Appendix Q2

Integrated Design Description

SHELL E&P IRELAND LIMITED

CORRIB GAS FIELD DEVELOPMENT PROJECT

Q2.1 – PIPELINE AND LVI INTEGRATED DESIGN

DOCUMENT No: COR-25-SH-0011

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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

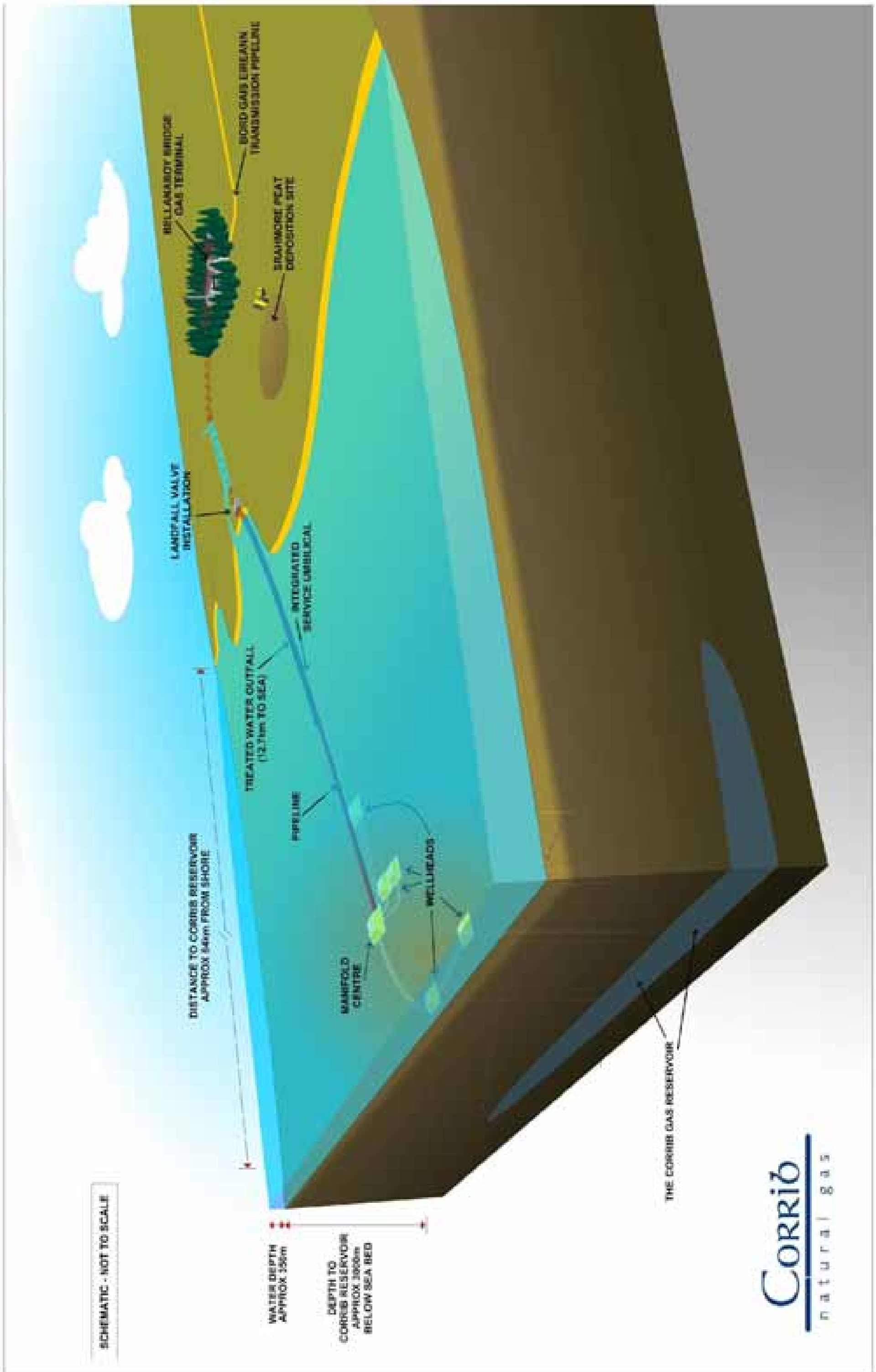
The Corrib Field Development comprises:

- 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.

