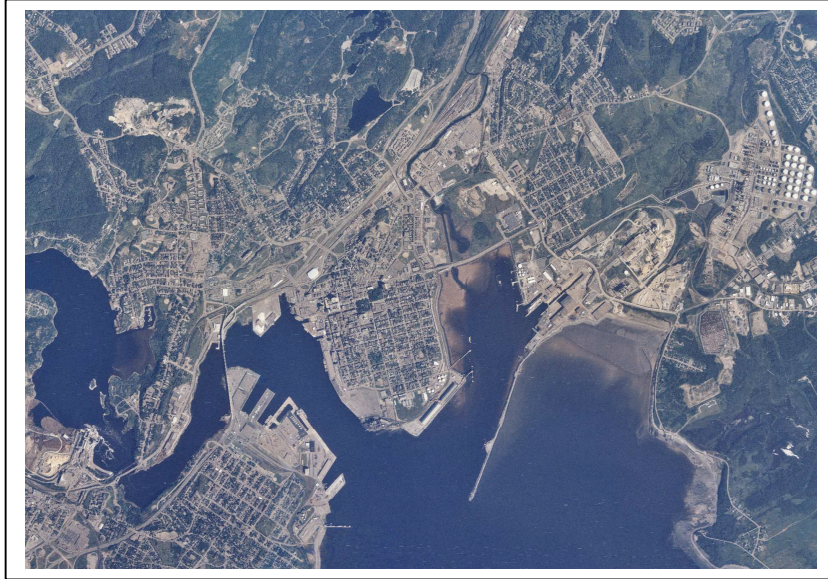


Accufacts Inc.

“Clear Knowledge in the Over Information Age”



An Independent Analysis of the Proposed Brunswick Pipeline Routes in Saint John, New Brunswick

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

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I. Executive Summary

The Friends of Rockwood Park commissioned Accufacts Inc. to perform an independent analysis of the Application to the National Energy Board for the Brunswick Pipeline Project (“Application”) as it pertains to two major route options affecting the city of Saint John, New Brunswick. This analysis is based on a review of the May 2006 Final versions of the Application and supporting submitted documents listed in the Bibliography at the end of this report. Accufacts finds the Application to be seriously incomplete in at least two crucial areas: 1) the declaration dismissing the marine route option that would essentially bypass the City of Saint John as “not feasible” is not adequately supported, raising significant questions as to the claimed difficulty/cost/scheduling impact of this option, and 2) the Quantitative Risk Analysis (“QRA”) is missing critical information to support or justify the risk transects determined for the on-land route through the City of Saint John.

Additional information for the relatively short (less than 9 km) marine “harbour crossing” option is warranted. Potential impact zones for a pipeline rupture with most likely early ignition along the proposed on-land route through the city have not been clearly demonstrated, delineated, or presented to assure confidence in the QRA determinations or findings for this alternative. For most gas transmission pipelines, the large thermal impact zones generated from early (within minutes) ignition sets the “controlling case” defining the potential impact zone. Accufacts must advise that over reliance on Emergency Response Planning utilizing Emergency Planning Zones to reduce risk will prove ineffective during the early high heat flux stages of early ignition for a pipeline rupture. As clearly demonstrated in this report, no credit for risk reduction should be taken in risk analysis for such efforts.

It is the opinion of Accufacts that the Application appears to be misrepresenting or over estimating the difficulties/costs/risks associated with the harbour crossing, while understating the risks associated with an on-land route through the city, to favor an on-land choice. As indicated above, additional information is warranted to permit an informed and proper decision concerning a prudent Brunswick Pipeline route selection within the city.

II. The Brunswick Pipeline’s Design Intent

The Brunswick Pipeline is intended to serve as a supply line to transport natural gas produced from imported LNG to Canadian Maritime and U.S. Northeastern markets, via a U.S./Canadian border interconnection to the Maritimes and Northeastern Pipeline. LNG imported to Canada is to be received at the new Canaport™ LNG Terminal consisting of marine receiving, storage, and re-gasification facilities located in Mispic Point, New Brunswick. LNG marine ships, up to the new class capacity of 250,000 m³, would be unloaded at a deepwater unloading berth/dock located in the Bay of Fundy just south of the on-land LNG receiving facility. The Canaport™ LNG Terminal would be located approximately 5 miles (8.3 kilometers) from the city of Saint John, New Brunswick. Accufacts’ work scope focuses only on issues related to the pipeline siting in the proximity of the city of Saint John. The siting of the LNG facility is not part of this

report's work scope, though variations in gas quality or future capacity impacts associated with the LNG receiving terminal expansion that could affect the pipeline are considered. Without the Canaport™ LNG Terminal, this pipeline would not be needed. The proposed initial capacity of the Brunswick Pipeline is 750,000 Dth/d (791,000 GJ/d). The current stated capacity of the LNG re-gasification facility is 1 billion SCF/d (1 million Dth/d or 1.06 million GJ/d). The stated total future capacity of the pipeline is 850,000 Dth/d (897,000 GJ/d) and no compressor stations are planned along the pipeline.¹

III. Canadian Gas Transmission Pipeline Regulations

In Canada, transmission pipelines must meet the minimum regulatory requirements defined in standard, CSA Z662.² As is usually the case with pipeline standards, these documents are periodically reviewed and updated. CSA Z662 had undergone a major updating in 2003 and several relatively short updates, through 2005. The Application for the Brunswick Pipeline cites the 2003 code as the standard upon which design, operation, and maintenance procedures will be based.³ It is not clear in the Application which of the Updated standards, if any, serve as the design, operating, and maintenance standard for this system. The National Energy Board ("NEB") has appropriately inquired as to why the latest 2005 version of these important standards was not referenced in the Application.⁴ A significant addition in the 2005 updates relates to codifying certain integrity management minimum requirements. In addition, the Application references an "Onshore Pipeline Regulation, 1999," that sets certain minimum informational and safety requirements to be provided to the NEB for pipelines.⁵

Many areas of the Canadian approaches to pipelines are superior to the U.S. or other foreign regulatory or code approaches. For example, CSA Z662 details more internal corrosion factors, or risks, that can become important on certain pipelines. Other foreign codes, including the U.S. code standards, are not as thorough. Note, however, that even the CSA Z662 does not require that an internal corrosion control program be effective. We must caution, however, that this author has observed that no one country's regulatory standard approach is prudent for all pipelines. Accufacts has repeatedly found that there is no one "Best International Standard" when it comes to pipelines.

One area that the Canadian pipeline siting process appears to be superior is in their more open approach to providing information about new pipelines to the public. A recently

¹ Emera Brunswick Pipeline Company Ltd., "Application to the National Energy Board – Brunswick Pipeline Project," May, 2006, page 20.

² CSA Z662-03 (Canadian Standards Association issued June 2003) and its subsequent Updates.

³ Ibid., Application, page 41.

⁴ NEB letter to Emera Brunswick Pipeline, Ltd., "Information Request No 1," dated July 20, 2006.

⁵ National Energy Board Act, "Onshore Pipeline Regulations, 1999."

published paper on the public's right-to-know and pipelines should prove helpful.⁶ The key to making proper informed pipeline decisions is to be able to provide decision makers, including the public, with appropriate key information relative to pipelines and their potential impacts, especially as to safety. Given the vast sums of money at stake in today's energy market involving multinational corporations whose interest may transcend national borders, a more open check and balance approach assures, though it doesn't always guarantee, that critical energy decisions are in the public interest of the specific country involved. One objective of this report is to assure that such key pipeline information is presented to the various parties involved in this important pipeline siting consideration to permit a more informed and balanced decision.

