there is no assurance that the equipment would function as expected when required and it would not be possible to claim the device as a credible, effective control on the bowtie.

For the most part, Safety Critical Activities are day-to-day tasks, assigned to individuals or teams, that are routinely carried out as part of normal operations i.e. they are not new activities which are 'invented' by the bowtie analysis. Verification (via audits, inspections or supervisory checks for example) that these activities are being carried out provides confidence that the risk controls are in place and are effective.

Mapping the major risks in this manner (i.e. building a detailed bowtie diagram and then linking the controls to supporting Safety Critical Activities) promotes a structured assessment of each risk, identifying not only what is in place (the controls), but also why they will continue to be in place (the Safety Critical Activities).

5.1.3 Safety Critical Elements

A Safety Critical Element (SCE) is defined as a structure or item of equipment whose failure could cause or contribute to release of a major risk, or whose purpose is to prevent, or limit the effect of, the consequences of that release.

Where a bowtie diagram depicts a major risk scenario, hardware (equipment or structural) controls illustrated on the bowtie are therefore, by definition, SCEs. Similarly, any hardware failure causes on the left side of major risk bowties are also SCEs.

Figure 5.6 illustrates how management of the performance of SCEs supports the integrity of the risk controls identified by the bowtie analysis.

5.1.3.1 Performance Standards

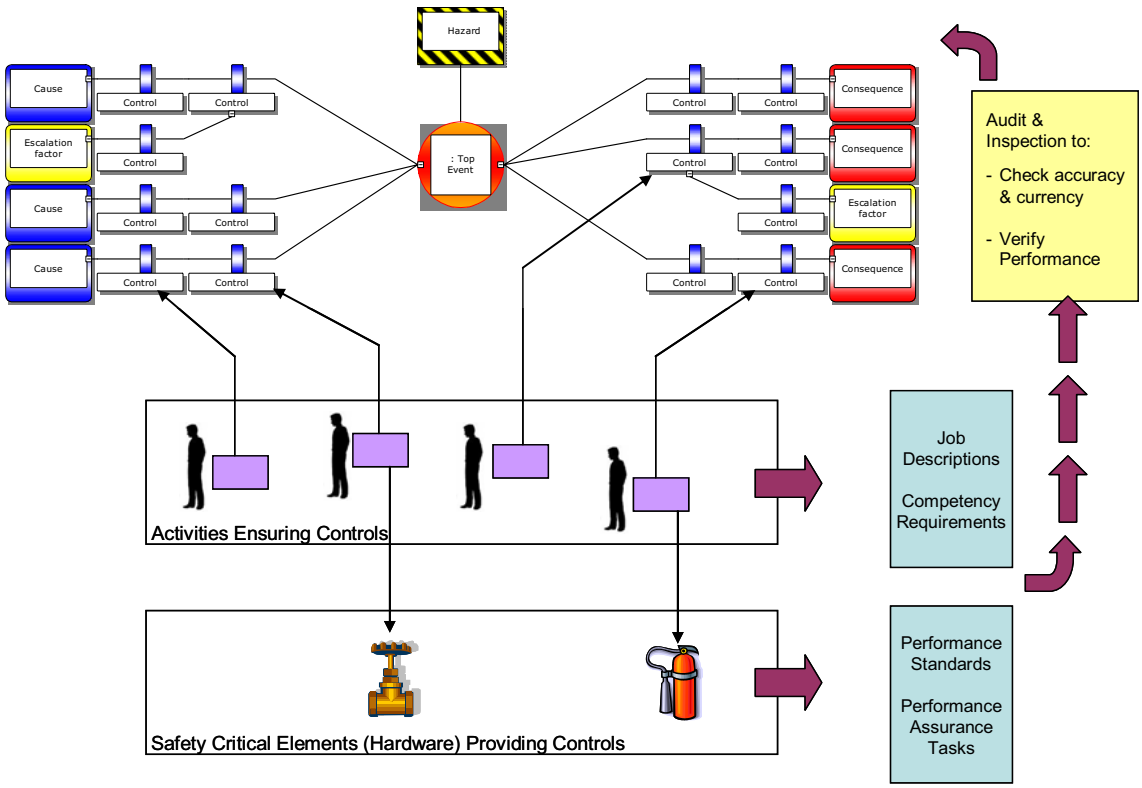
A performance standard is defined as a qualitative or quantitative statement of the functional performance required from an item of equipment and which is used as the basis for managing the major risks.

For each SCE, goals are defined which identify what the SCE is intended to achieve. The goals are aligned with the role that the SCE plays in the event of a major risk scenario.

5.1.3.2 Performance Assurance

Performance assurance involves testing that SCEs are working as required and confirming that they are meeting the goals specified in their performance standards.

Figure 5.6: Relationship Between Controls, Safety Critical Activities and Safety Critical Elements



5.2 CORRIB PIPELINE BOWTIE ANALYSES

The Corrib bowtie assessments have been developed over a number of years and build on the numerous qualitative risk assessments conducted since the start of the project, as described in Section 2.

They provide an additional, detailed qualitative risk assessment of the major risk scenarios, over and above that presented in the Corrib Risk Register (see Section 3).

The bowties developed for the Corrib pipeline are illustrated in Attachment Q6.3B at the end of this document.

5.2.1 Pipeline Bowtie Workshops

Several bowtie workshops have been undertaken for the Corrib pipeline facilities, as summarised in Table 5.1. Additional bowtie assessments have also been held specifically for the Gas Terminal, but are outside the scope of this document.

The objective of each of the bowtie workshops was to capture, in one place and in a readily auditable format, the control measures in place to prevent each major risk from being realised or, in the event that these controls fail and an incident occurs, the measures in place to mitigate and recover from the effects.

In this way, the effectiveness of each of the identified controls could be assessed and a judgement made as to the adequacy of the protection in place and any further risk reduction measures to be considered. This forms the basis for a demonstration that the risks associated with the major scenarios are reduced to ALARP levels (see Section 6).

Table 5.1: Corrib Pipeline Bowtie Assessments

Date	Description of Bowtie Assessment
2006	Initial bowtie assessments for the identified major risks in the preliminary HSE Case. Generic bowties in tabular format, showing the standard / expected controls applicable for each of the identified threats and consequences for each major risk.
August 2007	Bowtie assessment of hydrocarbon releases from the onshore pipeline, LVI and umbilical as part of the work carried out to develop an alternative route for the onshore pipeline following independent mediation and Advantica recommendations. This analysis identified nineteen threats which could potentially lead to release of hydrocarbons from the onshore pipeline and assessed the effectiveness of the controls planned to be in place to prevent such a release or limit its impact. The workshop concluded that, subject to implementation of a number of identified actions, risks associated with a release of hydrocarbons from the onshore pipeline were reduced to ALARP levels.
September 2008	The previous bowtie assessments were revisited as part of further development work on the Corrib HSE Case. Each major risk from the risk register was subject to detailed bowtie analysis during the workshop; the bowties identified the potential causes of the major risk scenario, the worst case credible consequences, and the controls in place to prevent the event from occurring or to minimise the severity of the outcome. The bowtie workshop teams involved individuals associated with both the design and operations of the facilities in order to fully capture the as-built engineered controls and planned operational controls for the Corrib facilities.
December 2009 / January 2010	Following the request from An Bord Pleanála for further information on the onshore pipeline in November 2009, a further series of bowtie assessment workshops was undertaken covering the subsea wells, flexible jumpers and manifold, the offshore pipeline, the LVI, the onshore pipeline from the landfall up to the first Emergency Shut Down Valve inside the terminal boundary and the control umbilical. The workshops reviewed each bowtie threat and consequence branch, and each individual control in turn, to verify its accuracy and the completeness of the assessment. Where appropriate, threats and consequences were sub-divided to clearly illustrate that the bowties address all sections of the pipeline route and all operating conditions.
March 2010	In parallel with the 2009 / 2010 bowtie analysis, a process was underway to determine the optimal route for the onshore pipeline, following An Bord Pleanála's request to change the proposed route of the pipeline in November 2009. In general the bowtie analysis is independent of the detailed pipeline route; the causes and consequences of pipeline failure are identified and controls evaluated for generic route sections e.g. on land, at water crossings, under the stone road, at public road crossings, etc. However, once the final route was decided upon, any route-dependent causes, consequences and controls were reviewed at a follow-up workshop.

Each bowtie workshop involved a multidisciplinary team of relevant people providing a wide range of skills and experience (and therefore an objective assessment of the control measures in place). The workshops were facilitated by an independent chairperson, who was responsible for guiding the team through the structured bowtie analysis process, challenging the information provided and recording the workshop output. Workshop outputs were internally quality assured.

As explained in Section 1.5, the specialist consultancy responsible for the QRA for the Corrib pipeline also participated in the bowtie workshops to ensure consistency and alignment between the quantitative and qualitative risk assessments.

The output from each successive bowtie workshop was incorporated into the suite of Corrib bowties held in the Corrib HSE Case. As explained in Section 2.1, the bowties are a living document which will continue to be updated.

5.2.2 The Corrib Pipeline Bowties

On completion of the latest bowtie workshop, the extent of the Corrib pipeline bowtie analysis stood at four pipeline-related bowties (covering the pipeline major risk scenarios plus control umbilical failure). Between them the four bowties include 112 causes (threats), 30 potential consequences and over 1,000 control measures.

For the purposes of this Section Q6.3, extracts from the bowties have been selected to illustrate the output from the bowtie analyses and are presented in Attachment Q6.3B. The bowtie extracts have been selected on the basis that they:

- illustrate risks which cannot be easily defined mathematically;
- include scenarios which are relevant to / contribute to the QRA;
- address issues of concern raised at the 2009 oral hearing (e.g. umbilical failure); and
- cover a range of locations and operating conditions.

5.2.3 Pipeline Safety Critical Activities

As defined in Section 5.1.2, Safety Critical Activities support and maintain the controls illustrated on the bowtie diagram and make sure they continue to function correctly.

For the Corrib pipeline major risk bowties, preliminary Safety Critical Activities were developed during the bowtie workshops, by asking questions such as:

<u>For hardware (equipment) controls:</u>

"who is responsible for maintaining that control?"

"how do they know when and how to carry out the maintenance?"

"how can we assure ourselves that the maintenance has been carried out properly and on time?"

<u>For controls involving a person doing something:</u>

"who is responsible for doing that activity?"

"how do they know when and how to do it?"

"who is responsible for making sure the person is competent?"

The competence of people is therefore important when ensuring risk controls continue to function and the results of the qualitative risk assessment process have been used to screen and inform the required job-specific training and competencies of Corrib personnel. Competence assurance arrangements specific to the Corrib pipeline are described in more detail in the Pipeline Integrity Management Scheme (PIMS), see Appendix Q5.

The Corrib Safety Critical Activities are held within the HSE Case (see Section 2.1) and are a 'work-in-progress'. The next phase of the HSE Case development work involves progressing the Safety Critical Activities with pipeline operations personnel and contractors to reflect operating procedures, task instructions, etc. Example of the current preliminary Safety Critical Activities are illustrated in Table 5.2.

Table 5.2: Example Safety Critical Activities

Job Position	Activity	Input to Activity	Verification of Activity
Control Room Operator	From the Gas Terminal control room, monitor wells, pipelines, LVI and terminal process equipment to ensure conditions remain within operating limits. Follow all relevant procedures and manuals. Confirm correct functioning of the computerised monitoring, control and inhibit systems. Respond to abnormal conditions and process upsets, including initiating controlled and emergency shut downs when necessary.	Start up and Shut Down Procedures Operating Manuals (especially Nos. 5, 6, 7 and 9) Control Room Operator training	Shift Log
Health, Safety, Security and Environmental Advisor	Plan and arrange emergency response drills (including periodic exercises involving third parties such as the local fire service). Record the output from such drills and participate in reviews to ensure that the emergency response procedures and emergency response personnel training are fit for purpose and reflect the findings from drills.	Emergency Drill Schedule Emergency Response Procedures	Drill Records Emergency Response Debriefings
Inspection Engineer	Carry out scheduled inspections and breakdown maintenance on cathodic protection system. Carry out inspections after maintenance works to ensure that cathodic protection system is correctly reinstated and functioning properly.	Cathodic Protection Inspection Schedule Cathodic Protection Operating Procedure Task Instructions Cathodic Protection Inspection Standard	Inspection Records

5.2.4 Pipeline Safety Critical Elements

During development of the Corrib bowties, the major risk bowties were reviewed and each SCE claimed in the bowties was identified in terms of the role it plays in the major risk scenario (e.g. cause, prevention or mitigation). The bowtie analysis also confirmed that each SCE illustrated on the major risk bowties had a defined performance standard (see Section 5.1.3.1).

Each Corrib wellhead structure and wellhead valve is defined as a SCE, providing containment of reservoir fluids. The well-specific SCEs are listed in the Well Examination Program Execution Checklist.

Each pipeline in the system of Corrib pipelines is a SCE, safeguarded against loss of containment by aspects of its design and operations. Each pipeline SCE is further divided into sections with defined start and finish points. Pipeline SCEs are described further in the Pipeline Integrity Management Scheme (see Appendix Q5).

Performance assurance tasks for the Corrib facilities' SCEs have been defined as part of the development of their performance standards. They are included in the Corrib computerised maintenance management system, through which the tasks are scheduled, their results recorded, and any backlog or failed tasks managed.

For the Corrib wells, performance is also assured by independent examination in accordance with Irish law. The program of examination activities is carried out by a specialist third party company and a government-appointed verifier audits the scheme on an annual basis.

For the Corrib pipeline systems, performance assurance tasks are also captured in the PIMS (see Appendix Q5).

5.2.5 Safety Management System (SMS)

As described in Section 5.2.3 above, the qualitative risk assessment process has identified Safety Critical Activities to make sure the risk controls continue to be effective and it is important that people are competent to carry out these activities. The procedures in place to check competence of personnel and provide training where required is a key element of the Corrib Safety Management System (SMS).

As described in Section 5.2.4, the qualitative risk assessment has identified Safety Critical Elements (SCEs) which prevent or mitigate a major risk and must be maintained, tested and inspected so that they continue to meet their performance standards. The procedures in place to conduct such maintenance, testing and inspection also form part of the Corrib SMS.

A SMS is a structured set of policies, procedures, etc. which provides the processes and business controls to enable staff to identify safety risks and manage them adequately, to plan and safely carry out work and to achieve continuous safety improvement.

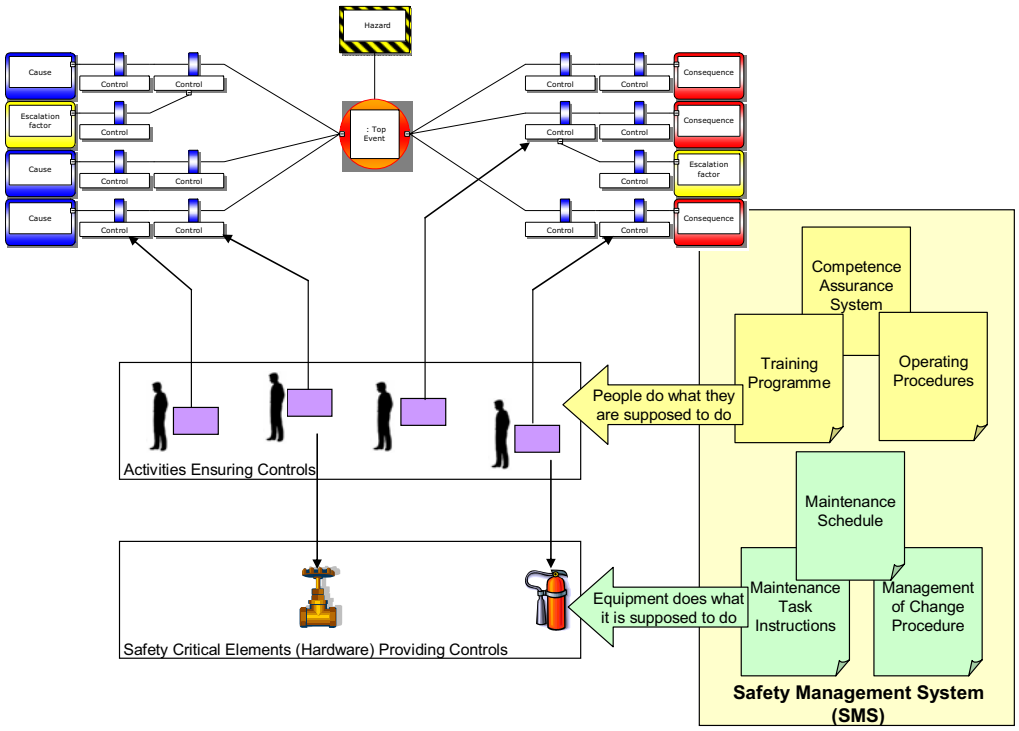
The SEPIL organisation has a SMS in place describing how SEPIL manages or intends to manage safety at all locations and facilities. The Corrib SMS, a sub-set of the SEPIL SMS, covers a number of areas including:

- safety policy and objectives;
- organisation, roles and responsibilities;
- competence of personnel
- management of contractors;
- identification, assessment and control of safety risks;
- planning work activities;
- processes and procedures for safety of operations, maintenance, etc.;
- measuring and monitoring safety performance; and
- auditing safety performance.

Everyone in the Corrib organisation, whether a SEPIL employee or contractor, is responsible for complying with the SMS within their sphere of operations. The Corrib SMS complies with the recently enacted Petroleum (Exploration and Extraction) Safety Act, which requires a SMS to be implemented and its adequacy demonstrated in a Safety Case.

By defining Safety Critical Activities and SCEs, the bowtie analysis therefore clearly demonstrates the links between control of major risks and the SMS (Figure 5.7), thus ensuring that controls will continue to be effective during the operations phase.

Figure 5.7: Relationship Between Major Risk Controls and Management System



6 AS LOW AS REASONABLY PRACTICABLE (ALARP)

This section explains the concept of ALARP, describes the work carried out for the Corrib pipeline to make sure that risks are reduced to ALARP levels and then concludes with a demonstration that pipeline risk levels are indeed ALARP.

6.1 REQUIREMENT FOR AN ALARP DEMONSTRATION

Within Shell, every UI Company is required to produce a documented demonstration that the risks from its medium- and high-risk hazards are tolerable and have been reduced to ALARP levels.

The recently enacted Petroleum (Exploration and Extraction) Safety Act also requires petroleum undertakings to demonstrate that they have the ability to properly assess and effectively control risks to a level that is ALARP.

In terms of pipeline codes (see Section 1.3), BS PD 8010-1 requires that risks are reduced to ALARP levels. I.S. EN 14161 requires that risk reduction is considered but does not use the term 'ALARP'. I.S. 328 requires that, for pipelines where risk assessment is carried out, the principles of A.S. 2885 should apply (and A.S. 2885 requires that risks are reduced to tolerable and ALARP levels).

In its letter of 29th January 2010, An Bord Pleanála stated that *"In the event that individual risk of 10^{-6} or higher applies then the undertaker will have to demonstrate ALARP".* As the individual risk calculated in the QRA (see Appendix Q6.4) is well below 10^{-6} per year, under this criterion a demonstration of ALARP is not required.

However, as explained above, demonstration of ALARP is required by Shell standards and the recently enacted Petroleum (Exploration and Extraction) Safety Act and hence a demonstration of ALARP is presented here.

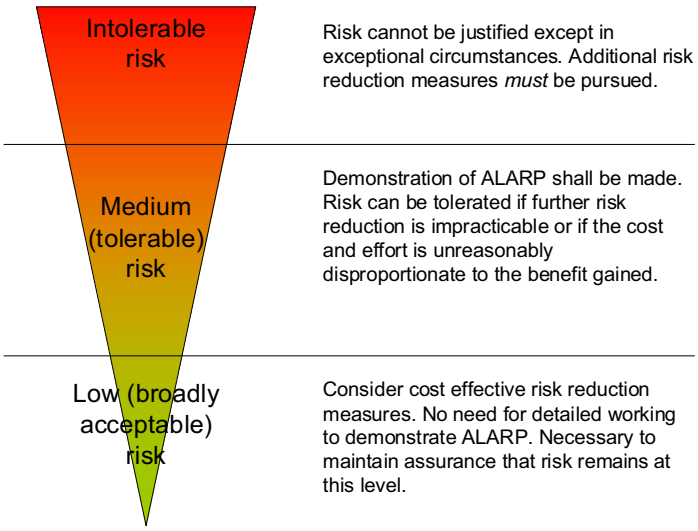
6.2 WHAT IS ALARP?

6.2.1 Risk Levels

The level of safety risk ranges from relatively low to relatively high (Figure 6.1). At the lower end of the risk spectrum, the risks are comparable with those we are subjected to as part of our every day activities and, as such, the risk is deemed "broadly acceptable". At the opposite end of the risk range, the risk is so high that it cannot be tolerated. Between these two extremes, there is a mid-range of risk values where the risk can be tolerated provided that it is demonstrated that the risk has been reduced to a level which is ALARP.

The quantitative risk assessment carried out for the Corrib pipeline (see Appendix Q6.4) indicates that the overall risk at the nearest occupied dwelling lies well within the broadly acceptable zone.

Figure 6.1: Risk Levels and Demonstration of ALARP



6.2.2 ALARP Definition

ALARP is defined as the point where, when objectively assessed, the time, cost and difficulty of introducing further risk reduction measures becomes grossly disproportionate to the additional risk reduction achieved. Risk levels have been reduced to ALARP when the only additional risk reduction measures that can be identified entail an effort (time, cost, difficulty) which is grossly disproportionate to the risk reduction they would bring about.

The process is not one of balancing the costs and benefits of measures but, rather, of adopting measures except where they are ruled out because they involve grossly disproportionate effort. Risk levels are ALARP when the resources required for implementation of additional measures which may further reduce risk are unreasonably large when compared to the potential benefit to be gained. Resources would be better applied to reduce risk elsewhere.

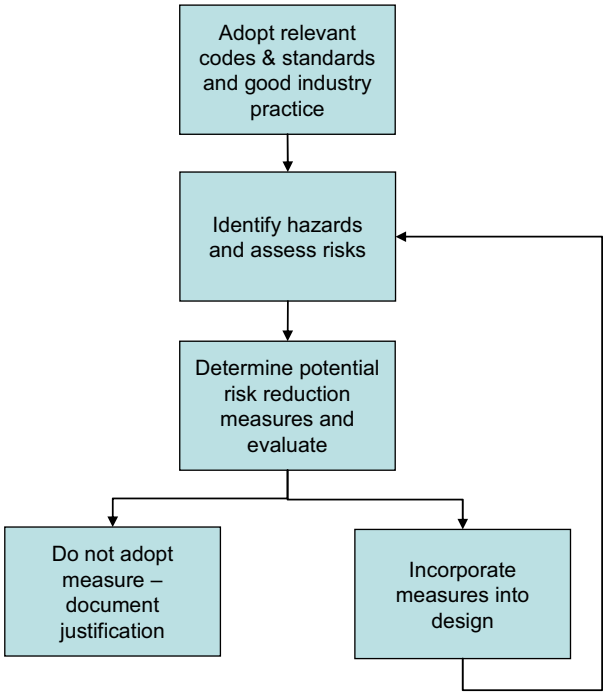
The concept of ‘gross disproportion’ enables the assessment to take account of the fact that the higher the risk, the more time, attention, effort and cost needs to be directed towards reducing it. What might be reasonably practicable when risks are high, may well not be reasonably practicable if risk levels are low.

6.2.3 Demonstrating ALARP

Figure 6.2 illustrates the process followed to demonstrate that risks are reduced to ALARP levels.

The first step in the process is to ensure that the design meets certain minimum standards (otherwise the risk levels cannot be claimed to be ALARP). For example, Shell considers that risk levels are not demonstrably ALARP if they lie in the “intolerable” zone of Figure 6.1. In some jurisdictions there may be legal requirements which are also mandatory. In the case of the Corrib pipeline, these minimum standards include compliance of the design with the pipeline codes, as described in Appendix Q3.

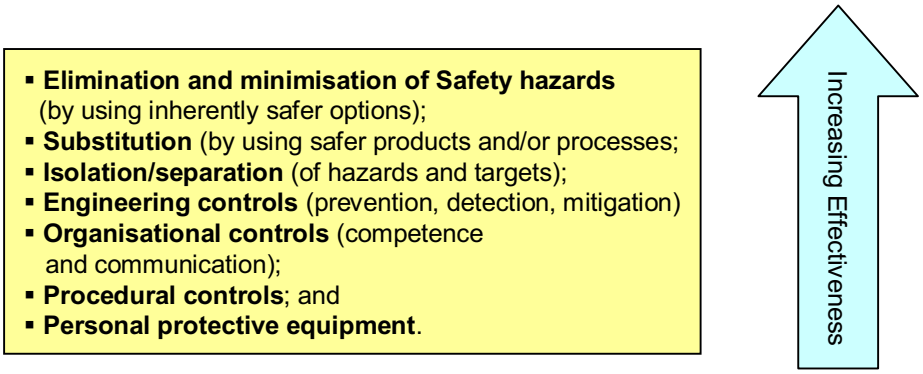
Figure 6.2: Demonstrating ALARP



Once such minimum standards are met, there is still a requirement to demonstrate that the remaining risks are reduced to ALARP levels. This is achieved by assessing the risk and identifying measures which, if implemented, could bring about a reduction in the risk level. For the Corrib pipeline, risk assessments such as those described in Sections 2, 3 and 5.2 have been carried out to identify potential design changes and other measures which can be incorporated to reduce the levels of risk.

Generally the philosophy is that risks should be eliminated wherever possible. Where elimination is not possible, various types of risk reduction measures are available, with different levels of effectiveness (Figure 6.3).

Figure 6.3: Hierarchy of Risk Reduction Measure Effectiveness



For each suggested risk reduction measure, the effort involved in implementing measure is compared against the potential risk reduction achieved and the 'gross disproportion' test is applied i.e. measures are implemented except where they involve grossly disproportionate effort. The comparison can involve numerical values for effort and risk or it can be qualitative and, as explained in Section 6.3, a qualitative approach has been adopted for the Corrib pipeline.

Demonstrating ALARP involves documenting the above process, to provide a written statement that:

- the design meets the mandatory minimum standards; and
- a number of alternatives and additional risk reduction measures have been considered; and
  - the measure has been adopted (where the effort involved in implementing the risk reduction measure is not grossly disproportionate to the risk reduction benefit gained); or
  - the measure has not been adopted (where the effort involved in implementing the risk reduction measure is grossly disproportionate to the risk reduction benefit gained).

6.3 DEMONSTRATING ALARP WITH BOWTIE ANALYSIS

Given the extremely low levels of public risk associated with the Corrib pipeline, once the principal concept and design has been decided upon, the scope for determining numerical benefit from further, more detailed risk reduction measures is limited by the sensitivity of the QRA. The principal means adopted for assessing whether there are sufficient controls in place and the benefit from additional risk reduction measures has therefore been via the qualitative bowtie-based approach.

The bowtie analysis does not stop once the currently existing or planned controls have been recorded. The analysis identifies a large number of individual preventative and mitigative controls in place to manage each major risk. To make sure risks are reduced to ALARP levels, the analysis team, in addition to identifying and recording controls, also reviews the controls to determine whether it can be improved and reviews each branch to determine if extra controls can practicably be added. Therefore, during the workshops, the following questions are asked:

- *"are there a suitable number of independent, effective control measures in place?";*
- *"do we comply with company and industry standards?" ;*
- *"can we improve the effectiveness of the existing controls?";* and
- *"are there any more measures that can be implemented to reduce the risk?" .*

The qualitative risk assessment may therefore identify additional measures, over and above the currently planned controls, which have the benefit of reducing the risk still further. These additional risk reduction measures are then assessed by the workshop team in terms of the benefit gained from adopting the measure and the potential effort (time, trouble, cost, etc.) of implementation. The additional measures are recommended for implementation or further evaluation unless the effort is assessed to be grossly disproportionate to the benefit.

This process by which additional risk reduction measures are identified, evaluated and implemented to progressively reduce the risk, ensures the residual risk associated with the hazard is reduced to ALARP levels.

6.4 CORRIB QUALITATIVE (BOWTIE) ALARP WORKSHOPS

Any potential risk reduction measures identified during the various bowtie workshops (see Section 5.2.1) were recorded and a qualitative assessment was made by the workshop team of the potential benefit versus expected effort (time, trouble, cost, etc.) of implementing the measure. Measures where the effort involved was not grossly disproportionate to the potential benefit were recommended for implementation. Closure of actions raised to further evaluate or implement such risk reduction measures is tracked.

The bowtie workshops therefore confirmed, by qualitative assessment, that the major risks associated with the Corrib pipeline are reduced to ALARP levels (subject to close out of the actions).

The output from this part of the Corrib bowtie workshops is summarised for each major risk below.

6.4.1 Release from Wells, Flexible Lines and Offshore Pipeline

The bowtie workshops conducted for releases offshore concluded that codes and standards have been met and that sufficient effective controls are in place to prevent or mitigate such an incident. These controls are documented in detail in the bowties (see Attachment Q6.3B) and are summarised in Section 4.1.

Given the extensive number and efficacy of the controls in place, the workshops did not identify any additional, practicable, risk reduction measures, over and above those already planned.

6.4.2 Release from Landfall Valve Installation

The bowtie workshops conducted for releases at the LVI concluded that codes and standards have been met and that sufficient effective controls are in place to prevent or mitigate such an incident. These controls are documented in detail in the bowties (see Attachment Q6.3B) and are summarised in Section 4.2.

The bowtie workshops identified three measures which were accepted for implementation at the LVI:

- landfall valve installation design to comprise duplicated high integrity fail closed valves;
- vibration assessment for small bore pipework / connections (and incorporate findings into design as necessary); and
- independent audit of construction quality assurance and control regime.

6.4.3 Release from Onshore Pipeline

The bowtie workshops conducted for releases onshore concluded that codes and standards have been met and that sufficient effective controls are in place to prevent or mitigate such an incident. These controls are documented in detail in the bowties (see Attachment Q6.3B) and are summarised in Section 4.3.

The bowtie workshop identified the following additional risk reduction measures which were accepted for implementation at the onshore pipeline:

- independent audit of construction quality assurance and control regime;
- define design of concrete slabs (thickness, dimensions, etc.) at road crossings based on level of protection required; and
- investigate potential for movement of backfill material and amend design accordingly.

6.4.4 Umbilical Failure

Umbilical failure is not considered to be a major risk but nevertheless it was subject to the same process of ALARP workshop as the above major risk scenarios. The bowtie workshops concluded that codes and standards have been met and that sufficient effective controls are in place to prevent or mitigate umbilical failure. These controls are documented in detail in the umbilical failure bowtie (see Attachment Q6.3B) and are summarised in Section 4.1.

The bowtie analysis workshops did not identify any additional, practicable, risk reduction measures, over and above the controls already planned.

6.5 ADDITIONAL DESIGN CHANGES

The concept of ALARP has been applied throughout the design process by performing qualitative and quantitative risk assessments. The assessments sought to identify and assess the benefit from various risk reduction measures, for example as described in Section 6.4 above, so that risk reduction benefit versus effort could provide one of the inputs to the decision to either adopt the measure or to reject it.

Alternatives assessed at concept evaluation and risk reduction measures adopted during earlier design stages have been presented in previous risk assessments and ALARP demonstrations and are captured in the HSE Case (see Section 2.1). In 2009, the cumulative effect of these design changes resulted in a design which complied with all relevant pipeline codes of practice, had numerical levels of risk well within the "broadly acceptable" region (Figure 6.1) and a qualitative risk assessment (bowtie) process which demonstrated sufficient risk controls for each major risk scenario. At that point, the risks associated with the design were therefore considered to be ALARP.

In response to issues raised at the 2009 oral hearing and An Bord Pleanála's request to consider further modifications, SEPIL has developed the following design changes:

- modified onshore pipeline route and installation of the onshore pipeline within a tunnel where it runs beneath the Sruwaddacon bay (as opposed to other alternative methods of installation) (as described in Chapter 3 of this EIS);
- reduction of onshore Maximum Allowable Operating Pressure (MAOP) and implementation of an offshore MAOP (see Appendix Q4); and
- adoption of a fibre optic intruder and leak detection system in addition to the mass balance system (see Chapter 4 of this EIS).

These changes go beyond what is required under the ALARP concept for pure safety risks i.e. the effort involved in implementing the measure is expected to be grossly disproportionate to the benefit gained in terms of safety risk reduction.

6.6 CONTINUED RISK CONTROL ONCE OPERATING

The hierarchy of risk controls (Figure 6.3) will continue to be applied through operation of the Corrib facilities, although once operation commences risk reduction focuses on enforcing and improving operational controls, maintaining asset integrity and managing changes.

Operational controls include:

- defining operating limits, using appropriate safety equipment / devices and controlling overrides;
- maintaining equipment in a good state of repair and verifying that SCEs continue to meet their performance standards;
- developing, maintaining and communicating a suite of procedures and task instructions which tell people how and when to carry out their tasks;
- providing relevant training and adequate levels of supervision, to ensure that people are competent to do their job;
- implementing systems for job-specific hazard identification, risk assessment and risk control (e.g. Job Safety Assessment (JSA), ISSOW, PTW);
- inspecting and auditing to ensure that all these operational controls continue to be implemented; and

- reviewing any additional risk control measures that may be identified in the future and implementing them as appropriate in line with the management process of continuous improvement.

Changes to equipment, procedures, operating limits, maintenance frequencies, roles and responsibilities, etc. are strictly managed (as referenced in Appendix Q5) and followed up, post implementation, to verify that control measures are functioning as expected.

These operational risk controls are illustrated on the bowtie diagrams and will be covered by various elements of the Corrib Safety Management System (see Section 5.2.5).

6.7 CORRIB PIPELINE ALARP CONCLUSIONS

Figure 6.2 provides a simplified illustration of the process adopted throughout the design stages of the Corrib project to ensure that risks associated with the pipeline are reduced to ALARP levels.

A key requirement of the design process was to ensure that good industry practice and relevant codes of practice were adopted. The Corrib pipeline design goes beyond these minimum standards, by including a number of further design changes and risk reduction measures over the history of the project including some significant design changes which, as described in Section 6.5, would not be necessary under purely safety ALARP grounds.

A large number of safety studies have been carried out to identify hazards and assess risks associated with operation of the Corrib facilities. Recommendations identified by these studies have been implemented, unless it can be shown that the benefit gained, in terms of risk reduction, is grossly outweighed by the effort, cost, difficulty and impracticality of implementation.

A QRA has been completed which shows that the risk associated with the pipeline is outside the region where achievement of ALARP risk levels needs to be demonstrated; indeed the numerical risk value is so low that the potential for demonstrating ALARP via numerical estimates of risk reduction is extremely limited.

A qualitative approach to ALARP demonstration has been adopted in addition to the numerical assessment and the potential to further reduce the risk was considered during the bowtie workshops. By challenging the design, the bowtie workshops therefore confirmed, using qualitative assessment and based on the collective experience and judgement of the bowtie analysis teams, that the major risks associated with the pipeline are reduced to ALARP levels.

It is therefore concluded that, the risks associated with the Corrib pipeline design are reduced to ALARP levels because:

- it complies with relevant codes of practice;
- the numerical risk value is in the broadly acceptable zone; and
- for major risks, sufficient controls been incorporated and additional risk reduction measures have been sought, assessed and implemented where reasonably practicable.

By documenting application of the ALARP process for the project, this Section Q6.3 complies with the Shell framework for managing risk and the requirements of the pipeline codes of practice and Petroleum (Exploration and Extraction) Safety Act to demonstrate that risks are controlled to a level that is ALARP.

Once operations commence, the risk reduction measures identified during the design stages will be maintained. The opportunities for further risk reduction change emphasis, from design changes to enforcing and implementing operational controls, but there remains a drive to continue to reduce risks to ALARP levels and residual risks can be effectively managed.

It can be concluded that the cumulative effect of the preventive and recovery measures incorporated into the design, together with the opportunities for risk reduction which will be implemented through operations, reduce major safety risks to tolerable and ALARP levels.

7 FUTURE PLANS FOR QUALITATIVE RISK ASSESSMENT

The sections above demonstrate that qualitative risk assessments have been used to develop and challenge the Corrib pipeline design to a point where the risk levels are considered to be ALARP. The assessments will continue to be used as an operational tool to make sure that the work conducted during the design phase of the Corrib pipeline continues to be implemented to manage risk throughout the lifetime of the facility.

The Corrib HSE Case acts as a repository for the qualitative risk assessment work, including the Corrib Risk Register and the major risk bowties. The HSE Case is a live document which will continue to be updated and used once operations commence. It is anticipated that the next stage of HSE Case development will involve submission of a Safety Case to the CER in compliance with the requirements of the Petroleum (Exploration and Extraction) Safety Act.

The outputs from qualitative risk assessments provide inputs into operations activities and controls, for example:

- SCEs identified as controls on the bowtie diagrams will have defined performance standards with independently verified checks as part of operating and maintenance routines to assure these standards are achieved.

- The controls identified on the major risk bowtie diagrams are supported and enforced through a number of activities undertaken by operations, maintenance and other personnel. The required competencies to perform these Safety Critical Activities effectively will provide input to job descriptions and competence assurance programmes.

- Completion of the Safety Critical Activities, on time and effectively, is assured through a structured system of procedures, manuals, databases, schedules, task instructions, etc. These collectively form the Corrib Safety Management System (SMS).

- Regular auditing to confirm that the Safety Critical Activities are performed, SCEs are maintained, competencies are met and risk controls as illustrated on the bowtie diagrams are in place, will ensure that the management of major risks continues to be effective and maintain risks at ALARP levels.

- Where there are temporary occasions where the controls on the bowties are impaired, measures will be in place to enforce restrictions on operations such that acceptable risk levels are maintained.

8 CONCLUSIONS

The objectives of a qualitative risk assessment are to ensure that all the risks are known and assessed, are effectively managed and that suitable and sufficient control measures are in place such that no further risk reduction measures could practicably be implemented.

It is concluded that these objectives have been met because this Section Q6.3 demonstrates that:

1. a systematic qualitative risk assessment process has been applied (so that all risks are known and assessed, as documented in the Corrib Risk Register in Attachment Q6.3A);

2. the risk assessment process aligns with relevant codes of practice and regulatory requirements (as described in Section 1.3);

3. the qualitative risk assessments carried out are robust, complete and comprehensive, and for major risks include detailed bowtie analysis (as presented in Attachment Q6.3B);

4. suitable and sufficient controls have been incorporated and additional risk reduction measures have been evaluated and implemented such that the risks associated with the Corrib pipeline have been reduced to ALARP levels (as demonstrated in Section 6); and

5. through definition of Safety Critical Activities, SCEs and implementation of the supporting SMS, the risks associated with the pipeline will continue to be maintained at ALARP levels during operations.

6. qualitative risk assessment is an ongoing process which will continue to be captured in the Corrib HSE Case as the detailed design develops, through construction and commissioning, into operations.

9 ABBREVIATIONS

ALARP	As Low As Reasonably Practicable
CCTV	Closed Circuit Television
CER	Commission for Energy Regulation
EIS	Environmental Impact Statement
GPS	Global Positioning System
HAZID	Hazard Identification
HAZOP	Hazard and Operability
HSE	Health, Safety and Environment
ISSOW	Integrated Safe Systems of Work
JSA	Job Safety Assessment
LVI	Landfall Valve Installation
MAOP	Maximum Allowable Operating Pressure
MODU	Mobile Offshore Drilling Unit
MOPO	Manual of Permitted Operations
MSDS	Material Safety Data Sheet
PIMS	Pipeline Integrity Management Scheme
PPE	Personal Protective Equipment
PTW	Permit to Work
QA/QC	Quality Assurance / Quality Control
QRA	Quantitative Risk Assessment
RAM	Risk Assessment Matrix
SCE	Safety Critical Element
SDU	Subsea Distribution Unit
SEPIL	Shell E&P Ireland Ltd.
SMS	Safety Management System
UI	Upstream International

ATTACHMENT Q6.3A

CORRIB RISK REGISTER

RISK REGISTER

This attachment to Section Q6.3 presents the Corrib Pipeline Facilities Risk Register.

The first Corrib HSE Case Workshop was held in Dublin in October 2005 at which the major risks associated with the proposed gas terminal, pipeline and subsea system that had been identified during the design phase were reviewed. A formal HAZID study session was held, using an agreed set of generic guidewords, with the objective of ensuring that all potential major risks had been identified and their nature defined in order to identify the key risk drivers. 'Major Risks Sheets' were compiled to fully document all major risks at this stage.

As part of the development work for the current Corrib HSE Case, a further HAZID workshop was held in September 2008, to systematically review all the hazards associated with operation of the wells, pipeline and gas terminal and determine the level of risk and control measures expected to be in place. Workshop participants included Corrib project, operations, production and maintenance personnel. The starting point for the workshop was the list of major risks generated by the previous HAZID study and a generic hazard hierarchy provided in Shell guidance for use with all types of hydrocarbon installations including pipelines (Figure A1).

For each hazard on the checklist, the workshop asked:

> *"Is this hazard relevant to our operations?"*
>
> *"What are the worst case credible potential consequences if we were to lose control of this hazard (as measured on the Shell Group Risk Assessment Matrix (RAM))?"*
>
> *"What is the frequency of an event of this magnitude occurring (again using the RAM)?"*
>
> *"What are the potential causes of this loss of control?" and*
>
> *"What are the controls we have (or expect to be) in place to either prevent the loss of control or recover from it?"*

Responses to each of the above questions were recorded in the register. The complete register, including those risks judged to be irrelevant, and risks associated with Gas Terminal facilities and operations, is presented in the Corrib HSE Case. The version presented here is abridged to show only those risks relevant to the Corrib pipeline facilities (i.e. irrelevant risks and Gas Terminal-specific risks have been removed).

The Risk Register is subject to periodic review and update, as part of the review and update process for the HSE Case which continues to be developed through the design phase and in anticipation of commencement of operations.

RISK ASSESSMENT MATRIX

Risks associated with hazards are categorised in accordance with Shell's Risk Assessment Matrix (Figure A2); those risks judged potentially as 'high' or severity level 5 are classified as major. Bowties are developed for major risks (and for other risks on a selective basis) as recorded in the Risk Register. Examples of bowties are provided in Attachment Q6.3B.

The Shell Risk Assessment Matrix aligns closely with those contained in qualitative risk assessment standards such as ISO 17776:2000(E) Petroleum and Natural Gas Industries – Offshore Production Installations – Guidelines on Tools & Techniques for Hazard Identification and Risk Assessment and AS 2885.1-2007 Pipelines - Gas and Liquid Petroleum - Design and Construction.

Note that the risk is assessed assuming control of the hazard has been lost i.e. no credit is assumed for correct functioning of the controls planned to be in place. This means that the risk value recorded in the risk register is actually the *potential risk* rather than the residual risk which remains once the controls have been implemented and are working correctly.

The reason for assessing the risk in this way is to highlight which risks have the inherent potential to be high, so that commensurate levels of control can be identified, implemented and enforced. The higher the level of potential risk, the greater the level of control needed.

Similarly, the higher the level of potential risk, the greater the level of detailed risk assessment carried out, hence the bowtie analysis focuses on the events with the highest potential risk.

Assessment of the acceptability of the residual risk for the major risk scenarios is documented in Section 6, which considers the effectiveness of the identified controls, reviews options for additional risk reduction measures and documents those risk reduction measures which have been implemented. This process by which additional risk reduction measures are identified, evaluated and implemented to progressively reduce the risk, ensures the residual risk associated with the hazard is reduced to ALARP levels.

RISK CONTROLS

The specific controls in place for each risk are recorded in the Risk Register (or, where bowties have been developed, are illustrated on the bowtie diagram).

In addition to the SEPIL-specific controls listed in the register, Shell operates a system of Global and UIE-specific company standards for management of hazards. Wherever possible the relevant controlling document has been adopted in its entirety by SEPIL, rather than producing separate, SEPIL-specific documents. For the purposes of clarity however, the entire library of Shell standards has not been individually listed in the Risk Register.

CORRIB PIPELINE MAJOR RISKS

The 2008 HAZID workshop identified a number of major risks associated with operations at the Gas Terminal and the following major risks associated with operation of the Corrib subsea and pipeline facilities:

- H-01.03 Hydrocarbon release from subsea facilities (wells, flexible flowlines, manifold or offshore pipeline);
- H-01.03 Hydrocarbon release from LVI;
- H-01.03 Hydrocarbon release from onshore pipeline; and
- H-05.03 Dropped objects at LVI.

These major risks were carried forward for detailed qualitative risk assessment (bowtie analysis) (see Attachment Q6.3B).

Figure A1: Shell Generic Hazard Hierarchy for Hydrocarbon Installations*

H-01 Hydrocarbons (Unrefined)
H-02 Hydrocarbons (Refined)
H-03 Explosives
H-04 Pressure
H-05 Differences in Height
H-06 Objects under Induced Stress
H-07 Dynamic Situations
H-08 Natural Environment
H-09 Electricity
H-10 Physical
H-11 Toxic Atmosphere/Medium
H-12 Chemical Substances
H-13 Biological
H-14 Ergonomic
H-15 Psychological
H-16 Security
H-17 Environmental Aspects

* Based on a generic hierarchy provided in ISO 17776:2000(E) Petroleum and Natural Gas Industries – Offshore Production Installations – Guidelines on Tools & Techniques for Hazard Identification and Risk Assessment.

Figure A2: Risk Assessment Matrix

Severity	Consequences				Increasing Likelihood				
					A	B	C	D	E
	P	A	E	R	Never heard of in industry	Heard of in industry	Incident has occurred in UIE (or more than once per year in industry)	Incident has happened at location (or more than once per year in UIE)	Has happened more than once per year at location
0	No injury or health effect	No damage	No effect	No Impact					
1	Slight injury or health effect	Slight damage	Slight effect	Slight impact					
2	Minor injury or health effect	Minor damage	Minor effect	Minor impact					
3	Major injury or health effect	Moderate damage	Moderate effect	Moderate impact					
4	PTD or up to 3 fatalities	Major damage	Major effect	Major impact					
5	More than 3 fatalities	Massive damage	Massive effect	Massive impact					

Risk Level	Low (Routine)	Medium (Significant)	High (Major)

Note: The definition of Likelihood C was changed from “Incident has occurred in SEPIL (or more than once per year in industry)” to “Incident has occurred in Upstream International Europe (UIE) (or more than once per year in industry)” during the meeting. It was considered that, due to the current size and operating experience of SEPIL, using UIE instead of SEPIL would provide a more representative assessment. Likelihood D was similarly modified.

Corrib Pipeline Risk Register

Haz No	Hazard & Source	Threats (Causes)	Top Event	Consequences	Risk Potential				Controls	Comments
					P	A	E	R		
H-01	**Hydrocarbons (Unrefined)**									
.03	Reservoir hydrocarbons • Wells	• Wirelining • Coiled tubing • Well stimulation	Loss of well control	• Unignited blowout/spill • Ignited blowout	-	-	-	-		Exploration and development drilling is performed by contracted MODUs - outside scope of this risk register. Subsea activities are well intervention only. Exploration and development drilling will be done as an addendum to the Operations HSE case.
	• Wells • Subsea manifold • Offshore pipeline • Infield flowline system	• Impact (from vessel anchors, dropped objects, fishing) • Corrosion • Erosion • Scouring/seabed deformation • Material failure • Overpressure • Hydrate formation • Well integrity testing – operated remotely	Loss of Containment	• Unignited release • Fire	B4 B5	B4 B4	B2 B2	B4 B4	**See Bowtie H-01.03a (Release from Wells. Flexible Lines and Offshore Pipeline)**	Potential exists that unignited gas release from subsea pipeline could result in loss of buoyancy for passing vessels.
	• landfall valve installation (LVI)	• Impact (vehicle or dropped object) • Corrosion • Erosion • Material failure • Overpressure • Third party activities • Intentional damage • Ground movement / landslip • Hydrate formation		• Unignited release • Fire	C2 C5	C5 C5	C3 C3	C4 C5	**See Bowtie H-01.03b (Release from LVI)**	Initially subject to a detailed bowtie analysis in 2007 as part of onshore pipeline study.
	• onshore pipeline	• Impact (excavation) • Corrosion • Erosion • Material failure • Overpressure • Third party activities • Intentional damage • Ground movement / landslip • Hydrate formation		• Unignited release • Fire	C2 C5	C5 C5	C3 C3	C4 C5	**See Bowtie H-01.03c (Release from Onshore Pipeline)**	Initially subject to a separate detailed bowtie analysis in 2007.

Corrib Pipeline Risk Register

Haz No	Hazard & Source	Threats (Causes)	Top Event	Consequences	Risk Potential				Controls	Comments
					P	A	E	R		
H-02	**Hydrocarbons (Refined)**									
.06	Lubricating oil	• Equipment failure • Mechanical damage • Corrosion • seal failure	Loss of containment	• Release to sea	B0	B3	B2	B1	Valve design and selection.	Only oil in subsea valves is oil within the actuators - small volume (litres only).
	Hydraulic oil • LVI • Umbilical (onshore or close to shore)	• Equipment failure • Mechanical damage • Seal failure • Corrosion • Third party activities	Loss of Containment	• High pressure jet	C4	C3	C2	C2	Equipment inspection and maintenance schedules. Umbilical design and selection. **See Bowtie H-12.10/154 (Umbilical Failure)**	Valves fail closed and will result in production loss until reopened. Water based fluids are used as hydraulic fluid. It is assumed that releases of hydraulic fluids are reportable if they are onshore or in the bay and not reportable if they are offshore and outside the bay. Although not rated as a major risk, this scenario was subject to detailed bowtie analysis in December 2009 / January 2010 workshops.
	• Umbilical (offshore)	• Equipment failure • Mechanical damage • Seal failure • Corrosion	Loss of Containment	• High pressure jet	C0	C4	C0	C1		
H-04	**Pressure**									
.01	Gas under pressure – bottles (nitrogen in hydraulic compensators)	• Equipment failure • Mechanical damage • Seal failure • Corrosion	Loss of containment	• Valves fail shut resulting in shutdown of the relevant well	A0	A4	A0	A0	Valve design and selection.	
	Gas under pressure in pipework	-	-	-	-	-	-	-	-	No hazards identified over and above those assessed under H-01.03 above.
.04	Hyperbaric operations (diving)	-	-	-	-	-	-	-	-	Major diving operations performed by specialist subcontractors from dedicated diving support vessel - outside the scope of this risk register.

Corrib Pipeline Risk Register

Haz No	Hazard & Source	Threats (Causes)	Top Event	Consequences	Risk Potential				Controls	Comments
					P	A	E	R		
H-05	**Differences in Height**									
.01 & 02	Personnel at height >2m (at LVI) • Scaffolding • Ladders, work platforms	• Human error, slips, trips • Equipment failure	Falls to lower level	Injuries / fatality	C4	C1	C0	C1	PTW required for all cases where working above ground level but where there is no handrail. Training for personnel in use of fall arrest harnesses. Harnesses checked under Preventive Maintenance System. Physical markings (hazard notification). Scaffolding standard and training in scaffold construction - Scaff Tags to show status. Hand rails on scaffolding, cages on ladders. Audit / inspection program includes checks on stairways, ladders etc.	Working at height is only allowed where adequate working platforms are in place. NOTE: Working at height regulations have changed and now apply to all heights above ground level.
.03	Objects overhead (at LVI) • Cranes • Equipment / stores • Tools, scaffolding • Chain hoists	• Sling / rigging failure • Crane mechanical failure • Hydraulic failure • Equipment failure - part of equipment falling from height • Overloaded crane • Severe weather • Human error – incorrect rigging • Human error – snatched load / incorrect lifting movement	Loss of control / falls to lower level	Major/heavy load dropped – injuries, fatality, equipment damage possibly leading to a release of hydrocarbons	D4	D3	D2	D2	**See Dropped Objects threats on Bowtie H-01.03b (Release from LVI).**	Considered as cause of loss of containment (from dropped object impacting process equipment, piping, tanks, etc.) as appropriate. Control of heavy lifts – PTW system and JSA.
.04	Ground/slope stability	-	-	-	-	-	-	-	**See Ground Movement threats on Bowtie H-01.03a, b and c (Release from Offshore Pipeline, LVI and Onshore Pipeline)** Ground movement risks captured in a specific Geotechnical Risk Register (see EIS Appendix M).	Ground / slope instability considered as a potential cause of damage to offshore / onshore pipeline and LVI – see H-01.03.

Corrib Pipeline Risk Register

Haz No	Hazard & Source	Threats (Causes)	Top Event	Consequences	Risk Potential				Controls	Comments
					P	A	E	R		
H-06	**Objects under Induced Stress**									
.01	Objects under tension (at LVI) • Cables • Slings, hoists • Guide wires • Tag lines • Winches	• Equipment failure • Operator error – incorrect attachment, overload • High winds	Uncontrolled release of energy	Cable whip	C4	C3	C1	C2	Maintenance schedules and procedures. Inspection and maintenance of slings. Safe work plans developed for major works. Lifting procedures.	
H-07	**Dynamic Situations**									
.01	Land transport (driving) (at LVI) • Company light vehicles • Cranes • Road tankers / trucks	• Vehicle mechanical failure • Driver error • Speeding • Poor weather • Failure to secure loads • Other road users	Loss of control	• Truck containing hazardous substances accident site – fire / spill • Impact with equipment / structures on site	C5	C3	C2	C2	**See HSE Case Bowtie H-07.01 (Onsite transport accident)** Shell Road Safety standards Corrib Transport and Logistics HSE Case	Individuals travelling to/from work in private vehicles on public roads, and offsite operations of condensate / methanol / diesel trucks are outside the scope of this risk register but covered in separate Transport and Logistics HSE Case. Action: A traffic management plan for the site is to be developed. *Action closed – traffic management plan superseded by Transport and Logistics HSE Case.* Personnel will only be at the LVI to carry out inspection and maintenance jobs.
.02	Water transport • Activities at subsea facilities e.g. periodic inspection of subsea facilities and pipeline • Offshore pipeline • Outfall	• Loss of propulsion system/drifting • Extreme weather (wind, sea state) • Collision from other vessel (supply boats, standby boats, fishing boats)	Loss of control / moving off position	• Heel/list, loss of vessel stability/grounding • Sinking (loss of cargo, pollution, fatalities) • Collision with fishing vessel • Man overboard	C0 A5 B3 B3	C0 A0 B0 B0	C0 A3 B3 B0	C0 A3 B3 B2	Vessel design. Vessel selection in line with Shell procedures. Crew training and competency. Lifesaving equipment. Emergency response procedures.	Offshore activities are planned to be extremely infrequent. North sea class inspection vessel.
	Motion sickness • Activities at subsea facilities • Offshore pipeline • Outfall	• Excessive motion	Exposure to	• Motion sickness	D2	D0	D0	D0	Weather limits on boat operations. Competency of vessel personnel (specifically the captain).	Offshore activities extremely infrequent.

Corrib Pipeline Risk Register

Haz No	Hazard & Source	Threats (Causes)	Top Event	Consequences	Risk Potential				Controls	Comments
					P	A	E	R		
	Boat collision hazard • Passing shipping - fishing, merchant, protesters	• Loss of power / mechanical failure • Poor weather • Helmsman error	Impact with platform or pipeline	• Low energy impact • High energy collision - loss of structural integrity • Environmental impact due to spilled substances	-	-	-	-	**See Accidental and Intentional Impact threats on Bowtie H-01.03a (Release from Offshore Pipeline)**	Impact of manifold / offshore pipeline by vessel anchors etc. is assessed as a potential threat of hydrocarbon release from manifold / pipeline (see H-01.03).
.04	Equipment with moving or rotating parts (at LVI) • Pumps, coolers compressors, fans • Reciprocating equipment • Emergency generator • Valves	• Equipment failure • Operator error • Operation outside design limits	Loss of control/ separation	Crushing / entanglement	C4	C2	C1	C1	Personnel hazard awareness. Facility-specific training. Competent personnel. Equipment design (guards, barriers, shielding etc.). Maintenance policy and procedures. Lock out and tag out for maintenance work on powered equipment.	Risk shown is for rotating equipment at Terminal. Moving equipment on the wells and at LVI limited to valves so risk at LVI should be lower.
				Missiles (disruptive failure of turbines, impellers etc.)	B4	B4	B2	B3	Scheduled inspection and maintenance of equipment to maintain integrity. Instrumentation and operator rounds to provide early indication of potential problems. Maintenance procedures for pumps, compressors, generators, etc. Facility-specific training. Competent personnel.	
.05	Using hand tools (at LVI) • Grinders • Cutting torches • General workshop equipment • Circular saws, jig saws • Utility knives	• Operator error • missing guards	Loss of separation	• Crushing, cutting, lacerations	C4	C2	C1	C1	Personnel competence and training. New hire supervision for use of hand tools. Work with potential to generate ignition source outside of safe areas requires PTW. Pre-use inspection of electrical tools. Procedure for welding and burning in hazardous areas. Facility-specific training. Competent personnel.	Risk shown is for use of hand tools at Terminal. Use of hand tools at LVI will be limited – much less than at Terminal, so risk at LVI should be lower.

Corrib Pipeline Risk Register

Haz No	Hazard & Source	Threats (Causes)	Top Event	Consequences	Risk Potential				Controls	Comments
					P	A	E	R		
H-08	**Natural Environmental**									
.01	Weather	• Rain	Heavy rainstorm	• Surface run-off/pollution • Slips and falls	E1	E0	E2	E1	Personnel competence and training. Raingear. LVI drain system. **See Flooding threat on Bowtie H-01.03b and c (Release from LVI and from Onshore Pipeline)**	Although not rated during the HAZID as a major risk, heavy rain / flooding of the LVI or washout of ground around onshore pipeline was identified as a potential threat in December 2009 / January 2010 bowtie workshops.
		• High winds	Windstorm	• Plant damage • Crane operations compromised • Structural failure • Flying debris	B2	B1	B0	B0	No work performed outside during high winds. Crane operations cease on warnings of poor weather. Adverse Weather Working standards	Weather limits on a number of operations, as recorded in the MOPO.
		• Temperature extremes	Extreme cold	Slips and falls	C3	C1	C0	C0	Personnel competence and training. PPE. Cold weather gear.	Exposure not considered to be a realistic hazard.
.02	Marine/water conditions	-	-	-	-	-	-	-	-	Offshore activities infrequent. Marine / water conditions considered as a potential cause of boat accident (see H-07.02).
.03	Tectonic/land effects	-	-	-	-	-	-	-	-	Considered to be remote hazard. Area is one of low tectonic activity. See also H-05.04.
.04	Fire	Fire originates off site	Fire /smoke reaches facility	• Precautionary shutdown • Injuries / fatalities	-	-	-	-	-	There could be fires offsite but the pipeline will not be affected as it is buried.
.05	Lightning	• Lightning storms	Lightning strike	• Lightning strike - fire, equipment damage • Electrocution • Plant shutdown	D1	D3	D2	D2	**See Lightning threat on Bowtie H-01.03b and c (Release from LVI and from Onshore Pipeline)**	Although not rated during the HAZID as a major risk, lightning strike of the LVI or onshore pipeline was identified as a potential threat in December 2009 / January 2010 bowtie workshops.

Corrib Pipeline Risk Register

Haz No	Hazard & Source	Threats (Causes)	Top Event	Consequences	Risk Potential				Controls	Comments
					P	A	E	R		
H-09	**Electricity**									
.01	Voltage > 50 < 480V (at LVI) • Control Panel • Lighting • CCTV	• Maintenance activities • Short circuit • Sparks	Contact with electricity	• Electrocution • Burns • Switchgear explosions/ fire • Total power outage inc. UPS	D3 B4	D1 B3	D1 B2	D2 B2	Maintenance procedures for working on electrical systems. Access to systems restricted to site electricians only. Use of competent personnel. Facility-specific training includes electrical safe working practices. New hire supervision for hand tools. Pre-use inspection of electrical tools. ISSOW / PTW system.	
H-10	**Physical**									
.01	X-rays	-	-	-	-	-	-	-	-	See H-10.09.
.02	Ultraviolet light (at LVI) • Sunlight • Welding	-	-	-	-	-	-	-	-	See Bellanaboy Terminal Hazards and Effects Register (H-10.02).
.08	Extremely low frequency magnetic radiation	Electrical generation, switchgear	Exposure to	-	-	-	-	-	-	It is not considered that these present a hazard.
.09, .10	Alpha, Beta particles, gamma rays • Well logging	• Operator error • Equipment/ shielding failure	Exposure to	Over exposure/ exposure to lost source	A3	A0	A0	A0	Specialist subcontractor usage only. Use of radioactive sources will require a permit and marking of area. PPE as required by the ISSOW / PTW system.	
.12	Naturally occurring ionising radiation	• Maintenance activities • Produced fluids	Exposure to	Overexposure - health effects	B4	-	-	-		Radon gas is not considered a hazard. It is not expected that there will be any NORM within the process system.
.14	Vibration (at LVI) • Hand tools • Needle guns	• Plant operations • Maintenance activities • Paint chipping	Exposure to excessive levels	• Vibration white finger • Repetitive strain injury	C4/ D3	C0	C0	C0	Operator experience and training. Hand-arm vibration strategy for project – all machines will have their vibration levels marked and the time spent on each item noted.	

Corrib Pipeline Risk Register

Haz No	Hazard & Source	Threats (Causes)	Top Event	Consequences	Risk Potential				Controls	Comments
					P	A	E	R		
.15	Cold temperature differentials • Wells • LVI	• Joule Thompson effect downstream of the chokes	Excessive cold temperatures	• Material failure leading to gas release	B0	B4	B2	B4	Design of wells, flexible lines and pipeline. Operating procedures. **See Extreme Low Temperature threat on Bowties H-01.03a (Release from Wells, Flexibles and Offshore Pipeline) and Bowtie H-01.03b (Release from LVI)**	Considered as a potential cause of hydrocarbon release from wells.
.18	Cellulosic materials • Scaffolding planks • Packaging	• Electrical fault • Hot work	Ignition	Fire, smoke inhalation	C3	C2	C2	C2	Dedicated vented storage container for paint with adjacent fire fighting equipment. Painting operations checklist and requires a permit. Hot work requires a permit.	Smoking permitted in designated areas only.
H-11	**Toxic Atmosphere/Medium**									
.01	Oxygen concentration in air (confined spaces) • Sumps / chambers at LVI	• Insufficient O_2 atmospheres • Toxic gas accumulation	Exposure to	Asphyxiation	C4	B1	B0	B2	Confined space entry procedures. Permit required for all confined space entries. Facility-specific training. Standby man. Self Contained Breathing Apparatus. Lifeline. O_2 testing. Double block and blinds for entry lines.	
	Oxygen concentration in air (displacement by other gases) • Use of fire extinguishers in confined space • CO_2 deluge system at LVI control panel	• Spurious release of CO_2 deluge • Fire fighting activities	Exposure to	Asphyxiation	C4	B0	B0	B2	Facility-specific training includes use of fire extinguishers. Monthly and yearly checks on fire extinguishers. Time delay and alarms prior to CO_2 deluge release.	Not required to inform Environmental Protection Agency if CO_2 extinguishers are released.
	• Welding fumes	• Maintenance activities / on-site repairs • Confined spaces	Exposure to/ release	• Asphyxiation • respiratory irritants (ozone), CO, phosgene etc.	C2/ B3	C0	C0	C0	Safe work area well ventilated. PPE. Specific training for welders. Use of BA sets.	

Corrib Pipeline Risk Register

Haz No	Hazard & Source	Threats (Causes)	Top Event	Consequences	Risk Potential				Controls	Comments
					P	A	E	R		
.03	Particulates in air/ dusts • Grit blasting	Maintenance activities	Exposure to/ release	Respiratory irritant	C4	C0	C0	C0	Procedure for grit blasting and painting operations. PTW and job specific safe work plans developed. PPE.	Grit blasting expected to be infrequent activity.
	Smoke • Accidental fires • Exhaust systems	• Fire fighting activities	Exposure to/ release	• Health effects • Smoky flares	-	-	-	-	PPE and specialist training for fire crews. **See Fire at LVI threat on Bowtie H-01.03b (Release from LVI)**	Combustible materials are not stored at the LVI. The LVI is not continuously occupied. Fire at LVI was identified during the December 2009 / January 2010 bowtie workshops as a potential cause of release of hydrocarbons at the LVI.
.04	Water • Offshore activities e.g. inspection, maintenance • Onshore pipeline water crossings	• Human error • Slip/trip • Poor weather	Immersion	• Drowning	-	-	-	-	All work over water requires a permit. PPE will include a floatation vest. Emergency response procedures cover incidents at water.	See H-07.02 for scenario of man overboard from boat at offshore facilities. Manual inspection of the pipeline close to land and under the bay is not necessary as the pipe is buried / tunnelled.
H-12 Chemical Substances										
.010	Additives									
	Corrosion inhibitors • Control systems • Injection into onshore / offshore pipelines and subsea systems • Umbilical	• Production operations • Maintenance activities • Handling operations	Exposure to/ release	Moderate to severe skin and eye irritant, corrosive	C3	C1	C2	C0	Procedure for safe handling of chemicals. MSDS. Facility-specific training. PPE. **See Bowtie H-12.10/154 (Umbilical Failure)**	Corrosion inhibitor is injected with methanol. The corrosion inhibitor product has not yet been defined.
	Defoamer/water clarifier/coagulant	• Production operations	Exposure to/ release	Minimal toxicity, skin irritation	C3	C1	C2	C0	Procedure for safe handling of chemicals. MSDS. Facility-specific training. PPE.	Antifoam may be injected along with methanol.
	Oxygen scavenger	• Production operations • Corrosion control	Exposure to/ release	Irritation	C3	-	-	-	Procedure for safe handling of chemicals. MSDS. Facility-specific training. PPE.	Oxygen scavenger is injected with methanol. The oxygen scavenger product has not yet been defined.

Corrib Pipeline Risk Register

Haz No	Hazard & Source	Threats (Causes)	Top Event	Consequences	Risk Potential				Controls	Comments
					P	A	E	R		
.011	Man made mineral fibre • Insulation at LVI	• Maintenance activities • Installing / removing insulation	Exposure to	Respiratory and skin irritation	B3	-	-	-	Insulation removal is irregular activity and performed by specialist subcontractors. PPE as required by ISSOW.	Action: To be confirmed whether the man made fibres used in insulation are carcinogenic.
.018	Solvents/paints (at LVI)	Painting operations	Exposure to	Skin/eye irritation, chronic effects	B3	C0	C0	C0	Procedures for grit blasting & painting operations. Procedure for safe handling of chemicals. MSDS. Facility-specific training. PPE.	Non toxic paints used. Only fabric maintenance paints.
.153	Mercury	-	-	-	-	-	-	-	-	There are small quantities of mercury in the gas stream which may form part of the pipeline scale. This is not within the scope of the Safety Case but will form part of the abandonment project.
.154	Other - methanol • Umbilical • Injection at manifold / wells • Injection at LVI as required	• Impact (vehicle or dropped object) • Corrosion • Seal failure • Material failure	Loss of Containment	• Health / environmental effects at LVI • Release to sea • Fire	C2/ B3 C0 B4	C1 C4 B4	C2 C2 B2	C1 C2 B3	Procedure for safe handling, storage and transfer of chemicals. MSDS. Drums stored in baskets at dedicated locations when not in use. Permit required for hot work. Heat detection **See Bowtie H-12.10/154 (Umbilical Failure)**	Although not rated during the HAZID as a major risk, umbilical failure was identified in the bowtie workshops as a potential contributor to release of hydrocarbons from the pipeline. In the December 2009 / January 2010 bowtie workshops, umbilical failure was assessed in detail in a separate bowtie diagram.
H-13 Biological										
-	-	-	-	-	-	-	-	-	-	Covered by separate Corrib Health Risk Assessment.
H-14	**Ergonomic**									
.01	Workspace	• Inadequate positioning of controls and valves • Inaccessible, cramped work locations • High valves • Poorly designed office workstations	Exposure to	Repetitive strain injury, back strain, eye strain	C3	-	-	-	Modern plant design with accessible controls and valves. Temporary scaffolding erected where required. Ergonomics review of office workstations.	Can be potential cause of falls from height - see H-05.

Corrib Pipeline Risk Register

Haz No	Hazard & Source	Threats (Causes)	Top Event	Consequences	Risk Potential				Controls	Comments
					P	A	E	R		
	Visible light (poor lighting)	• Enclosed areas • Night working	Exposure to	• Accidents • Eye strain	-	-	-	-	Additional lighting brought in as required.	Included as a cause of accidents for other hazards as appropriate. Maintenance tasks may require additional temporary lighting.
.02	Physically demanding task - manual materials handling • Drums & bags • Valves • Repetitive tool use	• Plant operations • Maintenance activities	Loss of control	• Personnel injury/ repetitive strain injury/ permanent disability • Impact, dropped object strikes plant	D4	D0	D0	D0	Operator experience and training. Mentoring and observation of new staff.	Impact from dropped objects is considered as potential initiator for loss of containment incidents as appropriate.
.03	Human machine interface	-	-	-	-	-	-	-	-	Considered as a contributor to other accident scenarios as appropriate.
H-15	**Psychological Hazards**									
.01	Organisation, systems and culture	• Organisational re-design • Single source contractors	Inadequate supervision /manning	• Accidents • Poor quality work	-	-	-	-	Contractor audits. Long term relationships wherever possible.	Considered as a contributor to other accident scenarios as appropriate.
.02	Job demands • Work planning issues	• Concurrent operations, e.g. interaction between drilling and production • Overloading personnel - poor scheduling	Interaction of jobs, inadequate time to perform jobs properly	Accidents	C3	-	-	-	Safe work plan produced for all major works. Limitations on concurrent operations (MOPO).	May act as an initiator for another accident with potential fatal consequences e.g. falls, opening live system, isolation blinds, etc.
	• Insufficient resources	• Long/irregular working hours • High demands on supervisory staff	Fatigue/stress	Illness, mistakes, accidents, leading to personnel injury, asset damage or environmental impact	-	-	-	-	12 hour shift pattern ensures all staff get sufficient time off / working hours are monitored. Safe work plans developed for extended jobs.	Considered as a contributor to other accident scenarios as appropriate.
.07	Critical incidents at work	• Previous accidents • Downsizing	Increased stress	Accidents	-	-	-	-		Additional stress may be initiator for accidents.
H-16	**Security**									
-	-	-	-	-	-	-	-	-	-	Refer to facilities security plan (confidential).
H-17	**Environmental Aspects**									
-	-	-	-	-	-	-	-	-		Assessed in detail in Environmental Impact Assessment.

ATTACHMENT Q6.3B

CORRIB MAJOR RISK BOWTIES

INTRODUCTION

This attachment to Section Q6.3 presents extracts from the major risk bowtie diagrams constructed for the Corrib facilities. The bowties form a core component of the HSE Case which is under development and present a detailed, qualitative risk assessment to demonstrate the effectiveness of risk controls in place to manage the identified hazards.

A detailed description of the bowtie analysis method is presented in Section 5.1 of the main body of Section Q6.3, and a summary is given below.

BOWTIE ANALYSIS METHOD

A simple bowtie diagram is illustrated in Figure B1. In the diagram, the hazard (e.g. hydrocarbon gas in a pipeline) is located at the centre of the diagram together with the top event i.e. the release of the hazard (e.g. loss of containment of the gas). On the left side are the identified potential causes or threats (e.g. corrosion, overpressure, impact damage, etc.) and on the right side, potential consequences (e.g. flammable gas cloud, or fire if the release is ignited).

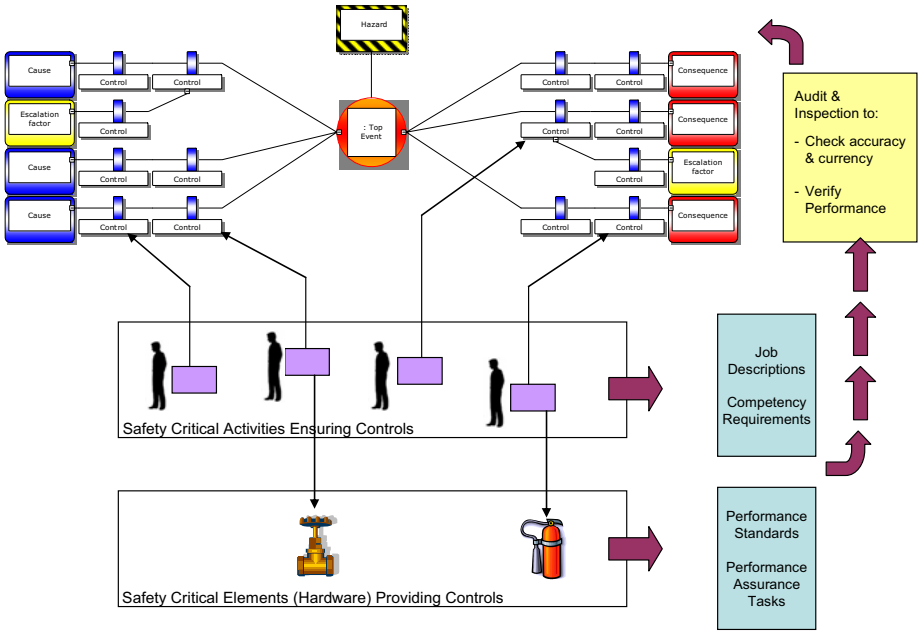
In between the threats and the top event are the controls that prevent the top event occurring. In the example of the hydrocarbon gas hazard, a typical preventive control would be a pressure alarm and trip to help prevent overpressure, or design features such as coatings to minimise the risk of corrosion.

On the right side of the diagram are the recovery controls that serve to minimise or prevent consequences, in the event that the top event occurs. Taking the example of loss of containment of hydrocarbon gas, a recovery control would be the process monitoring system which identifies when a leak has occurred and raises an alarm so that emergency response actions can be taken.

Also illustrated on the bowtie diagram are escalation factors on certain control measures. These can be used to illustrate that there are also measures in place to prevent failure of the identified preventive controls and recovery measures.

In the example, an escalation factor would be that the pressure alarm has been malfunctioning for a number of weeks and so has been overridden or taken out of service pending repair. A control on this escalation factor might be that additional measures are put in place (e.g. more frequent readings of the pressure indicator) while the alarm is out of action.

Figure B1: Bowtie Diagram Schematic

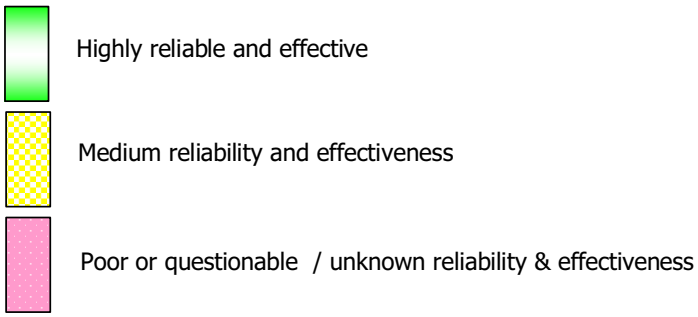


BOWTIE CONTROL EFFECTIVENESS

When building a bowtie, the effectiveness of each preventive and recovery control is assessed and recorded (Figure B2).

Some types of control are more effective than others. For example, eliminating the hazard all together or substituting it for a less hazardous one is the most effective type of control; a hardware / engineered control is more effective than something that relies on a person to do something; a passive guard is more effective than something with moving parts which can break down, etc.

Figure B2: Bowtie Control Effectiveness



CORRIB BOWTIES

The development of detailed bowties for the Corrib facilities started in 2006 (see Section 5.2 of the main body of this document Q6.3) and continues as a work in progress as part of operational preparedness and HSE Case development.

There are four bowties which present the qualitative risk assessment of hazards associated with the pipeline facilities (Table B1). The four bowties currently include (between them) 112 causes (threats), 30 potential consequences and over 1,000 preventive and recovery control measures.

Table B1: Corrib Pipeline Facilities Bowties

Hazard No.	Scenario
H-01.03a	Release from wells, flexible lines and offshore pipeline
H-01.03b	Release from LVI
H-01.03c	Release from onshore pipeline
H-12.10/154	Umbilical failure

An overview of the threats and consequences for all four bowties, and detailed extracts showing the extent of the analysis for selected branches are presented on the following pages (Table B2).

The bowtie extracts have been selected on the basis that they:

- illustrate risks which cannot be easily defined mathematically;
- include scenarios which are relevant to / contribute to the QRA;
- address issues of concern raised at the 2009 oral hearing (e.g. umbilical failure); and
- cover a range of locations and operating conditions.

It can be seen from Table B2 that there are more extracts included in this document from the left (threat) side of the bowties than from the right (consequence) side. This is because, for left side branches, each distinct cause (threat) has a set of preventive measures which are specific to that cause. However, once a release of hydrocarbons occurs, the recovery controls initiated to limit the consequences are all very similar for the different major risk scenarios (e.g. detect the release, isolate the release, initiate emergency response procedures) and there is a high degree of repetition between the right side branches of all four bowties.

An extract from the right (consequence) side for a release from the onshore pipeline has, however, been included to illustrate the extent of the recovery controls in place to deal with a hydrocarbon release. These recovery measures are illustrated in Figure B5.20 on page B42 and Figure B5.24 on Page B46 of this attachment. Extracts from the right (consequence) side of the umbilical failure bowtie are also included (Figure B6.3 and B6.4) to illustrate the recovery controls in place to respond to umbilical failure.

Table B2: Corrib Pipeline Facilities Bowties Extracts

Figure No.	Hazard No.	Scenario	Extracts Shown in Detail
B3	H-01.03a	Release from wells, flexible lines and offshore pipeline	*Threats (causes):*
			Offshore pipeline internal corrosion (Figures B3.4 – B3.9)
			Offshore pipeline external corrosion (Figures B3.10 – B3.12)
			Hydrate formation in offshore pipeline system (Figures B3.13)
			Fatigue induced by pressure cycles in offshore system (Figure B3.14)
B4	H-01.03b	Release from LVI	*Threats (causes):*
			Dropped objects (Figures B4.3 & B4.4)
			Intentional 3rd party damage to the LVI (Figure B4.5)
B5	H-01.03c	Release from onshore pipeline	*Threats (causes):*
			Onshore pipeline internal corrosion (Figures B5.4 – B5.9)
			Onshore pipeline external corrosion (Figures B5.10 – B5.13)
			Peat slide affects onshore pipeline (Figures B5.14 - B5.16)
			Accidental impact of pipeline on land (Figure B5.17)
			Peat fire threatens pipeline (Figure B5.18)
			Maintenance error (Figure B5.19)
			Consequences:
			Onshore pipeline rupture (Figures B5.20 - B5.23)
			Onshore pipeline fire (Figure B5.24)
B6	H-12.10/154	Umbilical failure	*Consequences:*
			Loss of hydraulics (Figure B6.3)
			Loss of corrosion inhibitor / methanol (Figure B6.4)

Figure B3.1 - H-01.03a Release from Wells, Flexible Lines and Offshore Pipeline Overview of Threats and Consequences

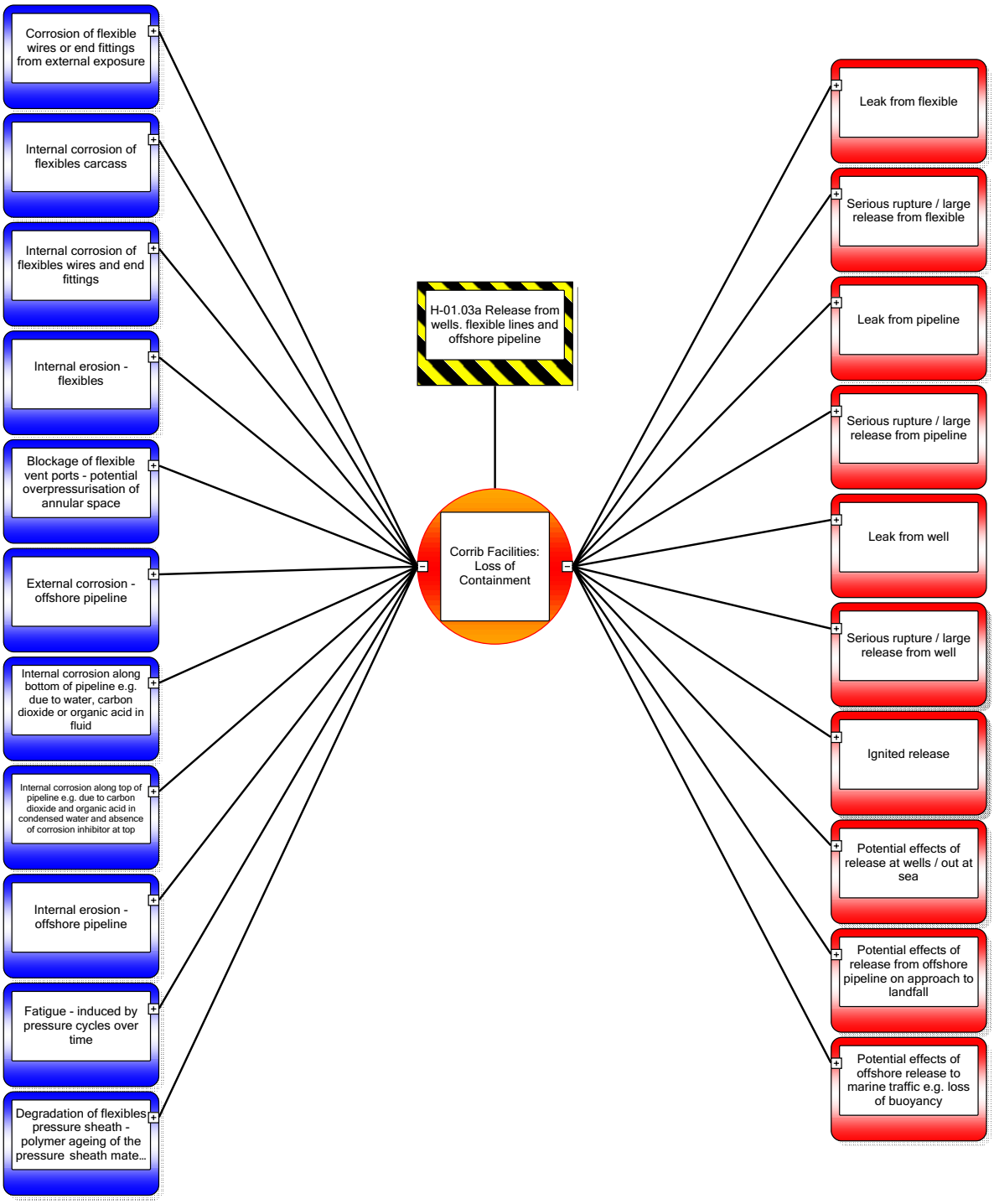


Figure B3.2 - H-01.03a Release from Wells, Flexible Lines and Offshore Pipeline Overview of Threats and Consequences (continued)

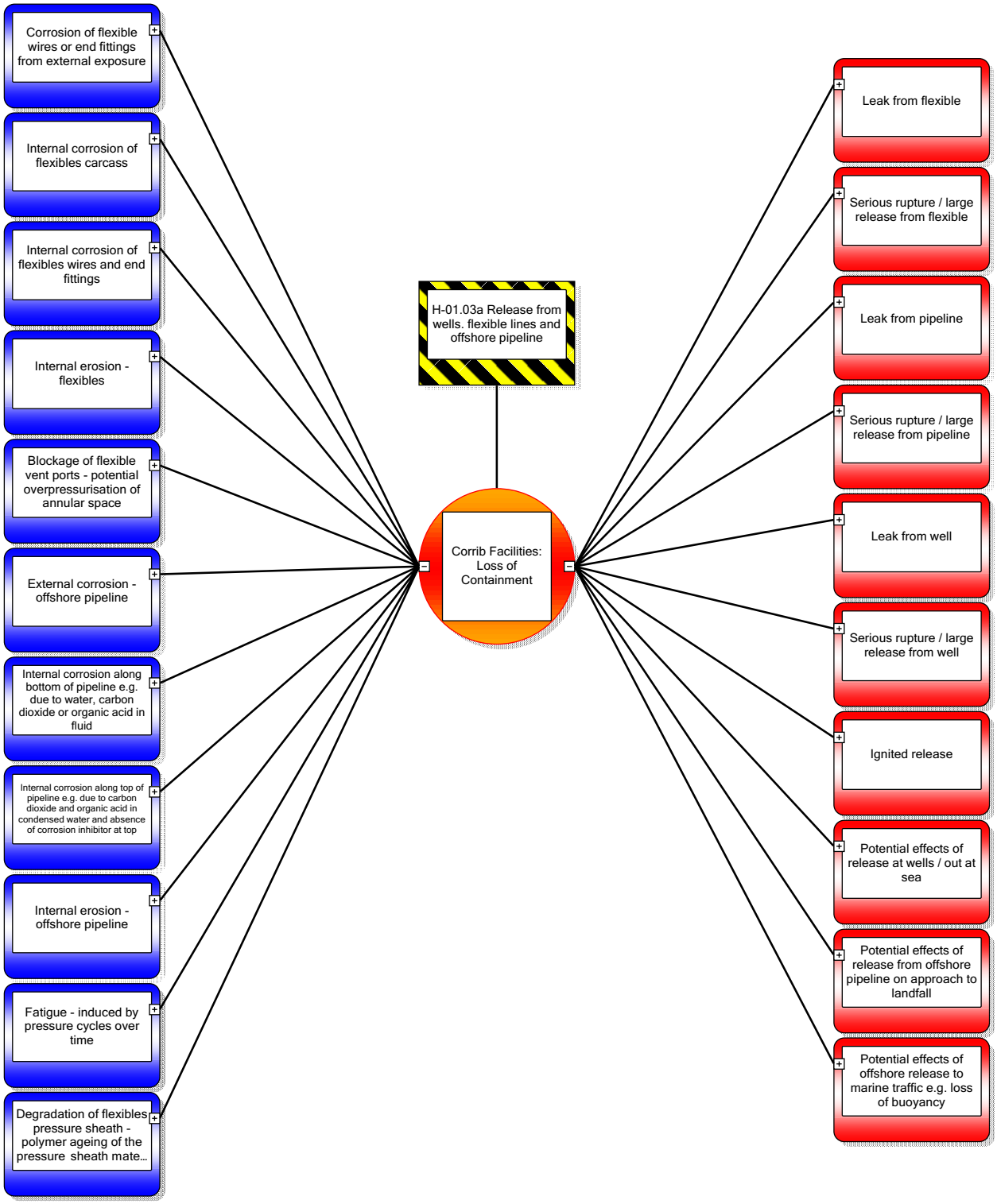


Figure B3.3 - H-01.03a Release from Wells, Flexible Lines and Offshore Pipeline Overview of Threats and Consequences (continued)

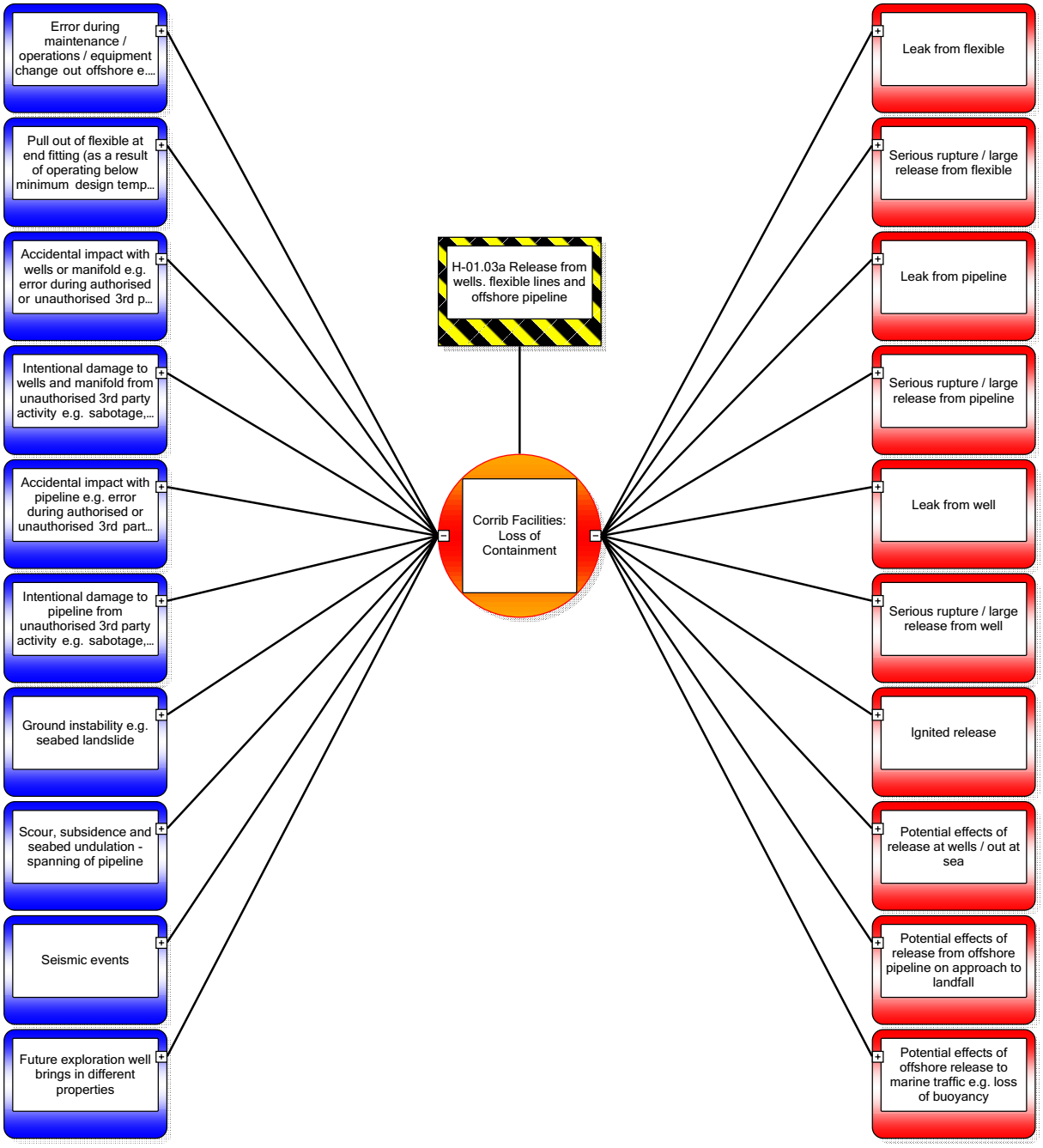


Figure B3.4 - H-01.03a Release from Wells, Flexible Lines and Offshore Pipeline
Detailed Extract – Internal Corrosion along Top of Offshore Pipeline (Preventive Controls)

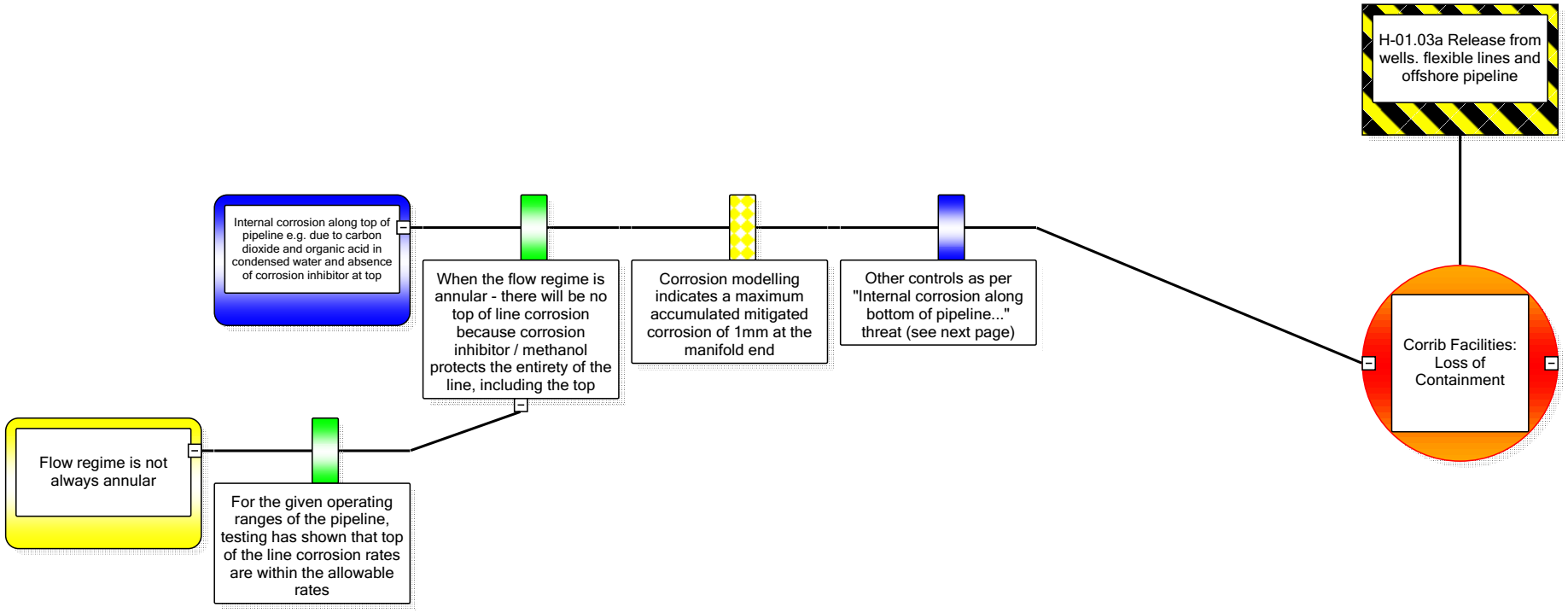


Figure B3.5 - H-01.03a Release from Wells, Flexible Lines and Offshore Pipeline
Detailed Extract – Internal Corrosion along Bottom of Offshore Pipeline (Overview of Preventive Controls)

