“ICGB” AD

Safety Study for The Natual Gas Interconnector Pipeline Greece – Bulgaria (IGB Project)

ICGB AD Contract No. P-02-C- 18-5-2017

Quantitative Risk Assessment for the Greek Part (QRA)

Main Report

AUGUST 2017

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EXECUTIVE SUMMARY

ICGB AD, an equal partnership between Bulgarian Energy holding EAD and IGI Poseidon, is planning to construct the gas Interconnector Greece-Bulgaria. This pipeline will connect the Greek gas network at Komotini to the Bulgarian gas network at Stara Zagora.

Sybilla ltd Consulting Engineers has been awarded the Quantitative Risk Assessment study for the proposed 32 inch pipeline. within the Greek section of the pipeline.

An Initial Quantitative Risk Assessment Study prepared by the Penspen-C&M Consortium mainly focousing in the “KALCHAS” area has been used as a starting point for discussions with the Permitting Authority which proposed some corrections and amendments. All these have been incorporated in the present study.

The most densely populated area along the proposed pipeline has been identified as the point at which the pipeline passes close to the outskirts of Kalchas, the area identified contains a large petrol filling station with an associated tyre services centre. The area also contains a sanitary ware shop, although it currently appears to be unoccupied, and the third is a small supermarket with apartments on the first floor.

One more area of interest exists in the east of “RODITIS” village. In the near area there are two Psychiatric Hospitals that are considered Sensitive Receptors and increase the population that could be subjected to Accident Risk in the case of a pipeline catastrophic failure.

The IGB pipeline has been designed according to relevant codes of practice, EN 1594 and ASME B31.8, and appropriate national regulations.

This report represents the methodology and results of the QRA, and concludes that individual risk levels on the pipeline at the assessed location are greater than the Greek Technical Regulation limit of 1 x 10^{-6} per year.

It is observed that individual risk levels on the pipeline at the assessed location are greater than the Greek Technical Regulation limit of 1 x 10^{-6} per year. It must be stressed here that a very conservative definition of “Individual Risk” has been used considering a totally exposed person remaining at the specified point for 100% of time. When the pipe wall thickness is increased the Individual Risk falls below the obovementioned limit. While the “exceedance” of the Regulation limit does not create any real problem in the non-populated areas, in the two points, namely west of Kalchas and east of Roditis some measures have to be taken in order to reduce the Individual Risk to the population in acceptable levels (Less than 1x10^{-6}). In order for this requirement to be met, an increase in pipe wall thickness, to 14,2 mm (as in Class Location 2) is necessary.

1 INTRODUCTION

1.1 Main Project Information

The IGB pipeline has been designed according to relevant codes of practice, EN 1594 and ASME B31.8, and appropriate national regulations.

This report represents the methodology and results of the QRA, and concludes that individual risk levels on the pipeline at the assessed location are greater than the Greek Technical Regulation limit of 1 x 10*6 per year. In order to meet this requirement. Class 2 pipe with a wall thickness of 14.2 mm would be needed.

The following is a summary of the main components of the project:

- High pressure gas transmission pipeline of nominal OD 32” (812,8 mm) between Komotini and Stara Zagora in Bulgaria; Greek part about 31.5 Km and Bulgarian Part about 150.5 Km.
- Ten (10) Block Valve Stations (BVs) along the route of the pipeline, in compliance with applicable norms, one (1) in Greece and nine (9) in Bulgaria.
- Gas Metering Station (GMS) Komotini and Pigging Launcher Station (PS) in Komotini
- Metering and Pressure Reducing Station in Kardjali, Bulgaria ;
- Gas pipeline connection along with metering and Pressure Regulating Station in Dimitrovgrad Bulgaria;
- Gas Metering Station (GMS) and Pigging Receiver Station (PS) in Stara Zagora Bulgaria;
- Integrated Control and telecommunication systems.
- Dispatch Center and operation and maintenance base (O&M Base) in Haskovo, Bulgaria.
- Provision for future compressor facilities in Bulgaria.
- Various ancillary facilities to support the abovementioned infrastructure.

Fig 1. Schematic Drawing of the IGB Project

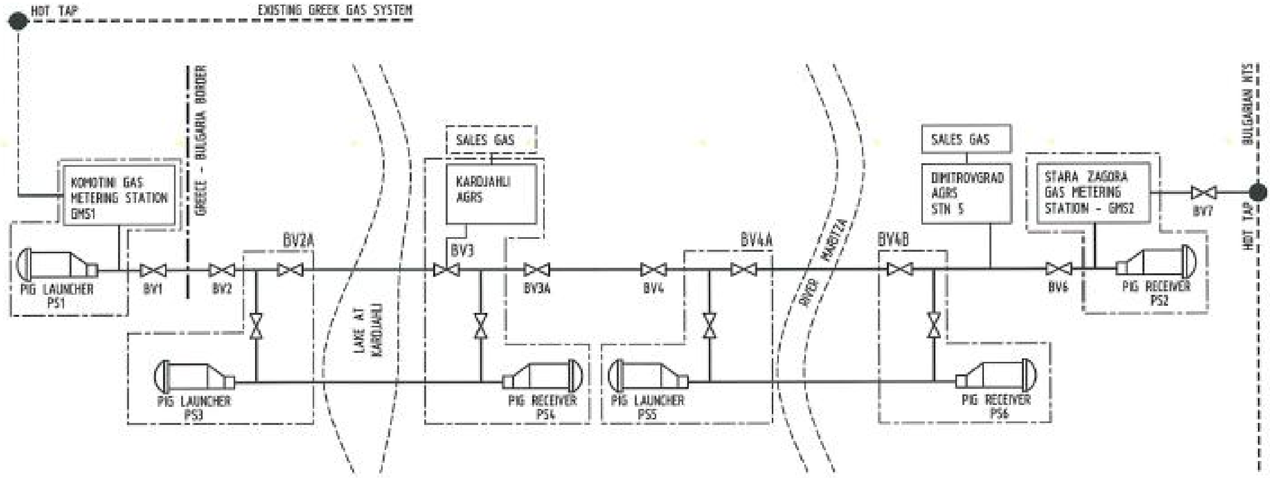


Fig 2. Schematic Drawing of the IGB Project. Greek Section

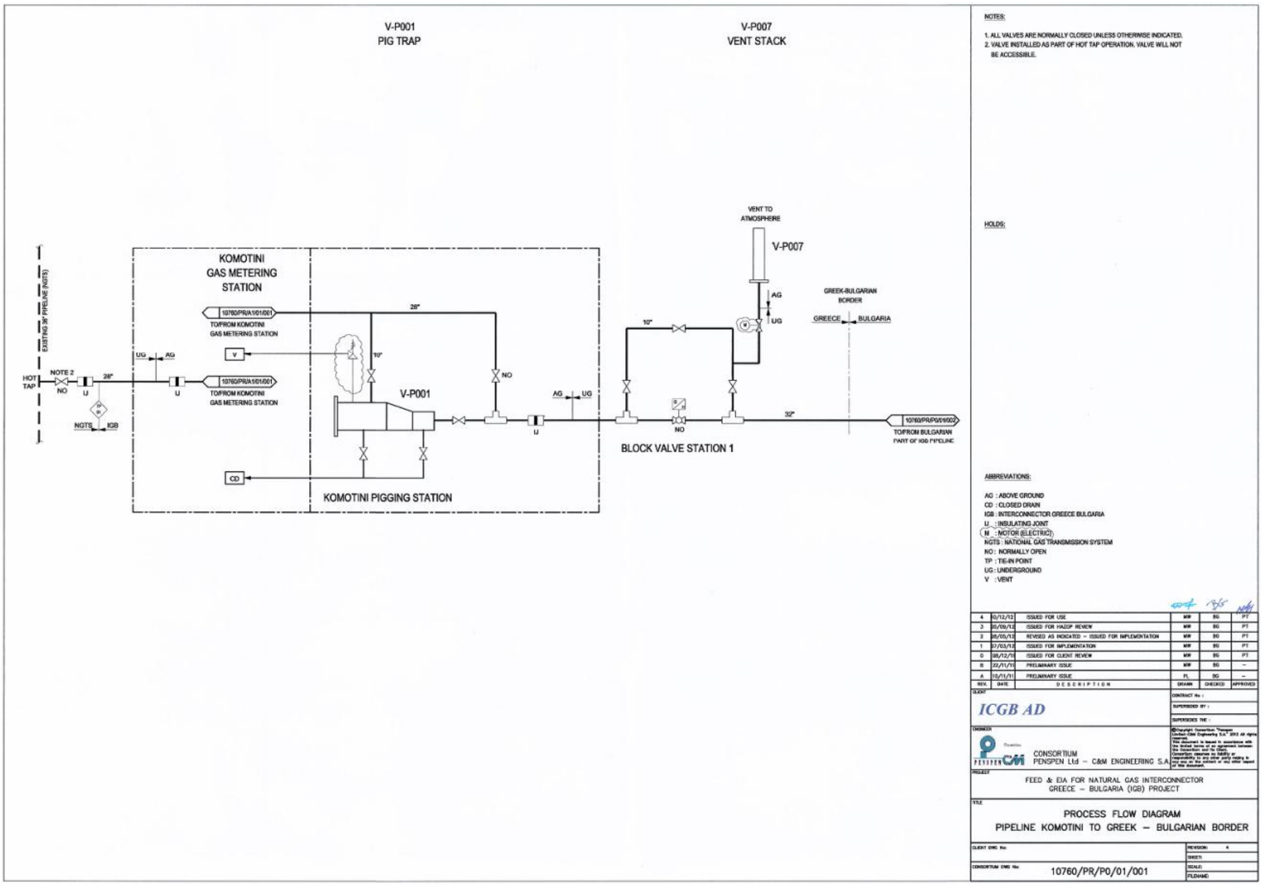


Figure 3 below presents a Map of the Pipeline Route.

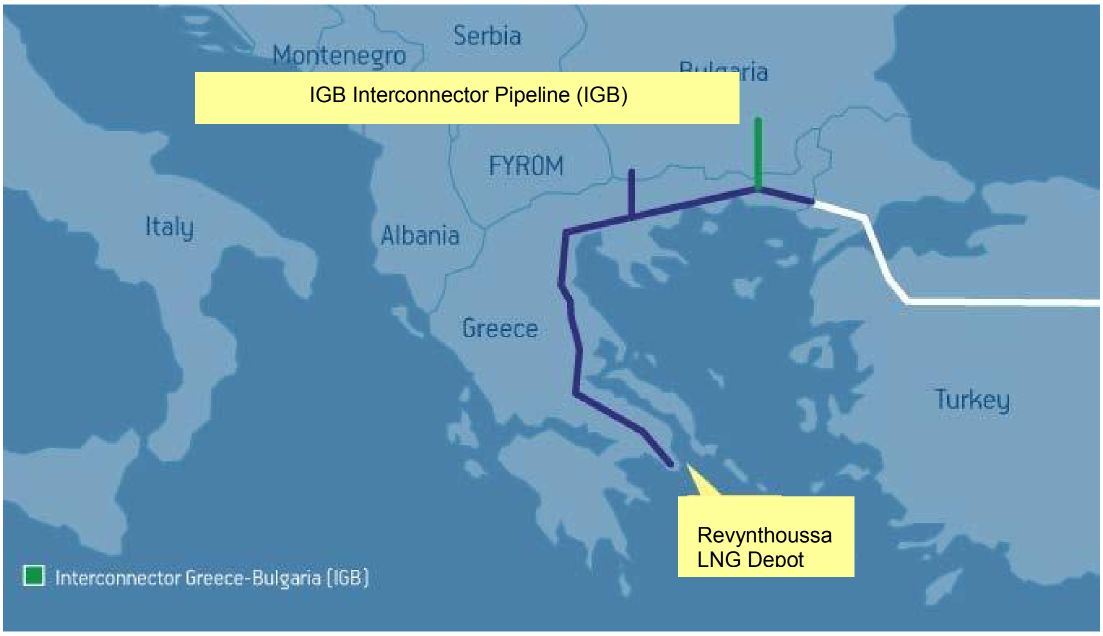


Fig 3. Map of Pipeline Route

1.2 Project Owner

The project owner is ICGB AD, a company, entered into the Commercial Registry of the Registry Agency of Bulgaria, under unified identification code 201383265, having a registered office and address of management at 66 Pancho Vladigerov Blvd., District Lyulin 2, Sofia, Bulgaria.

ICGB is duly represented by the Executive Officers Mr. Konstantinos Karayiannakos and Mrs. Teodora-Georgieva Mileva.

1.3 Contact Information

The contact person for the QRA Study, regarding the Greek Section, in ICGB AD is Mr. Konstantinos Tyroyiannis.

The present Quantitative Risk Assessment (QRA) Study has been elaborated by the company SYBILLA ltd Consulting Engineers in the context of contract P-02-C/18-05-2017 awarded by ICGB AD to the company SYBILLA ltd Consulting Engineers

The company SYBILLA ltd Consulting Engineers has offices in Greece, 16 Ipsilantoust., 154 52, Maroussi-Athens Tel.: +30-210-6024244, Fax: +30-210-61412457220298www.sybilla.gr., e-mail: mail@sybilla.gr .

Mr Panagopoulos Yannis, Chemical Engineer A.U,Th, MSc is Project Director and Responsible for this study and Mr Athanasios Karayannis Chemical Engineer N.T.U.A is assistant Project Director .

1.4 Project Design Philosophy

The IGB buried pipeline will transport natural gas over the border between Greece and Bulgaria, connecting the existing Komotini Station in Greece with an existing gas pipeline near the Bulgarian town of Stara Zagora. The proposed pipeline will measure a total distance of approximately 182 Km, (about 31.5 Km in Greece and 150.5 Km in Bulgaria).

The design of this bi-directional pipeline system shall be in accordance with the internationally recognized codes of practice: EN1594 and ASME B31.8, and also in conjunction with Bulgarian Ordinances, for the safe transportation of 3bcm/yr of gas initially, with the provision for the future expansion up to a maximum technical capacity of 5bcm/yr. The project also includes the construction of the following Above Ground Installations (AGIs):

- 2 off Gas Metering Stations (GMS) and 2off Pigging Stations (PS), one at Komotini and the other one near Stara Zagora;
- Four (4) intermediate Pigging Stations (PS), on either side of lake Kardjali and river Maritza in Bulgaria.
- Ten (10) off Block Valve Stations (BVs), one (1) in Greece and nine (9) within Bulgaria;
- 2 off Offtakes and Automated Gas Regulation Stations (AGRSs) at locations close to the Bulgarian towns of Kardjali and Dimitrovgrad.
- 1 off Dispatch / Operational and Maintenance Base in Haskovo, Bulgaria.

1.5 QRA Study Team

This study was elaborated by the company SYBILLA ltd Consulting Engineers. The study team consisted of the following scientists :

- Panagopoulos Yannis, Chemical Engineer A.U,Th, MSc (Registered under the Ministry Of Environment, Energy & Climatic Change) Project Director and Project Responsible for this Study.
- Ahanasios N. Karayannis, Chem. Engineer N.T.U.A (Registered under the Ministry Of Environment, Energy & Climatic Change) Assistant Project Director and Project Assistant Responsible for this Study.
- George Gouvalias, Chem. Engineer.
- Kostantinos Theophylaktos, Mechanical Engineer MSc
- Vasiliki Stamatopoulou, Environmental Engineer.
- Panayiotis Karayannis, Mininng Metallurgical Engineer N.T.U.A
- Nikolaos Karayannis, Agricultural Engineer A.U.A., GIS expert.

2 SHORT DESCRIPTION OF ICGB PIPELINE

2.1 Pipeline Routing

The routing of the High Pressure gas pipeline was chosen based on criteria as the safety of the population, the protection of ecosystems and the terrain structure. These criteria are the same as those observed in other high pressure gas pipelines designs of the existing Hellenic Gas Transmission System, which was recently relocated from DEPA and transferred to DESFA S.A.

The routing of the pipeline has a total length 31479.87m. (K0-K109), beginning at point K0 (Metering station and Pigging Station), which is located at the south-western edge of Industrial Area of Komotini and ending at the connection point K109 of the Greek section pipeline with the rest (Bulgarian) section of the pipeline at the border of Greece – Bulgaria.

With direction from south to north, the routing is located consecutively as follows:

Segment K0-K20 (0–11km): The routing of the pipeline has north western direction at first and northern afterwards, it starts south-western from the Industrial Area of Komotini, passes from Metering Station (GMS1) and Pigging Station (PS1) “KOMOTINI” (K1+363.56) that are going to be installed in a common land plot northern from the settlement Fylakas, continues southern at first and western afterwards from the settlement Thrylorio, eastern from the settlement Roditis and the city of Komotini and ends between the settlements Karydia and Kalchas, passing through extended cultivated areas of cotton and wheat.

It crosses mostly with the asphalt road Fylakas – Thrylorio (K3+71.89m), the under study DESFA’s Greece – Italy (IGI) natural gas pipeline and the existing Komotini - Thessaloniki natural gas pipeline of DESFA (K4+209.36m. & K4+221.72m), the Old National Road Alexandroupoli – Komotini (K8+88.56m), the stream “Trelochimaros” (K18+225.50m) and at the end, the Regional road Karydia – Kalchas (K19+989.66m).

Segment K20-K36 (11-16km): With north western direction the routing of the pipeline passes south-western from the settlement Tychiro, passing through hilly area of gentle slopes with cultivations, trees and heath parts and crosses mostly the asphalt road to Tychiro (K25+21.68m), the under construction (construction works haven’t started yet) New National Road “Komotini – Nimfea – Greek-Bulgarian Borders – Axis 75” (K32A+100.36m) and the asphalt road to Pandrosos (K33+24.43m). In this segment the following rerouting that the local Forest Inspection Authority demanded was realized :

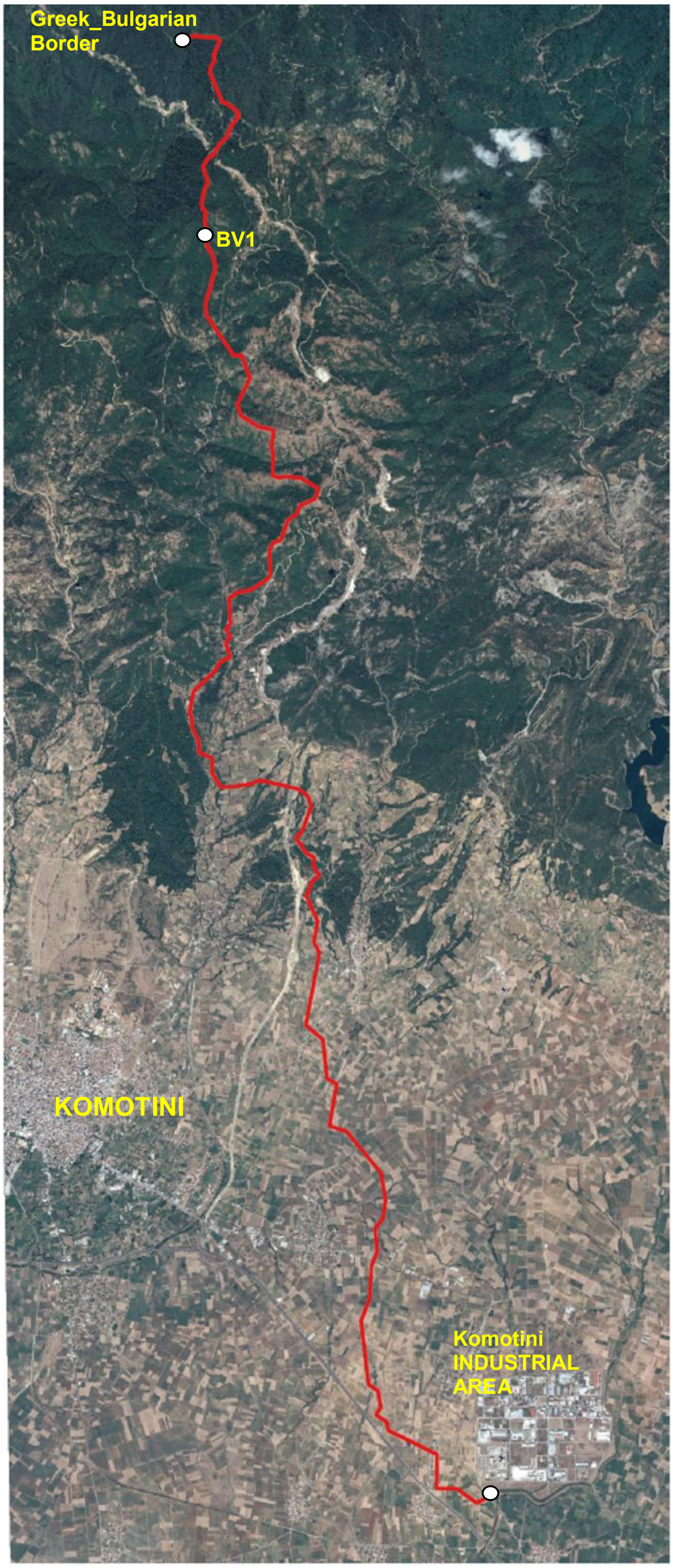
- In the area between the points K32 - K33 (of the initial routing REC), where a pine forest exists (from reforestation in order to protect the settlements below it as well as the city of Komotini from severe floods) it was required to bypass the abovementioned forest by relocating the pipeline to the east (Part K29-K30-K31-K32-K32A-K32B-K32C-K33 of Final Routing REC).

Segment K36-K109 (16-31.5km): The routing of the pipeline has northern direction, passing western at first and northern afterwards from the settlement Pandrosos, western from the settlement Nimfea, from the Block Valve Station (BV1) “Nimfea” (K84+72.66m), which is located 4km about western from the settlement Mytikas, it continues western from the settlement Ano Mytikas and ends to the Greek – Bulgarian borders, passing through mountainous area with trees and heath parts. It crosses mostly with the ravine Karydorema (K36+30.27m. & K46+63.13m) and the New National Road "Komotini – Nimfea – Greek-Bulgarian Borders – Axis 75" (K92+55.36m) above a tunnel that has already constructed. In this segment the following rerouting that the local Forest Inspection Authority demanded was realized :

- In the area between the points K37 - K39 (of the initial routing REC), where the pipeline is near the "Nimfea" forest, it has been relocated for about 15m to the east for fire protection reasons. (Part K37-K38-K39 of Final Routing REC).

