Accufacts Inc.

"Clear Knowledge in the Over Information Age"

The Proposed Corrib Onshore System

An Independent Analysis

Prepared for the Centre for Public Inquiry

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This document is based on an evaluation of information readily available in the public domain

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I. Executive Summary

Accufacts Inc. was commissioned by the Centre for Public Inquiry to perform an independent review of the onshore proposals for the Corrib pipeline project, specifically the onshore production pipeline and the gas processing plant at its terminus. All analyses in this report were developed from information supplied in the many referenced public documents concerning this very unusual, highly unique and controversial, "first of its kind" project in Ireland. This report raises serious concerns about the completeness of previous key leveraging statements, misrepresentations, mischaracterisations, prior risk analyses, and conclusions regarding safety decisions driving current siting choices for the proposed Corrib onshore facilities. To assist readers first skimming this report, coloured text boxes capturing many of the critical issues are provided throughout the paper.

It is Accufacts' opinion that the current direction for this project's proposed siting reflects a lack of specialised experience, or a serious breakdown in management and/or decision processes. We find past Quantitative Risk Analysis (QRA) for the onshore pipeline not in compliance with even the minimum basic risk analysis requirements defined in the now outdated and cited design standard for this pipeline, BS 8010.[1] Given the uniqueness of this project and the incredibly high potential pipeline pressures in close proximity to civilians, easily exceeding the limits of most normal pipelines, Accufacts believes a QRA is not the appropriate mechanism, or satisfactory approach, for prudent project design and siting decisions for this unusual experiment.

For background reference, a brief explanation of why the Corrib pipeline is anything but normal is discussed. Key information is then presented that quickly dispels the illusion or myth that the 508 mm (20 inch) diameter 27.1 mm (1.07 inch) thick-wall Corrib pipe is somehow invincible to specific threats associated with high-pressure production pipelines that can cause leaks or ruptures. As a reality reference check, the well-documented "moderate" release gas transmission pipeline rupture in Carlsbad, New Mexico (August 19, 2000) is presented in the section on pipeline rupture consequences. The Carlsbad pipeline rupture graphically demonstrates the consequence potential of even a lower pressure pipeline, which failed at approximately 46.6 Bar (675 psig, or 58% Specified Minimum Yield Strength). The Carlsbad pipeline failed as a result of aggressive selective internal corrosion and other operating factors, and the age of the pipe played no role in its failure. Ironically, the pipeline operator complied with corrosion monitoring programs defined by minimum U.S. federal pipeline regulations of the time. Attempts to characterise that the Corrib pipeline cannot rupture from internal corrosion need to be seriously challenged and investigated. The corrosion pipe failure information presented in this report utilises well known and accepted pipeline industry tools.

Given the much greater thermal impact zones associated with a Corrib onshore pipeline rupture, our analysis indicates that pipeline routing should be at least 200 metres from dwellings and 400 metres from unsheltered individuals to avoid massive casualties and/or multiple fatalities. These recommended distances indicate that the current proposed onshore pipeline route is unacceptable. The large safety zones necessitated by an onshore Corrib pipeline rupture reflect the exotically high potential operating pressures and subsequent fatal radiation thermal fluxes associated with a rupture. To date, the pipeline operator has failed to adequately or satisfactorily demonstrate that the onshore pipeline will not experience pressures within the boundary conditions of 150 to 345 Bar (2175 to 5000 psi) studied in this report.

This report also focuses on matters related to the onshore Gas Processing Plant. The impact that plant siting has on factors affecting the onshore pipeline are clarified and explored. Pros and cons of gas processing plant site selection options are then presented, specifically focusing on major advantages/disadvantages of deep water off shore, shallow water off shore, and on shore gas plant processing options. We find that many of the previous statements driving the present

[1] BS 8010, "Code of Practice for Pipelines – part 2. Pipelines on Land: Design, Construction and Installation, Section 2.8 Steel for Oil and Gas," 1992, has now gone out of date and is obsolete.

onshore gas plant site and onshore pipeline route to be overstating the difficulty and costs of offshore alternatives, while apparently understating the risks of the onshore proposal. This is a most troublesome example of what is called "Space Shuttle Syndrome," the propensity to rush launch at all costs while downplaying or ignoring very real risks. Readers are welcome to form their own opinion as to whether this phenomenon is occurring on the Corrib project after studying this report.

Particular attention is paid to the issues of cold venting and excess flaring in gas processing plant design. More progressive governments have chosen to discourage cold venting and excess flaring practices for many prudent reasons and we would highly recommend avoiding either practice.

Additional observations regarding siting considerations raise further concerns about the present siting process and use of QRAs. Various warning signs are also identified that signal inappropriate application of QRA, even though risk analysis may be allowed in pipeline regulations. Quite simply, QRA should never be utilised to supplant experience, sound engineering judgment, or prudent management practices. Lastly, further discussion is presented on several other factors related to the impact on the decision making process when financial rewards are so great and liability impacts so small so as to rush or distort risk analysis resulting in very poor outcomes that are all too predictable. The impression of huge potential reward with little or no liability for poor decisions can cause even the brightest of organisations to make very unwise decisions.

It is not up to the author to decide which option bests serves the community. It is hoped, however, that this paper injects appropriate factual information into a process that, based on less than complete information supplied to date, appears to be rapidly losing credibility, and the confidence of the citizens.

II. This Isn't a "Normal" Onshore Natural Gas Pipeline

Crucial to any discussion concerning the proposed Corrib project onshore facilities is a fundamental understanding of the various differences in the types of gas pipelines. Within the industry there are essentially three general categories of gas pipelines: 1) production, 2) transmission, and 3) distribution. The role each of these categories plays in ultimately delivering gas to the consumer is illustrated in Figure 1.

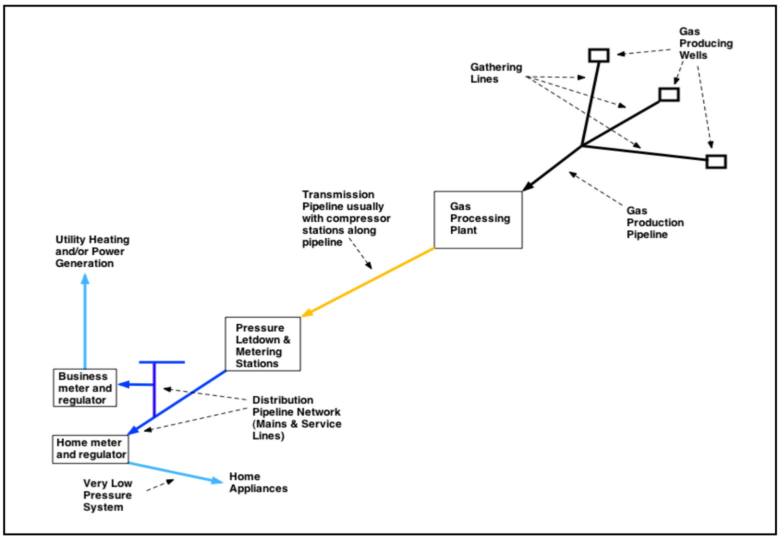

FIGURE 1. GAS PIPELINE SUPPLY SYSTEM - SIMPLIFIED FLOW SCHEME

Production Pipelines

Production pipelines, more specifically gas production pipelines, also sometimes called gathering or flow lines, are those pipelines connecting the gas producing field wells to gas processing plants that process or treat the gas to meet transmission pipeline quality specifications. Transmission pipeline gas is more restrictive in quality requirements for reasons that will be explained shortly. In rare cases, gas production pipelines connect directly to transmission pipelines as the gas produced from some wells either meets or does not significantly degrade gas moving in the transmission system. In most gas processing plants, liquid is removed and the gas dried to substantially reduce corrosion potential. Additional treatment of the gas may be required to remove certain higher risk contaminants, such as H_2S if present in sufficient quantities, to prevent problems on transmission pipelines.

Because most production gas can contain the multiple phases of solid, liquid (water and hydrocarbons), and gas, production pipelines must be able to withstand additional "reactive forces," both internal loading stresses (i.e., slugging[2]) and chemical, not encountered on transmission or distribution pipelines. As production pipelines are usually remotely located, in many countries the regulatory requirements for production pipelines can, ironically, be less stringent than those for transmission or distribution pipelines. Production pipelines vary in size and pressure based on the specific quality and operating conditions of the gas field reservoir that can fluctuate or change considerably with time in any one producing field as the gas field is depleted. Substantial variations can also occur in gas quality if other new gas fields are added into the main production pipeline, should further fields be discovered or developed. The composition of the gas in the future is thus basically unknown. The corrosiveness and toxicity of the gas is dependent on the specific gas composition and there are usually very limited, if any, regulatory restrictions on many contaminants that can seriously chemically attack, impact the pipeline, or create other problems on their release. Depending on their pressures, production pipelines can fail as either leaks or ruptures.

Transmission Pipelines

Gas transmission pipelines are those pipelines that move or transport conditioned or treated natural gas, meeting various quality specifications, from the gas fields or processing plants to the lower pressure distribution systems. Transmission pipelines tend to be larger in size, moderate to moderately high in pressure, and traverse long distances as their primary purpose is to move large volumes of non-reactive gas as economically as possible. Usually such main arterial pipelines consist of one large diameter pipeline, though multiple main pipelines can be run in parallel (called looping) to increase capacity. Along the transmission pipelines are compressor stations to re-pressure the gas as it moves down the system. Transmission pipelines operate under published quality specifications requiring that the gas carried be non-reactive and non-corrosive to the pipeline.[3] Transmission pipelines are operated as a single-phase, gas, mainly composed of methane and other minor components (i.e., ethane, propane) and inert gases (e.g., nitrogen, carbon dioxide). Odorant with a very distinctive smell is usually added to the gas in transmission pipelines to aid in the identification of possible gas leaks from these systems. Not all countries require odorant on all transmission pipelines, however.

Distribution Pipelines

Distribution pipelines consist of that network of lower pressure gas pipelines usually taking gas from transmission pipelines, at various points down the system, through pressure reducing/metering stations that drop the gas pressure from the transmission system pressure to the much lower pressure distribution system. Distribution pipeline systems consist of a grid of

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[2] Slugging occurs when liquid periodically drops out inside the pipeline and then is picked back up by the changing flow of the gas stream, causing impulse forces on the pipeline that can be quite large.

[3] This does not mean that internal corrosion (i.e., selective corrosion attack) cannot take place, but the potential for both general and selective internal corrosion on transmission systems are usually many orders of magnitude lower than that for production pipelines.

larger diameter pipes called mains, and smaller diameter service lines that run from the mains to connect directly to homes or businesses. Because distribution systems are in close proximity to large concentrations of people, they are designed and operated at much lower pressures (usually much lower than 14 Bar, or 200 psig) than production or transmission systems. Newer modern distribution pipelines are made of steel or plastic while older networks may be cast, or wrought iron, or other metals such as copper. Because of their much lower pressures, distribution pipelines fail as leaks rather than ruptures (see Section IV Pipeline Routing Issues, discussing the difference between leaks and ruptures). Odorant is added to the gas in distribution pipelines to aid in the identification of possible gas leaks, both in the distribution system piping and in the much lower pressure home piping network (downstream of the home pressure regulator/meter) which is not considered part of the distribution pipeline system.

Gas Processing/Treatment Plant aka Terminal

Typically, along a production pipeline is a processing plant that contains equipment to process or treat gas gathered directly from field producing wells, permitting the natural gas to meet quality specifications for transmission pipelines. Depending on its capacity, a processing facility may accept more than one production pipeline. Processing facilities are usually located on or near gas production fields particularly if the gas is especially reactive. For the Corrib proposed project, the gas processing plant has, for some reason, been called a "Terminal." In this paper we will call this specific facility what it really is: a "Gas Processing Plant." A more detailed discussion of the Gas Processing Plant and its influence on pipeline routing choices is provided in Section VIII – Why the Gas Must be Treated.

The Model One Syndrome

Because of the deep water (350 metres) and severe location of the Corrib producing field (approximately 80 kilometres into the Atlantic Ocean off the west coast of Ireland), the operators have proposed to site the gas field wells on the ocean floor (subsea) eliminating the

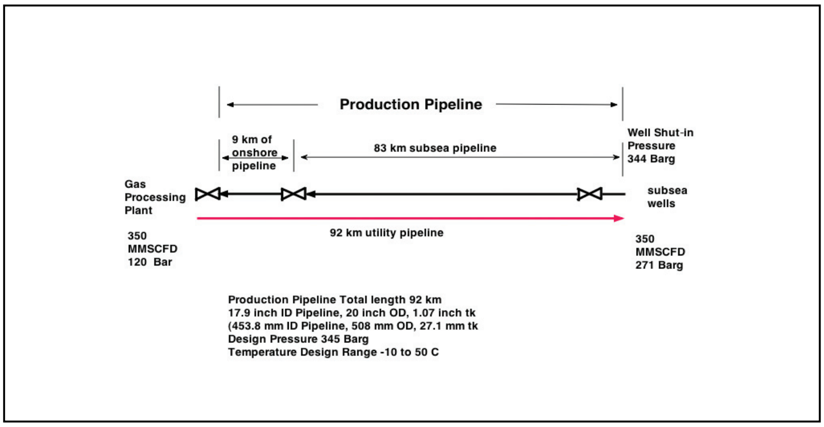


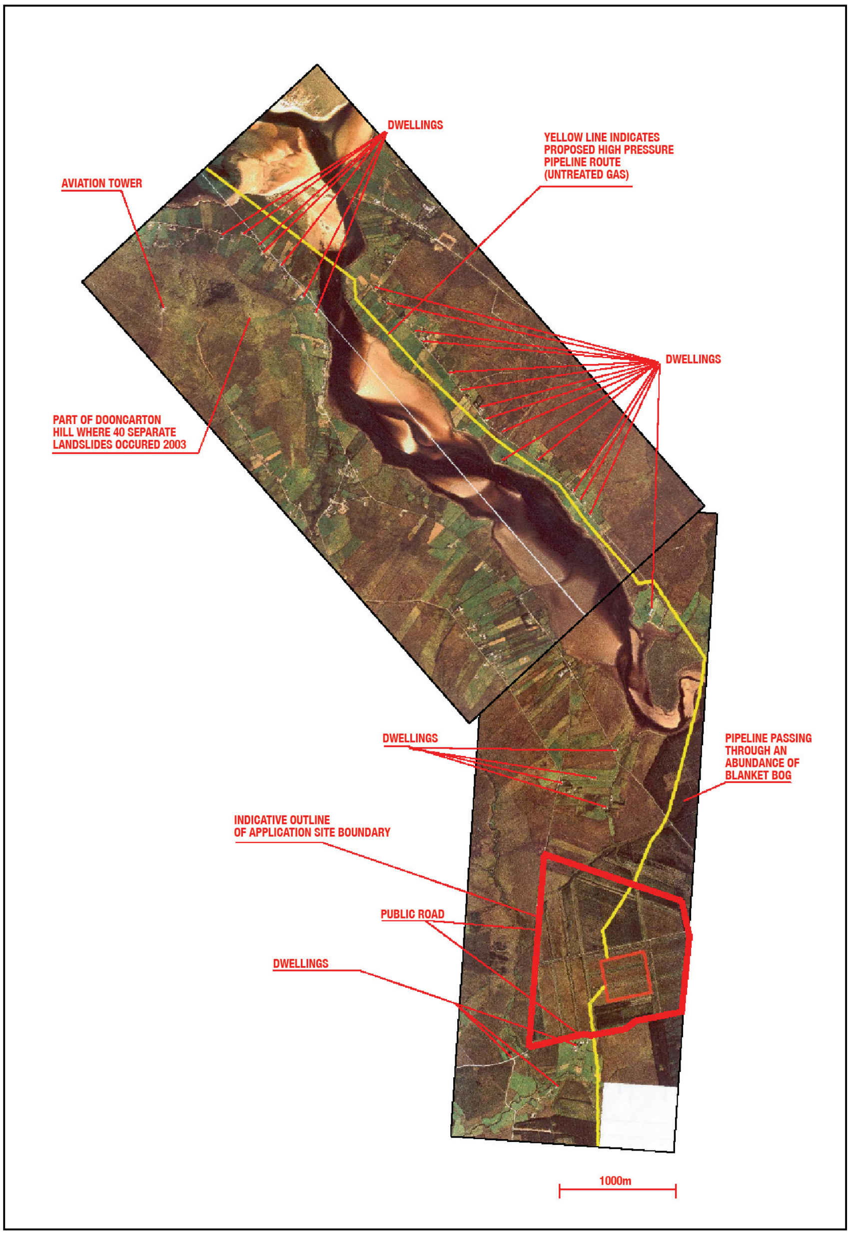
FIGURE 2. CORRIB PIPELINE DESIGN BASIS

need (and significant expenses) of a deep-water offshore platform. Figure 2 briefly summarises the proposed Corrib pipeline system design basis.

