

OPTIMISING THE LAND-USE AROUND TRANSMISSION PIPELINES

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SYNOPSIS

This paper shows that the present more simplified approach to risk assessment for high-pressure hydrocarbon pipelines is somewhat conservative. The outflow modelling is more complex that might be predicted by the traditional, simple outflow equations due to two-phase formation in gas pipelines and froth formation in oil pipelines. The consequence models for jet fires, historically based on flare type model, are shown to be conservative. Taking these two points together the magnitude of the hazards can be overstated. The failure rate data for (underground) pipelines show that the greatest causes of massive releases are due to mechanical faults and third party intervention. When these effects are dealt with through design standards and policing of the pipe corridor the full bore failure rate of oil and gas pipelines is very low, 2×10^{-5} per kmyr which indicates that the frequency of the hazard is probably significantly over stated.

Taking all of the results together, both failure data and modelling, and knowing the specifics of each case, the assessed risks for land-use near Transmission Pipelines will be reduced, so releasing land for use in strategic areas.

INTRODUCTION

There are many potentially hazardous materials transported in pipelines at high pressure within the United Kingdom. Failure of the pipeline could affect a large population if it is close to residential houses. As a result there is careful attention given to land use close to such pipelines. However, in the United Kingdom, there is a high population density particularly near industrial areas and there is a conflict between the need for development of land for industry or housing and the need for the maintenance of the safety of the public at large.

Example of the piping in use are 17000 kms carrying high pressure Natural Gas, 200 kms carrying “live crude oil”, 200 kms carrying high vapour pressure LPGs and 1000 kms carrying high pressure Ethene. There are, in addition, other pipelines carrying refined hydrocarbon products for both civil and military uses.

Inevitably there is pressure to develop land closer to the pipelines. The requirements for land-use planning are generally given in the Third Report of the Advisory Committee on Major Hazards (ACMH 3) [1] and the Health and Safety Executive’s approach to risk criteria are discussed in Risk Criteria for Land-use Planning [2]. In this there are general duties placed on the Planning Authorities and the Health and Safety Executive. The first has to take the decisions taking into account the potential gains and risks to the local community and the second gives the assessment of the risks in order to make a Safety Judgement. ACMH 3 highlights this clearly, “Decisions where safety is involved often present a dilemma for the planning authorities. In many cases the authorities have to weigh up the advantages which a proposed development might bring against the disadvantages that more people might be at risk. The decision is less difficult when the risk is very great or very small, but in many cases fall between these extremes" [paragraph 111, verbatim]. However ACMH 3 then states further on in paragraph 111 "When a planning application is being considered a balanced view should be taken of all aspects including social and economic factors and not just health and safety".

It is at this point that there may be some conflict between the planning requirements and the risks defined by more simple risk models. As a result more sophisticated risk models and assessment are required. However many risk screening models are of necessity relatively simple, quick to use and also introduce some conservatism, which may preclude development in an area that might be assessed as "safe" if more sophisticated models were used. This paper discusses those areas where the conservatism may arise and shows that there has to be a better understanding of the outflow characteristics of the fluids, the consequence modelling and of the appropriate failure rates for piping. It is clear that the outflows for hydrocarbons in particular are complex, they can not be treated as simple fluids and the modelling must take into account the physical properties of the fluids at the transport conditions. The consequence models, particularly for fires, have to be re-examined to ensure that they represent the reality pertaining to the conditions of the assessment. Finally the failure rate data have to be carefully examined on a case-specific-basis to ensure that they are robust and relevant.

A significant percentage of this paper is based on work carried out following the Piper Alpha disaster as it was essential that the oil industry understood the out-flow characterises of both oil and gas pipelines in great detail when determining the need for sub-sea isolation valves (SSIV) and the fluid properties temperature, flow and phase. This work can now be applied to on-shore pipelines.