Concerning the administrative structure of the routing, the pipeline is located at the Region of East Macedonia – Thrace, at the Prefecture of Rodopi and at the Municipality of Komotini.

Fig 4. Pipeline Routing – Greek Part.



2.2 Additional Installations.

2.2.1 Additional Installations siting

The pipeline will be accompanied by the associated Metering/Regulating Stations, Block Valve/Scraper Stations according to the FEED :

- Gas Metering Station (GMS) “Komotini” and Pigging Station - Launcher (PS) “Komotini” in a common plan in the Komotini area.
- A Block Valve Station “NIMFEA” near the Greek-Bulgarian border.

Table 1. Stations Positions

S/N / Α/Α	NAME / ΟΝΟΜΑΣΙΑ	DESCRIPTION / ΠΕΡΙΓΡΑΦΗ	DRAWING NUMBER / ΑΡ. ΣΧΕΔΙΟΥ 1:5.000	LOCATION / ΘΕΣΗ	PROGRESSIVE DISTANCE / ΧΙΛΙΟΜΕΤΡΙΚΗ ΘΕΣΗ (m)	REMARKS / ΠΑΡΑΤΗΡΗΣΕΙΣ	ACCESS ROAD LENGTH / ΜΗΚΟΣ ΟΔΟΥ ΠΡΟΣΒΑΣΗΣ (L)
1	KOMOTINI / ΚΟΜΟΤΗΝΗ	PIGGING STATION (PS1) / ΣΤΑΘΜΟΣ ΑΠΟΣΤΟΛΗΣ ΞΕΣΤΡΟΥ (PS1) GAS METERING STATION (GMS1) / ΜΕΤΡΗΤΙΚΟΣ ΣΤΑΘΜΟΣ(GMS1)	10760/PL/P1/02/421	K1A+67.16	633.37	RECOMMENDED LOCATION / ΠΡΟΤΕΙΝΟΜΕΝΗ ΘΕΣΗ	L= 380 m
2	NIMFEA / ΝΥΜΦΑΙΑ	BLOCK VALVE STATION (BV1) / ΒΑΛΒΙΔΟΣΤΑΣΙΟ (BV1)	10760/PL/P1/02/430	K84+114.55	27608.57	RECOMMENDED LOCATION / ΠΡΟΤΕΙΝΟΜΕΝΗ ΘΕΣΗ	L= 1667 m

2.2.2 Block Valve Stations

2.2.2.1 <u>Design philosophy</u>

Block valves will be installed on the pipeline for the purpose of isolating the pipeline for maintenance and for response to operating emergencies. When determining the placement of valves for sectionalising the pipeline, consideration will be given to locations that provide continuous accessibility to the valves.

For determining the number of valves, assessment of the following factors will be carried out

- The amount of gas release due to repair and maintenance blowdowns, leaks or ruptures
- The time to blow down an isolated section

- The impact to the area of gas release
- Continuity of service
- Operating and flexibility of the system
- Future development in the vicinity of the pipeline.

EN 1594 does not specify limits for spacing of valves, however, the spacing between valves should not considerably exceed 30 km.

One (1) Block Valve station will be installed inside the Greek Territory, near the Greek-Bulgarian border.

2.2.2.2 Configuration

Live Valve Stations will consist of the following:

- Main Block valve with actuator
- Bypass line with isolation valve to assist in the equalization of pressure each side of the main Block valve to allow it to be operated under minimum differential pressure
- Isolation valves on each tee for the bypass line to allow maintenance of the bypass valve
- Vent line with valve to a vent stack
- Connections for pressure and temperature transmitters

The bypass and vent valves are to be plug valves installed above ground to aid operability and maintainability. Above ground pipework will be electrically connected to the main Cathodic protection system with spark gaps provided for grounding. The distance between valve and vent stack is to be determined during the design phase based on gas dispersion, hazardous areas and noise. The piping to the vent stack will be buried after the above ground vent valve.

2.2.2.3 Stab-outs philosophy

Provisions for stab-outs on the Block valve locations for future above ground installations will be considered during the design phase, if required.

The stab outs will take the form of tees with guide bars and buried, blanked valves. Tees will be placed upstream and downstream of the Block valve to ensure supply to the future installation can be maintained should a single section of pipeline be isolated.

2.2.3 Pipeline Scraper Launcher/Receiver

2.2.3.1 Design philosophy

Scraper launcher and receiver stations will be installed at both ends of the pipeline. These stations will occur:

- at the start of the pipeline at Komotini
- at the end of the pipeline at Stara Zagora (Bulgaria).

The scraper stations will be designed for the use of permanent scraper launcher and receiver traps. The traps will be designed for bi-directional scraper operations in that launcher and receivers will be identical.

Scraper stations will be designed to permit venting, depressurization and scraper operations.

Intermediate scraper launcher and receiver stations will be installed at both ends of the parallel twin pipeline of the special crossing of the lake at Kardjahli and the river Maritza in Bulgaria, according to the Bulgarian law provisions.

2.2.3.2 Configuration

The scraper stations will include the following:

Weld end permanent universal scraper trap with quick closing door installed on foundations

- Above ground full bore weld end isolation valve
- Above ground offtake barred tee
- Above ground Isolation joint, before the barred tee, for electrical isolation of the pipeline Cathodic Protection system
- Above ground offtake valve with bypass
- Kicker line with isolation valve for the forcing of pigs connected to the major barrel of the scraper trap
- Balance line to enable filling and pressurization of the scraper trap barrel on both sides of the pig at the same time
- Vent line with valve to vent stack for the blowdown of scraper trap and depressurizing/degassing of pipeline
- Pig Signalers to indicate the passage of pigs into or out of the pig trap will be installed.

The scraper launcher and receiver will be equipped with pressure indicators, pig signalers and safety locks with vent line to prevent unintentional opening of the quick closing door.

Drain lines will be incorporated into the scraper traps and into the pipeline upstream of the scraper in order to drain off liquid moved through the pipeline by pigs.

The bypass and vent valves are to be plug valves installed above ground to aid operability and maintainability.

The distance between valve and vent stack is to be determined during the design phase based on gas dispersion, hazardous areas and noise. The piping to the vent stack will be buried after the above ground vent isolation valve.

2.2.3.3 Stab-outs to Future Facilities

Stab-outs for future facilities will be considered during the design phase, if required.

2.2.4 Metering / Regulation Stations

The scope of the Metering/Regulation Stations is the measurement of the quality & quantity of gas passing through them and (if needed) the regulation (lowering) of the gas pressure.

They consist of the following two parts:

- A roofed area under which the mechanical equipment is installed (valves, filters, flow regulators, flow meters etc.) The use of roof will be decided upon during the design stage.
- Small building in which all the auxiliary equipment is installed: boilers, air conditioners, batteries, flow and supervisory computers, UPS, Auxiliary power generator (EDG), offices, WC, etc.

In the surrounding space and inside the building all the underground auxiliary networks of electro-mechanical and communications networks are installed (water, sewer, power & data cables).

A small roofed space will be provided for the installation of the gas composition analyzers installation (along with their auxiliary equipment).

These stations operate automatically without personnel. However they are visited regularly by the maintenance and monitoring teams crews.

2.3 Assessment of sensitive / densely populated areas

Pipelines designed in accordance with recognised codes and standards can usually be considered to automatically have acceptable levels of risk. Risk assessment at the design stage can be performed as an additional confirmation of the acceptability of the associated risk. ICGB AD has requested a Quantitative Risk Assessment (QRA) to be completed for the Greek section of pipeline and SYBILLA ltd have reviewed the proposed route to identify the most sensitive/densely populated area within this section. In which population could be exposed to Risk.

As a general design guideline the pipeline avoids populated areas and passes in a great deistance from them.

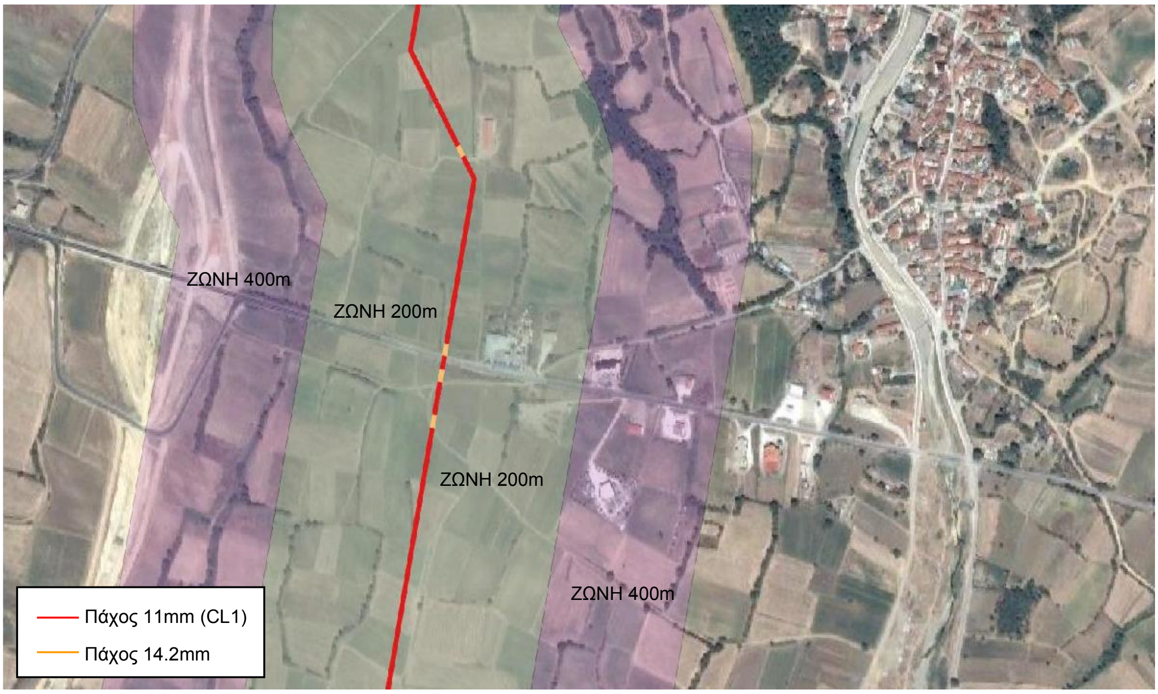
However, in the wider area of the ICGB pipeline routing there are two points where special attention in respect of safety has to be given. These are :

- The area west of KALCHAS village between K19-K20 (A) and
- The area east of RODITIS village near the crossing with the National Road between Komotini and Alexandroupolis between K8-K9-K10 (B).

2.4 Area A - Kalchas

In the area A during the last decade there has been considerable development west of Kalchas village near the new road that connects Egnatia Highway with the Greek-Bulgarian Border.. Although the Class Location Classification of the pipeline in the two areas seems unaffected (remains Class Location 1) the accumulation of establishments like gas station, car maintenance, shops etc gradually increases the population that could be exposed to Risk in the event of a pipeline catastrophic failure. The observed accumulation is expected to increase now that the abovementioned road that connects Egnatia Highway with the Greek-Bulgarian Border is operational.

Fig 5.Pipeline Routing near Kalchas village (200m and 400m zones)



The most densely populated section along the proposed Greek route of the IGB 32 inch natural gas pipeline is where the pipeline passes close to the outskirts of Kalchas. Within the hazard range there are three buildings, the first is a large petrol filling station and associated tyre services, the second is a sanitary ware shop, although it currently appears to be unoccupied, and the third is a small supermarket with apartments on the first floor. Other buildings are more than 250 m distant from the pipeline and are outside the hazard range.the new road that connects Egnatia Highway with the Greek-Bulgarian Border lies more than 250m from the pipeline axis to the west. The area near Kalchas village and the IGB pipeline routing is presented in Figure 5.

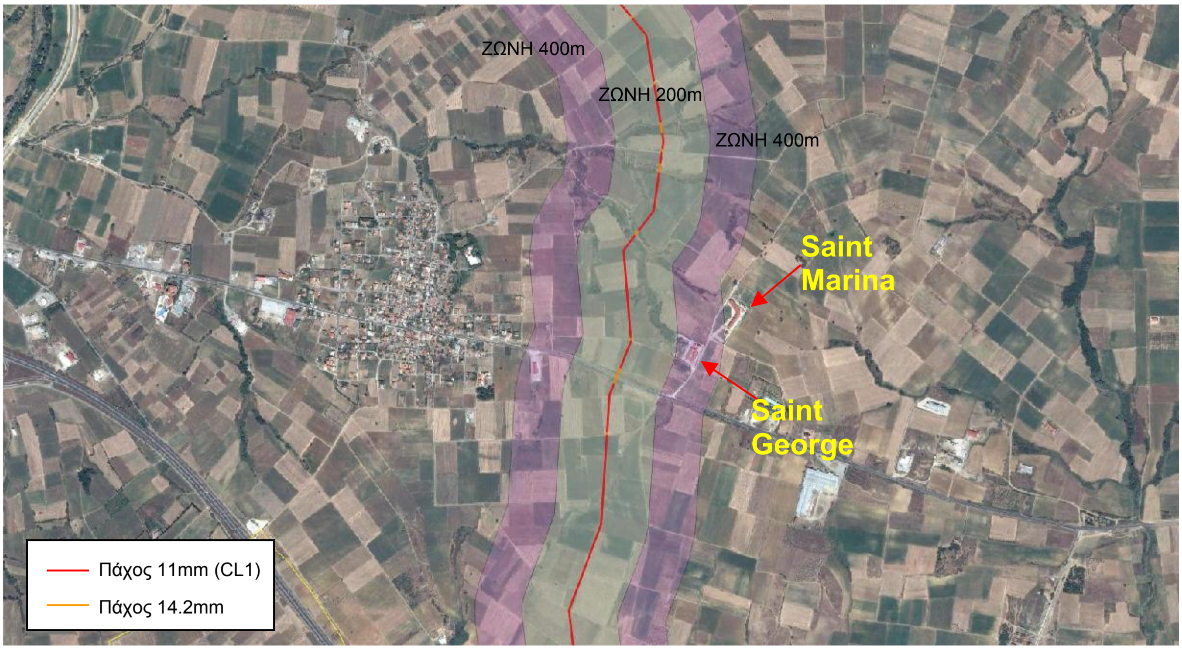
2.5 Area B - Roditis

In the area B during the last decade there has been considerable development east of Roditis village. Although the Class Location Classification of the pipeline in the two areas seems unaffected (remains Class Location 1) in the near area there are two Psychiatric Hospitals that are considered Sensitive Receptors and increase the population that could be subjected to Accident Risk in the case of a pipeline catastrophic failure.

The oldest of the two “Saint George” with 120 patients beds lies near the pipeline route (about 250m) but it is not operational since 2011. “Saint George” was the first Psychiatric Institution for “Closed Treatment” that operated in Greece. Operation started in 1999 with a capacity of about 120 patients.

Today, only the new “Saint Marina” Clinic with 160 patients beds is operational (since 2011) and lies at a distance of about 400m from the pipeline route. The area near Roditis village and the IGB pipeline routing is presented in Figure 6.

Fig 6. Pipeline Routing near Roditis village (200m και 400m zones)



Although the assessment of Individual Risk was performed for the whole length of the pipeline, special attention was given for the two abovementioned points and measures were recommended for the decrease of Risk in these areas.

2.6 Abbreviations

3LPE	3 Layer PolyEthylene
ALARP	As Low as Reasonably Practicable
CP	Cathodic Protection
cpm	Chance per Million
EGIG	European Gas pipeline Incidents data Group
EIA	Environmental Impact Assessment)
FBE	Fuse Bonded Epoxy)
FEED	Front End Engineering Design
FRED	Fire, Release, Explosion and Dispersion
HSE	Health & Safety Executive (UK)
IGB	Έργο Διασυνδετήριου αγωγού Ελλάδας – Βουλγαρίας
ICGB	Εταιρεία Διασυνδετήριου αγωγού Ελλάδας – Βουλγαρίας
IGEM	Ινστιτούτο Μηχανικών και Διευθυντικών Στελεχών Αερίου
MOP	Maximum Operating Pressure)

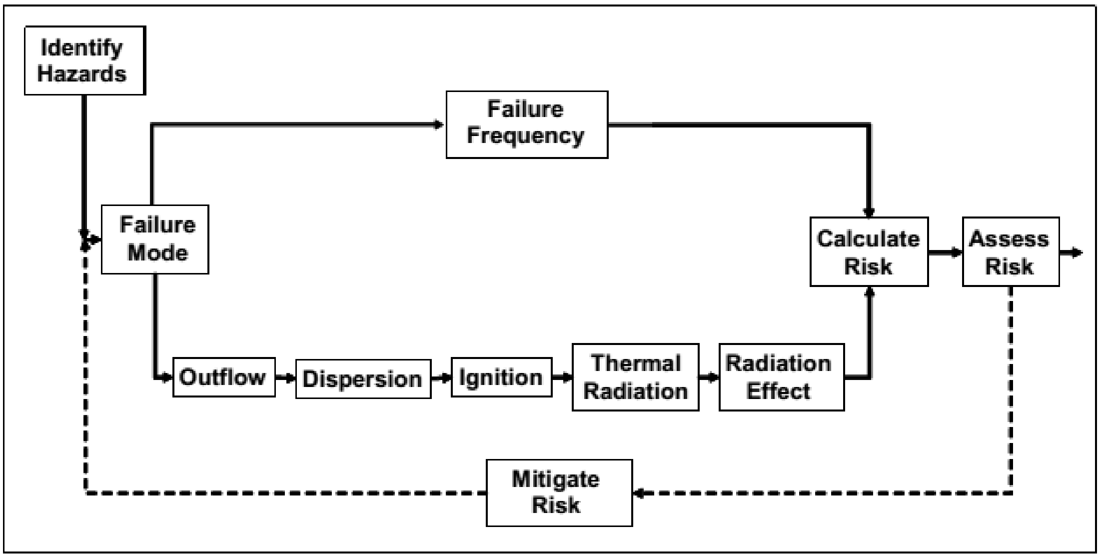
PE	PolyEthylene
QRA	Quantitative Risk Assessment)
SCC	Stress Corrosion Cracking)
SRB	sulfur reducing bacteria)
T/R	Transformer / Rectifier)
TDU	Thermal Dose Unit)
UKOPA	United Kingdom Onshore Pipeline operators Association

3 RISK ASSESSMENT METHODOLOGY

3.1 The adopted Risk Assessment Methodology

The general methodology used in pipeline quantitative risk assessments is shown diagrammatically in Figure 7 below.

Fig 7. Elements of QRA



It is important that, as far as is reasonably possible, the frequency values used in the QRA reflect the actual design, conditions and environment within which the pipeline will be operating. The standard approach is to take generic data (which has the advantage of being collected over an extensive sample base like the European Gas Pipeline Incident Data Group-EGIG, UKOPA, RIVM)) and then to customise tins to reflect the specific pipeline.

The starting point for the QRA are data on the causes of failure and the associated hole sizes; these are drawn from industry databases and are examined below.

Only holes and ruptures are considered as leaks from cracks or pinholes are very unlikely to give fatalities and it should be borne in mind that the datasets for pipelines similar to ICGB are very small, so there is uncertainty in the derivations of specific frequencies as detailed below

Details of general assumptions and methodology used in the risk assessment can be found below and are in agreement with standard IGEM/TD/2.

3.2 Failure modes taken into account

Failure modes lor most pipelines are typically well known and generally include:

Failures due to External interference

- Failure due to the activity having caused the incident (e.g. digging, piling, ground works)
- Failure due to the equipment involved in the incident (e.g. anchor, bulldozer, excavator, plough)
- Failure due to the installed protective measures (e.g. casing, sleeves)

Failures due to Manufacturing Defects

- Manufacturing/welding/fabrication defects,
- Equipment related,
- Fatigue,

Critical issues are the type of defect (construction or material), defect details (hard spot, lamination, material, field weld or unknown), pipeline component type (straight, field bend, factory bend))

Failures due to Corrosion,

- Internal corrosion,
- External corrosion,
- Stress corrosion cracking,

Critical issues are corrosion location (Internal, External, Unknown), The appearance (General, Pitting, Cracking), In line inspected (yes, no, unknown)

Failures due to Ground Movement

- Weather related and outside forces (e.g. ground movement);

Critical issue is the type of ground movement (dike break, erosion, flood, landslide, mining, river or unknown.

Failures due to Other and unknown reasons,

- design error,
- lightning,
- maintenance error.
- Internal corrosion,

The applicability of the potential failure modes to the Greek section of the 32 inch IGB pipeline is discussed in further detail below.

Detailed Analysis of Pipeline Failure rates is given in Appendix D.

3.3 External Interference Failure Mode

3.3.1 Historical Records of External Interference related Failure Mode incidents based on EGIG data

EGIG 9th report recognizes тhat External Interventions is responsible for a significant percentage of the total incidents.

From this report some general conclusions can be drawn

- Large diameter pipelines are less vulnerable to external interferences than smaller diameter pipelines). There might be several explanations for this: small diameter pipelines can be more easily hooked up during ground works than bigger pipelines, their resistance is often lower due to thinner wall thickness and might be found more frequently in urban areas where third party activity is generally higher
- The depth of cover is one of the leading indicators for the failure frequencies of pipelines. Pipelines with a larger depth of cover have a lower primary failure frequency.
- Pipelines with a larger wall thickness have a lower failure frequency of external interference.

3.3.2 How External Interference Failure Mode has been taken into account in ICGB Pipeline FEED.

Any pipeline that crosses publicly accessible land is at risk from external interference, e.g. from ditch clearance or construction activities. The chance of external damage occurring is reduced by regular pipeline route surveillance, either aerial or vantage point surveys, clear pipeline marker posts and regular landowner liaison. **In he case of the IGB pipeline marking along the route will be made accorsing to specifications and a clearly visible plastic net will be placed over the pipe inside the trench.**

External interference typically leaves a dent, a gouge or a dent combined with a gouge. Plain denting is defined as damage that causes a smooth change in curvature without a reduction in pipe wall thickness. The dent introduces high localised stresses and causes yielding in the pipe wall but these are usually accommodated by the pipeline ductility and do not significantly reduce the burst pressure of a pipeline.

Gouges are caused when a foreign object, e.g. the tooth of a mechanical digger, scrapes the surface of the pipeline removing part of the pipe wall. Gouges reduce the strength of the pipeline due to the metal loss and a work hardened layer below the gouge may also be formed. This hard spot will reduce the local ductility and therefore affect the failure behaviour.