The current Corrib design proposal gathers the production gas from various subsea producing wells into a 92 kilometre production pipeline, consisting of approximately 83 kilometres of 508mm (20 inch OD) offshore underwater pipeline and approximately 9 kilometres of similar onshore pipeline to the onshore Gas Processing Plant. In addition, a utility pipeline runs parallel to the gas production pipeline. The utility pipeline will contain a package of smaller separate pipes containing: 1) a methanol/corrosion inhibitor cocktail for injecting into the production pipeline near or at the wellheads, 2) hydraulic fluid to drive well head valve operation, and 3) communication fibre optics for gas field data relay.

What makes this pipeline proposal highly unique is the long production pipeline, very high, even exotic, pressures, and onshore siting in close proximity to population (e.g., the citizens of Rossport; see Figure 3 Onshore Pipeline Route Through Rossport).

FIGURE 3. ONSHORE PIPELINE ROUTE THROUGH ROSSPORT



It would be fair to assume that this is the first design of its kind or the "model one" for Ireland. One would expect that given the uniqueness of this project, critical information related to specific design, operational, and routing issues would be forthcoming. Unfortunately, inconsistent and conflicting answers (such as expected onshore maximum operating pressure) have only served to increase local concerns and apprehensions about this project. Further information included in this report should serve to raise more questions from the public about past information presented for this proposed project.

Given a detailed review of the many documents describing the pressures for the pipeline system, we would surmise that the onshore segment has a very high probability, or a certainty, to reach or exceed 150 Bar, and a much lesser probability, though not zero, to attain 345 Bar pressures. Since the pipeline operator is not restricted to physically limiting onshore pipeline pressures to lower than 150 Bar, nor has any adequate design to avoid such overpressure been released, prudence would indicate a high likelihood of future onshore pipeline operating pressures reaching the levels between 150 to 345 Bar, much more than suggested by past public documents on this matter. As a result, this paper will benchmark further discussion on the 150 and 345 Bar operating pressures as boundary conditions to illustrate important concepts that should be considered for this pipeline whatever the future holds for pressures for possible offshore gas field development.

III. Onshore Pipeline Design Key Issues

There are several key issues that play a critical role in informed decision making related to onshore pipeline design, operation, and siting. It is very important for both decision makers and the public to understand these fundamental issues and how they influence the safety of a pipeline. Many pipeline parameters, such as CO_2 composition, operating pressure or temperature, are not truly restricted, so a wide range in these variables is possible, even allowed. Once the pipeline has been installed, many critical assumptions as demonstrated in further detail in this report, can change and seriously increase the risk of failure for the onshore systems. Failure to incorporate these many potential operating changes, which are much more varied for production pipelines than their cousin transmission pipelines, can be regarded as reckless as these changes can accelerate pipeline failure. As will be soon demonstrated, any pipeline break at these pressures can be very unforgiving.

> The maximum pressure this pipeline is permitted to experience has not been clearly demonstrated.

Should any present or future operating changes (e.g., pressure) place the pipeline into a failure scenario, no pipeline regulations or standards would necessarily have been violated. For example, flow rate, gas composition, and temperature can change in a manner that can seriously affect internal corrosion (i.e., additional fields connected to the production pipeline). All too often QRAs fail to properly incorporate future changes into the base case design premise resulting in an incomplete or improper risk finding of no significance. Any risk analysis should be clearly able to define its basis and identify critical variables that are leveraging to a risk call. Many of these important factors usually aren't as significant a problem for transmission pipelines because of their more restrictive gas quality specification limitations.

Pressure and SMYS (Specified Minimum Yield Strength)

While the impact that pressure plays on pipelines is somewhat obvious to most people, a second related and important factor is not commonly understood, even by many pipeline operators: SMYS (or Specified Minimum Yield Strength).[4] In order to perform a proper pressure analysis on modern pipeline steel, the operating pressure and SMYS are needed (along with wall thickness and approximate pipe metal toughness) to define the containment capabilities of any pipe during its operation. Despite possible claims to the contrary, these basic factors apply whether the pipe is thin-walled or thick-walled, at least the thick-wall pipe proposed for this pipeline. All pipelines have anomalies. Flaws and anomalies exist in pipelines, even pipelines that have undergone strenuous hydrotesting.[5] Hydrotesting removes or filters out larger anomalies but leaves smaller anomalies (the higher the test pressure, the smaller the remaining anomaly). Most anomalies are not an issue of concern, but some, such as those that are corrosion influenced, can become problematic for various reasons over the life of a pipeline. Pressure in relation to SMYS plays a critical role in characterising if and how a pipe will fail, either as a leak or a rupture. Leaks are releases where the through wall failure in a pipe remains essentially fixed or very close to its original size. Ruptures represent failure dynamics associated with high stress steel pipelines where the original through wall pipe failure goes unstable and rapidly (in microseconds) propagates down the pipeline, enlarging the initial failure as the pipe shrapnels (usually resulting in a full bore release or its equivalent).

[4] SMYS is a quality specification of the pipe, defined or usually specified at the time of its manufacture. The SMYS of the Corrib pipe is 70,000 psi (482 N/mm^2).

[5] An anomaly is any imperfection in pipe wall or weld. All pipelines contain anomalies and many anomalies are not of concern. The purpose of a hydrotest is to remove anomalies that can fail at the hydrotest pressure. The key is to maintain control of or avoid aggravating anomalies that remain after a hydrotest that could grow and then fail at pressures much lower than the hydrotest. Hydrotesting thus has limits in its application to control certain anomalies.

Depending on the four characteristics mentioned above, graphs can be developed for a pipeline that define anomalies that can be tolerated (i.e., usually won't fail), their method of failure (leak or rupture), and, in some cases, estimated time to failure for time dependent anomalies.[6] Not all anomalies are time dependent (e.g., some are stable and then become time dependent and vice versa), as their classification depends on the pipeline and its operating characteristics, which can also change over time.

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.

Such a series of graphs for corrosion have been developed and will be discussed in the following segment in this section describing, in detail, internal and external corrosion issues. Depending on the anomaly, thick-wall pipe can be even more susceptible to certain issues that can result in rupture or full bore releases than thin-walled pipe and vice versa. Risk analysis that portrays the myth of thick-walled pipe invincibility or superiority over thin-walled pipe usually misses the very real difficulties that can threaten the very integrity of onshore highly stressed thick-walled pipe. The choice of either thick-walled or thin-walled pipe depends on many factors specific to a particular pipeline operation and design, as well as its location.

Generally, and I emphasis this key word as there are some important exceptions, steel pipelines operating below 25 - 30% of SMYS will fail as leaks rather than ruptures. For example, requirements in BS 8010[7] establish that pipelines in most higher population density classification areas (i.e., Class 2 and Class 3, and high potential loading areas such as road crossings) incorporate a design factor (a maximum operating stress) for safety of 30% SMYS, and the preponderance (there are exceptions) of such failures in these lower design factor, low stress areas are leaks rather than ruptures.

When reviewing any pipeline system, it is important to evaluate the downstream and upstream facilities to assess their potential to place the interconnecting pipeline system under high pressures that can result in high stress levels and cause anomalies in the pipe to fail. Any downstream facility design that can close or block in the pipeline, or that overemphasizes reliance on electronic safeties to prevent overpressure events, needs to be carefully scrutinized as the potential for such electronics to fail when most needed can be very high and the consequences severe. In addition, upstream systems that can place any pipeline into high stress scenarios from elevated pressures must also be carefully reviewed. It is especially important that designers not rely on flow dynamics (i.e., pressure drop associated with fluid flow and pipe resistance) to prevent excessive pressure. The potential for a pipeline to reach various pressures must be evaluated from the entire system point of view including the production wells, the offshore pipeline, onshore pipeline, and gas plant processing facility. To date we find descriptions of this system on this critically important pressure matter to be seriously incomplete. This is an acute deficiency given the exotic potential pressures liable to occur on the pipeline and the extreme consequences associated with a failure in close proximity to people.

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

[6] Estimated time to failure usually incorporates very large safety margins because of major uncertainties associated with critical measurements of key variables.
[7] Ibid., BS 8010.

Gas Composition

Gas composition factors are especially important on production gas pipelines as composition can seriously impact the operability of a pipeline, especially the pipeline's integrity. Critical composition issues include:

Wet Gas Versus Dry Gas

It is extremely unusual for gas produced from a gas field to be in a dry state. The presence of water is almost always assured. Gas containing water is classified as "wet gas" and brings with it certain risks to a pipeline operation. Water is required for internal corrosion on pipelines to occur. In addition, water or other liquid slugs can seriously change loading stresses on a pipeline. As mentioned earlier, slug catchers (large catch vessels to trap liquids) are placed along production gas pipelines. The settlement of water in low points in production pipelines can also serve to concentrate and accelerate selective internal corrosion attacks that can occur much faster than general corrosion. As a result, over emphasis on a general corrosion allowance to protect a pipeline can be ineffective at preventing pipeline failure from selective rapid corrosion attack, especially on production pipelines most at risk from such occurrences.

Gas Components Other Than Methane

Components other than methane in produced gas can have serious impacts on production pipelines. Carbon dioxide and certain sulphur compounds (e.g., COS, H_2S) in the presence of water can lead to acid attack and internal corrosion. Heavier components, such as propane butane and heavier (C5+) will also tend to form liquids and periodically drop out along the pipeline adding to loading stresses associated with liquid slugging. As mentioned previously, it is important to realise that the stated design components and gas composition may not necessarily be the same as the field ages, or if a new gas field is brought on line and tied into the same production pipeline. These changes can affect the internal corrosion rate as well as the internal corrosion potential on the pipe.

Temperature

Temperature can play a role in basically two areas. Higher temperatures can rapidly increase the corrosion rate, especially for selective corrosion attack, decreasing time to failure estimates from corrosion. The effect of temperature on rate can be better understood by reviewing Figure 4 in the internal corrosion discussion in the next section. Lower temperatures, depending on gas composition, can increase the probability of hydrate (a solid) formation that can lead to plugging of the pipeline and/or operating equipment while reducing the corrosion rate. Methanol injection should inhibit the formation of hydrates that might pose a problem on this system. The design temperature range on this pipeline has been stated as -10 to +50 °C. The onshore pipeline should not see the upper temperature range realised at the wellhead, but even at the lower temperatures expected to be encountered onshore, internal corrosion can be a serious risk. Remarkably, there is no mention in any of the public documents of monitoring the critically important temperature as it enters the onshore pipeline segment.

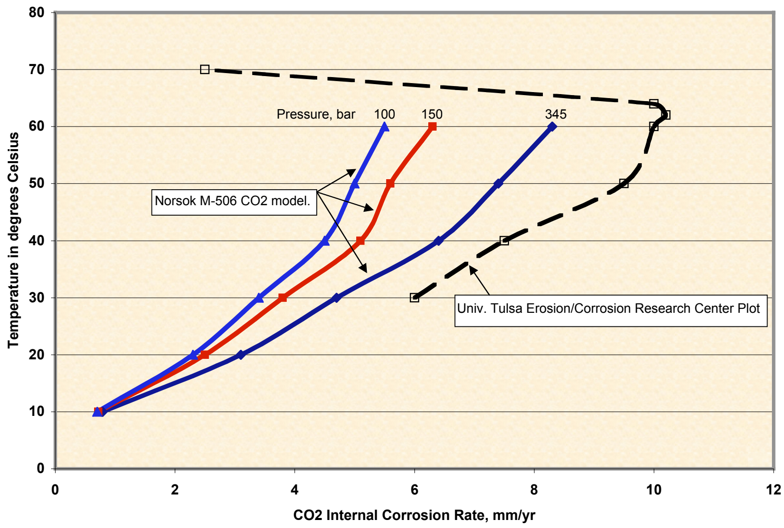
Corrosion Issues

Pipeline design considerations should properly address both internal and external corrosion potentials. We have previously indicated the pitfalls of relying on a corrosion allowance especially for selective corrosion attack. Internal corrosion prevention has advanced over the years, but over reliance on corrosion inhibitor programs can prove a serious mistake. External corrosion design has also advanced considerably in the past forty years. Despite all the advances in internal and external corrosion technology, there is still no steel pipeline that is corrosion free.

Internal Corrosion

To underscore the sensitivity of CO_2 composition and temperature on internal corrosion, Figure 4 plots CO_2 internal corrosion growth rates (in mm/yr) as a function of temperature for steel pipe using two models as indicated. One version generates a series of three curves for various pressures using a Norsak M-608 model; and the other single comparison curve is developed using a model from the University of Tulsa Erosion/Corrosion Research Center. It should be noted that variations in gas composition and temperature can significantly change the corrosion rates plotted, but the curve shapes won't change significantly, just shift their positions left or right affecting the "call" for the mm/yr corrosion rate. None of these plots suggest a corrosion allowance of 1 mm over the life of the pipeline for the temperature, pressure, or composition ranges suggested for this pipeline. It would also be most unwise to expect corrosion inhibitor injections to be 100 percent effective in preventing corrosion on a production pipeline. This author is not attempting to cast aspersions on or support for any corrosion rate model, just strongly suggesting that the application of any modeling and reality can be very different. This is especially true if a model's application fails to adequately capture fast acting selective corrosion attack because of composition or operational changes.

FIGURE 4. INTERNAL CORROSION RATE ESTIMATES VS. TEMPERATURE



To underscore the importance of not being overly optimistic about underestimating internal corrosion rate for gas production pipelines, the graph in Figure 5 has been developed.

