Response to request for clarification Entec – Submission No 2.

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9	Corrosion Protection	Can the CP operate effectively in fully grouted tunnel? 4.3.1 says yes but is this system the same as used in grouting sleeves at road crossings etc?	There are no grouted sleeves used at road crossings. The impressed current cathodic protection system will operate effectively in the tunnel. The cementatious grout is conductive and the segment design is such that there is no continuous steel reinforcement bar which might interfere with the cathodic protection. A similar system used for the Ems pipeline tunnel between the Netherlands and Germany has been shown by modelling and subsequent measurements to be effective. Cathodic protection modelling will also be carried out for the Corrib pipeline and monitoring points will be positioned and each end and inside the tunnel.
10	Corrosion Prevention	Where is the interface between onshore (impressed current) and offshore (sacrificial anode) protection? What measures are to be put in place to ensure that it is effective? Q4.7 s 7.2.3 / 7.2.2 intertidal/ nearshore area.??	The onshore impressed current system will be monitored through checks on the transformer/rectifier up-time and output, standard test posts and coupon polarisation probes, close interval potential surveys (CIPS) and direct voltage current gradient (DCVG) surveys. The cathodic protection design for the section of onshore pipeline in the tunnel is still to be defined but will include cathodic protection monitoring facilities. Particular attention is required for the interface between the offshore and onshore pipelines to ensure that there is no current drain from the offshore pipeline anodes to onshore. Following a detailed assessment it was concluded that the installation of an isolation joint between the offshore and onshore pipeline was not necessary, but potential monitoring coupons/probes will be installed close to the LVI to allow potentials to be accurately measured. This satisfies the recommendation of the Advantica Independent Safety Review (see section Q3.1 of this Appendix). An isolation spool is fitted between the onshore pipeline and the Terminal facilities and this will be subject to monitoring to assure isolation and absence of any degradation. Balancing of the offshore and onshore CP systems is needed to prevent one system becoming a drain on the other with current flowing say from the offshore anodes to protect the onshore section or vice versa. The main objective of balancing the offshore and onshore pipeline potentials is to ensure that the offshore CP system does not protect the onshore section, as if this occurs it could result in early depletion of the sacrificial bracelet anodes installed close to the landfall. In order to monitor CP potentials along the onshore pipeline section, test stations will be installed at regular intervals, including one installed very close to the offshore/onshore interface. Permanent reference electrodes and coupons will also be installed at each test station that will allow measurement of pipeline on and coupon instantaneous off potentials. To balance the offshore and onshore pipeline voltage potentials and prevent the passage of CP current onshore, first the voltage potential imposed from the offshore anodes onto the onshore pipeline (with all onshore CP switched off) is measured. Then the level of potential needed from

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			the onshore CP system to make the onshore system slightly more negative than the offshore voltage potential is calculated. This means that a small current will flow from the onshore system to the offshore pipeline, and not vice versa. Prior to commissioning of the permanent impressed current CP, this will be achieved by adjusting the current output of the temporary, sacrificial magnesium anodes (with variable resistors installed within test stations). Once the permanent CP system has been commissioned, the current output from the Transformer Rectifier is adjusted to achieve the same objective and then set to automatic current control.