If a dent occurs in combination with a gouge, or other defect, then the increased localised stresses act over an area containing a stress concentrator. The effect is to promote ductile tearing of the defect through the remaining ligament as the dent moves outwards under the action of the internal pressure. Any hard spot may crack when the indenting force is removed and the pipe attempts to return to its original shape. Dents in combination with gouges can have very low burst pressures and short fatigue lives.

External interference defects can fail either as a leak or rupture depending on the type and dimensions of the defect as well as pipeline operating and material parameters.

Routing Selection

The following factors are taken into consideration in order the optimal pipe routing to be selected.

- The minimum distance of the pipeline route from existing buildings should be considered;
- no vicinity to hazardous areas which may affect the integrity of pipeline installations, such as areas with tank farms, explosive storage yards and other sources of inflammation (proximity to exceed 30 m from plot boundaries), quarry yards, mines, and other hazardous installations;
- to be in areas with reduced risk of fire and the pipeline installations can be protected from fires on adjacent properties which are not under the control of the pipeline operating company;
- Passing of the pipeline route through the following areas should be avoided wherever possible or minimized:
  - Areas with foundations that may impact trenching of the pipeline;
  - Proximity of past, present and future extraction works;
  - Existing of planned built-up areas;
  - Areas that are zoned for future development (domestic, industrial, commercial or mineral) or other developmental control
  - Areas with planned future projects;
  - Areas with underground man-made obstacles.

3.3.2.1 Class Locations and Design Factors

The pipeline Design Factors (DF) will be in accordance with EN 1594, enhanced where appropriate by the guidance given by ASME B31.8 regarding population density and crossings. Design factors will in no case be higher than the maximum values defined in EN 1594 Clause 7.2.1.

The pipelines will be classified as: Location Class 1 & 2 as presented in the Class Location Table in APPENDIX B. These location classes and associated design factors are defined as guided by ASME B31.8 Clause 840 and table 841.1.6-1.

Table 2. Class Locations

From Drawing Number / Από Αρ. Σχεδίου 1 : 1000	To Drawing Number / Έως Αρ. Σχεδίου 1 : 1000	Position / Θέση		Progressive Distance / Χιλιομετρική Θέση (m)		C1 (m)	C2 (m)	C3 (m)	C4 (m)	Remarks / Παρατηρήσεις
		From / Από	To / Έως	From / Από	To / Έως					
10760/PL/P1/02/601	10760/PL/P1/02/616	K0+0.00	K35+102.03	0.00	15996.78	15996.78				
10760/PL/P1/02/616	10760/PL/P1/02/618	K35+102.03	K42+183.56	15996.78	17596.78		1600.00			
10760/PL/P1/02/618	10760/PL/P1/02/619	K42+183.56	K49+374.76	17596.78	19256.78	1660.00				
10760/PL/P1/02/619	10760/PL/P1/02/621	K49+374.76	K57+78.01	19256.78	20856.78		1600.00			
10760/PL/P1/02/621	10760/PL/P1/02/634	K57+78.01	K109+0.00	20856.78	31636.66	10779.88				
TOTAL / ΣΥΝΟΛΟ						**28436.66**	**3200.00**	**0**	**0**	

3.3.2.2 Pipeline materials

Line Pipe will be in accordance with a project specific specification which is supplementary to EN 10208-2. The grade has ben selected as L450MB..

Only steel pipes and piping components will be used.

Spiral (helical) welded pipes may be used for DN ≥ 600.

Screwed and threaded connections and fittings will be limited to above ground instruments installation.

Pipeline and fittings will be Charpy impact tested. The test temperature and acceptance for arrest of running ductile fracture will be defined during the course of the project. Pipes or piping components will be supplied with inspection certificates EN 10204 Type 3.1 or 3.2.

3.3.2.3 Pipeline marker posts

Durable marker posts will generally be provided at field and property boundaries, at changes in route alignment and at each side of the road, rail and watercourse crossings. The posts will bear identification plates to a design approved by Owner.

Consideration may be given during detail design to the need for aerial markers at appropriate intervals to aid routine maintenance surveys by helicopter or light aircraft.

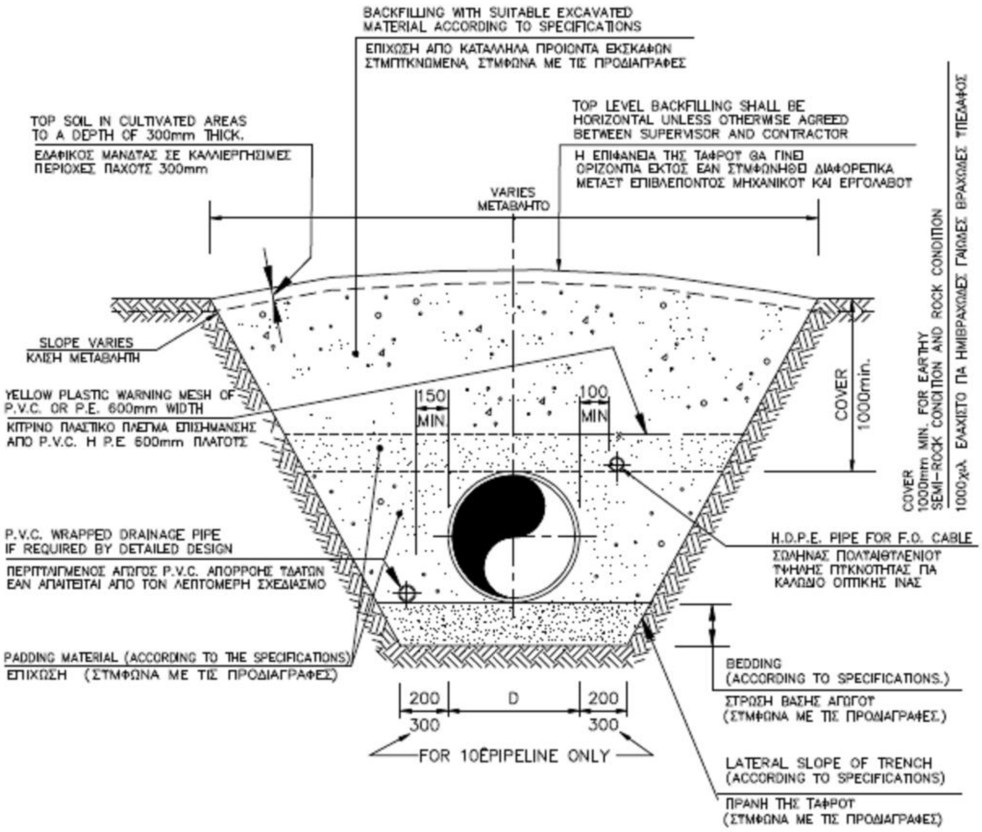
3.3.2.4 Burial and protective cover

The depth of buried cover to the top of pipe will be a minimum of 1.0metre in all cases as per DESFA existing practice. Within more heavily populated areas and at most crossings, it will be at least 1.2metres but in special areas it will be defined at detail design stage.

The following figures taken from the project EIA present :

- Typical Trench for NG pipelines Cross Section
- Typical protection measures utilizing cement / sand bags
- Typical Diversion Berms for Soil Erosion Prevention.
- Typical Gabon Box Bank Erosion Prevention

Fig 8. Typical Trench for NG pipelines Cross Section (from IGB EIA)



REMARK

TYPICAL TRENCH IS NOT APPLICABLE FOR PIPELINE CROSSINGS WITH NATIONAL ROADS, RAILROADS, ROADS, RIVERS, IRRIGATION AND DRAINAGE CHANNELS, ACTIVE SEISMIC FAULTS, ETC.

Η ΤΥΠΙΚΗ ΤΟΜΗ ΤΑΦΡΟΥ ΔΕΝ ΕΧΕΙ ΕΦΑΡΜΟΓΗ ΣΤΙΣ ΔΙΑΣΤΑΥΡΩΣΕΙΣ ΤΟΥ ΑΓΩΓΟΥ ΜΕ ΕΘΝΙΚΕΣ ΟΔΟΥΣ, ΣΙΔΗΡΟΔΡΟΜΟΥΣ, ΔΡΟΜΟΥΣ, ΠΟΤΑΜΙΑ, ΑΡΔΕΥΤΙΚΑ ΚΑΙ ΑΠΟΧΕΤΕΥΤΙΚΑ ΚΑΝΑΛΙΑ, ΕΝΕΡΓΑ ΣΕΙΣΜΙΚΑ ΡΗΓΜΑΤΑ, Κ.Λ.Π.

TYPICAL TRENCH SECTION IN EARTHY, SEMI ROCKY OR ROCKY SOILS IN OPEN COUNTRY
ΤΥΠΙΚΗ ΔΙΑΤΟΜΗ ΤΑΦΡΟΥ ΣΕ ΓΑΙΩΔΗ, ΗΜΙΒΡΑΧΩΔΗ Η ΒΡΑΧΩΔΗ ΕΔΑΦΗ ΣΤΗΝ ΥΠΑΙΘΡΟ

Fig 9. Typical protection measures utilizing cement / sand bags (from IGB EIA)

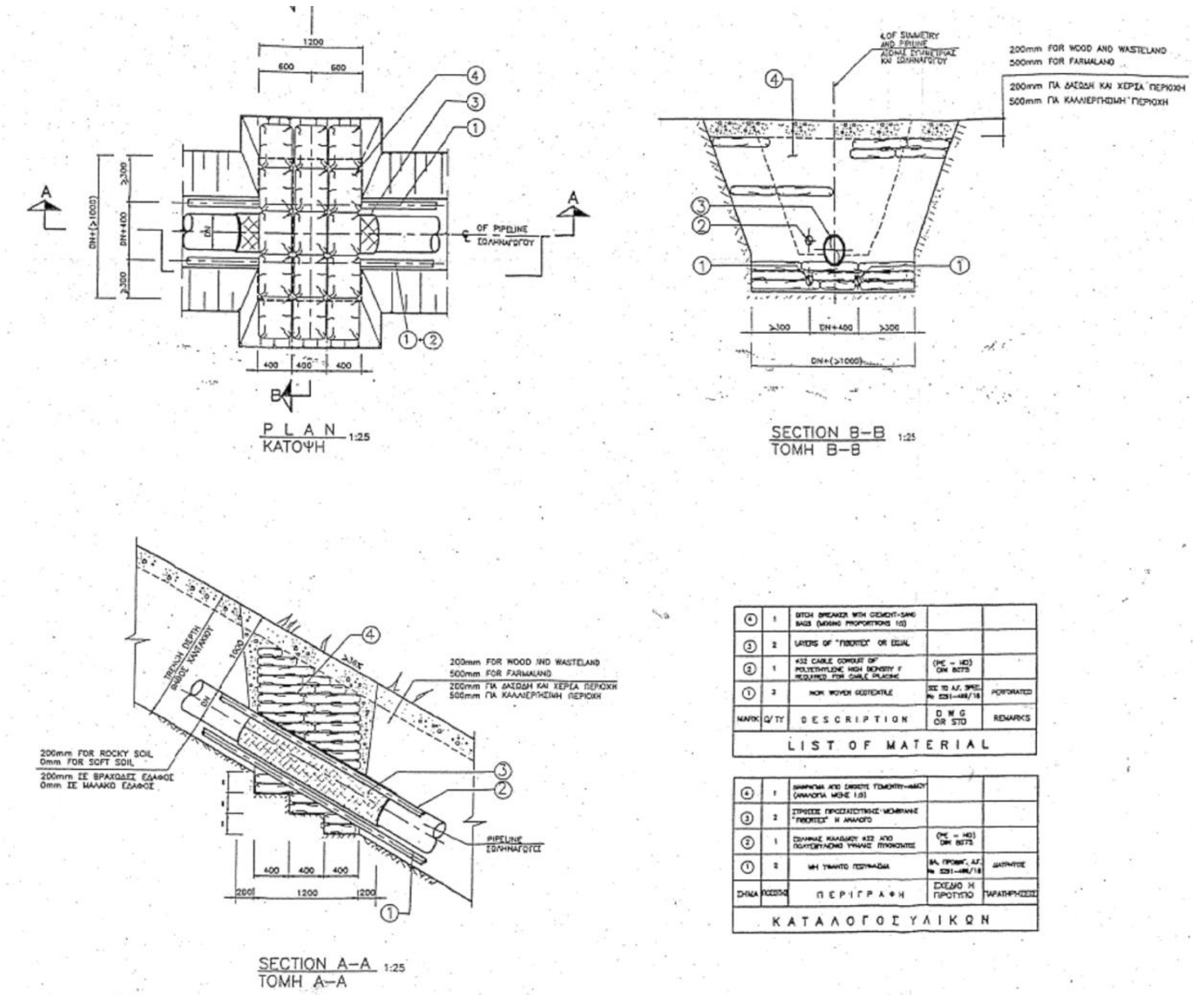
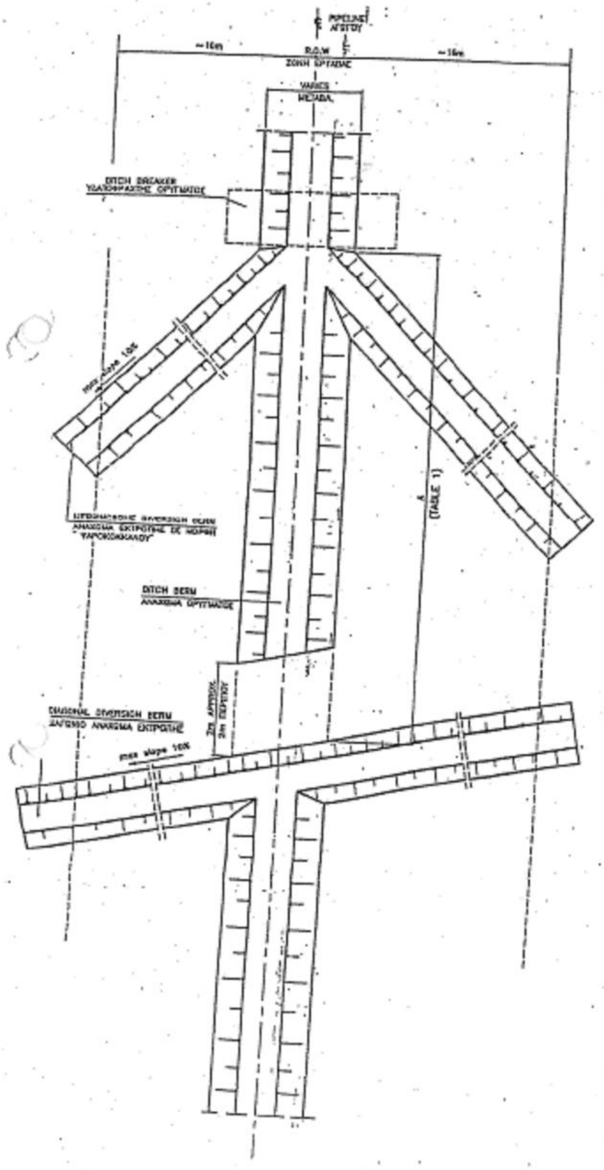


Fig 10. Typical Diversion Berms for Soil Erosion Prevention (from IGB EIA)



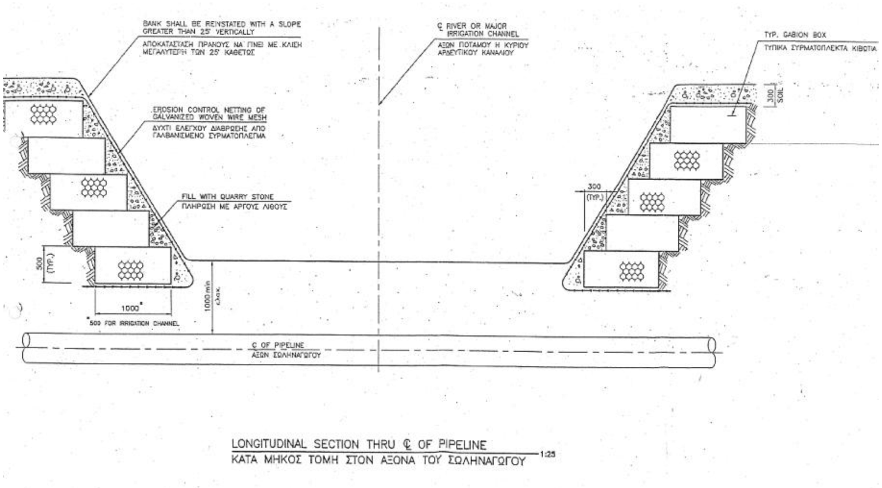
PLAN OF DIVERSION BERMS
ΚΑΤΟΨΗ ΑΝΑΧΩΜΑΤΩΝ ΕΚΤΡΟΠΗΣ

A: TYPICAL DIVERSION BERMS SPACING
ΤΥΠΙΚΗ ΑΠΟΣΤΑΣΗ ΜΕΤΑΞΥ ΑΝΑΧΩΜΑΤΩΝ ΕΚΤΡΟΠΗΣ

SLOPE ΚΛΙΣΗ	SOIL EROSION POTENTIAL ΕΠΙΚΙΝΔΥΝΟΤΗΤΑ ΕΔΑΦΟΥΣ ΣΕ ΔΙΑΒΡΩΣΗ		
	HIGH–ΥΨΗΛΗ (m)	MODERATE–ΜΕΤΡΙΑ (m)	LOW–ΧΑΜΗΛΗ (m)
GENTLE (<10%) ΟΜΑΛΗ	45	60	NOT WATERWAYS NECESSARY ΔΕΝ ΑΠΑΙΤΟΥΝΤΑΙ ΑΝΑΧΩΜΑΤΑ ΕΚΤΡΟΠΗΣ
MODERATE (10%÷20%) ΜΕΤΡΙΑ	30	45	60
STEEP OVER 20% ΜΕΓΑΛΗ	$\frac{305}{\%GRADE\ ΚΛΙΣΗ}$ =m	$\frac{305x1.5}{\%GRADE\ ΚΛΙΣΗ}$ =m	$\frac{305x2}{\%GRADE\ ΚΛΙΣΗ}$ =m

TABLE
ΠΙΝΑΚΑΣ 1

Fig 11. Typical Gabon Box Bank Erosion Prevention (from IGB EIA)



The detailed failure rate approximation due to external interventions is presented in Appendix D.

3.4 Construction/Equipment Faults related Failure Mode

3.4.1 Historical Records of Construction/Equipment Faults related Failure Mode incidents based on EGIG data

EGIG 9th report recognizes construction defects / material failures as one of the causes of pipeline incidents. During the last ten years, they have represented about 16% of the pipeline incidents and are ranked third in the causes of incidents .

EGIG 9th report makes it possible to distinguish between construction defect and material failures and presents figures for the failure frequencies for the incident cause "construction defect" for different classes of construction year and leak sizes.

From this report some general conclusions can be drawn

- Failure frequencies for "construction defect" generally decrease with increasing year of construction. New pipelines are less vulnerable to construction defects due to technical improvements.
- This phenomenon has also been observed in the ageing analysis.
- Grade A material has the highest failure frequency for "material failure" in the period 1970-2013, although in the period 2004-2013, no incidents were caused by material failure on grade A pipelines.

3.4.2 Manufacturing Defects

Material defects, such as inclusions or laminations, and seam weld defects will have been subjected to a mill test and a high-level hydrotest which will cause any significant defects to fail. Construction defects, including girth weld defects, must similarly have survived the high-level hydrotest. Failure due to manufacturing defects is then only likely to occur if there is a growth mechanism like fatigue or they are subject to a high load due to, for example, ground movement. The likelihood of these events occurring in the Kalchas section of the 32 inch IGB pipeline is discussed below.

3.4.3 Fatigue

Defects in pipelines, either manufacturing defects or those introduced in service, can grow under cyclic loading to reach a critical size and cause failure. The load applied by the pre-service high-level hydrotest is designed to ensure that any manufacturing defect surviving the test will not grow to failure within the operating life of the pipeline.

It is assumed that the operational duty of the pipeline is such that fatigue is not expected to be a significant failure mode.

3.4.4 How Construction/Equipment Faults related Failure Mode has been taken into account in ICGB Pipeline FEED.

3.4.4.1 Class Locations and Design Factors

The pipeline Design Factors (DF) will be in accordance with EN 1594, enhanced where appropriate by the guidance given by ASME B31.8 regarding population density and crossings. Design factors will in no case be higher than the maximum values defined in EN 1594 Clause 7.2.1.

The pipelines will be classified as: Location Class 1 & 2 as presented in the Class Location Table (See table 2). These location classes and associated design factors are defined as guided by ASME B31.8 Clause 840 and table 841.1.6-1.

3.4.4.2 Pipeline materials

Line Pipe will be in accordance with a project specific specification which is supplementary to EN 10208-2. The grade has ben selected as L450MB..

Only steel pipes and piping components will be used.

Spiral (helical) welded pipes may be used for DN ≥ 600.

Screwed and threaded connections and fittings will be limited to above ground instruments installation.

Pipeline and fittings will be Charpy impact tested. The test temperature and acceptance for arrest of running ductile fracture will be defined during the course of the project. Pipes or piping components will be supplied with inspection certificates EN 10204 Type 3.1 or 3.2.

3.4.4.3 Corrosion protection - Coating

Pipeline will be provided with an external protective coating of three layer polyethylene (3LPE).

The pipe will be furnished with an internal epoxy coating in order to reduce the pressure loss during operation.

Field joints coating will comply with ISO 21809-3.

Induction bends, buried valves, fittings and other specials shall be protected against corrosion by polyurethane coating.

Cathodic protection will be installed on the complete buried pipeline system..

3.4.4.4 Pipeline bends

Factory made bends, elastic bends or cold field bends will be used at locations of horizontal and vertical changes in direction.

The minimum wall thickness of bends will be calculated in accordance with Clause 7.2.2 of EN 1594.

Induction bends manufactured in accordance with project specific specification supplementary to EN 14870-1. Bends will be heat treated after forming and will be Charpy impact tested. Spiral welded pipe will not be used for induction bend manufacture..

3.4.4.5 Electronic caliper checking

At the end of the pressure testing activities and before the commencement of the drying works, a single or multi channel electronic calliper (geometry) pig will be propelled through the pipeline in order to check the geometry of the pipeline and locate diameter reductions due to dents, buckles and flat spots.