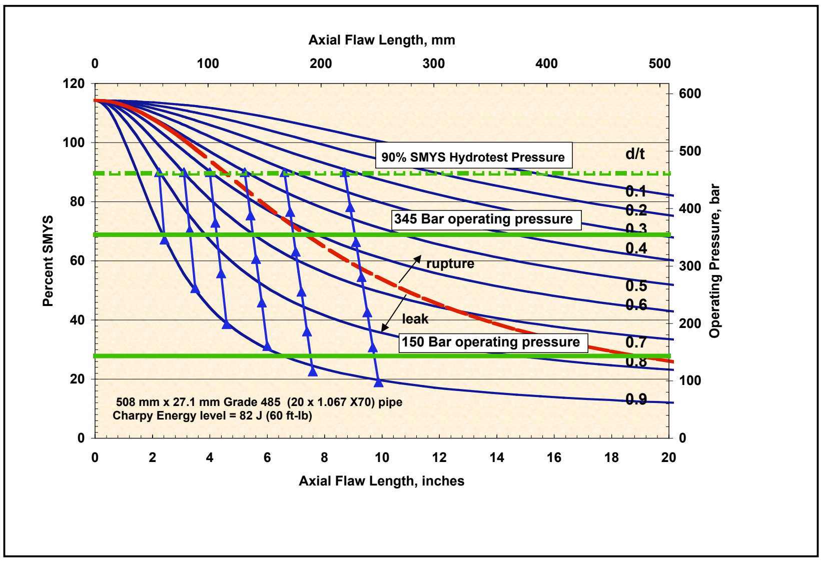


FIGURE 5.
PIPE FAILURE HOOP STRESS VS. CORROSION FLAW SIZE – CO2 INTERNAL CORROSION RATE OF 2.5 MM/YR (0.098 INCH/YR)

This graph, known as a pipeline corrosion flaw growth plot, was developed utilising a well established industry recognized pipe flaw failure program (PTFLAW) that predicts corrosion related failures on steel pipelines. This figure illustrates corrosion influence on anomaly flaw lengths and depths that a steel pipeline can tolerate at various stress levels. Figure 5 is for the Corrib pipeline, a 508 mm by 27.1 mm Grade 485 pipe. A fracture toughness that maximises the flaw tolerance (tougher pipe will not tolerate longer or deeper flaws) was chosen at a Charpy Energy of 82 J (60 ft-lb). If the pipe toughness is markedly lower, the flaw tolerance will slowly decrease resulting in failure at smaller flaw sizes than indicated in the figure. Figure 5 may appear a little busy so additional discussion is warranted for such an important graph. This corrosion tool will also be utilised in the next section discussing external corrosion.

On the vertical or Y-axis, the hoop stress is indicated as a percentage of SMYS (left axis) and operating pressure (right axis), versus the axial flaw length (the most critical flaw orientation) on the horizontal or X-axis. Overlaid across the chart are various downward sloping thin line curves representing flaw or anomaly depth as a ratio of flaw depth to pipe wall thickness, or d/t. For reference, three straight green horizontal lines across the chart represent pipe stress levels at the minimum hydrotest pressure of 90% SMYS (the dashed green line), an operating pressure limitation of 345 Bar, and 150 Bar, respectively (the solid green lines). Hoop stress and operating pressure are directly related. The small blue triangles represent the flaws after each year's assumed corrosion rate of 2.5 mm/yr that initially just survived the hydrotest (the first blue triangle in each series is time = 0 which is hydrotest time) at various d/ts. The specified corrosion rate of the flaws (both in depth and in length) in this case is assumed to be 2.5 mm/yr (based on the earlier Figure 4 Norsak curve for 150 Bar pressure and 20 °C). Lastly, the bold dashed red sloping curve line represents the transition point from leak to rupture. Corrosion flaws that develop to the right and above this red line will fail as ruptures and those that fall below and to the left will fail as leaks when the blue flaw growth indicators fall on or below the pressure ranges (150 to 345 Bar) indicated. This is a lot to work through so an example may help to gain a better understanding. Some important general observations about this graph will then be made.

Looking at the top right hand series of almost vertical blue triangles, the first uppermost triangle of this series indicates that at the hydrotest of 90%SMYS (dashed green line), a flaw that has a depth of 0.3 X 27.1 mm (d x t) = 8.13 mm and is almost 9 inches long could exist (doesn't mean there is one) and survive the hydrotest. Since each additional triangle represents a year's worth of corrosion growth at the stated corrosion rate of 2.5 mm/yr it would take 2 years for this particular flaw to grow to where a pressure spike of 345 Bar would cause failure and this failure would be a rupture as the growth flaw is to the right (upper part) of the leak/rupture transition curve. Following the triangle line for this same flaw series, another 3 triangles down or 3 additional years of corrosion could occur before a pressure spike of 150 Bar or slightly above would cause failure, and this failure would be as a leak. Another way to look at this, should this same initial flaw exist and if the operating pressure spikes above 150 Bar after approximately 5 years of corrosion, the pipe will fail. If the pressure goes much higher than 150 Bar, time to failure will be shorter than 5 years with the time and type of failure (leak or rupture) depending on how high the pressure spiked and the anomaly size at the time of failure.

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.

Because engineers often start to believe their models actually calculate exact time to failure, several additional points need to be made about Figure 5. Anomalies that survive a hydrotest will most likely be above rather than on the 90% SMYS (the dashed green line) suggesting a slightly longer time to failure from internal corrosion growth. Complicating this conclusion, however, is the proposed plan to allow the pipeline to sit in hydrotest water (probably inhibited with chemical) for approximately one year.[8] We do not advise this procedure as even inhibited hydrotest water can act as an internal corrosion activator, increasing corrosion and shortening time to failure at selective pipeline wall sites. Because of various uncertainties, variations in time to flaw growth failure are in all probability plus or minus several years. If fatalities can result from failure, one would be very unwise to operate by testing the operating pressures in the uncertainty time range suggested by the plots. Each blue linked triangle series is just for illustration purposes as the specific anomaly may not exist, though bear in mind that no pipeline is anomaly free. For example, we could have illustrated an additional, almost parallel, blue triangle series for d/t of 0.1 or 0.2 to this already busy chart that would have shown flaws that could grow to rupture. In reality there is an infinite series of almost parallel lines representing a wide range of anomalies that can survive a hydrotest (some of these are manufacturing related, others are not). Initial anomalies that are deep and short in length can grow to leak failures, while initial shallow and long anomalies can grow to rupture failure.

FIGURE 6. CORRIB PIPELINE IN OUTSIDE STORAGE

For those who may foolishly deny that such shallow long anomalies can't exist on a modern pipeline, Figure 6 is a photograph of the Corrib pipeline segments stored prior to installation. While not attempting to raise undue alarm, the shallow long rust sites on these pipe segments could be considered precursors to internal corrosion sites. For those who may continue to deny internal corrosion is a possibility, or the specific attack shown is just mill scale, how long has this pipe been stored in the Irish climate?

To add to the above points, remember that there is a plan to keep this pipeline sitting under hydrotest water for a year. In all fairness the internal corrosion rate can be lower than the 2.5 mm/yr rate indicated in Figure 5, or it can be much greater. Any risk assessment that assumes the internal corrosion rate is unfavourably low because of corrosion inhibitor effectiveness on a production pipeline operating at exotically high pressures in the presence of local civilians, is in the realm of the recklessness.

The need for high confidence that the selective internal corrosion rate on any pipelines system is understood and under control is critical on a production pipeline.[9] To date, information from various Corrib pipeline public documents suggests: 1) an over reliance on injection of corrosion inhibitor in combination with corrosion coupons, 2) no cleaning pig program, and 3) a less than detailed smart pigging program. As a result, little confidence is instilled that the operator will have sufficient control on internal corrosion, especially if aggressive metal attack occurs. This observation is supported by further operator comments suggesting serious misunderstandings or deficiencies concerning cleaning and smart pigging programs discussed later in this report. (See Section VI Operational and Maintenance Issues of Concern).

[8] Andrew Johnson, "Corrib Gas Pipeline Project – Report on Evaluation of Onshore Pipeline Design Code," March 28, 2002.

[9] There is usually a very large difference in rate between faster selective corrosion attack and much slower general corrosion attack.

Important Conclusions Derived from Figure 5

1) Thick-walled pipe is not invincible to internal 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 uncertainty in internal corrosion rates and time to failure by several years, either 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.

External Corrosion

A similar prediction for external corrosion of the Corrib pipeline can be developed as indicated in Figure 7. The parameters are the same as that described for Figure 5 with the exception that external corrosion rate for the one-year growth triangles is calculated using 0.25 mm/yr corrosion rate (or one tenth the rate of internal corrosion illustrated in Figure 5). External corrosion rates typically range from 0.152 to 0.305 mm/yr (0.006 to 0.012 inches/yr). A corrosion rate of 0.25 mm/yr would be a conservative rate for a well-coated new pipeline.

Comparable observations can be made from Figure 7 that were followed for Figure 5. The major point is that thick-walled pipe is not invincible from external corrosion attack failure, though because of the much slower rates, time to failure is much greater. We have a higher degree of confidence in estimating external corrosion rates for a new pipeline, but a much lower degree of confidence (if any) that internal corrosion rates will be as low as implied by previous publicly released documents for this proposed pipeline.

Following an approach similar to that described in Figure 5 and looking at the left most column or series of triangles, a flaw initiating at a d/t of .8 with a length of slightly over fifty mm (two inches) could have survived the hydrotest and would be expected to grow for approximately 10 years and still be able to just survive an operating pressure of 345 Bars. While not indicated, this same flaw could take an additional 20 years of external corrosion (for a predicted service life of 30 years) before it failed if pressure were limited to a maximum of 150 Bars. Failure of this specific anomaly at 150 Bars would be as a leak.

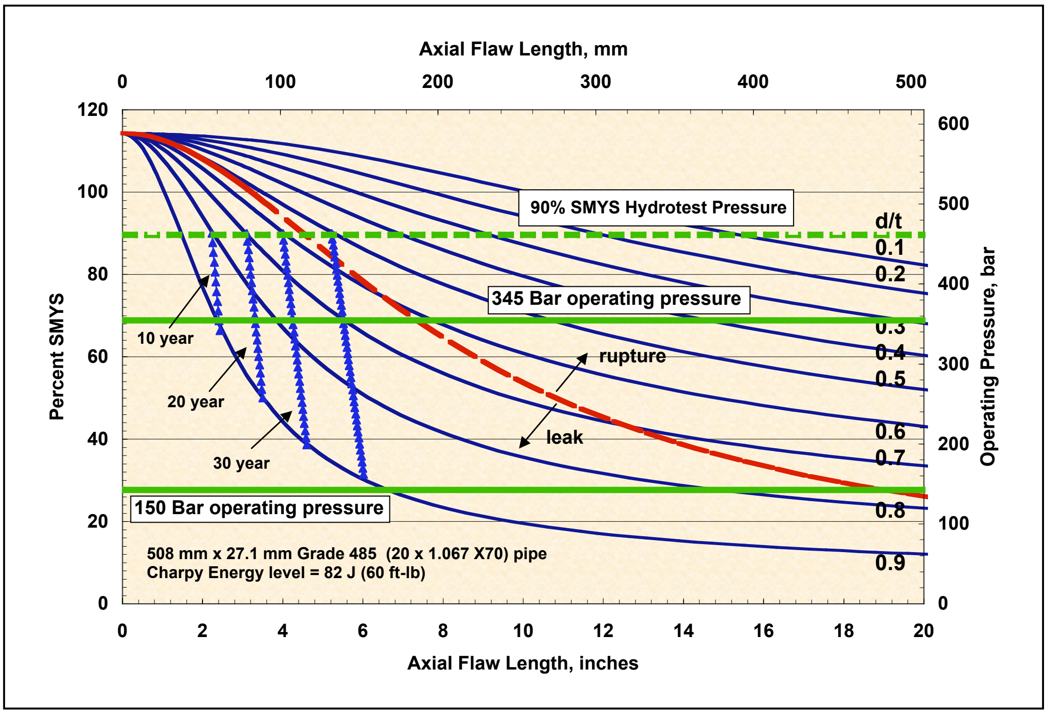


FIGURE 7. PIPE FAILURE HOOP STRESS VS. CORROSION FLAW SIZE – EXTERNAL CORROSION RATE OF 0.254 MM/YR (0.0098 INCH/YR)

From this figure it should be concluded with a high degree of confidence that external corrosion would not be a primary risk of concern for this pipeline. This observation assumes that the appropriate cathodic protection is made operational in a timely manner, and close interval surveys are properly undertaken to ensure no external selective corrosion "hot spots," where external corrosion rate could be accelerated, develop over the life of the pipeline. Close interval surveys employ various above ground inspection techniques to periodically determine the effectiveness of the CP system and pipeline coating to resist external corrosion on a pipeline.

Gas Velocity and Pipe Erosion

The actual gas velocity within a production pipeline is critical for two reasons: erosion velocity and liquid loading. Erosion can occur because of high velocities within the pipeline especially from gas associated with production wells that can contain solids such as sand. Velocity changes can also place additional load stresses on a pipeline from liquid slugging as liquid that is dropped out at lower flow rates is swept back up when gas flow is increased, causing changes in mass flow or "slugs." Actual gas velocity is dependent on pressure. The higher the pressure, the lower the actual gas velocity within the pipe for the same design mass flow rate. At the design capacity and pressure ranges stated for this pipeline we do not see any critical concerns related to internal erosion, as actual flow velocities should be well below erosion thresholds.[10]

Abnormal Loading Issues

Paramount for the pipeline operator is the requirement to determine, calculate, and document solutions for all abnormal loading conditions, both internal (slugging, temperature change, etc.) and external (e.g., crush, earth movement such as landslide, etc.) that the pipeline might experience. While we would expect a thick-walled pipeline to absorb some limited earth movement, we find very disturbing comments suggesting that a serious landslide can be

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[10] Maximum flow of pipeline from Figure 2 is 350 MMSCF/D, and using a pressure range of approximately 100 to 345 Bar.

absorbed by this pipeline without failure.[11] Detailed loading calculations for major land movement developed by the pipeline operator need to be carefully scrutinized as the author knows of no pipeline that can take high mass, high momentum external loading associated with large landslides. Figure 8 speaks volumes for the kinds of land mass flow that can be expected in the area. The author understands that a pipeline route that places the pipe above the landslide might leave the pipe suspended and thick-walled pipe should be able to take some extreme "left hanging" loading forces. However, any suggestions that the pipeline should be routed either at the base of such landmass, or within the major flow of potential land movement needs to be seriously challenged and reviewed. Failure of the pipe in these severe loading conditions, in all probability, will result in full bore ruptures. There are methods to protect pipelines in such high-risk land movement areas, but no mention is made in any public documents of these approaches. In such higher risk land movement areas, a prudent pipeline operator may endeavor to reroute the pipeline out of the area, removing the risk. He could also elect to bury the pipe deep into stable bedrock or soil, or otherwise shelter the pipe, from the unstable soil. Reroute is preferred as it is usually the most effective approach.

FIGURE 8. AREA LANDSLIDES

Peat, a unique form of boggy acidic soil, is a special type of environment that can place abnormal loads on the pipeline from movement, especially as the design of this pipeline is negatively buoyant, wanting to sink within the peat. The operator has indicated that the pipeline will traverse these peat conditions by spanning the pipeline along stone column supports within peat bogs. The designers should be able to demonstrate through clear documentation and calculations that a particular pipeline route, design, and span through peat will not generate abnormal loading on the pipe that can cause its failure.

Pipeline Safety Equipment

In the design of pipeline safety systems, there can be a tendency to stay on one course based on an original "game plan" while attempting to correct serious deficiencies by incorporating additional changes to "fix" the original flawed design premise. The very nature of these "fixes" introduces complexity that can inadvertently drive the system to the very failure needing to be avoided. In complex energy system design such as high-pressure pipelines, we call this phenomenon of adding complexity to fix simple fundamental basic design premise errors, "Space Shuttle Syndrome." This label was coined after the NASA Challenger space shuttle loss and verified again after the second Columbia shuttle loss, and subsequently reaffirmed in the July, 2005 Discovery space shuttle launch. In Discovery's case, after approximately two billion dollars and a two year engineering effort, the foam hitting the shuttle on launch, the same problem that caused the Columbia's loss, had all too obviously not been fixed. Space Shuttle Syndrome has come to mean a complex organisation rushing to launch at all costs, failing to fix or address fundamentally flawed initial approaches, while utilising poor risk management to cloak their misguided confidence that everything will work.

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?

[11] Corrib Field Development Project, "Onshore Pipeline Quantified Risk Assessment," Version F, dated April 22, 2005.

