INDEPENDENT SAFETY REVIEW OF THE ONSHORE SECTION OF THE PROPOSED CORRIB GAS PIPELINE

PREPARED FOR: The Minister for Communications, Marine & Natural Resources

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Customer Reference: Corrib Gas Pipeline Safety Review

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Executive Summary

The independent safety review of the onshore section of the proposed Corrib gas pipeline involved a detailed process of document review, discussions with Shell and their consultants, and consideration of oral and written submissions. A large amount of information was processed (approximately 150 documents in all) and Advantica carried out additional analyses where appropriate as an independent check on specific technical aspects that impact critically on the conclusions and recommendations.

The report presents the detailed findings of the review, which ranges from a general consideration of the process followed in selecting the preferred design option, to detailed analysis of highly technical aspects of the engineering design and risk assessment. The original Advantica review team was expanded to include other Advantica specialists required for the assessment of specific technical documents. To complement Advantica's expertise in soil geotechnics, we obtained information and advice on Irish peat, in particular peat landslip conditions, from the Geological Survey of Ireland (GSI) and also consulted with contacts in National Grid (Advantica's parent company) with direct experience of constructing high pressure pipelines through areas of peat in the UK.

The main findings and recommendations of the review are summarised as follows:

- Proper consideration was given to safety issues in the selection process for the preferred design option and the locations of the landfall, pipeline route and terminal. Quantified risk assessment (QRA) techniques were used to evaluate the levels of risk to the public, and deemed to be acceptable according to recognised and relevant international criteria. However, there appears to be no formal framework in Ireland for decisions on the acceptability of different levels of risk, which should be in place to enable potential developers to gauge whether or not a proposed project is likely to be permitted and to ensure consistency of decisions made on safety issues. We recommend that consideration should be given by the Irish Government to establishing a risk-based framework for decisions on proposed and existing major hazard pipelines and related infrastructure, to ensure transparency and consistency of the decision-making process.

- The unusually high design pressure (345 bar) resulted from a cautious approach to the pipeline design, such that the pipeline is designed to withstand the highest pressure it could possibly experience, despite the higher cost of pipeline construction. This approach results in a pipeline with a very thick wall, which offers the main line of defence against threats to its integrity.

- In general, conservative assumptions were used in the detailed engineering design. However, we have identified a number of areas of concern in the documentation reviewed, where detailed technical recommendations should be taken into account in the engineering design.

- The composition of the Corrib gas is similar to that normally transported through gas transmission pipelines, with a very high methane content.
However, because the gas is unprocessed, small quantities of other fluids will be present, that introduce safety issues not normally of concern for onshore gas pipelines, notably internal corrosion, possible blockage of the pipeline due to hydrate formation, and the possibility (albeit very unlikely for the Corrib gas field) of H2S being produced as the wells age. Pipeline technology for transporting unprocessed gas is well-established, and appropriate measures have been identified to manage these additional hazards.

- Provided that the recommendations in this report are followed, we believe that the pipeline will be constructed to an appropriate standard and will be “fit for purpose”. However, there is insufficient evidence at present to conclude with confidence that integrity management plans will be sufficient to ensure that the integrity of the pipeline is maintained to a sufficiently high standard throughout its life. We recommend that a formal integrity management plan is established prior to construction, including the operational and maintenance philosophy, and that an independent audit and inspection regime for both the construction and operation of the pipeline is established.

- The quantified risk assessment (QRA) carried out on behalf of Shell has been reviewed in detail and an independent check on the calculated risk levels has been carried out using Advantica’s pipeline risk assessment methodology including predictions of the consequences of pipeline failures. The levels of risk to an individual living in the vicinity of the pipeline were found to be within recognised international limits and “broadly acceptable”, with the risk levels calculated by Advantica lower than those in the Shell QRA. However, the risk assessment submitted by Shell fails to recognise the uncertainty in the risk modelling for such high design pressures as 345 bar, and takes no account of societal risk to the local population as a whole. An independent assessment of the levels of societal risk, calculated using Advantica’s methodology, is included in this report and shows a significant increase in risk with increasing pressure, due to a predicted increase in both the failure frequency and the consequences of a pipeline failure. The calculated societal risk levels are also in a region that would normally be regarded as broadly acceptable, but we note that there is a significant level of uncertainty in the risk calculations at pressures as high as 345 bar.

- Limiting the pressure in the onshore section to pressures no greater than 144 bar (equivalent to a design factor of 0.3, consistent with the design of pipelines passing through more densely populated suburban areas) is believed to be both practical and an effective measure to reduce risk (and will only be required in the early years of the life of the pipeline because the pressure in the gas wells will decline naturally as gas is extracted). In view of the societal concerns, the level of uncertainty in the risk analysis, the extent of extrapolation of onshore pipeline design codes beyond their normal range of application and mindful that the results of risk analysis are only one factor in the decision-making process, we believe that this measure should be taken and the pipeline design revised accordingly. We recommend that the pressure in the onshore pipeline should be limited to no greater than 144 bar, with a design factor not exceeding 0.3, and the pipeline design revised accordingly.
Further work will be required to determine the most appropriate engineering solution to limiting the pressure in the onshore pipeline. The FMECA (Failure Mode, Effect and Criticality Analysis) carried out on the planned subsea systems for Shell could form the basis for the reliability analysis required. We recommend that a full and 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.

The potential for ground movement to damage the pipeline due to instability of the peat, and the possible unsuitability of peat for pipeline construction, were significant issues for the review. The results of calculations undertaken on behalf of Shell and confirmed by Advantica's own analysis, indicate that the pipeline would be expected to withstand the worst-case ground movement event (albeit we recommend the results are checked by consideration of additional parameters), and that instability of the peat does not present a significant threat to the integrity of the pipeline. However, peat is one of the most difficult materials in which to construct pipelines. Documents supplied by Shell include reports by AGEC Ltd describing investigations of the ground conditions along the pipeline route, which appear to deal adequately with the ground stability issues. 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.

The pipeline safety review addressed only the design and route of the onshore section of the Corrib upstream pipeline as proposed. It does not include detailed examination of the feasibility of alternative project design options, alternative pipeline designs or routes, and assumes that the gas transported through the pipeline is produced from the existing Corrib wells as identified. In the event that additional fields were proposed to be tied in to the pipeline at any future date, a full review would be required to consider issues such as extension of the life beyond the initial design life, changes in the fluids in the pipeline or changes in the operating pressures.

Provided that it can be demonstrated that the pressure in the onshore pipeline will be limited effectively, and that the recommendations made elsewhere in this report are followed, we believe that there will be a substantial safety margin in the pipeline design, and the pipeline design and proposed route should be accepted as meeting or exceeding international standards in terms of the acceptability of risk and international best practice for high pressure pipelines.
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1 INTRODUCTION

The Corrib gas field was discovered off the west coast of Ireland in 1996. Following that discovery, a consortium led by Enterprise Energy Ireland Ltd (the operator) applied for permission to develop the field. In 2002, the Royal Dutch Shell Group acquired Enterprise Oil, including Enterprise Energy Ireland Ltd and its interest in the Corrib gas field, and through its Shell E&P Ireland subsidiary has continued to take the lead in the development of the project on behalf of its partners (Statoil Exploration (Ireland) Ltd and Marathon International Petroleum Hibernia Ltd).

The Corrib field, containing gas with a very high methane content (over 90% by volume), is located approximately 65km off the coast of County Mayo in deep water (approximately 350m). The proposed development comprises the following main elements:

1. A number of subsea gas wells connected together on the seabed via a central manifold with associated facilities including isolation valves.
2. An offshore steel pipeline, 83km in length, to bring the gas to the shore, landing at Broadhaven Bay.
3. An onshore steel pipeline (20" in diameter), buried throughout its length, to carry the gas from the landing point to a reception terminal at Bellanaboy Bridge, 9km inland.
4. A reception terminal where the untreated gas will be processed, dried and exported from there via the Irish gas transmission and distribution network operated by Bord Gáis Éireann.
5. A "control umbilical", running alongside the pipeline from the terminal to the sub sea facilities, carrying power and communication cables and hydraulic fluid to operate the sub sea equipment, and liquids added to the gas to prevent freezing and inhibit corrosion.
6. A polyethylene outfall pipeline, taking waste water from the terminal to be discharged at sea, buried along its onshore length in the same trench as the gas pipeline.

Mayo County Council granted planning permission for the terminal, which was referred on appeal to An Bord Pleanala. Following refusal of the original application, a substantially revised application was made and permission was granted in 2004, subject to a number of conditions. Subsequently, construction work commenced on both the terminal site and along the route of the onshore pipeline. However, due to strong local opposition to the pipeline, partly because of concerns for the safety of people living nearby, work on both the terminal and the onshore pipeline was stopped.

Key concerns expressed by members of the public regarding the safety of the pipeline include:

- The very high design pressure (345 bar), much higher than conventional onshore gas transmission pipelines.
• The proximity of the pipeline to housing and the consequences of a pipeline failure.
• The pipeline would be carrying untreated gas, presenting hazards not accounted for in the design code.
• The proposed pipeline route crosses areas of deep peat, and the pipeline would be laid in unstable ground and vulnerable to landslides.

[Discussion of the issues associated with the above points is given in Section 6 (sub-sections 6.2 to 6.5 respectively).]

In order to address the safety concerns, Advantica was appointed by the Technical Advisory Group (TAG) established by the Minister for Communications, Marine and Natural Resources, to undertake an independent safety review of the onshore pipeline. The scope of the safety review included identifying and obtaining relevant documentation relating to the onshore pipeline, undertaking a critical review to confirm the completeness and suitability of the documentation, and preparing a report to TAG to provide an independent professional opinion as to whether the proposed design, construction and operation of the pipeline meets applicable safety standards and is consistent with international best practice. The scope of the review did not include assessment of the environmental impact or safety aspects of the pipeline construction work itself, and was originally limited to the onshore pipeline only (not the terminal or the offshore section). However, as discussed later in the report, the requirement for the onshore pipeline and the selected route are largely determined by the chosen location of the landfall and the terminal, and therefore Advantica also examined the selection process for the overall project design and the consideration given to safety issues in that process.

It should be noted that the safety review addresses only the design and route of the onshore section of the Corrib upstream pipeline as proposed. It does not include detailed examination of the feasibility of alternative project design options, alternative pipeline designs or routes, and assumes that the gas transported through the pipeline is produced from the existing Corrib wells as identified. In the event that additional fields were proposed to be tied in to the pipeline at any future date, a full review would be required to consider issues such as extension of the life beyond the initial design life, changes in the fluids in the pipeline or changes in the operating pressures.

This report presents the findings of the review, and follows a detailed examination of documents supplied to Advantica by the Petroleum Affairs Division, additional documents and information obtained from Shell, submissions received from members of the public both in writing via TAG and at two days of oral hearings held in the nearby village of Geesala on 12th and 13th October 2005, and incorporates amendments made following receipt of comments on the draft version of the report.
2 THE SAFETY REVIEW PROCESS

The scope of the safety review was to deliver a report to the Minister for Communications, Marine & Natural Resources, on the health and safety aspects of the proposed Corrib Gas Onshore Pipeline, that:

1. "Identifies all relevant documentation relating to the design, construction and operation of the onshore, upstream section of the Corrib gas pipeline and associated facilities, i.e. from landfall to the gas terminal.
2. Critically examines all such documentation
3. Concludes whether or not, in the professional opinion of the consultant, the proposed installations:
   a. have been or will be designed, constructed, installed and operated to appropriate standards, codes of practice, regulations and operating procedures,
   b. comply with recognised international "best practice",
   c. will deliver a facility which is "fit for purpose".
4. Identifies any deficiencies in any respect relating to the above
5. Makes recommendations regarding such deficiencies
6. Provides detailed guidance on the implementation of any recommendations."

Following award of the contract to Advantica, an initial meeting was held with representatives of the TAG, following which 70 documents relating to the proposed onshore pipeline were supplied to Advantica. The documents supplied included detailed technical reports on specific design aspects of the pipeline, documents providing background information on the project, and previous technical reviews of aspects of the project design and risk assessment.

Each document was allocated an Advantica reference number and recorded in a spreadsheet. Documents were classified as:

1. Technical documents requiring detailed review by an appropriate specialist (e.g. the quantified risk assessment, or QRA).
2. Documents providing background information only (e.g. maps, copies of the relevant design codes and environmental impact statements)
3. Documents falling outside the scope of the review (e.g. relating to specific environmental aspects of the pipeline construction).

Where earlier versions of any particular document were identified, the most recent version available took precedence and earlier versions were not normally considered in the review.

Subsequently, a meeting was held at Shell's offices in Dublin, to obtain clarification of points of detail, and in particular to confirm our understanding of the process that led to the proposed overall project design and locations of the terminal and pipeline route. In the course of the review and during that meeting, approximately 30 additional documents were requested and supplied by Shell. Approximately 150 documents were eventually identified in total in the course of the safety review. Full co-operation was received from Shell in response to requests for clarification and...
further information, including retrieving specific documents from early stages of the project dating back several years and arranging for direct contact to be made between Advantica specialists and consultants working for Shell to discuss detailed technical aspects as appropriate. In some cases, requests were made for documents that did not yet exist (in particular operating procedures and emergency plans), and in these instances Shell responded by indicating the basis on which these documents would be prepared at a later date.

For the key technical documents identified as requiring detailed review by a specialist, each specialist was asked to complete a simple proforma to record their comments in a consistent manner. Any issues identified were assessed as either "technical" or "general best practice" and classified as having high, medium or low significance. As a result of the wide technical range and quantity of documents identified, the Advantica team involved in the review was expanded to include additional specialists with the appropriate expertise to undertake reviews of certain aspects of the pipeline design. The Advantica personnel involved in the pipeline safety review are named in Appendix A, with a summary of their skills and relevant experience.

The list of documents obtained was checked for completeness by comparison with the recommendations of relevant codes of practice, but also from Advantica's experience of documentation prepared for other pipeline projects in the UK and elsewhere, including both upstream pipelines and onshore high pressure gas transmission pipelines.

In order to confirm our understanding of the pipeline route, proximity to occupied buildings and the local ground conditions, a site visit was made on 22nd September 2005, accompanied by representatives of the TAG and Shell (Figure 1). During the visit, it was also possible to examine sections of the pipeline that had been laid out (Figure 2), including some sections that had already been welded and the field joints coated.

In order to provide an opportunity for concerned parties to raise issues directly with members of TAG and the consultants undertaking the safety review, two days of oral hearings were held at the village of Geesala on 12th and 13th October 2005. The hearings commenced with presentations by TAG and Advantica describing the safety review process, and full transcripts of the submissions made on both days were recorded. In addition, the TAG made provision for written submissions to be made up to the end of October 2005, to be published on the Department's website along with the transcripts of the oral hearings, and forwarded to Advantica to be taken into account in the review. The issues raised through the public consultation process relating to the safety of the onshore pipeline are summarised in Appendix B.

Advantica's draft report on the Independent Safety Review as submitted to TAG was published for comment on 8th December 2005 (accompanied by a presentation given by Advantica in Belmullet), followed by a 2 week period to provide an opportunity to submit comments on the report. The main changes made to the draft report in preparing this final report, as a result of comments and additional information received, are also summarised in Appendix B.
Figure 1: View of Pipeline Route looking North across Sruwaddacon Bay

Figure 2: Pipeline Sections Laid Out Prior to Construction
3 OVERALL PROJECT DEVELOPMENT PLAN

Although the scope of the pipeline safety review was limited to the onshore pipeline itself, it became clear that a review of the pipeline in complete isolation from the main constraints that determined the requirements for the pipeline would not address all of the pipeline safety concerns raised. The main project constraints influencing the route and other safety issues associated with the onshore pipeline were considered to be the selection of the subsea tie-back option for development of the project, the location of the landfall for the offshore pipeline to come ashore, and the location of the terminal. Although a detailed review of the documentation associated with all aspects of the project was not possible within the timescale or scope of the pipeline safety review, the selection process and reasons given for the decisions taken in terms of the overall project design, were considered in terms of their impact on the safety issues addressed in the pipeline safety review.

The main sources of information used in this part of the safety review were the Corrib Field Development Project Plan of Development and Addendum (documents originally prepared by Enterprise Energy), relevant sections of the Environmental Impact Statements prepared for the Bellanaboy Bridge gas terminal and the upstream pipeline (offshore field to terminal), Inspector's Reports from An Bord Pleanála planning enquiries, discussion with Shell personnel at a clarification meeting, early documentation provided by Shell dating back to the original design selection process including comparisons of alternatives, and impressions gained from the site visit.

3.1 Selection of Subsea Tie-Back Development Option

The selection of the proposed development option for the Corrib gas field involved a series of engineering studies, each more detailed than the last, to narrow down the range of options and to refine and select the preferred design. Five design options were initially considered, which included:

1. Deepwater fixed steel jacket or guyed tower at the field location, with associated processing facilities, and a gas export pipeline to shore.
2. A steel jacket or guyed tower in shallow water, located between the subsea infrastructure and the shore, again with a gas export pipeline to shore.
3. A floating platform or floating production vessel, located between the subsea infrastructure and shore, as in 2.
4. A subsea development with a moored remote control buoy and upstream pipeline to an onshore terminal.
5. A subsea development controlled by an umbilical and an onshore terminal.

The first three of these would require offshore processing and accommodation facilities, and would mean that the gas transported to shore would have already been processed before being transported to shore. However, there would still be a requirement for an onshore terminal to receive the gas, and a high pressure gas pipeline. The last two both involve transporting unprocessed gas and other fluids through a high pressure pipeline to the onshore terminal, with production controlled
remotely from onshore. An onshore terminal would be required for all of the options considered, although the operations undertaken at the terminal would vary depending on the option selected, and the terminal required would be smaller in size for the offshore processing options.

In selecting the preferred option, consideration was given to a number of factors, including economic viability, technical feasibility, environmental impact, and safety to workers and the public. Specific factors relating to Corrib included the deep water (350m) and hostile marine environment (which would make it technically difficult to construct a suitable offshore facility), and the relatively dry nature of the Corrib gas (which eliminates the need to process the gas close to the field).

It was concluded that the overall environmental impact of any of the offshore processing options would be greater than for the onshore processing options. Construction in deep water (option 1) was considered to pose major engineering difficulties, and the use of remote control buoy technology (option 4) was considered to be unproven and would require further development. However, subsea production technology controlled from shore by an umbilical (option 5) is increasingly being used worldwide for developments of a similar size to Corrib, and because of the relatively dry nature of the gas, was identified as a feasible development option.

Option 5 was chosen over the shallow water processing alternatives (options 2 or 3) for a number of reasons, including lower cost, lower environmental impact and reduced risk to personnel, although any of the first three options would have eliminated some, but not all, of the public safety concerns raised subsequently in connection with the onshore pipeline.

Project documentation shows that safety issues were considered in the design selection process. Offshore workers are exposed to a wide range of risks, including helicopter transport to and from the facility and the risks associated with working on the platform itself. The risks to personnel working on an equivalent onshore facility are typically much lower, and an analysis undertaken by John Brown Hydrocarbons Limited for the Corrib project in 2002 [Ref. 1] concluded that both the individual risk levels and the potential loss of life (PLL) estimates for personnel were lower, by a factor of approximately three times, for the onshore processing option than for processing offshore in shallow water. Although a detailed technical review of the risk assessments of the different gas production options was outside the scope of the pipeline safety review, the conclusion that risks are significantly higher for offshore workers in the oil and gas industry than the equivalent onshore is consistent with our experience.

The same report also states that the risks to the public would be within acceptable limits in both cases, "and would not result in any fatalities". The basis of the assessment is not clear, although the conclusion that the risks to the public would be within generally accepted limits is consistent with the conclusions of the quantified risk assessment (QRA) for the onshore pipeline undertaken later by JP Kenny, discussed in detail in Section 5, and with a formal safety assessment of the selected project development option undertaken in 2003 by Det Norske Veritas (DNV) [Ref. 2].
3.2 Landfall and Terminal Locations

The Bellanaboy Terminal location in particular was subject to an extensive planning enquiry. Mayo County Council (the planning authority for the terminal) received an application for planning permission for the terminal and associated works on the 30th of April 2001, and granted permission on the 3rd of August of the year. This decision was appealed to An Bord Pleanala and was eventually refused by that body on the 29th of April 2003 due to the "high probability of failure" of proposed repositories for peat excavated from the site. A substantially revised planning application was submitted to Mayo County Council on the 17th of December 2003 and granted on the 30th of April 2004. Following appeal to An Bord Pleanala, that body decided to grant permission, subject to conditions, on the 21st of October 2004.

The selection process for the terminal location and landfall was explored at a meeting with Shell, supported by consideration of early project documentation describing feasibility studies carried out for Enterprise Oil by Arup Consulting Engineers [Refs. 3, 4 and 5] and Granherne [Ref. 6]. The selection process is described in detail in the Environmental Impact Statement (EIS) for the Bellanaboy Bridge Terminal [Ref. 7] and the Corrib Offshore EIS [Ref. 8]. Initially, a large part of the west coast of Ireland was considered and a subsea survey was carried out to establish technically possible routes to bring the pipeline ashore. The offshore topography was found to be very difficult for pipe-laying, which considerably narrowed the number of feasible options for the landfall (where the offshore pipeline comes ashore) to four main areas, including Broadhaven Bay, which was ultimately selected as the preferred option.

The selection of the subsea tie-back option introduced constraints on the total length of the pipeline from the subsea wells to the terminal. Because the pipeline would be carrying untreated gas, the possibility of the formation of ice-like crystals called hydrates could not be ruled out, and therefore hydrate inhibitor is added to the gas to prevent their formation. However, the combination of water and hydrate inhibitor in the pipeline can also exacerbate operational problems due to liquid "slugs". To reduce the possibility of operational problems due to these issues, it was important to minimise the length of the pipeline between the wells and the terminal. This meant that there was a preference for a landfall and terminal location that provided the shortest practical length of pipeline between the wells and the terminal.

Two possible terminal locations were considered in the Broadhaven Bay area. The visual impact of the terminal was a strong consideration, and together with environmental concerns, was one of the main reasons for siting the terminal inland at Bellanaboy Bridge, despite the operational disadvantages in terms of the increased length of upstream pipeline. The inland location of the terminal drives the need for an onshore section of the upstream pipeline, which would clearly not be required for a terminal location on the coast, although an export pipeline connecting the terminal to the gas transmission network would still be needed. At other subsea tie-back developments elsewhere in the world, the terminal is often located directly on the coast, with a minimal length of onshore pipeline feeding directly into the terminal. Other reasons for the selection of the landfall and terminal locations included practical considerations (such as the availability of a large enough area of land suitable for construction). It was also considered that the selected site would present a number of practical options for an onshore pipeline route, taking into account the
ground conditions and environmental constraints, with two possible landfalls, at Dooncarton and Brandy Point.

Public safety was, therefore, one of many factors in the selection of the landfall and terminal locations. Risk levels for the proposed development as a whole, including the onshore section of the upstream pipeline, were estimated and found to be acceptable in comparison with widely used risk criteria. However, we note that Ireland has not formally adopted a risk-based framework for decision-making on major hazard pipelines and related infrastructure, and therefore there are no available guidelines on what levels of risk would be deemed to be acceptable by the authorities in Ireland.

**Recommendation:** Consideration should be given by the Irish Government to establishing a risk-based framework for decisions on proposed and existing major hazard pipelines and related infrastructure, to ensure transparency and consistency of the decision-making process.

### 3.3 Proposed Onshore Pipeline Route

Once Broadhaven Bay had been selected as the preferred area for the terminal and landfall, options for the available pipeline routes were considered. There were three main options:

1. Rossport Option, utilising Dooncarton landfall
2. Pollatomish Option, utilising the Dooncarton landfall
3. Brandy Point Option, from Brandy Point landfall

A fourth option, to route the pipeline up through the Sruwaddacon Bay was abandoned at an early stage due to environmental concerns. This option would also have presented a number of engineering challenges due to the deep and shifting nature of the sand in the bay, but these were not insurmountable.

In selecting the Rossport Option over the other two main options, consideration was given to a number of factors including the suitability of the ground for pipe-laying, environmental constraints and avoidance of archaeological remains. All three routes involved crossing significant stretches of blanket peat bog (including the Glenamoy Box Complex - designated as a “Special Area of Conservation” or SAC). The Brandy Point route was technically difficult, the longest, and involved crossing areas close to extensive archaeological remains. The Pollatomish Option involved crossing an area of steep slopes on the south side of Sruwaddacon inlet, which had suffered from landslips in the recent past (Figure 2). Overall, the ground conditions for the Rossport Option were believed to the most stable and suitable for pipe-laying, since much of the route, especially that nearest to housing, passed through agriculturally improved land with relatively gentle slopes, along the north side of Sruwaddacon Bay.

We have examined available documentation relating to the selection of the pipeline route, which includes early assessments of the risk to the public from the alternative options, and are satisfied that public safety considerations did play an important part in the selection of the onshore route of the upstream gas pipeline once the landfall
and terminal locations had been determined. Risk assessments carried out in 2000 of the two routes from the Dooncarton landfall [Refs. 9 and 10] by SP Technologies for Enterprise Energy Ireland show that the risks to the public were estimated, and considered to be within acceptable limits in both cases, for the pipeline parameters proposed at that time. It was recognised that the Pollatomish Option in particular would involve close proximity to housing and a school, and this was one of the reasons why it was rejected in favour of the Rossport Option.

These early risk assessment reports refer to a minimum separation distance of 3m between the pipeline and normally occupied buildings according to the Irish standard IS328 [Ref. 11], due to the heavy wall nature of the design, but recommend that a minimum separation distance of 20m should be maintained. Consideration of appropriate proximity distances depends critically on the pipeline pressure and diameter, as well as the wall thickness. Because of the selected project development plan, with no offshore processing, the natural pressure at the subsea wellheads (initially 345 bar, but declining steadily over the life of the field as the gas is extracted), determines the maximum pressure that the pipeline could possibly be exposed to. Under normal operating conditions, gas flows through the pipeline to the terminal at rates determined by choke valves at the wellhead, with a pressure profile that decays along the length of the pipeline to the terminal. Under these normal operating conditions, the pressure in the onshore pipeline will typically be in the range 100 to 120 bar, fluctuating as the gas flow through the terminal varies, depending on the demand for gas into the Bord Gais network. However, if the flow through the pipeline was stopped for any reason, and the subsea valves failed to isolate the pipeline from the subsea well, then the pressure in the pipeline could rise over a period of time (at least several hours) until the maximum gas pressure in the well is reached, which in the worst case, at the start of the field life, would be 345 bar.

A later report by Andrew Palmer and Associates (APA) in 2001 [Ref. 12] also considered the issue of minimum proximity distances, recommending a minimum distance of 86m, based on an assumed pipeline operating pressure of 150 bar, and where this could not be achieved, that the pipeline wall thickness be increased locally to 19.1mm. In fact, a cautious approach to the pipeline design was later adopted, and the decision was taken to design the pipeline to withstand the highest pressure that it could theoretically experience, i.e. the full pressure of 345 bar in the gas well at the start of its life. This decision resulted in the entire onshore pipeline being designed with a pipeline wall thickness well in excess of the 19.1mm recommended in the APA report. As discussed later (see Sections 5 and 6), the determination of a minimum proximity distance based on the onshore pipeline standards where a minimum proximity distance is specified requires extrapolation at pressures above 100 bar, and for the full pipeline design pressure of 345 bar, such extrapolation would result in very much larger distances than those for a pipeline designed for 150 bar.