OUT FLOW CHARACTERISTICS

The out flow characteristics from high pressure pipelines are too complex for them to be reduced to simple single or two phase models. In the case of high pressure hydrocarbons operating in the dense phase above the critical pressure the fluids enter the two-phase regime following pressure loss resulting from loss of containment. In turn the compression wave velocities fall to a fraction of the gaseous values, the fluid is released as an aerosol and in some conditions it may pass through the phase diagram and be released as a cold gas. This in turn reduces the out flow rate but extends the duration. In the case of liquids with elevated vapour pressures transported at a pressure greater than the vapour pressure the fluids "boil" on loss of containment and are released as a froth or aerosol.

In the case of high-pressure hydrocarbons such as high-pressure Natural Gas and Ethene the temperatures of the fluids and the piping may fall to levels which might compromise the integrity of isolation valves. Further the reduction in the compression wave velocity in the two-phase fluids can result in the crack propagation velocity being greater then the compression wave velocity and there is then a "running crack" which will propagate from the source to the end of the line. In the worst-case scenario this will result in a crack starting in a benign zone of the pipeline route propagating into a sensitive area. The effect of this is that the contents of the pipeline will be released as a line source and not a local point source.

The outflow characteristics from severed high vapour pressure oil pipelines, which were modelled by the computer code OLGA [3], are discussed in Oil and Gas Pipeline Failure Modelling [4]. In this typical sub-sea oil pipeline with length 100 km and diameter 0.6 m (24 inches) was modelled with different vapour pressures (compositions are given) and static heads. In the paper it is shown that the pressure, the diameter, the length and the properties of the fluid dictate the outflow characteristics. This indicates that the simple assumption, that there will be no flow from a live crude oil pipeline provided the static head of a column of fluid is greater than the vapour pressure of the fluid, is totally erroneous. The out flows of the oil were first dictated by the stored energy in the fluids and the pipeline (line pack) and then by the physics of the system. Initially, for a severed line (full bore rupture, FBR), the pack was some 25 to 50 tonnes; thereafter the vapour pressure of the fluid and the static head of the fluid dictated the out flow. In the case in question the modelling was carried out as a single fluid in a pipeline with the two ends at different elevations representing different riser heights. (The riser is the vertical section of pipeline which connects the pipeline on the seabed to the platform itself.) The vapour pressure was then varied by adjusting the composition and the temperature. The initial loss of containment resulted in the lower molecular weight components "coming out of solution", this in turn resulted in the mean density of the column of fluid falling from about 825 kg/m^3 to about 275 kg/m^3 and as a result the imposed head at the bottom of the column would be below the vapour pressure of the fluid. The nett result was that the fluids in the 100 km reservoir of liquid in the horizontal section of the pipeline would release the lower molecular weight gases, which would then drive the "bubble pump". In reality the physical properties of oils would result in a foamy system and not discrete bubbles. The final result is that the reservoir of fluids would release about 10 % of the line content at a rate of 500 kg/s falling to 250 kg/s. The outflow with time will be regulated by two–phase pressure drops and not the traditional single phase as well as the residual driving gas reserve in the pipeline. The result is that flows will arrest at some time after the initial rupture. Figures 1 to 4 show the typical outflow characteristics. The outcome of this analysis is that any severed pipeline either under water or under ground carrying high vapour pressure oil has the potential to release a significant percentage of its total content over some minutes and only when the true static head imposed by the line contours exceeds 3 times the vapour pressure of the oil being transported is non-continuous release from a severed riser, or pipeline, realistic.

The small-bore releases were not modelled in detail. However it is clear that the line pack must be released before the pressure in the line reaches atmospheric pressure. Due to the surface chemistry the frothing action will ensure that there is still some of the line content discharged, but that will be dictated by the position of the hole and the line contours. Theoretically, for a long horizontal oil line transporting fluids with an elevated vapour pressure, nearly all of the fluids will be released following rupture but at a rate declining with time. This has some significant implications for a Pipeline Integrity Monitoring System (PLIMS) that uses mass balance and pressure transients to detect loss of containment. In the theoretical example in [3] the line capacity is about 300 kg/s and for a 25 mm hole at an operating pressure of 70 bar the outflow will be about 39 kg/s, if on the seabed, and 54 kg/s, if on land. Of this total outflow about 3 to 5 % will boil off. The impact of small releases with breach sizes of less than 2.5 mm suggests that there will be more environmental risk than human risk and that it may be some time before the initial defect is detected by the PLIMS and the pipeline is shutdown. As first the pressure profile may not change significantly and also the mass balancing may not be sufficiently accurate to detect such small releases.

