21st World Gas Conference – June 6-9, 2000 – Nice – France

Report of Working Committee 4

«*Transmission of Gases*»

Rapport de la Commission 4

«*Transport des gaz*»

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ABSTRACT

Report of the WOC 4 Transmission contains the results of works carried out during 1998-2000 by the Committee members and the three study groups.

The most important is:

- review of actual situation and prospects for the gas pipeline transmission system development;
- report of SG-4.1 "Pipeline Ageing and Rehabilitation", including analysis of pipeline steels, weldings and insulation, methods of rehabilitation, the program of pipeline reconstruction;
- report of SG-4.2 "Emission monitoring" including appraisal of gas losses and methods of lowering of methane and other emissions of the gas units in different countries;
- report of SG-4.3 "Pipelines Integrity Management and Safety" including basic information on gas pipeline failure intensity, key elements of the Integrity Management System of the gas transmission, methodes of risk evaluation and the effectiveness of the approache.

RÉSUMÉ

Rapport du WOC 4 Transportation du gaz de l'UIIG présente les résultats des travaux effectués en 1998-2000 par les membres du Comité et de ses trois groupes d'études

Les résultats les plus importants sont:

- aperçu de l'état et les perspectives du développement de la transportation du gaz par les gazoducs;
- rapport du SG-4.1 "Pipeline Ageing and Rehabilitation" comprenant l'analyse des aciers, soudage et isolation des gazoducs, les methodes de l'inspection et de monitoring, les methodes de la réparation, le programme de la réconstruction des gazoducs
- rapport du SG-4.2 "Emissions monitoring" comprenant l'évaluation des pertes de gaz et les méthodes de la diminution des émissions du methane et d'autres émissions polluantes des unités industrielles gasiéres;
- rapport du SG-4.3 "Pipelines Integrity Management and Safety" comprenant l'information de base sur l'intensité des défaillances des gazoducs, les éléments-clés du systéme de Integrity Management des gazoducs, les methodes de l'évaluation des risques et de l'efficacité de cette approche.

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REVIEW OF THE DEVELOPMENT OF THE WORLD GAS TRANSMISSION SYSTEM, 1996-1998

The growth of the gas industry between 1996-1998 has been encouraged by the world economic development, new fields of natural gas, utilization as the most ecologically safe primary energy and more binding environmental requirements.

A rise in marketed gas production and consumption was noted in practically all the regions of the world. Development of the remote world regions that are difficult to access became a characteristic trend. These included offshore fields, northern and desert territories which entailed complicated problems in the field of gas transmission.

The average global growth rate of natural gas demand is about 3%, however, in different countries it varies widely.

1 - NATURAL GAS PRODUCTION

The world gross gas production has risen by 0.5% in 1997, comparing to 1996, and reached 2898.2 BCM (2884.9 BCM in 1996). Marketed gas production amounted to 2298.3 BCM in 1997. According to the latest estimates, the world marketed gas production will rise by 3.5-4.8% in 1998 and will reach the volume of 2355-2409 BCM.

Major growth of marketed gas production will take place in the North Sea region and to a certain extent in Asia and the Middle East countries according to the forecast of the International Natural Gas Information Center CEDIGAZ, France.

The USA marketed gas production amounted to 536.9 BCM in 1997. In 1998, it is expected that this value will rise to 540-545 BCM. The market gas production amounted to 165.6 BCM in neighboring Canada in 1997 and is expected to reach the level of 174-178 BCM in 1998.

Significant growth of natural gas production (12-16%) is expected in Latin America in 1998.

Gas production in European Organization for the Economic Cooperation and Development (OECD) member-states is expected to grow by 6.5% in 1998 which is mainly related to production growth in the North Sea.

Due to the state transformations and slow-down in the rates of economic growth in the countries of Central Europe gas production will remain at the level of 1997 (25-26 BCM).

In Africa natural gas is an aggressively rising substitute for oil by increasing its application in power generation. In Algeria, Egypt and Nigeria natural gas production is rising with a major part of this production going to foreign customers.

The Middle East represent the regions where natural gas reserves are developed efficiently with gas production growing, and both natural and liquefied gas exports increasing.

2 - NATURAL GAS CONSUMPTION

An analysis of the world gas consumption dynamics indicates a steady growth of utilization as natural gas is ecologically the safest primary energy. Gas consumption in 1997 remained at the level of 1996 (2298 BCM). However, in certain regions gas consumption has risen: in the Asia-Pacific region by 7.3%, in the Middle East - by 7.4%, in Latin America - by 5.5% and by 2.8% in Africa.

North America is traditionally a major gas consumer - 702 BCM. The CIS and Baltic states remain one of the world’s leading regions as far as gas consumption is concerned - 551.6 BCM. Gas consumption in European OECD member-states amounted 393.4 BCM in 1997, in the Asia-Pacific region - 252.4 BCM, in the Middle East - 160.3 BCM, Latin America - 113.9 BCM and Central Europe - 72.4 BCM.

By 2010 gas consumption will exceed the level of 1994 by 2.5 times according to the International Energy Agency (IEA). The demand growth will reach 29% in North America by 2010, in the OECD countries of the Pacific region - 46%, and in European OECD member-states - 70%.

The increase in demand will be followed by growing competition in the energy markets. When 60% of oil consumption in West European and USA is used in motor vehicles, there will be the potential to replace gasoline and other fuels with natural gas. This will entail significant technological innovations in transport mechanical engineering and automobile industry as well as the change of the consumers' psychology itself.

3 - NATURAL GAS INTERNATIONAL TRADE

Natural gas international trade through gas pipelines and LNG carriers has increases in 1997 and amounted to 439.5 BCM, compared to the previous year of 427.3 BCM. The volume of the world gas sales through the pipeline systems reached 327.4 BCM in 1997 which is slightly above the level of 1996.

The main international gas trade reflect the geography of its production. Russia remains a leader in natural gas exports. Its share in the world gas exports amounted to 27% in 1997 which exceeds the total actual volumes of gas deliveries from other two major European producers - the Netherlands and Norway by 8%. Canada is the second major gas supplier (19%), Algeria is the third (11%).

The USA is the world biggest gas importer. Its share of the world gas imports is 20%. Germany is the leading European importer - 17%, followed by Italy - 9%, France - 8%, Czech Republic and Slovakia - 4%, Belgium - 3%.

Japan is the world leader in imports of LNG; the country's purchases amounted to 62 BCM of gas in 1996 and 64 BCM in 1997.

4 - WORLD GAS PIPELINE CONSTRUCTION

Development of the power sector and consumers' demand for natural gas as primary energy has accelerated the commissioning of new pipeline grids.

From the total length of all the pipelines commissioned from 1996 - 1999, gas pipelines occupy the leading position. The gas pipelines amounted to 19,900 km or 53.4% in 1998, crude pipelines - 10,000 km or 26.9%, and product lines - some 7,400 km or 19.7%. In 1999 the length of the gas pipelines was up to 46,900 km or 66.1% which indicates the priority of gas pipeline construction, related to the total volume of pipeline construction throughout the world.

The growth of natural gas consumption has resulted in more large diameter pipelines. Gas pipelines above 558.8 mm diameter were only 55% (10682 km) of the total volume in 1996, however in 1999, the corresponding value is 75% or 35576 km. The growing ratio of gas pipelines of these diameters demonstrates the rising portion of gas pipelines with large diameters in the world gas pipeline construction.

A center of gravity shift from Europe to Asia means a new development in new pipeline construction.

In spite of the economic crisis in 1997, the Asia-Pacific countries demonstrate a high level of gas pipeline construction, which is particularly characteristic of 1998 - 1999 period. The European region still remains one of the world leaders as far as the length of gas line construction is concerned for the some period. In the USA, stable expansion of a powerful gas line network confirms their lead in the world gas industry. In Latin America construction of gas transmission systems in 1999 demonstrates the potential of the region for the global gas industry.

The specific features of the gas sector in each region influences the structure of corresponding pipeline systems. In the USA, most attention is traditionally paid to gas distribution network. In Canada, construction of 558.8 - 762 mm pipelines is required because of its high export potential. Development of interstate gas transmission systems in Latin America is reflected in construction of 558.8 - 762 mm pipes. In the Asia-Pacific region, construction of 306 - 508 mm gas lines is important. In Europe with its high gas imports major efforts are concentrated on construction of pipelines 812 mm and larger. In Africa, despite the difference with Europe, large diameter (812 mm and more) pipelines are often constructed because of the development to delivery gas beyond the bounds of the African continent.

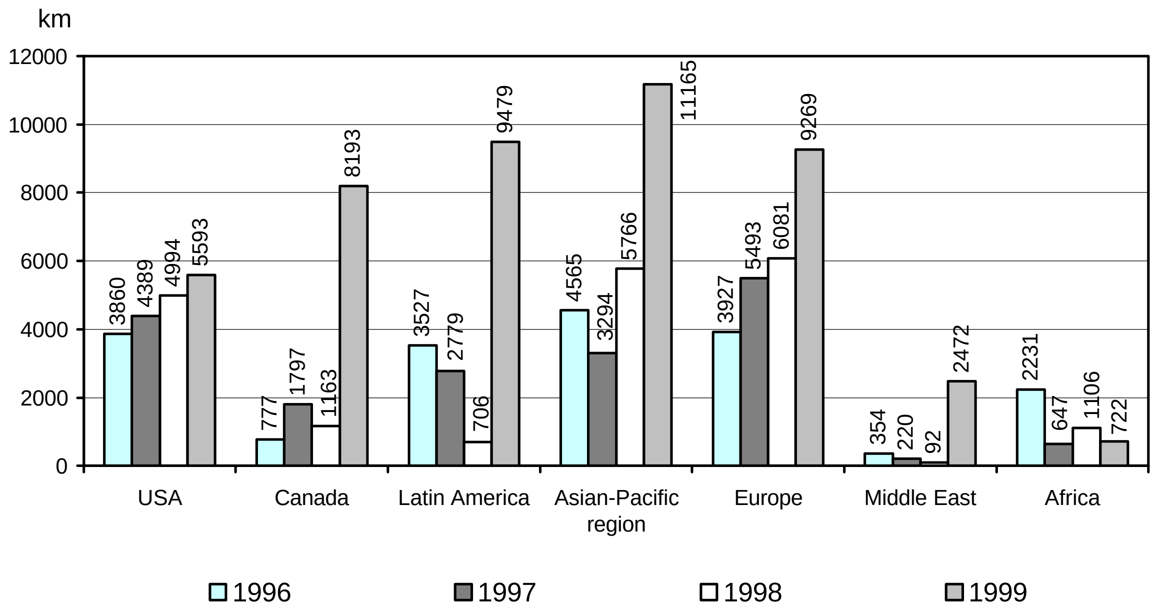

Figure 1: World gas pipelines construction, km

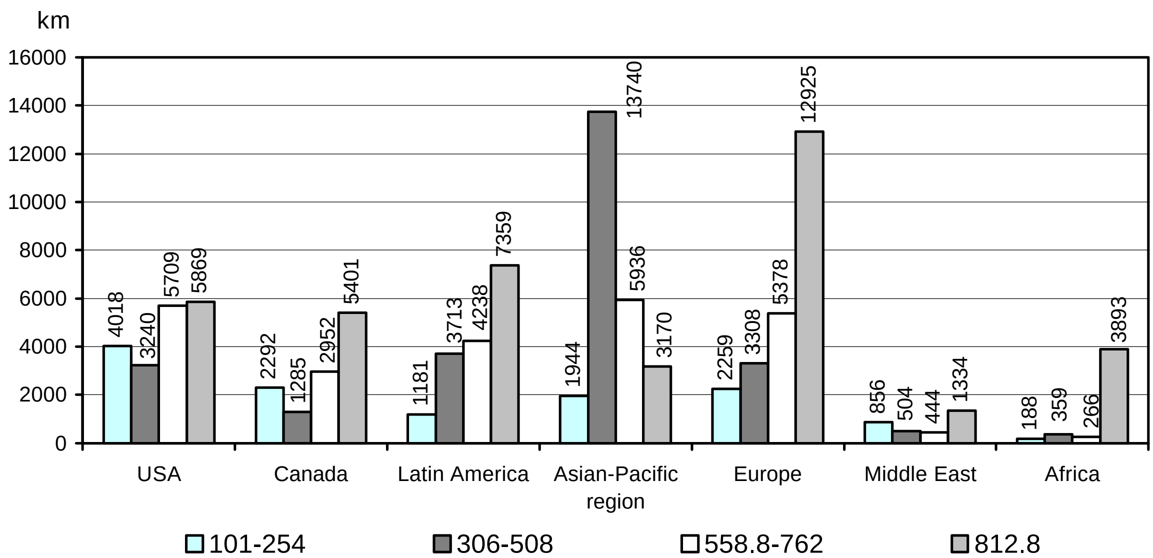

Figure 2: Regional structure of gas pipelines construction, 1996-1999, km

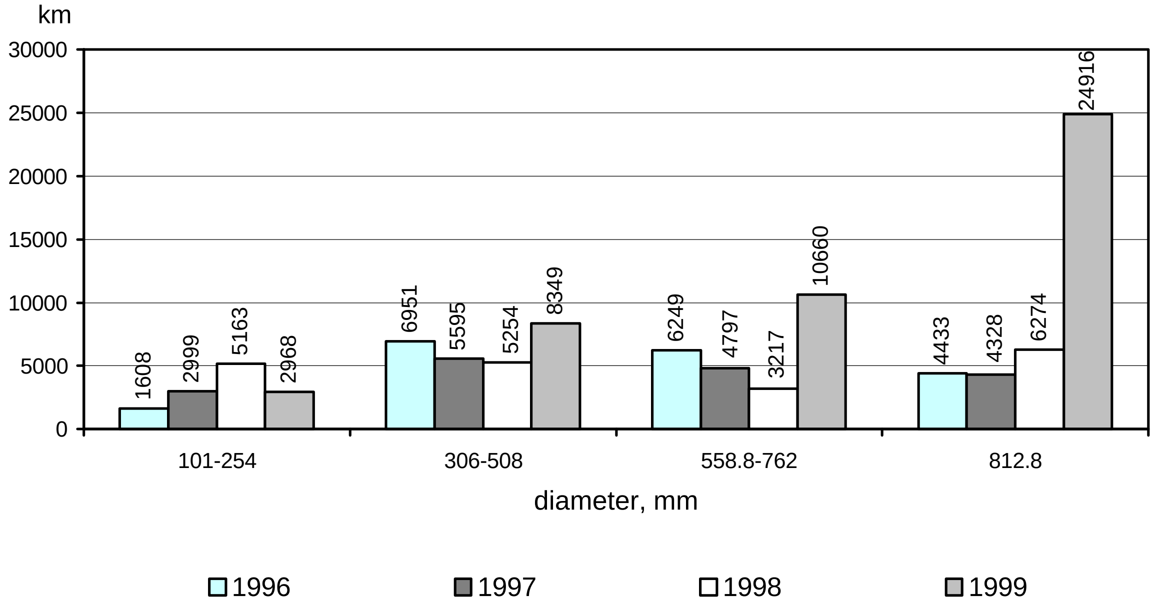

Figure 3: Structure of gas pipelines construction, km

5 - OFFSHORE PIPELINE CONSTRUCTION

Data on offshore pipeline construction after 1968 is summarized. The boom in the projects of this type started then with initiation of the deep-water pipeline construction and with manufacture of the second-generation of lay barges.

Before 1968 the data on construction of the offshore crude and gas pipelines were included in the general statistics.

Since 1968 and until 1997, 38370 km of the offshore gas pipelines were constructed in the world. During the last decade, 1987 - 1997, annual commissioning of the offshore pipelines has grown almost 6 times: 390 km in 1987 and 2450 km in 1997. Construction volume reached its maximum in 1990 when the total length of the pipelines commissioned was 2430 km. This result was surpassed only seven years later. 2190 km were put in operation in 1995, 2260 km - in 1996, and 2450 km in 1997.

- The total cost of the offshore construction exceeded $1.5 bln in 1998:
- $627,5 mln for pipelines 101-254 mm;
- $585,6 mln for pipelines 304-508 mm;
- $353,2 mln for pipelines 610-762 mm.

Total cost of the offshore construction will exceed $2.1 bln after 1998.

The statistics of the offshore pipeline construction indicate a steady growth of this particular type of pipeline transport which reflects a general trend in the development of gas-bearing continental shelves and the expansion of pipeline gas supply.

6 - BIGGEST GAS PIPELINE PROJECTS

6.1 - Europe

6.1.1 - Yamal-Europe

Yamal-Europe pipeline occupies a special place among new gas projects as Russian gas will be supplied to Poland, Germany, France and other countries.

Yamal-Europe gas transmission system will be connected to the existing gas systems with the aim of gas supply security enhancement. This system will provide for supply of 30 BCM/year for the first stage, 60 BCM/year for the second stage. The length of the pipeline to Berlin - 4226 km. The cost of the first stage of the pipeline is estimated as $10 bln. The project completion is scheduled for 2008-2010. Yamal-Europe will require investment of some $50 bln in total.

At present, Russian gas is delivered to Germany through the existing pipeline grid in the territory of Byelorussia, Poland and the completed sectors of Yamal-Europe system. Current supplies of natural gas from Russia into Germany, France, Switzerland and Austria are transited over the territories of Ukraine, Slovakia and Czech Republic.

6.1.2 - North-European gas pipeline

The North-European pipeline project will allow transmission of Russian natural gas to growing energy market of Western Europe through Finland. OAO Gazprom and Neste Oy company jointly set up North Transgas Oy company for this purpose. Its main task for the initial period is a feasibility study for the pipeline construction. The feasibility study is expected to be completed by the beginning of 1999. This will allow a final decision to be made to progress the project. The feasibility study should examine the following issues: practicability and profitability of the construction along three alternative routes. One of the routes passes from Russia to the German coast through Finland and Sweden; two other routes - to the German coast through Finland and Baltic Sea. Two of the three route assume laying the pipeline on the sea bottom. The design of the offshore pipeline section will be carried out by Kvaerner Process company. Designing and construction of the new pipeline is planned for the period of 1998 - 2005.

6.2 – North Sea and Irish Sea Pipeline Systems

6.2.1 – Interconnector UK - Belgium

Laying of the 235 km, 1,016 mm Interconnector line from Bacton, UK, to Zeebrugge, Belgium, was completed in summer 1998. The Interconnector pipeline is designed to handle up to 23 mln cu m daily and 20 BCM per year. The construction of Bacton and Zeebrugge terminals was completed in June, 1998 and commissioned in October 1998.

6.2.2 – Interconnectors Scotland – Ireland and Scotland – Northern Ireland

Since 1993, 2 subsea pipelines have been built in the Irish Sea connecting the UK transmission system in Scotland to gas networks in Ireland and Northern Ireland. The pipeline between Scotland and Ireland is 206 km and 610 mm diameter. The pipeline thet supplias Northern Ireland is 169 km long and 610 mm diameter. The pipelines have a combined daily capacity of 25 million cubic metres of gas. A third pipeline is being considered to deal with the developing growth in Ireland.

6.2.3 - NorFra gas pipeline

NorFra, the biggest offshore gas pipeline, was planned to be commissioned in 1998. The pipeline was planned in 1995 when Norway and France made arrangements to transport natural gas from Draupner platform in the North Sea to the terminal in Dunkerque. As a result of the agreement Norwegian gas company Den Norske Stats Oljeselskap A.S., as an operator of the NorFra joint project, drew up a schedule of the construction. The 835 km, 1,067 mm gas pipeline is designed for 15.7 MPa operation pressure. The throughput of the system is planned to exceed 13 BCM/year. NorFra will be the fifth Norwegian export gas pipeline and the first to supply France directly. Contrary to other pipelines, NorFra will deliver gas from as many as three gas fields.

The NorFra partners plan to put into operation the 185 km, 1,117 mm gas pipeline from Dunkerque to Paris in 1999. The designed capacity of the pipeline is 15 BCM/year.

6.2.4 - Zeepipe IIA + IIB

Two offshore gas pipelines from Norway's sector of the North Sea to Kollsnes (Norway) were commissioned in 1996-1997. These are Zeepipe IIA+ IIB pipelines. Zeepipe IIA is a 303 km, 1,016 mm trunk line designed to handle 13 BCM/year. Another gas pipeline of the same diameter, IIB, is 249 km long and has a transmission capacity as high as 18 BCM/year.

6.2.5 - Gas pipeline from Aasgard

The development of a new Aasgard crude and gas field in the Norwegian sector of the North Sea requires the construction of a new offshore gas pipeline. Aasgard is a collective name of three fields - Smorbukk Main, Smorbukk Sud and Midgard. The depth of the producing horizons is 2500 - 4700 m. The sea depth above the field ranges from 250 to 280 m. Gas production from the field is planned to begin in 2000. Daily production will amount to 40 thousand cu m. The 700 km offshore gas pipeline will connect the field with the receiving terminal in Kaarsto (Norway).

6.2.6 - Elgin-Franklin gas pipeline

A project to develope of the two large Elgin and Franklin Fields in the UK sector of the North Sea is currently in progress.

In parallel with the development of Elgin & Franklin, a group of companies is planning joint construction of gas pipeline connecting the Shearewater and Puffin fields and laying a pipeline to Bacton where is the starting point of the UK Interconnector pipeline.

Nippon Steel Corporation and NKK Corporation won the contract to deliver 198.45 thousand t of pipes for construction of the 467 km gas pipeline from Elgin - Franklin field to Bacton. The cost of the contract is estimated as $108 mln.

6.3 - Asia

6.3.1 - Blue Stream

Russia and Turkey signed an agreement in 1997 to increase the Russian gas supply. The agreement was made to develop the Russia to Turkey gas trunk line project named Blue Stream. First gas deliveries are planned for as early as in 2000 when Turkey will receive 0.5 BCM and by 2007 the deliveries will go up to 16 BCM/year.

The total length of the Blue Stream pipeline is 1226.5 km including 370 km through the Russian territory, 392.5 km in the Black Sea and 464 km in Turkey. The cost of the pipeline is estimated at $3 bln.

The sea depth along the twin pipe line route is up to 2,200 m. The designed operation pressure in the marine section is 250 bar.

6.3.2 - Pipelines of the Central Asian region

A number of major gas pipeline projects are being considered in Turkmenistan today. One of the most ambitious projects is an 8,000 km pipeline Eastwards through China to Japan. The pipeline will be 1,000 mm diameter and will handle about 20 BCM/year. The estimated cost of the pipeline to China will be $11.8 bln. If it is extended to Southern Japan this will increase to $22.6 bln.

One of the variants is a 4,800 km twin pipe gas line from Ashgabad to Turkey, through the Caspian Sea, Azerbaijan and Armenia. The estimated cost of the project is $8.5 bln. for a throughput of 40 BCM/year.

The Turkmenistan - Azerbaijan - Turkey project is being developed by Enron and Botas (Turkey). Beginning in Turkmenistan, the pipeline will run across the Caspian Sea to Baku and then across the Caucasus to Turkey. The cost of the project will amount $16 bln. for a throughput of 40 BCM/year.

Iran, Russia, Turkey and Turkmenistan have signed an agreement on $8 bln Turkmenistan - Iran - Turkey gas pipeline project to transport 28 BCM/year of Turkmenian gas to Turkey and Europe.

The length of the proposed Turkmenistan - Afghanistan - Pakistan gas pipeline will be 1,300 km. It will have a throughput of not less than 56.6 mln cu m per day and a probable cost of $3 bln.

The proposed 5,000 km Turkmenistan - Iran - Turkey gas pipeline will transport Turkmenian gas through Iran to Turkey. The estimated cost of the onshore part of the project is $10 bln.

6.3.3 - Russia - China

There is a number of projects for natural gas transmission from Russia to China. One of them beginning from Kovyktinskoye field, across Mongolia and China, to a sea port and further on to South Korea. The pipeline will be 3,370 km in length.The project will require some $8 - 8.5 bln of capital investment.

An alternative route of natural gas transmission to China is a pipeline construction project which begins at a group of fields in the North of West Siberia, via Surgut and Novosibirsk through a corridor between Mongolia and Kazakhstan, to the North-West region of China. The total length of the pipeline will amount to 5.5 thousand km.

According to the Russian forecast, supplies of Russian gas to the East Asia countries may total approximately 100 - 120 BCM in 2015 and up to 160 BCM by 2030. This will include 70 - 80 and 100 BCM to China, 12-15 and up to 20 BCM to South Korea, 18-25 and up to 35 BCM to Japan.

By 2030-2040, the creation of the Euro-Asia-Pasific global gas supply network looks likely to provide 65-80% pipeline gas and 20-35% LNG. This would be larger than the North American grid.

6.4 – Middle East

A joint venture was set up in November, 1995. To develop the Levant pipeline project that will supply natural gas from Egypt to Israel, Palestine and Jordan. The cost of the project is $1.3 bln. Deliveries will begin in 2002 - 2003. The throughput of the pipeline will reach the level of 13 - 16 bcm / year by 2010. The pipeline is expected to be linked to the European network in Bratislava. Another project to supply natural gas from Russia to Israel as early as 2001 will require $2 bln financing.

The government of Iraq is examining the project to develop the biggest gas field in the country. Negotiations with foreign companies are under way. The agreement will include clauses on the gas field development and construction of an export gas line to Turkey.

Several projects to construct gas pipelines linking a number of the Middle East countries are being considered. One of the pipelines, beginning in Qatar, is expected to cross the Gulf, through UAE and the Oman Strait, in parallel with the Iranian coastline, to Pakistan and, probably, India. In total, it will be a 1,072 km long pipeline.

Another pipeline project proposed by the UN Commission on Industrial Development and a group of companies (Kioda, Japan, and ENI) may link up Iran, Oman, Qatar, Saudi Arabia and UAE, and probably Iraq and Kuwait, into a single network extending West to Europe, and East to Asia.

6.5 – Other projects in Asia-Pacific region

Chevron Asiatic Ltd. is planning construction of a gas pipeline (estimated cost - 2 mln Australian Dollars) between Papua-New Guinea and Australia. The pipeline will cross the Torres Strait.

Enron and Shell are intending to build a gas pipeline project between Bangladesh and India.

In Australia, construction of a relatively short but vitally important gas pipeline (150 km, 457 mm) is nearing completion. This pipeline between Melbourne and Canberra in the South East of the country was to be commissioned in June 1998 and to provide the first connection between two separate pipeline systems in the country.

As there is no gas supply system on Tasmania, the government of this Australian state has granted Duke Energy a contract to construction a pipeline from the offshore gas fields.

6.6 – North America

In spite of the low cost of Canadian gas, the transportation costs affect its competitiveness relative to natural gas delivered to USA from the Gulf of Mexico.

Several pipeline projects were proposed in 1996 aimed at by-passing the conventional gas export routes.

The Alliance Pipeline project looks the most feasible 3,000 km, 914 mm gas pipeline will link the fields in the vicinity of Fort Saint John (British Columbia) with Chicago. The initial version of the project was estimated as $2.5 bln and was designed for 10 bcm/year (28.3 mcm/d).

As a result of preliminary studies, a group of 17 private companies proposed to undertake the project.

Gas transmission from the offshore fields through the continental Eastern Canada to the North-West of USA is becoming more realistic.

A group of gas producers headed by Mobil Oil Production is planning to realize a project proposed in October 1996, to develop a large gas field offshore of Sable Island.

There are two projects of gas transportation from the Sable Island field. One project proposed by Maritime and North-East provides for construction of the $975 mln 1,173 km pipeline to deliver gas from Sable Island to New England.

The second stage of the gas transmission system development to deliver Canadian gas to USA includes construction of a 37 km, 610 mm line connecting Wells with Woodland point at the Canadian-American border.

6.7 – South America

Gas began flowing in the second quarter of 1997 through the $350 mln, 462 km, 610 mm Argentina - Chile pipeline. Initial pipeline throughput amounted to 3.5 mln cu m/d. Extension of the network will increase the throughput up to 6.0 mln cu m/d in 2000 and up to 17.0 mln cu m / d by 2007.

The government of Uruguay has approved a pipeline construction project. The 215 km gas line between Argentine and Uruguay is expected to be commissioned in the 3rd quarter of 2000. The cost of the project is $135 mln with a production capacity of 2.5 mln cu m/d. A 60 km section of the pipeline is 610 mm in diameter, the rest is 304 mm.

The Bolivian pipeline construction project is becoming a reality. The 3,700 km gas pipeline Bolivia with the South-East of Brazil finalized in mid 1999 up to San Paulo. The Bolivia-Brazil pipeline runs via Santa Cruz de la Sierra, Brazilian border at Corumba point and then separates into two lines - to Campinas and San Paulo. The first 2,800 km of the pipeline are built of 762 mm pipes, the rest of the pipeline is of smaller diameter. According to the original inter-state contract, Bolivia is expected to supply Brasilia with gas during 20 years period.

Based on the results of preliminary study, the Latin America’s Economics Commission (Cepal) has expressively advocated a project of the pipeline connecting Suedad-Pemex in Mexico with the Central American countries.

Energy ministers of Mexico, Guatemala, Salvador, Honduras, Nicaragua, Costa-Rica and Panama have agreed to initiate a feasibility study of the pipeline construction project. An estimated cost of the construction may amount to $1.1 bln. The estimated length is 800 km.