IIIa. Key System Details Affecting this Pipeline

The Brunswick Pipeline's Application is proposing an all on-land route that would be approximately 145 km in total length (31 kilometers within the city of Saint John), consisting of 762 mm OD (30-inch Outside Diameter) pipe running from the Canaport LNG™ Terminal in Mispic Point to a location near Saint Stephen, New Brunswick where it crosses the international border to connect to the Maritime & Northeast Pipeline (at Baileyville, ME). The city could be essentially bypassed by utilizing a marine route crossing Saint John Harbour that would shorten the pipeline by approximately 10 kilometers (these two pipeline routes are discussed in further detail in the next section).

The pipeline is intended to transport sweet natural gas produced from re-gasification of LNG received via marine transport to the Canaport™ LNG Terminal. Gas analysis equipment to measure a number of gas quality factors that could affect pipeline operation will also be included at the upstream end of the pipeline.⁷ A crucial device will be the moisture analyzer.⁸ The anticipated quality of the natural gas is:

Heat content = 38.86 MJ/m³ (1043 Btu/SCF)
Specific gravity = 0.57

Note that there may be some variation in the actual gas quality depending on the source of the LNG shipments that may change over the life of the pipeline. As no

⁶ Richard B. Kuprewicz, "Pipelines – National Security and the Public's Right-to-Know," prepared for the Washington City and County Pipeline Safety Consortium, April 24, 2003.

⁷ Ibid., Application, page 48.

⁸ Given the low dew point (very dry nature) of LNG produced natural gas, the author does not anticipate a serious internal corrosion problem, but the unique internal coating design of the pipeline in combination with smart pigging, increases the risks of this pipeline to a highly aggressive form of internal corrosion, should moisture inadvertently get away, even briefly, from the operator.

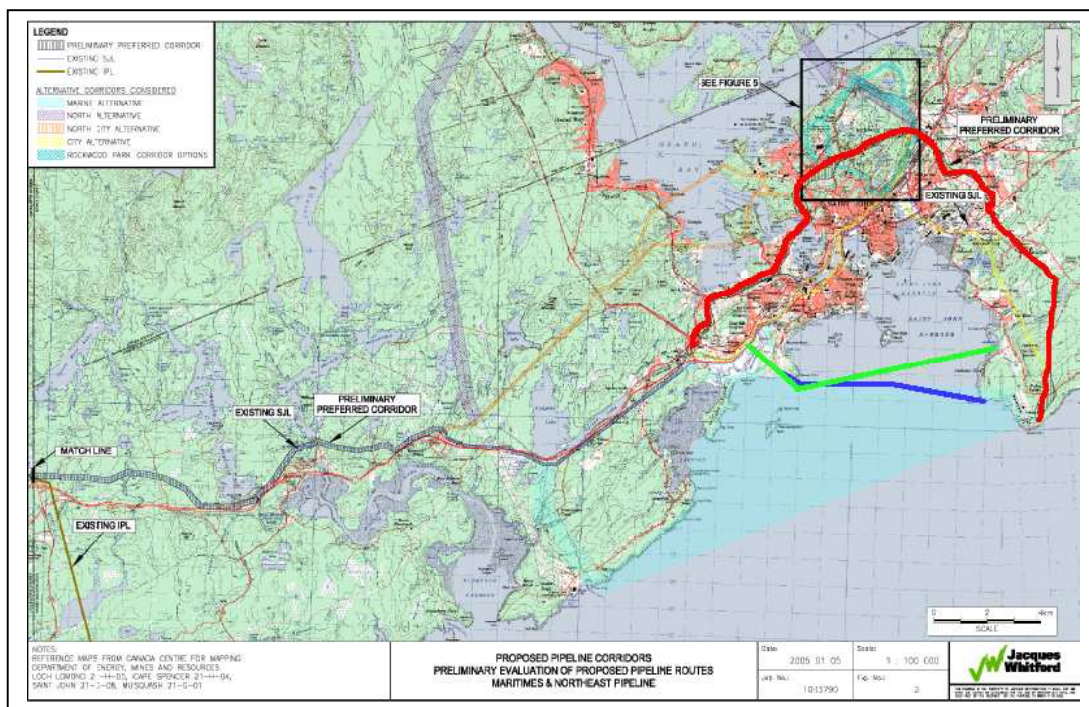


Figure 1: Applicant's Proposed Saint John On-land Route with Marine Option Routes Added

specific mention is made of this important matter in the Application, Accufacts must conclude that the gas in the Brunswick Pipeline will not be odorized.⁹

The design pressure of the pipeline is 9,930 kPa (1,440 psig), and the pipe will be grade 483 with a pipe wall thickness of 9.8 mm for class location 1 and 15.7 mm for class location 3. There apparently is no class location 2 pipe incorporated into this design. There may be class location 2 areas but the operator has chosen to design these areas to the more stringent thicker pipe, class location 3 requirements. All pipe will be designed for a maximum temperature of 120 °F (49 °C) and specified pipe toughness is above the critical threshold level utilized in pipe fracture mechanics. All welds are to be 100% non-destructively examined to insure weld integrity and, as required by regulation, the weld inspection records will be retained for the operating life of the pipeline. All facilities along the pipeline (i.e., remote operated valves, pig launcher/receivers, custody transfer meters) are to be designed to a design factor of 0.8, area class location 3, with a location factor of 0.625.

The initial capacity of the pipeline is 750,000 Dth/d and can be increased to 850,000 Dth/d without adding any compression along the pipeline as the

In the event of a rupture, this pipeline will release gas as if the rupture were on a larger diameter pipe.

⁹ CSA Z662 does not require the use of odorant (utilized to assist in detecting leaks by smell) in gas transmission pipelines that service other downstream processes. This exclusion from odorant injection for gas transmission pipelines is not unusual in many countries.

Canaport™ LNG Terminal can supply the needed pressure.¹⁰ This pipeline is unusual in that an epoxy coating will be applied to the inside of the pipeline, apparently to increase the flow efficiency of the pipeline for the given pipe diameter by decreasing the friction factor of the pipewall. As a result, this pipeline will experience much higher mass flow rate releases in the critical earlier stages of a rupture, before the pipeline segment can be isolated, than conventional uncoated steel pipe. While this internal coating practice is relatively rare in transmission pipelines, it is becoming more prevalent. There are certain additional internal corrosion risks associated with this internal coating practice. Given the dryness of the natural gas produced from LNG (very low dew point gas), Accufacts would characterize the risk of pipe failure from internal corrosion on this system as “low” provided certain integrity inspection practices are incorporated into the operation. On more conventional pipelines operating with wetter, much higher dew point natural gas, internal coating can actually accelerate and markedly increase the risk of pipe failure from selective, very high rate, internal corrosion.

The pipeline will be externally coated with a fusion bonded epoxy (FBE) with girth welds undergoing field application of either an epoxy spray or roll-on epoxy system. An impressed current cathodic protection system, supplemented by anode groundbeds, will complement the external coating protection in mitigating pipeline external corrosion.