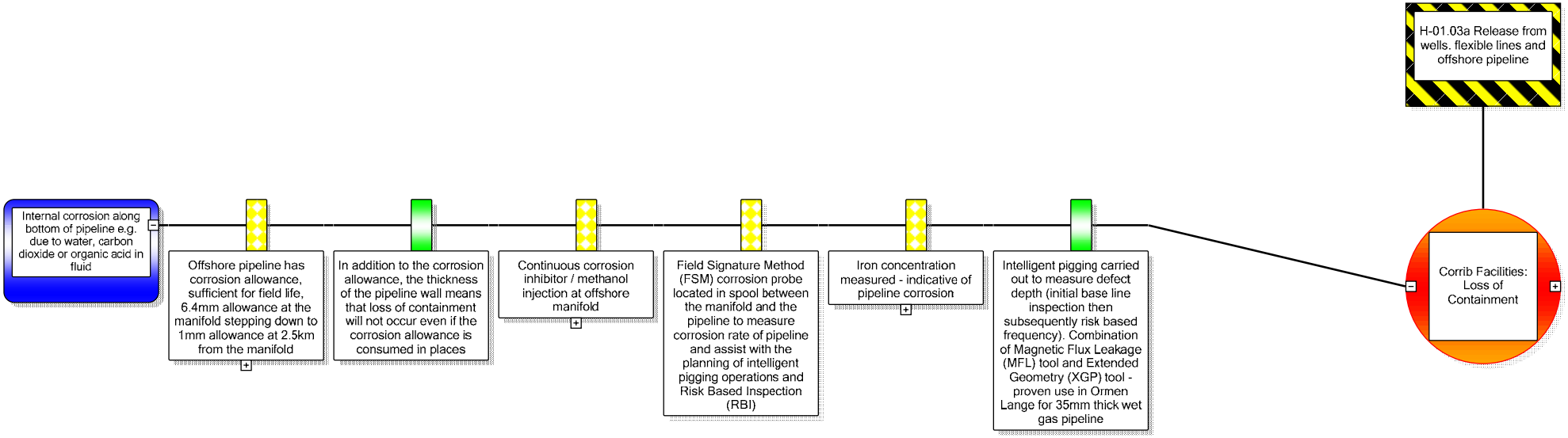


Figure B3.6 - H-01.03a Release from Wells, Flexible Lines and Offshore Pipeline
Detailed Extract – Internal Corrosion along Bottom of Offshore Pipeline (Preventive Controls 1 & 2)

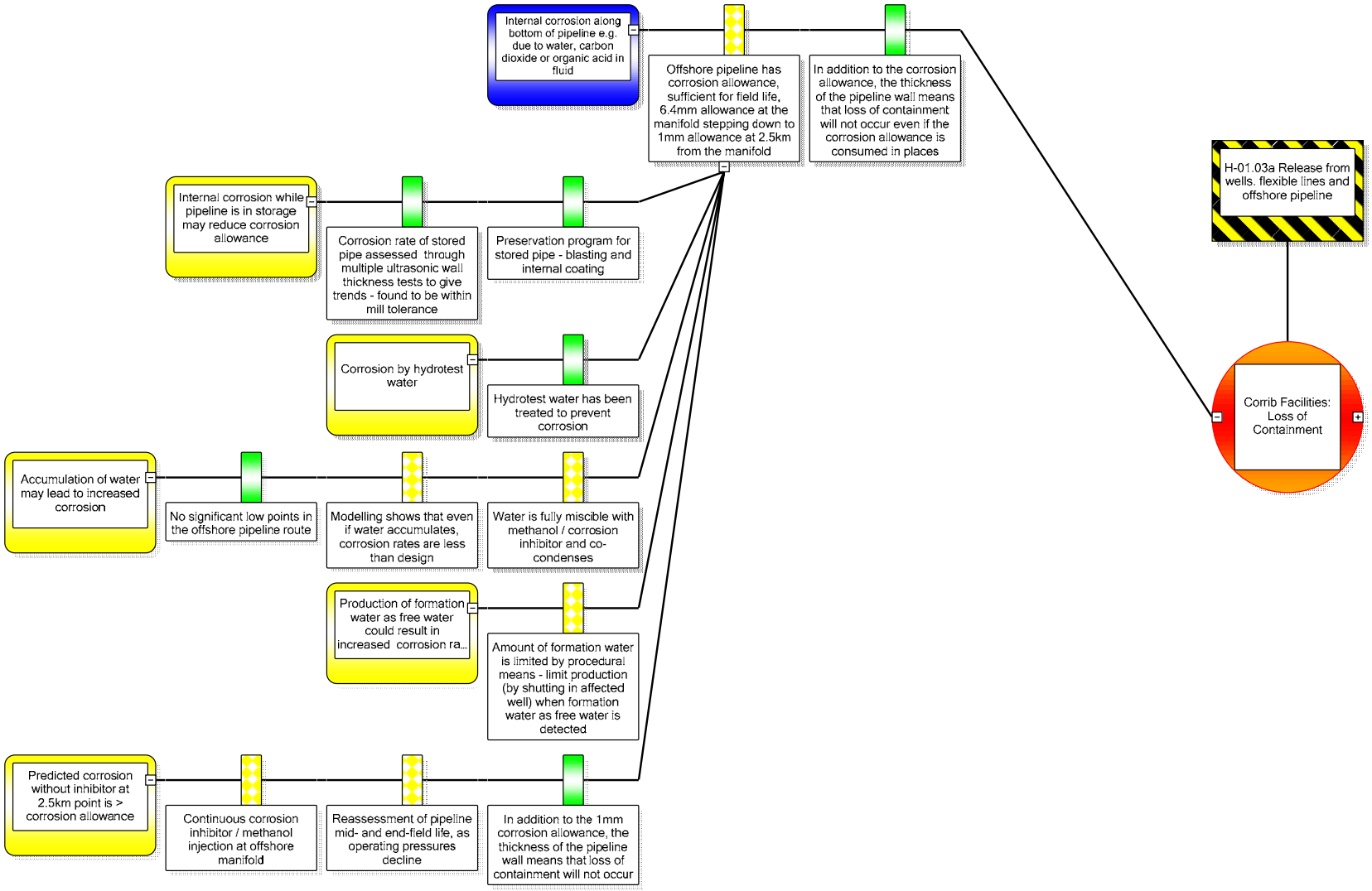


Figure B3.7 - H-01.03a Release from Wells, Flexible Lines and Offshore Pipeline
Detailed Extract – Internal Corrosion along Bottom of Offshore Pipeline (Preventive Control 3, Escalation Factors 1 -3)

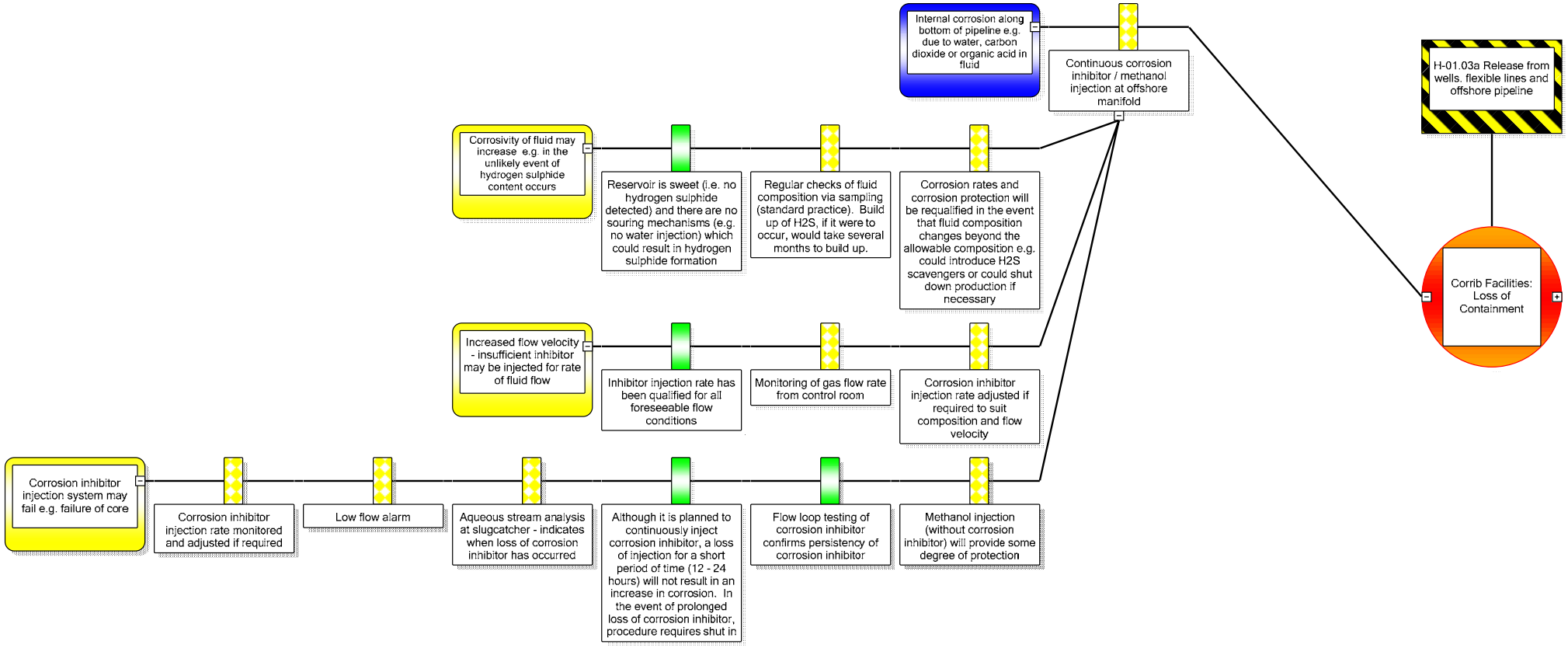


Figure B3.8 - H-01.03a Release from Wells, Flexible Lines and Offshore Pipeline
Detailed Extract – Internal Corrosion along Bottom of Offshore Pipeline (Preventive Control 3, Escalation Factors 4 - 7)

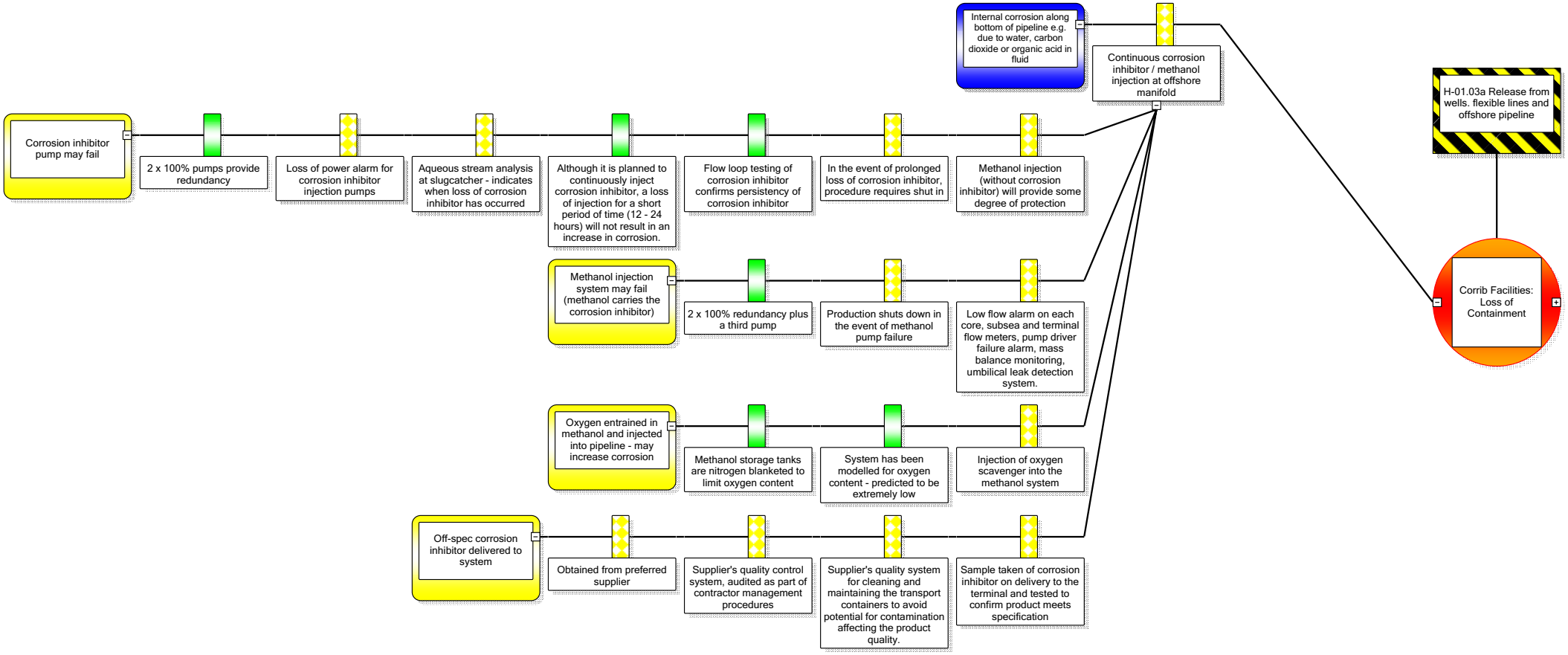


Figure B3.9 - H-01.03a Release from Wells, Flexible Lines and Offshore Pipeline
Example Extract – Internal Corrosion along Bottom of Offshore Pipeline (Preventive Controls 4 - 6)

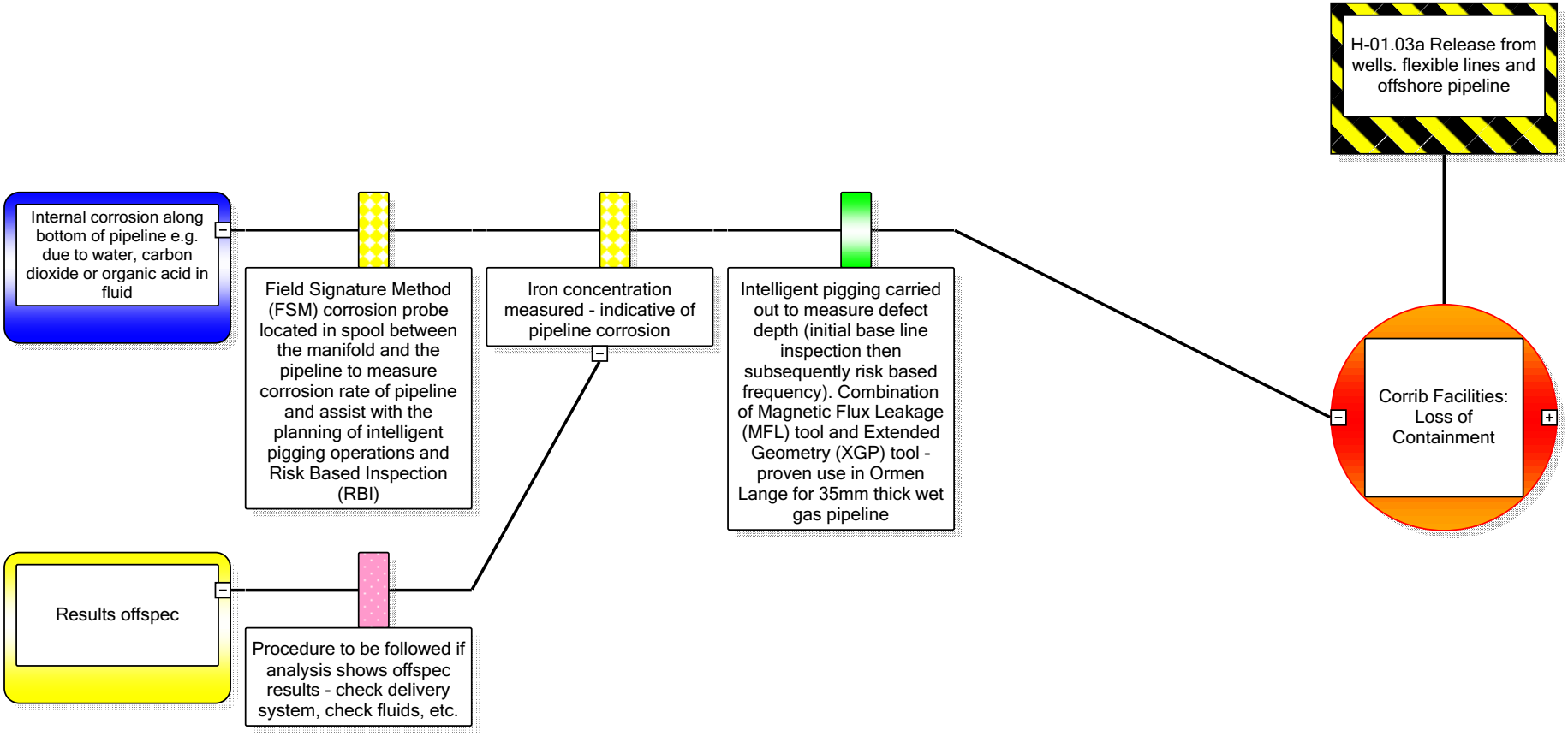


Figure B3.10 - H-01.03a Release from Wells, Flexible Lines and Offshore Pipeline
Detailed Extract – Offshore Pipeline External Corrosion (Overview of Preventive Controls)

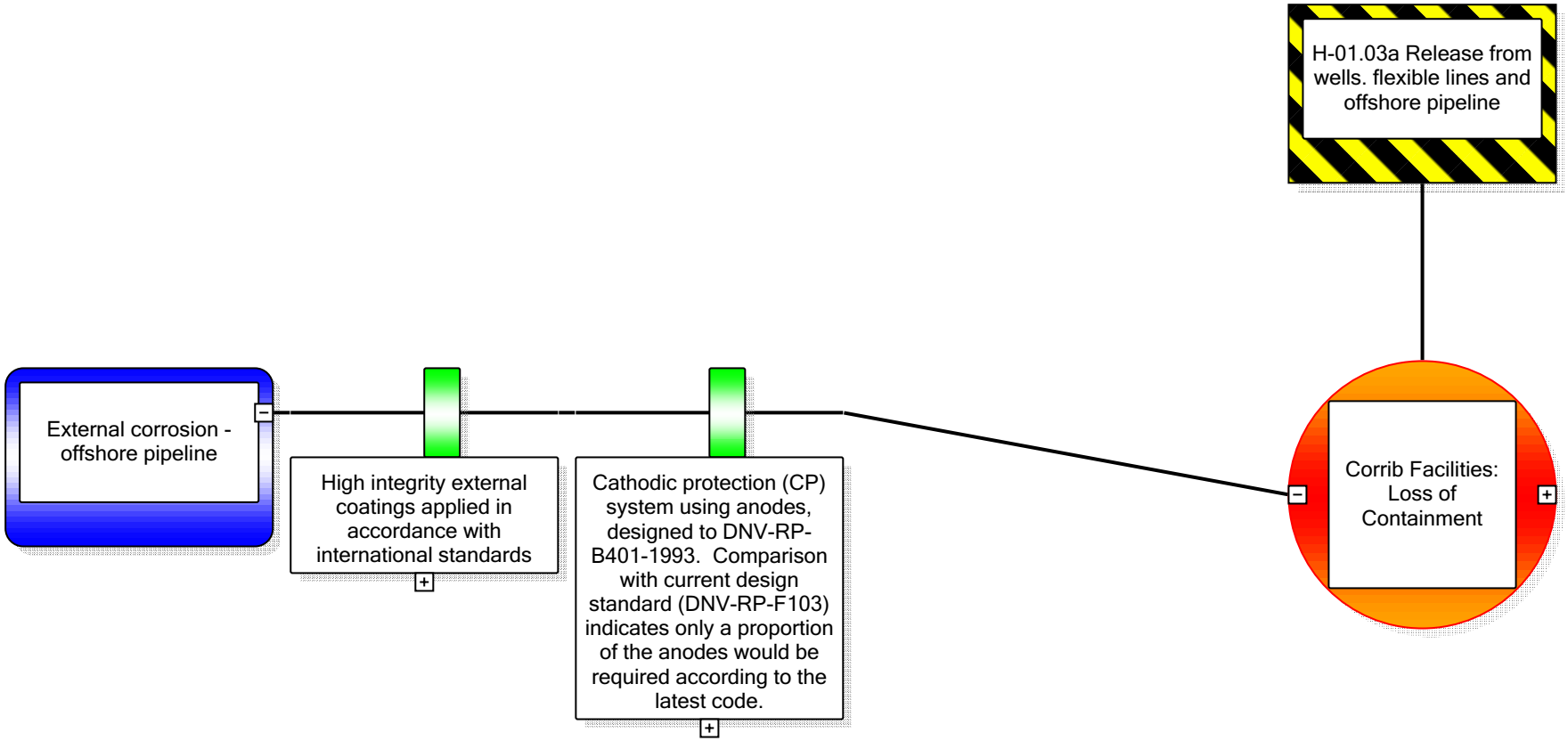


Figure B3.11 - H-01.03a Release from Wells, Flexible Lines and Offshore Pipeline Detailed Extract – Offshore Pipeline External Corrosion (Preventive Control 1)

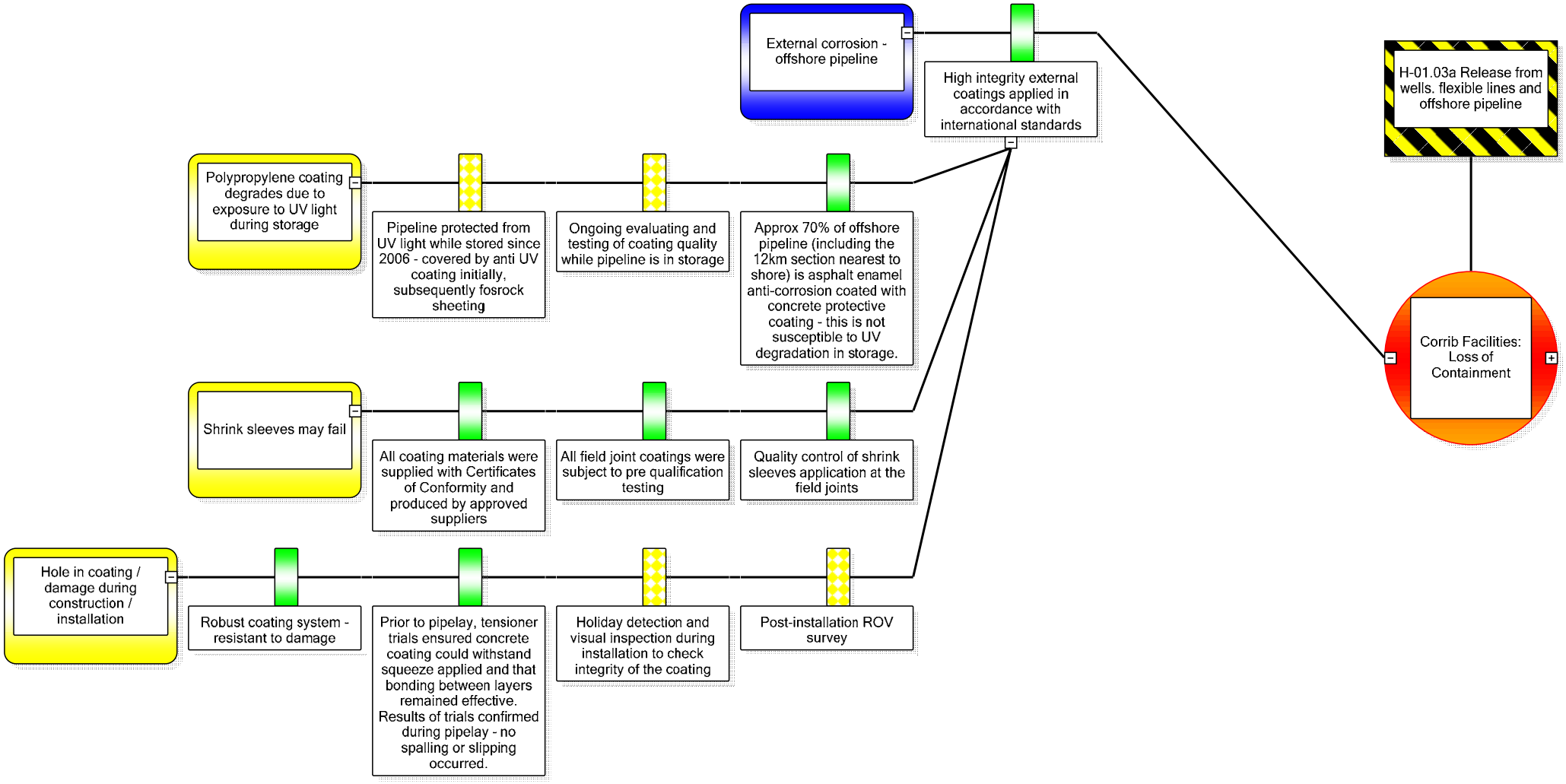


Figure B3.12 - H-01.03a Release from Wells, Flexible Lines and Offshore Pipeline Example Extract – Offshore Pipeline External Corrosion (Preventive Control 2)

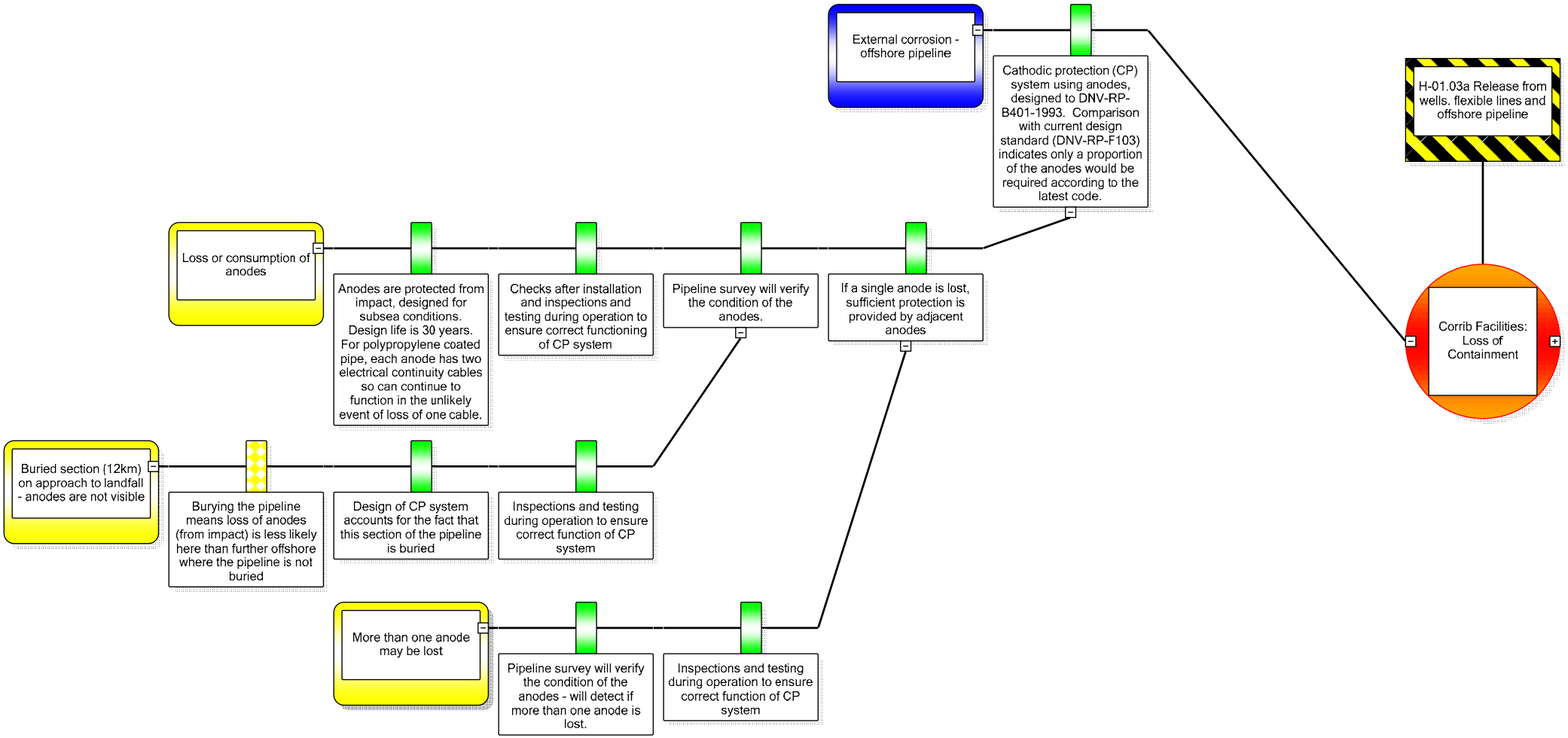


Figure B3.13 - H-01.03a Release from Wells, Flexible Lines and Offshore Pipeline
Example Extract – Hydrate Formation in Offshore Pipeline System (Preventive Controls)

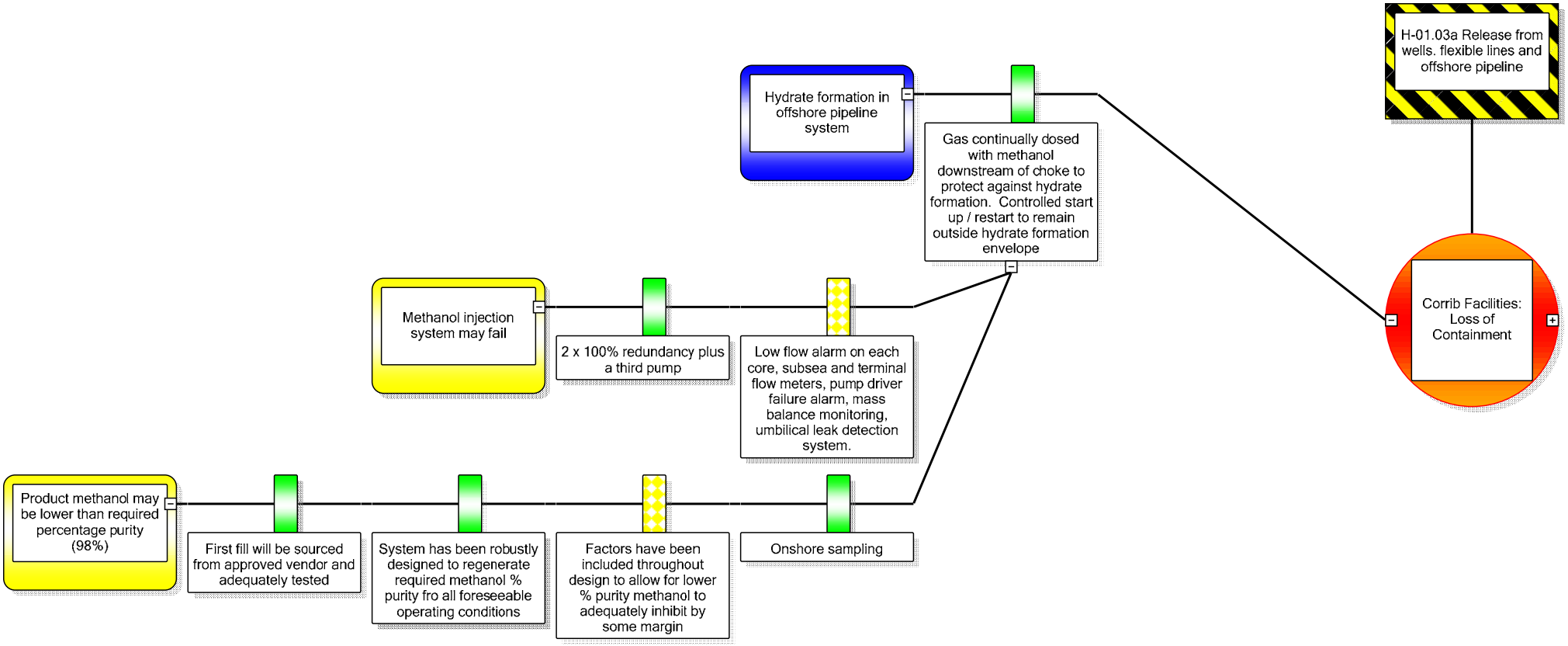


Figure B3.14 - H-01.03a Release from Wells, Flexible Lines and Offshore Pipeline
Example Extract – Fatigue in Offshore Pipeline (Preventive Controls)

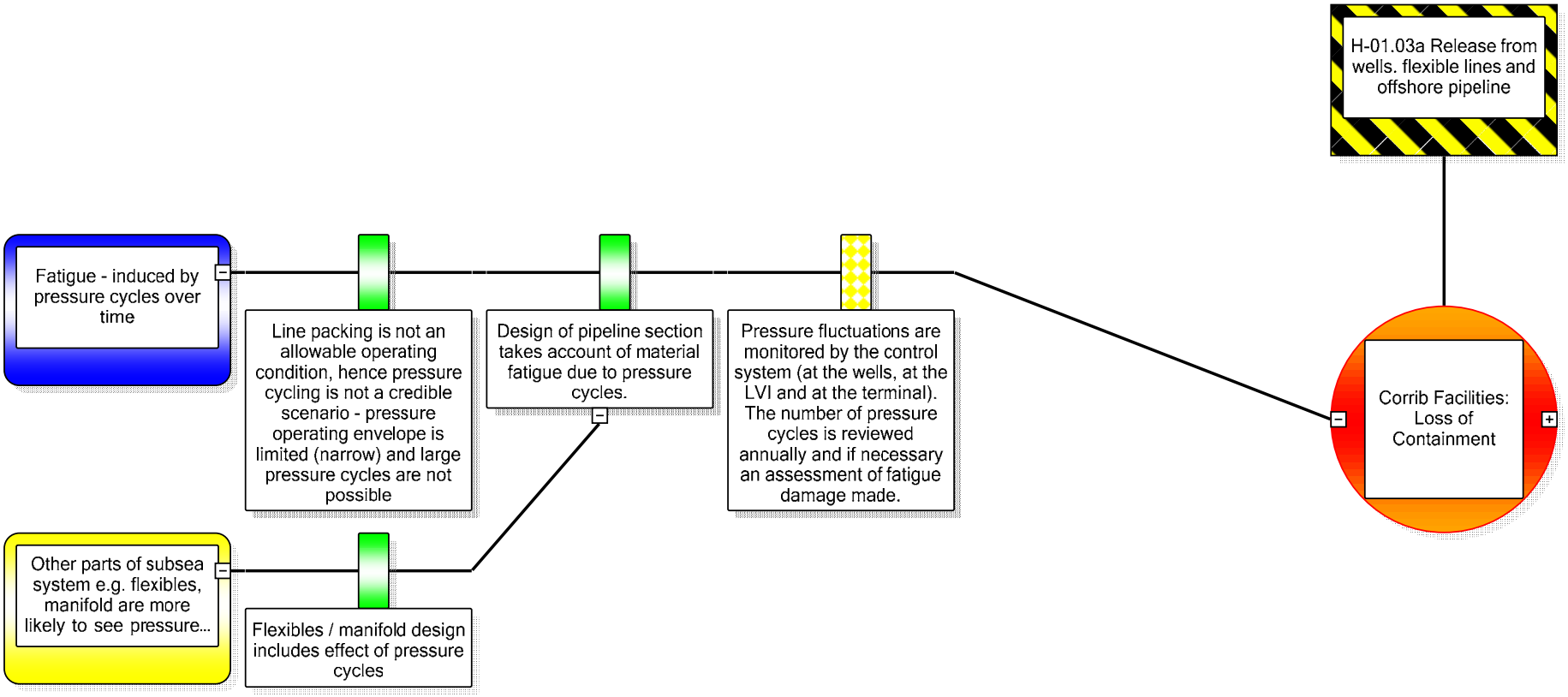


Figure B4.1 - H-01.03b Release from LVI
Overview of Threats and Consequences

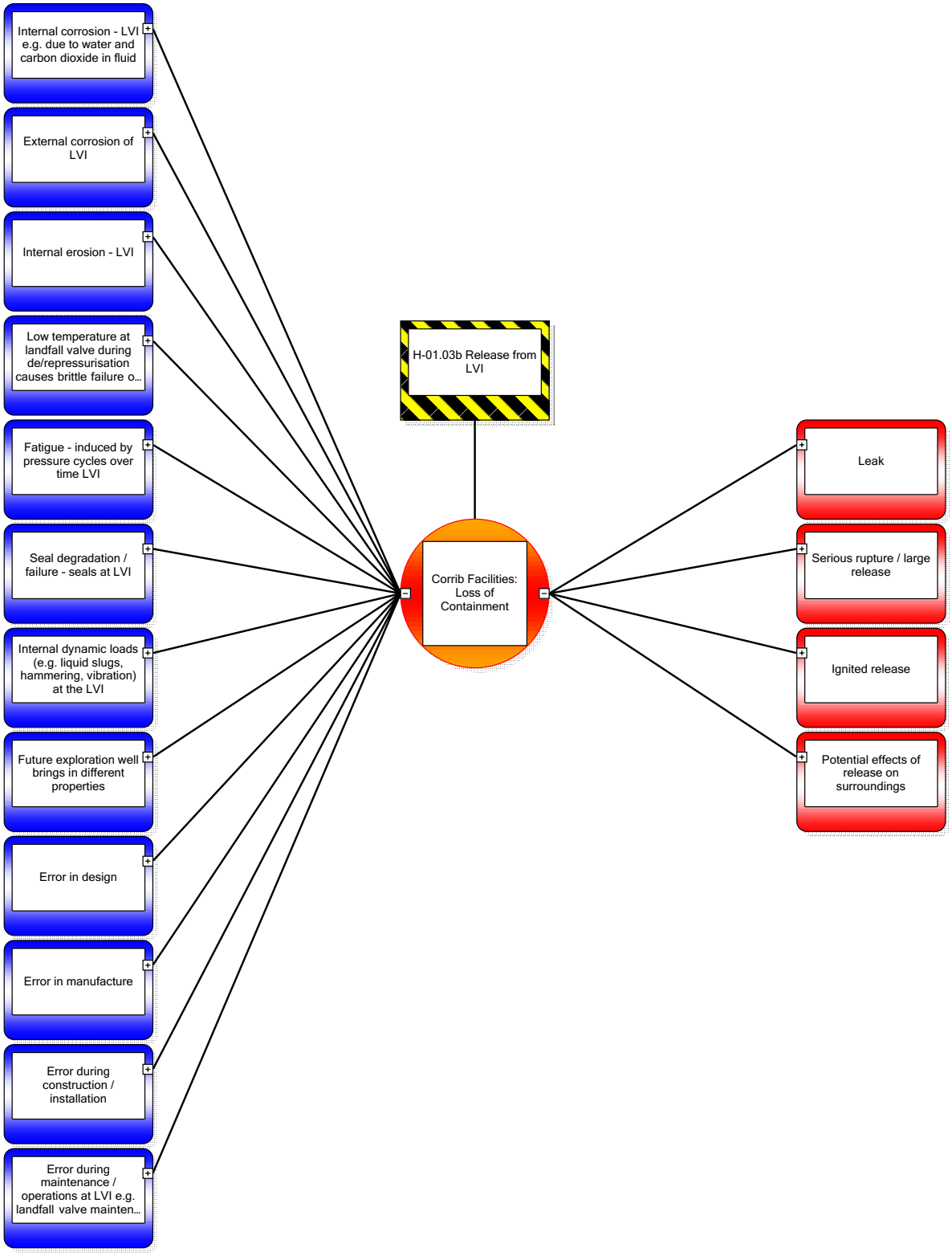


Figure B4.2 - H-01.03b Release from LVI
Overview of Threats and Consequences (continued)

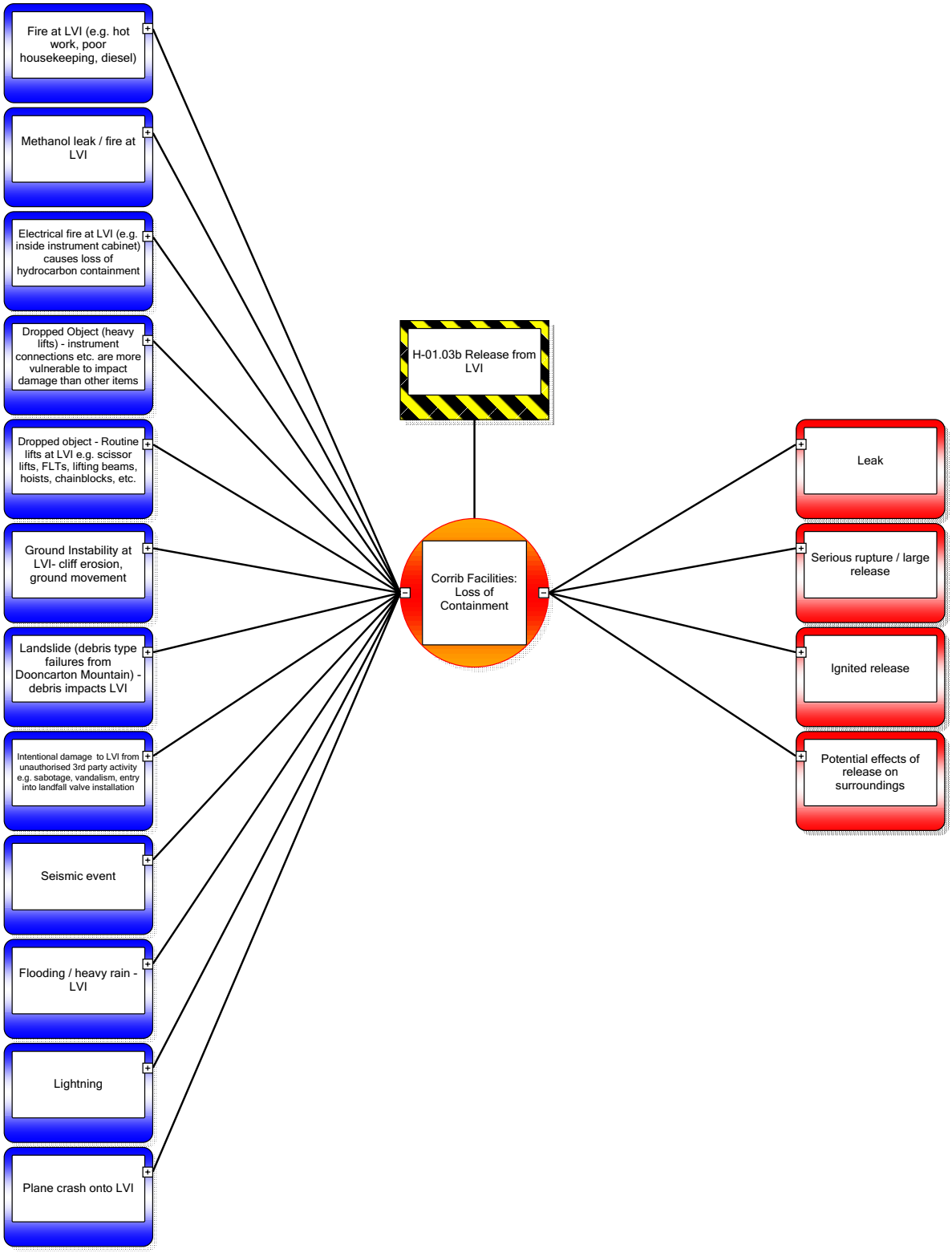


Figure B4.3 - H-01.03b Release from LVI
Detailed Extract – Dropped Object During Heavy Lift (Preventive Controls)

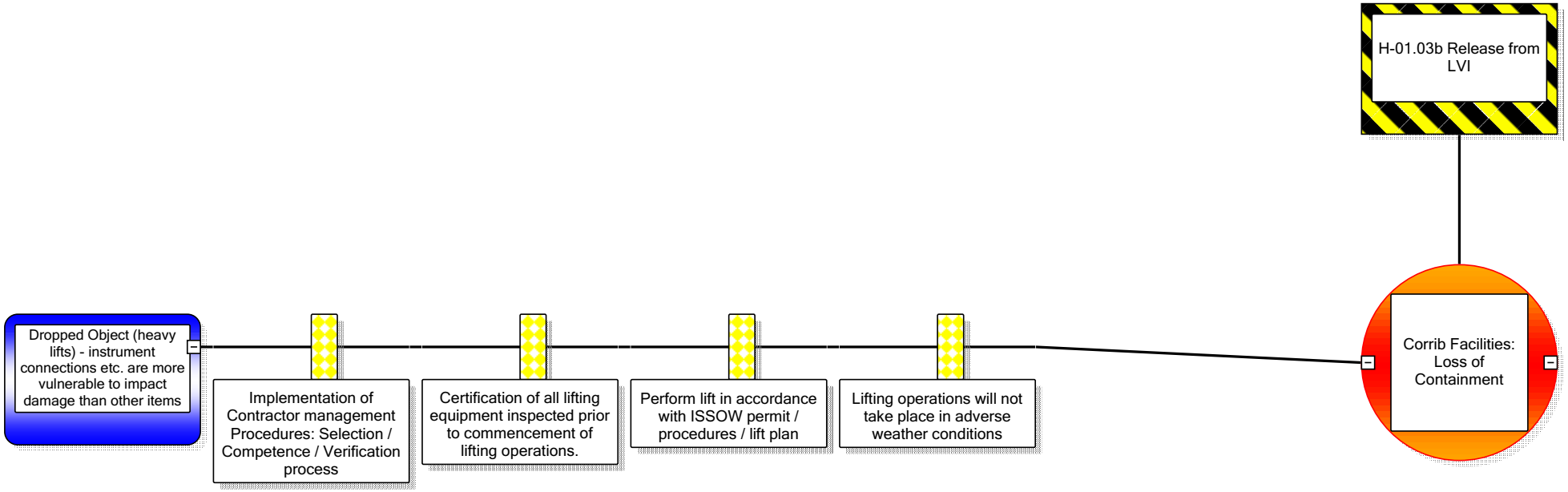


Figure B4.4 - H-01.03b Release from LVI
Detailed Extract – Dropped Object During Routine Lift (Preventive Controls)

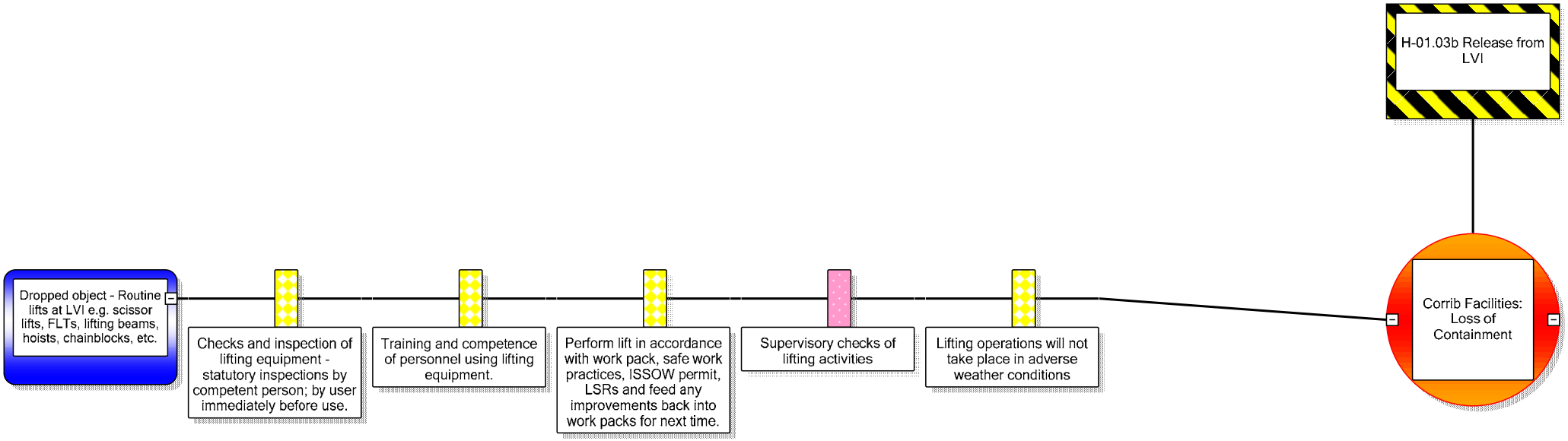


Figure B4.5 - H-01.03b Release from LVI
Detailed Extract – Intentional Damage to LVI (Preventive Controls)

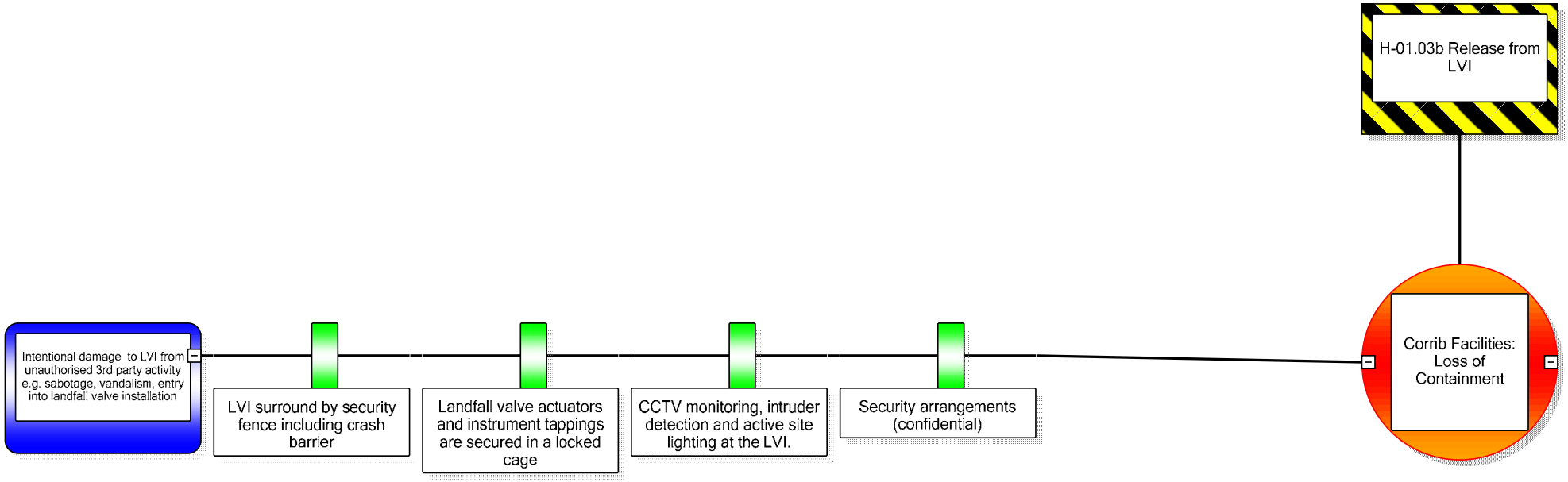


Figure B5.1 - H-01.03c Release from Onshore Pipeline
Overview of Threats and Consequences

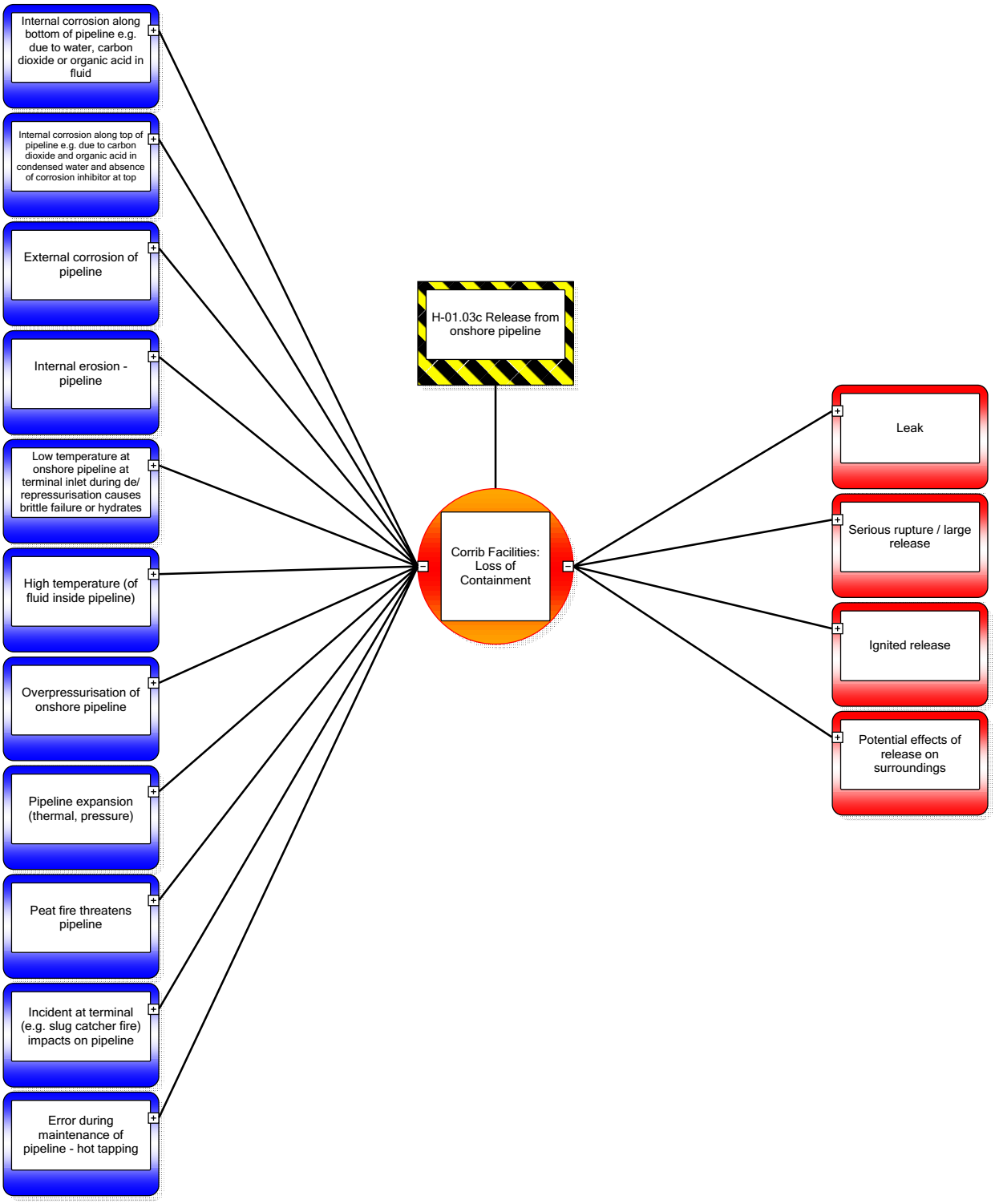


Figure B5.2 - H-01.03c Release from Onshore Pipeline
Overview of Threats and Consequences (continued)

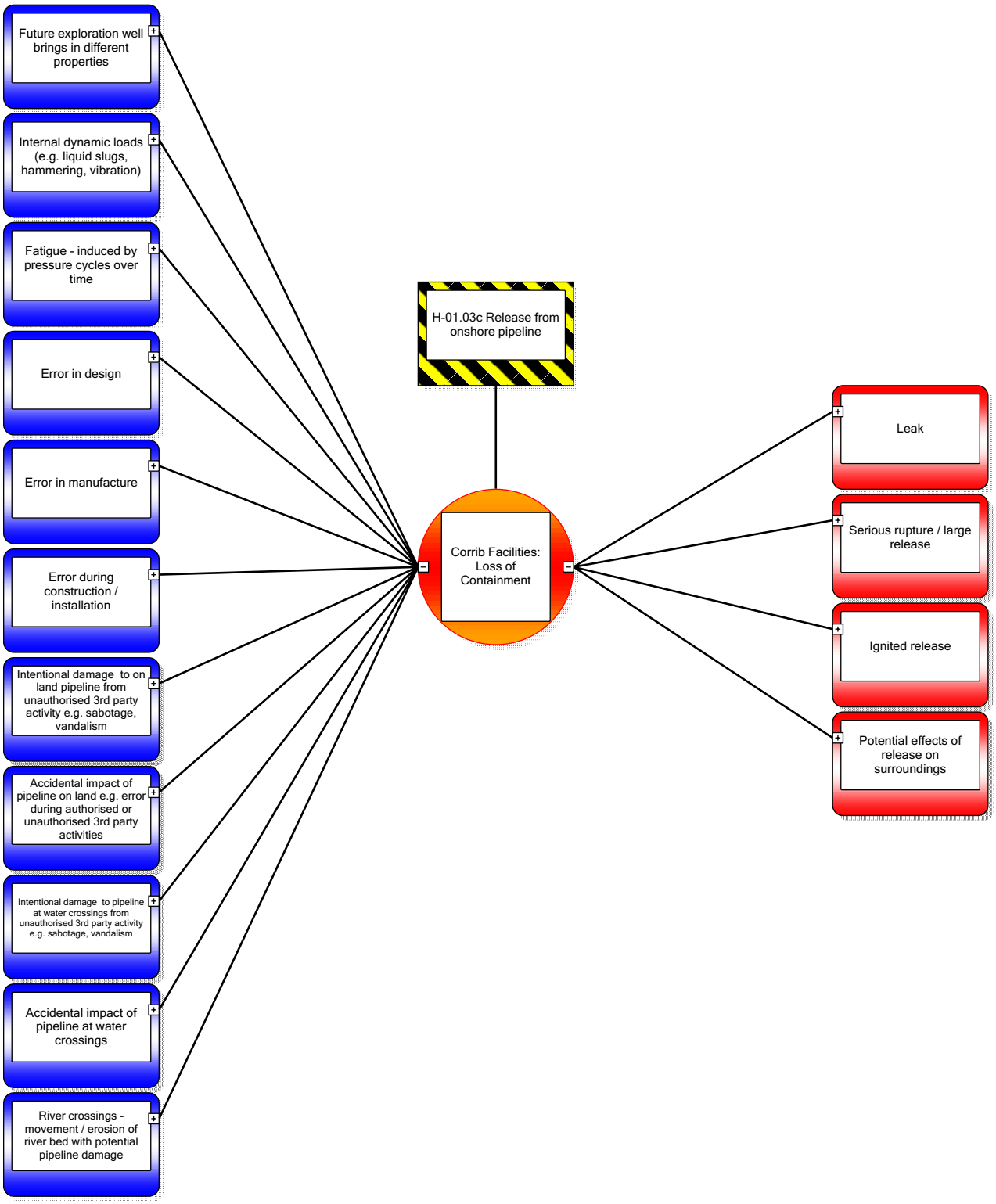


Figure B5.3 - H-01.03c Release from Onshore Pipeline
Overview of Threats and Consequences (continued)

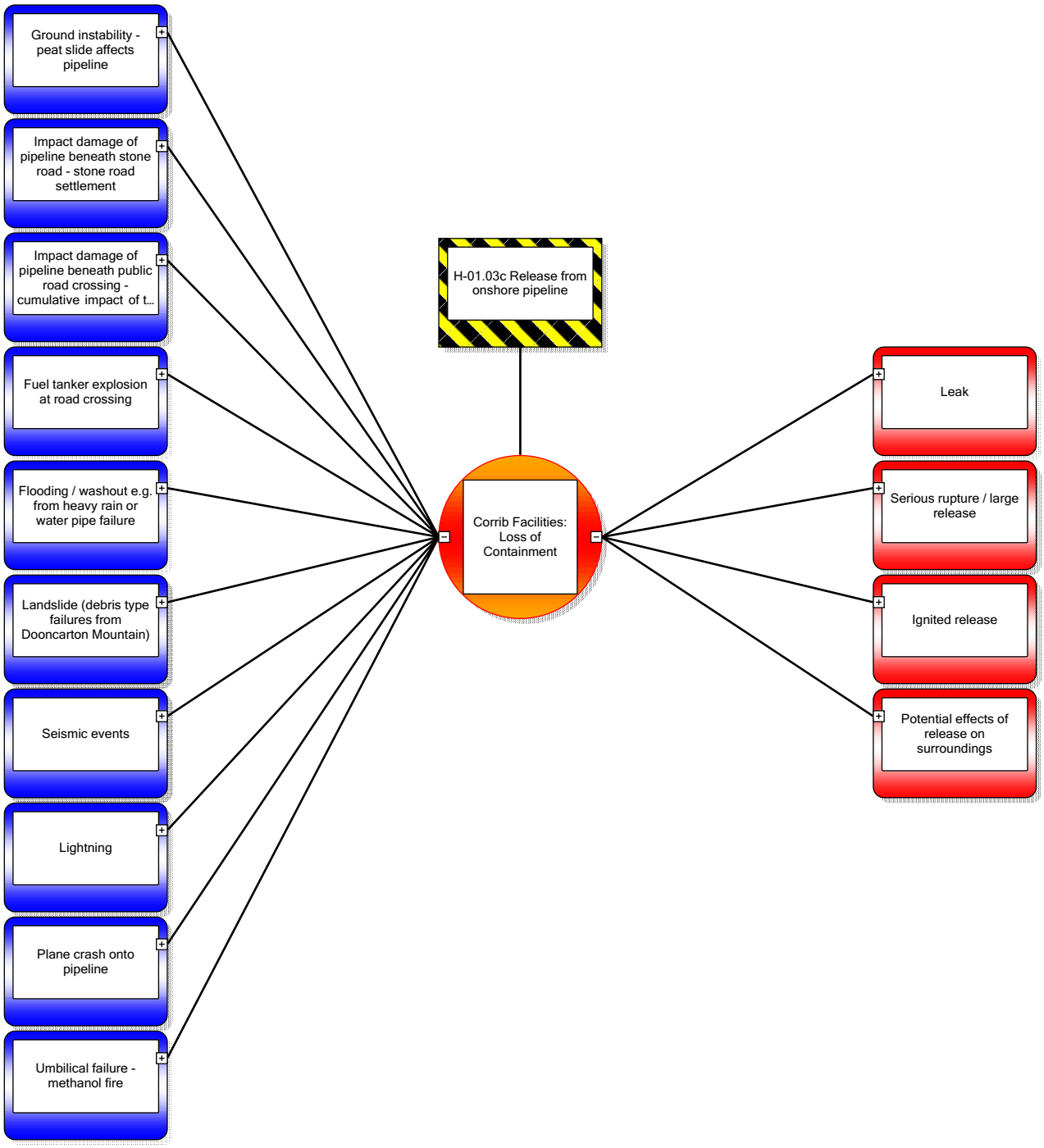


Figure B5.4 - H-01.03c Release from Onshore Pipeline
Detailed Extract – Internal Corrosion along Top of Onshore Pipeline (Preventive Controls)

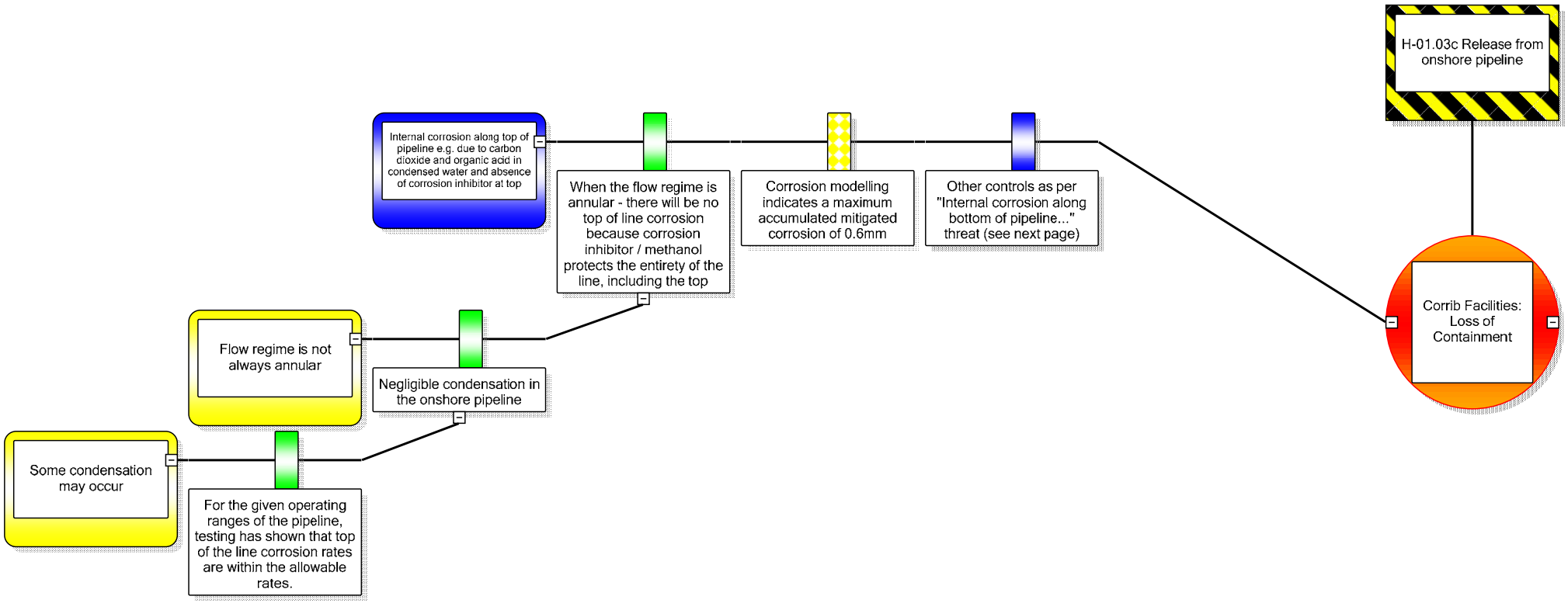


Figure B5.5 - H-01.03c Release from Onshore Pipeline
Detailed Extract – Internal Corrosion along Bottom of Onshore Pipeline (Overview of Preventive Controls)

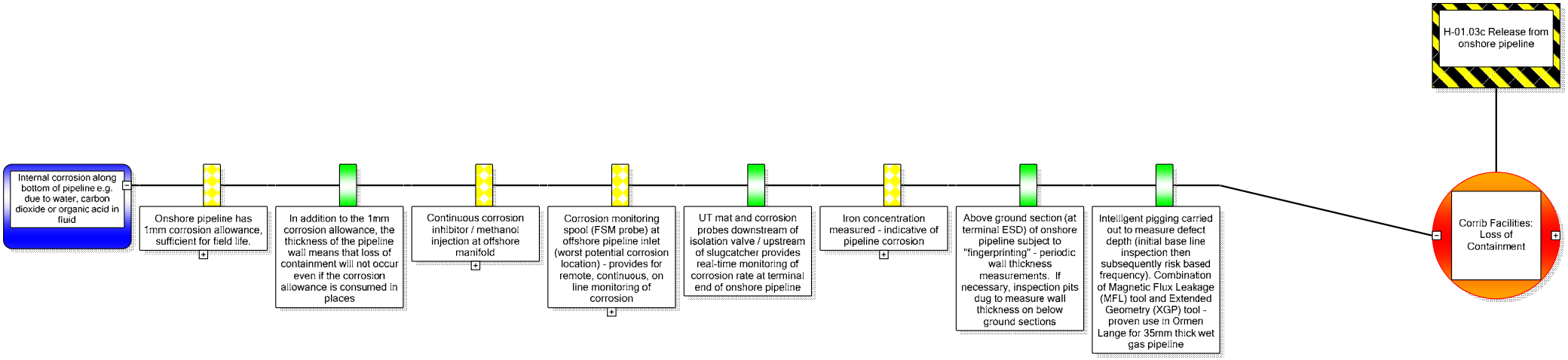


Figure B5.6 - H-01.03c Release from Onshore Pipeline
Detailed Extract – Internal Corrosion along Bottom of Onshore Pipeline (Preventive Controls 1 & 2)

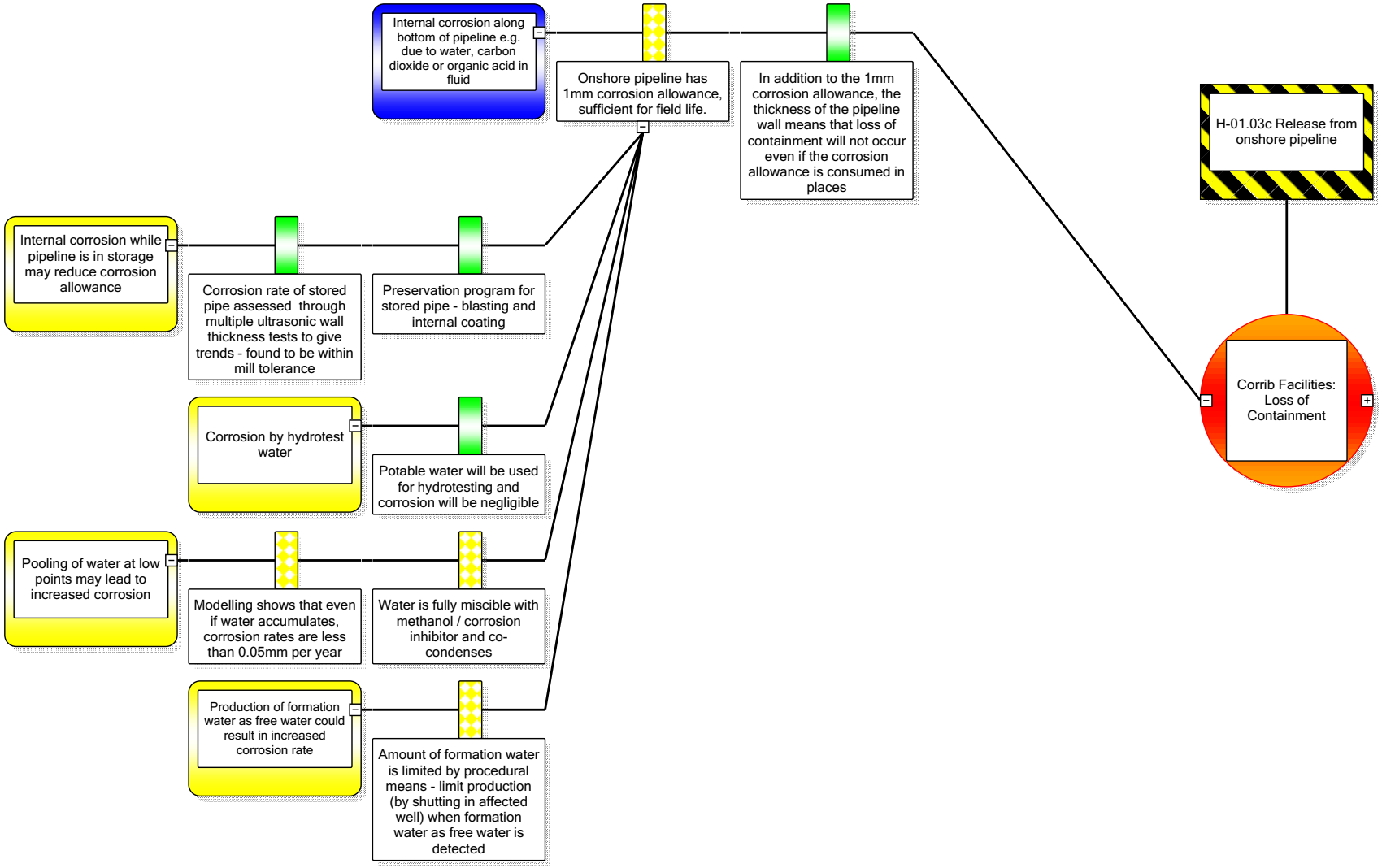


Figure B5.7 - H-01.03c Release from Onshore Pipeline
Detailed Extract – Internal Corrosion along Bottom of Onshore Pipeline (Preventive Control 3, Escalation Factors 1 - 4)

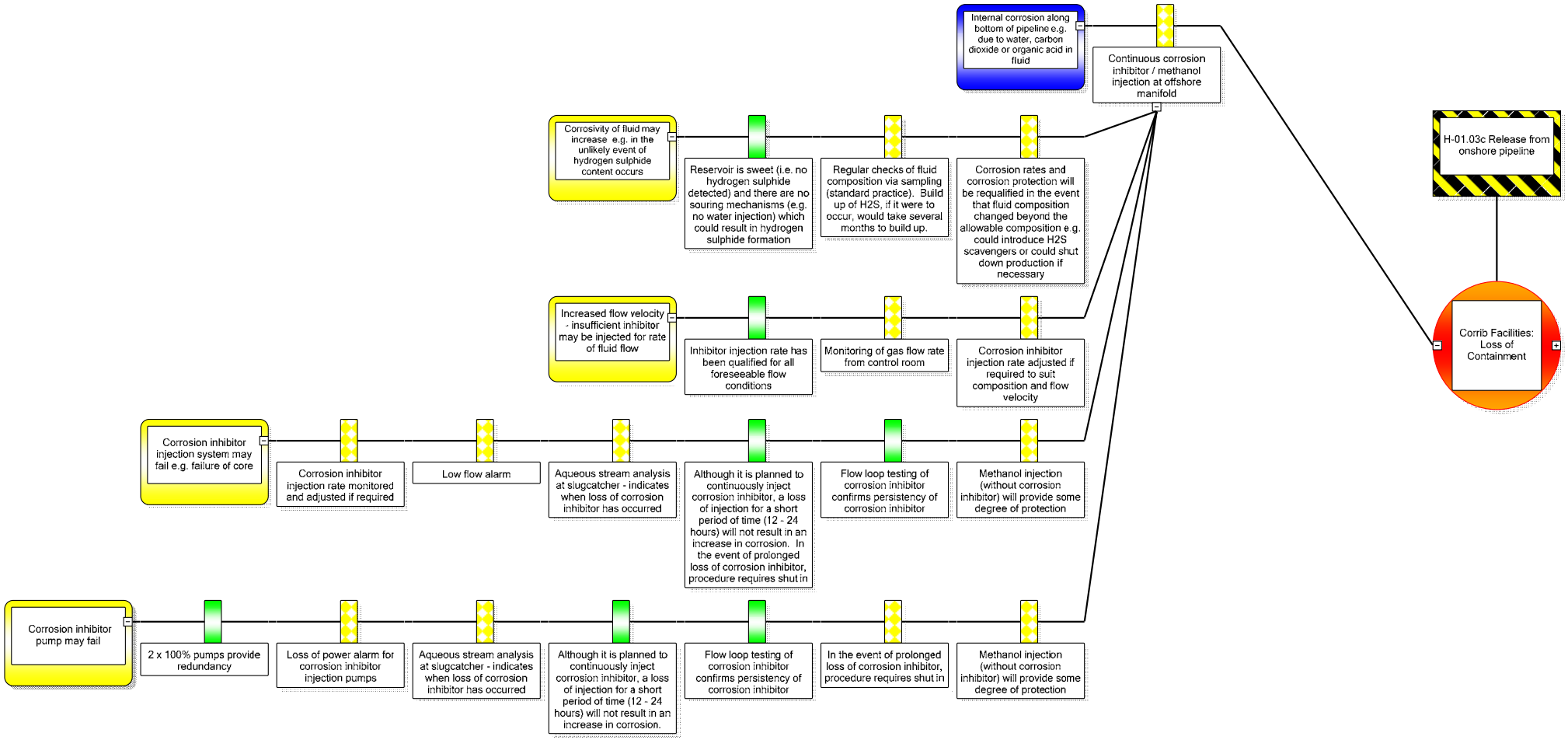


Figure B5.8 - H-01.03c Release from Onshore Pipeline
Detailed Extract – Internal Corrosion along Bottom of Onshore Pipeline (Preventive Control 3, Escalation Factors 5 - 7)

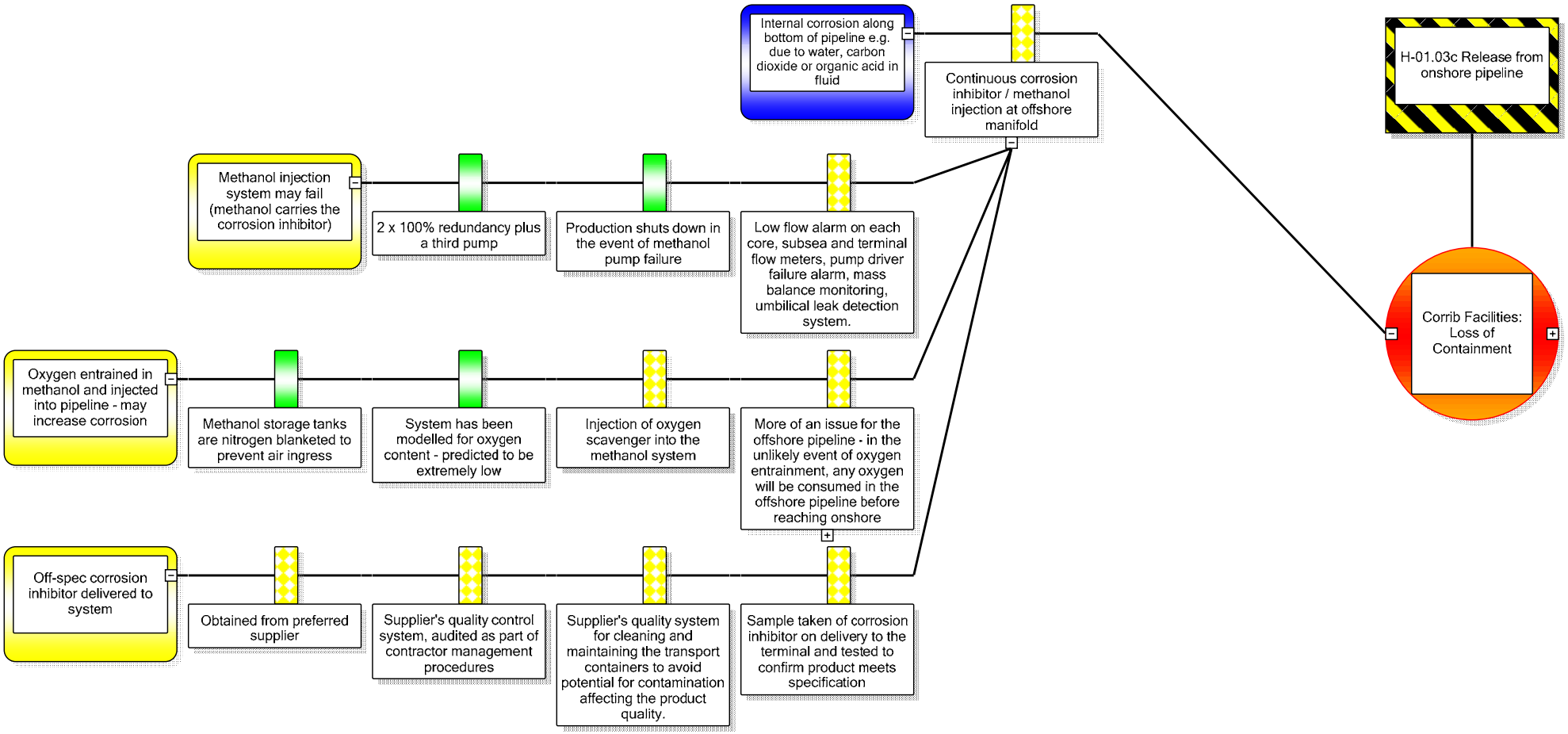


Figure B5.9 - H-01.03c Release from Onshore Pipeline
Detailed Extract – Internal Corrosion along Bottom of Onshore Pipeline (Preventive Controls 4 - 8)

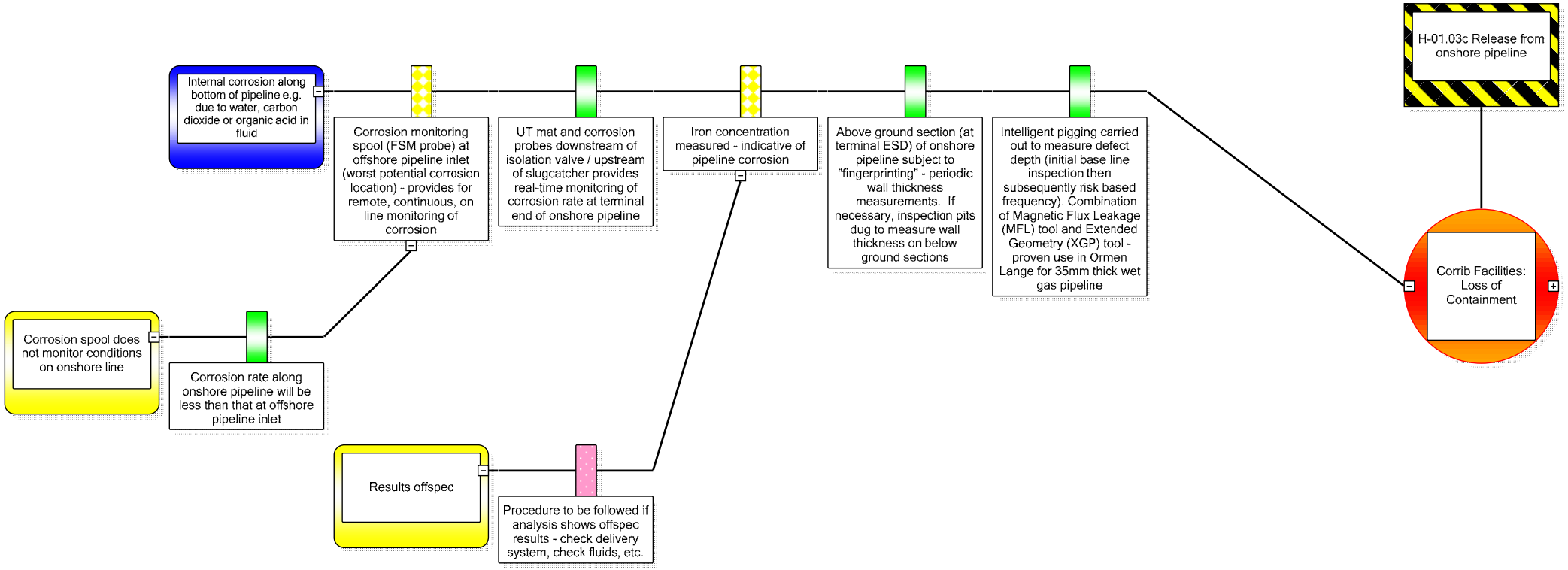


Figure B5.10 - H-01.03c Release from Onshore Pipeline
Detailed Extract – External Corrosion of Onshore Pipeline (Overview of Preventive Controls)

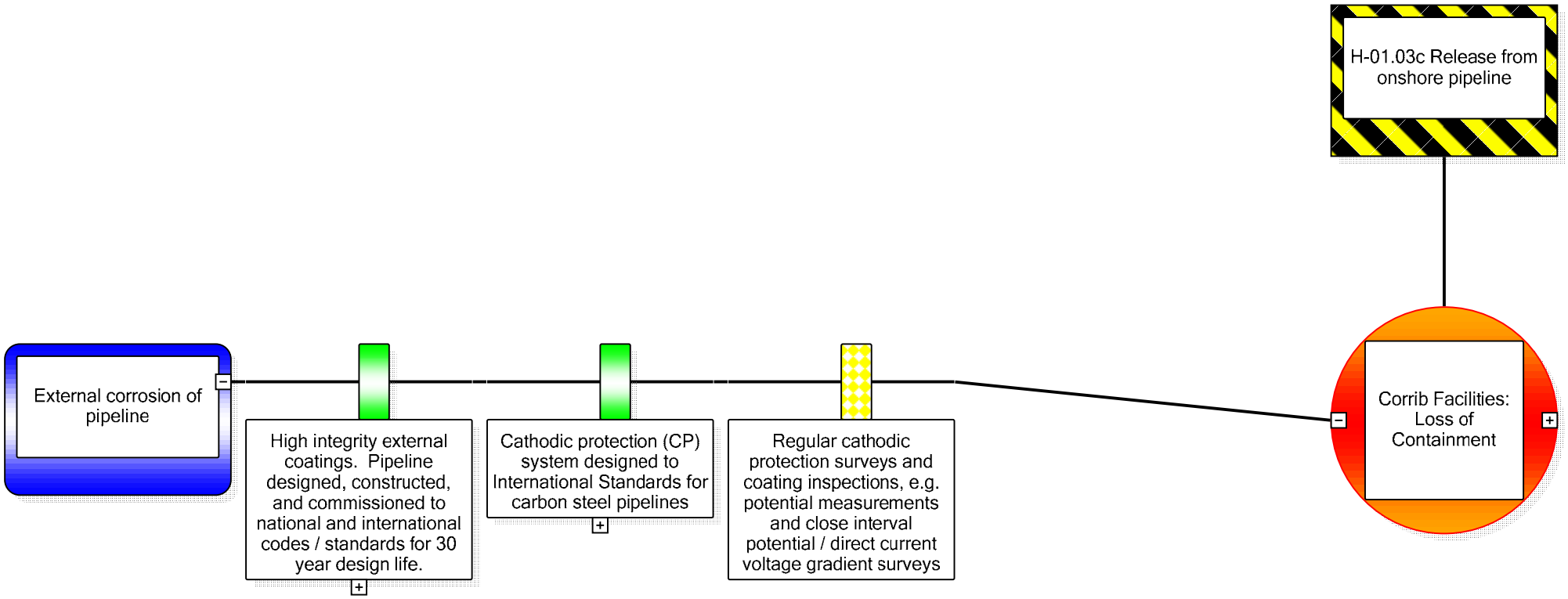


Figure B5.11 - H-01.03c Release from Onshore Pipeline
Detailed Extract – External Corrosion of Onshore Pipeline (Preventive Control 1)

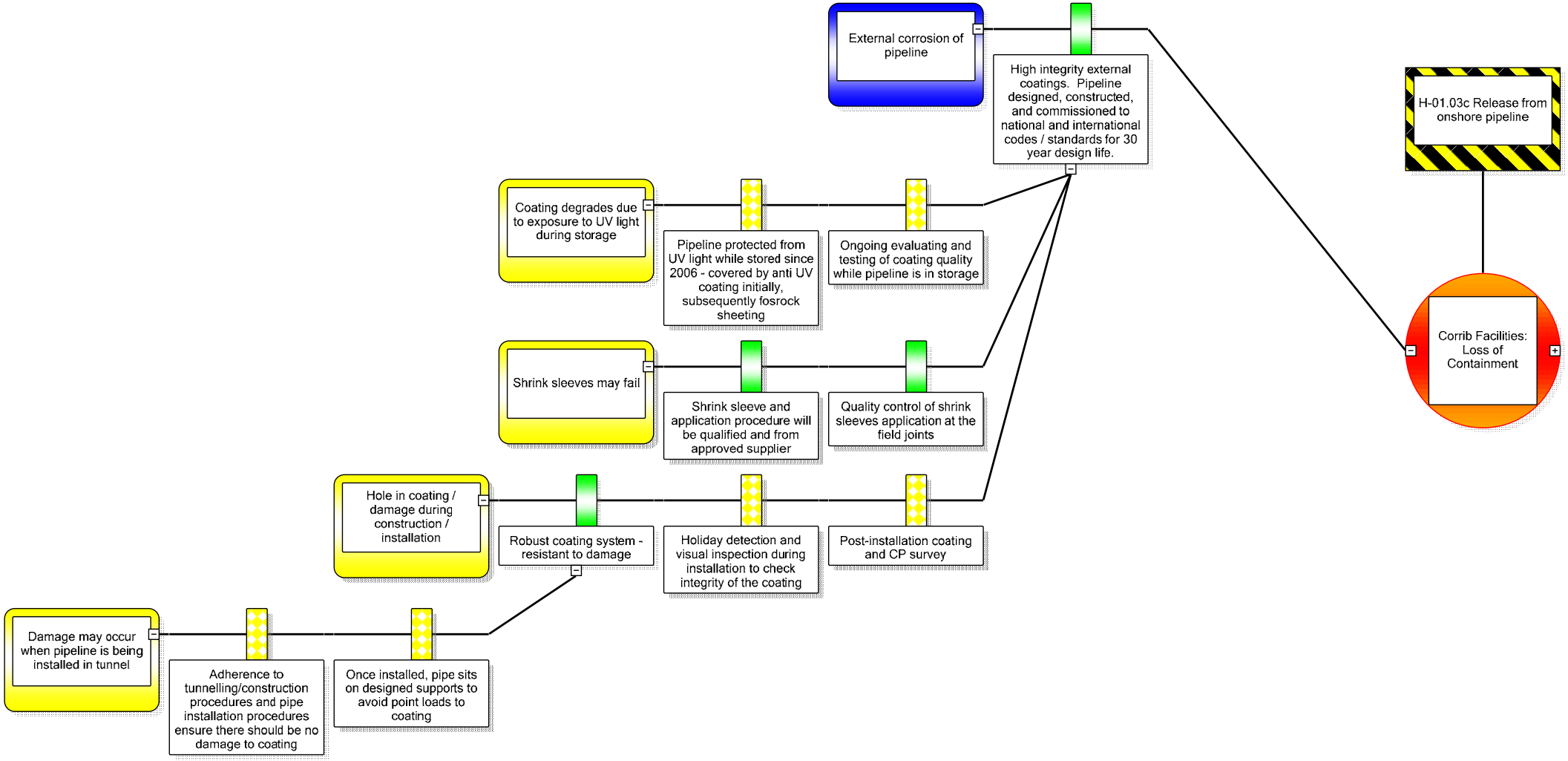


Figure B5.12 - H-01.03c Release from Onshore Pipeline
Detailed Extract – External Corrosion of Onshore Pipeline (Preventive Control 2, Escalation Factors 1 - 3)

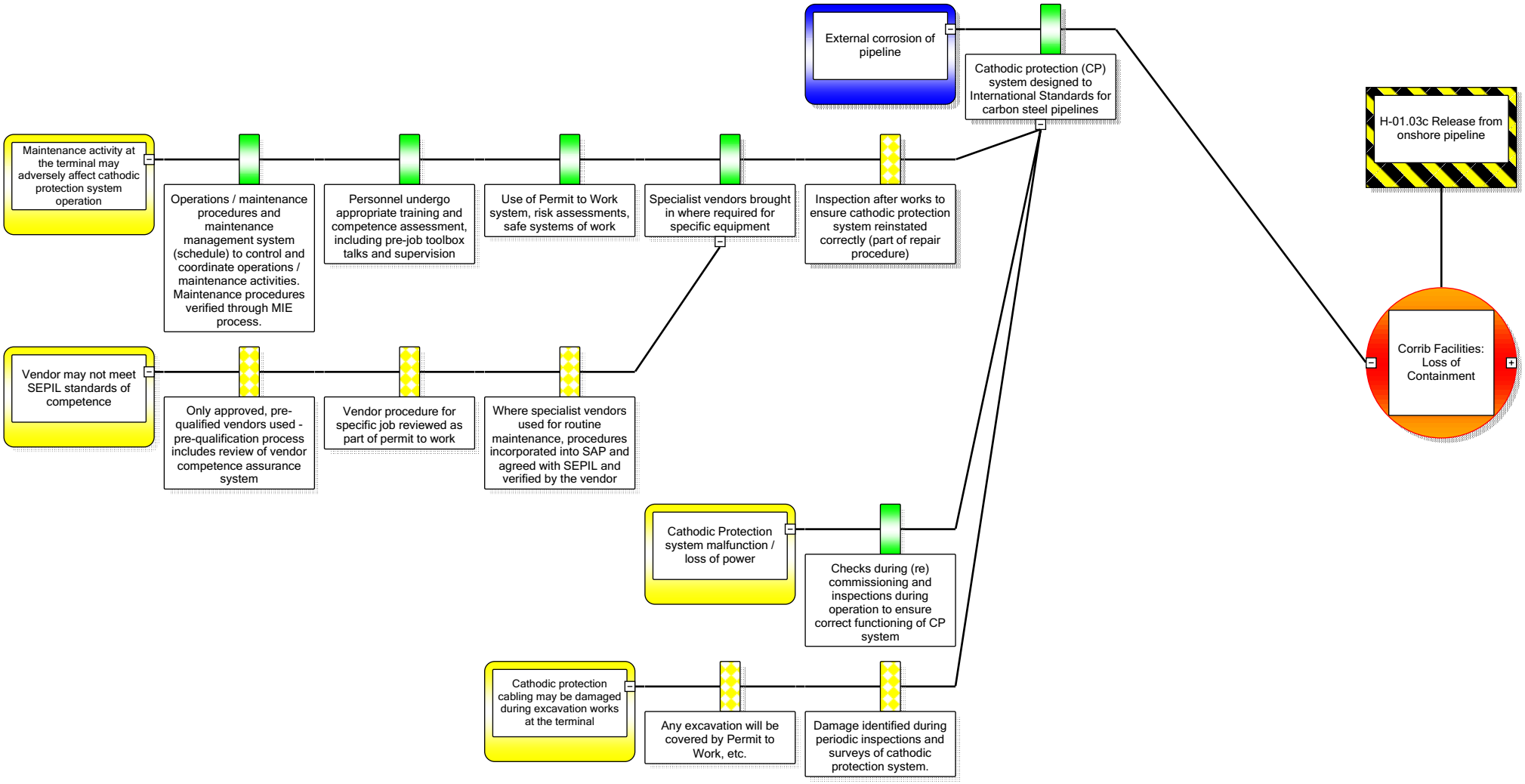


Figure B5.13 - H-01.03c Release from Onshore Pipeline
Detailed Extract – External Corrosion of Onshore Pipeline (Preventive Control 2, Escalation Factors 4 - 7 & Preventive Control 3)