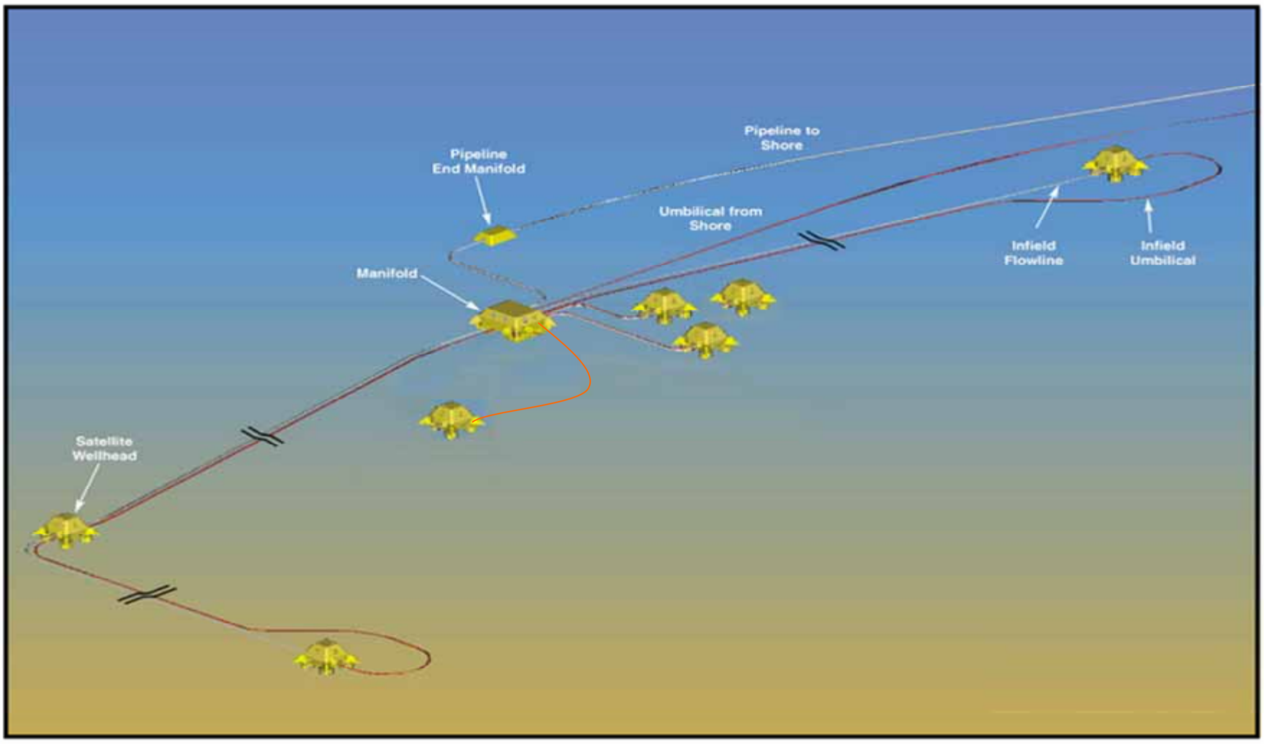


Figure 2.2 Overview of Corrib Subsea Development

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.