11	Pipeline and service Repair in Tunnel	Repair: If any defects are discovered after filling the tunnel with grout then how would remedial measures be undertaken? Defects might include: • Higher than anticipated internal corrosion; • Manufacturing defects / inclusions growing post commissioning; • Damage to pipe coating during the grouting operation;	It is unlikely that defects will be discovered after filling the tunnel with grout as before grouting the pipe in the tunnel will be hydrotested to 504barg, the coating will be checked and there will be UT testing of the welds. 1.Higher than anticipated internal corrosion; Corrosion modelling and subsequent corrosion testing under simulated onshore pipeline conditions indicate very low internal corrosion rates (< 0.02 mm/yr) even without corrosion inhibition. Should higher than anticipated corrosion occur then this will be assessed using the damage assessment map given in Appendix Q4.8 of the EIS. This map shows that relatively large areas of corrosion with a depth of 10mm can be safely tolerated. Smaller areas with an approximate depth of 20mm can be tolerated. This damage would be discussed and agreed with the regulatory authority should significant corrosion occur. If the corrosion were to become intolerable then the envisaged repair would be to pull a new smaller diameter 16” pipeline through the 20” pipe. 2.Manufacturing defects / inclusions growing post commissioning The linepipe has been subject to extensive testing and inspection during manufacture. The girth welds in the pipeline will also be subject to extensive testing and inspection during fabrication including automatic ultrasonic testing. This is a very effective technique for discovering even small defects. All defects which do not meet the strict specification requirements will be repaired. Furthermore the completed pipeline will be subject to a hydrostatic test at 504 bar which is considerably above that required for a design pressure of 144 bar. This test will confirm the absence of any significant defects. There are two generic types of weld defects, planar and volumetric. Volumetric defects are not prone to growth and if within code requirements can be considered benign. Planar defects such as lack of fusion require some form of mechanism such as fatigue to initiate growth. Our assessments indicate no credible growth mechanism such as fatigue in the pipeline. Given the level of inspection and hydrostatic test pressure and the absence of any growth mechanism such as fatigue there is negligible risk of defect growth post commissioning. 3.Damage to pipe coating during the grouting operation A thorough inspection of the coating system will be carried out following installation and any damage will be repaired. Once installation is complete the tunnel will be filled with a

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			cementatious grouting compound. The grout typically has shrinkage of 2 to 5% and normally takes over 24 hours to harden. As it shrinks on to the pipe it will not damage the coating and will form a protective layer which will, to a large extent, exclude free water and oxygen. The grout also has a pH of 12 which is alkaline and would effectively passivate the steel against corrosion if exposed to water. The grout is conductive which will allow the pipeline cathodic protection system to protect any exposed steel should water penetrate the grout.
12	Isolation Valves	Q2 6 page 23. In the UK offshore industry the HSE require an operator to specify an "acceptable" passing rate for tests of isolation valves. How will the operator ascertain the acceptability of tests on the isolation valves? Standard passing rates have been quoted in the calculation are these the maximum acceptable? SEPIL sensitivity analysis shows higher rates would be acceptable.	SEPIL will ascertain the acceptability of tests on the isolation valves via our Verification system and the associated performance standards – they are based on detection of pressure build-up & decay during pressure tests. A number of passing rates have been used, and a number of cases developed to demonstrate the potential for pipeline pressure to increase due to valves passing. For a more detailed analysis, please see section 4 in Appendix Q4.5 (The question is based upon Appendix Q2 – but this is only a summary of the work that has been performed and presented in Q4.5). Further information on testing is also given in Appendix Q4.5 (see Page 26 in this Appendix, Section 4.2.5: Valve In Situ Testing Regime). The acceptable leakage rates for A) the subsea valves are determined from the Well Integrity Management System. This sets the acceptable leak rate at 14.7 scf/min. Note: see page 31 for the absolute worst case scenario where all of the subsea valves are leaking at their maximum allowable leakage rate as per testing (highly unlikely). This results in a period of 80 days for offshore pipeline to increase to it's MAOP. B) the acceptable leakage rates for the HIPPS valves and the 20" DEGV at the LVI will be based upon the applicable performance standard for pipeline isolation valves. This will ensure that the maximum acceptable rate will be lower than the absolute worst case sensitivity (which is stated one page 33, indicating it would take approximately 10 hours for the onshore pipeline to reach its MAOP with a leakage rate of 0.25 MMSCFD).
13	QRA	Q6.4 Section 6.4 identifies land slide debris risk but has not included it in discussion analysis. Given additional design measures proposed would expect a justification of those protection measures	Clarification has been provided in relation to the issue of landslide risk and mitigation at watercourse crossings.