In our opinion, the minimum acceptable proximity distance for the pipeline should have been considered further at these early stages, prior to finalising the pipeline route, particularly given the unusually high design pressure for an onshore pipeline, above the range for proximity distances given in the available standards. The most cautious approach would have been to estimate the maximum hazard range for the worst case event, so that in the highly unlikely event of a pipeline failure, the
proximity distances would be sufficient to prevent any significant level of harm to residents or damage to property. This approach, which has in Advantica's experience occasionally been adopted for high pressure pipeline projects, is rarely possible except in very remote areas with little population present. The technical justification for an appropriate minimum distance could have been agreed with the approving authorities and then used in the process of considering the routing options for the pipeline. This approach would have addressed many of the safety concerns expressed by local residents at later stages of the project.

In the event, a pragmatic approach was adopted in routing the pipeline along the northern shore of Sruwaddacon Bay (Figure 3), with the pipeline corridor chosen to allow the pipeline to be located where possible in improved ground to reduce the risk of ground stability problems, and between the majority of the housing and the shore to minimise possible problems in future should further development along the existing road parallel to the shore take place. Within this corridor, the maximum distance practical between the pipeline and nearby housing was maintained, which resulted in the nearest normally occupied building being a distance of 70m away. Once the detailed route had been identified, a quantified risk assessment (QRA) was carried out to predict individual risk levels as a function of distance from the pipeline, which were found to be within internationally recognised limits at all distances from the pipeline, including directly above the pipeline. As discussed in Section 5, it is very rare for the individual risk levels estimated for high pressure pipelines to approach these limits, because of the small frequency of failure within the length of pipeline that would affect an individual location. In the case of the proposed Corrib pipeline, the pipe has been manufactured with an extremely thick wall (because it is designed to withstand the full 345 bar well head pressure). The wall thickness is one of the main defences against the possibility of failure, and therefore the predicted failure frequencies for the pipeline (expressed per km year) are extremely low. However, because of the high pressure, the consequences of a failure are also potentially very severe, and there is therefore the potential for several people to be harmed in an incident at any location along the pipeline. In order to take this into account, societal risk should also have been evaluated, relating the potential numbers of casualties to the frequencies of the possible events, and the results considered by the Petroleum Affairs Division (PAD) as part of the approval process before granting consent.
4 REVIEW OF PIPELINE DESIGN

4.1 General Remarks

Design standards or design codes are documents produced to codify knowledge and good practice. They are based on a combination of theoretical analysis, experimental testing and experience. The production of a code is usually done by a group of experts representing interested parties. They produce an initial draft, which is then circulated for public comment before a finalised version is produced. There is normally a mechanism for revising and re-issuing the code, either at fixed intervals or when there is a consensus that a new edition is required.

The standards most relevant to this review are:

- BS 8010, the UK code used for the original design [Ref. 13]. This was published in several parts covering different pipe materials. The relevant part is Section 2.8, covering onshore steel pipelines for oil and gas. This was published in 1992. This code covers design, construction and installation but does not address operation and maintenance.

- Recommendations for high pressure gas transmission pipelines have been produced by the UK Institution of Gas Engineers and Managers, formerly known as the Institution of Gas Engineers. These recommendations, usually referred to as IGE/TD/1 [Ref. 14], are now in their fourth edition.


- PD 8010 [Ref. 15] is a British Standards Institution published document, produced in 2004 to replace BS 8010. The reasons for this are discussed in more detail in Section 6. It is worth noting that this does cover the full pipeline lifecycle, including operations and maintenance.

- EN 14161 [Ref. 16] is the European implementation of the ISO pipelines standard ISO 13623. On-land pipeline systems used by the gas supply industry are specifically excluded from the scope of EN 14161, although they are covered by ISO 13623. The UK national foreword to the EN states "...that a more comprehensive approach to the design of pipelines is possible through using BS EN 14161 in association with the following Codes of Practice: — PD 8010-1:2004..." This note is not included in the Irish national foreword.

- ASME B31.8 [Ref. 17] is a US code for gas transmission and distribution systems. Although it is often considered to be the national design code, the actual minimum US Federal safety requirements are given in the Code of Federal Regulations 49 Part 192.

During the course of the project, various reviews have been carried out of these standards, and it was considered that BS 8010 was the most appropriate standard to use as a design basis.
The use of BS 8010 as the base design code is considered an appropriate selection at the time the project commenced. However, the scope of BS 8010 only covered the life cycle up to pressure testing and commissioning, so there was no code to cover operations and maintenance. Section 4 of BS 8010 was intended to cover pipeline operations but this was never issued by BSI. Further discussion of these issues is included in Section 6 below.

This section reviews specific issues associated with the design, construction and operation of the pipeline that are not covered in Section 5 below, which deals with risk assessment. The sequence of this section is broadly similar to that in PD 8010. Wider issues associated with the use and application of this and other design codes are covered in the discussion in Section 6.

4.2 Flow Analysis

Shell provided details of internal flow simulations carried out during the pipeline design. These were used to set the pipeline diameter and to predict pressures, temperatures and liquid drop-out along the pipeline. The output from this is relevant to the design of the onshore section, for example in predicting the pressure variations and assessing corrosion rates.

A steady state flow analysis [Ref. 18] was carried out using PIPESIM, which is an industry standard package. The temperature profiles showed that the contents will have cooled to ambient temperature at the onshore section, and so thermal expansion and buckling effects would not be significant. The results relating to liquid formation were not taken into account in the internal corrosion analysis; this is discussed more fully in Section 4.5.2 below.

Transient flow analyses [Ref. 19] and a slugging analysis [Ref. 20] were carried out using the OLGA package, which is also a widely used package (Advantica uses this program for flow assurance work). The results confirmed the previous steady-state analysis and considered behaviour of the wells during field start up. This study also predicted the extent of liquid accumulation at dips in the pipeline. These results were not considered in the corrosion analysis and were not explicitly addressed in the HAZID documentation reviewed (see Section 5.1).

4.3 Mechanical Integrity

4.3.1 Fatigue Design and Monitoring

Various analyses were provided that considered the fatigue life of the pipeline. They differ principally in the assumptions made for the stress ranges, which have been predicted from the flow simulations, both steady state and transient. However, they are dependent on the assumptions made regarding flow rates and nominations from the field partners. The resulting predicted hoop stress ranges ranged between around 39 N/mm² and 20 N/mm²; the exact values depending on the assumed conditions. These are around (and in some cases below) the IGE/TD/I and BS 8010 cut off stress range of 35 N/mm². Thus it is likely that the actual fatigue usage for the pipeline will be low. Despite the low predicted usage, we consider that monitoring of the actual fatigue usage should be carried out. This will provide actual data, rather
than assumptions, in the event that defect assessments are required in the future. It
is also possible for actual pipeline usage to change during the life of a project, and
the availability of measured data will remove the need to make assumptions. An
annual check of the fatigue usage could be made at minimal cost based on the data
recorded by the terminal SCADA system combined with a proprietary cycle counting
software package.

It has been assumed that the pipeline design does not have any features that are
likely to be susceptible to flow induced vibration. One possible area of concern
would be the bypass on the beach valve. The bypass is required to equalize the
pressure across the main valve after the pipeline has been shutdown for
maintenance. Our experience is that these smaller attachments may suffer flow
induced vibration in service. A vibration survey should be carried out to check this.

**Recommendation:** The actual fatigue usage of the pipeline should be monitored by
carrying out an annual fatigue cycle count.

**Recommendation:** Small bore attachments at the beach valve, such as the bypass,
should be checked for flow induced vibration once the pipeline is operating.

Although the terminal is outside the scope of this review, Advantica would
recommend that a post-commissioning vibration survey is carried out on the terminal
to identify any vibration issues.

### 4.3.2 Impact Protection

A formal safety analysis was produced and included in later versions of the QRA
[Ref. 41] as a result of earlier reviews to justify not using thicker walled pipe at the
road crossings to reduce the design factor. As a result, a design factor of 72% was
accepted as appropriate. To provide additional protection at road and ditch
crossings, concrete slabs have been specified. However, these are described in the
drawing as “marker slabs” and there has been no data supplied to support the
design of the slabs that will be used. The design appears to have been reproduced
directly from IGE/TD/1. Large elements of the design of the impact protection have
been left to the discretion of the contractor. 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.
4.3.3 Ground Movement

4.3.3.1 General Remarks

Parts of the pipeline are to be laid in peat, which may be subject to a landslide or ground movement. The designers carried out analysis to determine the stresses that a landslide would cause in the pipeline [Ref. 21]. Advantica has reviewed this analysis based on its extensive experience in modelling pipe-soil interactions. The main results of this review are summarized in this section. However, it is noted that although the original analysis was carried out early in 2005 the proposed construction method has now changed so that where the peat depth is less than 4 metres the pipeline will be laid on the underlying subsoil. Depending on the local ground conditions this may have the effect of increasing the depth of cover from that originally assumed.

It was noted in the original ground movement analysis that there was considerable uncertainty in the soil properties assumed for peat. Advantica would concur with this. In view of this uncertainty it is considered that measurements should be made of the actual performance of the pipeline in areas of peat. The measurements should identify displacement of the pipeline and soil movement or failure. The measurements could include direct measurement of pipe wall strains, monitoring of markers, high accuracy survey of the pipeline position and measurement of settlement and groundwater levels. Acceptance criteria should be set for these. The monitoring and assessment of the results should form part of the overall pipeline integrity management system.

Recommendation: Consideration should be given to long 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. No information has been provided to indicate how the pipeline will be fixed to the top of the piles.

4.3.3.2 Results of Review of JP Kenny Analysis

Finite Element Model

- The number of finite elements used to model the 1000m pipeline section is not stated; the accuracy of the results will be affected if insufficient elements are used.
- The single vertical springs should be separated into two springs for upward and downward directions, as the stiffness in the upward direction is often different from that in the downward direction due to the limited depth of soil above the pipe. In addition, in areas where the pipeline has been laid on the subsoil the downwards stiffness should represent the subsoil properties rather than those of peat.
Applying the soil movement loading as a uniformly distributed load (UDL) is not the best method of representing a landslip in a finite element model (see below).

**Applied Loading**

- The design pressure of 345 bar should have been used instead of the operating pressure of 150 bar for the internal pressure loading. This would have a major influence on the calculated equivalent pipe stresses.
- The maximum operating temperature of 20 °C was used, which gives a maximum temperature difference of 10 °C from the stress-free condition. However, the maximum design temperature is 50 °C, which gives a worst case maximum temperature difference of 40 °C. The additional temperature difference would have a major influence on the pipe stresses, although it is likely that in the onshore section the temperatures would be well below 50 °C.
- The use of a UDL is not the best way to represent ground movement loading due to landslip, since the loading is non-uniform and displacement dependent. A better approach is to apply the loading as a soil movement field via the lateral soil springs. This approach produces a more realistic loading so that the amount of ground movement, width of landslip, and ground movement pattern can be specified explicitly.
- The ground movement pattern assumed in the analysis is not realistic and no information was presented to support the use of it. The assumed pattern could generate stresses on the pipeline that are over-conservative.
- Secondary loadings from overburden soil, live load due to vehicles/plant, and construction-induced stress due to an uneven trench bottom were not considered in the analysis. These could affect the pipe stresses.

**Soil Restraints**

- The 1m pipe cover used in the analysis is less than the specified minimum cover depth of 1.2m. The revised construction specification for peat will allow the depth of peat to reach 4m. This could affect the soil restraints.
- The basis of the soil parameters used to calculate passive soil resistance and the basis of the selected value of passive soil resistance of 12.8 kN/m are unclear. Comparing with Advantica's in-house data for peat, the passive soil resistance of 12.8 kN/m falls within the upper and lower bound limit pressure values for the axial and upward directions, but is lower than the lower bound in the lateral and downward directions.
- There has been no consideration given to the variation in soil restraint in the different restraint directions, or to use bounding soils data values, which could provide a confidence level in the restraint parameters used.
- There has been no consideration given to the likely scenario that granular finefill surrounds the pipe, or to the difference in properties of backfilled soil and the natural ground.
Allowable Stress Limits

- The analysis [Ref. 21] used the offshore standard DNV OS-F101 (Submarine Pipeline Systems) [Ref. 22] as the benchmark for checking the limit states, in which the maximum equivalent stress limit is 96% SMYS. However, in the primary code specified for the onshore pipeline, BS 8010, the acceptance limit is 90% SMYS. The maximum equivalent stress level calculated in the analysis was 94% SMYS, which exceeds the BS 8010 limit. No justification has been given for using an alternative design code.

- Additional checks such as stability against buckling and membrane stress in the landslip area were not carried out.

Recommendation: The results of the analyses should be assessed for acceptability to the project design code.

4.3.3.3 Summary of Advantica Analyses

In order to address the concerns identified in the previous section, Advantica has carried out additional analyses using our in-house models. Full details of this analysis are given in Appendix C. This analysis has shown that at a pressure of 150 bar, above the expected operating pressure, the worst case stresses in the pipeline are less than the limits of BS 8010. Checks of other failure modes such as buckling have also been carried out, and the results are acceptable. We consider that the JP Kenny analysis has correctly identified the worst case landslip for the pipeline configuration analysed. However, we note that only one configuration, a landslip perpendicular to a straight pipe, has been analysed. In our experience the presence of bends in an area of ground movement can have a large effect on the predicted stresses, and ground movement parallel to the pipe can also generate significant stresses. It is not possible to predict which will be the worst case, and so we consider that these other cases should also be analysed.

Recommendation: Additional ground movement analysis is required of the sections of the pipeline with bends, and of a landslip parallel to the pipeline.

4.3.3.4 Conclusions

We consider that the use of the finite element method to assess the effects of landslip is appropriate, and our additional analysis has shown that the results of the JP Kenny modelling are conservative for a reduced internal pressure of 150 bar. However, we consider that further analysis is required for cases that were not considered.

Recommendation: Additional analysis should be carried out to consider increased depth of cover up to 4m of peat.

4.4 Materials

The pipeline is designed with a nominal outside diameter of 508 mm (20 inches) and a nominal wall thickness of 27.1 mm. The material is Grade 485 to the DNV OS-
F101 specification. This specification is a more onerous specification than the most widely used linepipe specification API 5L [Ref. 23], where the equivalent strength grade is X70. We consider the material specification an appropriate material for the project. Grade X70 or 485 material has been widely used for onshore projects in Europe and North America and for major offshore projects in the North Sea. The parent plate material has been sourced from Dillinger Huttenwerke AG and Nippon Steel. Both companies are suppliers with extensive experience in producing plate for high quality linepipe. The pipe was produced by Corus Tubes at Hartlepool; this mill has a long track record in producing high quality linepipe. A sample of plate and pipe mill test certificates was provided by Shell for review. These showed that the pipe met the project specifications.

One area of concern for the review was the specification of Charpy impact energy levels. Best practice requires that these are derived from a fracture control plan. A fracture control plan will consider both fracture initiation and propagation. A formal fracture control plan has not been produced, but Shell have stated that the material toughness levels were based on the recommendations of DNV OS-F101 for ensuring crack arrest in lean natural gas transmission pipelines. For high pressure gas pipelines fracture arrest is usually the controlling factor in setting the material toughness.

Control of fracture propagation is based on semi-empirical models, calibrated against full scale test data. The DNV recommendations are based on these models, although some experts, including Advantica, consider that the DNV upper thickness limit of 30 mm is an unjustifiable extension beyond the database of test results, and that 25 mm would be a more appropriate limit. In addition, the Corrib design pressure is outside the database of tests and the range of validation of gas decompression models at 345 bar. To address this, Advantica has checked the required toughness using its FRACPROP model with the proposed untreated gas composition. The results show that the specified Charpy toughness will be sufficient to ensure crack arrest, as there is a factor of five difference between the required toughness and the specified value. In fact the margin will be greater as the actual toughness of the pipe supplied exceeds the specification minimum value.

4.5 Corrosion Control

A pipeline will require measures to control corrosion over its lifetime. If corrosion cannot be fully prevented, the design should take account of the anticipated metal loss, so that there is sufficient remaining wall thickness at the end of the design lifetime. For the Corrib pipeline it is necessary to consider both external corrosion due to the environment in which the pipe is laid, and internal corrosion from the pipe contents. These have been considered separately as the control methods are different. It should be noted that stress corrosion cracking has not been considered in the review, as the contents are not considered to be likely to cause this failure mode. The requirements to ensure that the corrosion control measures are effective are considered as part of the review of operations and maintenance in Section 4.8.
4.5.1 External Corrosion

External corrosion in pipelines is controlled by two methods: coatings and cathodic protection. The coating prevents the external environment from contacting the steel. The main coating is applied by a specialist coating contractor after the pipe is manufactured. The mainline coating cannot be applied close to the welds, as the heat of the welding process would destroy it. Thus, the areas of the girth welds are protected by a field joint coating applied after welding. As the coating system is not 100% effective, a cathodic protection (CP) system is also used. The CP system produces a voltage difference between the pipe and the surroundings. This difference opposes the voltage generated by the corrosion reactions and prevents corrosion occurring.

4.5.1.1 Coatings

The mainline coating is a three layer polypropylene (PP) system, specified in Reference 24. This specification was reviewed. It encompasses most of the requirements of the French, DIN and Draft European standards. However, omissions have been made which may impact on the deterioration of a 3-layer coating during long-term storage. These are:

- A stress crack resistance test for the PP coating should have been specified, e.g. ASTM D1693 [Ref. 25]. Stress crack resistance is important to prevent problems during long-term storage and in-service operation.

- The surface profile of the steel should be angular to optimise the fusion bonded epoxy (FBE) layer's adhesion to the steel and hence its water soak and cathodic disbonding resistance. Rounded profiles, typical of those produced by the use of shot will compromise the long-term performance of the FBE layer.

- The FBE coating should have been applied to a minimum thickness of 100 mm above the blast profile.

- The inclusion of differential scanning calorimetry (DSC), flexibility, water soak and cathodic disbondment (CD) tests on the FBE layer would have indicated whether surface profile, application temperature and cure time were being adequately controlled. These parameters are critical to the long-term storage and in-service performance of the FBE layer. Adhesion problems that have occurred with 3-layer systems have initiated between the FBE and steel substrate. These have been attributed to poor control of surface profile and application temperature.

- The inclusion of a DSC, water soak and CD test should have been considered for the reasons indicated above.

- Guidance on long-term storage should have been provided to prevent degradation due to ultra violet light (UV), as provided by the French 3-layer PP Standard (NFA49-711) [Ref. 26] and Draft European Standard EN 10286 [Ref. 27].
In general, line pipe is laid very soon after coating and hence the implications of long-term storage are not an issue. Where it is foreseen that pipe will be in storage long-term (e.g. greater than 6 months), the coating should be protected from the effects of sunlight (UV light). This may be accomplished by covering the pipe stacks with sheeting or by the application of a coating that will mitigate the effects of UV. The use of white emulsion over the surface of the coating is a low cost option for mitigating the UV weathering process and has been successfully used on single layer FBE coated pipe. Only those pipes on the outside of the pipe stack will be exposed to UV and therefore it may be possible to minimise the number of pipes that require UV protection.

If concerns exist about the stage to which the PP coating has degraded, tensile tests should be performed on the aged PP to compare its tensile strength and elongation at break with values generated on unaged PP. This concern is particularly relevant for the section that was strung and part welded in the summer of 2005, and was subsequently dismantled. These joints will have been exposed to sunlight along their upper surface for an additional period. Tests should be carried out on the coatings of a representative sample of these pipes. It is understood that Shell are discussing this testing with the coating contractor.

**Recommendation:** Tests should be carried out on the coatings of a representative sample of the joints strung in summer 2005 and subsequently removed.

Water ingress at the coating cut back may result in loss of coating adhesion from the pipe ends. This will present problems during construction and may require the mainline coating to be cut back to a film edge. An extension of the coating cut back region, and hence the width of the field joint, may require the use of wider heat shrink sleeve (HSS) field joint coatings.

The field joint coating system specified for the pipeline is a heat shrink sleeve. This is considered acceptable for the relatively small diameter of the Corrib pipeline, as there is extensive experience of satisfactory performance of these systems on small diameter pipelines. Three layer PP heat shrink sleeves have been developed to match the performance of 3-layer PP mainline coatings. The use of such a sleeve would allow greater integration of the pipeline coating system. The Raychem WPC 100M heat shrink sleeve, specified in the field joint drawing, is a two layer PE based system (PE backing + adhesive).

During the Advantica site visit in September 2005 it was noted that a significant number of the field joint coatings that had been applied to the welded section showed disbonding. Figure 4 shows a typical example. The welded section has since been dismantled and the coatings removed. Shell have stated that these sleeves had not been inspected due to disruption to the construction programme, and under normal circumstances, the disbonded coatings would have been repaired. However, this observation does show that the field joint coating process should be improved.
Recommendation: The application of the field joint coatings should be improved and additional inspections made to ensure that disbonding is not occurring.

4.5.1.2 CP System

The overall design proposed for the CP system is considered acceptable, with the exception of the decision not to use an insulation joint to separate the onshore and offshore sections. A factory built insulation joint (I/J) installed at the landfall is considered to be best practice and cited in DNV RP B401 and ISO/CD 15589-2. The absence of a landfall I/J will make accurate polarised close interval potential surveys more difficult to achieve. Such surveys are required to validate the applied cathodic protection throughout the pipeline. Also, due to the differences in pipeline length, environment and protection scenarios between onshore and offshore pipelines, the land based impressed current system is likely to experience significant current drain from the offshore section. This may result in increased difficulty in managing the CP system to deliver effective protection onshore.

We consider that a high quality factory built I/J would not provide a preferential leak path and could be buried. Increased corrosion due to CP interaction effects across the I/J is not likely to be significant; and even if present at low levels, it is unlikely to accelerate corrosion on a pipeline with an effective cathodic protection system.

I/J's require CP test cables to be installed on both sides (e.g. on onshore and offshore sides).

Recommendation: A factory built insulation joint should be considered at the landfall to separate the offshore and onshore CP systems. Alternatively the detailed CP system design should be revised to take account of the possible effects of the offshore section.
Note that the use of flanged insulating kits (using bolted flanges with insulating gaskets and washers) is not recommended for any location.

Other issues with the CP system are:

- 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.

- 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.

- 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 plate.

- 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.

- 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 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.
4.5.1.3 Conclusions

Whilst the proposed system is generally satisfactory, we consider that the issues identified in the discussion above should be addressed to improve the long term performance of the external corrosion protection systems and achieve best practice.

4.5.2 Internal Corrosion

Where internal corrosion may occur in a pipeline it is accepted practice to add additional thickness to the inner surface. This allows for the loss of metal over the life of the system, so that at the end of the life there is sufficient thickness remaining to satisfy the original design requirements. If corrosion inhibitors are used, their effect can be included in the calculation of the corrosion allowance. The method adopted to determine the pipeline corrosion allowance for the onshore section of the Corrib pipeline has been reviewed to determine if it meets current industry best practice [Refs. 18, 19, 28, 29, 30].

The general procedure followed by the oil and gas industry for selecting corrosion allowances consists of the following stages:

1. Determine the corrosion rate along the pipeline
2. Determine the effect of any corrosion prevention measures
3. Use the results of steps 1 and 2 to determine the likely total metal loss over the pipeline service life
4. Select a corrosion allowance in excess of the calculated total metal loss from step 3

The review will also follow these stages.

4.5.2.1 Corrosion rate calculation

Internal corrosion rates have been calculated using the commonly used DeWaard and Milliams equation. This uses carbon dioxide partial pressure and temperature to give a corrosion rate. It has been assumed that only water condensing from the gas is present (i.e. the wells do not produce any water). A corrosion rate has been estimated for each year of life using the predicted pressure and flow conditions, and the total internal corrosion obtained by summing the loss in each year.

The base corrosion rate calculated by the DeWaard equation is normally adjusted by a series of factors to give an adjusted corrosion rate. JP Kenny appears to have only used the factor for fugacity (i.e. non-ideal gas) and neglected the other factors. In particular, the pH factor has not been used to adjust the corrosion rate. The pH factor accounts for the phenomenon that in once through systems it is very difficult to saturate water with iron corrosion products. This is particularly relevant to systems where fresh water is being continually generated by condensation as in the Corrib pipeline. The analysis explicitly states that condensed water has been assumed and that corrosion rates have not been reduced for high pH values, however, it appears that corrosion rates have not been increased due to the potential presence of low pH values either. The pH factor can increase the calculated corrosion rate from the base
equation by factors of 2.2 to 3 at pH values below those associated with iron saturation.

4.5.2.2 Effect of corrosion prevention measures

Corrosion protection is provided by the addition of corrosion inhibitor to the methanol employed for hydrate inhibition. Its effect is accounted for by JP Kenny by using an inhibitor efficiency factor. The factor chosen is 95%, this means that the calculated corrosion rate is multiplied by 0.05 to give an inhibited corrosion rate.

However, in the JPK analysis corrosion rates are dominated by top of line corrosion so that effectively a 90% corrosion reduction factor has been used. Actually, top of line corrosion would not be expected to be an issue for the onshore section of the pipeline, as there is insufficient temperature difference between the interior of the pipe and the external environment to drive water condensation. Thus, although top of line corrosion will not occur in the onshore section, assuming it will is a conservative assumption, albeit not a realistic one.

The concept of inhibitor efficiency has fallen out of use in the larger oil companies and consultancy firms and been replaced by the concept of inhibitor availability [Ref. 31]. The availability concept states that if inhibitor is present it will reduce corrosion to a constant rate \( C_{\text{inh}} \), if inhibitor is not present then the base corrosion rate will apply \( C_{\text{base}} \). The proportion of time the inhibitor is present is the availability. The overall availability is calculated by:

\[
A\% = \frac{100 \times \text{Time inhibitor is present at an effective dosage}}{\text{Pipeline lifetime}}
\]  

One of the main issues with the efficiency model is that it predicts that inhibitors can always reduce the uninhibited corrosion rate by a fixed percentage regardless of its original value. For example, with a calculated base rate of 0.2 mm/y, the model would predict an inhibited rate of 0.02 mm/y with an efficiency of 90%. This is well below the accepted minimum corrosion rate of 0.05 mm/y used for pipeline design [Ref. 32]. Many of the JP Kenny inhibited corrosion rates are below 0.05 mm/y so would normally be regarded as over-optimistic for design purposes.

The use of a 95% efficiency factor is also more optimistic than common industry practice. EFC 23 states that "given careful inhibitor selection, values of 90% can be achieved in the field in straight pipe under typical pipe wall stresses and in the absence of highly energetic flow (e.g. at tees and in slug flow conditions)." Considering that the transient flow analysis predicts slug flow under normal full flow operational cases the use of a 90 or 95% efficiency would seem unjustified. A factor of less than 90% would be more appropriate for the Corrib pipeline.

4.5.2.3 Determination of metal loss

JP Kenny have determined the total metal loss by summing the individual metal loss calculated for each year over the field lifetime using inhibited corrosion rates, i.e.

\[
\text{Total loss} = \sum_{n=1}^{30} \text{loss in year } n
\]  

[2]
If using the efficiency model this is a reasonable approach. However, as stated in the previous section most companies now use the availability model where the metal loss in each year would be calculated using:

\[ Metal \ Loss = \left( C_{\text{inh}} \times \frac{A\%}{100} \right) + \left( C_{\text{base}} \times \left[ 1 - \frac{A\%}{100} \right] \right) \]  

The individual metal losses for each year would then be summed over the lifetime as in equation [2]. The practical consequence of using the availability model is that metal losses would be higher than when using the efficiency model. Thus, the JP Kenny work may have underestimated metal losses.