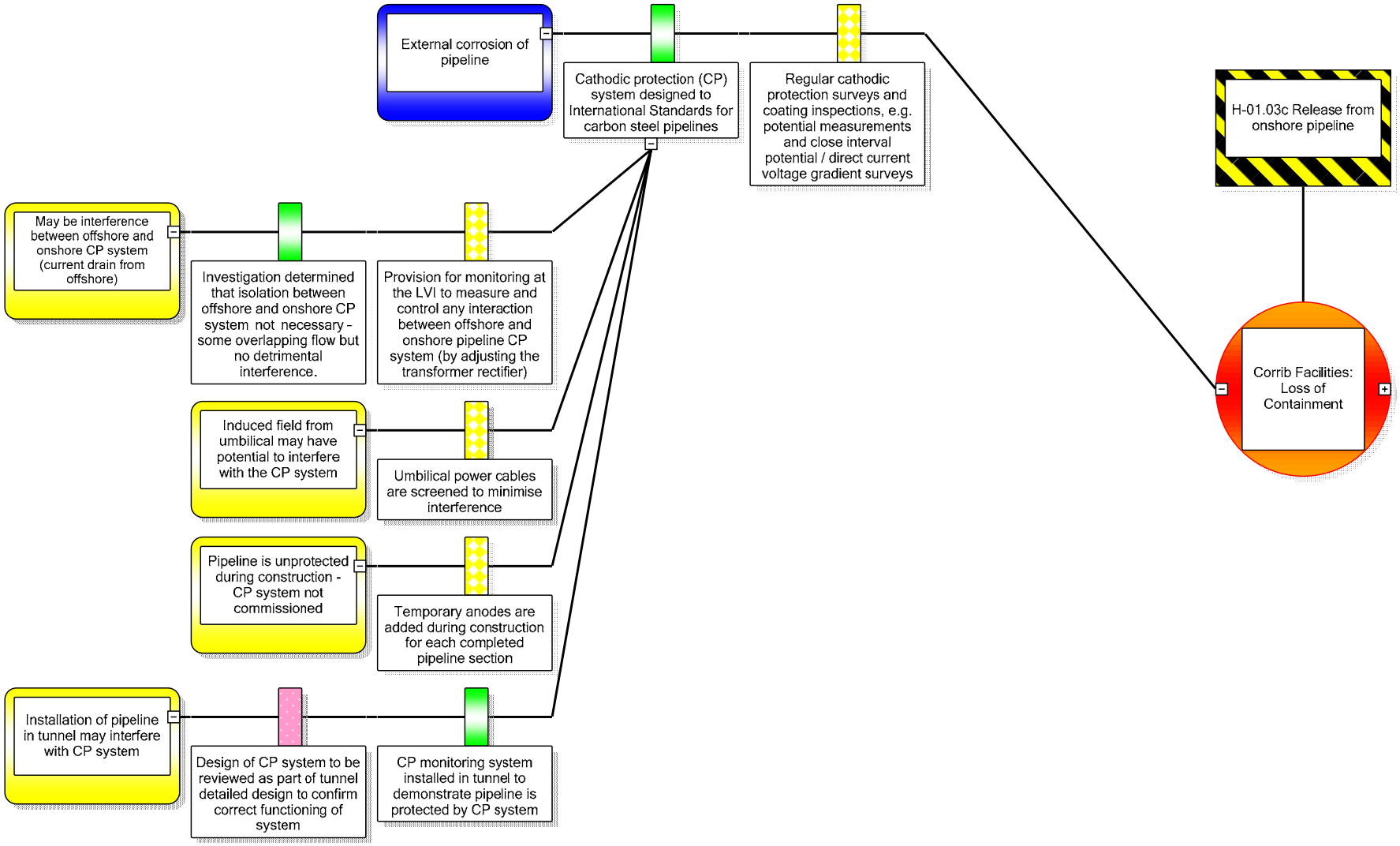


Figure B5.14 - H-01.03c Release from Onshore Pipeline
Example Extract – Ground Instability – Peat Slide Affecting Pipeline (Overview of Preventive Controls)

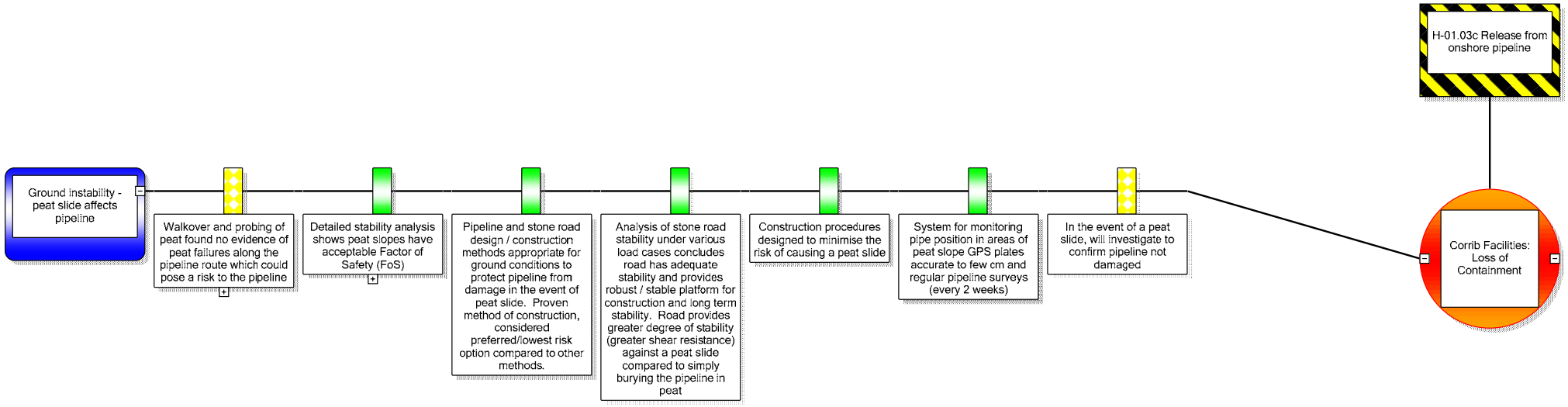


Figure B5.15 - H-01.03c Release from Onshore Pipeline
Example Extract – Ground Instability – Peat Slide Affecting Pipeline (Preventive Controls 1 – 3)

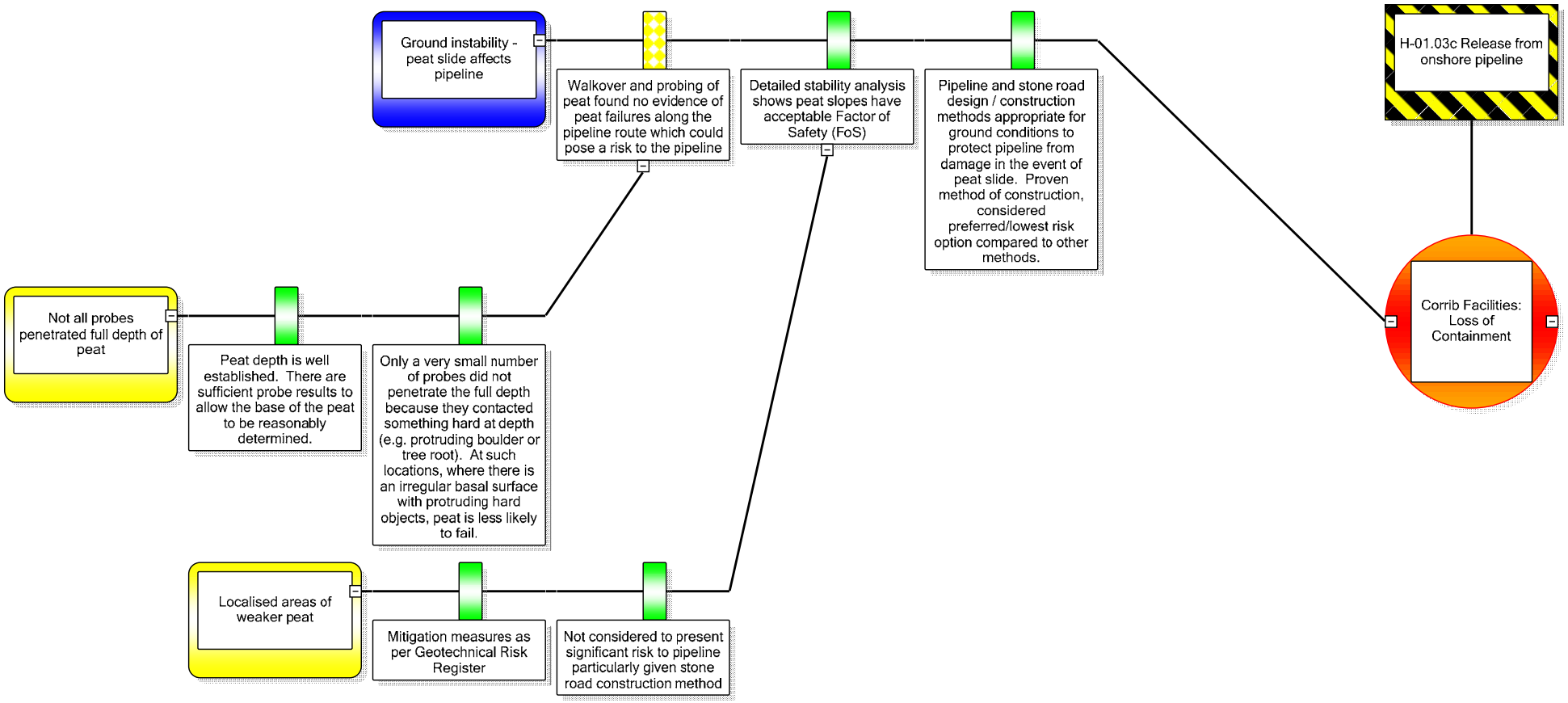


Figure B5.16 - H-01.03c Release from Onshore Pipeline
Detailed Extract – Ground Instability – Peat Slide Affecting Pipeline (Preventive Controls 4 - 7)

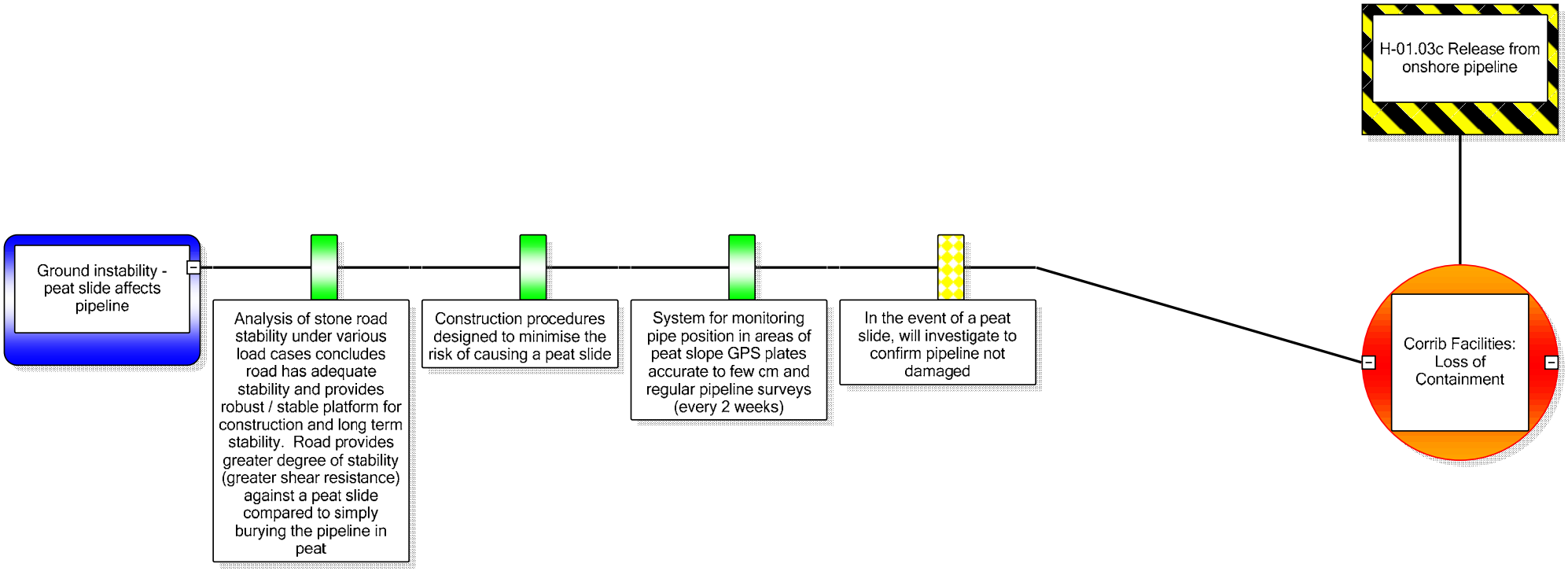


Figure B5.17 - H-01.03c Release from Onshore Pipeline
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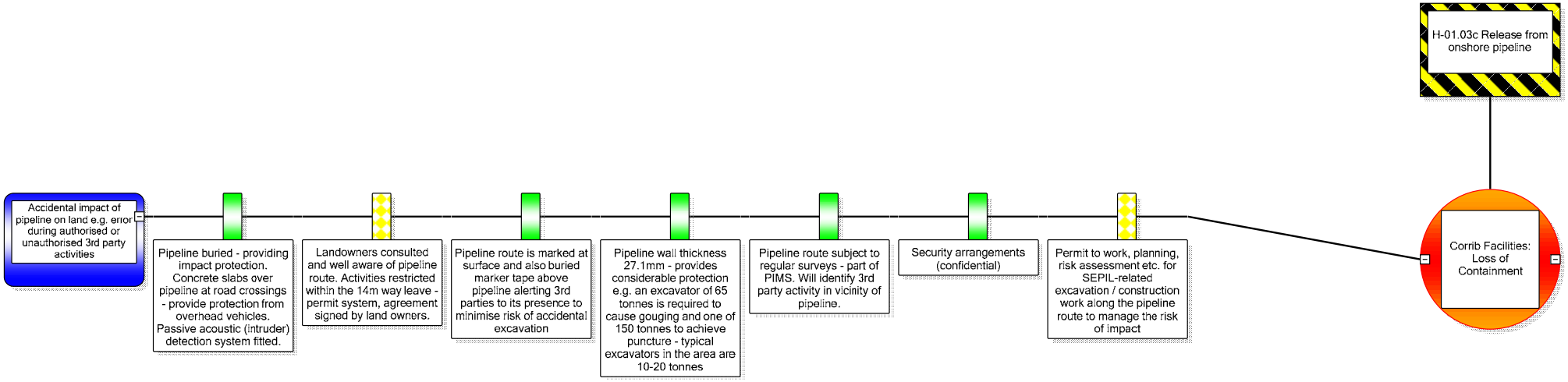

Figure B5.18- H-01.03c Release from Onshore Pipeline
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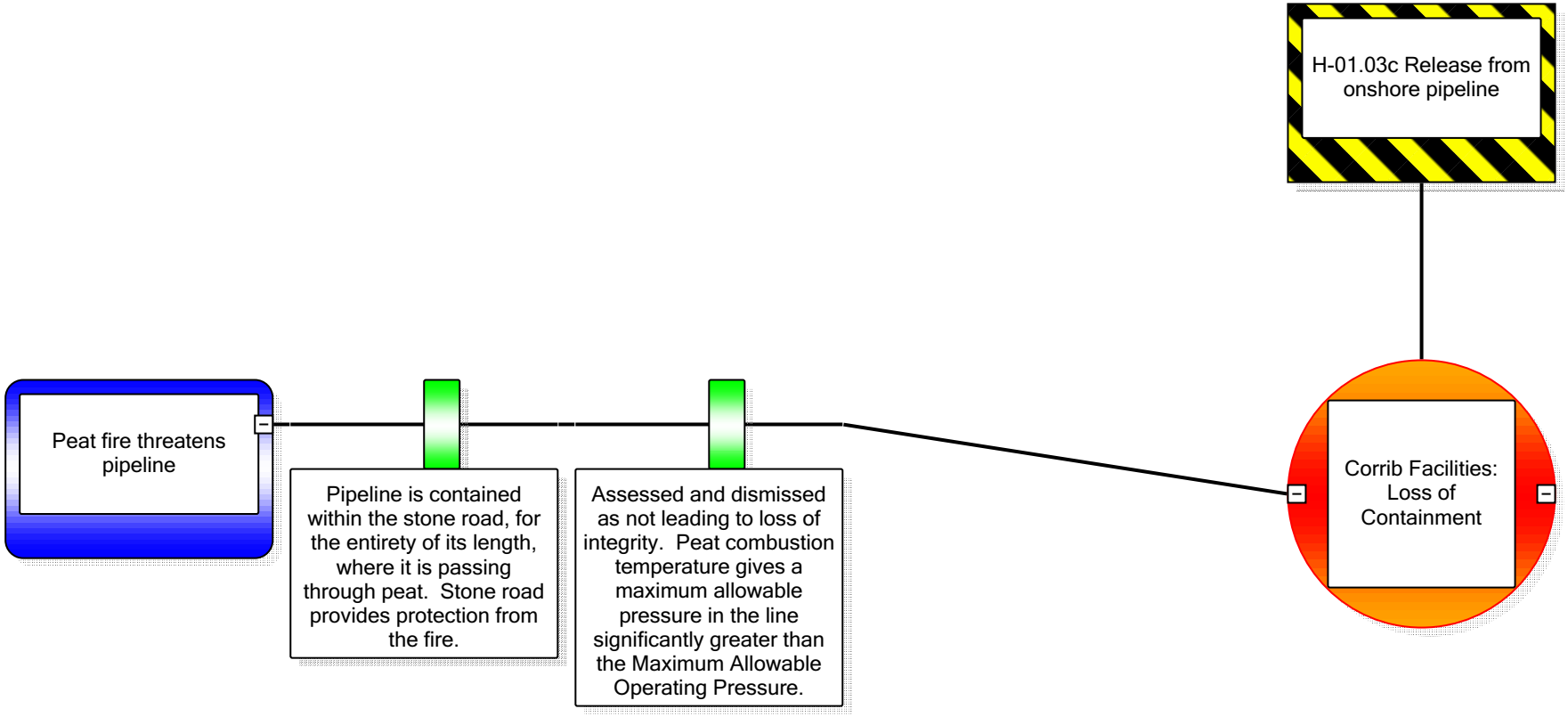

Figure B5.19 - H-01.03c Release from Onshore Pipeline
Detailed Extract – Error During Maintenance of Pipeline – Hot Tapping (Preventive Controls)

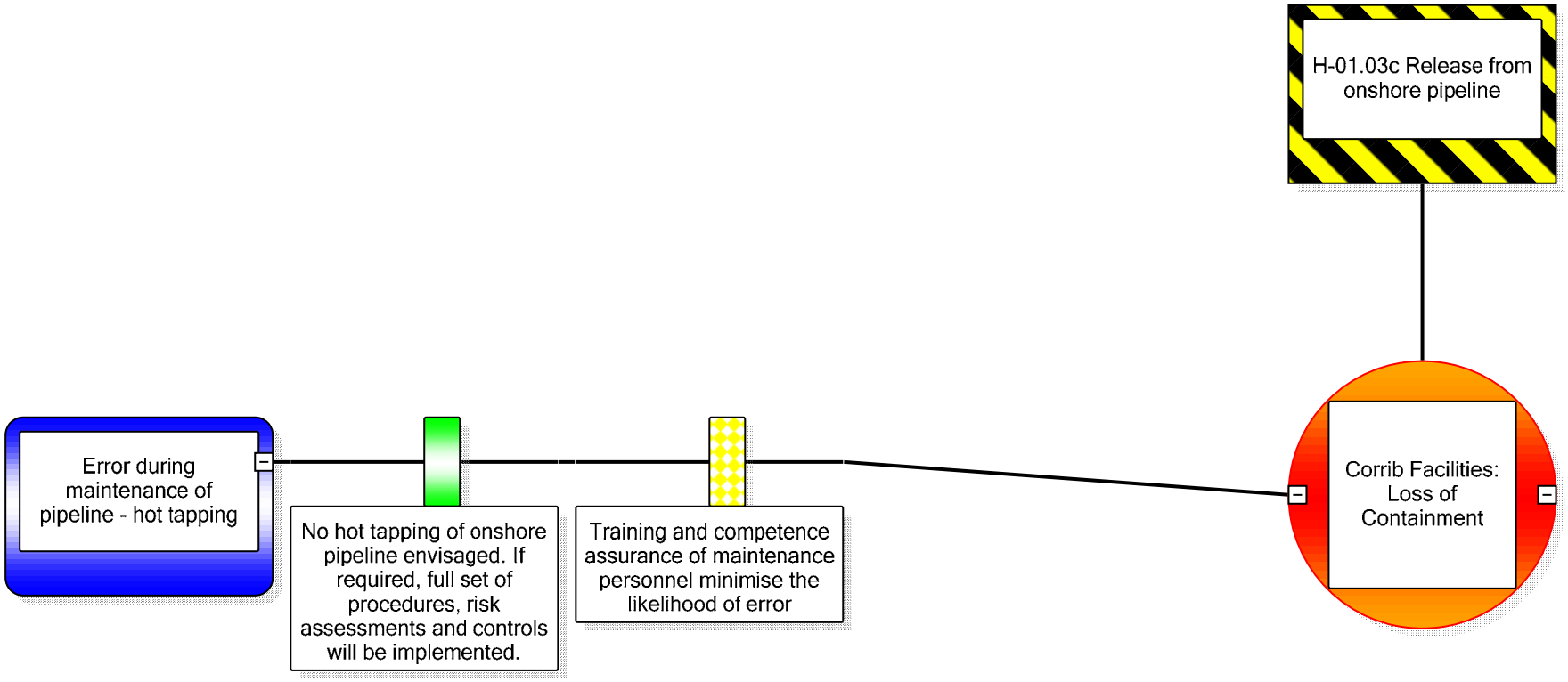

Figure B5.20 - H-01.03c Release from Onshore Pipeline
Detailed Extract – Serious Rupture / Large Release (Overview of Recovery Controls)

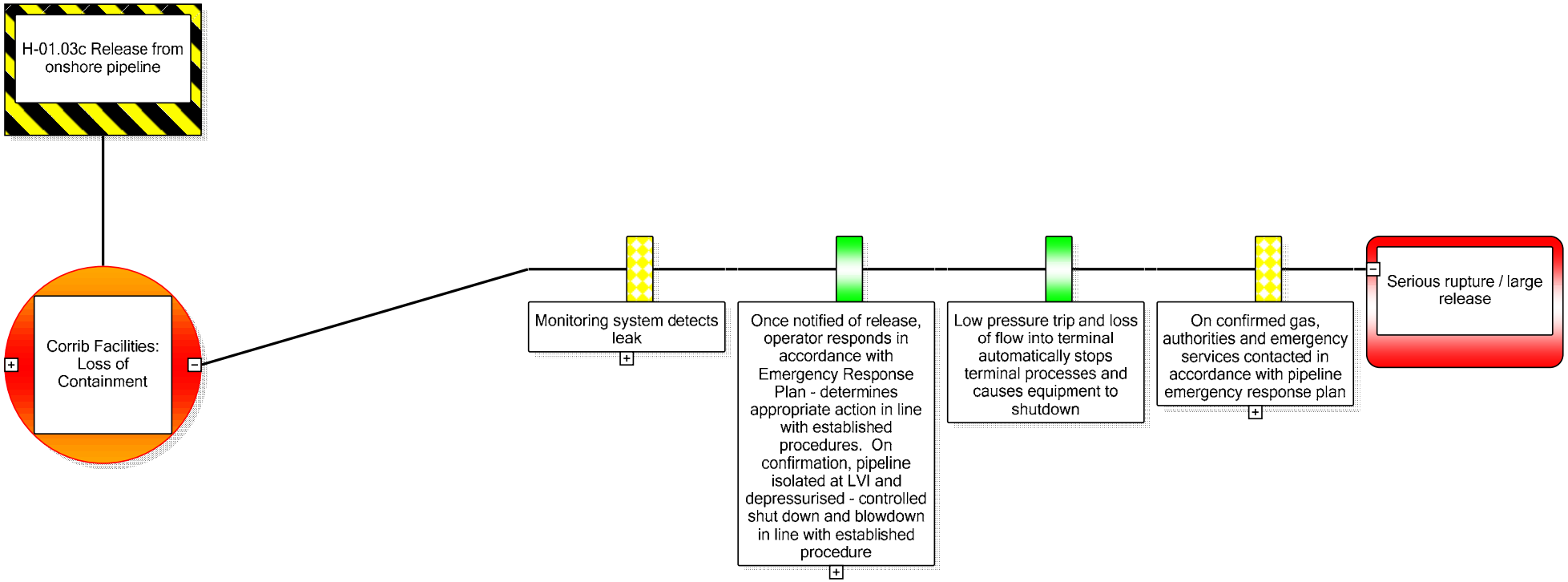

Figure B5.21 - H-01.03c Release from Onshore Pipeline
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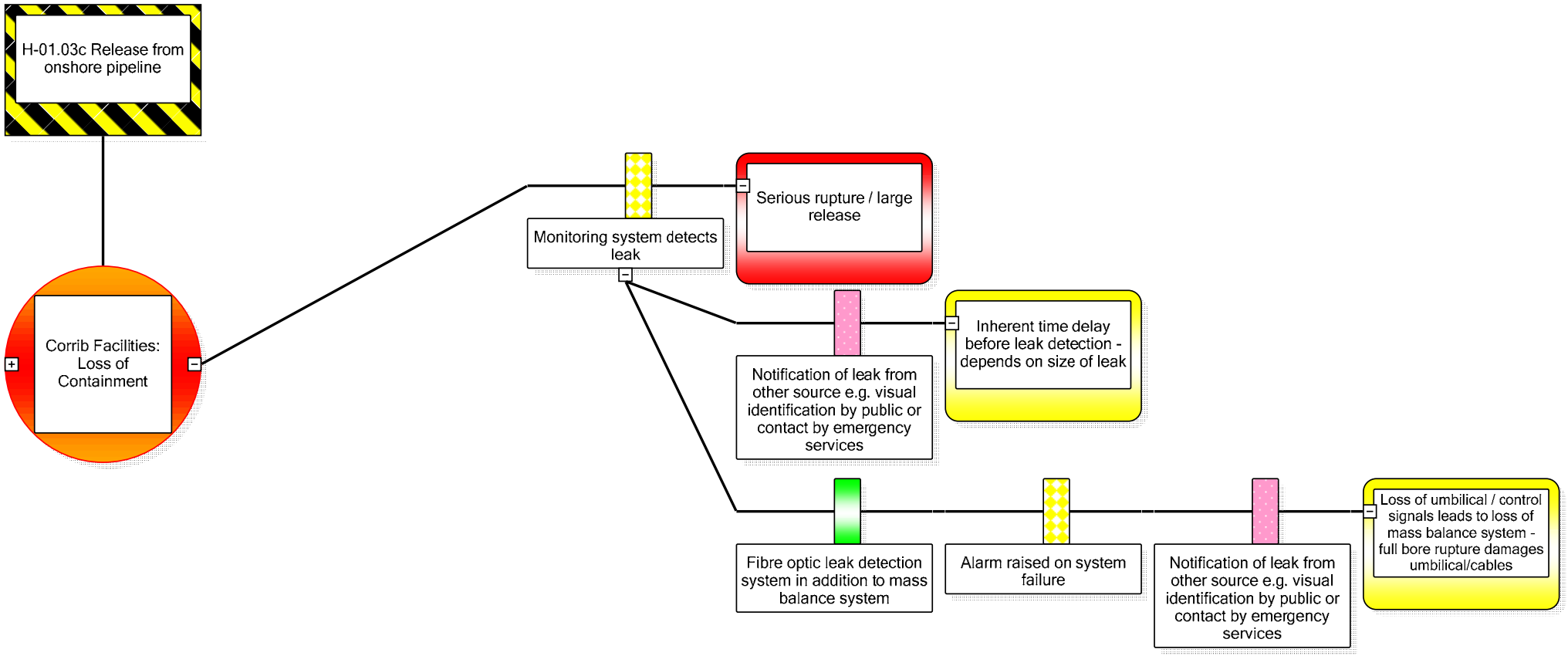

Figure B5.22 - H-01.03c Release from Onshore Pipeline
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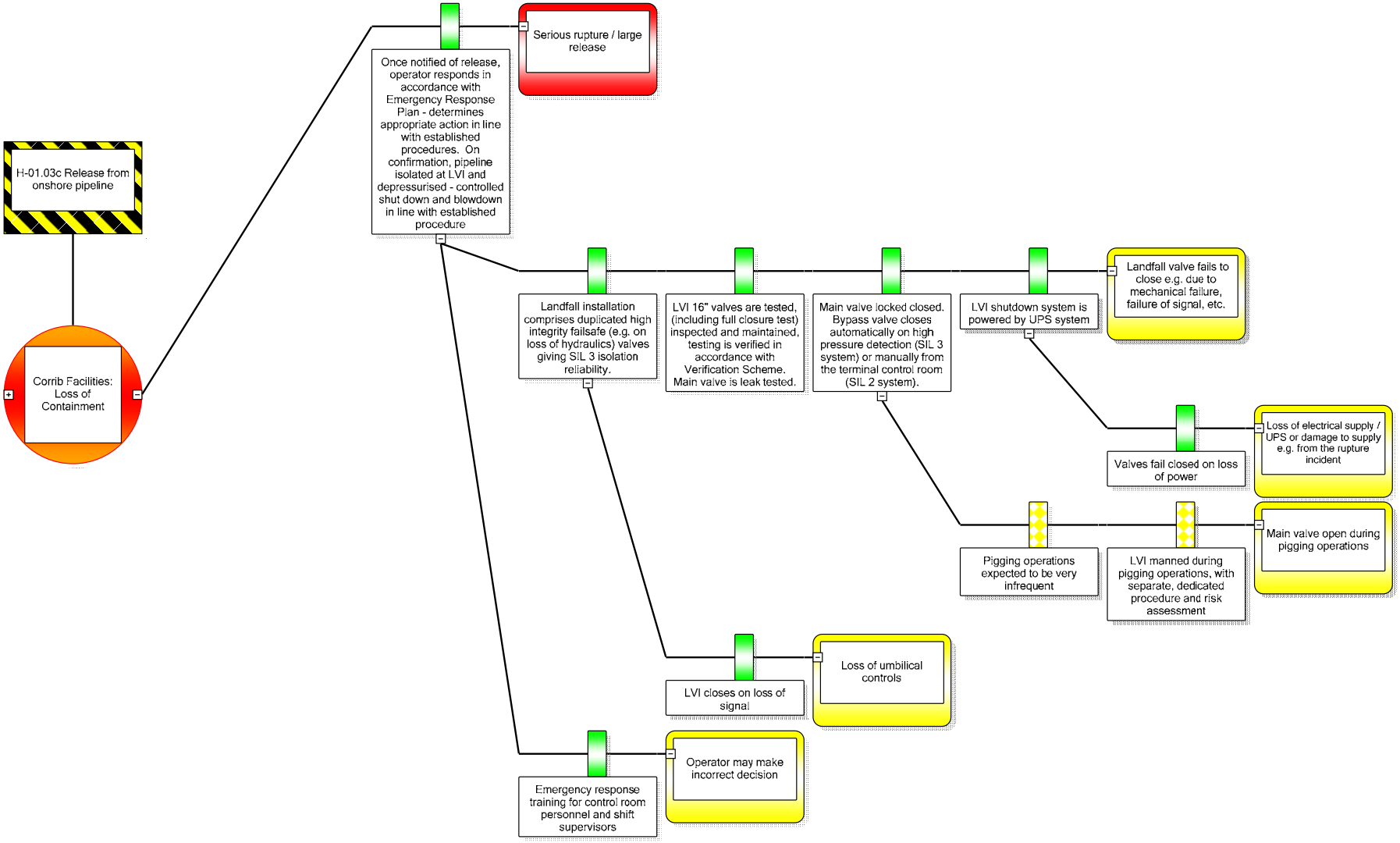
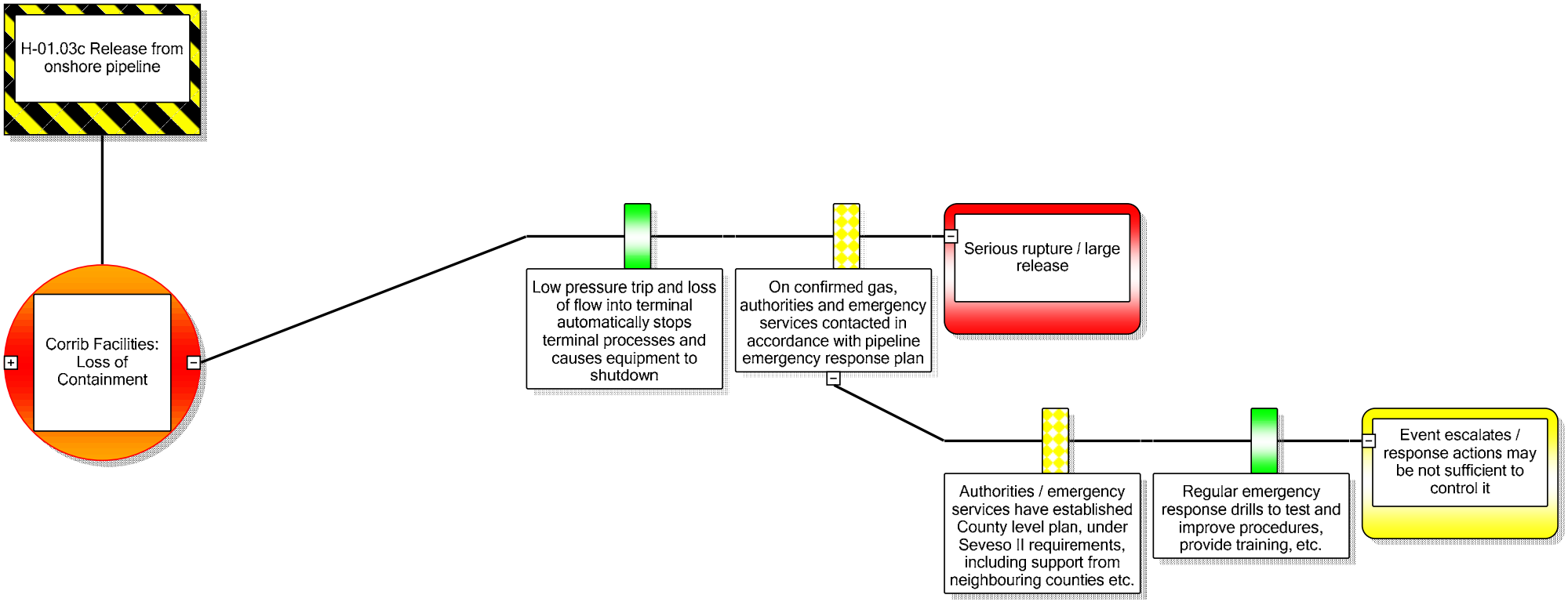


Figure B5.23 - H-01.03c Release from Onshore Pipeline
Detailed Extract – Serious Rupture / Large Release (Recovery Controls 3 & 4)



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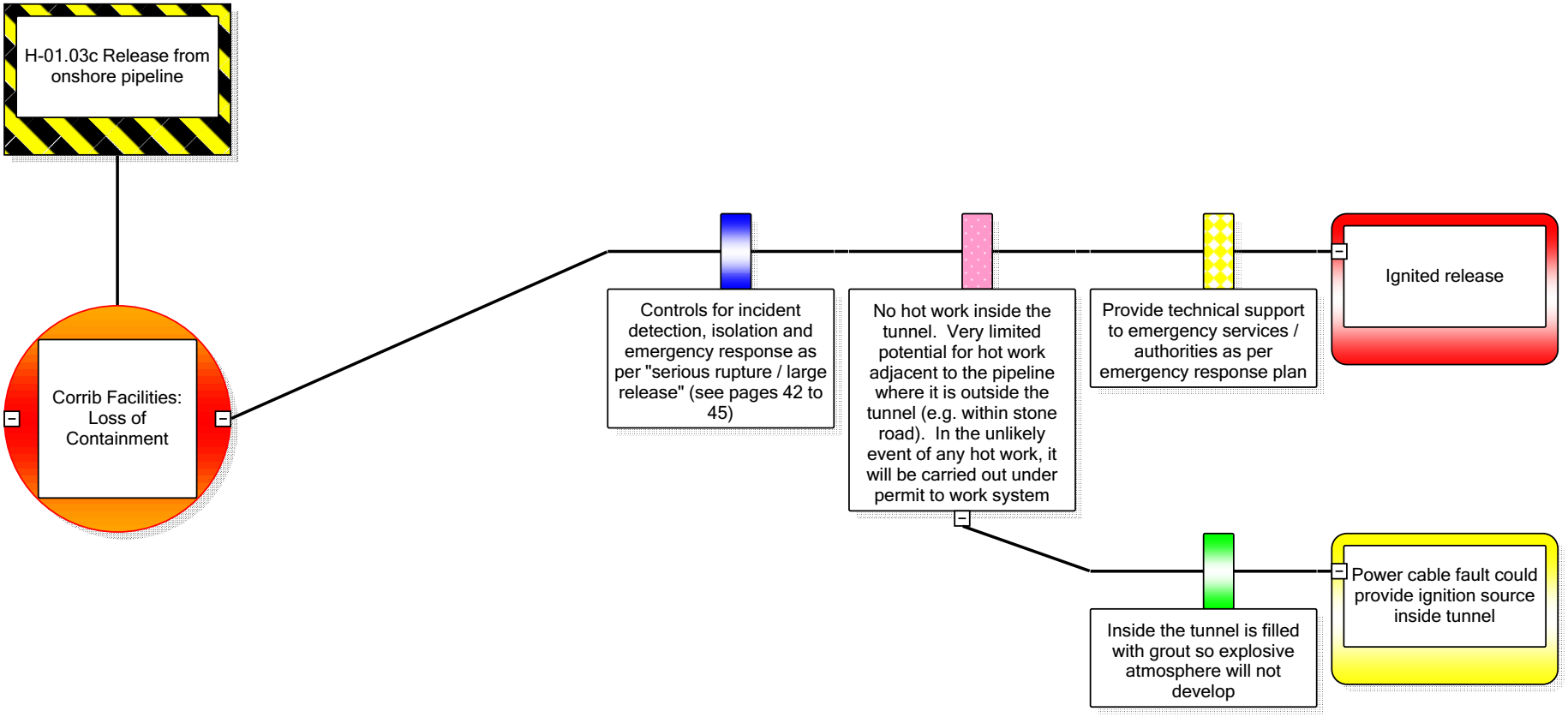

Figure B6.1 - H-12.10/154 Umbilical Failure
Overview of Threats and Consequences

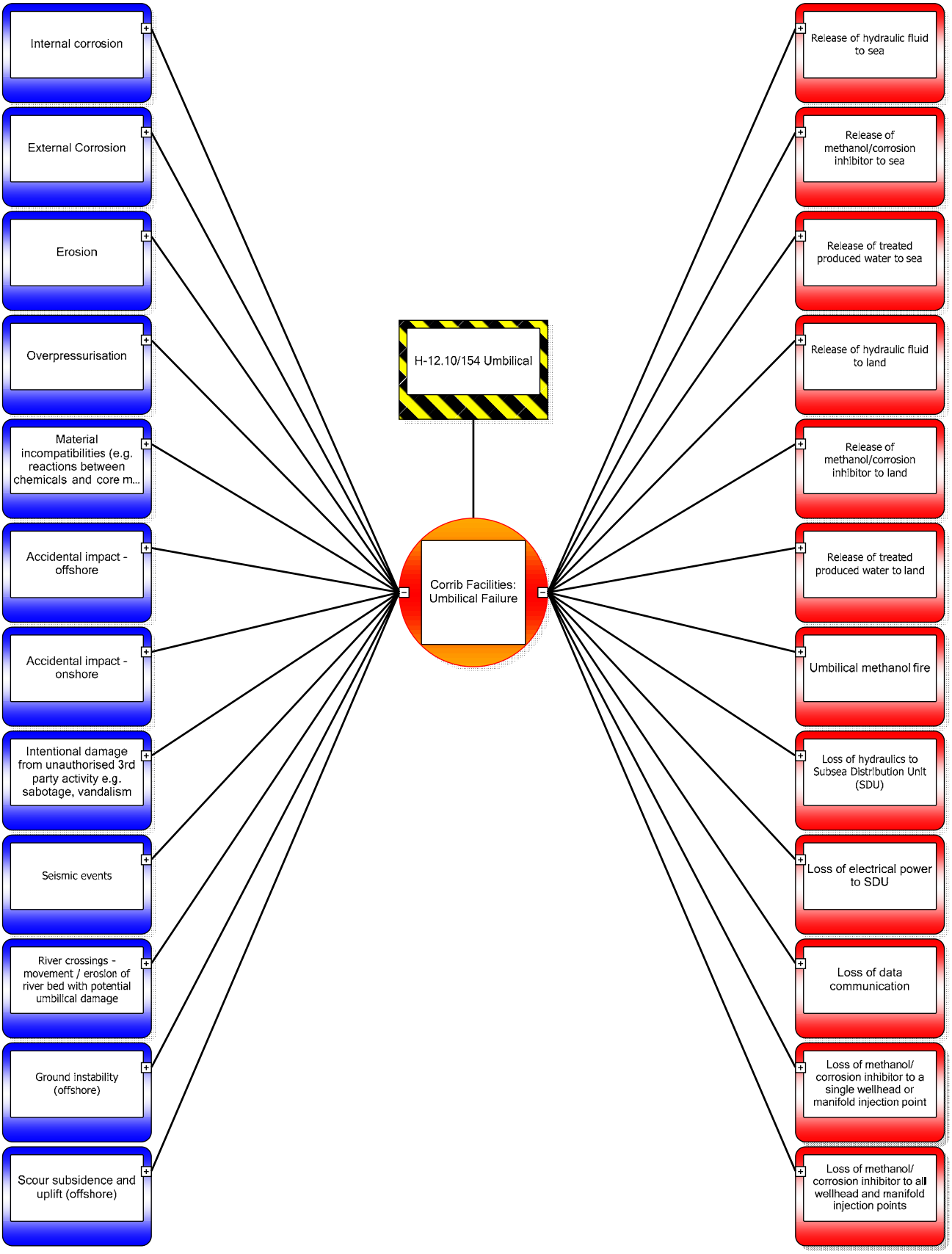

Figure B6.2 - H-12.10/154 Umbilical Failure
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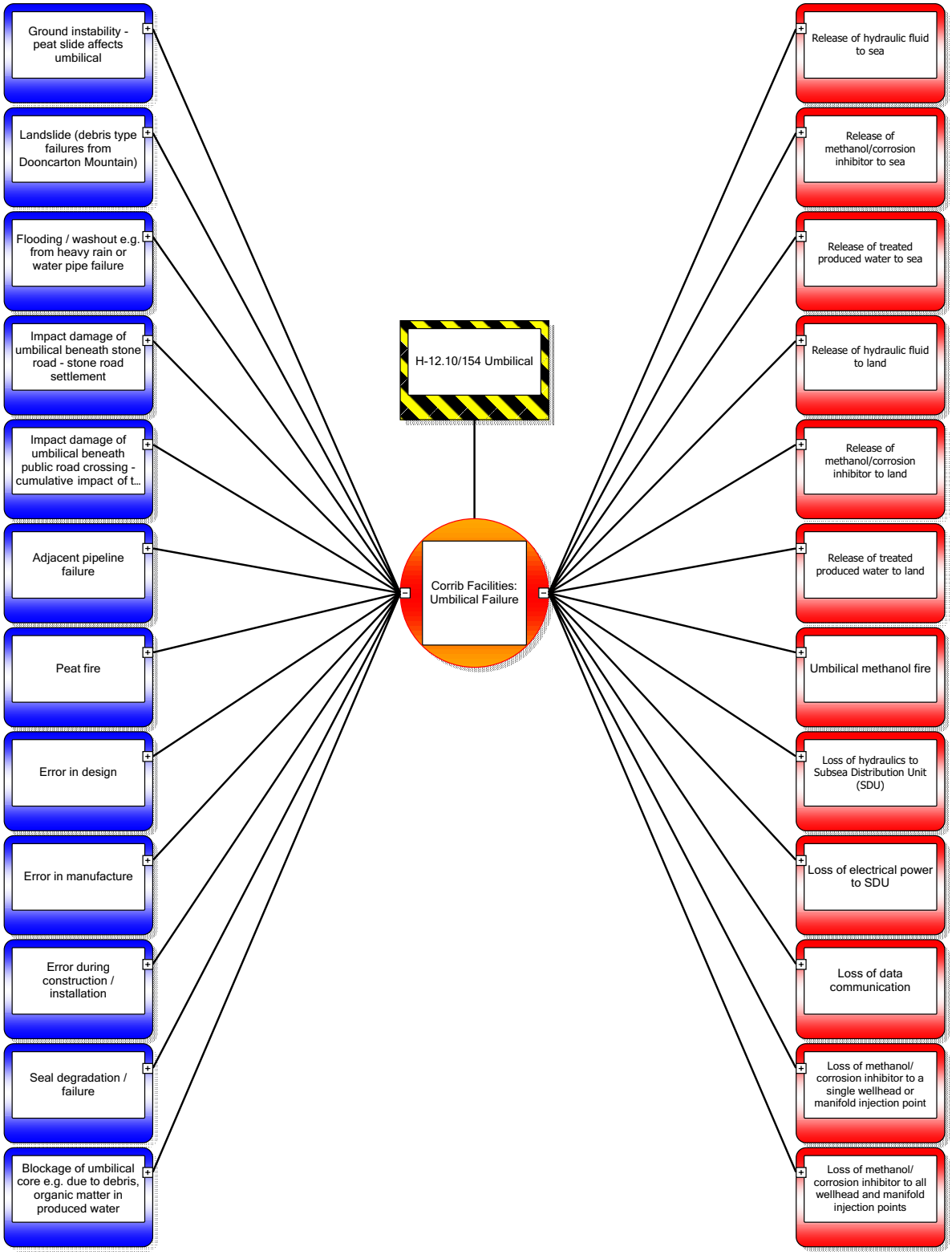

Figure B6.3 - H-12.10/154 Umbilical Failure
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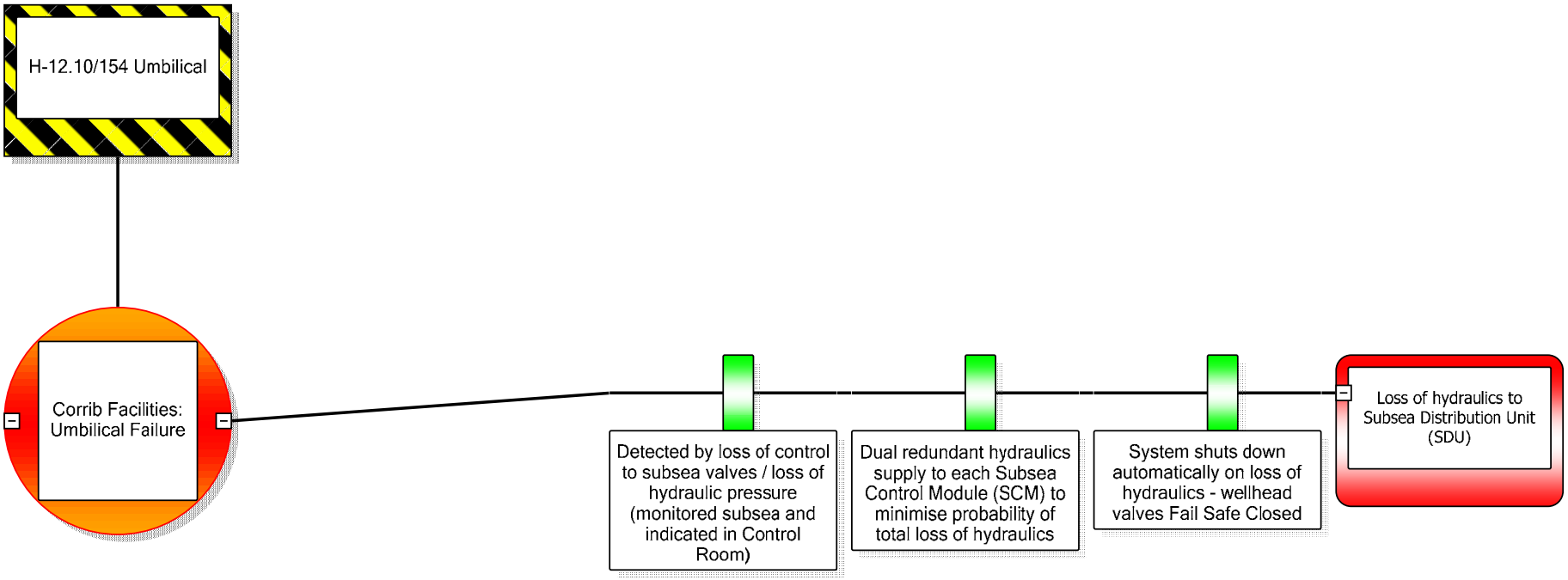

Figure B6.4 - H-12.10/154 Umbilical Failure
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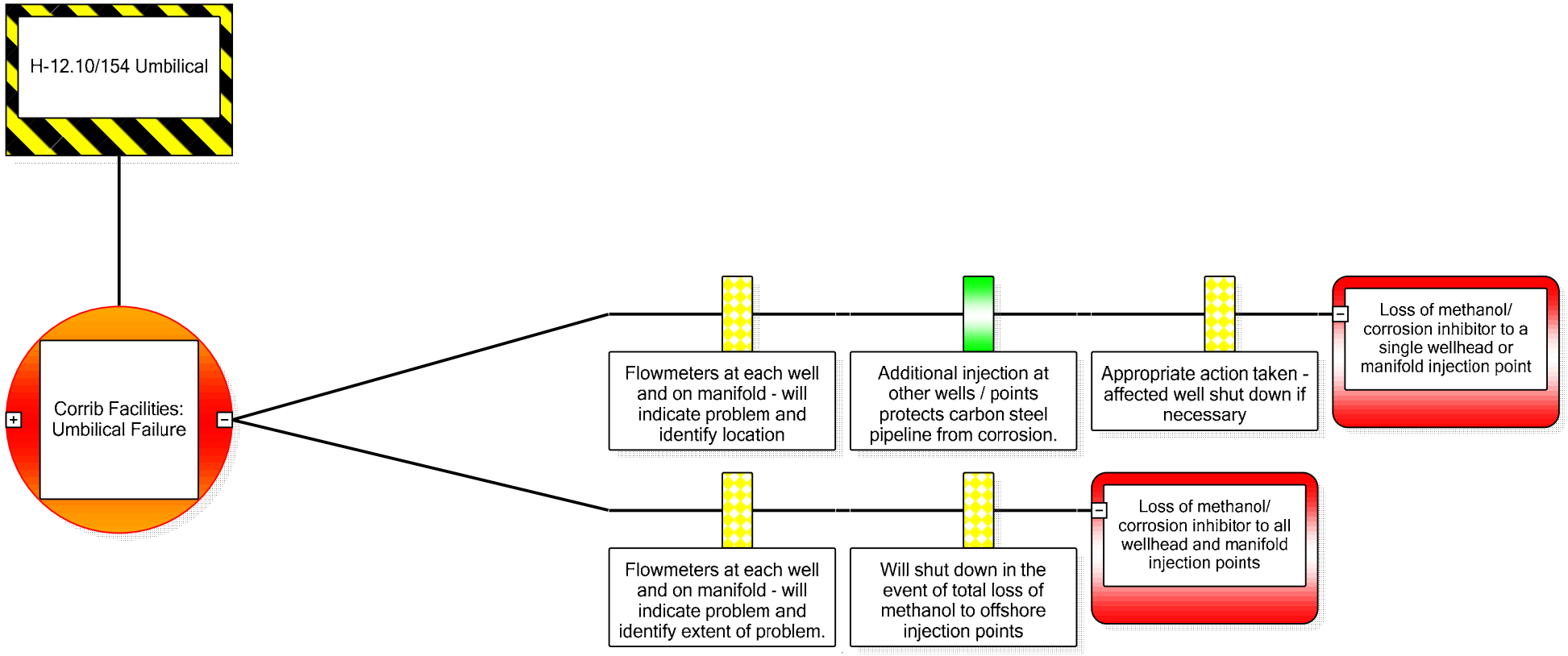

DET NORSKE VERITAS

Report
Corrib Onshore Pipeline QRA

Shell E&P Ireland Ltd.

Report no/DNV Reg No.: 01/ 12LKQW5-2
Rev 01, 2010-05-18

Corrib Onshore Pipeline QRA	DET NORSKE VERITAS LTD, UK HIGHBANK HOUSE SK30ET STOCKPORT, UNITED KINGDOM TEL: +44(0)161 477 3818 FAX: +44(0)161 477 3819 HTTP://WWW.DNV.COM ORG. NO: GB 440 6013 95
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Date of First Issue:	2010-05-18	Project No.	32176602
Report No.:	01	Organisation Unit:	Manchester Solutions
Revision No.:	0	Subject Group:	

Summary:

This document gives details of the quantified risk assessment which forms part of the Environmental Impact Statement that is to be submitted by Shell E and P Ireland Ltd for an onshore pipeline to connect offshore wells with the Bellanaboy Terminal. This follows on from previous QRAs carried out in 2006 (Advantica) and 2009 (DNV). This QRA covers the amended pipeline route in a tunnel under Sruwaddacon Bay and a reduced maximum operating pressure (150 barg upstream of the landfall valve installation, LVI) and 100 barg downstream of the LVI. The conclusion of the QRA is that the predicted levels of risk associated with the proposed pipeline and LVI pose an extremely low risk to the occupants of dwellings along the route of the pipeline.

Prepared by:	*Name and Position* Phil Crossthwaite Chief Specialist	*Signature* P.J Crossthwaite
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01. 2010-05-18	First issue	P Crossthwaite	R Whitehead	R Whitehead

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SUMMARY & CONCLUSIONS

Summary

In order to comply with relevant pipeline design Codes and meet the requirements of An Bord Pleanála's letters dated 2nd November 2009 and 29th January 2010 Det Norske Veritas (DNV) has carried out a Quantified Risk Assessment (QRA) of the Corrib onshore and nearshore pipeline and Landfall Valve Installation (LVI).

This report explains the QRA process, how the QRA has been carried out, and the measures of risk presented. It describes the analysis of likelihood and consequences associated with potential pipeline failure, the data and assumptions used in the analysis, and presents the QRA predictions. These predictions provide a numerical estimate of the residual public safety risks during the operational phase associated with hydrocarbon gas releases from the pipeline and LVI in terms of:

- Individual risk.
- Societal risk.
- Distances to the boundaries of the inner, middle and outer zones.

The QRA uses the latest information concerning the facilities and their surroundings, has been carried out in accordance with the methodology in PD 8010 Part 1 [3] and PD 8010 Part 3 [1], uses similar methodology to that used by the UK Health and Safety Executive (HSE) and applies the risk criteria adopted by An Bord Pleanála as described in their letters dated 2nd November 2009 and 29th January 2010.

Conclusions

The overall conclusion is that the predicted levels of risk associated with the proposed pipeline and LVI pose an extremely low risk to the occupants of dwellings along the route of the pipeline.

In support of this conclusion key predictions of the QRA are summarised below:

Pipeline:

- The predicted level of individual risk of receiving a dangerous dose or more at the nearest dwelling to the pipeline is 1.8×10^{-11} per year (i.e. 1.8 chances in every 100,000,000,000 years). This is almost five orders of magnitude, or 100,000 times, below An Bord Pleanála's adopted level of risk below which the risk is classified as 'broadly acceptable' (1×10^{-6} per year i.e. one chance in 1,000,000 years)
- The predicted level of individual risk of receiving a dangerous dose or more standing at the pipeline is 2.9×10^{-9} per year (i.e. 2.9 chances in every 1,000,000,000 years); this is also well below the 1×10^{-6} per year level. Furthermore it is also below the level adopted by An Bord Pleanála for the outer boundary of the outer zone of 0.3×10^{-6} per year. It is therefore not possible to plot the individual risk contours or the inner, middle and outer zone boundaries for the pipeline as requested in An Bord Pleanála's letters of 2nd November 2009 and 29th January 2010.

- The societal risk associated with the pipeline is also very low, being almost six orders of magnitude, or 1,000,000 times, below the criterion line for 'broadly acceptable' in PD 8010 Part 3 [1].

The above conclusions are drawn based on the predictions from the 'base case' assumptions applied within the QRA. This base case is regarded by DNV as the most appropriate application of data, assumptions and rule-sets specific to the Corrib pipeline. However, a number of sensitivities using more onerous frequencies and assumptions have been carried out to test the QRA predictions, examples are:

- Inclusion of a frequency for ground movement (not considered as a credible cause of failure in the base case) increases the predicted individual risk of receiving a dangerous dose or more from 1.8×10^{-11} to 7.3×10^{-10} per year at the nearest dwelling and at the pipeline from 2.9×10^{-9} per year to 1.7×10^{-8} per year. Thus the individual risk at the pipeline remains almost two orders of magnitude below the 'broadly acceptable' region boundary.
- Application of a slower speed of movement to safety of 1m/s (2.5m/s is used in the base case) within the rule-set adopted for consequence modelling to determine the individual risk of receiving a dangerous dose or more at the nearest occupied dwelling shows only a marginal increase from 1.8×10^{-11} per year to 2.5×10^{-11} per year.

LVI:

- The predicted levels of individual risk of receiving a dangerous dose or more from the LVI are such that the 1×10^{-6} per year contour is 63m from the facility. The nearest dwelling is 280m from the LVI.
- The predicted distances from the LVI to the middle and outer zone outer boundaries are 63m and 91m respectively. The predicted risk level at the LVI is just below 1×10^{-5} per year, which is the outer boundary of the inner zone.
- Applying a sensitivity to the valve failure frequency in the base case gives predicted distances from the LVI to the the outer boundaries of the inner, middle and outer zones of 111m, 124m and 132m respectively.

1 INTRODUCTION

This section of Appendix Q presents the quantified risk assessment (QRA) of the proposed Corrib pipeline (onshore and nearshore), and the Landfall Valve Installation (LVI) and addresses the specific points in An Bord Pleanála's letters dated 2nd November 2009 and 29th January 2010. It covers the routing of the pipeline beneath Sruwaddacon Bay and Maximum Allowable Operating Pressure (MAOP) now applied and follows on from previous pipeline QRAs carried out by Advantica (2006) [28], and DNV (2009) [16].

This report provides a general introduction to the QRA process and goes on to explain how QRA has been carried out for the Corrib pipeline. It describes the data and assumptions used in the assessment, and presents the Corrib pipeline QRA predictions.

2 OVERVIEW OF QRA METHODOLOGY

2.1 Purpose of this Section

This section describes the method and study structure applied for the Corrib pipeline as a lead-into the full technical analysis and assessment in the sections that follow.

2.2 Risk & Risk Assessment

In the context of a QRA risk may be considered as the likelihood or chance of somebody being harmed by a hazard (where hazard is defined as anything that can cause harm e.g. chemicals, electricity, driving a car). The level of risk is based on a combination of the likelihood of the event happening and the consequence of the event. Likelihood is expressed within a QRA as a frequency or probability.

Risk can however be assessed either qualitatively or quantitatively.

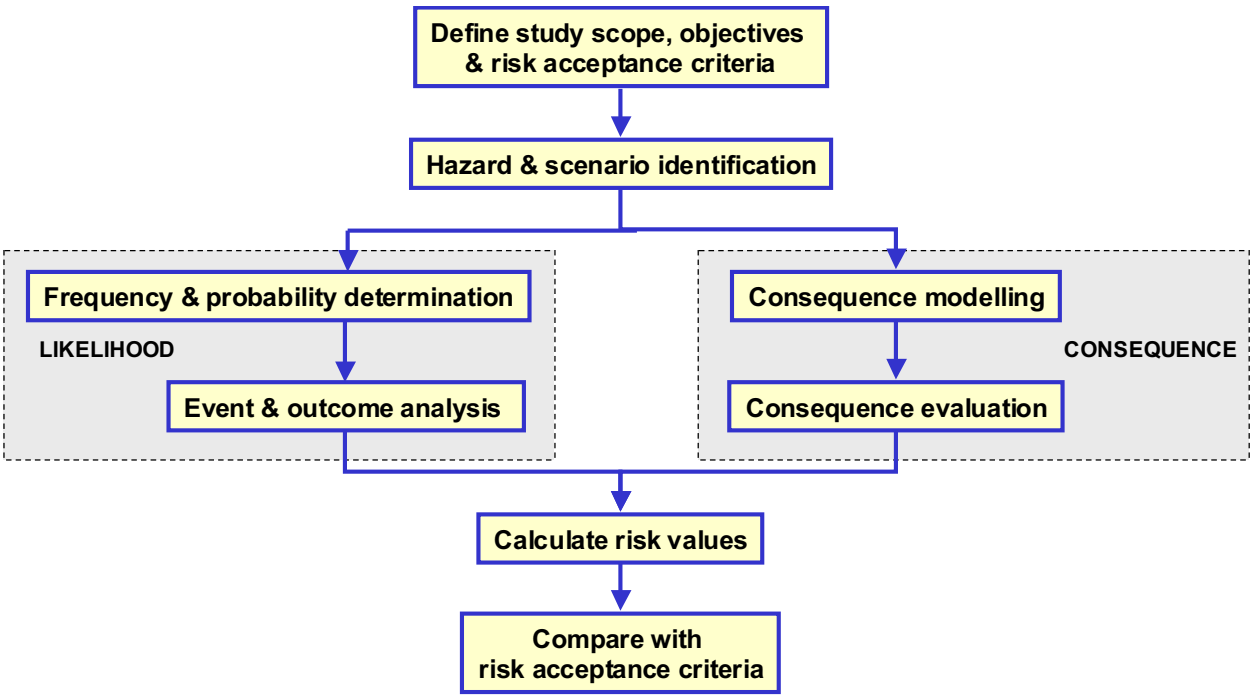
Qualitative risk assessment incorporates a judgment of likelihood and consequence or severity (and therefore risk) which does not involve numbers but instead uses categories such as 'high', 'medium' and 'low'.

Quantitative (or Quantified) risk assessment (QRA) involves assigning, for each discrete event, numerical values to the likelihood (frequency) and severity (or consequences) of the outcomes. All the discrete events are then combined to give a (total) numerical risk level. These calculated numerical risks are then assessed by comparing with risk acceptance/tolerability criteria (risk criteria).

2.3 Overview of QRA

Typically, a QRA will consist of the steps shown in Figure 1 that illustrate the principal elements and broad structure of a QRA. The methodology used for the Corrib pipeline QRA is consistent with this approach and the applicable pipeline codes PD 8010-3 [1] and IGEM/TD/2 [2].

Figure 1: QRA Method



2.3.1 Define QRA Scope, Objectives and Criteria

The QRA must have clear boundaries, deliverables, objectives and risk criteria; these are defined in Section 3 and the principles adopted explained further below.

2.3.2 Hazard & Scenario Identification

For a gas pipeline the principal hazard is an ignited unintentional release of the hydrocarbon gas being transported in the pipeline.

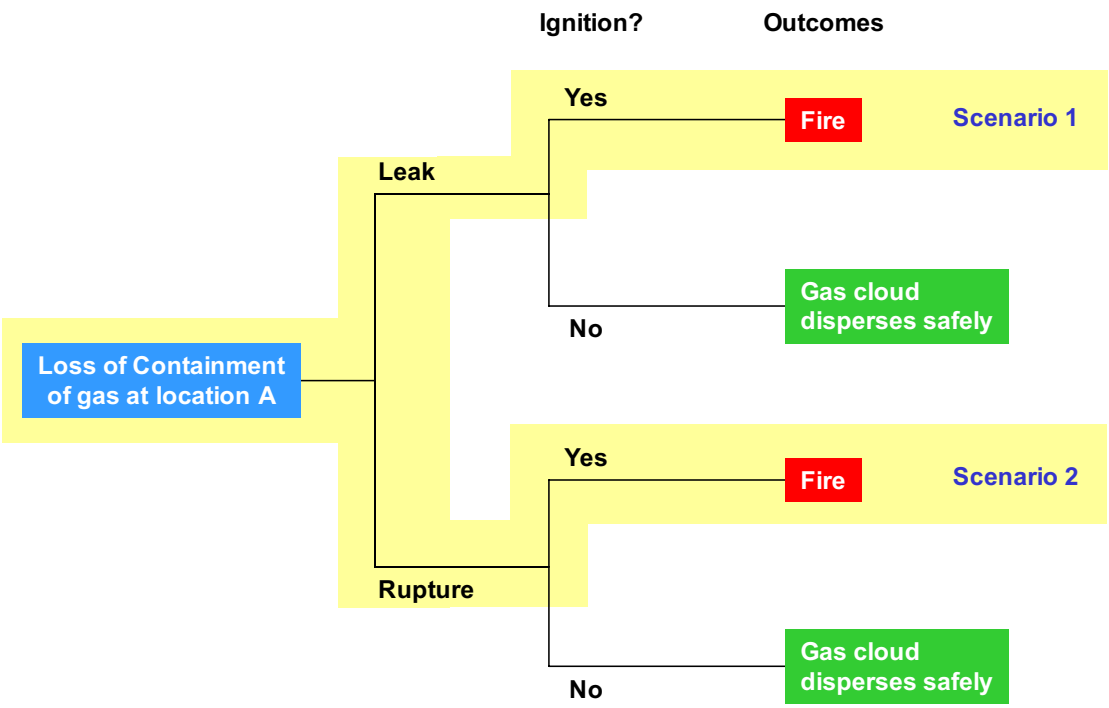
The qualitative risk assessment [Appendix Q6.3] contains the bowtie-based analyses undertaken for loss of containment from the pipeline and the LVI. The threats (causes of failure) that may lead to loss of containment are contained in the bowties and provide input to the QRA. Within the QRA these threats are screened to identify threats for inclusion in the QRA.

Within a QRA, loss of containment is assumed to occur either through a hole in the pipe wall or the equipment. Such a hole may be very small (often termed a pinhole) or larger (often termed as leak or a puncture) or could be as large as a full-bore rupture. Depending on the hole size, whether the release is ignited, when ignition occurs, and where along the pipeline the release occurs a discrete event (or scenario) is built up.

As there is a wide range of loss of containment variables and combinations it is necessary to rationalise scenario selection. To aid rationalisation QRA studies use event trees to model the chronological series of events from the initial release to the final outcome. Event trees provide a

systematic method to ensure all potential outcomes as a result of a specified initial release are identified. Where two possibilities exist, for example ignition or non-ignition, the event tree is branched to form a 'yes' or a 'no' branch and each branch (or outcome scenario) is assigned a probability. Figure 2 shows a simple event tree.

Figure 2: Event Tree Example



2.3.3 Frequency & Probability Determination, and Event Outcome Analysis

The frequencies at which potential failures are expected to lead to loss of containment are estimated using published databases of failure frequencies, suitably modified to reflect the specific conditions under consideration, or predicted using recognised models. The leak frequency data are apportioned by hole size to model the distribution of leaks (as smaller leaks occur with a higher frequency than larger leaks).

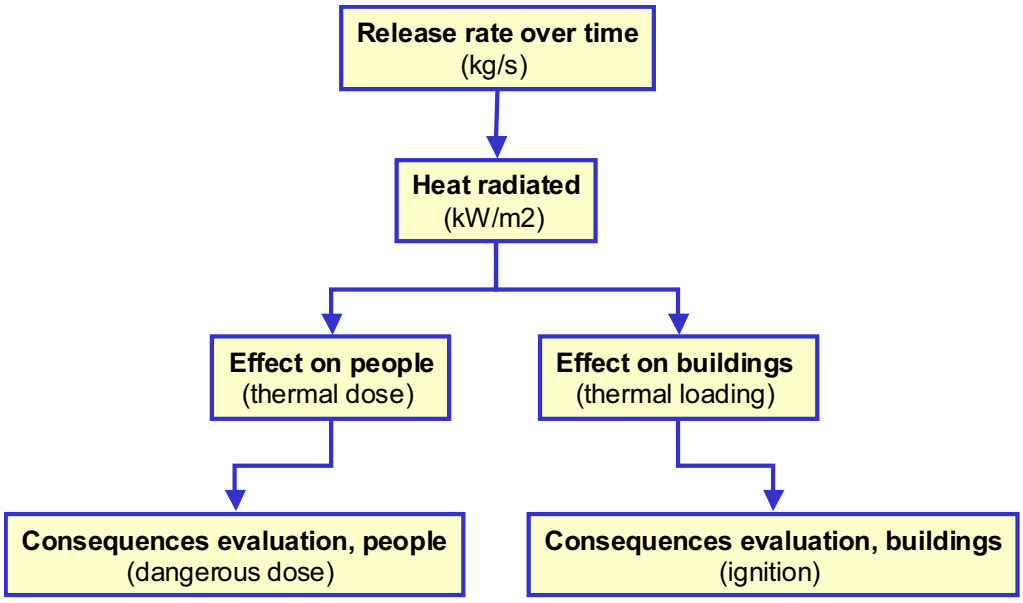
'Yes' and 'no' probabilities at each branch of the event tree are also assigned based on historical data or guidance within Codes, or predicted using recognised models. The frequency of each outcome from each initial release is given by multiplying the initial release frequency by the probabilities along the event tree branches that lead to a particular outcome.

The frequency analysis for the pipeline and LVI is contained in Section 6.

2.3.4 Consequence Modelling and Evaluation

Consequences are modelled for each scenario based on a number of defined inputs (for example, hole size, gas pressure at time of release, environmental conditions). The steps taken for each scenario are shown in Figure 3.

Figure 3: Consequence Modelling for an Event which involves Ignition



Proprietary software that integrates the various sequential steps in Figure 3 is used to process the inputs.

Within this QRA consequence analysis involves primarily the prediction of the levels of thermal radiation that exist as a result of the immediate ignition of a release of gas at varying distances from the pipeline. This is then translated into a corresponding measure of harm to an individual or population, including, where appropriate, consideration of the effects of mitigation (for instance by people being indoors or moving to the shelter of an adjacent dwelling).

Consequence calculations are dependent on a large number of variable parameters, for example:

- Physical (e.g. burning rate, heat radiated);
- Environmental (e.g. humidity, ignition sources) and
- Geometrical (e.g. elevation, shelter).

Input assumptions are selected to provide as realistic a representation of the various scenarios as possible within the limits of the methodology. Some assumptions are developed and included as a 'rule-set' (some of which may be specified by a Regulatory body in order to ensure consistency within and between studies).

The consequence analysis for the pipeline and LVI is contained in Section 7.

2.3.5 Calculate Risk Values

The corresponding pairs of likelihood or probability and consequence for each scenario included in the analysis are combined to calculate numerical estimates of risk per scenario; these are then totalled to give the cumulative risk from the pipeline and the LVI. Risk calculation software (which is an integral part of the software mentioned above for consequence modelling) is used to total all hazard scenarios and all affected locations.

2.3.5.1 Sensitivity Analysis

The QRA is carried out using a 'base case' set of parameters (e.g. frequency of failure, assumptions as to movement of people). Sensitivity studies are carried out to assess the significance and evaluate the influence on the QRA predictions by varying some selected parameters.

2.3.5.2 Presentation of Predicted Risk Values

The predicted risks are presented as:

1. Individual risk.
2. Societal risk.
3. Risk zones.

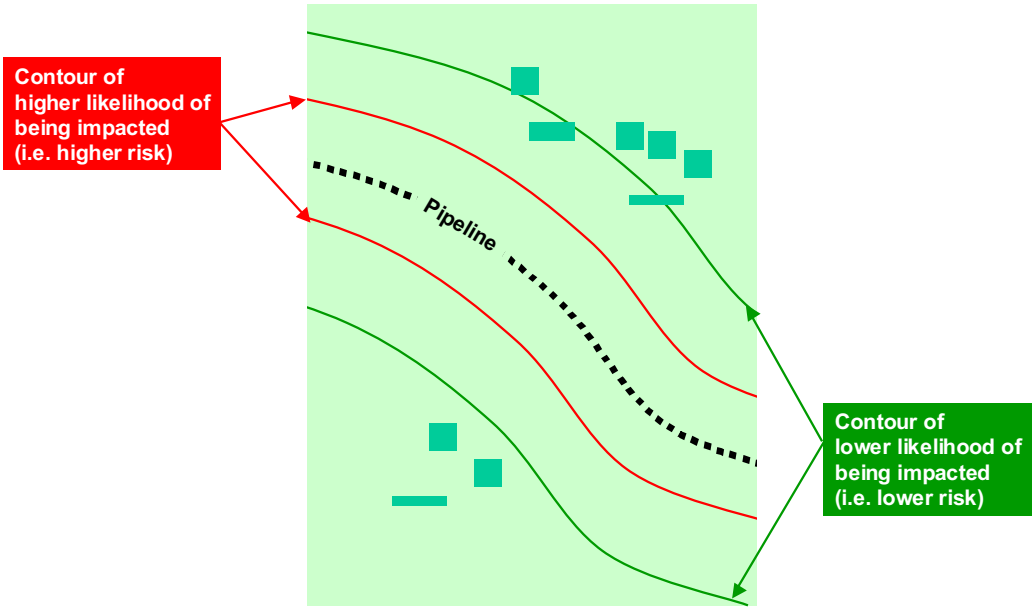
Individual and societal risk are used to assess the acceptability of a proposed facility or pipeline route with respect to existing buildings and infrastructure. Risk zones are used to assess how a proposal may constrain any future development plans for the land adjacent to the facility or pipeline.

A description of these risk measures and their presentation is given below:

Individual Risk

Individual risk is the risk of harm to an individual person, i.e. the frequency with which an individual could be exposed to potentially harmful effects. It can be presented as a single value at a specific location, or in the form of contours showing lines of equal risk as shown in Figure 4 for a pipeline. An individual risk value represents the cumulative risk to that individual as a result of all potential hazardous events affecting that individual.

Figure 4: Example Individual Risk Contour associated with a Gas Pipeline



Individual risk contours are generally 'location risk contours', i.e. it is assumed that the hypothetical individual spends 24 hours per day, 365 days per year at each location. This may be true for some house residents, but generally people change location for at least part of each day. It is thus important to recognise that risk contours calculated in this way are more conservative than the actual risk and should not necessarily be interpreted as characterising the risk to any particular individual.

In addition to risk contours individual risk associated with a pipeline can be presented in the form of risk transects. These illustrate in cross-section the variation in risk with distance from the pipeline. An example risk transect is illustrated in Figure 5.

Levels of individual risk are presented numerically and this can be done in various formats as illustrated in Table 1.

Figure 5: Example of Pipeline Individual Risk Transect

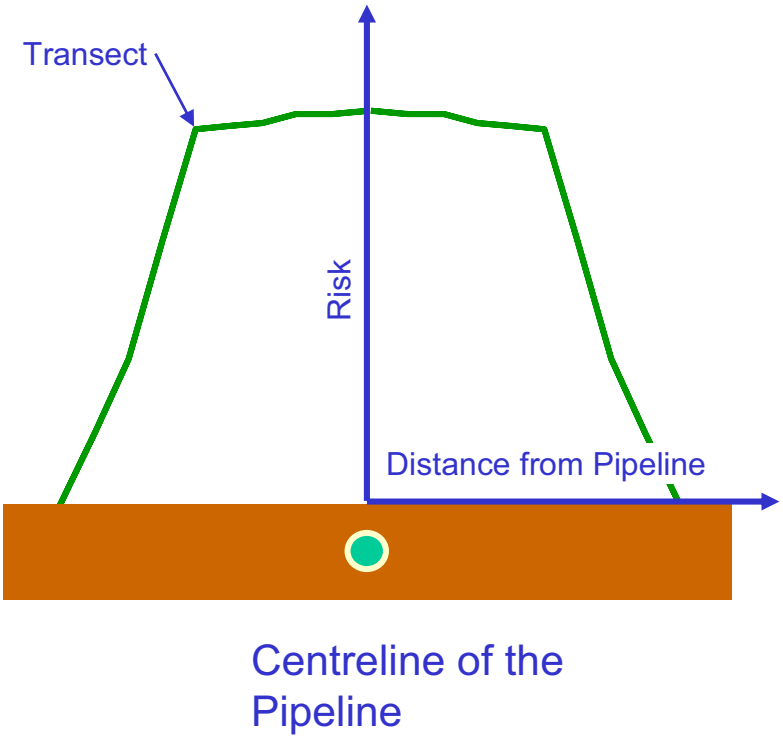


Table 1: Ways of Presenting Numerical Values of Individual Risk

'10' Format (frequency per year)	'E' Format (frequency per year)	Equivalent Chance (chance per year)
1×10^{-5}	1E-05	1 in 100,000 (one in one hundred thousand)
1×10^{-6}	1E-06	1 in 1,000,000 (one in one million)
3×10^{-7}	3E-07	3 in 10,000,000 (three in ten million)
1×10^{-7}	1E-07	1 in 10,000,000 (one in ten million)
1×10^{-9}	1E-09	1 in 1,000,000,000 (one in one billion)

For the Corrib onshore pipeline individual risk is shown using two metrics.

Risk of receiving a dangerous dose which the UK Health and Safety Executive (HSE) define as the risk of a person receiving an amount of radiated heat of 1000tdu or more (see section 7.3 for explanation).

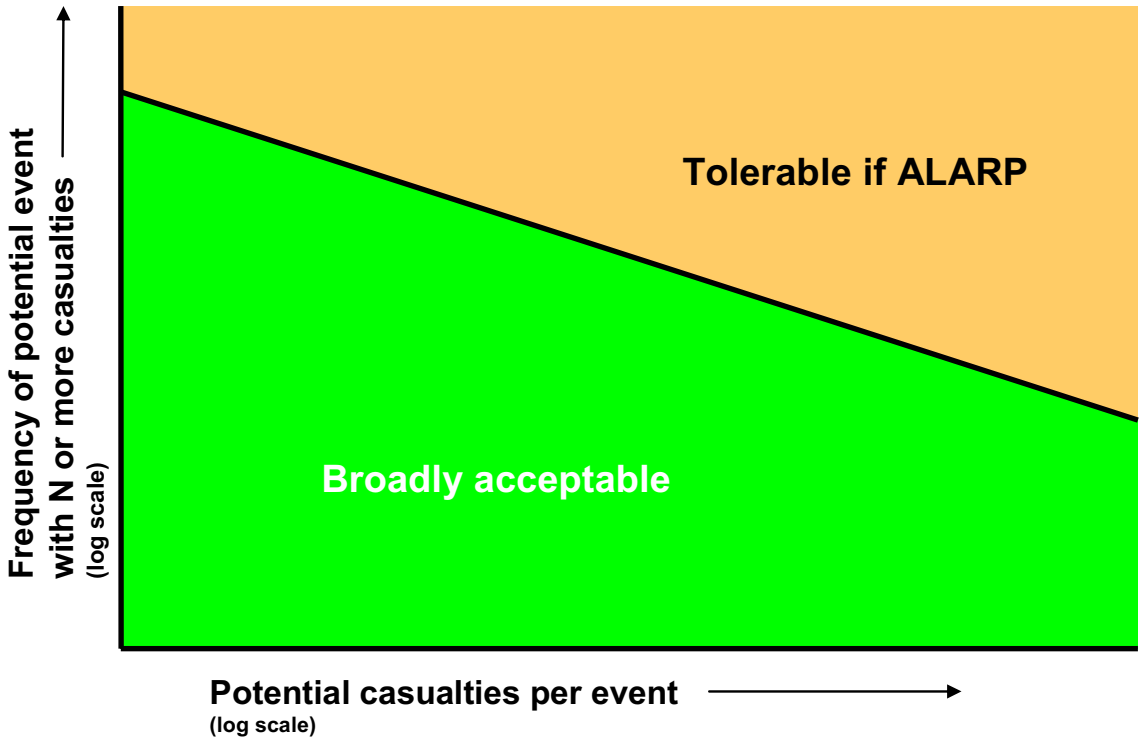
Risk of fatality which is defined as the risk of a person receiving an amount of radiated heat that is fatal.

In measuring these risks a hypothetical individual is assumed to act in a way that is described in 'rule sets' (described in Section 7.3).

Societal Risk

Societal risk is a measure of the possibility of a single outcome simultaneously affecting more than one person and requires an estimate of the location and number of people at risk. Again it can be represented by a single numerical value, but is usually shown as a curve on an FN graph. The graph plots a set of points representing increasingly serious events, relating the numbers of persons potentially affected (N) to the frequencies (F) the events (see Figure 6).

Figure 6: Example F-N Graph



Zoning

Zoning can be used by a regulator or planning authority to control future development in the vicinity of a pipeline. In the UK and some other European countries inner, middle and outer zones are defined on each side of a pipeline. Within each zone restrictions are placed on the type of buildings or facilities that may be developed thus enabling the relevant planning authority to assess whether a proposed or existing pipeline may conflict with any known or possible future development proposals.

2.3.6 Comparison of QRA Predictions with Risk Criteria

Risk criteria are specified either in relevant codes and standards, or by the relevant regulating authority. This includes the distinction between a level of risk that is:

- Tolerable (i.e. negligible and/or broadly acceptable),
- Tolerable, but risks must be demonstrated as being As Low As Reasonably Practicable (ALARP), or
- Intolerable.

The QRA predictions are compared with criteria in order to assess acceptability or tolerability. As part of this comparison the outcomes of any sensitivity studies and any aspects concerning the achievement of risk levels may be considered.

3 QRA OBJECTIVES, SCOPE AND RISK CRITERIA

3.1 Objectives of the QRA

The main objective of this QRA is to examine in a logical and transparent way whether or not the proposed pipeline and LVI pose an unacceptable risk to the public and to address the issues raised in An Bord Pleanála's letters.

Application of QRA is described in the pipeline codes (see Section 4.2 of this Appendix) and the approach used in this QRA follows the methodology in pipeline codes PD 8010-1 [3] and PD 8010-3 [1].

Other objectives of a QRA can include:

- Identification of the main contributors to the overall risk (so that potential measures to reduce risk can be identified and an assessment of the effectiveness of these measures can be made).
- Increasing awareness of hazards, potential hazardous events and mitigation.
- Providing an aid to communication to stakeholders of their exposure to risk.

With reference to the first bullet point, the relocation of the pipeline under Swuraddacon Bay has reduced pipeline operational phase risk levels, even though the risk levels were already within the broadly acceptable region as demonstrated in the previous DNV QRA [16]. However, it cannot be claimed that the reduction in risk is a step towards achievement of ALARP as the costs associated with the re-routing of the tunnel and the safety risks associated with the extended construction period and the more hazardous nature of tunnel construction will outweigh the benefit of the reduction in risk associated with the operation of the pipeline.

3.2 QRA Scope

The scope of the QRA covers all pipeline and LVI related loss of containment events when the ignition of the released hydrocarbon has the potential to affect the public. This QRA therefore includes:

- The section of the pipeline upstream of the LVI where a release may affect persons onshore;
- The LVI and onshore pipeline up to the inlet valve at the Bellanaboy Bridge Gas Terminal.

The following facilities are excluded from the scope of this QRA.

- The offshore wells and offshore pipeline system (except as noted above).
- The Bellanaboy Bridge Gas Terminal which is subject to a separate QRA.

The discrete sections of the pipeline for which specific QRA predictions are appropriate are:

- The section upstream of the LVI (50m offshore, the beach crossing and trenched section up to the LVI).

- The LVI itself.
- The trenched section downstream of the LVI to the point where the pipeline enters the tunnel.
- The pipeline within the tunnel.
- The pipeline downstream of the tunnel through the peat area where it is buried in a stone road up to the terminal.

3.3 Risk Criteria

The risks presented within this QRA, are as follows:

- Individual risk.
- Societal risk.
- Risk zones.

The risk criteria applicable are either those adopted by An Bord Pleanála (individual risk and risk zones) or those specified in PD 8010-3 [1] (societal risk). These are detailed below.

3.3.1 Individual Risk

An Bord Pleanála's letter of 2nd November 2009, page 2, item (a) states:

> "….that the following standards, when applied to the proposed pipeline, are the appropriate standards against which the proposed development should be assessed and that the Board should, therefore,
>
> (a) adopt the UK HSE risk thresholds for assessment of the individual risk level associated with the Corrib Gas Pipeline,
>
> - Individual risk level above $1x10^{-5}$ * – intolerable.
> - Individual risk level between $1x10^{-5}$ and $1x10^{-6}$ – tolerable if ALARP (as low as reasonably practicable) is demonstrated.
> - Individual risk level below $1x10^{-6}$ broadly acceptable.

In their letter of 29th January 2010 An Bord Pleanála provided clarification that this risk was the risk of an individual receiving a dangerous dose, (although it is noted that the UK HSE risk thresholds for assessment of tolerability and ALARP are based on risk of fatality, HSE 2001 [26]). Consequently the individual risk of fatality is also presented within this QRA, and as this is the metric used in previous QRAs it enables a comparison of relative risks with previous assessments to be made accordingly.

The 'broadly acceptable' category covers individual risk levels that are considered insignificant and adequately controlled. The 'tolerable if ALARP' category requires that mitigation measures

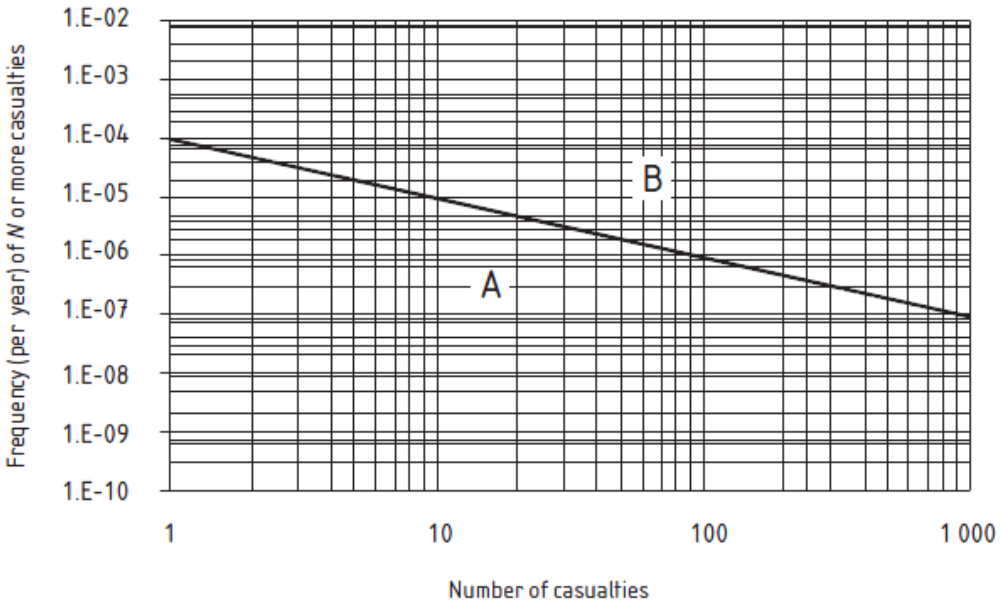
* Numerical values of individual risk may be presented in the form 1×10^{-5} as in the letter from An Bord Pleanála or in 'E' format. 1E-05 is the same as 1×10^{-5}. In general the 'E' format is used throughout this document. Three different ways of presenting risk numerically are shown in Table 1.

are employed to reduce the risk levels to such an extent that further risk reduction is impracticable or requires action that is disproportionate to the risk reduction that the measure can give. The 'intolerable' category indicates that the risks have to be reduced irrespective of the cost.

3.3.2 Societal Risk

The criterion contained in PD 8010-3 [1] (see Figure 7) is used as the format for presentation and basis of acceptance for societal risk predictions.

Figure 7: PD 8010-3 FN Criterion Line



A Broadly acceptable risk region.

B Tolerable if ALARP risk region.

3.3.3 Risk Zones

An Bord Pleanála's letter of 29th November 2009, Page 3, item (j) requests:

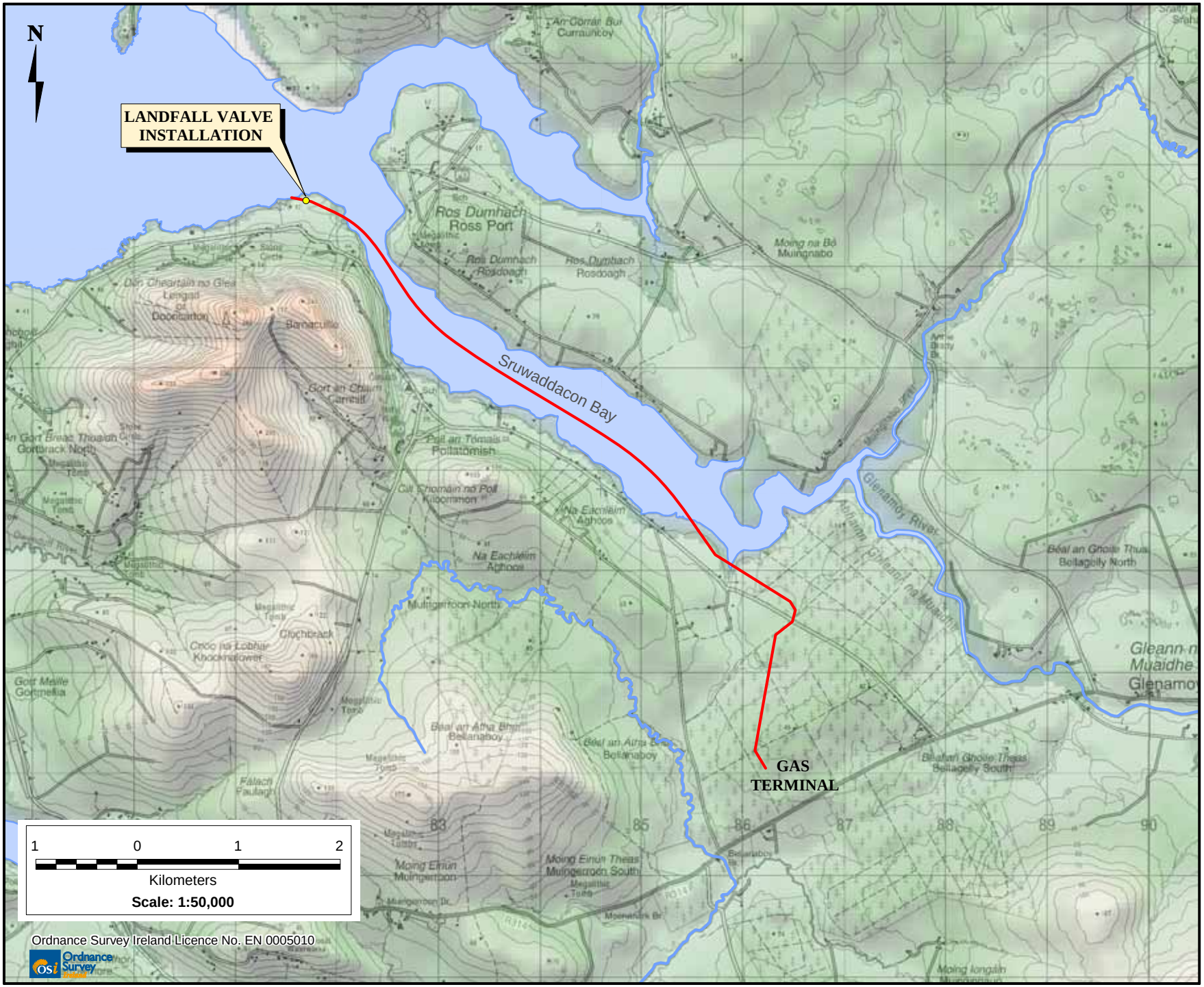
> (j) Provide details separately of the inner zone, middle zone and outer zone contour lines for the pipeline. These shall represent the distance from the pipeline at which risk levels of $1x10^{-5}$, $1x10^{-6}$ and $0.3x10^{-6}$ per kilometre of pipeline per year exist.