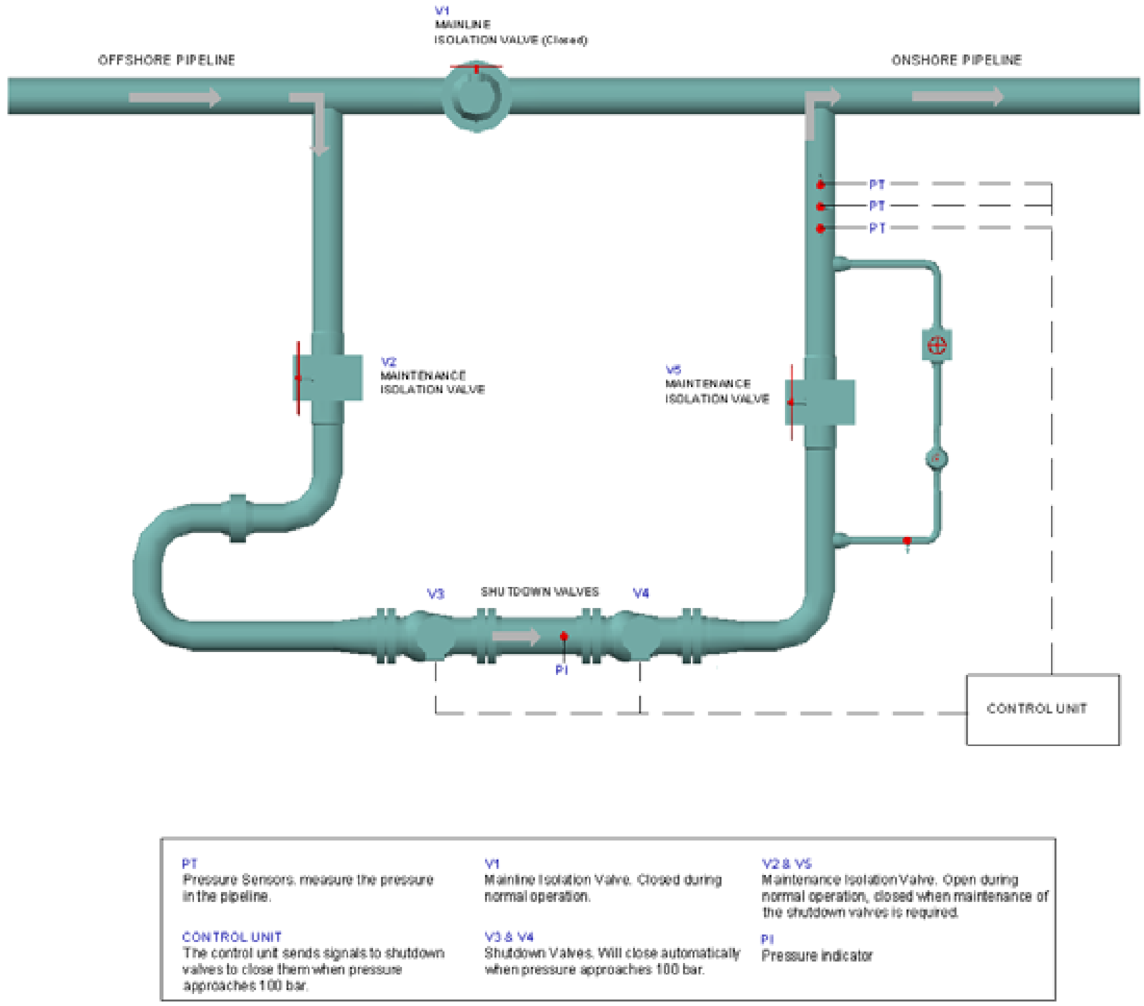


Figure 2.3 Configuration of the LVI

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

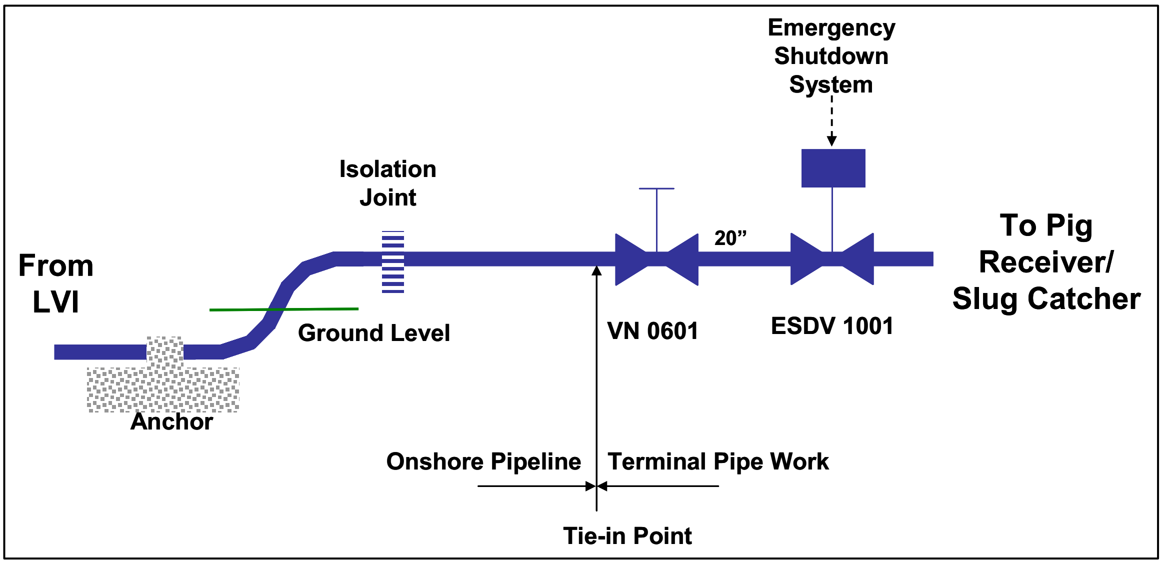


Figure 2.4 Schematic of pipeline tie-in at the Gas Terminal

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.

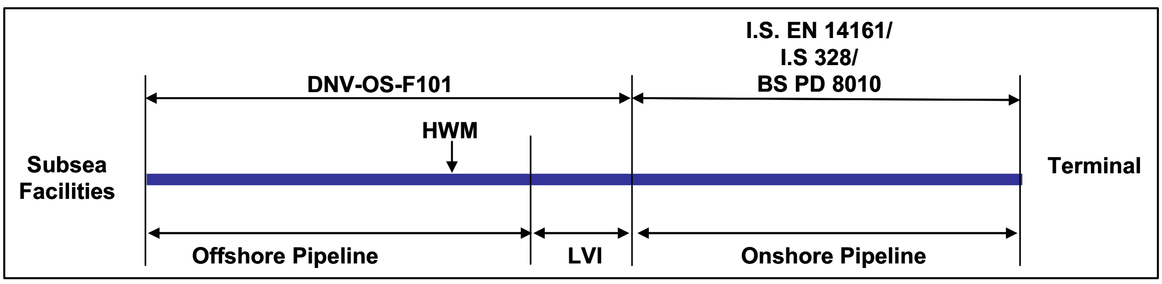


Figure 3.1 Application of Pipeline Design Codes

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.