6.8 - Africa

The Mahreb - Europe (stage I) gas pipeline was commissioned at the end of 1996. The pipeline is designed for natural gas export deliveries from Algeria to Spain and Portugal through Morocco. The pipeline length totals 1,861 km and diameters range from 220 to 711 mm. The throughput is 10 BCM/year. The length of the Algerian sector is 530 km and the Morocco section is 547 km. Cordoba in Spain was linked with Setubal in Portugal through the Mahreb - Europe line.

In line with the Transmed intercontinental pipeline from Algeria to Italy, the Mahreb - Europe gas transmission system connected the Northern Africa and the European gas grids. It has become an important natural gas source for the countries of the Pyrenean peninsula.

7 - NORTH AMERICAN GAS TRANSMISSION NETWORK DEVELOPMENT

North American gas transmission network development will be concentrated in the Mexican Gulf and Canada. New construction will be aimed at further gas supply development in the east of the Mississippi state and the southern markets where non-conditional gases are on sale.

Region	Number of projects (proposed)	Throughput	
		mln cu m/day	BCM/year
USA			
East	9	59	21.5
Center	13	74	27.0
South (southern states adjoining the Gulf of Mexico)	17	123	44.9
Canada			
West	11	122	44.5
Total	50	378 (283 - under 75% load in case construction projects will be realized)	137.9 (103 - under 75% load in case construction projects will be realized)

Table 9: Prospects for the USA and Canadian gas transmission networks' development

8 - THE PROSPECTS FOR THE WORLD GAS TRANSMISSION NETWORK

The length of the world gas lines has reached 1,255 th km. It will rise by another 43% by 2015 and will amount to almost 1,800 th km.

Region	1995	2010	2015
North America	617.9	661.3	695.1
Latin America	17.7	66.0	91.7
Europe + Russia	506.8	588.9	611.4
Middle East +Africa	25.7	90.1	123.9
Asia + Pacific region	86.9	197.9	271.9
Total	1255.0	1604.2	1794.0

Table 10: Prospects for the world gas transmission network by 2010 and 2015

Source: ENRON (USA) Fnnual report, 1997

1 trillion 246 BCM of natural gas will be delivered to natural gas markets through these new transmission systems by 2015.

Enron's forecast indicates that the volume of sales at the world natural gas market will rise from 2.0 to 4.2 trillion cu m in 2015. To achieve this volume, the following is required:

- pipeline construction rate should be increased;
- a sharp rise of gas transmission infrastructure including partial substitution of pipeline potential with liquefied gas transmission;
- combination of two or more gas liquefaction processes.

Obviously, not all the projects will be realized. Some companies may fail to achieve financing or sign contracts. The most economically efficient are the “short” pipeline construction and existing gas networks’ extension projects.

Asia, Europe, Middle East and Africa are the leaders in the pipeline construction. Over 185,000 km of new pipelines will be commissioned in South Asia and Pacific areas by 2015 which will double the pipeline throughput in the region.

According to the forecasts, the annual expansion of the world gas transmission network will amount to 27,200 km/year.

9 - NATURAL GAS UTILIZATION IN THE POWER PRODUCTION IS THE MAIN STIMULUS FOR THE PIPELINE CONSTRUCTION DEVELOPMENT

Conclusions

The analysis of the world gas transmission systems development from 1996-1998 indicated the following stable trends:

- Growth of the world gross and marketed gas production;
- Development of the hard-to-access, remote areas;
- Pipeline gas supply growth;
- A shift of new pipeline construction from Europe to Asia;
- Larger diameter pipeline construction;
- Increased operating pressure in new pipelines;
- Sub-sea pipeline construction development;
- Global integration of new pipeline systems.

The influence and development of these will continue in the first decade of the next century.

Appendix A

Region	Pipeline diameter, mm					
	101-254	306-508	558.8-762	812.8+	Total	Proportion, %
USA	721	1792	866	481	3860	20.1
Canada	436	51	2	288	777	4.1
Latin America	84	741	2606	96	3527	18.3
Asian-Pacific region (Regions east of the Urals and south of the Caucasus, excluding Middle East)	10	2825	1067	663	4565	23.7
Europe (Regions west of the Urals and north of the Caucasus)	169	1101	1351	1306	3927	20.4
Middle East	-	177	177	-	354	1.8
Africa	188	264	180	1599	2231	11.6
Total	1608	6951	6249	4433	19241	100.0

Table 1: World Gas Pipeline Construction, 1996*, km

Pipeline diameter, mm	Regions						
	USA	Canada	Latin America	Asia-Pacific region	Europe	Middle East	Africa
101-254	18.7	56.1	2.4	0.2	4.3	-	8.4
306-508	46.4	6.6	21.0	61.9	28.0	50.0	11.8
558.8-762	22.4	0.3	73.9	23.4	34.4	50.0	8.1
812.8+	12.5	37.0	2.7	14.5	33.3	-	71.7
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0

Table 2: Structure by regions, 1996,%

Region	Pipeline diameter, mm					
	101-254	306-508	558.8-762	812.8+	Total	Proportion, %
USA	933	798	2462	196	4389	24.8
Canada	637	296	359	505	1797	10.1
Latin America	1017	1421	161	180	2779	15.7
Asia-Pacific region	53	2325	916	-	3294	18.6
Europe	343	520	856	2874	4593	25.9
Middle East	16	204	-	-	220	1.2
Africa	-	31	43	573	647	3.7
Total	2999	5595	4797	4328	17719	100.0

Table 3: World gas pipeline construction, 1997, km

Pipeline diameter, mm	Region						
	USA	Canada	Latin America	Asia-Pacific region	Europe	Middle East	Africa
101-254	21.2	35.4	36.6	1.6	7.5	7.3	-
306-508	18.2	16.5	51.1	70.6	11.3	92.7	4.8
558.8-762	56.1	20.0	5.8	27.8	18.6	-	6.6
812.8+	4.5	28.1	6.5	-	62.6	-	88.6
Total:	100.0	100.0	100.0	100.0	100.0	100.0	100.0

Table 4: Structure by regions, 1997, %

Region	Pipeline diameter, mm					
	101-254	306-508	558.8-762	812.8+	Total	Proportion, %
USA	2261	462	1343	928	4994	25.1
Canada	640	137	306	80	1163	5.8
Latin America	80	190	193	243	706	3.5
Asia-Pacific region	528	3570	1176	492	5766	28.8
Europe	1654	739	156	3532	6081	30.6
Middle East	-	92	-	-	92	0.6
Africa	-	64	43	999	1106	5.6
Total	5163	5254	3217	6274	19908	100.0

Table 5: Pipeline construction in 1998, km

Pipeline diameter, mm	Region						
	USA	Canada	Latin America	Asia-Pacific region	Europe	Middle East	Africa
101-254	45.3	55.0	11.4	9.2	27.2	-	-
306-508	9.2	11.8	26.9	61.9	12.1	100.0	5.8
558.8-762	26.9	26.3	27.3	20.4	2.6	-	3.9
812.8+	18.6	6.9	34.4	8.5	58.1	-	90.3
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0

Table 6: Structure by regions, 1998, %

Region	Pipeline diameter, mm					
	101-254	306-508	558.8-762	812.8+	Total	Proportion, %
USA	103	188	1038	4264	5593	11.9
Canada	579	801	2285	4528	8193	17.5
Latin America	-	1361	1278	6840	9479	20.2
Asia-Pacific region	1353	5020	2777	2015	11165	23.8
Europe	93	948	3015	5213	9269	19.8
Middle East	840	31	267	1334	2472	5.3
Africa	-	-	-	722	722	1.5
Total	2968	8349	10660	24916	46893	100.0

Table 7: Projects started in 1998 and be completed in 1999 or later, km

Pipeline diameter, mm	Region						
	USA	Canada	Latin America	Asia-Pacific region	Europe	Middle East	Africa
101-254	1.8	7.0	-	12.1	1.0	34.0	-
306-508	3.4	9.8	14.4	45.0	10.2	1.2	-
558.8-762	18.6	27.9	13.5	24.9	32.5	10.8	-
812.8+	76.2	55.3	72.1	18.0	56.3	54.0	100.0
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0

Table 8: Structure by regions in 1999, %

Appendix B

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Report of Study Group 4.1

«Pipeline ageing and rehabilitation»

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ABSTRACT

This report describes the work on the subject “pipeline ageing and rehabilitation” carried out by the Study Group 4.1 and related to the triennium 1997 - 2000.

The report is focused on ageing and rehabilitation of natural gas transmission pipelines and more in detail on the following topics:

- Definition of pipeline ageing;
- Different ageing elements;
- Main causes of ageing;
- Inspections and monitoring;
- Repair methods on ageing pipelines;
- Programmes and strategies for pipeline maintenance and rehabilitation.

The report includes the state of the art of the different techniques used to assess pipeline ageing such as pig inspection, landslide areas monitoring as well as advanced monitoring methods used nowadays by pipeline operators; a clarification of the concepts for different maintenance approaches is also presented.

In addition the report gives some information regarding repair methods in use, the methodologies to evaluate the defects and the philosophy on which each repair system is based.

The remaining topics deal with the strategies of pipelines and coating rehabilitation, focus the attention in the economical and technical considerations also beyond the ageing concept and describe in details the main causes of ageing as indicated by operators.

A questionnaire on these topics was in fact distributed and the obtained results are included in this report.

RÉSUMÉ

Ce rapport décrit les travaux ayant pour objet le vieillissement et la réhabilitation du pipeline et énumérés par le groupe d’étude 4.1 et concernant la période 1997 - 2000.

Le rapport met l’accent sur le vieillissement et la réhabilitation des gazoducs avec force détail sur les questions suivantes:

- la définition du vieillissement du pipeline;
- les diverses catégories de vieillissement;
- les causes principales du vieillissement;
- inspections et monitoring;
- les méthodes des réparation des vieux pipes;
- les stratégies et les programmes pour la maintenance et la réhabilitation des pipelines.

Le rapport donne les règles de l’art des différentes techniques utilisées pour vérifier le vieillissement du pipeline comme par exemple, l’inspection par pig, le contrôle des zones instables et les méthodes les plus avancées utilisées à ce jour par les exploitants des pipelines. Une clarification des concepts des différentes approches de maintenance y est aussi présentée.

De plus le rapport donne quelques informations concernant les méthodes de réparation utilisées, les méthodologies permettant d’évaluer les défauts ainsi que la philosophie sur laquelle se base chaque système de réparation.

Les points restant traitent des stratégies de réhabilitation qu’il s’agisse du pipeline ou bien du revêtement, mettent l’accent, en plus du concept de vieillissement, sur les considérations techniques et économiques, en décrivant en détail les causes principales du vieillissement comme indiqué par les exploitants.

Un questionnaire sur ce point a été distribué et les résultats sont inclus dans ce rapport.

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GENERAL

Although its infrastructure has reached different age levels in different parts of the world, the gas transmission industry is generally recognised as a mature industry. As with any industry that has grown and matured, the gas transmission industry operates an infrastructure that will continue to age.

Such a vast, ageing and complex infrastructure demands a systematic management approach to ensure its integrity, especially in the light of constantly shifting population centres.

It is generally recognised that the protective capabilities of external pipeline coating system, used (in conjunction with cathodic protection) to prevent pipeline external corrosion, tend to degrade with passing time.

With this degradation of the coating's protective capabilities, the pipeline operator has to review more thoroughly those options available to ensure the continual safe and economic operation of a pipeline.

The ageing of pipeline systems and the regulatory and environmental initiatives are responsible for the increased emphasis given by pipeline operators on their maintenance and rehabilitation.

This has been attributed to ageing of the pipeline systems and more particularly to deterioration in the protective properties of the existing external pipeline coatings.

Over the last decade new maintenance scheme procedures and techniques were made operational.

As a consequence, although the average age of pipeline network is increasing, failure frequencies are constantly diminishing.

To assist in preparing a complete and up-to-date report, a detailed questionnaire on this topic was distributed to all members of IGU WOC 4. Companies from thirty-five countries responded to the questionnaire, providing very useful information. This information is included in this section.

1 - DEFINITION OF PIPELINE AGEING

We focused our attention on the definition of pipeline ageing and the relevant economical and technical considerations which are beyond this concept.

Pipeline ageing can be explained either with a general concept or with a technical definition. The following considerations show a different way to express a general concept about the pipeline ageing.

General concept of pipeline ageing

- a period of time after which the technical characteristics worsen and extraordinary maintenance costs become important thus forcing towards a reconditioning or a replacement of the line;
- from an economical point of view; the "design life" is reached when the total cost of existing pipeline (capital and operating costs) exceed the total cost of new investment.

The "depreciation period" is always taken into consideration when evaluating whether make interventions for recovering integrity impaired by pipeline ageing or to build a new pipeline.

Most companies consider that in the ageing process the growth of maintenance costs is crucial.

Technical definition of pipeline ageing

The quality of “old” pipelines, produced before the sixties or early seventies does not comply anymore with the modern standards but no properties evolution has been in general noticed.

As figure 1 shows, most companies consider that original toughness is the first steel ageing indicator, whilst the integrity of welds and coating are considered at the second place.

2 - DIFFERENT AGEING ELEMENTS

While age alone is not enough to require the need for extra maintenance, common sense suggests that with ageing, selected pipelines or pipeline sections will require increased attention.

The probability of failure due to progressive deterioration of a pipeline depends on degradation of the pipeline coating materials, corrosion, stress corrosion cracking, all of which are affected by the breakdown of the cathodic protection effectiveness.

Pipeline failure rates are best considered in terms of the probability of failure versus time: failures occurring at an initially high rate due to construction around the pipeline, followed by a constant (and low) rate of failure during operation of the pipeline, and consequently the “wear out” phase.

From an engineering and economic standpoint the onset of the wear out phase should correspond to the design life of the pipeline.

Pipeline age is therefore a significant factor in terms of likelihood of failure.

2.1 - Pipe steel

The technologies and materials used in old pipeline construction may be considered of low level compared with the standards applied today. They usually contained high impurities level (phosphorus, sulphur) and were produced with not constant rolling temperature range.

These older pipelines were made of steel having low toughness and yield strengths and consequently require more attention.

In addition to this, the problem of brittle fracture has sometimes been encountered with some producer due to faults in early pipe production.

In order to solve these problems, a new family of steel pipes has been developed, with a high toughness and yield strength which are the current design choice for new gas pipelines.

2.2 - Welding

It is acknowledged that girth welds in “old” pipelines might have suffered from effects of strain ageing and associated embrittlement during installation (as a result of weld thermal cycles, high plastic straining in the root area at elevated temperature and the presence of nitrogen).

The processing of precipitation is normally slow, but it can be faster sometimes only in local points, where the temperature abnormally increases during the welding process. In this case, the welding is likely to suffer from an artificial ageing.

In general, the melted zone is harder than pipe steel, consequently it has a minor precipitation and therefore it becomes less brittle.

The HAZ (heat affected zone) would not show any particularly different performance than the pipe steel. The heating of this zone during the welding is so short in time that it would not to be able to create any problem.

Some problems, however, can develop during the welding of thicker pipes. In this case the post-heating can produce an artificial ageing of the welding.

In addition, during different layers of welding formation, the heating and cooling produce an ageing due both to the compression strain and the thermal cycle.

Furthermore the welded joints can have a performance which is more sensitive to ageing than pipe steel if the weld pool is not protected against the contamination of the atmosphere. It is necessary to note that during the welding phase, it is very important to protect the weld pool against the external agents.

Another important factor of weld ageing is a decrease in plasticity.

On the other hand, yield and tensile strength of girth welds in “old” (low strength) pipelines is significantly higher than the strength of the pipe metal (“overmatching”).

2.3 - Coatings

It is generally recognised that the protective capabilities of external pipe coating systems tend to degrade with time.

The speed of this phenomenon is affected by the soil characteristics, laying methodologies and materials used.

Coating materials and application technologies used in the past had poor quality control, especially for field applied coatings, and for mechanical operations around coated pipes.

The result is that the coatings of many pipelines needed to be rehabilitated in the early nineties due to coating degradation.

Some pipeline elements had coatings with more susceptibility to degradation:

- hand applied bitumen coating on pipes, bends and field joints is not able to withstand soil stress, water and chemical aggression;
- bend obtained from pipe cold bent in field. This operation on bitumen coated pipes produced cracking and disbondment from the steel, with consequent water infiltration and absorption. This effect was especially recorded on pipes laid with hard environmental conditions, due to the poor mechanical properties of the coating;
- pipeline coated directly over the ditch with cold machined tapes presented many large disbondments, long wrinkles and damage to the steel, from corrosion, due to the poor application (surface preparation, tapes tensioning, lack of primer);
- hand applied material on field joints (bitumen, coal tar, tapes, very low grade shrinkable sleeves, petrolatum) gave rise to corrosions due to a combination of poor quality of the materials and poor quality in application.

The ageing process is generally accelerated by soil characteristics (bacteria activity, water table variability) and third party interference (agricultural activity, proximity to other pipelines etc.).

According to pipeline operator’s experience, the greatest concerns on coating degradation are coating embrittlement and disbondment, as shown in figure 5.

3 - MAIN CAUSES OF AGEING

Environmental conditions along pipeline route are among the major causes of ageing. Most ageing factors are related to:

- type of soil (swampy areas, presence of clayey soils, water table presence and its variability etc.);
- third party interference (mechanical damage, construction works around the pipe etc.);
- soil instability;
- chemical or electrical pollution (presence of petrol products, presence of AC induced voltages or AC/DC stray currents).

Based on the case histories of pipeline's operators who responded to the questionnaire, as reported in figure 2, main causes of ageing for on-shore pipelines are:

- coating degradation;
- corrosion;
- variation of load;
- pipe manufacturing.

During pipeline operation, cyclic variation of pressure and temperature are considered to be among the worst factors which can cause ageing.

All the above mentioned ageing elements can cause a drop of performance and possible cut-outs with important consequences to the continuity of gas supply and relevant costs.

3.1 - Coating degradation

The extent and significance of corrosions that can occur on pipelines depend on a variety of factors including the type of coating, its condition, cathodic protection system type and status, and soil corrosivity.

The characteristics of the major coating systems are reported below.

Bitumen

Bitumen (or asphalt) based coatings have been used all around the world on gas pipelines. It represents a great deal of existing coatings on gas pipelines.

Main ageing factors are:

- embrittlement at temperature below 15°C. This produce many damage during pipelaying and during service life (soil and pipe movements, vibrations and interference with root of plants). These stresses produce coating disbonding and cracking;
- softening with temperature above 30°C. This can reduce the mechanical resistance producing disbonding, squashing and perforation;
- poor application and surface preparation in case of manual application;
- bacteria activity in the soil (see PE tape coating) when coating is disbonded;
- chemical pollution in the soil.

Typically the main defects are produced by a loss of mechanical properties as consequence of temperature out of range.

PE tape coating

PE tape coating is used in many gas transmission companies all around the world. Mainly in Central and Eastern Europe it represents a great deal of the total amount of coatings.

For this coating the main ageing factors are:

- hardening and loss of flexibility after 20-30 years of service, due to the loss of plasticizers in the materials; these effects can be also due to high service temperatures (around 50°-60°C)
- Pipeline or soil movements that can produce shear stress, wrinkles and disbonding of the coating
- Poor application (poor surface preparation or tensioning during wrapping) can accelerate degradation
- Bacterial activity in the soil. Bacteria can easily reach the steel and accelerate corrosion.

Epoxy and Polyurethane based coating

Epoxy and polyurethane based coating has been used around the world for about 20 years and the principal ageing factors are:

- Poor applications (poor surface preparation) that can accelerate degradation;
- Type of soil (heavy soil);
- Chemical soil quality and bacteria activity;
- Pipeline or soil movements that can break coating layers (cracking);
- High service temperature, especially in wet conditions.

Manufactured coating: Extruded coatings (polyolefine based) PE-PP

Polyolefine extruded coatings have been used all around the world for about 20 years.

The principal ageing factors are:

- Service temperatures when close to upper or lower limits (fragility at very low temperature < -30°C);
- Type of soil;
- Possible lack of protection (from CP system) for very small holidays.

Referring to the experience of all around the world, the most flexible coating to solve corrosion protection problems is polyolefine based coating, particularly three layer extruded polyethylene (with wide range in operating temperatures it is possible to maintain all the technical properties as adhesion to the steel, flexibility, impact and indentation resistance and electrical insulation).

Field joint coating (girth weld)

Pipe cut-backs to be coated in the field is the main element that can decrease the final quality level and pipeline reliability.

Poor application and low material quality can affect the duration of the structure in terms of service life time.

Overlapping between field applied coating and mill coating can produce air voids and/or air entrapments. These points can decrease the impact resistance and make the coating more brittle and soil movement sensitive.

Moreover, high service temperature, humidity, stones and generally heavy soils can produce the best conditions for corrosion due to shear stress and penetration.

Tapes and liquid coatings can produce the above mentioned problems.

The best coating to avoid this phenomena is probably the heat shrinkable sleeve with hot melt adhesive and epoxy primer, that can flow on the steel, filling up all surfaces and providing anticorrosion protection by epoxy layer.

The final conclusion is that coating main degradation factors for coatings are:

- Poor application, not detectable with field inspections, and consequently decreases in coating resistance;
- Soil movements or heavy soil effects;
- High service temperatures;
- Chemical or bacterial activity in soil.

3.2 - Internal and/or external corrosion

When a pipeline fails, the consequences can be very serious. Unprotected pipelines, whether buried in the ground, exposed to the atmosphere, or submerged in water are susceptible to corrosion.

Without proper maintenance, every pipeline will eventually deteriorate. However, technology exists to extend pipeline structural life if applied correctly and maintained consistently.

Internal or external corrosion may produce the complete shutdown of a pipeline, the reduction of operating pressure or pipe replacement. According to world pipe corrosion statistic data, pipes coated by manufactured coating can resist corrosion activity for many years.

The WOC 4 - SG 4.1 defined corrosion probability of pipelines according to different type of coatings after many years in use.

Internal corrosion of gas pipelines is very rare and can be found on irregularly cleaned pipes or in pipelines used for wet gas transportation.

Tape coatings seem to be the major concern for pipeline’s operators as, in particular conditions (clay soils, improper cleaning of pipe steel, incorrect application) they are bound to suffer from disbonding. This type of defect can be very dangerous due to the fact that the tape hinders cathodic protection current to reach the metal. On the other side, bacteria activity can develop in the metal/coating interface where electrolyte can penetrate.

Stray currents from DC systems is one among major factors influencing corrosion likelihood of pipelines.

In stray current areas, pipelines’ cathodic protection monitoring is usually more stringent and accurate. Drainages are often used in these cases to return DC current to the original source. Both maintenance measurements and the control of correct working conditions of drainages are of great importance in the corrosion control of buried pipelines.

In the last years, a new phenomenon is becoming increasingly important: AC influence. This is mainly due to capacitive, resistive and inductive influences on pipelines due to parallel High voltage electricity power lines or AC traction systems.

Among the factors which contribute to increase a.c. voltages on buried pipelines there are the growing number of High Voltage Power Lines, the installation of High Speed Traction Systems operated with a.c., together with the increased use of high quality coatings, such as three layer polyethylene.

These induced AC voltages on one hand create safety problems for the personnel and on the other may produce corrosion, when current density exchanged in the electrolyte/exposed steel interface exceeds 30 A/m^2.

When pipelines are influenced by AC voltages, traditional pipe to soil potential measurements do not guarantee an efficient cathodic protection against corrosion; additional measurements and specialised/dedicated electrical surveys are performed in these cases. The use of dedicated apparatus such as AC discharge devices, grounding systems and spark gaps are of great importance in these conditions.

3.3 - Stress Corrosion Cracking

Stress corrosion cracking (SCC) is a corrosion phenomenon associated with many different factors among which the most important are:

- mechanical stress, especially when induced by cyclic variation of gas pressure;
- defective cathodic protection, coincident with coating faults (coating defect/disbonding, shielding of the protective current);
- type of electrolyte.

Two types of SCC are known: High pH SCC or Near Neutral (Low) pH SCC.

The mechanical stress may be the result of residual stresses due to welding/coupling operations during construction, induced by land slides, soil movements or subsidence, or by variation of gas pressure.

Usually, the principal orientation of the cracks is perpendicular to main stress direction.

Due to the branching of different smaller cracks which initially grow on the pipe wall surface, a leak is usually the result when the stress is longitudinal to the pipe (e.g. such as the one induced by a landslide) but a break can be expected when the main direction of the stress is radial (e.g. such as the one induced by cyclic gas pressure variations).

High pH Stress Corrosion Cracking - general conditions for the occurrence

• pipe grades:	grades B through X70
• mechanical stress :	> 35% SMYS)
• operating temperature:	> 35°C
• electrolyte:	CO3 and $HCO3^-$ – presence of carbonate and bicarbonate ions
• pH conditions:	> 9
• crack nature:	primarily intergranular, either 90° or 45° to pipe surface
• location:	greatest probability of occurrence at high temperature and pressure, (e.g. immediately downstream of compressor stations)
• potential range:	-0.60 to –0.75 V (SCE)
• type of coating:	bare pipe, PE tape, asphalt, coal tar
• crack appearance and occurrence:	colonies of cracks deeper and widely spread than Low SCC

Near-neutral (Low) pH Stress Corrosion Cracking - general conditions for the occurrence

• pipe grades:	X52 through X65
• mechanical stress:	> 45% SMYS
• operating temperature:	<40°C (no temperature influence)
• electrolyte:	H_2CO3^{--} (presence of carbonic acid)
• pH conditions:	between 6 and 7
• crack nature:	usually transgranular with some intergranular, generally 90° to pipe surface
• location:	at any point along the pipeline where conditions may exist
• potential range:	free corrosion potential
• type of coating:	usually tapes, asphalt
• cracks appearance and occurrence:	colonies of shallow cracks, often associated with general corrosion

HIC and HISCC Hydrogen induced cracking and hydrogen stress cracking

Hydrogen Stress Cracking is not a general problem in natural gas transmission pipelines.

However, Hydrogen embrittlement may occur where hard spots, hard weld zones or mechanical damages coincide with a coating fault (namely, a lack of the coating).

Hard spots may be caused by construction, whereas the hard welded zones may be produced during the pipe manufacturing process.

They can produce typical risk factors for HIC/HSCC phenomena: the formation of a brittle (often longitudinal) portion of the pipe wall, a local stress concentration and a loss of coating with CP current absorption and hydrogen charging of the relevant bare metal.

The time period for the crack initiation would be in the order of several years (delayed fracture).

Hydrogen produced due to overprotection during the cathodic process, diffuses into the steel, embrittling the structure thus reducing its capacity to withstand hoop and residual stresses.

The risk is higher at hardness greater than 360 Brinell (ultimate tensile strength greater than 175 ksi).

A fault location survey may easily locate these faults; repairing them prevents brittle zones to absorb further hydrogen.

Cracks can easily be found by ultrasonic pigs. In order to use ultrasonic a liquid batch is necessary, hence the difficulty of detecting cracks on gas pipelines. Existing MFL pig can hardly detect cracks, especially the longitudinal ones.

Studies are in course for developing new types of pig having a different direction of magnetic field (radial, instead of longitudinal) for finding transverse cracks.

3.4 - Mechanical damage

Mechanical damage due pipe movements are generally connected to extraordinary events (environmental and meteorological).

Dents

When the size of the dent is not in the acceptable range, the cut out of this part of the pipe is imperative. It may happen that during excavation of this part of spool the dent releases becoming smaller and no more dangerous for inspection and cleaning operation (pig blockage).

Unless ultrasonic controls show cracks, this type of defect usually is not repaired.

Dent with metal loss

In these cases investigations are needed from two points of view : the severity of metal loss and dent depth.

According to proven tests and computerised methods (i.e. finite element methods), the severity of these defects can be evaluated by calculating residual and safety pressure and consequent decisions may be taken.

The combination of dents with gouges join a variable stresses are a formidable threat to the long term integrity of ageing pipelines.

Dent in the weld

This is considered a special case of damage; the steps to be followed are similar to the above.

Gouges

Gouges can eventually produce cracks which may give rise to what is generally called “delayed fracture”.

Gouges of pipe wall may have various origin:

- careless handling during construction, repair or digging works in the vicinity of pipes;
- pipe movements due to soil instability, landslides, temperature variations which comes in contact with stones or rocks which can scratch the pipe wall;
- insufficient soil covering of pipe. In this case heavy machines used for ground movement or agriculture may scratch the top of the pipe.

In order to prevent mechanical damages, the pipeline route is monitored at regular frequencies by helicopter or by visual inspections. In these last years, monitoring by satellite is also becoming a quite reliable and affordable method.

Due to the intrinsic difficulty and crucial importance of correct assessment of the severity of mechanical damages, pipelines operators often establish collaborations with Mechanical Institutes/Research Centres.

Mechanical damage like dents, pipe wall deformations etc. can be very easily detected by caliper pig. Other mechanical damage such as gouges, can only be detected by using intelligent pig.

Until now, no commonly defined rules for assessing the severity of mechanical damages and consequent repairs have been adopted by pipeline operators.

Some specialised organisations are at present preparing rules which could be universally accepted by all pipeline operators.

3.5 - Landslides and soil subsidence

This is a typical problem of pipe network in hilly or unstable flat areas.