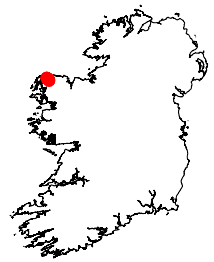
Although not specified by An Bord Pleanála, because the UK HSE use these numerical values in terms of the risk of receiving a dangerous dose or more per year, the same metric has been used in this QRA.

4 PIPELINE DESCRIPTION

A full description of the Corrib pipeline facilities is presented in Appendix Q2, with more detail presented in Appendices Q4 and Q5.

The onshore pipeline route is described in detail in Chapter 4 of the EIS. For ease of reference it is illustrated in Figure 8.





Proposed Pipeline Route

Overall Layout of the Onshore Pipeline and Landfall Valve Installation

Figure 8

File Ref: COR25MDR0470Mi2145A03
Date: May 2010

CORRIB ONSHORE PIPELINE

Corrib natural gas

RPS

5 HAZARD, RISK & SCENARIO IDENTIFICATION

5.1 Hazard & Risk

The qualitative risk assessment (Appendix Q6.3) includes a risk register and identifies a number of major risks. For the QRA, the principal hazard is the unintentional ignition of the hydrocarbon gas being transported in the pipeline and the output from the QRA is therefore the risk of an ignited release of the gas affecting members of the public.

5.2 Event Scenarios

The event scenarios associated with loss of containment in the QRA are very unlikely to occur but could occur as releases from the two main pipeline sections:

1. Upstream of the LVI isolation valves, with the LVI closed at the MAOP for the offshore pipeline (150 barg).
2. Upstream or downstream of the LVI, with the LVI open, at the MAOP for the onshore pipeline (100 barg).

The actual scenarios modelled in the QRA are dependent on the hole sizes selected to represent the failures of the pipeline and the failures in the equipment at the LVI. These are detailed in Sections 6.5 and 6.9 respectively.

6 FREQUENCY ANALYSIS

6.1 Introduction

This section of the report deals with the determination of the frequency of potential releases from the pipeline and the LVI along with allocation of the representative hole sizes.

It is important that, as far as is reasonably possible, the frequency values used in the QRA reflect the actual design, operating conditions and environment within which the pipeline/equipment will be operating. The standard approach is to take generic data (which has the advantage of being collected over an extensive sample base) and then to customise this to reflect the-Corrib pipeline. It is recognised that this approach carries margins of error and hence sensitivity studies associated with uncertainty are carried out to measure and assess the effects of modifying key parameters.

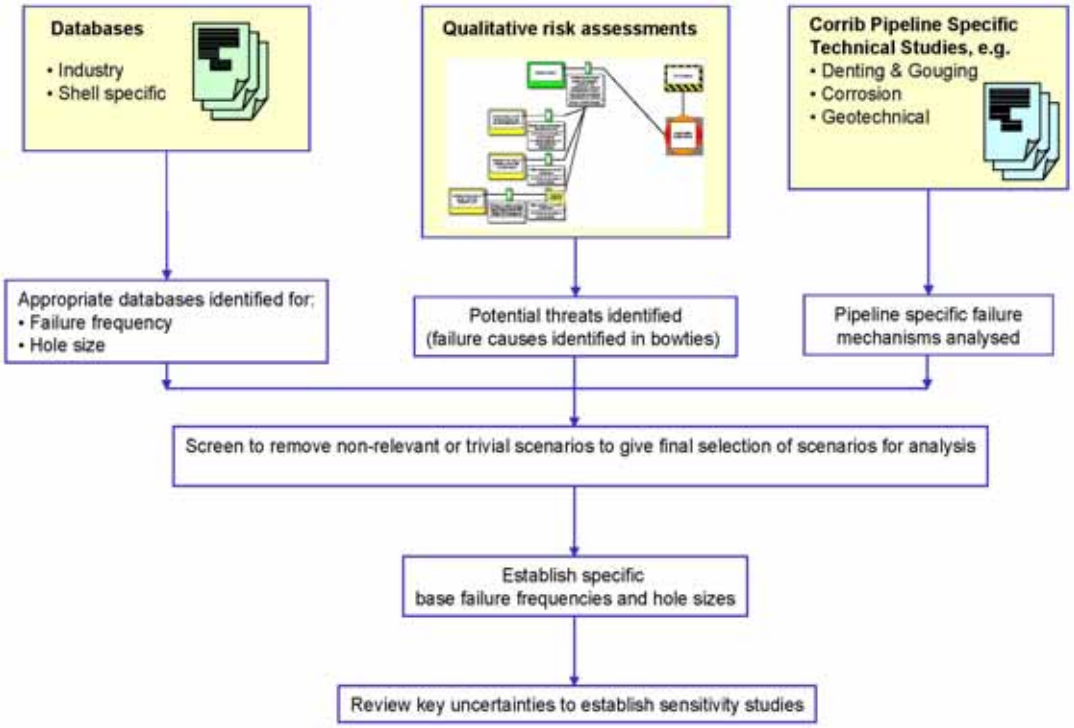
The starting point for the QRA is data on the causes of failure and the associated hole sizes; these are drawn from industry databases. Various databases have been considered and the most appropriate sources of data have been used. The data are then screened to;

- Remove scenarios that are from failure causes that are either not relevant to the Corrib pipeline or LVI (termed non-credible scenarios), or are of such trivial frequencies that they can be discounted without detriment to the accuracy of the QRA.
- Incorporate factors that are specific for this pipeline and LVI.
- Identify aspects for which sensitivity studies may be appropriate (to test the effects of uncertainties in the base case frequencies).

The data are reviewed against the qualitative analysis (see Appendix Q6.3) to ensure that all credible scenarios have been considered. Technical studies carried out as part of this EIS are also taken into consideration to establish the final base data set specific to the Corrib pipeline and LVI.

This process is shown in Figure 9 and provides the structure for this Section.

Figure 9: Process for selection of Failure Frequency and Hole Size value



6.2 Appropriate Databases for the Corrib Pipeline

In order to assist with safe operation, industries (e.g. petrochemical, road transport, offshore etc.) collect extensive amounts of data which are used for a number of purposes including QRAs. The formally maintained databases that are considered most applicable for the Corrib pipeline are:

- European Gas Pipeline Incident Data Group (EGIG) [5].
- Conservation of Clean Air and Water in Europe (CONCAWE) [6].
- Pipeline and Riser Loss of Containment (PARLOC) [7].
- United Kingdom Onshore Pipelines Operators' Association (UKOPA) [8].

In addition, Shell collects data associated with its operations and for this project has made available data from its global unprocessed gas pipeline operations (see Appendix Q4.9).

6.2.1 EGIG [5]

The main database for onshore gas pipeline failures in Europe is compiled by the European Gas Pipeline Incident Data Group (EGIG). This QRA has used the 7th Report 1970-2007 [5], which covers experience from 1970-2007 giving a total exposure of 3,250,000 km years. EGIG comprises 15 organisations including Bord Gais Eireann. The pipelines in the EGIG database are almost all now used for the transport of dry treated gas but, apart from the possible effect of internal corrosion, (discussed further in Section 6.5.3) the data are valid for the Corrib pipeline. The failure causes are categorised into six different primary causes which are detailed in Table 2.

Some general observations from the EGIG report are:

- The number of loss of containment incidents (releases) is generally decreasing although the pipeline system length monitored is increasing; the primary failure frequency (per km per yr) over the last five years is approximately one third of the average frequency over the lifetime of the EGIG database.
- The reduction in failure frequencies is due to technological developments (e.g. welding, inspection, condition monitoring using on line inspection) and improved procedures for damage prevention and detection.

The database also categorises failures into three different hole sizes (pinhole, hole and full bore rupture).

Table 2: Summary of Pipeline Failure Causes (European Gas Pipeline Incident Data Group (EGIG) 7th Report 1970-2007.

Primary Cause	% of Total	Secondary Cause	% of Primary Cause	Tertiary Cause	% of Secondary Cause
External Interference	49.6	Digging	38		
		Ground and Public Works	18		
		Agriculture	9		
		Drainage	8		
		Other	27		
Construction Defect/ Material	16.5				
Corrosion	15.4	External	81	Pitting	68
				Galvanic	12
				Stress Corrosion Cracking	5
				Unknown	15
		Internal	15		
		Unknown	4		
Ground Movement	7.3	Landslide	55		
		Flood	19		
		Unknown	12		
		Mining/River/Other	14		
Hot Tap made in Error	4.6				
Other and Unknown	6.7	Lightning	25		
		No details	75		

6.2.1.1 External Interference

This type of damage is caused by equipment such as bulldozers, excavators, ploughs, etc. Throughout the whole life of the EGIG database, this is the most common cause of pipeline failures and currently represents 50% of the recorded failures.

6.2.1.2 Corrosion

EGIG records that internal and external corrosion is the third most common cause of pipeline failures (15% of total failures) with the majority of failures due to external corrosion. Corrosion failures recorded predominantly result in pinhole type leaks.

There is only one instance recorded where corrosion caused a full bore failure and this was internal corrosion on a pipeline constructed before 1954 which was used for the transportation of coke oven gas.

6.2.1.3 Fabrication and Construction Defect/Material Failure

This type of failure is strongly dependent on the year of construction, being approximately 10 times less likely for pipelines constructed after 2004 than those constructed before 1954 (thought to be mainly due to technological improvements in quality control). Recorded failures include those due to material defects, e.g. due to laminations or incorrectly specified materials, and defects introduced by the pipeline construction, e.g. weld defects and undue external stresses.

6.2.1.4 Hot Tap Made in Error

This type of failure is due to a hot tap connection (which requires drilling into a pipeline) being made in error i.e. to a pipeline which has been incorrectly identified as another pipeline (usually when a number of pipelines share a pipeline corridor).

6.2.1.5 Ground Movement

This includes failures caused by natural events such as a dike break, subsidence, flooding, landslides, mining or rivers. Historically, landslides are the most common cause of failure in this group (approximately 55%), followed by flooding (19%). Ground movement gives the largest proportion of full bore ruptures of all the primary causes. Incidentally, there is no pipeline failure reported resulting in loss of containment due specifically to peat slides.

6.2.1.6 Other and Unknown

This includes all minor and unknown causes such as design error, erosion, lightning, operational or maintenance error and poor repairs. 25% of these incidents were due to lightning (and out of 20 incidents, 19 gave pinhole leaks), but no details are given of other causes

6.2.2 CONCAWE [6]

Failures in liquid pipelines in Europe are given in the CONCAWE Report 7/08. Performance of European cross-country oil pipelines. August 2008. Data have been collected since 1971 and the experience comprises some 35,000km and some 850,000 km years. Data are provided by some 70 companies and agencies which operate oil pipelines. Classification of the types of failures is similar to that for EGIG [5] and is shown in Table 3. Spillages of $1m^3$ and above are recorded. Some general observations from the CONCAWE report are;

- Similar to EGIG, the most common causes of failures for cold* pipelines are third party activity (42%) followed by mechanical (28%) and corrosion (19%). Failures due to third parties are reducing but those due to mechanical failure have been increasing over the last 13 years.
- The number of spillage incidents has been steadily reducing since the mid 1970's.

Unlike EGIG, this database includes failures due to intentional or malicious activities by third parties (which are generally as a result of attempts to steal the pipeline product). Of the 170 third party incidents recorded within the CONCAWE database, the majority (120) were as a result of accidental damage, with only 23 (approximately 5% of all pipeline releases) resulting from intentional damage, of which 2 were from terrorist activity, 5 from vandalism and 16 from attempted product theft.

6.2.3 PARLOC [7]

PARLOC 2001: The Update of Loss of Containment Data for Offshore Pipelines, (PARLOC) contains data on all offshore pipelines in the North Sea and captures all actual and potential loss of containment incidents. This database covers some 25,000km of steel and flexible lines and has an operating experience of 330,000 km years (approximately one tenth of the EGIG [5] exposure). It is of relevance to Corrib as many of the pipelines transport unprocessed gas and failures in the near shore are included. Some general observations on the PARLOC report are:

- Classification of failure types is similar to that of EGIG [5] and CONCAWE [6] except that the causes of third party incidents differ, reflecting offshore operating conditions.
- Some 2% of incidents occurred in the shore zone and these were due to anchors, vibration (vortex shedding) and storm damage; none resulted in a loss of containment.
- The most common cause of a loss of containment was corrosion (40%) with internal corrosion contributing the most (22%), primarily local to the well or in the mid line area.†

However, it was concluded that for this QRA PARLOC could not be used to determine failure frequencies as it was not possible to isolate failures for pipelines transporting unprocessed gas, nor failures specifically in the shore zone. Consequently this database was not used further.

* 'Cold' pipelines are used for the transport of materials such as crude oil and white products. Black products are transported through heated lines which are referred to as 'hot' pipelines.
† Mid line area refers to pipelines that are more than 500m from either the platform or the well but are not in the shore approach.

Table 3: Summary of Pipeline Failure Causes (CONCAWE)

Primary Cause	% of Total	Secondary Cause	% of Primary Cause		% of Secondary Cause
External Interference	36	Accidental	71	Construction	40
				Agriculture	30
				Underground Infrastructure	23
		Intentional	13	Theft	67
				Vandalism	19
				Terrorist	10
		Incidental	16	Underground Infrastructure	15
Mechanical	25	Design and Materials	37	Faulty weld	25
				Incorrect installation	23
		Construction	63	Faulty material	38
				Incorrect design	10
Corrosion	28	External	78	Coating failure	32
				Cathodic protection failure	29
		Internal	19		
		Stress Corrosion (SCC)	3		
Natural Hazard	3	Ground movement	87	Landslide	38
				Subsidence	23
				Flooding	23
		Other	13		
Operational	7	System	32	Instrument and control system	30
				Equipment	20
		Human	68	Incorrect operation	57
				Incorrect maintenance or construction	19
				Not depressurised or drained	14

6.2.4 UKOPA [8]

The UKOPA Pipeline Fault Database - Pipeline Product Loss Incidents (1962-2008) (UKOPA) is a sub set of the EGIG [5] database and relates to onshore pipelines in the UK. It was specifically developed to enable the estimation of leak and rupture frequencies for UK pipelines and to test the effectiveness of design changes. The total experience for the period 1952-2008 is 750,000 km years. The data are contributed to by ten organisations, including Shell. The main structure is similar to that of EGIG [5], although there is a more comprehensive distribution of the hole sizes. Some points from the database are:

- Dry natural gas accounts for more than 90% of the pipeline systems.
- Ignitions are documented individually.
- Specific details of the causes of releases in the 'other' category are given. These are shown in Table 4.

Table 4: Causes included in 'Other' Category (UKOPA Database)

Cause	Number of incidents	% of group
Internal SCC due to wet town gas	30	75
Pipe fitting welds	4	10
Leaking clamps	2	5
Lightning	1	2.5
Soil stress	1	2.5
Threaded joint	1	2.5
Electric cable arc strike	1	2.5
Total	40	100

6.2.5 Shell Data

A recent overview of unprocessed gas pipelines operated in the Shell Group has been made, see Appendix Q4.9. This shows extensive experience of successful operation of these pipelines. In many cases the performance of the inhibited pipeline systems with respect to corrosion has been verified by intelligent pig inspection or ultrasonic examination. No failures of unprocessed gas pipelines have been experienced for those pipelines referenced within the database. The observed low corrosion rates demonstrate the effectiveness of the management of corrosion control within Shell's unprocessed gas pipeline operations.

6.2.6 Appropriate Database for the LVI

There is no database which contains information on the failure frequency of large items of buried equipment. Further, EGIG [5] does not include incidents involving equipment or components.

The database that is considered to represent the most appropriate data for use on the LVI equipment is therefore the Hydrocarbon Releases Database [9] which has been used by DNV as the basis for failure frequencies of items of equipment for the last nine years.

6.2.7 Hydrocarbon Release Database [9]

The Hydrocarbon Releases Database was set up following the report of Lord Cullen into the Piper Alpha disaster in 1989, in order to provide data for use in QRAs. It covers hydrocarbon releases from offshore facilities and contains information from October 1992 to March 2008 as reported to the UK HSE Offshore Division (OSD) under the Reporting of Injuries, Diseases and Dangerous Occurrences Regulations 1995 (RIDDOR), and prior offshore legislation. It contains 3644 releases from equipment with a total of more than 25 million operating years in some 120 equipment categories and the data are considered to be of good quality.

Primary causes of failures are classified as equipment, operational, procedural and design causes (66%, 53%, 28% and 15% respectively in the latest available report [28], note that it is possible to have multiple entries), with secondary causes such as corrosion, mechanical failure, erosion, material defect, operator error or other.

6.3 Potential Causes of Loss of Containment from the Pipeline

6.3.1 Qualitative Risk Assessment

The detailed qualitative consideration of the barriers against potential failure causes (threats) that may lead to loss of containment is facilitated through the use of bowtie analysis as described within the qualitative risk assessment (Appendix Q6.3). The qualitative risk assessment considers different operating conditions and locations along the route as required by the An Bord Pleanála letter of 2nd November. A total of 32 potential failure causes were identified (see Figure 10 and Table 5 for clarity).

The results of the qualitative analyses have been used to perform a screening exercise (as per PD 8010-1 [3]) in order to identify those causes that do not require further consideration in the QRA, either because they are assessed as being non-credible causes for loss of containment (i.e., the cause could not possibly lead to loss of containment) or have such a low frequency of occurrence that their omission will have negligible impact on the risk predictions. These are shown and discussed in Section 6.3.2

Those failure modes not screened out were carried forward to the QRA where further consideration was given to any appropriate modifications to base failure frequencies to account for the specific conditions and the conclusions of detailed engineering studies for certain aspects of the design. Consideration of these failure modes with respect to the specifics of the proposed Corrib pipeline is presented in Section 6.4.

Figure 10: Possible Threats Identified in the Qualitative Risk Assessment for the Onshore Pipeline

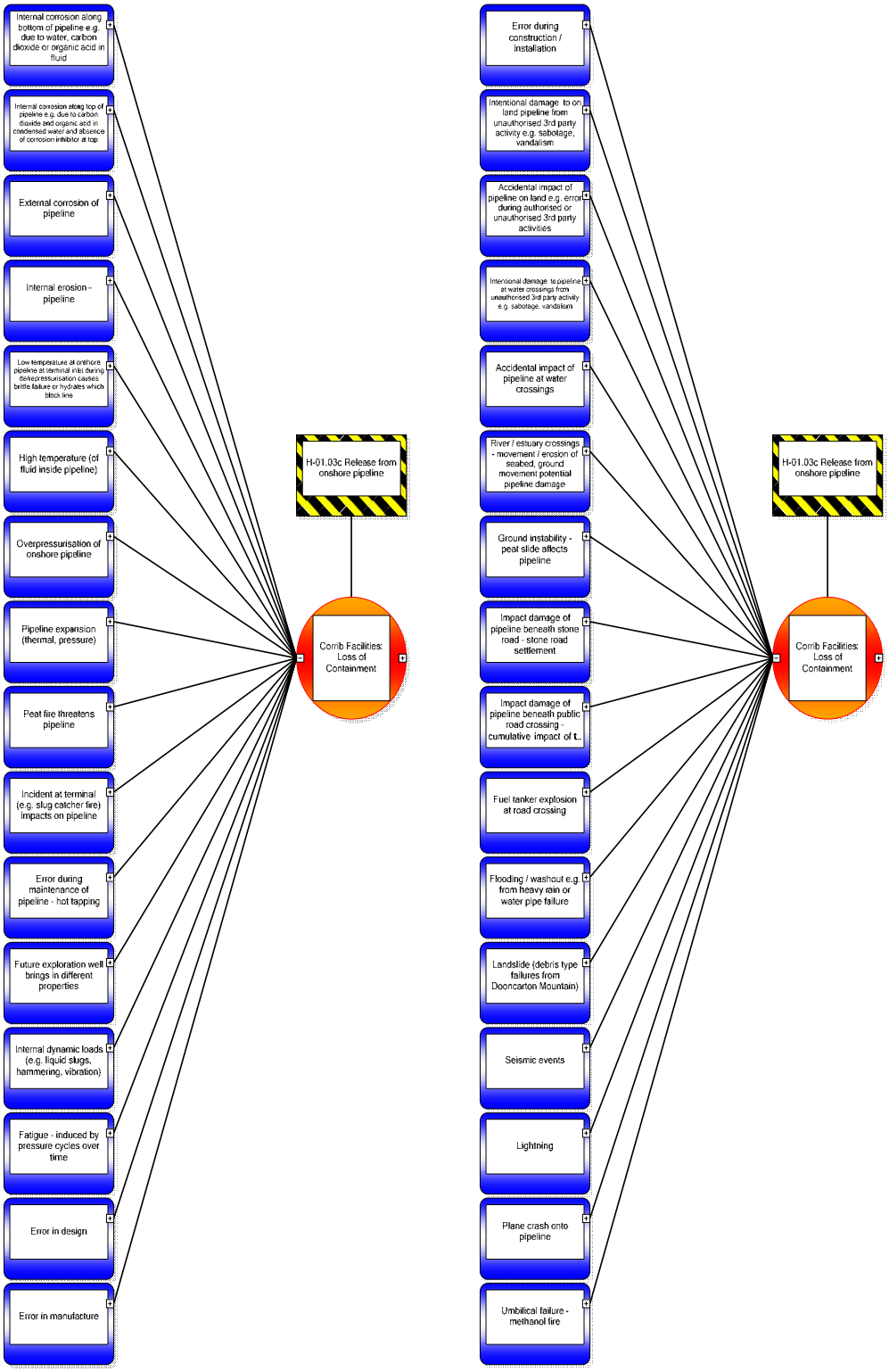


Table 5: Possible Threats Identified in the Qualitative Risk Assessment for the Onshore Pipeline

Threats Identified in the Qualitative Risk Assessment
Internal corrosion along bottom of pipeline e.g. due to water, carbon dioxide or organic acid in fluid.
Internal corrosion along the top of the pipeline e.g. due to carbon dioxide and organic acid in condensed water and absence of corrosion inhibitor at top.
External corrosion of the pipeline.
Internal erosion of the pipeline.
Low temperature at onshore pipeline at terminal inlet during deprepressurisation causes brittle failure or hydrates which block line.
High temperature (of fluid inside pipeline).
Overpressurisation of onshore pipeline.
Pipeline expansion (thermal, pressure).
Peat fire threatens pipeline.
Incident at terminal (e.g. slug catcher fire) impacts on pipeline.
Error during maintenance of pipeline – hot tapping.
Future exploration well brings in different properties.
Internal dynamic loads (e.g. liquid slugs, hammering, vibration).
Fatigue – induced by pressure cycles over time.
Error in design.
Error in manufacture.
Error during construction / installation.
Intentional damage to on land pipeline from unauthorized 3rd party activity e.g. sabotage, vandalism.
Accidental impact of pipeline on land e.g. error during authorized or unauthorized 3rd party activities.
Intentional damage to pipeline at water crossings from unauthorized 3rd party activity e.g. sabotage, vandalism.
Accidental impact of pipeline at water crossings.
River / estuary crossings – movement / erosion of seabed, ground movement potential pipeline damage.
Ground instability – peat slide affects pipeline.
Impact damage of pipeline beneath stone road – stone road settlement.
Impact damage of pipeline beneath public road crossing
Fuel tanker explosion at road crossing.
Flooding / washout e.g. from heavy rain or water pipe failure.
Landslide (debris type failures from Dooncarton Mountain).
Seismic events.
Lightning.
Plane crash onto pipeline.
Umbilical failure – methanol fire.

6.3.2 Screened Failure Scenarios

The potential failure scenarios identified in the qualitative risk analysis and screened from inclusion in the QRA, either because they are assessed as being non-credible causes for loss of containment or have such a low frequency of occurrence that their omission will have negligible impact on the risk predictions, are shown in Table 6.

Table 6: Failure Causes Screened Out of the QRA

Threat Description (Failure Cause)
Internal erosion
Low temperature
High temperature (of fluid inside pipeline)
Overpressurisation
Peat fire
Pipeline expansion (thermal, pressure
Incident at terminal
Hot tapping
Future exploration well
Internal dynamic loads (e.g. liquid slugs, hammering, vibration)
Impact damage of pipeline beneath public road crossing
Fatigue
Fuel tanker explosion at road crossing
Seismic events
Plane crash onto pipeline
Methanol fire

The justification for screening out the above failure causes is provided below.

6.3.2.1 Internal Erosion

Internal erosion could potentially occur as a result of the presence of contaminants such as sand, liquids or proppant (a material occasionally used in gas wells). Tests have indicated that sand, although possible, will not be produced in sufficient quantities to give erosion of the pipeline. Only one of the wells required the use of proppant, and subsequently no significant proppant production was observed during clean-up of the well in 2001 and none was observed during a subsequent well test in 2008. An erosion assessment has indicated no significant effect on the pipeline and LVI should some proppant be produced (see Appendix Q4.9). Furthermore, the

flow velocities in the pipeline are well below those required to cause flow induced erosion-corrosion or liquid droplet induced erosion (typically 20m/s and 38m/s respectively for carbon steel).

6.3.2.2 Low Temperature – Brittle Fracture

Low temperature has the potential to cause pipeline failure by brittle fracture of the line pipe material. All the components of the pipeline system have been designed and fabricated to resist both brittle and ductile fracture at the temperature conditions that will exist in the pipeline (see Appendix Q4.7). Under start-up or blow-down conditions it is possible that sections of the pipeline system will experience low temperatures due to the Joule-Thomson cooling effect. The most likely scenarios that could give low temperature are opening up cold wells to a depressurised pipeline, equalisation of a pressurised offshore pipeline with a depressurised onshore pipeline, or blow-down of the pipeline system. These are all expected to be infrequent events and detailed operating procedures will be put in place to ensure that the pipeline and LVI temperature limits are not exceeded (see Appendix Q4.7). The potential for gas exiting a small hole causing the pipe material to make a transition from a ductile to a brittle regime (thus increasing the risk of crack propagation and ultimately leading to full-bore failure) has been considered (see Appendix Q4.7) and discounted as being non credible.

6.3.2.3 Low Temperature – Hydrates

Since the produced gas is wet hydrate formation can be expected in the pipeline at the normal operating pressure and temperature. Methanol will be injected to prevent hydrate formation and it is only if methanol is not injected in sufficient quantities that a hydrate plug could be formed. Methanol injection rates are automatically monitored and reduction or cessation of methanol injection initiates reduced production or shut down to avoid hydrate formation. Hydrate formation could result in a blockage of the main pipeline. This would cause production to cease and would require the deployment of measure to eliminate the blockage. Specialist procedures would be used to remediate any hydrate blockages but the primary defence is the avoidance of operation in the hydrate formation region. Pressure build up in the pipeline as a result of hydrate blockage is limited to the MAOP of the pipeline by virtue of the safeguarding facilities and therefore does not pose a threat to the integrity of the pipeline. Hydrates are complex gas water crystalline formations and are not like ice and cannot, of themselves, cause a pipeline to fail by expansion causing excessive hoop stress.

6.3.2.4 High Temperature

Given the length of offshore pipeline, the Corrib gas temperature will be at ambient seabed temperature well before it reaches the onshore pipeline and LVI. Downstream of the LVI the pipeline temperature will not exceed ambient soil temperature, which is well below the upper design temperature limit of the pipeline. Temperatures above ambient soil temperature conditions could occur if the onshore pipeline was re-pressurised by back feed gas from the terminal. Facilities are in place to limit the temperature of the back feed gas to below the pipeline

maximum design temperature. There is no credible pipeline high temperature condition that could lead to loss of containment in the pipeline.

6.3.2.5 Overpressurisation

The pipeline is protected against exceeding the MAOP by pressure sensors, alarms, trips and isolation valves with a high level of reliability (see Appendix Q3.1). The onshore pipeline will be hydrostatically tested to 504barg and has a design pressure of 144 barg. Loss of containment due to over pressurisation is not therefore considered a credible event.

6.3.2.6 External fire - Peat

Where the pipeline passes through peat bog, it is contained within a stone road, which will serve to insulate the pipeline from potential peat fires. Even if the pipeline was directly in the peat, the estimated maximum temperature reached within a peat fire is 600° (see Grishin et al [29]). The strength of the steel at this temperature is well in excess of that required to maintain containment (see Barker [15]).

6.3.2.7 External fire – Methanol

Methanol is transported in the umbilical line, and in the event of umbilical failure would be released. If containment was lost the pressure would be quickly dissipated (as methanol is essentially incompressible) and the rate of release would be low (of the order of 2 kg/s). The pressurised release of methanol is likely to cause the surrounding material to be displaced to create a pathway through the soil through which the methanol could flow. On contact with air methanol is potentially flammable. Should ignition of methanol occur, the flame would stabilise above the methanol liquid (pool) fire (which is predicted to have a steady state pool diameter of approximately 12m) and the temperature of the unburnt liquid would remain at the boiling point (65°C). This would pose no risk to the gas pipeline more than 1m below the surface of the ground.

6.3.2.8 Pipeline Expansion

Under normal production the onshore pipeline will operate within a narrow temperature range dictated by ambient sea bed and soil temperatures. During start-up and depressurisation a wider temperature range is predicted but this is still within the range of design temperatures for the pipeline. Any expansion will be within the pipeline design stress limits as specified in the design code.

6.3.2.9 Incident at the terminal

There is a short (approximately 3-4m) length of the pipeline above ground within the terminal fence, which could be exposed to a jet fire if there was a major release from equipment in the

vicinity. This section of pipeline is protected by the application of passive fire protection to protect against potential impingement of a jet fire.

6.3.2.10 Hot Tapping of the Wrong Pipeline

Releases due to hot-tapping (the process of making a connection with the pipeline whilst it is still in operation) have been known to occur when there are multiple pipelines within a trench and the wrong pipeline is inadvertently selected for working on. This situation would not arise for the Corrib pipeline as there is no foreseeable need for hot-tap and if hot tapping were to be carried out, the gas pipeline is the only steel pipeline thus this event is not considered further.

6.3.2.11 Future Exploration Well brings in different Properties

Any such development would be subject to a separate regulatory approval process in future and is not considered in this QRA.

6.3.2.12 Internal Dynamic Loads

The pipeline has been designed for multiphase flow. The pipeline will operate in the dispersed or stratified wavy regime with low liquid loading and hence dynamic loads will not cause failure

6.3.2.13 Fatigue

Fatigue is caused by stress cycling (usually due to pressure cycling from line packing, but could result from thermal cycling or external loading). The pipeline will not be operated in this mode and so fatigue is not considered as a potential contributor to failure. Pressure cycles will however be monitored at the Terminal.

6.3.2.14 Impact damage of pipeline beneath public road crossing

The road crossing design and construction will be in accordance with the code (see Appendix Q4.1). and so separate consideration of this potential failure mode is not appropriate.

6.3.2.15 Fuel tanker explosion at road crossing

The majority of tanker traffic in the vicinity of the terminal is expected to be associated with the terminal operation itself, and all these tankers are routed such that they do not cross the buried pipeline. Other traffic, e.g. domestic deliveries, may occasionally cross the pipeline. In the event of a road tanker incident with loss of containment and subsequent ignition of the tanker cargo, burning would be on the surface at ground level and there would be no effect on the integrity of the gas pipeline.

6.3.2.16 Seismic events

Earthquake risk in Ireland is very low (British Geological Safety [30]) and Erris is categorised as less than "very low". Hence, in accordance with the codes, the pipeline design incorporates no specific provisions for seismic activity.

6.3.2.17 Plane crash onto pipeline

Given the small cross sectional area of the pipeline, its remote location and the absence of any major airports in the vicinity, the likelihood of a plane impact is judged to be sufficiently remote that it can be discounted from further consideration.

6.4 Failure Scenarios Specific to the Corrib Pipeline

The threats carried forward from the qualitative risk analysis to the QRA are shown in Table 7, cross-referenced to the applicable database failure mode.

An assessment of each failure scenario noted in Table 5 is made taking account of the specific design and operational intent of the Corrib pipeline and any studies carried out as input to the derivation of a representative failure frequency.. This process involves the identification of the most suitable failure frequency from one of the selected databases and, if appropriate, the application of a modifier to this selected frequency to reflect Corrib specific aspects in order to arrive at the base-case frequency.

Table 7: Corrib Pipeline Specific Failure Scenarios

Threat Description (Failure Causes)	Failure Mode
Internal corrosion along the bottom of the pipeline e.g. due to water, carbon dioxide or organic acid in fluid	Internal Corrosion
Internal corrosion along the top of the pipeline e.g. due to carbon dioxide and organic acid in condensed water and absence of corrosion inhibitor at top	
External corrosion of the pipeline	External Corrosion
Error in manufacture	Construction/Material Defects
Error during construction / installation	
Intentional damage to the pipeline from unauthorised 3rd party activity e.g. sabotage, vandalism	Intentional or Malicious Activities - Buried section
Intentional damage to the pipeline at water crossings (excluding tunnelled section) e.g. sabotage, vandalism	Intentional or Malicious Activities
Accidental impact of the pipeline e.g. error during authorised or unauthorised 3rd party activities (excluding tunnel)	Accidental External Interference
Accidental impact of the pipeline at water crossings	
River / estuary crossings - movement / erosion of seabed, ground movement potential pipeline damage	Ground Movement
Ground instability - peat slide affects pipeline	Ground Movement: Glengad and Aghoos to Bellanaboy Bridge Gas Terminal
Impact damage of the pipeline beneath the stone road - stone road settlement	
Flooding / washout e.g. from heavy rain or water pipe failure	
Landslide (debris type failures from Dooncarton Mountain)	
Lightning	Other/Unknown

6.4.1 Screening Against Pipeline Failure Mode using Specific Technical Reports

Relevant technical reports as contained in Appendix Q which have been used in the derivation of specific failure modes are shown in Table 8.

Table 8: Relevant Technical reports

Report Number	Title	Aspects covered	Comments
Q4.8	Assessment of Locally Corroded Pipe Wall Area	Length versus depth of corrosion that would lead to failure at MAOPs.	The results show that there is a significant margin of safety with respect to thinning of the pipe wall due to corrosion
Q4.9	Assessment of Wet Gas Operation, Internal Corrosion & Erosion	An assessment of the internal corrosion and erosion rates for the offshore and onshore sections of the Corrib pipeline.	Concludes that the expected corrosion and erosion rates in the offshore and onshore Corrib pipeline are within the design corrosion allowances for a service life of 20 years provided corrosion mitigation with corrosion inhibitor and methanol is correctly applied.
Q4.10	Denting & Puncturing Evaluation	Covers evaluation of the potential for mechanical damage of the Corrib onshore pipeline by 3rd party activities that may lead to loss of containment	Concludes: To puncture the pipe an excavator significantly in excess of 65 tonnes weight would be required An excavator in excess of 65 tonnes is required to produce a dent gouge that would fail at a burst pressure less than MAOP.
App M2	Report on Corrib Onshore Pipeline Ground Stability Assessment	Evaluation of ground movement in the location of the pipeline as input to pipeline stress analysis. Analysis covers: • Stability of natural peat slopes with the potential to affect the pipeline • Stone road settlement • Peat slide with the potential to affect the stone road • Erosion of the cliff at Glengad • Ground stability in the event of a ruptured water pipe • Ground stability risk within the tunnel.	Output describes the estimated ground movement.
App Q 4.1	Attachment A	Pipe stress analysis for predicted ground movements compared with forces predicted to lead to pipeline failure.	Concludes that predicted ground movements (as above) will not cause pipeline failure and there is a significant margin of safety.

The Sections below further discuss the key conclusions from these Reports and any consequent modifications proposed to the base case failure frequency.

6.4.2 External Corrosion

As noted 81% of EGIG [5] corrosion failures were external, mainly as a result of pitting and galvanic action. These and other potential mechanisms for external corrosion (stress corrosion cracking, stray current corrosion and hydrogen induced stress cracking) are considered in detail in Appendix Q4.7. To mitigate external corrosion of the pipeline, the primary barrier is a robust 3 layer polypropylene coating. The field joints will use a standard shrink sleeve system. For the onshore pipeline an additional epoxy primer will be used under the shrink sleeve.

As a secondary barrier to external corrosion should the coating be damaged, the pipeline will be protected by a cathodic protection system using sacrificial aluminium anodes for the offshore pipeline and an impressed current system for the LVI and onshore pipeline. The design and installation of the tunnel section of the onshore pipeline will provide a similar level of protection against external corrosion (see Appendix Q4.7).

This combination of external coating and cathodic protection will give the Corrib pipeline the same level of protection against external corrosion as that of similar pipelines designed in accordance with the current codes.

6.4.2.1 External Corrosion Failure Frequency

The factors that influence the selected generic base frequency for loss of containment due to external corrosion are:

- The pipeline wall thickness;
- The use of in-line inspection;
- The coating specification;
- The cathodic protection system.

These factors have been addressed by de Stefani et al [10] who analysed the failures in historical pipeline databases and developed an empirical model to estimate numerical modifiers to the generic failure frequencies. This approach has been used to determine a specific frequency for external corrosion.

The base frequency for external corrosion of natural gas pipelines with external polypropylene coating is taken from EGIG [5] and is 1E-05per km per year. The modifying factor for pipeline wall thickness >15mm is 0.003. There is no modification factor for cathodic protection (as most pipelines in the database have this protection). Periodic in line inspection using intelligent pigging will be carried out for the onshore pipeline (Appendix Q.2), but a conservative approach

was taken and no modification has been applied for in line inspection.* The overall failure frequency due to external corrosion is therefore taken as 3E-08 per km per year.

6.4.3 Internal Corrosion

A detailed review of all the relevant corrosion mechanisms has been conducted (see Appendix Q4.7), and the strategy for monitoring and control is given in Appendix Q5.1 The main aspects of corrosion mechanisms and management relevant to the selection of frequencies within this QRA (taken from the above references) are given below.

CO_2 and Organic Acid Corrosion

Carbon dioxide (CO_2) becomes corrosive when it dissolves in water to form carbonic acid, and this will be the primary corrosion threat to the pipeline. The presence of organic acids can increase the corrosivity. If the fluids in the pipeline are uninhibited, the predicted corrosion rates in the onshore pipeline are 0.12mm/yr for condensed water and 0.2mm/yr for formation water. To mitigate such corrosion it is common practice to inject corrosion inhibitor (which forms a barrier against the corrosive fluids) or to inject glycol or methanol which are miscible with the corrosive water and further reduce the corrosivity.

For the Corrib pipeline the threat of CO_2 and organic acid corrosion will be mitigated primarily by injecting corrosion inhibitor but will also benefit from the presence of methanol. The predicted inhibited corrosion rates in the onshore pipeline are <0.05mm/yr for all production scenarios. The pipeline design includes a 1mm corrosion allowance and in addition the 27.1mm wall thickness of the design provides further contingency.

For sections of the pipeline where protection of the carbon steel pipe by the film forming corrosion inhibitor cannot be assured, e.g. due to insufficient length to establish the film or where there is turbulent flow, corrosion resistant materials have been used. This includes the LVI pipework and valves. The section of onshore pipeline and 20" valve within the LVI has also been overlay welded with Alloy 625 because of the potential for turbulent flow and the presence of stagnant conditions during normal operation.

Top of the Line Corrosion

CO_2 or organic acid corrosion can occur in pipelines where the flow regime is stratified and condensation occurs at the top of the pipeline. The corrosion inhibitor does not generally provide protection here, but mitigation will be provided by the co-condensing methanol. The expected flow regime over the full length of the Corrib pipeline is annular dispersed for the 20 year field life which precludes top of line corrosion as a mechanism.

Preferential Weld Corrosion

Pipelines in wet gas service are susceptible to preferential CO_2 corrosion at the welds but this will be mitigated by the corrosion inhibitor as described above, and control of the weld chemistry.

* At the time that the QRA was carried out SEPIL was in the process of verifying the accuracy of potential intelligent pig technologies. Subsequently SEPIL has confirmed that the selected technology is capable of measuring the wall thickness to the desired accuracy, and so if the QRA was to be carried out now, an additional modification factor of 0.175 would be used.

Galvanic Corrosion
Galvanic corrosion occurs as a result of differences in electrochemical potential between metals, e.g. between the stainless steel T-piece and the pipeline at the LVI, but has not generally been observed in producing oil and gas systems and will not occur along the pipeline. Mitigation at the interface will be provided by the corrosion allowance, and the absence of this mechanism will be confirmed by wall thickness checks at the LVI.

H_2S Corrosion
As there is no hydrogen sulphide (H_2S) in the Corrib wells, this type of corrosion will not occur (however measurements will be taken at the terminal to monitor for the presence of H_2S).

Microbial Induced Corrosion
Bacterial related corrosion is unusual in gas/condensate production systems and with no requirement for water injection there is no expectation that this mechanism will occur in the Corrib pipeline during operation.

Corrosion by Hydrotest Water
In common with other gas pipelines, there will be a pressure test using water. Standard methods will ensure that all threats of corrosion from this activity are mitigated prior to putting the pipeline into service.

Stress Corrosion Cracking
There are no credible internal stress corrosion cracking mechanisms for carbon steel and no chloride stress corrosion cracking of stainless steels is anticipated with the Corrib production conditions.

Stray Current Corrosion
Stray current corrosion can occur when an isolation joint fails due to bridging or short circuiting. An isolation joint is provided between the pipeline and the terminal and will be periodically monitored for this corrosion mechanism. There is no isolation joint between the offshore and onshore cathodic protection systems thus eliminating the possibility of stray current corrosion.

6.4.3.1 Internal Corrosion Failure Frequency

There is no database frequency for internal corrosion that directly correlates with, and hence can be directly applied to, the Corrib pipeline. The two most closely appropriate databases are EGIG [5] for treated natural gas and CONCAWE [6] for hydrocarbon liquids. Expert metallurgical review has concluded that the overall corrosion potential associated with the Corrib gas is greater than that for treated natural gas (EGIG) but less than that for crude oil (CONCAWE) (see Appendix Q4.7). Consequently the use of CONCAWE [6] for crude oil pipelines only as a base frequency would be conservative and has thus been adopted. This value is 5.85E-05 per km per year

The same modification factor as discussed above (6.4.3.1) from de Stefani [10] for external corrosion was used for pipeline thickness (0.003) together with an additional modification factor of 0.175 for in-line inspection which gives an overall base case failure frequency of 3.1E-08 per km per year.

6.4.4 Material Manufacture and Construction Defects

The pipeline has been manufactured to industry standard quality assurance processes, including frequent quality assurance examination and testing. Construction of the pipeline (and LVI) will be performed according to specified procedures by competent personnel, including independent verification. The final pre commissioning check will be a hydrostatic test to 504barg which is over 5 times the MAOP downstream of the LVI.

6.4.4.1 Material Manufacture & Construction Defects Failure Frequency

Given the above, despite the hydrostatic test, there are no grounds for assuming that the Corrib pipeline is less vulnerable to material or construction defects than any other pipeline that is laid to current standards. EGIG [5] indicates that no failure has occurred due to this cause in pipelines laid after 2004. However, in order not to use a statistical frequency, the base frequency for the period 1994-2003 has been used without any modification.

6.4.5 Ground Movement

A series of studies has been carried out to assess the potential for ground movement of various types along the length of the pipeline (see Appendix M2). The aim has been to determine the extent to which the pipeline may be subjected to movement (e.g. as a result of a landslide, or settlement of the stone road) and then assess whether this may lead to failure of the pipeline. To complement these studies and enable safety margins to be demonstrated the degree of movement required that may lead to failure of the pipeline has been assessed.

The geotechnical based studies (see Appendix M2) cover the following:

- A peat stability and potential for peat failure assessment for the proposed onshore pipeline route from the landfall at Glengad Headland to the Bellanaboy terminal site. This involved the assessment of the stability of natural peat slopes along the proposed pipeline route.
- Assessment of the proposed use of a stone road in areas of peat involving an assessment of ground investigation, an interpretation of ground conditions, and stability analysis of the stone road.
- Assessment of the ability of the stone road to resist lateral loading from any potential peat landslide impact.
- Assessment of the risk of instability of the stone road during the operation of the pipeline.
- Ground stability risk associated with landslides originating on Dooncarton Mountain.
- Erosion of the cliff at Glengad with the potential to lead to ground movement affecting the pipeline and the LVI.
- Ground stability in the vicinity of the pipeline and umbilical in the event of a ruptured water pipe.

The conclusion of these studies is that ground movement (settlements, land/peat slides encroaching on the pipeline) in the vicinity of the pipeline and umbilicals is not expected to impact the pipeline (instability is assessed as 'negligible or unlikely to occur').

The degree of movement that may lead to pipeline failure has been analysed (see Appendix Q4.1) as follows:

- An assessment of the effect of settlement in all pipelines and services (gas pipeline, outfall pipeline, umbilicals and cables) to demonstrate that the design settlement values will not cause failure.
- A demonstration of the safety margin inherent in the design by estimating the settlement required to cause rupture/breakage in the gas pipeline.
- An assessment of the stresses developed in the Gas Pipeline during operation due to an unsupported length of 40m occurring within the stone road.

These studies demonstrate there is a significant margin of safety with respect to pipeline failure. (e.g. the pipeline could tolerate a settlement 10 times greater than that predicted for the stone road and the pipeline is capable of free spanning 40m, a significantly greater distance than the estimated width of a water pipe rupture washout).

6.4.5.1 Ground Movement Failure Frequency

Based on these studies it is concluded that none of the potential ground movement scenarios poses a credible threat to the pipeline sufficient to lead to a loss of containment and consequently this failure cause has been allocated a zero frequency.

However, given the previous concerns associated with this failure mode, a sensitivity analysis has been carried out based on application of the frequency value provided in PD 8010-3 [1] which is at the upper end of the lowest landslip category (9E-08 per km per year frequency of failure).

6.4.6 Accidental External Interference

The main safeguards against failure due to external interference are:

- The pipeline wall thickness (27.1mm). Wall thickness is a major factor in the potential for failure and there are no recorded failures of pipelines in EGIG [5] with a wall thickness in excess of 15mm.
- Burial of the pipeline with concrete slabs at road and small water crossings (onshore).
- Burial in a fully grouted tunnel beneath Sruwaddacon Bay.
- Surface and buried marking of the route, fortnightly surveys and excavation controls.

Appendix Q4.10 reviews the potential for mechanical damage of the Corrib onshore pipeline by 3rd party activities that may lead to loss of containment. It describes the results of an evaluation of the effect of third party mechanical damage on the integrity of the landfall section upstream of the LVI and the section downstream of the LVI to the terminal.

The potential for damage leading to loss of containment has been correlated with the puncture and denting resistance for the Corrib pipeline. It was concluded that:

- In order to puncture the pipe an excavator in excess of 65 tonnes weight would be required, due to the large wall thickness of the pipeline. Indeed, the estimated energy required to puncture the pipeline would be equivalent to that of an excavator of 150 tonnes weight (it is likely that excavators operating in the locality will be a maximum of approximately 30 tonnes).
- Denting or gouging of the pipeline that may not immediately lead to loss of containment but may result in subsequent failure should the pressure in the pipeline increase (so-called burst pressure) would also require an excavator in excess of 65 tonnes to produce a dent gouge that would fail at a burst pressure less than the MAOP.

6.4.6.1 Accidental External Interference Failure Frequency

The DNV QRA of 2009 [16] contained a study by Haswell and Lyons (PIE) [27] which is also included with this QRA (see Attachment A). This gave a detailed calculation for the failure frequency due to external interference. Further studies for this EIS (Appendix Q4.10) confirm that the conclusions of Attachment A are unchanged. The PIE study gives a total failure frequency of 2.24E-09 per km per year for a pipeline at 100 barg.

For the tunnelled section of the pipeline, given that the bay is too shallow for significant marine traffic together with the burial depth and the protection afforded by the fully grouted concrete walled tunnel, no credible failure scenario has been identified and hence a failure frequency of zero has been assigned to this section of pipeline.

6.4.7 Third Party Intentional Damage

It is not normal practice to consider this mode of failure in a QRA, but it has been specifically requested by An Bord Pleanála in their letter of 2nd November 2009, page 2, item (d).

Throughout the majority of its route onshore the Corrib pipeline will be protected against intentional damage by its burial depth and the large wall thickness. Additionally for the section running beneath Sruwaddacon Bay, the line will be encased within a concrete tunnel, rendering such damage extremely difficult.

The LVI will be surrounded by a security fence. The only equipment within the LVI plot which will be above ground and connected to the buried pipeline will be the valve actuators and instrument connections. The compound will be protected by, CCTV monitoring and intruder alarms.

CONCAWE [6] reports that on liquid pipelines there were 23 spillages caused by intentional damage by third parties; two resulting from terrorist activities, five from vandalism, but the majority (16) were from attempted or successful product theft. The incidents were either on above ground sections of pipelines/valve stations or at road or river crossings.

Experience with natural gas pipelines in USA records four incidents attributed to vandalism. Although no descriptive text is recorded, one incident was in an underground pipeline. Data on liquid pipelines give 10 vandalism incidents, but only one in an underground pipeline.

6.4.7.1 Third Party Intentional Damage Failure Frequency

For the base case a value of zero has been used, and a sensitivity has been carried out in order to comply with the request from An Bord Pleanála. A failure frequency has been taken from de Stefani [10] assuming that the frequency is in the lowest (of three categories) for a gas pipeline. This frequency is 9.3E-06 per km per year and is applied to the 'hole' category. There is no similar factor that can be referenced for below ground equipment, so a factor of 10 increase was used for the potential for holes at the LVI. Intentional damage to the tunnelled section of the pipeline is not considered to be a credible scenario and has not been considered further.

6.4.8 Other / Unknown

The qualitative risk analysis is the primary means for identification of specific failure modes; the use of failure causes specified in the databases is the secondary means of identification. The former have been considered in the previous sections, the latter are considered in this section. The only other/unknown cause specifically identified in EGIG [5] is lightning (and this is also the most common cause in this category). Although not specified in EGIG, it is understood that most if not all of the lightning strike incidents occurred on above ground sections; it is difficult to comprehend lightning causing loss of containment of a below ground pipeline although ignition of existing leaks from such pipelines could occur.

Of the loss causes in UKOPA [8], (see Table 4) pipe fitting welds, leaking clamps and threaded joints are not applicable. Internal cracking due to wet town's gas is also not applicable (see Appendix Q4.7) as the pipeline will not be used for this purpose. This corrosion mechanism requires the presence of CO_2 and carbon monoxide (and is enhanced by oxygen). Neither carbon monoxide nor oxygen is present in the Corrib gas. Electric arc strike is a maintenance activity but is not applicable because of the thickness of the Corrib pipeline. The incident classified as soil stress is known to be a combination of a pipeline modification and external loading; the latter has been considered and allocated a zero frequency. This leaves only lightning in the 'other' category in the UKOPA database.

6.4.8.1 Failure Frequency due to Other Causes

As the measures taken to protect the pipeline from lightning will be the same as those for any other buried pipeline, the frequency due to lightning has been included by taking 20 incidents and the EGIG exposure during the period 1970-2007 (6.4E-06 per km per year).

6.5 Pipeline Hole Size Distribution

As stated previously EGIG [5] gives failures in terms of three hole sizes. In this analysis, possible releases from holes and ruptures have been included; ignited leaks from pinholes would

impact only very near to the pipeline and have been neglected. The distribution of the overall frequency into the different hole sizes has been based on the databases and Attachment A.

A hole in a high pressure gas pipeline can, if certain conditions are met, propagate to a full bore rupture. Consequently in order to determine a hole size that is appropriate to use for the 'hole' category, (i.e. from an equivalent diameter of 20mm up to a hole with the same cross sectional area as the pipeline), the size of the defect that will propagate to a rupture needs to be determined. This is known as the critical defect length. The critical defect length for a pipeline operating at 100 barg has been determined as 447mm and an equivalent hole is estimated to have diameter of 80mm (Attachment A). It has been assumed that any hole with an equivalent diameter in excess of 80mm would propagate to give a full bore rupture, irrespective of the cause. In the 'hole' category of releases it was thus assumed that the representative hole for the purposes of the analysis had an average cross sectional area between the lower diameter of the 'hole' category (20mm) and the upper critical hole size (80mm) which gives a hole diameter of 58mm.

A summary of the overall failure frequency for each failure cause, the basis for the hole size distribution and the corresponding frequency of each hole size used in the QRA are given in Table 9.

6.6 Overall Corrib Pipeline Failure Frequency

The overall failure frequency of the Corrib pipeline is the total of the frequencies for the three different hole sizes in Table 9 (1.28E-05 per km per year). This value may be compared with that derived from specific Shell unprocessed gas experience for 40384 km years without a loss of containment incident, which, assuming a Poisson distribution and a 50% confidence interval, gives a frequency of 1.7E-05per km per year (for all causes).

Table 9: Base Failure Frequencies for the Pipeline

Failure Mode	Pressure	Source of Base Data	Total Failure Frequency	Source of Hole distribution	Probability of Pinhole	Probability of Hole	Probability of Rupture	Pinhole Frequency (Per km per year)	Hole Frequency (Per km per year)	Rupture Frequency (Per km per year)
	barg		per km per year					per km per year	per km per year	per km per year
Internal Corrosion - All sections	All	CONCAWE Crude Oil	3.07E-08	CONCAWE	0.59	0.34	0.07	1.81E-08	1.04E-08	2.15E-09
External Corrosion - All sections	All	EGIG 7	3.0E-08	EGIG 7	1	0	0	3.0E-08	0	0
Material & Construction Defects - All sections	All	EGIG 7	6.36E-06	IGEM	0.83	0.17	0	5.28E-06	1.08E-06	0
Accidental External Interference – Buried Sections	100	ATTACHMENT A	2.24E-09	ATTACHMENT A	0	0.98	0.02	0	2.19E-09	5.35E-11
	150	ATTACHMENT A	4.46E-09	ATTACHMENT A	0	0.85	0.16	0	3.77E-09	6.92E-10
Accidental External Interference - Tunnelled Section	100		0		0	0	0	0	0	0
Ground Movement Glengad and Aghoos	All	PD 8010-3 and Specialist Reports	0		0	0	1	0	0	0
Other and Unknown - All sections	All	EGIG 7	6.4E-06	EGIG 7	0.95	0.05	0	6.03E-06	3.17E-07	0
Total for buried sections								1.14E-05	1.41E-06	2.20E-09
Total for tunnelled section								1.14E-05	1.41E-06	2.15E-09

6.7 Equipment at the LVI - Generic Frequencies and Hole Size Distribution

The LVI comprises the following equipment, specified in accordance with the categories included in the Hydrocarbon Releases Database [9];

- Large valves (>11" diameter).
- Small valves (<3" diameter).
- Large flanges (>11" diameter).
- Instruments.

The data for these items have been screened to eliminate entries where;

- The hole was less than 1 mm diameter.
- The release was from equipment that was at a pressure of less than 1 bar ('zero' pressure releases).
- The hole size was unspecified (but a hole size was estimated by calculation based on the material released and the conditions at the time of release if this information was given).

The hole sizes are given in the database numerically up to 100mm diameter and then as '>100' mm diameter. For the purposes of the QRA these need to be grouped and a single hole size determined to represent the group. Grouping is normally undertaken so that the average of the area of the upper and lower hole sizes is a diameter found in piping or equipment. The hole size grouping and the associated generic frequencies for the items of equipment that have been selected for the LVI are shown in Table 10.

There were no failures in the '>100mm' group for large flanges or for large valves. It is normal for the largest hole size to be taken as the gasket thickness multiplied by the pipe circumference. The gasket thickness for the 16" pipeline will be 1.2mm (there are no flanges on the 20" pipeline) so this would give a 41mm equivalent diameter hole. This is in the range 31-100mm diameter, so the largest hole size considered for a large flange is 75mm. The absence of data in any particular group of data indicates that such a failure is either very rare or not credible. For very rare events a frequency may be derived by assuming a statistical distribution with a percentage confidence. Two statistical values based on a Poisson distribution with 50% confidence are thus included in Table 10.

Table 10: Generic Failure Frequencies for Equipment at the LVI

Equipment	Total Failure Frequency	2mm Frequency (1-2.8mm)	12mm Frequency (2.8-16.7mm)	25mm Frequency (16.7-31.1mm)	75mm Frequency (31.1-100mm)	Frequency >100mm
	per year	per year	per year	per year	per year	per year
Large Valve	5.42E-04	4.09E-04	7.44E-05	3.72E-05	1.24E-05	8.69E-06 (1)
Small Valve	1.34E-04	6.36E-05	5.25E-05	8.75E-06	9.54E-06	
Large flange	1.41E-04	8.56E-05	4.28E-05	3.33E-06 (1)	9.51E-06	0.00E+00
Instrument	5.55E-04	2.83E-04	2.51E-04	1.52E-05	5.84E-06	

HCRD Raw Data 2008/Large Valves Subset

(1) Statistical prediction, 50% Poisson distribution, as no reported failures for this range of hole sizes.

6.7.1 Specific Failure Frequencies for the LVI Equipment

The valves in the LVI will be of several different types. These valves were aligned as closely as possible with the different types of valves listed in the database (e.g. block valves, actuated valves). The different failure causes in the database were then considered and modifications/exclusions were made by reference to the qualitative risk analysis. This was used to identify those causes that do not require further consideration in the QRA because they are assessed as being non-credible causes for loss of containment or the frequency was sufficiently low that they can be discounted without detriment to the accuracy of the QRA. Consequently, by accounting for the specific conditions and aspects of the design (see below), the modified frequencies are considered appropriate for the actual equipment proposed for the LVI.

6.7.1.1 External Corrosion

The measures taken to prevent external corrosion of the valves etc at the LVI will be the same as those taken for the buried pipeline. Consequently the base failure data for the equipment were modified in the same way as the base failure data for the pipeline (to account for the protection afforded by the thickness, the external coating and the cathodic protection).

6.7.1.2 Internal Corrosion

The valves at the LVI will be manufactured with corrosion resistant alloy to prevent internal corrosion. Further protection will be provided by the injection of corrosion inhibitor and methanol into the gas stream. The base failure data were therefore modified using the same reduction factor as was used for the pipeline.

6.7.1.3 Erosion

As was the case for the pipeline, internal erosion is not considered to be a credible failure mode and hence failures due to this mode have been excluded (see Section 6.4.2.1 for the pipeline).

6.7.1.4 Manufacturing or Material Defect

The equipment will be manufactured to standard quality assurance procedures and processes by recognised and qualified suppliers. There will be frequent examinations, tests in accordance with an Inspection and Test Plan approved by SEPIL, independent inspections and both factory and site acceptance tests. As with the pipeline, however, there are no grounds for assuming that the equipment is more (or less) vulnerable to material or construction defects than any other similar equipment, so no modifications have been made to the generic data.

6.7.1.5 Mechanical Failure due Improper Maintenance or Wear

Invasive maintenance is not a routine activity and if it were to take place there is a maintenance management system to control and coordinate such operations which would also be verified, and work would only be carried out under a formal Permit to Work system and by personnel with appropriate training and competence. Further, as the valves are not duty valves, wear to cause loss of containment will not occur. Consequently loss of containment failures due to this cause are not considered credible.

6.7.1.6 Incorrect Fitting

Failures due to this cause were neglected as the initial hydrostatic test during pre commissioning is specifically carried out to prove the integrity of the system and this would indicate incorrect fitting. This failure cause has been neglected.

6.7.1.7 Mechanical Failure due to other causes

The database contains entries classed as ‘mechanical failure’, but no secondary cause is given. There are consequently no grounds to consider such failures as non credible and so no modifications have been made to the generic frequencies for this cause.

6.7.1.8 Opened in Error

These releases are caused by incorrect identification of equipment and they were excluded as this is inappropriate for the LVI as it is of simple design with few valves.

6.7.1.9 Other/unknown

As for 6.7.1.7 no information is given in the database so it was not possible to further screen these releases. No change was made to the generic frequencies.

6.7.1.10 Frequency Derivation

By separating the data into the different valve types and removing some failures because of non-credible failure modes, the population for each valve type was reduced. If this resulted in zero failures for a specific hole size or an extremely low population, rather than determining a statistical value the reduction factor was applied to the generic frequency for all valves in the relevant hole size range. Where the modifications resulted in a specific frequency which was higher than the generic frequency (because of the lower population), the higher value was retained.

As identified previously, the upper hole size in the data for large valves is 75mm and there are no recorded holes in the >100mm category for large valves. The experience with large valves tends to indicate that a failure to give a hole size >100mm is non-credible rather than very rare. This is considered especially to be the case for valves that are on concrete supports and buried below ground. Consequently the base case has used a zero failure frequency for an event to give a hole size >100mm diameter, but a sensitivity has been carried out using the statistically determined value. Failure of a large flange that leads to a hole in the range 16-31mm was considered to be a rare rather than a non-credible event (as there has been a larger failure), so the statistical value was used for this event. The failure frequencies determined by this process, the hole sizes and the number of each item of equipment at the LVI (base case) are shown in Table 11.

6.8 Overall LVI Failure Frequency

The overall frequency for loss of containment of gas at the LVI is calculated by multiplying the frequencies in Table 11 by the number of equipment items in high pressure gas service, which gives an overall frequency of release of gas through a hole 16mm or above of 4.9E-04 per year.

Table 11: Base Failure Frequencies for the LVI

Equipment	Total Failure Frequency (1) Per year	Probability of 25mm hole (Overall)	Probability of 75mm hole (Overall)	Probability of >100mm (Overall)	25mm hole Frequency Per year	75mm hole Frequency Per year	Frequency >100mm Per year	Number at LVI
Large Manual Block Valve (MBV)	2.45E-04	0.1	0.05	0	2.48E-05 (2)	1.24E-05	0.00E+00	3
Large Actuated Safety Shutdown Isolation valve (ASSV)	5.95E-04	0.04	0.12	0	2.48E-05 (2)	7.21E-05	0.00E+00	2
Small Manual Block Valve (MBV)	2.10E-05	0.17	0.04	0	3.66E-06	8.46E-07 (2)		23
Small Manual Choke Valve (MCOV)	1.71E-04	0.02	<0.01	NA	4.23E-06 (2)	8.46E-07 (2)		1
Small Manual Check Valve (MCV)	7.03E-05	0.06	0.01	NA	4.23E-06 (2)	8.46E-07 (2)		3
Large flange	6.18E-05	0.05	0.08	NA	3.33E-06 (3)	4.76E-06		5
Instrument	2.88E-04	0.02	0.01	NA	4.91E-06	3.50E-06		5

Pipeline Blast 2010/LVILoop 2010

(1) Includes frequencies for 2mm and 12mm holes.

(2) Based on all data.

(3) Statistical value, 50% Poisson distribution.

6.9 Ignition Probability

The historical probability of ignition of releases from gas pipelines is given in EGIG [5] (see Table 12)

Table 12: Ignition Probabilities of Release from Gas Pipelines

Size of Leak	Probability of Ignition
Pinhole	0.04
Hole	0.02
Rupture (16" diameter and below)	0.1
Rupture (more than 16" diameter)	0.33

In QRAs, the time when ignition occurs is traditionally divided into either early (or immediate) ignition (when ignition occurs very soon after the start of the release, possibly up to 30s after the start of the release IGEM/TD/2 [2]) or delayed ignition (when there is a time delay, not normally specified, between the start of the release and the time that the release ignites). The reason for the distinction is that the consequences and effects (see next section) are different for releases ignited immediately compared with those where there is a delay. The data in EGIG [5] do not give the separation of the overall ignition probability into immediate and delayed ignitions.

An analysis of rupture incidents suggests that there is a relationship between the pipeline diameter, the operating pressure and the probability of ignition IGEM/TD/2 [2], which takes the form:

$P_{ign} = 0.0555 + 0.0137\ pD^2$ (for pD^2 between 0 and 57)

$P_{ign} = 0.81$ (for pD^2 above 57),

Where: P_{ign} = probability of ignition.

p = pipeline operating pressure (bar).

D = pipeline diameter (m).

In this QRA, the probability of ignition of ruptures has used the above expression, and the probability of ignition of smaller releases has been taken from the historical gas pipeline data EGIG [5]. For releases of natural gas or similar material from pipelines, the consequences are more severe when ignition occurs at the same time as the release starts, i.e. immediate ignition with no time delay whatsoever, compared with the consequences when ignition is delayed, so, conservatively, it has been assumed for all scenarios that ignition occurs immediately (at time zero).

6.10 Presence Factor

The presence factor is the probability that a person is in the vicinity of the pipeline and whether they may be indoors or outdoors at the time of failure.

For the purposes of predicting individual risk within this QRA the rule set has been adopted that people are residing at a dwelling 365 days per year, and the typical resident spends 10% of the time outdoors at the same location and the rest indoors. A sensitivity has been carried out using 36% of the time outdoors (60 hours per week) with the balance indoors.

For the determination of societal risk it is necessary to adopt a rule set that defines the number of occupants residing at each normally occupied dwelling as well as the probability of persons being indoors or outdoors. It is specified in I.S. 328-2003 [11] that, for population density purposes, there are four persons per dwelling, and this number of persons has been adopted within the rule-set. For the calculation of societal risk at Glengad it has been assumed that there is one person outdoors for 50 hours per week, two people outdoors together for 25 hours per week, three people outdoors together for 10 hours per week and four people outdoors together for 5 hours per week.

7 CONSEQUENCE ANALYSIS

Should the measures taken to prevent a failure of the pipeline or equipment at the LVI fail, gas will be released. Consequence analysis determines the potential severity of these releases should ignition occur The approach applied and the steps taken during the analysis are shown in Figure 3. Each of these steps is now described.

7.1 Release Rate

The release rate from a hole is assumed to be constant as the pressure in the pipeline is assumed to remain constant. The release rate of gas following a full bore rupture of a pipeline decays rapidly with time as the pressure in the pipeline falls. The release immediately after a rupture occurs may be described as 'quasi instantaneous'; it is changing rapidly (decreasing).

7.1.1 Release Rate from Holes

The standard gas equation for sonic releases has been used to determine the release rate from holes (58mm diameter for holes in the pipeline, 75mm and 25mm diameter for holes in the equipment at the LVI). In this equation a discharge coefficient is used to account for turbulence and viscosity losses; conservatively a value of unity has been used. These assumptions give release rates of 48, 80 and 9 kg/s respectively.

7.1.2 Release Rate from Ruptures

When a gas pipeline ruptures, typically part of the pipeline length fails resulting in two open ends with a crater between the two open ends. Gas is released from both the upstream failure and the downstream failure (i.e. there is discharge from two open ends each with a cross sectional area equal to the cross sectional area of the pipeline).

There are several models available to predict the rate at which the release of gas decreases with time. For this analysis an in house model incorporated within DNV software Neptune [18] was used rather than a bespoke model as these cannot easily be integrated into the sequential steps of the overall consequence analysis. The predictions from the in house model were, however, aligned with release rates predicted by two bespoke models (Pipetech [20] and Pipesafe [21]) so that the release rate predictions over the first few minutes used in the QRA were comparable with the predictions from these codes. The predicted release rate with time for a rupture of the 20" pipeline is shown in Figure 11 for a pressure of 100 barg.

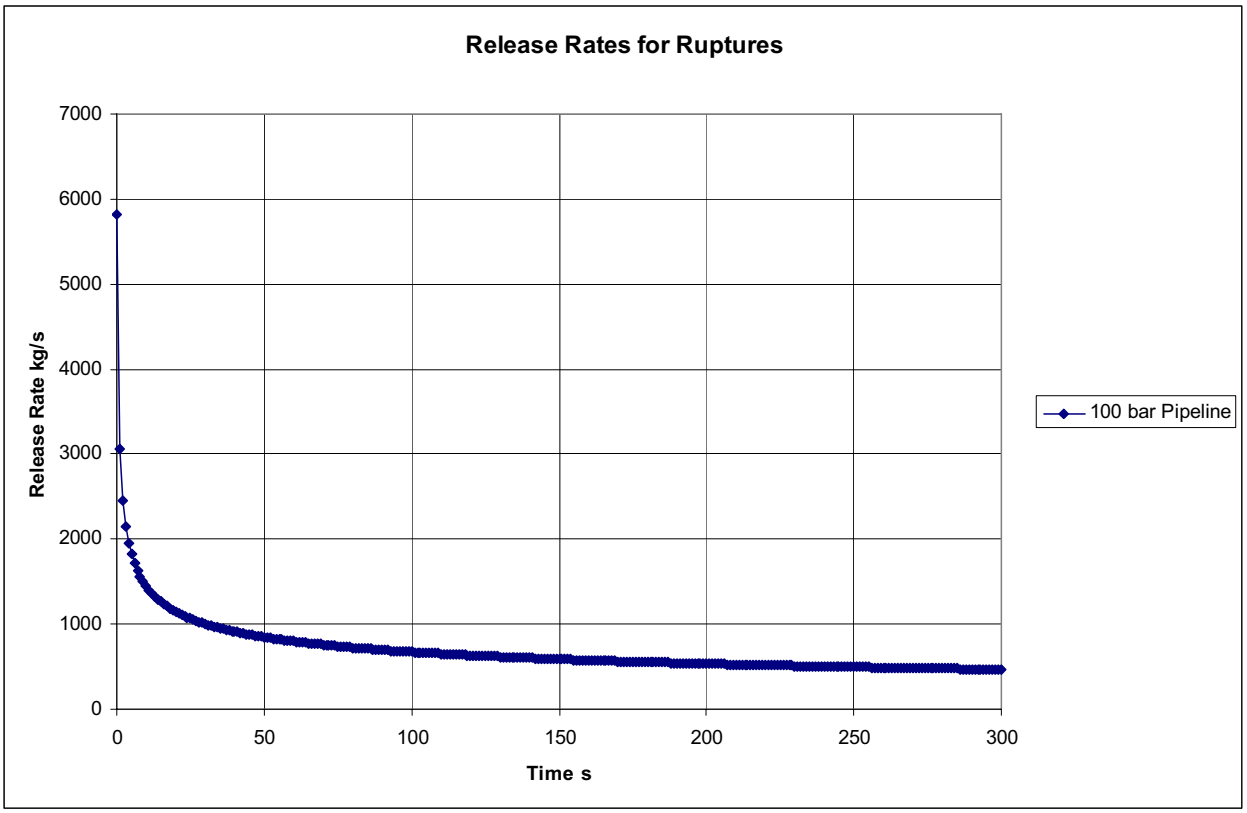
In the determination of the release rate, the pressure is of critical importance as the higher the pressure the greater is the release rate for the same size hole. The QRA has been conservatively based on all releases occurring at the MAOP.

For a release downstream of the LVI at the MAOP it is assumed that the LVI would remain open and as a result gas would be released from both open ends of pipe.

For the upstream pipeline to reach the MAOP, the LVI valves would be in the closed position. The release upstream of the LVI is modelled on the basis that the pipeline fails near to the LVI at

the MAOP of 150barg (resulting in a release of gas from the pipeline upstream of the failure, but an insignificant release from the pipeline downstream of the failure).

Figure 11: Release Rates from Ruptures



7.2 Heat Radiated

Ignition of the gas released from a rupture or hole would cause a flame which radiates heat to the surroundings. The heat radiated, and hence the effects on people or buildings is dependent on the rate of the release as described above and the time that ignition occurs. The time of ignition is generally described as either immediate or delayed.

7.2.1 Immediate ignition

The release rate following a rupture, if ignition was immediate, would be too high to give a stable flame, and the initial 'quasi instantaneous' release is characterised as a fireball. The combustion would develop into a stable jet fire or crater fire once the quasi instantaneous release has been burnt and the release rate has become sufficiently steady for a flame to stabilise (Bilo and Kinsman [17]). A release from a hole, if ignited, gives a stable flame close to the hole and produces a jet fire.

Both fireballs and jet fires produce high temperature flames which emit thermal radiation from the surface of the fire. The thermal radiation is measured in kW/m^2 and typical values at the fire surface are in the order of 250-300 kW/m^2 (Bilo and Kinsman [17]). This heat is radiated away from the surface and models are available to determine the level of thermal radiation at locations

away from the fire (i.e. at a receptor). Two models have been utilised in this analysis: one for the fireball and one for the jet (or crater) fire. Both models are of the solid flame type, i.e. they consider a uniform thermal flux over the fire surface which has a specified shape. The heat received by the receptor is then determined using the view factor between the shape and the receptor taking account of the heat absorbed by the atmosphere as the radiation travels between the surface of the flame and the receptor.

7.2.2 Delayed Ignition

If the release of gas from a rupture or hole in the pipeline is not ignited immediately, the gas would mix with air and the gas concentration in the gas/air cloud would be progressively reduced. The gas/air cloud would be potentially ignitable if the gas concentration is within the flammable range (approximately 5-15% of gas in air by volume). Dispersion of the release has been modelled using DNV's PHAST model (v 6.5.3) [19]. Delayed ignition of the gas/air cloud would cause a flame to flash back to the release location and develop into a stable jet or crater fire. Under certain circumstances delayed ignition can give overpressure as well as a thermal radiation (see next section). The effect range associated with a delayed ignition is mainly dependent on the release rate at the time of the ignition. For a full bore rupture the release rate decays rapidly and so delayed ignition would give a smaller flame than immediate ignition, so the effect range would be less. For a hole, as the rate of release is constant, the effect range is the same for immediate and delayed ignition.

7.2.2.1 Overpressure Hazard

Overpressure hazards are not normally considered for natural gas releases from pipelines (PD 8010-3 [1]), however, for this analysis the possibility has been specifically considered. In order for a delayed ignition of a gas release in the open air to create overpressure, some or all of the flammable cloud has to be in a region of congestion. Congestion can take many forms, but includes process plant, forest and dense undergrowth. The influence of the congestion is to increase the flame front and thus the rate of burning (flame speed) and this generates the overpressure. The minimum distance between the pipeline and any form of congestion (in this case conifer forest) is 40 m. Dispersion predictions for a full bore rupture for two weather conditions (see Section 7.2.4) show that the flammable gas/air cloud is well above any trees, and so could not give rise to overpressure in the event of delayed ignition (see Attachment C). The maximum predicted dispersion distance to the lower flammable limit for a release from a hole which is directed horizontally is 98m (see Attachment C)[*]. Consequently overpressure could be generated within the conifer forest should there be a release at this location, with the release directed horizontally towards the congestion and the release is ignited. However, even if overpressure was generated by this mechanism, the degree of overpressure would not be sufficient to present a threat to any people in the vicinity over and above the effect of the jet fire that would follow.

[*] Note that the gas cloud shown in Attachment C updates the gas cloud predictions presented at the 2009 Oral Hearing

7.2.3 Model Validation

The fireball modelling is based on the model used by the UK HSE when assessing the risk from natural gas pipelines (Bilo and Kinsman [17]). The cumulative mass burnt in the fireball is given by the discharge model. The time required to release a particular mass is compared with the burn time of a fireball containing that mass. The mass of gas in the fireball is taken as that released from the pipeline when these two times are equal. The fireball is assumed to be spherical and to touch the ground for its duration (i.e. no fireball rise is incorporated). The thermal radiation absorbed by the water vapour and carbon dioxide in the atmosphere was calculated in DNV's PHAST model [19] using the method of Wayne [23]. A research report (Kinsman and Lewis [24]) compared the predictions of the UK HSE model with historical information on pipeline accidents. This comparison indicated that the fireball model tends to over estimate the 'burn' area by up to a factor of seven. Use of this model is therefore considered to be conservative.

Once the fireball phase has been completed, the release is then modelled as a jet fire (with a declining release rate modelled in steps of 30s intervals). The basic jet fire model used was that in DNV's PHAST software [19] based on work by Chamberlain [25]. The jet fire which follows the fireball is assumed to be directed vertically upwards out of the crater. The jet fire shape is the frustum of a cone and the location and orientation of the frustum are dependent on a number of factors including the rate of release and the wind speed. Recent work has compared the base PHAST predictions with predictions from the Pipesafe* [21], which has been internationally developed over a period of more than 10 years through basic research and experimental validation (and is approved by the Dutch government for Gasunie pipeline QRAs). Pipesafe has been validated for larger release rates than the Chamberlain model and the comparison indicated that the PHAST model overpredicts the thermal flux when compared with the Pipesafe model. A slight modification to the fraction of heat radiated in the DNV model enabled the predictions to align more closely with the Pipesafe model, and this adjustment was made for the modelling of jet fires that followed the fireball. The jet fire modelling for the releases from the holes are within the validation range for the base model, so no adjustment was made to the modelling of jet fires from holes. It was assumed that the direction of the jet from a hole was either as for the rupture (vertical with loss of some momentum - impeded), or vertically upwards with no loss of momentum (unimpeded), or horizontal. The thermal radiation from the jet fire absorbed by the atmosphere was calculated in the same way as that for the fireball.

7.2.4 Weather

The meteorological conditions, such as the wind speed and direction, have an influence on the potential consequences following a failure of the pipeline; the fireball is considered to be located at the release location and independent of the weather conditions, but the jet fire and unignited releases are affected by the wind. It is common practice to reduce the large number of possible wind speeds to one or two representative speeds (typically 2 m/s and 5 m/s, see Health and Safety Authority March 2010 [13]). The predictions for the level of thermal radiation received at a particular location generally increase with wind speed (as the flame angle with the horizontal reduces). For the jet fire analysis a single wind speed of 5 m/s was used to represent the different wind conditions. The local meteorological data indicate that the annual average wind speed is 3.8

* Pipesafe is a software package for risk calculations relating to underground natural gas transmission

m/s and the wind speed is less than 5 m/s for over 70% of the time. The use of 5 m/s is therefore considered to be conservative. A local wind rose was not used; consequences were assumed to be distributed uniformly (this is normal practice for pipeline analyses because of the changing direction of the pipeline). The relative humidity assumed for the predictions was 70%.

7.3 Physical Effects

The heat received from the flame can affect both people and structures. The way that these effects have been predicted is described below.

7.3.1 Effects on People

The effect of thermal radiation on people from ignited releases from pipelines is typically determined by considering both the level of thermal radiation (in kW/m^2) and the duration of the exposure. The measure adopted by the UK HSE is termed a thermal dose unit (tdu) which has units of $(kW/m^2)^{4/3}$ s. The rule-sets governing the effects of various levels of thermal dose as adopted by the UK HSE on people are shown in Table 13.

Table 13: Rule sets for the Effect of Thermal Radiation Dose on People

Thermal Dose (tdu)	Effect
3500	Assume 100% fatality (due to the spontaneous ignition of clothing)
1800	Assume 50% fatality
1000	Dangerous dose – Assume 1% fatality (typical population)
500	Dangerous dose for a vulnerable or sensitive population.

A dangerous dose of thermal radiation is defined by the UK HSE as a dose that:

- Would cause severe distress to almost everyone;
- Would cause a substantial proportion to require medical attention;
- Would cause serious injury, which could require prolonged treatment, to some people;
- Could be potentially fatal to any highly susceptible people.

When assessing the risks from ignited releases from pipelines, the UK HSE assumes that people are able to move away and seek shelter or be sufficiently far from the source of heat that their thermal dose received when moving away does not exceed the dangerous dose threshold (1000tdu). In rural areas people are assumed to move away from the incident at a speed of 2.5m/s and a distance of 75m is taken as the distance over which the thermal dose received is calculated.

In the QRA when modelling an immediately ignited full bore rupture it is further assumed that there is a 5 s reaction time between the ignition of the gas to form the fireball and a person starting to move.

The effect on people is calculated by determining the thermal dose received as a hypothetical person travels the 75m plus, in the case of an immediately ignited full bore rupture, the thermal dose received during the reaction time. The distance from the pipeline from which a person would just receive a thermal dose of 1000 tdu is termed by the UK HSE as the 'escape distance'.

The ground in the vicinity of the Corrib pipeline is generally at a higher elevation than the pipeline. As the thermal flux received increases with increasing height (at the same plan distance from the pipeline), effect distances for the fireball and subsequent jet fire have been calculated assuming that persons and buildings are 38m higher than the pipeline.

It is recognised that not all people will be able to move away from the incident at 2.5 m/s. The UK HSE use a lower speed of moving away of 1 m/s for vulnerable people (e.g. nursery children or very old people) and a sensitivity has been carried out using this lower speed over the same distance (75m).

The size of the effect area for a jet fire from a hole is significantly less than that associated with a fireball. There is a rapid reduction in the predicted level of thermal radiation with distance for these jet fires, consequently people accumulate only low doses when moving away from the fire. It is therefore more appropriate to determine the effects by the level of thermal radiation (flux) rather than the thermal dose, the following rule-sets have been applied for people outdoors:

- The extent of a thermal flux of 35 kW/m^2 was used to define the area within which people would be fatally injured.
- The extent of a thermal flux of 6 kW/m^2 was used to determine the extent of the outer limit beyond which persons would be assumed to survive

7.3.2 Effects on Buildings

People inside a building at the time of an incident are assumed to be safe unless the building catches fire. Two rule sets (see Bilo and Kinsman [22]) are used by the UK HSE to determine whether a building exposed to thermal radiation catches fire. One rule set is for spontaneous ignition, the second is for piloted ignition*. There are limiting levels of thermal flux for these relationships; the thermal flux for spontaneous ignition must be above 25.6 kW/m^2 and for piloted ignition the thermal flux must be above 14.7 kW/m^2. The UK HSE assumes that if a building is exposed to more than 40 kW/m^2, then all the occupants are fatally injured; this assumption has been used in this QRA.

The rule sets used to define the two ignition levels for buildings are based on experimental tests on American whitewood. As the dwellings in the vicinity of the pipeline are primarily stone and slate construction, which are incombustible, and there are relatively small areas of potentially combustible materials, these rule sets are considered to be conservative for the buildings in the vicinity of this pipeline.

* Spontaneous ignition takes place if the incident thermal flux is sufficiently high to ignite combustible material. Piloted ignition occurs if the combustible parts of the building are heated but do not ignite until induced to do so by a source of flame (e.g. a burning brand).

In the event that a building is ignited, however, people are assumed to leave the building and are then subject to the thermal radiation from the ignited release. The effects of this on the people escaping from the building are determined by applying the same rule sets as people who are outdoors at the time of the start of the incident (but without a reaction time).

For people indoors subject to thermal radiation from ignited releases from holes in the pipeline, the following rule-sets have been applied:

- People in buildings exposed to a thermal flux above or equal to 40 kW/m^2 were assumed not to survive
- People in buildings exposed to a thermal flux below 25 kW/m^2 were assumed to be safe or able to move away to safety.

7.4 Sensitivity Studies

Various sensitivity studies have been identified in Sections 6 and 7 of this report, where it was considered appropriate to test an assumption (frequency assumptions in Section 6 and consequence assumptions in Section 7). These sensitivities are summarised in Table 14.

Table 14: Sensitivity Studies

Sensitivity	Base Case	Sensitivity Case
Ground movement leading to pipeline failure	Frequency of zero (considered not credible). Lower value from the lowest frequency range in PD 8010-3 [1]	Frequency of 9E-08 per km used. Upper value from the lowest frequency range in PD 8010-3 [1]
Third party intentional action leading to failure of the pipeline or equipment at the LVI	Frequency of zero (not normally considered in a QRA)	Frequency of 9.3E-06 per km per year for a hole in the pipeline. Value taken from the lowest category of third party intentional action in de Stefani [10]. No known data for equipment items so the frequency of holes at the LVI was increased by a factor of 10.
Failure of a valve at the LVI which gives a hole size with an equivalent diameter >100mm	Frequency of zero (not credible).	Statistically determined frequency of 8.7E-06 per year. The determination of a representative hole size followed the same principle as the other holes at the LVI to give 296mm and 366mm diameter for the 16” and 20” valves respectively.
Time that a person spends outdoors	10% (standard assumption which represents 17 hours per week)	36% (which represents 60 hours per week)
Speed of moving away	2.5 m/s (standard assumption for an able bodied person)	1 m/s (standard assumption for a vulnerable person, e.g. children, old people).

7.5 Risk Estimation Rule Sets

It is apparent that the potential effects of an ignited release on people either indoors or outdoors decrease as the distance from the pipeline increases to the point where the effects are not hazardous. In order to determine the risk at distances from the pipeline the distances to the flux and dose levels used as rule-sets and as shown in Table 15 were calculated.

Table 15: Thermal Flux and Dose Rule -sets Used for Risk Calculations

Dose or Flux	Rule-set Effects
40 kW/m^2	Assume the building will ignite and all occupants are fatally injured
Spontaneous ignition of building	The building is assumed to ignite, and people initially inside the building will need to leave the building and seek shelter further away from the pipeline
Piloted ignition of building	The building may ignite with ignition being induced, and in this case people will need to leave the building and seek shelter further away from the pipeline
Either 35 kW/m^2 or 3500 tdu	Assume 100% fatality for people outdoors
1800 tdu	If a person receives this dose level whilst stationary for 5s then moving away from the pipeline for 75m at 2.5m/s in the open air, it is assumed there is a 50% chance of becoming fatally injured.
1000 tdu	If a person receives this dose level whilst stationary for 5s then moving away from the pipeline for 75m at 2.5m/s in the open air, it is assumed there is a 1% chance of becoming fatally injured.
25 kW/m^2	The assumed threshold of fatality for people indoors when exposed to a jet fire from a hole in the pipeline.
6 kW/m^2	The assumed threshold of fatality for people outdoors when exposed to a jet fire from a hole in the pipeline..

8 PREDICTIONS

The pipeline comprises several different sections as identified in Section 3.2.

Predictions for the release rate and associated fireball mass from a pipeline rupture upstream of the LVI at a pressure of 150 barg and isolated from the pipeline downstream of the LVI were greater than those for a rupture of the pipeline (unisolated, with the LVI open) at 100 barg:

- Upstream of the LVI at the MAOP of 150barg, with the LVI closed, the mass into the fireball was 21.1 te.
- Downstream and upstream of the LVI at the downstream MAOP of 100barg, with the LVI open, the mass into the fireball was 28.2 te.

The latter case is the determinant for the risk to people both indoors and outdoors and has been used in this QRA.

The predictions from this QRA are presented as shown in Table 16.

Table 16: Rule Set Consequence, and Risk Predictions

Section	Rule Set Consequence, and Risk Predictions
8.1	Rule set based consequence distances used in conjunction with frequency
8.2	Transects of individual risk of exceeding a dangerous dose at locations perpendicular to the pipeline and at the LVI
8.3	Individual risk of exceeding a dangerous dose presented as risk contours for the LVI
8.4	Predicted risks at houses closest to the pipeline
8.5	Societal risk
8.6	Risk zones
8.7	Sensitivity studies

8.1 Rule Set based Consequence Distances

The maximum distances to the various rule set based consequence levels used with associated frequencies in the prediction of risk from immediately ignited releases from the pipeline are shown in Table 17.

Table 17: Consequence Distances

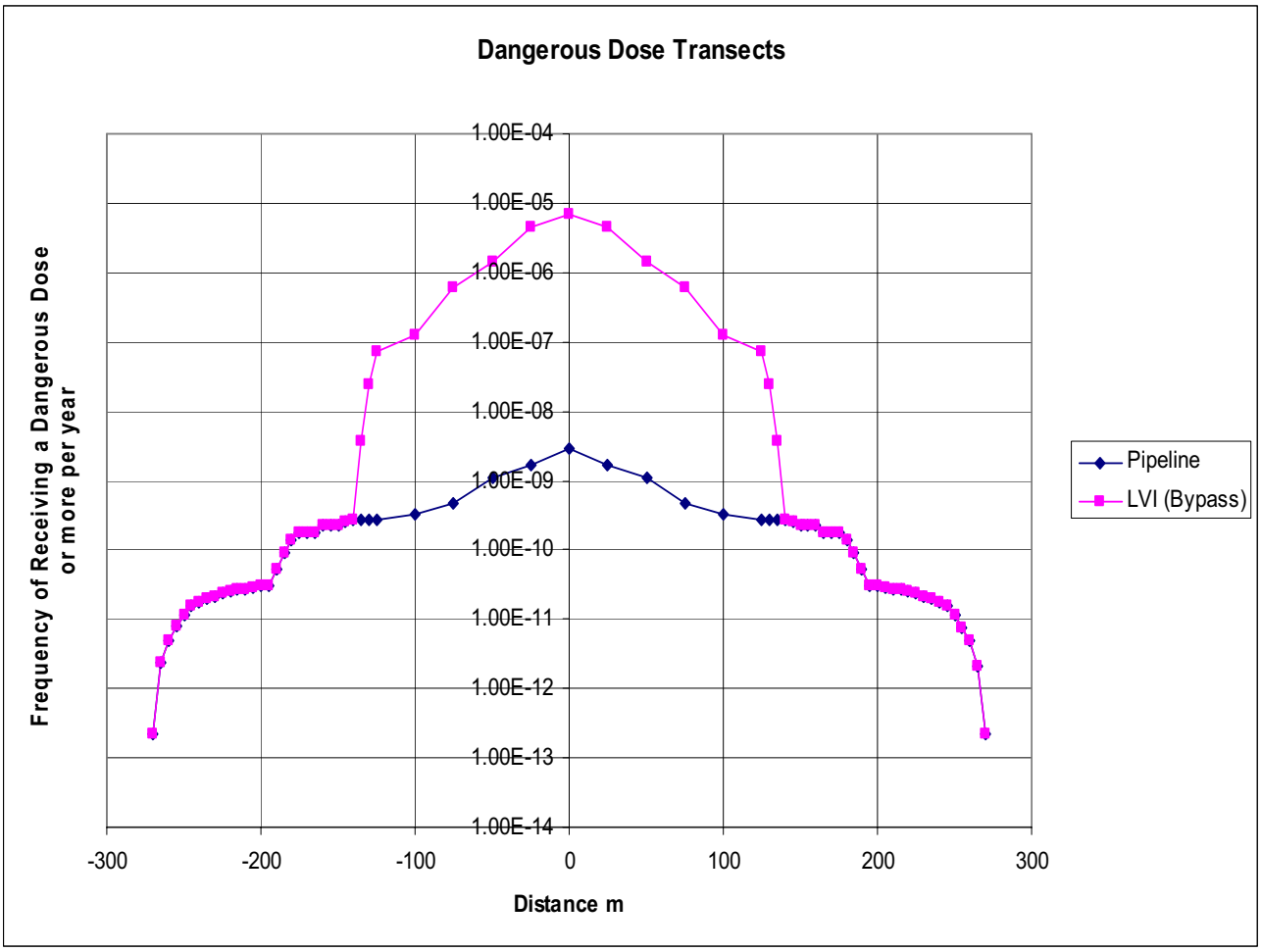
Dose or Flux	Effect and Scenario	Distance (m)
40 kW/m^2	Building ignition from rupture, 100% fatality	193
Spontaneous ignition of buildings	Building ignition from rupture, people evacuate building	180
Piloted ignition of buildings	Possible building ignition from rupture, people evacuate building	205
Either 35 kW/m^2 or 3500 tdu	100% fatality for people outdoors (rupture or hole)	205
1800 tdu	50% fatality for people outdoors (rupture)	218
1000 tdu	1% fatality for people outdoors (rupture)	273
25 kW/m^2	1% fatality for people indoors (hole)	100
6 kW/m^2	1% fatality for people outdoors (hole)	136

In the unlikely event of failure of the umbilical there would be a release of methanol. This may ignite and burn as a pool fire. The predicted distance from the pool fire to a thermal flux of 6 kW/m^2 is less than 35m, so cannot affect any existing dwellings. It has been demonstrated (Section 6.4.2.8) that ignited methanol could not cause escalation to the pipeline, so this scenario is not considered further.

8.2 Risk Transects

The risk transects for the pipeline and the LVI (base case) are presented in Figure 12 in terms of the frequency of exceeding a dangerous dose for a person who spends 10% of the time outdoors and 90% of the time indoors.