IV. Routing Options for the City of Saint John

The Application to the National Energy Board as well as the Environmental & Socio Assessment for the Brunswick Pipeline describe a number of pipeline corridor alternatives considered, both within the vicinity of Saint John proper, as well as along the much more rural western corridor to the U.S. - Canadian Border.¹¹ Figure 1 represents a graphic of one of the documents showing the various pipeline route proposals submitted in these filings.¹² In the interest of time and given the compressed response schedule, this author was asked to focus on evaluating two Brunswick Pipeline route options in the vicinity of Saint John: 1) a Saint John Harbour crossing marine route that essentially bypasses the city of Saint John, and 2) an on-land route passing through Saint John proposed in the pipeline company’s Application. For ease of reference, Accufacts has highlighted general routes discussed in this report affecting the city to an exhibit submitted in the Application and present as Figure 1 above.¹³ The heavier blue and light green highlighted lines represents simple marine crossings discussed in detail below,

¹⁰ Ibid., Application page 20.

¹¹ Final Report Volume 1 of 2 for Brunswick Pipeline (sections 2.2.2.3 through 2.2.2.4, pages 8 - 25), and Application (section 4.3, pages 31 - 39), documents both dated May 2006.

¹² Final Report, Project Description for the proposed Brunswick Pipeline Project, Appendix A – labeled “Figure No 2,” January 5, 2005, available as an electronic file as AOS7G4_-Project_Description.pdf on NEB web site.

¹³ Ibid., Final Report, “Project Description for the proposed Brunswick Pipeline Project, page 44.

while the heavier red highlight line represents the general on-land route through the city proposed in the Application.¹⁴ Note that in either of the marine options indicated in Figure 1, the suggested crossing should pass north and stay out of the “Anchorage Area A Zone” located further out in the harbour. The routes indicated in Figure 1 are also approximate as actual routes could change slightly pending further review/evaluation.

IVa. Harbour Crossing Marine Route

Appendix A3 and A4 of the Application provide some discussion of several harbour crossing routes considered by Project Consulting Services®, Inc. (“PCS”) and AK Energy Services that could bypass the city. The PSC harbour crossing feasibility study in Appendix A3 discusses a Proposed Northern Route, two longer marine routes further south in the harbour, as well as a “tunnel option.”^{15,16} The straight line distance for the shortest harbour crossing route presented in the PCS study, the “Proposed Northern Route,” highlighted in heavy blue in Figure 1, is approximately 4.2 miles (6.7 km) with original landfall “just north of Black Point, and runs westerly across the outer Saint John Harbour to a landing site on the western edge of the harbour just north of Sheldon Point.”¹⁷ The general water depth along this route ranges from 8 to 10 meters at lowest normal tide, except at the shorelines. This alignment crosses the outer harbour just north of Anchorage Area A, and traverses the shipping lanes used by vessels entering and leaving the inner harbour. The study assumes each landfall for this route would require a horizontal directional drill, or HDD, as would the other PCS identified harbour crossing routes exclusive of the tunnel option.

In evaluating the specific harbour crossings, PCS concluded “that while the construction of a marine pipeline across the outer Saint John Harbor is possible from a marine construction standpoint it may not be practical given the higher costs, risks and longer project durations, especially if other more viable land options exists. The marine project would be of a very high risk in an extremely hostile marine weather environment where no other pipelines of a similar nature exist.”¹⁸

Accufacts does not agree with the PCS conclusions and believes their determination to be based on less than complete information presented in a manner that appears to overly focus on schedule while overstating the difficulty, costs, and scheduling risks for a relatively short harbour crossing (in the range of 6.5 to 9.0 kilometers, or 4 to 6 miles). Figure 2 represents marine pipelines located in the Cook Inlet of Alaska near

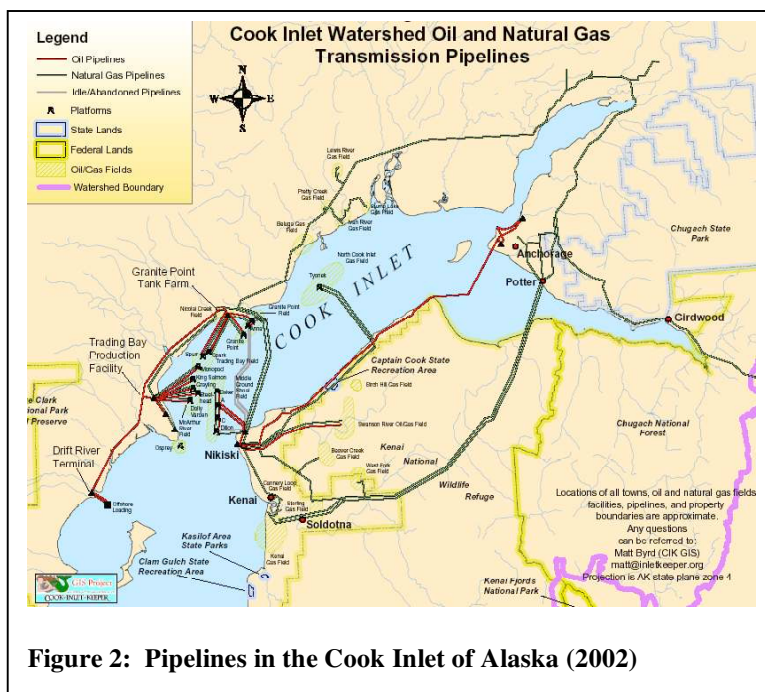
¹⁴ The Application maps indicate many areas within the on-land route with considerable variation in corridor location and width. The pipeline can be located anywhere within these corridors.

¹⁵ Appendix A3 - Project Consulting Services®, Inc., “Feasibility Study of a Proposed Crossing of the Outer Saint John Harbour.”

¹⁶ Appendix A4 - AK Energy Services, “Feasibility Assessment of Horizontal Directional Drills for Duke Energy’s M&N LNG #4 Project,” Revised August 2, 2005.

¹⁷ Ibid, Appendix A3, page 9.

¹⁸ Ibid Appendix A3, page 5.



the city of Anchorage, an area of some of the most extreme/rapid tidal surges in the U.S., in addition to seasonal high winds in excess of 50 MPH, and lengthy periods of extreme cold/fog.¹⁹ In Figure 2, the red product line crossing to the city of Anchorage is roughly 13 miles across the inlet, while the green line segment (to Potter) represents a natural gas transmission line inlet crossing of about 4 miles. The pipelines shown in Figure 2 have

been in service for many decades. While the author can appreciate certain challenges of the Saint John Harbour crossing, the information presented in the PCS feasibility study appears to be less than complete, and presented in a manner that suggests bias for the on-land route through the city. The other pipelines indicated in Figure 2 clearly indicate that, with the proper motivations, marine pipelines can be laid in a wide spectrum of challenging environments. Given the proposed startup schedule of the Canaport™ LNG Terminal, it is easy to conclude that an over focus on schedule for the pipeline, and the possible delays associated in gaining permits for a pipeline marine route have weighed all too heavily on the declaration that a Saint John Harbour marine route option is not feasible.^{20,21}

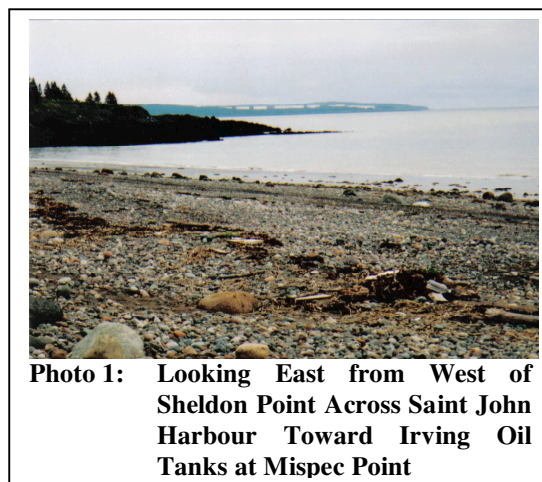


Photo 1 represents a view looking

¹⁹ Lois N. Epstein, for Cook Inlet Keeper, “Lurking Below: Oil and Gas Pipeline Problems in the Cook Inlet Watershed,” September 2002.