3.4.4.6 Burial and protective cover

The depth of buried cover to the top of pipe will be a minimum of 1.0metre in all cases as per DESFA existing practice. Within more heavily populated areas and at most crossings, it will be at least 1.2metres but in special areas it will be defined at detail design stage..

3.4.4.7 Crossings

The design and construction of crossings will follow the requirements of relevant codes and standards plus project specifications and will take account of any demands by third parties.

The pipeline Design Factors (DF) will be no higher than those defined in EN 1594 Clause 7.2.1. These design factors will be in accordance with those detailed in ASME B31.8 table 841.1.6-2. Design Factors for crossings of private roads, public roads, highways, motorways, railroads either with cased or uncased pipe.

3.4.4.8 Casing pipes

The use of cased crossings will be minimized due to adverse effects on cathodic protection. Casing pipes material will be per EN 10208-2. The design of casing pipes will be according to EN 1594 requirements.

3.4.4.9 Insulating Joints

Insulating joints will be installed along the pipeline route for cathodic protection.

During detail design, if special conditions are met, such as existence of industrial areas, stray current areas, abrupt soil resistivity changes, corrosive soil resistivity, marine crossings, etc, then additional isolation joints may be considered, if deemed necessary.

3.4.4.10 Welding

Welding procedures and field welding will comply with a detailed project specific specification supplementary to EN 12732. The welding procedures must be qualified using project pipe, bends and fittings.

Piping and vessels for underground installations (UGI) will have only butt welded joints.

3.4.4.11 Non-Destructive Examination

All welds will be visually examined in accordance with EN 12732 and will be X-rayed or automatic ultrasonic tested in accordance with EN 12732.

All welds will be completed using Gas Metal Arc Welding Process (automatic, mechanized or manual).

"Golden welds" are welds which are not pressure tested in the field and will be 100% visually examined, 100% X-radiographed, 100% ultrasonic tested and 100% magnetic tested in accordance with EN 12732 and project specifications.

Cut ends will be checked for laminations using ultrasonics.

3.4.4.12 Pressure Testing

Pressure testing of the pipeline system will be performed in accordance to EN 1594, EN 12327 and project specifications. Test pressures will be calculated by the contractor and submitted for Owner approval.

A strength test and tightness test should be carried out, although the tightness test may be combined with the strength test.

The test pressure will be calculated in accordance with Clause 9.5.3 of EN 1594. There may be instances when pretesting may be appropriate (as listed in Clause 9.5.5 of EN 1594).

For mountainous areas, the static head due to increased elevation will be considered and line pipe of suitable pipe wall thickness will apply, to compensate for this static head that will be defined in the course of the project.

3.4.4.13 HDPE Conduit

Telecommunications with Block Valve and Scraper Stations will be using Fibre Optic Cables (FOC) installed as part of the pipeline installation. The FOC will be installed within a High Density Polyethylene (HDPE) conduit buried in the same trench as the pipeline.

The detailed failure rate approximation due to Construction/Equipment Faults is presented in Appendix D.

3.5 Corrosion related Failure Mode.

3.5.1 Historical Records of Corrosion related Failure Mode incidents based on EGIG

There are many teams around the world collecting pipeline failure data. The most relevant with Natural gas pipelines on Land in Western Europe are the EGIG data.

EGIG 9th report shows the failure frequencies for the incident cause "corrosion" for different pipeline parameter classes and leak sizes. The parameters considered are year of construction, type of coating and wall thickness.

From this report some general conclusions can be drawn

- It seems that older pipelines, with predominantly tar coatings, will have higher failure frequencies. Nowadays, most transmission operators use modern coatings like polyethylene coatings.
- Different protective measures are undertaken by pipeline owners to overcome the problem of corrosion. These measures are for example cathodic protection and pipeline coating. In line inspections and pipeline surveys also allow corrosion to be detected at an earlier stage.
- The failure frequency decrease with increasing year of construction.
- The failure frequency decrease with increasing wall thickness. Corrosion is a time dependent phenomenon of deterioration of the pipelines. Corrosion takes place independently of the wall thickness, but the thinner the corroded pipeline wall, the sooner the pipeline fails. Corrosion on thicker

pipelines takes longer before causing an incident and therefore has more chance to be detected by inspection programs. Different protective measures are undertaken by pipeline owners to overcome the problem of corrosion. These measures are for example cathodic protection and pipeline coating. In line inspections and pipeline surveys also allow corrosion to be detected at an earlier stage.

- Pipelines coated with a polyethylene coating have a far lower failure frequency than pipelines with other types of coating.
- Pitting is the most common form of corrosion. Almost all corrosion incidents with pitting occur on the external surface of the pipelines.
- General corrosion is the second corrosion form to be found on the external surface of the pipelines. Uniform corrosion, also known as general corrosion, takes place evenly over the surface of the metal.
- Corrosion incidents, where cracking was involved, occur in about the same percentage on the external and inner surface of the pipelines.

3.5.2 Internal Corrosion

Internal corrosion is usually unlikely in pipelines carrying clean dry "sales" gas as the gas composition and water content are tightly controlled at the input to the pipeline system Internal corrosion also typically results in small pinhole leaks if left to grow unhindered and the contribution to risk levels from pinhole leaks is small.

The IGB pipeline is not yet built but it is assumed that appropriate operational controls and inspection, maintenance and repair policies will be implemented. Therefore, the risk of internal corrosion can be assumed to be low and will not be included within this assessment.

3.5.3 External corrosion

The 32 inch IGB pipeline will be protected from external corrosion by a 3 Layer Polyethylene (3LPE) external coating of the pipeline. An impressed current cathodic protection (CP) system will also be installed to protect the pipeline in the event of coating damage.

However, external corrosion is likely, albeit at a slow rate, for all buried pipelines in temperate climates and regular inspection of pipelines is undertaken to detect it. Typical inspection methods include Transformer/Rectifier (T/R) and test post monitoring; close interval protection surveys (OPS) and inspection by intelligent pig.

It is intended that the IGB pipeline be cased at road crossings; this creates an environment which is more likely to promote external corrosion. However leaks from external corrosion in a well-managed pipeline have a very low probability of occurrence. Furthermore External corrosion typically causes failures by pinhole leaks and there are ample opportunities to identify corrosion before a leak has occurred. Thus external corrosion not normally considered to be a significant contributor to the risk surrounding a pipeline.

3.5.4 Stress Corrosion Cracking (SCC)

Stress corrosion cracking (SCC) is a corrosion process associated with highly stressed structures that creates crack-like defects, rather than corrosion pits. SCC typically occurs in groups or colonies in which the small individual cracks can join up to cause pipeline failure. SCC can occur both internally and externally as discussed below.

3.5.4.1 Internal SCC

Internal SCC depends on specific mechanical and chemical conditions which lead to the formation of atomic hydrogen which diffuses into the pipeline wall. Internal SCC is not expected in pipelines carrying clean dry gases and therefore, the risk of internal SCC will be negligible.

3.5.4.2 External SCC

External SCC was the cause of several recent pipeline failures in North America and has been the subject of much study. Factors identified as necessary for the development of SCC are a potent corrosive environment, poor or disbonded coating, a susceptible material and certain loading conditions. There are two forms of external SCC, high pH and near-neutral pH.

High pH SCC (or classical SCC) is more likely at higher temperatures and requires the presence of a carbonate/bi carbon ate environment. It is typically found up to 20 km downstream of a compressor station, due to the higher pipe wall temperature'6'. Older coatings, such as coal tar enamel and polyethylene tape wrappings, particularly if field applied, have shown susceptibility to SCC but more modern coatings, such as fusion bonded epoxy (FBE) have not, especially if factory applied. High pH SCC also needs partial CP protection to develop

Near-neutral pH SCC requires groundwater containing dissolved C02, from decaying organic matter, to reach the pipe surface. Cracking can be exacerbated by the presence of sulphate reducing bacteria (SRB) which can occur under disbonded coatings where the cathodic protection current is shielded from the pipe wall. Cyclic loading is critical in crack initiation and growth.

There are no compressor stations on the IGB pipeline, it is not expected to be subject to significant cyclic loading and has a modern, factory applied coating system. Therefore, neither near-neutral or high pH SCC is likely to occur, and this failure mode has not been considered further.

3.5.5 How Corrosion related Failure Mode has been taken into account in ICGB Pipeline FEED.

3.5.5.1 Pipeline materials

Line Pipe will be in accordance with a project specific specification which is supplementary to EN 10208-2. The grade has ben selected as L450MB..

Only steel pipes and piping components will be used.

Spiral (helical) welded pipes may be used for DN ≥ 600.

Screwed and threaded connections and fittings will be limited to above ground instruments installation.

Pipeline and fittings will be Charpy impact tested. The test temperature and acceptance for arrest of running ductile fracture will be defined during the course of the project. Pipes or piping components will be supplied with inspection certificates EN 10204 Type 3.1 or 3.2.

3.5.5.2 Corrosion protection - Coating

Pipeline will be provided with an external protective coating of three layer polyethylene (3LPE).

The pipe will be furnished with an internal epoxy coating in order to reduce the pressure loss during operation.

Field joints coating will comply with ISO 21809-3.

Induction bends, buried valves, fittings and other specials shall be protected against corrosion by polyurethane coating.

Cathodic protection will be installed on the complete buried pipeline system..

3.5.5.3 Casing pipes

The use of cased crossings will be minimized due to adverse effects on cathodic protection. Casing pipes material will be per EN 10208-2. The design of casing pipes will be according to EN 1594 requirements.

The detailed failure rate approximation due to Corrosion is presented in Appendix D.

3.6 Ground Movement related Failure Mode

3.6.1 Historical Records of Ground Movement related Failure Mode incidents based on EGIG data

EGIG 9th report recognizes That Ground movement is responsible for 8% of the total incidents of the database. It presents the failure frequencies for the incident cause "ground movement" for different pipeline diameter classes and leak sizes.

From this report some general conclusions can be drawn :

- For the period 1970-2013 failure frequencies for "ground movement" generally decrease with increasing pipeline diameter.
- There are many types of "Ground movement" incidents. Landslides are by far the most common type causing a ground movement incident.

Fig 12. Distribution of the sub-causes of ground movement (1970-2013)

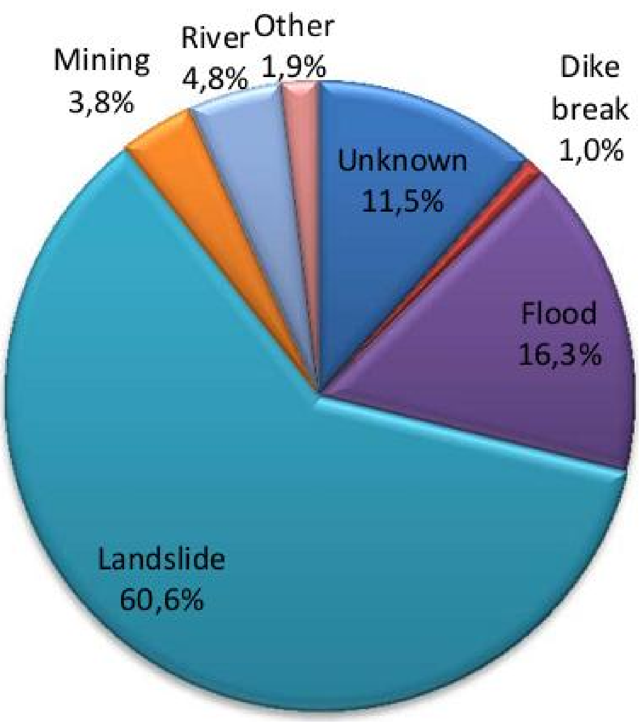
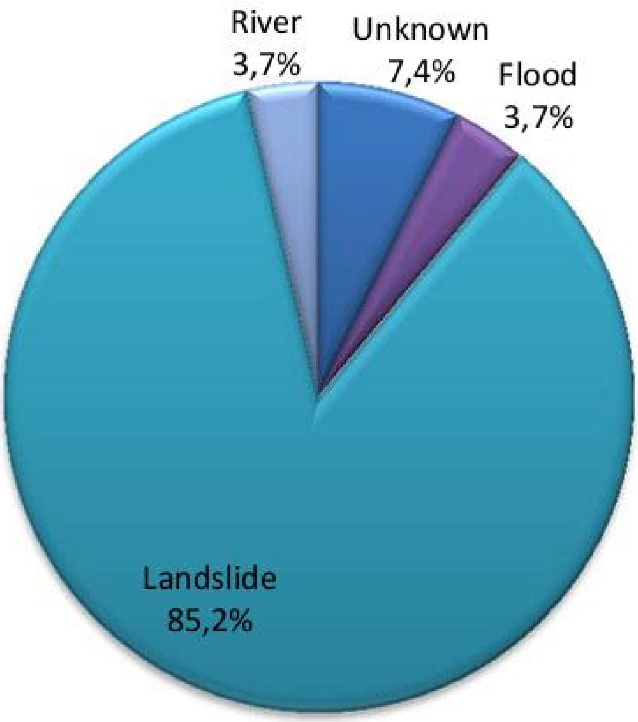


Fig 13. Distribution of the sub-causes of ground movement (2004-2013)



The Mining, River, Other, Unknown & Flood percentages for events occurring in the prriod 2004-2013 compared with the period 1970-2013 is clearly demonstrated

3.6.2 How Ground Movement related Failure Mode has been taken into account in ICGB Pipeline FEED.

Ground movement can be a significant cause of pipeline failure but requires the pipeline route to cross unstable slopes or through areas of mining subsidence. The IGB pipeline crosses a wide range of land types and there are known fault lines along the pipeline route.

The IGB crosses Greek territory for about 31km.

The pipeline route is divided into two main parts in terms of the geomorphological and geological structure. The southern part (approximately 17km long) is characterized predominantly by a flat area (<5% slope dips) and a few gentle slopes (5-15% slope dips) that does not exceed slope dips of 15%. This is the Komotini – Xanthi plain that consists of sedimentary deposits. These deposits are conglomerates, marls and sandstones and are both molassic since Eocene in age as well as more recent Pliocene and Pleistocene mostly marine sediments and Holocene alluvium. This is an area where no landslides occur, but potential liquefaction phenomena can not be excluded.

On the other hand, the northern part of the route approximately 14.5km long is characterized by steep slopes and higher elevation, entering the Rhodope mountain area. Elevation ranges from 200m up to almost 900m high, southwards from the Greek-Bulgarian borders. This part of the route that crosses the Rhodope Mt, is characterized by metamorphic rocks mostly gneisses, but there are also amphibolites and some schists with marble intercalations. The pipeline route crosses mainly through gneisses that belong to the Sidironero Geotectonic unit. These rocks that are Paleozoic in age have been severely metamorphosed during the Upper Jurassic and Lower Cretaceous orogenetic phase. Despite the fact that slopes are steep (e.g. up to 60% slope dip) few landslides are observed. This is because metamorphic rocks are less prone to landslides compared to other sedimentary rocks such as marls or the flysch.

The division between the southern flat area of the sedimentary basin of Thrace and the steep topography of the northern area of the Rhodope mountains, where the metamorphic rocks outcrop is marked by a major active fault zone. This fault zone is a ENE-WSW trending major oblique normal fault zone that dips and downthrows to the SSE and intersects perpendicular the pipeline route. In 1784, a strong earthquake M=6.7 occurred producing significant damage to the town of Komotini and most probably part of this fault was activated. Fault with id 4 in active faults map, has been accessed as capable and with the current data we have, it will not give a significant seismic event.

Thrace is the region surrounding the Greek section of the IGB pipeline, this region is characterised by low seismicity. Further to this only one strong earthquake, has occurred at distances smaller than 50 km from the pipeline. This earthquake was in the Komotini region and occurred in the year 1794. Eight further moderate earthquakes have been recorded between the years 1900-2011, however these were located between 40- 50 km from the pipeline at depths between 2 and 48 km.

According to the Study for the correlation of active seismic faults along the route of the IGB pipeline in the Greek territory, [Ref: 10760-STU-PL-P1-502 (P513-100-ST-GEO-02), Rev 0], the route crosses a large active fault zone (Id 1), which is known as the Kavala-Xanthi-Komotini fault zone .This fault zone has a length of about 90Km and crosses the pipeline route nearly vertically so that no alternative route can avoid it. Furthermore, it consists of many parts and faults between them in close distance so that the total width reaches about 2.4 km along the route of the pipeline (from 16.0km to 18.4km). **In these areas, by design, the tube thickness is increased in order to withstand the possible fault movements.**

On the other hand only a small number of medium earthquakes has been recorded at a distance up to 50Km from the pipeline for the last 100 years.

Routing Selection Criteria

The following factors are taken into consideration in order the optimal pipe routing to be selected.

- The pipeline route has to be as much as possible perpendicular to contour lines to facilitate construction activities and pipeline supporting;
- no vicinity to hazardous areas which may affect the integrity of pipeline installations, such as areas with tank farms, explosive storage yards and other sources of inflammation (proximity to exceed 30 m from plot boundaries), quarry yards, mines, and other hazardous installations;
- to be in areas with reduced risk of fire and the pipeline installations can be protected from fires on adjacent properties which are not under the control of the pipeline operating company;
- avoid areas of potential flooding and areas with high water table;
- to be away from seismic faults
- Steep slopes should be avoided, where possible;
- The longitudinal slope has to be maximum 45 degrees (or 100% slope);

- Big lateral slopes (side or cross slopes) should be avoided, as much as possible;
- Running closely parallel to watercourses, roads, motorways, railways, seismic faults, foreign major pipelines and overhead electricity transmission lines should be avoided. A minimum distance beyond the right-of-way boundaries (existing or planned) has to be considered;
- Crossings of the pipeline route with:
  - major roads, motorways, railways, seismic faults, overhead electricity transmission lines, other major pipelines, rivers, creeks, canals and other utilities, should be considered perpendicular to the centerline (axis) of the crossed object when practical, but with crossing angle not less than 70o or as governed by authorities having jurisdiction;
  - rivers should be considered so that the crossing to be located in a straight section of the river to minimize active bank erosion and at the most suitable riverbed (avoiding as much as possible bedrock and very silty beds), as well as to avoid side slopes on the approaches to the river and to avoid fast flowing sections of the river wherever possible;
  - watercourses should be considered so that, wherever reasonably practical the route to avoid crossing, exposed aquifers and/or passing immediately upstream of intakes for waterworks or impounding reservoirs;
  - existing or planned overhead power lines has to be considered and checked for possible AC interference and for timely design of personnel safety;
- Passing of the pipeline route through the following areas should be avoided wherever possible or minimized:
  - Areas with geological / geotechnical implications, e.g. unstable slopes, erosive soils, rocky terrain, potential landslide or subsidence areas, faults, faults displacement hazards, fissuring, etc.;
  - Earthquake sensitive zones;
  - Muddy bottom areas
  - Areas with soft or waterlogged ground;
  - Areas of potential flooding and areas with high water table;
  - Areas with potentially corrosive ground conditions;
  - Areas with underground man-made obstacles.

Detailed analysis of Aeismic Effects in given in Appendix B

The detailed failure rate approximation due to Ground Movement is presented in Appendix D.

3.7 Hot Tap Failure Mode

3.7.1 Historical Records of Hot Tap related Failure Mode incidents based on EGIG data

EGIG 9th report defines that "hot tap made by error" means that a connection has been made by error to the gas transmission pipeline, assuming it was another pipeline. It presents the failure frequencies for the incident cause “hot tap made by error" for different pipeline diameter classes and leak sizes.

From this report some general conclusions can be drawn

- the failure frequency for "hot tap made by error" decreases with increasing pipeline diameter.
- The same trend is true for every leak size.
- larger diameter pipelines are less vulnerable to hot tap made by error
- This kind of error has led to pinholes and holes, especially with smaller diameter pipelines.

The detailed failure rate approximation due to Hot Tapping is presented in Appendix D.

3.8 Other and unknown Failure Mode

3.8.1 Historical Records of Other and unknown Faults related Failure Mode incidents based on EGIG data

3.8.1.1 Llightning

EGIG 9th report recognizes that within the period 1970-2013, 25 incidents due to lightning have been recorded in the EGIG database, which represents a failure frequency due to lightning equal to 0.006 per 1,000 km-yr. It presents the failure frequencies for the incident cause "ightning" for different leak sizes.

Out of 25 incidents, 23 were pinholes/cracks and only 2 resulted in a hole. No incidents were recorded that were caused by earthquakes..

3.8.1.2 Ageing

EGIG 9th report presents the failure frequencies for the incident cause "Ageing" as a function of construction year and the age of the pipeline at the moment of the incident.

Out of 25 incidents, 23 were pinholes/cracks and only 2 resulted in a hole

From this report some general conclusions can be drawn

- Early constructed pipelines (before 1964) have indeed a higher failure frequency than recently constructed pipelines .
- Failure frequencies of the pipelines constructed before 1964 have slightly decreased in time after an age of 25 to 30 years.
- Pipelines constructed, commissioned and operated before 1960s are subject to failure due to corrosion.
- Pipelines constructed after 1964, have a failure frequency lower than 0,01 per 1,000 km-yr for corrosion.
- No corrosion incidents were reported for pipelines with wall thicknesses larger than 15 mm.

- Pipelines with smaller wall thicknesses are affected most by ageing.
- Higher wall thicknesses protect against failure due to corrosion, so corrosion incidents will occur later in time and with a lower failure frequency.

It must be stressed here that modern pipelines like IGB are designed and built in a way that allows the internal inspection with "Intelligent Pigs" so that the abovementioned problems can be revealed and prevented before the actual failure occurs.

3.8.2 How Other and unknown Faults related Failure Mode has been taken into account in ICGB Pipeline FEED.

Routing Selection Criteria

The following factors are taken into consideration in order the optimal pipe routing to be selected.