The stresses created by movement of the soil in addition to the stresses due to the internal pressure can be the reason of the pipeline damage.

Experience has shown that higher stresses are due both to the movements of the soil along the pipes and to direction changes of the pipes themselves.

Moreover, slow movements of the soil (a few cm/year) but repeated over time, could be detrimental to the integrity because they constantly increase the stresses on the pipe and the operator should be aware to detect these slow movements.

4 - INSPECTIONS AND MONITORING

The control and the maintenance of pipeline's integrity is achieved by the use of different monitoring tools. A careful organisation and the synergistic use of different techniques is essential in order to reach cost-effective results and performance.

A complete inspection and monitoring strategy generally includes:

- Cathodic protection monitoring (electrical measurements, route inspection, remote control by telemetric apparatus etc.);
- Electrical surveys (eventually performed on selected sites);
- Visual inspections (either by walking along or flying over main pipelines);
- Monitoring of soil stability (remote or local control of known land slides);
- Excavations for coating inspections in suspicious areas (after specialised surveys);
- Metallurgical investigations for pipe steel and weld metal deterioration (when excavations are made);
- Intelligent pig inspections (the choice of pipes and frequency of inspections are made according to a risk priority evaluation).

While coating fault location methods give a picture (foot-print) of coating conditions (i.e. C.P. current demand, risk of stray current due to electrified railways which releases currents into the soil etc.), intelligent pig inspections give a complete picture of the conditions of the metal of pipe wall.

As already said, various events could impair a pipeline's integrity.

For pipelines which cannot be inspected by intelligent pig, external surveys and electrical measurements have no alternatives and can be used to evaluate whether a pipe could be modified and adapted to pig inspection or to start a preventive rehabilitation program to ensure the integrity.

Figure 3 shows ageing assessment technologies mostly used by operating gas companies.

Due to huge costs sometimes involved, the frequency of each monitoring activity is an important element to be carefully evaluated.

For example most of companies use intelligent pig inspection with a frequency ranging between 5 and 10 years; other companies use a frequency based on the results of previous inspections.

A strategy of periodic internal inspection, followed by integrity assessments using fitness-for-purpose criteria and selective remedial action, is the most cost-beneficial way of improving the performance of ageing pipelines.

4.1 - CP monitoring

Cathodic protection has been in use around the world for many years. This is a very important part of corrosion protection of pipes. Monitoring of CP potential/current values and the control of CP systems and relevant devices (CP feeders, drainages, test points, insulating joints, ground beds, spark gaps, earthing systems, etc.) can provide a reference base for the personnel technically involved.

Every change in the electric status of a CP system previously measured/recorded must be verified, as any change in the electrical characteristics of the pipeline has a reason which may be tied to changes in pipeline characteristics or to environmental conditions.

Coating faults (which may result from mechanical damage, landslides or soil instability), metallic contacts, electrical interferences may produce a variation of the electric status of pipelines thus invalidating cathodic protection effectiveness.

Generally, a survey for assessing coating conditions is performed immediately after pipe-laying.

Analogous surveys performed some years after the laying (e.g. three to five years), can be of great help for assessing CP conditions along the entire pipeline and is a base reference in case of future changes of coating conditions.

Methods exist nowadays to accurately locate every (even small/very small) coating fault (e.g. Transverse or Longitudinal Gradient measurements or intensive pipe-to-soil potential measurements). Other systems give a rough indication of CP currents absorbed by different sections of pipelines (e.g. Electromagnetic Current Attenuation Methods).

All these methods allow pipeline owners to review the conditions of pipe coating and, indirectly, to be warned when the pipeline steel may have been mechanically damaged by operating machines or other types of interferences by third parts.

In the last years, the huge development of data transmission systems such as GSM (Global System Mobile) or LOS (Low Orbit Satellite) allow the remote control of CP Systems at low cost.

These technologies allow a continuous monitoring of CP Systems, a better overview of the effectiveness of cathodic protection, the control of main parameters and the instantaneous detection of malfunctions or failures.

Especially on stray current influenced pipeline networks, a remote control system allows functional checks and routine measurements for CP effectiveness to be made on demand, automatically at pre-set intervals or when an alarm condition exist, thus reducing the costs and improving the overall quality and safety of CP Systems.

4.2 - Electrical surveys

Both during construction and operation a pipeline’s coating could have been damaged. Construction coating defects can be formed by incorrect handling and lowering procedures. During the hydraulic test damage to the coating can be produced, due to weight of water filling the pipe.

During operation, the coating could be damaged by stones or hard soil in the trench due to pipe movement, especially nearby compressor station, where the gas temperature is higher. Third party activities or soil movements can also damage pipeline’s coating during operation.

Electrical surveys for fault location on pipeline areas affected by possible third party activities are generally performed to ensure that no damage has occurred on the pipe.

Electrical surveys allow early detection of steel surfaces contacting the electrolyte and possible associated mechanical damage that occurred just before or during the pipe-laying.

Two results arise from these surveys:

- a better general quality of coating;
- a coating which is virtually immune from any coating defect.

On existing pipelines, a variety of different electrical surveys can be performed in order to:

- assess the pipe current demand on different sections of pipe;
- detect areas of anomalous trends of current demand and/or potential levels;
- detect areas mostly influenced by stray currents (for example to install insulating joints at appropriate positions, provide new CP stations where necessary, modify the electrical asset of CP System, provide the rehabilitation of the coating where needed).

4.3 - Pig inspection

Although monitoring methods are progressively improving as a check for pipeline integrity, in-line inspections by using intelligent pigs have proven to be a valuable complement of the condition-monitoring system and can be considered an important tool to help defining the status of a pipeline.

Various types of pigs are nowadays available, which have different capabilities. They are normally pushed by the transported product.

Traditional MFL pigs can not detect longitudinal cracks. Transverse cracks could be detected if the crack is in an advanced status (open cracks). On the contrary, cracks can be easily detected by ultrasonic pigs. For ultrasonic measurements a liquid contact between sensors and pipe wall is necessary. This means that in order to use ultrasonic pigs, a liquid batch is necessary. After this type of inspection, cleaning pigs are to be used in order to fully eliminate liquid in the pipe; a careful control of the chemical composition of the gas is also needed.

New technologies are in progress, using transversal MFL to detect longitudinal defects.
For corroded pipelines, the MFL method is best. Many companies can provide the inspection equipment with different resolutions.

Criteria for the detectable metal loss size are different for pitting and general corrosion. It depends on the grade of steel, wall thickness, diameter of pipe, pressure ratio, etc..

The earliest pigs were used simply to remove any deposit of dirt in order to maintain a flow through the pipeline. Today, pigging can be used during each phase in the life of a pipeline, for many different reasons, such as:

- during commissioning (removing construction debris, acceptance testing, etc...);
- during operation (pipe cleaning, product separation);
- for inspection (to detect physical damage and corrosion).

In short, pipeline pigs help to ensure that the pipeline is constructed properly and is well maintained.

4.3.1 - Kaliper pig

One of the oldest methods for checking whether deformations of pipe diameter exist is by using gauging pigs. This is a pig with a metal plate whose diameter is a percentage (usually 95%) of the nominal inside diameter of the pipe. If the gauging plate is damaged, the operator has to find out where this deformation is. In order to solve this problems, kaliper pigs are used.

This type of tool locates and measures reductions in diameter of the pipeline, caused by factors such as ovality, dents, partially closed valves. There are two basic technologies which are used for geometry survey: electro-mechanical and eddy currents. In the first case, changes of the internal diameter are detected by arms or fingers which are spring loaded in order to keep them pressed against the pipe wall. Any change in diameter causes these arms to move and this motion is converted into an electrical signal, which is digitally recorded.

Eddy currents are electrical currents which occur when an alternating magnetic field is induced into the pipe wall; these currents are affected by any changes in the geometry of the material.

4.3.2 - Magnetic Flux Leakage pig (MFL)

The MFL tools are fitted with two rings of magnets, spaced apart and with opposing poles to induce a magnetic flux into the pipe wall. Sensors are mounted between the poles to detect any flux leakage which occurs due to thinning of the wall. It is important to saturate the pipe wall so that any metal loss will cause flux leakage. This requires very powerful and often very large magnets, held in close contact with the pipe wall. The accurate identification, sizing and location of defects is a fundamental requirement and involves a lot of high powered computer processing.

The Magnetic Flux Leakage (MFL) is able to detect:

- Corrosions;
- Mechanical damages (such as those due to third party interferences, dents, gouges or both dent and gouge);
- Material and construction defects which have survived to hydraulic test;
- The presence of metallic objects nearby or touching the pipe;
- Casings and their possible contact with the carrier pipe;
- This type of pig is also able to detect valves, bends, fittings, welds and most of the mechanical features of a pipeline;
- It is also able to distinguish external and internal corrosions.

Many companies can provide the inspection equipment with different resolution.

For assessment methods such as the R-STRENGTH, the use the High resolution inspection equipment with the range of accuracy for depth of defect up to ±10% of nominal wall thickness is required. For the correct data assessment of serious and dangerous metal loss we have to know exactly the profile of the feature known as "river bottom". This information can be provide by only with high resolution (e.g. HR MFL) equipment.

Low Resolution (LR) inspection equipment can be used for base monitoring of very severe defects because the sensitivity and accuracy is about ±20% of nominal wall thickness.

4.3.3 - Ultrasonic pig (UT)

In this tool a transducer emits a pulse of ultrasonic sound which travels at a known speed. On entering the pipe wall there is an echo and another echo as the pulse reflects off the wall. The time taken for these echoes to return provides a virtual direct reading of the wall thickness. The most important drawback of this tool is that the sound will only travel through a liquid. A gas pipeline can be inspected by a UT tool, by running batching pigs in the line at the end of a slug of liquid in which the UT tool travels.

A great advantage of this method is high accuracy and possibility of crack detection and sizing.

4.3.4 - GPS (Global Positioning System) pig

This tool is used to detect any movement of the pipeline, due to subsidence, landslides, earthquakes, erosion. To monitor the profile of a pipeline the pig must be capable of measuring and recording its position in all three axes on a continuous basis, by using an inertial navigator system on board the tool. These systems rely on gyroscopes and the technology and equipment is sufficiently advanced to be used as the basis for monitoring the profile of a pipeline. Recent developments include a positioning system utilising satellites in geostationary orbit.

GPS module can be fitted to any type of pigs like profile pig, MFL and US.

4.4 - Landslide areas monitoring

Experience has shown that it is possible to operate pipeline networks safely even if they cross landslide areas.

Depending on how critical the crossed area is, measures may vary from simple periodical site examination by visual inspection, to instrumental monitoring of both the area and the pipeline. Real-time continuous transmission of monitored data allow a correct organisation and economic management of checks and corrective measures.

The purpose of monitoring is to keep the critical areas under control. One way for observing the movement of pipeline is the direct geographical measurement: two reference static guaranteed points are generally needed: one control point (base) and additional control points along the pipe. The number of points depends on the length of the monitored pipeline.

Referring to the results, additional stresses from differential length between points on the pipe can be calculated by comparing previous measurement.

In order to monitor the movement of the soil and the stresses induced on the pipes appropriate equipment is generally installed both around the pipeline route (inclinometers, piezometers and rain gauges) and on the pipelines themselves (strain gauges).

An important development in monitoring system is the automatic data acquisition and real time transmission. This technology has already been applied in certain geological risk areas.

The management and monitoring of pipelines in unstable areas can be nowadays achieved by using decision support systems: they include different methods and tools such as Geographical Information Systems (GIS), expert models based on the relation between rainwater and soil movements and knowledge management expert systems.

Moreover, studies are on course to use interferometric data from satellites to identify and measure ground movement along gas pipelines.

5 - REPAIR METHODS ON AGEING PIPELINES

Operator should consider inspection as a key part of an overall strategy to ensure the integrity of ageing pipelines. Internal high-resolution inspection devices can accurately establish the condition of the pipeline. Subsequent analyses can define rehabilitation requirements, repair methods and relevant timescales.

For rehabilitation assessment, most of companies use ASME B-31.G code.

Currently, many gas transportation and distribution companies start using the R-STRENGTH method, which allows a more accurate evaluation of remaining strength of the pipe. Nevertheless, this method needs high quality data only given by high resolution inspection equipment which is very expensive. Some companies have got the impression that these standard methods are not suitable for all kinds of defects and consequence most of them use finite element method for assessment of defects.

Different types of repair are used according to severity of corrosion features. A correct assessment of corrosion feature severity is therefore a key factor as repair methods may have very different costs.

Fitness-for-purpose methods are now available which allow the operator to relate the severity of any defect to the pipeline operating conditions and plan future safe operating strategies.

Most companies are provided with a set of guidelines to help them match the appropriate repair method with each pipeline damage and repair circumstances. They have developed, formulated and field-tested their own repair methods. In most cases these repair methods have not to be approved by authorities or government bodies.

Most companies use cut out, mechanical clamps and full welded shells, as shown in figure 4.

For repairing the most common anomalies they use a detailed repair manual which sets out the procedures for repairs. Other international surveys indicate similar repair methods.

In particular, gas companies carried out a similar repairs when the damage was:

a) to the external coating;

b) leak damage.

With regard to point a) all companies use wall checks and re-coating, while for point b) they usually adopt the cut-out method for permanent repairs. The repair methods, for the other type of damage, will depend largely on the damage assessment and criteria used by individual companies.

Most companies use welded sleeve and cut-out methods when the risk associated with the damage becomes greater.

During the repair operation most companies reduce the operating pressure. The level of pressure reduction depends on a number of factors, however, it is usually reduced by 10% to 20% of the actual operating pressure.

Most companies adopt repair method according to following:

- cut-out;
- welded sleeves;
- epoxy-filled sleeves.

With reference to the above, it is more common to have severe outside damage to the pipe wall.

Most companies use their own personnel to perform certain repair. This reason for this are:

- the availability of trained company personnel;
- familiarity with the equipment;
- cost effectiveness and speed.

However, there is a tendency towards the use of external contractors as most companies are ready to subcontract the installation work of the repair system to such operators for the following reasons:

- company philosophy (outsourcing of specialist work);
- reduction of company work-force;
- it does not make sense to provide special training for internal personnel for works which are rarely performed.

6 - PROGRAMMES AND STRATEGIES FOR MAINTENANCE AND REHABILITATION OF PIPELINE

Pipeline rehabilitation is referred either to restoring the technical characteristic of the pipe when costs in maintaining pipeline integrity becomes too high or to improving the existing state of the pipe to allow it to operate at MAOP (Maximum Allowable Operating Pressure) in optimised economical conditions.

After the pipeline has been rehabilitated and an assessment has confirmed that the pipeline is fit-for-purpose, a maintenance plan (inspection, assessment, repair) can be defined to ensure continuing fitness-for-purpose.

6.1 - Maintenance approach

A topical concern is life extension of older pipeline systems. A procedure based on high-resolution internal inspection followed by expert fitness-for-purpose assessment is the recommended method for extending the life of older pipelines.

Maintenance is defined as a process to keep pipeline performance within safety and reliability standards. Maintenance is necessary to highlight defects in order to prevent further development of a condition that could result in a failure or threat to the pipeline integrity.

The objectives of the maintenance are:

- to minimise the normal wear during life time of a pipeline and its equipment (valves, traps etc...);
- to detect in an early stage an anomalous/unusual condition on/at the pipeline and in the vicinity of the pipeline;
- to restore (before repair) the original status of the pipeline;
- to prevent external interferences.

Figure 8 shows the maintenance approach adopted by the gas companies to ensure continuity of supply and safety.

Preventive maintenance is prevailing whilst the predictive approach is growing among gas companies.

The predictive approach to maintenance is difficult to achieve and needs information which may be difficult to collect. A systematic data collection and relevant failure analysis on previous cases is essential in order to address the predictive approach towards the components/systems which had failures. Expert systems are being developed in the last years which allow a quick use of the information available from “case history”.

Predictive maintenance has a higher initial costs but in the long run is cheaper than the other approaches.

The corrective approach is only allowed when other approaches are missing or fail or if the consequences are acceptable.

6.2 - Pipeline rehabilitation

When and where aged pipelines are to be rehabilitated or replaced are questions which do not have set answers. Each situation must be evaluated in terms of specific local conditions and the type and amount of information available.

Pipelines must be capable of withstanding the maximum operating pressure (MOP) with an acceptable safety level.

The pipeline rehabilitation will depend largely on the damage assessment and acceptance criteria and environmental safety used by individual companies.

Data Bases containing Technical Characteristics, records of previous interventions and other historical data of a Pipeline System are of great importance for maintenance and rehabilitation purposes.

Prior to any decision on whether to continue to operate the pipeline "as it is", replace or rehabilitate the pipeline, the operator needs to establish a data-base of information on the physical integrity, protected status and environmental safety of the pipeline.

Furthermore the pipeline rehabilitation, if it is a part of a company program, depends on the maintenance strategy adopted by the companies.

Evaluation of the overall integrity of pipelines

The synergistic use of different techniques allows an overall evaluation of pipeline's integrity.The evaluation of different parameters deriving from:

- CP monitoring (routine maintenance or intensive measurements);
- Coating conditions (specialised surveys);
- Metal conditions (intelligent pig inspections);
- Soil information (landslide, soil stability, urban areas vicinity).

allows appropriate interventions such as:

Safety rehabilitation of pipelines

- coating repair;
- pipeline repair;
- replacing pipe with increased thickness at specific locations;
- spool replacement;
- laying of alternative pipeline to be far from urban areas;
- construction of mechanical protecting devices (casings, artificial tunnels);
- release of mechanical stress on the pipe by excavation in appropriate position.

Interventions for external safety

In order to maintain:

- minimum soil cover;
- safety condition according to National Standards.

Different measures can be taken such as:

- install the pipe inside casings or reinforced concrete tunnels;
- provide an alternative routing;
- provide protective actions:

* increase coating thickness;
* increase pipe wall thickness.

Modern technologies allow the computerised use of data deriving from kind of surveys.
GIS (Geographic Information Systems) can easily be used nowadays with low cost among most gas companies.

Starting from the georeferenced maps in a GIS representation, all the information regarding a given pipeline can be treated in alignment sheets which allow the contemporary view of different data which are of interest for pipeline integrity.

6.3 - Coating rehabilitation

For the purpose of this chapter, coating rehabilitation includes the steps taken by a pipeline operator to return a pipeline to normal service after degradation of the coating has been discovered.

Different pipeline operators will use a different type of coating for rehabilitation depending on the operator's policies.

Figure 6 shows the types of coating used for rehabilitation. Although bitumen is the most common system for rehabilitation, its long term performance, particularly in aggressive soils is questionable. In fact it is sensitive to temperature, has relatively poor ageing characteristics and its application (manual) is unsafe and low quality.

Polyethylene tapes and other tape systems permit rapid coating and re-burying of the pipe. In general, however, they have not provided long term protection, being prone to soil stress and cathodic protection shielding.

New epoxy and polyurethane based coatings are becoming more used, using improved field technologies for cleaning and coating (applicable by brush or spray systems). They have better performance characteristics and better versatility with special formulations for individual applications. Their single components are somewhat toxic and more expensive than conventional coating materials.

As with all pipeline and coating operations, an accurate account of the coating rehabilitation processes must be incorporated into the pipeline system's data base.

6.3.1 - Coating removal

The removal of exiting (deteriorated) coatings from pipelines may be achieved in a variety of ways, including:

- manual (most common system);
- sand blasting;
- mechanised scrapping off the coating;
- high pressure water jetting of the coating.

The method of cleaning which is chosen depends on whether the pipeline is in or out of service, and the type of refurbishment coating that is to be used in rehabilitation the pipeline. With the exception of sand blasting, little information on the effectiveness of the different cleaning methods exists.

Most companies, as shown in figure 7, used manual methods to remove old coating from their pipeline.

Mechanical equipment's and systems are preferred for large scale and sections of rehabilitation.

6.3.2 - Surface preparation

Mechanical abrasive blast cleaning of line pipe prior to the application of the external pipe coating is now something of a standard procedure in the construction of new pipelines.

Similarly, manual cleaning and sand blasting are the most common systems used in the field to prepare the surface of the pipeline.

External pipeline coating rehabilitation, by virtue of the field environment in which the process is undertaken, is likely to promote the presence of contamination on the cleaned pipe surface. All contaminants must be removed from the pipe surface to ensure the rehabilitation coating's performance.

6.3.3 - Re-coating

The need for pipeline rehabilitation is due mainly to the failure of existing coatings on pipelines which, with the passage of time, do not continue to effectively isolate the pipeline from its surrounding corrosive soil environment.

Generally, the need for external pipeline coating rehabilitation exists because of:

- coating unsuitable for the service conditions;
- poor pipe surface preparation or coating application;
- poor construction and installation standards;
- the coating did not meet the imposed pipeline operational requirements.

All these factors may be associated with older pipelines and the older pipeline coatings used on them.

Despite the numerous problems with tape coatings, including soil stress and cathodic protection current shielding, bitumen and tape coatings are still frequently used.

The basic requirements of a rehabilitation coating, apart to satisfying those standards requirements of cathodic disbonding resistance, adhesion, flexibility, etc.., are the ease of handling of coating materials and related application equipment, low health hazard level and quick set-up times.

The epoxy and polyurethane based systems are becoming increasingly popular rehabilitation coatings. These system offer better performance characteristics than conventional tape and bitumen coating systems, and a greater versatility in terms of formulation to meet the needs of the pipeline engineering.

CONCLUSION

During the construction of pipelines, the gas industry uses the best available technical specification, design, material selection, manufacturing, quality of coatings, welding, types of safety equipment and methods of construction. During pipe life the operator will maintain this high level of integrity by the application of standards and codes. Thus ensure high levels of safety and minimise the risks to man and the environment.

Pipeline operators use a variety strategies aimed at:

- technical safety;
- pipeline integrity;
- management system;
- emergency planning.

Careful construction and operation pipelines system provide a safe and continuous supply of natural gas.

Pipeline operators are proactive in reviewing and improving their procedures for ensuring that the pipeline systems are maintained in fit-for-purpose conditions. Records are retained to demonstrate good engineering practice during normal operation and record relevant information about the pipe safety (i.e. coating, welds, corrosion, aggression points, stresses etc...). Careful review of historical data covering 20 to 30 years of the pipe life provides an excellent estimate of the pipe status with a good confidence level. When necessary, a few additional visual or non destructive inspection fulfil the requirements for safety examination.

Pipeline ageing could be a significant factor in terms of likelihood of failure if a set of preventive measures were not taken(technical and/or organisational measures). The effectiveness of these measures can be proved analysing the historical data about the failure frequency of the pipelines network and the failure modes/causes subject to ageing.

Pipeline operators continue to maintain pipelines at a high level of safety and reliability, thus ensuring safety towards the public and environment.

A strategy for pipeline integrity should also consider the need to include additional surveys and inspections such as electrical surveys, intelligent pig inspections.

While electrical surveys give a picture of the coating conditions (except for disbonded coatings where CP current is shielded from reaching the bare metal), intelligent pig inspections indicates the real conditions of the metal and pipe wall of pipelines.

These two techniques could also synergistically be used with great advantage for monitoring the pipeline’s integrity.

Three main factors are responsible for the more frequent maintenance and rehabilitation of pipelines:

- ageing of pipeline systems that may result in increased likelihood of failure;
- regulatory and environmental initiatives;
- pipeline operating costs, and the economic balance between rehabilitation and pipeline replacement.

Where possible, on-line inspection could form part of the basis for establishing pipeline rehabilitation and repair strategies. Rehabilitation and repair technologies are constantly developed by the gas companies.

A topical concern is life extension of older pipelines. Internal inspection, expert assessment and selective repair provides strategy for extending the life of ageing pipelines. It is possible to extend structural life of ageing pipelines considerably or even indefinitely if these technologies are applied correctly and maintained consistently.

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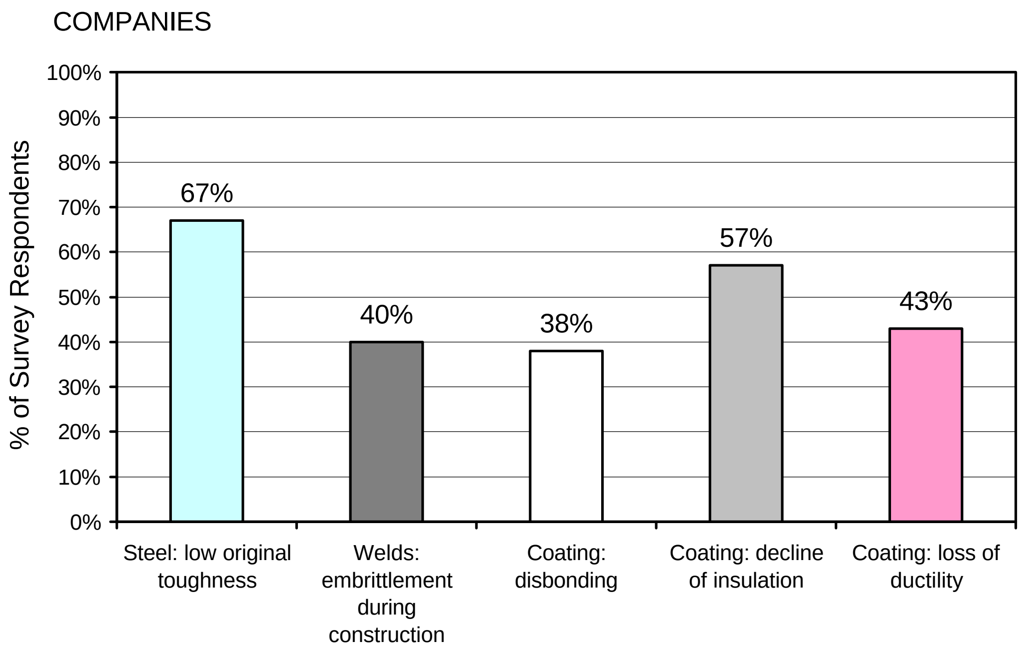