### 4.5.2.4 Corrosion allowance selection

The design corrosion allowance is the additional thickness added to a pipe wall to take account of the effect of corrosion over the pipeline lifetime. It is added to the minimum thickness required to resist the internal pressure and other mechanical loadings. The design corrosion allowance is set to be higher than the calculated metal loss over the field life. JP Kenny have used this approach and thus are in line with the usual industry practice. However, as explained above their calculated corrosion rates may be over optimistic and thus the 1 mm corrosion allowance specified could be too low.

Many companies use a minimum corrosion allowance of 1.5 mm or select corrosion allowances from fixed values [Ref. 33] as follows:

- 1.5 mm: Conditions where inhibition is reliable and easy to apply (moderate temperatures, long experience in similar circumstances)
- 3 mm: More severe service regimes as regards the effectiveness of inhibition (higher temperatures, fluctuating flow patterns, unmanned facilities etc)
- 6 mm: Severe service regimes with regard to the corrosivity of the medium or difficulty in applying inhibition (high temperatures, rapid flow velocities, fluctuating conditions)

If this approach were taken then a corrosion allowance of at least 3 mm would be applied as the pipeline operates in a slug flow regime.

### 4.5.2.5 Conclusions

The overall conclusion from the review is that the corrosion analysis described in the documentation represents general industry practice for 2001 before the more advanced company protocols became generally available. However, it does not represent the best practice used at that time as, for example, both the BP Cassandra (1998) and Norsok M-506 (1998) models were available and being used by certain contractors and companies.

**Recommendation:** The internal corrosion rate prediction should be re-evaluated and the implications of the resulting predicted metal loss on the pipeline integrity assessed.
Recommendation: 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.

4.6 Construction and Installation

The main concern for the safety of the pipeline under this heading is the welding of the individual pipe sections into the main pipeline (girth welding). Issues concerning the long term safety aspects of a pipeline constructed in deep peat are addressed in our consideration of ground movement issues in Section 4.3.3. We note that there will be HSE issues associated with the actual construction such as working in deep excavations in peat, but these are outside the scope of this review.

Shell provided copies of the welding procedures qualified by their contractor. These referred to an internal Shell specification and also to BS 4515 [Ref. 34]. Shell subsequently advised that the welding code for the project is BS 4515, as the internal specification quoted in the SICIM procedures is supplementary to API 1104 [Ref. 35], not BS 4515. The edition of BS 4515 was not stated by Shell but on the procedure the 2004 edition is called up. The procedure is an automatic Gas Metal Arc Welding procedure, using an internal copper backing. The inspection procedure is radiography, with the workmanship acceptance criteria from BS 4515 rather than a project specific fitness for purpose approach.

The mechanical test requirements are more onerous for the Charpy impact test than required by BS 4515, where in the 2004 edition the weld metal Charpy impact energy limits are 40 J average, 30 J minimum for materials up to Grade X80. The values used in procedure qualification by SICIM, the contractor, appear to be based on the (yield/10) approach referenced in Appendix A, B201 of DNV OSF101 [Ref. 22], with a temperature shift of 20 degrees for a gas pipeline in Table 6-4 for wall thicknesses in the range 20 to 40 mm. We consider that the criteria used will give a high quality weld with good tolerance of defects.

4.7 Testing

No documented pressure test procedures were available, but it is understood from discussions with Shell that a pressure test producing a hoop stress of 90% of the Specification Minimum Yield Strength (SMYS) is planned to be carried out with a 24 hour hold period. The 90% SMYS level is the "standard" test level in BS 8010 for a design pressure of 72% SMYS. However, BS 8010 and PD 8010 give an alternative option of a "high level" test carried out to a stress level of 90% to 105% SMYS. The benefit of a high level test is that it provides a more searching test for the presence of defects at the start of life. It is also consistent with the fatigue design guidance of PD 8010 and IGE/TD/1.

Given that the cost of pressurizing to the higher level is marginal compared with the overall cost of the pressure test, it is considered that a high level pressure test of the onshore section should be carried out, to gain the maximum benefit and demonstration of integrity at the start of life.

The proposed test pressure is stated in the QRA as 431 bar, and this value has been used in Advantica's analysis of failure frequencies in Appendix D. The basis of this
pressure is not given, but our analysis suggests it is based on achieving a hoop stress of 90% of SMYS in the design wall thickness. We consider this incorrect, as the test pressure should be adjusted to take account of the additional thickness above the design thickness due to the corrosion allowance, as is the practice in pressure testing of pressure vessels. IGE/TD/1 specifies the use of the nominal wall thickness for calculating the test pressure. On this basis, for a high level test at 105% SMYS the appropriate test pressure would be 543 bar.

Pipeline Integrity International (PII) have proposed a "fingerprinting" run [Ref. 36] with an in-line inspection vehicle during the commissioning stage whilst removing the test water. This is supported, as it will provide a baseline for comparison with future inspection runs to estimate the growth rate of corrosion defects. An initial run at start of life will also assist in determining if features reported in future inspection runs are likely to be fabrication defects rather than defects that are growing in service.

Recommendation: 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.

Recommendation: An initial fingerprinting in-line inspection run should be carried out during pipeline commissioning.

4.8 Operations and Maintenance

4.8.1 Integrity Management System

Best practice for pipeline systems now requires a full integrity management system. Basic requirements for such a system are given in Section 13 of PD8010-1 [Ref. 15]. Ideally, the integrity management system should form an integral part of the pipeline design and should be used from the start of the project. The integrity management system should not only include the specific inspections to be carried out, but should define management responsibilities, systems for the management of change and an audit and corrective action function to give a "closed loop" system which identifies any deficiencies and ensures they are corrected.

Increasingly integrity management systems are software based, often using Geographic Information Systems (GIS) to manage the data generated by inspections. In particular, such systems can "align" the data from inspections to give an improved analysis of trends. Construction data such as pipe identities and weld inspection data can also be stored in these systems, which can help to discriminate between fabrication defects and defects that have been introduced in service.

The documents relating to integrity management provided by Shell were early studies that mainly referred to the implementation of a leak detection system to assure integrity. In Advantica's experience, leak detection systems are not widely used for gas pipelines, as they are unlikely to detect small leaks. In addition, a leak detection system will not prevent a leak occurring; other systems are required to assure this. Overall, we consider that the documents supplied did not describe a full integrity management system. It is understood that further work by Shell is in hand in this area.
Based on the review carried out to date, the following specific issues have been identified:

- The proposed frequency of internal inspection should be re-assessed in the light of the comments on the management of internal corrosion and the aggressive external environment. The integrity management system should ensure that the interval is re-assessed after each inspection run, taking account of the results to update the interval to the next planned inspection.
- River crossing surveys will be required for the two crossings of Sruwacaddon Bay.
- Vantage point surveys should suffice instead of aerial surveillance given the limited length of the onshore section.
- Other best practice measures for integrity management should be formally defined and implemented such as landowner liaison and the installation of marker posts at field boundaries.

Recommendation: A formal integrity management system should be established for the pipeline before construction is allowed to commence.

4.8.2 Defect Assessment and Repair

Defect assessment procedures should be defined in advance, so that if indications are reported in by an inspection, their significance can be assessed immediately and any actions such as a temporary pressure reduction can be implemented without delay. These procedures should consider various types of defect and their structural significance. Appropriate repair procedures should be identified for each type of defect. For example, for minor corrosion defects it may be appropriate to dress the surface and repair the coatings rather than attempt a full repair.

One report was provided describing a repair philosophy [Ref. 37]. This is considered to be inadequate, as it only considers complete replacement of section of pipe as a repair approach. Even at this level, the document does not follow best practice as pipe used for repairs should be hydrostatically pre-tested in advance and the coating protected from UV degradation in storage. It is considered that the repair philosophy should specifically consider repair of coating damage and non-leaking damage. A range of proprietary techniques are available for the repair of non-leaking damage, for example the epoxy shell, Clock Spring® and the DML carbon fibre wrap system. It may be necessary to carry out some work to determine if these systems are suitable for use long term use in a saturated peat environment.

Although not within the remit of this review, it is considered that the repair procedures should take account of safety issues arising from working in deep excavations in peat. Procedures for safe working near the pipeline should be established, for example limiting the use of mechanical excavators close to the pipeline.

Recommendation: Defect assessment procedures specific to this pipeline should be developed.
Recommendation: 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.

4.8.3 Presence of the control umbilical

The presence of a control umbilical close to the main gas pipeline is an unusual feature of the Corrib project compared with most onshore transmission pipelines. The effect on the main pipeline of a failure of the umbilical is discussed in Section 5, but 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.

4.8.4 DCMNR Permission System

Full details of the DCMNR system for regulation of pipeline safety have not been reviewed. Advantica understands that for the Corrib project consents have been given on a phased basis, with the final phase being commissioning. Operational and maintenance issues would have been considered at this stage. This would have been followed by an approval for "First Gas" before gas production could begin. This approach is likely to make it more difficult to achieve an integrated integrity management system. Advantica consider that the operational and maintenance philosophy should be considered as a whole with the pipeline design. It is suggested that for future projects the Government review the regulatory system to ensure that an integrity management system is included from the pipeline design stage.
5 RISK ASSESSMENT

All activities involve an element of risk, defined as the frequency of the occurrence of an undesired event. However carefully a system is designed, constructed and operated there remains the possibility, however small, of failure and the consequences of such failures may pose a risk to people, property or to the environment. Such failures have occasionally occurred of high pressure gas pipelines around the world.

For a high pressure gas transmission pipeline, a failure may take the form of a puncture or complete rupture of the pipeline, with ignition of the escaping gas giving rise to a large fire, observed in incidents and many large and full scale experiments. The main features of pipeline incidents, that need to be taken into account in a robust risk assessment, are summarised below:

Failure - Failure of a gas pipeline can occur due to a number of different causes such as external interference, corrosion, fatigue, ground movement, material or construction defects. The failure modes that can occur are leaks (punctures), or breaks (ruptures). The failure mode is determined by the length, depth and type of defect, and is dependent on the pipe diameter, wall thickness, material properties and the operating pressure. Estimates of failure probability can either be made from historical data where appropriate, or by the application of predictive methods, or a combination. Preventive measures to reduce the likelihood of failure usually offer the main opportunity to reduce risk.

Gas Outflow - Due to the pressure at which transmission pipelines are operated, a failure of a pipeline leads to a turbulent and complex gas release. Following a rupture, or large puncture, there will be rapid depressurisation in the vicinity of the failure. For buried pipelines, the overlying soil will be ejected with the formation of a crater of a size and shape that influences the behaviour of the released gas. Depending on the alignment of the pipe ends in the case of a rupture, the gas will escape to the atmosphere in the form of a jet, or jets. At the start of the release, a highly turbulent mushroom shaped cap is formed which increases in height above the release point due to the source momentum and buoyancy, and is fed by the gas jet and entrained air from the plume which follows. In addition to entrained air the release can also result in entrainment of ejected soil into the cap and plume. Eventually, the cap will disperse due to progressive entrainment and a quasi-steady plume will remain. Immediately following a rupture the flow from each side of the rupture will be balanced. However, at later stages the flow through each limb will be determined by the pipeline system, including action taken to isolate the damaged section by closing valves, which will determine whether the flow through the pipeline at the rupture will gradually decrease to zero or to a steady-state value.

Punctures in buried pipelines may also displace the overlying soil and form a crater. In this case, however, it is likely that the outflow from the hole is small enough so that the pressure is either maintained in the pipeline or decreases very slowly, such that the release is effectively taking place at a steady state.

Ignition - Ignition can occur at any time during the release. If it occurs immediately on, or shortly after, rupture, a transient fireball will occur. The fireball, which is the result of combustion of the mushroom-shaped cap lasts, typically, for up to thirty seconds, and then burns out leaving a quasi-steady state fire. If ignition occurs after
the initial highly transient phase, the transient involved in establishing a quasi-steady fire is much less pronounced and, for modelling purpose, the consequences of the quasi-steady fire only are considered. Releases from punctures may either be into free air or may interact significantly with the ground crater, depending on the orientation. This means that it is possible for the release to emerge into the atmosphere with a wide range of different speeds and directions. If a puncture release is ignited, the resulting fire will be a high momentum jet fire.

Mathematical models to predict the dispersion behaviour of an unignited plume of gas released by a high pressure pipeline failure can be used for specific situations to evaluate the likelihood of flammable gas concentrations being produced at a specific location where ignition sources are available. Generally, however, routine assessments take values for ignition probability based on historical data.

Thermal Radiation - The levels of thermal radiation incident on the area surrounding the ignited release vary with time after rupture and with distance from the release point, and are dependent on the shape, nature and extent of the fire (determined by the source and atmospheric conditions), and the atmospheric transmissivity between the fire and the receiver (determined by the humidity). Following the initial fireball phase after a pipeline rupture, the gas outflow gradually decays, and the fire behaviour can be treated as though it is quasi steady-state. In the case of ignited puncture releases, the fire behaviour is effectively steady-state throughout the duration of the event, until action is taken to isolate the damaged pipeline section.

Thermal Radiation Effects - Both people and property in the vicinity of an ignited pipeline release can be affected by the levels of incident thermal radiation. People can become casualties as a result of receiving large doses of thermal radiation, and buildings can be ignited by thermal radiation directly from the fire or from secondary fires (e.g. from burning vegetation). A number of different criteria can be used for predicting casualties, which should also take account of the distance from the pipeline and the availability of shelter.

Risk Calculations - The calculation of risk at a particular location from an extended pipeline source is complicated by the fact that the failure position is unknown in advance. It is necessary to consider the effects from the predicted pipeline fire along the interaction length, which is the length of pipeline that could pose a hazard to the development or point of interest. Risk can be expressed either as individual risk, meaning the frequency of an individual at a specified location being a casualty; or societal risk, defined as the relationship between the frequency of an incident and the number of casualties that may result. Societal risk is usually expressed in the form of a graph of the cumulative frequency (F) of producing N or more casualties plotted against N (an "FN curve"). An expectation value (i.e. the numbers of casualties expected on average per year) may be calculated by integration of an FN curve.

The following sections describe the review of the available documentation describing the hazard identification (HAZID) process, the quantified risk assessment (QRA) undertaken by JP Kenny on behalf of Shell, other supporting documents including the population density analysis and consideration of further risk reduction measures and pressure safety measures.
5.1 Hazard Identification (HAZID)

5.1.1 Initial HAZID

A small team undertook the initial HAZID for the onshore section of the Corrib pipeline: A HAZID leader, a safety consultant and a project engineer. It is not clear from the report on the HAZID [Ref. 38] whether this small team had sufficiently wide areas of expertise to be able to address all the potential aspects necessary to identify and assess the hazards associated with the pipeline. However, the basis for the HAZID study was a checklist developed by JP Kenny, which was comprehensive in that it covered all the hazard groups that would normally be considered to address the hazards associated with onshore steel transmission pipelines.

The outcome of the HAZID study is presented as a tabulated checklist in which the potential causes for each hazard are listed along with the accident scenario that could occur and the resulting consequences. The checklist also details actions and remarks. This method of presenting the outcome of a HAZID is common and provides a clear summary of the HAZID study. However, in reviewing the document concerns were raised due to the fact that there were no apparent means for assigning identified actions to individuals or to other project groups making it difficult to find evidence that any of the actions have been, or will be, addressed. This could be done through a follow-up review to track whether the HAZID findings have been addressed in other documents. For example, within the hazard section 'objects under stress', pipeline fittings are considered and the action is that the number of small bore connections should be minimised and designed appropriately. Without a follow up review or cross-references to other documents it is not possible to see whether this will be addressed adequately. However, if a HAZID action review had been undertaken and reported it should have been possible to point to specific documentary evidence that this issue has been addressed, for example, in a detailed design document.

Another concern about the way in which the HAZID study was undertaken is that basing the study on a checklist for a generic pipeline may have resulted in some potentially credible threats to the pipeline integrity being missed for this specific pipeline. For example, in the environmental hazards section extreme weather is considered, but no consideration seems to be given to tidal conditions. Another example appears to be that there has been no consideration of the potential for liquid slug causing damage to the pipeline.

Other apparent deficiencies in the HAZID study that were noted during the document review were:

- Inadequate consideration of the potential for escalation of a minor incident to a major incident.
- Limited consideration of potential human factor influences on the hazard causes.
- High pressure has been dealt with by saying that pipeline has been designed for wellhead shut-in pressure; however there may be situations where an
event that leads to the wellhead pressure being shut-in also poses an additional threat to the pipeline integrity.

5.1.2 HAZID review

Following comments made by Advantica about the problems tracking the status of any actions identified in the HAZID study, Shell requested JP Kenny assist them in producing a Project Hazard Register. The Project Hazard Register document [Ref. 39] was submitted to Advantica for inclusion in this safety review. The stated purpose of the Project Hazard Register is to collate and record the hazards, and the recommended methods and procedures to overcome these hazards provided on the Quantified Risk Assessment Report and the HAZID Report. The Project Hazard Register lists all the credible hazards identified through the Quantified Risk Assessment and HAZID Study, and the identified action. In addition, the register includes Action Party and Status.

This document is valuable in that it provides an insight into the methods and procedures that will be employed to control the risks from the pipeline. However, a review of the document identified some limitations with it as it is currently. Examples of the limitations identified include:

- Some actions are given status to be incorporated in the operating procedure. However as these have not yet been prepared, it is not possible to assess whether they will be addressed adequately. For example, where monitoring is to be included in the operating procedures, there should be an indication of the likely frequency.

- Some actions appear to not fully address the identified hazard. For example, internal corrosion resulting from Hydrogen Sulphide (H₂S) has an action to undertake periodic monitoring to determine concentrations — there is no indication of what criteria will be used to determine unacceptably high levels or what would be done to mitigate such levels.

- 'Hazard incorrect location of pipeline markers' is stated as being addressed through an assessment of third party risks in the QRA. It is not clear that this is the case, as the QRA employs failure frequencies based on pipelines that would be expected to be operating with correctly located markers.

It is also noted that the register is not complete as a number of items are still on "Hold".

5.2 Population Density Analysis

Analysis of population density was carried out following the method specified in BS8010, and documented in [Ref. 40]. The population density analysis is a critical part of the pipeline design process, because the population density classification is a key parameter used in pipeline design codes to determine the engineering design requirements for the pipeline, in particular the design factor, which is the main defence against failure of the pipeline and accidental releases.

The process of evaluating population density is similar in most design codes, including BS8010, IS328 and IGE/TD/1, and involves calculating an area, 1.5km long...
(in BS8010, 1 mile in IS328 and IGE/TD/1) whose width depends on the diameter and operating pressure of the pipeline, within which the numbers of people resident are estimated. The section of pipeline that gives the highest population density is identified, and the results used to determine the location class of the pipeline (e.g. Class 1 or Class 2 in BS8010, equivalent to "Rural" and "Suburban" in IS328 and IGE/TD/1). A threshold value of 2.5 persons per hectare is used in all three codes as the upper boundary of a Class 1 (Rural) location. Above this value the area is classified as Class 2 (Suburban) and the degree of protection required increases.

Ref. 40 shows that the process for estimating population density was followed as specified in BS8010 for a pipeline transporting methane (a Category D substance). This is appropriate, because although the Corrib onshore pipeline is designed to carry unprocessed gas, the composition of the gas is very close to that of processed natural gas supplied to consumers, with a methane content between 93 and 94% by volume. The pipeline design pressure of 345 bar was used as the basis for the calculation of the area within which the population density was estimated for the purpose of determining the location class. This pressure is well above the 100 bar range of the proximity distance graphs provided by the codes, and so a simple extrapolation of the BS8010 proximity distance graph to 345 bar was carried out by JP Kenny, and a minimum proximity distance of 170m was obtained. This part of the code is intended for application to onshore pipelines carrying dry gas at pressures up to 100 bar, although BS8010 does allow for higher maximum operating pressures where demonstrated to be safe by further analysis. The linear extrapolation to 170m is a reasonable starting point for the purpose of population density analysis, subject to the reservations expressed below, but this figure does not appear to have been used in considering routing options for the pipeline, nor supported by any detailed analysis of whether the minimum proximity distance of 170m was appropriate, taking account of the uncertainty in the knowledge and limited operational experience for onshore pipelines at such high pressures.

Based on a minimum proximity distance of 170m, the population density was estimated by taking a 1.5km long strip, 1700m wide (i.e. 10 times the minimum proximity distance as per BS8010, extending to 850m on either side of the pipeline), centred on the pipeline. The pipeline section with the highest population was identified as being the western end of the northern shore of Sruwaddacon Bay. No buildings likely to contain large numbers of people (such as schools) were identified (although in fact the school in Rossport lay just within the area considered), and based on a typical average of 3 people per dwelling, the population density was calculated to be 0.65 persons per hectare, well below the 2.5 persons per hectare threshold value, and therefore designed as a Class 1 (Rural) location.

Our review of the document identified a number of issues. The area chosen as having the highest population density is reasonable. However, the nature of the proposed pipeline route in relation to the buildings in this area warrants a more detailed consideration. As stated in BS8010, special consideration should be given to population clusters in rural areas, such as ribbon developments, which can give rise to an anomaly in classification, when a more stringent classification may be appropriate. The document does not comment on whether this is an issue or not in this case. Within the selected area, the pipeline route is roughly parallel to a minor road, along which the majority of the housing included in the population density analysis has been built. A particular concern is that the large proximity distance...
(170m) estimated by extrapolation of the BS8010 proximity distance graph results in a turn in a large strip (1700m wide) being used to estimate average population density, even though the majority of the developments are within 400m of the pipeline. Because of the nature of the development in the area, this means that large areas of unoccupied farmland are included in the analysis on the north side, and large areas of open water on the south side, so that the population density calculated will tend to increase with decreasing pressure. For the normal operating pressure of 120 bar used in the QRA, the minimum proximity distance obtained by the same method of linear extrapolation would be approximately 71m, which would have resulted in the population density calculated being higher by roughly a factor of two. Over the lifetime of the onshore pipeline, the pressure will continue to fall as the gas wells are depleted. However, it is nevertheless considered unlikely that if the analysis were to be repeated on a more cautious basis, that the population density calculated would take the pipeline into a higher class location, although a more cautious approach should be used in future in calculating population density in any future reassessment of the pipeline classification.

5.3 Quantified Risk Assessment (QRA)

Risk, defined as the frequency of an undesired event, is calculated by combining the predicted frequencies of credible failure events with the consequences. The assessment of the risk can be performed at a number of different levels, ranging from qualitative screening assessments through to fully quantified, case specific assessments. For the onshore section of the Corrib pipeline, which has the potential to generate a major hazard to the local population in the event of a failure, and whose design parameters lie outside the typical range of application of the design codes for high pressure onshore gas pipelines, it is appropriate to undertake a fully quantified risk assessment (QRA). This work was carried out by JP Kenny for Shell [Ref. 41] broadly in accordance with the project risk assessment procedure [Ref. 42], and using mathematical models developed by Shell to predict the consequences of gas releases.

Several versions of the QRA have been issued, and other consultants have previously carried out reviews of the QRA documents. Our comments relate to the latest version of the QRA available to us [Ref. 41] and not to any earlier versions. The comments made represent the independent opinion of Advantica experts in this field. Calculations have also been undertaken by Advantica, using our own methodology, to provide an independent check on the risk levels quoted, and to provide additional information to support our recommendations where appropriate. The Advantica calculations are described in detail in Appendix D.

5.3.1 Failure Frequency Analysis

The QRA report by JP Kenny considered a wide range of possible failure causes for the Corrib pipeline, including overpressure, pressure cycling, effects of a methanol fire following a failure of the umbilical, third party interference, damage at estuary/river crossings, internal erosion, ground movement, external corrosion, internal corrosion, and inherent (material) and construction defects. In our opinion, all the relevant credible failure causes normally applicable to onshore gas transmission pipelines were covered, in addition to those that are particular to this
pipeline. Each failure cause was assessed in turn, and those that were assessed as making a negligible contribution to the overall risk (with a predicted frequency of less than $1 \times 10^{-6}$ per km per year) were not considered further. Examination of the reasons given for eliminating the other causes from the analysis shows that in many cases, the contribution to the overall failure frequency is negligible, assuming that certain measures are in place to protect the integrity of the pipeline, a conclusion supported by our own analysis (see Appendix D). Elimination of possible failure causes on this basis is consistent with best practice for pipeline risk assessment, provided that the proposed measures together with those recommended in this report are actually in place as assumed, and maintained throughout the entire lifetime of the pipeline, which will need to be documented through the operational and maintenance procedures, as discussed in Section 4.

**Recommendation:** 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.

Attention is drawn to the comment made above in Section 5.1 relating to Hydrogen Sulphide (H$_2$S). There is no evidence to suggest that H$_2$S is present in the Corrib gas and good operational practice should prevent any increase in H$_2$S concentrations. However, H$_2$S is both toxic and corrosive, and its presence in even relatively small quantities could have a significant impact on the level of risk, which would need to be taken into account in a revised risk assessment. A procedure should be prepared to identify the actions to be taken in the event that H$_2$S is detected in the gas stream, and the threshold concentrations of H$_2$S above which action would be required.

**Recommendation:** A procedure should be established for monitoring of the gas for H$_2$S, specifying the actions to be taken and the threshold concentrations above which action would be required.

The three remaining causes included in the failure frequency calculation as input to the QRA were:

1. Third party interference
2. Ground movement
3. Inherent defects and construction defects

The limited historical experience of onshore pipelines with such a thick wall as the Corrib pipeline and with such a high design pressure means that it is difficult to use historical data to estimate appropriate failure frequencies.

For third party interference, a combination of historical data and limit state modelling was used. Historical data from the UKOPA database for UK transmission pipelines [Ref. 43] was used to estimate the frequency with which the pipeline would be predicted to suffer an impact due to external interference, with a limit state model used to estimate the probability of a failure given that an impact occurs. The combination of the two gives a failure frequency per km year due to third party interference. The approach allows the specific pipeline parameters to be taken into account in the assessment, in a way that cannot be achieved using historical data alone, and is consistent with best practice for pipeline risk assessment. The
methods used to estimate the failure frequencies due to third party interference are similar to (and partly based on) methods developed by Advantica. Nevertheless, some significant differences were observed when predictions for the failure frequencies obtained using Advantica's own models were compared with those obtained by JP Kenny, with the Advantica models giving higher predicted failure frequencies for the rupture mode in particular (see Appendix D).

Generic data from the UKOPA database were used to estimate failure frequencies due to ground movement and inherent and construction defects, with engineering judgement applied to reduce the estimated ground movement frequency to take account of the thick wall. For the purpose of the QRA, failure frequencies were estimated for both leaks (a single leak hole size of 25mm) and full bore ruptures. Based on the historical data, inherent and construction defects contributed to the risk of leaks only, whereas ground movement contributed to the frequencies for both leaks and ruptures. It is not clear why ground movement was included, when the conclusions of the landslip analysis undertaken by JP Kenny [Ref. 21] concluded that the pipeline would be able to withstand the loading from a range of landslip events, including the worst case. Advantica's calculations suggest that the JP Kenny analysis is cautious (albeit we recommend additional parameters should be investigated to confirm the conclusions - see Section 4 and Appendix C), and therefore we would not expect ground movement to make a significant contribution to the failure frequency. Similarly, provided that the steel quality and pipeline construction methods meet modern standards and the pipeline is hydro-tested in accordance with our recommendations (as discussed in Section 4), then the contribution of inherent and construction defects to the risk associated with the pipeline should be negligible, leaving third party interference as the dominant contribution to the predicted failure frequency.