²⁰ Maritimes & Northeast Pipeline letter to Environment Canada Re “Maritimes & Northeast Pipeline Management Ltd. (“M&NP” Brunswick Pipeline Project Clarification of Routing Alternatives,” dated February 3, 2006.

²¹ Maritimes & Northeast Pipeline letter to Environment Canada Re “New Brunswick Pipeline Project, NS, EA #2006-013, File No. 4194-82-2,” dated March 8, 2006.



Photo 2: View of Anthony Cove Beach Looking Northward

eastward from the west shore of the Saint John Harbour (Sheldon Point Beach). Note the white Irving Oil tanks at Mispic Point (next to the proposed location of the Canaport™ LNG Terminal). Photo 1 clearly indicates, even given the challenges of the daily tidal changes, we are considering at most a 9-kilometer (5.6 mile) crossing in a relatively

sheltered harbour. Additional informed discussion is warranted before a harbour crossing route is dismissed so quickly as a “not feasible” route option for this pipeline. The burden of project schedule risk falls on the pipeline operator and schedule arguments should not be misused to drive less than complete or uninformed pipeline routing decisions. Over focus on schedule for a major energy project at the expense of more balanced information that would permit more prudent pipeline routing decisions, can have serious ramifications for a mega dollar project.

Another harbour crossing option not presented in the PCS feasibility study, is a route proposed by Mr. Horst Sauerteig to the City of Saint John, highlighted as the heavier light green line on Figure1.²² Mr Sauerteig suggests a land pipeline route to Anthony Cove and then a harbour crossing of approximately 9 kilometers, to a landfall just west of Sheldon Point. Photo 2 is the east harbour beach landfall area for Mr. Sauerteig’s proposed harbour crossing and both Photos 1 and 2 clearly demonstrate that HDD would not be needed for these sites. Increasing a short harbour crossing route by a few tenths of a kilometer could eliminate the cost and challenges associated with the proposed marine HDDs suggested by PCS.

Accufacts views the “tunnel option” as an extreme boundary case that in all probability sets the upper limit on marine crossing costs, given the less challenging marine options discussed above.

The Saint John Harbour marine crossing options appear to not have been thoroughly or properly evaluated or documented as a bona fide pipeline route, calling into serious question the credibility of the declaration of not feasible by the pipeline operator for this alternative.

²² Mr. Horst Sauerteig letter to Mayor Norm McFarlane and Councillors of the City of Saint John, June 15, 2006.

IVb. The Applicant's Proposed On-Land Route

Figure 1 indicates an on-land route option (heavier red highlighting by Accufacts and black cross hatch labeled by the pipeline as the “Preliminary Preferred Corridor”), proposed in the Application that takes the pipeline through the city of Saint John. The Application indicates that most of the pipeline route has been chosen to utilize existing or planned utility rights-of-way, but the corridors utilized within the city are not clearly indicated or identified in the Application. For the purposes of this study, Accufacts Inc., in order to maintain our neutrality, will call this option though the city the “on-land” route option. In evaluating the wisdom of certain pipeline routes, specific attention should be paid to the population density (both building and especially potential unsheltered individuals), and possible escape routes that can be hindered or restricted by the terrain, as well as sensitive facilities or industries in proximity to a transmission pipeline route. Utility corridors are seldom of sufficient width to provide adequate protection for the controlling pipeline safety case, a pipeline rupture. Few countries have proximity regulations defining minimum offset distances that a gas transmission pipeline must be from sensitive receptors that might be impacted in the event of a pipeline failure (either a leak or rupture). Neither the Canadian nor U.S. gas transmission pipeline regulations, standards, or codes define or require transmission pipeline safety offset distances.

The traditional historical method for siting gas transmission pipelines usually promulgated in regulation is to utilize a “class location” approach that requires thicker pipe for higher building density areas and/or higher density gathering areas, where people may congregate, within so many meters (feet) from a pipeline along a specified length of the pipeline. The pipeline operator has indicated that the Brunswick Pipeline on-land route through the city of Saint John will be built to class location 3 standards (the pipe will be 15.8 mm thick in this class location). Canadian standards incorporate a higher design factor for steel pipe, resulting in a pipewall thickness in a Canadian class 3 location being slightly less than that specified for a comparable pipeline in a class 3 location in the U.S. We must caution that while thicker pipe reduces the probability of pipeline failure from certain risks of concern, no pipeline is invincible to failure should the wrong set of conditions appear or develop during the long life of the pipeline.²³

²³ For example, thicker pipe tends to modify third party damage to develop as only a cut or groove, resisting or avoiding denting that can take on the more serious dent with a groove/cut whose time to failure is much more unpredictable.

Valve Location	Approximate Kp Location
Canoport™ LNG Terminal Facility Valve	0
South Side of Loch Lomond Road	11
East of the Saint John River Crossing, West side of Bridge St.	20
East side of Manawagonish Road	27
Adjacent to the existing M&NP Saint John Lateral valve 63	52
Adjacent to the existing M&NP Saint John Lateral valve 40	76
West side of Route 760 at the Digdeguash River	110
Baileyville Compressor Station, Terminus of Pipeline	145

Table 1: Proposed Valve Locations

For the proposed on-land alternative, six gas operated hydraulic remote valves, in addition to valves at the termini, are proposed for the entire length of the approximately 145 km pipeline. Three of these valves would be located in the City of Saint John. The valves are to be located along the pipeline as indicated in Table 1, with those proposed within the City highlighted in blue and bolded.

As discussed in Section V below, the safety role that valves play on gas transmission pipelines in defining potential impact zones (“PIZ”) is illusionary, really only impacting the number of “hours” that a pipeline segment would require to vent or blow down, should a pipeline rupture occur within the City limits.

Figure 3 represents a close-up aerial photo of the city of Saint John developed from composite high resolution detailed aerial Orthophotomaps (allowing distortion free aerial photos to gauge distances between receptors) of the proposed onshore route.²⁴ For some reason the higher population density west side of Saint John is not captured in satellite images displayed in Google™ Earth

In determining the consequence or control case defining potential thermal impact zones for gas transmission pipelines, valving has no role or real safety impact during the early critical stages when a rupture places citizens most at risk.

that permit the public to easily zoom through the proposed on-land pipeline routes and critical structures within the city. Ironically, the east side of the city, including the Irving Oil Refinery and Mispic Point areas can be Google™ mapped.

In Figure 3 the PIZ for the estimated on-land route have been highlighted (pipeline location approximated in yellow and subsequent potential impact zones in opaque red) to provide a quick appreciation of the possible receptors in the pipeline’s potential impact zone. Note that the exact location of the on-land pipeline has not yet been established so there can be a wide variation in the location as well as the boundary of the impact zones. **The highlighted zone in Figure 3 is provided for illustration purposes only** and is based on the Application’s QRA provided distance values for 20 KW/m² in the event of a pipeline rupture (approximately 600 meters on each side of the pipeline, see Table 2 later in this report). As presented in further detail in the next section discussing ruptures, 20 KW/m² thermal flux is still quite high. Lower acceptable thermal flux values are warranted and such lower thermal values define larger potential impact zones. One of the key questions in addressing the on-land route option is what is the acceptable thermal flux for this route?