Figura 1: Ageing definition

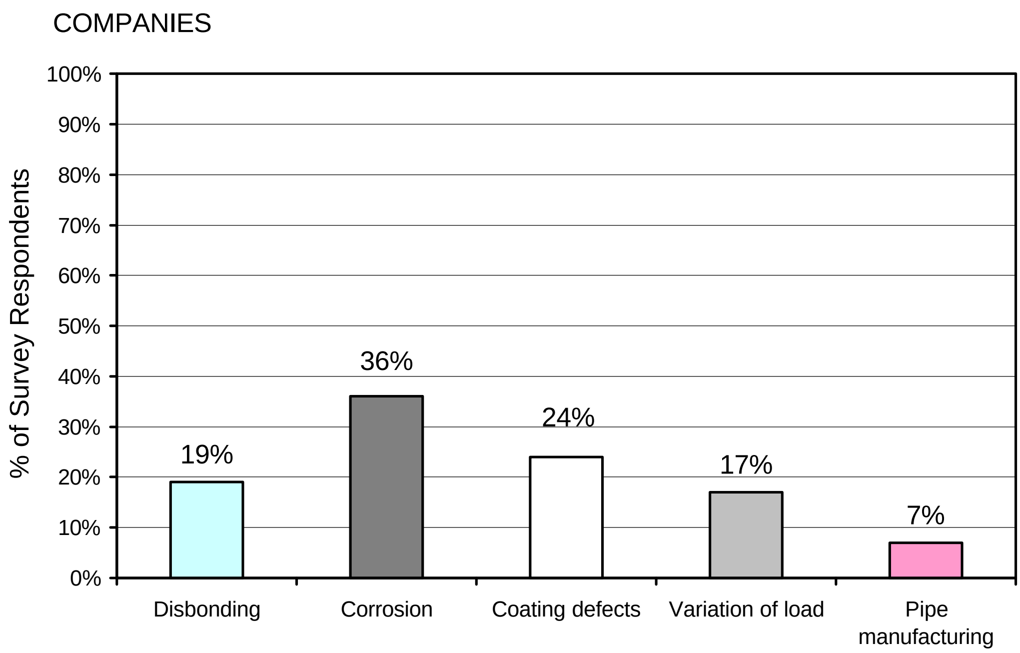

Figure 2: Based on cases history, main causes of ageing

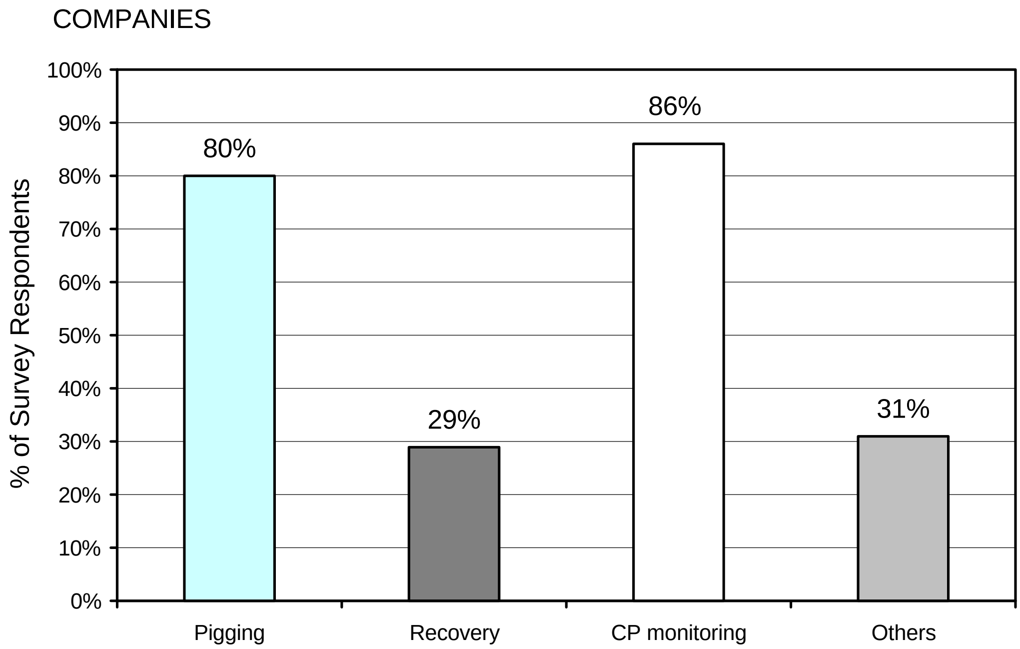

Figure 3: Ageing assessment techniques

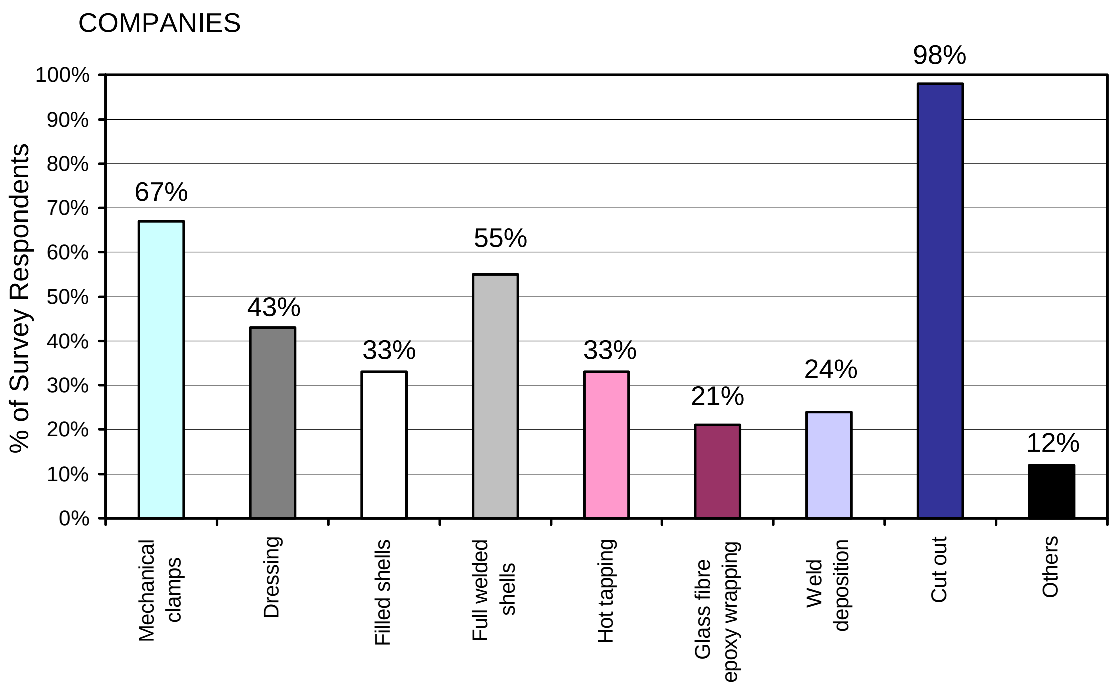

Figure 4: Repair methods used by gas companies on their pipelines

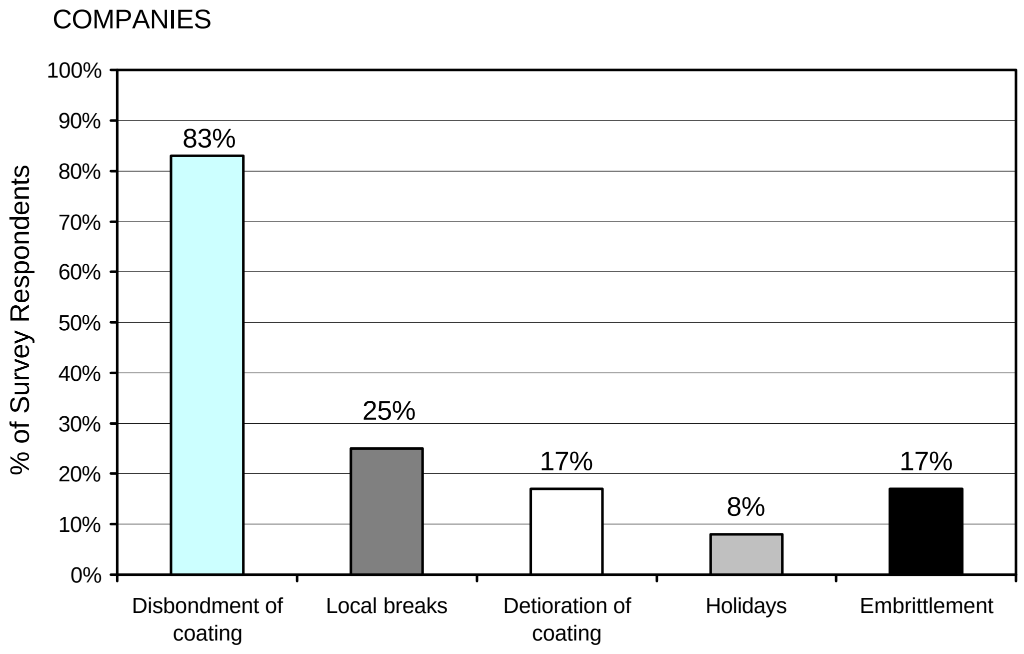

Figure 5: Coating condition

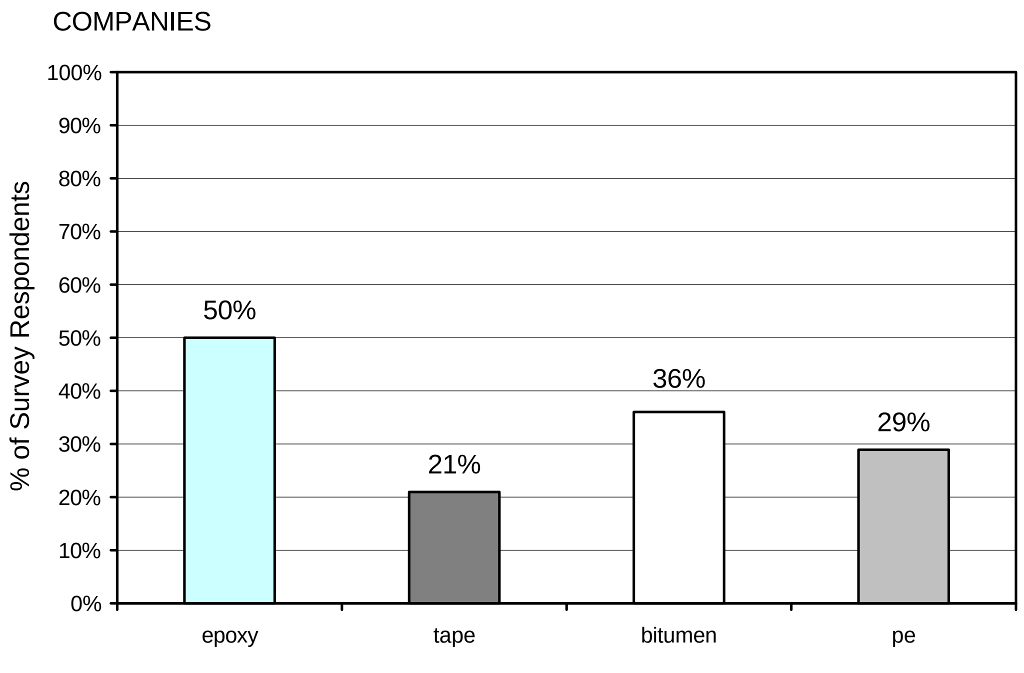

Figure 6: Type of coating for rehabilitation

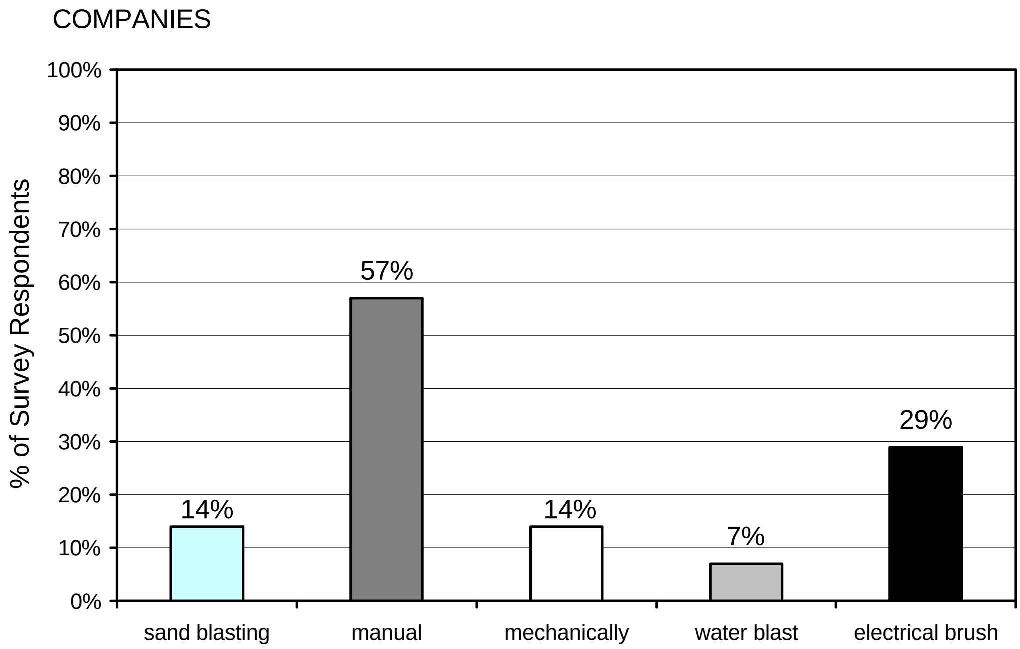

Figure 7: Methods used by gas companies to remove old coating

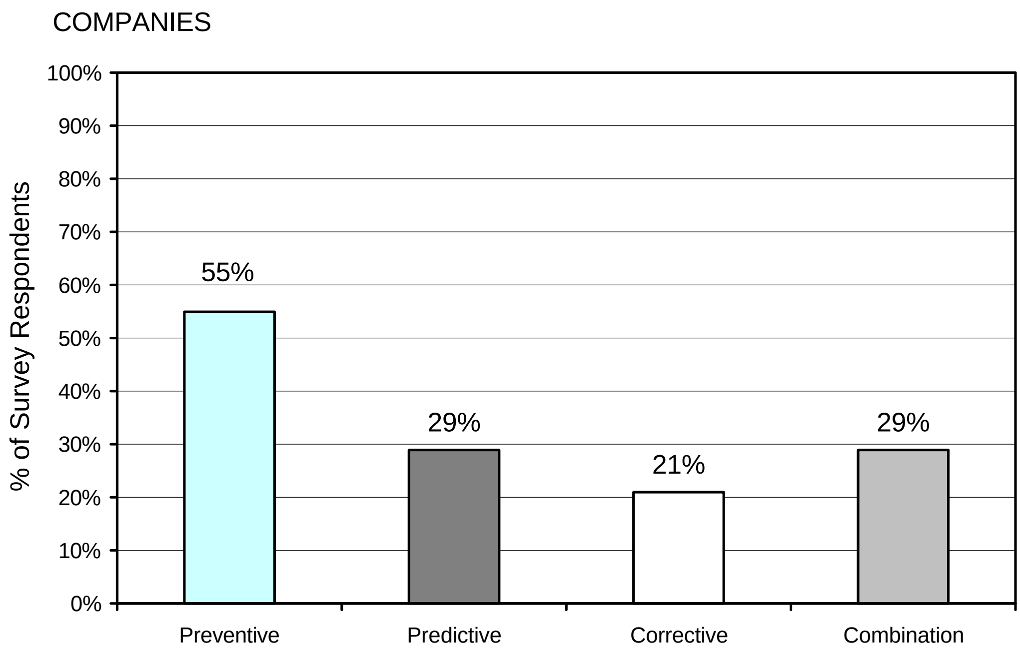

Figure 8: Maintenance approach

21st World Gas Conference – June 6-9, 2000 – Nice - France

Report of Study Group 4.2

«Emissions monitoring»

Chairmen

Boris Krivoshein

Russia

ABSTRACT

SG-4.2 report represents an analysis of causes and gives a quantitative evaluation of gas losses in transmission.

The document contains some results of monitoring of emissions in situ operating facilities.

The topics dicsussed are as follows:

- questions of standartization of emissions in different countries

- methodes and technical means of localization and evaluation of gas leaks

- principles of organization of the system of gas leakage control

The report offers recommendations, based on the experience of different countries, of reducing leaks in transmission and pollutant emissions from GT-units.

RÉSUMÉ

Rapport SG-4.2 contient l'analyse des causes et l'evaluation quantitative des pertes de gaz lors de la transportation.

Des resultats de monitoring des emissions aux unités opérationnelles existantes sont présentes.

Le rapport examine:

- questions relatives aux limitation des émissions dans differants pays

- methodes et moyens techniques de localisation et de l'évaluations des fuites

- principes de l'organisation du système de contrôle des fuites de gaz

Le rapport présente des recommandations sur la réduction des fuites à la transportation et des émissions des turbines à gaz, fondées sur l'examen de l'experience de differents pays.

TABLE OF CONTENTS

1 - INTRODUCTION

This report summarises the world experience monitoring of hazardous substances emissions and gas leakage in transmission. The main characteristics of the gas transmission networks are examined for the countries with a developed gas industry. Causes of gas losses are classified by different locations - gas compressor stations (CSs), pipeline linear sections (LSs) and auxiliary facilities, underground gas storages (UGSs), gas metering stations (GMSs), gas distributing stations (GDSs) and gas commingling stations (GCSs). Emission standards effective for industrial facilities and living quarters are analysed country by country.

Analytical information was gathered through a comprehensive Questionnaire approved by the IGU SG-4.2, which includes members from 11 countries of Europe, the USA and Canada. The Questionnaire data was collected as follows:

- basic limits set by inspection services and comparisons of the standards and norms adopted in the field by different countries;

- gas leakage detection at pipelines and equipment of CSs, GDSs, GMSs and GCSs; and the methods used to reduce the leakage;

- combustion product emissions (mainly, CO, CO2, NOx) by gas turbines and gas engine units.

Russian gas is 44% of the total volume of gas transmitted through the international pipelines. Demand growth in Western Europe is projected in the range of 140 - 250 $m^3 \times 10^9$/year for the next two decades.

Consequently the entire gas pipeline system, and the Russian gas pipelines in particular, could be considered as a major source of methane and other greenhouse gases emissions into the atmosphere.

The Protocol annexed to the Frame Convention on Climate Change and adopted in December 1997 in Kyoto predetermines quantity obligations to reduce greenhouse gases emissions (mainly, methane and CO2) by the industrial states and transition economies for the period of 2008 -2012.

The cumulative volume of emissions over the limits set for industrialised countries will create an international market of emission quota exchange, according to Article 17 of the Kyoto Protocol. For the said period this will amount to 10 to 14 billion tons in CO2 equivalent; according to the estimates, which translates into US$ 10 - 30 billion.

Expenditure to reduce greenhouse gases emissions, particularly in natural gas transmission, affects the efficiency of gas export deliveries and should be included in new strategies for gas transmission companies. Thus, for the industrialised countries, the import of electricity might be preferable to the import of gas to be fired within their own territoriy.

Fulfilment of the obligations by the companies and states on greenhouse gases emissions, and the opportunity to offer quotas (saved) to the market, require more precise and standardised quantities of the emissions generated by different emission sources. That is why Article 5 of the Kyoto Protocol defines as a mandatory requirement the creation of «...the national system of evaluation of emissions of the anthropogenous type viewing greenhouse gases by sources...» not later than one year before the first period of obligations effective under the Protocol, i.e. before 2007. The latter obligation is often referred to as «the creation of greenhouse gases emissions monitoring system».

In new of this, the Questionnaire has focused on these urgent tasks for gas transmission companies and firms over 10 - 12 years.

Completed Questionnaires were returned by 11 firms from Europe, Canada, the USA and Russia operating over 700 thousand km of pipelines.

The companies, which participated in filling-in the Questionnaire, employ over 400 thousand persons. The total volume of gas transported in excess of 1100 $m^3 \times 10^9$/year which is about 50% of the global gas transmission volume. The total capacity of gas compressor units (GCUs) is over 85 MKW.

If not clearly referred to other country/company, the numbers in the report are based on Russian experience.
The following information is included in the present report:

- sources and volumes of gas losses in transmission;
- organization of the system control and registration of gas losses;
- methods and technical means for reducing and locating gas losses;
- measures and technical means used for reducing gas losses;
- hazardous gases emissions;
- methods and technical means for qualitative control of CO, CO2, NOx, SO2 emissions;
- standard requirements for technological emissions (NOx and CO) by modern gas-turbine units (GTUs).

2 - OBJECTIVES AND DETAILS OF THE STUDY

Objectives of the Study:

- analysis of the gas emission sources and quantities from different elements of the gas transmission system during the operation;
- experience change of different gas leakage detection methods used in participating companies and countries;
- summary of environmental authority regulations for hazardous emissions of compressor stations in different countries;
- evaluation of different means and technological solutions to reduce the hazardous emission to atmosphere to permissible level.

Details of the Study:

- collection of information from leading gas companies by a questionnaire;
- analysis of the collected data in order to achieve the objectives of the study;
- evaluation methods for hazardous atmospheric emissions quantification;
- comparison of the environmental authority regulations and standards for air quality in the residential and industrial areas;
- analysis of action undertaken by the gas companies to reduce hazardous emissions into the atmosphere.

3 - MAIN CHARACTERISTICS OF GAS TRANSMISSION SYSTEMS

Data on the gas transmission companies of different countries participants in the Study are in Table 1 (as of 1997).

[1]	Parameters	Country/Company										
		France (Gaz de France)	Finland (Gasum)	Germany (Ruhrgas)	Italy (SNAM)	Norway (Statoil)	Slovakia (Slovtransgaz)	Canada (TransCanada)	The Netherlands (Gasunie)	Spain (Gaz de Euskadi)	Russia (Gazprom)	UK (TransCo)
1	Length of gas mains (2.5 MPa and above o.p.), km, including a) 900 mm and more b)300-900 mm c) less than 300 mm	806 9508 18005	898 48 641 209	8774 4048 4205 521	24932 4384 10691 9857	2386 809 -	2179 2084 95 -	14491 8901 96 -	11178 - - -	4600 500 3100 1000	148000 91144	4400 1670 14
2	Length of pipelines (km) with different service life:											
	a) up to 15 years	8970	318	2506	11116	4075	1279				70004	1351
	b)15-30 years	11830	290	4224	10378	-	900				5632	4696
	c) over 30 y.	5480	-	2044	3500	-	-				21164	37
3	GCU											
	a) number, CS.	32	3	27	20	12	4	58	10	8	247	20
	b) UGS	14	-	12	8	1	1	-	-	-	23	n/f
	c) GTCU	163	9	81	66	46	107	213	69	25	4000	52
	d)GCU capacity, MW	565.6	63	758	884	700	993	2372.7	630	170	41700	783
	e) GTU, MW	443.6	63	697	882	700	768	2039.9	590	150		783
4	Pipeline gas intake, $m^3 \times 10^9$/y	26	3.5	60	57.8	40	84	71	94.8	12.2	592.4	8.0

Table 1: Parameters of gas transmission companies of different countries (1997)

4 - CLASSIFICATION OF GAS LEAKAGE AND CAUSE OF GAS TRANSMISSION LOSSES

Gas losses may be classified in 2 groups:

1. Critical losses, connected with complete or partial destruction of a pipeline section. Such leakage entails serious local gas blow-out, gas transmission failure and serious environment pollution. In half of the cases, the pollution is caused by large ignited releases due to high power equivalent of a pipeline which is 0.5 gW / year per 1 BCM / year of gas transmitted.

2. Minor leakage caused by insignificant defects of the pipe wall, welds, pipeline accessories. Pipeline crossings over the natural and artificial obstacles (rivers, railroads, highways) have a special grade of danger.

Gas loss, that directly or indirectly leads to releases into the atmosphere [1,2], may be classified in two groups (Fig. 1):

1. Technologically justifiable gas loss caused by production activity of transmission facilities, i.e. fuel gas consumption by fuel consuming equipment.

2. Technologically unjustifiable gas losses with blowouts into the atmosphere may be subdivided into two groups:

   a. gas loss with blow-out into the atmosphere connected with different operations at transmission facilities;
   b. technical losses; the volume of the latter is predetermined by the quality of construction, operation, the equipment reliability and other factors. This subgroup includes:

      - technically inevitable loss, connected with leakage through the valves sealing of the main and auxiliary equipment of CSs, linear parts of a pipeline, a GDS, a GMS and an UGS;

      - caused by failures at CSs and pipelines as well as gas leakage through a pipe wall flaw. Note: gas emitted into the atmosphere at an emergency is only considered a loss before the valve closure and isolation of the damaged section, when it is regarded as consumed for own operational needs.

There are also losses connected with:

- the so-called “gas misbalance” between gas suppliers and consumers, connected with metering devices and instruments errors. The loss of this kind is called “out-of-control”. The loss makes up to 1.9% of the volume of gas intended to be delivered to consumers. The analysis of the gas loss profile in the recent years shows that it has an upward trend. It is explained by the growth of volumes, distance of gas transmission, pipeline length (in a single line), a number of valving pieces of different diameter, a total number of discharge plugs, all of which being probable sources of gas losses.

In gas production, gathering, transmission and distribution, 70 % of adverse ecological emissions are caused by the gas transmission systems.

Technologically unjustified losses make up to 70% of the total gas loss by the gas pipelines.

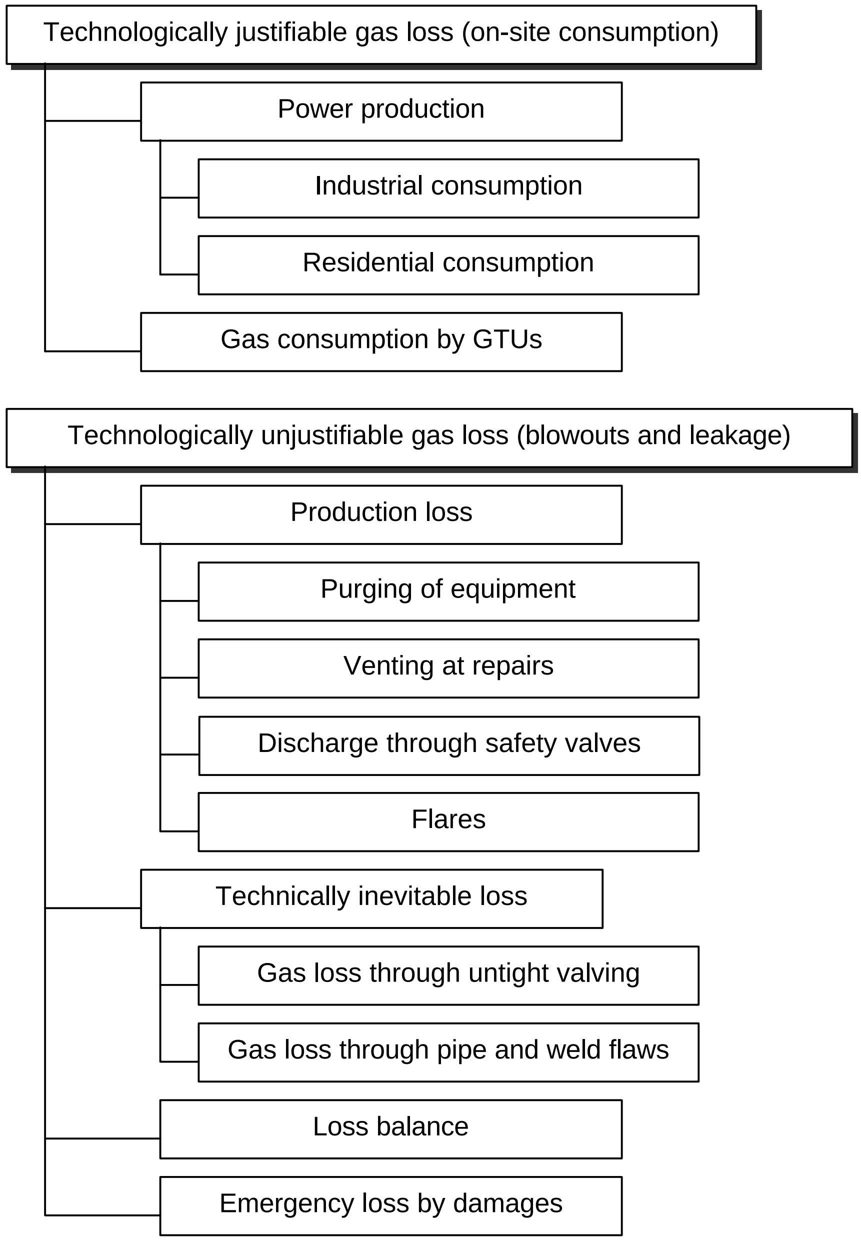

Figure 1: Gas losses in transmission by pipeline

Not only direct leakage to the atmosphere is regarded as «unjustifiable» loss in gas transmission but also excessively high gas consumption for technological needs and energy supply. That is why the ways to reduce gas consumption for the pipeline operation are analyzed in details below as follows:

- gas consumption by CSs gas-turbines;
- technological gas consumption;
- gas loss as leakage.

Energy gas consumption by CSs gas-turbines

The key factors influencing the specific gas consumption in transmission of over 1000 cu m of commodity gas by a pipeline of certain length are as follows:

- gas-turbine drive efficiency ratio;
- load factor of the gas-turbine drive versus its nominal capacity;
- specific characteristics of the gas-transmission technology used;
- hydraulic characteristics of the linear part of a pipeline.

The load factor of operating GCU versus its nominal capacity has a direct impact on fuel gas saving due to the use of high-efficiency gas-turbine drive.

Technology used for gas compression significantly influences the fuel gas specific consumption. The gas compression ratio depends on the pipeline throughput and the distance between CSs.

Extra consumption of capacity (about 13%) for gas transmission is of real significance due to the pressure loss in the structures set both at the inlet and outlet of a CS.

Lowering pressure loss in the structures and at a CS equipment leads to proportional reduction in the CS capacity overconsumption when compressing gas.

Another important factor influencing the specific energy consumption in gas transportation under other equal conditions is the pipeline hydraulic condition which is usually evaluated by its hydraulic efficiency (E).

CS's technological gas consumption

Possibilities to save gas consumed for technological operations are less impressive. Nevertheless, gas saving may be provided in this area as well. Over 25% of gas consumption in technological operations at CSs are connected with the gas-turbine unit start-ups and shut-downs. The start-up of a GTU by the turbo-expander running on compressed gas is obviously an enviromentally damagin solution as in that case the exhaust gas discharged into the atmosphere remains unutilized.

In view of the fact that one start of a 16-25 MW GTU requires up to 6 - 10 t (about 8 - 14 thousand m^3) of gas transmitted, the total gas loss in this operation may reach significant volumes within the entire gas grid.

Gas loss in the blowing of the booster at the start of GTU is approximately of the same amount.

Gas losses in the “gas - oil” sealing system are practically at the same level as those of the GTU start-up - shut-down operations. Introduction of more sophisticated systems of the kind will lead to the gas loss reduction at a CS.

Accidents

Gas losses due to failure of the pipeline are much greater. This can be due to cracks and fissures, etc., propagating in the course of the operating process, or damage to the pipeline.

Sources and causes of gas leakage

The most severe gas leakage sources are located at:

- the pipeline;
- the compressor station;
- the underground gas storage.

The SG-4.3 “Pipelines Integrity Management and Safety Report” contains a detailed analysis of the causes and structure of the accidents and failures for pipelines in Europe, the USA and Asia. As far as the UGSS of Russia is concerned (the data not included in the SG-4.3 Report), the statistics of emergencies for gas leakage from gas pipelines for the 15-year observation period are analysed as follows. The five major causes of failures were identified through the statistical analysis (Fig. 2) [3]:

- material defects which may be caused both by worsening of the defects present in the original material and the defects formed in the process of pipe manufacture and pipeline construction. For example, welding defects, metal lamination, etc.;
- corrosion prone failure of the metal of the pipeline wall in the process of operation;
- operator’s mistake in the process of operation and servicing of the pipeline;
- external intervention, e.g., by earth-moving equipment;
- environmental influence. This category includes such phenomena as ground subsidence or washout caused by heavy rains, etc.