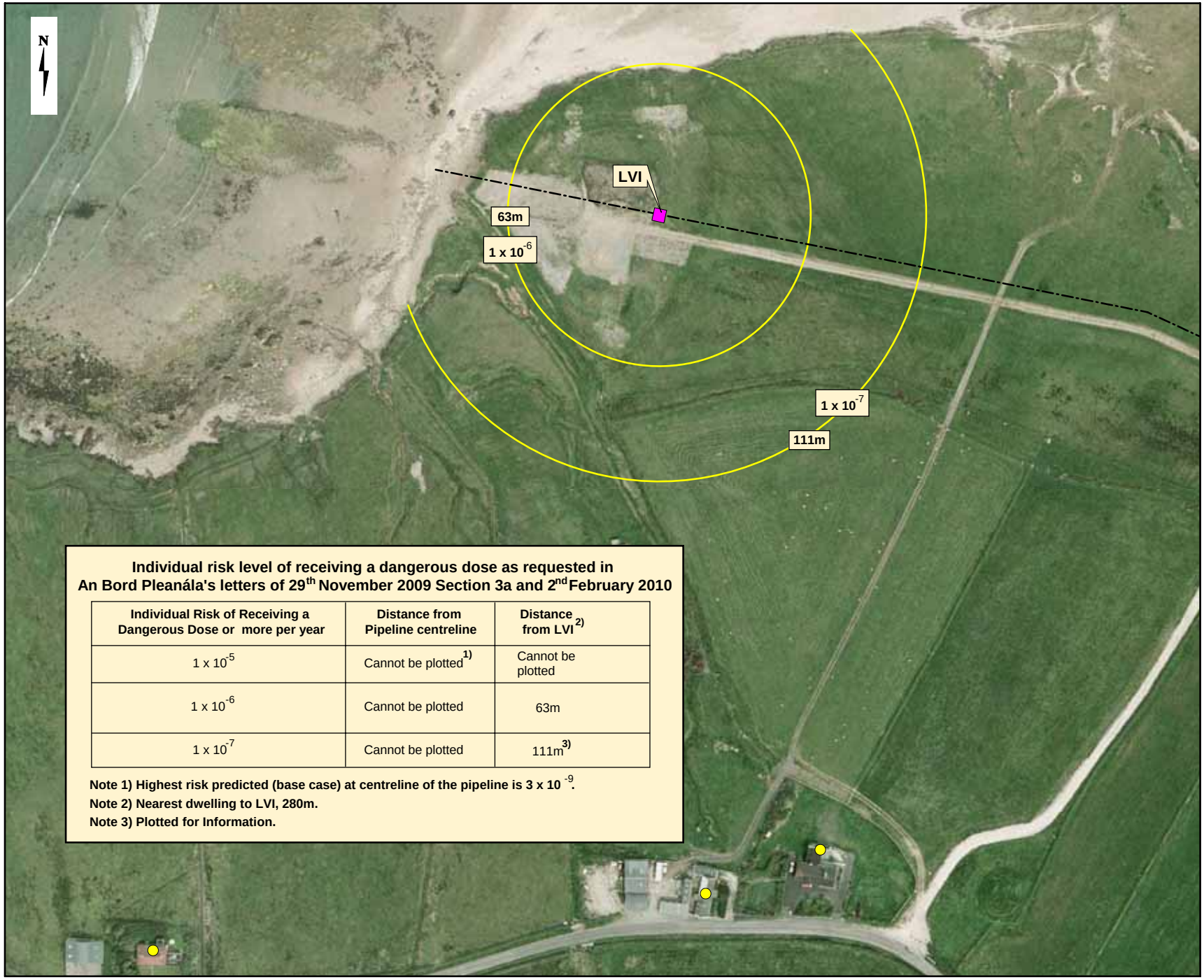
Figure 12: Transects of Individual Risk of a Dangerous Dose or more (LVI and Pipeline)



C:\Data\321766\New Pipeline\NewPipelinePreds\Base Out andgraphs

8.3 Risk Contours

The risk of receiving a dangerous dose or more in contour format are shown in Figure 13. Contours are shown for risk levels of 1E-06 per year and 1E-07 per year. The predicted risk levels at the pipeline are below these levels.



Individual risk level of receiving a dangerous dose as requested in An Bord Pleanála's letters of 29th November 2009 Section 3a and 2nd February 2010

Individual Risk of Receiving a Dangerous Dose or more per year	Distance from Pipeline centreline	Distance from LVI 2)
1×10^{-5}	Cannot be plotted 1)	Cannot be plotted
1×10^{-6}	Cannot be plotted	63m
1×10^{-7}	Cannot be plotted	111m 3)

Note 1) Highest risk predicted (base case) at centreline of the pipeline is 3×10^{-9}.
Note 2) Nearest dwelling to LVI, 280m.
Note 3) Plotted for Information.

LEGEND:

House Location

Proposed Route:

Trenched Section

Corrib Onshore Pipeline and LVI: Individual Risk Contour Plots

Figure 13

File Ref: COR25MDR0470Mi2490R01
Date: May 2010

CORRIB ONSHORE PIPELINE

Corrib natural gas

RPS

8.4 Predicted Individual Risks at houses closest to the Pipeline

The predicted individual risk of receiving a dangerous dose or more (and individual risk of fatality) at the currently normally occupied houses closest to the buried section of pipeline and to the tunnelled section of pipeline are shown in Table 18. It can be seen that the predicted individual risk levels (dangerous dose basis) are more than four orders of magnitude, or 10,000 times, below the broadly acceptable level (1E-06 per year).

Table 18: Predicted Individual Risks at the Houses nearest to the Pipeline

Distance of house from pipeline (m)	Risk of Receiving a Dangerous Dose or more (per year)	Individual risk of fatality (per year)
246 (Buried)	1.5E-11	3.8E-12
234 (Tunnelled)[1)]	2.1E-11	5.3E-12

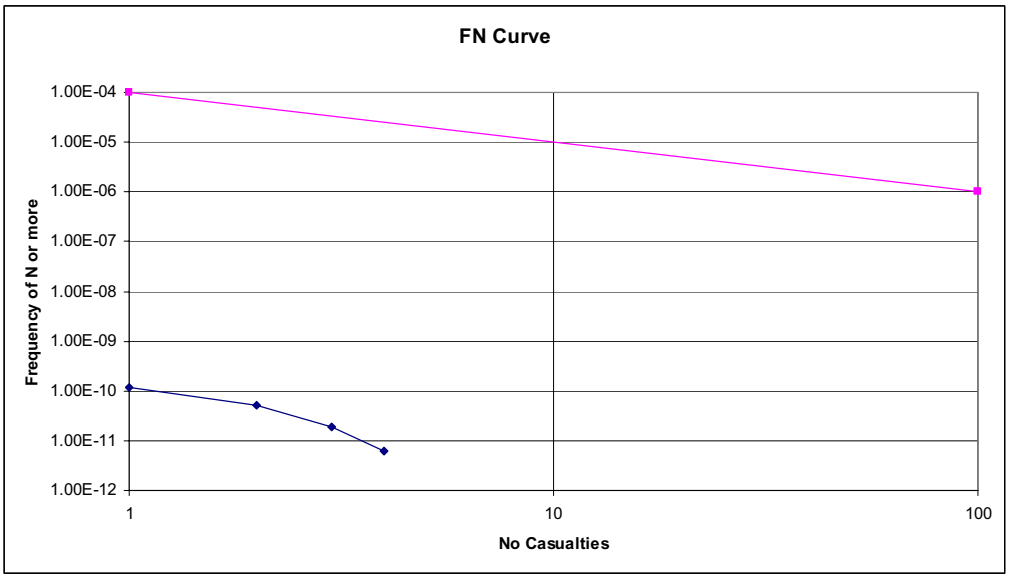
1) Modelled on 230m

8.5 Societal Risk

The societal risk curve for the pipeline and LVI at Glengad is shown, together with the criterion line from PD 8010-3 [1] in Figure 14.

It can be seen that the predicted societal risk is almost six orders of magnitude below the criterion line. The maximum number of fatalities is associated with the maximum number of people in one house (assumed to be four (see S 6.10)) and the period they would be present outdoors (since no houses fall within the piloted ignition of buildings distance).

Figure 14: Predicted Societal Risk at Glengad

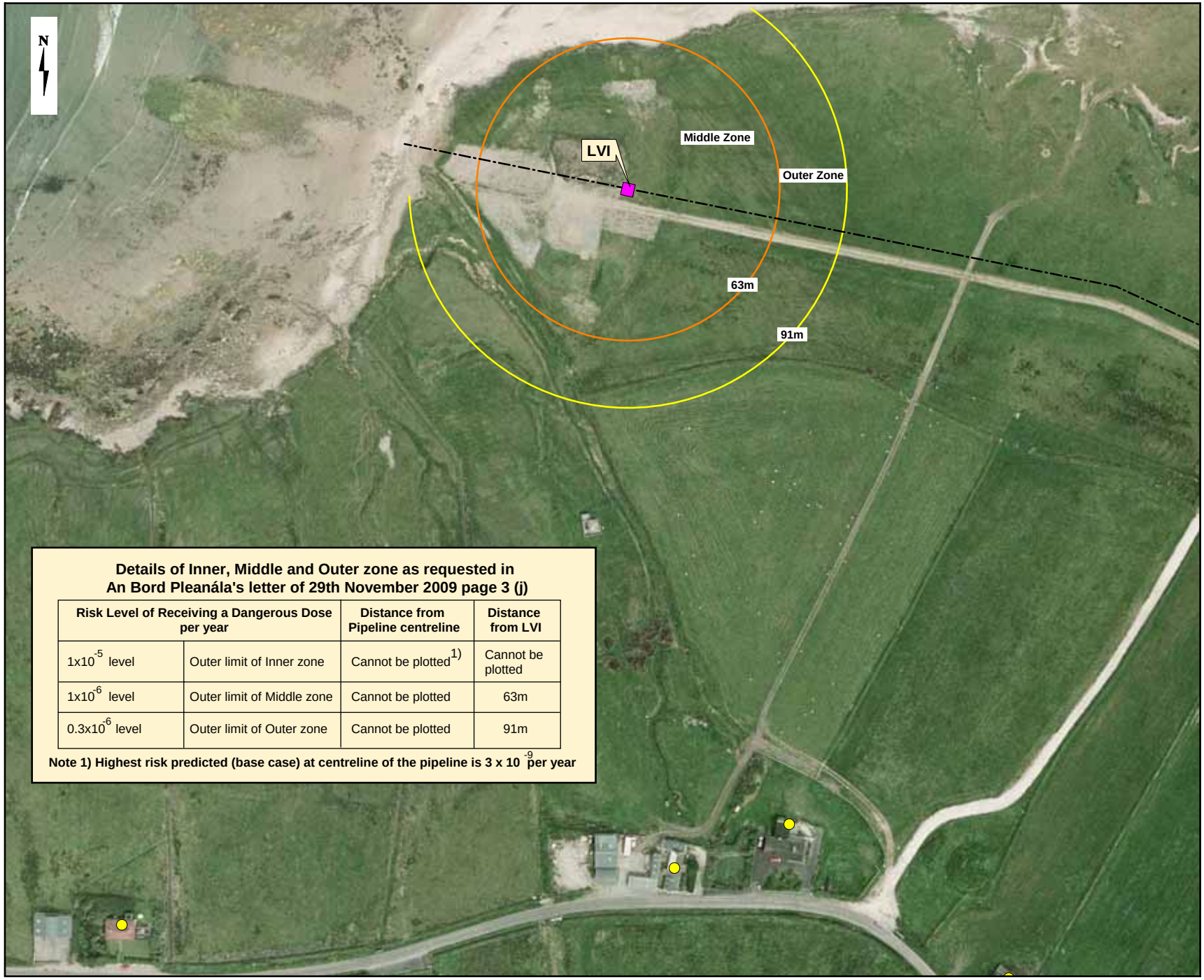


8.6 Risk Zones

The risk of receiving a dangerous dose or more at the pipeline is 3E-09 per year. This is two orders of magnitude (or 100 times) below the level specified by An Bord Pleanála in their letter dated 2nd November 2009 at item 3(a) of 0.3×10^{-6} per year for the outer zone.

The risk of receiving a dangerous dose or more at the LVI is 7E-06 per year. The distance to the outer boundary of the middle zone (1E-06 per year of receiving a dangerous dose or more) is 63m from the LVI and the distance to the outer boundary of the outer zone (3E-07 per year of receiving a dangerous dose or more) is 91m from the LVI.

The risk zones for the LVI are plotted in Figure 15, It is not possible to plot any risk zones for the pipeline.



Details of Inner, Middle and Outer zone as requested in An Bord Pleanála's letter of 29th November 2009 page 3 (j)

Risk Level of Receiving a Dangerous Dose per year		Distance from Pipeline centreline	Distance from LVI
$1x10^{-5}$ level	Outer limit of Inner zone	Cannot be plotted[1)]	Cannot be plotted
$1x10^{-6}$ level	Outer limit of Middle zone	Cannot be plotted	63m
$0.3x10^{-6}$ level	Outer limit of Outer zone	Cannot be plotted	91m

Note 1) Highest risk predicted (base case) at centreline of the pipeline is 3×10^{-9} per year

LEGEND:

House Location

Proposed Route:

Trenched Section

Zone Contour:

Outer limit of Inner Zone (Cannot be plotted)

Outer limit of Middle Zone

Outer limit of Outer Zone

Corrib Onshore Pipeline and LVI: Zone Details

Figure 15

File Ref: COR25MDR0470Mi2479R01
Date: May 2010

CORRIB ONSHORE PIPELINE

Corrib natural gas

RPS

8.7 Sensitivity Studies

The predictions for the sensitivity studies are presented in Attachment B, both in terms of the frequency of exceeding a dangerous dose and individual risk of fatality. Some observations from these sensitivities are presented in Table 19.

Table 19: Sensitivity Studies

Description	Risk of receiving a dangerous dose or more at the pipeline (per year)	Risk of receiving a dangerous dose or more at 246m from the pipeline (per year)	Description	Risk of receiving a dangerous dose or more at the LVI (per year)	Distance to a risk of receiving a dangerous dose of 3E-07 per year (m)
Base Case	2.92E-09	1.5E-11	Base Case	6.91E-06	91
Moving away at 1 m/s	2.93E-09	2.29E-11	LVI Generic	2.52E-05	132
Landslip	1.73E-08	6.38E-10	Third Party Intentional	6.91E-05	129
Third Party Intentional	1.98E-08	1.52E-11			

It can be seen that the highest risks at the pipeline are still below the outer boundary of the outer zone level of 3E-07 per year, and the highest risk at the closest house is still below 1E-09 per year, three orders of magnitude, or 1,000 times, below a level that is generally assumed to be broadly acceptable.

The inclusion of a large failure for valves at the LVI increases the risk at the LVI above 1E-05 per year (with a predicted distance of 124m to the outer boundary of the inner zone and a distance of 132m to the outer boundary of the outer zone).

The closest dwelling to the LVI is 280m from the LVI and 246m from the pipeline.

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ATTACHMENT

A

FAILURE FREQUENCY PREDICTIONS DUE TO 3RD PARTY INTERFERENCE FOR CORRIB PIPELINE

REPORT BY

HASWELL J AND LYONS C

(PIE REPORT)

- o0o -

PIE/07/R0176
Issue: v1.0
February 2008

FAILURE FREQUENCY PREDICTIONS DUE TO 3rd PARTY INTERFERENCE FOR CORRIB PIPELINE

Authors: J Haswell & C Lyons

CLIENT	**DNV**
Contract Number	**-**
Client Document Number	**-**

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Amendment and Approval Record

1.0	Final including Client Comments 12/02/08	J V Haswell	J V Haswell.	RA McConnell		G Senior	G Senior
0.1	Draft for Client Comment 08.10.07	J V Haswell	J V Haswell.	RA McConnell		G Senior	G Senior
0	Draft Issue 02/10/07	J V Haswell	J V Haswell.				
		C Lyons					
Issue	**Change**	**Name**	**Sign**	**Name**	**Sign**	**Name**	**Sign**
		Author		**Reviewer**		**Approver**	

Distribution List: February 08

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Executive Summary

In assessing the risks posed by hazardous pipelines, the damage mechanism which may result in failure which is most relevant is that due to 3rd party interference. A key objective of UKOPA (United Kingdom Pipeline Operators' Association) is the development and agreement with all stakeholders of an accepted and consistent approach to pipeline risk assessment. To this end, UKOPA have drafted risk assessment code supplements to the UK pipeline codes IGE/TD/1 Edition 4 and PD 8010 Part 1. These code supplements, which are scheduled for final publication in 2008, include guidance on the prediction of failure frequencies due to 3rd party interference, which is of particular importance in assessing the residual risk levels of pipelines. To develop this guidance, UKOPA required a methodology for the prediction of pipeline failure frequencies due to dent and gouge damage.

A prediction methodology was developed for UKOPA by Pipeline Integrity Engineers Ltd (PIE). The methodology is a reconstruction of the dent-gouge failure model developed and prediction methodology using damage probability distributions for the prediction of pipeline leak and rupture failure frequencies, which was originally developed and published by British Gas. The methodology developed by PIE uses damage probability distributions constructed using the current UKOPA fault data.

The reconstructed model, entitled the PIE model in this report, has been used to carry out investigative studies for UKOPA Predictions obtained using this model compare well with predictions from the gas industry failure frequency prediction methodology, FFREQ, and operational failure data from the UKOPA fault database. The results have been reviewed in detail by UKOPA, and the model is accepted by UKOPA as a method for the predicting the leak and rupture frequency of pipelines due to 3rd party interference for use in quantified risk assessments carried out in accordance with the UK pipeline codes PD 8010 Part 1 and IGE/TD/1 Edition 4. The PIE model has been used to predict failure frequencies for the Corrib pipeline at the request of DNV. The failure model and the predictive methodology are described, and the results obtained for the Corrib pipeline are presented in this report.

Conclusions

A methodology for the prediction of pipeline failure frequencies due to 3rd party interference developed by, and based on work originally carried out for and published by British Gas has been used to predict failure frequencies for the Corrib pipeline.

The predicted failure frequencies for the specified operating pressures are:-

Predictions		**Operating Pressure bar**			
		345	**144**	**100**	**55**
Probability of Failure	Leak	5.83E-05	4.53E-06	2.57E-06	1.83E-06
	Rupture	1.08E-04	6.86E-07	6.30E-08	0.00E+00
	Total	1.66E-04	5.22E-06	2.64E-06	1.83E-06
Failure Frequency Km.yrs	Leak	4.95E-08	3.85E-09	2.19E-09	1.55E-09
	Rupture	9.15E-08	5.82E-10	5.35E-11	0.00E+00
	Total	1.41E-07	4.43E-09	2.24E-09	1.55E-09

Comparison with other published failure frequency predictions and the results of sensitivity studies have confirmed that it is reasonable to apply the prediction methodology to the Corrib pipeline.

Application of the PIE model in this study indicates that the rupture frequency of the Corrib pipeline is approximately 200 times lower than that of an equivalent pipeline of standard wall thickness, typical of those in the UK pipeline population.

Contents

1.0 Introduction

In assessing the risks posed by hazardous pipelines, the damage mechanism which may result in failure which is most relevant is that due to 3rd party interference. A key objective of UKOPA (United Kingdom Pipeline Operators' Association) is the development and agreement with all stakeholders of an accepted and consistent approach to pipeline risk assessment. To this end, UKOPA have drafted risk assessment code supplements to the UK pipeline codes IGE/TD/1 Ed 4 and PD 8010 Part 1. These code supplements, which are scheduled for final publication in 2008, include guidance on the prediction of failure frequencies due to 3rd party interference, which is of particular importance in assessing the residual risk levels of pipelines. To develop this guidance, UKOPA required a methodology for the prediction of pipeline failure frequencies due to dent and gouge damage.

A prediction methodology was developed for UKOPA by Pipeline Integrity Engineers Ltd (PIE). Studies carried out for UKOPA included assessment of pipeline failure models [1,2,3,4], reconstruction of the methodology for the prediction of pipeline leak and rupture failure frequencies originally developed and published by British Gas [1,5] and application of damage probability distributions developed using the current UKOPA fault data [6].The methodology is a reconstruction of the dent-gouge failure model and prediction methodology using damage probability distributions for the prediction of pipeline leak and rupture failure frequencies, which was originally developed and published by British Gas. The methodology developed by PIE uses damage probability distributions constructed using the current UKOPA fault data [6].

The reconstructed model, entitled the PIE model in this report, has been used to carry out investigative studies for UKOPA, and is an accepted method for the predicting the leak and rupture frequency of pipelines due to 3rd party interference for use in quantified risk assessments carried out in accordance with the UK pipeline codes PD 8010 Part 1 [7] and IGE/TD/1 Edition 4 [8]. Predictions obtained using this model compare well with predictions from the gas industry failure frequency prediction methodology FFREQ [9] and operational failure data from the UKOPA fault database. The PIE model has been used to predict failure frequencies for the Corrib pipeline on behalf of DNV. The failure model and the predictive methodology are described, and the results obtained for the Corrib pipeline are presented in this report.

1.1 Scope

This report describes the fracture mechanics model used to predict the failure of pipelines containing damage, the methodology used to predict failure frequency using damage probability distributions based on fault data from the current UKOPA Pipeline Fault Database, and presents failure frequency predictions obtained using the model and methodology for the Corrib pipeline.

1.2 Report Structure

The report is structured as follows:

Section 2: Provides a general overview of the methodology for predicting the probability and frequency of failure of a pipeline subject to 3rd party interference.

Section 3: Describes the PIE model for the prediction of failure frequencies due to 3rd party interference.

Section 4: Presents failure frequency predictions for the Corrib pipeline.

Section 5: Discussion of results.

Section 6: Presents the conclusions drawn.

Appendix 1 Provides a glossary of terms.

Appendix 2 Includes full details of the PIE dent-gouge failure model.

Appendix 3 Includes a flow diagram for the PIE predictive procedure.

Appendix 4 Gives a summary of 3rd party failure frequency models applied to the Corrib pipeline.

1.3 Glossary

The report refers to a number of organisations and models by acronyms; these are defined and explained in Appendix 1.

2.0 Methodology for prediction of failure of pipelines due to 3rd party interference

2.1 Overview

Pipeline damage due to 3rd party interference occurs in the form of gouges, dents or combinations of these. This type of damage is random in nature, and as operational failure data are sparse, recognised engineering practice requires that a predictive model is used to calculate leak and rupture failure frequencies for specific pipelines. The approach taken to develop a methodology for the prediction of the probability and frequency of pipeline failure due to 3rd party interference involves three key requirements:

i) Modelling of the failure state of a specific pipeline subject to dent-gouge damage, using a fracture mechanics failure model (or limit state). Such models are used to calculate whether a given combination of pipeline conditions together with specific dent and gouge damage exceed the failure condition (see Section 2.2).

ii) Prediction of the likelihood of occurrence of the dent-gouge damage which results in failure for specified pipeline conditions. The likelihood of occurrence of specific dent-gouge damage is obtained from the statistical distributions of measured gouge length, gouge depth and dent depth damage in operational pipelines (see Section 2.3).

iii) Modelling of the incidence rate of 3rd party damage. The rate at which 3rd party damage occurs is obtained from the number of damage incidents recorded over the operational exposure of a pipeline population (see Section 2.4).

2.2 Failure Models for Damaged Pipelines

The original work to develop a failure model for damaged pipelines was carried out for British Gas at the Engineering Research Station, Newcastle, UK. The model is a general, two parameter fracture mechanics model, which assumes steel structures containing defects can fail due to a combination of plastic collapse and brittle fracture. The model, which is used to calculate the failure conditions of a pipeline containing specified dent and gouge damage and is referred to as the original dent-gouge model in this report, is semi-empirical, in that the basic formulation is theoretical, but the actual formulation is fitted in accordance with empirical failure data.

The empirical data comprises burst test results for pipe rings and vessels containing gouge and dent damage. This recorded failure data was used to calibrate the model. As the model is semi-empirical, its application is constrained by the limits of the data used in its calibration. Additionally, the model is intrinsically conservative, in that it is 2–dimensional, and represents the through-wall failure of an infinitely long part wall defect. This model and its application have been critically reviewed by experts and are well understood [1,2]. The model is well documented and published, and is relatively straightforward to reconstruct.

The original dent-gouge model was updated by Advantica for UKOPA. The updated model, referred to as the UKOPA mechanical damage limit state model in this report, includes incorporation of a number of additional parameters (eg. micro-crack, plasticity and residual stress due to the dent etc.), and a revision of the statistical calibration to the empirical data used to develop the original dent-gouge model to take account of the additional parameters. This model represents an update to the original dent-gouge model, but is essentially a similar, semi-empirical model.

Failure calculations carried out using the fracture mechanics models described above may be performed as simple, deterministic calculations, in which single

mean, upper or lower bound parameter values are assumed, or as a sophisticated structural reliability analysis, which takes account of the probabilistic variation of all parameters.

2.3 Probability of Failure

In order to determine the probability of failure due to 3rd party interference, the likelihood of dent and gouge damage which may occur and the probability that this will cause failure of the pipe is required.

In the original British Gas (dent-gouge) methodology, the likelihood of damage is modelled as damage size probability distributions. This approach assumes that damage of a given size can occur in any pipeline, ie the damage size is not related to the resistance of the pipe in which it occurs. This is conservative for pipes with a high resistance to damage (ie large diameter, thick wall).

One alternative and potentially more realistic approach is to convert the damage data into a force probability distribution, ie the force required to produce specific dent and gouge damage is calculated from the pipe parameters and recorded damage data. The force probability distribution is then applied in the failure calculation, so the dent and gouge damage caused to a pipe of specified geometry and material is predicted. This approach takes account of the pipe resistance, and is therefore less conservative for high resistance pipes, such as the Corrib pipeline.

A further approach would be to model the force applied by specific excavation machines, and calculate the dent and gouge damage which this causes. Unfortunately, however, there is no published data available in UK relating machine size/type to applied force to support such an approach.

With respect to the Corrib pipeline, application of the original British Gas methodology using existing dent and gouge damage data is conservative, as in applying the damage to the pipe, this model does not take account of the increased resistance of the thick wall of this pipeline. Less conservative predictions would be obtained if the damage size distribution was represented by a force distribution, but this has not been done in this analysis.

2.4 Failure Frequency

In order to calculate the failure frequency, the probability of failure is multiplied by the incident rate for 3rd party interference for a given population of pipelines:-

Failure Frequency = Probability of Failure x number of incidents of 3rd party interference per km yr

The incident rate applied is derived from the UKOPA Pipeline Damage Database (i.e.8.49E-04 per year, see Appendices 2 and 3).

3.0 Development of the PIE Model for the prediction of failure frequencies due to 3rd party interference

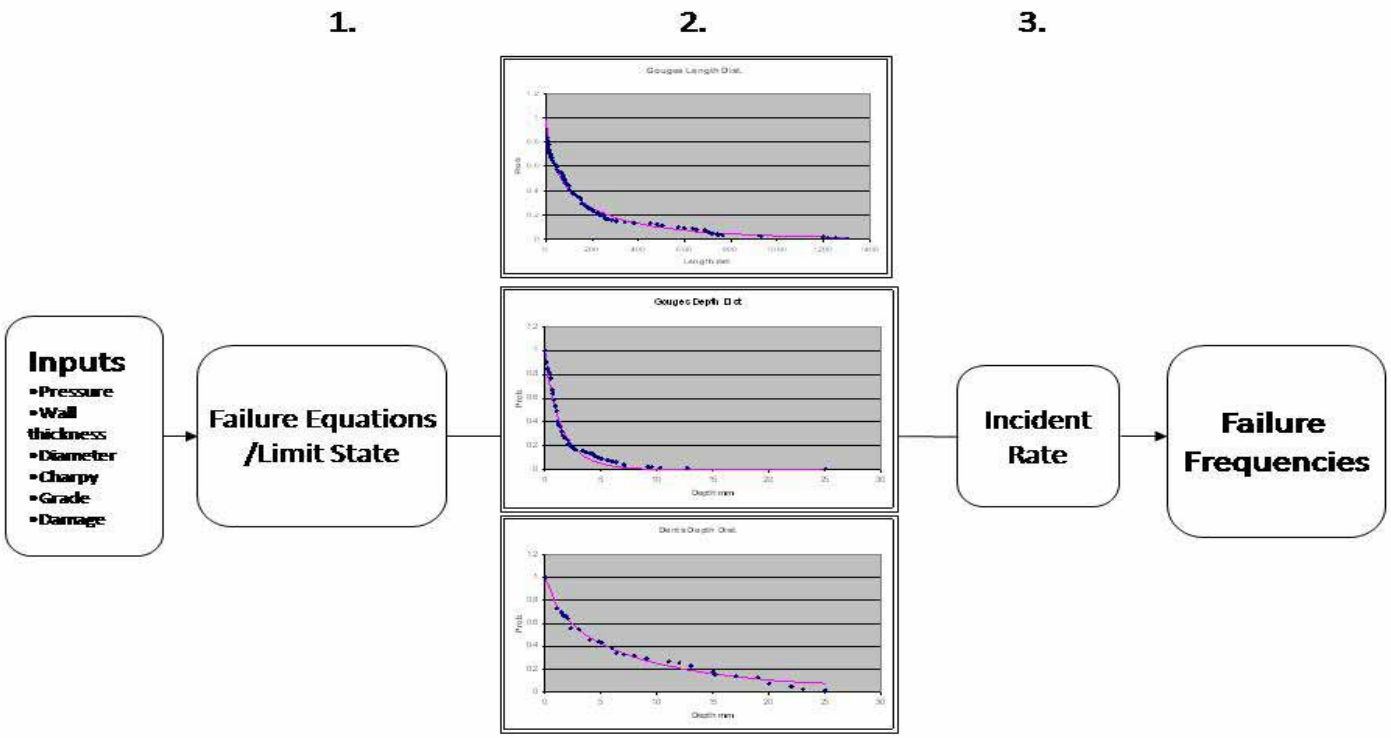
3.1 Background

In order to derive realistic failure frequencies for UK major accident hazard pipelines due to 3rd party interference, UKOPA has initiated work to assess available failure models, and the predicted failure frequencies obtained using these models. As stated in 2.2 above, Advantica updated the original British Gas dent-gouge failure model to the UKOPA limit state model. A comparison was carried out of predicted pipeline failure frequencies provided by Transco (now National Grid) using (1) the original dent-gouge model implemented in the failure frequency prediction software FFREQ, (2) the UKOPA limit state model incorporated in Advantica's pipeline structural reliability analysis software, and (3) the PIPIN software developed and used by the HSE. It was observed that the predictions obtained by Advantica using the updated failure model and structural reliability analysis were up to an order of magnitude higher than the predictions obtained by Transco using FFREQ and HSE using PIPIN.

In order to investigate this difference, PIE undertook a series of studies looking into predictions obtained using different models. As part of this work, the original failure frequency prediction methodology published by British Gas and later incorporated into the gas industry risk assessment software PIPESAFE [7] as FFREQ was reconstructed. The reconstructed methodology, referred to as the PIE Model in this report, uses 3rd party damage (gouge depth, gouge length and dent depth) data obtained from the UKOPA Pipeline Fault Database, filtered and interpreted in the same way as in the original British Gas work.

3.2 The PIE Model

The PIE model uses the original dent-gouge failure model to predict failure caused by dent and gouge damage. The probabilities of the size of damage which may occur, and the incidence or hit rate of 3rd party damage, are obtained from the UKOPA Pipeline Fault Database. The model is illustrated in Figure 1.



Failure Prediction:- 1 – Failure model 2 – Probability of damage size 3 – Frequency of damage

Figure 1 – Illustration of the PIE Model

Details of the PIE model, the procedure for predicting the probability of failure and the dent and gouge damage data used to predict pipeline failure frequency are given in Appendices 2 and 3.

3.3 Comparison of the PIE model and FFREQ

As part of the work undertaken for UKOPA, a detailed comparison of predictions obtained using the PIE model and FFREQ for a number of pipeline cases was carried out. As these models are similar, in that they both use the original dent-gouge failure model, demonstration of reasonable agreement was required. A summary of the results is given in Table 1 and Figures 2 and 3.

P bar	Dia mm	Wt mm	Grade	PIE failure frequency km.yrs		FFREQ Failure Frequency km.yrs	
				Rupture	Total	Rupture	Total
69	273	6.4	X46	3.13E-05	6.33E-05	3.19E-05	6.45E-05
70	324	7.1	X46	2.51E-05	5.06E-05	2.79E-05	5.80E-05
70	508	11.1	X46	4.32E-06	1.05E-05	3.41E-06	1.10E-05
75	610	9.5	X52	1.80E-05	3.22E-05	1.14E-05	3.11E-05
75	762	11.9	X52	7.73E-06	1.55E-05	3.37E-06	1.07E-05
70	914	12.7	X60	4.22E-06	1.28E-05	2.81E-06	1.00E-05
85	914	19.1	X60	1.97E-07	1.50E-06	4.12E-08	2.30E-06

Table 1 – Comparison of PIE and FFREQ Failure Frequency Predictions

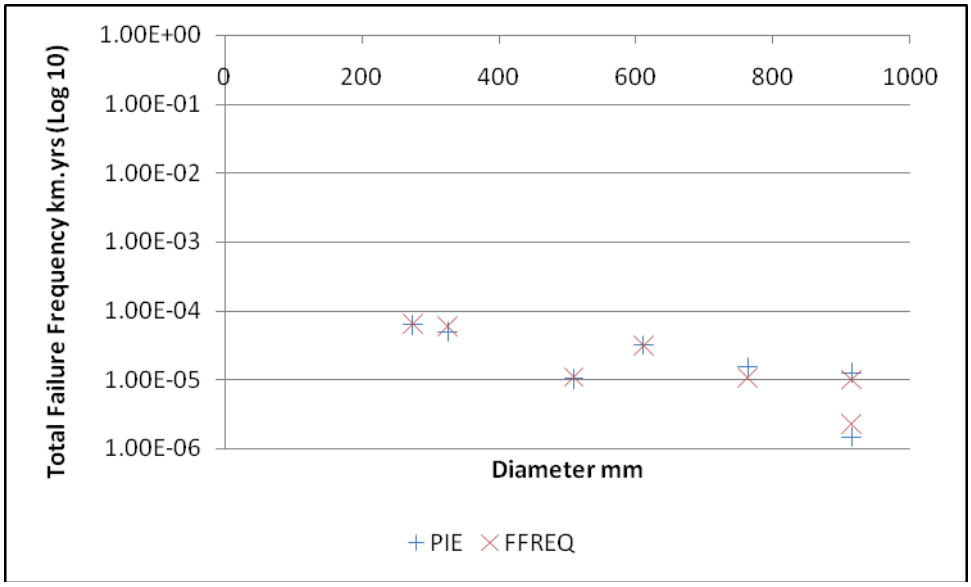


Figure 2 – Comparison of PIE and FFREQ Total Failure Frequency Predictions

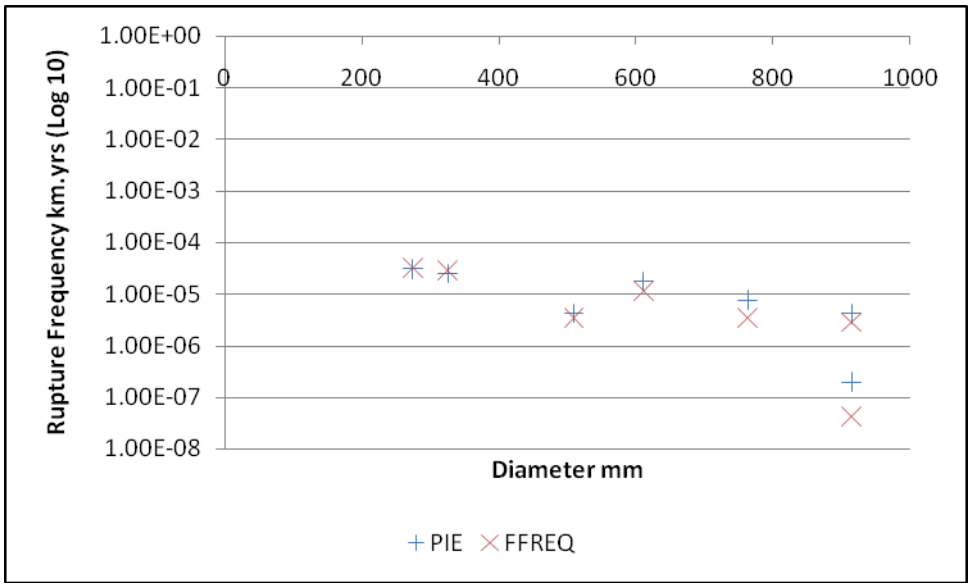


Figure 3 – Comparison of PIE and FFREQ Rupture Frequency Predictions

More recent work carried out for UKOPA in relation to the development of the code supplements to IGE/TD/1 and PD 8010 Part 1 has compared predictions for pipe cases selected to present the range of pipelines in the UKOPA database with operational failures, where failures are defined as product losses. This comparison is shown in Figure 4.

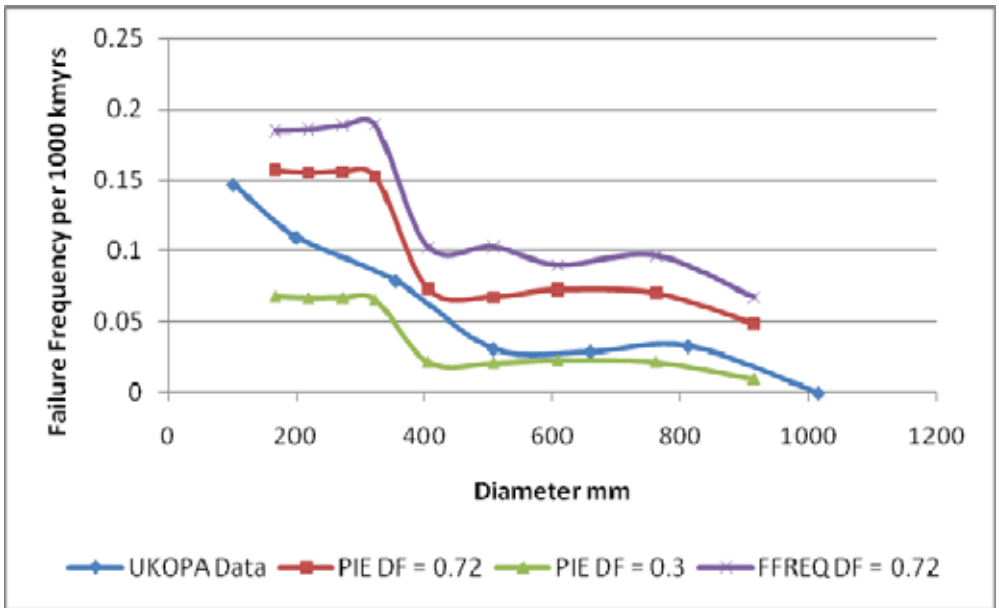


Figure 4 – Comparison of PIE and FFREQ Total Failure Frequency Predictions with UKOPA Data

Figure 4 shows that the PIE model predictions of total failure frequency for pipelines operating at a design factor of 0.72 and 0.3 bound the operational data, and the FFREQ predictions of total failure frequency are higher than the PIE model. Based on the above comparisons, UKOPA concluded that reasonable agreement had been demonstrated between the PIE model, FFREQ and operational data recorded in the UKOPA pipeline fault database.

3.4 Prediction of pipeline failure frequencies – UKOPA recommendations

Following detailed review and consideration of the results of the study shown above and comparison of pipeline failure models and failure frequency predictions obtained using the original dent-gouge and the UKOPA limit state models, UKOPA concluded that the original dent-gouge model has been subject to detailed review, and has been applied extensively in the period of its existence. It is widely recognised and is included in a number of expert methodologies, including the PIPESAFE risk assessment software package [7], the EPRG defect assessment guidelines [9] and the Pipeline Defect Assessment Manual PDAM [2]. The same level of review is not yet available for other models, including the UKOPA limit state [3, 4]. In addition, it is appreciated that further work relating the probability of damage caused to specific pipelines by the force applied by different machinery is required, but currently this data does not exist in detail for the UK. In this situation, the application of UKOPA dent-gouge damage data is conservative, particularly with respect to larger diameter and thicker wall pipelines.

Based on the above, UKOPA has therefore recommended that failure frequency predictions for use in pipeline risk analysis should be based on application of the original dent-gouge model (i.e. the PIE model in this work), as there is extensive practical experience in the use and interpretation of predictions from this model, and comprehensive validation against empirical failure data has been carried out. In addition, UKOPA has recommended the use of FFREQ as the standard industry failure frequency prediction software tool. The FFREQ software is currently being prepared by Advantica for release to UKOPA members as a standalone software module, and the damage data distributions are being updated to include data from the current UKOPA Pipeline Fault Database. At the time of the current work, these developments were not available, so the PIE model was used to obtain failure frequency predictions due to 3rd party interference for the Corrib pipeline.

4.0 Prediction of Failure Frequencies due to 3rd party interference for the Corrib Pipeline

4.1 Pipeline Parameters

DNV required failure frequency predictions for the Corrib pipeline at four operating pressures, 345 bar, 144 bar, 100 bar and 55 bar. The pipeline parameters supplied by DNV for use in the PIE model are given in Table 2.

Parameter	Value
Diameter	508 mm
Wall thickness	27.1mm
Material Grade	X70

Table 2 – Pipeline Parameters for the Corrib Pipeline

The material properties used in the analysis are based on BS EN 10208-2:-

SMYS = 485 N/mm^2

SMTS = 570 N/mm^2

In addition, the Charpy energy value assumed was taken from published risk analyses for the Corrib pipeline [10,11], which quote a Charpy impact energy of 130 Joules with a COV of 0.4. Based on this, a Charpy energy value of 70 Joules was selected for use in the analysis.

4.2 Probability of failure and failure frequency predictions

The probability of failure and failure frequency predictions for the Corrib pipeline obtained using the PIE model are given in Table 3.

Predictions		Operating Pressure bar			
		345	144	100	55
Probability of Failure	Leak	5.83E-05	4.53E-06	2.57E-06	1.83E-06
	Rupture	1.08E-04	6.86E-07	6.30E-08	0.00E+00
	Total	1.66E-04	5.22E-06	2.64E-06	1.83E-06
Failure Frequency Km.yrs	Leak	4.95E-08	3.85E-09	2.19E-09	1.55E-09
	Rupture	9.15E-08	5.82E-10	5.35E-11	0.00E+00
	Total	1.41E-07	4.43E-09	2.24E-09	1.55E-09

Table 3 – Probability of Failure and Failure Frequency Predictions for the Corrib Pipeline

Note:- Failure Frequency = Probability of failure x number of incidents per kmyr

5.0 Discussion

5.1 Factors affecting the failure of gas pipelines

5.1.1 Temperature effects

Release of high pressure gas through a defect in a pipe wall will result in cooling of the depressurising gas due to the Joule-Thompson effect. However, as the area through which the gas is released is small, gas expansion will not occur until the gas has passed through the defect/crack/hole, ie external to the pipe, so in general, cooling of the pipe material is unlikely to have an effect on the failure mechanism.

This possibility of material cooling has been acknowledged, and research programmes to investigate it have been proposed, but to date such proposals have not been supported as there is no immediate practical operational evidence that this temperature effect has a major impact on failure behaviour. There are no current reports of practical operational evidence which indicate that material cooling due to gas depressurisation affects the predicted failure mechanism, and this is not included in existing failure models.

5.1.2 Critical defect length

The most common form of 3rd party damage is a gouge, which is assumed to act as a crack-like defect. Depending upon the depth and the pressure, the gouge will fail as a through wall defect, resulting in a leak. If the length of the gouge is greater than a critical length (which is dependent upon the pipe properties and pressure), the defect will be unstable and fast propagation driven by the energy of the pressurised gas will occur. This will result in a rupture, in which the fracture runs along the axis and then around the circumference, resulting in two open pipe ends. This behaviour is observed in research studies and real incidents.

The leak/rupture behaviour has a discrete boundary, which is characterised by the critical defect size. This defect size is the axial length of a crack-like defect. To facilitate release rate calculations, the through wall critical crack is generally represented by an equivalent diameter hole. In the PIE model used in the current study, the length of the critical defect is calculated from fracture mechanics relationships. The equivalent hole size is derived from an experimental study reported by Baum and Butterfield [10]. The hole size equation is:-

$$\frac{A}{A_0} = 0.1x0.0007548\left[\frac{L}{Dt^{0.5}}\right]^{3.706}$$

Where:-

A = leak area
Ao = cross sectional area of pipe
L = defect length
D = diameter of pipe
t = wall thickness

The failure frequency model predictions for critical crack length vs pressure have been used to partition the leak hole size for the four operational conditions considered, ie 345 barg, 144 barg, 100 bar and 55 bar as follows:-

Operating Pressure - barg	**Critical length mm**	**Equivalent hole size Dia, mm**	**Proportion of leaks which are pinholes**	**Proportion of leaks which are greater than pinholes**
345	103.58	6.7	100%	0%
144	304.89	38.4	91.5%	8.5%
100	447.06	79.71	84.99%	15.01%
55	822.16	263.57	78.8%	21.2%

Table 4 – Calculated critical defect lengths and equivalent hole diameters

Note that the calculated equivalent hole diameters are much smaller than the critical defect lengths. This is because the opening crack-like defect through which gas is escaping is long and very narrow, typically with an aspect ratio of a/c <0.1. This type of defect becomes unstable because of the sharp crack shape at the ends of the defect, which have a high stress concentration and stress intensity factor. The equivalent hole diameters determined in this way do not represent through-wall, rounded punctures.

5.1.3 Charpy energy values

Low Charpy energy values result in increased predictions of failure frequency and an increase in the proportion of ruptures. The Charpy energy values used in the prediction of failure frequencies for the Corrib pipeline in the current study was assumed to be a lower bound of 70J. This value is conservative, project personnel have confirmed that all Charpy energy values for material used in the construction of the Corrib pipeline exceed this value.

5.2 Comparison of current with previous predictions

The probability of failure and failure frequency predictions for the 345 bar operating pressure given in Table 3 are compared with the previous predictions reported by J P Kenny [12] and Advantica [13] in Table 5 below:-

Predictions for 345 bar Operating Pressure		**PIE**	**J P Kenny**	**Advantica**
Probability of Failure	Leak	5.83E-05	2.55E-04	2.50E-04
	Rupture	1.08E-04	6.09E-05	8.70E-04
	Total	1.66E-04	3.16E-04	1.12E-03
Failure Frequency km.yrs	Leak	4.95E-08	4.74E-07	3.75E-07
	Rupture	9.15E-08	1.13E-07	1.31E-06
	Total	1.41E-07	5.87E-07	1.69E-06

Table 5 – Comparison of PIE probability of failure and failure frequency predictions with those reported by J P Kenny and Advantica

The results in Table 5 show that the total failure frequency predicted by J P Kenny is 4 times greater than the PIE prediction, but the J P Kenny predictions give the proportion of ruptures as 19.2% of the total failure frequency, while the PIE predictions give the proportion of ruptures as 65% of the total. Comparing the predictions for ruptures, it is noted that the probability of failure due to rupture reported by J P Kenny is 0.56 times the value predicted using the PIE model, and the failure frequency is 1.24 times the value predicted using the PIE model. The models used by PIE and J P Kenny for the prediction of the probability of failure due to rupture are very similar, the lower probability of failure due to ruptures reported by J P Kenny compared to PIE is considered to be due to the different treatment of dent damage data; the J P Kenny model converts the dent damage data into applied force data, whereas the PIE model assumes the probability of the dent damage can occur to any pipeline. In this respect, the PIE model is conservative. The difference which then occurs in translating the probability of failure into a failure frequency is due to the higher incident rate assumed by J P Kenny. It is noted that J P Kenny refer to a gas industry (pipeline uprating) paper, which quotes a single typical incident rate for 36” diameter pipes. The incident rate used in the PIE model is derived from damage data recorded in the UKOPA database, interpreted using the same

approach developed in the original British Gas work, ie the data has been interrogated to remove incorrectly classified damage, and to remove wrap-only damage. Taking these factors into account, the rupture failure frequencies reported by J P Kenny and PIE are not dissimilar.

The major difference in the total failure frequency predictions and the proportion of leaks vs ruptures is due to the higher leak frequency predicted by J P Kenny. J P Kenny use a model which predicts the probability of pipewall puncture by an excavator bucket tooth, whereas the PIE model uses the same failure model for the prediction of the probability of leaks and ruptures, the model calculates the critical gouge length, and the failure is predicted to be a rupture if this critical length is exceeded. The J P Kenny report states that the puncture model has been calibrated against results obtained from a recent joint industry project carried out in North America. The J P Kenny report notes that the machine size distribution data is considered conservative, and truncates the distribution to account for this. In this respect, it is considered that the J P Kenny model predicts a higher probability of failure due to leaks than the PIE model.

The comparison in Table 4 shows that the probability of failure reported by Advantica is 8.08 times the value predicted using the PIE model, and the failure frequency is 14.4 times the value predicted using the PIE model. This indicates the values reported by Advantica are higher than those predicted by the PIE model. The differences in predictions are similar to those considered by UKOPA (ref Section 3.1) and are considered to be due to the use of i) the updated failure model, which includes additional parameters (microcrack, plasticity and residual stress, modified Charpy correlation) which result in more conservative predictions but for which there is currently no validation data or verification process, and ii) the Advantica structural reliability analysis software, which gives conservative predictions, but the reasons for this are unknown.

A summary of the methodologies used for predicting the failure frequency due to 3rd party interference for the Corrib pipeline is given in Appendix 4.

5.3 Sensitivity studies

The Corrib pipeline differs from the general population of UK MAHPs in that it is ultra-thick wall. Simple sensitivity studies were therefore carried out to assess the influences of the pipeline parameters on the predicted failure frequency.

The variation of the rupture and total failure frequency for a 508 mm diameter, X70, 0.72 design factor pipeline of varying wall thickness is shown in Figure 5.

Figure 5 shows that failure frequency falls to minimal value at wall thicknesses greater than 15mm. Typically, 508 mm diameter gas pipelines in the UK population have wall thicknesses of 8mm. The above figure shows that the rupture frequency for a 508 mm diameter pipeline is approximately 3.5E-05, compared to a rupture frequency of 1.76E-07 for a pipeline of 27mm wall thickness, ie the rupture frequency of the 27mm wall thickness pipe is

approximately 200 times lower than that of a pipeline with a typical wall thickness. This confirms that the increase in wall thickness significantly reduces the pipeline rupture frequency.

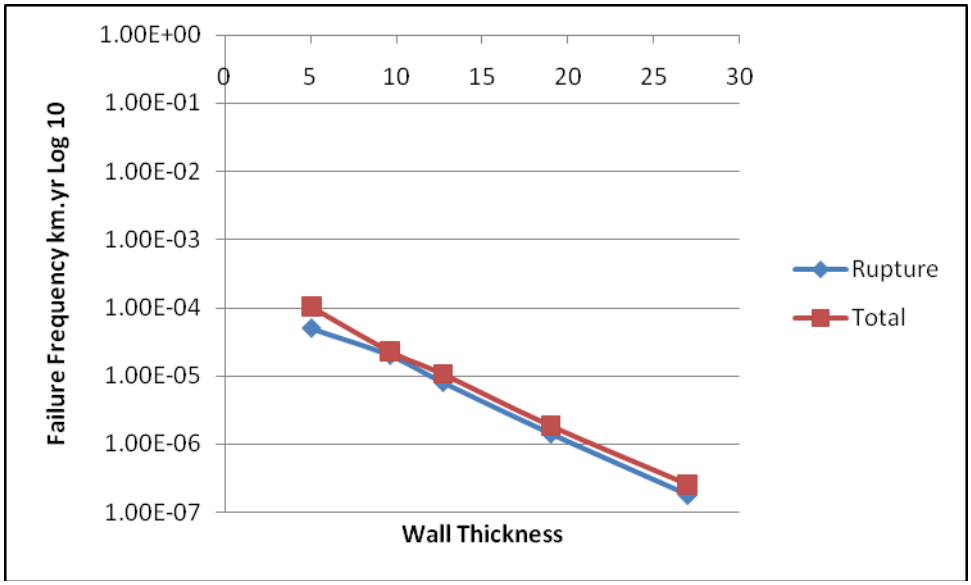


Figure 5 – Variation of Failure Frequency for a 508mm dia, X70, 0.72 design factor pipeline with varying wall thickness

The variation of the total failure frequency with design factor is shown in Figure 6, and the rupture frequency as a proportion of the total frequency with design factor is shown in Figure 7.

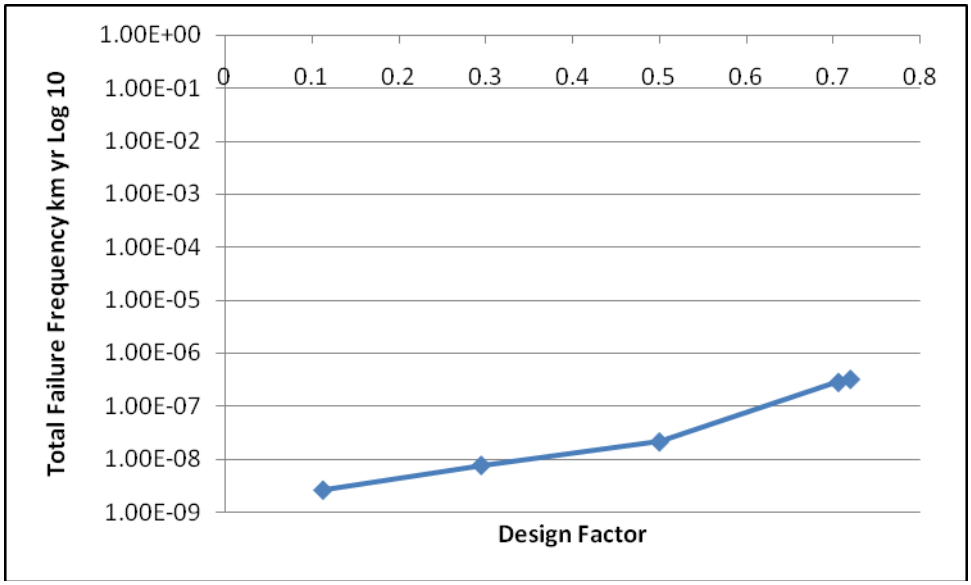


Figure 6 – Variation of Total Failure Frequency with Design Factor

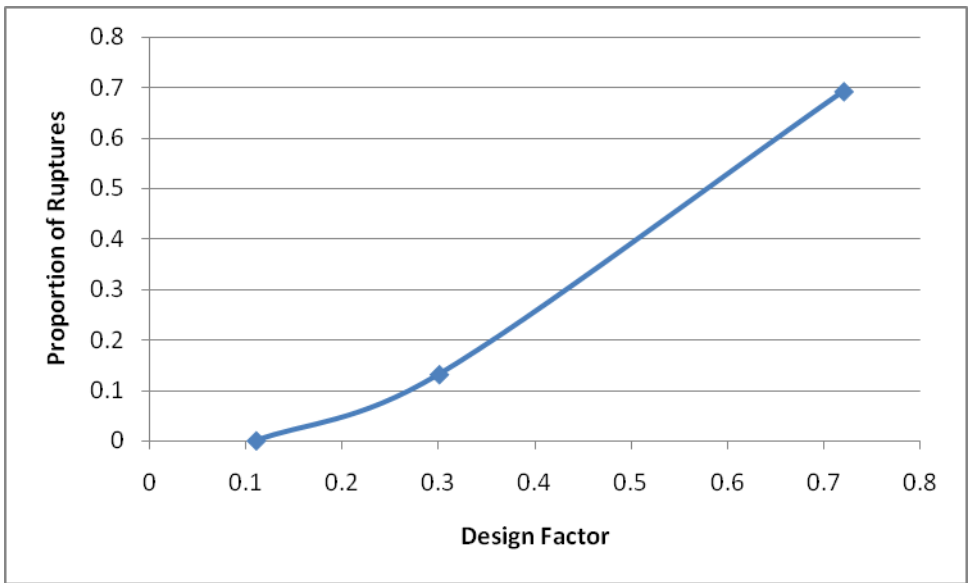


Figure 7 – Variation of the proportion of ruptures with design factor

Figure 7 shows that the proportion of ruptures increases with design factor. This is due to the reduction in the critical gouge length with increase in pressure and therefore stress. The trend is confirmed in Figure 8, which compares the variation in the proportion of ruptures with pressure reported by Advantica and predicted using the PIE model. This confirms that for high pressure gas pipelines, the failure rate is dominated by the rupture rate.

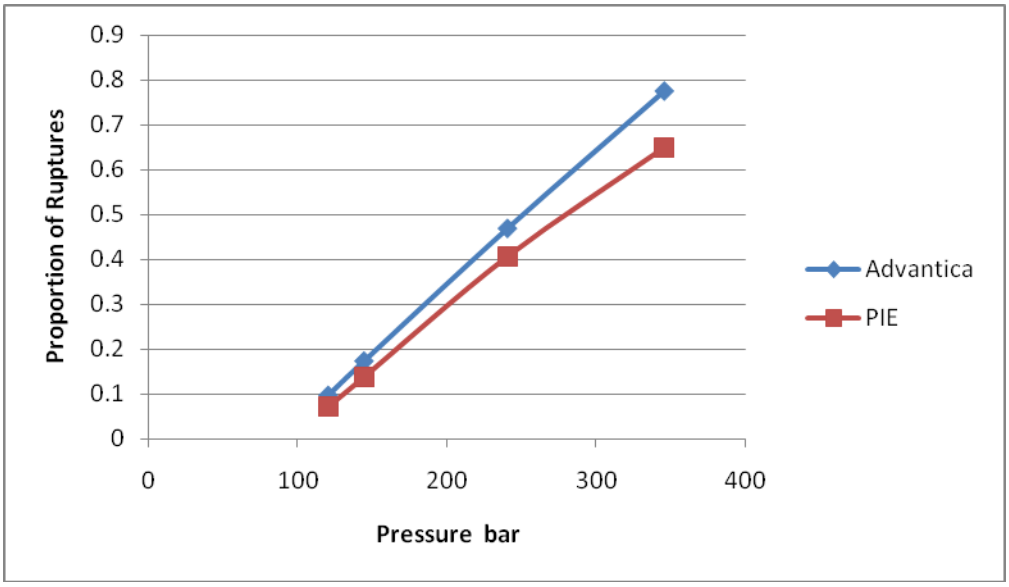


Figure 8 – Comparison of proportion of ruptures with pressure as reported by PIE and Advantica

5.4 Application of the PIE model to the Corrib Pipeline.

The comparison of the PIE model predictions and FFREQ predictions for equivalent pipeline cases reported in Section 3.4 confirms that the PIE model gives similar values to predictions to those obtained using the recognised gas industry model FFREQ over the range of pipeline parameters representing typical UK major accident hazard pipelines (ie diameter 200 – 1000mm, wall thickness 5 – 19mm, operating pressure 40 – 90 bar, design factor 0.3 – 0.72). The Corrib pipeline differs from the typical pipeline population in that the wall thickness is much greater, and the thicker wall means that the pressures are greater for equivalent design factors The comparison discussed in Section 5.1 shows that the predictions obtained using the PIE model are similar to those reported by J P Kenny for the 345 bar operating pressure. This comparison also shows that the PIE model predictions are lower than those reported by Advantica using their updated failure model and structural reliability analysis software. The order of magnitude difference between the PIE model and Advantica for the Corrib pipeline is similar to that observed by UKOPA over a wide range of typical pipe conditions.

Work carried out by UKOPA confirmed that while the Advantica updated failure model and structural reliability analysis predictions were higher than predictions obtained using FFREQ, the variation of failure frequency predictions with structural parameters was similar, ie increase in failure frequency prediction with increase in design factor and reduction in wall thickness. In this regard, the increase in the proportion of ruptures with pressure predicted using the PIE model compares closely with the trend predicted by Advantica.

Based on the above, it is considered reasonable to apply the PIE model to prediction of failure frequencies for the Corrib pipeline. Application of the PIE model indicates that the rupture frequency of the Corrib pipeline is approximately 200 times lower than that of an equivalent pipeline of standard wall thickness, typical of those in the UK pipeline population.

6.0 Conclusions

A methodology for the prediction of pipeline failure frequencies due to 3rd party interference developed based on work originally carried out for and published by British Gas has been used to predict failure frequencies for the Corrib pipeline.

The predicted failure frequencies for the specified operating pressures are:-

Predictions		Operating Pressure bar			
		345	**144**	**100**	**55**
Probability of Failure	Leak	5.83E-05	4.53E-06	2.57E-06	1.83E-06
	Rupture	1.08E-04	6.86E-07	6.30E-08	0.00E+00
	Total	1.66E-04	5.22E-06	2.64E-06	1.83E-06
Failure Frequency Km.yrs	Leak	4.95E-08	3.85E-09	2.19E-09	1.55E-09
	Rupture	9.15E-08	5.82E-10	5.35E-11	0.00E+00
	Total	1.41E-07	4.43E-09	2.24E-09	1.55E-09

Comparison with other published failure frequency predictions and the results of sensitivity studies have confirmed it is reasonable to apply the prediction methodology to the Corrib pipeline.

Application of the PIE model indicates that the rupture frequency of the Corrib pipeline is approximately 200 times lower than that of an equivalent pipeline of standard wall thickness, typical of those in the UK pipeline population.

7.0 References

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Appendix 1: Glossary

UKOPA - United Kingdom Onshore Pipeline Operators Association is an industry association formed to co-ordinate industry best practice with respect to safe operation and integrity management of pipelines. This organisation has a long term strategic goal to achieve consistency in pipeline risk assessment with respect to models, methods assumptions and data, specifically with respect to risk based land use planning zones. UKOPA is currently progressing risk assessment supplements to the onshore pipeline codes IGE/TD/1 and PD 8010 Part 1. UKOPA membership comprises in the UK: National Grid, Shell, BP, Sabic UK Petrochemicals, Esso, Ineos, Total UK, BPA, OPA, Northern Gas Networks, Scotia Gas Network, Wales and West Utilities, BG Group, Eon UK, Unipen, Centrica.

EPRG - European Pipeline Research Group is a cooperation of European pipe manufacturers and gas transmission companies. EPRG undertakes a wide range of research directed to increased integrity and safety of gas transmission pipelines, and provides authoritative guidance to members and publishes the results of its research widely. EPRG membership comprises 18 member companies, 9 gas transmission and 9 pipe manufacturing companies, from 8 European countries.

FFREQ - methodology for the prediction of pipeline failure probability due to 3rd party interference damage. It combines historical UK gas industry data on the frequency and severity of damage (using Weibull distributions for the gouge and dent damage parameters) with a structural model that determines the severity of damage required to cause failure of a specific pipeline. This method allows the influence of the main pipeline parameters (diameter, wall thickness, grade and toughness) on failure probability to be quantified.

PIE Model – Reconstruction of the FFREQ methodology using the original dent-gouge failure model and dent and gouge damage probability distributions derived from operational data recorded in the UKOPA database.
PDAM - Pipeline Damage Assessment Manual – comprehensive manual developed as a joint industry project sponsored by sixteen major oil and gas companies. The manual provides a critical and authoritative review of available pipeline defect assessment models and methods, reports comparisons with empirical data and gives recommendations for the best current method for each type of damage.

PIPESAFE – knowledge-based, integrated software package for risk assessment of gas transmission pipelines, originally developed in 1994 by an international collaboration of a number of gas transmission companies, and since then has been developed and enhanced in a number of key phases. The software package allows risk assessments to be carried out following different methodologies, depending on company practices and/or the regulatory

environment in which the pipeline is operated, and provides the user with substantial flexibility and freedom to select different rules and procedures.

Appendix 2: Pipeline Failure Model and Methodology for Prediction of Probability of Failure due to 3rd Party Interference

British Gas Failure Model

The original work to develop a method for the prediction of failure frequencies due to 3rd party interference was carried out for British Gas at the Engineering Research Station, Killingworth in the mid 1980s. This section details the fracture mechanics equations used in the modelling of the failure state of a specific pipeline to 2-dimensional (infinitely long) dent-gouge damage in this model[1].

The depth of gouge required to cause failure for a particular pipeline geometry and known operating conditions can be obtained by rearranging the gouge failure equation

$$d = t\left[\frac{1.15 - \sigma_f / \sigma_{SMYS}}{1.15 - \sigma_f / M\sigma_{SMYS}}\right] \quad (1)$$

Where

d	=	defect depth
t	=	wall thickness
σ_f	=	failure stress
σ_{SMYS}	=	specified minimum yield stress of pipeline material
M	=	Folias factor.

For the purposes of this study the Folias factor is defined as

$$M = \sqrt{1 + 0.26\left(\frac{2c}{\sqrt{Rt}}\right)^2} \quad (2)$$

Where

2c	=	gouge length
R	=	pipeline radius

By defining a leak/rupture limit to the Folias factor

$$M_{crit} = 1.15\sigma_{SMYS} / \sigma_f \quad (3)$$

[1] Note, the equations in this section are taken directly from the original British Gas references [5-10] and are given in imperial units.

And substituting in to the original Folias factor definition the critical length of the gouge can be determined

$$L_{crit} = \left[\left(1.3225\left[\frac{\sigma_{SMYS}}{\sigma_f}\right]^2 - 1\right)3.846Rt\right]^{1/2} \qquad (4)$$

Gouges of length L_{crit} or larger will rupture, shorter gouges will leak[2]. This is used to determine the differences between leak failure frequencies and rupture failure frequencies.

It has been shown that the failure stress of a pipeline incorporating a dent/gouge combination of known geometry can be predicted with reasonable accuracy from:

$$\frac{\sigma_f}{\bar{\sigma}} = \frac{2}{\pi}\cos^{-1}\left[\exp-\left(\frac{1.5\pi E}{\bar{\sigma}^2 Ad}\left[Y_1\left(1-1.8\left[\frac{D}{2R}\right]\right)+Y_2\left(10.2\frac{R}{t}\left[\frac{D}{2R}\right]\right)\right]^{-2}\exp\left[\frac{\ln(C_v)-1.9}{0.57}\right]\right)\right] \qquad (5)$$

Where:

E	=	elastic modulus of pipeline material
A	=	0.083
d	=	gouge depth
D	=	dent depth
C_v	=	Charpy energy (measured using 2/3 specimen)

All other factors are as above
$\bar{\sigma}$ is the flow stress, a measure of the resistance of the material to plastic collapse and is defined as:

$$\bar{\sigma} = 1.15\sigma_{SMYS}\left(1-\left(\frac{d}{t}\right)\right) \qquad (6)$$

Y_1 and Y_2 are defined as follows:

$$Y_1 = 1.12 - 0.23\left(\frac{d}{t}\right) + 10.6\left(\frac{d}{t}\right)^2 - 21.7\left(\frac{d}{t}\right)^3 + 30.4\left(\frac{d}{t}\right)^4$$
$$Y_2 = 1.12 - 1.39\left(\frac{d}{t}\right) + 7.32\left(\frac{d}{t}\right)^2 - 13.1\left(\frac{d}{t}\right)^3 + 14.0\left(\frac{d}{t}\right)^4 \qquad (7, 8)$$

[2] Note: risk analysis consequence models require interpretation of critical gouge length in terms of hole size.

The size of dent required to cause failure with a particular gouge can be obtained by re-arranging equation (5):

$$D/2R = \frac{\left[\dfrac{\exp\left(\dfrac{\ln[C_v]-1.9}{0.57}\right)}{\ln\left(\sec\left[\dfrac{\pi\sigma_f}{2\bar{\sigma}}\right]\right)\left(\dfrac{\bar{\sigma}^2 Ad}{1.5\pi E}\right)Y_1^2}\right]^{1/2} - 1}{10.2\left(\dfrac{Y_2}{Y_1}\right)\left(\dfrac{R}{t}\right) - 1.8} \qquad (9)$$

Equation (5) is semi-empirical based on multiple regression of the $(\ln[C_v]-1.9)/0.57$ term. The subject of the equation has been changed from σ_f/σ_{SMYS} in equation (5) to D/2R and hence it is necessary to perform a new regression for the new subject. This procedure results in the constants 1.9 and 0.57 being replaced by 2.049 and 0.534 respectively [5]

A more detailed discussion of this model and the parameters which influence predictions is given by Cosham and Hopkins [2].

Methodology for prediction of the likelihood of occurrence of dent-gouge damage

The methodology developed for the prediction of the likelihood of occurrence of the dent-gouge damage which results in failure for the specified pipeline conditions is summarised in this section. This methodology is reconstructed from the original work undertaken by the British Gas Engineering Research Station [5,6,7,8,9,10].

Weibull Probability Curves

The methodology for the prediction of the likelihood of occurrence of the dent-gouge damage is a probabilistic model making use of Weibull probability distributions specific to the dimensions of the dent-gouge damage to give the probabilities of the damage occurring.

Cumulative probability distribution curves were produced for i) gouge length, ii) gouge depth and iii) dent depth. In each case the cumulative probability relates to the probability of occurrence for a specified size of damage or greater.

The cumulative probabilities shown with fitted Weibull probability distributions are given in Figures A1 – A3 below. In all cases, operational damage data has been interpreted conservatively, i.e. the worst case damage dimensions recorded for each incident are assumed, based on using the gouge depth as the overall selection parameter.

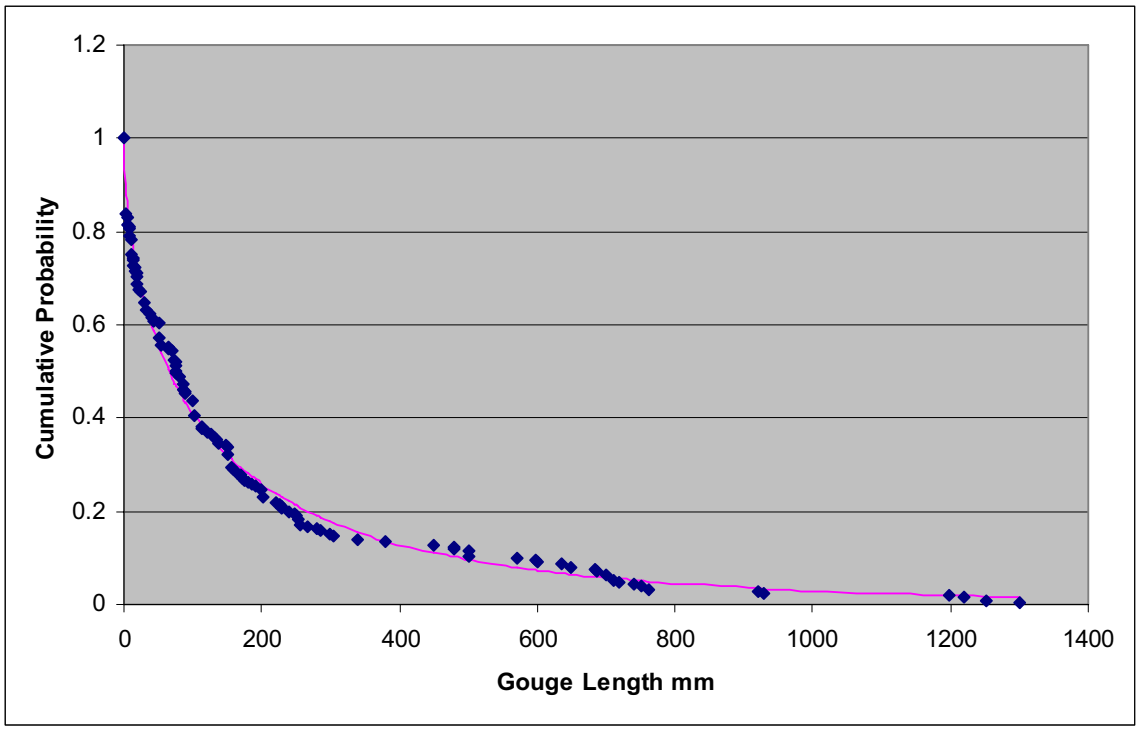


Figure A1 – Cumulative Probability of Gouge Length L or Greater

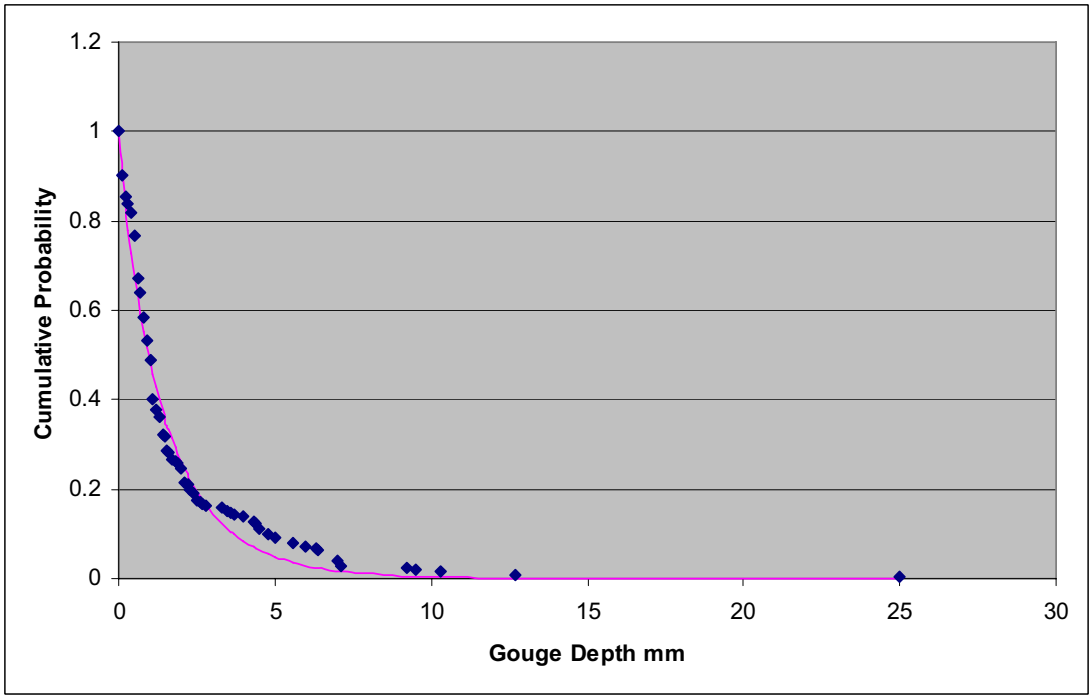


Figure A2 – Cumulative Probability of Gouge Depth D or Greater

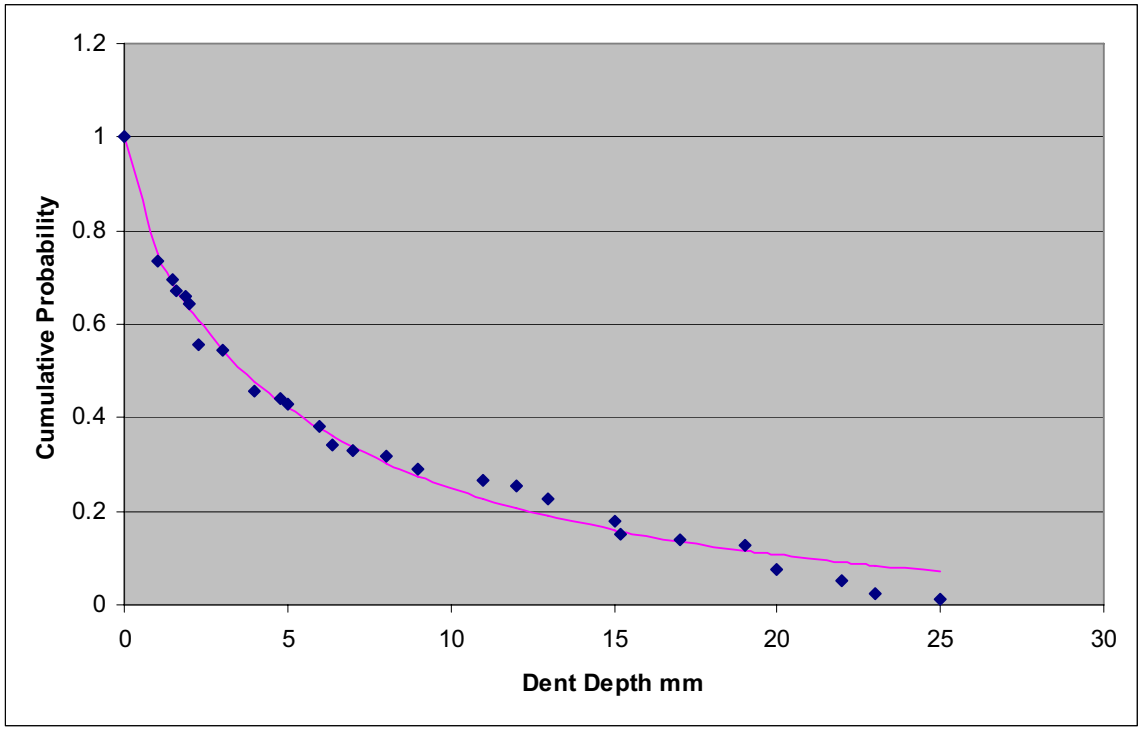


Figure A3 – Cumulative Probability of Dent Depth D or Greater

Likelihood Methodology

The method for the calculation of the likelihood of occurrence of the dent-gouge damage which results in failure for specified pipeline conditions using the above cumulative probability curves for gouge length (Figure A1), gouge depth (Figure A2) and dent depth (Figure A3) and it's use in conjunction with a dent-gouge failure model in the prediction of pipeline failure frequencies is briefly summarised below.

For given pipeline parameters (diameter, wall thickness, pressure) use a defined (published) engineering equation for a dent-gouge model to calculate the critical defect length L_c for rupture.

Assume that gouges of length L >= L_{crit} will rupture, gouges of length L< L_{crit} will leak.

Determine the probability of occurrence $P(L_{crit})$ of a gouge of length L_{crit} from Figure A1.

Obtain the probability of occurrence $P(d_{wt})$ a gouge of depth d = wt from Figure A2, and calculate the probability of failure as:

$PoF = P(L_{crit})*P(d_{wt})$

This value is the start of the PoF Sum for leaks.

Divide the gouge length between 0 – L_{crit} into increments, L_{crit}/N_i
Calculate the mean length L_i and incremental probability $dP(L_i)$for the current increment from Figure 2.

Calculate d_{crit} at L_i using a dent-gouge model.

Determine the probability of occurrence $P(d_{crit})$ of a gouge of depth d_{crit} from Figure A2, and calculate the probability of failure as:

$PoF = P(d_{crit})*dP(L_i)$

Add this to the PoF Sum for leaks.

Divide the gouge depth cumulative probability curve into a number j, of gouge depths, d. For each gouge depth d_j, determine the probability of occurrence $dP(d_j)$ from the Figure A2 and calculate the depth of dent Dc_j using the dent-gouge model which would cause failure in combination with this gouge depth using a failure equation/limit state.

Determine the probability of occurrence P_{Dcj} of dent depth Dc_j from Figure A3

Calculate the probability of failure as:

$PoF = P(Dc_j)*dP(d_j)*dP(L_i)$

Add this to the PoF Sum for leaks.

Repeat steps iii)-x) for each gouge length increment up to L_{crit} and add all the PoF sums to obtain the leak probability.

To obtain the rupture probability, repeat steps iii) – xi) using gouge length increments between L_c and L_{max}.

Obtain the total probability of failure by adding the leak and rupture probabilities.

Calculate the failure frequency using the calculated total PoF and the incident rate (the incident rate calculated from current data is $8.49x10^{-4}$ per kmyear)

FF = Incident Rate x PoF

Weibull Distribution

The most significant factor in the failure frequency prediction methodology is the use of probability distributions to obtain occurrence probabilities. The probability distributions used in this case are Weibull distributions which are fitted to the filtered operational damage data recorded in the UKOPA 2004 fault database [11]. The process of fitting the Weibull curves is detailed below.

Weibull Definition

The standard Weibull distribution is defined as:

$$f(x) = abx^{b-1}\exp\left(-ax^{b}\right) \qquad \begin{array}{l} x \geq 0 \\ a,b \geq 0 \end{array}$$

$$F(x) = 1 - \exp(-ax^{b})$$

$$R(x) = 1 - F(x)$$

Where

f(x)	=	density function
	=	probability of a gouge depth x
F(x)	=	distribution function
	=	probability of a gouge depth less than or equal to x
R(x)	=	risk function, 1-F(x)
1-F(x)	=	probability of a gouge greater than x

Fitting Weibull Curves

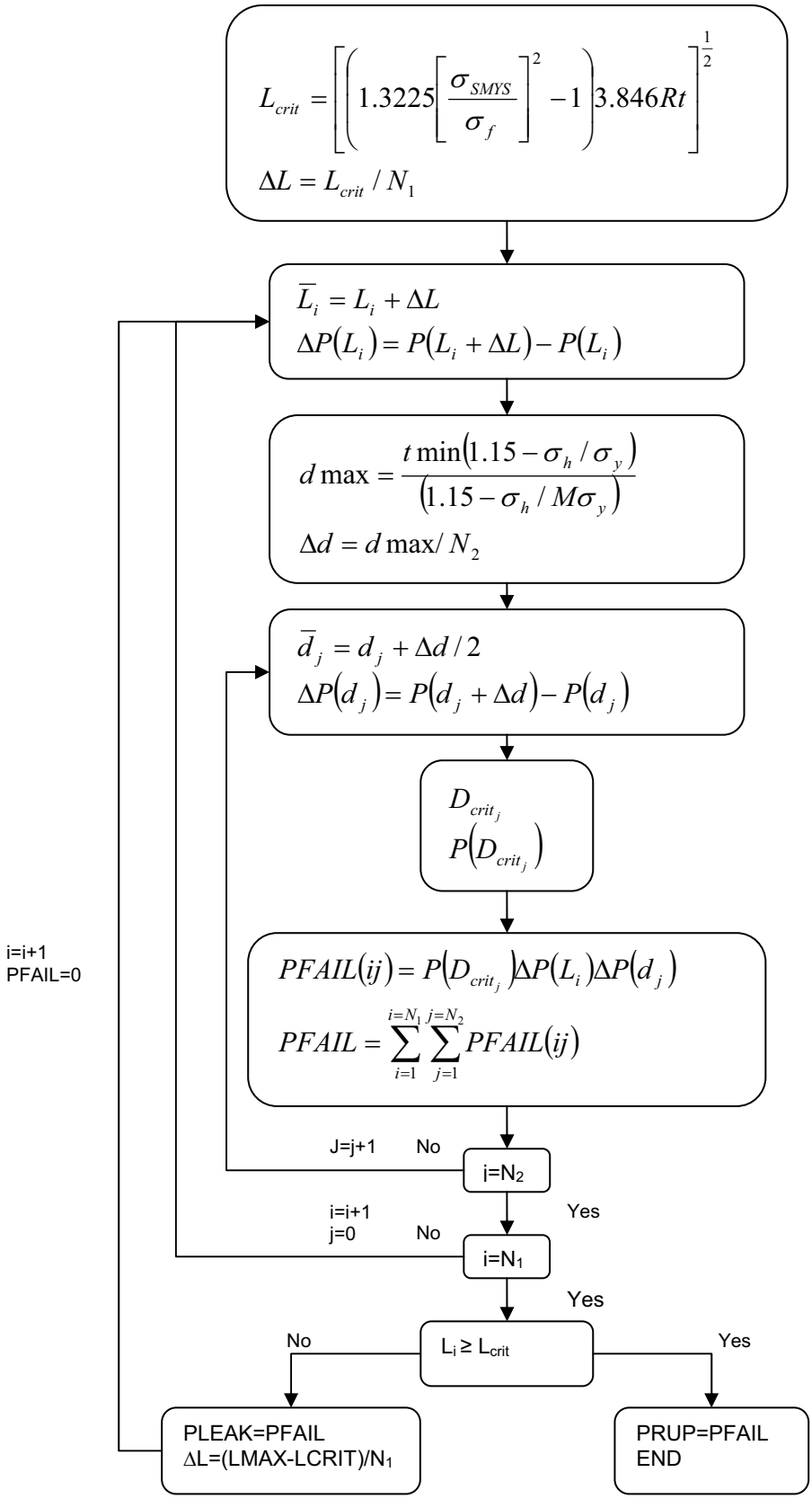
Weibull curves were fitted via the determination of two unknowns in the Weibull equation. The Weibull parameters were fitted using a generalised nonlinear regression function in the maths solution software Mathcad.

The values produced by Mathcad for the three required curves are shown in Table A1

Table A1. Weibull Fit Parameters

Parameter	A	β
Gouge Length Weibull	0.6	120.851
Gouge Depth Weibull	0.889	1.442
Dent Depth Weibull	0.69	6.202

Appendix 3: Flow Diagram for Failure Frequency Prediction Methodology using PIE Model


$L_{crit} = \left[\left(1.3225\left[\frac{\sigma_{SMYS}}{\sigma_f}\right]^2 - 1\right)3.846Rt\right]^{\frac{1}{2}}$
$\Delta L = L_{crit} / N_1$
$\overline{L}_i = L_i + \Delta L$
$\Delta P(L_i) = P(L_i + \Delta L) - P(L_i)$
$d\max = \frac{t\min(1.15 - \sigma_h / \sigma_y)}{(1.15 - \sigma_h / M\sigma_y)}$
$\Delta d = d\max / N_2$
$\overline{d}_j = d_j + \Delta d / 2$
$\Delta P(d_j) = P(d_j + \Delta d) - P(d_j)$
D_{crit_j}
$P(D_{crit_j})$
$PFAIL(ij) = P(D_{crit_j})\Delta P(L_i)\Delta P(d_j)$
$PFAIL = \sum_{i=1}^{i=N_1}\sum_{j=1}^{j=N_2} PFAIL(ij)$
i=i+1
PFAIL=0
J=j+1
No
i=N2
Yes
i=i+1
j=0
No
i=N1
Yes
No
Li ≥ Lcrit
Yes
PLEAK=PFAIL
ΔL=(LMAX-LCRIT)/N1
PRUP=PFAIL
END

Appendix 4: Summary of 3rd Party Interference Failure Frequency Models Applied to Corrib Pipeline

Methodology	Probability of Damage	Structural modelling of through-wall failure	Probability of failure due to i) leaks and ii) ruptures	Failure Frequency
J P Kenny	Gouge depth & length parameters as published by BG Technology for UK gas industry (Gouge depth - Weibull distribution, length – offset logistic) Dent force calculated using dent-force relationship published by Corder and Chatain using correlation with excavator mass from US JIP	EPRG published version of the original dent-gouge failure model developed by the UK gas industry	Probability calculations carried out using Monte Carlo simulation taking into account probability distributions for wall thickness, yield strength and fracture toughness as well as damage dimensions (dent depth, gouge length and depth).	Probability of failure x 3rd party damage incident rate published in BG Technology technical paper on structural reliability modelling applied to pipeline uprating
Advantica	Gouge depth and length parameters as above, Dent-force – Weibull distribution based on dent force calculated for gas industry dent data.	Dent-gouge model updated to include Alignment with latest R6 defect assessment procedures, dent residual stress and microcrack in gouge.	Probability calculations carried out using structural reliability analysis, taking into account probability distributions for wall thickness, yield strength and fracture toughness as well as damage dimensions (dent depth, gouge length and depth).	Assume - Probability of failure x 3rd party damage incident rate from gas industry data
PIE Model	Weibull distributions for gouge depth and length and dent depth from UKOPA database	EPRG published version of the original dent-gouge failure model developed by the UK gas industry	Probability calculations consider damage dimensions (dent depth, gouge length and depth) only, nominal wall thickness assumed, specified minimum yield stress and lower bound Charpy energy. Rupture probability calculated from the cumulative probability of a gouge length equal to or exceeding the critical defect length.	Probability of failure x 3rd party damage incident rate from UKOPA database

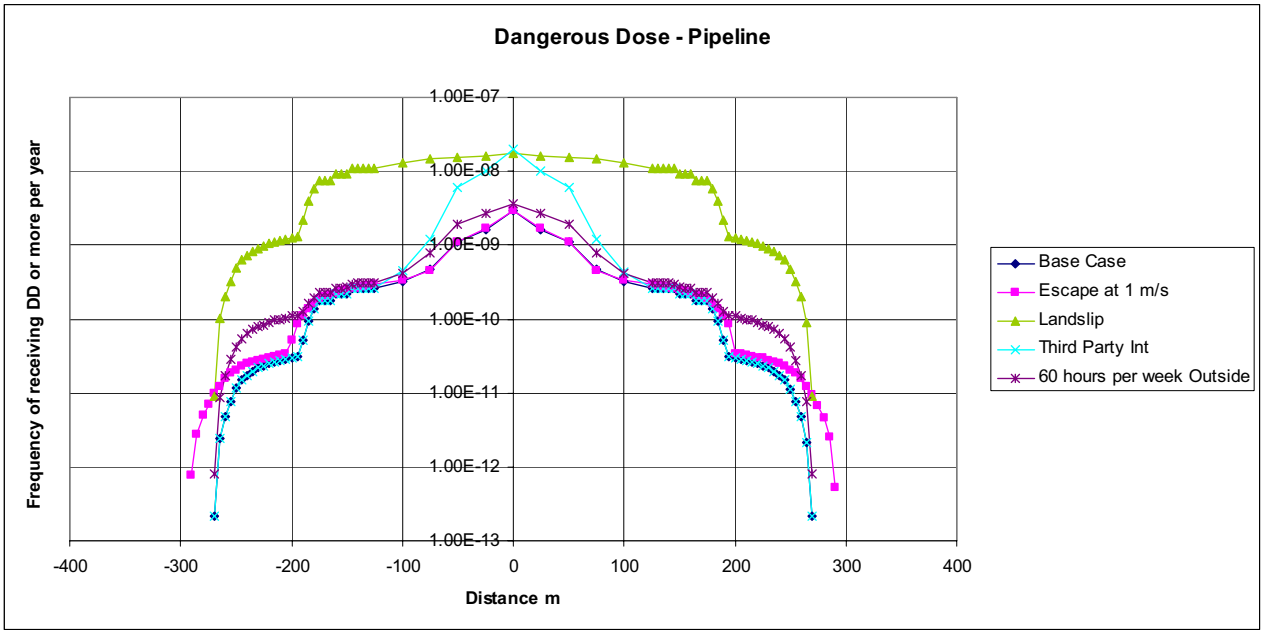
ATTACHMENT
B

SENSITIVITY PREDICTIONS

- o0o -

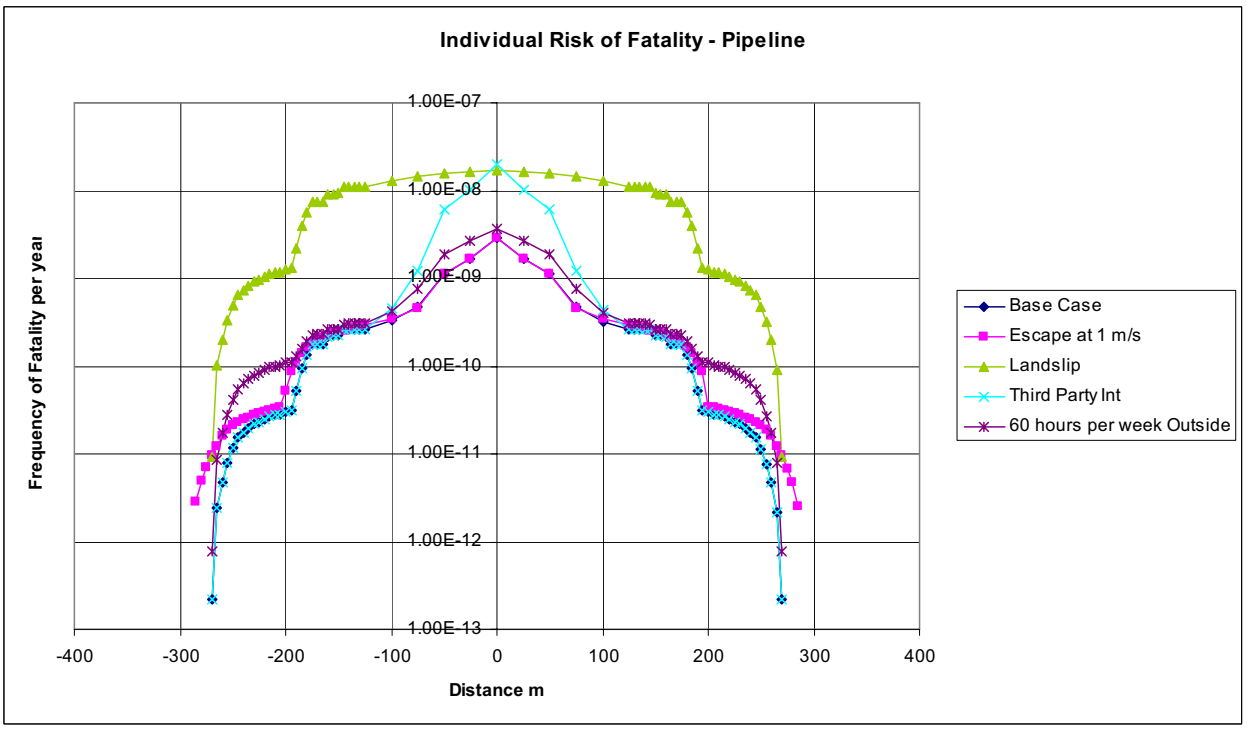
The predictions for the sensitivity studies detailed in Table 14 are given below.