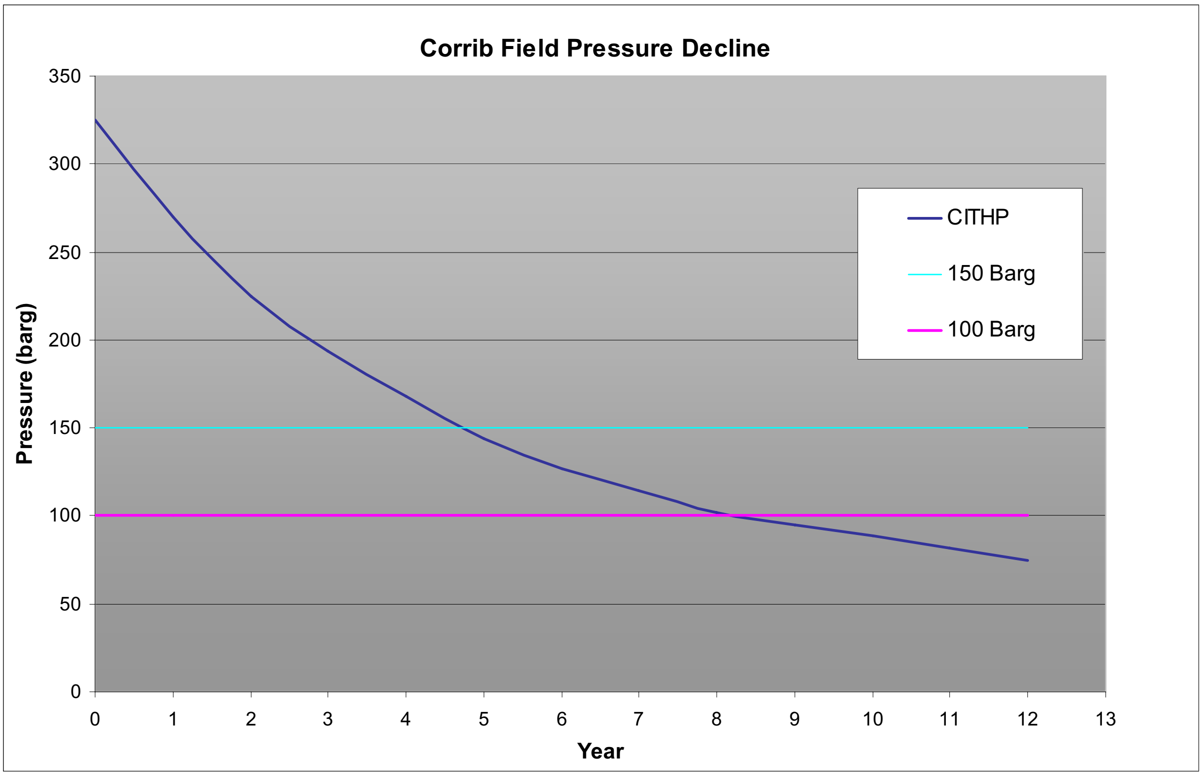


Figure 4.1 Decline in Corrib Field Pressure

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.

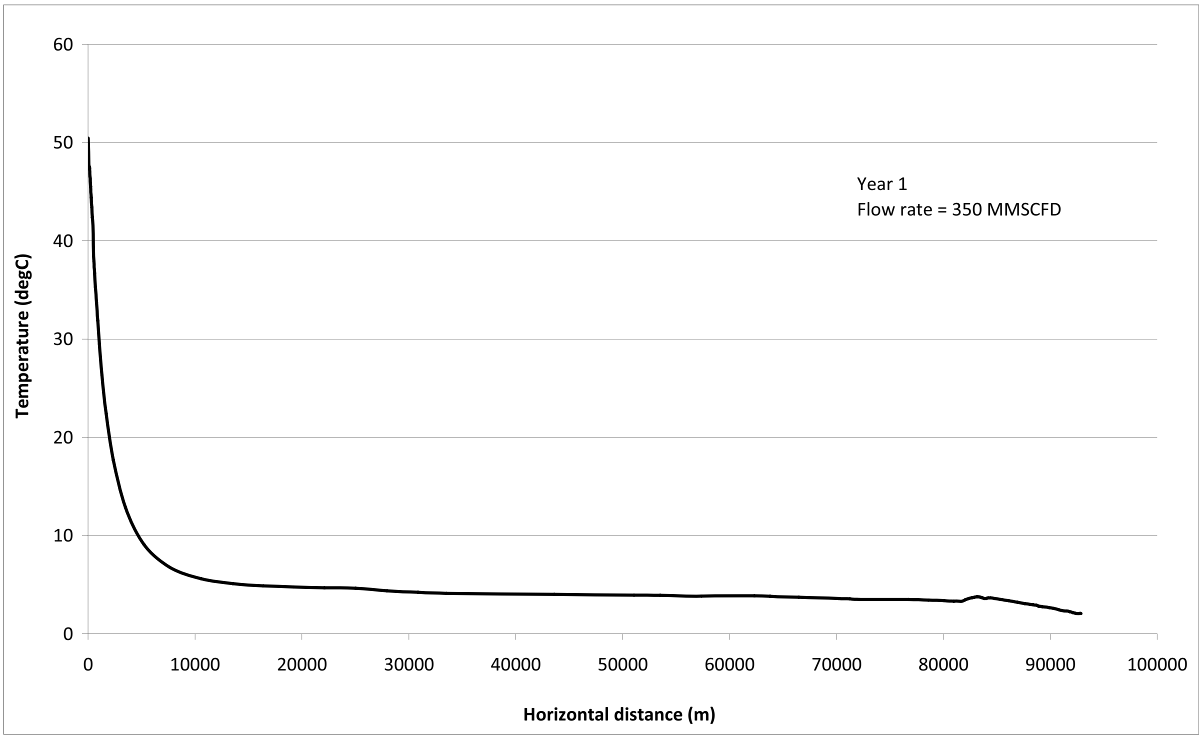


Figure 4.2 Temperature profile along the Corrib Pipeline

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.