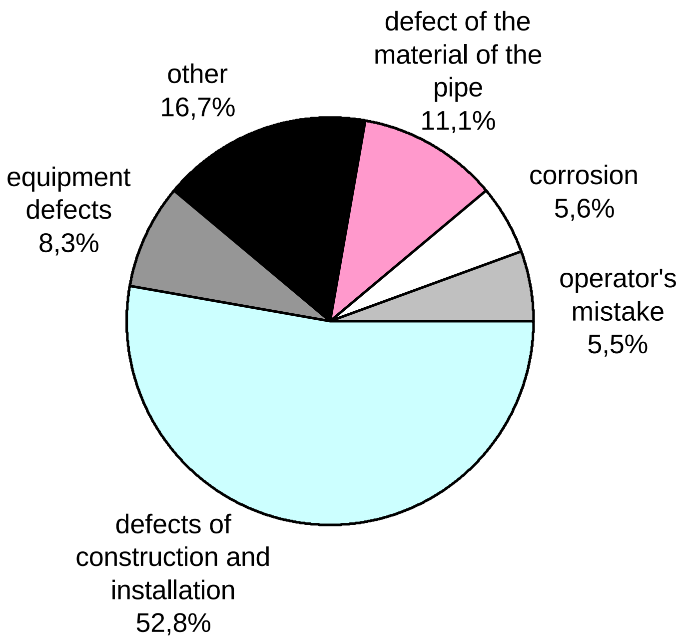

Figure 2: Causes of failures at the gas mains (∅ 1420 mm)

5 - GAS TRANSMISSION LOSS EVALUATION

Summarized data on gas losses in volume in the linear parts (LPs) and at CSs in a number of the European companies are in Table 2.

1	Loss	Country/Company							
		France (Gaz de France)	Finland (Gasum)	Germany (Ruhrgas)	Italy (SNAM)	Norway (Statoil)	Slovakia (Slovtransgaz)	The Netherlands (Gasunie)	Russia (Gazprom)
1.	Total gas loss (for 5 (Values include transmission and fractionation (rectification, distillation) of LPG): LOS Flares Fuel gas)		562	9260	48500	 2810 31893 339121	11202	7800	5873300 4108120 0
1.1	Loss at CS (less fuel gas)	1500	415	7400	19400	2200	8038		2006300
1.1.1	CS, Technologically justifiable loss	90	345	5100			8038		389200
1.1.2	CS, gas leakage	10	70	2300					1617100
1.2	Gas loss at pipeline		147	1860	8500		3164		3867000
1.2.1	Technologically justifiable loss at pipeline		117	860			3164		1348000
1.2.2	Gas leakage at pipeline		30	1000					462800

Table 2: Sources and volumes of losses in gas transmission, $m^3 \times 10^3$ (1997)

As an example, the profile of gas losses at various parts of a CS of the major gas transmission company is below (%):

1. CS gas loss
   (fuel gas not included) - 100

2. Technologically justifiable loss, including - 19.4
   - GTUs start-up and shut-down - 3.5
   - blow-down (cleaning) of gas filters and other equipment - 3.8
   - operation of GTUs sealing system - 4.6
   - gas discharge at repair works - 7.5

3. Gas leakage, including - 80.6
   - through leaky valving - 6.9
   - through plugs - 74.4

Correspondingly, the profile of gas losses at LPs is as follows (%):

1. Gas losses at LPs	- 100
2. Technologically justifiable losses, including:	- 34.8
- gas discharge at repair works, pipe branch cutting-in,	
- valve replacement	- 20.9
- gas discharge while pigging	- 13.9
3. Leakage, total	- 11.9
- leaky valving	- 6.9
- others	- 5.1
4. Losses during failures liquidation	- 1.2
5. Losses at GDSs, GMSs and GCSs	- 52.1

The analysis of the data shows that approximately 20% of gas losses at CSs caused by maintaining the gas transmission system are technologically justifiable. For a linear part this factor is as high as 35%.

Thus, there is a significant potential to reduce gas losses and correspondingly, to improve the efficiency of gas transmission.

6 - MONITORING OF GAS EMISSIONS AT REPRESENTATIVE FACILITIES, A CASE STUDY

The data above are the result of statistical analysis of operational information.

To evaluate actual gas losses an international study was initiated. It was carried out by the American Agency on Environmental protection [2], Rurhgas AG [4, 5] and with participation of the Russian specialists in Central and Northern regions of Russia (Table 3).

Measurement period	Facilities	Region	Construction period	Technical characteristics	Throughput, $m^3 \times 10^9$/year
May - Sept. 1996	CS 1 CS 2 Pipelines in the vicinity of CS “V.Kazyma” (mainly, measurements made from a helicopter at the selected points)	Tyumen, W. Siberia	1971 - 1977 1983 - 1997 1971 - 1983	222 MW 667 MW 2000 km, 1420 mm	83 277 360
April - May	Pipelines and fitting at the linear part of the «Uhzgorod» corridor	Sechenov, N.Novgorod	1983 - 1987	630 km, 1420 mm 350 valve units	168

Table 3: Representative facilities features

The methodology approach lies in the division of CSs into a number of standardized units and the experimental identification of an «emission factor» characterizing an average leakage volume by source and within certain time span. The results of the measurements are in Table 4.

Unit	Emission factor, $m^3 \times 10^3$/year
Valve unit plug	49.0
Recirculation plug	21.3
Fuel valve plug	20.6
Starting circuit plug	11.8
Bypass valve plug	1.2
Automated air cooling system plugs	0.2
Stop cock	4.2
Ball cock	0.2
Valve	0.1
Flange	0.2
Thread joints	0.1
Other elements	0.02
Ball cock (L4)	0.2
Stop cock	0.01
Valve	2.9
Flange	0.04
Thread joints	0.01
Other	0.07

Table 4: Data on natural gas actual loss and leakage at CSs and LPs

The results of the study [5] show that the emission factor for CS with 10 MW units is in the range of 62 - 75 $m^3 \times 10^3$/ year / MW while for CS with 16 - 25 MW units it is 15 - 17% lower ranging from 53 to 62 $m^3 \times 10^3$/ year / MW.

Typical structure of gas losses at a CS is presented in Fig. 3.

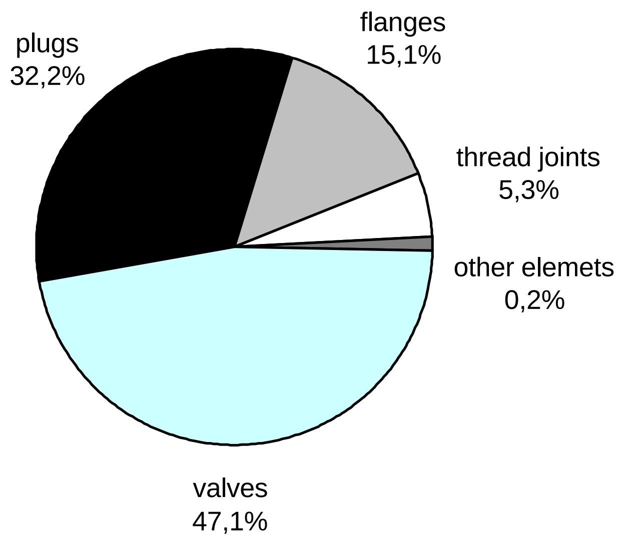

Figure 3: Exemplary structure of gas losses at a CS.

The analysis shows that valves, plugs and flanges are responsible for some 90% of the leakage at a CS. Thus, to reduce gas leakage at CSs ,first of all, one should provide for the air-tightness of the valving system.

It was noted that the major physical wear is a precondition of the reliability of the valving. The gas dynamics regime of the pipeline operation, erosion and corrosion of the fittings, fatigue damage in sealing constructions are factors of potential damage as well. The cyclical load is of special attention as it affects all the service life of the accessories.

Operational factors affecting the reliability of the valving are characterized by the following [7]:

- cyclical load - 31%;
- mechanical damage - 21%;
- fatigue damage - 19%;
- erosion - 17%;
- corrosion - 12%.

Valving system reliability is of great importance in the stand-by regime when the isolation of a pipeline section at the moment of a failure is needed. Untimely and unpurposeful isolation of the pipeline section is unacceptably and faluvre to issolat the pipeline whem required intensifies the environmental impact to the incident. Of the total volume of the gas losses during failures, 17 - 20% is directly attributable to reliability of the valving [7].

It is generally considered that failure of valving (tightness inferior the established norm) should not happen during the entire service life of a pipeline. However, the normative service life of valving is 2 - 2.5 times lower than that of a pipeline (under equal other conditions).

There is no physical theory to standardize the ecological safety of the pipeline valving reliability with satisfactory accuracy. If we take the pipe wall strength under conditions of operational stability and deformation as the main criteria of the LP reliability, than the dominating criteria of the valving reliability is its tightness.

In the total failures the share of valving failure lies in the range of 0.03 - 0.005 of the pipeline failure factor. However, if translated to actual ecological damage due to gas losses and environment pollution, the valving leakage is added to the pollution component generated by the LPs failures.

To calculate the safety factor of the valving, it is necessary to examine and quantitatively estimate friction and wear of the contact sealing of an isolation unit, and its effect on the valving loss of tightness and increased risk for the “LP - valving” system.

Overall maintenance of the reliability and ecological safety of the valving should provide:

- at the construction stage - standardized level of assembly and on-site testing quality;

- at the operational stage - scheduled preventive repair and servicing, instrumental control and diagnostic system installation;

- at the reconstruction and modernization stage - complex inventory check, technical diagnostics of the resource available, the evaluation of ecological and economic risks;

- development of technologies and technical means necessary for a replacement of the valving with the minimal risk of natural gas emission into the atmosphere;

- adoption of an universal approach to equip valving with the atmospheric methane detectors.

Statistical analysis of operational failures of pipelines identified a common occurrence of the ecological risk growth with time. Minimal ecological risk is attributable to pipelines with an average life-cycles of not longer than 8 - 10 years. This is due to the fact that the construction defects are detected and corrected in time and external corrosion of pipes is minimal.

In September, 1996, Ruhrgas AG jointly with the Russian specialists fulfilled measurements of CH4, NOx and CO at representative facilities.

They recorded planned methane emission (at starting-ups - shutting-downs of GTUs, blowing-down of pipeline sections) and unplanned emission (leakage from the valving, plugs, flange and threaded connections). Leakage measurements were carried out with the help of devices supplied by Rurhgas AG.

6.1 - Methods of methane emissions detection [4, 5]

When making measurements the methane emissions caused by leakage, degassing of the sealing oil as well as the blowouts of unburned methane were recorded with exhaust gases of turbine units. Other emissions were identified based on the operational characteristics, technical specifications of the units, their load and the duration of overhaul periods.

Measuring equipment included various instruments calibrated before and after the measurements. Thus, a common level of a $\leq$ 2% error was set for the instruments used. Leakage detection was carried out with the use of a semiconductor gas analyzer (concentration range from 0 to 2000 ppm), ani flame ionization detectors (FID, concentration range 0 - 10000 ppm). For qualitative evaluation of more significant methane leaks thermo-conductive detectors were used (concentration range from 0 to 100 volume-%). Gas volume flow and temperature were measured with the thermocouple and anemometer in combination (measurement interval 0 - 30 m/sec. and 0 - 80^0 C).

Detected emissions were classified by CH4 concentration degree in the vicinity of leakage locations. After that the leaks were evaluated in quantity and the results were translated to represent the entire CS facilities emission.

Each CS was examined during a week. The following elements of a CS were examined: the valving, plugs, gas feed and relief lines, units, separators and filters.

No significant methane emissions were detected in turbine shops. Insignificant leaks were registered in instrumentation shops. In all gas compressor shops CH4 leaks were detected which were exhausted through the exhaust device. The most substantial emissions were detected in the lines of sealing oil degassing. Then the entire GCU block was isolated and the methane emission was measured. CH4 leaks were also detected in relief piping.

The study group also examined about 2000 km of the gas mains with the help of “Aeropoisk-3” lazer instrument. No leaks were detected on the pipelines themselves; however, leaks at fittings and valve unit plugs were registered.

Two methods of leakage quantitative analysis were selected.

6.1.1 - Direct measurement of methane velocity and concentration

A measuring nipple is set on the plug to eliminate any wind intervention. There are two holes in the nipple: one for anemometer, another - for gas sampling. Inside the nipple methane concentration is measured as well as outlet velocity and gas temperature inside the nipple. On the basis of the data registered and the plug diameter the volume of discharge gas is calculated. The method provides for improvement of estimation accuracy with the rise of the leak volume.

6.1.2 - Methane direct suction

The fitting is enclosed (e.g., PVA coat) and the gasairmixture is exhausted through a hose. Methane velocity, temperature and concentration are measured inside the hose. CH_4 concentration is estimated taking into consideration the cross-section of the latter and the air volume in the blower. If the emission source is insignificant, the air volume is determined with the help of velocity counter (Fig. 4).

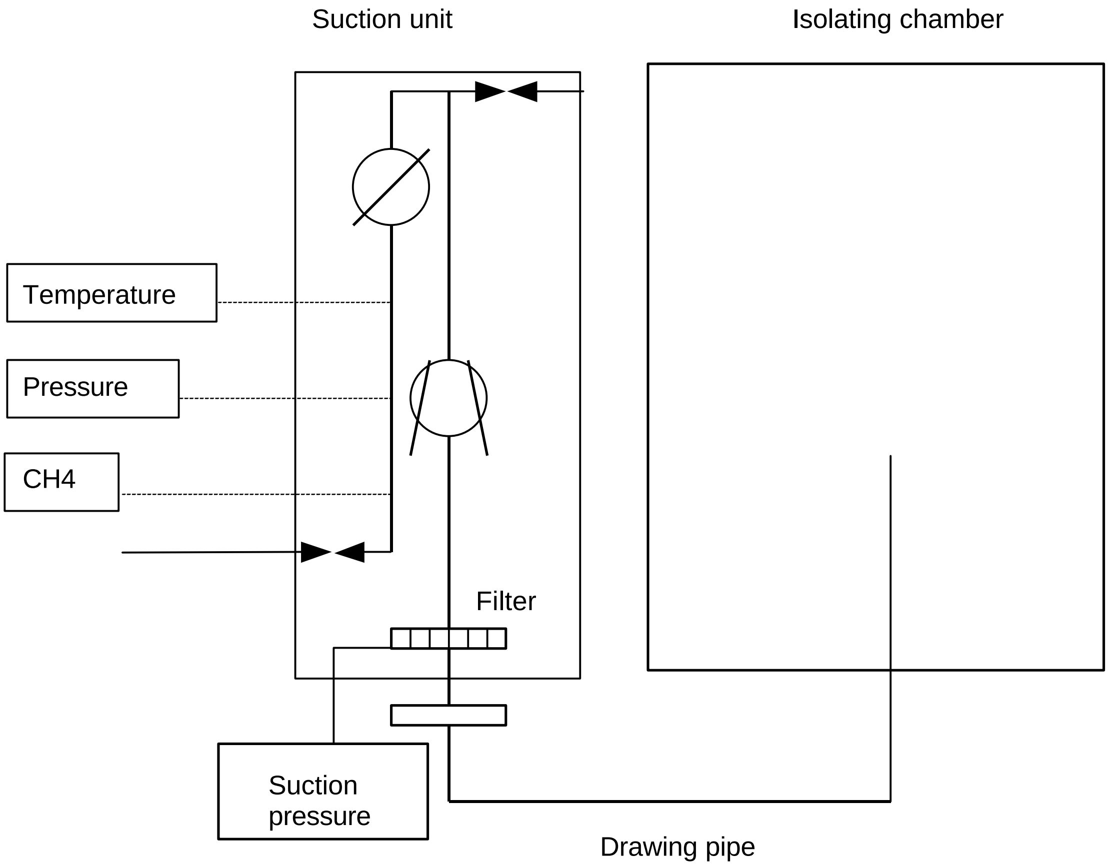

Figure 4: Scheme of methane drawing off

6.2 - Measurement results

Methane blowouts were registered by walking and flying around CS and the gas mains sections. Then qualitative evaluation of numerous emission sites was carried out. However, due to the size of CS premises, all the emission sites could not be detected. Because of this, the types of emission source were classified first (sealing lubricant, leaks at fittings, leak at plugs, etc.) and then recalculation was made for the CS on the whole. Emission volumes on the pieces on equipment were correlated to the installed capacity of CS. As the result, emission volumes for equipment were determined (Table 5).

Indices	CS-1	CS-2
Volume, $m^3 \times 10^6$/year:		
* gas transmitted	83000	277000
* organized production emission	6.1	8.87
* leakage emission	7.71	26.57
* total emission	13.81	35.44

Results were extrapolated on the basis of production data

Table 5: Methane emission at CS

Multiplying the values received by the installed capacity of the units, we may determine the volume of emission of the CS.

Results qualitative measurements of methane emission at ten pipelines were correlated with the length of examined sections to determine a relative emission volume. This value was multiplied by the length of the pipelines of the gas transmission companies to calculate the volume of emission of the entire grid. It should be noted that the examination of the gas pipelines is still under way, so the results may not be considered as representative for the entire network.

Estimations made by Rurhgas AG assumed a 365-days leakage period. This is “the worst” of the scenarios and thus, the results should be considered as maximum.

However, serious leakage may not continues for the full a year, so actual methane emission would be lower. The data presented in Table 6 correspond to a big territorial gas transmission company and the UGSS (Source: Rurhgas AG).

Indices	Territorial company	UGSS
Volume, $m^3 \times 10^6$/year:		
• gas transmitted	432246	534472
• organized production emissions	287.63	1592.02
• leakage emission	612.03	2086.89
• total emission	899.66	3678.91
Ratio between emission volume to transported gas volume, %	0.21	0.69

Table 6: Total methane emission at CS

The results of the measurement were used as a basis for methane emission evaluation for gas transmission through the pipelines of CS-2 (Table 6).

The leakage duration and GCU load were not taken into consideration by the RUHRGAS AG estimates.

Methane emission at CS-1 and CS-2 was correlated with the installed capacity at the stations. According to Ruhrgas estimat, the methane emission specific volume is 0.06 $m^3 \times 10^6$/ year / MW (CS-1) and 0.05 $m^3 \times 10^6$/ year / MW (CS-2) (Table 4). According to Ruhrgas extrapolation, methane emission at CS amounts to 0.69% or 3.68 $m^3 x10^9$/ year (Table 5).

Methane emission at CSs of the UGSS of Russia does not exceed 0.7% of the transported gas volume. Gas losses at preventive maintenance and planned repairs amounted to 221 $m^3 \times 10^6$/ year (0.05% of the transported gas volume).

In line with the other representative facilities the study group examined compressor stations at the long-distance pipelines Urengoy - Uzhgorod, Urengoy - Center, Yamburg - Yelets, Progress, Yamburg - Tula, Yamburg - Povolzhje, SRTO - Ural (P oprt. = 7.5 MPa, D = 1420 mm).

With the total pipeline throughput of 430 $m^3 \times 10^9$/ year, the measured emission volume amounted to 0.0037% or 15.5 $m^3 \times 10^6$/ year.

Extrapolation of data on the gas mains and CS was carried out separately. According to Ruhrgas, the volume of methane emission on the linear part of the UGSS pipelines makes some 0.2% of the transported gas volume. Ruhrgas AG continued the methane emission study in 1997.

The 1420-mm “Progress” pipeline is an export line equipped with the valving manufactured by various Western companies an hence is representative for any gas transmission system (GTS). Examination was conducted over 6 pipelines of the Uzhgorod corridor which were put into operation in 1983 - 87. The results of measurements and calculations are presented in Table 6.

The identified emission level was correlated with the length of the pipelines examined. Specific emission volume resulting from gas leaks amounts to 2.7 $m^3 \times 10^3$/ year / km.

Apart from emission caused by leakage, gas blow-out caused by failures should be taken into consideration (99 $m^3 \times 10^6$/ year) and venting at planned repairs (673 m3 x 10^6/ year). The correlation of the total emission volume (1156 $m^3 \times 10^6$/ year) to the length of the UGSS pipelines provided the specific value of the total emission volume calculated as 8.2 $m^3 \times 10^3$/ year / km.

Calculation results are presented in Table 7.

1	Indices	Measurement unit	Total emission volume	Per cent
1	Leakage	$m^3 \times 10^6$/ year	384	33.2
2	Failure	$m^3 \times 10^6$/ year	99	8.6
3	Gas loss at planned repair	$m^3 \times 10^6$/ year	673	58.2
4	Total emission level	$m^3 \times 10^6$/ year	1156	100
5	Transported gas volume (1995)	$m^3 \times 10^9$/ year	534.4	
6	Relative methane emission	%	0.22	

Table 7: Total methane emission volume at the UGSS gas mains

As illustrated by Table 7, the source of the major methane emission is gas losses at planned repairs (PR) (58.25) and leakages connected with poor valving tightness (33.2%). That is why ensuring the economic and ecological safety of the gas transportation is connected with those two problems, and with the creation of the emission monitoring system, usage of mobile recompressor units at planned repairs and development of technology for rehabilitation of the valving tightness without shut-down of gas transmission.

Thus, on the basis of the measurement results and calculations, methane emission of LP of the UGSS was evaluated as 0.22% of the transported gas volume.

As an example, Table 8 represents specific emission values determined on the basis of Ruhrgas study.

1	Facility, emission source	Value
1	Pipeline linear section (per 1 km), including	8.2
	failure	2.7
	repair	4.8
	other losses	0.7
2	Compressor stations (per MW)	
	N ≤ 10 MW units	62 ÷ 75
	N (16 ≥ 25 MW) units	53 ÷ 62

Table 8: Natural gas emission specific values ($m^3 \times 10^3$ / year)

The indices are associated with the failure intensity (failure/th km/year). If this index enables the forecast of the possible number of failures in a pipeline network depending on its length, then the indices in Table 9 allow evaluation of the volume of emission in relation to the capacity of a single GCU of a compressor station and an average diameter of the pipeline.

It would be interesting to conduct similar investigation of the pipelines of different countries and to carry out a comprehensive analysis.

6.3 - General atmospheric emissions in different countries

Generalized data on gas loss in the pipelines of different countries and estimated specific gas loss in transportation are presented in Table 9.

Country/ Company	Volume		Pipeline length, km	Number of compressor stations	Gas loss, % of the gas delivery	Gas loss, m^3/km
	Gas delivery, $m^3 * 10^9$/a	Gas loss, $m^3 * 10^6$/a				
2	3.5	0.562	898	3	0,016	626
3	60.0	9.260	8774	27	0,015	1055
4	57.8	48.5	24932	20	0,084	1945
6	84.0	11.2	2179	4	0,013	5140
8	94.8	7.8	11178	10	0,008	698
10	592.4	5873	148000	243	0,991	39682

Table 9: Specific gas losses in gas transportation in 1997

The generalized data on hazardous emissions of the pipelines of different countries are presented in Table 10.

1	Substance	Country/Company						
		Finland (Gasum)	Germany (Ruhrgas)	Italy (SNAM)	Norway (Statoil)	Slovakia (Slovtransgaz)	Canada (TransCanada)	The Netherlands (Gasunie)
1	CO2	44.8	762	500	794	1540	8526	277
2	CH4 ($1ktCH_4 = 21$ kt CO_2) CO2 equivalent	0.3 6.3	7.4 155.4	33.1 695.5	0.8 21.0			4.544 95
3	Nox (1 kt NO_2 = 206 kt CO_2) $N0_2$ (1% of NOx) CO2 equivalent	0.768 0.00077 0.1582	3.05 0.003 0.618	2.65 0.003 0.5	0.78 0.0078 1.607	2.94 0.0294 6.05	32.5 0.325 66.95	0.535 0.0005 35 0.1102
4	CO	0.001	0.44	0.77	0.32	3.25		1.012
5	SO2	0		0.005	2.4	0.0087		0

Table 10: Generalized data on hazardous gases emission, kt (1997)

7 - STANDARDIZATION OF EMISSIONS

On the basis of the Questionnaires received from the biggest gas companies from different countries, the following is important:

1. Who regulates hazardous emissions of gas transmission enterprises and how?
2. Norms for the quality of air in industrial and residential areas setting the limits of the maximum admissible emissions from the units generating such emissions (Table 11).

The analysis reveals the following conclusions:

Both the governmental (federal) and regional (municipal) bodies regulate and control hazardous emissions in practically all the countries. In the Netherlands the regional control is absent.

“Self-control” by the ecological departments of the companies is widely spread but not everywhere. There is no such control in Norway, Slovakia, the USA and the Netherlands.

The following materials were used in preparation of the regulating papers:

- Convention on evaluation of environmental impact in cross-boarder context (Espoo, 1991);
- Clean Air Code;
- EU Directive “Large combustion Plant - LCP directive (88/609);
- Agreements “United Nations Framework Convention on Climate Change”;
- ENISO 14000;
- European standards on the quality of air and the data base on emission limitations. The data for the document were presented by Austria, Denmark, France, Germany, Italy and the Netherlands.

An important criteria for the atmospheric air quality and corresponding norms for hazardous emissions from industrial facilities are the qualitative indices of concentration and content of those hazardous substances in the air of industrial and residential areas.

Table 11 summarizes the existing norms on the maximum admissible concentration (MAC) (CH_4, CO, CO_2, NO_x, SO_2) in the atmosphere. MAC is regulated in the industrial and residential areas; the norms are set for maximum single emissions and average daily values.

Substance	Concentration							
	Industrial areas						residential	
	maximum single			average daily			max. single	avrg. daily
	mg/m^3	kg/h	lower explosive limit	mg/m^3	kg/h	lower explosive limit	mg/m^3	mg/m^3
CH_4	n/a	216	20%		213	10%		
CO	150-200	3		30 - 40	3		10-100	n/a
CO_2	45000			9000-9500				n/a
NO_x, including NO NO_2	20-200 30 9	 n/a 95	 - -	70-175 30 9	90 n/a n/a		50-450 0.2 0.085	0.1 0.2 0.085
SO_2	250-830	1		5-500	0.2		0.03-250	0.05-80

Table 11a: Generalized table of operating standards for the MAC
of hazardous substances in the air

The analysis of existing standards in different countries emissions and corresponding concentrations in the air of industrial zones or residential zones shows that there is no uniformity. This is probably due to different established methodological approaches to protect the atmosphere. Consequently, we should stress the urgency of the development of a constant approach.

Different standards are valid in the industrial zones of different countries:

- per fuel gas volume unit;
- per combustion product volume unit under normal conditions and 15% O_2;
- per mass gas flow unit;
- in per cent of lower explosive limit.

	Concentration		
	CO	**NOx**	**SO2**
France (Gaz de France)			
N<20MW Gas Turbines (at 15% of O2)	100 mg/Nm3 300 mg/Nm3 when operating less than 500 h/year	150 mg/Nm3 300 mg/Nm3 when operating less than 500 h/year	1100 mg/Nm3
Reciprocating Engines (at 5% of O2)	800 mg/Nm3 650 mg/Nm3 after 1st January 2000	350 mg/Nm3 500 mg/Nm3 before 1st January 2000	3000 mg/Nm3
N>20MW Gas Turbines (at 15% of O2)	85 mg/Nm3	80 mg/Nm3 for 20<P<50MW 50 mg/Nm3 for P>50MW without exceeding, in any case, 75 mg/Nm3	10 mg/Nm3
Reciprocating Engines (at 5% of O2)	650 mg/Nm3	350 mg/Nm3 for 20<P<50MW 250 mg/Nm3 for P>100MW without exceeding, in any case, 500 mg/Nm3	35 mg/Nm3
Germany (Ruhrgas)			
N<50MW Gas Turbines (at 15% of O2) Existing Plants* (if *th>0,3 limits rise in same relation)	100 mg/Nm3	150 mg/Nm3 300 mg/Nm3	
Reciprocating Engines (at 5% of O2)	650 mg/Nm3	500 mg/Nm3 for 4-stroke 800 mg/Nm3 for 2-stroke	
Italy (SNAM)			
	100 mg/Nm3	100 mg/Nm3	
The Netherlands (Gasunie)			
	40 mg/Nm3 daily average		830 mg/Nm3 maximal one-time 500 mg/Nm3 daily average
Gas Turbines		65 g/GJ for new gasturbines 200 g/GJ for existing gasturbines	
Gas Engines		140 g/GJ for new gasengines 500 g/GJ for existing gasengines	
UK (TransCo)			
	200 mg/m3	200 mg/m3	

Table 11b: Operating standards of hazardous substances in the air in different countries according to gas transmission companies experience.

In some of the European countries (Austria, Denmark, France, Germany, Italy, Netherlands) the "European standards on the air quality and the data base on emission limitations" is used to regulate the NOx content. The standards were developed by the permanent committee on MARCOGAZ.

Considering the above, as well as the existing agreement on limiting trans-border transfer of emissions it is recommended that the unified international requirements on the harmful substances maximum admissible concentrations (MAC) are agreed by qualified experts.

8 - METHODS FOR QUANTITATIVE EMISSION CONTROL

8.1 - Methods for gas leakage determination and localization

Most countries use the following methods for gas leakage localization:

- air or surface monitoring of gas leakage with mobile and portable technical devices;
- pressure control over the gas pipeline route;
- intra-tube diagnostic pigs.

The CH_4 concentration measurement is the main operational principle of these technical devices.

As a rule, a pipeline emergency location is found through pressure drop over time.

The methods and technical means for emission quantitative control in Russia have been described as an example.