Figure 16: Sensitivities for the Pipeline (Individual Risk of a Dangerous Dose)



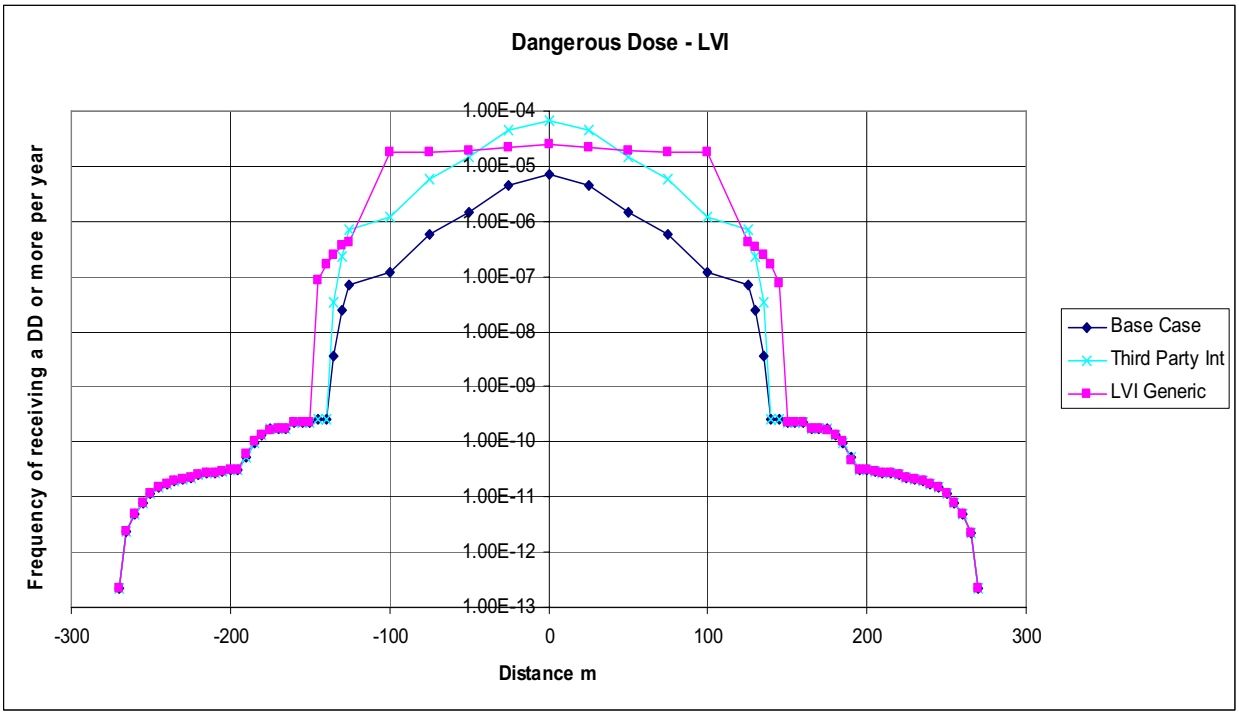
NewPipelinePreds/Summary

Figure 17: Sensitivities for the Pipeline (Individual Risk of Fatality)



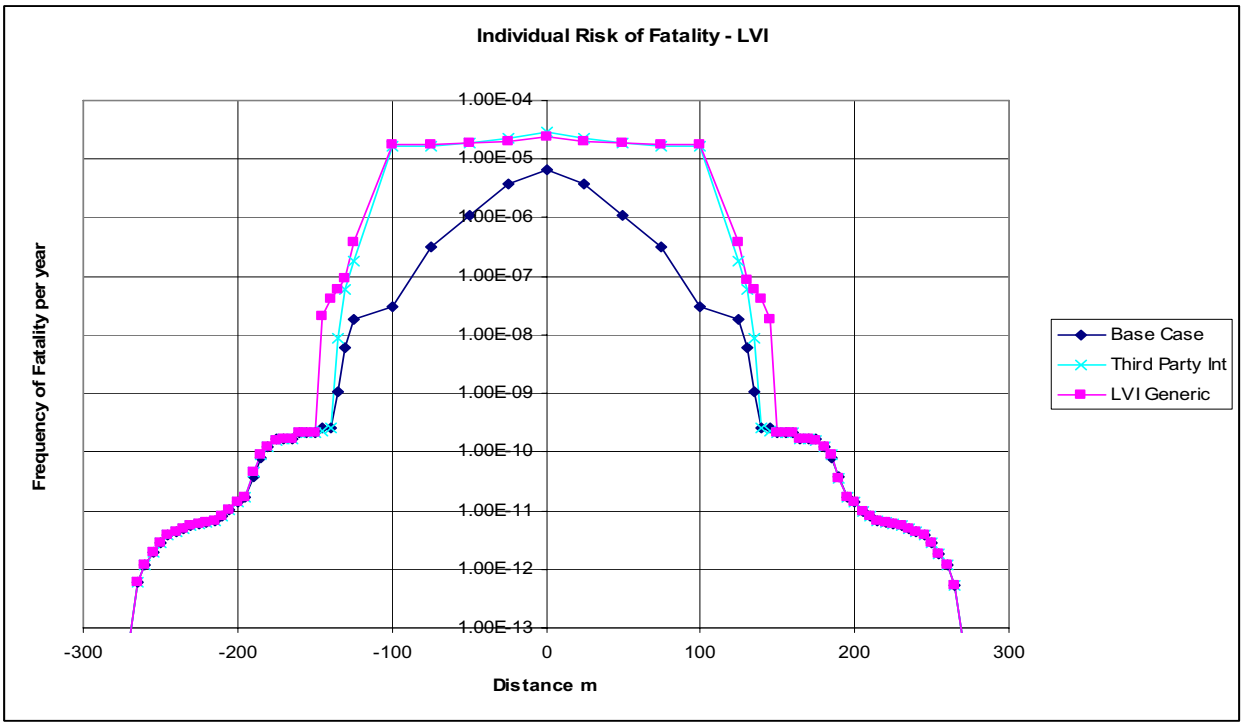
NewPipelinePreds/Summary

Figure 18: Sensitivities for the LVI (Individual Risk of a Dangerous Dose)



NewPipelinePreds/Summary

Figure 19: Sensitivities for the LVI (Individual Risk of Fatality)



NewPipelinePreds/Summary

Table 20: Sensitivity Predictions (Individual Risk of Fatality)

Description	Individual Risk of fatality at the pipeline (per year)	Individual Risk of fatality at 246m from the pipeline (per year)		Individual Risk of fatality at the LVI (per year)	Distance to a risk of fatality of 3E-07 per year (m)
Base Case	2.18E-09	3.80E-12	Base Case	6.53E-06	76
Moving away at 1 m/s	2.19E-09	5.73E-12	LVI Generic	2.47E-05	125
Landslip	3.84E-09	1.60E-10	Third Party Intentional Damage	2.92E-05	125
Third Party Intentional Damage	3.95E-09	3.80E-12			

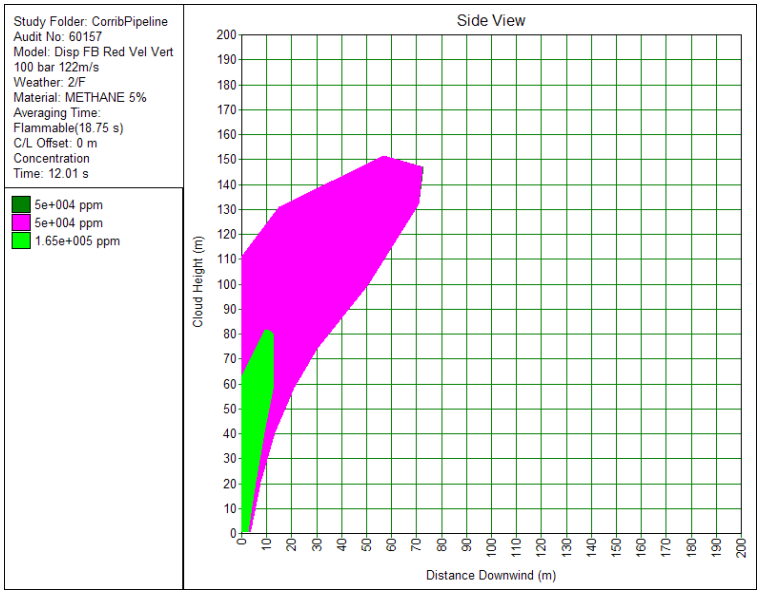
NewPipelinePreds/Summary

ATTACHMENT C

GAS DISPERSION PREDICTIONS

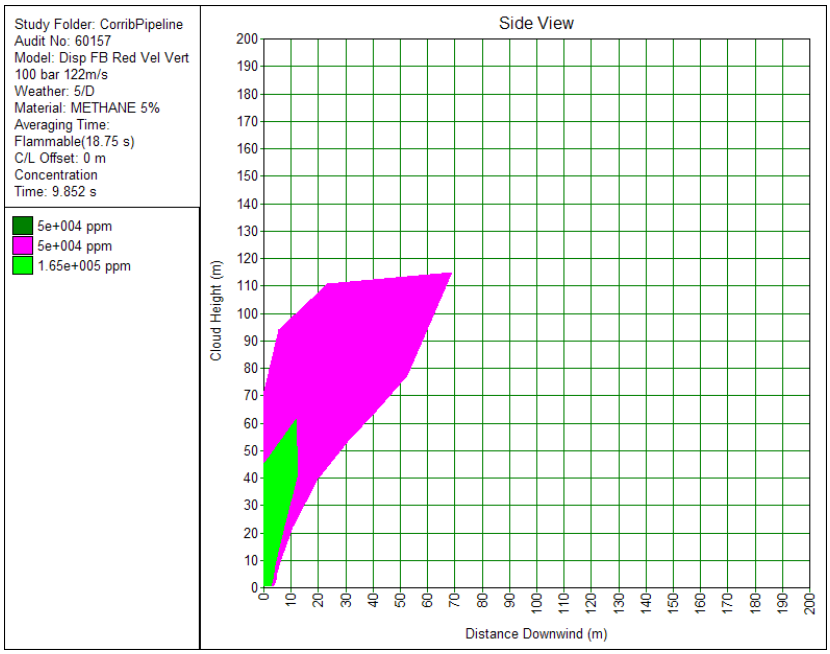
- o0o -

Figure 20: Gas Dispersion for Full Bore Release Weather F Stability Wind Speed 2 m/s



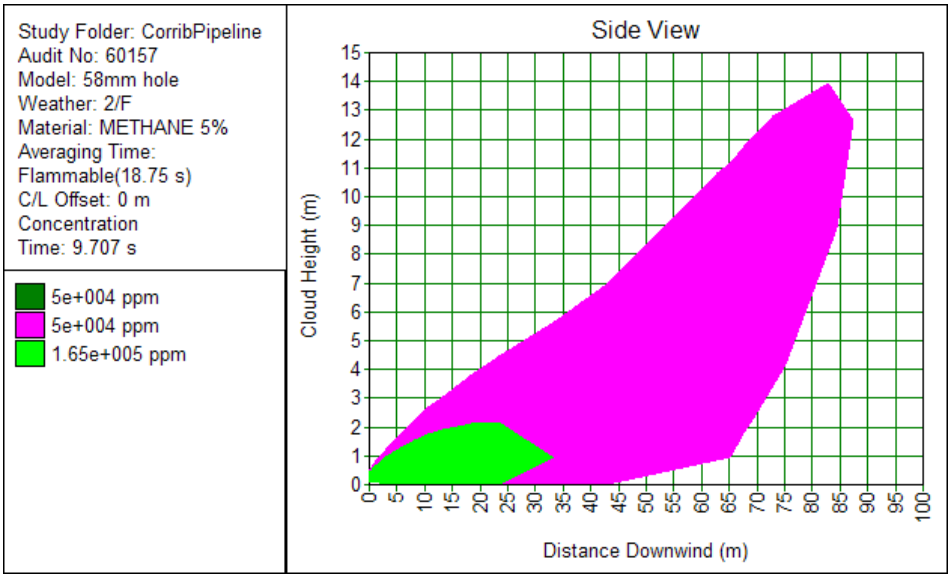
Note. The pink area shows the part of the gas/air cloud that is in the flammable region. F stability represents stable conditions.

Figure 21: Gas Dispersion for Full Bore Release Weather D Stability Wind Speed 5 m/s



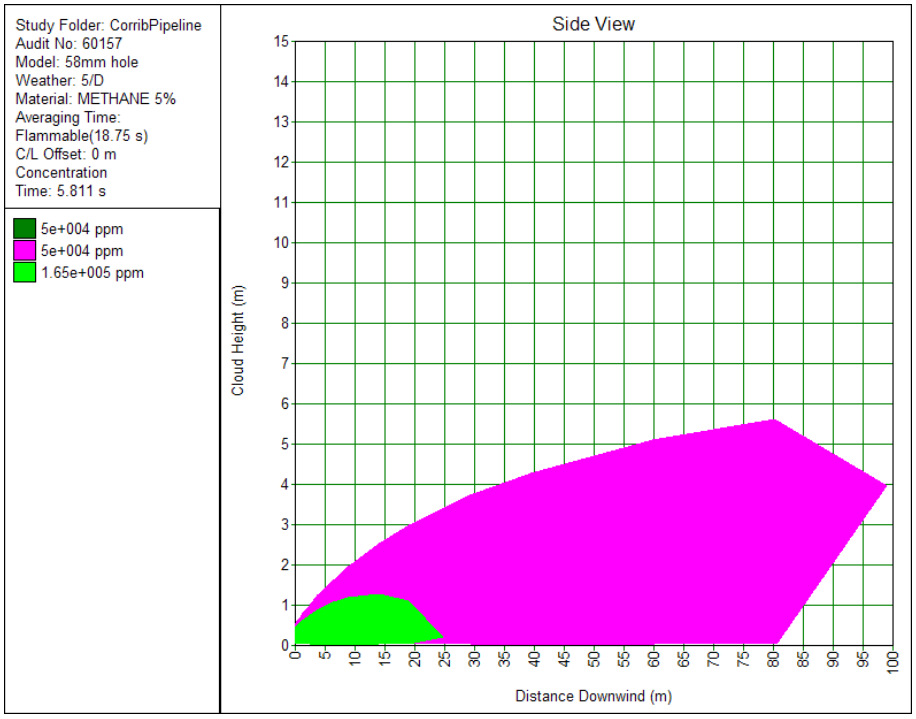
Note. The pink area shows the part of the gas/air cloud that is in the flammable region. D stability represents neutral conditions.

Figure 22: Gas Dispersion from a hole in the pipeline directed horizontally in Weather F Stability Wind Speed 2 m/s



Note. The pink area shows the part of the gas/air cloud that is in the flammable region. F stability represents stable conditions.

Figure 23: Gas Dispersion from a hole in the pipeline directed horizontally in Weather D Stability Wind Speed 5 m/s



Note. The pink area shows the part of the gas/air cloud that is in the flammable region. D stability represents neutral conditions.

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CORRIB GAS FIELD DEVELOPMENT PROJECT

Corrib
natural gas

Q6.5(i) – Response To An Bord Pleanála Regarding The Query Raised In Section 3b of Letter Dated 2nd November 2009

DOCUMENT No: COR-14-SH-077

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1 BACKGROUND

The key paragraphs extracted from letters received from An Bord Pleanála following the 2009 Oral Hearing are reproduced here to enable ready reference to the context of the request to address what An Bord Pleanála designate as 'appropriate hazard distance'.

In the letter received from An Bord Pleanála dated 2nd November 2009 it was stated:

> "[…..the Board should, therefore,] adopt a standard for the Corrib upstream untreated gas pipeline that the routing distance for proximity to a dwelling shall not be less than the appropriate hazard distance for the pipeline in the event of a pipeline failure. The appropriate hazard distance shall be calculated for the specific pipeline proposed such that a person at that distance from the pipeline would be safe in the event of a failure of the pipeline".

An Bord Pleanála's letter of 29th January 2010 in response to SEPIL's request for clarification stated:

> "..it is the intent of An Bord Pleanála to ensure that persons standing beside the dwellings will not receive a dangerous dose of thermal radiation in the worst case scenario of "full-bore rupture" of the pipeline at maximum pressure".

This document addresses the above request from An Bord Pleanála.

2 INTRODUCTION

An Bord Pleanála has requested pipeline safety to be demonstrated through a combination of a risk-based approach and an approach based on an analysis of the consequences of a full-bore rupture without taking the probability of failure into account. It is noted that subsequent to An Bord Pleanála's request the Petroleum Exploration and Extraction Safety Bill has passed into law and the control and auditing of pipeline safety now enshrined in this legislation is risk based and not consequence based.

This document describes the detailed analysis of the consequences arising from an ignited full-bore rupture and demonstrates that An Bord Pleanála's request "to ensure that persons standing beside the dwellings will not receive a dangerous dose of thermal radiation in the worst case scenario of full-bore rupture of the pipeline at maximum pressure" has been achieved.

To address the concerns expressed by An Bord Pleanála with respect to the consequences of pipeline failure the pipeline has been re-routed in Sruwaddacon Bay (and installed underwater within a tunnel beneath the Bay) such that it is as far from existing occupied dwellings as is technically practical. Furthermore the Maximum Allowable Operating Pressure (MAOP) is now set at 100 barg.

The likelihood of a full-bore rupture is, in SEPIL's view, negligible.

2.1 CONCLUSION OF THIS ANALYSIS

In response to An Bord Pleanála's request it is demonstrated that persons standing beside existing occupied dwellings will not receive a dangerous dose of thermal radiation associated with an immediately ignited full-bore rupture of the Corrib pipeline.

In providing this demonstration a solely consequence based analysis has been made with no account being taken of the probability of a full-bore rupture occurring, the probability of ignition, and probability of persons being outdoors exposed to the effects.

As a consequence based safety assessment as requested by An Bord Pleanála is not a designated Code requirement it is necessary to make assumptions and define parameters when establishing the scenarios on which to base the analysis. These are described within this document.

Key conclusions from this analysis of consequences are shown in Table 1, and are summarised as:

For the worst conceivable full-bore rupture scenario and assuming immediate ignition, then:

- No person standing beside an existing normally occupied dwelling would receive a fatal level of thermal flux
- A person standing 'beside' the nearest dwelling would be able to reach the shelter of that dwelling without receiving a dangerous dose of thermal radiation.
- All existing normally occupied dwellings provide safe shelter in that none would spontaneously catch fire or catch fire at a later stage.

A summary of key predictions from the calculations made is presented in Table 1.

Table 1: Summary of Key Predictions

Parameter	Criteria	Determining Case	Outcome
Distance of nearest dwelling from pipeline		234m	
Distance from pipeline that spontaneous ignition may occur, Building Burn Distance, BBD	UK HSE	180m	All dwellings are outside BBD
Dangerous dose received when a person is moving to the nearby dwelling as shelter			
Person standing still for 5s then moving 5m at 2.5m/s	1,000tdu	580 tdu	Criteria not exceeded for base cases
Person standing still for 5s then moving 5m at 1m/s	1,000tdu	830 tdu	
Maximum distance from the dwelling a person could stand without exceeding dangerous dose			
Person standing still for 5s then maximum distance moving at 2.5m/s	1,000tdu	17 m	
Person standing still for 5s then maximum distance moving at 1m/s	1,000tdu	7 m	
Distance from pipeline that the delayed induced ignition of a building may occur, Piloted Ignition Distance, PID	UK HSE	205 m	All dwellings outside PID
Distance from pipeline that a person beside a building will not see a thermal flux in excess of 31.5 kW/m^2	VROM (35kW/m^2 less 10%)	216m	All dwellings outside this distance

It can be concluded from the above consequence predictions that the pipeline design significantly exceeds Code requirements for public safety.

The predicted consequence effect distances (rationalised to take account of different dwelling elevations) are plotted for the full length of the pipeline (Attachment A) together with examples of building proximity distances as per applicable design Codes (see Appendix Q6.2).

3 INTERPRETATION OF AN BORD PLEANÁLA'S REQUEST

3.1 INTERPRETATION OF AN BORD PLEANÁLA'S LETTER

As An Bord Pleanála's request does not relate to a defined Code requirement it is necessary to define the approach and key assumptions used in SEPIL's response; this is outlined as follows:

- 'Maximum pressure' is taken as Maximum Allowable Operating Pressure, MAOP which is 100barg downstream of the Land Valve Installation, LVI, and 150barg upstream.
- Consequence models are those used for the QRA (see Appendix Q6.4, sub-section 6.1).
- The safety of persons beside dwellings is demonstrated for the nearest dwellings to the pipeline and to the LVI (for releases upstream of the LVI) on the basis that persons beside dwellings further away would also be safe.
- It is assumed that persons standing beside dwellings would, after taking a short time to react, move directly to the dwelling to seek shelter from the heat radiated
- It is demonstrated that all dwellings provide safe shelter
- It is demonstrated that when persons beside the dwelling moves to that dwelling the initial intensity of the fireball does not prove fatal and in moving to the dwelling they do not receive a 'dangerous dose of radiated heat'.

Subsequent sections of this document detail this approach, define the assumptions and parameters adopted, and present the outcome of the analysis.

4 BASIS OF CONSEQUENCE ANALYSIS

This Section identifies and describes the basic principles and parameters adopted in order to reply to An Bord Pleanála's request.

4.1 EVENT SCENARIO

4.1.1 Scenario Overview

For the analysis of a full-bore rupture it is assumed that gas is released from the two open ends of the pipeline. The initial release would rapidly mix with air and create a rising vapour cloud that, if immediately ignited, becomes a fireball burning back to a crater fire. (If ignition is delayed beyond the initial release (greater than 15 seconds) this would result in a short-lived fire burning back to a crater fire). The crater fire would diminish over time as the pressure in the pipeline declines.

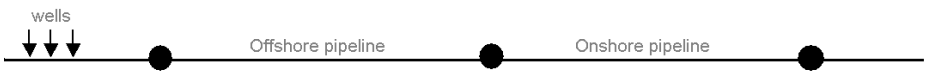
In the analysis of a full-bore rupture it is assumed that the gas is immediately ignited whereas, in reality, this would not always be the case and, indeed, for the section of pipeline in the tunnel under Sruwaddacon bay an ignition source cannot be present

4.1.2 Release Conditions

4.1.2.1 Maximum Pressure

For over 95% of the time during the first years of operation the pipeline will generally operate within the Normal Operating Pressure Profile shown in Figure 4.1. 4 - 7 years after start-up, depending on reservoir depletion, pipeline operating pressures will be reduced by some 30%, also at a reduced gas throughput.

The sub-sea wells are equipped with isolation valves designed to automatically shut such that 150 barg (MAOP upstream of LVI) is not exceeded. Similarly the onshore LVI is equipped with isolation valves that will automatically shut such that the MAOP downstream of the LVI of 100 barg is not exceeded. The pressure regimes are shown in Figure 4.1.



Pressure Profile	Manifold	LVI	Terminal
Normal Operating Pressure Profile	117 - 122 barg	85 - 90 barg	80 - 85 barg
Lower Operating Pressure	73 barg	58 barg	55 barg

Fig. 4.1: Corrib Pipeline Pressure Regimes

Based on the above the 'maximum pressure' as stated in An Bord Pleanála's letter of 29th January 2010 that are applied to determine the consequences of an immediately ignited full-bore release are:

- Offshore MAOP of 150 barg maximum pressure upstream of the LVI
- Onshore MAOP of 100 barg maximum pressure downstream of the LVI.

4.2 CONSEQUENCE ANALYSIS

The consequences are assessed based on the steps taken shown in Figure 4.2.

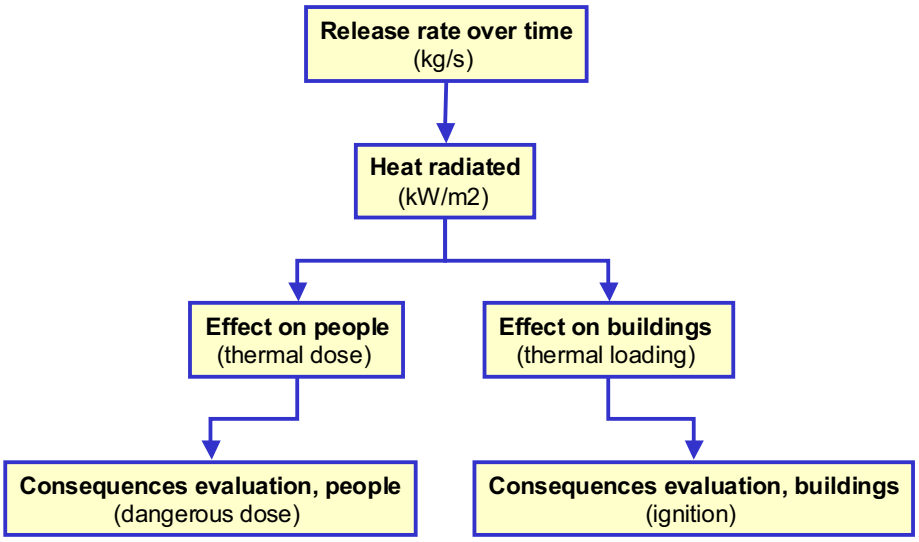


Fig. 4.2: Consequence Assessment

4.2.1 Release Rate

The two worst release cases are:

Release Case 1:	A full-bore rupture assumed to be immediately upstream of the LVI at maximum pressure of 150barg.
Release Case 2:	A full-bore rupture assumed to take place anywhere downstream of the LVI just before the LVI closes. The maximum pressure applied for this case is the MAOP of 100barg (although the LVI valves would close at 99barg and settle out pressure would be less than 99barg).

Release Case 1, Upstream of the LVI at 150barg: The LVI must be closed for the upstream MAOP of 150 barg to be reached. Any rupture that would occur upstream of, and close to, the LVI at 150 barg would therefore release gas from the 83km of pipeline upstream of the rupture and the relatively small inventory of, say, 50m of pipeline between the rupture and the closed LVI. For this Case therefore, only the release from the upstream open end of the rupture is modelled.

Release Case 2: Downstream of the LVI at 100barg: A full-bore failure when the pipeline is approaching the downstream MAOP would release gas from the full length of the pipeline through both open ends of the rupture as the LVI would be open at the time of the rupture. The energy that would be released during a full-bore rupture would most probably destroy any signal cables, umbilicals etc. routed alongside the pipeline; the resultant cessation of the signal from the Bellanaboy Bridge Gas Terminal would cause the safety shutdown valves at the LVI to automatically close. Full closure would take some 12 seconds and, whilst this would not significantly reduce the fireball size or duration, it would significantly reduce the intensity and duration of the subsequent crater fire. No credit has been taken for this in the calculation of consequence distance.

The predicted release rate calculated for Case 2 is greater than that for Case 1, nevertheless the predictions from both Cases have been presented.

4.2.2 Heat Radiated

Consequence modelling of the physical effects arising from a full-bore release is carried out through the use of the DNV models as used in the QRA (see Appendix Q6.4).

It is conservatively assumed that the effects of the full-bore release from the section of the pipeline under Sruwaddacon Bay will be equivalent to those of the trenched pipeline.

Elevation is taken into account within the model as the degree of exposure to thermal radiation, which is a function of the area of the fireball being seen, increases with height. .

It is assumed that a wind of 5m/s would always be blowing from the rupture location towards the dwelling.

The model shows that the fireball provides the dominant contribution to heat radiated; the crater fire is less intense.

4.2.3 Consequential Effect Analysis

The basic premise adopted is that the "persons standing beside the dwellings" would move directly to the dwelling and take shelter such that:

1. The initial intensity of the fireball does not prove fatal.

2. When moving to the dwelling the persons do not receive a dangerous dose of radiated heat.

3. When sheltering behind or within the dwelling the building itself provides safe shelter (i.e. it does not catch fire before it is safe for persons to move away from the building).

It is assumed for the base case analysis that 'persons standing beside the dwellings' are standing 5m from the dwelling (i.e. they have to move 5m to reach shelter) and would move at 2.5m/s. It is also assumed for the base case that persons would take 5 seconds to react before moving to shelter. A sensitivity analysis is made applying 1m/s speed of movement and 5 seconds reaction time. For both the analyses based on 2.5m/s and 1m/s speed of movement the maximum distance a person could be away from the dwelling without receiving a dangerous dose is derived.

The selection of 5m distance from the dwelling provides a purely arbitrary start-point for the analysis. The use of 2.5m/s and 1m/s speed of movement to safety stems from the UK HSE. [1]

4.3 CONSEQUENCE EVALUATION

Thermal loading criteria adopted by the UK Health & Safety Executive [1] and the Dutch Ministry of Housing, Spatial Planning and the Environment [2] for people in the open and people within buildings are used here as the basis for consequence evaluation. These criteria are selected because they are well documented, mature in their application, and consistent with the criteria suggested by An Bord Pleanála within their correspondence.

It is noted that it is not normal practice to apply these criteria to evaluate absolute measures of consequence as a basis for establishing safe proximity distances. These criteria are primarily used in combination with a frequency of ignited release events within a QRA to provide a consistent basis for determining potential loss of life or injury per scenario. This has the advantage of achieving consistency within and between studies thus enabling valid comparisons of major accident risks for different facilities.

4.3.1 Evaluation Criteria for Persons in the Open

Evaluation criteria are required to enable an assessment of how a person in the open may be impacted by the initial intensity of the fireball and thermal dose received until safe shelter is reached or on leaving shelter that may catch fire.

4.3.1.1 Initial Thermal Loading

The rule-set adopted for the QRA is that persons exposed to a 35kW/m^2 thermal flux become fatalities. The value of 35 kW/m^2 is applied within the Purple Book [2]. (The Purple Book also allows people subject to thermal flux lower than 35 kW/m^2 to escape).

For the calculation of consequence distance as adopted by An Bord Pleanála consideration has been given as to how to address the cut-off point inherent in determining if a person receives a 35kW/m^2 thermal loading or not. In the absence of any known precedence within consequence analyses that can be used as a reference a conservative basis has been adopted here that only allows persons to move to safe shelter when the maximum thermal flux seen by the person beside the dwelling does not exceed 31.5kW/m^2 (i.e. 35kW/m^2 less 10%). Any thermal flux received by a person beside the dwelling that is higher than 31.5kW/m^2 is therefore considered as not meeting An Bord Pleanála's criteria.

4.3.1.2 Dangerous Dose

The concept of 'dangerous dose', measured in Thermal Dose Units, tdu, is adopted by the UK HSE. This measure is used to determine the effect of thermal radiation on a person who is moving. It indicates that the effect of thermal radiation on an exposed person depends on both the level of thermal radiation and the duration of exposure.

The paper Thermal Radiation Criteria Used In Pipeline Risk Assessment [1] states that: "The UK HSE opted for a dangerous dose defined as 1000 tdu for a normal population and 500 tdu for particularly vulnerable people. These criteria are based on the assumption that the exposed people are clothed normally and in the open". This analysis is based on a person receiving a Dangerous Dose if they receive a dose of 1,000 tdu or greater whilst moving to the building.

4.3.2 Evaluation Criteria for People Within Buildings

The methodology used by the UK HSE [1] assumes that people who are indoors are fully protected from any thermal radiation if the building they occupy does not catch fire. Buildings will ignite if their outer combustible parts catch fire, and this may occur by either of two mechanisms, spontaneous ignition or piloted ignition.

Spontaneous ignition occurs if the incident thermal radiation flux on the building is sufficiently high to ignite combustible material; put simply, the absolute amount of radiated heat generated in the early phase of the fire is sufficient to ignite the fabric of the building should that building be close enough. The term Building Burn Distance, BBD, is used in this analysis to define the closest a building can be to the pipeline without spontaneously igniting. This is a conservative metric based on experiments on the ignition of American white wood. Buildings adjacent to the Corrib pipeline are predominantly stone or brick walled with tiled or slate roofing and therefore would not be expected to spontaneously ignite at the predicted BBD.

Piloted ignition occurs if a building does not spontaneously ignite but over time the building is heated to the point when the fabric of the building would catch fire if induced by a source of flame such as a burning ember or brand. The UK HSE adopt the term Piloted Ignition Distance, PID, again this is a conservative metric used within a QRA based on experiments carried out with American white wood.

The evaluation criteria used within the Corrib Pipeline QRA (i.e. where the likelihood of an unwanted event is also taken into account) to determine the number of potential fatalities for each event scenario are:

- For buildings located inside the BBD the building is assumed to ignite, and people initially inside the building will need to leave the building and seek shelter further away from the pipeline in order to survive and in doing so receive less than a dangerous dose of thermal radiation.

- For buildings between the BBD and PID the building may ignite at a later stage, and in this case people will need to leave the building and seek shelter further away from the pipeline and in doing so receive less than a dangerous dose of thermal radiation. .

- People sheltering within buildings outside the PID are fully protected from thermal radiation.

Conservatively therefore (given that the above criteria are based on buildings constructed of American white wood) the evaluation criteria adopted in this response to An Bord Pleanála request are:

- No building shall be within the Building Burn Distance
- For a building to be guaranteed to provide safe shelter then that building shall not be within the Piloted Ignition Distance.
- Should any buildings between the BBD and PID catch fire then any dose of thermal radiation received by persons leaving the building in addition to the dose received moving to the building, would be taken into account in their total dose received.

5 APPLICATION OF ADOPTED CALCULATION BASIS

The previous Section identified and described the assumptions and parameters adopted. This Section describes the Corrib pipeline-specific application of the adopted assumptions and parameters the steps being:

1. Section 5.1: Describes the determining cases (the dwellings potentially most exposed to Release Cases 1 and 2)
2. Section 5.2: Tabulates the assigned values of parameters used for base case and sensitivity studies
3. Section 5.3: Presents the predictions for determining cases
4. Section 5.4: Tabulates the basis for the consequence distance contour plots provided in Attachment A.

5.1 DETERMINING CASES

Two groups of dwellings (A and B) are identified as determining. Refer Figure 5.1:

- Group A: Closest to the LVI and therefore closest to a full-bore rupture upstream of the LVI (Release Case 1).
- Group B: South of the Bay and closest to the pipeline, and therefore closest to a full-bore rupture when LVI is open (Release Case 2).

Table 1 provides the dimensions used as input to this consequence analysis.

Table 2: Determining Cases

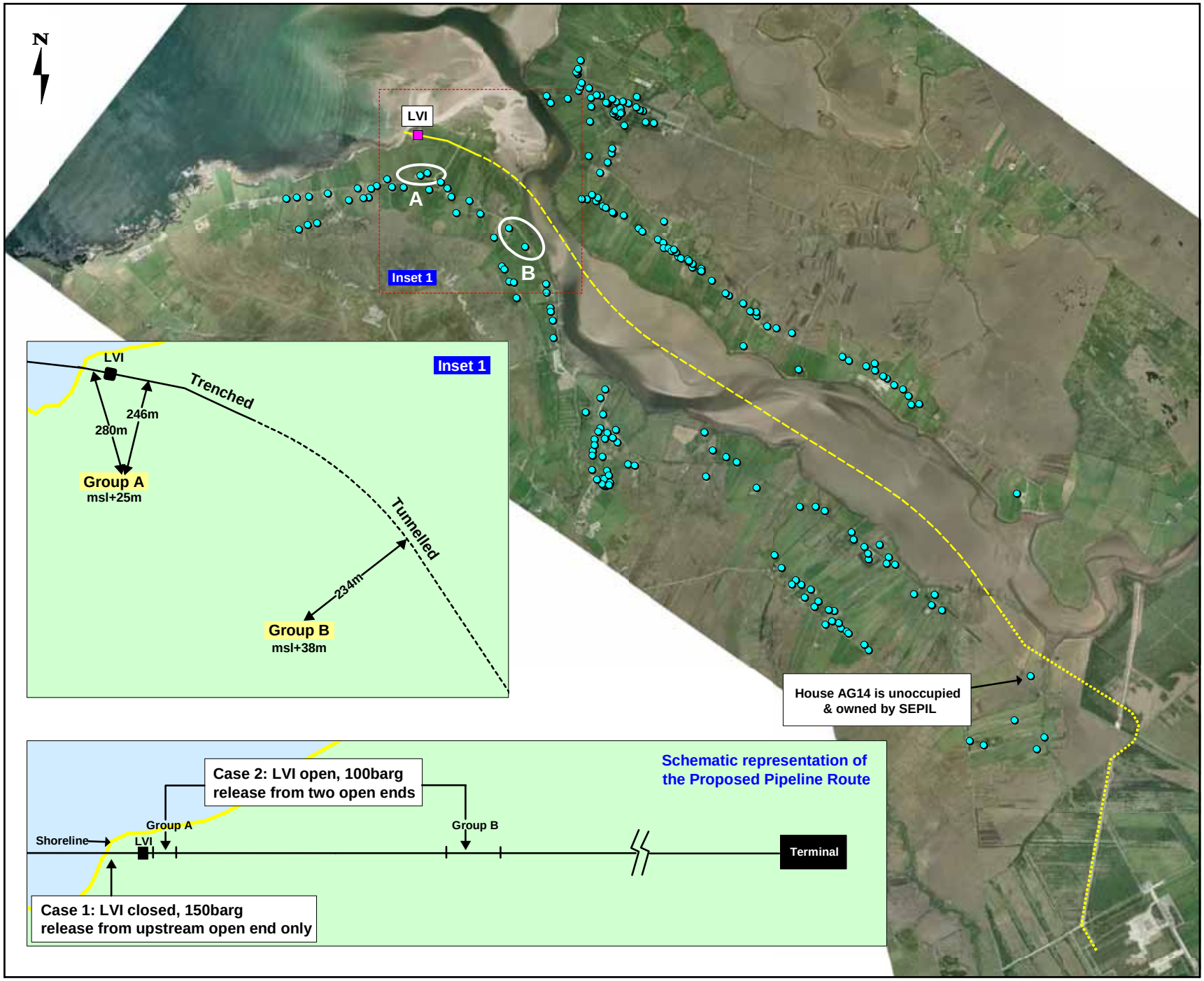
Determining Cases				
Dwelling Group	**Distance to Pipeline**	**Distance to LVI**	**Elevation above msl**	**Release Case Applied**
A	(246m[1)])	280	+25m	Case 1
B	234m [2)]	(Approx 900m [3)])	+38m	Case 2

Notes:

1) Distance to pipeline downstream of the LVI (Group B dwellings are closer and at higher elevation and therefore provide the determining case)

2) The distance to the pipeline from the closest dwelling is 242m +/- 8m, which gives an actual minimum distance of 234m. A distance of 230m is used to model the determining case.

3) Group A is the determining case for the consequences arising from any release upstream of the LVI.



LEGEND:

Proposed Route:

- Trenched Section
- Tunneled Section
- Stone Road Section
- House Location

Response to An Bord Pleanála Regarding The Query Raised in Section 3b of Letter Dated 2nd November 2009

Figure 5.1

File Ref: COR25MDR0470Mi2480R01
Date: May 2010

CORRIB ONSHORE PIPELINE

Corrib natural gas

RPS

5.2 ADOPTED PARAMETERS & SENSITIVITIES

Table 3: Parameters and Sensitivity Studies used for the Consequence Analysis.

Limiting Case Group B Dwellings, 234m[1)] from Rupture, 38m above msl		
No.	**Base Case Parameter**	**Sensitivity**
1.	Maximum pressure, MAOP of 100barg	
2.	Full-bore rupture LVI open and remains open Release Case 2	
3.	DNV models used.	
4.	Person is not exposed to thermal radiation in excess of 31.5kW/m^2	
5.	Persons beside the dwelling take 5s to react before moving	
6.	Persons beside dwellings move to dwelling for shelter and will not receive a dangerous dose equal to or greater than 1,000tdu. Predict thermal dose received if 5m from dwelling and moving at 2.5m/s.	Predict thermal dose received if 5m from the dwelling and moving at 1m/s Predict maximum distance persons can move from beside a dwelling such that they will not receive a dangerous dose equal to or greater than 1,000tdu
7.	Nearest dwelling is not within Building Burn Distance, BBD	
8.	Nearest dwelling is not within Piloted Ignition Distance, PID	
Determining Case Group A Dwellings, 246m from Rupture, 25m above msl		
No.	**Base Case Parameter**	**Sensitivity**
As above except:		
1.	Maximum pressure, MAOP of 150barg, LVI closed.	
2.	Release Case 1	

Note 1) 230m has been used as the basis for modelling

5.3 PREDICTIONS FOR DETERMINING CASES

5.3.1 Outcome of Analysis

Table 4: Predictions for the Determining Cases

	Parameter	Criteria	Determining Cases		Outcome
			Case 2 Release Group B Dwellings	Case 1 Release Group A Dwellings	
	Maximum pressure		100 barg	150 barg	
	Release mode		2 ends open	1 end open	
	Distance of person beside dwelling from rupture		234m[1)]	280m	
1.	Highest thermal flux received	31.5kW/m2	25 kW/m2	14.5 kW/m2	All cases below criteria
2.	Building Burn Distance, BBD	UK HSE	180m	155m	All dwellings are outside BBD
3.	Dangerous dose moving to dwelling as shelter				
3a.	5s stood still then 5m @ 2.5m/s	1,000tdu	580 tdu	247 tdu	Criteria not exceeded for base cases
3b.	5s stood still then 5m @ 1m/s	1,000tdu	830 tdu	352 tdu	
4.	Maximum distance without exceeding dangerous dose				
4a.	5s stood still then maximum distance @ 2.5m/s	1,000tdu	17 m	183m	
4b.	5s stood still then maximum distance @ 1m/s	1,000tdu	7 m	73m	
5.	Piloted Ignition Distance	UK HSE	205 m	178m	All dwellings outside PID
6.	Distance to thermal flux threshold of 31.5kW/m^2	VROM	216m	192m	All dwellings outside PID
7.	Dangerous dose moving away from the dwelling	Not relevant as all dwellings are outside PID			

Note 1) 230m has been used as the basis for modelling

5.3.2 Discussion of Predictions

The key outcomes are:

- Case 1 (150barg upstream of LVI, LVI closed) release has less severe consequences than Case 2 (100barg, LVI open)

For Case 2 releases:

- No normally occupied dwellings fall within the Building Burn Distance.
- No normally occupied dwellings fall within the Piloted Ignition Distance thus all such buildings can be regarded as safe shelter in the event of an immediately ignited full-bore rupture.
- No person beside a dwelling would receive a fatal level of thermal flux
- A person standing 'beside' the nearest dwelling and 5m from the dwelling would be able to reach safe shelter without receiving a dangerous dose of thermal radiation.

  Sensitivity studies with respect to the latter demonstrate that persons beside a dwelling moving at a speed of 2.5m/s towards the dwelling can be 17m away and a person moving at a speed of 1m/s 7m away.

5.4 CONSEQUENCE CONTOUR DISTANCE

In order to plot a contour of the consequence distance from the pipeline as requested by An Bord Pleanála it is necessary to assume a single set of variables. The selected set of variables and related distance are shown in Table 5.

Table 5: Basis for Contour Plot of Consequence Distance

Basis used for plotting consequence distance contour as requested by An Bord Pleanála (letter of 29th January 2010)	Upstream and Downstream of LVI, m
Distance of dwelling from pipeline based on: Dwelling elevation of 38m above msl The person is not exposed to a thermal flux in excess of 31.5 kW/m^2 Person beside the dwelling starts moving 5 seconds after the start of the event Person moves 5m to the dwelling at 2.5m/s without exceeding a dangerous dose of 1,000 tdu. The dwelling provides safe shelter (i.e. is outside the PID)	216m

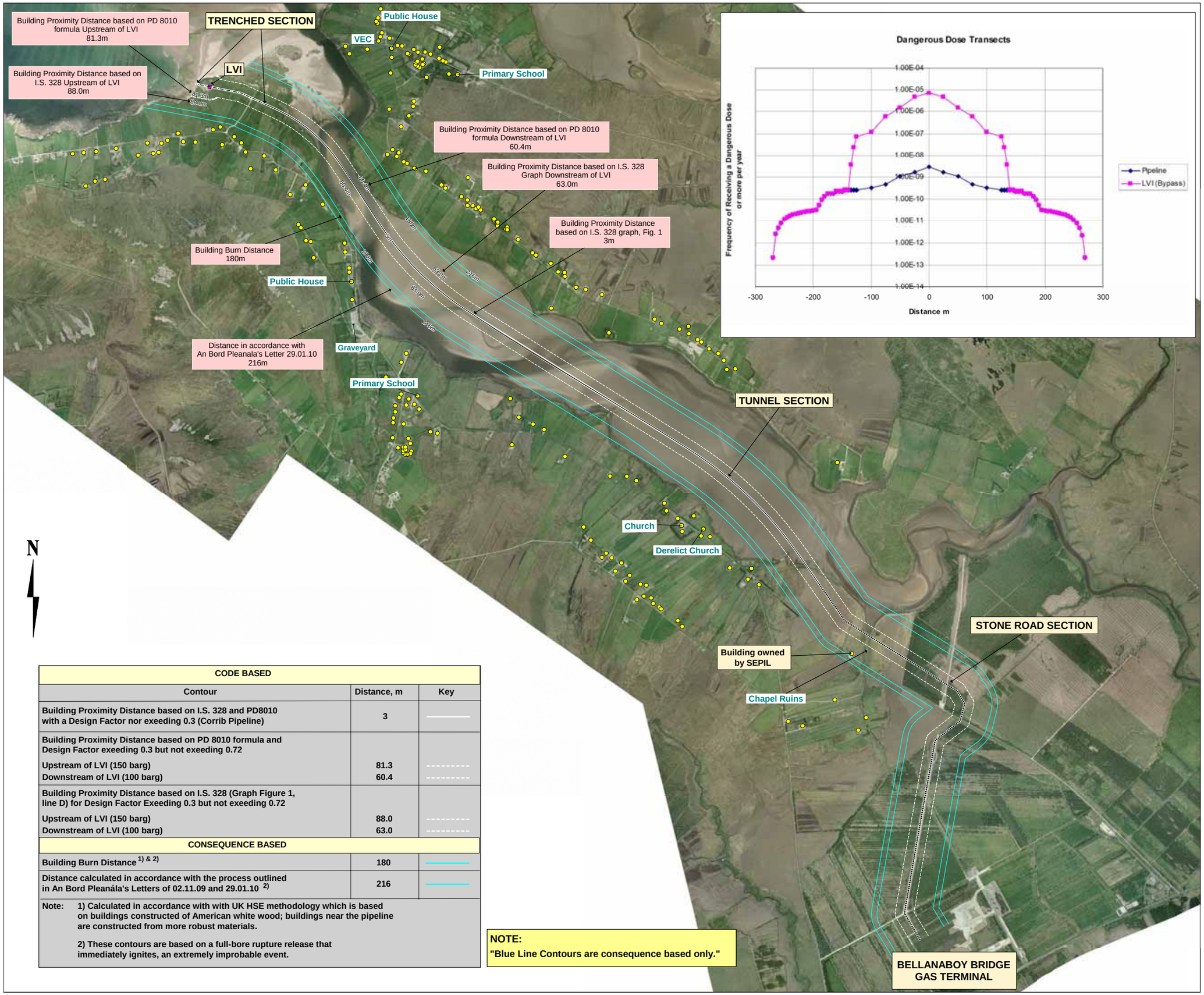
ATTACHMENT A: CONTOUR PLOTS

Public safety related contours plots for the entire pipeline associated with the modified pipeline design shown in this Attachment are listed in Table 6.

Note that the combined influence on safety contours from the pipeline and BBGT is not shown.

Table 6: Contours Plotted

Contour	Distance, m
Code Based	
Building Proximity Distance based on I.S. 328 and PD8010 with a Design Factor not exceeding 0.3 (Corrib Pipeline)	3
Building Proximity Distance based on PD 8010 formula and Design Factor exceeding 0.3 but not exceeding 0.72 - Upstream of LVI (150 barg) - Downstream of LVI (100 barg)	 81.3 60.4
Building Proximity Distance based on I.S. 328 (Graph Figure 1, line D) for Design Factor exceeding 0.3 but not exceeding 0.72 - Upstream of LVI (150 barg) - Downstream of LVI (100 barg)	 88.0 63.0
Consequence Based	
Building Burn Distance	180
Distance calculated in accordance with the process outlined in An Bord Pleanála's Letters of 02.11.09 and 29.01.10	216



CODE BASED		
Contour	**Distance, m**	**Key**
Building Proximity Distance based on I.S. 328 and PD8010 with a Design Factor nor exeeding 0.3 (Corrib Pipeline)	3	
Building Proximity Distance based on PD 8010 formula and Design Factor exeeding 0.3 but not exeeding 0.72		
Upstream of LVI (150 barg)	81.3	
Downstream of LVI (100 barg)	60.4	
Building Proximity Distance based on I.S. 328 (Graph Figure 1, line D) for Design Factor Exeeding 0.3 but not exeeding 0.72		
Upstream of LVI (150 barg)	88.0	
Downstream of LVI (100 barg)	63.0	
CONSEQUENCE BASED		
Building Burn Distance 1) & 2)	180	
Distance calculated in accordance with the process outlined in An Bord Pleanála's Letters of 02.11.09 and 29.01.10 2)	216	

Note: 1) Calculated in accordance with with UK HSE methodology which is based on buildings constructed of American white wood; buildings near the pipeline are constructed from more robust materials.

2) These contours are based on a full-bore rupture release that immediately ignites, an extremely improbable event.

NOTE:
"Blue Line Contours are consequence based only."

LEGEND

Proposed Route:

- Trenched Section
- Tunnel Section
- Stone Road Section
- House Location

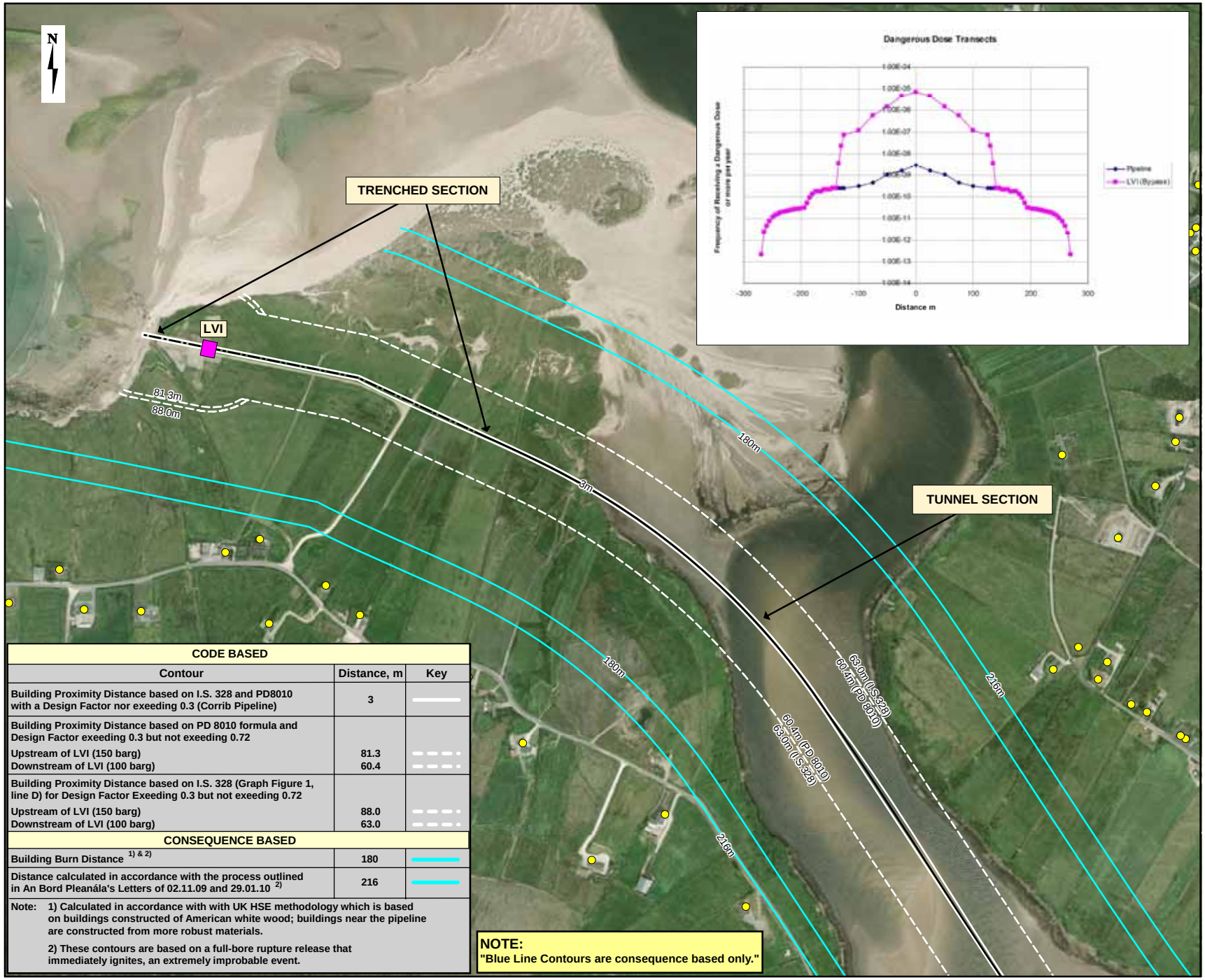
Consequence and Code Based Contours

File Ref: COR25MDR0470Mi2471R04
Date: May 2010

CORRIB ONSHORE PIPELINE

Corrib natural gas

RPS



CODE BASED		
Contour	**Distance, m**	**Key**
Building Proximity Distance based on I.S. 328 and PD8010 with a Design Factor nor exeeding 0.3 (Corrib Pipeline)	3	
Building Proximity Distance based on PD 8010 formula and Design Factor exeeding 0.3 but not exeeding 0.72		
Upstream of LVI (150 barg)	81.3	
Downstream of LVI (100 barg)	60.4	
Building Proximity Distance based on I.S. 328 (Graph Figure 1, line D) for Design Factor Exeeding 0.3 but not exeeding 0.72		
Upstream of LVI (150 barg)	88.0	
Downstream of LVI (100 barg)	63.0	
CONSEQUENCE BASED		
Building Burn Distance 1) & 2)	180	
Distance calculated in accordance with the process outlined in An Bord Pleanála's Letters of 02.11.09 and 29.01.10 2)	216	

Note: 1) Calculated in accordance with with UK HSE methodology which is based on buildings constructed of American white wood; buildings near the pipeline are constructed from more robust materials.

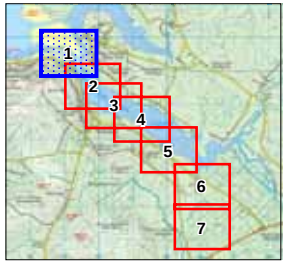
2) These contours are based on a full-bore rupture release that immediately ignites, an extremely improbable event.

NOTE:
"Blue Line Contours are consequence based only."

LEGEND:

Proposed Route:

- Trenched Section
- Tunnel Section
- Stone Road Section
- House Location



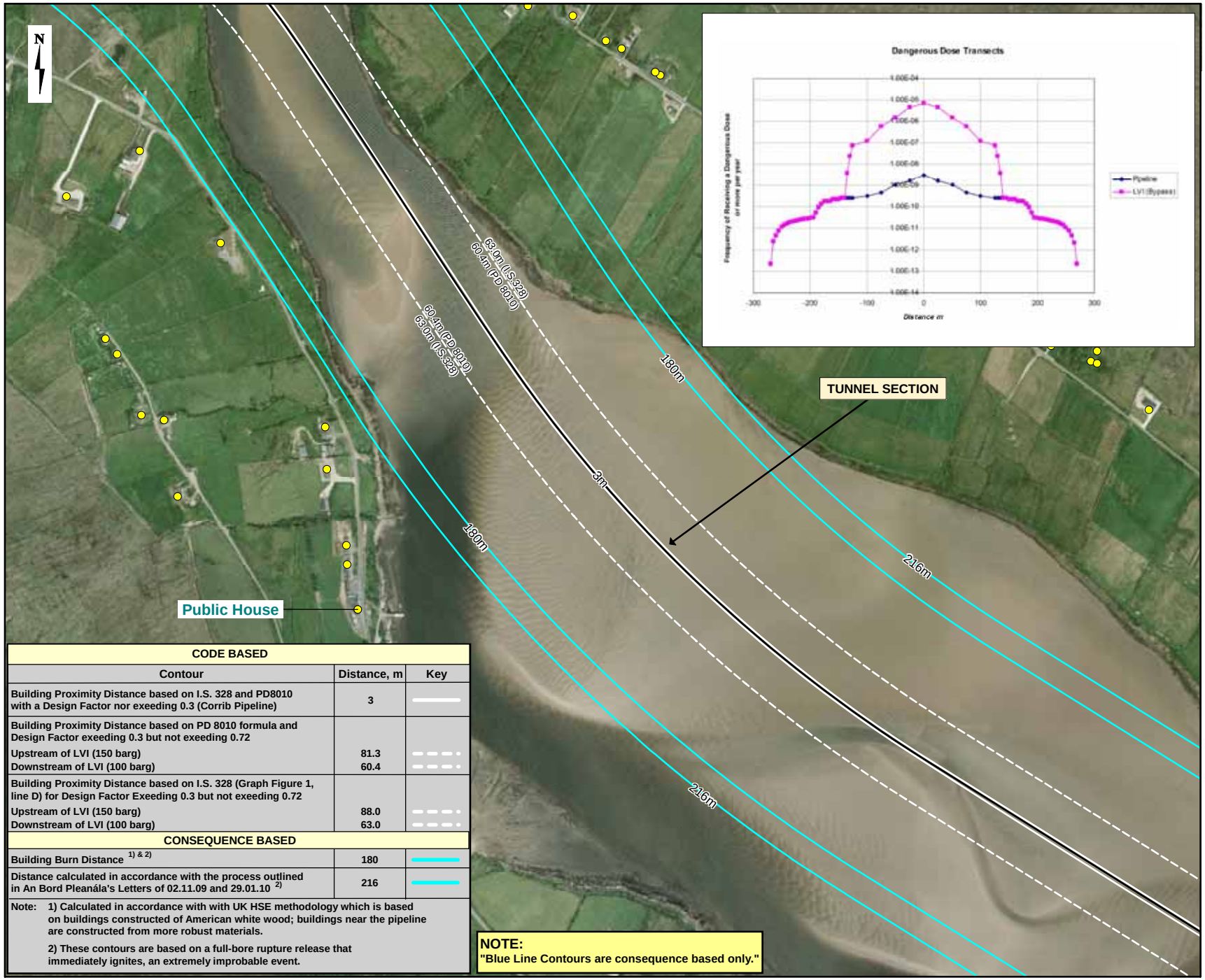
Consequence
and Code Based Contours
(Sheet 1 of 7)

File Ref: COR25MDR0470Mi2472R04
Date: May 2010

CORRIB ONSHORE PIPELINE

Corrib natural gas

RPS



CODE BASED		
Contour	**Distance, m**	**Key**
Building Proximity Distance based on I.S. 328 and PD8010 with a Design Factor nor exeeding 0.3 (Corrib Pipeline)	3	
Building Proximity Distance based on PD 8010 formula and Design Factor exeeding 0.3 but not exeeding 0.72		
Upstream of LVI (150 barg)	81.3	
Downstream of LVI (100 barg)	60.4	
Building Proximity Distance based on I.S. 328 (Graph Figure 1, line D) for Design Factor Exeeding 0.3 but not exeeding 0.72		
Upstream of LVI (150 barg)	88.0	
Downstream of LVI (100 barg)	63.0	
CONSEQUENCE BASED		
Building Burn Distance 1) & 2)	180	
Distance calculated in accordance with the process outlined in An Bord Pleanála's Letters of 02.11.09 and 29.01.10 2)	216	

Note: 1) Calculated in accordance with with UK HSE methodology which is based on buildings constructed of American white wood; buildings near the pipeline are constructed from more robust materials.

2) These contours are based on a full-bore rupture release that immediately ignites, an extremely improbable event.

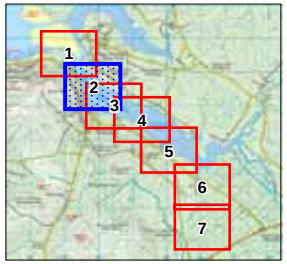
NOTE:
"Blue Line Contours are consequence based only."

LEGEND:

Proposed Route:

- Trenched Section
- Tunnel Section
- Stone Road Section

- House Location



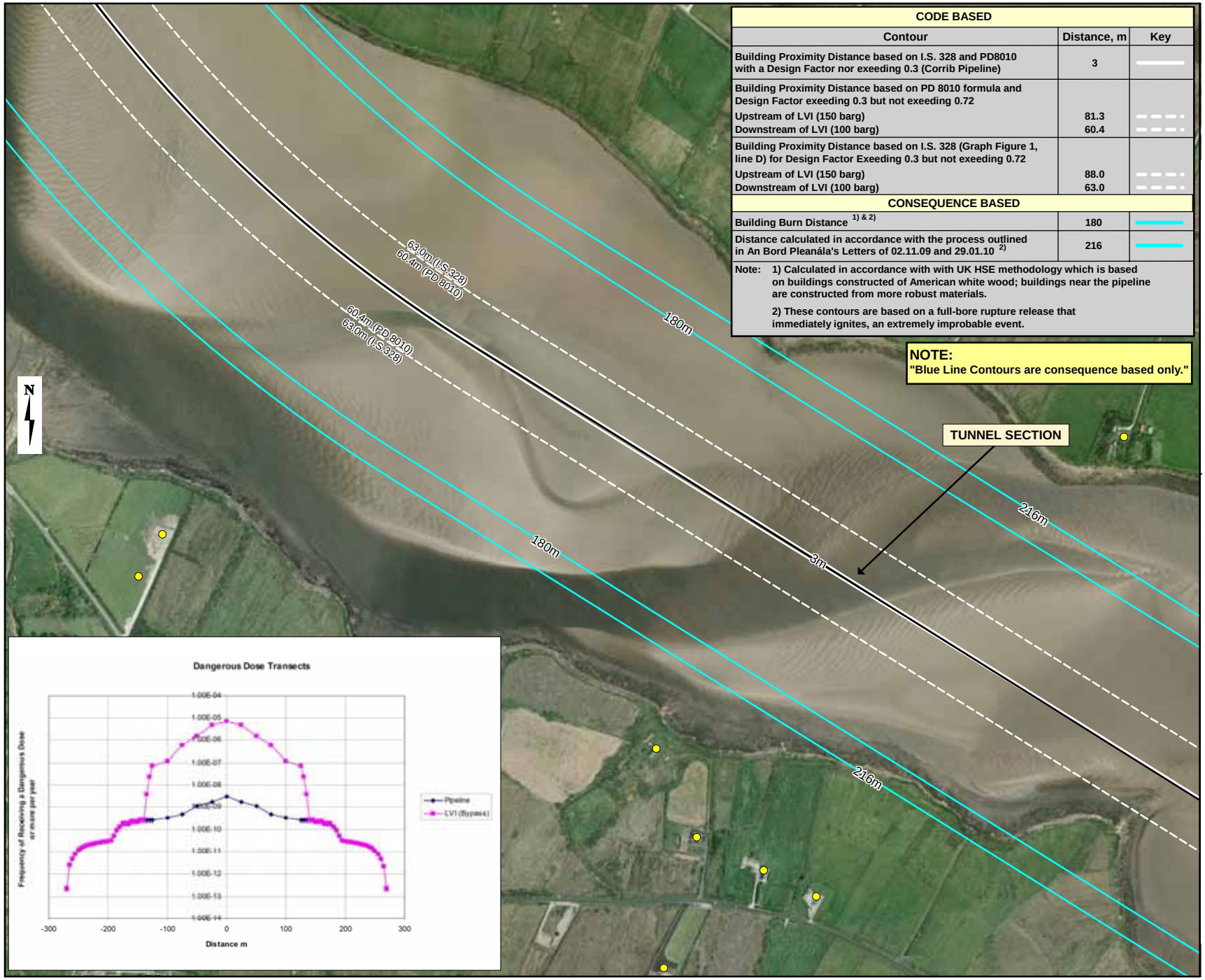
Consequence
and Code Based Contours
(Sheet 2 of 7)

File Ref: COR25MDR0470Mi2473R04
Date: May 2010

CORRIB ONSHORE PIPELINE

Corrib natural gas

RPS



CODE BASED		
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Building Proximity Distance based on I.S. 328 and PD8010 with a Design Factor nor exeeding 0.3 (Corrib Pipeline)	3	
Building Proximity Distance based on PD 8010 formula and Design Factor exeeding 0.3 but not exeeding 0.72		
Upstream of LVI (150 barg)	81.3	
Downstream of LVI (100 barg)	60.4	
Building Proximity Distance based on I.S. 328 (Graph Figure 1, line D) for Design Factor Exeeding 0.3 but not exeeding 0.72		
Upstream of LVI (150 barg)	88.0	
Downstream of LVI (100 barg)	63.0	
CONSEQUENCE BASED		
Building Burn Distance 1) & 2)	180	
Distance calculated in accordance with the process outlined in An Bord Pleanála's Letters of 02.11.09 and 29.01.10 2)	216	

Note: 1) Calculated in accordance with with UK HSE methodology which is based on buildings constructed of American white wood; buildings near the pipeline are constructed from more robust materials.

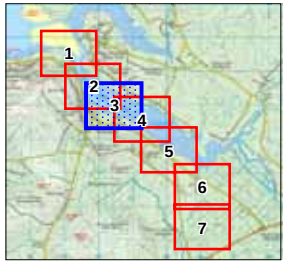
2) These contours are based on a full-bore rupture release that immediately ignites, an extremely improbable event.

NOTE:
"Blue Line Contours are consequence based only."

LEGEND:

Proposed Route:

- Trenched Section
- Tunnel Section
- Stone Road Section
- House Location



Consequence
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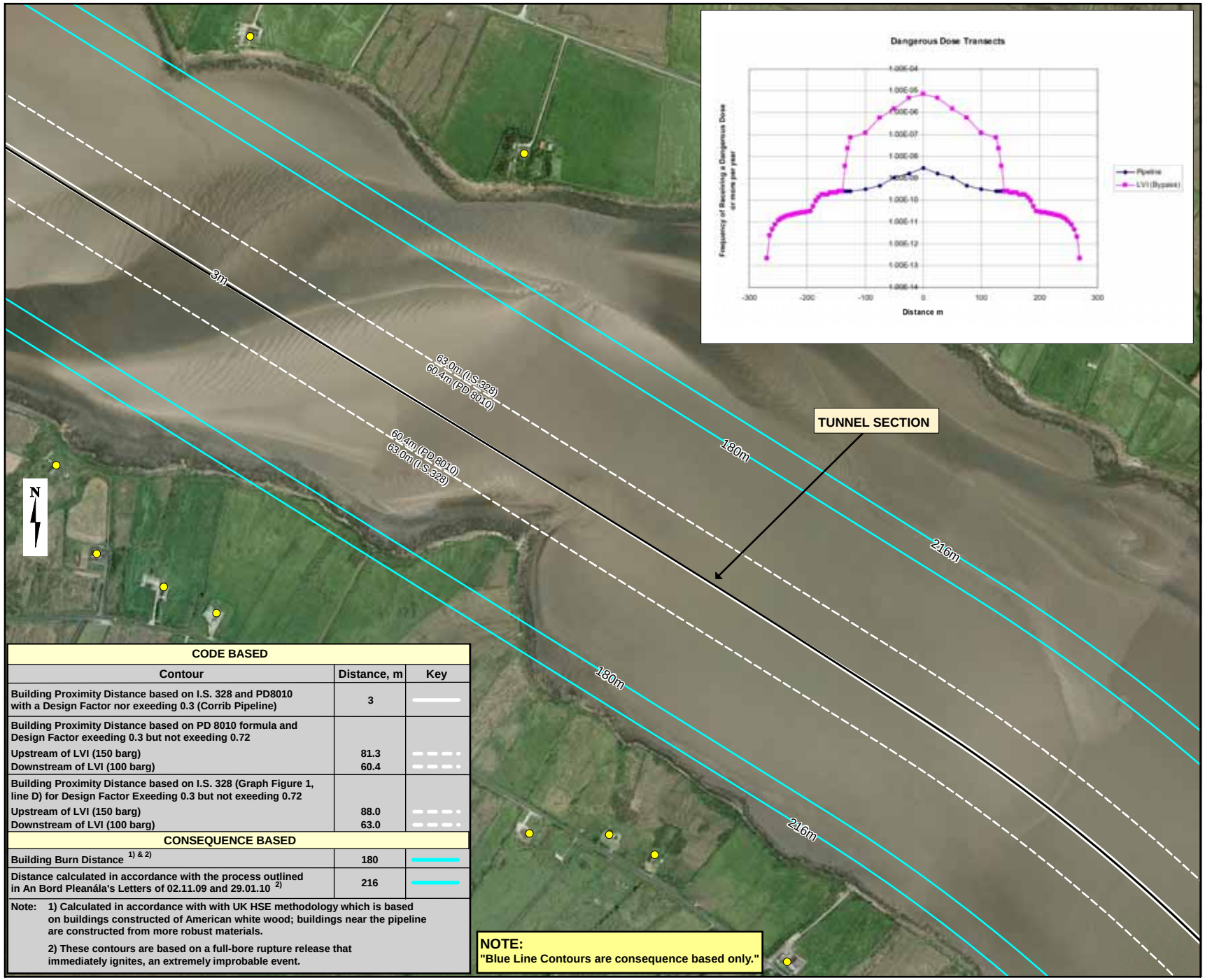
(Sheet 3 of 7)

File Ref: COR25MDR0470Mi2474R04
Date: May 2010

CORRIB ONSHORE PIPELINE

Corrib natural gas

RPS



CODE BASED		
Contour	**Distance, m**	**Key**
Building Proximity Distance based on I.S. 328 and PD8010 with a Design Factor nor exeeding 0.3 (Corrib Pipeline)	3	
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Downstream of LVI (100 barg)	63.0	
CONSEQUENCE BASED		
Building Burn Distance 1) & 2)	180	
Distance calculated in accordance with the process outlined in An Bord Pleanála's Letters of 02.11.09 and 29.01.10 2)	216	

Note: 1) Calculated in accordance with with UK HSE methodology which is based on buildings constructed of American white wood; buildings near the pipeline are constructed from more robust materials.

2) These contours are based on a full-bore rupture release that immediately ignites, an extremely improbable event.

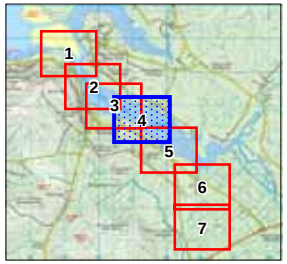
NOTE:
"Blue Line Contours are consequence based only."

LEGEND:

Proposed Route:

- Trenched Section
- Tunnel Section
- Stone Road Section

- House Location



Consequence
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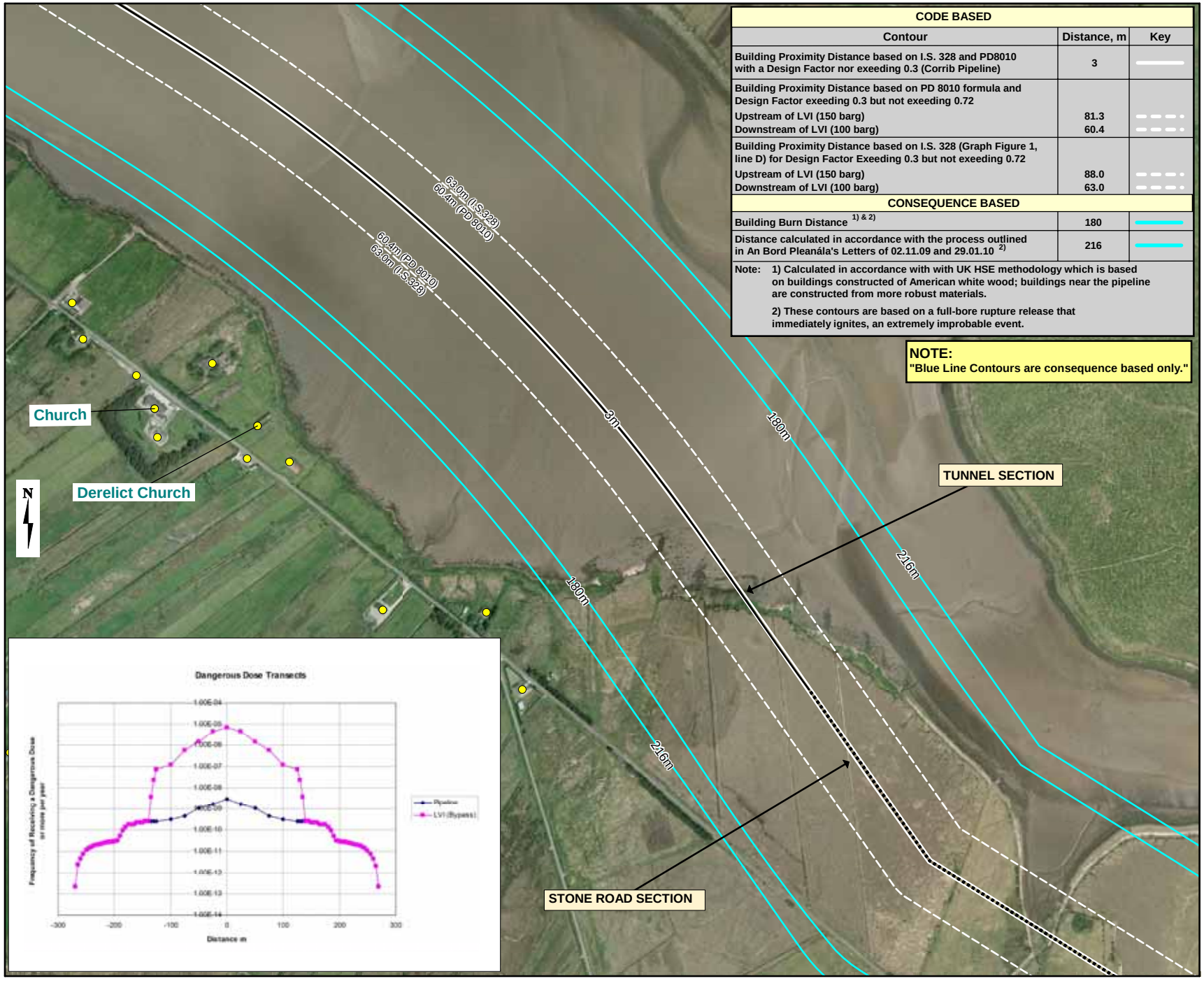
(Sheet 4 of 7)

File Ref: COR25MDR0470Mi2475R04
Date: May 2010

CORRIB ONSHORE PIPELINE

Corrib natural gas

RPS



CODE BASED		
Contour	**Distance, m**	**Key**
Building Proximity Distance based on I.S. 328 and PD8010 with a Design Factor nor exeeding 0.3 (Corrib Pipeline)	3	
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Downstream of LVI (100 barg)	63.0	
CONSEQUENCE BASED		
Building Burn Distance 1) & 2)	180	
Distance calculated in accordance with the process outlined in An Bord Pleanála's Letters of 02.11.09 and 29.01.10 2)	216	

Note: 1) Calculated in accordance with with UK HSE methodology which is based on buildings constructed of American white wood; buildings near the pipeline are constructed from more robust materials.

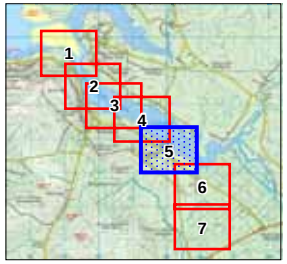
2) These contours are based on a full-bore rupture release that immediately ignites, an extremely improbable event.

NOTE:
"Blue Line Contours are consequence based only."

LEGEND:

Proposed Route:

- Trenched Section
- Tunnel Section
- Stone Road Section
- House Location



Consequence
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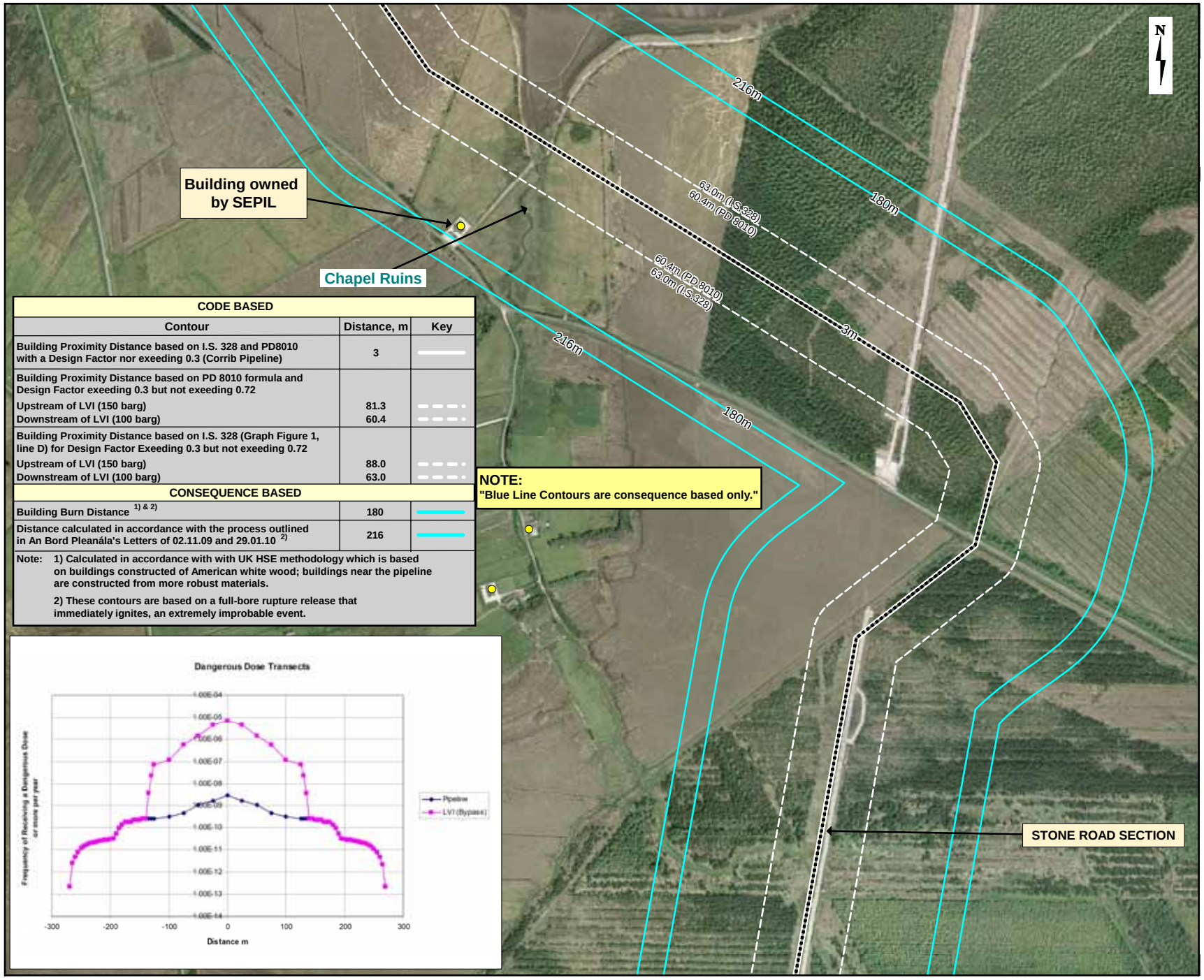
(Sheet 5 of 7)

File Ref: COR25MDR0470Mi2476R04
Date: May 2010

CORRIB ONSHORE PIPELINE

Corrib natural gas

RPS



CODE BASED		
Contour	**Distance, m**	**Key**
Building Proximity Distance based on I.S. 328 and PD8010 with a Design Factor nor exeeding 0.3 (Corrib Pipeline)	3	
Building Proximity Distance based on PD 8010 formula and Design Factor exeeding 0.3 but not exeeding 0.72		
Upstream of LVI (150 barg)	81.3	
Downstream of LVI (100 barg)	60.4	
Building Proximity Distance based on I.S. 328 (Graph Figure 1, line D) for Design Factor Exeeding 0.3 but not exeeding 0.72		
Upstream of LVI (150 barg)	88.0	
Downstream of LVI (100 barg)	63.0	
CONSEQUENCE BASED		
Building Burn Distance 1) & 2)	180	
Distance calculated in accordance with the process outlined in An Bord Pleanála's Letters of 02.11.09 and 29.01.10 2)	216	

Note: 1) Calculated in accordance with with UK HSE methodology which is based on buildings constructed of American white wood; buildings near the pipeline are constructed from more robust materials.

2) These contours are based on a full-bore rupture release that immediately ignites, an extremely improbable event.

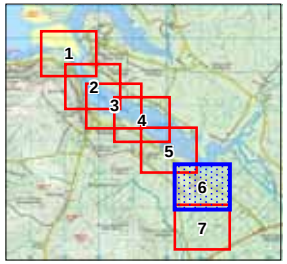
NOTE:
"Blue Line Contours are consequence based only."

LEGEND:

Proposed Route:

- Trenched Section
- Tunnel Section
- Stone Road Section

- House Location



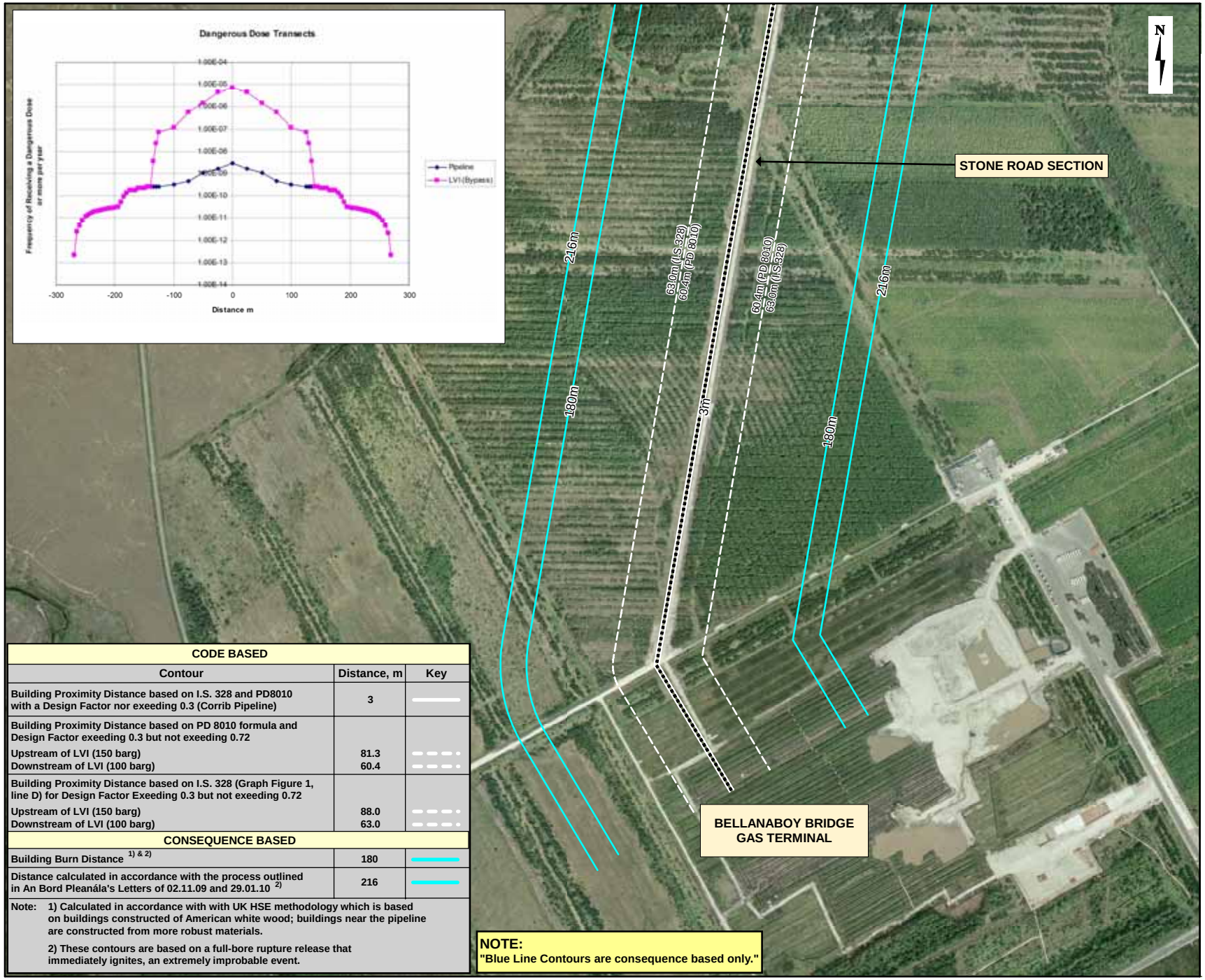
Consequence and Code Based Contours (Sheet 6 of 7)

File Ref: COR25MDR0470Mi2477R04
Date: May 2010

CORRIB ONSHORE PIPELINE

Corrib natural gas

RPS



CODE BASED		
Contour	**Distance, m**	**Key**
Building Proximity Distance based on I.S. 328 and PD8010 with a Design Factor nor exeeding 0.3 (Corrib Pipeline)	3	
Building Proximity Distance based on PD 8010 formula and Design Factor exeeding 0.3 but not exeeding 0.72		
Upstream of LVI (150 barg)	81.3	
Downstream of LVI (100 barg)	60.4	
Building Proximity Distance based on I.S. 328 (Graph Figure 1, line D) for Design Factor Exeeding 0.3 but not exeeding 0.72		
Upstream of LVI (150 barg)	88.0	
Downstream of LVI (100 barg)	63.0	
CONSEQUENCE BASED		
Building Burn Distance 1) & 2)	180	
Distance calculated in accordance with the process outlined in An Bord Pleanála's Letters of 02.11.09 and 29.01.10 2)	216	

Note: 1) Calculated in accordance with with UK HSE methodology which is based on buildings constructed of American white wood; buildings near the pipeline are constructed from more robust materials.

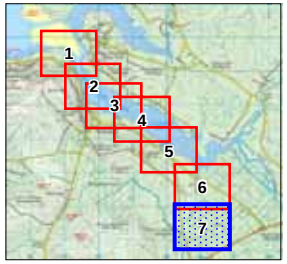
2) These contours are based on a full-bore rupture release that immediately ignites, an extremely improbable event.

NOTE:
"Blue Line Contours are consequence based only."

LEGEND:

Proposed Route:

- Trenched Section
- Tunnel Section
- Stone Road Section
- House Location



Consequence
and Code Based Contours
(Sheet 7 of 7)

File Ref: COR25MDR0470Mi2478R04
Date: May 2010

CORRIB ONSHORE PIPELINE

Corrib natural gas

RPS

REFERENCES

1. Thermal Radiation Criteria Used In Pipeline Risk Assessment. Bilio & Kinsman. December 1997

2. Uijt de Haag PAM and Ale BJM. Guidelines for Quantitative Risk Assessment. PGS 3. (Purple Book). VROM (Verantwoordelijk voor wonen, ruimte en milieu). Dec 2005

SHELL E&P IRELAND LIMITED

CORRIB GAS FIELD DEVELOPMENT PROJECT

Corrib
natural gas

Q6.5(ii): Response to An Bord Pleanála Regarding the Request for Further Information, Item (i) of Letter 2nd November

DOCUMENT No: COR-14-SH-0078

TABLE OF CONTENTS

1 INTRODUCTION

This document is prepared in response to An Bord Pleanála's letter of the 2nd November 2009 Page 3 item (i) requesting information as follows:

> *"Provide details of the hazard distances, building burn distances and escape distances in contours for the entire pipeline. The applicant should indicate the outer hazard line contour, which should show the distance from the pipeline at which a person would be safe. A number of these contours were provided at the oral hearing (copies of which are attached to this letter), however, the set of hazard contours should be completed and should include the entire onshore pipeline as far as the terminal. Please indicate the assumption made in determining these hazard contours and indicate any limitations that apply to these hazard contours."*

The distance from the pipeline at which a person would be safe is covered in Appendix Q 6.5(i), which takes account of An Bord Pleanála's letter of clarification dated 29th January 2010.

This document covers the provision of the Building Burn and Escape Distances for the full length of the pipeline onshore in order to complete the submission provided at the oral hearing.

2 LIMITATIONS AND ASSUMPTIONS APPLIED

2.1 LIMITATIONS

The Building Burn and Escape Distance are those applied within the rule sets adopted for the Quantitative Risk Assessment, QRA, (Appendix Q 6.4).

These consequence based rule sets are intended for use in combination with frequency of pipeline loss of containment events, probability of ignition, probability of persons being exposed, various meteorological conditions etc. in order to derive the level of risk associated with the Corrib pipeline. The Building Burn Distance is used in the context of determining whether persons inside buildings within this distance would survive. Escape distance is used in the context of whether persons outdoors may survive when escaping the event. In combination with other rule-sets these two distances are used to generate a value of potential loss of life or receipt of a dangerous dose per scenario outcome for a range of release scenarios.

2.2 ASSUMPTIONS APPLIED

Together with the base assumption that a number of preventative measures have failed simultaneously, the following key assumptions are applied in the application of these rule sets:

General:

- A full bore rupture occurs (the likelihood of which SEPIL regard as negligible)
- The release is the worst-case release scenario, being a release at 100barg with the LVI open and the full pipeline inventory of gas escaping from two open ends. (see Appendix Q6.3 Section 7.1.2)
- The release immediately ignites
- The wind is blowing at 5m/s from the point of release towards the receptor
- Receptors are at an elevation of 38m above the release point (the higher the elevation the greater the thermal loading received)

For Building Burn Distance:

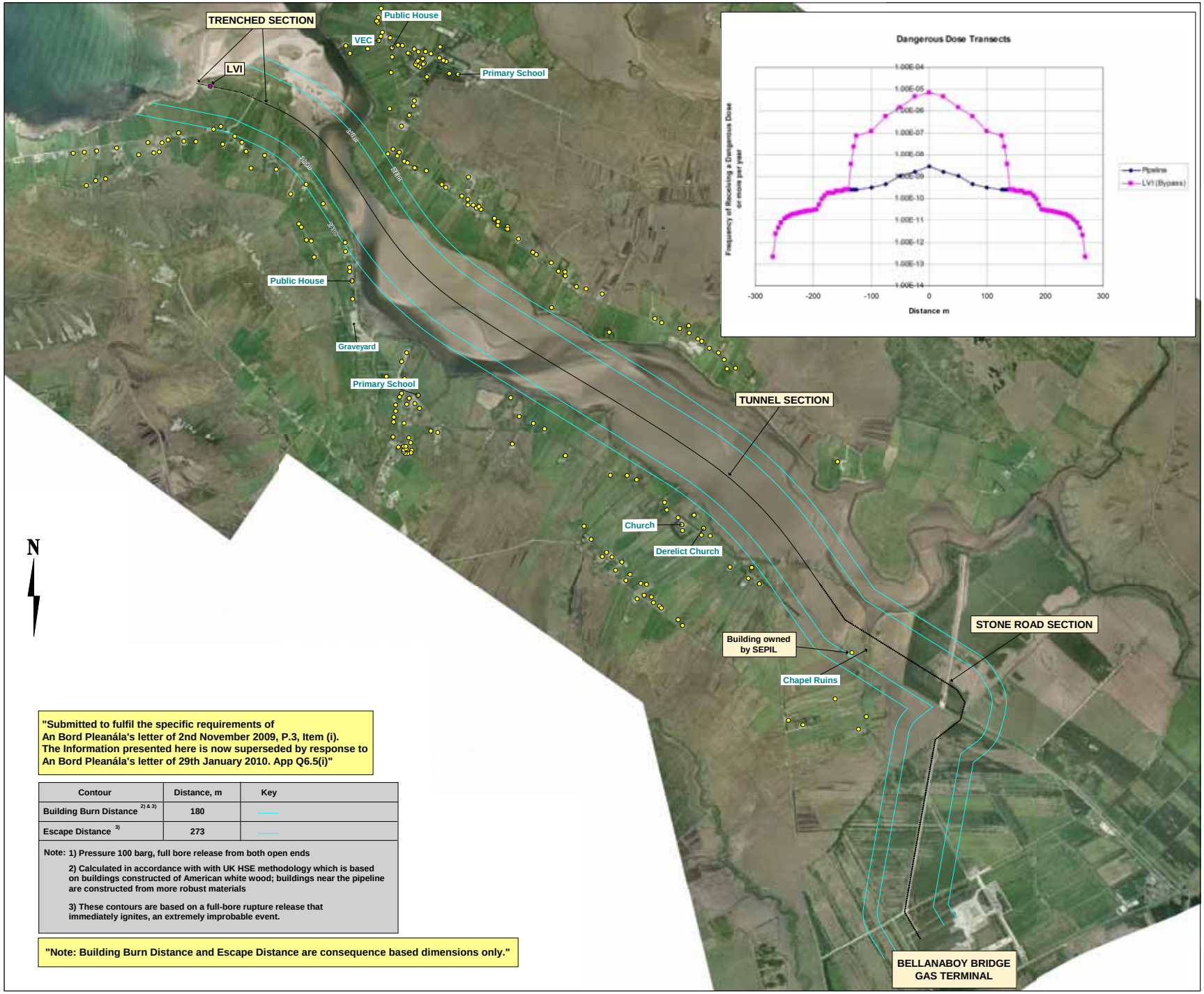
- The building is made of American white wood (as opposed to the building materials used in the vicinity of the pipeline which are brick, stone, slate, tile etc.)
- Thermal flux for spontaneous ignition is equal to or greater than 25.6 kW/m^2

For Escape Distance:

- The person is outdoors at the time of the event
- There is a reaction time of 5s during which the person is stationary
- The person does not receive a fatal level of thermal flux greater than 31.5 kW/m^2 and moves at a speed of 2.5 m/s for a distance of 75m away from the source of heat (perpendicular to the pipeline) and in doing so does not receive a dose greater than 1000 tdu

3 CONTOUR PLOTS

Contours of Building Burn Distance and Escape Distance are overlaid on aerial photographs for the entire length of the pipeline.