5.3.2 Consequence Analysis

5.3.2.1 Data and Assumptions

The QRA uses a gas flow rate averaged over the first 60 seconds for a rupture. This is a weak assumption, and not representative of the physics of the gas release behaviour. Observations of pipeline rupture experiments showed that if there is immediate ignition of the release (which reports of incidents suggest is possible), then there is an initial highly transient fireball phase. The methodologies used by Advantica (and others) now include a model specifically for this highly transient phase. The radiation emitted from this may be greater (or less) than that from an averaged steady state jet fire, and hence it is appropriate to investigate this behaviour within the QRA. Alternatively, some indication of sensitivity to the averaging time is required. The risk calculations undertaken by Advantica to provide an independent check on the results of the QRA, described in Appendix D, include modelling of the initial transient fireball phase.

The use of three release types for the punctures is considered reasonable. However, the 'buried' release would not behave as indicated in this report. Observations suggest that the momentum is not 'destroyed'. In fact, more often than not, a jet emerges from the crater, albeit possibly angled. Such jets have some dilution within the crater and emerge at a lower velocity than the 'free' jets assumed...
in this analysis (and observed in real life for releases from the top portions of the pipe). However, they do not emerge with 'zero' momentum. The use of 25%, 25% and 50% for vertical, horizontal and buried releases is considered reasonable. For ruptures, the assumption that the release would be directed horizontally along the line of the pipe is not representative of what is observed in real incidents or full and large scale experiments. Initially at least, the release is likely to emerge in a vertically upwards direction from the crater, becoming angled as time progresses. Only rarely, and in very special circumstance, have horizontal releases been observed. This assumption may lead to an overly optimistic societal risk assessment, depending on the location of people relative to the pipeline route.

The assumed meteorological conditions are considered reasonable, although it is not clear how the wind angle has been accounted for in the assessment. For the punctures, the use of a higher wind speed may be beneficial to demonstrate the risks have not been underestimated.

There are clear differences between the values used for ignition probability in the QRA report, and those used by Advantica. We agree that use of historical data is reasonable. However, based on an assessment of worldwide pipeline incident data, ignition probability is found to increase with the pipeline size and initial pressure. Based on this data, a correlation has been developed by Advantica to estimate ignition probability based on the pipeline size and initial pressure, which gives a higher ignition probability than that assumed in the QRA report in all cases. The values for ignition probability obtained using this correlation for the Corrib onshore pipeline are given in Appendix D, and are a factor of two to three times greater. We recognise this is an area of uncertainty, but we believe our ignition correlation is more appropriate for the larger sized rupture releases (and acknowledge that it maybe overly cautious for the smaller punctures). The assumption an early ignition probability of 0.9 for ruptures appears cautious.

5.3.2.2 Results

Advantica's models would give similar results for the outflow versus time as presented in the QRA report, albeit we have strong reservations about the applicability of the models at pressures as high as 345 bar (see Section 5.3.4). However, we note that the QRA reported only uses the averaged flow rate for the first 60 seconds in the assessment, and is not obviously cautious.

Given similar assumptions regarding the outflow, Advantica's models would give similar results for the horizontal and vertical jet fires from punctures although we would not model the buried punctures as performed here. We cannot comment on the consequences of ruptures, as values are not given in the report. However, we would model the release initially as vertically upwards and use a crater source model to predict how this changed over time, if appropriate. For cases in which there was a need to ensure all possibilities had been thoroughly investigated, we would take a probabilistic approach to defining the crater parameters.

Advantica would advocate using a more realistic approach to the prediction of the effects of thermal radiation from ignited releases, including calculating dosage rather than using a fixed flux in the assessment. We would also assume that people
attempt to escape and calculate the dosage they receive in attempting this, and allow people to benefit from available shelter from buildings.

Predictions of the consequence distances for punctures and ruptures calculated using Advantica's methodology are given in Appendix D. The consequence distances calculated represent the distance beyond which people would be expected to escape to safety (the "escape distance") and the distance up to which houses would be predicted to catch fire (the "building burning distance"). These calculations take account of the time-dependent nature of the event, and the variations due to the effects of parameters that cannot be known in advance of the event, such as the prevailing weather conditions or the crater source conditions, and range from a few metres for vertical puncture releases to distances up to several hundred metres for rupture releases, depending on the initial pressure assumed. However, it should be noted that the models have not been validated at the higher pressures (see Section 5.3.4), and the results should be treated with caution. The effect of adopting a more realistic approach, including taking into account the time-dependent nature of the event, is discussed in Appendix D, but in general the effect in this case is to reduce the predicted hazard distances from those calculated by JP Kenny.

5.3.3 Individual and Societal Risk

Despite reference to IOOOTDU, the risk calculations are said to be based on exposure to a flux of greater than 6 kW/m². This is a simplification, and is one of a number of factors contributing to differences between the individual risk levels calculated by JP Kenny and Advantica. In general, for a large fire with a relatively slowly decaying radiation field with distance, such an assumption may err on the optimistic side, but for a small fire, with a rapid decay of radiation, it may be a pessimistic assumption.

The calculated Individual Risk levels are generally similar to, or higher than, those calculated by Advantica in Appendix D. Strictly, the quoted individual risk levels represent a "location specific risk", because they assume that a person is at a particular location 100% of the time. Individual Risk would take the residency (i.e. the proportion of time that a person is actually present) into account, which will reduce the risk levels quoted, but best practice would be to take a cautious approach and assume that they are always present, as assumed in both the JP Kenny and Advantica analyses. Even though a cautious approach to the modelling of the risks has been taken, both the JP Kenny and Advantica analyses show that the levels of Individual Risk at all distances from the pipeline are below the figure of 1 x 10⁻⁶ (i.e. a 1 in a million chance of becoming a fatality) per year typically used as the criterion for acceptability of Individual Risk. The JP Kenny QRA report includes an overview of the risk criteria adopted in different countries, and there is broad consensus for the use of this figure, which represents a level of Individual Risk that is small compared with other risks that individuals are exposed to in everyday life. For comparison, according to Reference 44, the risk of death from all causes for women aged 35-44 in the UK based on data from 1999 was approximately 1 x 10⁻³ (i.e. 1 in a thousand) per year and 1.5 x 10⁻³ for men.

However, it would be very unusual for a high pressure gas pipeline to fail the Individual Risk criterion of 1 x 10⁻⁶ per year, because the failure frequencies for a specific section of pipeline are normally found to be very low. As noted above, the
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Hazard distances for a rupture of a high pressure gas pipeline are significant, and a full bore rupture in particular has the potential to affect many people in a single event. For this reason, it is appropriate to consider Societal Risk as well as Individual Risk, to take account of both the frequency of the credible scenarios and the number of casualties that could result. As noted in JP Kenny’s QRA report, guidelines for the acceptability of Societal Risk do exist. Furthermore, the Corrib Project Risk Assessment Procedure [Ref. 42] specifies that the numbers of people exposed to the effects of an event should be taken into account, and includes a Societal Risk standard. The QRA report includes a discussion of the population density surrounding the pipeline, which is only relevant for calculation of Societal Risk. Nevertheless, the JP Kenny QRA deliberately omits Societal Risk assessment, (although we note that societal risk was considered in earlier versions) which, in our opinion, is essential for a full understanding of the risks associated with a major hazard pipeline such as the Corrib onshore gas pipeline.

The statement in the QRA report that FN curves are not normally produced for pipelines is not true and the claim that an FN curve would not represent a true picture is given without justification. It is, however, important that the length of pipeline used in the assessment is the same as that assumed in the criterion used, because otherwise the calculated risks will simply increase with increasing pipeline length. The process for calculating Societal Risk for high pressure gas pipelines is described in the most recent edition of the IGE/TD/1 pipeline design code [Ref. 14] together with an example Societal Risk criterion envelope for a 1 mile (1.6km) length.

In order to address this gap in the QRA, Advantica has undertaken site-specific calculations of societal risk for a 1.6 km (1 mile) section of the Corrib onshore pipeline, selected following a screening investigation to determine the highest risk section. The 1.6 km length chosen for detailed analysis was similar to that selected as having the highest population density in the population density analysis report [Ref. 40]. The method used by Advantica to calculate Societal Risk, together with a comparison of the results with the IGE/TD/1 Societal Risk criterion envelope, is presented in Appendix D. The results indicate that the calculated levels of Societal Risk are significantly higher for the 345 bar initial pressure than 144 bar (nominally equivalent to a design factor of 0.3), although both are in a region that would be considered to be broadly acceptable. However, uncertainty in the consequence modelling at pressures above the range of validation of the models, particularly at an initial pressure of 345 bar, is acknowledged, as discussed in the following section.

5.3.4 Uncertainty

An important area of uncertainty for the Corrib onshore gas pipeline is the assumed operating pressure at the time of failure. As noted in Section 3.3, the pipeline has been designed to withstand operation at the full well head shut-in pressure of 345 bar. This would only be possible under exceptional circumstances, and the normal operating pressure in the pipeline is expected to be in the range 100 to 120 bar. For this reason, the JP Kenny QRA contains results for both the 120 bar and 345 bar, and the Individual Risk levels for both pressures were found to be within acceptable limits. However, because of the use of single values for the failure frequency due to ground movement derived from generic historical data, and because this failure cause dominates the risk of rupture in the JP Kenny QRA, the
increase in Individual Risk levels close to the pipeline are relatively small. In our opinion, provided that the pipeline is designed to withstand the worst case ground movement event, the failure frequency is not dominated by ground movement, but by third party interference. The Individual Risk levels calculated by JP Kenny were higher than those predicted by Advantica, suggesting that the JP Kenny QRA was conservative in many of its assumptions. However, the JP Kenny results show little sensitivity to the assumed pressure. In Advantica’s analysis, there is a significant increase in failure frequency with an increase in pressure from 120 to 345 bar, due to the smaller critical defect size predicted by limit state models for a pipeline subject to higher stress levels. In addition, an ignited pipeline rupture release at the higher pressure of 345 bar would present significantly larger hazard distances, with the potential to affect larger numbers of people. The full effect of the increase in consequences for a pipeline failure at the higher pressures is not apparent in the Individual Risk results, which show only that the hazard distances are greater. The impact of the increased hazard distances on the population around the pipeline also needs to be taken into account, through analysis of Societal Risk. The results of Advantica’s calculation of Societal Risk for the Corrib onshore pipeline are presented in Appendix D, and show a marked increase in Societal Risk at the higher pressure.

We agree that the circumstances under which the pipeline could experience a pressure of 345 bar are likely to be rare events, and would require either a blockage in the onshore section of the pipeline (due to hydrate formation, for example) or for gas flow through the terminal to stop without isolation of the subsea wells by the subsea isolation valves. However, on the basis of the available information, we cannot conclude that such an event is not credible. For example, although the subsea valves are designed to “fail safe” in the event of a loss of hydraulic pressure (e.g. due to physical damage to the umbilical), our understanding is that the valves do not fail safe in the event of a loss of communication. Events that could cause shut down of gas flow through the terminal, and could also result in loss of communication from the terminal to the subsea valves, have not been ruled out. Consideration of the pressure safety measures is covered in the following section, but we would agree with the approach adopted by JP Kenny in the QRA, to include the full well head pressure in the QRA, on the basis that exposure to the full well head pressure is a credible event, and that the higher pressure should be considered in a cautious assessment.

The reason for this is that any damage to the pipeline at any stage in its life will remain unless repaired. Experience indicates that damage, that is not critical under normal operating pressures, becomes critical if the operating pressure rises. In the case of third party damage, it is highly unlikely that an impact would coincide with the time at which the pipeline experiences the full 345 bar pressure. Unless the damage is reported to the pipeline operator or detected during routine inspections, it will remain dormant in the pipeline until the pressure rises to a level at which the defect becomes critical, with the potential to result in a gas release incident. This scenario has given rise to several major incidents involving high pressure gas pipelines, and must be considered a credible event unless the pipeline and the systems controlling its operation can be designed to ensure that the pipeline cannot experience the higher pressure. In our opinion, on the basis of the pipeline design as assessed in the safety review, the possibility of the pipeline experiencing the higher pressure cannot be eliminated, and therefore the QRA should consider the 345 bar pressure.
However, there is no mention of uncertainty in the JP Kenny QRA report regarding the use of models for 345 bar releases. We are not aware of any large scale data for the consequences of high pressure gas pipeline releases that approaches this release pressure, and have doubts over the validity over the models used by JP Kenny for this application, and certainly at such high pressures. On querying the extent of validation of the consequence models used in the QRA, we were directed to technical specialists working for Shell Global Solutions (SGS), who developed and maintained the Shell FRED suite of consequence models used in the analysis. A teleconference with the appropriate specialist confirmed that the range of validation data for high pressure gas releases is essentially limited to data we were already aware of. Much of the large scale test data for jet fires was obtained in experiments at Advantica's Spadeadam test site to study releases from above-ground pipework, often as part of joint industry projects. This jet fire data for natural gas releases spans a much lower range of release rates than would be relevant for rupture modelling of the Corrib gas pipeline, and covers a lower range of pressures. The opinion of the SGS specialist was that there was no reason to doubt the results of the models for initial pressure of 345 bar. In our opinion, this position would be correct for releases of pure methane, but for mixtures containing higher hydrocarbons, uncertainty in the predictions increases with increasing release pressure and richer gas mixtures, and without experimental data, there is little available evidence to confirm the extent of the uncertainty for initial pressures as high as 345 bar.

The validation that underpins Advantica's methodology for pipeline risk assessment includes a range of large scale experiments, comparison with recorded details from incidents, and two full scale experiments. The full scale experiments involved the deliberate rupture of a 36" diameter pipeline, operating at an initial pressure of 60 bar, with gas release rates comparable with those predicted for the Corrib gas pipeline. The large scale experimental data spans a range of pressures up to 120 bar and supplementary information from full scale pipeline fracture propagation testing at Spadeadam is available for higher pressure releases (up to 200 bar) but for short duration releases only. The composition of the gas used in experiments at Spadeadam is comparable with that of the Corrib gas, with high methane concentrations plus components of higher hydrocarbons (e.g. ethane), and we are confident that for initial pressures up to 150 bar, the results from Advantica's models are applicable to the Corrib gas pipeline. As the initial pressure is increased above this value, we acknowledge that the uncertainty in the predictions will increase, with errors being introduced to the predictions of gas outflow and the fire behaviour, however we have no reason to believe that a fundamental change in the basis of the hazard analysis (i.e. a major fire, fuelled by gas outflow over a sustained period until the release is isolated), will occur. Investigation of the phase envelope for the gas composition from the Corrib field suggests that the errors due to 2-phase effects are likely to be small in the initial stages of a release, because of the time taken for the temperature of the gas in the pipeline to fall, however this is a recognised area of uncertainty, and one in which research activity is currently underway in order to try to address the issues.

In terms of failure frequency, there is a significant difference between the failure frequency predictions by JP Kenny and those of Advantica's models. Both adopt a probabilistic modelling approach, combining historical data on hit rates and damage
distributions with fracture mechanics to predict failure frequencies due to third party damage. Differences may arise both from the assumed hit rate and damage distributions and from the details of the treatment of the fracture mechanics. Both JP Kenny and Advantica's models assume, in effect, that both the hit rate and damage distributions due to third party interference in Ireland will be comparable to those in the UK. We believe that this is cautious for the Corrib onshore pipeline, because the presence of the pipeline will be well-known and clearly marked, and we are not aware of any reason to believe that the nature of excavating machinery normally in use in the vicinity of the Corrib pipeline is likely to be able to cause more severe damage than machinery in the UK. The wall thickness of the Corrib gas pipeline is much greater than typical for gas transmission pipelines, because of the high design pressure, and is above the range both of the historical data used to calculate damage distributions, and the test data used to validate the fracture mechanics. However, there is evidence that for the wall thickness proposed, very few excavating machines would actually be capable of causing sufficient damage to cause through-wall failure due to accidental impact. Advantica has a number of in-house models, developed over a period of years, for predicting the frequency of failure due to third party damage. These models, which have been refined over time to take account of improved fracture mechanics treatments and updated historical data, also exhibit significant variations in the predicted frequencies. For the purpose of the Societal Risk analysis in Appendix D, the most recent version of these models has been used, which gives the highest predicted failure frequencies for ruptures in this case, and the assessment is believed to be cautious.

5.4 Risk Reduction Measures and Demonstration of ALARP

The QRA assumes that a number of risk control measures are already in place, and assesses the residual risk remaining after these have been taken into account. In the JP Kenny analysis, it was argued that these measures would effectively eliminate all the causes of pipeline failure with the exception of third party damage, ground movement and inherent/construction defects. As discussed above, in our view, provided that the pipeline is designed and constructed as proposed, and that the additional recommendations in this report are followed, the failure frequency due to third party damage will dominate the residual risk. Therefore, only additional measures to reduce the predicted frequency of third party damage or that limit the consequences or a pipeline failure would be effective in reducing the predicted risk levels further.

Measures already identified to protect against the threat of third party damage include the use of plastic warning tape buried in the ground, marker posts at field boundaries to warn of the presence of a pipeline, a minimum burial depth of 1.2m, and physical protection (concrete slabs) over the pipeline at road crossings and other locations where the possibility of accidental damage is higher. The QRA also states that enhanced inspection of the pipeline route will be carried out, which should help to identify activities that could present a threat to the pipeline. However, the proposed surveillance intervals are not stated, and no benefit has been taken for this in the QRA. The proposed arrangements for surveillance and landowner liaison (to maintain landowner awareness of the presence of the pipeline throughout its life and
of the means to contact the pipeline operator prior to any construction work in the vicinity) should be specified in the operations and maintenance procedures.

**Recommendation:** The proposed arrangements for surveillance and landowner liaison should be specified in the operations and maintenance procedures.

Further measures that could be taken to reduce the-predicted frequencies of third party damage include increasing the burial depth of the pipeline and the pipeline wall thickness, providing physical protection along the whole of the pipeline route, or fencing the pipeline route. Because the predicted failure frequencies are already low, the benefit in terms of quantifiable further reduction in risk levels due to these measures will be small, and there are practical difficulties in implementing measures such as slabbing along the whole of the pipeline route, especially through areas of peat. The main protection against failure is the wall thickness of the pipe, the size of which is such that few machines will be sufficiently large and powerful enough to cause through-wall damage.

The Corrib gas will not be deliberately odorised. Odorant is typically added to gas in low pressure gas distribution systems, to facilitate gas detection in the event of a gas leak from the gas distribution network or from appliances and pipework within homes. However, it is not normally added to gas transported through high pressure transmission pipelines, where the benefit in terms of gas detection is limited, because gas releases from high pressure pipelines are usually obvious through visible signs and/or noise.

However, the Societal Risk analysis carried out in Appendix D shows that by limiting the pressure to 144 bar, a significant reduction in risk is achieved, because this reduces both the predicted frequency and the consequences of failure. The calculated risk levels are generally within the broadly acceptable region, in which the level of risk would normally be deemed to be as low as reasonably practicable (ALARP), and further measures would normally only be recommended if a significant reduction in risk can be achieved at minimal cost. However, there is significant uncertainty in the calculation of the risks, particularly at the higher pressures, and bearing in mind the potential consequences of failure, this merits a cautious approach. In our view, it should be possible to limit the pressure in the onshore section of the pipeline to 144 bar (i.e. consistent with the pressure for a pipeline in a Class 2 "Suburban" area) by practical means without significant impact on operations and without incurring excessive cost, as discussed in the following section.

Furthermore, risk analysis should be used to inform decisions on safety-related issues, but is not the only factor. Guidelines developed by UKOOA (the UK Offshore Operators Association) provide a useful framework that considers the processes that should be used when decisions are required that have safety implications [Ref. 45]. The framework, reproduced in Figure 5, takes the form of a spectrum of decision bases, ranging from those decisions dominated by purely engineering concerns, to those where company and societal values are the most relevant factors. Down the right hand edge of the framework are typical characteristics that indicate the decision context: these can be used to help determine the context for a specific decision. Once this level has been identified, reading horizontally across the framework shows the suggested balance of decision bases to be taken into account in the decision.
Some means of calibrating or checking the decision basis are shown on the left hand side of the framework.

Figure 5: UKOOA Risk-based Decision Framework

The Corrib onshore gas pipeline is conventional in the sense that pipeline technology is well understood, and the pipeline can be designed to accommodate the required pressure by increasing the wall thickness accordingly. However, it lies outside the range of normal application of onshore pipeline design codes in terms of operating pressure, and has given rise to significant societal concerns. The fact that the pipeline parameters lie outside the normal range of application of the onshore design codes does not in itself make the pipeline unsafe, but it does make the requirement to demonstrate that the pipeline is safe more onerous. This, coupled with a level of uncertainty in the risk analysis and the societal concerns, leads us to recommend that in this case the pressure in the onshore pipeline should be limited to around 144 bar, such that the pipeline can be reclassified as a Class 2 (Suburban) pipeline, with a design factor not exceeding 0.3. [In fact, the relevant onshore pipeline codes (IGE/TD/1, BS8010, IS328 and PD8010) all allow pipelines in Class 2 (Suburban) areas with a wall thickness greater than 19.1mm to be designed with a design factor not exceeding 0.5 (equivalent in this case to a design pressure of 240 bar) without the requirement for any further justification by risk assessment.] Pressure control to achieve this will only be required in the early years of production, until the maximum possible pressure that the pipeline could experience falls naturally below 144 bar.

Provided that it can be demonstrated that the pressure in the onshore pipeline can be effectively limited to a pressure no greater than 144 bar, and that the recommendations made elsewhere in this report are followed, we believe that there will be a substantial safety margin in the pipeline design, and the pipeline design and proposed route should be accepted as meeting or exceeding international standards in terms of the acceptability of risk and international best practice.
Recommendation: 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.

5.5 Assessment of Pressure Safety Measures

5.5.1 Assessment of Existing Pressure Safety Measures

Under normal operation, the subsea pressure control systems should ensure that the pressure in the onshore pipeline is less than 144 bar. If the pressure in this section of the pipeline is to be required to be less than 144 bar, it becomes important to understand the pressure control and isolation systems specified in the existing design and the potential for these systems to fail to control the pressure adequately. This will provide some input to determining any further actions that may be needed to ensure the effective limiting of pressure in the onshore pipeline.

The initial review of pressure control and isolation systems was based upon an early document provided by the project [Ref. 46]. This document detailed an assessment by the project of the reliability of different subsea pressure control and isolation systems and was found to have a number of technical issues, which were described in the draft report.

Following completion of the draft report, additional information was provided by the project that indicated:

- The document initially provided [Ref. 46] described early design work that was subsequently superseded.
- Remotely operated subsea isolation will be provided by subsurface and wellhead valves with pressure control being provided by subsea choke valves.
- A detailed Failure Mode, Effect and Criticality Analysis (FMECA) had been carried out [Ref. 47] on the planned subsea systems.

The primary focus of the FMECA was to determine failure modes that could affect production from the subsea field. However, many of the failure modes relevant to loss of pressure control subsea will have been considered in the FMECA and it could therefore form the basis of a reliability assessment carried out to determine the expected frequency of loss of pressure control.

5.5.2 Options for Additional Pressure Control Measures

In order to determine the requirements for additional pressure control measures, it is recommended that as a first step, a full and technically thorough reliability analysis be carried out of the subsea pressure control and isolation systems specified in the field design. This analysis should not only consider the equipment reliability, but should include any potential human factors related to field shutdown. As part of this reliability assessment, the existing FMECA [Ref. 47] should be reviewed in order to highlight any failure modes relevant to loss of pressure control. These failure modes should then be analysed to ensure that all relevant failures have been captured.
The arrival pressure at the terminal is expected to be around 110 bar in normal operation, with a pressure protection system located at the terminal inlet to prevent damage to equipment and pipework within the terminal due to excess pressure. The upstream break point for the pressure limitation is at the beach landing and it is probable that any system to be considered would be located at this point. It is not believed that pressure reduction would be required at this point, given the normal operating pressures (and is not required by the relevant standards). However, some form of isolation over and above that currently planned (a locally operated isolation valve) appears to be appropriate and practical. Upgrading this valve to remote operation from the terminal is an example of one option that should be considered.

The selection of the appropriate option needs to follow a clear decision process and take into account the UKOOA decision framework described in the previous section.

Recommendation: A full and 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.
6 DISCUSSION

6.1 Selection of Design Code and Comparison with International Standards

6.1.1 Selection and Use of Design Codes

As stated in Section 4.1 above, we consider that the selection of BS 8010 as the primary design code at the start of the project was appropriate. This code represented a synthesis of the accumulated experience in high pressure pipeline design in the UK, with much of the material relating to high pressure gas pipelines being derived from the recommendations produced by the IGE. The Irish national standard, IS 328, is also closely related to these documents. The correct use of BS 8010 would have constituted “best practice” and a practice consistent with previous experience. As BS 8010 did not contain an operations and maintenance section, use could have been made of the relevant sections of IS 328.

During the project, BS 8010 was withdrawn and replaced with PD 8010 in July 2004. It has been suggested that as a result the project should have changed the design code. We consider this is not a valid criticism. It is generally accepted practice on long running projects to continue with the original design code when there is a change during the project, unless the original code has been shown to be unsafe. As will be discussed below, this is not the case with the withdrawal of BS 8010. In fact, IGE/TD/1 allows a pipeline constructed to an earlier Edition to continue operating to the current Edition after a new edition is issued. However, we do consider that the project could have considered using the sections in PD 8010 covering operations and maintenance, which had no equivalent in the BS.

It has been stated in various documents and submissions that BS 8010 was withdrawn because it was “obsolete”. The withdrawal of BS 8010 was not due to “obsolescence” as it was mainly a consequence of the introduction of a European standard for onshore high pressure gas pipelines, EN 1594, and the adoption, with modifications, of the ISO pipeline standard ISO 13623 as EN 14161. When a European standard is produced, conflicting national standards have to be withdrawn and so BSI was obliged to withdraw BS 8010. A Published Document, PD 8010, was developed using the content of BS 8010. This ensured that the guidance in the BS was still available to regulators, designers, operators and constructors in the UK. During the revision process some updates were made, particularly to take advantage of changes that were made with the issue of Edition 4 of the Institution of Gas Engineers' recommendations IGE/TD/1. In particular, sections were introduced into PD 8010 to cover operations and maintenance.

Design codes are not static documents. They evolve to incorporate advances in materials and technology, although this should be carried out in a controlled manner. As the new technology becomes accepted, it is codified and incorporated in the codes. A specific example relevant to this project is that the original IGE transmission pipeline design recommendations limited the pressure to 24 bar (350 psi); the current limit is 100 bar. The four-fold increase in pressure has not been accompanied by an increase in failure rates; in fact the data suggest that modern pipelines have a lower failure rate. Developments using new technology will
inevitably be outside the scope of a design code, and it is the responsibility of the
designer to identify the areas of the proposed design that are outside code. Having
done this, any necessary analysis or testing should be carried out to ensure an
acceptable level of risk from the new developments.

Thus we consider that the fact that the Corrib pipeline has a design pressure outside
the range of the existing codes does not automatically make the pipeline unsafe,
provided that steps are taken to ensure that the resulting pipeline provides a level of
safety as good as, or better, than a code compliant pipeline.

6.1.2 Comparisons with International Codes
Documents considered in this review have also concluded that BS 8010 was an
appropriate choice of code on which to base the design of the Corrib pipeline. Various
issues in these comparisons are discussed in this section.

- The calculation of design wall thickness in the US code, ASME B31.8 and the
  international code, ISO 13623 (EN 14161 in Europe) is less conservative than
  in BS 8010. ASME B31.8 bases the wall thickness on the nominal wall
  thickness, whilst BS 8010 uses the minimum wall thickness. The minimum
  wall thickness takes account of the manufacturing tolerances. EN 14161
does use the minimum wall thickness, but uses the mean diameter rather than
  the outside diameter. Thus adopting other codes would have led to a thinner
  pipe wall.