Systematic continuous instrumentation control and estimation of the greenhouse gases release in the atmosphere is being developed in the gas industry of Russia. Methods and devices are used to detecti the CH_4 concentrations in the working area to control the explosion hazard and to find natural gas leakage in linear sections of gas pipes.

8.2 - Emission control methods

The main emission control methods are:

- remote control to register the CH_4 concentrations in the air in excess of the background values at a distance from the leakage point;
- contact control to indicate higher CH_4 concentration levels directly at the leakage point.

The leakage control is based on various CH_4 concentration analysis methods, sampling methods and the way gas samples are prepared for the analysis. Russia investigates and appreciates possible implementation of the following emission detection methods widely used Europe and the USA:

- balance methods;
- on-site measurements simulation;
- gas leakage detection systems based on the infrared absorption;
- acoustic methods;
- optical methods.

Many countries apply an aerial (aviation inspection) or ground control using mobile and portable instruments to locate gas leakage.

Pressure control of the gas pipelines is used for the same purpose. Diagnostic pigs (including those with an aerial monitoring in accordance with the ASME Code) are widely used and acoustic and ultrasonic methods are under investigation.

Gas emission remote monitoring is used mainly for the critical sections of gas pipelines (intersections with roads and railways, pipeline sections approaching communities, etc.).

To measure NOx and CO emissions, some countries use chemical luminescence methods in conformity with the VDI 2456/E (NOx) standards, and an infrared absorption in compliance with DI 2459 (CO). Oil moisture traps (demistere) are also implemented in gas engines.

A CS fire-protection system may use other harmful substances - halons or CO_2 (other companies) in the UK these have been replaced with HKH pressure water mist systems.

8.3 - Devices for emissions detecting

To detect leakage, the following gas analyzers are used:

- solid-state and thermo-catalytic gas analyzers;
- electrochemical gas analyzers;
- infrared and optical gas analyzers;
- flame-ionization gas analyzers.

Optimal choice of detector (device) depends on the selectivity requirements of the gas to be measured, service life, area of application, design simplicity, maintenance requirements and price. Each devise has its advantages and disadvantages, the mains of which are listed in Table 12.

Detector type	Advantages	Disadvantages
Catalytic	Stability Response time Maintenance availability Good linearity	Non-selectivity Sensitivity to outer disturbances Large-sized if explosion-proof
Electrochemical	High stability Relatively quick response Good selectivity Good repeatability	Sensitivity to disturbances Limited service life Additional expenses are required for servicing and maintenance
Infrared	Good selectivity Minor errors	Non-selectivity Auxiliary equipment is required for work.
Solid-state	High sensitivity Good repeatability Quick response Extended service life Non-sensitivity to electrical disturbances	Non-selectivity Sensitivity to moisture and temperature variations

Table 12: Advantages and disadvantages of various standard-sized detectors for CH_4 concentration measuring.

The analysis of the information on pollutant emission control methods and estimates of gas transmission leakage from various world gas transportation companies shows that:

- All the companies usually perform regular and direct instrumentation control over the emissions.
- Nevertheless, gas emissions to the atmosphere are not included in this control system everywhere. To take into account gas leakage, some countries (Finland, Germany, Norway and Russia) use, in general, annual (quarterly) data. In Norway and Russia, an air laser remote unit is in use to find leakage.

- A «normative method based on periodic test leakage detection and direct calculation of losses occurred during process operations» is one of the common estimation methods. Pipeline pressure control is also used.
- Instrumentation methods which usually use mobile and portable technical devices are starting to be used in the USA, Germany and Russia.

NOx emissions are measured indirectly by comparison with fuel gas consumption which is easy to measure. It is possible due to correlation between NOx emissions and fuel gas consumption. This method is applied for gas turbines equipped with a standard combustion system and is not applied for gas turbines equipped with DLE and SCR and water (steam) injection into combuston. These indirect measurements are calibrated once in three years by independent monitoring institutions.

The systems of continuous CO, CO_2, NOx, SO_2 monitoring include:

- systems to measure concentrations (CEMS - continuos emission monitoring system);
- design systems (PEMS - predictive emission monitoring system).

Application of airspace methods for probing gas facilities involving implementation of lasers, infrared imagers and radar photography are the main new trends.

NIIGazeconomica and Institute of Energy Problems in Chemical Physics of Russian Academy have jointly developed a mobile laser and infrared complex designed for quick detection of gas leakage as well as for ecological monitoring at gas industry facilities. This complex includes a laser gas analyzer, inrfared and TV systems, and a coordinate-determining satellite system. Flight tests performed at the Mostransgas's facilities have confirmed high efficiency of the laser and infrared method of gas leakage detecting.

The infrared and TV cameras and the coordinate-determining satellite system allow location of leakages of natural gas and other hydrocarbons in the pipelines, joints, and gas equipment parts. Laser gas analyzers detect light hydrocarbons, aldehyde, methanol, and other spirits as well as mercaptans at the atmospheric surface layers. There is a possibility of cartographic mapping of pollutant concentration distribution profiles.

Gazavtomatica (Russia) has developed an aviation complex to detect remotely the hydrocarbon emissions (RHLDC) which is designed for:

- remote detection of hydrocarbon leakage from pipes with an estimate of their intensity and coordinates;
- ecological monitoring of hydrocarbons emission level.

The complex includes:

- 2-spectral end-scanning infrared highly-sensitive imager;
- continuous 2-wave differential colidar;
- 2-channel TV system.

The RHLDC complex provides:

Investigation speed	up to 150 km/h
Detecting leakage minimum intensity (based on methane)	up to 100 m^3/day

RHLDC is used to detect from an aircraft the areas of higher CH_4 concentration in the atmospheric surface layer in the zone where natural gas was released from the gas pipeline.

The system includes differential infrared laser radars operating over the reflecting infrared radiation.

9 - SYSTEMS TO CONTROL AND ESTIMATE GAS LEAKAGE DURING TRANSMISSION

Service departments in gas transmission companies usually control and estimate gas leakage. Different companies have different inspection intervals. This ranges from continuous control at compressor stations to once a month, once a year or when required.

Vent losses, losses through sealings and during venting through flares are checked and considered.

The following control methods are used to check losses during gas transportation:

- an estimate of differences in the volumes of gas input and withdrawn from the system («non-estimated gas»);
- a normative method based on periodical leakage detection and direct calculation of gas losses during process operations;
- summary of annual emissions data submitted by service enterprises;
- annual audit of gas losses occurred during gas transportation in conformity with a specialized questionnaire (applied only in some companies).

The following measurement methods are used:

- measurement of emissions, CH_4 concentration in the air, gas velocity and temperature at the flares;
- measurement of CH_4 concentration at the vents in compliance with the above mentioned methodology.

10 - REDUCING GAS TRANSMISSION LOSSES

The main measures and technical devices to reduce gas losses during break-downs are aimed at:

- decreasing the number of failures and their sizes;
- improving detection and effective location;
- cutting the time required to repair failures.

The Russian gas transmission systems have taken specific measures to cut transmission losses. Gas losses reduction in the Unified Gas Supply System (UGSS) is achieved through the following:

10.1 - Reduced energy consumption at gas turbine compressor stations (GTCS)

The main areas of activity are:

- improvement of GTU efficiency through replacement of old drivers with new generation highly-efficient drivers. This reduces fuel gas consumption at CSs by 20-30%;
- GCU efficiency increase from 23% to 33-36%. That allows savings up to 8-9 bln.m^3 of fuel gas annually;
- construction of combined cycle plants that improves the CS total efficiency up to 47-52% and, thus, save 18-22 bln.m^3 of fuel gas annually.

10.2 - Gas consumption reduction at CSs process operations

The most dramatic way to reduce gas losses is to improve the reliability of gas turbines and increase the between-failure interval in order to decrease the number of GT starts and shut-downs.

Utilization of gas releasing during GC starts and shut-downs is an important way to cut losses. Implementation of advanced gas-oil sealing system also reduces gas losses at CSs.

The following additional measures may be implemented:

- replacement of natural gas with pressurized air in the starting turbo-expanders, use of electrical and electrohydraulic starting systems;
- limitation of the number of gas emissions from compressor circuits during normal and partly-emergency shut-downs of GCUs;
- development of systems used to withdraw gas from compressor circuits and CS process communications (similar to linear section);
- prevention and control of gas losses over flares.

10.3 - Increase of stop valves tightness

The maim reasons of gas leakages from stop valves are the following:

- wear and tear of ball lock part surfaces;
- disruption of elastomer sealing segments;
- failure of lock seat spring mechanism;
- jam of a foreign body in a lock.

Preventive and urgent repair of stop valves reduces failures arising from leaking and failure of CS stop valves.

Operational resistance of stop and control devices used in the pipelines carrying natural gas contaminated with abrasives significantly depends on the protective materials employed.

10.4 - Pipeline operation effectiveness improvement may be achieved through:

- development and implementation of individual methods to repair linear sections of gas pipes, including those without disrupting gas supplies (under pressure connections);

- use of mobile recompression units to deliver gas from pipeline section to be decommissioned to a parallel gas pipeline or downstream the isolation valve.

As an example, technical performance of the Russian Mobile Recompression is given in Table 13.

1	**Items**	**Units**	**Value**
1	MRCU inlet pressure of pumping gas • max. • min.	MPa	 7.5 1.0-1.4
2	Time • to pump (withdraw) gas from releasing gas pipeline section • to prepare station for work • station service life before the first overhaul	 h h th.h	 no more than 48 no more than 12 not less than 20
3	Overall station service life	th.h	not less than 60
4	Blower pressure ratio		1-5.35
5	Gas turbine power	MW	5

Table 13: Technical and operational performance of the Russian Mobile Recompression units (MRCUs)

All the CS accessories are standard production units (gas turbine drive) or analogous to the sizes manufactured by producer's compressor. The Netherlands has considerable experience in implementing MRCUs.

10.5 - Electrical generators with piston engines using low pressure gas

Gas transportation processes produce low-pressure gases of various compositions and pressures and, in general, in insignificant volumes compared with the flow volume of gas passing. Considering the above, these gases are burnt in flares or released to the atmosphere, thus resulting in ecological and economic damage.

A new trend in utilizing low pressure gases is being investigated in Russia this invorves the creation of a complete range of powerful electrical generators with piston engines which use hydrocarbon low pressure gas as a fuel. Pilot engines with a capacity of 8 kW to 1,100 kW have been tested. Ensuring that the project stipulates the utilisation of low-pressure gas to generate heat and power is a universal way to cut natural gas losses at gas transmission and storage facilities.

10.6 - Reduction of gas losses during repairs

Application of MRCU to pump gas from a pipeline to be decommissioned into parallel gas pipeline or downstream the isolation valve is one of the possible technical solutions. To market the MRCUs, the «Energomashexport» consortium of Russian developers and manufacturers was established.

10.7 - CS and pipeline technical diagnostics

Reliability and security of technical facilities is important to reduce ecological damage. Creation of complex and effective diagnostics system is the basis of Gazprom's technical policy to address this issue.

The intra-pipe diagnostics pigs identify defective pipeline sections and selective repairs can be carried out to avoid accidents. In 1998 11,470 km of gas mains were checked by intra-pipe diagnostics pigs, and 40,980 km - by electric measurement methods. The amount of intra-pipe diagnostics pig inspection has almost doubled compared with 1996.

This has reduced the accident ratio of the gas pipelines from 0.26 per 1000 km in 1997 to 0.24 in 1998, this is close to those registered at the European gas pipelines.

Diagnostics are being performed with the application of the new technological means enhancing the efficiency of such works. The defect detector KOD-4 M was designed and tested in 1998. This device is used for the detection of longitudinal cracks occurring under the stress corrosion cracking.

A systematk approach to the diagnostics in the DAO Orgenergogaz has been provided through the setting up and development of the Integrated - Dissolved Inter-active System aimed at collection, accumulation and the analysis of data on the state gas transmission facilities, and the planning of operating units maintenance.

This System includes the following information blocks:

- actual and statistical data;
- operational data;
- instrumental control data.

The visualization of information is conceived with locality peculiarities to be shown based on the Russian Geo-Informational System Panorama.

10.8 - Measures used to reduce gas losses in Europe

Country/Company	MEASURES USED TO REDUCE GAS LOSSES
France (Gaz de France)	1. Replacement of gas actuated valves by electrically or compressed air-operated valves. 2. Utilisation of dry seals on new engines to replace oil seals. 3. Utilisation of electrical starters on engines to replace gas starters. 4. Research in to minimizing the vent gas quantities during periodic safety tests.
Germany (Ruhrgas)	Pipeline 1. Surveying all pipelines by helicopters every two weeks. 2. A PC-Programm for calculating the pressure loss between the compressor stations on the pipelines. 3. Walking surveys over very old pipelines to asses gas losses or influences of external companies who could damage the pipeline. 4. To avoid gas losses by maitanance on pipelines by recompression into that part which is not to be decompressed. CS 1. Replacement of gasoperated drive assamblies on valves. 2. Utilisation of dry seals on new engines to replace oil seals. 3. Utilisation of elåctrical starters on engines to replace gas starters. 4. No venting of compressors which do have dry seals. 5. Minimizing vent gas quantities whilst carryowt safety test on vent valves by closing hand operated valves in the lines.
Italy (SNAM)	The methodology consists of four different phases: 1. Identification of each specific emitting source; 2. Adjustment of already existing GRI-EPA emission factors and measurement of typical large emitters in order to calculate more accurately their emission factors; 3. Collection of typical activity factors, that are the emitting equipment population and the frequency of emitting events; 4. Calculation of the emission rates for each identified source type, generally multiplying the activity factor by the emission factor for the specific source; 5. Electro-hydraulic and air pneumatic actuators are under test also in M&R stations and along the pipelines; 6. Alternatively, the compressor units can be equipped with electric or hydraulic motors instead of gas expansion turbines; 7. The system allows the compression of the gas to be vented (both from the station and from the unit pipework) directly into the transmission pipeline. Natural gas emissions from vents are also decreased by reducing pipeline network pressure at the lowest possible level before venting for maintenance operations; 8. Part of the gas may be used as fuel gas for the submerged combustion vaporisers while the rest is sent to an absorption tower. The absorption tower contains two rings packing sections where the compressed boil-off gas is absorbed by part of the LNG coming from the booster pumps.
The Netherlands (Gasunie)	1. Stopped rinsing ñompressors. 2. Actuating valves by air instead of natural gas. 3. Chang regulators working with natural gas to regulators working with air. 4. Changing the principal of blending systems. 5. Changing from actuating all kind of equipment with natural gas to air. Also continuously investigating if it is possible to change equipment and processes in a way that less gas is vented to the atmosphere.

11 – REDUCTION OF HARMFUL SUBSTANCES EMISSIONS

In most countries the problem of harmful emissions by stationary combustion units is being solved in two ways: through the fuel firing technology improvement and by nitrogen oxides removal from exhaust gases.

The best approach to optimization is connected with the application of two ways of NOx removal: a dry technology based on the regeneration reaction and a wet one based on the oxidization process.

The state-of-the art technology makes it possible to practically consider the following ways of NOx emissions reduction in the GCUs operation:

- the improvement of processes of natural gas burning in combustion chambers;
- water or steam injection into the GCU chain;
- catalytic units implementation for nitrogen oxides neutralization set up at the exhaust of GCU;
- the enhancement of efficiency of existing GCUs' gas turbine drives followed by the more effective turbine drives of the new generation. This may result in a 20-30% fuel gas consumption decrease and a corresponding CO2 exhaust reduct, because 1 m^3 of natural gas fired in gas turbines produces 1.84 kg of CO2.
- the further NOx decrease due to the GTU's combustion chambers modernization and the implementation of a unit start-up system based on the compressed air, to the optimization of gas engine compressors (GECs) operation in line with the ecological requirements. The implementation of various modifications of GTU (by electrical start-up systems, air-fuel mixture adjustment systems, the automated control of engine rate and leveling off of cylinders load) can provide fuel gas consumption decrease by up to 20%.

In Russia new technology is being use to reduce the impact on the environment: at present there are more than 15 types of engines for equipping GCUs' drive in design, under construction and in the commissioning phase.

Work is progressing in 2 ways to improve ecological performance of gas turbine drives. The first, a decrease of NOx and CO2 emissions by engines operating at compressor stations, will meet the requirements of GOST 28775-90 (NOx content to be not more than 150 mg/Nm^3 and CO - not more than 300 mg/Nm^3). The second, the decrease of NOx emissions by newly designed gas turbine engines to 50 mg/Nm^3, [8-11].

Nitrogen oxide emissions from the process of hydrocarbon fuels firing may be reduced by lowering of temperature in the burning zone and decreasing the time that the burning components are present in the zone of high temperature.

With regard to combustion chamber of GTU, these factors may be achieved by increasing the ratio of air saturation and air velocity registered in the prime zone. At the same time the redistribution of air between the elements of a combustion chamber to raise excessive air flow leads to the decrease in the completeness of fuel burning thus increasing carbon monoxide emission and the hydraulic resistance of a combustion chamber.

This negative performance may be minimized or completely avoided when using air injection into the high temperature zones of a combustion chamber. The method implies the injection of additional air volumes locally, in the zones of burning, where temperature is the highest. Such injection eliminates implicit NOx generation in high temperature zones and "freezes" the burning reaction.

Improvements in the ecological performances of gas compressor units such as Frame-5 and Frame-3 (delivered to Russia at the beginning of 1980 s by the GE licensees) is achieved by reducing NOx emission to 130-140 mg/m^3 with a 15% O2 content. The LDB method is also used due to its efficiency and versatility. This proved when applied to GCU of GTC-10 and when it delivers ecologically improvements to other tyres gas turbine engines. Table 14 shows the summary of data of the works provided, [8].

GTU	Nominal		Modernized	
	Concentration NOx	Concentration CO	Concentration NOx	Concentration CO
GTC-10	788	89	140	200
GT-750-6	840	144	150	200
GT-1500	340	0	97	300
Frame-3	320	0	132	0
GT-100	617	157	300 (Combustion chamber tests were made in a laboratory, the results were translated into actual parameters as if obtained in an on-site tests)	300 (Combustion chamber tests were made in a laboratory, the results were translated into actual parameters as if obtained in an on-site tests)

Table 14: Combustion chambers for various GTUs modernization through the LDB method, (at 15% O2 content), parameters in mg/m^3

Nitrogen oxides emission by the modernized units of GTC-10 (about 140 mg/cm) equals to the technical parameters for the regenerative GCUs under operation in the world meeting the standards (mg/m^3) existing in Russia and in such countries as the USA, Japan, Germany, Italy, The Netherlands.

Research in the lowering of emission level from GCUs in Russia are underway since 1991. In 1992-1998 the modernization of 700 units for GTU-10-4 and 65 units for GT-750-6 made possible a reduce in NOx emissions by 160 t/a (1.8 times lower) despite the extension of GCUs stock by 8% over that time.

A program on low-emission combustion chamber design is based on the «lean-rich» scheme of fuel firing to decrease NOx to 100 mg/cm and lower, and the «lean-rich» burning to decrease NOx emission to 50 mg/m and lower when applied to the two-zone combustion chamber. The engine (gas generator) PS-90GP1 having the above mentioned structure of a combustion chamber with partially out-stead high temperature pipes is under tests. In 1999, this structure will be a basic construction for making experiments with combustion chambers to be applied in 12 and 16 MW capacity engines.

New approaches were applied to the design of a combustion chamber for the NK-36ST engine which include the control of secondary air consumption, the decrease of a fuel presence time in the burning zone; the leaning of an air-fuel mixture; the construction of the two-zone combustion chamber as well as the combustion chamber with out-stead high temperature pipes. The engine with the two-zone combustion chamber produces NOx emissions less than 150 mg/m^3 and CO - less than 300 mg/m^3. The combustion chamber is designed with out-stead high temperature pipes with carburettors and a ceramic lining of inner sides under fire. In future, the ceramic combustion chamber with catalytic process of burning will be developed.

Methods of reduction of CO, CO2, NOx and SO2 in Europe

Country/Company	Methods
France (Gaz de France)	On compression engines, the only method employed consist in installing some Dry Low NOx systems on the new gas turbines. On the other engines, two ways are proposed: - modification of the traditional combustion chamber with Dry Low NOx combustion system; - minimising the use of "pollutant" engines; - replacing the engines, for which no Low NOx system replacement exist, by some new engines; - using, in particular case, some electrical motors instead of some reciprocating engines.
Germany (Ruhrgas)	On turbines the preferred method to reduce emissions is to install a DLN- or DLE-system. On older turbines it is usual to install new combustion liners which are lower in NOx- and CO-emissions. That is done by a system called "EKOL". On gas engines: - Installation of catalytic converters to minimise NOx- and CO-emissions; - Installation of burner to minimise the generation of Nox; - Reducing of output performance.
Italy (SNAM)	- wet methods (water or steam injection); - DLE (dry low emissions) method; - SCR (catalytic combustion).
The Netherlands (Gasunie)	Changed the gas engines to lean burn gas engines and this resulted in a reduction of NOx emission of about 75 %. Carry out tests with low NOx burning cans for some types of gasturbines.

Table 15: Methods of reduction of CO, CO2, NOx and SO2 in Europe

Reduction of CO, CO_2 and NOx

The technology currently nowadays 3 methods for emission reductions from compressor stations installation:

- wet methods (water or steam injection);
- DLE (dry low emissions) method;
- SCR (catalytic combustion).

The wet methods, are widely used in bigger applications (typically energy generation in the range 100 MW and higher) and are not very suitable in compressor stations for the following reasons:

- the amount of water/steam to be injected in the combustion chamber can double the amount of fuel in a particular application, in order to achieve very low emissions limits;
- it is nearly impossible to achieve ultra low emissions limits;
- a water/steam supply is required next to the compressor station;
- because of the non constant working condition of the compressor station, it is not difficult to keep a steam/water injection system and regulate it according to the turbine working load.

For the above mentioned reasons, in the last years DLE methods were developed world-wide and applied to mechanical drive gas turbines - e.g. compressor stations. An example of a DLE combustion system available nowadays is shown in the next figure 5.

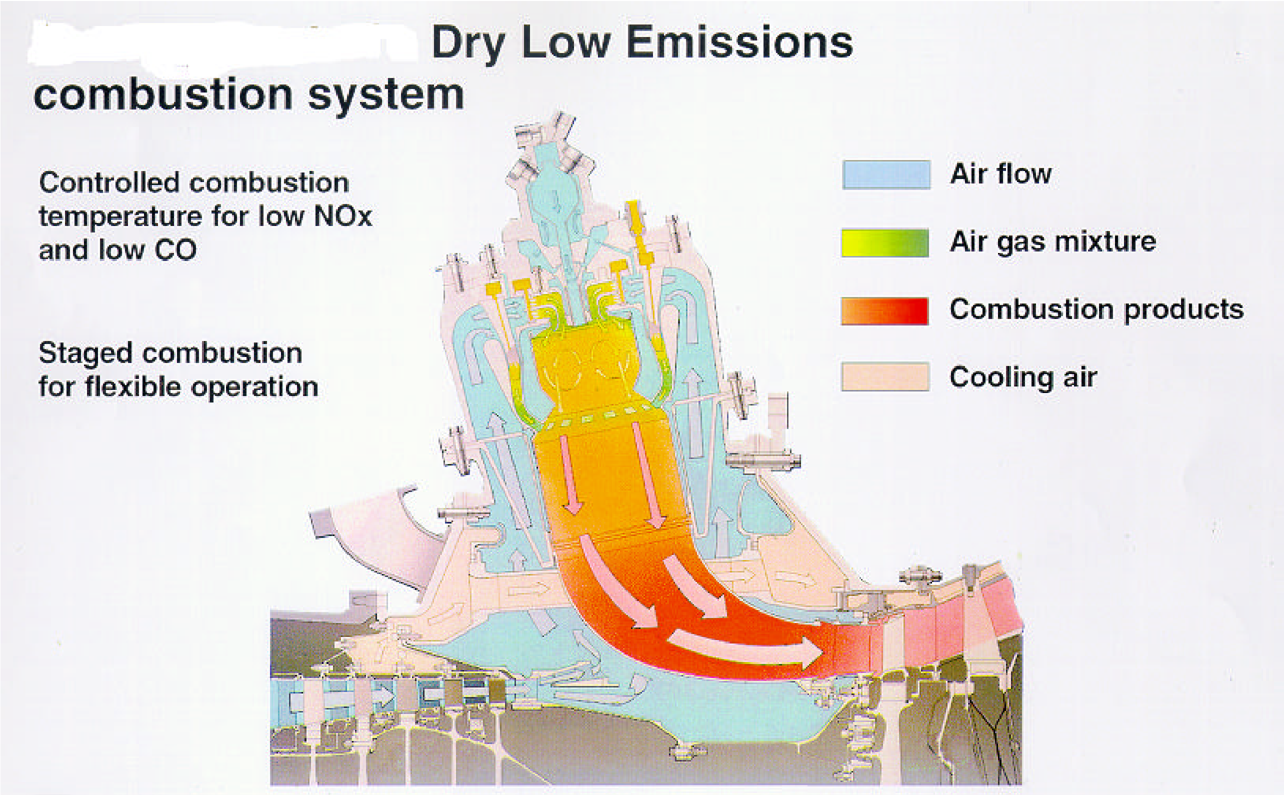

Figure 5: A DLE combustion system

These methods are based on the fluidynamic concept of air/fuel premix prior to the combustion chamber inlet; such premix determines a very minute fluid mixture which does not generate any high peak temperature when ignited, and therefore low NOx emissions value can be achieved (NOx is directly linked to the flame temperature, as shown in the following figure 6). Also if a reasonable amount of fuel is provided to the system, the oxidation reaction of the carbon can be completely developed with nearly no CO formation, but only CO_2.

In this way, running the combustion in the narrow window where both NOx and CO formation is negligible (see fig. 6), very low emission standard can be achieved, in the order of 30 ppmvd for both NOx and CO.

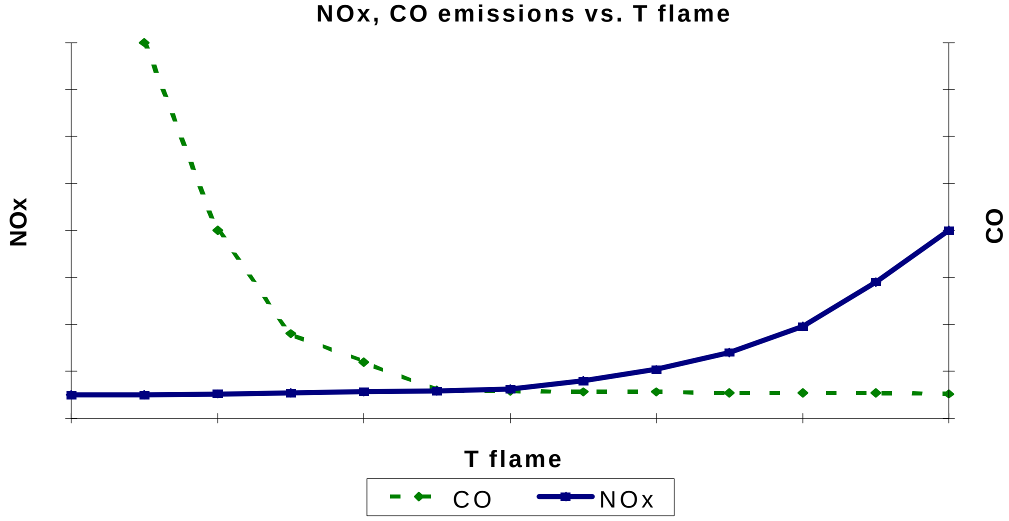

Figure 6: NOx and CO versus T flame

In order to achieve even lower emission values, the catalytic combustion technology can be applied. Such technology is based on the punctual control of the combustion, which follows the stechiometric reaction, with nearly no pollutants formation. In fact, some manufacturers declare emission values in the range of few ppmvd for both NOx and CO. However, it is useful to remember that such technology is nowadays normally adopted just for big thermal plants (in the order of hundreds of MW's).

All the technologies presented above are aimed to reduce the pollutants produced during the combustion - e.g. NOx, CO, UHC, SO_2 etc - but are not effective in respect to the CO_2 formation, because it is the natural product of an oxidation reaction. In order to reduce the CO_2 emissions from gas transmission companies, only one road can be followed: reduction of fuel burned, which means increase of the general efficiency of the plant considered, assuming the need to perform the same service. Such considerations are very strictly related to greenhouse gases emissions reduction and should be considered assuming a bigger point of view.

In accordance with the Directive EV Large Combustion Plant the technological emissions by new GTUs are limited as follows:

NOx - 50 mg/m^3 (at O2 - 15%)

CO - 100 mg/m^3

Modernizing of GTUs to decrease NOx emissions will continue and CO and SO2 emissions are of minor importance. Ruhrgas managed to enhance technological units efficiency in various ways. Gas turbines are being purchased to provide the best efficiency parameters. The process of drying will be modified to improve impurity of gas. Units are being controlled by the central computer, and the main objective of optimization of gas consumption by major unit is obtained.

In addition, the efficiency of an individual unit is under a constant check.