"Submitted to fulfil the specific requirements of
An Bord Pleanála's letter of 2nd November 2009, P.3, Item (i).
The Information presented here is now superseded by response to
An Bord Pleanála's letter of 29th January 2010. App Q6.5(i)"

Contour	Distance, m	Key
Building Burn Distance [2) & 3)]	180	
Escape Distance [3)]	273	

Note: 1) Pressure 100 barg, full bore release from both open ends

2) Calculated in accordance with with UK HSE methodology which is based on buildings constructed of American white wood; buildings near the pipeline are constructed from more robust materials

3) These contours are based on a full-bore rupture release that immediately ignites, an extremely improbable event.

"Note: Building Burn Distance and Escape Distance are consequence based dimensions only."

LEGEND

Proposed Route:

- Trenched Section
- Tunnel Section
- Stone Road Section
- House Location

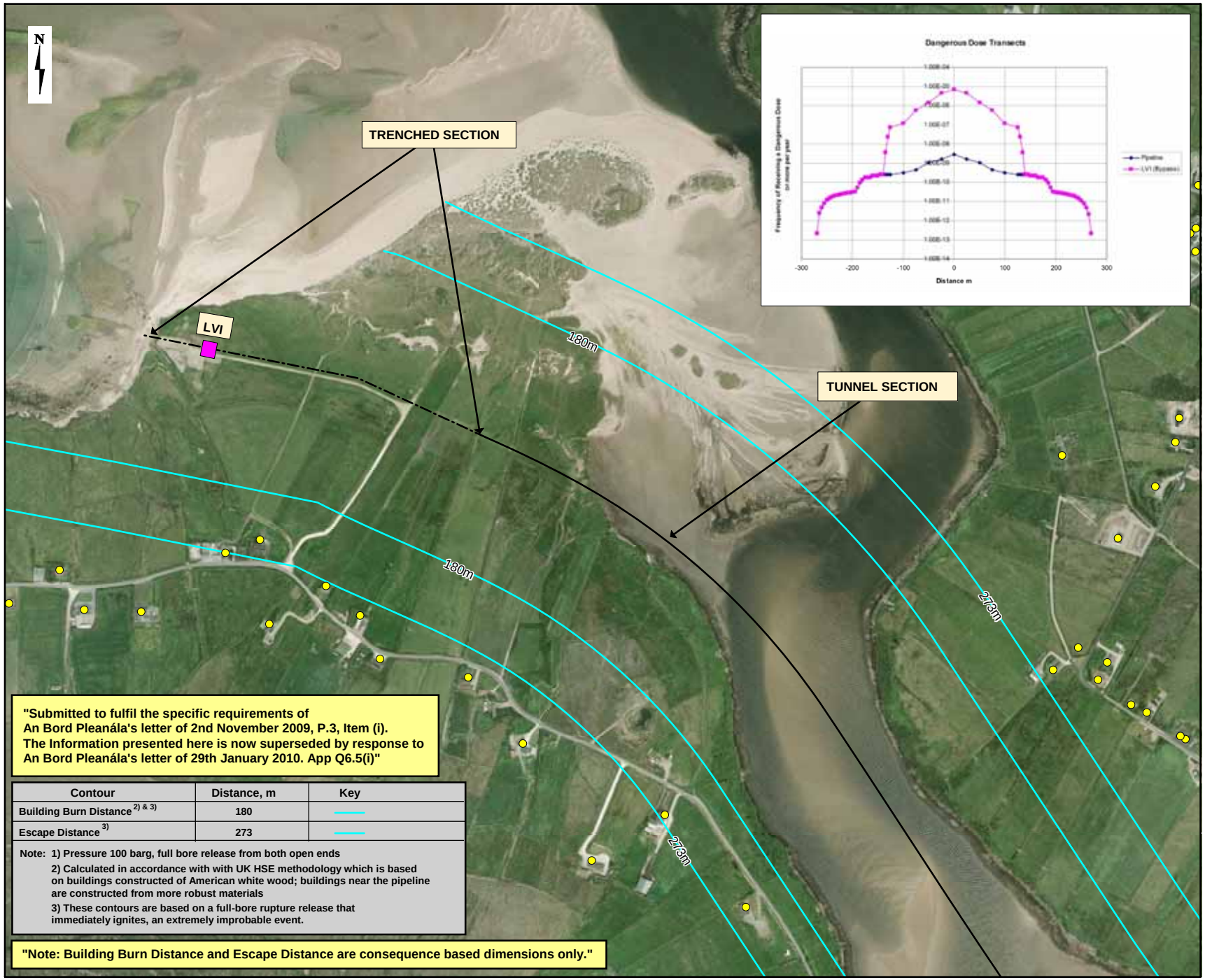
Response to An Bord Pleanála's letter of 2nd November 2009 P.3.Item (i).

File Ref: COR25MDR0470Mi2495R02
Date: May 2010

CORRIB ONSHORE PIPELINE

Corrib natural gas

RPS



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An Bord Pleanála's letter of 29th January 2010. App Q6.5(i)"

Contour	Distance, m	Key
Building Burn Distance 2) & 3)	180	
Escape Distance 3)	273	

Note: 1) Pressure 100 barg, full bore release from both open ends
2) Calculated in accordance with with UK HSE methodology which is based on buildings constructed of American white wood; buildings near the pipeline are constructed from more robust materials
3) These contours are based on a full-bore rupture release that immediately ignites, an extremely improbable event.

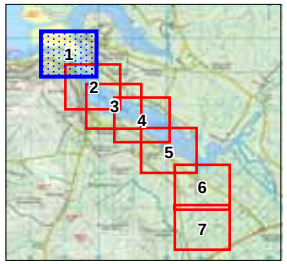
"Note: Building Burn Distance and Escape Distance are consequence based dimensions only."

LEGEND:

Proposed Route:

- Trenched Section
- Tunnel Section
- Stone Road Section

House Location



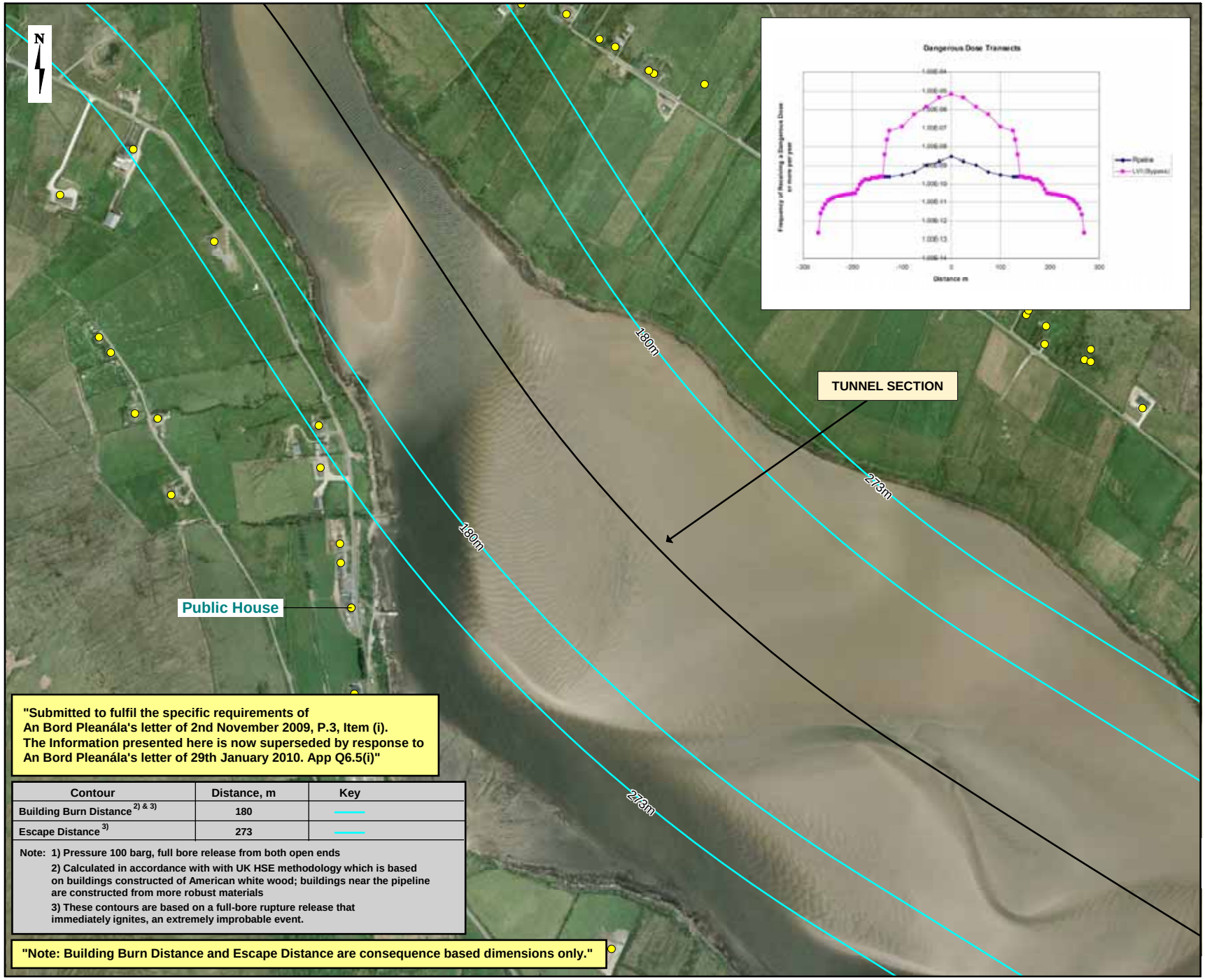
Response to An Bord Pleanála's letter of 2nd November 2009 P.3.Item (i).
(Sheet 1 of 7)

File Ref: COR25MDR0470Mi2481R03
Date: May 2010

CORRIB ONSHORE PIPELINE

Corrib natural gas

RPS



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An Bord Pleanála's letter of 29th January 2010. App Q6.5(i)"

Contour	Distance, m	Key
Building Burn Distance 2) & 3)	180	
Escape Distance 3)	273	

Note: 1) Pressure 100 barg, full bore release from both open ends
2) Calculated in accordance with with UK HSE methodology which is based on buildings constructed of American white wood; buildings near the pipeline are constructed from more robust materials
3) These contours are based on a full-bore rupture release that immediately ignites, an extremely improbable event.

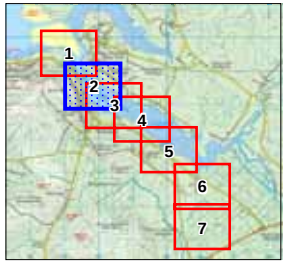
"Note: Building Burn Distance and Escape Distance are consequence based dimensions only."

LEGEND:

Proposed Route:

- Trenched Section
- Tunnel Section
- Stone Road Section

House Location



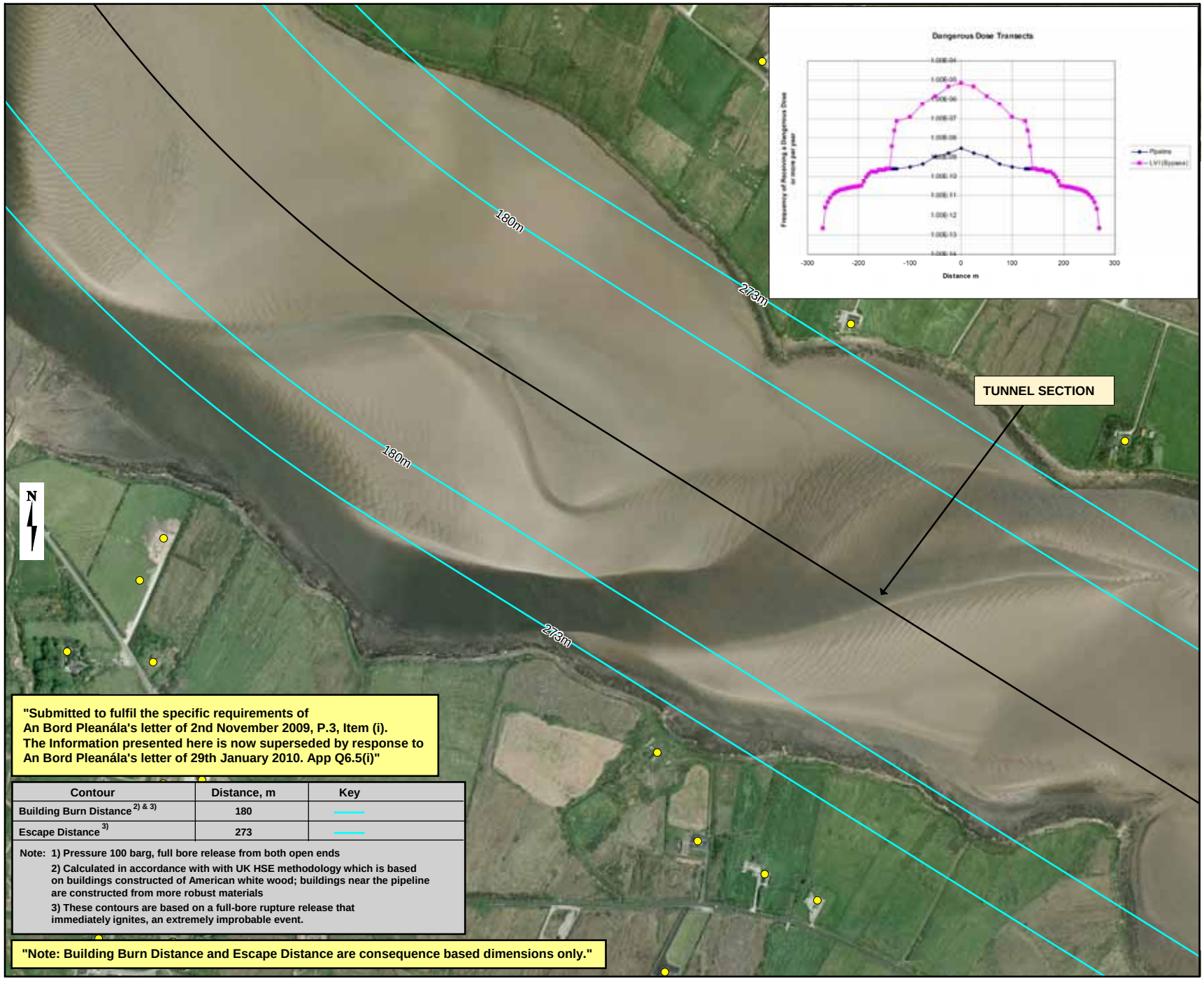
Response to An Bord Pleanála's letter of 2nd November 2009 P.3.Item (i).
(Sheet 2 of 7)

File Ref: COR25MDR0470Mi2483R03
Date: May 2010

CORRIB ONSHORE PIPELINE

Corrib natural gas

RPS



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Contour	Distance, m	Key
Building Burn Distance 2) & 3)	180	
Escape Distance 3)	273	

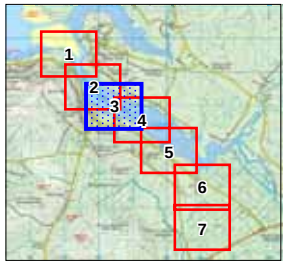
Note: 1) Pressure 100 barg, full bore release from both open ends
2) Calculated in accordance with with UK HSE methodology which is based on buildings constructed of American white wood; buildings near the pipeline are constructed from more robust materials
3) These contours are based on a full-bore rupture release that immediately ignites, an extremely improbable event.

"Note: Building Burn Distance and Escape Distance are consequence based dimensions only."

LEGEND:

Proposed Route:

- Trenched Section
- Tunnel Section
- Stone Road Section
- House Location



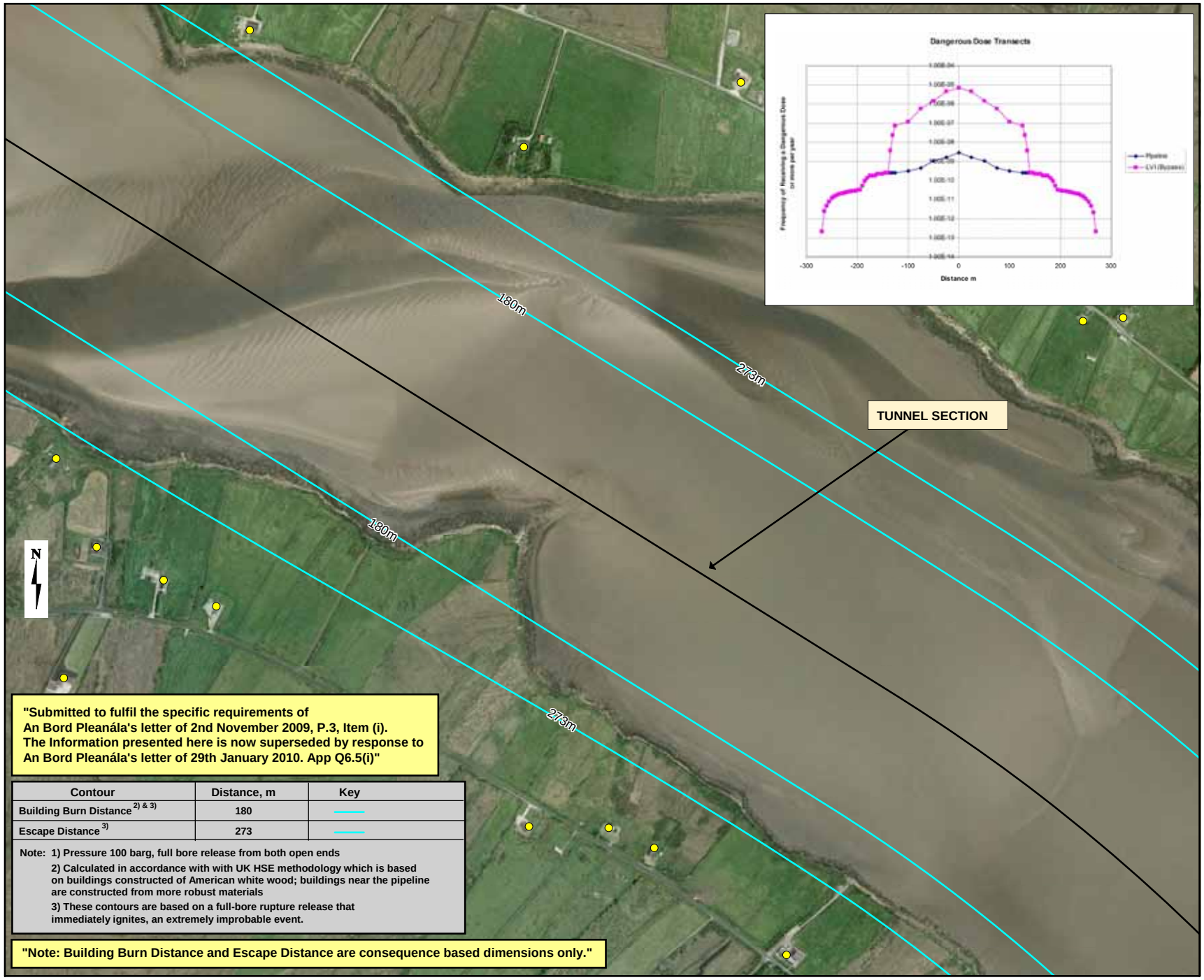
Response to An Bord Pleanála's letter of 2nd November 2009 P.3.Item (i).
(Sheet 3 of 7)

File Ref: COR25MDR0470Mi2484R03
Date: May 2010

CORRIB ONSHORE PIPELINE

Corrib natural gas

RPS



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Contour	Distance, m	Key
Building Burn Distance 2) & 3)	180	
Escape Distance 3)	273	

Note: 1) Pressure 100 barg, full bore release from both open ends
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"Note: Building Burn Distance and Escape Distance are consequence based dimensions only."

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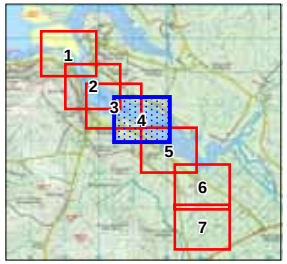
Proposed Route:

- Trenched Section
- Tunnel Section
- Stone Road Section
- House Location



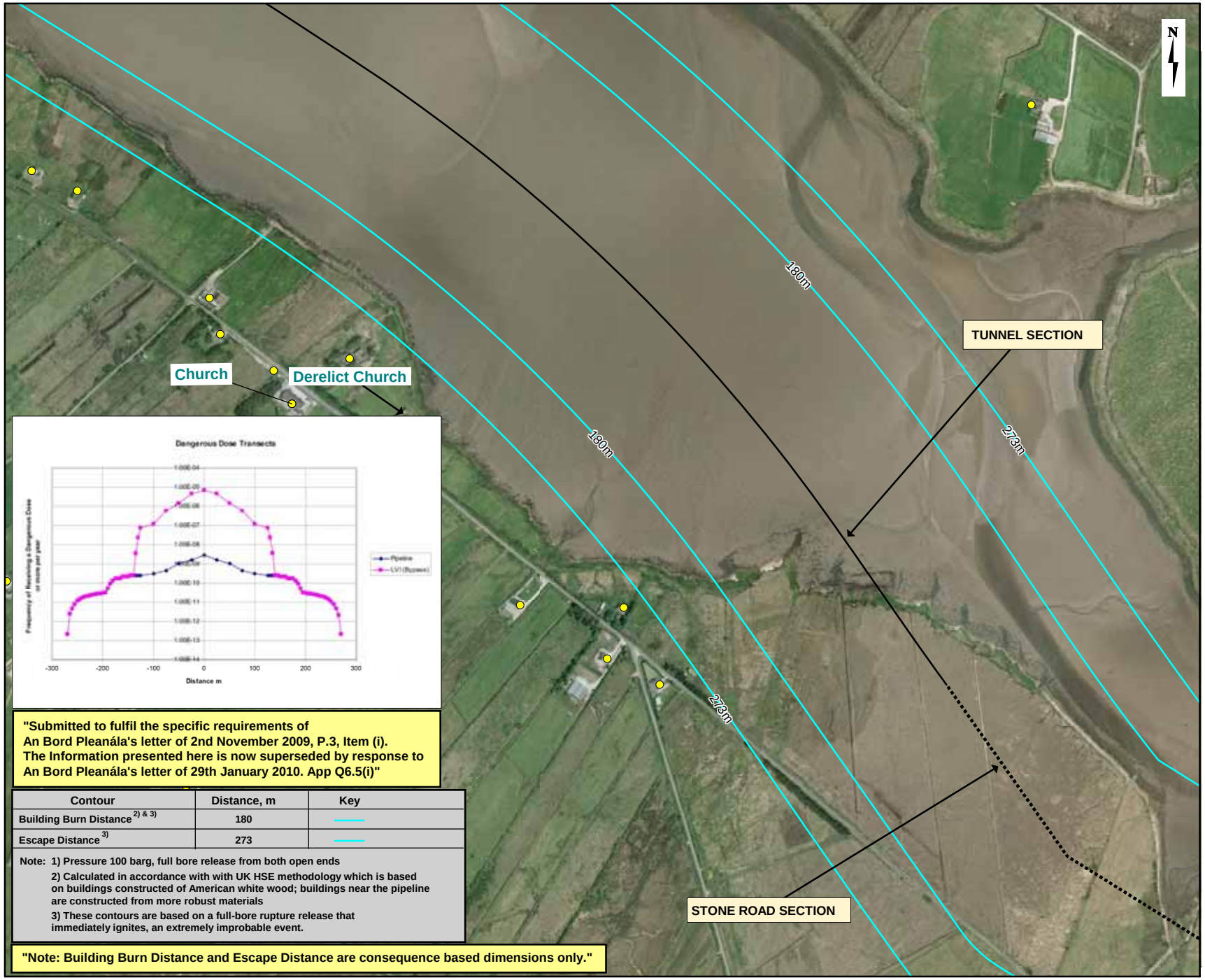
Response to An Bord Pleanála's letter of 2nd November 2009 P.3.Item (i).
(Sheet 4 of 7)

File Ref: COR25MDR0470Mi2485R03
Date: May 2010

CORRIB ONSHORE PIPELINE

Corrib natural gas

RPS



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Contour	Distance, m	Key
Building Burn Distance 2) & 3)	180	
Escape Distance 3)	273	

Note: 1) Pressure 100 barg, full bore release from both open ends
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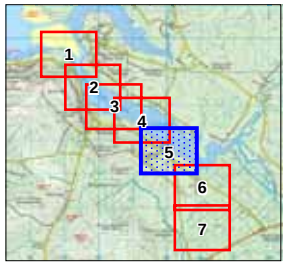
Proposed Route:

- Trenched Section
- Tunnel Section
- Stone Road Section

House Location



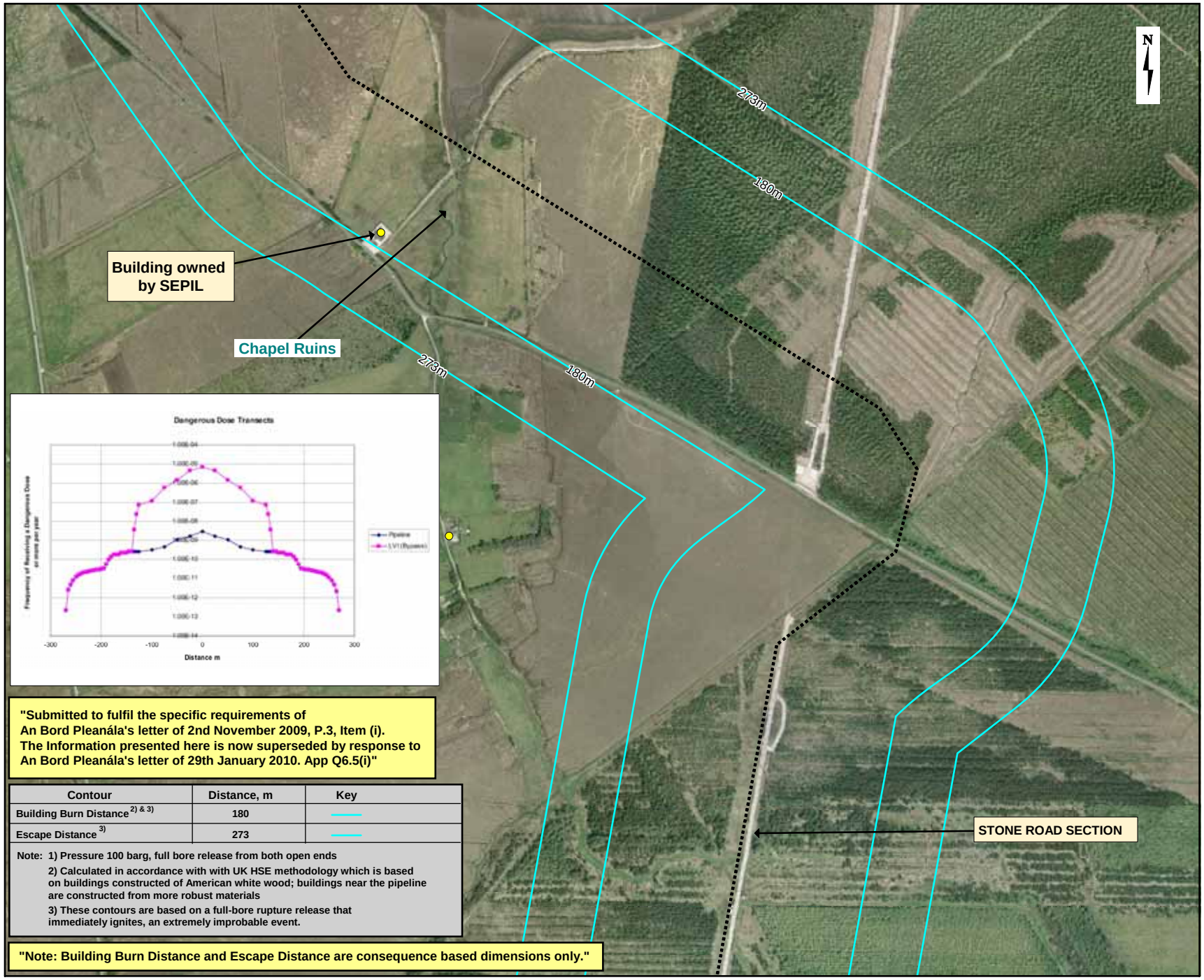
Response to An Bord Pleanála's letter of 2nd November 2009 P.3.Item (i).
(Sheet 5 of 7)

File Ref: COR25MDR0470Mi2486R03
Date: May 2010

CORRIB ONSHORE PIPELINE

Corrib natural gas

RPS



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Contour	Distance, m	Key
Building Burn Distance 2) & 3)	180	
Escape Distance 3)	273	

Note: 1) Pressure 100 barg, full bore release from both open ends
2) Calculated in accordance with with UK HSE methodology which is based on buildings constructed of American white wood; buildings near the pipeline are constructed from more robust materials
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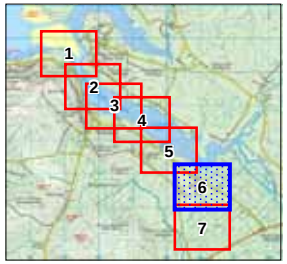

Response to An Bord Pleanála's letter of 2nd November 2009 P.3.Item (i).
(Sheet 6 of 7)

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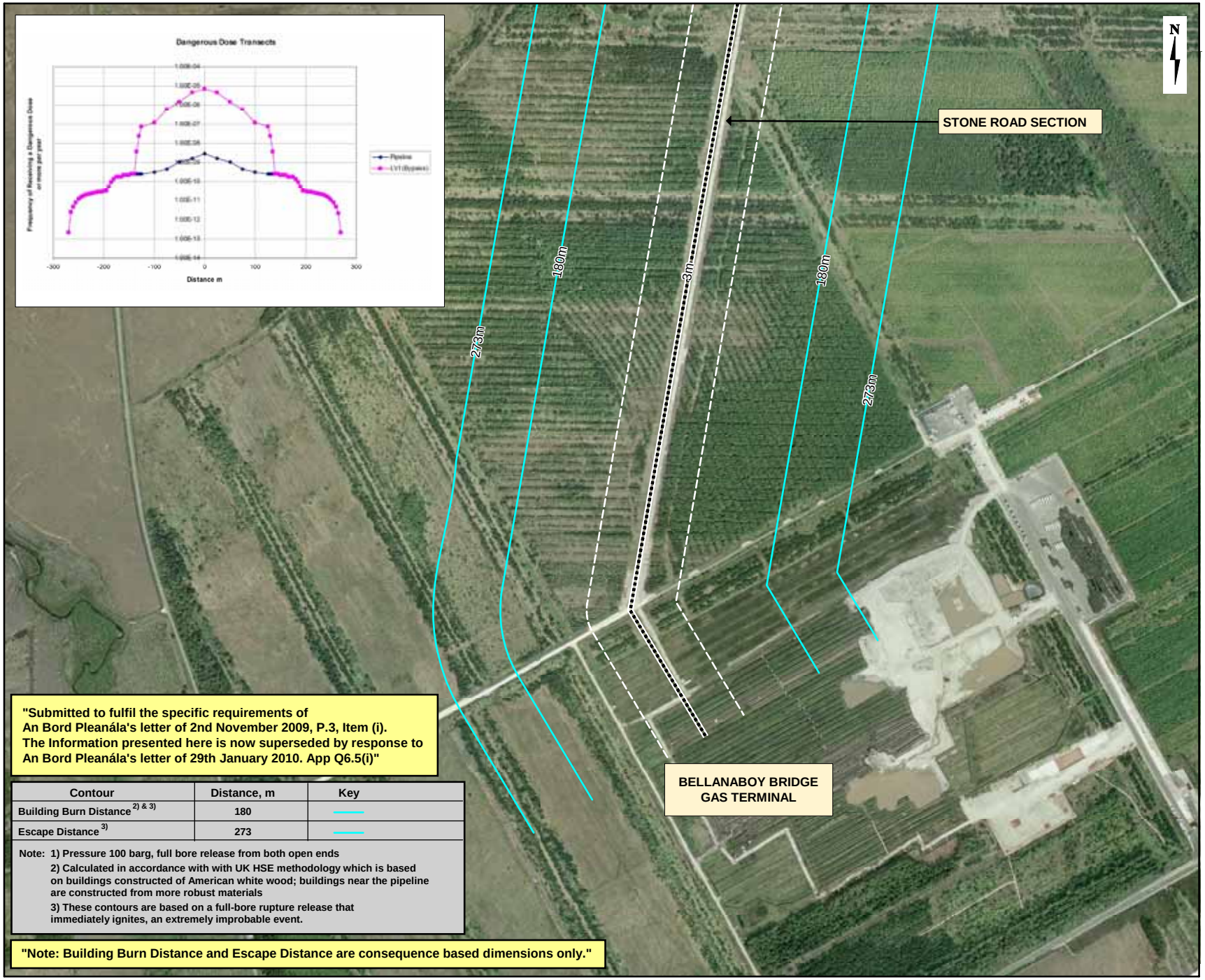
CORRIB ONSHORE PIPELINE

Corrib natural gas

RPS



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Escape Distance 3)	273	

Note: 1) Pressure 100 barg, full bore release from both open ends
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"Note: Building Burn Distance and Escape Distance are consequence based dimensions only."

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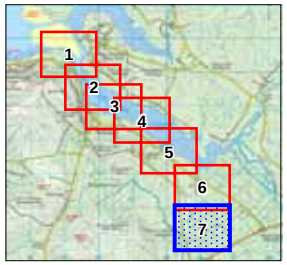
Proposed Route:

- Trenched Section
- Tunnel Section
- Stone Road Section

- House Location



Response to An Bord Pleanála's letter of 2nd November 2009 P.3.Item (i).
(Sheet 7 of 7)

File Ref: COR25MDR0470Mi2488R03
Date: May 2010

CORRIB ONSHORE PIPELINE

Corrib natural gas

RPS

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CORRIB GAS FIELD DEVELOPMENT PROJECT

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Q6.6 – EMERGENCY RESPONSE PLANNING AND PROVISIONS

DOCUMENT No: COR-14-SH-0069

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LIST OF FIGURES

LIST OF TABLES

ATTACHMENTS

1 INTRODUCTION

This document presents a summary of the emergency response arrangements that will be in place for the operation of the Corrib pipeline. It presents information regarding the provisions (e.g. plans and equipment) that will be established, key roles and responsibilities and the means by which it will be ensured that the emergency response plans will be fit for purpose for all credible emergency scenarios. Figure 1.1 in Chapter 1 shows the onshore pipeline routing. It also outlines the interface with the local public in such an event and how people will be informed during such an event.

The document specifically addresses major accident scenarios that may have the potential to escalate and threaten the public.

Note:
1. This document has been prepared for inclusion in the Corrib Onshore Environmental Impact Statement (EIS). It will ultimately cease to be a stand-alone document but instead be incorporated within the Corrib asset-wide documented Emergency Response Planning and Provisions.

2. As the route and detailed design of the onshore pipeline are fully developed, the pipeline specific aspects of this document will be finalised. Consequently parts of this document represent work in progress.

3. Formal liaison with Emergency Services and Mayo County Council will commence after planning permission has been granted, thus this document outlines the anticipated action and issues relevant to the role and involvement of those Agencies.

4. The term “Emergency Services” is used throughout this document to refer to the Principal Response Agencies (Gardaí, Ambulance Service, Fire Brigade) and the Coastguard.

2 INTERFACE WITH THE PUBLIC

An Emergency Response Plan is a mandatory regulatory requirement for pipeline systems in Ireland. SEPIL has given due consideration to the development of the proposed Emergency Response Plan which will be required to be put in place should the pipeline receive planning permission.

A key element of any emergency response system is the interface with the public and the following points highlight SEPIL intentions with respect to interfacing with the local community on issues relating to the Emergency Response Plan.

2.1 COMMUNITY LIAISON

Prior to the pipeline becoming operational SEPIL plant personnel responsible for emergency provisions, will liaise with all residents living within a pre-determined emergency planning zone. Part of this liaison will be to ensure that residents are briefed on the specific details of what they are advised to do in the case of an emergency and how they would be contacted.

It is proposed that residents would receive an information pack containing briefing material on what to do in an emergency, with all relevant contact details of emergency response services. The briefing pack would also contain details of the automated IT contact system (see below) to be operated by SEPIL emergency response. This information will also be published on the SEPIL website.

2.2 PUBLIC NOTIFICATION

The Bellanaboy Bridge Gas Terminal will be equipped with an automated IT system to enable rapid and synchronous notification of all parties in the event of an incident associated with the pipeline. The system will allow for messages to be entered at the Gas Terminal and will then in turn relay the message to all the telephone numbers held within the system database

Prior to commencement of pipeline operations, all dwellings within a specified distance of the pipeline route will be contacted and invited to submit their priority contact details for entry into the automated system. Local residents and other relevant community neighbours can register their details, only if they wish to do so. It will be the ongoing responsibility of the Terminal HSSE Advisor to ensure that these important details are maintained up to date. The information will be retained as confidential strictly for use in an emergency or if an exercise is being planned of which the public should be made aware

2.3 INFORMATION DURING AN INCIDENT

The following information will be released to the general public during an incident:

- Type of incident
- Location and proximity of the incident to people in the vicinity
- Actions the general public should take
- Action being taken to correct the situation and time period anticipated
- Contacts for additional information

3 OVERVIEW OF PIPELINE EMERGENCY RESPONSE SCENARIOS

Emergency Response Plans are a mandatory regulatory requirement for pipeline systems in Ireland. Any Emergency Response system is developed on the basis that, although extremely unlikely, adverse events may occur (should the preventative measures fail). An Emergency Response Plan, however does not provide any indication of the likelihood of such events occurring in practice. The design and operational controls in place to minimise the possibility that such events may occur are discussed in detail in Appendix Q6.3.

The hazard assessment studies performed for the Corrib pipeline are brought together in the Qualitative Risk Assessment (Appendix Q6.3), with detailed consequence effects e.g. distances, contained within Appendix Q6.4. From these studies, the following major accident scenarios with the potential to threaten the public exist for the pipeline:

- Hydrocarbon release from subsea facilities (wells, flexible flowlines, manifold or offshore pipeline);
- Hydrocarbon release from LVI; and
- Hydrocarbon release from onshore pipeline;

The design and operational controls in place to minimise the possibility that such events may occur are discussed in detail in the Qualitative Risk Assessment in the form of bowtie diagrams.

3.1 HYDROCARBON RELEASE FROM OFFSHORE PIPELINE

Potential causes of a release from the offshore pipeline (including the small on-land section up to the LVI) are described in the Qualitative Risk Assessment together with detailed review of the preventative controls. Should a release occur, the credible outcomes are:

- an unignited, relatively small leak of hydrocarbons;
- an unignited large hydrocarbon release or rupture; and / or
- an ignited release with associated fire effects.

For the majority of the offshore pipeline length, should a release occur, any released gas will be into deep water and hence it is probable that the gas will disperse to below its lower flammable limit and cannot be ignited. Should the release occur in shallower water near-shore, then the possibility exists that ignitable gas clouds (i.e. above the lower flammable limit) may occur (which may impact persons onshore) and, for the duration of the release, the gas may cause a reduction in water density (affecting buoyancy) which may affect any nearby vessels.

The potential environmental effects of any release are minimal as the hydrocarbon fluids contain only very small amounts of condensate, methanol and water.

3.2 HYDROCARBON RELEASE FROM LVI

Potential causes of a release from the LVI are described in the Qualitative Risk Assessment together with detailed review of the preventative controls. Should a release occur, the credible outcomes are:

- an unignited, relatively small leak of hydrocarbons;
- an unignited large hydrocarbon release; and/or
- an ignited release.

Should a large ignited event occur, then possible consequences may be a jet fire (should ignition occur immediately) or a flash fire (should gas accumulate and later ignite).

The LVI is a normally unmanned installation and is remote from occupied dwellings. There are few ignition sources at the LVI; all electrical systems are installed and maintained to the appropriate

hazardous area classification and hot work is an infrequent occurrence managed and controlled by the permit-to-work system.

As noted above, the potential environmental effects of any release are minimised as the gas has only very small amounts of condensate, methanol and water. For any releases occurring at the LVI, there are drainage and spill containment systems to further reduce the potential for offsite effects.

3.3 HYDROCARBON RELEASE FROM ONSHORE PIPELINE

Potential causes of a release from the onshore pipeline are described in the Qualitative Risk Assessment together with detailed review of the preventative controls. Should the preventive measures fail and one of the potential causes result in a hydrocarbon release, the magnitude of any consequences will primarily be determined by the size of the hole in the pipeline and the operating pressure at that time. Should a release occur, the credible outcomes are:

- an unignited, relatively small leak of hydrocarbons;
- an unignited large hydrocarbon release; and/or
- an ignited release.

For the purposes of emergency response planning, the majority of potential pipeline releases taken into account would be from small holes rather than rupture of the pipeline itself. For these majority cases, depending on whether the gas immediately ignites (in which case a jet fire will occur) or disperses (in which case should an ignition source be found, a flash fire may occur) the extent of possible harm has been assessed in Appendix Q6.4.

For a rupture on land, very early ignition of the release generally results in a fireball which then rapidly dies back to a jet fire burning within the crater formed by the force of the release. The intensity of the fire will decline as the pressure within the pipeline reduces.

For releases underwater (i.e. in Sruwaddacon Bay), as with the offshore section, some dispersion may occur as the gas passes through the water, however this will depend on the water depth at the release point, and the potential hence exists for a gas cloud above the lower flammable limit to form at the surface and/or localised buoyancy effects. Although the pipeline is encased within a fully grouted tunnel for the underwater section (providing additional protection against impact and also ignition), the tunnel is not intended to be gas-tight, and hence any small releases will be revealed as surface bubbles, allowing for corrective actions to be taken.

4 MANAGEMENT OF EMERGENCY RESPONSE FOR THE CORRIB DEVELOPMENT

The Corrib Gas Field Development comprises four distinct but inter-related elements:

- reservoir and offshore seabed installation (subsea wells, wellheads and manifold);
- offshore gas pipeline (between the wellheads and landfall at Glengad);
- onshore gas pipeline between landfall and the gas terminal at Bellanboy including the Landfall Valve Installation (LVI), at Glengad; and
- Bellanboy Bridge Gas Terminal and export to the Bord Gáis Éireann (BGE) operated pipeline.

Emergency response for the entire Corrib asset operations will be managed in an integrated fashion, with a single internal organisation responsible for ensuring appropriate response to emergencies within Corrib associated with any of the four elements from the offshore wells through to the point of export of treated natural gas to the BGE pipeline. SEPIL's emergency response arrangements will provide support and back-up to the active response provided by the emergency services and Mayo County Council as required by the exact nature of the situation.

The emergency response arrangements for operation of the Corrib facilities will be documented in the operation's Emergency Response Management System documentation, which ensures that the findings of the facility and pipeline safety assessments are used to identify the credible foreseeable emergencies and to prepare and test the emergency plans.

The emergency response organisation consists of three tiers that provide the operational, tactical and strategic response to dealing with a major incident or emergency. These three tiers are based on emergency response being handled at the incident site (Local Response Team, LRT), with emergency management and strategic support being provided by an Emergency Co-ordination Team (ECT) at SEPIL's Belmullet office and crisis management being provided for by the SEPIL Crisis Management Team (CMT) based in Corrib House in Dublin. For significant offshore incidents, management of the response is escalated up to Shell's Dispatch Co-ordination Centre in Aberdeen.

At all stages, the local Emergency Services will be fully involved in management of on-the-ground activities.

4.1 DEFINITIONS AND CLASSIFICATIONS

In the context of this document the following definitions are used by SEPIL:

Emergency

"Any sudden, abnormal or unplanned situation, which requires immediate attention and may endanger human life or the environment."

Emergency Response

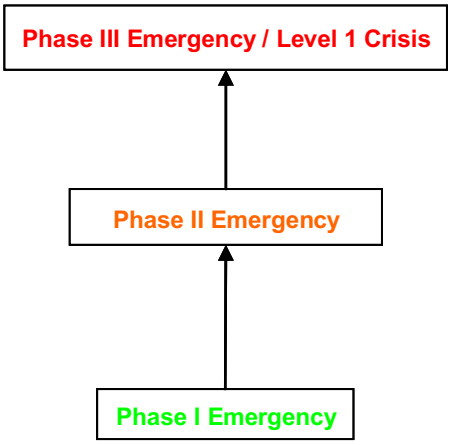
"The marshalling of support to physically intervene and respond to an emergency such that the situation is brought under control in order that recovery measures can be implemented."

Crisis

"Any event, or series of events, that falls outside normal business contingency and emergency response arrangements"

Whilst an emergency may escalate into a crisis, it must be recognised that this will not always be the case. The Duty Manager will make the decision whether or not "emergency response" needs to be escalated to "crisis response".

Escalation of an Emergency to a Crisis



Local Crisis
An incident occurs at a local business level and is not likely to have immediate country or broader business implications.

Local Emergency
A local incident that requires immediate attention
To re-establish control

Location Emergency
A non-routine situation needing immediate attention (e.g. medical, minor fires and oil spills)

Escalation of the situation is defined using "Emergency phases" (Phases I to III) and "Crisis levels" (Levels 1 to 3). There is a crossover point when an "Emergency" becomes a "Crisis" and this occurs at "Phase III Emergency / Level 1 Crisis".

Emergency Phases

Phase I Emergency ***- Location Emergency***
A non-routine situation needing immediate attention (e.g. medical, minor fires and minor spills)

Emergencies will be reported to the Location Manager (anyone who is responsible for managing the situation at a local level, i.e. Plant Installation Manager). A Location Response Team (LRT) will be formed to support the Location Manager.

The Location Manager will inform the Emergency Co-ordinator (EC) and, if the situation allows, their Asset Leader. If the situation escalates, the EC will liaise with the location Asset Leader to declare an emergency.

Depending on the nature and location of the emergency, the EC will constantly monitor the requirement for alerting/involvement of local services (Gardaí, ambulance, fire brigade, coastguard) to assist in managing the incident and ensuring public safety.

Phase II Emergency ***- Local Emergency***
A local incident that requires immediate attention that is not under control

If an emergency is called, the EC is responsible for managing the situation. The EC will mobilise the Emergency Co-ordination Team (ECT), and inform the Crisis Management Team (CMT) depending on the situation.

If an ECT is assembled, they will provide support to the Location Response Team. The EC shall follow initial verbal notification by a written incident summary for all events to the CMT.

Phase III Emergency / Level 1 Crisis ***- Local Crisis***
An incident occurs that has the potential to have wider implications.

If a crisis is called the Crisis Management Team (CMT) will convene in a Crisis Room (in Dublin), with the CMT leader responsible for managing the crisis in support of the affected Asset and addressing broader and longer-term implications.

In consultation with local Asset/Country management, the UIE duty manager will decide what resource and support is needed and, if the crisis escalates, whether to activate the UIE Regional Crisis Team.

The focus of this document is emergency response and thus crisis management is not further described in this document.

4.2 SAFETY AND EMERGENCY RESPONSE POLICY & PHILOSOPHY

The SEPIL commitment to emergency response is shown in the Emergency Response Policy.

Figure 4.1: Emergency Response Philosophy

Shell E & P Ireland Ltd. Emergency Response Policy

Shell E & P Ireland Limited (SEPIL) recognise that their operations and activities have the potential to give rise to emergencies and will seek to conduct its operations in such a way as to prevent harm to its employees, contractors, the community and the environment. This is in accordance with GOAL ZERO.

SEPIL will manage Emergency Response such that, in the event of an emergency, the harmful effect to people, the environment and assets are minimised and SEPIL and the Shell Group's reputation are safeguarded.

This policy is in accordance with the SEPIL Health, Safety and Environmental Policy and relevant Irish legislation.

SEPIL will retain an effective means of managing any emergency event which may occur in its operations. This will be achieved by:

- Clearly identifying responsibilities for emergency preparedness and response
- Ensuring that effective plans, organisations, procedures and resources are in place
- Responding effectively to any emergency under our operational control to minimise impact
- Carrying out exercises to test the effectiveness
- Reviewing the totality of arrangements in the light of experience gained from audits, exercises and response to real emergencies
- Implementing identified improvements.

Terry Nolan

Managing Director

Shell E&P Ireland Limited

The underlying philosophy of the Corrib facility's Emergency Response arrangements is to minimise:

- Risk to life i.e. harm to public, staff, contractors, visitors and the Emergency Services;
- Any possible harmful effects on the environment; and
- Damage to facilities and infrastructure.

With these critical and overriding objectives in mind, much of the plans and procedures are based upon minimising direct exposure of people to risk while containing and mitigating the consequence of any loss of control that creates an emergency situation.

In the event of an emergency all facility personnel are trained and instructed in the correct response to the various scenarios as described further in this document.

All planned responses are based upon quickly and effectively:

- Evacuating all personnel away from the area(s) of risk and into a safe location.
- Protecting the local community.
- Protecting the environment.
- Mitigating the effects of the emergency in other ways that are practical and do not increase the overall risk.

4.3 KEY CONTROLS

Due to the pipeline and terminal's location, the response, control and mitigation of any potential emergency situation are designed as far as is practicable to be self-sufficient.

Prompt direct intervention by the operations personnel and executive action by the automatic safeguarding systems is specifically designed to prevent an escalation of any emergency event. Operations personnel will take initial action in accordance with the final emergency response plan (e.g. gas test, cordoning, alerting) until such time as the public services arrive.

While the pipeline is designed and will be operated to prevent any uncontrolled/unintended events potentially leading to emergency situations, it is essential that plans and procedures must be in place to enable the recovery of control and mitigation of the consequences, however unlikely. Consultation, co-ordination and co-operation with the Emergency Services is a vital part of any emergency response plan to ensure they can fulfil any required roles and also are fully aware of any potential hazards associated with response to such incidents.

The plans and procedures for any unwanted event are to a significant degree based upon the robust and comprehensive automatic detection and shutdown systems described in greater detail in Appendix Q6.3.

Essentially, the pipeline routing and separation from occupied areas, remote location of the LVI, together with the manning strategy, effectively limits the numbers of people exposed to potential risks.

Maintenance and other activities that involve process interventions will, with the exception of some approved routine activities, be planned and executed during normal dayshift schedules. All activities whether on dayshift or nightshift will only be permitted following the appropriate level of risk assessments and controls including the Integrated Safe System of Work Permit Procedures. Note also that limitations will be in place in the Operation's HSE Case, as to the type and scale of activities that are permitted to take place during periods of lower manning levels and also during times where equipment and operational systems are taken out of service or have their effectiveness reduced.

Training, formal assessment, competence assurance, supervisory and management controls additionally enhance the inherent safe design features of the Corrib pipeline.

4.4 EMERGENCY RESPONSE MANAGEMENT SYSTEM

Emergency response for the pipeline will be managed in an integrated fashion, with a single internal organisational structure responsible for an appropriate response to incidents both at the pipeline and at the Gas Terminal through the emergency services and Mayo County Council as appropriate. With these objectives in mind, the Corrib Emergency Response Management System (ER-MS) will ensure all personnel know their roles, responsibilities and responses should an emergency occur at the Corrib facilities; defining the Emergency Response Organisation, philosophy and principles, together with all required actions.

It is recognised that such a management system cannot cover every emergency situation that may arise, however the effectiveness of the response depends on individuals being aware of their responsibilities and accountability within the framework of the emergency procedures. The actions taken in the event of an emergency will depend on the circumstances at the time, and hence the ER-MS acts as guidance for dealing with emergency situations.

The ER-MS is intended for several groups of target readers, including:

- Regulatory bodies and agencies such as Gardaí, Health and Safety Authority, Irish Coastguard, Health Service Executive, Department of Communications, Energy and Natural Resources, Commission for Energy Regulation and Fire Services who provide support or interface with SEPIL in the event of an emergency on the Corrib Facilities.
- All Corrib personnel, specifically those with Emergency Response duties;
- Other Shell personnel that may support Emergency Response;
- Contract companies and their personnel who interface with SEPIL on the Corrib Facilities;

4.4.1 ER-MS Owner and Custodian

The Gas Terminal Plant Installation Manager is accountable for the content of the ER-MS and for ensuring that sufficient competent resources are available to respond to any foreseeable emergency associated with the Corrib Facilities.

The Gas Terminal Health, Safety, Security and Environmental Advisor is responsible for ensuring that the ER-MS remains a controlled document, which is updated and revised as necessary.

4.4.2 ER-MS Review Periods

It is the responsibility of the Gas Terminal HSSE Advisor to ensure that the contents of the Emergency Response management system are updated as appropriate e.g. telephone directory is checked every six months etc. All relevant changes will be communicated to the SEPIL HSE Coordinator immediately.

The Gas Terminal review and audit programme includes Emergency Response as either a potential stand-alone subject, or integral with, for example a HSE MS audit. This will be incorporated as part of the agenda for the SEPIL HSE Committee meetings and significant conclusions of any audits and reviews will be included in the Annual Assurance Letter

Review and, if necessary, updating of the Gas Terminal ER-MS will take place:

a) In accordance with the facility's review programme (Table 4.1)

b) As a minimum on an annual basis as part of the HSE-MS review;

c) When changes occur that may impact the major accident hazards or how they are managed;

d) When hardware or software changes occur which may impact the document contents;

e) To implement mandatory Emergency Response requirements from Shell Group, UI or UIE.

After each revision of the document the changes will be communicated to the relevant individuals involved and the latest version uploaded the document management system. Superseded versions will be archived.

Table 4.1: ER-MS Review Programme

Emergency Response Management System Maintenance	As Required	Six Monthly	Annually
Directory Amendments	X		
Update due to operational changes	X		
Emergency Response resource review	X	X	
Emergency Response management system review			X

4.4.3 ER-MS Standards

The Corrib Asset ER-MS will be compiled in accordance with all legal and regulatory requirements for Emergency Response together with relevant Shell standards for emergency response and crisis management. It is the responsibility of the Gas Terminal HSSE Advisor to identify and include any updates required by changes in external documentation and/or legislation.

5 PIPELINE EMERGENCY RESPONSE PROVISIONS

5.1 DESIGN LAYOUT

The design of the pipeline routing and landfall valve installation (LVI) has been placed to achieve separation from locations where people (both public and plant personnel) may be present. The LVI is unmanned during normal operations (monitored from the terminal control room) and all initial emergency response will be from the terminal control room which is designed to give a high degree of protection to its occupants from any incidents occurring at the pipeline or terminal.

5.2 RELEASE DETECTION

The primary means of detecting releases from the pipeline system will be from process monitoring and alarms at the Gas Terminal control room. Depending on the size and location of any release, the following systems may be used:

- Pipeline mass balance
- Fibre optic system
- Well pressure sensors
- Terminal pressure/flow sensors
- Personnel intervention
- CCTV at the LVI.

5.2.1 Pipeline Mass Balance

The pipeline mass balance is a dedicated leak detection system that compares the pressures and flows from the subsea wells and the terminal using statistical and mass balance techniques. It monitors both the onshore and offshore sections with an interface to the Gas Terminal Distributed Control System that alerts the operator in the event of a problem. The speed of response of the mass balance system will be influenced by the magnitude of the release, allowing for the more onerous, larger, releases to be detected most rapidly.

5.2.2 Fibre Optic System

The onshore pipeline is to be fitted with a fibre optic system that will have dual functions of detecting disturbance (e.g. from an external digger) and also leak detection by registering the sound signature and reporting to the terminal control room.

5.2.3 Well Pressure Sensors

Each well is fitted with pressure sensors at the Xmas tree which, in the event of a major release from the offshore flexible flowline, will raise a low pressure alarm to the terminal operator.

5.2.4 Terminal Pressure/Flow Sensors

Low pressure trip and loss of flow into terminal will automatically stop terminal processes and cause equipment to shutdown, allowing for operator intervention to isolate the pipeline (e.g. at the wells, at the LVI).

5.2.5 Personnel Intervention

In addition to the above systems, releases may also be identified by plant personnel, security patrols or members of the public e.g. from water discolouration, noise of release, vapour cloud. It should be noted, however, that given the pipeline routing away from occupied areas no reliance is placed on external notification of a release.

Information will be provided to all local residents and notices posted (e.g. at the LVI) of actions to be taken if a release is suspected and of contact details.

5.2.6 CCTV

CCTV is provided for the interior and exterior of the LVI which may give a visual alert to the terminal control room operators of releases in this area from vapour signs.

5.3 SAFEGUARDING EMERGENCY SHUTDOWN

The pipeline is protected against overpressure scenarios by a number of layers. A detailed description of the layers of protection is given in Appendix Q4.5.

In the event of an incident, the shutdown levels cascade to place the terminal and pipeline progressively into a safer and safer condition.

5.4 ISOLATION

Isolation of various parts of the pipeline may be both manually initiated by the control operator or automatically by the plant protection systems. Dependent upon the exact nature of the emergency situation, isolation may be performed at:

- Individual Wells
- Pipeline End Manifold (by remotely operated vehicle (ROV))
- Landfall Valve Installation (LVI)
- Terminal Isolation Valve

5.5 DEPRESSURISATION

Where required by a loss of containment emergency situation, the control room operator may isolate the affected part of the pipeline either by closing the offshore wells or isolating at the LVI, and then may perform a controlled drawdown (or emergency blowdown using the flare) of the pipeline pressure using the terminal facilities, to reduce the pipeline pressure and hence outflow rates (See Appendix Q4.5).

5.6 COMMUNICATIONS TO SUPPORT EMERGENCY RESPONSE

An example of a Notifying the Emergency Services list for use by operators is shown in Attachment Q6.6A. A list of Relevant Emergency Contact Numbers will be completed at the appropriate time. A list such as this will be in place during pipeline operations and will be continuously updated.

5.6.1 Telephone System

In addition to the Gas Terminal internal telephone system, telephones with the ability to dial external numbers and the ability to receive calls directly from outside numbers and mobile numbers are provided at various locations. These telephones operate on the Private Automatic Branch Exchange which, in the event of failure is backed up by the Public Switch Telephone Network (PSTN) telephones located:

- Security x 2
- Control Room x 2
- Plant Installation Manager’s Office
- Production Supervisors Office
- HSSE Advisors Office
- Conference / Main meeting Room
- Telecommunications Equipment Room for testing and general use.

The LVI will be fitted with a landline telephone connection and is also covered by a mobile phone network.

In the event of failure of the PSTN, the Gas Terminal has a Vodafone cell on site in the telecommunications equipment room providing mobile phone coverage over the entire SEPIL land plot and pipeline route. The only type of mobile phones permitted on site are Intrinsically Safe mobile phones which are provided for staff working at the LVI and authorised personnel working on the Gas Terminal.

See also Section 2.2.

5.6.2 Plant Radio System

A UHF radio system is provided to give coverage throughout the entire Gas Terminal site, with sufficient spare radios to issue to Emergency Services' personnel on arrival at the terminal. This would be done in accordance with pre-incident planning agreements. The radios have four channels;

- Operations
- Maintenance
- Security
- Emergency Response

For pipeline incidents off the main terminal site, intrinsically safe mobile phones will be used to allow for communications between the Location Response Team members and the control room.

For offsite incidents, the emergency services will manage their own communications systems using their existing systems. A common centre e.g. the control room, will be designated, where command personnel e.g. the Chief Fire Officer and the Site Main Controller, will be located, allowing for close communication between all parties.

5.7 EMERGENCY EQUIPMENT

The dedicated Emergency Response Equipment storage base will be located at the terminal and will contain the following equipment:

- Breathing Apparatus (BA) Rescue Team equipment
- Additional PPE for fire fighting team
- Stretchers
- Chemical Spill Response Team equipment
- First Aid Equipment

Transportation of Emergency BA equipment will be via use of the on site Emergency Response Vehicle and Trailer.

Mobile and hand-held fire extinguishers are provided at the LVI and at the terminal.

In addition to the above, a contract is maintained with a specialist pollution response organisation providing 24 hour cover for any onshore events. Pollution response offshore will be coordinated with the Coastguard, with access to Shell's resources where required.

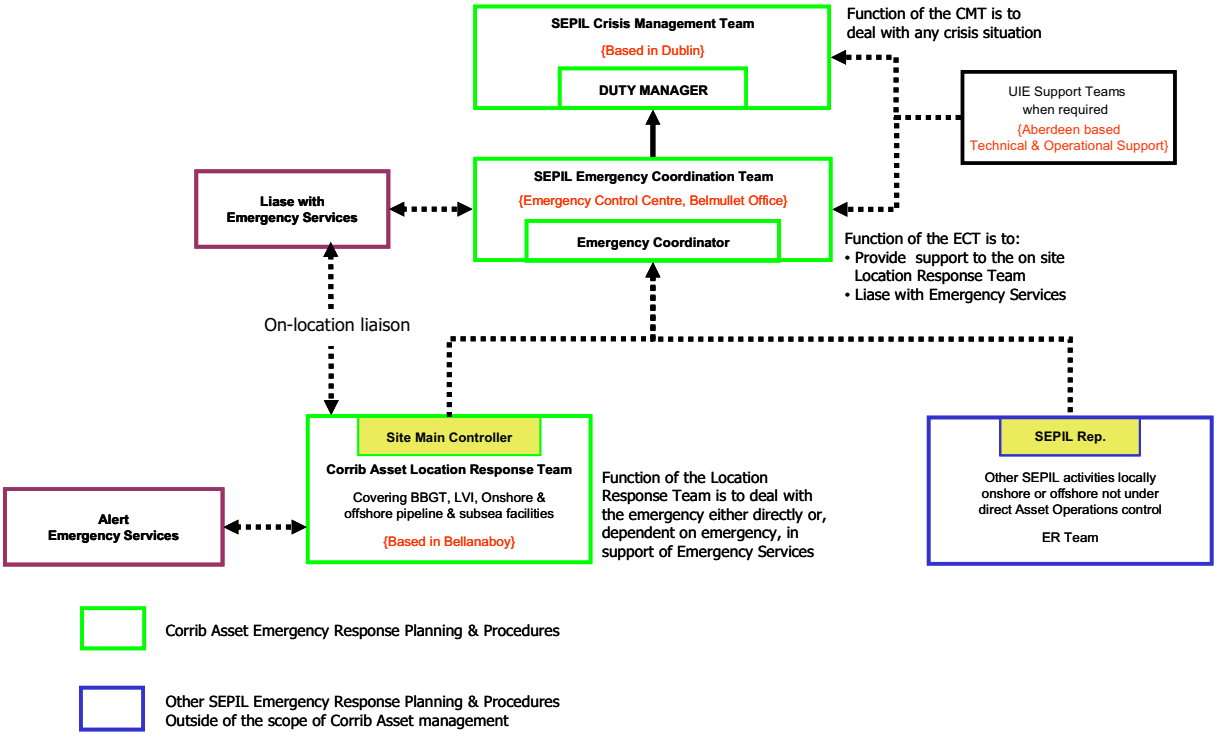
6 EMERGENCY RESPONSE ORGANISATION AND STRUCTURE

As noted earlier, emergency response for the entire Corrib operations will be managed in an integrated fashion, with a single internal organisational structure in place to ensure appropriate response to emergencies associated with any part of the operation, from the offshore wells through to the point of export to the BGE pipeline. SEPIL's emergency response arrangements will provide support and back-up to the active response provided by the emergency services and Mayo County Council as required by the exact nature of the situation.

6.1 SEPIL EMERGENCY RESPONSE STRUCTURE

The emergency response organisational structure shown in Figure 6.1 shows the SEPIL structure and interface with Shell in Aberdeen and elsewhere (where offshore emergency response, e.g. for well loss of containment, expertise is based and would play a critical role in technical and recovery support). It is the organisation that will address any emergency, or potential emergency within, or associated with, the Corrib facilities.

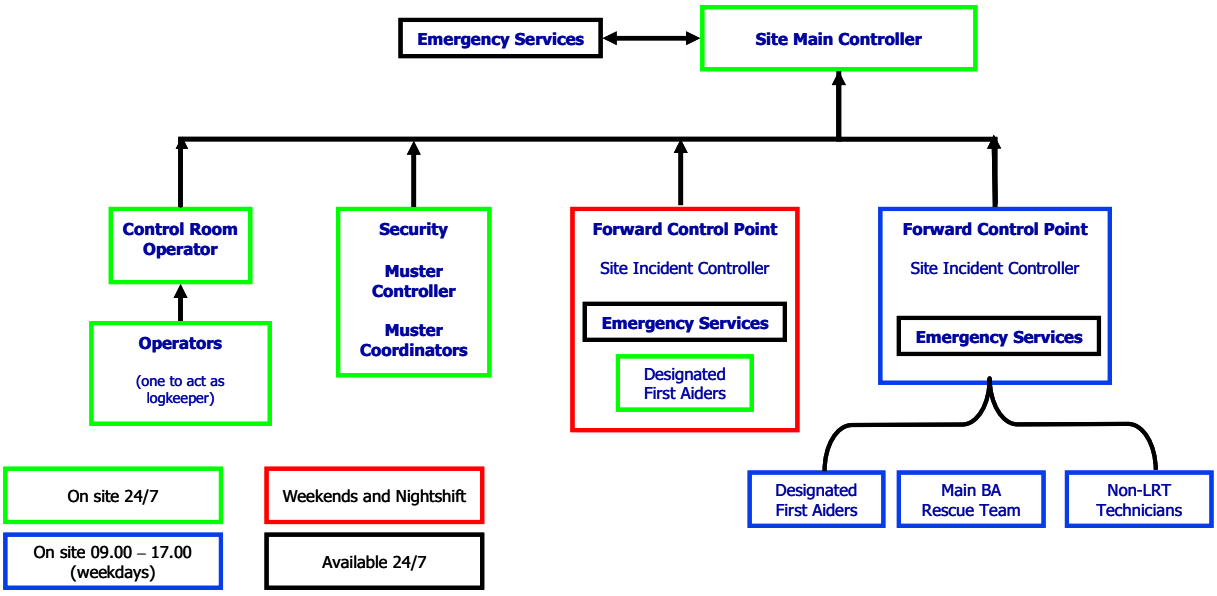
Figure 6.1: Emergency Response Structure for SEPIL Organisation



6.2 LOCATION RESPONSE TEAM ORGANISATION

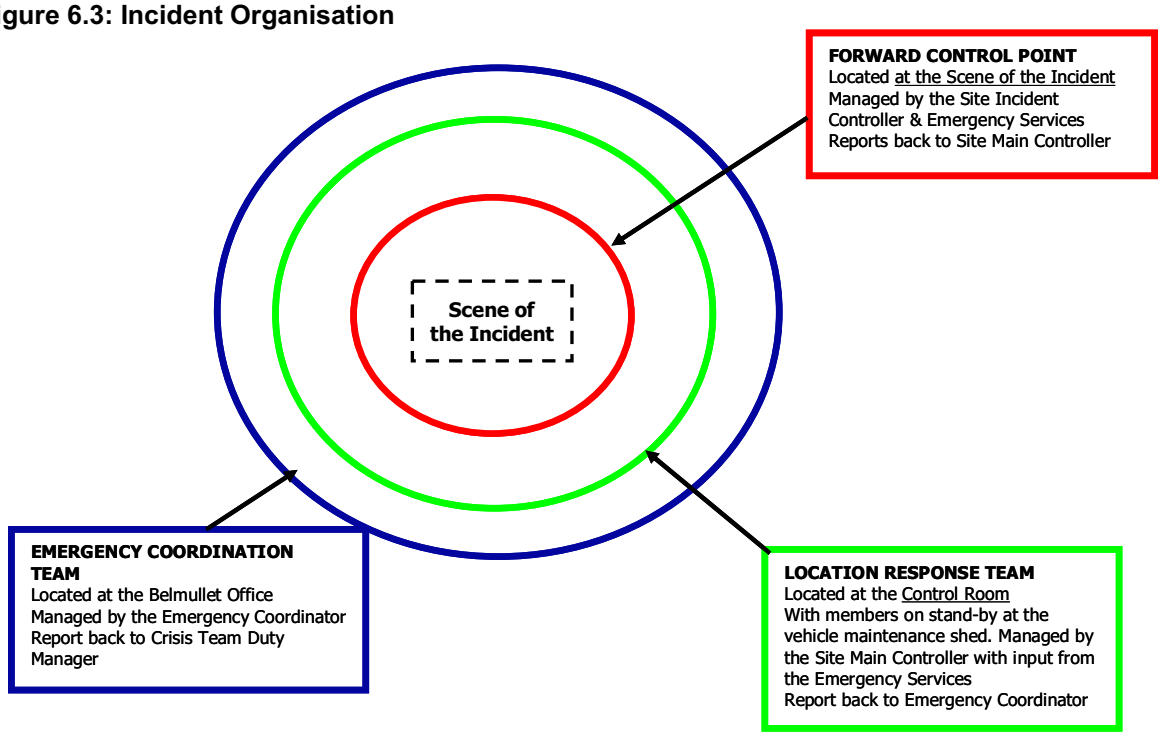
In the event of an emergency situation occurring on the pipeline the Location Response Team will be mobilised to deal with the situation. The Location Response Team leader is called the Site Main Controller. He/she will contact the Duty Emergency Coordinator (ECT Lead) who will decide whether or not to mobilise the ECT.

Figure 6.2: Location Response Team Structure



The Site Main Controller manages the incident from the Control Room and directs the Site Incident Controller who is based at the Forward Control Point at the scene of the emergency (see Figure 6.3). The Operators and Technicians will be trained as BA Rescue teams, First Aid Fire Fighting Teams etc. Security will provide First Aid cover and muster checking arrangements.

Figure 6.3: Incident Organisation



There is ongoing liaison for all the facilities with the Principal Response Agencies, namely the Fire Services, Gardaí and Health Services Executive (Ambulance service provider). In particular, this has ensured for a coordinated and effective response to an emergency event requiring support from external emergency services. This liaising will be formalised for the pipeline once planning permission has been granted.

The onshore and nearshore pipeline and LVI external emergency response planning will be developed jointly with the Principal Response Agencies, to record:

- Interface arrangements, including roles and responsibilities and communications requirements;
- Incident specific scenario analyses including, as appropriate, the use of physical effects modelling to enable communication and understanding of how each scenario may develop.

For significant incidents, the roles and responsibilities of the Principal Response Agencies are defined in the Mayo County Council “Major Emergency Plan” 2008.

For incidents at offshore facilities, SEPIL will comply, as applicable, with the DCENR’s Rules and Procedures Manual for Offshore Petroleum Production Operations. As with onshore incidents, emergency response planning will be developed in consultation with the Coastguard for their approval to cover interface arrangements and response for all incidents occurring on water.

7 EMERGENCY RESPONSE ROLES

7.1 ROLE OF THE PLANT INSTALLATION MANAGER OR APPOINTED DELEGATE

- The Plant Installation Manager is ultimately responsible for ensuring that, at all times, that adequate emergency response arrangements exist to cover the entire Corrib facilities.
- Holds overall responsibility for Emergency Response Management of the Gas Terminal, pipeline and wells.
- Ensures that only competent personnel are appointed to positions on the Location Response Team.
- Liaises with Emergency Services.

7.2 ROLE OF THE HSSE ADVISOR

- Ensures the emergency response documentation is maintained up to date in accordance with the relevant statutory provisions, any organisational or technical changes that may occur, and any Shell requirements
- Ensures all training and drill exercises are incorporated into the Gas Terminal HSSE Plan and carried out accordingly

7.3 ROLE OF LOCATION RESPONSE TEAM MEMBERS

The roles and responsibilities of all of the Location Response Team Members (shown in Figure 6.2) will be included in detail in the Corrib asset-wide documented Emergency Response Management System. The roles of the Site Main Controller and Control Room Operator are given below.

7.3.1 Role of the Site Main Controller

(Normally the Shift Supervisor based in the Control Room)
The initial responsibility for managing an incident will be with the on Duty Operations Shift Supervisor who assumes the role of Site Main Controller (SMC). Should the SMC be incapacitated then a pre-appointed stand-in (normally the CRO) will assume the role.

The role of SMC is crucial to ensure that the initial and ongoing response to any incident is robust, co-ordinated, and effective. In order to ensure this can be achieved, persons undertaking this role have the appropriate skills, knowledge, experience, and training.

Note: Depending on the emergency scenario and based on pre-incident planning agreements, the Site Main Controller may hand over overall on-site emergency management responsibility to the Emergency Services. In this case the intervention and control responsibilities below would, after handover, alter. However, the individual's fundamental responsibility for ensuring internal coordination and communication remains.

7.3.2 Role of the Control Room Operator (CRO)

The role of the CRO is to control the incident during an emergency event and to assist the Site Main Controller in responding to the incident by monitoring the wells, pipeline and plant and all safety systems from the Control Room (if safe to do so) and advising the Site Main Controller of any significant changes or developments.

7.4 ROLE OF THE EMERGENCY COORDINATION TEAM (ECT)

The role of the Emergency Coordination Team is to provide additional support to, and to reduce the administrative burden of the Location Response Team.

The duties of the Emergency Coordination Team will be included in detail in the Corrib asset-wide documented Emergency Response Management System.

7.5 DUTIES OF THE EMERGENCY SERVICES LEAD AGENCY

The mandate of the Lead Agency is described in Appendix A9 (pp. 82-83) of the Mayo County Council "Major Emergency Plan" 2008.

7.5.1 Duties of the Emergency Services Upon Arrival at Scene

The following is proposed as the basis for discussion and agreement with the Emergency Services following receipt of planning permission:

1. Mobilise to the pre-agreed Rendezvous Point (RVP)
2. Issue intrinsically safe radios compatible with the Gas Terminal LRT radios
3. Obtain a briefing from the Site Main Controller or his delegate on:
    a. The nature of the event,
    b. Missing or injured persons
    c. Possible escalation scenarios
    d. Any essential controls or precautions necessary
    e. Status of the pipeline
    f. Status of Site Incident Controller and their team
4. The Senior Emergency Services officer will now take control of the situation and carry out any action they deem necessary to bring the situation under control. These actions will, as appropriate, be based upon advice from the Site Main Controller.
5. The Senior Emergency Services officer may dispatch personnel to the Forward Control Point and take over command from the Site Incident Controller. The Site Incident Controller will follow the direction of the Principle Response Agencies.

8 RESPONSE FOR EMERGENCY SCENARIOS

The information presented provides initial guidance only, scenario specific pre-incident planning will be further developed to define, in detail, incident specific response plans. For all incidents the Site Main Controller and Emergency Services have authority to take any actions considered necessary to prevent escalation of any incident.

As noted in Section 3 there are three major accident hazard scenarios associated with the Corrib pipeline. The nature of the response will be dictated by the precise nature of the emergency and the status of any release (ignited, location, size etc.), but will typically, for major incidents, include:

- Operator intervention to isolate the pipeline (at wells, LVI etc.) and reduce pipeline pressures thus minimising the release
- Assessing the situation
- Alerting relevant parties e.g. public, Emergency Services
- Establishing restricted access areas
- Managing situation on-site until the arrival of Emergency Services

One of the initial tasks will be to confirm the release location i.e. offshore, LVI, on- or near-shore and then to ensure that the appropriate Emergency Services are alerted e.g. Coastguard for offshore releases. The following general principles will apply and will be developed further, tested and implemented prior to operations commencing.

8.1 OFFSHORE PIPELINE AND SUBSEA FACILITIES EMERGENCY

Offshore pipeline incidents can be expected to be reported by any the following ways:

- Instrument detection
- Pipeline patrols (ROV inspections)
- A member of the public e.g. fishing vessels (reporting to the Emergency Services or directly to the Gas Terminal)
- By the Emergency Services (Coastguard patrol)

Control Room Operator

- Inform Site Main Controller of any unexpected changes in flow characteristics.
- Attempt to confirm source of flow characteristics
- If flow characteristics indicate a leak or problem with the wells start shut in procedures (in consultation with Site Main Controller)

Site Main Controller

- Inform Duty Emergency Coordinator
- Attempt to confirm cause of changes to flow characteristics and release location
- Consider shutting in wells
- Consider shutting in flow lines
- If leak confirmed, or indication of a potential leak strengthens:
    - Initiate safeguarding procedure (well and LVI shut in etc.)
    - Depressurise flow lines
    - Escalate to SEPIL ECT

8.2 ONSHORE, NEARSHORE OR LVI EMERGENCY

Onshore, nearshore or LVI incidents can be expected to be reported by any the following ways:

- Instrument detection
- Pipeline patrols
- Operators / Maintenance Technicians carrying out routine activities
- A member of the public (reporting to the Emergency Services or directly to the Gas Terminal)
- By the Emergency Services

Control Room Operator (CRO)

- Notify the Site Main Controller
- Notify the Emergency Services if required
- In the event of a confirmed line failure initiate blowdown via emergency flare and wells shutdown as deemed necessary

Site Main Controller

- Inform Duty Emergency Coordinator and confirm notification of Emergency Services
- Dispatch LRT Technicians (including the Site Incident Controller) to the incident location with Gas Detectors
- Assess the situation based on information from CRO and Site Incident Controller
- Interface with the Emergency Services and offer technical support
- Confirm terminal shut down and depressurisation as deemed necessary
- Confirm off shore wells shutdown as deemed necessary

Site Incident Controller

- Set up Forward Control Point and liaise with Principle Response Agencies to provide support

8.3 PIPELINE DAMAGE

A potential scenario is damage to the pipeline as a result of SEPIL or 3rd party activities (e.g. excavation, maintenance activities). Extensive measures have been incorporated into the design to minimise this possibility (see Section 2.3) and contact details are posted at regular intervals throughout the onshore sections of the pipeline to enable the Gas Terminal to be contacted and appropriate emergency response initiated.

In the event that a near miss has been reported or is thought to have occurred response measures will include:

- Initiation of emergency response procedures
- Gas testing and inspection and assessment of damage
- Cordoning of area as appropriate
- Alerting of Emergency Services as appropriate
- Possible precautionary depressurisation of the pipeline
- Assessment of damage
- Implementation of ‘Pipeline Damage Procedure’ (See Appendix Q5)

8.4 DUTIES OF SITE MAIN CONTROLLER ON TERMINATION OF THE EMERGENCY

The all clear is announced by the SMC in agreement with the Duty EC, when the incident site is declared safe and under control by the Site Incident Controller or the Emergency Services.

- Inform BGE and Aberdeen EC.
- Make arrangements to stand down personnel and facilities.
- Control rehabilitation of affected areas.
- Ensure all evidence is retained or barrier off and secure area if required for investigation purposes (in liaison with Emergency Services).
- Assess the environmental impact of the incident and initiate the appropriate environmental remediation
- Retain all log sheet originals from Control Room
- Arrange for an internal investigation

9 EMERGENCY RESPONSE PREPARATION

9.1 EMERGENCY RESPONSE PLAN DEVELOPMENT

The emergency response plans for the pipeline will be continuously developed and tested ready for commissioning. Where required e.g. for commissioning, additional supplemental emergency plans may be developed. All emergency plans will be finalised prior to pipeline operations commencing.

The development of the pipeline Emergency Response Plans will include, but will not be limited to;

- Working arrangements with Emergency Services e.g. facilities, call-out and communications
- Designation of Rendezvous Points (RVP) (with alternates in case of impairment)
- Notifications for occupied buildings, including multi-occupancy such as public houses, and public places e.g. beaches, where appropriate
- Evacuation plans and treatment arrangements for the injured

9.2 DRILLS AND EXERCISES

Training will be scheduled (Table 9.1) to establish response capability prior to any new operation being implemented, when personnel are changed or at planned regular periods throughout the year.

Training will be progressive and will contain the following:

- Presentations, defining systems and teaching processes.
- Tabletop exercises, practicing the team procedures without mobilisation of resources and in slow time. Evaluating performance, identifying areas for development and establishing further training needs.
- Simulated/major exercises, practicing the combined response, mobilising resources in real time, evaluating performance, identifying areas for development and establishing further planning needs.
- Lessons learnt from previous actual mobilisations
- Post-exercise learning sessions

The public will be informed in advance of any major exercises.

Appropriate training and exercises may be outsourced to suitably qualified professional trainers who will be responsible for developing, delivering and evaluating such activities. This will also provide opportunities for external review and to share ‘best practices’.

Upon stand-down, it is the responsibility of the Site Main Controller (in liaison with Principle Response Agencies if involved) to ensure a “Lessons Learnt” session is held with all participants and with those responsible for incident response management.
Table 9.1: Drill and Exercise Schedule

Drill Type	**Frequency**	**Personnel involved**
General Muster	1/week (day shift only)	All personnel at terminal
Location Response Team (Safety)	every 4 weeks (day shift only)	All LRT members
Location Response Team (Environmental)	every 4 weeks (all shifts)	All LRT members
Exercise Type	**Frequency**	**Personnel Involved**
Table top exercise	2 per shift per year	All Operations shifts
External Exercise	1 per year	All Gas Terminal personnel plus external Principal Response Agencies

10 ABBREVIATIONS

BA	Breathing Apparatus
BGE	Bord Gáis Éireann
CCTV	Closed Circuit Television
CMT	Crisis Management Team
DCENR	Department of Communications, Energy and Natural Resources
EC	Emergency Co-ordinator
ECT	Emergency Co-ordination Team
E&P	Exploration and Production
ER-MS	Emergency Response Management System
HSE	Health, Safety and Environment
HSE-MS	Health, Safety and Environment Management System
HSSE	Health, Safety Security and Environment
LRT	Local Response Team
LVI	Landfall Valve Installation
PSTN	Public Switch Telephone Network
ROV	Remotely Operated Vehicle
RVP	Rendezvous Point
SMC	Site Main Controller
UHF	Ultra High Frequency
UIE	Upstream International Europe

ATTACHMENT Q6.6A

NOTIFYING EMERGENCY SERVICES

CONTACTING THE EMERGENCY SERVICES

FOR EVENTS REQUIRING ACTIVATION OF THE EXTERNAL EMERGENCY RESPONSE PLAN

RESPONSIBILITY OF THE CONTROL ROOM OPERATOR

1. Contact the Emergency Services by dialling **999**
2. Request the operator to be put through to the emergency service required
   - *Remember the operator who answers the phone is NOT a member of the Emergency Services*
3. When speaking to the Emergency Services Operator provide the following information

Information to be provided to the EMERGENCY SERVICES

- This is *State name and position*. I work for Shell E&P Ireland and I wish to inform you that *State the type of incident* has occurred/is imminent at the *choose one*;
  a. Bellanaboy Bridge Gas Terminal located at Bellanaboy Bridge, Bellagelly South, Glenamoy, Ballina.
  b. Landfall Valve Installation located at Dooncarton Point, Glengad.
  c. Pipeline between Dooncarton Point, Glengad and the Bellanaboy Bridge Gas Terminal located at Bellanaboy Bridge, Bellagelly South, Glenamoy, Ballina.
- I confirm that the External Emergency Response Plan has been activated.
- Give details of the incident using the ETHANE format:

E	Exact Location	Be as specific as possible
T	Type of Incident	Fire, Explosion, RTA, Chemical incident
H	Hazards	Current and potential
A	Access	From which direction to approach & to which RVP
N	Number of casualties	Including type and severity
E	Emergency Services	Present and required

- Verify that they have all the information they require.

4. If more than one Emergency Service is required the CRO will
   - After finishing with the first Emergency Service required, WAIT ON THE LINE to speak to the 999 Operator again by asking "OPERATOR ARE YOU THERE"
   - Request to be put through to the next emergency service required.
   - Repeat step 2

It is the responsibility of the CRO to verify they have contacted **EACH** of the Emergency Services required.

INFORMATION PROVIDED TO EMERGENCY SERVICES	
EXACT LOCATION OF THE INCIDENT Be as specific as possible	
TYPE OF INCIDENT Fire, Explosion, RTA, Chemical incident	
HAZARDS Current and potential	
ACCESS From which direction to approach and to which RVP	
NUMBER OF CASUALTIES Including type and Severity	
EMERGENCY SERVICES Present and required	
Verify that they have all the information they require.	

EMERGENCY SERVICES CONTACTED			
SERVICE	**YES**	**NO**	**Notes**
Fire Services			
Gardaí (Police)			
Ambulance Service (Health Services Executive)			
Coastguard			

Appendix R

Summary of Construction Materials Quantities

Corrib Onshore Pipeline - Materials Balance

Construction Element	Location	From Chainage	To Chainage	Stone In (m3)	Freshwater for Tunnelling (m3)	Wastewater Out (m3)	Stone Out (m3)	Subsoil Out (m3)	Tarmac In (m3)	Tarmac Out (m3)	Peat Out (m3)	Tunnel Arisings Out (m3)
LVI dished area excavation	Glengad	83.44	83.49					7,000				
SC1 Compound	Glengad	83.5	83.575	450			450					
Access Road to LVI	Glengad	n/a	n/a	1,620			450					
SC2 Reception Pit Compound	Glengad	83.86	83.91	280			280					
Pipeline Spread	Glengad	83.478	83.88	200			200					
SC3 - Tunnelling Compound	Aghoos	88.723	88.95	57,044	76,000	25,000	13,164		2,400	2,400	21,940	37,585
Access Roads to SC3 & Stringing Area	Aghoos	n/a	n/a	1,200			600					
Stringing Area	Aghoos	88.95	89.1	11,519			11,519		2,194	2,194		
12m Stone Rd	Aghoos to Terminal	89.1 to 89.35 & 89.535 to 90.721		42,091			10,361				28,030	
9m Stone Rd	Aghoos	89.35	89.535	5,089			1,004				3,181	
SC4	Coillte Forestry	n/a	n/a	2,000								
	TOTALS			**121,493**	**76,000**	**25,000**	**38,028**	**7,000**	**4,594**	**4,594**	**53,151**	**37,585**

Summary of Materials for Disposal

Classification	Volume (m3)
Stone	38,028
Subsoil	7,000
Tarmacadam	4,594
Peat	53,151
Wastewater	25,000
Tunnel Arisings	37,585

Appendix S

Information on Tunnelling

Appendix S1: **Preface**
(No Longer Relevant)

Appendix S2: **Typical Method Statement Direct Pipe Technique**
(No Longer Relevant)
Refer to Chapter 5

Appendix S3: **Review of Risks Associated with Micro-tunnelling**
(No Longer Relevant)

Appendix S4: **Management Plan for Materials Arising On-Site**

Appendix S4

Management Plan for Materials Arising On-Site

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LIST OF TABLES

1 INTRODUCTION

This report describes options for managing the materials arising on-site from the construction of the Corrib Onshore Pipeline project specifically the tunnel, the Landfall Valve Installation (LVI) and the demobilisation of the tunnelling compound.

The pipeline route now proposed includes a section (between Glengad and Aghoos) that is proposed to be tunnelled. The total length of the tunnel is approximately 4.9km and the tunnel will have an outer diameter of 4.2m. The tunnelling works will be carried out from a compound at Aghoos.

Details of the types and quantities of materials arising are provided along with a preferred strategy for managing the materials which maximises the resource potential of the material. Contingency arrangements are also described.

Materials arising from the demobilisation of the tunnelling compound on-site and the options for managing these are also addressed in this report.

This report does not address the management of disposal of peat. This is covered in Volume 3 of the Environmental Impact Statement (EIS).

This report has been prepared by RPS Consulting Engineers.

2 CONSTRUCTION ACTIVITIES

A summary of the construction works are outlined in the following Sections. Further details are provided in the relevant sections of the Environmental Impact Statement (EIS).

2.1 TUNNELLING WORKS

Construction of the Corrib Onshore Pipeline in Sruwaddacon Bay will be by segment lined tunnelling. This will entail constructing a 4.9km long concrete lined tunnel into which the pipeline will subsequently be installed. The tunnel will be constructed using a Tunnel Boring Machine (TBM).

The Tunnel Boring Machine (TBM) will be used to gradually excavate the tunnel at the front of installed concrete segments. As the excavation moves forward, new concrete segments will be assembled directly behind the TBM. The TBM will use the front edge of the concrete lined tunnel to push against and gradually cut away the material at the front of the machine. Figure 2.1 illustrates the proposed method.

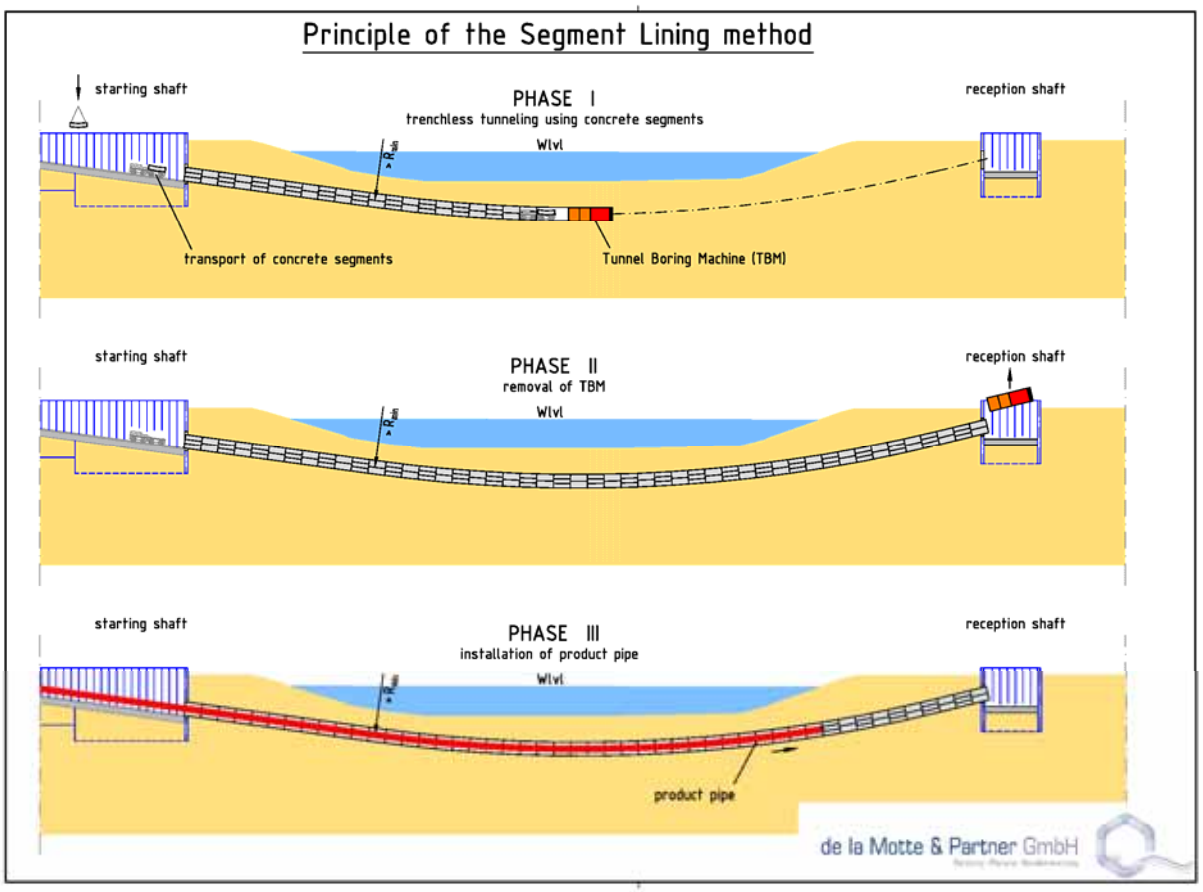


Figure 2.1 Segment Lining Method

Excavated cuttings from in front of the TBM will be removed (and crushed where necessary) through the cutting head. The cuttings will be mixed with the cutting fluid (bentonite slurry) and pumped to the start pit via dedicated hoses running through the advancing tunnel bore. When this mixture reaches the surface at the start pit, the excavated material will be separated from the bentonite slurry and segregated into different material gradings after which it will be stockpiled temporarily on-site. A description of the materials generated by the tunnelling works is set out in Section 3.2.

It is intended to reuse significant quantities of the materials arisings on-site with excess material reused or recovered off-site, (see Section 5.2). The drilling fluid in the tunnelling process will be recycled.

2.2 DEMOBILISATION OF TUNNELLING COMPOUNDS

The construction of the tunnelling compound will require the removal of the vegetated upper layer of peat in the area. The layer will be approximately 0.6m deep and the material will be carefully removed for stockpiling locally. To facilitate construction, the peat material will be replaced by stone and selected fill and capped with dense bitumen macadam. Figure 5.3 shows cross sectional details of the tunnelling compound.

When the tunnel is complete and the pipeline system has been installed, the area will be reinstated using the layer of peat that was stockpiled locally for this purpose. Any surplus excavated stone and fill material will be excavated and stockpiled for reuse and recovery off-site as outlined in Section 5.2. Following reinstatement, temporary fencing will be removed and the lands returned to normal use.

Construction and reinstatement of the tunnelling compound and stringing area at Aghoos is described in detail in Chapter 5 of the EIS.

2.3 LANDFALL VALVE INSTALLATION

During the construction of the LVI an estimated 7,000m^3 of soil and rock material will be generated and managed in accordance with best practice, see Section 5.2. The first stage of the construction of the LVI will be to excavate the site to the required levels. Topsoil will be stored separately to preserve the local seed-bank and facilitate reinstatement. Bedrock is located approximately 3 - 4m below ground level and after removal of the topsoil and overburden layers, approximately 3m of excavation in the rock layers will be required.

More details of the construction of the LVI are included in Chapter 5 of the EIS.