- The pipeline route has to be as much as possible perpendicular to contour lines to facilitate construction activities and pipeline supporting;
- no vicinity to hazardous areas which may affect the integrity of pipeline installations, such as areas with tank farms, explosive storage yards and other sources of inflammation (proximity to exceed 30 m from plot boundaries), quarry yards, mines, and other hazardous installations;
- to be in areas with reduced risk of fire and the pipeline installations can be protected from fires on adjacent properties which are not under the control of the pipeline operating company;
- avoid areas of potential flooding and areas with high water table;
- to be away from seismic faults
- Steep slopes should be avoided, where possible;
- The longitudinal slope has to be maximum 45 degrees (or 100% slope);
- Big lateral slopes (side or cross slopes) should be avoided, as much as possible;
- Running closely parallel to watercourses, roads, motorways, railways, seismic faults, foreign major pipelines and overhead electricity transmission lines should be avoided. A minimum distance beyond the right-of-way boundaries (existing or planned) has to be considered;
- Crossings of the pipeline route with:

- major roads, motorways, railways, seismic faults, overhead electricity transmission lines, other major pipelines, rivers, creeks, canals and other utilities, should be considered perpendicular to the centerline (axis) of the crossed object when practical, but with crossing angle not less than 70o or as governed by authorities having jurisdiction;
- rivers should be considered so that the crossing to be located in a straight section of the river to minimize active bank erosion and at the most suitable riverbed (avoiding as much as possible bedrock and very silty beds), as well as to avoid side slopes on the approaches to the river and to avoid fast flowing sections of the river wherever possible;
- watercourses should be considered so that, wherever reasonably practical the route to avoid crossing, exposed aquifers and/or passing immediately upstream of intakes for waterworks or impounding reservoirs;

- existing or planned overhead power lines has to be considered and checked for possible AC interference and for timely design of personnel safety;

- Passing of the pipeline route through the following areas should be avoided wherever possible or minimized:

- Areas with geological / geotechnical implications, e.g. unstable slopes, erosive soils, rocky terrain, potential landslide or subsidence areas, faults, faults displacement hazards, fissuring, etc.;
- Earthquake sensitive zones;
- Muddy bottom areas
- Areas with soft or waterlogged ground;
- Areas of potential flooding and areas with high water table;
- Areas with potentially corrosive ground conditions;
- Areas with underground man-made obstacles.

3.8.2.1 Crossings

The design and construction of crossings will follow the requirements of relevant codes and standards plus project specifications and will take account of any demands by third parties.

The pipeline Design Factors (DF) will be no higher than those defined in EN 1594 Clause 7.2.1. These design factors will be in accordance with those detailed in ASME B31.8 table 841.1.6-2. Design Factors for crossings of private roads, public roads, highways, motorways, railroads either with cased or uncased pipe.

3.8.2.2 Casing pipes

The use of cased crossings will be minimized due to adverse effects on cathodic protection. Casing pipes material will be per EN 10208-2. The design of casing pipes will be according to EN 1594 requirements.

3.8.2.3 Insulating Joints

Insulating joints will be installed along the pipeline route for cathodic protection.

During detail design, if special conditions are met, such as existence of industrial areas, stray current areas, abrupt soil resistivity changes, corrosive soil resistivity, marine crossings, etc, then additional isolation joints may be considered, if deemed necessary.

3.8.2.4 Welding

Welding procedures and field welding will comply with a detailed project specific specification supplementary to EN 12732. The welding procedures must be qualified using project pipe, bends and fittings.

Piping and vessels for underground installations (UGI) will have only butt welded joints.

3.8.2.5 Non-Destructive Examination

All welds will be visually examined in accordance with EN 12732 and will be X-rayed or automatic ultrasonic tested in accordance with EN 12732.

All welds will be completed using Gas Metal Arc Welding Process (automatic, mechanized or manual).

"Golden welds" are welds which are not pressure tested in the field and will be 100% visually examined, 100% X-radiographed, 100% ultrasonic tested and 100% magnetic tested in accordance with EN 12732 and project specifications.

Cut ends will be checked for laminations using ultrasonics.

3.8.2.6 Pressure Testing

Pressure testing of the pipeline system will be performed in accordance to EN 1594, EN 12327 and project specifications. Test pressures will be calculated by the contractor and submitted for Owner approval.

A strength test and tightness test should be carried out, although the tightness test may be combined with the strength test.

The test pressure will be calculated in accordance with Clause 9.5.3 of EN 1594. There may be instances when pretesting may be appropriate (as listed in Clause 9.5.5 of EN 1594).

For mountainous areas, the static head due to increased elevation will be considered and line pipe of suitable pipe wall thickness will apply, to compensate for this static head that will be defined in the course of the project.

3.8.2.7 HDPE Conduit

Telecommunications with Block Valve and Scraper Stations will be using Fibre Optic Cables (FOC) installed as part of the pipeline installation. The FOC will be installed within a High Density Polyethylene (HDPE) conduit buried in the same trench as the pipeline.

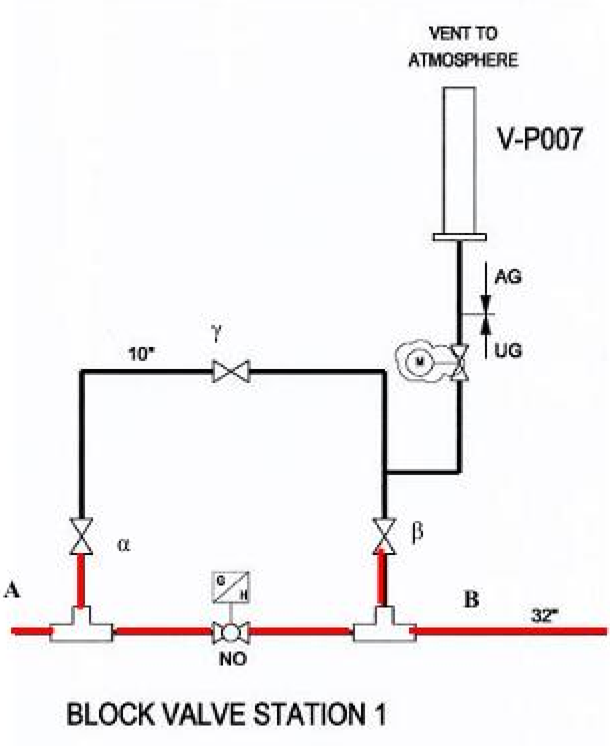
The detailed failure rate approximation due to "Other & Unknown" is presented in Appendix D.

3.9 Line Valve Station – Quantitative Risk Analysis of its Operation

3.9.1 Line Valve Station Operation

The normal operating condition of the Line Valve Station is presented in the figure below.

Fig 14. Valve station. Normal Operating conditions.



In normal Operating conditions only the pipes (marked in red in the figure above) connected to the main 32" valve (normally OPEN) are under pressure and caontain Natural Gas.

The three smaller valves (α,β,γ) of 10" and the relevant connecting piping are used only in the case that the pipeline has to be isolated (Central Valve 32" CLOSED) in order to be vented, either from side A (Valves α & γ OPEN, β CLOSED) or from side B (Valves β & γ OPEN, α CLOSED) up to the next Line-Valve station. So, in fact, only the central valve 32" and the smaller α & β 10" and the corresponding flanges are considered in the analysis.

The actual configuration refers to the part of the pipeline which for some meters (<20) lies inside a concrete well-hole (in a depth of about 1 meter) that also contains the 32" Valve. The whole area will be fenced as is clearly indicated in the following figure of an Indicative Line Valve Station. The rest of the pipework does not normally pose any threat of failure and/or accident.

Fig 15. Valve station. Indicative Photo.

3.9.2 Basic conclusions about the incorporation of the Line-Valve Station operation in the full pipeline system QRA.

A full analysis of the possible failures in the Line Valve Station is presented in Appendix D. The basic conclusions about the incorporation of the Line-Valve Station operation in the full pipeline system QRA are presented below :

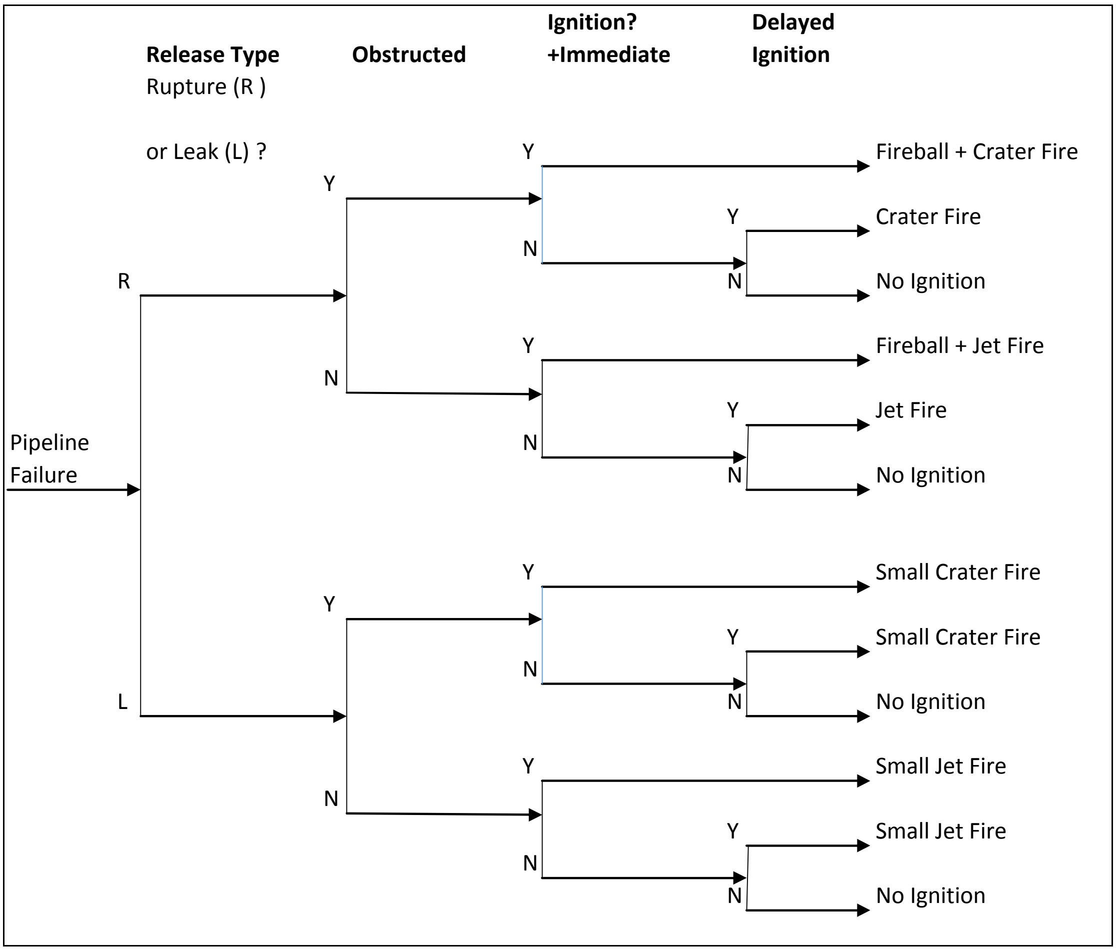
- The full rupture frequency of the Valves and Flanges (either 10 or 32 inch) is negligible.
- The leak frequencies of Valves and Flanges (either 10 or 32 inch) are I the order of magnitude of 10^{-6} (per year for a leak diameter of 50mm and constat operation, main valve 32'' and small valves α & β 10'').
- The two smaller Valves 10" (γ and vent) and the relevant pipework are used only in the case that the pipeline has to be isolated (conservatively for 1% of the total time). This results to a yearly leak frequency $10^{-8} = 10^{-6} \times 10^{-2}$ for the two 10” valves.
- The accident scenaria for the pipeline in the Line-Valve Station area these are similar with the accidents in the normal route. However, considering that the Line-Valve Station area is clearly marked and fenced the most serious failure mode “Third party Inetrvention” is minimized. This results to smaller Individual Risk levels than the one calculated for the normal pipeline route.
- The reduction of Individual Risk (IR) mentioned above is regarded to surpass the small increase of IR from the operation of the aboveground valves and flanges of the Line-Valve Station. This results to the fact that the Total IR in the Line-Valve Station area of the ICGB can be conservatively assessed with only the pipeline as presented in Appendix E.

- It must be stressed here that the LV1 Line Valve Station “NIMFEA” of the IGB is located at a great distance of any inhabited area.

3.10 Failure Mode Event Tree

Pipelines can either fail as a rupture or a leak or a pinhole and the resulting release can either ignite immediately, after a delay or not at all, leading to a range of possible outcomes as shown in Figure below. Ruptures of buried pipelines are almost always obstructed leading to a crater fire rather than a free jet fire.

Fig 16. Failure Mode Event Tree for Natural Gas releases from Pipelines



Although both full rupture and leak incidents have been modelled in this QRA, the majority of any predicted casualties will be from the immediate and delayed full rupture cases.

3.11 Pipeline Failure Rate Estimation

3.11.1 Historical Pipeline Failure Data

Several groups around the world collect data on pipeline failures. The most relevant to onshore natural gas pipelines in Western Europe are those of the European Gas pipeline Incidents data Group (EGIG) and the United Kingdom Onshore Pipeline Association (UKOPA) who collect data on incidents from a range of pipeline operators. A summary of the overall failure statistics from these two sources is shown in the table below.

Table 3. EGIG and UKOPA Incident Statistics

	EGIG	UKOPA
Χρονική περίοδος / Period	1970 - 2013	1962 - 2014
Μήκος αγωγού (km) / Pipeline Length (km)	143.727	22.158
Έκθεση (χλμ. έτη) / Exposure (km years)	3.980.000	877.598
Αρ. Περιστατικών / No. of Incidents	1.309	192
Συχνότητα περιστατικών (ανά 1000 χλμ. έτη) / Incident Frequency (per 1000 km year)	0,329	0,219

As can be seen, pipeline failures from all causes are rare and the number of failures from third party damage is not large enough to allow comparison with a set of specific pipeline operating parameters, especially for modern pipeline steels for which there is currently limited operating experience. Therefore, it is usually necessary to predict the pipeline failure frequency for a specific pipeline.

For site specific QRAs on proposed or existing pipelines, it is typical to concentrate on hazards that cannot be completely controlled, e.g. 3rd party damage and ground movement, and predict the failure frequency for the specific set of pipeline parameters.

3.11.2 Failure Frequency Used in this assessment

The following table summarizes the failure frequencies used in the present analysis. More details are presented in Appendix D.

Table 4. Failure Frequency Used in this study

Class Loc		**CL 1**	**CL2**	**CL3**	**CL4**	
Pipe wall Thickness (mm)		**11**	**12,4**	**16**	**20**	
Rupture	Διάρρηξη	5,45E-06	1,45E-06	9,10E-07	8,00E-07	events/Km.Year
Leak	Διαρροή	1,12E-05	3,20E-06	2,12E-06	1,90E-06	events/Km.Year

3.11.3 3rd Party Failure Frequency Prediction

Most third party defects do not cause failure but remain as dents and gouges until discovered by the pipeline operator (either by notification from the third party or by internal inspection) and repaired. Therefore, there is a much larger population of damage caused by third party interference than actual failure incidents. The UKOPA database uniquely holds details of the damage discovered as well as gas loss incidents. The number of dents and gouges in the database is shown below.

Table 5. Damage Statistics

	Gouge	Dent & Gouge	Dent	Total
No. of Damage Events	623	113	66	689

The UKOPA records of third party damage also contain details on the size of each incidence of damage. As this data has been gathered over many years operating experience of a wide range of pipeline diameters and thicknesses, it can be assumed to be generic and independent of pipeline parameters, and distributions of gouge and dent dimensions can be created. Once the data has been filtered to remove records with negligible width and depth, the incident rate for 3rd party damage, at the nominal UK depth of cover, can be calculated as 1,255 x 10^{-3} per km year.

3.12 Pipeline Outflow

When a high pressure gas pipeline fails as a rupture part of the pipeline length breaks resulting in two open ends. If the pipeline is buried, a crater will be formed as soil is thrown clear of the rupture location by the force of the escaping gas. Gas is released from both the open ends. The released gas will initially form a rising mushroom cloud which soon decays to leave a transient jet fed by the outflow of gas from the two pipeline ends. Initially, the pressure in the pipeline will rapidly fall until either a steady state is reached, as outflow from the pipeline matches the inflow, or the pressure will then gradually decline to zero if the pipeline is shut in.

There are many available models to predict the outflow relese rate of the gas and its variation with time (rate of decrease). In this analysis the model GASPIPE v3 which is incorporated in the “Long Pipeline Model” of PHAST 7.2 software of DNV-GL was used. A typical rate of gas release from a ruptured pipeline (ICGB) is presented in Figure 17. Figure 18 explains the various flows as computed by the model.

Fig 17. Rate of gas release (Kg/s) as a function of time (Full Rupture)

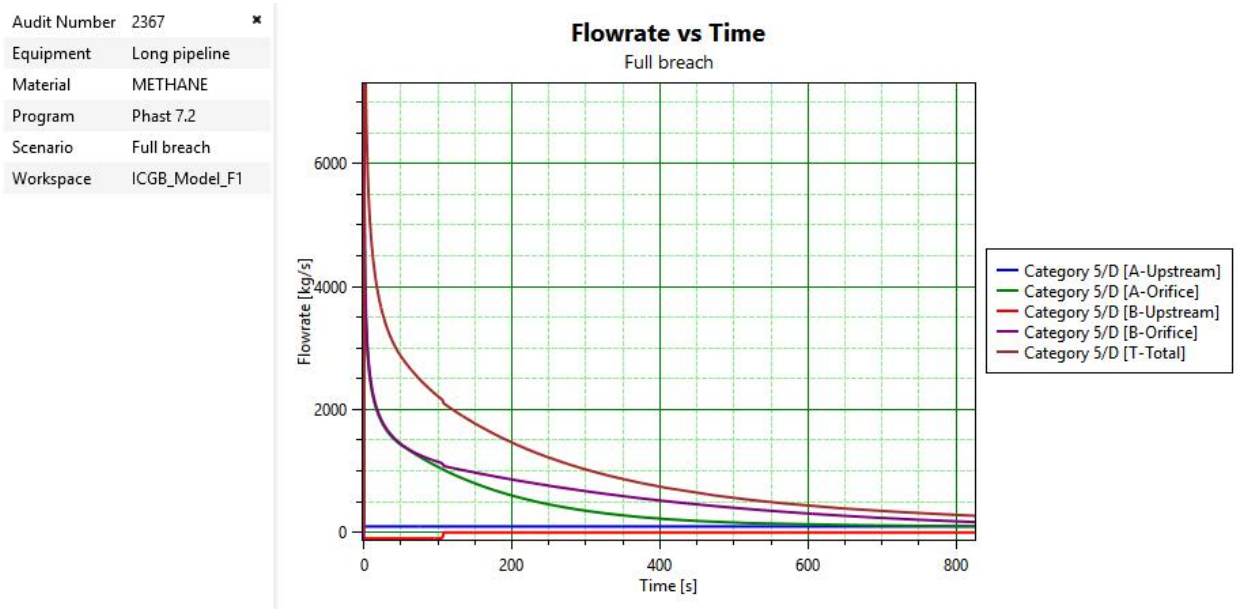
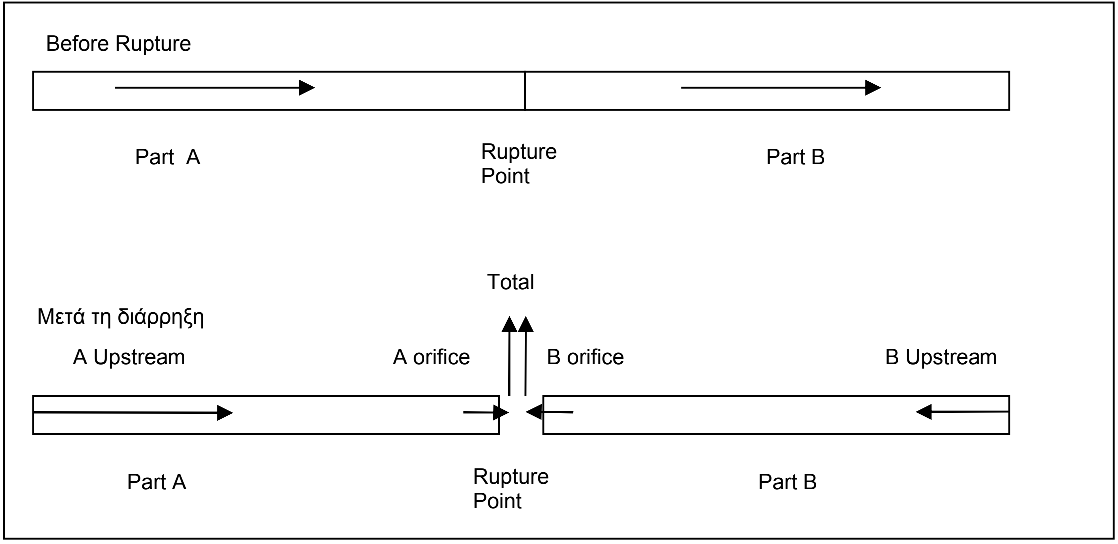


Fig 18. Rate of gas release after rupture (explanation of Fig. 17)

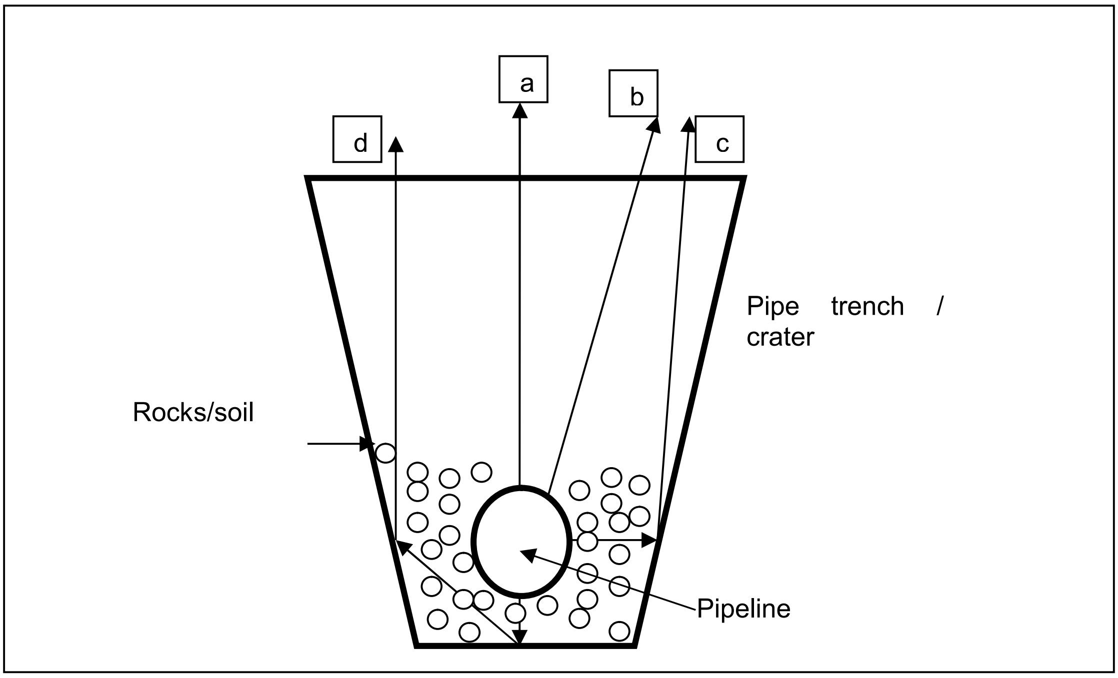


3.13 Release Direction

The logic of Obstructed/Non Obstructed Release gas been used in the present analysis because the rupture (or leak) releases occur inside the buried pipeline trench as indicated below and in Figure 19 :

- 25% vertically Upwards (Non obstructed release) - a
- 25% in small angles (up to 45 degrees) (Non obstructed release) - b
- 50% in angle > 45 degrees (c) or downwards (d) (Obstructed releases).