- If the BS 8010 option of a high level hydrottest is adopted, as recommended in
  this review, the test pressure will be higher than required by most other codes,
  and so the pipeline will have been subjected to a more searching test of its
  integrity at the start of life.

- The US Code of Federal Regulations and the Canadian design codes
  calculate a hazard distance based on models of the consequence of failure.
  However, this is only used in calculations of population density and for the
  definition of high consequence areas and is not used to control building
  proximity. Under these codes it is possible to operate a pipeline close to
  buildings so that the only constraint is access for maintenance. BS 8010 and
  IGE/TD/1, in contrast, do use a proximity distance within which inhabited
  buildings are not normally allowed. Hence, we consider that BS 8010,
  correctly applied, provides a greater level of safety than other codes that it
  has been suggested could be applied to the Corrib pipeline.

Recommendation: 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.
6.2 Design Pressure

The very high design pressure of 345 bar has given rise to much of the concern expressed over the safety of the pipeline, even though in practice it is unlikely that the pipeline could ever experience such a high pressure and would normally operate at pressures around one third of that value. 345 bar is considerably higher than normally encountered in onshore gas transmission pipelines transporting sales quality gas (which rarely exceed 100 bar), and is well above the normal range of application of the relevant onshore pipeline codes and standards. However, such high pressures are more common in upstream gas processing, and pipeline technology for accommodating unprocessed gas at high pressure is well established, albeit usually offshore and remote from housing. There are a number of examples where very high pressure offshore pipelines come onshore, typically for relatively short distances, with no obvious safety problems. The closest comparable situations to the Corrib onshore gas pipeline are probably pipelines in Norway, where several pipelines transporting gas from offshore fields come onshore, with normal operating pressures of around 170 bar.

The high design pressure for the Corrib onshore gas pipeline arose because a cautious approach was followed in the pipeline design, in order that the pipeline could withstand the highest pressure it could possibly experience. In our opinion, this approach is commendable, and the substantial wall thickness that results from the high design pressure offers the major defence against threats to the integrity of the pipeline. It should also be appreciated that the maximum design pressure could only be experienced in the early years of the pipeline, because the pressure in the subsea wells will decline steadily as gas is extracted. However, the high design pressure also gives rise to much of the concern expressed about the safety of the pipeline, largely because of the hazard distances that would arise from an ignited release of gas in the event of a pipeline rupture, regardless of the extremely low frequency predicted for such an event. Advantica has recognised these understandable concerns, and in Section 5, recommendations are made that the pressure in the onshore pipeline be limited to a pressure of no more than 144 bar (i.e. a “design factor” of 0.3), despite the results of risk analysis which suggest that risk levels would normally be regarded as “broadly acceptable”. In making this recommendation, we recognise a level of uncertainty in the risk analysis for pressures as high as 345 bar and are mindful that although risk analysis is a powerful tool used to inform the decision-making process, it is not the only factor.

With this pressure limitation, coupled with the considerable wall thickness of the steel, the stress levels in the pipeline are such that the relevant onshore pipeline design codes recognise that the likelihood of a full bore rupture is so low that the minimum proximity distance to housing is relaxed, allowing pipelines to be routed through more densely populated suburban areas. For the wall thickness of the Corrib onshore pipeline, design codes would generally permit operation at a higher design factor of up to 0.5 (equivalent to approximately 240 bar for this pipeline) in suburban areas, with a minimum proximity distance of just 3m.
6.3 Proximity to Housing and the Consequences of Pipeline Failure

The consequences of a pipeline failure depend on many factors that cannot be known in advance of a failure, in addition to the pipeline diameter and the pressure. These include whether or not the release is ignited, the time of ignition, the size and shape of the crater formed in the ground, the distance between the ruptured pipeline ends and their orientation and the prevailing weather conditions at the time. As a result, there is no single value for predicted consequence distances (particularly as different measures for consequence distances may be used, ranging from observed burn damage to vegetation, to damage to property, and varying degrees of harm to people). In a risk assessment, this variability can be handled probabilistically, with a probability assigned to different possible scenarios, and is the reason why the consequence distances calculated using Advantica’s PIPESAFE package show a range of possible values (see Appendix D).

The proximity distances specified in the BS 8010, IS 328 and IGE/TD/1 pipeline design codes are generic, and provide a means of calculating a single minimum proximity distance based on pipeline pressure and diameter alone. As discussed above, these codes are more cautious than most pipeline design codes used elsewhere in the world, in that a minimum proximity distance based on considerations of the hazard range is specified at all. Other codes, notably ASME B31.8 used widely in the US and other countries that follow US pipeline design practice, specify the pipeline design factor based on population density, but specify only a minimum proximity distance based on providing sufficient access to the pipeline for repairs to be carried out if required.

In submissions made to us, reference was made to the C-FER model for predicting hazard distances. This is a simple model for predicting hazard distances for gas pipeline ruptures based on the diameter and pressure of the pipeline [Ref. 48], developed by C-FER Technologies (a Canadian consultancy), and adopted as the means for calculating the size of “high consequence areas” by the US Code of Federal Regulations (CFR). The calculation of high consequence areas is used to determine the high risk sections of pipeline subjected to more onerous pipeline integrity management requirements, and not to determine any minimum proximity distance to individual housing. For the Corrib pipeline, operating at a maximum pressure of 144 bar as recommended in our review, the radius of the hazard area calculated using this method would be approximately 190m, comparable with the maximum hazard distances calculated using PIPESAFE for the same pressure (see Appendix D). Given the simplifying assumptions made in the C-FER model such that it can be used to calculate hazard distances based only on the diameter and pressure of the pipeline, this is reasonable agreement.

For the proposed route, the proximity of the Corrib onshore pipeline to the nearest normally occupied building is approximately 70m. A number of submissions have equated this distance to an extrapolation of the proximity distances curves in BS 8010 (identical to curves present in IS 328 and IGE/TD/1) to the normal operating pressure of the pipeline. Such extrapolation is explicitly permitted in IS 328. In fact, although a minimum proximity distance was calculated for the purpose of population density analysis (and estimated to be 170m for a pipeline at 345 bar), the pipeline route was determined by practical constraints, including maximising the proximity...
distance within the identified corridor. The risk assessment carried out by JP Kenny for Shell concluded that Individual Risk levels were within acceptable limits at all distances from the pipeline, which was used to justify the minimum proximity distance of 70m. The use of risk assessment to justify reduced proximity distances is explicitly allowed in several codes, including IS 328 which states that where it is impractical to comply with the proximity requirements, deviations may be justified by risk analysis. Risk analysis is also used in other countries, where there are no equivalent minimum proximity distance requirements, but the risk levels to nearby people are assessed to ensure that they are acceptable.

However, in the case of the Corrib onshore pipeline, we believe that there are practical measures that can be taken to limit the pressure in the onshore section, such that the pipeline will be compliant with the principles of the codes in terms of minimum proximity distance, which would, in our opinion, represent best practice. By limiting the pressure to 240 bar, such that the design factor is no greater than 0.5, the pipeline could be reclassified as a Class 2 (Suburban) pipeline according to the relevant codes, reducing the minimum proximity distance requirement to 3m. However, we recognise that 240 bar is a significant extrapolation of the codes above their normal range of application (up to 100 bar), and bearing in mind the significant societal concerns and a level of uncertainty in the risk assessment for a pipeline operating at these pressures, we have recommended that the pressure be limited to around 144 bar (i.e. a design factor of 0.3). This represents a much less significant extrapolation, in a region where existing risk assessment methodologies for high pressure gas pipelines can be used with confidence, and which affords a large safety margin in the pipeline design. The reduced minimum proximity distance requirements associated with Class 2 (Suburban) pipelines will also reduce potential problems in future in the event of any proposed new developments in the vicinity of the pipeline.

Examination of possible options for re-routing the pipeline were not part of the remit for the pipeline safety review, which was to examine the pipeline design and route as proposed. However, we are satisfied that the existing route was selected following a process that took the risk to the public into account. Practical alternative routes were limited, and only one appears to offer the possibility of increasing significantly the minimum proximity distances to housing, which would be a pipeline laid through Sruwaddacon Bay, landing at a point as close as possible to the terminal. This option would have presented a number of engineering challenges (although not insurmountable), but the main reasons for eliminating this option were serious concerns over the possible environmental impact, and in our opinion the possibility of adopting this alternative route should only be reconsidered if it proves impractical to limit the pressure in the onshore pipeline as recommended in this report.

Finally, we note the report submitted by Dr. Aldridge, which presents the results of simple calculations of the hazard ranges for an explosion under worst case conditions, fuelled by the entire inventory of gas in the upstream pipeline. A more detailed consideration of this report is provided in Appendix F, which recognises the concerns and acknowledges that a number of valid points are made, but concludes that the scenario proposed is not credible for a high pressure gas pipeline or consistent with experience of incidents or experiments, and grossly overestimates the hazard distances as a result.
6.4 Untreated Gas Composition

The composition of the Corrib gas is not significantly different to that normally transported through gas transmission pipelines, with a high proportion of methane (ca. 94% by volume). However, the gas stream will also carry other fluids, that introduce a number of additional safety issues, not normally of concern for onshore gas transmission pipelines carrying sales quality gas, that need to be managed effectively.

These include:

- The gas (although relatively "dry" compared with typical unprocessed gas) contains water, which when combined with carbon dioxide in the gas can cause internal corrosion of the pipeline. Measures to control this corrosion threat include the addition of corrosion inhibitor and a monitoring regime to check for corrosion rates, discussed in Section 4.

- The possibility of the formation of ice-like crystals called hydrates cannot be ruled out, and therefore hydrate inhibitor (methanol) is added to the gas to prevent their formation. We are aware of incidents of blockage of upstream pipelines having occurred due to hydrate formation, in some cases due to a failure to maintain appropriate levels of inhibitor, and it is important that the addition of hydrate inhibitor is maintained at all times.

- Although there is no evidence to suggest that hydrogen sulphide (H₂S) is present in the Corrib gas, it is not unknown for H₂S to start being produced in the later stages of the life of a gas well. Good operational practice should prevent any increase in H₂S concentrations, however, H₂S is both toxic and corrosive, and it is important that the gas composition is monitored regularly as proposed by Shell, with a plan in place for the action to be taken if H₂S is detected.

Provided that the proposed precautions to manage these additional threats to the pipeline integrity are taken and maintained throughout the lifetime of the pipeline, and the recommendations in this report are implemented, we consider that there is no reason to believe that these issues will have a significant impact on the safety of the pipeline.

6.5 Ground Stability

6.5.1 Effects of Ground Movement on the Pipeline

Section 4.3.3 above and Appendix C report our review of the effects of ground movement on the integrity of the pipeline. We consider that the analysis carried out to date shows that for the cases considered the pipeline is not at risk from credible landslips if the pressure is limited as discussed above. However, additional analyses are required to consider other possible landslips and pipeline configurations. Provided these analyses also give satisfactory results, and the recommendations of the AGEC report [Ref. 49] are implemented, then we consider that the pipeline is not at risk from ground movement.
If the analyses do not give acceptable results, then additional measures will be required to demonstrate the integrity of the pipeline. These are outside the scope of the present review, but possible options include the use of screw piles to stabilise the pipeline or additional testing to justify higher allowable loads. Screw piles have been extensively used in Canada to stabilise pipelines in areas of muskeg. With additional testing, it may be possible to show that the pipe material and the girth welds are able to sustain higher loads than the BS 8010 allowables. The Charpy impact energy acceptance levels used for the girth welds exceed the requirements of Tier 2 of the European Pipeline Research Group’s girth weld defect acceptance criteria [Ref. 50]. At Tier 2 the loading is limited to 0.5% total strain, which implies the material has been loaded above SMYS. The BS 8010 acceptance criterion is 90% SMYS. The wall thickness of the Corrib pipeline is, however, outside the range of the EPRG guidelines and so testing would be required to show that these criteria could be used.

6.5.2 Effects of Pipeline Construction on Future Ground Stability

During the public consultation process, concern was expressed that the construction of the pipeline could have an adverse effect on the stability of the ground along the route. Although Advantica specialists have extensive experience of soil geotechnics, we recognise that we do not have particular experience of the issues associated with pipeline construction in peat. In order to address the concerns over the possible effect of pipeline construction on peat stability, we researched the topic and consulted with others who do have expertise in this area. An assessment of the documentation provided by Shell in relation to the geotechnical investigations carried out along the pipeline route was carried out as input to the safety review by a member of the Geological Survey of Ireland (GSI), included as Appendix E. National Grid personnel who have been involved in the construction of pipelines in the UK in areas of peat were also consulted. National Grid experience identified a number of potential problems, but these issues were primarily associated with the difficulty of construction and the safety of the workers involved, rather than the threat to public safety, and therefore outside the scope of the independent safety review.

Based on this advice, and assuming that the recommendations in the AGEC report supplied to us are implemented in full, we consider that the pipeline is unlikely to have an adverse effect on future ground stability along the route. However, it is not clear to us at present if all of the recommendations of this report [Ref. 49] have in fact been implemented.

Recommendation: 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.

6.6 Risk Mitigation Options

A number of additional risk reduction measures were suggested in submissions. As discussed in Section 5.4, the main additional risk reduction measure that we recommend is adopted is to limit the pressure in the onshore pipeline, which has the effect both of reducing the predicted frequency of failure and the consequences of a gas release. Given that the calculated risk levels are already in a region that would be regarded broadly acceptable, particularly once the recommended pressure
limitation is taken into account, the scope for further reduction is limited and additional measures would not be justified. However, it is very important that the measures that have been assumed to be in place are actually implemented, not just when the pipeline is new, but throughout its lifetime, to ensure that the pipeline retains the same high standards of safety. This must be documented in appropriate operations and maintenance procedures, and we recommend that arrangements be made for an independent audit of construction work and an inspection regime established to confirm safe operation of the pipeline in future.

Recommendation: 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.
7 FINAL REMARKS AND RECOMMENDATIONS

The independent safety review of the onshore section of the proposed Corrib gas pipeline involved a detailed process of document review, discussions with Shell and their consultants, and consideration of oral and written submissions. A large amount of information was processed (approximately 150 documents in all) and Advantica carried out additional analyses where appropriate as an independent check on specific technical aspects that impact critically on the conclusions and recommendations.

The report presents the detailed findings of the review, which ranges from a general consideration of the process followed in selecting the preferred design option, to detailed analysis of highly technical aspects of the engineering design and risk assessment. The original Advantica review team was expanded to include other Advantica specialists required for the assessment of specific technical documents. To complement Advantica's expertise in soil geotechnics, we obtained information and advice on Irish peat, in particular peat landslip conditions, from the Geological Survey of Ireland (GSI) and also consulted with contacts in National Grid (Advantica's parent company) with direct experience of constructing high pressure pipelines through areas of peat in the UK.

The main findings and recommendations of the review are summarised as follows:

- Proper consideration was given to safety issues in the selection process for the preferred design option and the locations of the landfall, pipeline route and terminal. Quantified risk assessment (QRA) techniques were used to evaluate the levels of risk to the public, and deemed to be acceptable according to recognised and relevant international criteria. However, there appears to be no formal framework in Ireland for decisions on the acceptability of different levels of risk, which should be in place to enable potential developers to gauge whether or not a proposed project is likely to be permitted and to ensure consistency of decisions made on safety issues. We recommend that consideration should be given by the Irish Government to establishing a risk-based framework for decisions on proposed and existing major hazard pipelines and related infrastructure, to ensure transparency and consistency of the decision-making process.

- The unusually high design pressure (345 bar) resulted from a cautious approach to the pipeline design, such that the pipeline is designed to withstand the highest pressure it could possibly experience, despite the higher cost of pipeline construction. This approach results in a pipeline with a very thick wall, which offers the main line of defence against threats to its integrity.

- In general, conservative assumptions were used in the detailed engineering design. However, we have identified a number of areas of concern in the documentation reviewed, where detailed technical recommendations should be taken into account in the engineering design, including:
  - Fatigue usage of the pipeline due to variations in pressure to be monitored.
Possible vibration effects on small bore pipework at the beach valve to be checked.

Monitoring of pipeline stresses due to possible ground movement to be carried out.

Additional ground movement analysis to be undertaken to account for the effects of bends, pipe orientation and increased depth of cover.

Quality of the pipeline field joint coatings to be checked and inspected during construction.

Insulation joint at the landfall to isolate the onshore and offshore cathodic protection systems to be considered or the detailed CP design revised to take account of the possible effects of the offshore section.

Internal corrosion rates to be re-evaluated and determination of corrosion rates to be included in a pipeline integrity management plan.

Hydrotesting of the pipeline to be carried out to 105% SMYS (Specified Minimum Yield Strength).

An initial in-line pipeline inspection run to be undertaken during commissioning.

Defect assessment and repair procedures for possible pipeline damage to be established, with appropriate repair materials and equipment to be available at the terminal.

Arrangements for surveillance and landowner liaison to be specified.

Procedure to be established for monitoring Hydrogen Sulphide (H₂S) levels and action to be taken if detected.

The composition of the Corrib gas is similar to that normally transported through gas transmission pipelines, with a very high methane content. However, because the gas is unprocessed, small quantities of other fluids will be present, that introduce safety issues not normally of concern for onshore gas pipelines, notably internal corrosion, possible blockage of the pipeline due to hydrate formation, and the possibility (albeit very unlikely for the Corrib gas field) of H₂S being produced as the wells age. Pipeline technology for transporting unprocessed gas is well-established, and appropriate measures have been identified to manage these additional hazards.

Provided that the above recommendations are followed, we believe that the pipeline will be constructed to an appropriate standard and will be "fit for purpose". However, there is insufficient evidence at present to conclude with confidence that integrity management plans will be sufficient to ensure that the integrity of the pipeline is maintained to a sufficiently high standard throughout its life. We recommend that a formal integrity management plan is established prior to construction, including the operational and maintenance philosophy, and that an independent audit and inspection regime for both the construction and operation of the pipeline is established.
The quantified risk assessment (QRA) carried out on behalf of Shell has been reviewed in detail and an independent check on the calculated risk levels has been carried out using Advantica’s pipeline risk assessment methodology including predictions of the consequences of pipeline failures. The levels of risk to an individual living in the vicinity of the pipeline were found to be within recognised international limits and “broadly acceptable”, with the risk levels calculated by Advantica lower than those in the Shell QRA. However, the risk assessment submitted by Shell fails to recognise the uncertainty in the risk modelling for such high design pressures as 345 bar, and takes no account of societal risk to the local population as a whole. An independent assessment of the levels of societal risk, calculated using Advantica’s methodology, is included in this report and shows a significant increase in risk with increasing pressure, due to a predicted increase in both the failure frequency and the consequences of a pipeline failure. The calculated societal risk levels are also in a region that would normally be regarded as broadly acceptable, but we note that there is a significant level of uncertainty in the risk calculations at pressures as high as 345 bar.

Limiting the pressure in the onshore section to pressures no greater than 144 bar (equivalent to a design factor of 0.3, consistent with the design of pipelines passing through more densely populated suburban areas) is believed to be both practical and an effective measure to reduce risk (and will only be required in the early years of the life of the pipeline because the pressure in the gas wells will decline naturally as gas is extracted). In view of the societal concerns, the level of uncertainty in the risk analysis, the extent of extrapolation of onshore pipeline design codes beyond their normal range of application and mindful that the results of risk analysis are only one factor in the decision-making process, we believe that this measure should be taken and the pipeline design revised accordingly. We recommend that the pressure in the onshore pipeline should be limited to no greater than 144 bar, with a design factor not exceeding 0.3, and the pipeline design revised accordingly.

Further work will be required to determine the most appropriate engineering solution to limiting the pressure in the onshore pipeline. The FMECA (Failure Mode, Effect and Criticality Analysis) carried out on the planned subsea systems for Shell could form the basis for the reliability analysis required. We recommend that a full and 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.

The potential for ground movement to damage the pipeline due to instability of the peat, and the possible unsuitability of peat for pipeline construction, were significant issues for the review. The results of calculations undertaken on behalf of Shell and confirmed by Advantica’s own analysis, indicate that the pipeline would be expected to withstand the worst-case ground movement event (albeit we recommend the results are checked by consideration of additional parameters as noted above), and that instability of the peat does not present a significant threat to the integrity of the pipeline. However, peat
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is one of the most difficult materials in which to construct pipelines. Documents supplied by Shell include reports by AGEC Ltd describing investigations of the ground conditions along the pipeline route, which appear to deal adequately with the ground stability issues. 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.

- The pipeline safety review addressed only the design and route of the onshore section of the Corrib upstream pipeline as proposed. It does not include detailed examination of the feasibility of alternative project design options, alternative pipeline designs or routes, and assumes that the gas transported through the pipeline is produced from the existing Corrib wells as identified. In the event that additional fields were proposed to be tied in to the pipeline at any future date, a full review would be required to consider issues such as extension of the life beyond the initial design life, changes in the fluids in the pipeline or changes in the operating pressures.

Provided that it can be demonstrated that the pressure in the onshore pipeline will be limited effectively, and that the recommendations made elsewhere in this report are followed, we believe that there will be a substantial safety margin in the pipeline design, and the pipeline design and proposed route should be accepted as meeting or exceeding international standards in terms of the acceptability of risk and international best practice for high pressure pipelines.
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APPENDIX A  ADVANTICA PERSONNEL

The following Advantica personnel contributed to aspects of the Corrib onshore pipeline safety review. The advice and assistance of Mr Koenraad Verbruggen (Principal Geologist with the Geological Survey of Ireland) and Mr Stuart McDonald (Project Team Manager Network Strategy with National Grid) in connection with peat stability issues is gratefully acknowledged.

Mike Acton, BSc DPhil CPhys MinstP MSaRS
Dr Acton has worked for 17 years on safety and environmental issues in the oil and gas industry. He has worked on a broad range of projects, including joint industry projects on a range of pipeline safety issues. Projects include the development of risk assessment techniques for pipelines and associated facilities and studies to support safe working practices and procedures. Dr Acton has been involved in many large scale experiments to study fire and explosion behaviour, (including full-scale experiments in Canada to study transmission pipeline ruptures) and is an experienced investigator of gas-related fire and explosion incidents, including a major gas transmission pipeline failure. He is the Chairman of the PIPESAFE group, an international collaboration of gas companies, developing the PIPESAFE risk assessment package for gas transmission pipelines. He is a member of the Gas Safety and Environment Committee and the Gas Transmission and Distribution Committees of the Institute of Gas Engineers and Managers, and a member of the Safety and Reliability Society.

Bob Andrews, BEng PhD CEng MlMechE MIGEM
Dr Andrews has worked for Advantica for 10 years and prior to that for The Welding Institute for 10 years. He has broad experience of structural integrity issues in components and structures, particularly pipelines, pressure systems and offshore structures. He is experienced in non-linear finite element analysis, particularly of cracked bodies, fatigue, fracture mechanics, and fitness for purpose assessments. He is a specialist in pipeline integrity and fracture control, particularly in high strength line pipe. He was a member of the Institution of Gas Engineers panel that produced the fourth edition of TD/1, the UK code for high pressure gas pipelines, and the BSI committee responsible for BS 7910, the UK code for fitness for service assessment of defects in metallic structures. He has been a member of various European Pipeline Research Group and Pipeline Research Committee International technical committees in the areas of weld integrity and materials. He presents regularly at international conferences and is an editor of the international journal "Fatigue and Fracture of Engineering Materials and Structures".

Phil Baldwin, BSc PhD
Dr Baldwin is currently a Manager within the Advantica Hazard and Risk Management Team with responsibility for managing hydrocarbon transmission, distribution and environmental consultancy projects. He has worked for 18 years on hazard, risk and reliability projects for the oil and gas industry.
Phil Cleaver, BA PhD

Dr Cleaver has worked for 22 years on safety and environmentally related aspects of the gas and oil industry. During this period he has developed mathematical models to assess the consequences of gas or liquefied gas releases, including gas dispersion and accumulation, jet fires, pool fires and confined or congested explosions. He has managed consultancy projects, including many different international collaborative programmes of work. He is responsible for the technical content of computer risk assessment packages aimed at specific applications (e.g. LNG sites) and for defining methodology to be used within Advantica for quantified risk assessment of gas and oil facilities and pipelines.

Martyn Cooper, BSc

Mr Cooper graduated in Chemical Engineering from Imperial College, London, prior to joining Advantica (then the research division of British Gas) in 1980. Since that time, he has gained extensive experience in the development and practical application of consequence assessment techniques in the gas industry, particularly relating to major hazards. He has developed mathematical models and consequence assessment methods for gas dispersion, fires and explosions in relation to a wide range of flammable gases and liquefied gases. He has extensive experience in consequence assessment consultancy work, particularly relating to the preparation of safety reports for onshore storage and processing sites.

Mike Gardiner, BSc

Mr Gardiner joined British Gas in 1984, working at the On-Line Inspection Centre (later to become Pipeline Integrity International) with responsibility for software development in support of the Elastic Wave in-line inspection (ILI) vehicle for detecting pipeline cracking. He subsequently moved to the main offices of Advantica, and contributed to commercial development of Elastic Wave technology. On the conclusion of Elastic Wave ILI work at Advantica, he moved to a position in Structural Safety Solutions to become involved in structural reliability analysis (SRA). He has contributed to areas such as risk assessment of onshore pipelines, assessing the impact of mill and field hydrotests on structural reliability, and the extension of SRA to pressure vessels. This has included development of theory, writing software applications and using these to conduct investigations.

Tim Illson, BSc PhD CChem MRSC

Dr Illson has worked in industrial corrosion control for more than 17 years and is presently involved in consultancy for a wide range of oil and gas activities. Consultancy roles performed include corrosion engineering, production chemistry and flow assurance. He is involved with the development of Advantica's pipeline internal corrosion direct assessment methodology and assisted with its implementation as an advanced software tool. His specific areas of technical expertise include ICDA of gas transmission pipelines, corrosion prediction in gas and oil systems, interaction of flow regime and corrosion mechanisms, corrosion inhibitor selection, testing and deployment, selection and application of corrosion monitoring techniques, development of corrosion management programmes including specifying key performance indicators, sour corrosion and cracking prevention and microbiologically influenced corrosion.
Mike Johnson, MA CPhys MInstP

Mr Johnson has over 27 years experience in risk and reliability studies. In the early part of his career, he carried out work related to the risks of gas production and utilisation, including the application of event and fault tree techniques. These applications included a full risk assessment of the Canvey Island LNG terminal, carried out for a high profile public inquiry. In 1984 he took over responsibility of carrying out experimental studies of hazardous events. This included studies of gas cloud explosions on onshore and offshore facilities, pipeline failures and Boiling Liquid Expanding Vapour Explosions (BLEVEs). This work included managing large scale joint industry projects studying onshore and offshore hazards and mitigation techniques. He project managed the development of an offshore risk assessment package (ARAMAS). His responsibilities have also involved application of risk assessment methodologies to assess safety system performance and escape, evacuation and rescue provision. In the area of reliability, he has managed the development of the OPTAGON availability package and the application of OPTAGON in a wide range of projects. These applications have been for both onshore and offshore facilities, including sub-sea developments.

Marcus McCallum, BSc PhD

Dr McCallum has worked for Advantica since 1998 and is a technical specialist in the field of structural reliability analysis. He has worked on various projects involving Structural Reliability Analysis (SRA) of pipelines, pipework components and pressure vessels. He has developed software for use in the uprating of Above Ground Installations. The software follows the fitness-for-purpose methodology developed by Advantica and it has recently been used in testing the fitness-for-purpose of various Above Ground Installations as part of National Grid's 85 bar transmission pipeline uprating project.