²⁴ Orthophotomaps were provided from the Service New Brunswick web site: http://www.snb.ca/gdam-igec/e/2900e_1.asp

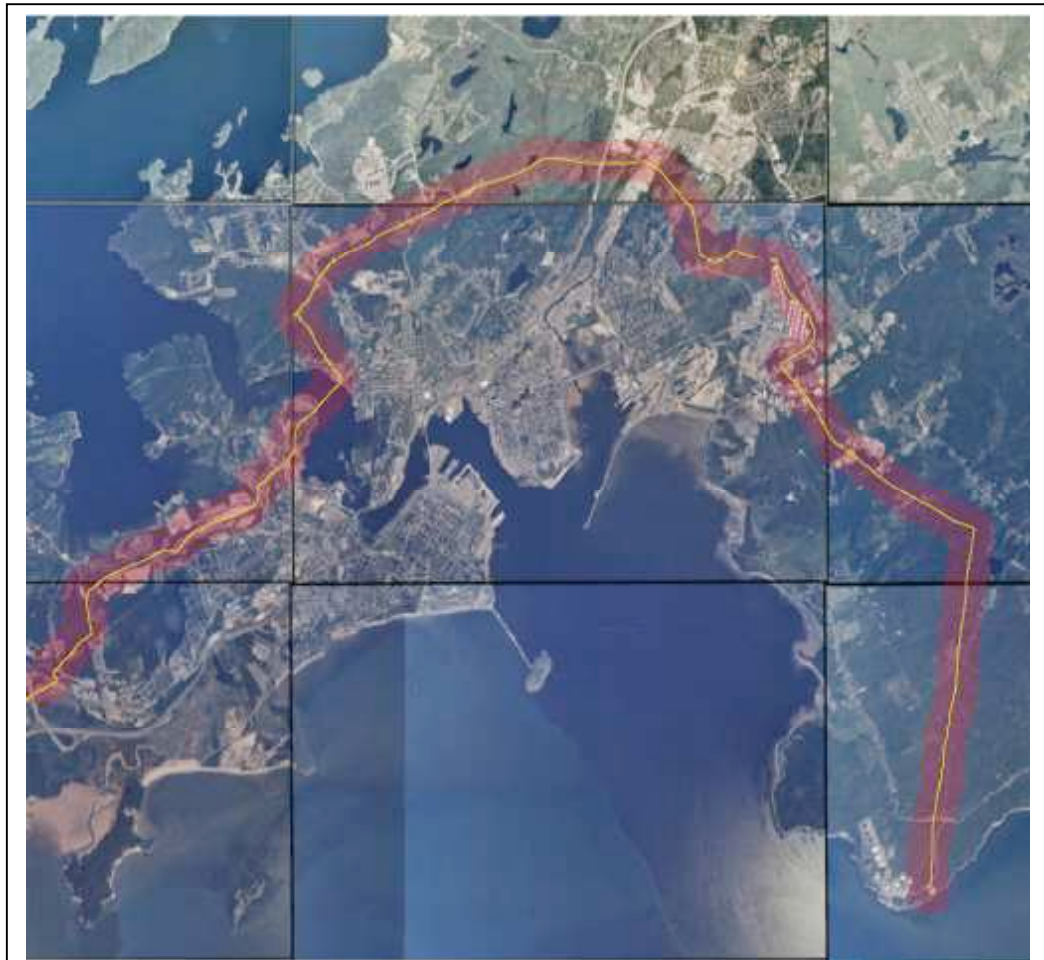


Figure 3: Aerial View of Saint John Approximate On-land Pipeline Route (yellow), with Illustrated 600 meter (20 KW/m²) PIZ Radius (red)

Figure 3 clearly suggests that there is considerable sensitive receptor and infrastructure at risk along the rupture potential impact zone along the on-land route through the city of Saint John.

V. Gas Transmission Pipeline Potential Impact Zones

The failure dynamics of a gas transmission pipeline falls into two major categories, leaks and ruptures. A leak is a gas release through a fixed hole or crack in the pipeline that stays essentially constant when release is initiated; while a rupture is a very high rate gas release through a large opening (usually a full bore mass release out both ends of a pipeline fracture).²⁵ In both scenarios, gas release rate is a function of the opening,

²⁵ It is the nature of the compressible gas and pipe characteristics that smaller anomalies or imperfections in gas transmission pipelines or welds can fail at certain critical sizes causing the defect to expand and the pipeline to rapidly fail (in microseconds), resulting in the pipeline shrapneling into full bore ruptures.

shape/size and pipeline internal pressure, with ruptures many orders of magnitude higher in mass rate release over leaks. Potential impact scenarios and consequences for each of these major failure categories are discussed further in the following sections.

Va. Leaks

Leaks are (depending on hole size) lower rate (kg/sec) gas releases that generally are not a problem for gas transmission pipelines as natural gas, being lighter than air, usually dissipates into the upper atmosphere. Leaks can become a serious risk, however, should they occur in environments where the released gas can migrate to where it can become trapped or accumulate, such as within a building structure or shed. In this environment the gas can become a potential explosion risk if the right mixture of gas, air, and ignition source are present. Despite the often-touted tight flammability range of natural gas (5 to 15 vol% for methane), all gas releases transition through the flammability range. The key to a leak's potential risk is whether an ignition factor is present in the area where the release is transitioning through the flammability range. Ignition does not have to be a flame, but can be as simple as static electricity.

Leaks can ignite and form flame jets but, because of their lower rate release, unless material is present that can ignite and burn, these flames tend to have very small or highly limited thermal impact zones. In mitigating the risks associated with gas pipeline leaks, the number one form of safety protection is distance. Because of the usually much lower mass release rates, the safety distances for leak risks are considerably less than that for ruptures which are described in more detail in the next section. This author has observed that safety distances of approximately 30 meters are usually adequate for the vast majority of transmission pipelines as any leak below ground usually dissipates before it can become trapped or ignited in any above ground structure. There are rare exceptions to this general observation. Accufacts has observed a gas explosion and fire caused by a transmission pipeline some 60 meters (200 feet) distant, but this situation involved a unique permafrost environment where the ground above and near the pipeline was capped or sealed by frozen soil. There have been other rare explosion/fire events in proximity to gas transmission pipelines caused by infrastructure encroachment, unique soil conditions, or wayward rodents (i.e., gophers) that can increase the length and likelihood of an underground gas leak migration pathway allowing gas leaks to spread some distance from a pipeline.

Absent unique at risk conditions, such as permafrost, 30 meters is an appropriate safety distance for most leak failure risks associated with a gas transmission pipeline.

Vb. Ruptures²⁶

As mentioned earlier, ruptures in gas transmission pipelines are very high mass rate releases usually associated with full bore releases from pipe fracture failure. The ability of a small anomaly within pipe steel to rapidly progress (within microseconds) to a full bore release in a gas transmission pipeline is a function of pipe stress level (high pressure), anomaly size/depth/type, orientation, pipe toughness, and gas compressibility. Advances over the last several decades have significantly improved the fracture mechanics tools used to predict failures for most forms of pipe anomalies (such as corrosion).²⁷ The rapid failure progression for “critical” sized flaws results in the pipe shrapneling as the pipe fractures and momentum forces eject the metal and surrounding ground resulting in a crater.