The outflow from a dense phase gaseous pipeline is equally complex. Once the fluids enter the two-phase regime the standard rules break down. The initial compression wave velocity will be about 380m/s for Natural Gas and about 310 m/s for Ethene but these could fall to well below 100 m/s. The reduced compression wave velocity in the two-phase fluid, about 5 to 10 % wet, forms this choke. See figure 1. The flow characteristics are then determined by the flow through the moving choke inside the pipeline and the frictional pressure drop. Once again using the code OLGA [4], a study [5], based on a typical North Sea gas pipeline operating at a pressure of 170 bar, the pressure at the exit of the pipeline choked at about 20 bar (compared to the hydrostatic pressure of 10 bar). The moving choke within the pipeline resulted in fluid velocities of about 175 m/s, falling with time, and the gas temperatures which fell to about 200K within 60 seconds. (The wall temperatures were about 5K warmer.) The pressure and temperature at the closed end of the pipeline does not change for some time; in the case of a long pipeline it could be many minutes. In effect the gas at the closed end of the pipeline is "dynamically isolated" from the rest of the pipeline and does not start to depressurise until the choke reaches it. This is to be seen in figures 5 and 6. A similar effect is to be found with Ethene [3] where the temperature falls as low as 169K. The nett effect is that once the moving choke is established the frictional effects greatly reduce the out flow within seconds. In this study the out flow fluxes fell to 5750 kg/s/m^2 in 30 seconds. In the Piper Alpha Disaster [3,6] the outflows fell, both by calculation and the fireball modelling, from a peak instantaneous value of 7000 kg/s to about 1000 to 2000 kg/s within 15 seconds depending on the assumed wall roughness. The later flows give fluxes of between 3500 and 7000 kg/s/m^2, which are similar to study [5] using OLGA [4]. Modelling the flames seen in the Piper Alpha Report [6] shows that the outflows some 2 hours into the event were about 50 to 100 kg/s and even after some 24 hours the flows were a few kg/s. This demonstrates the difficulty with depressurising long pipelines.

Clearly the modelling of the outflows for high pressure gases, be they hydrocarbon based or other, is very complex and requires more sophisticated analysis with time than the simple traditional flow models. The implications of this analysis is that the outflows will have a longer duration but at a lower absolute rate. If the initial concern is for radiation levels, as is to be expected the simple modelling will over state the risk. If the initial concern is for the safe dispersion of the gas the high initial out flow will generate a trench and thereafter the jet effects will result in jet dispersion.

The outflow characteristics from other piping systems where there are no complex phase effects can be modelled by the traditional out flow models, but the "pack" created by the strain energy in the fluid and the pipe walls must still be taken into account.

CONSEQUENCE MODELLING

The consequence modelling of hydrocarbon systems in particular requires an understanding of the dispersion and combustion processes. For other fluids there will be particular special features such as toxicity. More particularly there is the need to understand the failure modes of the piping itself.

First the material properties of the pipeline must be understood. In the case of dense phase fluids the drop in the compression wave velocity is such that it can be below the crack propagation velocity in the pipeline wall, which could result in a "running crack" in high pressure pipelines if crack arresters are not fitted. Also pipelines, which are highly stressed and have a low "toughness", are not tolerant of small defects, which could run into a total rupture. Conversely, lines which are less highly stressed, can tolerate quite large defects without the risk of total rupture, Fearnehough [6] suggests that, provided the ratio of the imposed to minimum yield stress does not exceed 60%, running cracks are unlikely for corrosion, and for "man-made defects" the value falls to 30%. However in the case of dense phase fluids the compression wave velocity influences the situation and the maximum stress will always be at the crack tip resulting in the potential for a running crack. The implications of this are quite significant. Highly stressed pipelines may spontaneously rupture and pipelines transporting dense phase fluids may split and the crack may run from a "notionally safe" zone to a zone where there may be a significant population. In particular it has some significance for the Offshore Gas Industry where tests on scored pipelines on land and under water produce different responses [8].