		Page 39 refers to galvanic corrosion – this is a known feature on offshore systems where small differences in metallurgy can lead to significant corrosion, particularly in hydraulic line connections and other features of the	The tubing in the control system is fabricated from stainless steel (austenitic or duplex) throughout and there are no significant galvanic couples. The termination assemblies (UTA) and subsea distribution units (SDU) are fabricated from carbon steel but are protected by coating and cathodic protection. All metallic components in the control system are electrically bonded and the cathodic protection system will ensure that no galvanic corrosion will occur in the system including couplings. Electrical continuity checks on subsea control systems prior to installation

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		control system. What safeguards are in place?	to ensure that all metallic components are electrically bonded were carried out. During operation regular checks will be made to ensure that the cathodic protection system is functioning as intended. Galvanic corrosion in subsea control systems is not common.
		Page 44 use of 58mm diam hole to represent 20 -80 mm range is not conservative under all assumptions.	This is a correct observation. The 58mm was selected as being a representative size for the 'hole' (which in terms of the EGIG database comprises hole sizes in the range 20mm to the pipe diameter). DNV's approach to QRA's is to define a hole size which is representative rather than conservative, and this can be done in a number of ways (but primarily using a hole size that is representative of a frequency range or a hole size which is representative of a consequence range). The approach in this QRA is the same as the approach in the 2009 QRA. Use of a more conservative hole size in the analysis would not affect the risk predictions at the nearest dwelling. It would be possible to indicate the sensitivity of the assumption (e.g. for a larger hole size) if required.
14		Q4.7 s4.4.1.1 where are temperature sensors located?	The temperature sensors are located at the wells, at the LVI and, at the point where the design temperature of the pipeline changes from -20 C to -10 C, i.e. 1150m downstream of the LVI.
15	Construction	Stone Road Construction Method: Does the detailed specification refer to choice of backfill to ensure no damage to pipeline or coating	Yes
16	Tunnel Construction	The drawings and text indicate that launch and reception shafts will be formed using sheet piled cofferdams. The drawings indicate that the piles extend into rock. No explanation is given as to how the piles will be installed in the rock and what the risks to the structures are if the piles cannot be taken to their design depth.	HOLD
17	Pipeline Safety Management	Q1 7.1.2 Building Proximity Distance is not normally a distance from dwellings but is the distance within which no building activity is allowed to protect the pipeline. However in the case of thick walled pipelines with a low design factor and where the risk can be shown to be below 1x10-6 per year, the separation from occupied dwellings may be reduced to the BPD – see PD 8010. See also App Q6.2 p1 3rd & 4th bullets.	Our understanding is that for the design stage, which is stage we are at, the purpose of the Code based Building Proximity Distance (BPD) is to define the distance from existing normally occupied dwellings. It is when the pipeline is in operation that the BPD can be used to define the distance within which no building activity is permitted (refer also to Land Use Planning clarifications provided below). For most pipelines, including the Corrib onshore pipeline, the 1 x 10-6 distance is considerably less than the Code based BPD.
18	Pipeline Safety Management	Q1 7.3 There are three risk levels quoted	Our remit in carrying out the QRA was the content of the letters from the Board which made no

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		by the UK HSE, these differ from the risk levels used in Land Use Planning advice by the HSA, who use 1x10-7 for the outer zone but expressed as risk of fatality not dangerous dose.	reference to HSA criteria or, in fact, mentioned the term '' Land Use Planning'. As stated in the QRA document: "An Bord Pleanála's letter of 29th November 2009, Page 3, item (j) requests: (j) Provide details separately of the inner zone, middle zone and outer zone contour lines for the pipeline. These shall represent the distance from the pipeline at which risk levels of 1x10-5, 1x10-6 and 0.3x10-6 per kilometre of pipeline per year exist. Although not specified by An Bord Pleanála, because the UK HSE use these numerical values and they do so in terms of the risk of receiving a dangerous dose or more per year, the same UK HSE metrics have been used in this QRA." We chose not to refer to (Irish) HSA criteria within the QRA since a) nowhere in their letters have ABP specifically referred to HSA criteria, they mention only UK HSE criteria and, b) the 0.3x10-6 outer boundary of the outer zone specified by the Board is the UK numerical value. We also felt that Land Use Planning criteria was a subject for planning authorities to consider; as the pipeline Operator SEPIL sees their role in this respect as one of providing information to enable Planning Authorities to make decisions.