Neil Millwood, BEng MSc

Mr Millwood obtained a Bachelor of Engineering degree, with honours, in Metallurgy from Leeds University in 1987. After working as a Metallurgist in the platinum and gold mining industry in South Africa for three years, he went on to gain a Master of Science degree in Welding Technology from Cranfield University in 1993. He worked as a Welding Engineer for European Marine Contractors (an offshore pipelay contractor) for five years. In this post he was responsible for reviewing client specifications, generating welding & NDT procedures, supervising the qualification of weld procedures, qualifying welders, sourcing welding consumables and welding equipment, and solving welding-related problems during pipelay. He joined BG Technology (now Advantica) as a Senior Engineer in January 1998. He has been involved with many aspects of pipeline welding and construction, both onshore and offshore. He has a detailed involvement with linepipe from writing of specifications, through mechanical testing, and into manufacture. In addition, he has completed a number of metallurgical failure investigations and on-site welding repair activities.

Paul Ng, BEng PhD CEng MICE MIHT MIGEM

Dr Ng is a consultant with 14 years experience in geotechnical research and practice. He has 8 years experience at Advantica of dealing with pipeline structural integrity issues arising from ground movement and external loading. He led the
development of several in-house software programs for pipeline integrity analysis. He is a chartered member of the Institution of Civil Engineers, a chartered Member of the Institute of Gas Engineers and Managers, and a member of the Institution of Highways and Transportation. He is an active member of the United Kingdom Society of Trenchless Technology and the associate editor of the Trenchless Technology Research Journal. He has been invited as an EPSRC College Member for 2006 to 2009.

Clive Robinson, BSc PhD CPhys CEng MInstP

Dr Robinson is a Chartered Engineer with 15 years of experience applying and developing risk and consequence assessment techniques to a range of topics in the oil and gas industry. These include pipeline risk assessment and explosion and ventilation assessments for onshore and offshore installations. Other skills and experience include pipeline system modelling and transmission system operational planning.

Ian Thompson, BSc PhD CChem MRSC MlCor

Dr Thompson is a Chartered Chemist, with over 34 years experience in materials testing, corrosion and corrosion protection. Activities include pipeline condition assessment, coating and pipeline failure investigations, technical audits and the development of coating and CP specifications and procedures. Over recent years he has been very active in researching into threats which compromise the integrity of high-pressure pipelines including AC induced corrosion, stress corrosion cracking and microbially influenced corrosion. He is an active member of a number of British and European working groups responsible for the development of test methods, standards, specifications and codes of practice for the oil and gas industry, and is a member of the Royal Society of Chemistry and The Institute of Corrosion.

Gary Toes, BSc

Mr Toes has worked within the Advantica Hazard and Risk Management Team since 2002. During this time he has primarily been involved in applying consequence and risk calculation techniques in risk assessments relating to the storage and transportation of hydrocarbons. He has undertaken risk assessment of gas transmission pipelines for various purposes including code infringements, pipeline uprating, routing issues and land use planning. He has also been involved in R&D work to develop new methodologies and improve existing methodologies applied in the risk assessment of transmission pipelines. Mr Toes has delivered papers related to quantitative risk assessment at professional international conferences.
APPENDIX B SUMMARY OF ORAL AND WRITTEN SUBMISSIONS

B.1 SUBMISSIONS RECEIVED

A number of written submissions were received via the Technical Advisory Group in the course of the review, both before and after the 2-day oral hearings at Geesala. Submissions were received from:

- Dr. Jerry Cowley T.D. (Independent T.D. for Mayo) including a written representation from Michéal O Seighin (one of the "Rossport 5")
- Enda Kenny, T.D. (Leader of Fine Gael)
- Gerard McDonnell (Chairman, Dooncarton Landslide Committee)
- The Joyce Family
- Harry Conti
- Professor Werner Blau (Rossport resident)
- Eamon ó Duibhir (Chairperson Erris Inshore Fishermen's Association)
- Dr Dave J Aldridge
- Monica Muller and Peter Sweetman (local residents)
- Gerry Costello (Project Director, Shell E&P Ireland)
- Leo Corcoran (An Taisce)
- Brid Mc Garry and Teresa Mc Garry (local residents)
- Winifred Macklin (local resident)
- Brendan Conway (local resident)

The oral hearings and written submissions raised a number of issues of concern relating to the safety of the pipeline (several of which were made in more than one submission received) and included constructive suggestions as well as expressing concerns. Transcripts of the two days of oral hearings and the written submissions received after the hearings were published on the DCMNR website. The main points made that were considered in the pipeline safety review, are summarised as follows:

- The local people have real concerns over the safety of the pipeline, and fear for themselves and their families if the pipeline goes ahead as planned.
- The quantitative risk assessment (QRA) focuses mainly on the probability of failure and does not take proper account of the consequences of a pipeline rupture, i.e. the effects on the surroundings of an accidental release of gas.
- At the full design pressure of 345 bar, the pipeline proximity distances are not compliant with the requirements of the design code BS8010 (selected as the basis for the pipeline design), which itself is less cautious than recent regulations introduced in the USA.
The consequences of an accidental release of the unprocessed gas and impurities being transported through the pipeline would be much worse than for normal gas transmission or distribution pipelines.

There is little relevant historical data on which to base an assessment of the risk of the pipeline, taking into account the high pressure, unprocessed gas and difficult ground conditions.

The design code BS8010 relates to refined odorised gas and there is little evidence to support its application to pipelines at design pressures of more than 100 bar.

The design code stipulates that a more onerous "safety factor" should be applied at road crossings (design factor of 0.3) than that applied in the design of the onshore section of the Corrib pipeline (design factor of 0.72).

Could the pipeline be buried to a greater depth if this improves pipeline safety?

Could an alternative route be considered, for example through Sruwaddacon Bay, to increase the proximity distance to housing?

Should the gas be odorised?

The scope of the pipeline safety review should be expanded to the entire pipeline, not just the onshore section.

The proposed pipeline is unprecedented, will be laid in unstable ground conditions, and the consequences of failure would be devastating.

The pressure in the onshore section of the pipeline should be limited to prevent the pipeline being subjected to the full well pressure of 345 bar.

The ground conditions are unsuitable for pipeline construction, because of the low strength of peat.

The scope of the pipeline safety review is too narrow, the whole project should be reassessed and the gas processed at sea.

The presence of the pipeline will sterilise nearby land preventing future development.

Automatic valves should be placed at intervals along the onshore section of the pipeline to limit the inventory of any gas release.

There needs to be clear ownership of the pipeline in future to ensure that safety levels are maintained.

Pressure cycling in the pipeline could lead to fatigue failure.

The worst case event would be a vapour cloud explosion, fuelled by the entire inventory of gas in the pipeline (report by DJ Aldridge).
- The pipeline will be carrying a mixture of gas and liquid, and the impact of multi-phase flow needs to be considered.
- The records of the pipeline material including seam welds should be audited.
- Pipeline construction should be inspected by a third party.
- The pipeline is close to a school and crosses a road used by a school bus.

All of the submissions were considered by Advantica, although not all were relevant to the scope of our work. We believe that we have addressed the main issues raised, where relevant, to the best of our ability, either in the main body of the report or the Appendices, as appropriate.

We would like to thank those who made submissions to the safety review, both at the oral hearings and in written submissions, for their active participation in the process.

B.2 COMMENTS ON DRAFT REPORT

Following publication of the draft report for comment, a number of written comments and additional information were received via the Technical Advisory Group, for consideration in preparing the final version of the report. All of the comments were considered by Advantica, although not all were relevant to the scope of our work. A request was also made by the Technical Advisory Group for Advantica to comment on a report prepared for the Centre for Public Inquiry (CPI), presenting an analysis of the Corrib gas project by Richard B. Kuprewicz, which was published shortly after Advantica's draft report had been submitted to the TAG.

Comments on the draft report were received from:
- Gerard McDonnell
- Harry Conti
- Dr Michael JS Egan
- Dr Dave J Aldridge
- Monica Muller and Peter Sweetman (local residents)
- Edward Moran
- Gerry Costello (Project Director, Shell E&P Ireland)
- JP Kenny (pipeline designers for Shell)
- Leo Corcoran (An Taisce)
- Brendan Cafferty
- Petroleum Affairs Division (PAD)
- Eddie Diver and Eamonn Dixon (Erris Inshore Fishermen's Association)
Following consideration of the comments received, including analysis of additional technical documentation supplied by Shell and of the CPI report, a number of changes were made to the draft report in preparing this final version. The main changes to the draft report, in addition to minor corrections and points of clarification throughout, were as follows:

- The discussion of pressure control systems, in particular Section 5.5, was largely rewritten to reflect updated information provided by Shell on the proposed subsea systems, superseding the document originally reviewed by Advantica.

- Appendix G has been added, giving comments by Advantica on the CPI report.

- Appendix E has been clarified and expanded.

- The recommendation (originally in Section 5.2) with regard to the calculation of population density has been removed, as we accept that this recommendation is no longer relevant provided that the recommendation to limit the pressure in the onshore pipeline is adopted as proposed.

- We accept the proposal by JP Kenny and Shell to base the revised pipeline design on the Irish standard IS EN 14161, supplemented by the use of IS 328 and PD 8010 where appropriate, as an alternative to the use of PD 8010 as the primary design code.
APPENDIX C GEOTECHNICAL ANALYSIS

C.1 INTRODUCTION

Additional analyses have been carried out to confirm the conclusions of the JP Kenny Landslip Analysis [Ref. C1] using a more realistic assessment methodology. This Appendix presents the results of the analyses to confirm whether or not the pipeline would be predicted to withstand the worst case landslip event considered in the report, based on the same inputs to the analysis assumed by JP Kenny. The analyses are based on current best practice for integrity assessment of onshore high pressure steel transmission pipeline.

Major comments are summarised in Section C2 and specific comments are provided in Section C3.

C.2 DETAILS OF ANALYSIS

C.2.1 Modelling of Soil/Pipe System

Calculations have been undertaken using Advantica’s in-house methodology (the PIPELINE finite difference code, Ref. C2) to predict the effect on the pipeline of the loading from the worst case landslip event considered in the JP Kenny analysis. This makes the same assumptions as JP Kenny, in order to confirm whether or not a more realistic treatment of the effects of a potential landslip event would have a significant effect on the conclusions.

PIPELINE uses the theory of an elastic beam on an elastic foundation approach for modelling the soil/pipe system subjected to ground movement. The theory represents the pipe as an elastic beam in contact with elastic springs along the pipe, representing the soil. The springs are mounted perpendicular to the pipe axis in the vertical and horizontal directions to restrain the pipe from longitudinal bending. Springs are also mounted parallel to the pipe axis to restrain the pipe from axial extension and compression.

One of the key inputs in a soil/pipe interaction problem is the appropriate soil restraints. These restraints are influenced by the pipe size and cover depth, the trench geometry, the pipe coating, the soil properties, and the restraint direction. Non-linear hyperbolic soil restraints have been determined in all four directions (upward, downward, lateral and axial). This approach is superior to the common assumptions of linear and bi-linear elastic soil restraints.

C.2.2 Pipe Properties

The pipe properties, as used by JP Kenny, are adopted (see Tables C1 and C2).

C.2.3 Soil Properties

Soil properties adopted are based on JP Kenny’s cohesive soil. Values for adhesion and angle of sliding friction for the soil/pipe interface are based on previous direct
shear testing of cohesive materials on simulated PE surfaces. Table C3 summarizes the soil parameters.

C.2.4 Soil Restraints

Calculations have been carried out using the validated Advantica spreadsheet ‘Soil restraint calculator.xls’ Version 4.2a, based on the international design standards and established researches [Refs. C3 to C9] summarised in Table C4. The calculated upper bound (more conservative) soil restraint values for the pipeline are presented in Table C5. The restraint values are applied to the whole section of pipeline in the analysis model.

C.3 LOADING

C.3.1 Ground Movement due to Landslip

In general, there are five geometric characteristics of a landslide which influence pipeline response in a horizontal plane; these are the amount of ground movement $\delta$, the transverse width $W$, the longitudinal length $L$, the depth $H$ and the pattern of ground movement across and along the slip zone (see Figure C1). For a pipeline crossing perpendicular to the landslide movement, only $\delta$, $W$ and the ground movement pattern across the landslide are relevant.

The landslide widths of 20 and 200m (bounding cases in the JP Kenny analyses) have been investigated in this analysis. The movements of 0.5 to 5m for $W = 20$m, and 2 to 10m for $W = 200$m are considered reasonable. For the transverse ground movement pattern (Figure C1b), the “Spatially Distributed” pattern illustrated in Figure C2 is more realistic [Ref. C10] and adopted in this analysis. The use of the “Localised Abrupt” displacement pattern could generate stresses on the pipeline that are over-conservative.

C.3.2 Internal Pressure

The maximum operating pressure of 150 bar used by JP Kenny is applied in the analysis. The internal pressure induces hoop stress and axial Poisson's stress to the pipeline.

C.3.3 Temperature

A temperature change of $\pm 10^\circ$C has been assumed. The temperature change induces longitudinal axial tension/compression in the pipeline.

C.3.4 Construction Stress

Pipelines are subjected to loads during construction due to uneven trench floor conditions and settlement of the pipeline [Ref. C6]. This leads to a longitudinal sag and hog response depending on the ground conditions, construction control and construction depth.
For the purposes of the integrity assessment, the construction stress has been obtained using guidance contained in the Dutch pipeline code NEN3650 [Ref. C6]. This code suggests the construction disturbance is simulated by a sinusoidal ground settlement profile defined by a maximum settlement value and a trough half-length of 20 or 50 m.

### C.3.5 Overburden Loading

The overburden load above the pipe crown is considered negligible and ignored due to the shallow burial depth (1m) and low density of the peat (0.97 to 1.11 Mg/m³) in this case.

### C.4 LOAD CASES

One basic load case has been considered: Normal Operating conditions with maximum internal pressure, soil movement loading, construction stress and temperature changes.

Only one set of soil restraints and one cover depth has been considered. Two landslip widths, each with three movement values have been analysed, which give a total of six cases (see Table C6 for details).

### C.5 PERFORMANCE ACCEPTANCE LIMITS

#### C.5.1 Introduction

The relevant performance acceptance criteria outlined in T/SP/GM1 [Ref. C11] and BS8010 have been adopted for this analysis. These are summarised below.

#### C.5.2 Hoop Stress

The acceptability criterion states:

\[ \sigma_{\text{hoop}} \leq f.s \]

where

- \( f \) = design stress factor = 0.72
- \( s \) = SMYS = 485 N/mm²

Substituting the values above gives:

\[ \sigma_{\text{hoop}} \leq 349.2 \text{ N/mm}^2 \]

#### C.5.3 Von Mises Equivalent Stress

The acceptability criterion states:

\[ \sigma_e \leq 0.9s \]

where \( \sigma_e \) = Von Mises equivalent stress, given by:
\[ \sigma_e = \sqrt{\sigma_c^2 + \sigma_l^2 - \sigma_c \cdot \sigma_l + 3\tau^2} \]

\( \sigma_c \) = circumferential stress
\( \sigma_l \) = longitudinal stress
\( \tau \) = torsional shear stress
\( s \) = SMYS = 485 N/mm²

Substituting the values above gives the acceptance criterion as:
\[ \sigma_e \leq 436.5 \text{ N/mm}² \]

**C.5.4 Membrane Stress**

The acceptability criterion states:
\[ \sigma_e \leq 0.8s \]

where \( \sigma_e \) = Von Mises equivalent stress, given by:
\[ \sigma_e = \sqrt{\sigma_h^2 + \sigma_a^2 - \sigma_h \cdot \sigma_a} \]

\( \sigma_h \) = hoop stress
\( \sigma_a \) = longitudinal axial stress

Substituting the values above gives the acceptance criterion as:
\[ \sigma_e \leq 388.0 \text{ N/mm}² \]

**C.5.5 Stability Against Buckling**

The acceptability criterion states that a factor of safety of 3 against buckling of the pipe wall should be demonstrated.

The calculation for the critical buckling stress is taken from Ciria Report 78 [Ref. C12] and is given by:
\[ f_c = \frac{f_b \times f_y}{f_b + f_y} \]

where \( f_c \) = critical buckling stress in pipe wall
\( f_y \) = yield stress
\( f_b = \frac{D}{t} \sqrt{8E'\cdot E''} \)
\( D \) = pipe diameter
\( t \) = minimum pipe wall thickness
\( E' \) = soil modulus (assumed range = 0.5 – 10 N/mm²)
\( E'' = \frac{E'd^3}{I} = \text{specific stiffness of pipe per unit length} \)
\( I = \frac{I^2}{12} \)

Depending on the soil modulus values chosen, the critical buckling stress is expected to lie in the range of -53.9 to -174.0 N/mm². Therefore, for a factor of safety of 3 to
be demonstrated and taking the lowest (most conservative) values, the compressive pipe wall stress must not exceed \(-18.0 \text{ N/mm}^2\).

### C.6 CALCULATION RESULTS AND PERFORMANCE ASSESSMENTS

#### C.6.1 Introduction

The results of the PIPELINE stress analysis have been combined with other stress components calculated by hand to obtain the final combined stresses. The results of the stress analysis have been assessed against the performance criteria outlined in Section 4. Summary of the analysis results are presented in Table C7 and discussed in detail below. Figure C3 shows the analysis model in PIPELINE, which illustrates a 200m pipeline section subjected to a 20m wide translational slide (Case 1).

#### C.6.2 Pipe Displacement

Figures C4 and C5 show the applied soil displacement load and the calculated pipe displacement for Case 3 and 5 respectively. Although the applied soil displacement is 5m in both cases, the pipe behaves differently for the different landslip widths. The pipe is relatively rigid at narrower slide (Figure C4) so the soil "flows" past the pipe. For wider slides (Figure C5), the pipe is relatively flexible and follows almost exactly the profile of the soil displacement.

#### C.6.3 Hoop Stress

The calculation for hoop stress was carried out within PIPELINE using the Barlow formula:

\[
\sigma_{\text{hoop}} = \frac{pD}{2t}
\]

where
- \(\sigma_{\text{hoop}}\) = hoop stress
- \(p\) = maximum operating pressure = 15 N/mm\(^2\)
- \(D\) = pipe external diameter
- \(t\) = wall thickness

The calculated hoop stress of 140.6 N/mm\(^2\), is lower than the allowable hoop stress of 349.2 N/mm\(^2\).

#### C.6.4 Von Mises Equivalent Stress

Table C7 gives the Von Mises equivalent stresses for the six cases. The maximum Von Mises equivalent stresses range from 150.4 to 344.5 N/mm\(^2\). The stresses are within the acceptable limit of 436.5 N/mm\(^2\).

The calculated Von Mises equivalent stresses distribution for Cases 1 to 3 and 4 to 6 are shown in Figures C6 and C7 respectively. The calculated maximum Von Mises equivalent stresses under different landslip magnitudes are plotted in Figure C8. It
can be seen that the under the same amount of movement, a narrower landslip imposes higher loading onto the pipeline. This is because the wider spatially distributed transverse ground movement imposes a more gradual pipe displacement, and hence generates lower stress. In addition, the larger the amount of ground movement, the higher the loading on the pipeline.

C.6.5 Membrane Stress

Table C7 gives the membrane stresses for the six cases. Since there is only negligible ring bending stress from the overburden loading, the calculated membrane stresses are the same as the Von Mises equivalent stresses. The maximum membrane stresses range from 150.4 to 344.5 N/mm². The stresses are within the acceptable limit of 388.0 N/mm².

C.6.6 Stability Against Buckling

The maximum pipe compressive wall stress is given by [Ref. C12]:

\[ f_p = \frac{OL \times D}{2t} \]

where \( OL \) = maximum overburden load
\( D \) = pipe diameter
\( t \) = minimum pipe wall thickness

Using a method by Young and Trott [Ref. C13], \( OL \) has been calculated by hand to be 0.016 N/mm². Therefore, the calculated maximum pipe compressive wall stress is -0.15 N/mm², which is well within the acceptance limit of -18.0 N/mm².

C.7 ASSESSMENT OF ADDITIONAL INFORMATION

Additional geotechnical information for the site and reports related to landslips in peat has been reviewed. The most relevant case history is the Derrybrien Windfarm peat slide [Ref. C14], with shallow gentle slope angle of 3 to 5 degrees and peat thickness of 1.5 to 2m. The major failure scar was 45 to 270 m wide by 1750 to 2450 m long by 1.5 to 2.5m deep with travel distance 1300 m. Dimensions of other failures on the site are much smaller, with width 5 to 50 m, length 20 to 140 m, depth 0.7 to > 2 m, and travel distance 2 to 130 m. The peat has a bulk unit weight of 10 kN/m³ and \( c_u \) values of 2.8 to 25 kPa (about 4 kPa at the failure surface from back analysis).

Various site investigation reports for the Corrib pipeline route are available. The most comprehensive report is the AGEC Draft Report on Onshore Gas Pipeline [Ref. C15]. It provides details of the peat from ch 89700 to 92200: peat depth 2.1 to 4.8m; vane shear strength 2 to 35 kPa (mean 10kPa), remoulded strength 0.5 to 5 kPa. Back-analysis of trial pit sidewall failures suggested average \( c_u \) of 5kPa. It was observed that backfilling of the trial pit excavation using excavated peat resulted in very soft ground.

IGSL and Irish Drilling Limited have reported site investigation work for ch 83400 to 89700. Only one trial pit: STP1-03A (ch 86200) is related to peat. The trial pit
revealed a peat depth of 1.8 m and density of 970 to 1110 kg/m³. More significantly, no access to the site was granted by the landowners from ch 87800 to 89700. Therefore no trials could be performed in this area and no soil data is available on this section. From the alignment sheets of the pipeline, this section of land consists mainly of virgin peat with unknown depth and properties.

Other publications related to properties of Irish peat reported cᵣ of 5 to 20 kPa. The information suggested that slides in peat are common in Ireland. Following failure the peat was found to have very low remoulded shear strength and run out distances can be very significant.

C.8 DISCUSSION

The response of the Corrib pipeline to possible peat slides has been re-analysed using a more realistic assessment methodology but based on the same inputs as assumed by the JP Kenny analysis. The results confirm that, under the landslip dimensions, soil properties and loadings considered in the analysis, the landslip will not affect the integrity of the pipeline.

The original concerns on the JP Kenny analysis have been resolved:

- Applied internal pressure of 150 bar and maximum temperature loading of 20°C have been clarified. The design pressure of 345 bar and maximum design temperature of 50 °C only exist at the well-head, and the pressure and temperature at the on-shore pipeline section will be much less. However, the pipeline operator must ensure the maximum operating pressure and temperature do not exceed the values used in the analysis.

- The widths of the landslip considered in this analysis (20 m and 200 m) are representative of the worst case from previous case histories. The landslip displacements (up to 10 m) are considered representative for sliding of a block of "intact" peat. For very large run out distances, the landslip will become more like a mud flow situation, and the water/peat mixture will have very low remoulded shear strength. This mud flow case has been studied by JP Kenny (20m wide waterflow case) and has found to be satisfactory.

- The adopted undrained shear strength of 4 kPa is close to the average strength of "intact" peat, but on the upper bound of "remoulded" peat. It can be argued that as the landslip progress, the peat strength will start from the stronger intact strength to become the weaker remoulded strength. Therefore the use of the average shear strength is justified.

- The integrity assessment has been carried out according to the requirements of Specification T/SP/GM1 and BS8010. All the relevant loading requirements have been considered, including internal pressure, soil movement loading, construction stress and temperature stress. The calculated maximum hoop stress, Von Mises equivalent stress, membrane stress and ring buckling stress were all within the acceptable limits.
The JP Kenny analysis method over-estimated the landslip loading and the calculated stresses in this analysis are lower. We find that the worst case is a narrow landslip with large movement; this is the same as JP Kenny's result.

Additional secondary loading such as construction stress has only a small effect on the pipe stresses.

Only depth of cover of 1 m has been considered in the analysis. Ground investigation shows peat depth of 1.8 m between ch 83400 and 89700. Due to the low density of the peat (970 to 1110 kg/m³), a slight increase of cover depth to the specified minimum of 1.2 m is unlikely to increase the overburden load above the pipe crown and affect the soil restraint by a significant amount.

However, the cases analysed in this analysis may not be the most critical since there are two important factors have not been considered:

- Influence of pipe bends – According to the pipeline alignment sheets, there are a number of bends along the route, ranging from a few degrees to 64 degrees. The most critical case (in peat) is likely to be the pair of 45 degree bends at ch 88283 for a road crossing. It is not known if field bends or forged bends will be used, nor the bend radius. NEN3650 [Ref C6] suggests that circumferential stress at bends due to internal pressure needs to be considered if bend radius is less than 10 pipe diameters. In addition, if the pipe bend is within or very close to the landslip, bending stress will also be higher at the bends (compare with a straight pipe) due to stress concentration.

- Influence of pipe orientation – Only perpendicular pipe crossing has been analysed, representing possible landslip from ch 83400 to 89400. Potential landslips parallel to the pipeline (ch 89700 to 92200) have not been considered. Landslip parallel to the pipeline mainly generates axial stress in the pipe. Ground investigation also indicated that the peat could be up to 4.8 m deep in this section, which may affect the soil restraints.

Without carrying out further detailed analysis, it is difficult at this stage to tell how much these factors will affect the results. In addition, strip maps for the whole route showing depth of different soils and location of the planned pipeline are needed to identify critical locations and to decide how many analyses are needed.

C.9 CONCLUSIONS

1. The results of this analysis confirm that the pipeline would be able to withstand the worst case landslip event considered in the JP Kenny report.

2. The parameters used in the JP Kenny analysis are reasonable.

3. The JP Kenny analysis over-estimated the landslip loading and the secondary loading has only a small effect on the pipe stresses.

4. This analysis only considered a straight pipe at shallow cover depth with landslip perpendicular to the pipeline. Other factors including the presence of
pipe bends, increase in depth of cover to 4m and the pipe orientation relative to
the landslip have not been considered, which may be more critical.

C.10 RECOMMENDATIONS

1. Access to ch 87800 to 89700 should be sought and ground investigation work
carried out to complete the soil data along the whole pipeline route. Strip maps
for the whole route should be produced to show the depth of different soils and
location of the planned pipeline in cross-section.

2. The pipeline operator must provide evidence that the maximum operating
pressure and temperature do not exceed the values used in the analysis.

3. After completion of the review of the strip maps, additional analyses should be
carried out to investigate the influence of increased cover depth up to 4m, pipe
bends and the pipe orientation relative to the landslip.

C.11 REFERENCES

05-2377-01-P-3-002 Rev 02, 11/02/05.


Bottom. ASCE Ocean Engineering Conference. Miami Beach.

C4. Grondonderzoek Gedrag Van Buisleidingen In Klei. Onderzoek Uitgevoerd Te

Engineering. Newnes-Butterworths.


Forces. The Danish Geotechnical Institute, Copenhagen. Bulletin No. 12.

Systems. Committee on Gas and Liquid Fuel Lifelines (CGL). ASCE Technical
Council on Lifeline Earthquake Engineering. American Society of Civil
Engineers.