The effects modelling of a sub-sea release of oil or gas are somewhat different to those on land. The effects will be very much location dependent. In the case of on-shore releases the effects will be one of:

- Dispersion
- Pool fires
- Jet fire
- Fire-ball

Dispersion without ignition is taken as a safe event other than for toxic or aggressive materials. However the fires are different. The geometry of pool fires and fireballs are fairly well understood but the geometry of jet fires, particularly those with high liquid contents are less certain. The traditional approach to a jet fire has been to model it as a flare using the work of Chamberlain [9]. This has been proved to work on flares but the results are less applicable to the releases in question. Examination of video footage of test liquid jets [3] and an analysis of real measurements on blow-outs [10] show that the predictions of the geometry are less certain. In addition the aeration of the fire has an effect on the Surface Emissive Powers (SEP), "optically thin" flames such as Methane have low SEPs with emissivities about 0.1 and flames which have soot as the radiating species have higher SEPs with emissivities approaching unity. The literature gives a whole range of SEPs ranging from an impossible value of 1000 kW/m^2 to less than 50 kW/m^2. The theoretical maximum SEP based on an energy balance round a flame is about 500 kW/m^2 but in reality non-idealities result in a maximum nearer 350 kW/m^2. The traditional way of assessing the amount of heat radiated from a flare has been to assume that a fraction of the total combustion heat, designated as "F", is radiated. This ranges from 0.1 to 0.35. Various references for values of SEPs are quoted in Reference [3] but some rules can be derived from the observation of flare flame colours. For methane the

SEP is about 75 kW/m^2 and for ethene it is 300 kW/m^2. A value of 100 kW/m^2 would be applicable to Natural Gas. Reference [10] gives some very useful real time measurement of SEPs around a blow out. Not surprisingly the values vary round the flame surface and are influenced by the local aeration such that the highest values are to be found on the upwind side. For the release of a well fluid with a gas to oil ratio of 0.10 to 0.15 wt/wt the SEPs were 150 kW/m^2 at the upwind side giving an overall SEP which would not exceed 150 kW/m^2. These figures are quite consistent with the SEPs from very high-pressure jet sources quoted in Reference 3. It is proposed that the SEP for a Natural Gas type torch fire is 75 kW/m^2 and for an oil based torch is 150 kW/m^2. Likewise the accepted SEP for a fireball is 250 kW/m^2.

The flame geometry for the only well (17A) that was well documented in Reference [10] shows that the predictions from Chamberlain are somewhat in error for blowouts. This is quite to be expected, as the mass fluxes at the source will be well outside the experimental boundaries. The results are compared in table 1.

Table 1. Results of analysis of well 17 a based on references [9] and [10]

Observed frustum length (m)	Observed maximum diameter of frustum (m)	Assessed percentage of heat radiated based on flame Shape (%)	Calculated frustum length (m)	Calculated maximum diameter of Frustum (m)	Percentage of heat radiated based on graph in reference 8 (%)
45	17	11.1	65	27	28

It will be noted that the sizes of the flames in Reference [10] are smaller than that predicted in Reference [9]. Not only are the predicted flame dimensions longer and wider but also the shape is fatter, also the amount of heat radiated is less. Taken together, the distance to a tolerable heat flux would be over stated by a factor of 2 by Reference [9]. (Although there is data from other wells in Reference [10], including the release rates, the size of the source is open to interpretation so were not included in this analysis). The value for the percentage of heat radiated in this assessment is very much in line with that experienced in real blowouts.

There is always a difficulty in predicting the SEP for a flame as it is affected by the physics and chemistry of the combustion process. The physics are the nature of the source and the mixing/aeration of the jet and the chemistry is the pyrolysis of the heavier molecules leading to soot or the primary radiating species in the flame, and thereby the reduction of the total heat that can be released. While Chamberlain predicts a radiated heat release for Methane of 15 to 29% the real value for the design of flare stacks is nearer 15 % for low velocity flares and less than 10% for high velocity flares using the Coanda effect [11]. Further observed jet Methane flames are almost translucent giving radiant heat releases of well under 10 %.