It has been stated that the onshore Corrib Pipeline will be failsafe. This term has been getting much misuse in the industry, especially with regard to its application in poor risk analysis. As defined by this author for this pipeline, failsafe is the design philosophy such that failure of a component or operator mis-operation cannot place the pipeline in an overpressure event that could result in pipe failure. As demonstrated in Figures 5 and 7, at these exotic pressures the room for error on the onshore pipeline is very small. We find it incredible that, given these very high pressures, more documentation has not been presented to clearly instill confidence that the onshore pipeline pressures will be maintained in the pressure ranges suggested by the operator.

For example, the wise addition of an onshore remote operated valve will reduce the outrageously long depressurising time (many hours) associated with an onshore pipeline rupture as the many kilometres of offshore system depressurising out the failure site will continue should this valve not be quickly closed. Incredibly, this remote valve was apparently not in the original design scheme suggesting a serious lack of appreciation of gas pipeline dynamics and failure consequences by the decision team. This remote valve (even if it were designed to automatically close), however, will not really impact the consequences associated with leaks or ruptures on the onshore pipeline. For leaks, the gas inventory is so large that the leak will in all probability result in an incident before the line can be depressurised. In a pipeline rupture, most consequences (i.e., fatalities) will occur in the early minutes of the rupture and the valve's closure will not occur in sufficient time to avoid a catastrophe from this highly compressed fluid. The valve on the boundary of the onshore pipeline is not really a true "safety" in the event of an onshore pipeline failure, though it will reduce the number of minutes that an onshore rupture could blow down out the pipeline. As will be shown in Section IV Onshore Pipeline Routing Issues, reducing the blow down time from a rupture to minutes will still result in very large fatality zones.

The Difference Between Base Design and Future Operation

While on the subject of the onshore valve, there have been varying statements about what the maximum pressures will really be for the onshore pipeline. If the operator cannot adequately demonstrate that the onshore pipeline will be truly "failsafe" (e.g., protected to prevent pressures in excess of 150 Bar, approximately 30 % SMYS), this pipeline needs to be moved and rerouted away from population.

We need to be very clear in keeping with the above system complexity comments that a pressure letdown control device designed to drop pressure at the shoreline will not be a failsafe design. Such a control would most likely introduce other system complexities that would substantially increase the likelihood of an onshore pipeline failure.

> No credible design scheme has been provided that commits or ensures that onshore pipeline pressures will remain below 150 Bar.

In any pipeline system one must have a clear understanding of and commitment to the basic system design to prevent overpressure. Relying on flowing (or dynamic) pressure drop to maintain safe operating pressure ranges represents poor engineering and management practices that should not be obscured by QRA attempts. Future pressure limitation commitments go with the design routing of the pipeline, as the current base design does not restrict the pipeline operating pressure in the future. For example, the entire onshore Corrib pipeline will be tested to permit a pressure of 345 Bar. There is no restriction on the pipeline operator to maintain or restrict future operating pressure so the operator could exceed 150 Bar and even reach the 345 Bar limit. The pipeline operator is not required to recertify the integrity of the pipeline or even notify the public before increasing to exotic higher pressures should he decide to increase the onshore pipeline pressure for whatever reason. A brief review of Figures 5 and 7 would clearly reinforce the real risks associated with the pressure ranges between 150 and 345 Bar for this system. The rupture flow dynamics and associated large fatality zones discussed in the next section, will help one gain an appreciation of the importance of avoiding rupture on this unique system at these exotically high pressures.

IV. Onshore Pipeline Routing Issues

Proximity to Population

One major factor when determining the route for a new on land pipeline is its proximity to population, usually captured as dwellings and unsheltered gathering areas (schoolyards or soccer fields for example). Depending on a country's standards or regulations, there may be minimum distance requirements that set or influence some of the choices for a pipeline's route. Various countries set no minimum distances between structures, unsheltered gathering sites, and pipelines, while others do.

BS 8010 attempts to address some of the concerns associated with population in proximity to pipelines using a classification of location designation that sets a design factor. There is a major weakness in setting the design factor for a pipeline via classification of location approach based on a population density approach of so many people per hectare. [12] Population density determinations don't adequately address the issue where a pipeline may elect to come in close to concentrations of people in sparsely populated countryside, that still meet the lower density requirement for location of class 1, such as small towns. A class 1 location permits pipelines to operate up to 72% SMYS (for this pipeline this factor places pressures in serious pipeline rupture territory). To help address the shortcoming of population density in class location approaches, BS 8010 to its credit also sets for methane (in Figure 2 chart within Part 2 of the standard) a minimum distance requirement for normally occupied buildings. Unfortunately, this chart only reflects pipeline pressures up to 100 Bar. The current proposed pipeline route through Rossport and other nearby villages meets the lowest population density class 1 location, but the pipeline pressures are off the chart and dwellings are close to the proposed pipeline route. BS 8010 allows pipelines off the chart provided a risk analysis meeting certain requirements is performed. A review of the proposed onshore pipeline route indicated in Figure 3, highlighting dwellings in close proximity to the pipeline, should underscore the problem and the reason for so much past effort being directed to risk assessments for this pipeline (the closest dwelling is apparently 70 metres from the pipeline).

Understanding Pipeline Releases

When discussing high pressure gas pipeline releases, it is important for the reader to understand the two release scenarios associated with the discharge of highly compressed gas, leaks and ruptures. At pressures greater than approximately 1 Bar, gas pipeline release will discharge at the speed of sound. This phenomenon, also commonly known as choked flow, is a property of the ratio of the heat capacities and the temperature of the gas.[13] For most natural gas rich streams and temperatures, the speed of sound is approximately 300 to 430 metres/sec (1000 to 1400 ft/sec) depending on how one compensates for non-ideal gas factors associated with highly turbulent high velocity flows. Regardless of the hole size, whether a pinhole leak or a full bore pipe rupture, the velocity of the gas will usually be limited by the speed of sound at the hole conditions. The major difference between a leak and a rupture, other than the fracture dynamics described earlier, is the difference in mass flow rate.

Mass flow rate determinations for leaks can be fairly easily calculated by assuming an orifice hole size and estimating the pipeline pressure (which stays essentially constant at the leak location). Leaks can be very destructive if the gas can become capped or trapped in structures where it can then accumulate (leading to higher probability of building explosions). At the higher operating pressures of this pipeline, leaks can still release a great deal of gas.

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[12] The design factor sets the maximum permitted percent of SMYS, or "internal design pressure," that has a specific meaning in the BS 8010 standard. The lower the design factor the lower the permitted maximum pressure.

[13] Gas composition will change the ratio of the heat capacities for a gas mixture.

Full bore ruptures release considerably larger mass at much higher rates than leaks. For rupture, the mass flow release rapidly spikes upward and then starts to decay with time. Mass release is defined by the full bore orifice (combined rate from the two open ends of the pipeline) and upstream/downstream gas pressures that will not drop quickly on a high-pressure gas pipeline. The mass flow changes with time as the density of the gas, not the velocity, changes with time. These density changes are a function of various factors associated with a particular pipeline. This concept is difficult for the layman and many engineers to understand, but pipeline ruptures are not like a balloon bursting where loss of containment drops pressure to atmospheric almost instantaneously.

The nature of a rupture mass release spike, or increase, and its subsequent decline depends on pipeline size, pressure, pipe hydraulics, pipeline length, deviation from ideal gas and, most importantly, the time to recognise and change the main gas flow near the rupture (time to recognise and actually close nearby valves if any are available). Dynamic simulation tools are used to predict mass releases over time for ruptures at specific locations on a specific pipeline. Depending on many complexities, there is a tendency for too many engineers to believe these models calculate exact releases. In reality, they are far from exact, especially when their efforts fail to properly capture the poor recognition times associated with remotely identifying a pipeline rupture. This delay adds greatly to already high mass release estimates, especially in the critical early stages of a rupture where fatalities are most likely to occur because of high mass releases with ignition (which usually occurs within minutes if not seconds).

It is easy for inexperienced engineers to believe that their calculations modeling a pipeline rupture at a specific point are exact, when in reality many transients can easily modify such calculated results by a wide margin. Two major and serious deficiencies we find in risk management approaches concerning pipeline ruptures are assumptions: 1) that rupture modeling assumes instantaneous or almost instantaneous identification by the SCADA or remote monitoring system of a rupture, and rapid (nearby) valve closure, and 2) that the massive air/fuel mixture doesn't explode or ignite quickly. Neither one of these assumptions is realistic especially for those very high pressures that can create their own ignition. Such erroneous assumptions critically understate the fatality zones and risks associated with a high-pressure gas pipeline rupture as will be explained in the next two sections.

A Reality Check on Understanding Gas Pipeline Ruptures

Given the incomplete information provided in previous public documents describing the dynamics and thermal consequence zones associated with a Corrib pipeline rupture, this author believes additional detail about this failure consequence is warranted. As clearly demonstrated in Figures 5 and 7, thick-walled pipe is far from invincible to failure, either as a leak or a rupture. Specifically focusing on ruptures, Figure 9 should serve as a reality check for anyone calculating or attempting to model gas pipeline rupture impact zones for regulatory or standard development, or for siting of high pressure gas pipelines.

Figure 9 is a photo of the Carlsbad, New Mexico, August 19, 2000 natural gas transmission pipeline rupture. This pipeline was a 30-inch pipeline with a 0.335 inch (8.51 mm) wall thickness (thin-walled pipe), Grade X-52 (52,000 psi SMYS), operating at a pressure of 675 psig (46.6 Barg) that failed from internal corrosion.[14] By now Figures 5 and 7 should have dispensed with any illusions that thick-walled and thin-walled pipe at these high stress level operating pressures will somehow fail differently.

[14] NTSB Pipeline Accident Report, "Natural Gas Pipeline Rupture and Fire Near Carlsbad, New Mexico August 19, 2000," NTSB/PAR-03/01, Adopted February 11, 2003.

FIGURE 9. CARLSBAD, NEW MEXICO NATURAL GAS TRANSMISSION PIPELINE RUPTURE (COURTESY OF THE NTSB)

To gain an appreciation of the height of the flame in Figure 9, the steel support towers are 24 metres (80 feet) tall which would place the flame at almost 110 meters (370 ft) into the air. Given the time needed to get a camera to the site to take this picture (the flame burned for approximately 55 minutes) it would be fair to assume that the photo was taken some time after the pipe rupture so the fuel release represented in the photo is well below the peak rapid spike increased mass flow which occurs at initial failure.

Figure 10 is an aerial photo of the Carlsbad failure site taken in the aftermath that should help everyone gain an appreciation of the thermal impact zone associated with a pipeline rupture. The nearest steel pipe support suspension tower on the river's edge is approximately 183 meters (600 ft) from the rupture site. An extended family of 12 (including five children) camping approximately 206 meters (675 ft) from the ruptured pipe all died as a result of the blast and thermal radiation received. Six of the victims, even though they were able to run and jump into the river further away from the failure and in the shadow of the river gully, still received fatal thermal dosages and (given the extent of 3rd degree burns over their bodies) died within hours. I do not provide these photos to scare or unduly alarm anyone, but rather to call serious attention to the fact that engineers and risk managers sometimes forget that the numbers they are oftentimes overworking fail to match the reality, especially if they are mistaken in their critical assumptions. Carlsbad serves as a very real reality check for anyone making poor risk management pipeline decisions.

Referring to Figure 10, one can get an appreciation of how rupture events extend well beyond the pipeline right of way. Once ignited, the large flame height significantly increases the thermal radiation dosage zone of the burning cloud. In the Carlsbad event, the steel towers were thermally stressed so badly that they and the pipelines they supported across the river had to be removed from service.

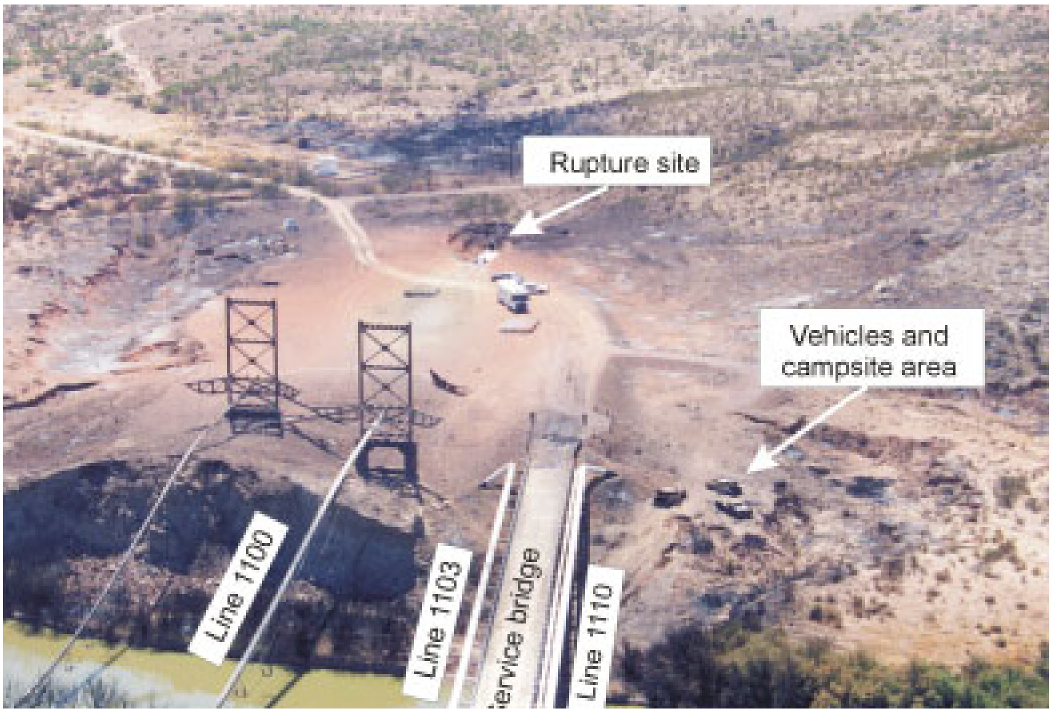


FIGURE 10. CARLSBAD PIPELINE RUPTURE, THE AFTERMATH (COURTESY OF THE NTSB)

Because the phenomenon of gas jetting, roaring or blowing directly out the end of a pipeline rupture, is often misrepresented in risk analysis to understate impact zones or risk, further discussion is needed on this important issue. All buried gas pipeline ruptures gas jet and very few generate flames that hug the ground. In fact, Figure 9 represents a flame from a gas jetting failure. Eventually, upon ignition, all the impact energy is dissipated and thermal energy raises the flame off the ground extending the impact zones. A closer examination of Figure 10 will indicate the typical circle of thermal impact zone from a rupture flame. In this case the photo doesn't extend beyond the service bridge, but the thermal burn zone (described in the NTSB report narrative) extended well beyond the service bridge and across the river, an area approximately 423 m (1400 ft) from the rupture site. The NTSB report clearly indicates that pipeline emergency response personnel were not able to cross the service bridge with vehicles to get to a nearby valve because of the high thermal flux. The point to be made here is that gas jetting doesn't really reduce the radius for the thermal impact zone, it just moves the thermal zone circle down the pipeline and the zone can extend well beyond any right-of-way. Note the relative absence of extended severe thermal burning in the opposite direction of the towers upstream of the rupture crater site (toward top of the photo).

FIGURE 11. CARLSBAD RUPTURE CRATER (COURTESY OF NTSB)

Finally, to put to rest any illusions that a gas jetting at sonic velocity from a pipeline rupture may be an insignificant event, Figure 11 is another photo of the crater from the Carlsbad release.