Because of the high gas compressibility, the release out the pipe bore is restricted by the laws of thermodynamics to the speed of sound, but the mass flow (kgs/sec) varies as the gas density upstream of the bore opening varies with time, and this density change is a function of the system dynamics. Despite conventional wisdom, pipeline ruptures are not a “balloon burst,” as less informed individuals sometimes try to characterize, but are very high rate jet releases of gas ejecting at the speed of sound over an extended period of time. Because of the compressible nature of the gas, pressure loss in the pipeline system is usually not immediately observed by the pipeline operator. For natural gas transmission pipelines, ejecting velocity is on the order of 1,400 to 1,500 ft/sec (430 to 460 m/sec), which explains the big craters, large flames upon early ignition, and roaring sound associated with gas pipeline ruptures. The mass rate release for ruptures is easily several orders of magnitude greater (on the order of 100 to 1000 times greater) than that for leaks. Rupture scenarios are usually the controlling cases when determining possible pipeline potential impact zones for safety siting considerations. Photo 3 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 transmission pipelines.

²⁶ Discussions in this section are derived from a segments of an earlier paper, “The Proposed Corrib Onshore System – An Independent Analysis,” by Accufacts Inc., concerning a very exotic high pressure 20-inch pipeline proposed in a highly sensitive receptor route, attempting to be justified via application of very inappropriate QRA.

²⁷ The failure prediction tools for determining failures from dents with stress concentrators (i.e., cuts, grooves or corrosion within a dent), is still proving to be highly unpredictable. Given this unpredictability, pipe codes do not allow the presence of dents with stress concentrators when they are discovered.



Photo 3: Carlsbad, NM Pipeline Rupture Failure, August 19, 2000 (Courtesy of the NTSB)

Photo 3 is a picture taken of the Carlsbad, New Mexico, August 19, 2000 natural gas transmission pipeline rupture approximately a mile upstream of a compressor station. This pipeline failure is one of the more well-documented pipeline ruptures in recent history, though not the largest loss of life case for a gas pipeline rupture. This pipeline was a 30-inch pipeline with a 0.335 inch (8.51 mm) wall thickness Grade X-52 (52,000 psi SMYS), operating at a pressure of 675 psig (4655 kPa) that failed from internal corrosion.²⁸

To gain an appreciation of the height of the flame in Photo 3, the steel support towers are 24 meters (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 remote site to take this picture (the flame burned for approximately 55 minutes before nearby manual block valves could be safely reached, closed, and the segment de-pressured), 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.

Photo 4 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 feet) from the ruptured pipe all died as a result of the blast and thermal radiation received. Six of

²⁸ 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.

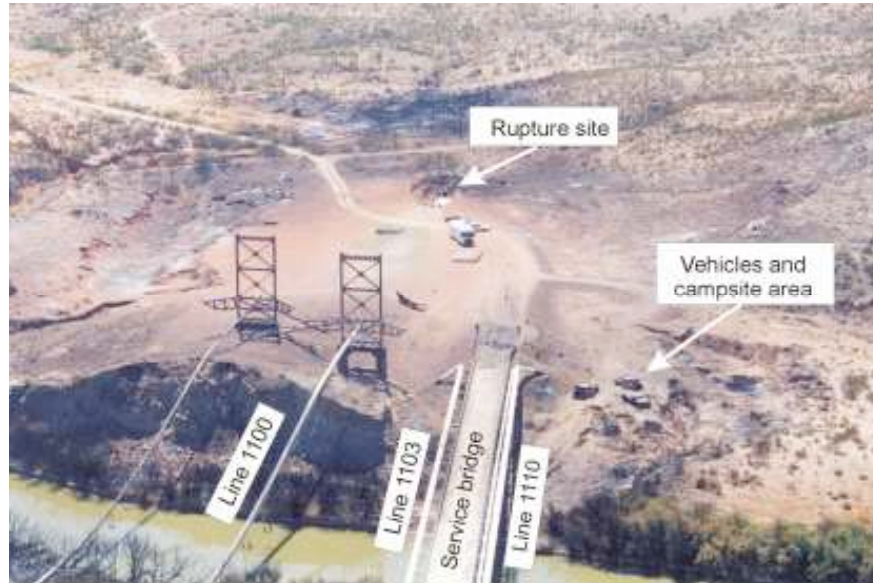


Photo 4: Carlsbad the Aftermath (Courtesy of NTSB)

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 third degree burns over their bodies) died within hours. I do not provide these photos to unduly alarm anyone. Carlsbad serves as a reality check for anyone making poor risk management pipeline decisions or misapplying QRA based on incomplete or poor information.

Referring to Photo 4, one can gain an appreciation of how rupture events can extend well beyond the pipeline right of way or utility corridor. 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.

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, Photo 3 represents a typical flame from a gas jetting rupture failure. Eventually, upon ignition, all the impact energy is dissipated and high thermal energy raises the flame off the ground, extending the impact zones. A closer examination of Photo 4 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 meters (1,400 feet) 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 usually moves the thermal zone

circle down the pipeline and the zone can extend well beyond any right-of-way corridor. Note the relative absence of extended severe thermal burning in the opposite direction of the towers upstream of the rupture crater site (toward top Photo 4).

Finally, to put to rest any illusions that a gas jetting at sonic velocity from a pipeline rupture may be an insignificant event, Photo 5 is another photo of the crater from the Carlsbad release. This photo is looking downstream of the rupture toward the river (the bottom of Photo 4). The crater in this rupture case was approximately 34 meters long by 16 meters wide (113 feet long by 51 feet 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 and clear documentation on this specific failure, including time to ignition that permits a reality check for those utilizing 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. Even though the Brunswick Pipeline is the same outside diameter and has a slightly smaller inside diameter than the 30

The Brunswick Pipeline, because of its much higher operating pressure and internal coating, will release natural gas at a much higher rate in the early critical stages, than that for the Carlsbad failure.

Photo 5: Carlsbad Rupture Crater (Courtesy of NTSB)



inch Carlsbad pipeline, the higher operating pressure and smoother, slicker internal pipewall proposed for the Brunswick Pipeline will release much more fuel at a higher rate during the early critical minutes of a pipeline rupture where ignition and subsequent fatalities are most likely than that of Carlsbad.

From recorded seismic measurements, time to ignition after pipe rupture at Carlsbad was determined to be approximately 24 seconds. Despite the fairly tight flammability range of natural gas (5 to 15 vol.%), many gas pipeline ruptures ignite for various reasons, especially as the pressure and size of the pipeline increase. 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 high rate releases, ignition usually occurs in the very early minutes of release when mass flow has spiked at its highest and is starting its decay, but is still very large. As pipeline diameters and pressures increase the probability that a pipeline rupture will ignite very early go up dramatically. Prudence would dictate that PIZs, potential impact

zones, be based on early (essentially immediate) ignition for gas transmission pipeline routes proposed in areas containing sensitive receptors where fatalities can be high.