The modelling of fireballs is relatively simple. The fireball is taken to be a sphere and then the sphere is assumed to sit on the ground. This has to be reviewed against the likely flame characteristics. The generally accepted parameters of Diameter (D_{Metres}) and Fireball Duration ($t_{seconds}$), for fireballs containing less than 35,000 kgs of fuel, are given [12] as:

$D_{Metres} = 5.8\ M^{1/3}$
$t_{seconds} = 0.45\ M^{1/3}$

These can be solved to produce a burning rate per m^2 of flame surface, this is 0.021 kg/m^2s. In the same manner it is possible to assess the burn rate for pool fires in the range 0.008 $kg/m^2/s$ for small fires rising to 0.014 $kgs/m^2/s$ for larger fires. It is now possible to assess the stand off distance should the release of fuel be ignited as a fireball. The dimensions have been compared to the photographs in the Piper Alpha Report [6] as shown in Table 2.

Table 2. Comparisons of observed and assessed fireball dimensions for Piper Alpha

Observed fireball diameter (m)	Outflow from fireball dimensions (kg/s)	Calculated outflow from line dynamics (kg/s)
340	7600	7000
180	2000	1000 to 2000 *

*Dependent on the roughness factor used

Clearly the model is consistent and can be used to assess any fireball knowing the outflow of fuel. This has been used for past offshore designs to assess the separation distances of "occupied structures" from Riser structures.

However for the full bore leakage from a severed oil pipeline, which has a vapour pressure greater than 101 kPa, there will be a fair measure of rain out and the fuel will burn as a mixture of a fireball and jet fire with the appropriate SEPs. The residue, which may be as high as 75%, will then burn as a smoky pool fire with a SEP of 75 kW/m^2 or lower.

FAILURE RATE DATA

It is evident that failure data for pipelines have to be examined with care to ensure that the data are both robust and relevant to the specific environment and fluid. Process piping may have a benign fluid and a harsh external environment and vice versa. For example the low temperature hydrocarbons such as Propane at a temperature of less than 273 K is a non-corrosive fluid but the external corrosion (corrosion under the insulation) can be rapid if the engineering is poor. Possibly the most secure source of oil pipeline failure data is CONCAWE where there are both annual reports and a 25-year summary [13]. In this report there are 341 recorded incidents of leakage in 520,717 pipeline years. The data have been examined in some detail and are summarised below in Table 3.

Table 3. Break down of main causes of transmission pipeline CONCAWE (Note the values sum to 345)

Cause	Number of incidents
Mechanical (construction)	32
Mechanical (materials)	56
Operational	25
Corrosion (internal and external – cold oil)	51
Corrosion (external – hot oil)	37
Corrosion (internal all lines)	18
Natural Hazards	14
Third Party	112
Third Party (accidental)	86
Third Party (incidental)	18
Pump Stations (included in the above)	43

However one of the major causes of leakage is Third Party (112) and again one of the sources of internal corrosion is to be found in Hot Oils. When the results are examined to determine the main causes of leakage in the pipeline itself the overall, cold oil corrosion rate both internally and externally is 10^{-4} per km per yr. It should be noted that crude oil can and often does contain traces of water so the internal environment of an oil lines may be more hostile than that of, say, gas pipelines. Further, while construction faults can be expected even in the best-regulated country, material defects are amenable to good engineering. More particularly for pipeline alone, not including fittings, the mechanical failures were only 35 of which 6 were "dents", 5 were "weld faults" and 13 were faulty materials (11 more were classified as "other" and "above ground"). This suggests that the Mechanical Failure Rate should be 0.5 x10^{-4} per km per yr.

The third party causes are the largest common cause of leakage as shown in Table 4.

It is assumed that the reference to drilling means drilling into the line to tap the fluids, that is with the intent to steal.