Fig 19. Obstructed and Non Obstructed Release Logic



In this way, the conservative approach for the releases from leaks, used in this analysis is :

- 50% of the releases occur Unobstructed Upwards resulting (if ignited) to a Jet Fire or a combination of a Fireball initially & Jet Fire right after.
- 50% of the releases occur Obstructed (Finally Upwards) after many reflections or through soil, rocks and other obstacles that may fall into the crater resulting (if ignited) to a Crater Fire or a combination of a Fireball initially & Crater Fire right after. Crater Fire is considered as a Jet Fire with consequences reduced by 30% due to the reduction of outflow rate and velocity from obstacles and reflections.

For full bore ruptures it is assumed that 80% occur Unobstructed Upwards and 20% Obstructed as above.

All gas releases are affected by the wind. Winds of velocity of 5m/s with Atmospheric Stability D (that gives the maximum consequence distances) and 2 m/s with Atmospheric Stability F according to the Greek Legistlation [KYA 172058 (ΦΕΚ 354 B')/2016 (SEVESO III)].

3.14 Ignition Probability

The historical probability of a release of gas, from a pinhole/crack and a hole, in a pipeline being ignited is given by European Gas Industry Group (EGIG) statistics

Table 6. Summary of EGIG Ignition Probabilities

Failure Type	Ignition Probability (%)
Pinhole/crack	4,4
Hole	2,3
Rupture (Pipeline OD ≤ 16”)	10,3
Rupture (Pipeline OD > 16”)	32,0

Historical data from ruptures have been analysed and it was determined that the ignition probability increased according to the expression, according to which there is a trend for rupture ignition probability to increase with pd^2:

$$P_{ign} = 0{,}0555 + 0{,}0137\, pd^2 \text{ when } 0 \le pd^2 \le 57$$

and $P_{ign} = 0{,}81$ when $pd^2 > 57$

where: p = pipeline operating pressure (barg)

d = pipeline diameter (m)

In the case of a puncture or leak, d is the hole diameter and the pd^2 term in the equation is halved..

Using the above equation gives ignition probabilities as shown in Table below.

Table 7.Ignition Probabilities for the Greek Section of the IGB Pipeline

Outside Diameter (mm)	Maximum Operating Pressure (barg)	Ignition Probability (%)	
		Leak	Full Rupture
813	75	6	73

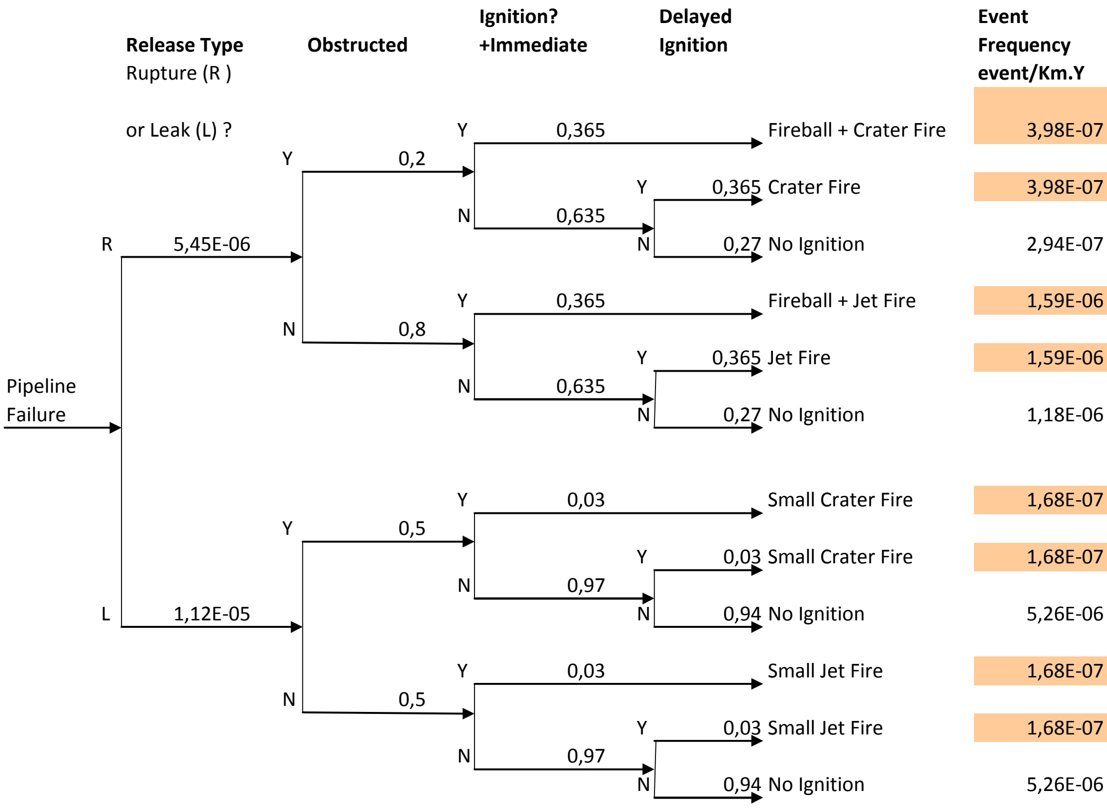
Ignition probabilities are specified in the analysis as either immediate or delayed. The consequences associated with holes are the same but those associated with ruptures are different. It is typically assumed that half of all ignited ruptures ignite immediately and half are delayed by 30 seconds.

3.15 Failure mode Event Tree complete with probabilities

Taking all the above in mind the failure mode Event Tree complete with the possible outcome probabilities is presented below (For Class Location 1 pipeleine segment):

Fig 20. Event Tree with Probability for each outcome (Class Location1)

CLASS LOCATION 1 - Wall Thickness 11mm



As full bore rupture is defined the full loss of containment of the pipe in the specified point. The failure mode Event Trees for the remaining three Class Locations are presented in Appendix E.

3.16 Thermal Radiation

In case of immediate ignition, the gas released during the initial mushroom cloud will burn as a transient fireball typically for less than 30 seconds, until burning out to leave a quasi-steady state crater jet fire. If ignition is delayed, then only the quasi-steady state fire will occur.

The Thermal Radiation effects from the initial Fireball and the Jet Fire have been calculated using the PHAST ver 7.2 software from DNV-GL

Winds of velocity of 5m/s with Atmospheric Stability D (that gives the maximum consequence distances) were assumed vertical to the axis of the pipeline.

3.17 Thermal Radiation Effects on People and Property

The thermal dose received by a building or an escaping person is calculated by integrating the incident thermal radiation flux as it varies with time and distance from the fire.

The time limit for all incidents is assumed to be 900 seconds from the release of gas, after which the fire is likely to have stabilised to a pseudo steady state as the pipeline unpacks. Any persons who do not receive a fatal dose of thermal radiation in 900 seconds are assumed to have survived the incident.

It is assumed that standard populations escape in a direction away from the fire after 5 seconds reaction time, at a speed of 2.5 m/s, and sensitive populations at 1 m/s. Anyone beyond the escape distance when the fire starts will be able to reach safety without receiving a fatal dose.

For standard populations, a fatality is defined as anyone receiving a dose equal to or greater than 1800 thermal dose units (tdu). For sensitive or vulnerable populations, such as children, the sick or elderly, a casualty is defined as anyone receiving a dose equal to or greater than 1050 tdu (sometimes referred to as the 1% lethality dose).

The time at which the piloted ignition of wood occurs is calculated for all distances. Any buildings beyond the distance to the piloted ignition of wood after 900 seconds are assumed not to burn down. This determines whether the buildings modelled in the assessment can provide shelter throughout the incident..

3.18 Risk Calculation

The risk from all incidents, i.e. immediate and delayed ignited ruptures and leaks, that may affect the populated areas as modelled are combined to calculate both the societal risk for the populated areas and the risk to a permanently resident individual, along a specific transect.

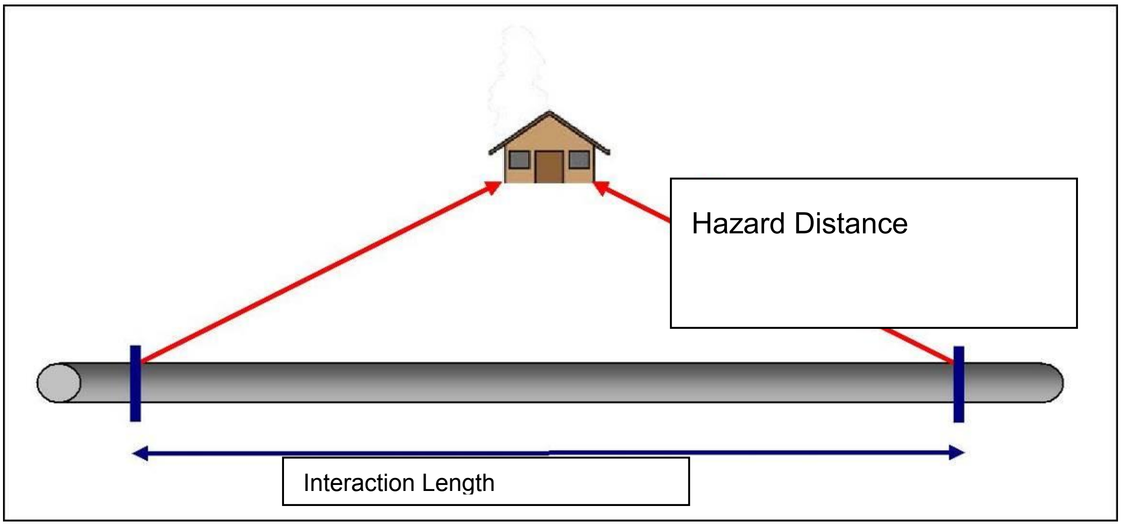
Individual Risk is calculated for a theoretical person remaining <u>totally exposed</u> at specified distances from the pipeline <u>for 100% of time outside of any dwelling</u>. This approach which is used in the present study is very conservative resulting to higher Individual Risk levels.

The usual approach is to assume that the theoretical population remain <u>only for a fraction of time (about 10-25%)</u> totally exposed outside any dwelling. In this way the calculated Risk Levels are <u>drastically reduced</u> resulting in much more realistic results.

Great care should therefore be given to the “interpretation” of the results produced using the abovementioned very conservative definition of Individual Risk.

Before the risk to a particular individual or development can be calculated, it is important to define the length of the pipeline that could cause harm to the person or development. This length is known as the interaction length and is illustrated in Figure 21 below. For a building, the hazard distance will be the building burning distance, whereas for a person, it is the relevant escape distance.

Fig 21. Illustration of Interaction Length



Obviously, the interaction length for a point lying on the pipeline is twice the hazard distance..

To calculate the risk to an individual at any point along a transect perpendicular to the pipeline, the interaction length is split into small steps, typically every 5 or 10 metres, and the risk calculated for a pipeline failure that results to a fire located at each step.

Consider a pipeline that has a predicted rupture failure frequency of/per km per year, there is a probability p_i, that the released gas will ignite and a person at distance y will have a probability of pcy of becoming a casualty. The individual risk per year from rupture for an individual step is:

$$f.dx.p_i.pc_y$$

where dx is the length of the individual step.

Therefore, the overall individual risk (IR), for someone at distance y is found from the summation of this expression along the interaction length, taking into account the variation in casualty probability with distance from the pipeline and the variation in failure frequency due to changes in wall thickness, depth of cover, location class etc., i.e.

$$IR = \sum_{j=1}^{n} \left(f \cdot dx \cdot p_i \cdot p_{cy}\right)_j$$

To construct an individual risk transect, this calculation must be repeated for a range of distances from the pipeline.

Having in mind the above theoretical approach the methodology for the calculation of Individual Risk (IR) for the whole length of the ICGB pipeline is the following :

At first a series of hypothetical “accident points” are created for the whole length of the ICGB pipeline one every 50m. These points are characterized as i=1……N.

Fig 22. Hypothetical "accident points" (Kalchas village area)

As a second step, a Grid of Hypothetical "Receiver points" from both sides of all the pipeline length until a distance of 500m that is regarded as a safe distance according to the consequence model results. The grid point distance for the two axes X & Y (Horizontal & Vertical) is 100m. These points are characterized as j=1…….M.

Fig 23. Hypothetical "Receiver points" Grid (Kalchas village area)

Every point i is a potential accident (rupture or leak) site with the frequency of occurance defined from the local pipe wall thickness. The potential accident evolution is then assumed according to the Event Tree with Probability for each outcome (Jet Fire, Fireball, Crater Fire κλπ.) as it is demonstrated in Figure 20 (for CL1).

Because every receiver point j can be affected by all accidents happening at its neighbour area (points i on the pipeline route $i_{1..k}$ for all the interaction length) the Total IR is the sum :

- Of the Individual Risk at receiver j as a result of accident at any one of points i
- In which all possible accident outcomes have been accounted for, according to the Event tree

This procedure is depicted in the following figure :

Fig 24. Points $i_{1...k}$ for all the interaction length

The consequences from any outcome of leak or rupture incidents (Jet Fire, Fireball, Crater Fire) has been calculated using the PHAST ver 7.2 software from DNV-GL.

Repeating the above procedure for all the “hypothetical accident” points i=1……N affecting all the “receptor points” σημεία j=1…….M a two dimensional field of Total Individual Risk is calculated for the area around (500m from each side) for all its length. This field is depicted using iso-risk contours with a suitable colour code. It is also presented as a risk transect plot. More information on the calculation procedure is presented in Appendix E

3.19 Risk Acceptability Criteria

According to the Greek Legislation in populated areas the acceptable risk level (under which there is no concern) is defined as 1 x 10^{-6} per year or aone chance in a million per year.

3.20 Technical Pipeline Details

This section includes both details of the important pipeline parameters and the population assumptions used in the assessment of the Kalchas section of the IGB natural gas pipeline.

The proposed IGB pipeline runs for approximately 182 km with 31.6 km in Greece and the final 150.6 km in Bulgaria. This pipeline is designed to be bi-directional but initially flow is expected to be from Greece to Bulgaria. The pipeline begins at Komotini on the Greek gas network, travels approximately 11 km north and passes the village of Kalchas, it continues north a further 20 km and proceeds into Bulgaria. From this point it travels a further 150 km to connect to the Bulgarian gas network at Stara Zagora. The IGB pipeline has been designed by Penspen Ltd and C&M

Engineering SA, thus the pipeline data in this report has been provided from the Design Basis Memorandum. This data is summarised below.

Table 8. Summary of the 32 inch natural gas pipeline parameters

Παράμετρος/Paramenter	**Τιμή /Value**			
Ονομασία αγωγού/ Pipeline Name	Διασυνδετήριος αγωγός φυσικού αερίου Ελλάδας - Βουλγαρίας (Natural Gas Interconnector Greece-Bulgaria)			
Διάμετρος (mm)/Diameter (mm)	813			
Μέγιστη πίεση λειτουργίας / MOP (barg)	75			
Τρέχουσα μέγιστη πίεση/ Current Maximum Pressure (barg)	57			
Πάχος τοιχώματος/ Wall Thickness (mm)	11	14,2	16	20
Κατηγορία υλικού/ Grade	L450MB			
Προδιαγραφές σωληνώσεων αγωγού/ Line Pipe Specifications	BS EN ISO 3183:2012			
SMYS (N/mm^2)	450			
Συντελεστής σχεδιασμού στη MOP/ Design Factor at MOP	0,72	0,6	0,5	0,4
Συνολικό μήκος αγωγού (km) Total Pipeline Length (km)	182,2			

4 RESULTS

4.1 Hazard Distances

Οι προβλέψεις για τη μέγιστη απόσταση μέχρι την πιλοτική ανάφλεξη ξύλου (απόσταση καύσης του κτιρίου) και την απόσταση διαφυγής (από την οποία είναι δυνατή η διαφυγή χωρίς να υπάρχει καταφύγιο) για μια αναφλεγείσα πλήρη διάτρηση (full-bore) του αγωγού IGB παρουσιάζονται στον παρακάτω Πίνακα.

Οι αποστάσεις διαφυγής δεν είναι αποστάσεις ασφαλείας, αλλά αποστάσεις από τις οποίες είναι εφικτή η διαφυγή εάν δεν υπάρχει κανένα διαθέσιμο καταφύγιο. Παρουσιάζονται αποστάσεις τόσο για άμεση όσο και για καθυστερημένη ανάφλεξη και συνυπολογίζεται το συνολικό μήκος του συστήματος του αγωγού.

Table 9. Summary of Predicted Hazard Distances

Pipeline	Pressure (barg)	Hazard Distance	Ignition Type	
			Immediate	Delayed
		Building Burning (m)	270	263
IGB	75	Escape (Standard) (m)	580	570
		Escape (Vulnerable) (m)	810	800

4.2 Failure Frequency Predictions

The model for predicting the failure frequency of pipelines due to external interference is discussed in Appendix D. During this assessment assumed comparisons between UK and Greek location classes were made and can be seen in the Table below. Results for ruptures and leaks for the three wall thicknesses at the Maximum Operating Pressure (MOP) of 75 barg are shown in Tables 11 & 12 below, at the minimum depth of cover. T

Table 10. Location Classes for the IGB Pipeline

UK Location Class	Greek Location Class
R/2	1
R	2
S	3

Table 11. Predicted 75 barg Rupture Failure Frequencies

Diameter (mm)	Wall Thickness (mm)	Grade	Internal Pressure (barg)	Location Class	Depth of cover (m)	Failure Frequency (x 10^{-6} km. years)
813	11	L450 MB	75	1	1	5,45
813	14,2	L450 MB	75	2	1	1,45
813	16	L450 MB	75	3	1	0,91

Table 12. Predicted 75 barg Leak Failure Frequencies

Diameter (mm)	Wall Thickness (mm)	Grade	Internal Pressure (barg)	Location Class	Depth of cover (m)	Failure Frequency (x 10^{-6} km. years)
813	11	L450 MB	75	1	1	11,20
813	14,2	L450 MB	75	2	1	3,20
813	16	L450 MB	75	3	1	2,11

Note that it has been conservatively assumed that the diameter of all leaks is that which gives the same outflow as the critical crack length (i.e. the maximum stable through wall crack that can exist without becoming a rupture). Therefore, a leak diameter of 10 mm has been used in this assessment.

4.3 Individual Risk

The individual risk transects calculated at 75 barg, for a point on a straight part of the pipeline, are shown in Figure 25 along with the acceptable risk criteria in Greece.

It can be seen that for points of Class Location 1 (pipe wall thickness 11mm), the risk levels are above the Greek Technical Regulations acceptable level of 1 x 10^{-6} per annum with a maximum value of $1.3x10^{-6}$. The very conservative definition of Individual Risk assuming a theoretical person remaining totally exposedfor 100% of time outside of any dwelling must be stressed here. When the pipe wall thickness is increased the IR levels fall in acceptable values.

The Individual Risk is presented as Iso-Risk Contour Maps for all the pipeline length overleyed on satellite maps produced by the Geographical Information System (GIS). It must be stressed that the local changes in pipe wall thickness along the pipeline (e.g. in the area of active faults) have been included in this approach leading to localized IR decreases.

From these maps it can be observed that while While the “exceedance” of the Regulation limit does not create any real problem in the non-populated areas, in the two points, namely west of Kalchas and east of Roditis some measures have to be taken in order to reduce the Individual Risk to the population in acceptable levels (Less than $1x10^{-6}$).

In order for this requirement to be met, an increase in pipe wall thickness, to 14,2 mm (as in Class Location 2) is necessary. For this reason the mathematical model was re-applied with increased pipe wall thickness to 14,2 mm in these two areas. As it can be seen in the following figures the total Individual Risk falls in acceptable levels.