19	LVI	Q2 2.1.3 does not make it clear that the mainline isolation valve is to be a special type that effectively provides the"Double Block and Bleed" level of protection.	Appendix Q2 is an overall summary of the technical aspects presented in the various Appendices comprising Appendix Q. The detail of the type of valves incorporated in the LVI is included in Appendix Q4.3 Section 5.1. The 20" mainline isolation valve and the 16" and 4" isolation valves are all double expanding gate valve types. It is agreed that these valves effectively provide a level of isolation that is equivalent to a double block and bleed arrangement. However, for clarity we have not used the term double block and bleed as it implies use of two valves with an independent bleed valve whereas the DEGV is a single valve.
20	Pipeline Integrity Management	Q2 9 Legislation does not give any assurance of integrity but can specify that the assurance process can take place. The operator must accep[t responsibility for the calculations, quality of manufacture etc.	Noted
21	Pipeline Integrity Management	Q4.5 Table 2.2 shows 6 layers of protection but they are not all independent.	Noted
22	Pipeline Integrity Management	Q4.5 Hydrate plug removal strategy, is it necessary to depressurise upstream of a plug, if so can SEPIL explain how?	No, it is not always necessary to depressurise from both sides. In the unlikely event of a hydrate plug forming, and in the further unlikely scenario of the plug forming close to the LVI or the terminal (the hydrates would have to travel 80km, and then form a hydrate plug at either of these locations), then depressurisation is required at both sides of the plug. The upstream end of the plug will be depressurised via a rig which would connect to the well tree with the usual workover equipment. (Note: work is currently being performed to determine if it's possible to depressurise via the manifold using a vessel and a flexible hose but this work is still ongoing).

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23	Testing Shutdown Valves	Q4.5 s 4.2.5 Testing Regime a more complete description / procedure will be needed and a demonstration of how the system is returned to safe operation condiution after testing (e.g. assurance of closure of main line isolation valve)	
24	Reliability	Q4.6 critical to reliability of pressure control. Can SEPIL state who the independent verification authority was and the qualification of the personnel involved? Summary does not introduce terminology of IEC 61508 / 61511 but is in effect stating that systems are better than SIL3	
25	Consequence Distance	Q1 P28 of 852: Building burn distance now given as 180m whereas according to ABP letter 29/1/10 it is 216m	Building Burn Distance is 180m for worst-case scenario. The 216m is the calculated “appropriate hazard distance” as required by the Board in their letters of November 2009 and January 2010. 216m is based on the governing factor for “appropriate hazard distance” being the closest a person may be to such an event without receiving a dose of thermal flux in excess of 31.5 kW/m2.
26	Potential Damage to Pipe	Q4.10 covers denting and gouging – smaller events could damage coating – at what point is repair initiated? The analysis in this section is assumed to refer to impacts on the steel pipe without any protective coating.	The denting and gouging analysis is intended to address the risk of pipeline failure leading to loss of containment; it is not intended to address the risk of coating damage. Although not stated, the analysis was made on the basis that the polypropylene external corrosion protection coating would not provide any mechanical protection to the pipeline against denting and gouging, which indeed it will not. The approach to repair of coating damage during the operational phase will be to repair damage. Note that any damaged areas will be protected by the cathodic protection until a repair can be effected. In the unlikely event of 3rd party related damage being undetected then our pipeline integrity management activities such as inspection and cathodic protection system monitoring would identify any anomalies.