Table 4. Causes of third party damage to pipelines

Cause	Number
Other	7
Ploughing	26
Digging	32
Bulldozing	11
Drilling	7
Unallocated	3

More particularly, well over 50% of the third party damage is due to trenching and farming activities. There is also clear evidence of the third party damage being both Company and Country related and the spread is a factor of 5 by Company and 3 to 4 by Country. The likely Third Party Failure Rate for the UK should not exceed 0.5×10^{-4} per km per yr.

The final oil pipeline failure rate for the UK should be as follows:

Table 5. Failure rate for oil pipelines in the UK based on CONCAWE data

Cause	Rate (per km per yr)
Corrosion	1×10^{-4}
Mechanical	0.5×10^{-4}
Third Party	0.5×10^{-4}
Total	2×10^{-4}

The CONCAWE report does show that overall there is a downward trend in failures per kmyr over the last 25 years (60% over 25 years) although the average age of the pipeline is increasing. The report also suggests that larger diameter pipelines, as might be expected, are less vulnerable to damage. A previous analysis of CONCAWE annual reports for the years 1982 to 1991 [3] gave an indicative total failure rate for oil pipelines of 2.62×10^{-4} per km per yr. Bearing in mind the larger data base and the downward general trend in failures these two numbers match well. However it is not only the failure rate but also the failure rate spectrum that counts. Possibly one of the more reasonable conclusions of the CONCAWE report is that the use of On Line Inspection Vehicles (OLIV) can go a long way to preventing leakage. It is possible that the downward trend shown in the 25 year analysis is to some degree explained by their usage.

The CONCAWE reports do not give explicit failure sizes and some deduction is required. If Full Bore Rupture is taken as resulting in greater than or equal to 1000 m^3 of material released, only 9 failures of this size or greater were of in pipelines giving a rupture rate of 1.8×10^{-5} per km per yr, averaged over the 25 years, which is similar to Reference 3. Moreover only two of these large events were due to corrosion the rest being due to impact, construction or material deficiencies. The final spectrum of smaller leaks is impossible to assess from the data but a reasonable judgement suggests that the spectrum would be 1/3 of 25 mm and 2/3 of 10 mm. If the improvements in leakage rates are sustained a further factor of 0.7 could be applied for pipelines built in recent years [13].

Table 6. Suggested leak spectrums for pipelines in UK

Leak size	Frequency per km per yr
FBR	1.8×10^{-5}
25 mm	6.1×10^{-5}
10 mm	12.1×10^{-5}

It is worth comparing the failure rate data for Gas Pipelines quoted by Fearnehough [7].

Table 7. Leak spectrums for UK gas pipelines [7]

Leak size	Frequency per km per yr
Over 80 mm	7.5×10^{-6}
20 to 80 mm	2.2×10^{-5}
O to 20 mm	2×10^{-4}

A further set of Oil Pipeline failure data is to be found [13].

Table 8. Leak spectrums for UK sub-sea oil pipelines [14]

Leak Size	Frequency per km per yr
Over 80 mm	4.43×10^{-3}
20 to 80 mm	5.04×10^{-4}
10 mm	1.7×10^{-3}

These data include fittings and such events as trawl board and anchor impacts. Clearly the spectrum is totally different and this data set is neither relevant nor applicable to the on-shore pipelines.

DISCUSSION

The modelling of out-flows from hydrocarbon pipelines is exceedingly complex and requires the use of sophisticated modelling. The flows will be both smaller and longer duration than that predicted from the standard out-flow equations. This results in the instantaneous worst-case hazard being over stated. By the use of more complex calculations it can be shown that out-flows are significantly less and therefore the perceived risk is lower.

The consequence of a leaking pipeline, other than the environmental impact, is likely to be a pool fire, a torch type fire or a fireball. The modelling of pool fires is robust, provided that the SEP can be assessed with accuracy, but the jet type fires assessed from the effects models are also complex and at present the oft used correlations for oil leaks, and also liquid oil product leaks, significantly over state the potential hazard. The resultant fireballs for ruptured oil pipelines will not involve total vaporisation and a significant proportion will burn as a smoky pool fire. In particular the effects of an ignited oil based leak will be over stated if it is not analysed in the correct detail. For jet fires of the gaseous form the present correlations are robust. The jet fire models previously used can be recalibrated for the releases of high momentum releases such as LPG and high vapour pressure oils.