3 DESCRIPTION OF TUNNELLING ARISINGS

The proposed tunnelling works will generate different types of materials. This material will be predominantly made up of rock cuttings and stone, sands and gravels, with lesser quantities of silts and other residual materials. The vertical alignment of the tunnel may vary between a minimum cover of 5.5m and a maximum depth of 10m below the indicated centreline (see Appendix M1-A). On this trajectory, the proposed tunnelling works will generate predominantly sand and gravels within the superficial deposits of Sruwaddacon Bay.

The following sections provide a general description of the tunnelling material and its expected composition.

3.1 LOCAL GEOLOGY

Information on the overburden deposits in Sruwaddacon Bay has been compiled from available geophysical data, from the Geological Survey of Ireland (GSI), across the bay and geotechnical data gathered as part of the previous onshore pipeline application lodged in 2009.

A geophysical survey was carried out in Sruwaddacon Bay in 2007 by Osiris Projects, refer to Appendix M1 for details. The geophysical survey indicated predominantly granular deposits in the bay. The deposits were up to depths of about 25m below bed level becoming shallower at the bay edges where exposures can be seen at ground surface. The sediments are a mixture of “reworked” medium to fine marine sands throughout the central parts of the bay and mixed gravel deposits derived from glacial tills and weathered bedrock at the margins of the bay and in areas of stronger current.

A more detailed description of the bedrock and overburden geology underlying the Bay can be found in Section 15.1 of the EIS and Appendix M1.

3.2 COMPOSITIONAL PROFILE OF TUNNELLED MATERIAL

Material extracted from the tunnelling works will be wet due to the introduction of drilling fluid (mostly water) during the drilling works, and will be returned to the launch pit for processing. Once the material reaches the launch pit, the separation plant will separate the materials being returned into different grades of crushed rock, sand, clays and silts. The separation plant will be a six stage process and a specification detail of the system is presented in Table 3.1.

Table 3.1 Specification of Separation Plant

Stage	System Output Procedure	Particle Separation Size
1	Shaker	> 8 mm (in rock the D50 of this will be approx 30 to 40 mm)
2	Cyclone	250 µm - 8mm
3	Cyclone	100 µm - 250 µm
4	Cyclone	50 µm - 100 µm
5	Centrifuge	6 µm - 50 µm
6	Filter Press	< 6 µm

It is expected that a large portion of the materials, with the exception of silts, once separated will be reusable as a Class 1 material (National Roads Authority (NRA) Design Manual for Roads and Bridges

Specification for Road Works, Series 600, Earthworks) and can be stockpiled on site. The coarse fraction of the materials (coarse gravel, cobbles) excavated by the TBM will be crushed at / within the cutting head. The maximum particle size of rock arisings from the TBM will be 30mm – 40mm. Figure 3.1 shows typical rock cuttings and a typical materials separation plant from a tunnelling process where a TBM was used.

Figure 3.1 Typical Rock Cuttings and Materials Separation Plant from Tunnelling Process

From the boreholes drilled in the Bay, it is estimated that there is an average of approximately 15% of silts/clays within the sands and gravels within the Bay. This type of material has limited reuse potential and suitable outlets for the material can be difficult to identify. As a result this material may need to be disposed of at an EPA Waste Licensed facility. Further details on the management of silts and residual materials from the tunnelling process are detailed in Section 5.2.

3.3 TUNNEL ARISINGS AND BENTONITE

Bentonite, a naturally occurring clay mineral (montmorillonite), will be used within the tunnelling process to aid the pumping of cuttings through the slurry pipe and also as a lubricant to the tunnelling head. The tunnelling slurry will be a suspension of very fine inert clay (bentonite) in water and is widely used in construction projects. The use of bentonite will be managed carefully at a bentonite handling unit, within the site compound, close to the launch pit.

After recovery through the separation plant, the excavated material will contain a residual quantity of bentonite of approximately 0.4% by weight. As bentonite is a natural material the trace quantities in the excavated tunnel materials are not considered as a contaminant, a view confirmed with the Environmental Protection Agency. At this concentration the bentonite has a negligible effect on the mechanical qualities of the material and will not impact on its classification as a construction material under the NRA Specification (Series 600 Earthworks). A detailed description of the use of bentonite in the tunnelling process is described in Chapter 5 of the EIS.

Apart from the trace quantities of bentonite in the excavated material, residual bentonite fines (after processing) will be generated daily from the tunnelling works estimated to be 1.75 tonnes per day. At the end of the tunnelling works bentonite fines will also be generated as part of the cleaning of the TBM and the draining of the slurry lines. This process will result in approximately 250m^3 bentonite slurry (approximately 8.75 tonnes of bentonite fines). This material will be disposed of at the end of tunnelling works and the options are outlined in Section 5.2.4.

4 QUANTITIES OF MATERIAL ARISINGS

Table 4.1 summarises the estimated quantities of material arising from the tunnelling works as well as arisings from the construction of the LVI and the demobilisation of the tunnelling compound. The quantities are presented in terms of m^3 and tonnes (a bulk density factor of 2 has been applied for the conversion of cubic metres into tonnes).

The tunnelling quantities presented represent the current best estimate of material arising from these works based on a tunnel trajectory which is mainly through sands and gravels. This is a conservative approach as this represents the scenario where there would be the greatest range in materials arising (rock cuttings, sands, gravels and silts / fines).

The quantity of material estimated to arise from the tunnelling works from Aghoos to Glengad is approximately 68,000m^3 or approximately 136,000tonnes. In addition there will be an estimated 7,000m^3 or 14,000tonnes of material generated by the construction of the LVI. It is anticipated that the tunnelling works will generate approximately 13.8m^3 of spoil material per meter tunnelled (based on tunnel diameter of 4.2m). It is anticipated that the tunnelling works will progress at an average rate of approximately 11m per day (this rate could be higher or lower on a daily basis depending on the material being tunnelled). Therefore, the quantity of tunnelling spoil arising from the works is expected to be on average of the order of 150m^3 per day.

In Table 4.1 the estimated quantity of material generated from the tunnelling works and LVI construction is separated out into three main constituents; rock cuttings and stone, sands and gravels and silts. Based on the geophysical and geotechnical information gathered to-date the representative quantity of each constituent has been estimated (based on the tunnel alignment shown in Appendix M1-A). It is estimated that 20% (approximately 27,200 tonnes) of the tunnelling materials generated will be rock and stone cuttings with the remainder (108,800 tonnes) primarily sands and gravels. It is expected that 15% of the sand and gravels will be silty material and the corresponding quantities are calculated to be 16,320 tonnes. The remainder will be sand and gravels estimated to be 92,480 tonnes.

Potential options and anticipated quantities of material for the reuse of material on-site and the possible reuse, recovery or disposal of material off-site are detailed in Table 4.1. In order to optimise the reuse of material on-site, due consideration has to be given to the programming of specific tasks and storage capacity on-site. The potential options identified for on-site reuse will occur for the most part after the tunnelling works.

The rock cuttings and stone generated from the tunnelling works can be reused in a number of site construction works, full details are provided in Section 5.2.1. The stone road has the largest requirement for this type of material and it is expected that most of the rock and stone cuttings will be used here. The possible on-site reuse applications include the:

- Permanent Access road at Glengad.
- Pipeline stringing area at Aghoos.
- Stone road.

Sand and gravels will also be reused on-site, albeit to a lesser degree, for example, in the construction of the pavement surface for the pipeline stringing area. Further details of the reuse on-site of sands and gravels are detailed in Section 5.2.1.

Surplus material generated from the tunnelling works will be sent off-site with the preferred approach to transport the material to a local construction project where the material can be put to use. Alternatively the material could be sent to a number of quarries identified in the area where the material would be reused in land remediation activities or processed for subsequent recovery. As a last resort material may be sent to landfill although this option will only be employed after all other options have been exhausted. The off-site options for managing the material are explored in more detail in Sections 5.2.3 and 5.2.4.

The material used in the construction of the tunnelling compound will be excavated at the end of the construction schedule and removed off-site following the completion of the entire on-site works. This material will be suitable for reuse in other construction projects off-site and suitable projects will be targetted. Alternatively this material may be transported to a local quarry which has the relevant planning and waste permission in place to accept the material for recovery. Further details of the management of this material are outlined in Section 5.2.

Table 4.1 Estimated Quantities of Materials Generated from Tunnelling Works and Other Related Works

	Rock Cuttings / Stone		Sand & Gravel		Silts/other non reusable		Total Arisings		Comments
	(m3)	Tonnes	(m3)	Tonnes	(m3)	Tonnes	(m3)	Tonnes	
Materials Arisings On-Site									
Landfill Valve Installation (LVI)	7,000	14,000	0	0			**7,000**	**14,000**	Excavation mainly in rock
Tunnelling (Aghoos)	13,600	27,200	46,240	92,480	8,160	16,320	**68,000**	**136,000**	4.9km x 4.2m O.D. 15% of sands / gravels is silt / other non re-useable
Total	**20,600**	**41,200**	**46,240**	**92,480**	**8,160**	**16,320**	**75,000**	**150,000**	
Materials Required On-Site (During Construction)									
LVI Permanent Access Road	600	**1,200**	-	-	-	-			
Aghoos Pipe Stringing Area	23,000	**46,000**	-	-	-	-			Compatible with programme
Stone Road	55,000	**110,000**	-	-	-	-			Subject to programme
Pipe Bedding	-	-	5,500	11,000	-	-			
Total	**78,600**	**157,200**	**5,500**	**11,000**	**0**	**0**			
Materials for Management Off-site									Potential to re-use on-site sands / gravels by mixing with rock cuttings / stone. No re-use potential for silts and other material.
Tunnel arisings (surplus materials)	0	**0**	40,740	81,480	8,160	16,320	**48,900**	**97,800**	
Bentonite arising during tunnelling	-	-	-	-	1,320*	779	**1,320***	**779**	Low / no re-use potential. * Bentonite fines after processing (density 0.59t/m3)
Surplus bentonite (from TBM & bentonite system, arising at end of project)	-	-	-	-	15*	9	**15***	**9**	
Demobilisation of compounds (Arising at end of project)	45,000	**90,000**	-	-	-	-	**45,000**	**90,000**	Removal of excess stone upon completion. Good re-use potential (off-site).
Totals	**45,000**	**90,000**	**40,740**	**81,480**	**9,495**	**17,108**	**95,235**	**188,588**	

Note: Above breakdown is based on tunnelling through 20% rock /80% sand and gravels.

5 MANAGEMENT OPTIONS FOR MATERIALS

The options for managing the material generated on-site are explored in detail and are outlined in this chapter of the report. A preferred approach which maximises the resource potential of the material is identified along with contingency arrangements if the preferred options do not materialise.

5.1 WASTE POLICY AND BEST PRACTICE

Ireland's waste policy sets out the preferred approach to sustainably managing inert wastes and wastes generated from construction projects. Irish waste policy is set down in a series of Policy Statements published by the Department of the Environment, Heritage and Local Government (DEHLG) which set targets and environmental objectives.

In the first National Waste Policy Statement, Changing Our Ways (1998), the DEHLG adopted the EU hierarchy of options for managing wastes. The design of the hierarchy favours higher management options in favour of disposal. This philosophy sits at the core of waste management in Ireland and fundamentally aims to minimise the disposal of material to landfill in favour of more sustainable solutions.

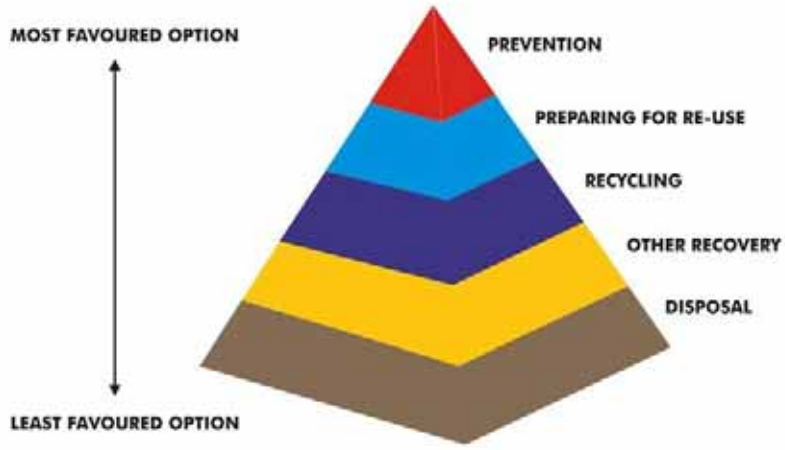


Figure 5.1 Hierarchy of Waste Management Options

Changing Our Ways identifies the need for stakeholders in the construction industry to take responsibility for managing construction wastes. The industry has responsibility to divert material from landfill by developing "environmental sustainability policies" to "ensure the environmentally sound management" of inert wastes on-site. This Policy Statement set the national recycling target of 85% for the construction waste stream by 2013.

Subsequent National Policy Statements have endorsed these original policy objectives and the hierarchical approach to waste management. Regional Waste Management Plans prepared by Local Authorities across Ireland have similarly followed suit.

The Replacement Waste Management Plan for the Connacht Region 2006 – 2011 (hereafter referred to as the Replacement Plan) takes account of national waste policy whilst setting out the strategic framework for the management of wastes generated in the region. The Replacement Plan contains specific objectives for the better management of wastes arising from construction projects in the region during the lifetime of the Plan.

The Replacement Plan requires stakeholders in the construction industry to "ensure that reuse and recycling of construction and demolition waste is maximised". In summary the Plan's stated policy for managing inert waste is:

"…To maximise the reuse and recycling of C&D waste" (*Page 100, Chapter 15, Replacement Plan*).

The implementation of this policy is set out in a series of specific objectives which endeavour to deliver sustainable management practices for inert wastes in Connacht. Those policy objectives which are most relevant are as follows:

- ***Recover and reuse materials where possible, in preference to disposal***
- ***Promote and encourage the development of C&D Waste facilities at quarry sites (both active and closed)***
- ***Promote and encourage the development of C&D waste facilities by the private sector***
- ***Reduce and or eliminate quantities of C&D recyclable waste other than clays or subsoils used in land reclamation***

Replacement Plan, Chapter 15, Page 100.

The Corrib Onshore Pipeline project is within the Connacht Region and is required to take account of the Replacement Plan policy objectives with respect to the management of inert materials generated on-site. Section 5.2 sets out the preferred strategy for managing material generated from the LVI construction, tunnelling works and similar material generated from the demobilisation of the tunnelling compound.

5.2 A SUSTAINABLE MANAGEMENT APPROACH

Inert materials generated from the LVI construction, tunnelling works and the demobilisation of the tunnelling compound will be managed sustainably and in accordance with best practice as set out in National and Regional Waste Policy.

The aim will be to reuse as much as possible of the material generated by the works. As set out in Section 3.3 the material generated will be a clean natural material and it is expected this material will be classified as a Class 1 material (as per NRA Specifications).

On-site material generated from the LVI construction tunnelling works can be put to reuse in one of several possible construction applications. These options are outlined in more detail in Section 5.2.1. Excess material which cannot be reused on-site will be managed in an appropriate manner. The demobilisation material falls into this category as it will arise at the end of the construction project. The proposal is to send this material off-site primarily for the purpose of reuse at a third party construction site or alternatively for recovery at a local quarry or waste facility. The strategy for managing material sent off-site is outlined in Sections 5.2.2 and 5.2.3.

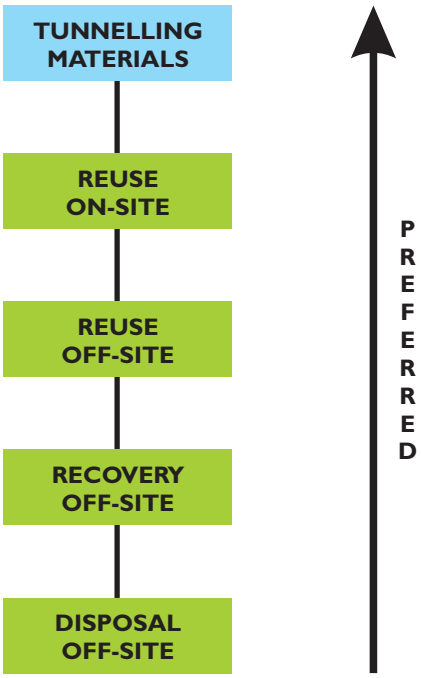
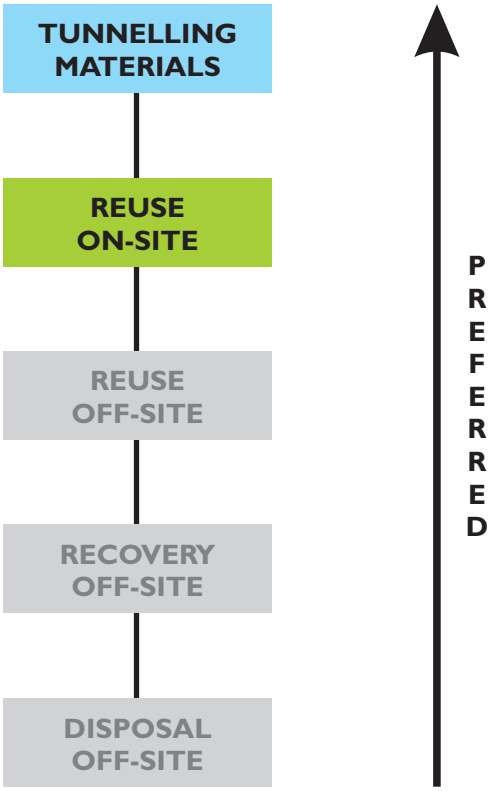


Figure 5.2 Preferred Strategy for Management of Materials

As a final option material which cannot be reused on-site or reused or recovered off-site at a suitable location/facility will be sent for disposal at an appropriately authorised waste facility such as a municipal or inert waste landfill. It is anticipated that the quantity of materials sent off-site for disposal will be limited and this option will be a "last resort" after exhausting higher order solutions. In order to account for a worst case scenario, facilities have been identified that have the capacity (both in terms of total tonnages and yearly limits) to take the entirety of the material generated. More details of the disposal solution are outlined in Section 5.2.4.

5.2.1 Reuse On-Site



The preferred outcome from an environmental, transportation and resource efficiency perspective is to maximise the reuse of material generated from the tunnelling works on-site. To enhance the suitability of the material it is likely that standard screening and or grading of the material will be carried out to ensure the end material is of a consistent quality and unsuitable fractions such as shells and similar matter are removed. The nature of the material and its reuse on-site will not require a waste permission to be put in place.

The material processed will be a clean and valuable resource. From the geotechnical data gathered, it is expected the material will be categorised as a Class 1 material suitable in accordance with NRA specifications and suitable as general fill. It is proposed to undertake standard testing e.g. Particle Size Distribution at regular intervals, to validate the specification and classification of the material.

The classified material will be made available for reuse as a suitable material in a number of possible applications on-site including:

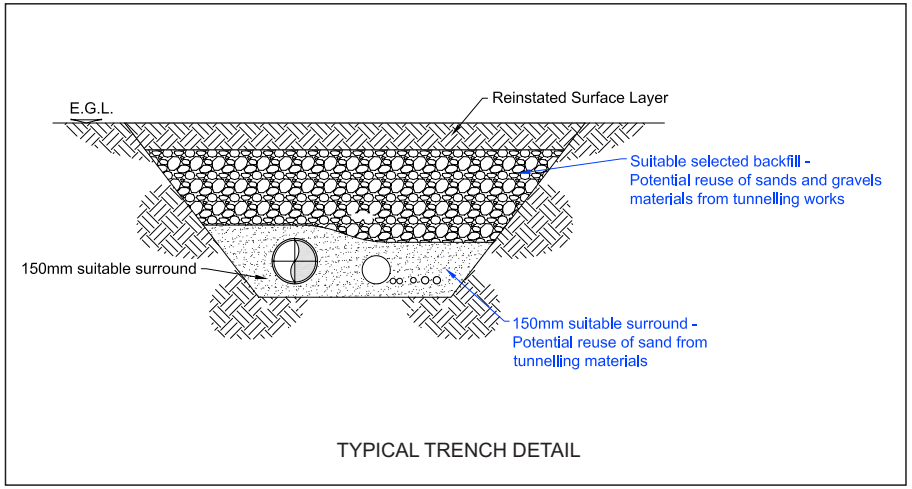
- Permanent Access road
- Pipeline stringing area
- Stone road
- Pipe bedding.

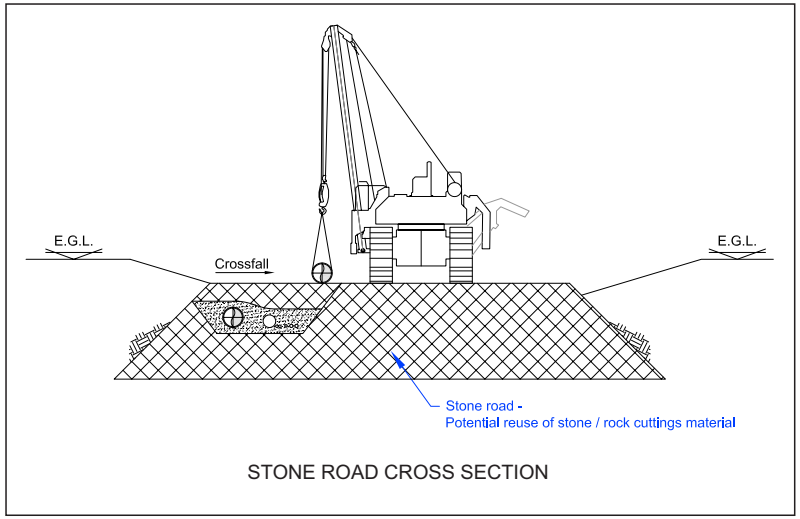
It has been estimated based on an analysis of the quantities presented in Table 4.1 that a minimum of 35% of material generated by the LVI construction and tunnelling works will be reused on-site. There is potential for further reuse of material on site depending on the type and quality of the material excavated.

As a Class 1 material, the arisings will be suitable for the stone road construction in the forestry from a geotechnical engineering point of view where the peat excavated forms a clean excavation, i.e. the peat is more fibrous and "punching in" of rock is not required. Where the peat is more amorphous a coarser rock fill material is typically used to displace and penetrate through the peat and to offer the high shear resistance needed to support the excavation.

For the upper zones of the stone road, finer grained Class 1 materials would be acceptable and materials generated from the tunnelling works (including sands and gravels) would be suitable, refer to Figure 5.3.

The pipeline stringing area will be constructed using the same principles as the stone road with materials available from the tunnelling works suitable for reuse as a fill material. On average fill material to a depth of 1m will be required across the stringing area to replace the peat removed during construction. A cross section of the pipeline stringing area showing construction layers is shown in Figure 5.3.





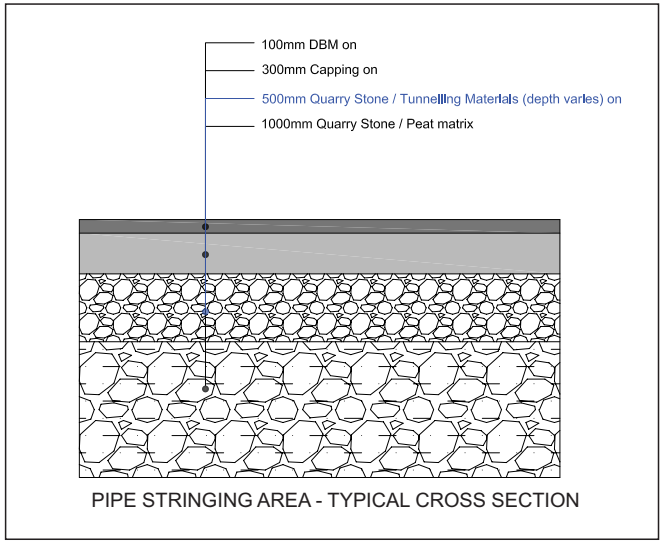
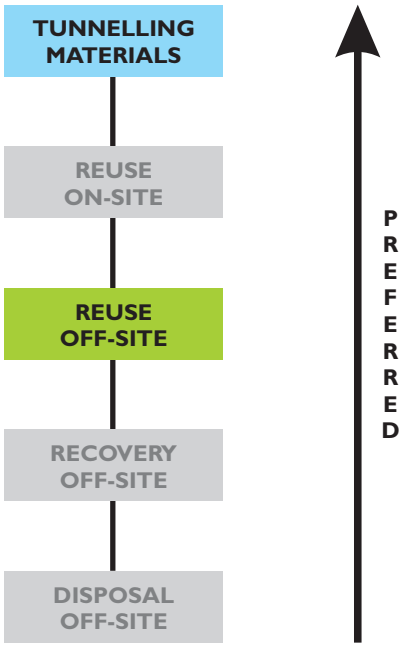


Figure 5.3 Construction Applications for the Reuse of Materials On-Site

It is also proposed to reuse quantities of sand and gravel materials generated by the tunnelling works as a bedding layer around the pipeline as a protective coating. The sand material will be very suitable for this application and an illustration showing its use is shown in Figure 5.3.

5.2.2 Reuse Off-Site

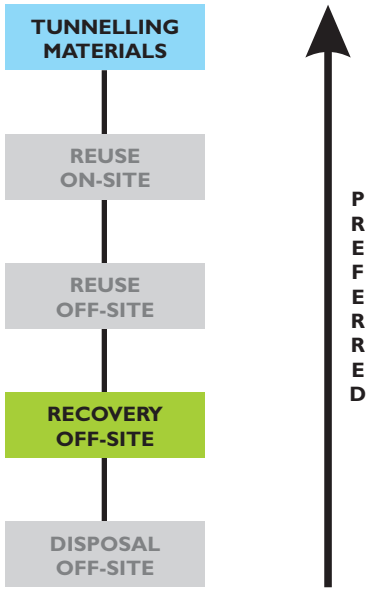


The reuse of material generated from the works will be maximised on-site, however excess materials will remain and require management. The excess materials will be primarily sand and gravels but also silt type material. Estimated quantities of the excess material are detailed in Table 4.1.

The preferred approach for the management of the excess materials will be to reuse them as a Class 1 fill material at third party development projects including existing quarries. There are several medium to large scale developments, particularly new renewable energy projects, planned in the area which will have a need for substantial fill materials. The material could be reused as fill in the construction of forestry roads, access roads or in foundations. Provisional discussions have been held with a number of developers, including Bord na Móna and Coillte, regarding the need and suitability of material from the tunnelling works and demobilisation. The developers contacted have expressed an interest in taking such material subject to their construction projects proceeding; the timeframes coinciding (i.e. availability of material from the onshore pipeline development coinciding with their construction requirements); and the surplus material meeting their requirements. At this stage it is too early to put into place commercial agreements but ongoing communication in relation to construction schedules with the different parties will continue.

The reuse of material off-site as a fill in third party construction project represents a good use of the resource and reduces the quantity of virgin material required for construction. Any material sent off-site for reuse will be tested to confirm its suitability in terms of it meeting the appropriate class specification. Similar testing as proposed for material to be reused on-site is proposed to ensure quality is maintained. The suitability of the material will be validated by the Project Engineer from the destination site prior to the transportation of material off-site. These controls will ensure the material can be treated and handled as a resource material and not as a waste.

5.2.3 Recovery Off-Site



If the options to reuse material off-site at third party development locations do not materialise the excess material will be sent for recovery at a location with a waste authorisation in place. Any material sent off-site, for recovery to a waste facility will be transported by a haulier holding a valid waste collection permit

There are several sites in Mayo which hold a Waste Facility Permit and can accept clean inert waste material for recovery as land remediation activity. These facilities are permitted by Mayo County Council and information on the location and details of the operation are all publicly available.

In close proximity to the site is the Tallagh Inert Landfill (formerly an operational quarry close to Belmullet) which holds a Waste Facility

Permit (PER 144) for the acceptance of inert waste material for the purpose of land remediation. In 2009 the operator of this facility applied to the EPA for a Waste Licence for the acceptance of 24,900 tonnes of inert waste material on an annual basis for land remediation purposes. The operator has estimated that over 600,000 tonnes of material can be accepted over the lifetime of the planned Tallagh Inert Landfill facility as part of the rehabilitation works. The facility is expected to be fully Licensed in 2010.

In addition to the Tallagh Inert Landfill there are quarries in the local area which have been contacted to discuss possible outlets for materials arising on the Corrib Onshore Pipeline project. The acceptance of material at these sites for recovery purposes will need to comply with existing planning conditions and or an appropriate waste authorisation provided this is necessary and in place.

Excess material from the project site could also be recovered at the Derrinumera Landfill Facility which is owned and operated by Mayo County Council. Active landfills have an ongoing requirement for inert materials for daily cover purposes and the material from the tunnelling works could be available for this purpose. Similarly the tunnelling material from the site could be used for recovery purposes in the future capping of landfill cells at the facility and the possible construction of internal access roads as part of the site development works. Discussions have been held with Mayo County Council in this regard.

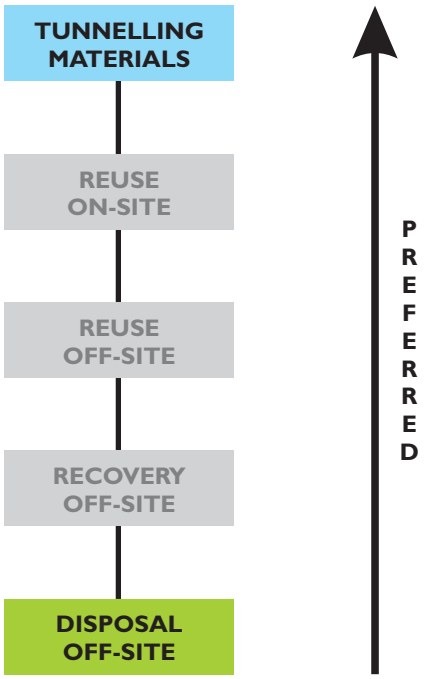
5.2.4 Disposal Off-Site

The disposal of excess materials generated on the Corrib Onshore Pipeline project to a Waste Licensed facility will only be considered when all other options to reuse or recover the material off-site have been exhausted.

It is expected that a minimum quantity of material will be sent to landfill for disposal. Depending on the quality of the silts separated from the excavated materials this material may be sent for disposal although the reuse and recovery options of this material will be first explored. If this material is found to be unsuitable for reuse or recovery purposes it will be sent to Derrinumera Landfill at Newport for disposal. Discussions have been held with Mayo County Council in this regard.

Table 5.1 provides a summary of the facility in terms of acceptable material and annual quantities and the Waste Licence indicates that inert wastes can be accepted for disposal.

Similarly bentonite residues and other similar materials arising as a result of the on-site processing may require disposal and, if so, will be sent to this landfill facility.



It is estimated that over 17,000 tonnes of material will require disposal off-site. The majority of this material will be silt.

Table 5.1 Details of the Derrinumera Landfill Facility

Facility	Description	Capacity / Potential Capacity	Materials Accepted	Location (Distance by Road)
Derrinumera Landfill (W0021-02)	EPA Waste Licensed Facility	Waste Licence **40,000 tonnes per annum** non-hazardous including C&D wastes. Potential capacity 400,000 tonnes to 2020	Household and Commercial residual waste & non hazardous C&D waste.	Newport, Mayo (70km)

5.3 CONTINGENCY PLAN FOR MATERIALS

In the event that suitable outlets cannot be identified for part or all of the materials generated during the course of the works, a Contingency Plan has been developed as a precautionary measure or "safeguard solution" and will ensure that the materials arising on-site will have a certain destination outlet.

The worse case scenario is that none of the material generated from the tunnelling works, the LVI construction nor the demobilisation of the tunnelling compound can be reused or recovered on-site or off-site as described in Sections 5.2.1, 5.2.2 and 5.2.3. In this event a suitable destination facility is required which can accept the estimated 240,000 tonnes of inert waste generated over approximately a 26 month construction period. The destination needs to be certain and the facility identified needs to be operational during the construction period when the material will arise.

The overall quantity of material eliminates waste facilities authorised with a Local Authority issued Certificate of Registration or Waste Permit. These authorisations are typically used for inert waste facilities although tonnages range from 10,000 to a maximum of 100,000 tonnes depending on the particular activity. Furthermore the lifetime for these authorisations is set by statute to 5 years, after which an option to renew the authorisation is available or alternatively it is abandoned.

Considering all of these issues a Waste Licensed Facility will be the most suitable destination. Waste Licenses are issued for different waste operations including landfills (municipal and inert), transfer stations, materials recovery facilities, biological treatment facilities and incinerators. From these possible destinations an inert landfill is the preferred option as it provides the certainty required.

Table 5.2 provides summary details of the two largest inert landfill facilities in Ireland. Both are operated by Murphy Environmental Limited and are located at sites in Meath and Dublin. The table shows that either facility has the capacity to accept all of material generated during the construction of the onshore pipeline and are safeguard solutions.

The latest Annual Environmental Reports (AER) available (2008) on the EPA website show that the facility in Gormanstown accepted 350,000 tonnes of inert waste while the Naul facility accepted approximately 226,000 tonnes for that year. These reports highlight the spare and available capacity at each facility and their suitability as safeguard solutions for materials generated by the project. The AERs for the facilities also provide details of the remaining void capacity at each site. The facility located in the Naul had a remaining void capacity of over 4.1 million m^3 at the end of 2008 and has 16 years of operation remaining based on the maximum annual tonnage being received,

Similarly the facility at Gormanstown has a significant remaining void capacity to be filled over its lifetime which has been confirmed with the EPA Inspector for the site.

Table 5.2 Details of Contingency Facilities for Inert Materials

Facility	Description	Licensed Annual Capacity	Materials Accepted	Location
Murphy's Quarry Inert Landfill (W0151-01)	EPA Waste Licensed Facility	750,000 tonnes 738,00 tonnes can be accepted for disposal at the site. 12,000 tonnes can be accepted for recovery.	Inert Wastes. Purpose: To fill/rehabilitate the quarry void. To recover material through processing.	Gormanstown, Co. Meath
Murphy's Quarry Inert Landfill (W0129-02)	EPA Waste Licensed Facility	500,000 tonnes	Inert Wastes. Purpose: To fill/rehabilitate the quarry void.	Naul, Co. Dublin

5.4 SUMMARY

A summary of the management options for the materials arising from the tunnelling works and the demobilisation of the compound area is presented in Figure 5.4.

The preferred strategy is to reuse as much of the material as possible on-site. This quantity is estimated to be at least 35% of the tunnelling materials. The reuse options on the Corrib Onshore Pipeline project are more limited for the material generated by the demobilisation works as this excavation will follow the construction of the tunnel and ancillary structures.

Excess material from the tunnelling works and material arising from the demobilisation of the tunnelling compound will be made available for reuse off-site. It is anticipated that the available material will be a clean and valuable resource meeting the specifications of a typical Class 1 material. This material can be reused in local projects under development and/or quarries in the local area and beyond. Initial discussions with developers have been met with positive responses. The availability of the material and the scheduling of local construction projects will be kept under review as the project develops.

If reuse of material is not possible surplus material will be sent for recovery, either for land remediation or processing, to a suitable site in the area. Any site identified will need to have the appropriate planning permission or waste authorisation in place to accept the material on-site. County Mayo has 17 active Waste Permitted Facilities and one Municipal Waste Landfill facility which could accept inert waste from the project site for recovery purposes. These facilities are all possible options. A former quarry located at Tallagh, Belmullet, (Tallagh Inert Landfill) currently holds a waste permit and has applied for an EPA Waste Licence to accept inert waste for remediation purposes and will be used to recover material if the reuse options are not available.

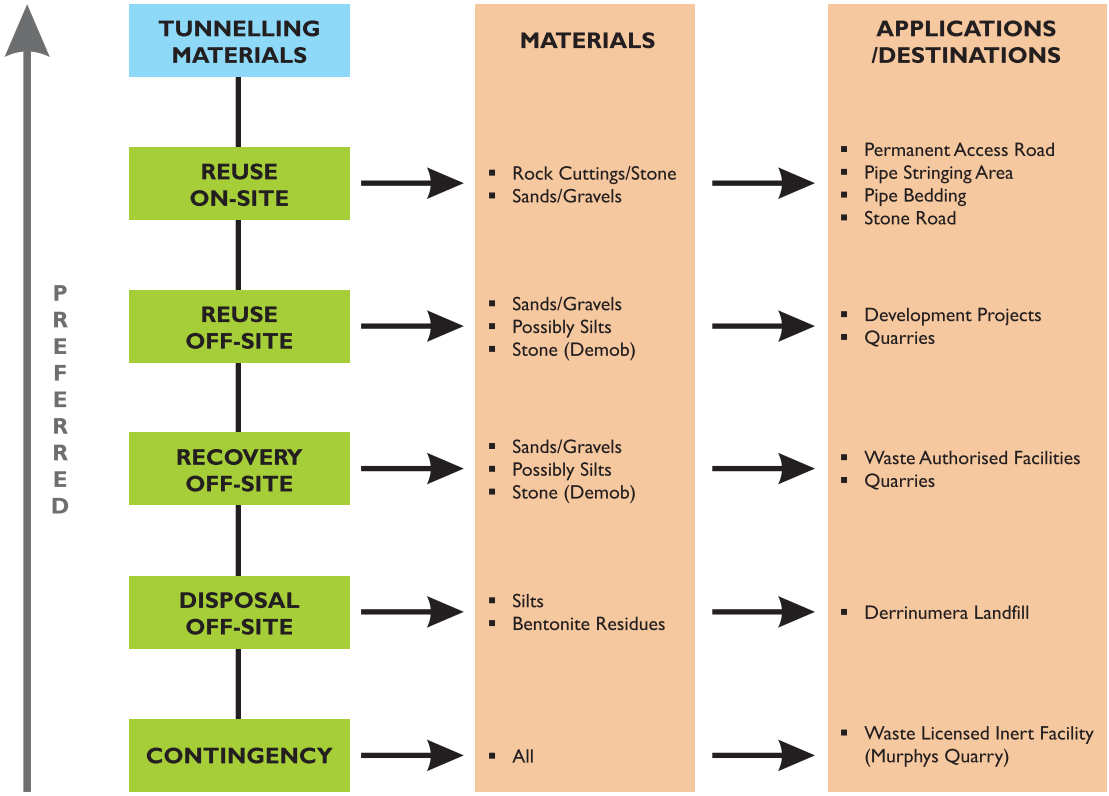


Figure 5.4 Materials Management Plan Summary

As a last resort material will be sent for disposal off-site. At this stage the most likely material which will be managed in this manner will be silts, bentonite residues or other residue material. Reuse and recovery options will be explored for these materials although disposal may be the only option. The intention will be to send these materials for disposal at Derrinumera Landfill, which is owned and operated by Mayo County Council. This facility holds an EPA Waste Licence and can accept inert waste for disposal.

The Contingency Plan for the management of materials has identified two Inert Waste Licensed Facilities operated by Murphy Environmental Ltd., as the safeguard solution for all of the materials arising from the construction of the LVI, tunnel and demobilisation of the tunnelling compound.

Appendix T

Route Selection Matrix

Clarification of Route Development Process

16th June, 2009

Introduction

As recorded in the minutes of the pre-application consultation meeting between the Applicant and An Bord Pleanála dated 21st January, 2009, in respect of the pending application for the proposed Corrib Onshore Pipeline, the Board's advice to the Applicant included the following:

- Robust route selection criteria should be detailed including considerations of a technical or commercial nature.

- Any negative outcomes of a chosen route should be measured and compared with the original route.

The route selection process, including the various route selection criteria employed in selecting the proposed onshore pipeline route is detailed in Chapter 3, Volume 1 of the Corrib Onshore Pipeline EIS. This note provides additional detail regarding the route development process for the Corrib Onshore Pipeline. As such it should be read in conjunction with Chapter 3 of the EIS.

The selection criteria used in the route development process derived from the public consultation process undertaken by RPS in the period February to June, 2007 as well as from input from the technical, environmental and other experts of the project team.

Corridor Evaluation and Short-listing Process (September, 2007)

Input from all specialists for each corridor was recorded on a matrix (see Sheet 1 attached) where the identified selection criteria were listed against identified corridor options and the previously approved route.

Each specialist provided input into the matrix, in his/her area of expertise and based on the extent of knowledge that had been obtained for each corridor by this time. In this way no criterion was deemed to be of any greater or lesser importance than another. The criteria were broken down into sub-criteria to allow for additional detail in the evaluation process.

At this stage, such information was generally of a high level, primarily based upon desk-top and vantage point / visual surveys. However, an additional detailed matrix on environmental factors was compiled (see Sheet 2 attached), deriving from the more extensive environmental studies that had been carried out in the area over the preceding years. This environmental information is summarised on the main evaluation matrix.

Following input of all specialist information, the characteristics of each corridor in respect of the agreed route selection criteria were evaluated qualitatively by the various members of the multi-disciplinary project team in a series of workshops.

A colour coding system was used in the evaluation process to assist in the determination of preferred corridors as follows:

- Green – indicates that the criterion is 'preferred';

- Amber – indicates that the criterion represents a 'potential constraint'; and

- No colour – indicates that one corridor cannot be distinguished from another in respect of a particular criterion i.e. it is not preferred or does not have potential constraints.

The matrix allowed a comparative evaluation of identified corridors and the previously approved route, in terms of community, environmental and technical route selection criteria. Resulting from this comparative evaluation, all route corridors emerged as having criteria that

constituted both potential preferences and constraints (envisaged positive and negative outcomes).

The result of the evaluation process was that Corridors A, B and C emerged as being preferred / having least constraint. The primary reasons for short-listing these corridors is detailed in Chapter 3 of the EIS. It is clear from the evaluation matrix (Sheet 1) that the preferred corridors were least constrained. The iterative qualitative evaluation process meant that the other identified corridors were not eliminated from further consideration should this have been required i.e. should new information cause the short-listed corridors to be eliminated.

Detailed Corridor / Route Evaluation (November, 2007 - February, 2008)
Further assessment of the short-listed corridors, and ongoing public and stakeholder consultation, revealed potential significant constraints with corridors A and C; this resulted in the identification of variations to these corridors as explained in Chapter 3 of the EIS.

The same multi-disciplinary qualitative process was used to evaluate the short-listed corridors and their variations against the agreed selection criteria, and with the input of new information which had been obtained in the interim period (see Sheet 3 attached). The evaluation continued to include the previously approved route. This ensured that in overall terms, the evaluation of alternative corridors / routes was consistent and robust.

Subsequently, criteria which had a neutral evaluation for all identified short-listed corridors were removed from the matrix (see Sheet 4 attached). This was because it was considered that these criteria no longer assisted in identifying a preferred corridor / route. However, this was no reflection on the importance or otherwise of these criteria. This allowed for a greater focus on the criteria which were considered to be more preferred / constrained for each route.

Having, done this, a further evaluation sought to remove criteria which were no longer considered to be of critical relevance to the selection process or which were effectively covered by other criteria. This iterative evaluation also allowed for input of new information as before.

The result of this process was a Reduced Route Evaluation Matrix (see Sheet 5 attached). This was further refined (with the elimination of 1 other criterion) in the Final Route Evaluation Matrix (see Sheet 6 attached), dated February, 2008.

The Final Route Evaluation Matrix identified Route C1 as having the least number of potential constraints when evaluated against the other identified potential routes and the previously approved route.

Conclusion
It is considered that the iterative qualitative route selection process carried out over the period September, 2007 to February, 2008 is very robust. It allowed for the inclusion of all route selection criteria that emerged during the public consultation process; it allowed for the evaluation of new information as more focussed environmental and technical studies were undertaken; it allowed for an evaluation of the previously approved route against this agreed set of route selection criteria; and finally it did not rely on a weighting of criteria. This process therefore allowed a clear understanding and evaluation of the balance of community, technical and environmental criteria for each identified route option.

Corrib Onshore Pipeline

Evaluation of Alternative Pipeline Corridors - Sheet 1

11th September, 2007

Preferred	Potential Constraints

		Rossport	Aghoos	Sruwaddacon Bay	Inver Upland	Inver / Barnatra	Portacloy	Glinsk	Curraunboy	Rossport
Technical Criteria		**CORRIDOR A**	**CORRIDOR B**	**CORRIDOR C**	**CORRIDOR D**	**CORRIDOR E**	**CORRIDOR F**	**CORRIDOR G**	**CORRIDOR H**	**APPROVED ROUTE******
1	**Safety**									
	Risk to people and community during operation	Low	Low	Low	Low	Low	Low	Low	Low	Low
	Risk of disturbance e.g. by third parties	Low	Low	Low	Low	Low	Low	Low	Low	Low
	Construction Safety Risk including offshore approaches and landfall	Low	Low	Low to medium. Longer section in marine areas.	Low	Low	Medium/High. Longer off-shore pipeline. Difficult landfall - northfacing narrow bay	Medium/High. Additional risks at landfall location (>50m cliffs). Longer off-shore pipeline. Northfacing bay	Low to medium. Longer section in marine areas.	Low
2	**Design**									
	Length of Pipeline - downstream of landfall valve	10.6km	8.3km	8.2km	9.6km	12.5km	14km	14.2km	11.8km	8.9Km
	Approx. additional length to currently approved Off-shore pipeline	0km	0km	0km	1.5km	1.5km	5km	20km	1.5km	0km
	Pipeline flow assurance issues	Acceptable	Acceptable	Acceptable	Acceptable	Acceptable	Reduced gas recovery from Corrib Field	Reduced gas recovery from Corrib Field	Acceptable	Acceptable
	Offshore pipeline routing risk	Low	Low	Low	Medium/High	Medium/High	High	High	Medium High	Low
	Offshore pipeline permitting risk	Low	Low	Low	Medium/High	Medium/High	High	High	Medium/High	None
	Risk of incompatibility with approved off-shore pipeline design/alignment	None	None	None	Medium	Medium	High	High	Low	None
	Suitability of landfall valve location	High	High	High	Medium. Requires further detailed study. Rocky coastline at northern landing.	Medium. Requires further detailed study. Rocky coastline at northern landing.	Low. Rocky coastline. Difficult perpendicular approach.	Medium	Low. Construction of landfall valve facility in Machair/sand system poses significant challenge.	High
3	**Construction**									
	Risk of Construction Difficulties	Medium. Mainly land based. One short and one medium water course crossings	Medium. Mainly land based. Short water course crossings	Medium/High. Section traversing bay technically challenging	Medium. Mainly land based. Slopes	Low. Mainly land based.	Medium/High. Pipeline pull-in difficult. Mainly land based. Sloping upland areas may pose additional challenges.	High.	Medium/High. Section traversing landfall area and bay technically challenging	Medium. Mainly land based. One short and one medium water course crossings
	Complexity of construction methodology	Low. Generally conventional construction with short crossings of Sruwaddacon Bay and rivers.	Medium. Generally similar to Corridor A but includes second crossing of Sruwaddacon Bay which will be longer and more complex.	High. Includes approximately 4.5km within Sruwaddacon Bay which will be technically challenging.	Low. Generally conventional construction.	Low. Generally conventional construction.	Medium. Generally conventional construction. Slope stability needs further detailed study close to landfall.	High. Landfall will be technically very challenging. Long section through extensive bog will be technically challenging.	High. Includes approximately 2.5km within Curraunboy Bay which will be technically challenging.	Low. Generally conventional construction with short crossings of Sruwaddacon Bay and rivers.
	Suitability of road access for construction	Medium	Medium	Medium	Medium	High	Medium	Low	Low	Medium
4	**GROUND CONDITIONS**									
	Risk of landslides and sandbank movements	Low	Low. Route perpendicular to slope in steep sections.	Low. Sections through bay can be stabilised by deeper burial of pipeline.	Low. Avoids slopes.	Low	Medium. Relatively steep slopes.	Low	Low	Low
Community Criteria		**CORRIDOR A**	**CORRIDOR B**	**CORRIDOR C**	**CORRIDOR D**	**CORRIDOR E**	**CORRIDOR F**	**CORRIDOR G**	**CORRIDOR H**	**CURRENT ROUTE**
5	**Proximity**									
	Minimum Distance from dwellings	>100m	>100m	>100m	>100m	>100m	>100m	>100m. Proximity significantly exceeds that for all other corridors.	>100m	70m
6	**Planning / Land Use**									
	Impact on development potential	Low	Low	Low	Medium. Greater development potential around Inver.	Medium to high. Greater development potential around Inver.	Low to Medium. Some development potential around Portacloy.	Low	Low	Low
	Temporary impacts on land use	Low	Low	Low	Low	Low	Low	Low	Low	Low
	Permanent Impacts on land use	Low/Medium. Turbary rights affected close to roadside.	Low	Low	Low/Medium. Turbary rights affected close to roadside.	Low/Medium. Turbary rights affected close to roadside.	Low/Medium. Turbary rights affected close to roadside.	Low/Medium. Turbary rights affected close to roadside.	Low/Medium. Turbary rights affected close to roadside.	Low/Medium. Turbary rights affected close to roadside.
7	**Landowner Consent**									
	Level of landowner agreement with corridor / Route	Full landowner agreement still outstanding	Full landowner agreement still outstanding	All landowners agreed previously consented route. This corridor may not require any new landowner consent.	Full landowner agreement still outstanding	Full landowner agreement still outstanding	Full landowner agreement still outstanding	Full landowner agreement still outstanding	Full landowner agreement still outstanding	Documented & Unresolved Landowner Opposition.
8	**Number of Affected Landowners**									
	Number of landowners involved directly	Medium	Medium	Medium	High	High	Low	Low	Low	Medium
	Number of commonage shares involved directly	High	None	None	High	High	High	Medium	Medium	High
9	**Number of Affected Residents**									
	Number of dwellings in the immediate vicinity of the development	Low	Low	Low	High in areas around Inver. Otherwise low.	High in areas around Inver and along R314.	High in areas around Portacloy. Otherwise relatively low.	Low	Low	Low
10	**Potential Impacts on Human Beings during Construction**									
	Air Quality	Low & temporary	Low & temporary	Low & temporary	Low & temporary	Low & temporary	Low & temporary	Low & temporary	Low & temporary	Low & temporary
	Drinking Water	Low & temporary	Low & temporary	Low & temporary	Low & temporary	Low & temporary	Low & temporary	Low & temporary	Low & temporary	Low & temporary
	Noise	Low & temporary	Low & temporary	Low & temporary	Low & temporary	Low & temporary	Low & temporary	Low & temporary	Low & temporary	Low & temporary
	Vibration	Low & temporary	Low & temporary	Low & temporary	Low & temporary	Low & temporary	Low & temporary	Low & temporary	Low & temporary	Low & temporary
	Traffic	Low & temporary	Low & temporary	Low & temporary	Medium & Temporary (denser habitation. Relatively busy area	Medium & Temporary (denser habitation. Relatively busy area	Low & temporary	Low & temporary	Low & temporary	Low & temporary
	Access to private property	Low & temporary	Low & temporary	Low & temporary	Low & temporary	Low & temporary	Low & temporary	Low & temporary	Low & temporary	Low & temporary
	Access to public areas and amenities	Low & temporary	Low & temporary	Low & temporary	Medium & Temporary	Medium & Temporary	Medium & Temporary	Low & temporary	Low & temporary	Low & temporary
	Negative economic impacts e.g. tourism, fishing	Low & temporary	Low & temporary	Low & temporary	Low & temporary	Low & temporary	Low & temporary	Low & temporary	Low & temporary	Low & temporary
Environmental Criteria		**CORRIDOR A**	**CORRIDOR B**	**CORRIDOR C**	**CORRIDOR D**	**CORRIDOR E**	**CORRIDOR F**	**CORRIDOR G**	**CORRIDOR H**	**CURRENT ROUTE**
11	**Impacts on Habitats and Wildlife**									
	Potential for impact on Habitats and Species of conservation value / Environmentally Designated Areas	Medium/High. Short crossings of watercourses; Sruwaddacon Bay (SPA) & Glenamoy Bog Complex (SAC). Crossing blanket bog - intact in areas	Low / medium. Short and one medium length crossings of Sruwaddacon Bay (SPA) & Glenamoy Bog Complex (SAC).	Medium / high. Long section within Sruwaddacon Bay / Glenamoy Bog Complex (SAC).	Medium/high. Fixed dune system / Machair (Annex I priority habitat at southern Inver landfall only. Potential to use landfall on Corridor E. Short sections through Pollatomish Bog (NHA).	Medium. Short section through Pollatomish Bog (NHA) and Carrowmore Lake Complex (SAC).	Low / medium. This Corridor includes some of a small dune system (Annex I habitat) at the landfall. Traverses maringal blanket bog sections of the SAC, some of which are intact.	High. Traverses through centre of intact blanket bog (Annex I priority habitat) Glenamoy Bog Complex (SAC). Part of Bog is being restored by Coillte.	High. Machair at Garter Hill, Annex I priority habitat. Periphery of Glenamoy Bog Complex (SAC). Feeding area for over wintering Geese. Flora Protection Order Petaphyllum ralfsii.	Low. Mainly land based. One short bay crossing and one medium water course crossing.
	Annex I Priority Habitat (SAC) exists within Corridor	Fixed dune grassland* Intact Blanket Bog	Fixed dune grassland*	Fixed dune grassland*	Machair	none	Intact Blanket Bog	Intact Blanket Bog	Machair	none
	Potential to impact on fauna**	Salmonids; feeding birds (Brent geese), sand martin colony, otters; protected plant species; heronry	Salmonids; feeding birds (Brent geese), sand martin colony, otters; protected plant species	Salmonids; feeding birds (Brent geese, waders); sand marten colony & otters.	Salmonids, otters; protected plant species.	Salmonids; overwintering Greenland white-fronted Geese, breeding seabirds; otters; protected plant species.	Salmonids; otter; protected plant species; hernory.	Grey Seals & Twite (red listed birds); Salmonids; beeding birds, otters; heronry; protected plant species	Salmonids; Brent geese; beeding birds; otters; protected plant species; heronry.	Salmonids; feeding birds (Brent geese), sand martin colony, otters; protected plant species
12	**Archaeology, Culture & Local Heritage**									
	Recorded Monument and Place Sites / Potenial archaeological constraints **	One area of archaeological potential identified from aerial photography (on land).	None recorded.	None recorded.	There are recorded archaeological features (cist, stone circule, field systems) and areas of archaeological potential within this corridor.	There are recorded archaeological features (field system, barrow, house site, enclosure) and areas of archaeological potential	One area of archaeological potential identified from aerial photography.	None recorded.	In Curraunboy townland, there is a large foreshore settlement site. One area of archaeological potential identified from aerial photography.	None recorded.
	Architectural Heritage Constraints**	No protected structures	No protected structures	No protected structures	No protected structures	No protected structures	No protected structures	No protected structures	No protected structures	No protected structures
	Potential for Cultural Heritage Constraints**	field & townland boundaries, past mining remains	field & townland boundaries, past mining remains	field & townland boundaries, past mining remains	Field & townland boundaries, past mining remains.	Field & townland boundaries, past mining remains.	field & townlamd boundaries, past mining remains.	field & townlamd boundaries, past mining remains.	field & townlamd boundaries, past mining remains.	field & townlamd boundaries, past mining remains.
13	**Other / General Criteria**									
	Potential Visual Impacts***	Low / Medium. Location of landfall valve is close to protected views and a scenic route. Potentially visible from a large number of vantage points. Short Term for Pipeline.	Low / Medium. Location of landfall valve is close to protected views and a scenic route. Potentially visible from a large number of vantage points. Short Term for Pipeline.	Low / Medium. Location of landfall valve is close to protected views and a scenic route. Potentially visible from a large number of vantage points. Short Term for Pipeline.	Low / Medium. Location of landfall valve is close to protected views and a scenic route. Potentially visible from a large number of vantage points. Short Term for Pipeline.	Low / Medium. Location of landfall valve is close to protected views and a scenic route. Potentially visible from a large number of vantage points. Short Term for Pipeline.	Low / medium. Location of Landfall is located within a narrow valley with residential properties. Short term for Pipeline.	Low / Medium. Location of landfall valve is close to protected views. Potentially visible from a large number of vantage points. Short Term for Pipeline.	Low / Medium. High Scenic View extends across the Bay to this area. Scenic Route at County Road North of Dooncarton offers long distance view across the Bay. Potentially visible from a large number of vantage points. Short Term for Pipeline.	Low / Medium. Location of landfall valve is close to protected views and a scenic route. Potentially visible from a large number of vantage points. Short Term for Pipeline.
	Impact on Project Programme	Low	Low	Medium. Potential delays due to slow construction and seasonal constraints.	High. Due to market constraints for offshore barges this can delay production start-up by up to two years. Significant negative impact on project.	High. Due to market constraints for offshore barges this can delay production start-up by up to two years. Significant negative impact on project.	High. Due to market constraints for offshore barges this can delay production start-up by up to two years. Significant negative impact on project.	High. Due to market constraints for offshore barges this can delay production start-up by up to two years. Significant negative impact on project.	High. Due to market constraints for offshore barges this can delay production start-up by up to two years. Significant negative impact on project.	Low
	Capital costs	No significant additional capital costs	No significant additional capital costs	Medium. Construction within Sruwaddacon Bay will add to project costs.	Medium - need additional laybarge for shallow water area	Medium - need additional laybarge for shallow water area	Significant additional offshore and landfall costs	Significant additional offshore and landfall costs	Medium - need additional laybarge for shallow water area	No significant additional capital costs
	Schedule induced additional costs	None	None	Medium. Construction time delay can cause late start-up and reduce net present value of project.	New landfall will result in deferral of current offshore contract and will result in major delay and additional costs.	New landfall will result in deferral of current offshore contract and will result in major delay and additional costs.	New landfall will result in deferral of current offshore contract and will result in major delay and additional costs.	New landfall will result in deferral of current offshore contract and will result in major delay and additional costs.	New landfall will result in deferral of current offshore contract and will result in major delay and additional costs.	None

* Priority habitat exists at edge of corridor.

** If this corridor were to be pursued, then further detailed studies would be required.

*** Careful site selection and design of facilities will avoid/reduce impacts.

**** Approved Route is not a corridor (300m wide). Assessment here is therefore of an area approximately 40m wide (wayleave width

Note: this is an ongoing process and colours may change as the route is defined.

Corrib Onshore Pipeline

Detailed Environmental Criteria - Sheet 2

Environmental Criteria*		**Route A**	**Route A1**	**Route B**	**Route C**	**CORRIDOR D**	**CORRIDOR E**	**CORRIDOR F**	**CORRIDOR G**	**CORRIDOR H**	**Route C1**	**APPROVED ROUTE**
11	**Impacts on Habitats and Wildlife**											
	Annex I Habitats (within SAC)	Atlantic salt meadows (Saltmarsh), Blanket Bog and Depressions on peat (Rhynchosporion), Estuaries & sandflats not covered by seawater at low-tide.	Atlantic salt meadows (Saltmarsh), Blanket Bog and Depressions on peat (Rhynchosporion), Estuaries & sandflats not covered by seawater at low-tide.	Atlantic salt meadows (Saltmarsh), Estuaries & sandflats not covered by seawater at low-tide.	Atlantic salt meadows (Saltmarsh), Estuaries & sandflats not covered by seawater at low-tide.	Machair, Fixed (grey) dunes, Blanket Bog and Depressions on peat (Rhynchosporion)	Blanket Bog and Depressions on peat (Rhynchosporion)	Embryonic shifting dunes, Fixed dunes(?)	Atlantic salt meadows (Saltmarsh), Blanket Bog and Depressions on peat (Rhynchosporion), Estuaries & sandflats not covered by seawater at low-tide.	Machair, Fixed (grey) dunes, Atlantic salt meadows (Saltmarsh), Blanket Bog and Depressions on peat (Rhynchosporion), Estuaries & sandflats not covered by seawater at low-tide.	Atlantic salt meadows (Saltmarsh), Blanket Bog and Depressions on peat (Rhynchosporion), Estuaries & sandflats not covered by seawater at low-tide.	Atlantic salt meadows (Saltmarsh), Blanket Bog and Depressions on peat (Rhynchosporion), Estuaries & sandflats not covered by seawater at low-tide.
	Annex I *Priority Habitat (within designated areas)	*Intact Blanket Bog (c.1km)	*Intact Blanket Bog (c. 950m)	None	None	*Machair and *Fixed dunes, *Intact Blanket Bog (NHA)	*Intact Blanket Bog (NHA)	*Intact Blanket Bog	*Intact Blanket Bog (more than 4km)	*Machair and *Fixed (grey) dunes	*Intact Blanket Bog (c. 150m)	*Intact blanket bog (c. 500m)
	Annex I Habitats present in non-designated area	Intact blanket bog	Intact blanket bog	None	Intact blanket bog	None	Intact blanket bog	Intact blanket bog	Intact blanket bog	Intact blanket bog	Intact blanket bog	Intact blanket bog
	Predicted impacts on annex habitats in designated sites - before mitigation	Blanket bog: Moderate to Significant. Salt marsh: Moderate to Significant. Estuarine habitats and tidal watercourses: Moderate (localised)	Blanket bog: Moderate to Significant. Salt marsh: Moderate to Significant. Estuarine habitats and tidal watercourses: Moderate (localised)	Salt marsh: Moderate to Significant. Estuarine habitats and tidal watercourses: Moderate (localised)	Salt marsh: Moderate to Significant. Estuarine habtats and tidal watercourses: Moderate (localised)	Fixed dune system / Machair: Moderate to Significant. Blanket bog: Moderate to Significant. (NHA).	Blanket bog: Moderate to Significant. (NHA).	Embryonic shifting dunes and Fixed dunes(?): Moderate to Significant. Blanket bog: Moderate to Significant.	Blanket bog: Moderate to Significant.	Fixed dune / Machair system at Garter Hill: Moderate to Significant. Blanket bog: Moderate to Significant. Estuarine habtats and tidal watercourses: Moderate (localised)	Blanket bog: Moderate. Salt marsh: Moderate to Significant. Estuarine habitats and tidal watercourses: Estuarine habtats and tidal watercourses: Moderate (localised)	Blanket bog: Moderate - short to medium term impact. Salt marsh: Moderate to Significant - short term. Estuarine habitats and tidal watercourses: Estuarine habtats and tidal watercourses: Moderate (localised)
	Predicted residual impacts on annex habitats in designated sites - after mitigation	Blanket bog: Moderate to Significant (pools & flushed areas) - medium term. Salt marsh: Slight - short term. Estuarine habitats and tidal watercourses: Imperceptible temporary.	Blanket bog: Moderate to Significant (pools & flushed areas) - short to medium term. Salt marsh: Slight - short term. Estuarine habitats and tidal watercourses: Imperceptible temporary..	Salt marsh: Slight - short term. Estuarine habitats and tidal watercourses: Imperceptible temporary.	Salt marsh: Slight - short term. Estuarine habitats and tidal watercourses: Imperceptible temporary..	Fixed dune system / Machair: Moderate to Significant - short to medium term. Blanket bog: Moderate to Significant short to medium term impact. (NHA).	Blanket bog: Moderate to Significant short to medium term impact. Carrowmore lake Complex SAC and Pollatomish Bog NHA.	Embryonic shifting dunes and Fixed dunes(?): Moderate - short to medium term. Blanket bog: Moderate - short to medium term.	Blanket bog: Moderate to Significant - short to medium term impact.	Fixed dune / Machair system at Garter Hill: Moderate to Significant - medium to long term. Blanket bog: Moderate to Significant - short to medium term impact. Estuarine habitats and tidal watercourses: Imperceptible temporary.	Blanket bog: Moderate - short to medium term. Salt marsh: Slight - short term. Estuarine habitats and tidal watercourses: Imperceptible temporary.	Blanket bog: Moderate to Significant (pools & flushed areas) - short to medium term. Salt marsh: Slight - short term. Estuarine habitats and tidal watercourses: Imperceptible temporary.
	Predicted adverse impact on the integrity of the site. (SAC)	Slight to Moderate (SAC 500 Glenamoy Bog Complex)	Slight (SAC 500 Glenamoy Bog Complex)	Potential (SAC 476 Carrowmore Lake Complex) - in event of run off into Lake via Aghoos River	Slight to Moderate (SAC 500 Glenamoy Bog Complex)	Slight to Moderate (SAC 500 Glenamoy Bog Complex)	Slight to Moderate (SAC 476 Carrowmore Lake Complex) - loss of GWFG feeding site	Slight (SAC 500 Glenamoy Bog Complex)	Moderate (SAC 500 Glenamoy Bog Complex)	Moderate to Significant (SAC 500 Glenamoy Bog Complex)	Slight (SAC 500 Glenamoy Bog Complex)	Slight (SAC 500 Glenamoy Bog Complex)
	Predicted adverse impact on the integrity of the site as a whole (SPA and Ramsar site)	None	None	None	None	None	Ditto (Carrowmore Lake SPA)	None	Potential	Potential	None	None
	Predicted impact on fauna	Otter: Moderate (Annex II & IV) - short term / Neutral - long term. Grey Seal: None. Harbour Seal (Annex II & IV): None Badger: Slight short term, neutral - long term. Bats: Imperceptible; neutral long term. Salmonids: None	Otter: Moderate (Annex II & IV) - short term / Neutral - long term. Grey Seal: None. Harbour Seal (Annex II & IV): None Badger: Slight short term, neutral - long term. Bats: Imperceptible; neutral long term. Salmonids: None	Otter: Moderate (Annex II & IV) - short term / Neutral - long term. Grey Seal: None. Harbour Seal (Annex II & IV): None Badger: Slight short term, neutral - long term. Bats: Imperceptible; neutral long term. Salmonids: None	Otter: Moderate (Annex II & IV) - short term / Neutral - long term. Grey Seal: None. Harbour Seal (Annex II & IV): None Badger: Slight short term, neutral - long term. Bats: Imperceptible; neutral long term. Salmonids: None	Otter: Moderate (Annex II & IV) - short term / Neutral - long term. Grey Seal: None. Harbour Seal (Annex II & IV): None Badger: Slight short term, neutral - long term. Bats: Imperceptible; neutral long term. Salmonids: None	Otter: Moderate (Annex II & IV) - short term / Neutral - long term. Grey Seal: None. Harbour Seal (Annex II & IV): None Badger: Slight short term, neutral - long term. Bats: Imperceptible; neutral long term. Salmonids: None	Otter: Moderate (Annex II & IV) - short term / Neutral - long term. Grey Seal: None. Harbour Seal (Annex II & IV): None Badger: Slight short term, neutral - long term. Bats: Imperceptible; neutral long term. Salmonids: None	Otter: Moderate (Annex II & IV) - short term / Neutral - long term. Grey Seal: None. Harbour Seal (Annex II & IV): None Badger: Slight short term, neutral - long term. Bats: Imperceptible; neutral long term. Salmonids: None	Otter: Moderate (Annex II & IV) - short term / Neutral - long term. Grey Seal: None. Harbour Seal (Annex II & IV): None Badger: Slight short term, neutral - long term. Bats: Imperceptible; neutral long term. Salmonids: None	Otter: Moderate (Annex II & IV) - short term / Neutral - long term. Grey Seal: None. Harbour Seal (Annex II & IV): None Badger: Slight short term, neutral - long term. Bats: Imperceptible; neutral long term. Salmonids: None	Otter: Moderate (Annex II & IV) - short term / Neutral - long term. Grey Seal: None. Harbour Seal (Annex II & IV): None Badger: Slight short term, neutral - long term. Bats: Imperceptible; neutral long term. Salmonids: None
	Predicted impact on birds	Brent Geese: None expected. Sand martin colony: None expected. Potential for nesting Golden Plover (Annex I) on intact blanket bog in SAC (timing). Heronry: Slight - temporary (timing). SPA resident and overwintering species: Slight - temporary (timing). Corncrake and other Annex species (Terns etc.): no impact expected	Brent Geese: None expected. Sand martin colony: None expected. Heronry: Slight - temporary (timing). SPA resident and overwintering species: Slight - temporary (timing). Corncrake and other Annex species (Terns etc.): no impact expected	Brent Geese: None expected. Sand martin colony: None expected. SPA resident and overwintering species: Slight - temporary (timing). Corncrake and other Annex species (Terns etc.): no impact expected	Brent Geese: None expected. Sand martin colony: None expected. SPA resident and overwintering species: Slight - temporary (timing). Corncrake and other Annex species (Terns etc.): no impact expected	Brent Geese: None expected. SPA resident and overwintering species: none expected (timing). Corncrake: no impact expected	Overwintering Greenland White-fronted Goose in Carrowmore Lake Complex SAC: potential loss of feeding grounds: Significant Impact - Medium to Long term	Potential for nesting Golden Plover (Annex I) on intact blanket bog in SAC (timing). Heronry: Slight - temporary (timing).	Nesting Twite (Red-listed) at landfall. Potential for nesting Golden Plover (Annex I) on intact blanket bog in SAC (timing). Heronry: Slight - temporary (timing).	Landfall approach is through one of two main feeding area for over wintering Geese: Significant impact - medium term. Potential for nesting Golden Plover (Annex I) on intact blanket bog in SAC (timing). Heronry: Slight - temporary (timing). SPA resident and overwintering species: Slight - temporary (timing).	Brent Geese: None expected. Sand martin colony: None expected. SPA resident and overwintering species: Slight - temporary (timing). Corncrake and other Annex species (Terns etc.): no impact expected	Brent Geese: None. Sand martin colony: None. Potential for nesting Golden Plover (Annex I) on intact blanket bog in SAC (timing). SPA resident and overwintering species: Slight - temporary (timing). Corncrake and other Annex species (Terns etc.): no impact expected
	Potential to impact on Protected Flora	Slight to Moderate (Blanket bog species)	Slight (Blanket bog species)	None expected	None expected	Slight	Slight	Slight	Slight to Moderate (Blanket bog species)	Moderate to High (*Petaphyllum ralfsii*)	Slight	Slight
	Potential to impact on Marine Fauna	Salmonids: None Marine Inverts: imperceptible temporary	Salmonids: None Marine Inverts: imperceptible temporary	Salmonids: None Marine Inverts: imperceptible temporary	Salmonids: None Marine Inverts: imperceptible temporary					Salmonids: None Marine Inverts: imperceptible temporary	Salmonids: None Marine Inverts: imperceptible temporary	Salmonids: None Marine Inverts: imperceptible temporary

* Prepared by Environmental Specialists J. Neff (EACS) and I. Wilson (Benthic Solutions Ltd.)

Corrib Onshore Pipeline
DRAFT Evaluation of Alternative Pipeline Routes (Landfall to Gas Processing Terminal) - Sheet 3

26th November, 2007

				Preferred	Constraints		
		Environmental Constraint on this Route (Priority Habitat)	1	3	4	5	Rossport
Technical Criteria		**Route A**	**Route A1**	**Route B**	**Route C**	**Route C1**	**APPROVED ROUTE**
1	**Safety**						
	Risk to people and community during operation	Low	Low	Low	Low	Low	Low
	Risk of disturbance e.g. by third parties	Low	Low	Low	Minimal	Low	Low
	Construction Safety Risk including offshore approaches and landfall	Low	Low	Low to medium. Longer section in estuarine areas (approximately 1.4km).	Low to medium. Longer section in estuarine areas (Approximately 4km).	Low to medium. Longer section in estuarine areas (approximately 1km).	Low
2	**Design**						
	Length of Pipeline - downstream of landfall valve	10.6km	10.31km	8.3km	8.2km	8.64km	8.9Km
	Approximate additional length to currently approved Off-shore pipeline	0km	0km	0km	0km	0km	0km
	Pipeline flow assurance issues	Acceptable	Acceptable	Acceptable	Acceptable	Acceptable	Acceptable
	Offshore pipeline routing risk	Low	Low	Low	Low	Low	N/A
	Offshore pipeline permitting risk	Low	Low	Low	Low	Low	N/A
	Risk of incompatibility with approved off-shore pipeline design/alignment	None	None	None	None	None	N/A
	Suitability of landfall valve location	High	High	High	High	High	High
3	**Construction**						
	Risk of Construction Difficulties	High. Mainly land based including construction in deep bog with bog pools. Two short water course crossings.	Low. Mainly land based including construction in bog. Two short water course crossings.	Medium. One relatively long crossing of Bay. Section traversing bay technically challenging	Medium/High. Long section traversing bay technically challenging	Medium. Mainly land based including construction in bog. One relatively long crossing of Bay. Section traversing bay technically challenging.	Low. Mainly land based. Two short water course crossings.
	Complexity of construction methodology	Low. Generally conventional construction with short crossings of Sruwaddacon Bay and rivers.	Low. Generally conventional construction with short crossings of Sruwaddacon Bay and rivers.	Medium. Specialist (trenchless option) crossing of Sruwaddacon Bay (approximately 1km).	High. Specialist (trenchless option) long crossing of Sruwaddacon Bay (approximately 4km).	Medium. Specialist (trenchless option) crossing of Sruwaddacon Bay (approximately 1km).	Low. Generally conventional construction with short crossings of Sruwaddacon Bay and rivers.
	Ease of access for construction	Medium	Medium	Medium	Medium	Medium	Medium
4	**GROUND CONDITIONS**						
	Risk of landslides / peat slides and sandbank movements (with mitigation)	Low	Low	Low	Low	Low	Low
Community Criteria		**Route A**	**Route A1**	**Route B**	**Route C**	**Route C1**	**APPROVED ROUTE**
5	**Proximity**						
	Distance from dwellings (over entire onshore pipeline)	74m. One dwelling must be acquired to achieve >100m separation distance on this route. This dwelling is currently 74m from pipeline route. Dwelling to east is >100m from pipeline route.	74m. One dwelling must be acquired to achieve >100m separation distance on this route. This dwelling is currently 74m from pipeline route. Dwelling to east is >100m from pipeline route.	>100m	>100m	74m. One dwelling must be acquired to achieve >100m separation distance on this route. This dwelling is currently 74m from pipeline route.	70m
6	**Planning / Land Use**						
	Impact on development potential	Low	Low	Low	Minimal	Low	Low
	Temporary impacts on land use	Low	Low	Low to medium.	Low	Low	Low
	Permanent Impacts on land use	Low/Medium. Turbery rights affected.	Low/Medium. Turbery rights affected.	Low	Minimal	Low/Medium.	Low/Medium. Turbary rights affected close to roadside.
7	**Landowner Consent**						
	Level of landowner agreement with corridor / Route (excluding commonage shareholders)	Substantial agreement expected. Possible CAO requirement.	Substantial agreement expected. Possible CAO requirement.	Documented objection.	All landowners agreed previously on sections of consented route. Possible CAO requirement. This corridor may not require any new landowner consent.	Substantial agreement expected. Possible CAO requirement.	Documented & Unresolved Landowner Opposition.
	Agreement from Commonage Shareholders	Unknown. Probability of objection from some share holders.	Unknown. Probability of objection from some share holders.	No commonage	No commonage	Unknown. Probability of objection from some share holders.	Unknown. Probability of objection from some share holders.
8	**Number of Affected Landowners**						
	Number of landowners involved directly	Medium	Medium	Medium	Medium	Medium	Medium
	Number of commonage shares involved directly	High	High	None	None	High	High
9	**Number of Affected Residents**						
	Population Density (as per IS 328)	Low	Low	Low	Low	Low	Low
	Level of compliance with recommendations of Cassells Report	Meets expectations on increased proximity to housing.	Meets expectations on increased proximity to housing.	Meets expectations on increased proximity to housing but involves another community.	Generally exceeds expectations on increased proximity to housing.	Meets expectations on increased proximity to housing.	N/A
10	**Predicted Impacts on Human Beings during Construction**						
	Air Quality	Low & temporary	Low & temporary	Low & temporary	Low & temporary	Low & temporary	Low & temporary
	Drinking Water	Low & temporary	Low & temporary	Low & temporary	Low & temporary	Low & temporary	Low & temporary
	Noise	Low & temporary	Low & temporary	Low & temporary	Low & temporary	Low & temporary	Low & temporary
	Vibration	Low & temporary	Low & temporary	Low & temporary	Low & temporary	Low & temporary	Low & temporary
	Traffic	High & temporary	High & temporary	High & temporary	High & temporary	High & temporary	High & temporary
	Access to private property	Low & temporary	Low & temporary	Low & temporary	Low & temporary	Low & temporary	Low & temporary
	Access to public areas and amenities	Low & temporary	Low & temporary	Low & temporary	Low & temporary	Low & temporary	Low & temporary
	Negative economic impacts e.g. tourism, fishing	Low & temporary	Low & temporary	Low & temporary	Low & temporary	Low & temporary	Low & temporary
Environmental Criteria		**Route A**	**Route A1**	**Route B**	**Route C**	**Route C1**	**APPROVED ROUTE**
11	**Impacts on Habitats and Wildlife**						
	Annex I Habitats (within SAC)	Atlantic salt meadows (Saltmarsh), Blanket Bog and Depressions on peat (Rhynchosporion), Estuaries & sandflats not covered by seawater at low-tide.	Atlantic salt meadows (Saltmarsh), Blanket Bog and Depressions on peat (Rhynchosporion), Estuaries & sandflats not covered by seawater at low-tide.	Atlantic salt meadows (Saltmarsh), Estuaries & sandflats not covered by seawater at low-tide.	Atlantic salt meadows (Saltmarsh), Estuaries & sandflats not covered by seawater at low-tide.	Atlantic salt meadows (Saltmarsh), Blanket Bog and Depressions on peat (Rhynchosporion), Estuaries & sandflats not covered by seawater at low-tide.	Atlantic salt meadows (Saltmarsh), Blanket Bog and Depressions on peat (Rhynchosporion), Estuaries & sandflats not covered by seawater at low-tide.
	Annex I *Priority Habitat (within designated areas)	*Intact Blanket Bog (c.1km)	*Intact Blanket Bog (c. 950m)	None	None	*Intact Blanket Bog (c. 150m)	*Intact blanket bog (c. 500m)
	Predicted adverse impact on the integrity of the site. (SAC)	Slight to Moderate (SAC 500 Glenamoy Bog Complex)	Slight (SAC 500 Glenamoy Bog Complex)	Potential (SAC 476 Carrowmore Lake Complex) - in event of run off into Lake via Aghoos River	Slight to Moderate (SAC 500 Glenamoy Bog Complex)	Slight (SAC 500 Glenamoy Bog Complex)	Slight (SAC 500 Glenamoy Bog Complex)
	Predicted adverse impact on the integrity of the site as a whole (SPA and Ramsar site)	None	None	None	None	None	None
	Potential to impact on Protected Flora	Slight to Moderate (Blanket bog species)	Slight (Blanket bog species)	None expected	None expected	Slight	Slight
	Potential to impact on Marine Fauna	Salmonids: None Marine Inverts: imperceptible temporary	Salmonids: None Marine Inverts: imperceptible temporary	Salmonids: None Marine Inverts: imperceptible temporary	Salmonids: None Marine Inverts: imperceptible temporary	Salmonids: None Marine Inverts: imperceptible temporary	Salmonids: None Marine Inverts: imperceptible temporary
12	**Archaeology, Culture & Local Heritage**						
	Recorded Monuments and Place Sites within 100m	None	None	None	None	None	None
	Features of Archaeological Potenial within 100m	Four	Three	Three	One	Two	One
	Architectural Heritage Constraints**	No protected structures	No protected structures	No protected structures	No protected structures	No protected structures	No protected structures
	Potential for Cultural Heritage Constraints**	Field & townland boundaries, past mining remains	Field & townland boundaries, past mining remains	Field & townland boundaries, past mining remains	Field & townland boundaries, past mining remains	Field & townland boundaries, past mining remains	Field & townland boundaries, past mining remains
13	**Other / General Criteria**	**Route A**	**Route A1**	**Route B**	**Route C**	**Route C1**	**APPROVED ROUTE**
	Potential Visual Impacts - Pipeline Construction	Temporary Impact during construction phase only.	Temporary Impact during construction phase only.	Temporary Impact during construction phase only.	Temporary Impact during construction phase only.	Temporary Impact during construction phase only.	Temporary Impact during construction phase only.
	Risk of delay to project due to lengthy statutory process	High	Low/Medium	Medium	High	Medium	N/A
	Impact on Project Programme (Construction phase, excluding third party interference)	Medium	Low/Medium	Medium	High. Potential delays due to slow construction and seasonal constraints.	Medium	Low/Medium
	Additional Capital costs	Low/Medium	Low	Medium	High	Medium	N/A
	Schedule induced additional costs	N/A	N/A	N/A	Likely	N/A	N/A

Notes:

Route evaluation is an ongoing process. Comments and colours on this spreadsheet may change as routes are further defined.

Routes A, B and C are centrelines of Corridors A, B and C evaluated for short-listing. All routes evaluated here are taken to be of wayleave width (approximately 40 - 60m wide)

Criteria that are no longer relevant to this stage of the Route Development Process have been omitted for greater clarity

Corrib Onshore Pipeline

DRAFT Evaluation of Alternative Pipeline Routes (Landfall to Gas Processing Terminal) - Sheet 4

Screened Criteria (Excluding non differential Criteria)

21st December, 2007

Not relevant at this stage or covered elsewhere	Preferred	Constraints

	Environmental Constraint on this Route (Priority Habitat)	1	3	4	5	Rossport
Technical Criteria	**Route A**	**Route A1**	**Route B**	**Route C**	**Route C1**	**APPROVED ROUTE**
Length of Pipeline - downstream of landfall valve	10.6km	10.31km	8.3km	8.2km	8.64km	8.9Km
Risk of Construction Difficulties	High. Mainly land based including construction in deep bog with bog pools. Two short water course crossings.	Low. Mainly land based including construction in bog. Two short water course crossings.	Medium. One relatively long crossing of Bay. Section traversing bay technically challenging	Medium/High. Long section traversing bay technically challenging	Medium. Mainly land based including construction in bog. One relatively long crossing of Bay. Section traversing bay technically challenging.	Low. Mainly land based. Two short water course crossings.
Complexity of construction methodology	Low. Generally conventional construction with short crossings of Sruwaddacon Bay and rivers.	Low. Generally conventional construction with short crossings of Sruwaddacon Bay and rivers.	Medium. Specialist (trenchless option) crossing of Sruwaddacon Bay (approximately 1km).	High. Specialist (trenchless option) long crossing of Sruwaddacon Bay (approximately 4km).	Medium. Specialist (trenchless option) crossing of Sruwaddacon Bay (approximately 1km).	Low. Generally conventional construction with short crossings of Sruwaddacon Bay and rivers.
Distance from dwellings (over entire onshore pipeline)	74m. One dwelling must be acquired to achieve >100m separation distance on this route. This dwelling is currently 74m from pipeline route. Dwelling to east is >100m from pipeline route.	74m. One dwelling must be acquired to achieve >100m separation distance on this route. This dwelling is currently 74m from pipeline route. Dwelling to east is >100m from pipeline route.	>100m	>100m	74m. One dwelling must be acquired to achieve >100m separation distance on this route. This dwelling is currently 74m from pipeline route.	70m
Impact on development potential	Low	Low	Low	Minimal	Low	Low
Temporary impacts on land use	Low	Low	Low to medium.	Low	Low	Low
Permanent Impacts on land use	Low/Medium. Turbery rights affected.	Low/Medium. Turbery rights affected.	Low	Minimal	Low/Medium.	Low/Medium. Turbary rights affected close to roadside.
Level of landowner agreement with corridor / Route (excluding commonage shareholders)	Substantial agreement expected. Possible CAO requirement.	Substantial agreement expected. Possible CAO requirement.	Documented objection.	All landowners agreed previously on sections of consented route. Possible CAO requirement. This corridor may not require any new landowner consent.	Substantial agreement expected. Possible CAO requirement.	Documented & Unresolved Landowner Opposition.
Agreement from Commonage Shareholders	Unknown. Probability of objection from some share holders.	Unknown. Probability of objection from some share holders.	No commonage	No commonage	Unknown. Probability of objection from some share holders.	Unknown. Probability of objection from some share holders.
Number of commonage shares involved directly	High	High	None	None	High	High
Level of compliance with recommendations of Cassells Report	Meets expectations on increased proximity to housing.	Meets expectations on increased proximity to housing.	Meets expectations on increased proximity to housing but involves another community.	Generally exceeds expectations on increased proximity to housing.	Meets expectations on increased proximity to housing.	N/A
Annex I Priority Habitat (within SAC)	Intact Blanket Bog (approximately 1km)	Intact Blanket Bog (400m at edge)	None	None	Intact Blanket Bog (200m at edge)	None
Predicted Adverse Impact on Integrity of the SAC & SPA/Ramsar	Low/Medium	Low	Low	Low/Medium	Low	Low
Potential to impact on Protected Fauna	Low. Salmonids; Lamprey, SPA overwintering & resident bird species, sand martin colony, otters; protected plant species; heronry, corncrake	Low. Salmonids; Lamprey, SPA overwintering & resident bird species, sand martin colony, otters; protected plant species; heronry, corncrake	Low. Salmonids; Lamprey, SPA overwintering & resident bird species, sand martin colony, otters; protected plant species; heronry, corncrake	Medium. Salmonids; Lamprey, SPA overwintering & resident bird species, sand martin colony, otters; protected plant species; corncrake	Low. Salmonids; Lamprey, SPA overwintering & resident bird species, sand martin colony, otters; protected plant species; corncrake	Low. Salmonids; Lamprey, SPA overwintering & resident bird species, sand martin colony, otters; protected plant species; corncrake
Predicted adverse impact on the integrity of the site. (SAC)	Slight to Moderate (SAC 500 Glenamoy Bog Complex)	Slight (SAC 500 Glenamoy Bog Complex)	Potential (SAC 476 Carrowmore Lake Complex) - in event of run off into Lake via Aghoos River	Slight to Moderate (SAC 500 Glenamoy Bog Complex)	Slight (SAC 500 Glenamoy Bog Complex)	Slight (SAC 500 Glenamoy Bog Complex)
Potential to impact on Protected Flora	Slight to Moderate (Blanket bog species)	Slight (Blanket bog species)	None expected	None expected	Slight	Slight
Risk of delay to project due to lengthy statutory process	High	Low/Medium	Medium	High	Medium	N/A
Impact on Project Programme (Construction phase, excluding third party interference)	Medium	Low/Medium	Medium	High. Potential delays due to slow construction and seasonal constraints.	Medium	Low/Medium
Additional Capital costs	Low/Medium	Low	Medium	High	Medium	N/A

Notes:
Route Evaluation is an ongoing process.
Comments and colours on this spreadsheet may change as routes are further defined.

Corrib Onshore Pipeline

DRAFT High Level Evaluation of Alternative Pipeline Routes (Landfall to Gas Processing Terminal) - 'Reduced Route Evaluation Matri
Sheet 5
4th January, 2008

Preferred	Constraints

	Environmental Constraint on this Route (Priority Habitat)	1	3	4	5	Rossport
High Level Criteria	**Route A**	**Route A1**	**Route B**	**Route C**	**Route C1**	**APPROVED ROUTE**
Length of Pipeline - downstream of landfall valve	10.6km	10.31km	8.3km	8.2km	9.13km	8.9Km
Distance from dwellings (over entire onshore pipeline)	2No. Unoccupied dwellings must be acquired to achieve >100m separation distance on this route.	2No. Unoccupied dwellings must be acquired to achieve >100m separation distance on this route.	>100m	>100m	2No. Unoccupied dwellings must be acquired to achieve >100m separation distance on this route.	70m
Level of landowner agreement with corridor / Route (excluding commonage shareholders)	Substantial agreement expected. Possible CAO requirement.	Substantial agreement expected. Possible CAO requirement (see comments below).	Documented objection.	All landowners agreed previously on sections of consented route. Possible CAO requirement. This corridor may not require any new landowner consent.	Substantial agreement expected. Possible CAO requirement.	Documented & Unresolved Landowner Opposition.
Agreement from Commonage Shareholders	Unknown. Probability of objection from some share holders.	Unknown. Probability of objection from some share holders.	No commonage	No commonage	Unknown. Probability of objection from some share holders.	Unknown. Probability of objection from some share holders.
Stated objectives for modifying the pipeline route (Cassells Report)	Meets expectations on increased proximity to housing.	Meets expectations on increased proximity to housing.	Meets expectations on increased proximity to housing but involves another community.	Generally exceeds expectations on increased proximity to housing.	Meets expectations on increased proximity to housing.	N/A
Predicted Adverse Impact on Integrity of the SAC & SPA/Ramsar	Low/Medium	Low	Low	Low/Medium	Low	Low
Predicted adverse impact on the integrity of the site. (SAC)	Slight to Moderate (SAC 500 Glenamoy Bog Complex)	Slight (SAC 500 Glenamoy Bog Complex)	Potential (SAC 476 Carrowmore Lake Complex) - in event of run off into Lake via Aghoos River	Slight to Moderate (SAC 500 Glenamoy Bog Complex)	Slight (SAC 500 Glenamoy Bog Complex)	Slight (SAC 500 Glenamoy Bog Complex)
Risk of delay to project due to lengthy statutory process	High	Low/Medium	Medium	High	Medium	N/A
Impact on Project Programme (Construction phase, excluding third party interference)	Medium	Low/Medium	Medium	High. Potential delays due to slow construction and seasonal constraints.	Medium	Low/Medium
Additional Capital costs	Low/Medium	Low	Medium	High	Medium	N/A

Comments

Route A	Not preferred mainly due to environmental constraint (approximately 1km of intact blanket bog with bog pools. (Priority Habitat)). Other viable alternatives exist.
Route A1	Potential constraint (approximately 140m crosses land belonging to documented objector). More direct alternatives exist.
Route B	Documented objection on this route. Route involves another local community which could lead to further division in the area. This route may be beyond scope of Cassells Recommendations. Other acceptable routes meeting these recommendations exist.
Route C	Not preferred for environmental, technical, cost and programme reasons. Other more appropriate alternatives exist.
Route C1	Preferred route as it is acceptable under all criteria including landowner issues.

Corrib Onshore Pipeline

DRAFT High Level Evaluation of Alternative Pipeline Routes (Landfall to Gas Processing Terminal) - 'Final Route Evaluation Matrix'
Sheet 6
1st February, 2008

Preferred	Constraints

	Environmental Constraint on this Route (Priority Habitat)	1	3	4	5	Rossport
High Level Criteria	**Route A**	**Route A1**	**Route B**	**Route C**	**Route C1**	**APPROVED ROUTE**
Length of Pipeline - downstream of landfall valve	10.6km	10.31km	8.3km	8.2km	9.13km	8.9Km
Distance from dwellings (over entire onshore pipeline)*	2No. Unoccupied dwellings must be acquired to achieve >100m separation distance on this route.	2No. Unoccupied dwellings must be acquired to achieve >100m separation distance on this route.	>100m	>100m	2No. Unoccupied dwellings must be acquired to achieve >100m separation distance on this route.	70m
Level of landowner agreement with corridor / Route (excluding commonage shareholders)	Substantial agreement expected. Possible CAO requirement.	Substantial agreement expected. Possible CAO requirement (see comments below).	Documented objection.	All landowners agreed previously on sections of consented route. Possible CAO requirement. This corridor may not require any new landowner consent.	Substantial agreement expected. Possible CAO requirement.	Documented & Unresolved Landowner Opposition.
Agreement from Commonage Shareholders	Unknown. Probability of objection from some share holders.	Unknown. Probability of objection from some share holders.	No commonage	No commonage	Unknown. Probability of objection from some share holders.	Unknown. Probability of objection from some share holders.
Stated objectives for modifying the pipeline route (Cassells Report)	Meets expectations on increased proximity to housing.	Meets expectations on increased proximity to housing.	Meets expectations on increased proximity to housing but involves another community.	Generally exceeds expectations on increased proximity to housing.	Meets expectations on increased proximity to housing.	N/A
Predicted Adverse Impact on Integrity of the SAC &	Low/Medium	Low	Low	Low/Medium	Low	Low
Predicted adverse impact on the integrity of the site. (SAC)	Slight to Moderate (SAC 500 Glenamoy Bog Complex)	Slight (SAC 500 Glenamoy Bog Complex)	Potential (SAC 476 Carrowmore Lake Complex) - in event of run off into Lake via Aghoos River	Slight to Moderate (SAC 500 Glenamoy Bog Complex)	Slight (SAC 500 Glenamoy Bog Complex)	Slight (SAC 500 Glenamoy Bog Complex)
Impact on Project Programme (Construction phase, excluding third party interference)	Medium	Low/Medium	Medium	High. Potential delays due to slow construction and seasonal constraints.	Medium	Low/Medium
Additional Capital costs	Low/Medium	Low	Medium	High	Medium	N/A

Comments

Route A	Not preferred mainly due to environmental constraint (approximately 1km of intact blanket bog with bog pools. (Priority Habitat)). Other viable alternatives exist.
Route A1	Potential constraint (approximately 140m crosses land belonging to documented objector). More direct alternatives exist.
Route B	Documented objection on this route. Route involves another local community which could lead to further division in the area. This route may be beyond scope of Cassells Recommendations. Other acceptable routes meeting these recommendations exist.
Route C	Not preferred for environmental, technical, cost and programme reasons. Other more appropriate alternatives exist.
Route C1	Preferred route as it is acceptable under all criteria including landowner issues.

* 2No. dwellings are both owned by the same person and are unoccupied. The Developer has agreed with the owner to purchase these dwellings. This criterion is therefore not identified as a constraint for route evaluation purposes.