27	Case for Safety	Q6.2 p4 3.2 point 5 The routing should consider the sensitivity of developments in the vicinity of the route.	We have been informed that there are no planning applications for new building development within the vicinity of the Corrib onshore pipeline currently lodged with Mayo County Council. Any future applications would be dealt with by Mayo County Council and take into account any Land Use Planning restrictions that they, as the planning authority, would establish. SEPIL do not consider themselves to be in a position to predict any sensitivities in this respect as Land Use Planning is the remit of the appropriate authority, however SEPIL would of course be willing to liase with the planning authority in the future.
28	Case for Safety	Q6.3 Description of Safety Case – SMS should include processes for MoC (People & Process as well as Plant),	The Safety Management System presented in Q6.3 is not intended as a fully detailed description of the operational phase Safety Management System, but rather a simple introduction to what an SMS is and its relation to the bowtie analysis. A fully detailed description of the SMS will be

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		Control of Work etc – Confirm Shell standards applied for this?	submitted as part of the Safety Case in accordance with the requirements of the PEES Act and will include reference to Management of Change, Permit to Work and other workplace safety controls. SEPIL confirms that Management of Change, Permit to Work and other essential safety control processes will be as per Shell Group standards as well as including any specific Irish regulatory requirements.
29	QRA Q6.4	P13 risk of construction and extended period increases risk to workforce	This observation is correct in that rerouting in a tunnel (where environmental impact is a driver) leads to additional construction phase exposure to risk (higher level of activity, longer duration) leading to a combination of a higher potential for accidents at the workplace and a higher statistical likelihood of road accidents that may affect workers and public. Our QRA only looks at residual risk to the public during the operational phase as per PD 8010-3:2009. However, we have acknowledged in our QRA that: "……, it cannot be claimed that the reduction in risk is a step towards achievement of ALARP as the costs associated with the re-routing of the tunnel and the safety risks associated with the extended construction period and the more hazardous nature of tunnel construction will outweigh the benefit of the reduction in risk associated with the operation of the pipeline." SEPIL has not carried out a quantitative ALARP assessment based on a comparison of construction and operational phase potential losses of life for the 2009 and 2010 design proposals (primarily because this would involve putting a value on the life of members of the public). However, such an assessment would be somewhat academic as the additional cost and project effort associated with the 2010 design proposal is significant and the construction safety risk has increased to an extent that may be seen as disproportional to the decrease in operational phase risks to the public.
		P14 UK HSE define 1x10-3 as limit of tolerability for workforce and 1x10-4 for members of the public. Some authorities (e.g. in Australia define 1x10-5 as a limit at the site boundary fort a fixed plant.	The QRA has been prepared to align with the approach to QRA contained in PD 8010-3:2009 Part 3. It has provided predictions against criteria specified by ABP. These are exclusively addressing risks to the public. Risks to workers during the operational phase have not been calculated as part of this submission. The Australian criteria for the limiting risk level at the site boundary for a fixed plant mentioned by DCENR is the type of risk tolerance criteria that could be reviewed as part of an integrated Bellanaboy Bridge Gas Terminal and incoming pipeline QRA currently being prepared separate to this submission, although care would need to be taken as the stated criteria are likely to be associated with a defined methodology which may be different from the methodology used for the terminal QRA. The 1x10-3 and 1x10-4 per year levels being referred to by DCENR presumably relate to the UK HSE document 'Reducing Risks, Protecting People' which states: (p. 46) "Nevertheless, in our document on the tolerability of risks in nuclear power stations, we suggested that an individual risk of death of one in a thousand per annum should on its own represent the dividing line between what could be just tolerable for any substantial category of workers for any large part of a working life, and what is unacceptable for any but fairly exceptional groups. For members of the public who have a risk imposed on them 'in the wider interest of society' this limit is judged to be an order of magnitude lower – at 1 in 10

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			000 per annum." A key factor in comparing risk tolerance criteria for workers and members of the public is that workers receive benefit for working with the risk; the public invariably do not. The risk of fatality per year for workers is calculated taking into account the duration that an individual worker is actually at work and on the basis that a) the actual individual may be doing inherently hazardous tasks, and b) that the locations where he or she does these tasks are, in themselves, hazardous. The fatal accident rate applicable to their inherently hazardous tasks (covering accidents such as falling, hit by machinery, electrocution) is thus applied to the length of time in a typical year these tasks are undertaken. The contribution to a workers risk due to working in an environment that is higher risk, such as a gas plant, is determined by estimating their cumulative exposure to this risk as they move around the plant over their working year; this is where 'individual risk contours' derived from QRA are used as these are the contours associated with a 'major accident' for a hypothetical individual. Risks to the public, calculated within the Corrib Pipeline QRA as Individual Risk, only indicate the risk to a hypothetical individual as a result of a 'major accident'. This is the part of an individual's risk that they, as a member of the public, can personally have little or no influence over. The contribution of pipeline major accident risk to the overall risk to workers during the operational phase would be extremely low as the Individual Risks predicted at or near the pipeline are very low and the presence of any worker near the pipeline would be infrequent. Similarly for the LVI.