This photo is looking downstream of the rupture toward the river (the bottom of Figure 10). The crater in this rupture case was only approximately 34 m long by 16 m wide (113 ft long by 51 ft wide). The pipe missing between the arrows was shrapneled in several pieces many hundreds of feet from the crater (part of the fracture process as the pipe fails in microseconds). The author has taken particular time to benchmark the Carlsbad rupture because of the extensive clear documentation on this specific failure, including time to ignition that permits a reality check for those utilising various pipeline rupture models. The author must state for the record that the Carlsbad pipeline failure is considered a moderate mass flow release for a high-pressure gas pipeline rupture. A Corrib Pipeline rupture, even though it is a smaller diameter pipeline, will release much more fuel at a higher rate during the early critical minutes of a pipeline failure where ignition and subsequent fatalities are most likely (as will be described shortly).

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.

Despite previous claims in some Corrib pipeline documents inferring that natural gas pipeline ruptures don't ignite, much less explode, the author invites the reader to review the website analysing the various explosions and blast forces determined for the Carlsbad event recorded on distant seismographs.

The New Mexico Pipeline Explosion Seismic Signals site where this information may be reviewed is:

http://www.ees.nmt.edu/Geop/Pipeline/pipeline.html

From these seismic measurements, time to ignition after pipe rupture at Carlsbad was determined to be approximately 24 seconds. Contrary to previous opinions stated in Corrib pipeline public documents, pipeline ruptures do not need a flame source to ignite a very large and turbulent gas cloud. Despite the fairly tight flammability range of natural gas (5 to 15 vol.%), many gas pipeline ruptures ignite for various reasons. Sparks generated by pipe shrapnel, thrown rocks sparking, and static electricity are just a few of the sources of ignition in addition to flame sources. For these massive rate releases, ignition usually occurs in the early minutes of release when mass flow has spiked at its highest and is starting its decay, but is still very large.

Corrib Pipeline Rupture Impact Zone

Figures 12 and 13 indicate energy release or thermal flux (in KW/m^2) as a function of distance from the pipeline for the Corrib onshore pipeline estimated for the boundary condition pressures of 150 Bar and 345 Bar, respectively. The two graphs represent a full-bore rupture release, corrected for non ideal gas effects associated with high flow turbulence, occurring in the vicinity of the neighboring Rossport homes. An instantaneous ignition curve (t= 0 seconds) and delayed ignition at various other times have also been estimated for reference. The thermal flux curves declining as a function of distance is characteristic of any major flame source from a pipeline rupture. The thermal flux decay with time is representative of mass flow degradation from high pressure pipelines. The spread between the time to ignition curves will be a function of pipeline hydraulics, point of rupture, the compressed gas inventory (e.g., density), and response time to close nearby valves.

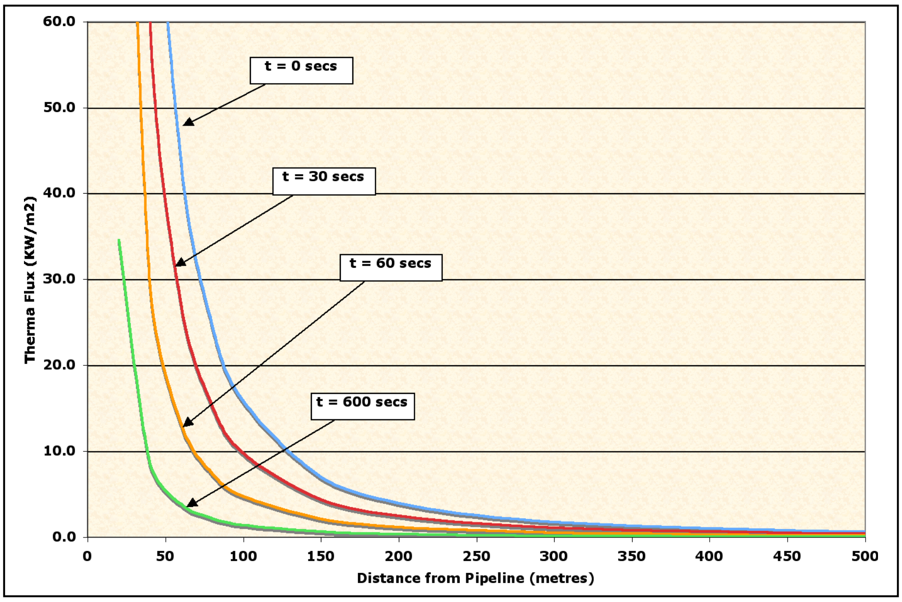


FIGURE 12. CORRIB ONSHORE PIPELINE RUPTURE THERMAL FLUX VS. DISTANCE FROM PIPELINE 150 BAR CASE

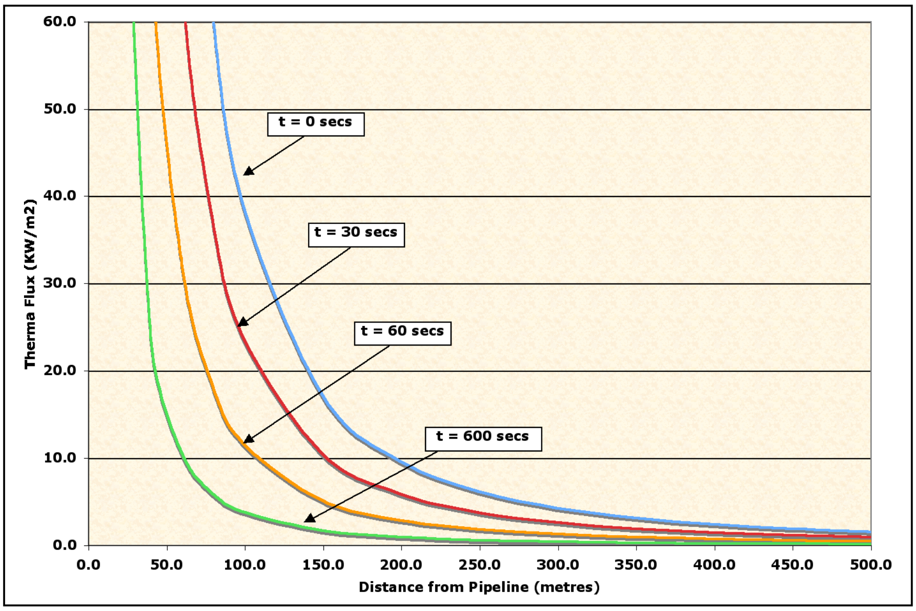


FIGURE 13. CORRIB ONSHORE PIPELINE RUPTURE THERMAL FLUX VS. DISTANCE FROM PIPELINE 345 BAR CASE

Unlike some thermal release curves developed for pipeline ruptures that run out for many minutes, and as a result downplay or miss the very high flux "thermal load" band, we have focused the thermal release graphs to draw attention to the early minutes (the first ten minutes) of a pipeline rupture. This is the most likely time for ignition/explosion (usually within 1 or 2 minutes) with high thermal fluxes and thermal loads most associated with fatalities. Depending on what transients and assumptions are utilized in any dynamic model, the results may be slightly different, but the general shape, approximate time to decay and high heat fluxes, will be characteristic for an onshore rupture on this system. The critical determination of the fatality zone will be the probability call for time to ignition. Note that the higher heat flux associated with 345 Bar is representative of a mass release more than twice the rate associated with the 150 Bar case.

Given the release forces associated with very high pressure pipelines and the large associated fatality zones, the burden of proof should fall on the operator to demonstrate why ignition will not occur, especially in the early moments of release that can result in the greatest risks of fatalities. At these high pressures, prudent modeling should assume essentially instantaneous ignition when determining pipeline routing near people.

Pipeline rupture siting analysis must incorporate the early minutes of initial ignition when causalities from high heat flux are at their greatest.

Figures 12 and 13 only tell part of the overall equation as the thermal flux for a certain distance needs to be translated (estimated from Figures 12 or 13) into a thermal dosage that either causes serious burns, fatality, or dwelling loss. Figure 14 represents a series of thermal dosage models derived from industry accepted thermal models.[15] Figure 14 is a "time to" chart graphically illustrating the time to which a fixed thermal flux can be tolerated for unsheltered (exposed) individuals and wooden structures. For example, a 20 KW/m^2 heat flux exposure for only a few seconds will result in 1 % mortality for those caught outside near a rupture, while a few seconds later at this thermal flux, 50 % mortality will result, and in slightly over one minute 100 % mortality of unsheltered individuals will result. A wooden structure receiving the same heat flux of 20 KW/m^2 should be able to survive, as this flux is left of the wooden dwelling spontaneous ignition curve drawn indicating that essentially, a wooden structure can take this heat flux indefinitely. Depending on the accuracy of the thermal model, Figure 13 would suggest that a dwelling approximately 150 metres from the pipeline would not "spontaneously ignite." This does not mean that secondary effects won't occur (i.e., vehicles explode).

Focusing on dwellings, however does not tell the full story. Often in risk analysis, assumptions are made that individuals caught outside in close proximity to a pipeline rupture will have the presence of mind to run and seek shelter from the heat. As figure 14 clearly illustrates, the time

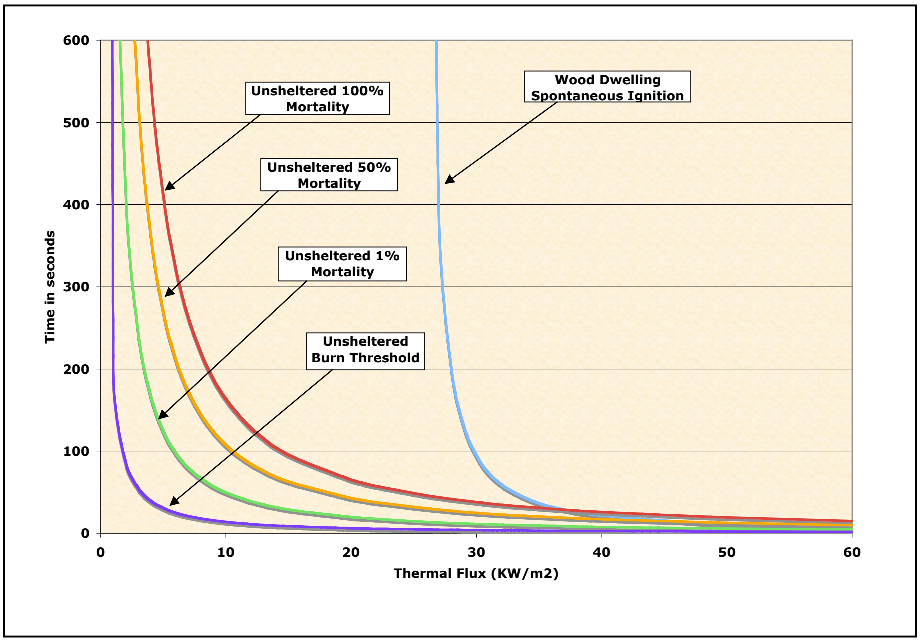


FIGURE 14. "TIME TO" FOR VARIOUS THERMAL FLUXES ON PEOPLE AND WOODEN STRUCTURES

[15] Various thermal dosage models quoted from GRI, " A Model for Sizing High Consequence Areas Associated with Natural Gas Pipelines," prepared by C-FER Technologies, October 2000.

to get into a shelter, away from the heat is measured in seconds. Figure 14 would also suggest that a 5 KW/m^2 heat flux provides only minutes for people to leave the area if they can. At 5 KW/m^2 heat flux, individuals within 300 metres of the pipeline are at risk. The Carlsbad reality check would, however, suggests that a more appropriate buffer zone for unsheltered individuals is 400 to 500 metres, and 200 metres for dwellings.

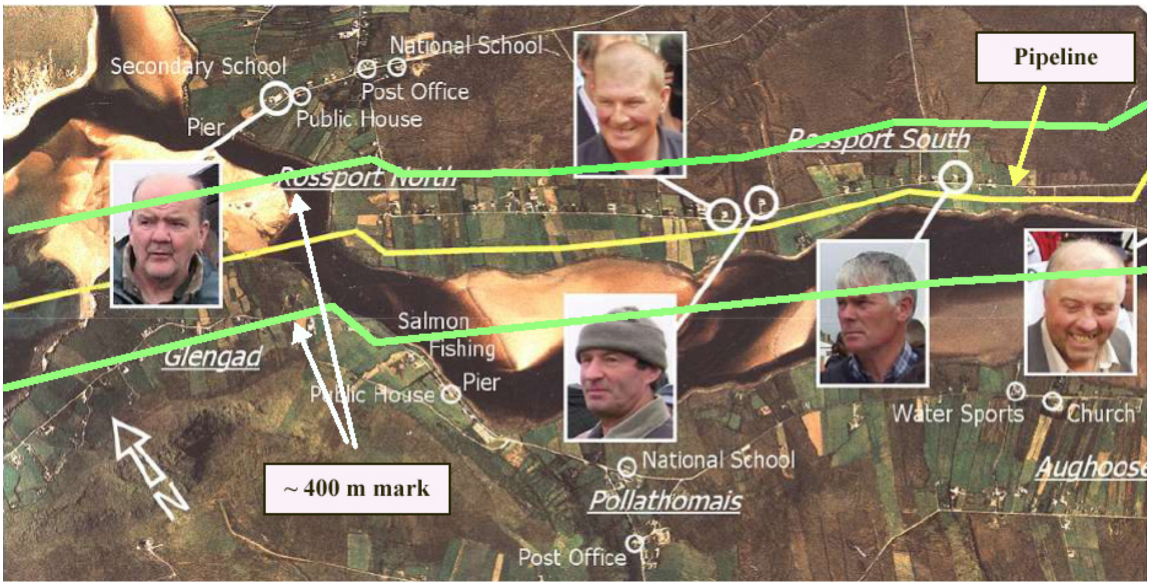
Early ignition scenarios and Carlsbad would place the safe distance for a dwelling at 200 metres and the safe distances for unsheltered individuals beyond 400 metres.

BS 8010's graph to 100 bars pressure is definitely coming up short on dwelling survival distance, but in all fairness the standard probably didn't envision such high pressure pipelines, as in the Corrib proposal, that can generate large heat fluxes for many minutes. These are large distance numbers, but again these are exotically high pressures, which begs the question "Who would want to run such a high pressure pipeline near people, especially when there appear to be many more remote routing options?" More restrictive countries establish lower KW/m^2 values as an offsite acceptable heat flux for facilities that can generate high thermal flux, while less progressive countries have higher threshold values, or none at all, for pipeline events.[16]

For those who may argue that someone located outside can run away from a pipeline flame and thus decrease the suggested safety zone, running will not compensate for the very high initial thermal load (radiation dosage) that can and will most likely occur on rupture. At these high thermal loads, credit for running to a safe distance is inappropriate. Imagine trying to maintain a frame of mind while running with your clothes and skin on fire! Referring back to Figure 10, the unfortunate victims in the Carlsbad tragedy, even if they had reached and crossed the service bridge, had already received and were continuing to receive fatal thermal dosages from the very high early thermal flux. In the Carlsbad case, no matter what direction and how fast the individuals had run, they were well beyond (right of) the "Time to" curve for 100 % mortality exposure shown in Figure 14 because of the severe initial thermal loading associated with early ignition. It is a mistake to portray that such high thermal loading occurs on high pressure gas pipeline system ruptures only for a few seconds.

[16] The U.S. has no defined federal pipeline siting regulations and no acceptable thermal flux limit for pipeline ruptures, though a 15.8 KW/m^2 (5000 $BTU/hr\ ft^2$) is often implied in analysis wrongfully suggesting there are such requirements to justify poor pipeline route selection.