Fig 25. IGB. Individual Risk Transects

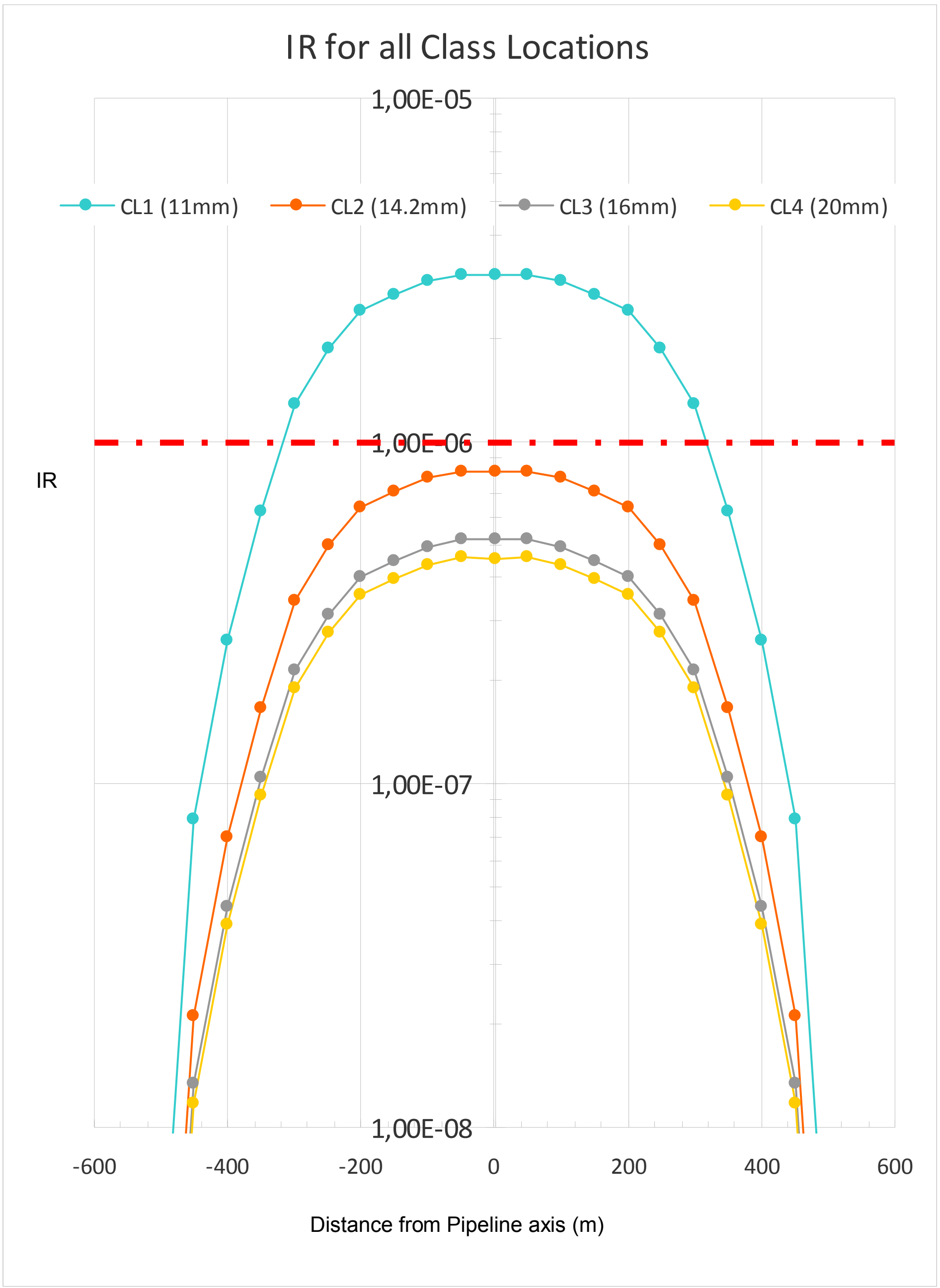


Fig 26. Iso-Risk map west of Kalchas village. Initial Design with pipe wall thickness 11mm

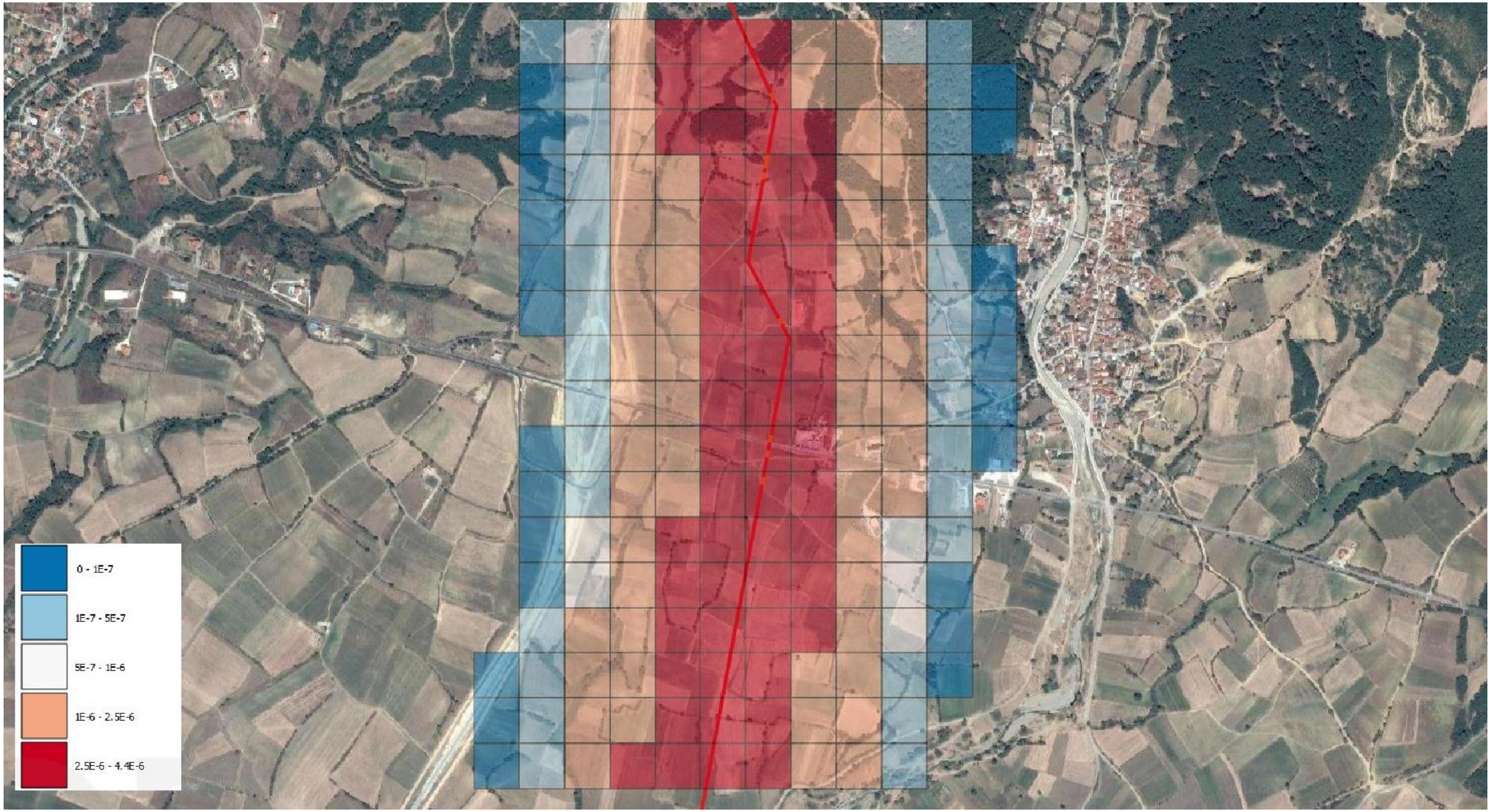


Fig 27. Iso-Risk map west of Kalchas village. Modified Design with pipe wall thickness 14.2 mm

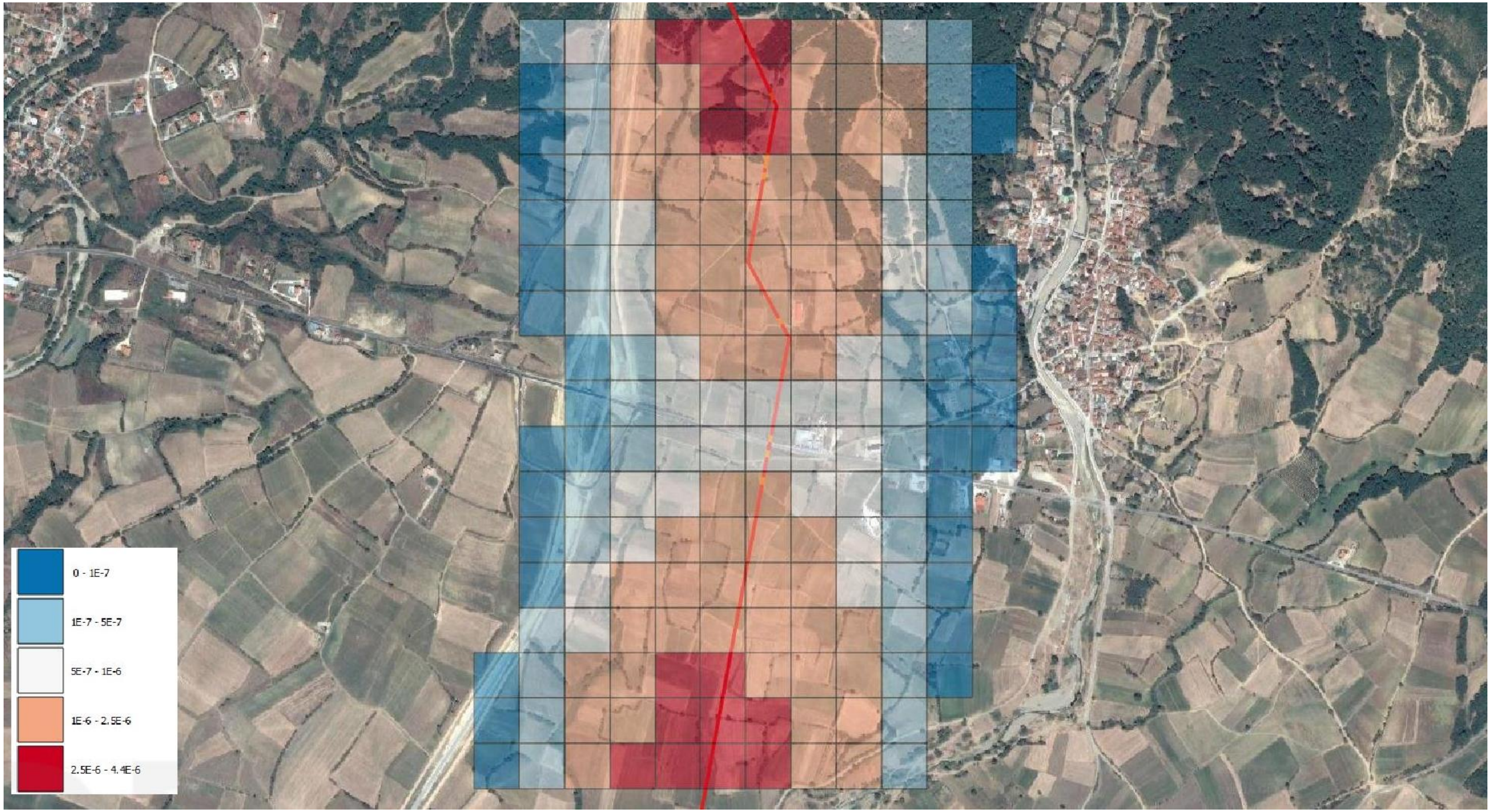


Fig 28. Iso-Risk map east of Roditis village. Initial Design with pipe wall thickness 11mm

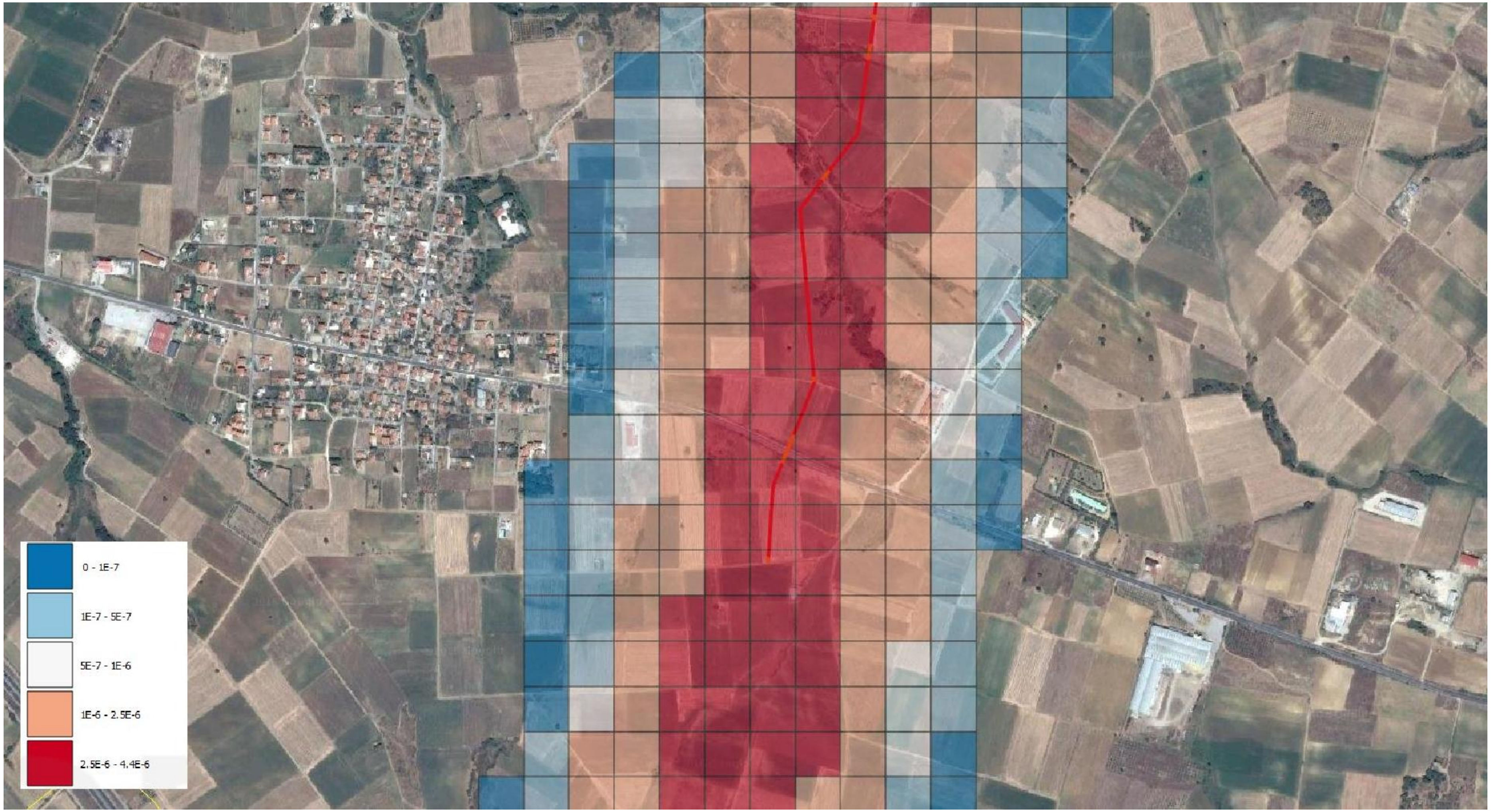
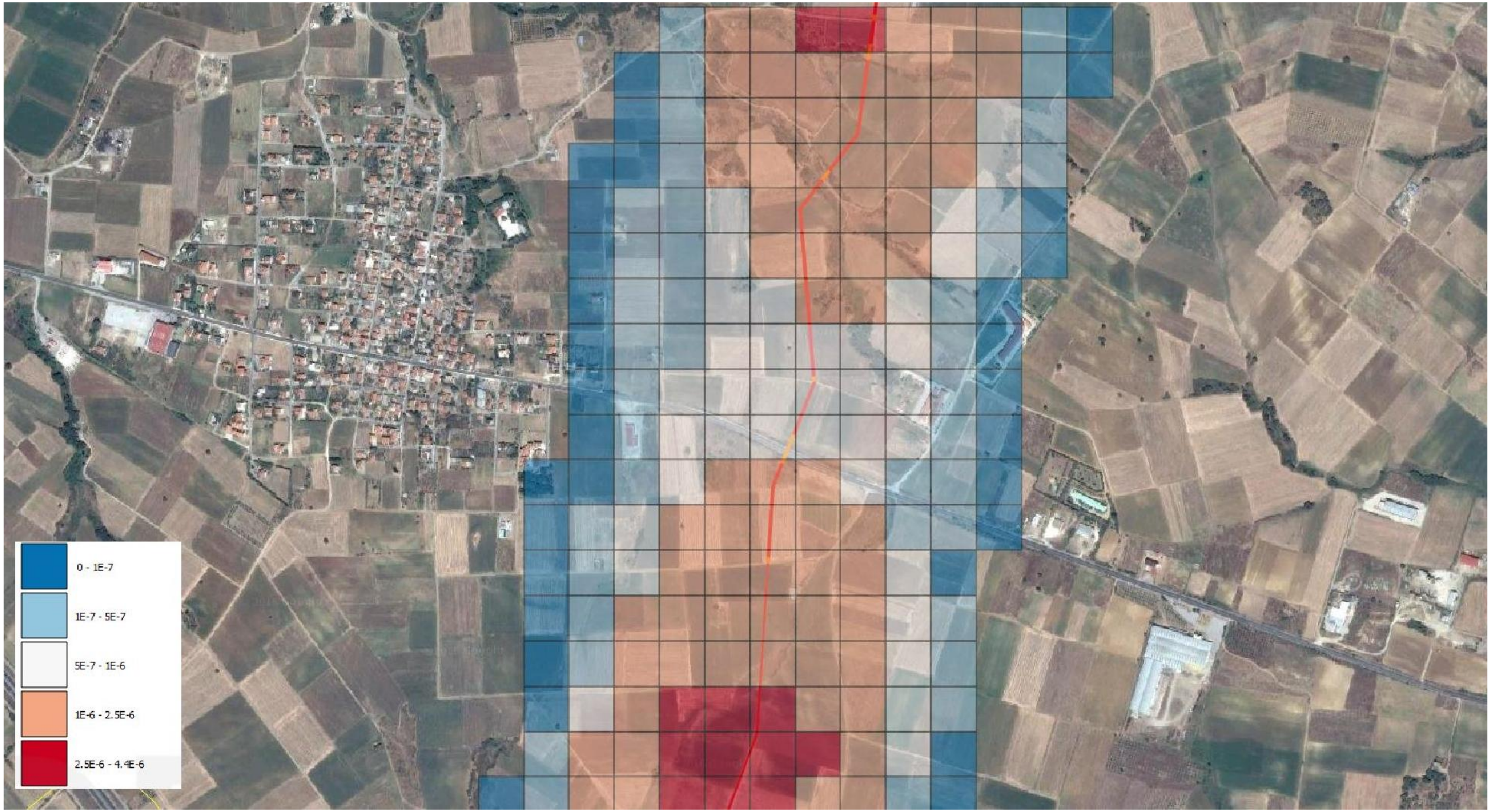


Fig 29. Iso-Risk map east of Roditis village. Modified Design with pipe wall thickness 14.2 mm



5 Protective Mitigation Measures

5.1 Introduction

The individual risk transects calculated at 75 barg, for a point on a straight part of the pipeline, are shown in Figure 25 along with the acceptable risk criteria in Greece.

It can be seen that fro points of Class Location 1 (pipe wall thickness 11mm), the risk levels are above the Greek Technical Regulations acceptable level of 1 x 10^{-6} per annum with a maximum value of $1.3x10^{-6}$. The very conservative definition of Individual Risk assuming a theoretical person remaining totally exposedfor 100% of time outside of any dwelling must be stressed here. When the pipe wall thickness is increased the IR levels fall in acceptable values.

As it can be seen in the figures 26-29 the total Individual Risk falls in acceptable levels when the pipe wall thickness is locally increased to 14,2 mm.

5.2 Failure Frequency Modifiers

5.2.1 Modifying Parameters to consider

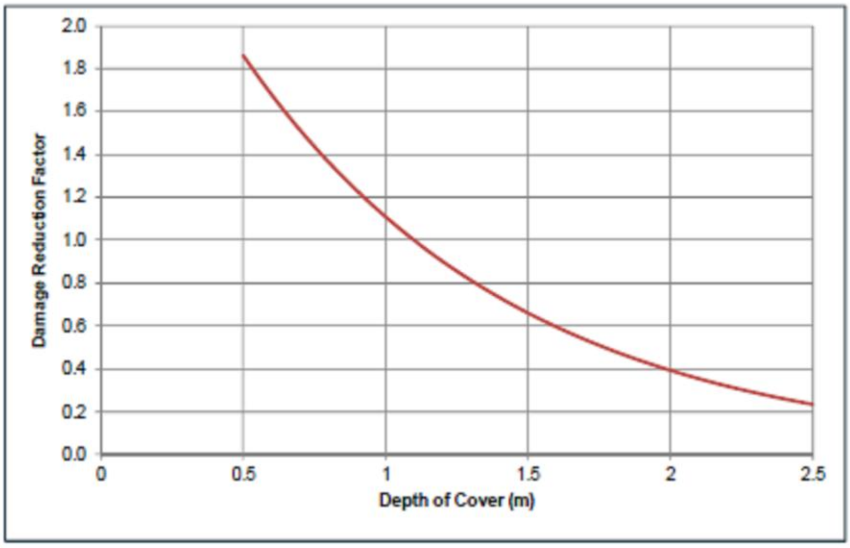
Frequency statistics and damage distributions derived from the UKOPA database allow the prediction of the average failure frequency for a certain diameter, wall thickness and grade of pipe. However, for a real pipeline section, the population area that the pipeline is in, the depth of cover and whether any protective mitigation measures have been installed must be taken into account as these factors will all affect the frequency of damage occurring on a pipeline.

5.2.2 Depth of Cover

Increasing the depth of cover of a pipeline will reduce the likelihood of external interference by reducing the proportion of construction and excavation activities that could reach and hence interfere with the pipeline.

The recently published IGEM/TD/2 contains a simple reduction factor for depth of cover which is derived from the results of published studies. This is shown graphically in Figure below which gives the factor by which the failure frequency (of a pipeline buried in 1m depth) is multiplied to give the resulting failure frequency for other depths. For instance the failrure frequency of a pipeleine buried in 2m depth is only the 40% of the same pipeline buried in 1m depth.

Fig 30. Effect of Depth of Cover on pipelines failure frequency



The use of protective measures to reduce the effect of external interference has been common practice in the pipeline industry for many years. Until the advent of reliable thick walled line pipe, all major traffic crossings were sleeved to avoid damaging the pipeline at a location likely to see construction activity.

Damage reduction factors for risk mitigation have been available since British Gas work in the mid-1990's. IGEM/TD/2 contains updated data on the reduction factors applicable for installing concrete slabbing and installing concrete slabbing with marker tapes. These more recent values have therefore been used where applicable in all assessments.

Table 13. External Interference Failure Rate Reduction Factor

Type of Protction	Failure Rate Reduction Factor
Installation of concrete (or equivalent) slab protection	10

5.2.3 Class Location & Country

The data collected by UKOPA on damage incidents on the UK gas transmission network included details on the local class location. For gas transmission pipelines in the United Kingdom, designed to either IGEM/TD/I1831 or PD 80101841, there are only two class locations, or area types, R or Rural and S or Suburban. R areas generally correspond to ASME B31.8 Class 2 and S areas to Class 3. As the UK is heavily populated, there are very few unpopulated or Class 1 areas that have any pipelines and Class 4 areas with multiple storey buildings are not allowed in the UK pipeline design codes.