Vbi. Rupture Impact Zone Determinations

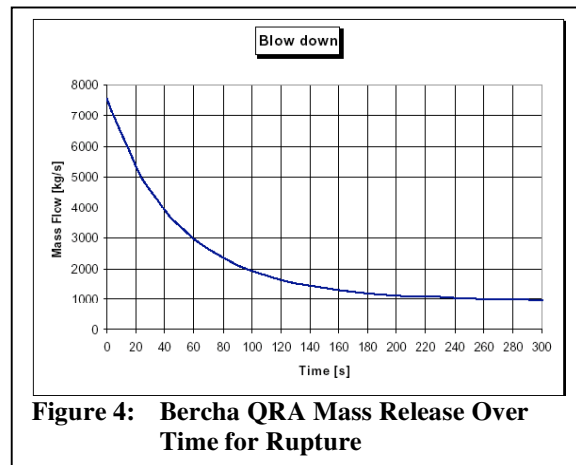
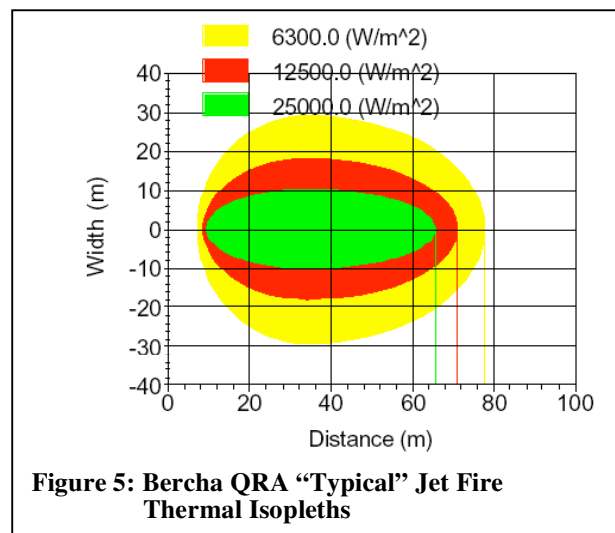


Figure 4 is taken from the Quantitative Risk Analysis submitted with the Application for the Brunswick Pipeline.²⁹ This figure is intended to represent a blowdown (mass release vs time) for a pipeline rupture in the urban segment defined in the report as BP1-R (the rupture blow down for the segment between Kp 0 to 11.0). The QRA states “There is very little difference among the 5 minute blowdown characteristics (and therefore consequences) of failure of different segments, because, until the

isolation valves are closed (which is 15 minutes or more), the entire pipeline is being emptied through the failed orifice.”³⁰ Accufacts agrees with this statement, but we believe the critical factor for a rupture is time to ignition as early ignition generates the greatest heat flux and largest thermal impact zone most injurious or fatal to the public.

Figure 5 is also taken from the submitted QRA.³¹ In comparing this “Typical” Jet Fire Thermal Isopleths (boundaries of constant heat flux), against Table 2, developed from information provided in the Bercha QRA, it appears that the QRA “Typical” Jet Fire Thermal Isopleths seriously confuse, misrepresent, and understate the thermal impact zones associated with a rupture (all ruptures upon ignition are a jet fire).³² While Figure 5 may be intended to convey the impression that a typical rupture impact zone is small,



²⁹ Application to the National Energy Board, Appendix A5, Bercha Group, “Quantitative Risk Analysis of the Brunswick Natural Gas Pipeline – Final Report,” February 14, 2006, page 4-10.

³⁰ Ibid, Appendix A5, page 4-12.

³¹ Ibid Appendix A5, Figure 4.5 of QRA, page 4-9.

³² Ibid Appendix A5, Table 4.3 of QRA, page 4-13.

Table 2 clearly indicates anything but this.

Scenario	Maximum Isoleth Distance (m)					
	Jet Fire Thermal Radiation (kW/m ²)			Explosion Overpressure (kPa)		
	50	20	10	35	25	7
BP1-H-MU	560	623	689	411	555	2090
BP1-H-MN	448	508	573	43	58	219
BP1-H-MS	572	639	702	182	246	926

Table 2: Maximum Isoleth Distances for Jet Fire Thermal Radiation and Explosions

Based on the Carlsbad information, and Accufacts' experience, realistic Jet Fire thermal isopleths for early ignition rupture cases for the Brunswick Pipeline need to be developed and presented for the specific pipeline segments proposed within the city of Saint John. These isopleths will indicate much larger potential impact zones than the Application's QRA suggests as "Typical" in Figure 5. Note that Table 2 values probably represent unsheltered/unobstructed maximum distances though this is not indicated in the QRA. Intervening structures would shelter and decrease the impact effects for receptors located behind or in the shadow of such structures.

Given the release risks associated with very high pressure pipeline ruptures 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 and destruction. At these high pressures and large pipe diameters, prudent risk modeling should assume essentially instantaneous ignition when determining pipeline routing risks near people or sensitive receptor areas.

Figure 6 represents a series of thermal dosage models derived from industry accepted thermal models.³³ Figure 6 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/m² heat flux exposure for approximately 20 seconds will result in 1% mortality for those caught outside (unsheltered) near a rupture, while an additional 25 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/m² should be able to survive, as this value is left of the light blue wooden dwelling spontaneous ignition curve drawn, indicating that essentially, a wooden structure can take this heat flux indefinitely. This does not mean that secondary effects won't occur (i.e., vehicles or propane tanks explode) that can cause injury or fatalities such as from glass shattering.

³³ 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.

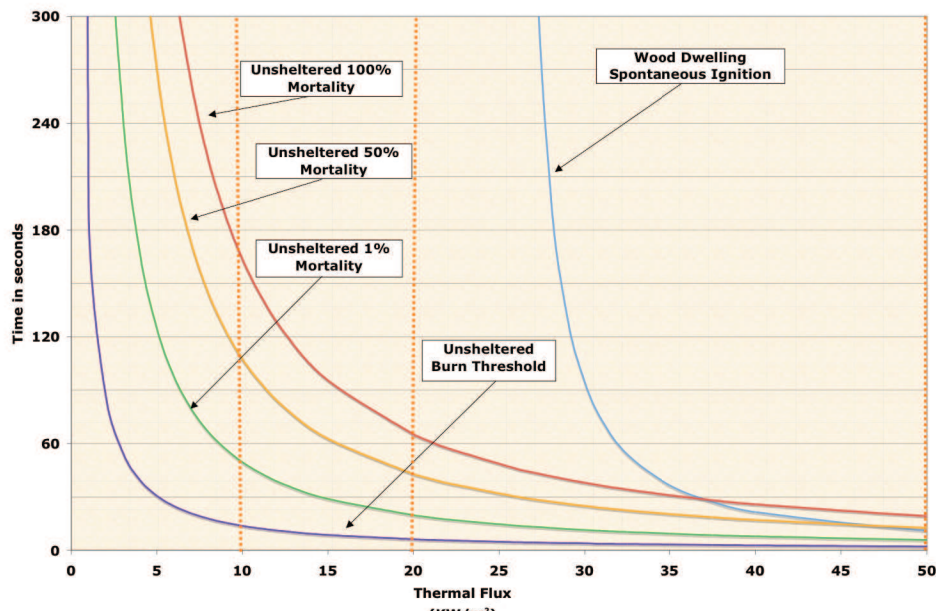


Figure 6: “Time To” for Various Thermal Fluxes on People and Wooden Structures

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 6 clearly illustrates, the time to get into a shelter, away from the heat is measured in seconds. Please note that there is some uncertainty for the curves, so making it to the right of the curves doesn’t guarantee survival as many site-specific factors affect actual heat thermal dosage upon an individual. At these high heat fluxes and roaring noise levels, individuals lose their sense of direction as sound and heat appear to be coming from all directions. The important point to note is that at higher heat fluxes unsheltered survivability is measured in seconds and confusion or panic can consume much of this time.