		P15 Quoting from ABP requirement should point this is UK HSE not HSA which is 1x10-7	Refer previous response to item 18 [Q1 7.3 There are three risk levels quoted by the UK HSE, these differ from the risk levels used in Land Use Planning advice by the HSA, who use 1x10-7 for the outer zone but expressed as risk of fatality not dangerous dose.] wherein we have described why we chose to make no reference to HSA criteria in this respect.
		P31 has the effect of hydrate partial blockage giving cooling been considered?	
		P32 6.3.2.5 note that 504barg is nearly 1.5 times well head shut in pressure and	It is confirmed that 504barg is approximately 1.5 times well head shut in pressure (closed in tubing head pressure).
		6.3.2.6 peat fire discussion different to Risktec?	This is a question of different styles as, whilst the discussion is different, the principles being discussed and conclusions reached do not differ.
		6.3.2.8 pipeline expansion in grout – any issues?	
		6.3.2.10 Umbilical and water discharge pipeline in tunnel as well as gas line – which has plastic wrap – different sizes but would unskilled operative appreciate	This refers to hot-tapping of the wrong pipeline, e.g. hot tapping into a gas pipeline that was thought to be a lower pressure oil pipeline. The argument for excluding this as a credible failure mode is that the need to hot tap will never arise. The possibility of hot-tapping into the water line thinking it might be the gas line would thus not arise (and anyway not be a loss of containment

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		differences?	of gas risk). Hot-tapping, indeed any safety critical operation or activity, would simply not be carried out by an 'unskilled operative' as there will be competency management systems in place coupled with task/activity risk management systems.
		6.3.2.10 How have all liquid slugs been ruled out in all circumstances? (Commissioning fluids, methanol, and future conditions?)	Slugging issues are not predicted to occur for the Corrib production facilities. The hydraulic behaviour of the Corrib pipeline, the liquid drainage capacity and liquid buffer volume of the receiving facilities resulted in: 1. An operating envelope for normal operations (steady-state operations). The pipeline flow within the operating envelope shows no slugging issues as observed by steady-state and dynamic pipeline simulations. For operations that may lead to a liquid surges within the operating envelope(a production ramp-up) procedures are in place (as determined by dynamic pipeline simulations) to limit the liquid outflow from the pipeline within the capacity of the receiving facilities. Operations outside the operating envelope (start-up) are guided by procedures (as determined by dynamic pipeline simulations) to limit the liquid surges within the capacity of the receiving facilities.
		6.3.2.14 Slabbing at road crossings (and water courses)	Noted
30	EIA Vol 2 Drawings	P17 AG14 is 159m from the pipeline is this owned by SEPIL? App Q Introduction says nearest housing 234m Also Q6.2 p1 nearest house 234m.	Yes, AG14 is a house owned by SEPIL and unoccupied. See Fig. 5.1 in Appendix Q6.5(i)