FIGURE 15. ROSSPORT 400 METRE RUPTURE IMPACT ZONE



The green band lines in Figure 15 represent an approximate 400 metre zone from the proposed pipeline in proximity to Rossport. Most of the citizens are within the band for unsheltered individuals. Note the large number of dwellings in close proximity to the pipeline well within 200 metres from the pipeline.

Sensitive Waterways

When reviewing possible routes for pipelines, priority is usually given to routes that avoid people as demonstrated by the discussion in the previous section. As possible routes are evaluated, additional environmental restrictions may come into play influencing route alternatives. Depending on a country's regulatory environment, these restrictions usually manifest themselves as conditions pertaining to sensitive waterways containing susceptible ecosystems.

It is the nature of gas systems that their failure is less prone to permanently damage large ecosystems. There will be exceptions to this statement, but it is generally true. Ironically, for a gas pipeline system, most of the ecological damage or risk from such damage usually occurs in the construction phase. Pipeline construction teams can get ahead of the operator's best intentions, especially if project schedules are pressing (as they usually always are).

FIGURE 16. SRUWADDACON BAY

In first reviewing the proposed onshore pipeline route, this author was struck with the question of why is the land route in close proximity to so many people?

It is this author's opinion that the current proposed land route has more to do with ease of construction and shortest pipeline path (cheapest route mentality) than a properly evaluated route selection. Given this author's experience and background, and a natural bias to first focus on protecting people, the next observation was why didn't the operator consider a route up the middle of the Sruwaddacon Bay? Closer examination suggests that a bay route does not provide quite enough proximity distance. It also appears that the bay may be a sensitive route with some very unusual construction and tidal surge challenges. This author has difficulty accepting the premise that all the other options for possible pipeline landfall are so difficult or restrictive so as to leave only the general bay location scheme.

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.

V. Pipeline Construction Issues

The pipeline is to be constructed to DNV OS-F101 SAWL standards, which is claimed to be equivalent to API 5L grade X 70. The pipe will have a nominal outside diameter of 508mm (20 inches) with a nominal thickness of 27.1 mm (1.07 inch). This is considered thick-walled pipe.

The Thick-Walled Pipe Conundrum

Thick-walled pipe brings certain positive benefits and certain different concerns. For example, thick-walled pipe operating at high stress levels increase the likelihood of third party damage becoming a time dependent failure.[17] It is important to realize that, in many cases, the thicker the pipe the greater the safety margin. This safety benefit, however, rapidly diminishes as the operating pressure as a percentage of SMYS increases. As mentioned and demonstrated in detail (see Figures 5 and 7), thick-walled pipe is not invincible to various failure threats such as corrosion that can cause either leak or rupture releases. Any attempts to represent that thick-walled pipe is invincible or that it can be treated with disrespect needs to be seriously challenged, as modern pipe fracture mechanics will prove such perspectives most unwise.

Thick-walled pipe also presents difficulties for smart pig or inline inspection (ILI) as discussed in detail in Section VI Operational and Maintenance Issues of Concern. Certain smart pig inspection technologies will not work well on thick-walled pipe, a point that has not been mentioned in previous Corrib pipeline public documents, implying that ILI will be a highly effective safety net on this system. Given the importance that corrosion, especially internal corrosion can play on possible premature pipe failure, specific information related to ILI inspection claims and performance need to be clearly defined and documented. Over reliance on ILI performance or effectiveness in a risk analysis to prevent pipe failure from corrosion could prove fatal with this pipeline. New ILI inspection processes have recently been promulgated as an API industry standard to better define the limits of ILI applications on a specific pipeline; a much needed improvement for the pipeline industry that may utilise ILI as an integrity management tool.[18]

[17] It is a very serious mischaracterisation for any risk analysis to utilise historical databases in their statistics suggesting the same third party damage frequencies on pipelines (even thick-walled) that are operating at much lower stress levels.

[18] American Petroleum Institute, API Standard 1163, "In-line Inspection Systems Qualification Standard, "First Edition, August, 2005.

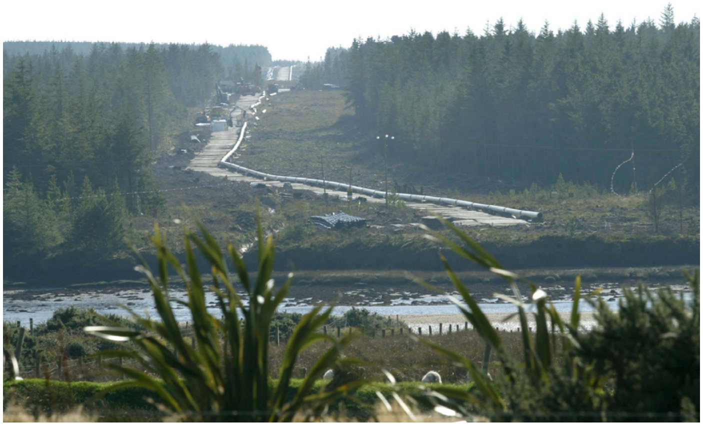


FIGURE 17. LOOKING FROM SRUWADDACON BAY

Girth Weld Inspection and Integrity Testing

One example of the problems that can be associated with thick-walled pipe is the importance of properly inspecting all girth welds joining pipe segments. Conventional x-ray radiography is ineffective at penetrating or clearly indicating thick welds. Usually ultrasonic technology is utilised for such pipe. We strongly advise that all records of onshore pipeline weld inspection be cataloged, auditable by an independent third party inspection organisation, and maintained for the life of this pipeline, wherever it is routed. This is especially important given the potential abnormal loading stresses associated with earth movement that the pipeline may face, as discussed previously, that may place additional stress on the girth welds. To be very clear, the initial high-pressure hydrotest (certifying the pipeline to operate at stress levels up to 72% SMYS) does not adequately or sufficiently test the girth welds on a pipeline that is going to see potential abnormal loading conditions. It is very important to clearly understand that a hydrotest test will not adequately test girth welds and that a girth weld failure will manifest itself as a pipeline rupture. At the potentially exotic pressures that this pipeline could see, there is little room or margin for error.

VI. Operational and Maintenance Issues of Concern

Corrosion Monitoring Program

There should be considerable concern raised on any gas production pipeline operating at these pressures and relying solely on corrosion inhibitor and corrosion monitoring, utilising only corrosion coupons. A reading of the previously cited NTSB Carlsbad pipeline failure report should demonstrate the shortcomings of overly relying on corrosion coupons.[19] The shortcomings of such programs are well documented.[20] Over reliance on corrosion coupons to monitor internal corrosion should be taken as a warning sign that internal corrosion may be not under control, a serious risk of failure for this very unique system. The cited reference standard for this pipeline, BS 8010, section 4.3, discusses application of corrosion inhibitor and corrosion coupons.[21] We would characterise this standard as deficient or incomplete in this area, especially given the importance that internal corrosion can play on production pipelines as demonstrated by Figure 5, even for thick-walled pipe.

The operator has asserted that the subsea design of this system makes application of an important component of an effective internal corrosion prevention program, a proper cleaning pig program (such as a sphere), unattainable.[22] The failure to incorporate a prudent cleaning pig program, especially for the onshore pipeline, should raise concerns about the ability of the operator to adequately prevent selective internal corrosion on this pipeline. A competent corrosion cleaning pigging program extends well beyond just running the cleaning pig.

[19] Ibid., NTSB Carlsbad Incident Report.

[20] Richard B.Kuprewicz, "Preventing Pipeline Releases," Prepared for the Washington City County Pipeline Safety Consortium, July 22, 2003.

[21] Ibid., BS 8010 1992 version.

[22] An Bord Pleanála, "Inspector's Report on Gas Terminal at Bellagelly South, Bellanaboy Bridge, Belmullet, Co. Mayo," signed by Kevin Moore and dated April, 2003.

Analysis of material removed with the pig, especially for corrosion products, is important to identify internal corrosion activity at possible "hotspots" that the inhibitor may not prevent, or coupons not indicate. This could lead to premature failure. The importance of properly evaluating internal corrosion rate in any analysis on this pipeline should be evident from a review of Figures 4 and 5 as selective corrosion can seriously reduce the integrity of this pipeline. Assuming there is no internal corrosion because one's corrosion inhibitor program and coupon monitoring program is assumed to work is a delusion fraught with much danger, especially given the proposed routing of this pipeline.

Smart Pigging and Thick-Walled Pipe

Smart pigging or inline inspection (ILI) is often claimed to be the superior method of inspecting pipelines for certain flaws or anomalies that can lead to failure, either leak or rupture. What is not well understood is that misapplication of the smart pigging process, such as the choice of the wrong pig, and mismanagement of the pig determinations and verifications can seriously render ILI ineffective.[23] New industry standards have now been incorporated to address some of these serious shortcomings concerning the misapplication of ILI to confirm pipeline integrity.[24] We find the public documents published to date for the Corrib pipeline to be incomplete and seriously deficient in detail concerning the issues of ILI and thick-walled pipe reliable inspection. Given the importance that ILI can play in preventing failure from corrosion, any risk analysis that fails to properly address ILI effectiveness on this system would be deemed critically deficient.

The application of smart pigging on thick-walled pipelines is not without serious challenges. The implication that such tools will prevent failure are overstated, a definite risk when taken in combination with other missing elements of an effective corrosion program. No details are provided about which ILI smart pig technology will be utilised to inspect this pipeline, a serious deficiency in any risk analysis approach. In all probability more than one smart pig technology will be required as running only one type of ILI is usually considered an indication of an incomplete ILI program. There are at least two serious threats that require different smart pig technologies, corrosion and third party damage of the type discussed shortly, which can result in time dependent pipe failure. There is a serious probability that QRAs to date have overstated the effectiveness of these important programs to prevent failure on this pipeline, and understated the likelihood of failure as a result.

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

Third Party Damage Concerns

While it is usually true that the thicker the pipe the higher the potential to avoid failure in many cases, this statement must be taken in the context of operating pressure, specifically the much higher likelihood that this pipeline will be operated at very high stress levels as mentioned previously. While thicker pipe tends to resist or prevent immediate failure from third party damage, this damage (i.e., cuts, gouges, grooves) is subject to cycling growth-induced failure at a later date. For the high stress levels expected on this production pipeline, we find risk analysis indicating that thick pipe will not be subject to cycle induced fatigue failure and thus "not a risk of concern" to be inadequate.

Risk analysis conclusions dismissing fatigue cycle induced third party damage failure on this high stress level pipeline appear incomplete.

[23] Richard B. Kuprewicz, "Observations on the Application of Smart Pigging on Transmission Pipelines," prepared for the Pipeline Safety Trust, September 5, 2005.
[24] Ibid., API Standard 1163.

It is the nature of production pipelines to load slug as liquid/solid carryover cycles the system. This, as well as the additional corrosion risks discussed in Section III, are some of the fundamental differences between design/operation of production and transmission pipelines. Theoretically, flaw growth plots similar to those for corrosion (Figures 5 and 7), can be developed for sharp edged pipeline flaws such as third party damage gouges. The tests, theories, and many years of field verification that evolved for corrosion failure tools on pipelines have yet to be clearly developed for the sharp edged flaws. Corrosion anomalies tend to have varying thickness that do not concentrate the stresses in a manner such as that associated with sharp edge flaws (gouges). A fracture mechanics model developed for steel pipe would take on a similar appearance to that of Figures 5 and 7, with flaw sizes of sharp edge permitted at the same pressure level being much smaller than that for corrosion. For a given pressure, a pipeline can tolerate a corrosion flaw but not necessarily the same size (depth and length) sharp edge gouge anomaly. It is very important that any pipeline route take rational precautions to avoid and prevent possible third party damage on such a high-pressure pipeline that commands such a large potential impact zone.

Thicker pipe, even at the higher stress levels, does provide one definite benefit in regard to a specific type of third party damage threat. Damages where a hit results in a stress concentrator within a dent (i.e., dent with a gouge, crack, or corrosion). Dent with stress concentrators are not permitted in most codes or regulations as their time to failure are very unpredictable (they can fail at any time). Most third party damage on thick-walled pipe will probably result in a gouge rather then a gouge within a dent. The stress concentrator may not fail immediately, but such damage would be susceptible to fatigue cycling and possible failure that is still very unpredictable.

Road crossing loading calculations need to be adequately documented.

Lastly, a major issue of concern regarding third party damage, that of the waiver from the requirement to utilise a 0.3 design criteria (much thicker wall pipe) for road and railroad crossings. The pipeline is proposed to be constructed with a 0.72 design factor throughout the system, including road crossings. There are two major risks associated with crossings: 1) possible damage associated with third party activity that could hit and possibly gouge the pipeline as discussed above, and 2) abnormal loading associated with heavy traffic crossing the pipeline. Requirements to install a concrete warning barrier and warning tape appear adequate to address the first risk of concern. Usually, to protect from the second risk of concern, the pipeline is either encased or buried very deeply to spread the loading forces. We do not advise casing the pipe in this environment as casing can accelerate selective external corrosion. The operator needs to provide detailed loading calculations assuring that each specific site crossing will provide adequate safety margin from abnormal loading that could result in pipeline failure from crush or similar loading. Given the thickness of the pipe, road crossing abnormal loading should not be an area of concern, but this needs to be clearly demonstrated.

Remote Monitoring of Pipelines

Little mention is given in various public documents as to how this pipeline will be remotely operated or controlled. This is no surprise as most regulatory requirements do not address this issue competently, or even provide minimal guidance. There is an indication that the control centre for the pipeline will be at the Gas Processing Plant control room. A clear reading of this paper should raise new questions as to how this pipeline should be controlled, protected from overpressure, and monitored.

The Illusions of Leak Detection

Several studies concerning the Corrib pipeline have indicated a desire to improve safety performance and reduce risks by incorporating "sophisticated automatic leak detection" on this pipeline. While common sense would suggest an attempt at some form of leak detection on this system, we must caution that any credit for such a system is highly illusionary for this production pipeline. Despite claims that may be made by leak system manufacturers selling such systems, the likelihood of any of these systems identifying leaks in real time is nearly zero (the author can't rule out random luck accidentally flagging a release). We find claims, assertions, or inferences that any sophisticated automatic leak detection system operating on the Corrib pipeline will actually prevent casualties or fatalities near the pipeline to be without merit. For the record, the author has seen many "leak detection" systems and none has really worked reliably to date. An analysis of the long record of gas pipeline failures will prove the frustrations of trying to get a remote leak detection system to properly signal a real release on a highly compressed gas system (i.e., forget mass balance) without burdening the control room operator with a phalanx of false alarms that train operators to ignore alarms.

The truth of the matter is that for leaks (releases from fixed orifices as described in section IV – Understanding Pipeline Releases), the compressibility of the gas and the multiple phase operation of this production pipeline make leak discovery via remote monitoring extremely difficult if not impossible. It must also be stressed that this gas will be unodorised (the traditional method of alerting the public and neighborhood of possible signs of leaks on a pipeline). The only method that has a chance of determining gas leaks on this onshore pipeline is the tried and true method of walking the pipeline with an appropriate gas detector, and even this approach is not infallible and only detects possible leaks at the time of the survey.

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

It is now important to discuss rupture releases and the inability of leak detection monitoring systems to reliably determine such massive releases. As incredible as this may appear, many in the pipeline industry do not easily understand or grasp this concept so the average layman can be forgiven for not comprehending this point at first review. Leak detection systems are not able to determine the high mass rate releases associated with ruptures in a gas pipeline in a timely manner. This is due to the many transient factors mentioned in Section IV such as the compressed nature of the gas, choke flow, and pipe hydraulic dynamics. As a result, the various critical signals don't get recognised by detection devices either upstream or downstream of the rupture in sufficient time to respond to a rupture and prevent fatalities within the zone. In fact, the number one method for detection of a gas pipeline rupture is a call in by observers who may witness such an event. Unfortunately, given the very large size of the rupture impact zone for this very unique pipeline, callers may not be nearby as those people near a rupture, in all probability, will be dead or dying. It has been suggested that the meter entering the Gas Processing Plant (at the end of the onshore pipeline) can be utilised to indicate a pipeline rupture on the onshore pipeline. Transient release calculations indicate the time it would take for such a clear indication to show up at the Gas Processing Plant, even at this relatively short distance, will be past the major and multiple fatality exposure time for a rupture event.