The DLE/DLN technology is considered as the most ambitious to minimize emissions. But, there are some problems with the DLE combustion chambers:

- flame pulsation;
- sensitivity to condensation;
- flame stripping;
- temperature overfall in transitory conditions.

With regard to the with effect of catalysts application on the efficiency of burning there is no operational data available and this problem is in a laboratory study phase.

Share of GCUs based on the DLE technology, %

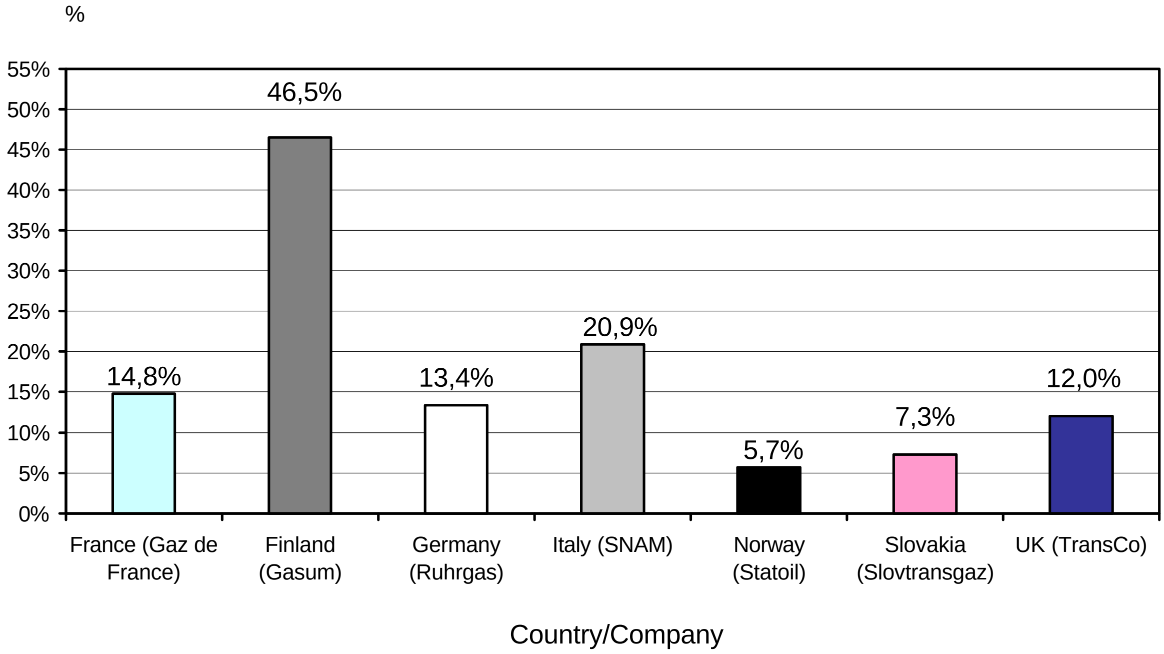

Figure 7: Share of GCUs based on the DLE technology, %

This data demonstrates the insufficient dissemination of this method and the necessity of wide-scale implementation of the DLE technology to decrease the emission of harmful substances due to for gas transmission.

12 - CONCLUSIONS

1. The methane emission problem is a concern to all gas companies. Measures are carried out into practice in order to reduce gas emissions and losses Nevertheless, necessary losses not related to technological features comprise significant amount. That is why reducing these losses would enhance the gas transmission efficiency.

2. The most complete and systematic on-site research of 1420 mm gas pipelines has been carried out by Ruhrgas and the US Environmental Protection Agency jointly with the Russian professionals. In the course of the analysis of compressor stations and linear parts of the pipeline emission causes were identified. It was shown that, methane emissions were less than 0.2% in pipework and 0.7% in compressor stations of the total gas transported through the United Gas Supply System.

3. Major sources of gas losses were detected in the above mentioned study and they are in compressor stations through valves, flare, flanges and during start-up of compressor units. That is why in order to reduce gas emissions new technology and technique are needed:

- leak-proof valves, flare and flanges over the operational life of compressor stations;
- replacement of valves on compressor stations with minimal gas emissions into atmosphere;
- utilisation of electrical and air starters preferentially to gas starters.

4. With regards to major emissions from operation pipelines, the above study showed that about 60% are caused by maintenance and about 30% are attributable to non-tight valving. In order to enhance efficiency and the ecological affect of gas transmission, it is recommended that mobile recompression units should be used to avoid venting of pipeline. That improved fittings are developed that avoid gas interruptions and venting.

5. The analysis of data on existing regulation of harmful emissions into the atmosphere in various countries shows the absence of generality of requirements for residential area and the area in the vicinity of industrial areas.

It is recommended that experts from countries interested in a preparation of the unified international standards on the limits of contaminating substances take into consideration the potential cross-border transference of these substances and their emission into the atmosphere.

6. The experience of diminishing harmful substances emission through exhaust of GCUs exhaust gases in the countries having a complex gas pipeline network was considered.

The DLE technology is regarded as the most efficient for a minimization of harmful substances emission and control. Application of catalysts for the reduction of a harmful substances emission is the next stage.

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21st World Gas Conference – June 6-9, 2000 – Nice - France

Report of Study Group 4.3

«Pipeline Integrity Management and Safety»

Chairman

Pierre Clavel

France

ABSTRACT

This report highlights the Pipeline Integrity Management methods being implemented by gas companies. These aim at maintaining the current high safety level, prevent major hazards, ensure the integrity of the pipeline and protect people and environment in the vicinity of the pipeline in the most cost effective way. It should be noticed that Pipeline Integrity Management aspects, technical and organisational, are included in the more general framework of the Safety Management System. Currently, more and more gas companies implement such a system on the basis of standards like ISO 9000 and so on.

In this way, the report shows how practices of Pipeline Integrity Management are continually developing in order to adapt to their environment, and to improve performance. Past experience and imminent developments show that Pipeline Integrity Management is a flexible and efficient approach to improve safety in the long term. Consequently, Pipeline Integrity Management Systems are, under the control of authorities, the best alternative to additional safety regulations.

Within the context of deregulation of the European markets and globalisation, Pipeline Integrity Management appears to be a tool to promote the gas industry in the eyes of the authorities, the market regulators and the customers (industrials, ...).

RÉSUMÉ

Ce rapport expose les méthodes de gestion de l'intégrité des canalisations mises en oeuvre par les compagnies gazières. Ces méthodes visent à maintenir le haut niveau de sécurité déjà atteint, à prévenir les risques d'accidents majeurs, à assurer l'intégrité des canalisations et à protéger les personnes et l'environnement au voisinage de ces dernières avec une efficacité technique et économique optimale. On peut déjà noter que les différents aspects propres à la gestion de l'intégrité des canalisations, qu'ils soient techniques ou organisationnels, sont inclus dans la structure plus globale des Systèmes de Management de la Sécurité. Actuellement, de plus en plus des compagnies gazières mettent en place des systèmes de ce type, basé sur de standards tel que l'ISO 9000.

Dans ce contexte, le rapport montre comment les pratiques en matière de la gestion de l'intégrité des canalisations sont l'objet de développements permanents afin de s'adapter à leur environnement et d'améliorer leur performance. Le retour d'expérience passé comme les prochains développements à venir montrent que la gestion de l'intégrité des canalisations est une approche flexible et efficace pour améliorer la sécurité sur le long terme. Les systèmes de gestion de l'intégrité des canalisations, mis en oeuvre sous le contrôle des Autorités, apparaissent donc comme la meilleure alternative à de nouvelles mesures réglementaires dans le domaine de la sécurité.

Dans le contexte de globalisation et d'ouverture du marché européen, la gestion de l'intégrité des canalisations apparaît comme un outil capable de promouvoir l'industrie du gaz aux yeux des Autorités, des régulateurs du marché et des clients (industriels, ...).

TABLE OF CONTENTS

1 - INTRODUCTION

Social opinion in all countries of the world demand more openness in respect to the safety and risk reduction in the gas industry.

Taking this into considerations, IGU's members decided to prepare this report which aims to demonstrate that:

- The high safety level of natural gas transmission pipelines are a result of good practices;
- Gas companies are making continuous efforts to maintain and improve this high safety level;
- Pipeline Integrity Management is a powerful tool for achieving and demonstrating the safety performance.

To support this report, an extended investigation into the gas transmission industry has been performed looking at among others:

- operator’s pipeline network;
- adopted practices of Pipeline Integrity Management;
- hazard identification;
- hazard/risk analysis;
- recommendations on "good practices", and the most beneficial rules to safeguard pipelines integrity.

A questionnaire has been used to collect information on gas transmission pipeline networks with an operating pressure above 16 bar, both offshore and onshore, consisting of pipelines and valves and all safety devices. Delivery station, pressure relief stations, compressor stations, metering stations, gas storages and gas treatment plants have been excluded.

The answers coming from Europe, Asia and America have included twenty-two gas companies with about 120 000 km onshore high pressure pipeline and about 5800 km offshore pipeline.

A considerable part of this system runs through populated areas reaching an high percentage of each national territory.

The gas companies co-operating in the study (with about 75000 employees) represent significant economical entities in their national countries.

The total volume of gas transported per year is more than 525 billion m^3 covering from 10% to 100% of the gas transport needs of each country.

The experience of these gas companies includes more than 50 years of activity: Their pipelines have been constructed and commissioned in different periods over the last half of this century and therefore they represent a complete outline, both technical and economical, of the development of onshore gas transportation.

More recently is the experience in the offshore gas transmission. Since 1974 the pipelines constructed offshore have been more than 5800 km.

The exposed length (i.e. the length of each pipe multiplied by its age) of the onshore pipelines grid considered is approximately 2.7 million kilometres.years.

Table 1 summarises some general information collected by the questionnaires.

Number of companies	22
Number of employees	~ 75.000
Operating Pressure	≥ 16 bar
Pipelines onshore length	~ 120.000 km
Pipelines offshore length	~ 5800 km
Total length	~ 125800 km

Table 1

Consequently the information collected and analysed represent an extensive and relevant reference for the goals of this study.

2 - OBJECTIVES AND GOALS OF PIPELINE INTEGRITY MANAGEMENT

Safety is one of the prime consideration for gas companies world-wide. It is central to every step of the process of gas supply and it is essential to maintain customer and public confidence.

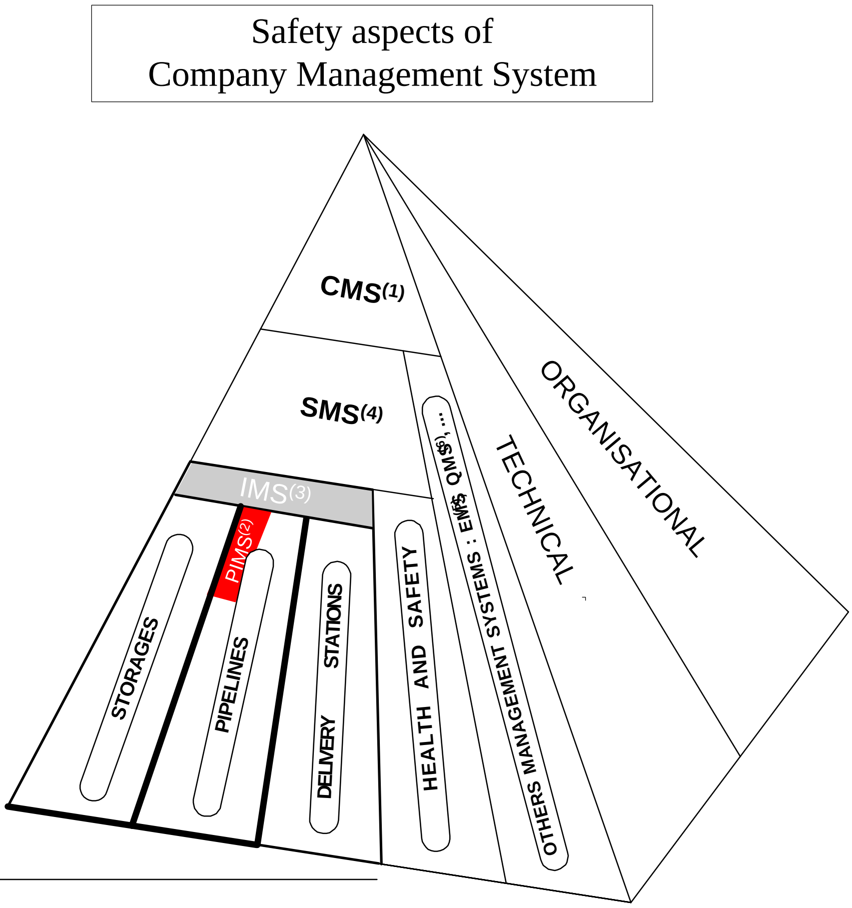
All the gas companies involved in the gas transportation business spend considerable amounts every year on safety related activities which are part of a comprehensive Pipelines Integrity Management System.

The main aim is to protect employees, the general public, the environment and the company assets through the systematic application of management policies, procedures and practices to identify, analyse and control hazards and risks.

The system has to demonstrate to competent authorities that adequate managerial and organisational measures have been put into place to prevent and control incidents, to limit their consequences for man and the environment and that appropriate emergency planning is in place. Additionally it has to demonstrate that technical safety and integrity of the whole system has been achieved by way of appropriate design, construction, operation, maintenance and inspection based on agreed high technical standards and codes.

Pipeline Integrity Management System is based on systematic and formalised improvement. This is achieved by identifying shortcomings and making corrections, taking into account lessons learned from reported incidents, and adopting new technologies. The effectiveness and suitability of system for auditing and reviewing procedures has to assure the efficiency and the updating of the system.

The relationship of Pipeline Integrity Management System to other management system is illustrated in the figure 1:



(1) Company Management System
(2) Pipelines Integrity Management System
(3) Integrity Management System
(4) Safety Management System
(5) Environment management system
(6) Quality management system

Figure 1

Safety management system (SMS) is one part of the global Company management system (CMS). Other specific management systems are also included in the CMS (e.g. Environment management system (EMS), Quality management system (QMS), Integrity management system (IMS) is the technical and organisational core of the SMS.

In this report the aspects given below are addressed in more detail in the following chapters:

- The role of the standards and international documentation;
- Design phase of a pipeline project;
- Construction;
- Operation;
- Methods to demonstrate the pipelines integrity;
- Incident/accident reporting, emergency planning, land use planning and public information;
- Role of the competent authorities.

3 - BASIC INFIRMATION REGARDING GAS OPERATOR’S NETWORK

As mentioned in the introduction of the report, the gas operator's network for which the study group collected technical and organisational data is a significant representation of the state of art, particularly as regard as the pipelines integrity and safety.

Figure 2 shows the year of construction of the pipelines network included in the present study.

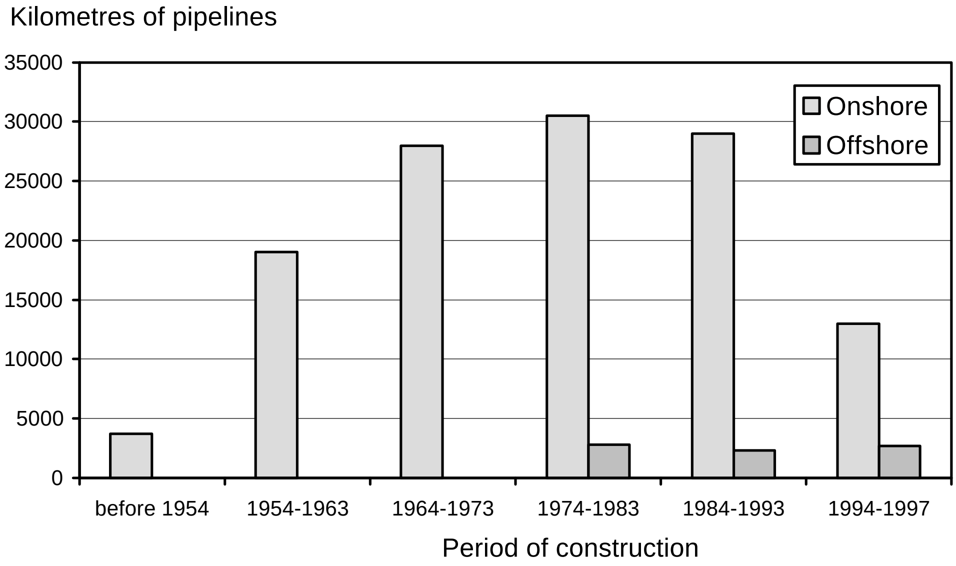


Figure 2: Year of construction of the pipelines.

In Figure 3, 4 and 5 some of the more significant parameters of this pipeline network are shown to give indications about the differences which the gas companies have to consider.

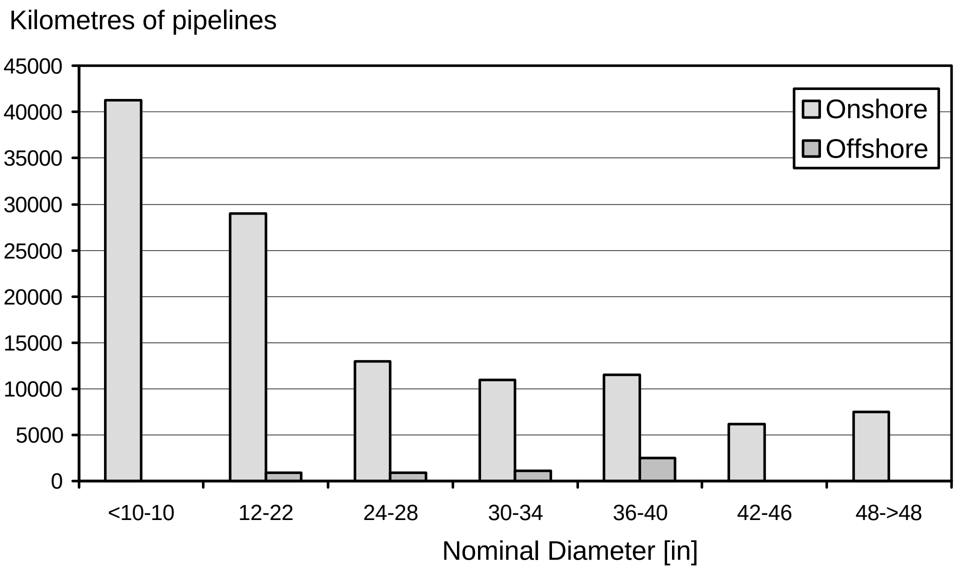


Figure 3: Diameters of the pipelines

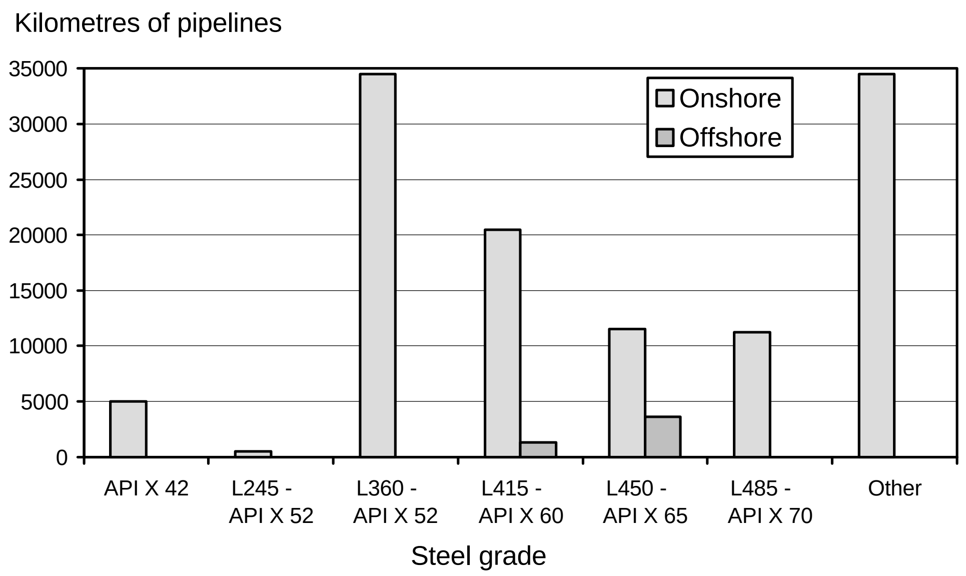


Figure 4: Steel grade of the pipelines

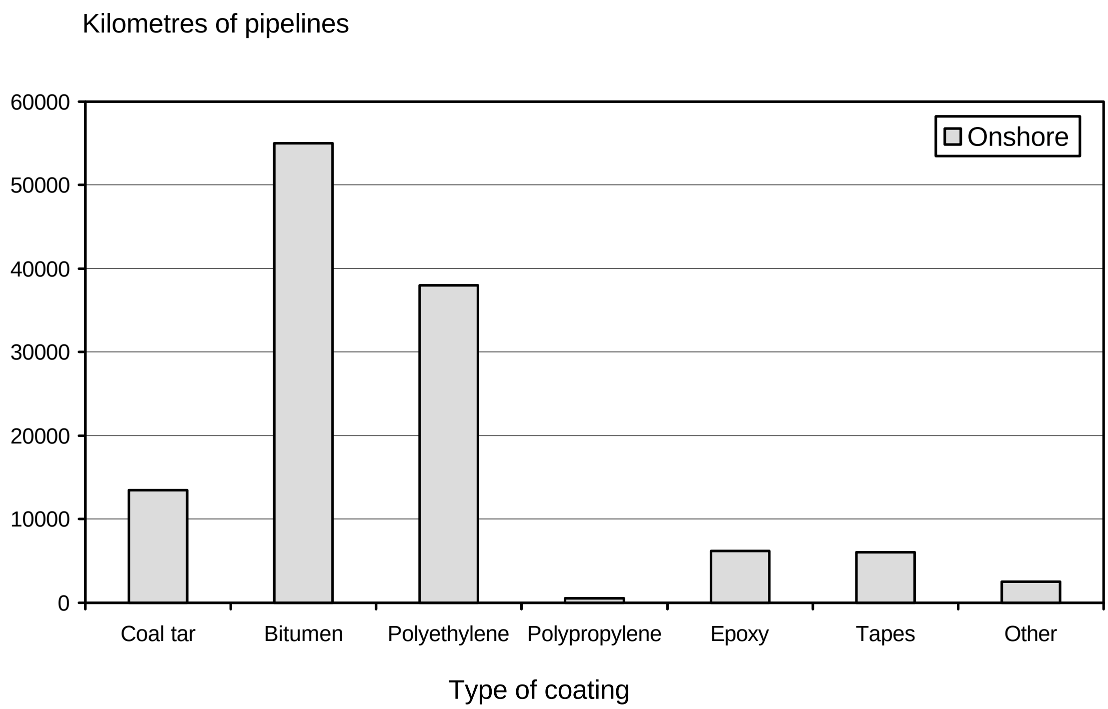


Figure 5: Type of external coating

A considerable number of technical problems have to be faced: the diameter range covers diameters up to 56” (40” for offshore); the steel grade has been modified and improved both for metallurgical quality and the production technology, especially over the last years. The coating type also has changed from bitumen to polyethylene.

Using these three parameters it is apparent that the gas companies participating are an average of the members of the International Gas Union.

Figure 6 and 7 show the approximate percentage of pipelines onshore and offshore grid vs. operating pressure: in more than the 70% of the onshore pipelines population the pressure is higher than 45 bars and more than 75 bar for 95% of the offshore pipelines population.

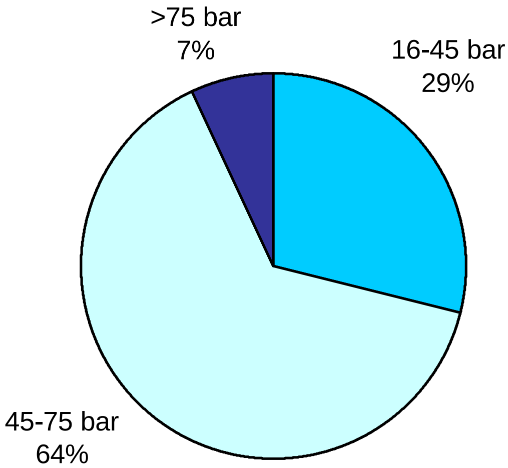


Figure 6: Operating pressure in the onshore pipelines network

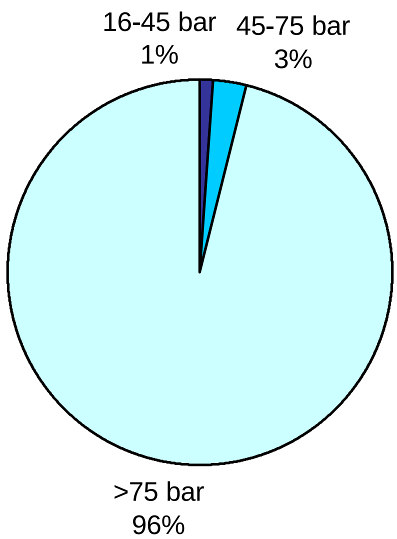


Figure 7: Operating pressure in offshore pipelines network

To manage such a complex industrial situation every Gas company has adopted detailed, prescriptive codes and procedures that are documented and recognised both at national and at international level. Standards as ANSI[1], API[2], ASME[3], DIN[4], EN[5], ISO[6] represent a common and accepted technical know-how available to all the companies.

This means that most operators design and operate their pipelines using similar codes and procedures.

It was established from the questionnaires returned that a large number of common or similar procedures regarding design, construction, operation and maintenance of a pipeline are in existence.

For instance, the design of a pipeline is based on a well-known vessel formula with design factor according to the limits of operation. In most cases the design factor used is set according to the classification of the territory (class location). The depth of cover adopted for new pipelines is set to be between 0.8 m and 1.5 m. The coating used nowadays is generally polyethylene. All gas companies operate a system for active cathodic protection in order to prevent corrosion (and in more than 90% of the received answers this applies to the whole pipelines grid). In the majority of the countries (with the exception for those gas companies operating in town areas) a strip of land on each side of the pipe is established with limited access during operation. The welds of all the new pipelines are examined by appropriate non-destructive methods as radiographs (X or gamma rays) and/or ultrasonic systems. Hydrostatic tests are carried out before commissioning.

Through the analysis of the information relevant to the operational phase it is possible to have a general idea about the measures taken for the pipelines integrity, e.g. such as surveillance for prevention of third party damages, check of cathodic protection criteria to avoid metal loss, measurement of pipe potential to detect coating defects, monitoring of ground movement to control additional stress, line inspection to monitor the condition of the pipes.

All gas companies survey and monitor the pipelines through patrolling and aerial survey, with different frequencies depending on the land use and the pipeline itself.

The main transport grid is constantly supervised and managed by a grid control/dispatching centre (about 90% of the situation).

The gas companies perform line inspection by intelligent pig (more than 40% for onshore and 100% for offshore of the total grid is piggable) on set times intervals.

The above technical aspects are a part of the activities carried out by the gas companies to ensure an efficient and safe gas transportation.

The gas companies have several additional preventive measures including control measures to identify and determine whether the standard operational measures are effective.

The technical aspects are included in structured management systems adopted by the majority of the gas companies even if structural and organisational differences exist among them (see figure 1).

In some cases (about 65% of the analysed situation) the whole system has been internally formalised and in some cases it is wholly or partially certified according to international standard (i.e. ISO 9000, BS 8800 and so on).

However, since the relationship with Authorities (Local or National), Land Owners, General Public are regulated by different rules and laws, differences such as the planning of the territory or the public information, can be adopted. However the differences, in most cases relate to form and not substance. All gas companies are interested in an open and confident relationship with the public.

4 - KEY ELEMENTS AND PERFORMANCES OF PIPELINE INTEGRITY MANAGEMENT

Key elements of a Pipeline Integrity Management System are:

- technical safety including codes and standards;
- pipeline integrity including monitoring and inspection;
- safety management;
- emergency planning;
- land use planning;
- public information / consultation;
- role of authorities.

In the following paragraphs the above seven key elements of the Pipeline Integrity Management will be discussed using the information extracted from the answers to the questionnaire:

4.1 - Technical safety including codes and standards

In most countries, standards and codes have been used in the design and construction phase for the selection of materials, equipment, methodologies and procedures. These standards and codes differ between companies and from country to country. Despite the differences in codes and procedures the overall level on incidents and accidents caused by gas transport is almost the same. In comparison with other means of transportation (road, rail, ship), transportation by pipelines is the safest form of transportation, and in relation to the amount of commodity transported it is the most efficient method of transportation.

Ongoing research and the introduction of quality systems for designing and construction appear to have significantly impoved quality.

Most gas companies in Europe participated to and have accepted the newly developed CEN standards for the safe design and use of gas supply systems, based upon the best available practices.

Therefore by using detailed, prescriptive standards and codes, the existing high levels of safety can be maintained and the hazards to people and environment can be minimised. Taking into account the long exposure in the sense of the integrated length of kilometres of pipelines per year, the gas industry has proven to be “fit for purpose”. With respect to safety, the different concepts are equal. All of them cover the same main key elements. Thereof there is no need for extra harmonisation.