### Table C1. Pipeline Dimensions And Cover Depth

<table>
<thead>
<tr>
<th>External Diameter (mm)</th>
<th>Wall Thickness (mm)</th>
<th>Coating Type</th>
<th>Cover Depth (m)</th>
<th>Comment</th>
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<tbody>
<tr>
<td>508</td>
<td>27.1</td>
<td>3-layer PP</td>
<td>1.0</td>
<td>AGI pipe</td>
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### Table C2. Pipeline Material Properties And Design Pressure

<table>
<thead>
<tr>
<th>Material Grade</th>
<th>SMYS (N/mm²)</th>
<th>Young's Modulus (N/mm²)</th>
<th>Poisson's Ratio</th>
<th>Coefficient of Thermal Expansion</th>
<th>Temperature range</th>
<th>Operating Pressure (bar)</th>
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</thead>
<tbody>
<tr>
<td>API 5L-X70</td>
<td>485</td>
<td>207000</td>
<td>0.3</td>
<td>1.2E-05</td>
<td>±10°C</td>
<td>150</td>
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### Table C3. Selected Geotechnical Parameters for Soil Restraint Calculation – Peat

<table>
<thead>
<tr>
<th>Bound</th>
<th>Watertable (metres)</th>
<th>Finefill</th>
<th>Trench Width (metres)</th>
<th>Backfill Bulk Density (kg/m³)</th>
<th>Soil Cohesion, $c_u$ (kN/m²)</th>
<th>Angle of Internal Friction (degrees)</th>
<th>Adhesion (kN/m²)</th>
<th>Angle of Sliding friction (degrees)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Upper</td>
<td>0</td>
<td>No</td>
<td>Variable with diameter and depth</td>
<td>1050</td>
<td>4</td>
<td>4</td>
<td>0</td>
<td>0</td>
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</table>
### Table C4. Soil Restraint Calculation Method

<table>
<thead>
<tr>
<th>Restraint</th>
<th>Method</th>
<th>Ref.</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>Uplift limit pressure</td>
<td>Lower value of 'shallow' and 'deep' cavity expansion solutions according to Vescic.</td>
<td>3</td>
<td>Pipe weight added as an equivalent pressure and buoyancy removed.</td>
</tr>
<tr>
<td>Uplift stiffness</td>
<td>Secant slope at 70% of limit load from hyperbolic equation fit to field tests.</td>
<td>4</td>
<td>Unpublished data from Casson also included. Experimental results used to select pipe displacement at ultimate load.</td>
</tr>
<tr>
<td>Downward limit pressure</td>
<td>General formulation for bearing capacity.</td>
<td>5</td>
<td></td>
</tr>
<tr>
<td>Downward stiffness</td>
<td>Secant slope at 70% of limit load based on 'Dutch' bearing model.</td>
<td>4 &amp; 6</td>
<td></td>
</tr>
<tr>
<td>Lateral limit pressure</td>
<td>Solution according to Brinch Hansen.</td>
<td>7, 8 &amp; 9</td>
<td>ATV127 method used to assess restraint contribution from backfill and natural ground.</td>
</tr>
<tr>
<td>Lateral stiffness</td>
<td>Secant slope at 70% of limit load from hyperbolic equation fit to field tests.</td>
<td>4</td>
<td>Experimental results used to select pipe displacement at ultimate load.</td>
</tr>
<tr>
<td>Maximum interface shear stress</td>
<td>Approach based on Dutch code NEN3650.</td>
<td>6</td>
<td></td>
</tr>
<tr>
<td>Displacement to slip</td>
<td>Based on Dutch code NEN3650.</td>
<td>6</td>
<td></td>
</tr>
</tbody>
</table>

### Table C5: Calculated Restraint Values

<table>
<thead>
<tr>
<th>Depth of Cover (metres)</th>
<th>Bound</th>
<th>Upward Restraint</th>
<th>Lateral Restraint</th>
<th>Downward Restraint</th>
<th>Axial Restraint</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Stiffness (N/mm²/mm)</td>
<td>Limit Pressure (N/mm²)</td>
<td>Stiffness (N/mm²/mm)</td>
<td>Limit Pressure (N/mm²)</td>
</tr>
<tr>
<td>1.0</td>
<td>Upper</td>
<td>0.0080</td>
<td>0.0227</td>
<td>0.0015</td>
<td>0.0240</td>
</tr>
</tbody>
</table>
### Table C6: Load Case Matrix

<table>
<thead>
<tr>
<th>Orientation</th>
<th>Load case</th>
<th>Landslide width (m)</th>
<th>Landslide movement (m)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Perpendicular crossing</td>
<td>1</td>
<td>20</td>
<td>0.5</td>
</tr>
<tr>
<td></td>
<td>2</td>
<td>20</td>
<td>2.0</td>
</tr>
<tr>
<td></td>
<td>3</td>
<td>20</td>
<td>5.0</td>
</tr>
<tr>
<td></td>
<td>4</td>
<td>200</td>
<td>2.0</td>
</tr>
<tr>
<td></td>
<td>5</td>
<td>200</td>
<td>5.0</td>
</tr>
<tr>
<td></td>
<td>6</td>
<td>200</td>
<td>10.0</td>
</tr>
</tbody>
</table>

### Table C7: Summary of Maximum Stresses and Displacement

<table>
<thead>
<tr>
<th>Load case</th>
<th>Hoop stress (N/mm²)</th>
<th>Equivalent stress (N/mm²)</th>
<th>Membrane stress (N/mm²)</th>
<th>Soil displacement (mm)</th>
<th>Pipe displacement (mm)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>140.6</td>
<td>213.7</td>
<td>213.7</td>
<td>500</td>
<td>142</td>
</tr>
<tr>
<td>2</td>
<td>140.6</td>
<td>270.1</td>
<td>270.1</td>
<td>2000</td>
<td>264</td>
</tr>
<tr>
<td>3</td>
<td>140.6</td>
<td>344.5</td>
<td>344.5</td>
<td>5000</td>
<td>379</td>
</tr>
<tr>
<td>4</td>
<td>140.6</td>
<td>150.4</td>
<td>150.4</td>
<td>2000</td>
<td>1991</td>
</tr>
<tr>
<td>5</td>
<td>140.6</td>
<td>231.6</td>
<td>231.6</td>
<td>5000</td>
<td>4975</td>
</tr>
<tr>
<td>6</td>
<td>140.6</td>
<td>347.9</td>
<td>347.9</td>
<td>10000</td>
<td>9948</td>
</tr>
</tbody>
</table>

Note: i. Tensile +ve.

ii. Equivalent stress is always +ve.
Figure C1. Characteristics of a landslide (from O'Rourke & Liu\textsuperscript{10})

Figure C2. Idealized transverse ground movement patterns (from O'Rourke & Liu\textsuperscript{10}).
Case 1 - Corrib landslide analysis 20m width 0.5m displacement

Soil restraint

Pipe

Applied ground movement

Figure C3. Analysis model in PIPELINE

Figure C4. Applied soil displacement and calculated pipe displacement

(Case 3)
Figure C5. Applied soil displacement and calculated pipe displacement (Case 5)

Figure C6. Calculated Von Mises equivalent stresses (Cases 1 to 3)
Figure C7. Calculated Von Mises equivalent stresses (Cases 4 to 6)

Figure C8. Calculated Maximum Von Mises equivalent stresses under different landslip magnitudes
APPENDIX D  SOCIETAL RISK ANALYSIS

D.1 ADVANTICA METHODOLOGY

D.1.1.1 The PIPESAFE Package

The risk assessment calculations made by Advantica as an independent check on the results reported by JP Kenny [Ref. D1] were undertaken using the PIPESAFE risk assessment package, developed by Advantica for an international collaboration of gas transmission companies, supplemented by additional in-house models for specific failure causes.

PIPESAFE is a software package for PCs that contains a range of mathematical models, linked in a logical manner, to calculate individual and societal risk [Refs. D2 and D3]. It is based on many years of research into the causes and consequences of transmission pipeline failures, including both mathematical modelling and experimental validation at both small and large scale. The package was developed in three phases, commencing in 1994, and although the major phases of development are now complete, the PIPESAFE collaboration continues to maintain and enhance the package.

The main elements of a pipeline failure considered in the PIPESAFE methodology are failure cause, failure frequency, failure mode, gas outflow, dispersion, ignition, thermal radiation and thermal effects. Knowledge and models are combined in a logical manner, to calculate casualty probability and risk, as illustrated schematically in Figure D1.

![Figure D1: PIPESAFE Risk Calculation Flowchart](For inspection purposes only. Consent of copyright owner required for any other use.)
D.1.1.2 Validation

In order to have confidence in the predictions of a package such as PIPESAFE, it is essential to demonstrate that the results are realistic. The approach adopted for the consequence models in PIPESAFE has generally been to develop the models on the basis of theoretical understanding, guided by the results from small scale experiments. However, because many of the processes involved are strongly dependent on the scale of the event, especially fires, it is also necessary to conduct experiments at as large a scale as practical, to validate the models and to provide an essential input to further development. All of the consequence models in PIPESAFE have been validated by comparison with results from comprehensive programmes of experiments carried out at very large scale, mainly conducted at the Advantica Spadeadam Test Site in the north of England. Spadeadam is a unique facility, consisting of a large area of open ground within an area controlled by the Ministry of Defence, equipped with gas storage and delivery systems and the necessary infrastructure to allow large and full scale experiments to study the behaviour of accidental releases of gas and other fuels at high and low pressure, to be conducted safely.

In addition to experiments undertaken at Spadeadam, a very important source of data for validation of the models and methodology in PIPESAFE is the results of two full scale experiments conducted in Canada as a collaborative project, managed by Advantica [Ref. D4]. The experiments involved the deliberate rupture of a 76km length of 914mm diameter natural gas pipeline operating at a pressure of 60 bar, with the released gas ignited immediately following the failure. Over 200 instruments were successfully deployed in each experiment to take detailed measurements, which included the weather conditions, the gas outflow, the size and shape of the resulting fire, and the thermal radiation levels. Large fires were produced in both experiments, with maximum flame heights of over 500m in the initial stages, which decayed rapidly in size as the gas outflow reduced following the initial rupture.

As a further check, the predictions of PIPESAFE have also been compared against information collected from actual pipeline incidents, involving rupture and ignition of the gas released. Three types of comparisons between PIPESAFE predictions and incidents were made:

1. Building ignition times,
2. Burn areas surrounding the failure, and
3. Injuries to people

An exercise to compare the predictions of PIPESAFE with details of 18 incidents and the two full-scale experiments indicated that PIPESAFE gives a reasonable but generally conservative prediction of burn area. However, because of the subjective nature of determining the burnt area, and uncertainty due to fire spread and moisture content of the surrounding combustible materials, a wide spread in the predicted and reported burn areas was found.

A more rigorous test of the PIPESAFE consequence models was possible where ignition times and thermal radiation effects on people were reported. Where comparisons were possible, the PIPESAFE predictions gave good agreement with
the ignition time of adjacent properties. The level of burn injuries seen in the population near to the pipeline fire was also consistent with the predictions of PIPESAFE. The PIPESAFE package has also been subjected to a comprehensive programme of software testing, and independent checking.

D.2 FAILURE FREQUENCY

D.2.1 Third Party Damage

The verification of third party damage failure frequencies has used values taken from Table A.1 in Ref. D1, with the following points to be noted:

- Wall thickness is described as nominal +/- 1 mm. Assuming that wall variations are normally distributed and that +/- 1 mm represents the 95% confidence limits, the wall thickness distribution is taken as a normal distribution with a mean of 27.1 mm and a standard deviation of 0.5 mm.

- The Charpy energy distribution is quoted as having a COV of 0.4, which seems extremely large. However, applying this, the Charpy distribution is taken as a lognormal distribution with a mean of 130 J and a standard deviation of 52 J; using the correlation between Charpy and KIC given at equation (12) of Appendix A, the fracture toughness distribution is taken as a lognormal distribution with a mean of 659 MPa√m and a standard deviation of 364 MPa√m. This distribution is more conservative that the one obtained when the correlation between Charpy and KIC in the Advantica Third Party Damage model is used.

- Since the Advantica interference model is based on a dent force distribution, the JPK excavator data could not be used directly. We have used the gouge length and depth data given in Table A.1, together with a dent force distribution taken as a Weibull distribution with a shape parameter of 2.12 and a scale parameter of 110.2 kN.

  - The model used is based on work done for UKOPA. This model is based on the best available current knowledge, and contains an improved limit state function.

The results of the verification runs are given in Table D1 below. The values in this table are failure probabilities for a single interference event, not failure frequencies.
Table D1: Comparison of Failure Probability Results for Third Party Interference

<table>
<thead>
<tr>
<th>Release Type</th>
<th>Probability of Failure Mode / Interference Event</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>JP Kenny</td>
</tr>
<tr>
<td>Leak (25mm)</td>
<td>2.55E-04</td>
</tr>
<tr>
<td>Rupture (Full Bore)</td>
<td>6.09E-05</td>
</tr>
<tr>
<td>Total</td>
<td>3.16E-04</td>
</tr>
</tbody>
</table>

Using the Interference model developed for UKOPA results in a total failure probability for third party interference that is 3.5 times higher than the quoted value in the report, and a rupture probability 14.3 times greater.

D.2.2 External Corrosion

The threat of external corrosion is deemed negligible in the JP Kenny QRA report. This is based on a consideration of historical data and the external corrosion protection that will be used on the pipeline.

In order to verify the conclusions of the QRA report, Advantica used in-house software, CORROSION V4.1, to calculate failure frequencies for external corrosion. The following assumptions were made:

- Wall thickness distribution is the same as that used for third party damage.
- Yield strength distribution is taken from the SUPERB JIP [Ref. D5]. This assumes a normal distribution with a mean of 1.1 times the specified minimum yield strength (SMYS) and a coefficient of variation of 4% (since the pipeline is constructed post-1970).
- Defect Length distribution constructed from actual corrosion defects found on the UK Transmission system.
- Defect Depth distribution is time-dependent and constructed from actual corrosion defects found on the UK Transmission system. The time-dependent distribution allows for the effect of corrosion growth.
- The incident frequency of external corrosion is taken from the UKOPA database for polyethylene-type coated pipelines. This coating is expected to have inferior performance to the polypropylene coating that will be used, so the incident frequency can be reasonably expected to be conservative. This gives an incident frequency of $4.47 \times 10^{-3}$ per km year. This is an incident frequency based on corrosion defects found on polyethylene-coated pipelines, NOT on product loss incidents on polyethylene-coated pipelines.
- AC corrosion and MIC are not issues on this pipeline.

Using this information and CORROSION V4.1, the failure frequency for external corrosion was found to be negligible in the first 30 years of operation, thus agreeing with the conclusion in the QRA report.
D.2.3 Internal Corrosion

The threat of internal corrosion is deemed negligible in the JP Kenny QRA report. This is based on effective corrosion inhibition (including verification by monitoring) and with the corrosion allowance of 1mm.

In order to verify the conclusions of the JP Kenny report, Advantica used in-house software, CORROSION V4.1, to calculate failure frequencies for internal corrosion. The following assumptions were made:

- Wall thickness distribution is the same as that used for third party damage.
- Yield strength distribution is the same as that used for external corrosion.
- Based on Advantica experience of internal corrosion defect lengths, the defect length distribution is taken as a normal distribution with a mean of 150 mm and a coefficient of variation of 0.25.
- Advantica have assumed an initiation size distribution for internal corrosion defects. This distribution will then grow using an assumption on the internal corrosion growth rate. The initial defect depth distribution is taken as a Weibull distribution, with a shape parameter of 2.1 and scale parameter of 0.57mm.
- The corrosion growth rate has been taken from the Corrosion Allowance Evaluation report [Ref. D6], using the rate for no corrosion inhibition. This calculated 6.6mm of growth in the 30 years.
- The incident frequency of internal corrosion is taken from the UKOPA database. This gives an incident frequency of 4 x 10^-6 per km year.

Using this information and CORROSION V4.1, the failure frequency for internal corrosion was found to be negligible in the first 30 years of operation, thus agreeing with the conclusion in the JP report.

D.2.4 Fatigue of Construction Defects

In the JP Kenny QRA report, the threat from construction defects is taken as 50% of the UKOPA failure rate from 1962 to 1998. This results in a failure rate of 4.625 x 10^-5 per km year.

In order to verify the conclusions of the JP Kenny report, Advantica used in-house software, CRACKRISK, to calculate failure frequencies for fatigue of construction defects. The following assumptions were made:

- Wall thickness distribution is the same as that used for third party damage.
- Yield strength distribution is the same as that used for external and internal corrosion.
- Fracture toughness distribution is the same as that used for third party damage.
- The defect depth distribution is taken from Advantica experience of conducting similar studies on above ground installations in the UK. This
distribution was chosen as being reasonably representative of welding defects on heavy wall pipe.

- Two different defect types are looked at:
  - Long circumferential external surface flaw
  - Long axial external surface flaw
- It has been assumed that each weld contains a defect.
- The hydrostatic test is 431.25bar. This is taken from Section 6.1.11 of Ref. D1.

Using this information and CRACKRISK, the failure frequency for fatigue of construction defects was found to be negligible in the first 30 years of operation. This confirms that the JPK report has assumed a conservative value.

**D.2.5 Ground Movement**

Calculations to investigate the possibility of failure due to ground movement are discussed in detail in Appendix C. The conclusions of the landslip analysis undertaken by JP Kenny [Ref. D7] was that the pipeline would be able to withstand the loading from a range of landslip events, including the worst case. Advantica's calculations confirm the JP Kenny results (albeit we recommend additional parameters should be investigated to confirm the conclusions - see Section 4 and Appendix C), and therefore we would not expect ground movement to make a significant contribution to the failure frequency.

**D.2.6 Methanol Pool Fire from Umbilical**

Calculations carried out by Advantica using an in-house fire response model indicate that a 20 inch pipeline, with a wall thickness of 27mm, would be expected to stay intact if subjected to a methanol pool fire along a significant portion of its length, confirming JP Kenny's conclusion in Ref. D1 that a methanol pool fire would not cause pipeline failure. The analysis assumes that the pipe is not entirely locked in at both ends (i.e. in the event that a failure of the umbilical gives rise to a release of methanol, although there would likely be a loss of hydraulic pressure such that the subsea valves close, gas flow through the terminal would continue). The calculation performed assumed an exposure to a flux of 60 kW/m² from the methanol pool fire. This is likely to exceed the value that is received in practice but was chosen to err on the side of caution.

**D.2.7 Summary**

In the QRA by JP Kenny [Ref. D1], failure of the pipeline was assumed to be possible due to three failure causes: Third party damage, ground movement and inherent defects and construction defects. Other failure causes were not considered to be credible. In addition, two sizes of release were considered: a full-bore rupture or a 25mm diameter leak. The predicted failure frequencies used are given in Table D2.
Table D2: Failure Frequencies used in JP Kenny QRA

Investigation of the possible failure causes for the Corrib pipeline performed by Advantica concluded that the dominant contribution to the predicted frequency of failure for the Corrib pipeline is third party interference.

Frequencies for third party interference failures were predicted using the new model developed by Advantica for UKOPA. This model is based on the best available current knowledge, and contains an improved limit state function. The failure frequency predictions are also higher than both those of the current model in this case and those quoted in the JP Kenny report.

The predicted failure frequencies from the UKOPA mechanical damage model are given in Table D3 for each of the operating pressures considered in the analysis.

Table D3: UKOPA Mechanical Damage Model Failure Frequencies

D.3 IGNITION PROBABILITY

The ignition probabilities used in the JP Kenny QRA are based on EGIG data [Ref. D8] and are separated into rupture and pinhole-crack probabilities. Advantica’s approach to calculating ignition probabilities for pipelines uses worldwide incident data and accounts for the pressure of the pipeline in addition to the release size. The ignition probabilities obtained by each method are presented in Table D4.
It can be seen that the Advantica ignition probabilities are greater in all cases, generally by a factor of around 2 to 3.

Consideration was also given to the possible effect on ignition probability of the presence of the umbilical, buried a distance of 1m away from the pipeline. The size of a ground crater formed due to a pipeline rupture would be expected to expose the umbilical, which carries electrical cables that could present an additional source of ignition. Small leaks would be unlikely to expose the umbilical. Because the ignition probability assumed by Advantica is already high for ruptures, and as argued by JP Kenny, the exposed section of umbilical is likely to be in a region where gas concentrations are above the flammable limits, it is considered unlikely that the presence of the umbilical would increase the probability of ignition for ruptures above the value of 0.8 already assumed.

**D.4 CONSEQUENCES**

**D.4.1 Casualty Criteria, Escape and Shelter**

In the JP Kenny QRA, the risk calculations are based on exposure to a flux of greater than 6 kW/m², which is assumed to represent 1000 Thermal Dose Units (TDU) or a 1% probability of fatality. Advantica's approach involves summing the varying radiation dose received over the event time to determine if this exceeds the casualty criterion selected. The casualty criterion that would generally be used, and for which escape distances are presented in Sections D.4.3 and D.4.4, is the 1800 TDU or Significant Likelihood Of Death (SLOD) criterion.

No mention is made in the JP Kenny QRA [Ref. D1] about whether people in the vicinity of a pipeline fire are credited with the ability to escape and attempt to find safe shelter. Advantica's approach is to perform transient consequence calculations, summing the radiation dose a person receives as they attempt to escape from the fire. A shelter density is also employed which determines a person's probability of finding a non-burning shelter as they escape. In addition, a probability of escaping from an ignited building (evacuation factor) is assigned.

For the purposes of this study the following assumptions were made:

- Escape speed of people – 2.5 m/s
- Shelter density – 0.2 shelters per hectare (i.e. 1 building per 5 hectares)
• Evacuation factor – 0.9 (i.e. for buildings that are predicted to ignite, 90% of the occupants escape from the building)

**D.4.2 Wind Speed and Direction**

Three wind speeds of 2, 5, and 10 ms\(^{-1}\) were used in the assessment, assumed to occur with equal probability and to be equally likely in any direction. [Actual wind data from Belmullet was subsequently available. The sensitivity of the results to the assumed wind conditions was checked in comparison with the actual data and the effect found to be insignificant.]

**D.4.3 Leaks**

The JP Kenny QRA considered three different release types for the purpose of the leak modelling. Release orientations were assumed to be evenly distributed around the pipeline circumference so the following probabilities were assigned to each release type:

- Vertical – 25%
- Horizontal – 25%
- Buried – 50%

The vertical and horizontal releases were modelled as free jets and the buried release was modelled as directly downwards so that the gas loses all momentum and disperses out of the crater in the downwind direction.

The Advantica approach modelling leaks assumed the following release types with the corresponding probabilities:

- Vertical free jet – 50%
- Vertical impacted jet – 25%
- Free jet, perpendicular to the pipeline, angled at 70° from the vertical – 12.5% on either side

In this case, impacted jets are those that impact on, for example, the crater wall or the machinery damaging the pipe. These are assumed not to lose all momentum unlike the buried release scenario used in the JP Kenny assessment. The release probabilities used in the JP Kenny assessment are believed to be reasonable.

The hazard distances obtained from the puncture calculations, for each puncture type, are given in Table D5 to Table D7.
### Table D5: Hazard Distances for Vertical Free Jet Punctures

<table>
<thead>
<tr>
<th>Pressure (bar)</th>
<th>Escape Distance (m)</th>
<th>Building Burning Distance (m)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Max.</td>
<td>Min.</td>
</tr>
<tr>
<td>120</td>
<td>5.0</td>
<td>2.1</td>
</tr>
<tr>
<td>144</td>
<td>3.4</td>
<td>2.3</td>
</tr>
<tr>
<td>240</td>
<td>3.7</td>
<td>1.9</td>
</tr>
<tr>
<td>345</td>
<td>4.5</td>
<td>2.0</td>
</tr>
</tbody>
</table>

### Table D6: Hazard Distances for Impacted Punctures

<table>
<thead>
<tr>
<th>Pressure (bar)</th>
<th>Escape Distance (m)</th>
<th>Building Burning Distance (m)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Max.</td>
<td>Min.</td>
</tr>
<tr>
<td>120</td>
<td>16.5</td>
<td>0.0</td>
</tr>
<tr>
<td>144</td>
<td>17.2</td>
<td>0.0</td>
</tr>
<tr>
<td>240</td>
<td>20.0</td>
<td>3.7</td>
</tr>
<tr>
<td>345</td>
<td>23.3</td>
<td>7.4</td>
</tr>
</tbody>
</table>

### Table D7: Hazard Distances for Angled Free Jet Punctures

<table>
<thead>
<tr>
<th>Pressure (bar)</th>
<th>Escape Distance (m)</th>
<th>Building Burning Distance (m)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Max.</td>
<td>Min.</td>
</tr>
<tr>
<td>120</td>
<td>36.7</td>
<td>0.0</td>
</tr>
<tr>
<td>144</td>
<td>39.2</td>
<td>0.0</td>
</tr>
<tr>
<td>240</td>
<td>43.3</td>
<td>0.0</td>
</tr>
<tr>
<td>345</td>
<td>56.4</td>
<td>0.0</td>
</tr>
</tbody>
</table>
D.4.4 Ruptures

The JP Kenny QRA assumes that ruptures result in a horizontal release along the pipeline. This does not agree with what is observed in full-scale experiments and the approach adopted by Advantica. Advantica’s approach is to model the rupture release as vertical due to the interaction of the jets from each side of the rupture with each other and the crater that is formed. The size and shape of the crater, and length of the pipeline fracture, influences the behaviour of the released gas and since there is a high degree of uncertainty associated with these parameters the approach used is to treat them in a probabilistic fashion. Therefore, calculations have been performed for a number of combinations of fracture length and crater width.

The hazard distances obtained from the rupture calculations are given in Table D8.

<table>
<thead>
<tr>
<th>Pressure (barg)</th>
<th>Escape Distance (m)</th>
<th>Max.</th>
<th>Min.</th>
<th>Building Burning Distance (m)</th>
<th>Max.</th>
<th>Min.</th>
</tr>
</thead>
<tbody>
<tr>
<td>120</td>
<td>181.2</td>
<td>155.9</td>
<td>74.8</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>144</td>
<td>203.1</td>
<td>166.6</td>
<td>80.7</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>240</td>
<td>267.1</td>
<td>193.7</td>
<td>93.3</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>345</td>
<td>315.2</td>
<td>217.1</td>
<td>110.6</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Table D8: Hazard Distances for Ruptures

Calculations were also performed to predict the overpressure produced by the sudden release of pressure in the event of a pipeline rupture and by the combustion of the gas plume during the initial transient stages, using the overpressure model in PIPESAFE. These calculations indicate that for a pipeline rupture at a pressure at 345 bar, an overpressure of around 30 mbar would be predicted at a distance of 50 m from the pipeline, falling with increasing distance. 30 mbar is usually taken as the minimum pressure required to initiate window breakage, and because no damage would be predicted at the nearest building, even for the highest pipeline pressure considered, the risk due to overpressure was taken to be negligible in the subsequent risk calculations.

D.5 INDIVIDUAL RISK

D.5.1 JP Kenny Frequencies and Ignition Probabilities

Individual risk calculations have been performed using Advantica’s consequence models and the failure frequencies and ignition probabilities proposed in the existing QRA by JP Kenny. This allows the sensitivity of the risk assessment results to more
realistic modelling of the consequences of the releases to be analysed. The calculations were performed for the 120 bar normal operating pressure case and for the 345 bar wellhead shut-in pressure case. In addition, consequence calculations were performed using the 1800 TDU casualty criterion and the 1000 TDU (1% lethality) casualty criterion. The individual risk transects are given in Figure D2 and Figure D3 for the 120 bar and 345 bar cases respectively.

