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

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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.

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

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

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

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TABLE OF CONTENTS

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:

(green)	Code to be adopted for designated section
(yellow)	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
6.10 Adverse groundbed and seabed conditions		
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		
6.16 Offshore risers		
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.