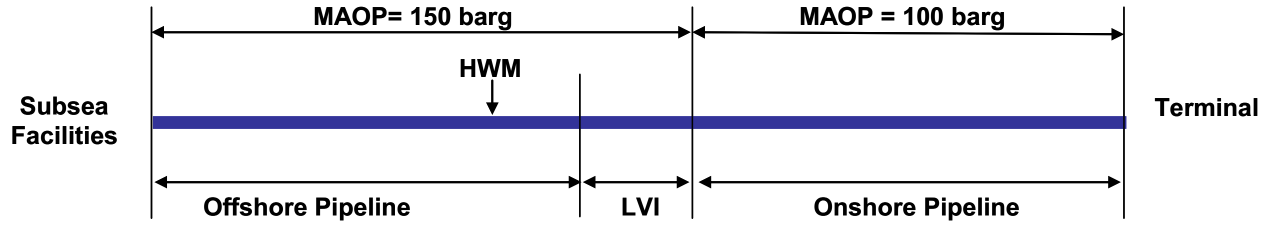


Figure 4.4 Application of MAOP

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:

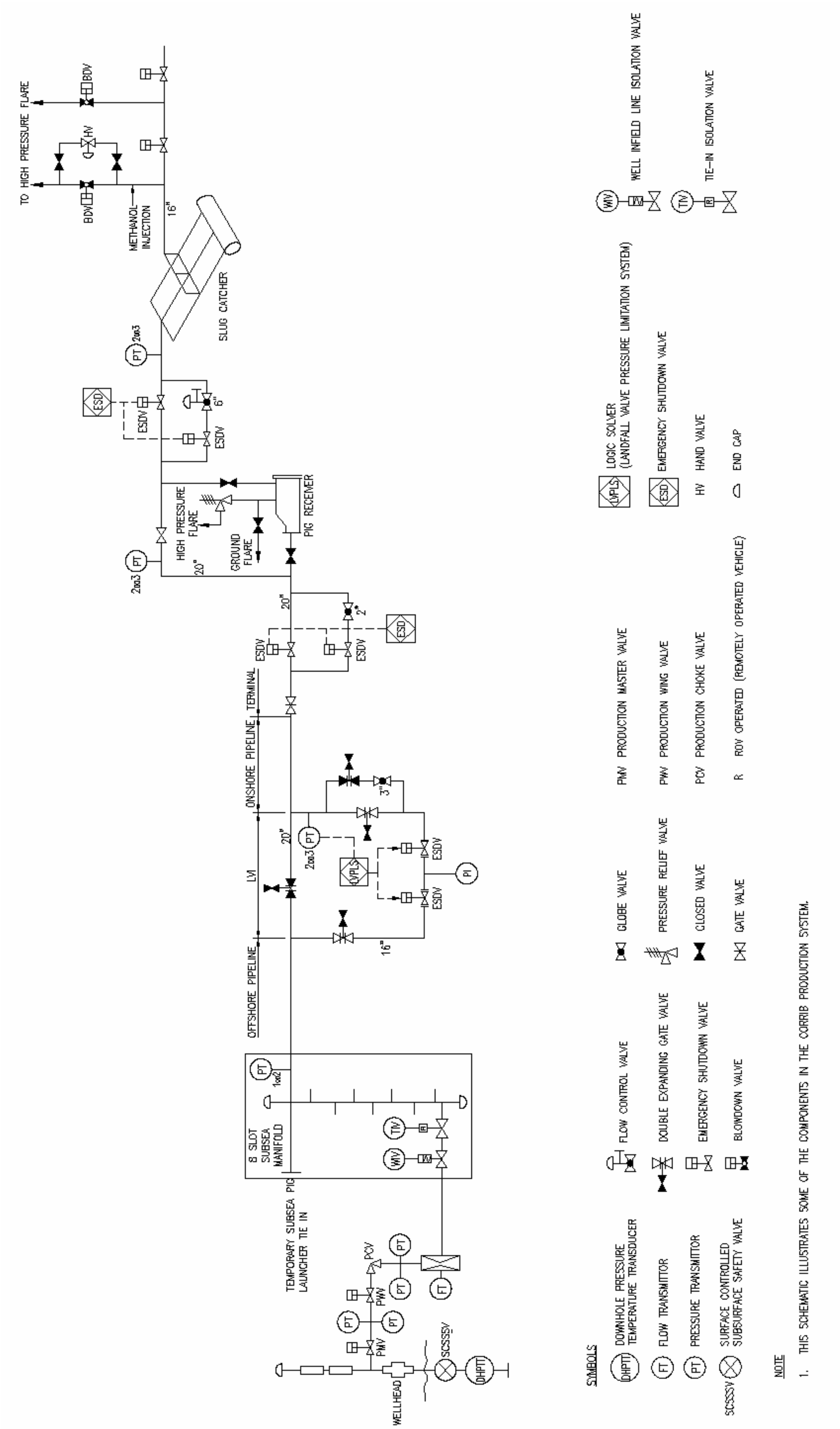
- Subsea wells
- The subsea manifold
- The LVI outlet
- At the Gas Terminal