Any claims that mass balance can identify leaks or failures on this pipeline need to be seriously challenged. Even if one could accurately mass balance in and out of the pipeline there is no way that a correct accounting of the change in gas inventory could permit an accurate leak or rupture detection. This pipeline contains a highly compressible fluid operating in the triple phase region (solid/liquid/gas) with a pipeline diameter that seriously affects transient dynamics. Under our obligation to maintain objectivity and completeness, a meter at the Gas Processing Plant end of the pipeline may eventually suggest a possible rupture, but by the time this signal is indicated (it isn't immediate because of line hydraulics), acknowledged, and responded to by control centre personnel, in all probability the rupture cloud has ignited. Our intent is not to scare, but this is serious material being transported at very high pressures. Frankness is merited especially given the extreme inexperience evidenced in previous statements implying the effectiveness of leak detection to prevent fatalities.

VII. The Myth of Highest International Standards

Major Differences in International Standards

Several international standards have been reported and compared in an accompanying study related to the Corrib pipeline.[25] A reading of that study will leave the observer questioning if there really is a clear guideline standard for this pipeline. There should be no surprise about this confusion as many of these standards are in a state of flux and do not adequately address the very unique operation of the Corrib onshore pipeline. For example, none of the cited standards directly address the extreme pressure operation of the Corrib pipeline (e.g., the pressure is off the chart in various standards that attempt to quantify separation distances from dwellings).

> 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.

The author is often asked about which international pipeline standards are the best. We believe that no one standard is the best. Some standards are better in some areas, even leading edge in certain areas, and very incomplete in other areas. These differences, that can be very important, vary from country to country. One particular country's standards, even if they are "better" in certain areas, may not be applicable to a particular situation in another country as many factors may be different. It is a myth perpetuated by the industry that there are international standards out there that reign supreme, especially if a country permits risk analysis to waive even those minimum requirements that may have been developed through years of experience.

Highest international standard statements tend to create an illusion that can be very dangerous, especially if this illusion relies on misapplication of risk analysis techniques, or if the project team starts to believe their own myths that nothing will fail, and takes very unnecessary or unwise risks in their design approach to reduce costs.

A pipeline design only complying with minimum regulations needs to be carefully analysed and scrutinised. This is especially critical if the project is pushing technical boundaries such as being a "model one" or "off the chart" in the minimum standards. There is nothing that prevents an operator from exceeding any standard. By now it should be obvious to most readers that critical information regarding this project has not been disclosed, and maybe not even considered, and these important details need to be publicly discussed and the project's proposed design reevaluated. This is especially important given the many serious misrepresentations concerning this project as identified in this report. One other important point regarding international pipeline standards is that the physical laws governing prudent engineering approaches know no international boundaries.

The Standard Driving This Pipeline

The standard most often cited in various public documents for the Corrib pipeline is BS 8010 (circa 1992), a standard that has now gone out of date. Because of the need to restrict the length of this paper, the author will focus on the one major section of this code that appears to be driving the over focus on risk analysis or QRA. The BS 8010 code, subsection 2.4.2.4 states "Pipeline designed to operate outside the range of maximum operating pressure and pipe diameters shown in figure 2 may be acceptable provided a more detailed assessment of potential additional hazard is made in conjunction with a safety evaluation (see 2.3)."[26] Figure 2 is a chart of "Minimum distances from normally occupied buildings for methane (a category D substance.)" The chart only goes up to 100 Bar maximum operating pressure. Subsection 2.3

[25] Ibid., Andrew Johnson, "Corrib Gas Pipeline Project Report on Evaluation of Onshore Pipeline Design Code."
[26] Ibid., BS 8010.

outlines requirements of a safety evaluation and includes subsection 2.3.2 defining the minimum requirements needed to incorporate a "Risk Analysis."

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 comparison of the many key issues noted in this paper to previous QRAs for the Corrib pipeline will clearly demonstrate serious deficiencies, mischaracterisations, and/or misstatements in these prior efforts. The QRA approach needs to be seriously re-evaluated for this unique onshore, very high pressure, pipeline system.

Misperceptions and Misapplications of QRA

While it should now be obvious after reading the above section why there is so much focus on QRA for this particular proposed pipeline, additional comments concerning the QRA process need to be captured as a matter of public record. While this author has been very clear that risk analysis for the Corrib proposal has failed to meet the minimum requirements for a risk analysis defined in BS 8010, a brief commentary on several additional common errors observed in all too many risk analyses is necessary. Special attention should be given to any risk assessment that summarily dismisses specific failure cases as "not credible" without sufficient proof. The burden of substantiation should rest on the risk performer to demonstrate why such an event was not evaluated. The dismissal of events as "not credible" can be overly utilised to manoeuvre a risk analysis to a preordained conclusion. That is not the intent or purpose in standards that usually allow the use of this tool.

While a statistically based assessment of failure mode and frequency is required in some risk assessment approaches, all too often the statistical base does not represent the assets being evaluated. For example, utilising past pipeline databases for rupture frequency that include distribution as well as transmission pipelines seriously under represent the high stress pipeline failure frequency, as distribution pipelines don't rupture. Assuming a production pipeline has the same failure frequency from internal corrosion as a transmission pipeline also understates production pipeline statistics for failure, as transmission pipelines are usually not permitted to transport the more corrosive fluids associated with production pipelines. And lastly, we must comment that statistical approaches mainly focusing on past historical events or databases don't properly apply to first of their kind or model one infrastructure. History is a very poor predictor of future failures for such new, complex, at-risk systems that may be pushing the envelope. Ask the NASA launch management team on the last Challenger launch about the follies of rushing to a pre-ordained objective based on past history prediction calls. Quite simply, it should be obvious by now that risk analysis is very inappropriate for this most unusual, first of its kind, application in Ireland.

VIII. Why the Corrib Gas Must be Treated

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

By now the reader should be starting to appreciate that the production gas from the Corrib field creates additional risks on a steel pipeline (see Figure 4, 5, and 7 for just the corrosion issues). The gas is not acceptable to be transported in gas transmission or distribution pipelines. This begs the question of why would such a high-pressure production pipeline be placed in the close vicinity of population. The bulk of the previous discussion has focused on the pipeline for very critical, and by now obvious, reasons. Pipelines can have very large impact footprints in close proximity to people. From a safety perspective, an onshore Corrib pipeline rupture presents the greatest safety risk to the population from a failure because a pipeline rupture will release many tons more material in close proximity to people than a Gas Processing Plant release (the plant equipment has very limited inventory in comparison to the pipeline). The Gas Processing Plant, as presently configured, has additional requirements (such as process safety management or Hazid) that tend to limit the impact of equipment failure to areas on or close to the plant site. A more detailed discussion of the Gas Processing Plant and how its location influences various risk factors on the onshore pipeline is now, however, appropriate.

The Major Contaminants

Liquids (hydrocarbon and water) must be removed from the wet production gas as such liquids not only add to corrosion potential but also create internal loading stresses on pipelines that can be quite high, especially when these accumulated liquids are driven by the high pressures expected for this field and production pipeline. In addition, unique contaminants such as excess CO_2 or H_2S must be treated if they are present in appreciable quantities that might affect transmission or distribution pipeline systems or customer safety. The original design for the Gas Processing Plant includes no removal for CO_2 or H_2S contaminants as the current field apparently, at least at the start of production, is not expected to contain these contaminants in quantities requiring treatment to protect downstream pipelines.

Key Equipment

A simplified flow diagram of the terminal proposed at the end of the Corrib pipeline is indicated in Figure 18. The bulk of this equipment is for simple liquid removal for elemental gas drying.

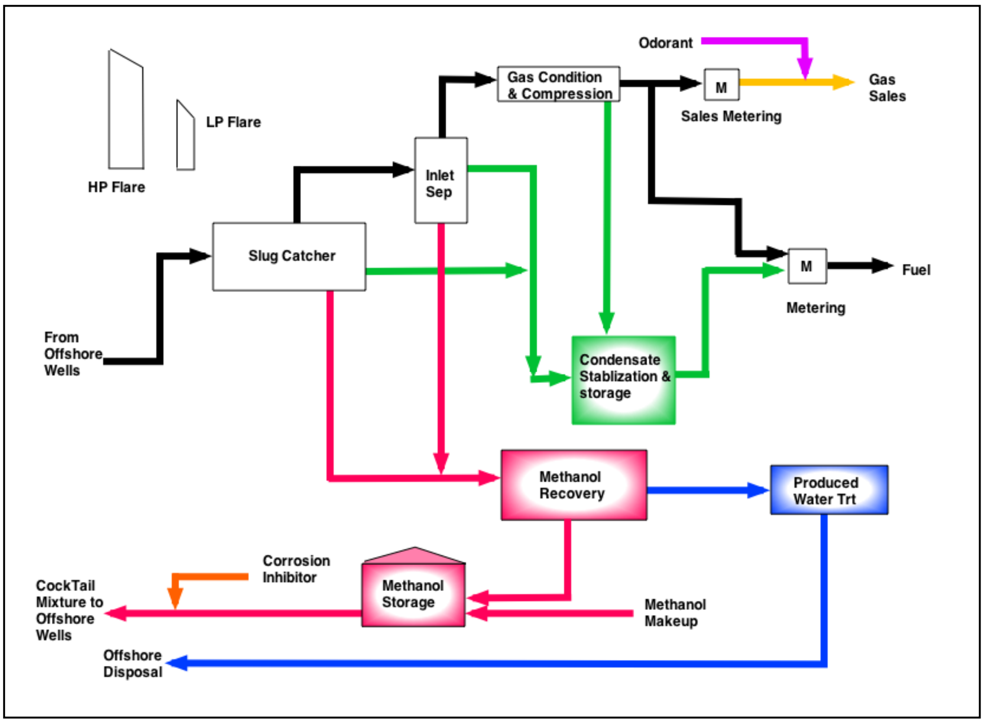


FIGURE 18. CORRIB PROPOSED ONSHORE GAS PROCESSING PLANT BASIC PROCESS FLOW SCHEME

Some minor complexity has been added to separate hydrocarbon liquid from water for fuel use or sale. Depending on the quality of the material from the gas field, a typical gas processing plant usually incorporates phase separation (gas/liquid/solid), additional gas drying as warranted, specialised gas treatment and/or liquid separation (i.e., removal of natural gas liquids, or NGLs). Additional treatment can involve the removal of various impurities and gas contaminants such as CO_2 or sulphur that are not part of the Corrib design to date.

For the Corrib plant, additional minor complexity has been added to process methanol recovered for recycle and reuse in the production pipeline. Some minor storage facilities have also been incorporated. We would classify this proposal as a low to moderately low complex gas processing or treating facility. Much of the stored chemicals are not required in gas transmission or distribution pipeline operations but are intended solely for the gas production line operation.

Cold venting should be avoided in prudent gas processing plant design.

Two flares, a high-pressure (HP) and a low-pressure (LP) flare, are proposed and we have not indicated their specific tie-in points in the facility as that has not been defined in previously reviewed documents. The HP flare will be a tall stack unit designed for a production line capacity of 350 MMSCFD. The LP flare is apparently a much smaller capacity unit (8 MMSCFD) intended for minor blow down or purging during maintenance of facility equipment. For safety reasons, we would advise the use of limited flaring over cold venting (discussed in the next section) given the capability of venting to generate heavier than air vapours that can produce catastrophic events in the area should a release get away from the operator.

Separation and treatment often entail producing constituents for sale, disposal, or re-injection into the producing fields if sale/disposal/use is not viable or economical. The specific plant design, complexity, and location will depend on the quality of the gas produced from the field(s) and the local demands and obstacles. The boxes in white in Figure 18 convey the simple processes involved in phase separation to produce sales gas. The other coloured boxes are additions the operator has selected to improve field efficiency (i.e., profitability) such as methanol recovery and recycle.

FIGURE 19. GAS PLANT SITE LOOKING TOWARD CARROWMORE LAKE

Documents also indicate that additional complexity concerning refrigeration components and storage (i.e., propane) suggest that additional hydrocarbon liquid recovery can be anticipated, either as the gas field ages or additional fields are brought into production.[27] This additional infrastructure would still be regarded as moderate, even if additional bulk storage is required, such as for propane refrigeration. It is important to recognise that this may not be the only production pipeline that might utilise this plant site.

A processing plant, while apparently not specifically defined in the BS 8010 standard, is a combination of process plant/treating, and storage facilities related to a gas pipeline operation.[28]

[27] Ibid., Inspector Report to An Bord Pleanála.

The term “Terminal” apparently is also not defined in the standard, but by reference to the same standard BS 8010 Figure 1, this proposed plant facility is not a “Terminal” in the strictest interpretation. The term Refinery within the industry is usually reserved for the much more complex series of processes intended for crude oil or liquid hydrocarbon processing facilities. We understand that Irish law may carry a specific meaning of the word “Refinery,” but this author is not familiar with this specific legal definition. We would thus characterise the facility at the end of the Corrib onshore pipeline as a Gas Processing Plant. The land footprint for this site would suggest that other major infrastructure is under consideration for this site as the footprint appears much greater than that needed for the basic simple Corrib design needs.

Cold Venting

An issue that can play a pivotal role in onshore siting decisions for a gas processing plant is the matter of cold venting. Cold venting is the release of gas (usually primarily methane) out a gas processing plant vent stack to atmosphere in such a manner that it is not burned. The theory is that the lighter than air gases rise up into the atmosphere. While most streams are mainly methane, which is lighter than air, serious safety concerns appear when heavier than air components or toxic chemicals start to show up in the gas stream than might be vented. Cold venting can be very dangerous, not only for plant personnel but also the neighbouring population. Depending on the composition of the material in the gas stream, especially if a plant is located on a site in proximity to people, dispersion can send heavier than air gas components to ground level with tragic results.

FIGURE 20. LOOKING WEST ONTO SRUWADDACON BAY AND PIPELINE ROUTE TO PLANT

Cold venting is usually the by-product of remote oil field design, but an over focus on capital reduction for gas field development (i.e., to boost rate of return) can drive a company to select cold venting over wiser alternatives that require additional equipment. Cold venting should not make sense in a world where energy prices are increasing, but it can still occur because of the economics and investment philosophies of particular companies. Failure to properly restrict the option of cold venting should be regarded as a serious deficiency and prevented in any modern processing plant design and approval. Several responsible governments and world agencies have incorporated practices to discourage cold venting in their energy field development.

Flaring Issues

Flaring is the intentional burning of gas (in a flare stack) before it is released to the atmosphere (forming combustion byproducts such as CO_2, NO_X and other compounds). Flaring is usually preferred over cold venting as several safety issues associated with cold venting as mentioned

[28] Ibid., BS8010: Section 2.8, “Figure 1. Extent of pipeline systems for conveying oil and gas which are covered by this Section.” 1992.

above are avoided.[29] The major issue with flaring is when plant operators flare excessively, either because of poor plant design or poor equipment maintenance, that results in frequent equipment breakdown causing long duration flaring. Excessive or frequent flaring, in addition to wasting a valuable commodity, can contribute to combustion pollutants, excessive noise (large flares can make a lot of noise), and light pollution. Excessive flaring can now be easily eliminated by proper gas plant design, maintenance, and investment encouraged by proper governmental permitting procedures.