The vertical orange dashed lines are just reference indicators of the arbitrary 10, 20 and 50 KW/m² thermal flux values reported in the Bercha QRA report and in this report’s Table 2. There is nothing magical about these specific threshold values. More proactive countries establish much lower KW/m² 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.³⁴

³⁴ The U.S. has no defined federal pipeline siting regulations and no acceptable thermal flux limit for pipeline ruptures, though a 15.8 KW/m² (5000 BTU/hr ft²), threshold commonly utilized for preventing equipment damage, is often implied in analysis, wrongfully suggesting there are such requirements to justify poor pipeline route selection.

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, especially the most likely early ignition. At these high thermal loads, credit for running to a safe distance is inappropriate. Referring back to Photo 4, 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 the right side of the “Time to” curve for 100% mortality exposure shown in Figure 6 because of the severe initial high thermal loading associated with early ignition. It is a serious mistake to portray that such high thermal loading occurs on high pressure gas pipeline system ruptures only for a few seconds.

Figure 6 also helps illustrate the illusion of counting on an emergency response plan to reduce the risks associated with possible gas transmission pipeline rupture in a poorly sited pipeline route. The realities are, as clearly demonstrated by Figure 6, that the first few seconds or minutes make the difference for those who are not in buildings that are designed to handle very high heat loads (i.e., brick/masonry are more tolerant and can provide some shelter and safety). No formal Emergency Response Plan can prevent casualties in these short and critical early minutes of a rupture.

The critical thermal isopleth drawings for an urban rupture case with early ignition need to be developed, confirmed, and presented to substantiate a realistic potential impact zone from pipeline rupture. This isopleth should be based upon a survivable agreed upon thermal flux limit or value.

Referring back to Table 2, explosion overpressure does not tend to build, or dissipates quickly (except for highly congested urban areas), such that usually, thermal heat flux considerations become the controlling design case factor in transmission pipeline siting safety considerations. This does not mean that overpressure damage or fatalities will not occur beyond the critical thermal impact zone, just that the probability of such overpressure in most surroundings will be very low compared to the thermal impacts. Accufacts believes that pipeline rupture with early ignition is the controlling case, not explosion, in evaluating the on-land route proposed through Saint John for the Brunswick Pipeline.

VI. Quantitative Risk Analysis and Gas Transmission Pipelines

It is not clear whether a specific QRA approach assures prudence in the siting process of Canadian pipelines. QRA is not referenced in the U.S. pipeline safety regulations for many very good reasons. Accufacts will leave the decision as to whether this tool is suitable or appropriate on a specific pipeline within Canada to its citizens. A detailed discussion as to the appropriateness of QRA to pipeline siting is beyond the scope of this

report. However, several application test questions listed in the following text box are offered to assist in evaluating the appropriateness of QRA as it relates to a specific pipeline. These basic factors transcend all international boundaries in the proper application of QRA techniques.

QRA Application Test Questions

Is history being over utilized as a predictor of future pipeline failure?

Is QRA being inappropriately utilized to fill in critical/crucial information gaps?

Are risk weighting factors real/reasonable and does analysis account for the linkages that can increase or actually drive failure risks by many orders of magnitude?

How complex is the system and is the analysis complete?

Is the system unique or the first of its kind?

Does the QRA spend too much effort selling comparative risks?

Are the real risk takers, usually the local public, really involved in the decision process?

It is all too common to assume that the past should be utilized to predict future events for complex systems such as pipelines. This isn't baseball or hockey where past statistics may somehow apply. Pipelines are high-energy systems carrying large inventories of high density compressible material, easily capable of impacting large zones. Historical records may be utilized to help identify critical breakdowns in management process associated with past design, siting, maintenance, and operation of pipelines, but they should never be utilized to predict the operation or failure of a specific system. One must never lose sight of an important fact that most pipeline failure databases are wrong or inaccurate for various reasons, so over-reliance on this historical information can prove fatally flawed.

It is all too easy for individuals or organizations to start to believe "the numbers," especially if their presentation in QRA format creates the illusion that all critical cases have been properly addressed. QRA should never be utilized to compensate for critically missing information or for poor subject matter experts or inexperienced decision makers who have left out critical pivotal scenarios, especially "linkages" that can drive a pipeline system to premature failure. The latest announcement of the shutdown of the largest oil producing field in the U.S. from internal corrosion that was a "surprise" or a "lapse" in judgment caused by poor maintenance practices, demonstrates very poor risk management practices based apparently on missing critical information not supplied to or disregarded by key management.

In evaluating the events used to apply probability calls, one needs to step back and ask whether the QRA process identifies the controlling case that truly drives or determines the risks to the public. More specifically, is the identified case really the controlling case or is there some future expected change, such as an expected capacity increase, that may change the QRA “sensitivity” or potential impact zones and thus the real risks? Lately, this author has been running into QRAs that have attempted to define risks for very highly unique, first of their kind, pipelines. We advise that application of QRA to such “pushing the technical envelope” unique systems can be highly inappropriate, especially if the QRA is incomplete and/or lacks appropriate sensitivity analysis.

QRA can be very inaccurate for highly complex systems where linkage factors can easily increase failure risk by many orders of magnitude, even driving the system to failure. An excellent discussion of this problem as it relates to the misapplication of risk management techniques to a complex energy system is a discussion of the many breakdowns that drove the Three Mile Island nuclear power plant core meltdown presented in Charles Perrow’s excellent book Normal Accidents – Living with High-Risks Technologies.

QRA, even if permitted in a country’s regulatory process, should never be utilized to supplant prudent engineering or management practices or processes.

Lastly, the final test of whether QRA is being utilized or applied properly is whether the public most affected by the system, the real risk takers, are being properly involved in the decision process. This does not mean that all parties will be in agreement on all issues or decisions, but in all systems certain truths or facts that are critical to final decisions are hard to hide or distort. The author has found that the public has an excellent grasp of when QRA is being misused to impose the risks on the many for the

benefit of the few.

VII. Conclusions

Before a final decision on a pipeline route option affecting the city of Saint John can be made, decision makers need additional information focusing on the cost, timing, difficulty, and realistic scheduling impact associated with a short Saint John Harbour marine crossing in the general areas depicted in Figure 1. Information provided to date leads Accufacts to conclude that the declaration of not feasible is overly dictated by concerns associated with permit scheduling rather than a full presentation of the facts. Project schedule is determined and the responsibility of the applicant, and it is a most unwise applicant that doesn’t develop alternative pipeline route contingency plans for such a major project.

In reviewing the Applicant’s proposed on-land route through the city of Saint John, proper thermal isopleths based on early ignition, indicative of a prudent survivable thermal impact zone for a pipeline rupture, have not been presented. Before the on-land option can be properly evaluated, such prudent potential impact zones should be clearly

defined using accepted survivable thermal flux limits, and these potential impact zones overlaid along the proposed on-land route to identify high density or other sensitive receptors that may be very inappropriate or unwise. Accufacts believes that this process has not been satisfactorily completed in the Application for the Brunswick Pipeline to date.

Acronyms/Abbreviations

CSA - Canadian Standards Association	mm - millimeter
Dth/d – Decatherm/day	MPH – Miles per Hour
FBE – Fusion Bonded Epoxy	NEB – National Energy Board
GJ/d – GigaJoules/day	NTSB–National Transportation Safety Board
GRI – Gas Research Institute	OD – Outside diameter
HDD – Horizontal Directional Drill	PIZ – Potential Impact Zones
Kp - Kilopost	psig – pounds per square inch gauge
kPa - Kilopascals	QRA – Quantitative Risk Analysis
KW/m ² – Kilowatts per square meter	SCF/d – Standard Cubic Feet/day
LNG – Liquefied Natural Gas	

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