The failure data for on-shore pipelines show that the failure rate is very low and that the most significant causes of leakage are mechanical specification and third party impact. If these are managed properly and there is a good monitoring program for corrosion the full bore rupture leak frequency could fall to less than 1 x 10^{-5} per km per yr. As the risk to the public is dominated by the full-bore leak frequency there is much to be said for monitoring and policing.

The result of this analysis is that there are good reasons for examining the risks near pipelines in the area of the public sector in more detail particularly if there are both social and financial implications. The analysis given supports this conclusion.

CONCLUSIONS

1. Land use planning near to developed areas creates a potential conflict between economic requirements of the many and the safety of a few.
2. Out-flow modelling from high-pressure hydrocarbon pipelines is complicated by their physical properties and complex models are required.
3. The consequence modelling, for jet fires in particular, still requires more research. Present models could over estimate the effects considerably.
4. Failure rate data are dominated by third party damage, which is both company and country sensitive.
5. More monitoring, both using OLIVs and routine survey or patrol of pipe corridors could reduce the risks in sensitive development areas.
6. Failure rate data for pipelines shows a general improvement with time.
7. Combining the better failure rate data with the outflow and consequence modelling, may free land for development, allowing a small but beneficial encroachment of local development, particularly at the approaches to industrial sites.

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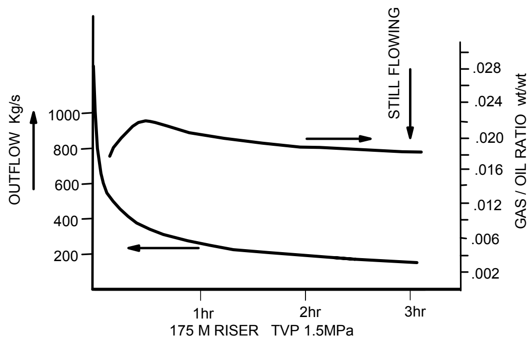