More to Come

If the Gas Processing Plant were the only equipment to be placed at the onshore site it would be fairly easy to recommend its placement as, relatively speaking, the equipment depicted in Figure 18 is fairly straightforward. The plant is limited in complexity and can be easily judged as to its safety by a basic review of: 1) a plant layout drawing to review major equipment placement and separation, 2) various simple P& ID's, and 3) an analysis of the HAZID.[30] The footprint for a simple gas plant is not the large size currently projected (see Figure 3, large red quadrangle), suggesting that other processes may be in future schemes. Given the lack of clarity related to this project to date and demonstrated by this report, it is understandable that the local citizens have little confidence in denials concerning future expectations for this site. It is beyond the scope of this report to analyse all possible additional infrastructures that could be sited, but it would not be beyond reason to assume that an oil refinery would be desired in close proximity to a reliable gas source. It is usually the responsibility of local governments overseeing land use planning to properly communicate the possible future infrastructure that a new energy supply brings to the area. Future site plans or alternatives for the proposed onshore facility should be clearly communicated.

IX. Is the Gas Processing Plant Site Driving the Pipeline Route?

There is a strong appearance that the availability of the Gas Processing Plant land site may be driving the decision to route a production pipeline in an unwise location. Given the choice to site the Gas Processing Plant, the operators have proclaimed that the proposed route for the onshore pipeline is the best route available and other alternatives have serious conflicts or challenges.[31] A quick scan of the countryside would clearly indicate that there are many ways to get to the Gas Processing Plant without utilising the particular route selected by the operator.

In Pipeline Routing, the Shortest path is Seldom the Cheapest

> 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.

Apparently, once the Gas Processing Plant site was chosen, the pipeline route near the bay appears to have been selected as the shortest and easiest path to get to the terminal. Ironically, as seen from Figure 3, this route places a very unique high-pressure production pipeline in close proximity to population. We cannot stress the importance of getting this highly unique production pipeline away from people, not just dwellings. As the public becomes more informed about the lack of clear information about this system, the delays in this project will cost more than any original cost savings ever proposed for this unwise route selection. This is an often observed phenomenon in pipeline routing decisions. Pipeline operators choose the shortest or easiest path based on perceived cost savings only to discover the folly of such

[29] Flaring is often incorporated as a safety design to protect processing plant and personnel. In these modern design schemes such plants rarely flare excessively for long periods of time as such flaring is only required during major plant equipment malfunction or breakdown.
[30] P&IDs are pipe and instrument drawings, while HAZID stands for a hazard identification process required for facilities falling under process safety management.
[31] Ibid., Inspector Report to An Bord Pleanála.

unwise tactics. An informed public becomes wise to their manoeuvres, and delays or changes the project in ways that quickly consume any cost savings that the original easiest path ever hoped to realise. The shortest pipeline path, especially if an unwise selection, is seldom the cheapest.

Land Use Planning

Land use planning as it relates to future activity near infrastructure is a critically important activity, not only when determining pipeline routes, but also for selecting other facilities such as gas processing plants or other complex infrastructure they may attract, such as refineries. The importance of keeping certain threats away from high-pressure pipelines that can release extremely large inventories of material should be obvious by now to the reader of this report. What is less understood is the importance of understanding the infrastructure that may be associated with gas plant siting. Ironically, from a safety perspective, these other non pipeline facilities usually, but not always, fall under the regulatory regime of process safety management.

Process safety management is a basket of requirements that assure that a company's management approach meets certain basic minimum process requirements and checks and balances to avoid potential failures, especially large catastrophic events associated with certain plant assets. It is one of the requirements of process safety management, sometimes referred to as process hazard management, to carefully review plant siting, design, and operation issues when chemical inventories exceed a certain capacity. Unfortunately, process safety management processes usually aren't required of pipelines. Typically a process safety audit requires an evaluation of the potential for various worse case events to leave the plant site. Please note that such a review does not involve an evaluation of environmental issues or concerns, and usually doesn't capture the impact or additional risk such a facility places on the pipeline.

X. Advice for Government, Public, and Regulatory Authorities

It is beyond the scope of this paper to pass judgment as to how a critical energy supply should be developed for Ireland. That is an issue best left to the Irish government and its citizens and the companies they choose to do business with. It is, however, clearly within the scope of this report to make observations as to the correctness of technical information related to this project and various options.

Various Offshore vs. Onshore Options

There are three basic fundamental processing option schemes for the Corrib gas field. The lengthy but very professional Inspector's Report should serve as an important information resource to explore these options in more detail if the reader is so inclined.[32] Several important factors (pros and cons) for each option are summarised in Table 1 for the reader's consideration. These options are briefly summarised as follows and are not intended to be an exhaustive list:

Option 1 Deep Water Offshore Processing Platform Located at Corrib Field

This scheme places a deepwater platform in water (350metres) with very harsh Atlantic weather conditions approximately 80 kilometres off the west coast of Ireland. Gas processing would be included on the platform and a gas transmission pipeline would run to landfall. This is similar to earlier traditional North Sea processing schemes.

[32] An Bord Pleanála, "Inspector's Report on Gas Terminal at Bellagelly South, Bellanaboy Bridge, Belmullet, Co. Mayo," signed by Kevin Moore and dated April 2003.

Option 2 Shallow Water Processing Platform with Processing Near Shore

Similar to Option 1 except the platform is moved closer to the Irish coast where it could be fixed to the ocean floor in shallow water and with much fewer challenges (and costs) than the deep water site. This option is similar to many traditional fixed offshore platforms across the world located in shallow water. Production pipeline from Corrib subsea wells would be routed to the offshore processing plant via a subsea production pipeline. A shorter transmission pipeline would be needed to make landfall.

Option 3 Onshore Processing Plant

A subsea production pipeline with a suitably routed onshore production pipeline would be placed in a proper location route to a suitably placed onshore gas processing plant.

TABLE 1. BASIC CORRIB GAS FIELD DEVELOPMENT OPTIONS

Option	Pros	Cons
Option 1 Deep Water Offshore Processing Platform Located at Corrib Field	1. Out of sight from land. 2. Safest for local communities. 3. No real environmental risk to communities. 4. Much lower transmission pipeline safety risk vs. higher production pipeline risks.	1. Most expensive by a wide margin. 2. Legitimate safety concerns at challenging platform site. 3. Potential offshore environmental risks. 4. Serious delay in field startup/development.
Option 2 Shallow Water Processing Platform with Processing Near Shore	1. Safest for local communities. 2. Much lower transmission pipeline safety risk vs. higher production pipeline risks.	1. Possible sight pollution from land. 2. More potential coastal pollution. 3. Still costly but much cheaper than option 1. 4. Shorter delay in field startup/development.
Option 3 Onshore Processing Plant	1. Cheapest option. 2. Lowest worker safety concerns. 3. Limited delay in field startup, development.	1. Most safety risks to communities. 2. Most environmental risk to communities. 3. Very limited local confidence in present proposal.

The simple comments in Table 1 focus on several fundamental factors: aesthetics, safety, environment, and economics. The reader can probably come up with additional factors, but these basic factors will raise enough discussion for the various players on a general level. How this project proceeds will be influenced by some combination of the approach decision makers take in prioritising at least these factors into their approval process. For example, the operator may tend to over focus on the economic factors (which usually aren't made public) at the expense of safety. Local citizens may tend to place a higher priority on aesthetics or quality of life issues at the expense of more economic considerations, especially if they don't realise any economic benefit while incurring all the perceived risks. Any project of this nature or magnitude requires proper communication, rational compromise, and appropriate balance. This can only occur if all parties bring to the table a willingness to discuss and agree on key fundamental facts, a process difficult to achieve in an atmosphere of deception or distortion. It is hoped that one of the objectives of this report is to get key leveraging facts on the table to allow parties to move constructively forward.

Dangers Associated with Retrofitting New Processes Onto Old Sites

All too often lately land that has been determined to be unsuitable has been made available, especially from governments who are looking for a quick way to unload a poor site on the next owner. Sometimes this bargain works out for all parties. Too often, however, cash strapped governments unload these sites in exchange for years of trouble for themselves and their constituents. Such fools' bargains end up being anything but a bargain for all. Governments typically answer to the people and it usually difficult to hide a bad arrangement that only gets worse with time. Bargain land sites that are inappropriate for their new use seldom end up saving money as retrofits or complications increase cost or seriously delay projects, while increasing the likelihood of system failure due to increased complexity from various quick retrofit fixes that should never have occurred. If a fundamental site is poor for its newly selected purposes, expect many delays in project schedule that can eat up profitability (and rate of return) because of the time value of money.

The Failure and Misapplication of QRA

In a more complex society, risk analysis or QRAs can be a valuable tool to ensure proper resources are allocated to a project. While a QRA can serve as a valuable tool, one should be on the lookout to determine if this approach is being misapplied to hide or confuse the real risk of a poor project approach or design. Too often QRAs, even those permitted in regulatory standards, can be manipulated or biased to serve a preordained objective, which is not the purpose of such an important tool. Warning signs that signal problems in QRA approaches are: 1) the inability to clearly define or commit to the project's base case and its important boundary parameters, 2) an undercurrent permeating the analysis that equipment can't fail, causing serious bias in the outcome, 3) limited evaluation indicated by a preponderance of too many "not credible case" determinations without sufficient backup documents proving such determinations, 4) misapplication of historical statistics that don't apply to the project conditions, 5) failure to recognise that new cutting edge applications are beyond the bounds of historical statistics and that failure mechanisms may thus take on new forms, 6) overemphasis on component failure that ignores the more likely probability that the system will be driven to failure by linked system complexity injected from quick fixes, 7) inconsistency in outlining a project's objectives, 8) an over-emphasis in presentations on low probability even though the consequences are enormous (like severe loss of life), 9) a sense that the analysis is failing to remain neutral, and 10) failure to tell the truth. There may be differences of opinion, but certain fundamental physical issues are hard to dispute once they have been uncovered. If too many of the above are showing up in a risk analysis for a project, the risk analysis approach needs to be rejected.

> The previously discussed issues 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).

Environmental Factors and Long Term Effects

It is not the objective of this paper to perform a detailed analysis of the possible environmental factors associated with this project. It should be obvious by now, however, that many issues have been identified that any decision concerning this project must include. Any environmental analysis that fails to address the long-term ramifications on its surroundings would be seriously deficient. All too often the message on the benefits of a project focuses only on the short-term issues (especially on QRA), while ignoring the long-term costs that are very real and may easily outweigh the short term benefits by orders of magnitude. This is an outcome of today's misinformation society where the rush to produce short-term results tends to overlook or understate the very real costs associated with the long-term impacts. And, of course, a major issue to all players is what the proposed gas plant site would look like a decade from now. A possible industrial complex can have serious implications for the area that may not be in line with its citizens' intentions.

Lastly, we have focused on the terrible consequences associated with fire/explosion from a pipeline failure. We need to not lose sight that there are pipeline failures where fire would not occur such as leaks and even some ruptures. Fire, while thermally destructive, tends to eliminate via combustion those chemicals that might be associated with future composition changes. The nature of releases without fire should not be toxic or have long term environmental effects that cannot be remediated, provided the composition of the gas transported in the pipeline has not changed markedly. The unknown in this prediction is the nature of the gas that may be produced or discovered in the future, especially if new fields introduce more toxic compounds, such as H_2S. It is advisable that this should also be considered in land use planning when choosing an appropriate site. In addition, while the production pipeline may not introduce long-term environmental effects, its failure could cause a release of the utility pipeline with its hydraulic, methanol/corrosion inhibitor cocktail lines. This cocktail mix could be a special problem to water given the tenacity for the cocktail to seek and hold onto water. Limited spill volume from the utility line would probably restrict the size and effects associated with long term environmental damage provided such releases are quickly addressed. Generally, the nature of a gas pipeline and its gas processing facility is limited on its long term environmental impacts compared to more industrialised facilities such as oil refineries. This does not mean that an improperly designed or operated gas plant cannot cause environmental damage, but by its nature a properly designed, operated, and maintained facility is limited on its long term impact to the environment including air, water, and nearby population.

Third Worlding and the Misuse of Land

Within the industry a term has become popular lately: "third worlding." In this context, third worlding means to unwisely allow use of land for purposes that, in all probability, will result in severe loss of life. However, the country's government places so little real value on such loss, that corporations, or for that matter, governments are willing to take the risk of massive catastrophic failure, usually for perceived short term gain. Now there is still a lot of open land in the world where very high risk corporate adventures would not place large populations at risk. Unfortunately, the reader can probably bring to mind examples where short term gain has driven governments to take foolish risks. Look for indications of over application of QRA to hide such poor risk approaches. Someone once told the author that risk management was the tool for the few in power to impose their will on the many. If I recall correctly, the person credited with that quote was talking about the Three Mile Island nuclear power plant, before the meltdown!

Liability and Financial Impacts of Poor Risk Management

In keeping with the theme that risk analysis may not be properly applied to a project, especially to an effort of this magnitude, each country and its citizens must decide the liability/reward equation for its interest. One of the factors showing up in too many countries is the phenomenon where fines or penalties are relatively small or inconsequential for inappropriate actions as compared to huge profit potential. This big profit/small fine factor can drive decision makers to take unwise risks that are not captured in a risk analysis, for example. From an international corporation's perspective, the risks are worth taking as the liabilities are perceived as small. In analyzing many failures in energy infrastructure, this author has observed in too many situations, how a group of very smart people in a company or government, can end up doing ill-advised things that as individuals they would never do. Liability risks can serve as a proper check and balance on such unwise processes to ensure businesses and governments stay professional and avoid recklessness. A question that needs to be answered by the citizens of Ireland concerning the present proposal is whether Irish law would permit legitimate actions for criminal negligence that caused serious environmental damage or loss of life. Some countries have such laws and effective processes in place to enforce them. This issue can be leveraging if risk management is applied in countries with few or illusionary liability risks that are not just reserved for third world countries.

XI. Conclusion and Recommendations

It should be fairly obvious by now that past information on this project has been less than complete. Much of this information appears to be of a propaganda nature intended to spin public relations to an ill informed or misinformed public or government. In today's information age this is a tactic fraught with risks as the deceptions are uncovered.

Regarding the proposed onshore pipeline route, serious challenges should be raised as to any risk analysis that fails to adequately address the issues raised by the production pipeline, as the thermal impact zones for this very unique high pressure pipeline are quite large with a high probability of mortality. It is the opinion of the author that the risks of the pipeline have been considerably understated. Various critical commitments that would ensure that the pipeline would not fail have not been clearly demonstrated or obligated, a serious indication that in all probability risk assessment is not appropriate for this project. If the Gas Processing Plant site location were to remain as proposed, we advise a reroute of the proposed pipeline incorporating safety buffer zones of 200 metres for dwellings and at least 400 metres for unsheltered individuals.

The recommendation concerning the placement of the onshore Gas Process Plant is more complicated by the unknowns associated with potential future complexities or possible additions that have not been defined in this project. The placement of a relatively simple Gas Process Plant onshore at the end of a production pipeline would not in itself create an unwarranted safety risk to the local public from the plant. Placement of a Gas Process Plant on a shallow offshore platform would substantially reduce production pipeline rupture impact zones associated with specific pipeline design modifications. A transmission pipeline from such an offshore facility could be operated at lower pressures, move much higher quality gas, and permit appropriate cleaning and smart pigging programs that would reduce the potential impact zone associated with a gas transmission pipeline failure. The final decision on the Gas Process Plant site placement rests with the citizens. It is hoped that this report permits all parties to shift into a more responsible dialogue and reach a more informed and balanced decision on this critical matter.

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