The factors for area type derived from the UKOPA database, i.e. S areas have approximately 3.6 times more 3* party damage than R areas, are considered to be suitable for Western Europe. For areas of the world outside Western Europe, specific factors must be selected based upon a review of the local population levels and likely development activity.

6 CONCLUSIONS & RECOMMENDATIONS

A risk assessment of the whole length of the proposed IGB high pressure natural gas pipeline has been completed at the current maximum operating pressure of 75 barg.

The individual risk transects calculated at 75 barg, for a point on a straight part of the pipeline, are shown in Figure 25 along with the acceptable risk criteria in Greece and outline the decrease of Individual Risk when the pipe wall thickness is increased more than its initial design of Class Location 1 (thickness 11mm). The Class Location 2 (thickness 14,2 mm) as well as Class Location 3 (thickness 16mm) pipe decrease IR significantly to levels lower than the Greek Technical Regulations acceptable level of 1 x 10^{-6} per annum.

The calculated individual risk levels (for a Class location 1 pipeline segment) have been shown to be above the Greek Technical Regulations acceptable level of 1 x 10-6 per annum. Note that this limit is equivalent to the UK HSE broadly acceptable level. The HSE defines individual risks between 1 x 10^{-6} and 1 x 10^{-4} as tolerable if they are shown to be as low as reasonably practicable (ALARP). The very conservative definition of Individual Risk assuming a theoretical person remaining totally exposed for 100% of time outside of any dwelling must be stressed here. When the pipe wall thickness is increased the IR levels fall in acceptable values.

It is therefore assumed that the “exceedance” of the Regulation limit does not create any real problem in the non-populated areas of the pipeline routing.

On the contrary in the two areas, namely west of Kalchas and east of Roditis some measures have to be taken in order to reduce the Individual Risk to the population in acceptable levels (Less than $1x10^{-6}$). In order for this requirement to be met, an increase in pipe wall thickness, to 14,2 mm (as in Class Location 2) is necessary as it has been clearly demonstrated by applying the same methodology.

6.1 Recommendations

It is recommended that:

- The pipeline wall thicknes is increased in the Kalchas Village area for about 600m from 11mm to 14,2mm in order to locally reduce the Individual Risk to acceptable ($<1x10^{-6}$) levels (see. Figures 26-27). More specifically it is recommended to increase the pipe thickness in the part defined from K19+665m to K21.
- The pipeline wall thicknes is increased in the Roditis Village area for about 800m from 11mm to 14,2mm in order to locally reduce the Individual Risk to acceptable ($<1x10^{-6}$) levels (see. Figures 28-29). More specifically it is recommended to increase the pipe thickness in the part defined from K7+324m to K10+120m.
- Except the obvious increase in pipe wall thickness it is recommended to take complementary measures for reducing the pipeline failure frequency, namely the local increase of trench depth or (for more drastic results) the installation of concrete (or equivalent) slab protection in the crossings points with roads and highways in the areas mentioned above.
- The results of the QRA should be reassessed if the actual population of buildings within the hazard range are significantly greater than the population assumed in this assessment.

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APPENDIX A. SOCIETAL RISK CALCULATION. Summary and Conclusions from the study by PENSPEN

A1. Summary of the study by PENSPEN

As a precursor to the present study, an Initial Quantitative Risk Assessment Study prepared by the Penspen-C&M Consortium mainly focousing in the “KALCHAS” area has been used as a starting point for discussions with the Permitting Authority which proposed some corrections and amendments.

According to the abovementioned report by PENSPEN, that is briefly presented in this Appendix, societal risk levels are within the UK IGEM broadly acceptable region and cost benefit analysis has shown that the risk levels at the assessed location near Kalchas are As Low As Reasonably Practicable (ALARP). As the assessed location is the most densely populated point on the Greek section of pipeline it is concluded that risk levels are ALARP along the entirety of the Greek section of pipeline

A2. Societal risk. Background.

The risk from all incidents, i.e. immediate and delayed ignited ruptures and leaks, that may affect the populated areas as modelled are combined to calculate both the societal risk for the populated areas and the risk to a permanently resident individual, along a specific transect.

Societal risk represents the likelihood of more than one person being injured at any one time and is usually expressed as an FN curve (i.e. the frequency of N or more casualties versus the number of casualties, N). The societal risk takes account of population movements and behaviour patterns throughout the day.

A3. Social Risk Calculation

A3.1 Interaction Length

Before the risk to a particular individual or development can be calculated, it is important to define the length of the pipeline that could cause harm to the person or development. This length is know as the interaction length. For a building, the hazard distance will be the building burning distance, whereas for a person, it is the relevant escape distance.

Obviously, the interaction length for a point lying on the pipeline is twice the hazard distance.

A3.2 Individual Risk Calculation Methodology

To calculate the risk to an individual at any point along a transect perpendicular to the pipeline, the interaction length is split into small steps, typically every 5 or 10 metres, and the risk calculated for a pipeline failure that results to a fire located at each step.

Consider a pipeline that has a predicted rupture failure frequency of/per km per year, there is a probability p_i, that the released gas will ignite and a person at distance y will have a probability of pcy of becoming a casualty. The individual risk per year from rupture for an individual step is:

$$f.dx.p_i.pc_y$$

where dx is the length of the individual step.

Therefore, the overall individual risk (IR), for someone at distance y is found from the summation of this expression along the interaction length, taking into account the variation in casualty probability with distance from the pipeline and the variation in failure frequency due to changes in wall thickness, depth of cover, location class etc., i.e.

$$IR = \sum_{j=1}^{n} \left(f \cdot dx \cdot p_i \cdot p_{cy} \right)_j$$

To construct an individual risk transect, this calculation must be repeated for a range of distances from the pipeline.

A3.3 Societal Risk Calculation Methodology

For each step in the interaction length, the failure frequency of the step length/and the number of casualties n are calculated. The consequence calculations must take into account the geometry of the development, the number of people present and outside at varying times of the day and their ability to escape to shelter.

To generate the corresponding values of F for N or more casualties and plot an FN curve, the values of/are summed for each different value of w to produce a histogram of Jh pairs which can then be plotted as a reverse cumulative distribution.

A3.4 Expectation Value

The calculation of societal risk Jh pairs as described above also allows and evaluation of the Potential Loss of Life (PLL) or expectation value which is a statistical expression for the average number of casualties per year and is given by the following equation:

$$EV = \sum f \,.\, n$$

Expectation Value is a useful measure for cost-benefit analysis calculations.

A4. Risk Acceptance Criteria

UK Health and Safety Executive publications state an unacceptable level of individual risk to a member of the public of 1 x 10^{-4} per annum which is approximately ten times less than the historical fatality rate for dangerous industries such as deep sea fishing or offshore oil and gas extraction in the North Sea. From this value, a level of risk below which there is typically no concern is set at 1 x 10^{-6} per annum or one chance per million (cpm). The no concern level is considered to be negligible in comparison with the total everyday risk in the UK as shown in Table below

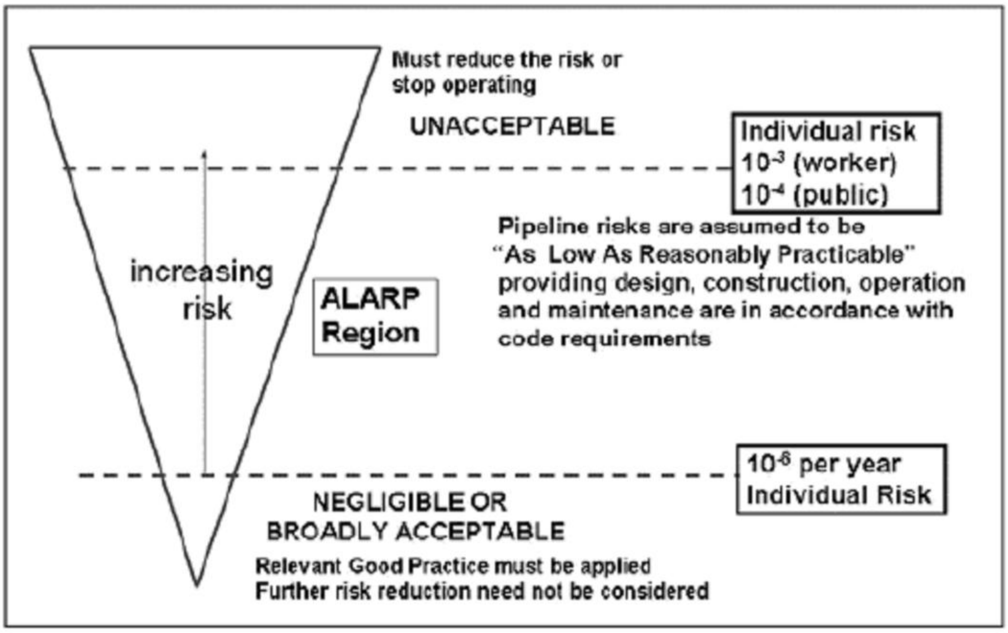
Πίνακας A1. Annual risk of death in the UK

Causes of Death	Ετήσιος κίνδυνος
All causes	1,0 x 10^{-2}
Cancer	2,6 x 10^{-3}
All accidents	2,5 x 10^{-4}
All of road accidents	6,0 x 10^{-5}

Between the unacceptable and no concern level is the ALARP, or as low as reasonably practicable, region. In this region risks are considered to be tolerable if further risk reduction is impracticable or requires action that is grossly disproportionate in time, trouble and effort to the reduction is risk achieved. This is typically proven using cost benefit analysis.

The limits derived by the UK HSE are shown diagrammatically below.

Fig A1. United Kingdom HSE Individual Risk Criteria



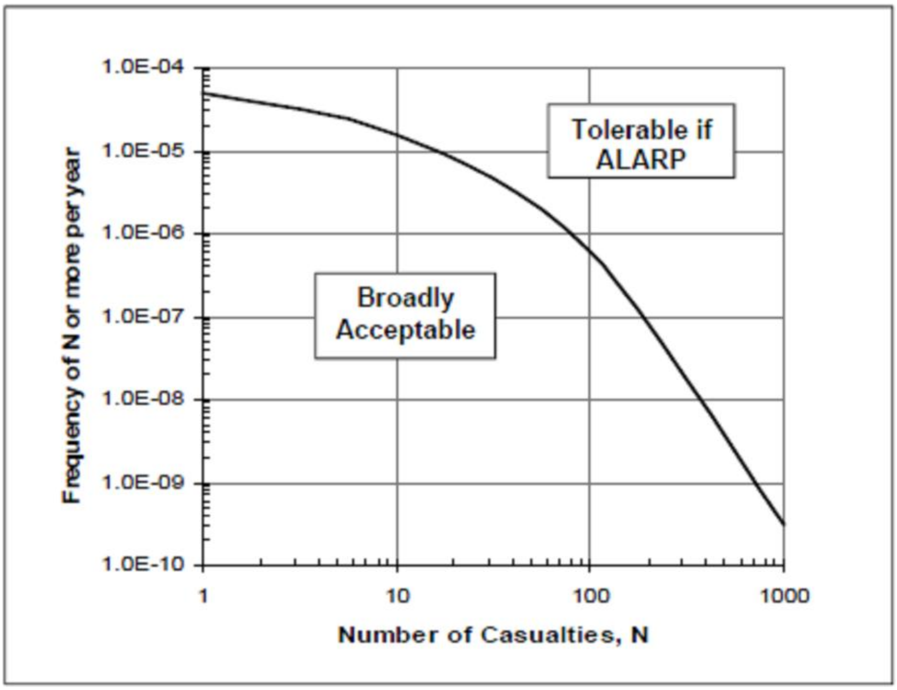
For linear hazards like pipelines, where significant numbers of people may be at risk in a single event, societal risk is a better measure with which to judge the acceptability of risk levels.

Acceptable levels of societal risk have been taken from the FN criteria in IGEM/TD/1 which is shown in Figure below. This criteria have been derived by assessing many pipelines built and operated to previous editions of this code by National Grid, and its predecessors, and producing an envelope of acceptable risk. This approach assumes that all pipelines previously designed, built and operated to the code implicitly have acceptable levels of risk.

The methodology used in the QRA detailed in this report is very similar to the methodology used to generate the FN envelope; however, it is thought that the methodology used in this QRA produces a slightly higher predicted risk level. Therefore, it is considered to be conservative to use the IGEM/TD/1 societal risk criteria.

If societal risk levels are outside, or close to, the IGEM/TD/1 envelope, then risk levels must be checked to determine if they are ALARP using cost benefit analysis.

Fig A2. IGEM/TD/1 Societal Risk FN Criteria



A5. Building Residency and Occupancy Assumptions

The proposed pipeline begins at the Greek gas network, travels north and runs parallel to the Egnatia Highway for approximately 11 km, it passes several villages on its proposed route including, Filakas, Roditis and Kalchas. The section of pipeline that passes close to Kalchas has been identified as having the highest risk. In this section the pipeline crosses three small roads and passes within 60 m west of a petrol station and adjacent tyre services centre.

Close to the petrol station and approximately 135 m from the pipeline is a sanitary ware shop, although this appears to be currently unoccupied. Approximately 220 m east at the same point on the pipeline is a building that is assumed to be an apartment block. Other buildings are in the area however they are all more than 250 m from the pipeline and are thus outside of the hazard radius. The pipeline then continues north for a further 20 km to the Bulgarian border..

The building occupancies have been estimated by Penspen and confirmed by C&M. The petrol station is assumed to have 3 employees, with 3 customers within the building and 5 outside at any one time. The adjoining tyre services centre is assumed to have 4 employees with 2 inside and 2 outside. 4 customers are also assumed to be split between inside and outside the tyre services centre buildings.

The second building within the hazard range is a sanitary ware shop, this appears to be currently unoccupied; however it is conservatively assumed that 2 persons are within the building during the day.

The third building within the hazard range is a small supermarket with adjoining apartments, 15 persons are assumed to be present at all times within the building.

The residency assumptions allow each week to be broken down into four time periods; weekday, week night, weekend day and weekend night. Day is considered to represent 10 hours, between 8 am and 6 pm, and night represents the remaining 14 hours.

During days, it is assumed that the petrol station and tyre services contain the maximum number of staff and customers. Nights are assumed to have 1 staff member and 2 customers. It is assumed that during the day 10% of time is spent outdoors with only 2.5% during the night.

The equivalent daily periods are detailed in Table 4.2 and the population residency assumptions in the Table below.

Table A2. Equivalent Daily Periods for Kalchas

Period	Equivalent Hours per day
Week day - Day	7,14
Week day - Night	10
Weekend - Day	2,86
Weekend - Night	4
TOTAL	**24**

Table A3. Summary of Population Residency Assumptions

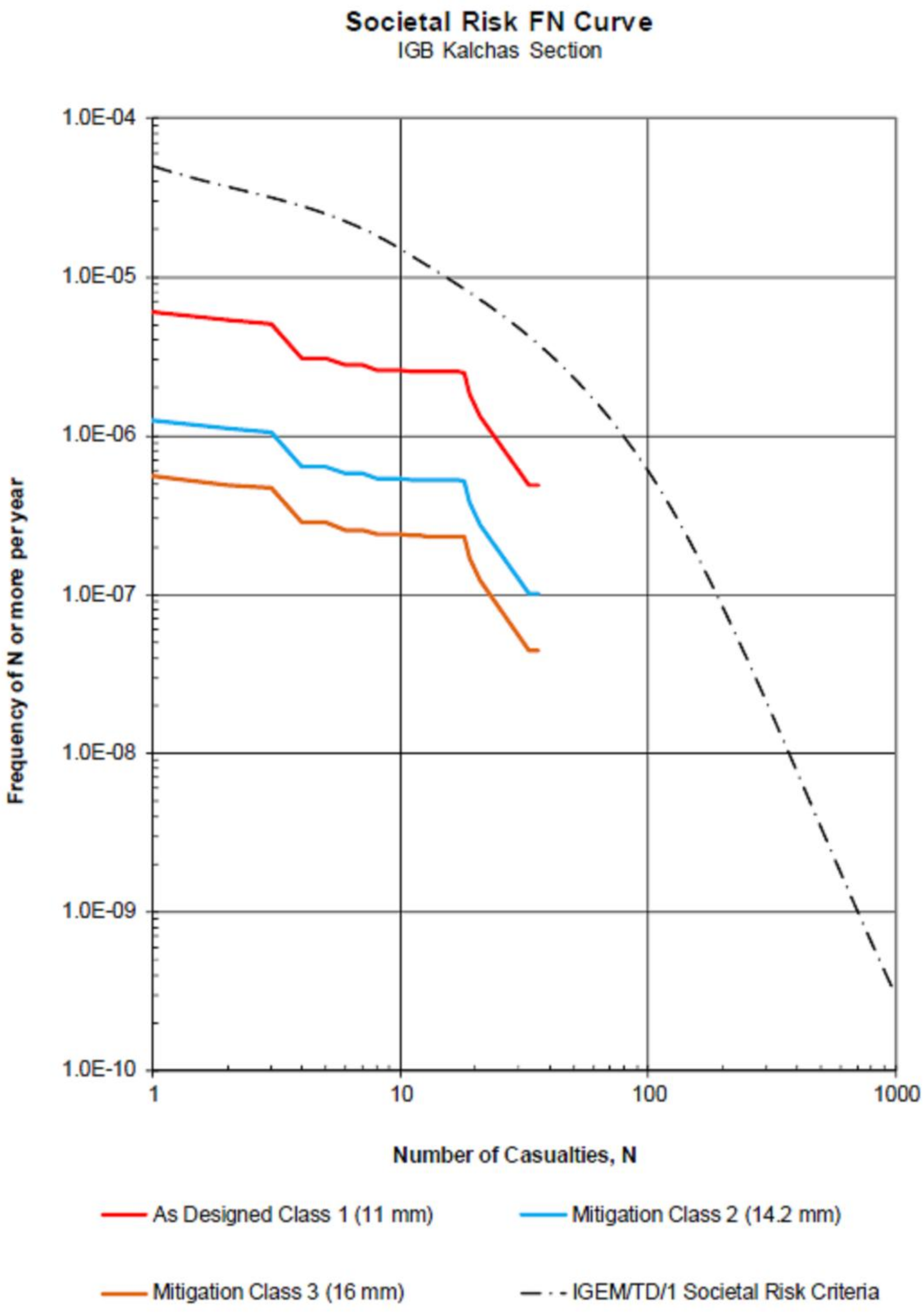
	Weekday – Day		Weekday – Night		Weekend – Day		Weekend – Night	
Location type	**Number Present**	**% out doors**	**Number Present**	**% out doors**	**Number Present**	**% out doors**	**Number Present**	**% out doors**
Petrol Filling Station Employee (Inside)	3	10	1	2,5	3	10	1	2,5
Petrol Filling Station Customer (Inside)	3	10	1	2,5	3	10	1	2,5
Petrol Filling Station Customer (Outside)	5	100	1	100	5	100	1	100
Tyre Services Centre Employee (Inside)	2	10	0	2,5	2	10	0	2,5
Tyre Services Centre Employee (Outside)	2	100	0	100	2	100	0	100
Tyre Services Centre Customer (Inside)	2	10	0	2,5	2	10	0	2,5
Tyre Services Centre Customer (Outside)	2	100	0	100	2	100	0	100
Sanitary Ware Shop	2	10	0	2,5	2	10	0	2,5
Supermarket / Apartments	15	10	15	2,5	15	10	15	2,5

A6. Societal Risk calculations near Kalchas village

The societal risk FN curve for the site of the Kalchas section of the IGB gas pipeline, and its surrounding area, at 75 barg is shown in the figure below. The FN curve can be seen to be within the envelope of the IGEM/TD/1 broadly acceptable region.

However, to confirm whether risks are acceptable at the MOP, an ALARP assessment is undertaken using cost-benefit analysis to confirm if the risks are "as low as reasonably practicable".

Fig A4. Societal Risk FN Curves for IGB pipeline at Kalchas



A7. ALARP Assessment

To confirm whether the risk levels at the maximum operating pressure of 75 barg are acceptable, installing the pipeline in thicker walled pipe has been considered for the

Kalchas section. The risk mitigation is assumed to begin approximately 545 m south of the petrol station and to continue approximately 545 m north of the petrol station.

A7.1 Cost Benefit Analysis

The cost per casualty averted (CCA) used in pipeline cost benefit analysis is calculated using the following equation:

$$CCA = \frac{\textit{Cost of Modification}}{\Delta EV \times \textit{Design Life}}$$

Where ΔEV = Change in Expectation Value due to the modification.

Expectation value is a statistical expression of the predicted average number of casualties per year. The remaining design life of an existing onshore pipeline is typically taken as 40 years in cost benefit analysis, regardless of pipeline age unless a specific decommissioning date has been agreed.

A summary of costs per casualty averted for modifying the pipeline with thicker wall pipe, are shown in the Table below. The additional cost of constructing the Kalchas section of the IGB pipeline with Class 2 (14.2 mm) and Class 3 (16 mm) wall thickness pipe, instead of 11 mm as required by the design code, has been provided by Penspen Engineering & Project Management.

Table A4. Cost per Casualty Averted – Risk Mitigation for Kalchas

Mitigation Option	Pressure	Length of Mitigation (m)	Original Expectation Value	Mitigated Expectation Value	Estimated Cost of Mitigation	Cost per Casualty Averted
Class 2 14,2 mm wt	75 brag	1060	6,816E-05	1,412E-05	€87.980	61 mil. €
Class 3 16 mm wt				6,251E-06	€153.700	94 mil. €

For a new pipeline designed in accordance with recognised international codes and standards, the cost per casualty averted is above the level that Penspen considers to be reasonably practicable. Therefore, risk levels for the proposed pipeline at this location are considered to be ALARP and no additional risk mitigation beyond code design is required.

The Kalchas section of pipeline was chosen as the most densely populated area on the Greek section of the IGB pipeline, with the most people in close proximity to the proposed pipeline. As risk levels at Kalchas are ALARP, it therefore follows that risk levels along the entire Greek section of pipeline can be considered to be ALARP.