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

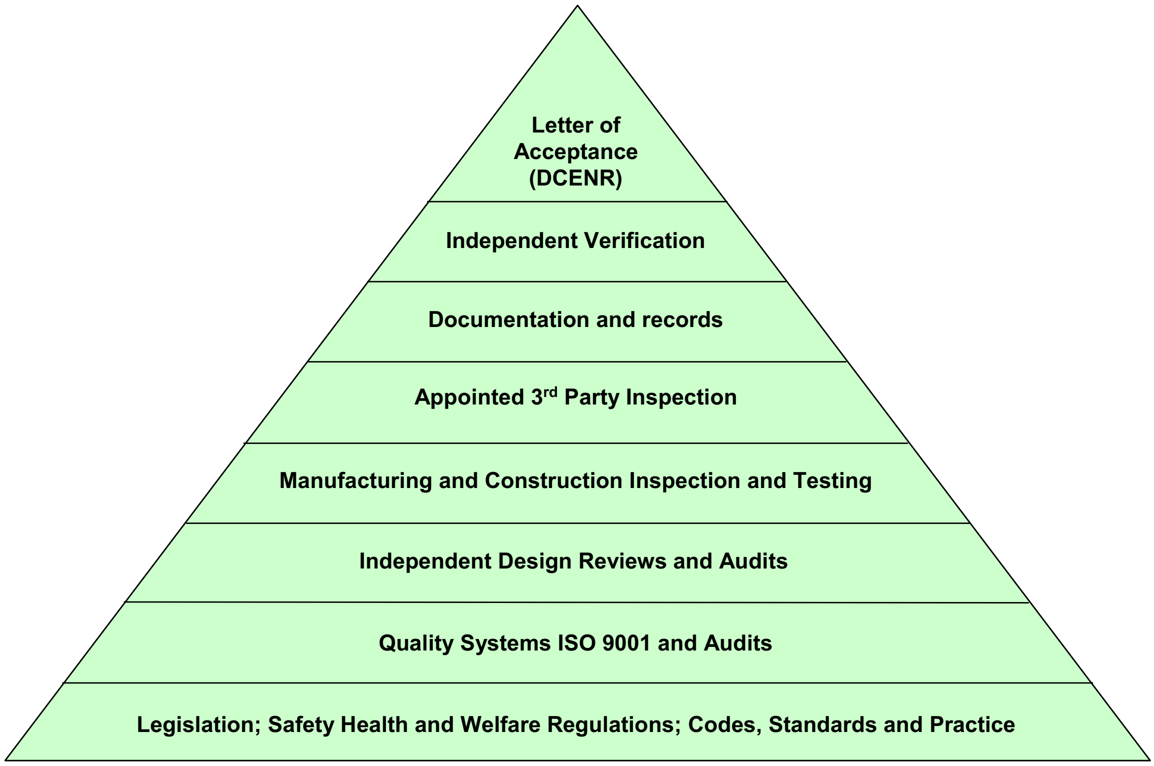
9.1 INTEGRITY PROCESS

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.

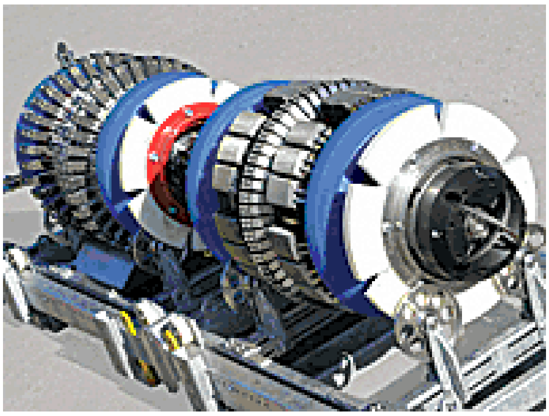


Figure 9.2 Typical Intelligent Pig Tool

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