Figure D2: Individual Risk Transects for 120 bar case

Figure D3: Individual Risk Transects for 345 bar case
D.5.2 Advantica Frequencies and Ignition Probabilities

Individual risk transects have also been produced using failure frequencies and ignition probabilities predicted by Advantica’s models, and the 1800 TDU criterion. These are given in Figure D4 for 144 bar, 240 bar and 345 bar initial pressures.

![Figure D4: Individual Risk Transects predicted using Advantica Methodology](image)

D.6 SOCIETAL RISK

Societal risk calculations have been performed using Advantica’s PIPESAFE package, including Advantica’s own predictions of failure frequencies and ignition probabilities in order to provide an independent view of the societal risk levels.

D.6.1 Site Data

An investigation was performed in order to determine the highest risk 1.6km length of pipe within the onshore section. This is to allow comparison with the IGE/TD/1 criterion envelope, which is based on a case length of 1.6km. The locations of buildings along the pipeline route were obtained from the alignment sheets.

All private dwellings were assumed to have three people present at all times. Between 09:00 and 17:00, people were assumed to be outdoors for 60% of the time and between 17:00 and 09:00 they were assumed to be outdoors 1% of the time.
D.6.2 Societal Risk Calculation

The results of Advantica's Societal Risk calculations are given in Figure D5 for the 144 bar, 240 bar and 345 bar cases respectively. Note that no data is included for the 25mm puncture scenario since there are no buildings close enough to the pipeline to be affected by releases of this size.

The FN curves obtained are within the published criterion envelope, and would therefore normally be regarded as broadly acceptable levels of risk.

D.6.3 Risk to Schools and School Bus at Road Crossing

At the oral hearings, concern was expressed over the risk to nearby schools from the pipeline and at a point where the pipeline crosses the road used regularly by a school bus. Although no schools were present in the area identified as the highest risk location, both aspects were therefore considered.

D.6.3.1 Risk to Schools

A number of schools were identified in the vicinity of the pipeline route, on both the north and south sides of Sruwaddacon Bay, a minimum distance of approximately 750m away from the pipeline.

This distance is substantially greater than the maximum hazard distance calculated for the wellhead shut-in pressure of 345 bar, even using the more sensitive 1% casualty criterion. Therefore, even at the highest pressure that the pipeline could theoretically experience, children at the schools should not be directly affected by a pipeline failure.

D.6.3.2 Risk to School Bus Route

A road crosses the pipeline close to the gas terminal that is used regularly by the school bus. Therefore, an assessment has been made of the frequency of an ignited rupture that could impact upon the road crossing occurring whilst the bus is in the range of the pipeline.

The frequency of an ignited rupture of the pipeline within the maximum hazard range of the road is $9.5 \times 10^{-7}$ per year, based on failure frequency predictions from the Advantica external interference and ignition probability models. Assuming that the bus travels at 25 mph and makes 2 journeys per day, 5 days per week and 40 weeks per year, the probability of the bus being within the hazard range of the pipeline is $9.9 \times 10^{-4}$.

Therefore, the frequency of an ignited rupture that could impact upon the road crossing occurring whilst the bus is in the range of the pipeline is $9.4 \times 10^{-10}$ per year (or once in a thousand million years). This frequency is considered to be negligible.
Figure D5: FN Curves predicted using Advantica Methodology
D.7 REFERENCES


APPENDIX E GEOTECHNICAL INVESTIGATIONS ON CORRIB PIPELINE ROUTE

BY EurGeol KOENRAAD VERBRUGGEN PGeo, PRINCIPAL GEOLOGIST, GEOLOGICAL SURVEY OF IRELAND

E.1 INTRODUCTION
As part of Advantica’s Safety Review in relation to the proposed Corrib Onshore Pipeline, I have reviewed a series of documents provided in relation to the geotechnical investigations carried out and proposed working methods.

It is important to point out that I am neither a Geotechnical Engineer nor Engineering Geologist, however as a Geologist I am the current Chairman of the Irish Landslide Working Group, founded in 2003, and have read and investigated Irish landslides extensively over the last two years. I offer these comments as part of my role as a member of the Ministerial Technical Advisory Group on the Corrib Pipeline.

E.2 GEOTECHNICAL REPORTS
The main documents reviewed are listed under references below. It is, however, important to note that there have been three separate campaigns of site investigation along several possible pipeline routes and parallel or close to the proposed route in areas of difficult access.

The most recent and probably most useful document in this respect is the AGEC Draft Report on Onshore Gas Pipeline – Glenamoy River Estuary to Corrib Gas Terminal, Geotechnical Interpretative Report (July 2004). This document deals with the area of deepest peat, and consequently greatest potential peat failure risk, south of the estuary. In particular, the comments under Section 5, in relation to Construction Practice need to be taken account of and it would be important to see that all of these have been acknowledged and dealt with by the contractors. A number of further trials and tests have been recommended, it needs to be established if these have been carried out, including:

10.3 “Contractor would need to demonstrate by appropriate analytical methods that the proposed applied load with respect to the condition of the underlying peat would not result in instability.”

Under 10.9 “Would advise that a dewatering trial be carried out to assess appropriate method of dewatering for trench.”

Section 6. Refers to the need to take account of possible methane build up during construction.

Under Section 7 Summary:
Point (5) Refers to the fact that in addition to the difficulty proposed by peat material, the Lower Till is potentially unstable.
"Lower Till was exposed in the bottom of trial pits though the base of the Lower Till was not encountered. Lower Till was described as ‘running’ or ‘unstable’ and where encountered in trial pits was saturated and sensitive to disturbance. Where there is disturbance and/or removal of confining pressure from saturated Lower Till liquefaction occurs with loss of strength."

This needs to be allowed for in construction, with AGEC reviewing the construction related issues under Point (9).

"A review of a possible construction method statement was carried out (Table 3).

Some of the issues arising from this review are as follows:

(a) Advise that trial or demonstration of access road and pipe laying techniques be carried out prior to works.

(b) Presence of saturated silty fine sand in the base of the trench needs to be considered. Dewatering of this sand, where encountered, will be necessary in order to achieve a dry trench. Advise that a dewatering trial be carried out to assess appropriate method of dewatering for trench.

(c) Several pipe founding options should be included based on anticipated range of ground conditions. This could include suspension on piles, direct founding on competent strata, localised supports (such as rubble mounds) formed on competent strata.

(d) Backfilling of excavation by peat spoil will result in very soft ground, which will effectively sterilise ground along pipeline route. Consideration should be given to backfilling operation, such as, use of alternative backfill, mixing of peat spoil with mineral soil, use of reinforcing geotextile in backfill."

A later document than the AGEC Report is the Overall Project Method Statement: 8 Feb 2005 Rev 2 from Sicim-Roadbridge (SR). This document appears to address some but not all of the issues raised by AGEC. Regarding the points listed under Point (9) by AGEC:

(a) SR include details of proposed access road and pipelaying techniques and include as an Appendix “Document 12215 Working platform calculations.

This document was originally prepared to verify the structural stability of a timber mat road for the construction of the Gas terminal. The calculations will also apply to the peat layers on the onshore gas pipeline.

(b) There is no explicit reference to the Lower Sandy Till Unit and any dewatering trial. The subsoil in the “Forested Peat” section is described as follows:

“The underlying soils from the soil investigation reports consist of a peaty material extending from between 3.5m to 4.5m below the surface. This material is underlain with a gravelly or stiffer material.”

(c) Different pipe-laying methodologies are referred to as being most appropriate for the different sections.
(d) There is no reference to backfilling in peat areas with other than the excavated peat material.

E.3 GEOTECHNICAL INVESTIGATIONS

It would appear from the documents furnished that an adequate level of investigation has been carried out along the pipeline route, with the following caveats:

i. Some additional testing appears to be still required as outlined by AGEC (e.g. there is no report of the peat dewatering test recommended).

ii. Access has apparently been denied to the intact bog area immediately north of the upper Glenamoy River crossing, as stated in the AllSeas “Preliminary Report Onshore Soil Trials Ireland” (2002).

"Some of the proposed trial locations could not be reached. This was caused partly by the refusal of some of the landowners granting the research team permission to access their land, and partly by the inaccessibility of the terrain in the forest area. Wherever access was unfeasible, new accessible locations were selected on the pipeline route as close to the proposed locations as possible. On the section of the pipeline route north of the river, which runs approximately from KP 87.800 to KP 89.800, no access to the site was granted by the landowners. Therefore no trials could be performed in this area and no soil data is available on this section. However, it is assumed that this section of land consists mainly of virgin peat with an unknown depth. This soil characteristics in this section are thus expected to be different than the examined sections of the route between KP 84.500 and KP 87.800."

This poses the problem that adequate geotechnical investigation therefore had not been carried out in this section. It needs to be established if access was available after that date allowing investigation and if results were satisfactory, and construction method proposed is appropriate. If access has not been allowed to date, adequate geotechnical investigation must take place in advance of any construction works once access is available, and the construction method proposed must be tested against the findings of the investigation and adapted where necessary.

It should also be noted that this section lies east of the improved farmland and immediately north of the proposed river crossing; an earlier proposed route with a river crossing further west (and therefore different chainage measurements) was accessed for site investigation as reported by IGSL.

E.4 LANDSLIDE RISK

The potential effects of loading on the pipeline from a landslip event are dealt with in the JP Kenny document, which was reviewed by Advantica. The specific risk of landslide occurrence, such as at Dooncarton-Glengad in September 2003, does not appear to be addressed directly, although the Tobin Engineering Report for Mayo County Council on the event is included in the documents provided. The Dooncarton-Glengad landslide occurred on steep slopes and was due to intense rainfall (Tobin, 2003). Failure occurred at the surface of the weathered rock in the
majority of cases, with some failures occurring within the peat where its thickness was appreciable. The solid bedrock of the area is highly stable, it did not fail as part of the event and there is no geological record of fault movement in the area within the last 100 million years (Creighton & Verbruggen, 2003). A similar style of landslide could not be repeated along the length of the pipeline, primarily due to the shallow slopes involved. The area of landfall of the pipeline, which is downslope from some of the failures, is of shallow slope, with site investigation revealing peaty soil depths of 0.5m or less (IGSL). Therefore, as long as adequate care is taken in the burying of the pipeline, such that it would not be affected by a repeat event upslope, including the scouring down action of streams and watercourses, no danger would arise.

Of more relevance to the pipeline route is the possibility of a failure such as occurred at Derrybrien, Co. Galway, in October 2003, where peat failure occurred on relative low slopes (less than 5 degrees), partly due to weak peat, a natural drainage channel and construction practices, in particular undrained loading (AGEC Report on Derrybrien Windfarm, 2004). The Corrib project has the benefits of the Derrybrien investigation and many of the findings of the report inform the recommendations made in the AGEC report on the pipeline. As long as the further geotechnical tests recommended are carried out with satisfactory results and construction practice recommendations made are carefully adhered to, the risk of peat failure should be avoided.

E.5 SUMMARY

The Geotechnical Reports provided appear to deal adequately with the route, with the exception of the area where access has been denied.

Shell or their contractors need to provide evidence regarding their response to some of the AGEC recommended further testing and changed construction methods.

E.6 REFERENCES


E5. Corrib Field Development Project, Landslip Analysis. JP Kenny, document no. 05-2377-01-P-3-002 Rev 02, 11/02/05


ADVANTICA

APPENDIX F

COMMENTS ON ROSSPORT PIPELINE HAZARD CALCULATIONS BY DJ ALDRIDGE PHD

F.1 INTRODUCTION

The author of this document has expressed serious concerns over the safety of the proposed Corrib pipeline. The concerns that a serious event may occur as a result of the pipeline should be taken seriously and, elsewhere, the results are presented of our independent assessment of the safety risks arising from the pipeline.

In his note, Dr. Aldridge backs up his concerns by presenting the results of a series of what he refers to as ‘ballpark’ or ‘back of an envelope’ calculations. If the conclusions drawn from the results of these calculations are to be considered in the debate, there is a need for his calculations to be the subject of a similar level of scrutiny to those presented by Shell. In particular, they need to be reviewed to ensure that the calculations are describing behaviour that could really happen in the event of a pipeline rupture. The purpose of this section of the report is to carry out such a review.

F.2 SCENARIO OF INTEREST

The underlying assumption of this work is that there is a possible scenario in which the contents of the 93 km length of pipeline could be released to form a single, effectively homogeneous gas cloud, containing all of this gas. It is then assumed that some time later after this release has occurred, the natural gas within the resulting cloud could still be within the flammable range and that it could be ignited, leading to an explosion (referred to as a detonation on occasions in Dr Aldridge’s report) or a fireball. Hazard distances are calculated by Dr. Aldridge for both of these cases.

F.3 REVIEW

F.3.1 Source Conditions

For either of these cases (explosion or fireball) to be possible at all, a pre-mixed cloud of natural gas and air has to be formed within the flammable range of concentrations from all (or at least a large portion) of the gas that is released. This could only occur if gas from the earlier stages of the release was prevented from dispersing freely in the atmosphere but was confined in some way. Assuming that such confinement existed, it is theoretically possible that a low momentum, neutral density, gas release could re-circulate in the neighbourhood of the release point and so the gas that had been released during the early stages could be re-entrained into the flow at later times. This provides a mechanism for the gradual accumulation of all (or a significant part of) the gas within such a fixed volume. However, in the case of a high pressure pipeline rupture, the initial momentum of the release cannot be ignored.
Immediately following a rupture, the initial momentum of the release is sufficient to create an emerging flow with significant velocity. Indeed, typical measurements made in experiments at field scale show that the flow emerges at velocities of up to about 200 m/s and that the gas is diluted within the crater and in its immediate vicinity to volume concentrations of about 10% to 40% for pipelines containing natural gas at pressures of up to about 70 bar. Such a flow will continue to entrain air and be diluted. A characteristic 'start-up' head is produced as the flow at the leading edge is progressing at a lower speed than the flow being fed into the head. Such a head would possess significant momentum and would be capable of penetrating into the atmosphere if directed vertically or would have sufficient momentum to propagate long distances (diluting as it travelled) if released horizontally. Once this has occurred, there is no longer a route for this gas to be re-entrained into a cloud growing around the release location. Such a cloud would have a gradual decay of concentration along its centreline and would develop a typical Gaussian profile for the mean concentration profile in a vertical or horizontal direction. Recirculation over the source would not occur. That is, a homogeneous cloud containing all (or a large part) of the material that is released would not be formed around the source location as suggested.

Nevertheless, at any one time after the release has occurred a certain fraction of the material could be within the flammable range and it is entirely reasonable and valid to question what level of overpressure or thermal radiation might be generated in a 'worst case' if this were ignited. This is addressed in the risk assessment performed for this study by Advantica. However, to consider further the validity or otherwise of the scenarios presented by Dr. Aldridge, it is necessary to consider the known behaviour of natural gas when ignited following its release into the atmosphere.

F.3.2 Explosion Overpressures

The primary causes of pressure generation in gas explosions are confinement of the clouds and products that are formed or the presence of high-speed flames. Natural gas is the least reactive of the commonly used hydrocarbon fuels and, for natural gas clouds, high-speed flames are only generated in an unconfined cloud by the presence of repeated obstacles within the cloud. Further, it has been shown that whilst repeated obstacles of the type that might be experienced in the worst case conditions, such as might occur offshore on a gas processing module for example, can sustain high-speed flames in a mixture of natural gas and air at the appropriate concentration, once such flames enter into less congested regions or open regions they rapidly decelerate and cease to generate significant pressures.

A density inversion in the atmosphere of the type described by Dr. Aldridge would be insufficient to cause the confinement required to allow pressure generation (granted it may inhibit the decay of a pressure wave once it has been generated in the atmosphere, but that is physically different to the flow during the combustion process). Further there are no other sufficiently large regions of confinement or congestion surrounding the pipe that would be capable of generating the magnitude and extent of the source pressures assumed by Dr. Aldridge. Hence, any pressures that are generated would be limited to those produced by the ignition of a turbulent gas-air cloud in the open atmosphere. Experimental measurements of the pressures generated by the combustion of the natural gas mixtures within the start-up head.
referred to earlier are typically a few tens of millibars (and less than 100 millibar) at the source. Such values would be expected on theoretical grounds given the likely flame speeds involved (typically, a few tens of metres per second and less than 100 m/s). The measurements made of overpressure produced by the combustion of the natural gas mixtures formed during pipeline rupture experiments confirm the above behaviour and demonstrate that any explosion risk (for natural gas mixtures at least) is far less than the risk arising from the fires that are produced. The presence of small quantities of other hydrocarbons, such as methanol, would not be sufficient to alter these conclusions.

F.3.3 Thermal Radiation

Given that significant overpressure is not produced by combustion of the natural gas clouds formed in the atmosphere, there are still significant hazards that might arise from combustion. Dr. Aldridge correctly identifies this and performs a series of 'fireball' calculations to estimate the thermal hazard produced. This is a reasonable approximation to take as a means of making an estimate of the radiation produced by immediate ignition and combustion within the start-up head referred to earlier, for example. Such a calculation will tend to underestimate the velocity of the head, as the fireball calculation assumes the cloud is motionless initially. However, the velocity of the 'head' may cause an increased rate of air entrainment into the head, and so produce a more rapid combustion, in the early stages, compared to a fireball. This in turn however may be limited by the rate at which fuel is added to the head. It requires a more detailed calculation for the combustion in this head (of the type included in the risk assessment performed by Advantica) to address the impact of this on the thermal radiation field produced. However, in any event, for the reasons discussed in the section addressing the source conditions, it is not reasonable to assume that all of the flammable material within the pipeline initially can contribute to this 'fireball'. It is the integrated effect of the thermal radiation from the initial fireball phase (if it occurs) and the subsequent quasi-steady fire that should be considered, taking a realistic calculation for the maximum amount of fuel that could be involved in the initial 'fireball' phase. The values obtained from this process are reported in the risk assessment performed by Advantica.

F.4 CONCLUSIONS

The note from Dr. Aldridge makes a number of valid and worthwhile points. He uses a number of simple calculations to estimate and illustrate what he believes are the hazards involved. As noted above, the assumptions taken in making these calculations are not valid in a number of instances and this has been pointed out above. Hence, the conclusions he draws from his study are unfounded. Nevertheless, the general principle — that it is necessary to consider the potential for explosion overpressure and the thermal radiation that a major release could produce — remain valid. This is dealt with by Advantica through its own risk assessment.

F.5 REFERENCE

"Rossport Pipeline Hazard Calculations" (Issue 0.2), Dave J. Aldridge, October 2005
APPENDIX G COMMENTS ON “THE PROPOSED CORRIB ONSHORE SYSTEM” BY RICHARD B. KUPREWICZ

G.1 INTRODUCTION
The above report was prepared by Richard B. Kuprewicz of Accufacts Inc. on behalf of The Centre for Public Enquiry, and was released shortly after Advantica’s draft report had been prepared and submitted to the TAG.

The Accufacts report was based on public domain information only, whereas the Advantica report was based on a comprehensive review of detailed engineering design documents and discussion with Shell, undertaken by a team with wide-ranging technical expertise, to allow in-depth analysis of specific technical issues. Advantica’s review included undertaking independent checks on the key results of engineering and risk assessment calculations using tools and models validated by large and full scale experiments, incidents and operational experience. The Accufacts report is a wide-ranging overview of the pipeline, terminal and gas processing options, whereas the Advantica report is a detailed and comprehensive assessment specifically of the onshore pipeline.

Despite obvious differences in style and the level of technical analysis, many of the issues identified in the two reports are common, although the Advantica report makes a number of specific recommendations to address the issues identified. The Accufacts report highlights a series of “critical issues” in coloured text boxes throughout the report, which are reproduced in the following section with commentary from Advantica (bulleted), drawing attention to the relevant sections of Advantica’s report where these issues are discussed.

G.2 CRITICAL ISSUES
Accufacts: “The maximum pressure this pipeline is permitted to experience has not been clearly demonstrated.”

- Advantica also identified this as a critical issue in Section 5.5 and discussed in Section 6.2. One of Advantica’s main recommendations is that “a full and 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.”

Accufacts: “No pipeline, regardless of wall thickness, is impervious to failure. Attempts to characterise thick-walled pipe as somehow invincible or better than thin-walled pipe appear to be incomplete efforts to deceive an uninformed government, public, or management team.”

- Advantica recognises fully that for any pipeline, the possibility of failure is a real threat, however unlikely, but it is also widely accepted that the probability of failure decreases with increasing pipeline wall thickness for a given operating pressure. This is the basis for the requirements in many pipeline design codes for a lower design factor (leading to an increased wall thickness)
to be applied in more densely populated areas. The likelihood of a failure of the onshore section of the Corrib gas pipeline is discussed in Section 5 and considered in more detail in Appendix D.

Accufacts: “The design concept to prevent onshore pipeline overpressure has not been clearly demonstrated or communicated to the public.”

- This is also identified as a critical issue by Advantica - see above comments on maximum pressure and recommendation.

Accufacts: “The main point to be appreciated is that the pressure has to only hit once to cause pipe failure if the wrong size anomaly is present.”

- Advantica agrees with this point – see discussion in Section 5.3.4.

Accufacts:
1. “Thick walled pipe is not invincible to corrosion failure, either leak or rupture.
2. A clear understanding of the aggressive and highly selective internal corrosion rate on a particular system is very critical.
3. Faster corrosion rates significantly spread out the triangles for any original flaw and can seriously reduce the years to pipeline failure, either leak or rupture, from internal corrosion.
4. Various factors unique to production pipelines can introduce uncertainties in internal corrosion rates and time to failure by several years, either by shortening or lengthening time to failure.
5. The influence of wet gas composition and temperature changes on internal corrosion rates needs to be reliably tracked and monitored for sensitive pipeline segments. Inhibitor and corrosion coupon programs can be very ineffective.”

- Advantica also identified management of the threat to the integrity of the pipeline from corrosion as an important issue, and corrosion control (internal and external) is discussed in Section 4.5 with recommendations. One of Advantica’s main recommendations is that “a formal integrity management plan is established prior to construction, including the operational and maintenance philosophy, and that an independent audit and inspection regime for both the construction and operation of the pipeline is established.”

Accufacts: “Is the Corrib project another space shuttle rushing to launch at all costs without listening to reason about a flawed initial design or routing approach?”

- We feel that it would inappropriate for Advantica to comment, other than to note that the project has been several years in development following the initial discovery of gas in 1996.

Accufacts: “No credible design scheme has been provided that commits or ensures that onshore pipeline pressures will remain below 150 bar”

- This is also identified as a critical issue by Advantica - see above comments on maximum pressure and recommendation.
Accufacts: "A Corrib onshore pipeline rupture in Rossport above 150 bar pressure will release fuel at a much higher rate in the early critical fatality minutes, and in all probability generate a much bigger flame than that shown in Figure 9 for the Carlsbad tragedy."

- Detailed analysis of the potential consequences of failure for the Corrib onshore pipeline has been undertaken by Advantica, described in Section 5.3.2 and discussed in Section 6.3, with detailed results provided in Appendix D of time-dependent consequence calculations for a full-bore pipeline rupture (i.e. taking account of the initial high flow rate of gas).

Accufacts: "Pipeline rupture siting analysis must incorporate the early minutes of initial ignition when casualties from high heat flux are at their greatest"

- As per the previous point - details of time-dependent consequence calculations are given in Appendix D. The calculations assume that for ignited releases, ignition occurs either immediately (50% of cases) or after a delay of 30 seconds (50% of cases).

Accufacts: "Early ignition scenarios and Carlsbad would place the safe distance for a dwelling at 200 metres and the safe distances for unsheltered individuals beyond 400 metres."

- Risk transects vs distance and hazard ranges for different release scenarios are given in Appendix D. The risk analysis combines the predicted frequency of a failure with the possible consequences. Provided that Advantica’s recommendation to limit the pressure in the onshore pipeline is followed, then the calculated levels of risk are within typical limits for the acceptability of risk by a large margin (see Section 5.3). Although Advantica’s conclusions and recommendations are informed by the results of risk analysis, it is not the only factor, as discussed in Section 5.4.

Accufacts: "A further analysis of pipeline route alternatives is warranted to ensure that options were properly reviewed and analysed should an onshore gas plant prove acceptable."

- Assessment of possible alternative pipeline routes was outside the scope of the Advantica safety review. However, the pipeline routing process was reviewed to confirm the part that public safety considerations played in selecting the preferred options and, in our opinion, proper consideration was given to safety issues in this selection process.

Accufacts: "Running a smart pig is the easiest and cheapest part of an overall effective ILI inspection program. Much more effort is involved in choosing the right pig and verifying and responding to observations."

- In-line inspection is discussed in Sections 4.7 and 4.8 of Advantica’s report. As noted above, one of Advantica’s main recommendations is that a formal integrity management plan is established prior to construction.

Accufacts: "Risk analysis conclusions dismissing fatigue cycle induced third party damage failure on this high stress level pipeline appear incomplete."
The possibility of failure due to third party damage is included in Advantica's analysis - see Section 5.3 and Appendix D, and considered as the dominant contributor to the probability of failure. Fatigue loading is also considered in Section 4.3, with recommendations. The stress levels that the onshore pipeline can experience will be substantially reduced if Advantica's recommendation to limit the pressure in the onshore section is followed.

Accufacts: "Road crossing loading calculations need to be adequately documented."

Advantica agrees with this point – impact protection and design of road crossings is discussed in Section 4.3.

Accufacts: "In any risk analysis no credit should be incurred for "automatic" leak detection on this system."

Leak detection systems are discussed in Section 4.8 of Advantica's report, and the limitations of such systems are noted. We agree that automatic systems are unlikely to have a significant impact on the consequences of an ignited pipeline rupture event, and no benefit has been assumed for such systems in the risk analysis.

Accufacts: "Proclamations claiming "highest international standards" carry very little weight and appear to be a public relations attempt to placate an inquiring public challenging or raising real issues of concern."

Discussion of relevant standards and design codes is included in Advantica's report – see Sections 4 and 6 in particular. Advantica's findings are based on an understanding of the principles underlying pipeline standards, the benefits and limitations of risk analysis, and engineering judgment.

Accufacts: "Risk analyses to date for the Corrib onshore pipeline have failed to properly or adequately comply with the five basic minimum requirements defined in Standard BS 8010, subsection 2.3 a) through e) allowing risk analysis."

A review of the most recent version of the quantified risk analysis (QRA) undertaken for the project is given in Section 5.3 of the Advantica report. Our concerns regarding the QRA are noted in that section, in particular uncertainty associated with the application of risk models at such high pressures as 345 bar and the omission of societal risk analysis from the final version of the QRA (although we note that societal risk was considered in earlier versions). In other respects, we consider that the QRA did address the five basic requirements specified in BS8010, and generally used conservative assumptions. Nevertheless, although risk analysis can be a powerful tool to inform difficult decisions on safety issues, it is not the only factor, as noted above.

Accufacts: "The proposed onshore route presents the greatest risk to population. The Gas Processing Plant placement greatly influences risks associated with the onshore pipeline."

As response above to comments on pipeline route alternatives.

Accufacts: "Cold venting should be avoided in prudent gas processing plant design."
Outside the scope of Advantica’s study.

Accufacts: “The burden of proof should fall on the pipeline operator to clearly explain and demonstrate that alternative routes to the plant were adequately explored and the reasons for their rejection clearly presented and properly communicated.”

As response above to comments on pipeline route alternatives.

Accufacts: “The previously discussed issue of cold venting and/or excess flaring are a classic example of a short-term fixation (rewards the operator) that may not be in the best interest of a country’s energy resource (waste of salable energy).”

Outside the scope of Advantica’s study.

G.3 REFERENCE

“The Proposed Corrib Onshore System – An Independent Analysis”, prepared for the Centre for Public Inquiry by Richard J. Kuprewicz, October 2005