Figure 1

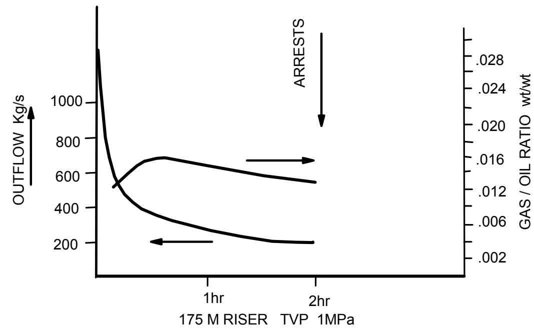

Figure 2

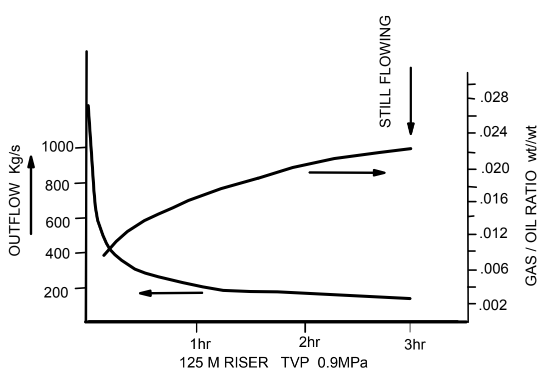

Figure 3

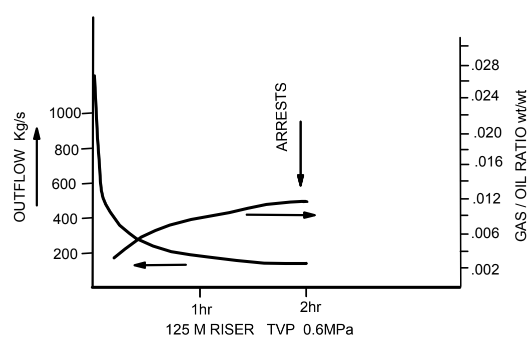

Figure 4

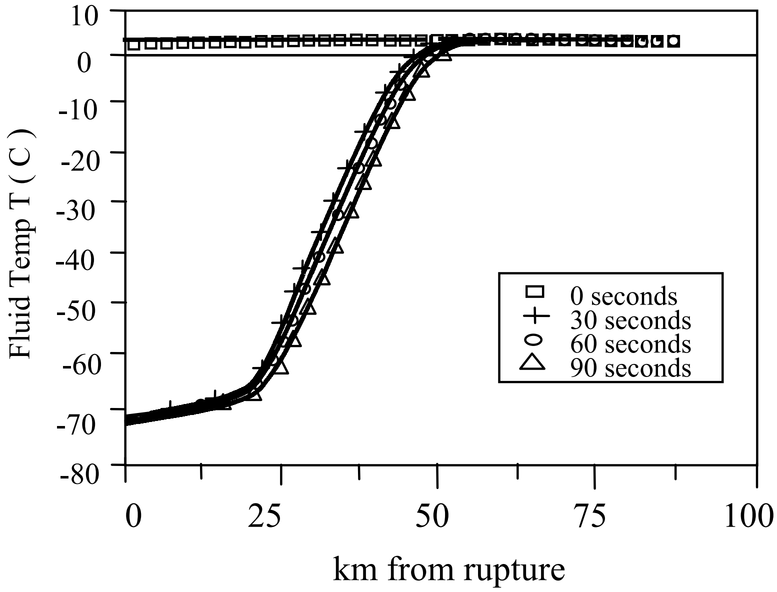

Figure 5. Temperature profile at 30's intervals after rupture

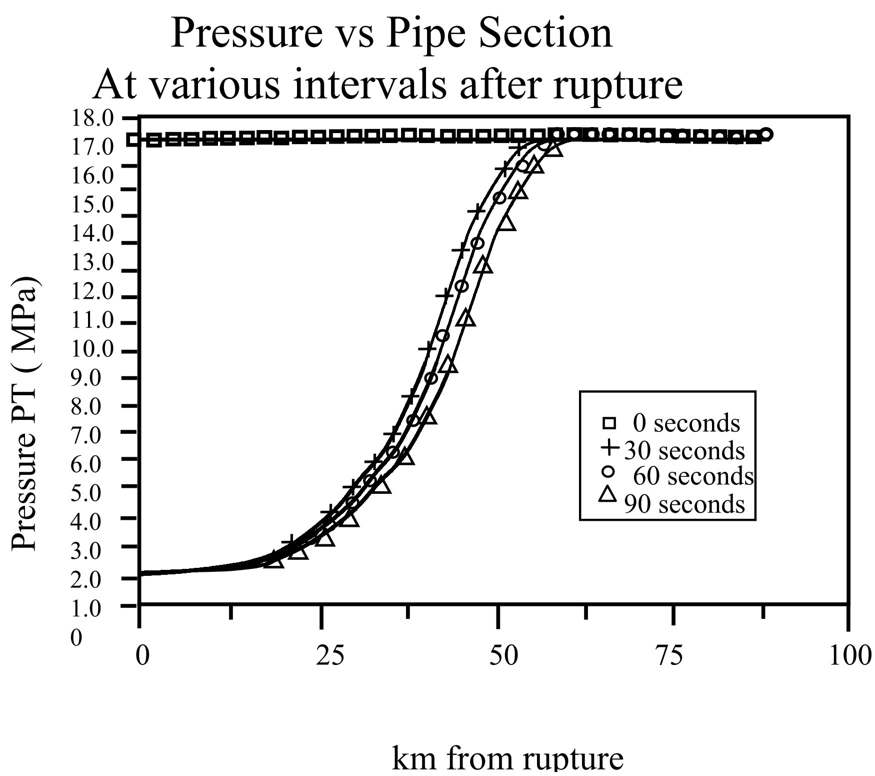

Figure 6. Pressure profile at 30's intervals after rupture