4.2 – Pipelines integrity including monitoring and inspection

Pipelines integrity consists of processes and activities to review on a regular basis and to continuously improve procedures in order to ensure that the pipeline is maintained fit for purpose. In general these measures prevent incidents caused by external interference, corrosion, ground movements and by construction and material defects. This means that gas companies can carry out integrity measures such as:

- non-destructive testing of welds;
- material testing (high yield loads and tensile strength testing);
- corrosion control and cathodic protection measurements;
- coating defect surveys;
- survey for detecting third party damage:
  - aerial survey,
  - patrolling by car,
  - walking over the pipeline,
- geographical and intelligent pigging;
- one call systems;
- surveying impact of changes from the land-use planning to the pipeline zoning;

- soil erosion, vegetation and ground movement observation or monitoring;
- stress and leak test hydrostatically and drying;
- modification procedures and monitoring.

The above mentioned measures can be divided into design, construction and operations measures.

The criteria and frequencies used for these measures differ from one Gas company to another, but are adapted to specific situations.

Measures used in the pipeline lifetime could be any combination in the following table:

Measures		
desing	**construction**	**operational**
detailed and specific desing criteria	non-destructive welding tests	cathodic protection monitoring
material testing	coating (holiday) test	corrosion control
quality management	cathodic protection tests	External inspection:
routing selection	strength test	• coating defects surveys
	tightness test	• aerial survey
	pigrun (clean / dents)	• car survey
	pipeline inspection	• ROV survey for off-shore pipelines
	quality controls	• walk over the line
		land use planning monitoring
		one call system follow up
		excavation supervision
		soil erosion/ground movement survey
		strength test
		pigrun (clean, geometric, intelligent)
		modification control
		feedback : incident/failure analysis
		quality controls

Table 2

From the replies received to the questionnaire the following conclusions may be drawn:

- a hydrostatic strength test is executed by all Gas company during the construction phase;
- all welds are completely tested by a non destructive test;
- depending on the environment and the pipeline itself, the frequency of route patrolling varies from 3 times a day to once a year;
- intelligent pigruns are not a standard operational measure in most of the companies. This measure is used only on specific cases to verify the effectiveness of the regular measures.

4.3 – Safety management

The safety management aspects of Pipeline Integrity Management System are linked to the overall Safety Management System. They cover:

- the managerial and organisational system and procedures by which the safety objectives are to be achieved;
- the performance measurement system;
- the audit system by which the efficiency and effectiveness of the system is to be maintained.

As mentioned in chapter 3, some gas companies have implemented the Pipeline Integrity Management into a certified system according to among others ISO 9000, BS 8800 and so on. Most of the gas companies have developed and are working according to the quality standards, without being formally certified. Some gas companies have their own internal auditing and reviewing processes.

From incidents reports and answers to the questionnaire regarding the influence of incidents on technical practices, it appears that every incident is thoroughly analysed. This is one of the key items of safety management. The principal impact of this feedback is the permanent adaptation of internal processes of gas companies to improve the safety level of their installation.

4.4 – Emergency planning

An emergency planning provides tested and reviewed procedures in order to mitigate the consequences from a hazardous incident. This comprises the following procedures:

- Activating the alarm and mobilising consequence reduction activities;
- Listing of responsible persons who will take charge of prescribed actions;
- Coordination of on- and off-site actions;
- Arrangements for co-ordinating actions and resources in the event that local authorities (mayor, fire brigade, police) are taking over the responsibility of the co-ordinating actions.

From the EGIG[7] database we learn that more than 40% of the incidents are reported first by the public. The second source (21%) of incident reporting for (European) gas companies is the patrolling survey.

In all gas companies the grid/dispatching centres are manned 24 hour a day. Gas companies are training their personnel on a regular basis, and with local authorities at least once a year.

4.5 – Land use planning

In most countries land use planning is regulated by national legislation and implemented by local authorities. In general new transmission pipelines require a permit from the authorities, such as:

- the right of way where the Gas company is not the landowner;
- restriction regarding constructions (buildings, other industry) in a zone hereafter called protection or safety zone.

Additional measures are taken in case of road, river or rail road crossings.

In most countries, the right of way zoning distance varies from 1 to 10 meter on either side of the pipeline. A 5 meter right of way zoning distance is normally used by most companies. The right of way zoning is normally established in a standard way or in some cases based upon the diameter or pressure of the pipeline.

The protection or safety zone varies from 2 to 50 meter either side of the pipeline. Construction work and agriculture work such as deep-ploughing in the protection or safety zone are strictly controlled or forbidden. The protection or safety zone is determined in many different ways. The minimum distance from the pipeline is calculated based upon:

- deterministic values or;
- risk assessment or;
- diameter or;
- pressure or;
- a function comprising pressure, diameter and design factor of the pipeline.

Specific or extra safety measures can be taken case by case to reduce the width of protection or safety zone and as risk reducing measures if the land is going to be used or the class location is changed due to new development plans.

To protect the right of way zoning distance from unauthorised access (for instance construction work, heavy loads, etceteras), gas companies monitor the land use planning on a regular basis and carry out survey.

All gas companies are using markers to indicate the location of the pipeline. Special attention is paid to the visibility of markers for aerial surveys. All road, water, rail road and cable crossing are amply provided with markers. The distance between markers along the pipeline varies according to criteria such as airborne visibility or changes of pipeline directions.

4.6 – Public information / consultation

The public and/or the local authorities are informed by most of the gas companies on a regular basis. The occasions on which information is legally required to be given to the public or local authorities are listed below:

- whenever an incident has occurred it will be reported to the local authorities depending on the severity of hazard of the damage caused;

- public hearings organised to inform the public and to obtain permission from local authorities for laying a new pipeline;

- large venting operations will be reported to the authorities and public living close the pipeline;

- gas companies provide information to the public through a number of methods. The information to the public is handed over by means of brochures, internal news papers, press releases/conferences, advertisements on national television channels, excursions to the head office, information material in libraries, etc.;

- in some cases a risk study or an Environmental Impact Assessment (EIA) has to be carried out and consequences will be discussed with the public, local and/or national authorities. As a result additional measures may be demanded by the authorities. This will also be the case when the company has not been able to show that the new pipeline meets the safety or environmental requirements;

- contractors performing digging activities close to pipelines in the past were visited to inform them about the associated hazards of gas pipelines. They were also made aware of the one call system (or regulatory system) in the country. As a result of this campaign more activities near pipelines are notified to the gas companies.

4.7 – Role of authorities

Authorities expect the gas industry (in the current regulatory climate) to manage the prevention of incidents and to minimise the eventual consequences. This control is based on a hazard/

risk analysis. Whether this analysis is performed in a deterministic or probabilistic way depends on practices and national legal requirements.

In the answers to the questionnaire the gas companies indicate that permits are required in the design / construction phase for laying new pipelines and diversions of the network. There are some official periodical controls or audits by the competent authorities in the operational phase of the pipelines lifetime, but a more controlling role by the competent authorities is not required. Because of the comprehensive set of detailed internal standards and codes and the national and international legislation, there is no need in many countries for additional regulations or new legal requirements.

Since transportation of gas is very well developed, the Codes of practice are comprehensive and do not require significant improvements. Consequently there is no need for competent authorities to move toward exercising more control to prevent incidents.

4.8 – Performances of Pipeline Integrity Management

The questionnaire to the members of the IGU obtained detailed information about the above mentioned issues. The answers from gas companies throughout Europe, America and Asia are summarised in Table 3:

Distribution of threats on pipelines	
Threat	**%**
third party interference	73
external corrosion	12
internal corrosion	1
ground movement	7
welding defect	2
lightning	1
other	4
Total	100

Table 3

Although the main threat to pipelines does not originate from the gas industry itself, the gas companies are doing their utmost to reduce any hazard. Pipeline Integrity Management allows gas companies to be able to control and to demonstrate to the public and competent authorities the effectiveness of preventive measures against associated threats.

The use of legislative requirements, national codes, internal standards and prudent operation results in specific and effective criteria for each process regarding the planning, design, construction, maintenance and abandonment phase of a specific pipeline. In order to maintain the high performance, the gas industry has worked diligently for the past decade on the development of a Pipeline Integrity Management.

Pipeline Integrity Management reflects the current activities to prevent and control incidents and accidents and the appropriate activities to minimise the consequences to people and environment. Since the majority of causes of incidents do not originate from the industry itself, good cooperation between authorities and gas companies is essential.

It is not the IGU's role to publish data that has already been collected in a more sophisticated way by other organisations. Some of the data received from the questionnaires can be compared to other sources like the DOT[8] and EGIG[7] database. All incidents are based upon events with unintended gas releases.

For instance, the EGIG[7] database consist only of incidents with an unintended release of gas related to onshore gas transmission pipelines with a design pressure above 15 bar outside fences of installations and excluding the valve and compressor stations. It is clear that the good performance of Pipeline Integrity Management is reflected as a decreasing overall incident frequency as shown in figure 8.

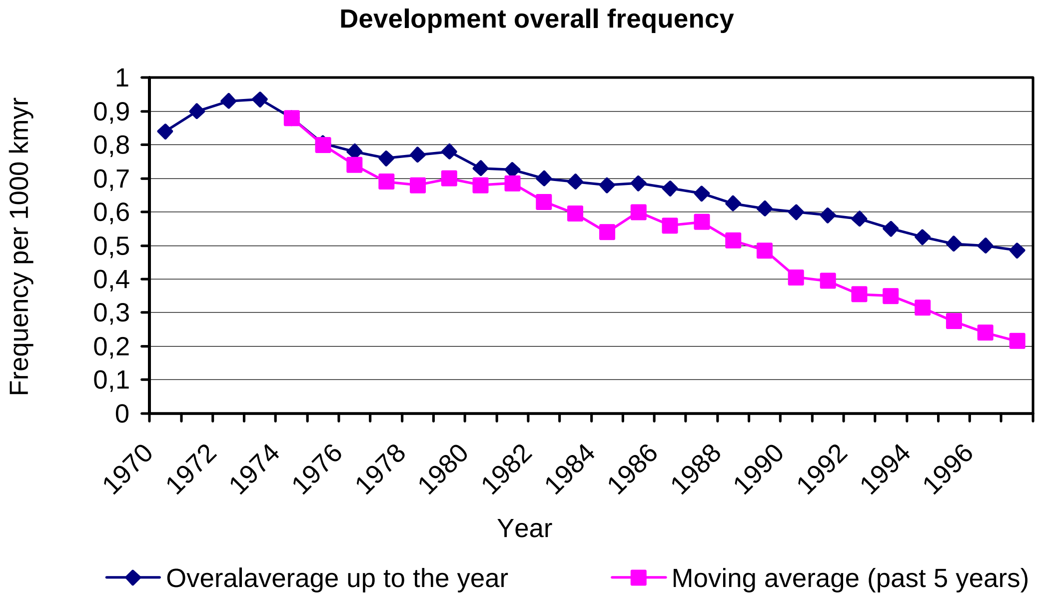


Figure 8

The incidents are categorised by the leak size into three types:

- pinhole/crack (defect size < 2 cm ∅);
- hole (2 cm ∅ < defect size < pipe diameter ∅);
- rupture (defect size > pipe diameter ∅).

An overview of the incident frequencies by cause and type of leak in the 1970 to 1997 period is given in figure 9.

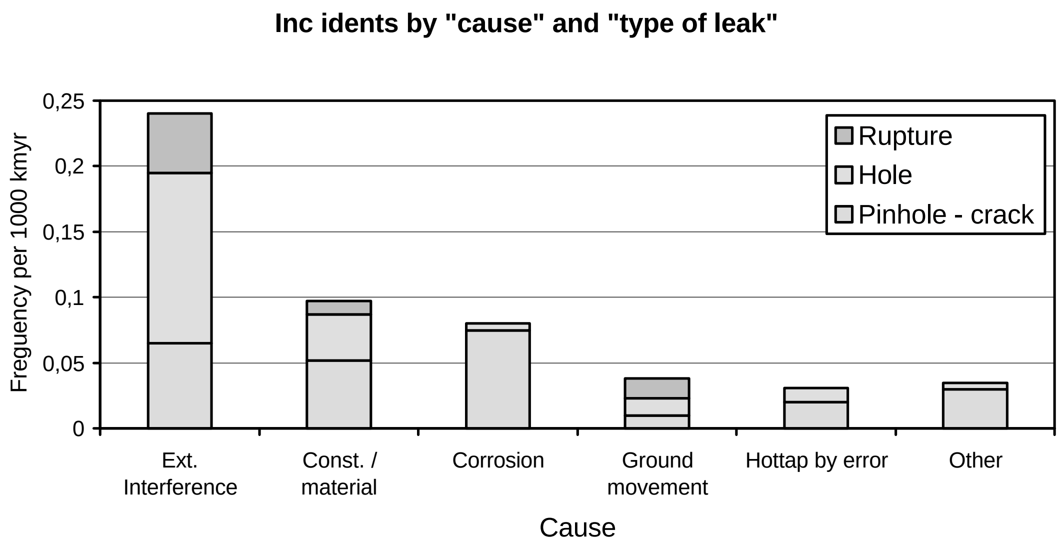


Figure 9

The distribution of incident causes or threats to the pipelines are detailed in table 4.

	Distribution of threats on pipelines		
	EGIG [1])	EGIG [2])	DOT [3])
Threat	% of reported incidents		
third party interference	50	47	40
external corrosion	12	13	15
internal corrosion	3	4	9
corrosion	15	17	25
ground movement	6	9	11
material & construction defects	18	11	12
lightning			1
hot tap	5	8	
equip. and operation			6
other	6	8	5
Total	100	100	100

Table 4

As stated previously, theses figures are more representative than the figures given in table 4.

This table highlight that the distribution of incident causes or threats to the pipelines are comparable in Europe and in the USA.

[1]) EGIG[7] figures based on the mean values of the cumulative figures from 1970 through 1997.
[2]) EGIG[7] figures based on the mean values of the cumulative figures from 1993 through 1997.
[3]) DOT[8] figures based on the information of the final DOT[8] report (PR-218-9603) named "Reportable Incidents Data Review Vat. Gas Transmission and Gathering Systems 1985 through 1995", and on information found on the Internet.

5 - HAZARD IDENTIFICATION AND SAFETY STUDIES

Activities to manage pipelines safety and determine the risk of loss of containment share common features throughout the world. However, many of these activities were developed under principles other than hazard, risk or safety management. They are often based on fundamental scientific and engineering principles relating to maintenance, loss prevention and equipment reliability.

The degree to which these practices and analysis of hazard or risk are developed by individual gas companies or government varies from country to country. The purpose of such analyses is to identify, classify, and rank, in relative terms, the kind of system failure modes that can lead to an incident.

5.1 – Hazard/Risk Identification : Review of Different Objectives

Hazard identification is strongly based on field experience. Hazards which must be taken into consideration have usually occurred in the past, or are plausible in view of similar failures or near misses. Therefore, collecting data from earlier experience is important for every Gas company and in many countries such work was initiated many years ago or at the latest when the gas business started up. Nowadays, many gas companies have their own electronic database with a unique and systematic data structure revealing all details of incidents or accidents that have occurred. They include information on time and location of a failure or near misses, technical design details, such as diameter, wall thickness, steel grade, year of construction, as well as details on operation, maintenance procedures and especially the cause of failure.

For all companies, a careful analysis of failure causes is the basis of assessing the severity of an incident in terms of possible repetition and taking any necessary additional precautionary measures. Some gas companies use the incident data collected to estimate failure frequencies required for risk studies.

Besides Gas company owned databases, there are a large number of different sources of information on incidents world-wide. Gas companies exchange data with other gas companies where they have compatible statutory or geographical frameworks. National associations or inspectorates provide data on incidents as do some reputed consultants. Especially for Western Europe, reliable data on incident frequencies have been collected by the EGIG[7] consisting of European gas companies with an overall pipelines experience of more than 1.98 million year-kilometres. Some gas companies have developed their own theoretical models for estimating failure frequency on the basis of such information.

There are various ways of classifying hazards: Classification by causes of failure produces the hazard categories presented previously in table 5.

Since the expected physical consequences of hazards involving unintentional gas releases depend on the size of the leak, it is obvious to distinguish between the three classes presented in figure 10 (pinhole/crack, hole, rupture, ...).

Generally, incidents of major concern are those which involve gas release (plume) <u>and</u> ignition causing fire and damage to people, property or the environment. (Other effects like overpressure or debris fall are sometimes considered but are typically of minor importance. In the case of "sour gas", the toxicity also needs to be taken into account.) This leads to different hazard classes based on the analysis of the vicinity of a pipeline and consequences for people, property or a monetary equivalent. Thus, the number of people involved, the amount of gas released, the duration of gas supply interruption, the re-construction costs are other scales for hazard classification. In addition, the likelihood of a hazard – especially the probability for ignition – can be considered as an important factor.

Statutory requirements also stipulate categories of incidents, such as those which involve the public or company staff (inside/outside installations), reportable incidents and minor incidents which are not reportable.

Hazard analysis presents a very mixed picture. For most gas companies, this analysis is performed in three principal steps:

1. analysing potential incident causes;
2. selecting appropriate mathematical models;
3. assessing consequences.

Related matters are:

- to identify appropriate action to counter various threats and reduce incident frequencies;
- to gain a deeper insight into the possible effects and the impact on the vicinity of a pipeline, we must keep in mind that incidents can and will happen since technology and human being will never be perfect and, as threats like third-party interference can never be totally excluded;
- to identify locations with a higher risk level where additional safety measures are required.

In essence, all these methods of hazard or risk identification show that operators have installed processes inside their companies to learn from experience, to promote the awareness of safety-related matters, and to contribute to continuous improvement of their safety records.

5.2 – Hazard/Risk Analysis : Review of Different Methods

Different incident scenarios can lead to different types of hazard with different degrees of severity. A systematic analysis linking the input data defining the scenario to the output data characterising the hazard is called "hazard analysis". If, in addition to the consequences of an incident, the likelihood of its occurrence is also considered, such an analysis is called a "risk analysis". By definition, risk R is the product of likelihood P and consequence C in the formula:

$\underline{R = P \cdot C,}$

and is therefore always a weighting of consequences.

Figure 10 is a brief outline of a typical risk analysis process. Hazard analyses are performed in a similar manner without evaluating incident frequencies.

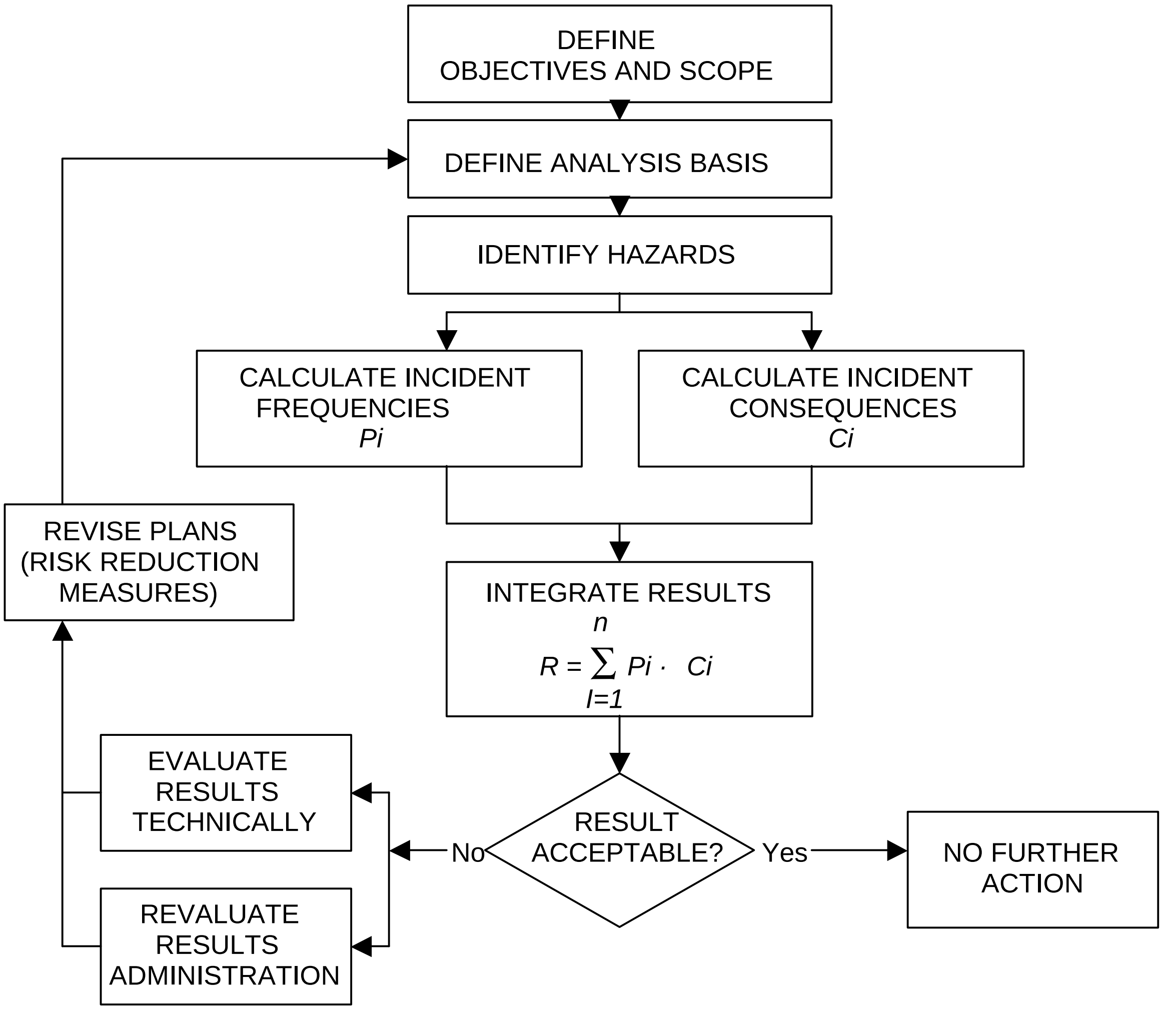


Figure 10: Risk analysis procedure

Hazard and risk analyses offer pipelines operators nothing which is completely new but provide a systematic set of methods to identify weak points in the pipelines grid or to assess the effectiveness of safety measures.

For this reason, it may appear difficult to judge whether a Gas company uses hazard or risk analysis techniques, although implicitly or explicitly it probably will use both.

In countries which have detailed technical codes and standards, these analyses have been carried out by engineering associations and the results incorporated into the technical codes and standards. Internal companies standards are constantly updated on the basis of experience gained in day-to-day operation and related analyses. Gas companies strictly follow established design standards and many also have a comprehensive set of internal standards. If these measures are implemented and the processes described in these documents followed, the company can be considered to have provided reasonable and sufficient protection against plausible hazards.

In other countries, the authorities also require, on a case-by-case basis, additional consequence or risk evaluations depending on their particularly favoured and widely accepted safety philosophy which would be probabilistic or deterministic. In the probabilistic philosophy, "risk" is at the forefront of all considerations. To determine the risk, possible negative consequences are quantified in a risk analysis, multiplied by the estimated probability of occurrence and then aggregated. In the deterministic philosophy, the chain of causal links that might lead to an undesirable incident is traced back and suitable precautions designed to preclude the event are determined.

In any case, a large number of details characterising a scenario have to be known for such analyses. The following steps are made (brackets indicate necessary calculations for risk evaluation only):

- identification and quantification of parameters characterising the pipe, gas, air, site, etc.;
- determination of failure mode;
- determination of failure size (and frequency);
- calculation of gas escape;
- (estimation of ignition probability);
- calculation of heat radiation;
- conversion into consequences on man – e.g. lethality - and structure;
- (calculation of risks such as individual risks, inhabitant risks or societal risks).

The majority of the physical models applied have been validated by experiments or, alternatively, by real incident data. Calculations on the effects on structure usually investigate the response of wood which can be found in all types of buildings. The response of wood has been broadly analysed and documented in the open literature. Threshold criteria for injuries of people as well as lethality criteria follow the classical Eisenberg approach or similar dosage-lethality relations. Alternatively, a rough preliminary estimation of the effects on people can be made by classifying scenarios into those demanding first aid or resulting in medical care, absence from work or leading to fatality.

Though the physical processes and mathematical models are well known and suitable, the choice of details of a scenario, like the time of exposure, type of ignition of gas after release (spontaneous or piloted), behaviour of people, etc. are variable. These parameters need to be determinated, based on a company-internal consensus or in dialogue with the authorities in order to reach a broad acceptance and a uniform methodology. Of course, this makes different hazard and risk methodologies in different countries almost impossible to compare, but no wrong or no right model exists.

To what extent hazard precautionary measures are reasonable or which level of residual risk is acceptable is another problem which remains largely unanswered. Nevertheless, in countries with a probabilistic approach an individual risk of 10^{-6} is often assumed to be sufficiently low. Only some of these countries have also established criteria for tolerable societal risks.

5.3 – Hazard/Risk Analysis : Added Value and Limitations

Generally, scientific research and experience, has been the basis for pipelines design codes in each country. Primary safety measures are established within the standards. Since transportation of gas is well developed, one would be not expect hazard or risk analysis techniques applied on a pipeline route to show any significant difference to established design Codes.

Nevertheless, hazard and risk analyses are good tools for operators in decision-making processes. Some operators use them for quantifying secondary safety measures, e.g. distances between buildings and the pipeline, others identify valve spacing distances and the most suitable locations for remotely controlled shut-off valves and flow or pressure measurement devices. Some gas companies adapt the frequency of surveillance to the associated risks of a pipeline in order to reduce the likelihood of external interference and to detect leaks at an early stage. Components of tools for performing hazard or risk analysis, like models for corrosion growth rates or pipe ageing, can be used to optimise pig-run scheduling, to prioritise rehabilitation measures and thus to achieve a optimum benefit from investment.

Not only existing pipelines can be analysed, new pipelines can also be assessed prior to construction in order to select the most appropriate route from various alternatives. Only very general safety studies are usually required for this purpose.

An analytical tool for performing safety analysis can be an element of a company's Pipeline Integrity Management System. Regardless of whether it has deterministic or probabilistic roots or whether it produces qualitative or quantitative results, it definitely makes the status of a pipeline more transparent and contributes to fostering the awareness of potential danger and risk. This is becoming of increasing importance in a competitive market with the need for continuous cost reduction.

Though techniques from hazard and risk analyses can help to assess threats and safety measures, the operator has to be aware of the problems and limitations. For some models, e.g. models for estimating multivariable failure frequencies, statistically significant data is missing due to the high safety level already achieved and the low number of incidents. Therefore, it has become necessary to use conservative models based on the engineer's best estimate which might lead to a less than optimum solution with failure frequencies often overestimated.

Hazard and risk analyses can be controversial. In some countries, the authorities refuse to allow the use of probabilistic methods. The public is dissatisfied with scientific debates on likelihood and wants guarantees that every precaution has been taken to avoid the occurrence of any undesired incident even if the likelihood of such an occurrence is very low. Debates on tolerable and unacceptable risks (on top of workaday risks) might end in a blind alley. In other countries, hazard or risk analyses are broadly accepted as they have simplified authorisation procedures and have promoted a dialogue between the gas industry and the authorities.

The choice of scenarios and "benchmark cases" is also a critical issue. It can make different hazard or risk tools incomparable causing their results to be criticised as arbitrary. Again, careful choice of scenario-defining parameters is essential and societal consensus or at least uniform criteria within gas companies are required.

Once contentious points have been eliminated, hazard and risks analyses can be applied to establish or improve pipeline integrity in an effective way and serve as an analytical tool of a Pipeline Integrity Management System.

6 - PIPELINE INTEGRITY MANAGEMENT, STATUS QUO AND OUTLOOKS FOR THE NEXT DECADE

Pipelines integrity and safety are two of the gas industry's major concerns for several reasons. The need to continue to deliver gas is an important commercial requirement. Construction of pipelines must be done to high safety standards. Pipelines integrity and safety are necessary prerequisites not only as far as the authorities are concerned, but also for the public, in order to maintain a positive and attractive public image. Finally, a pipeline represents such a major investment that its operational reliability is an economic necessity, even more so in a competitive environment. Thus, pipelines integrity and safety are both economic and structural necessities.

Given this background, gas companies have always shown a strong willingness to ensure an efficient and successful Pipeline Integrity Management.

Thus, the measures taken to maintain pipelines integrity have been developed according to past experience, technical developments, environmental constraints and regulations. Each Gas company has developed and adapted its Pipeline Integrity Management program depending on its domestic situation.

The purpose of this chapter is to highlight how practices of Pipeline Integrity Management have been improved continuously by gas companies. A survey of current best practices and future aims will allow us to consider the developments which will take place over the next decade.

6.1 – Developments in methods of Pipeline Integrity Management

Pipeline Integrity Management is based essentially on internal and external rules. External rules are, in general, the standards, codes and regulations which are particular to each country.

These rules have developed in such a way as to take into account those technological advances which allow improved efficiency of the measures used to maintain pipelines integrity. The diagnosis of pipelines by electrical surface measurement or intelligent pigs may be cited as an example.

Learning from experience, however, remains the main driving force in the development of practices of Pipeline Integrity Management.

When reviewing past experience, accidents/incidents are often taken into consideration. Thus, today, each Gas company systematically collects information regarding incident/accidents. It should be noted that such occurrences are not frequent on the natural gas transmission system, and that in the majority of cases, any serious effects are contained.

These accidents/incidents have, however, led to development of the internal rules and standards of gas companies. The principal measures that have been adopted concern:

- the monitoring of work performed by third parties: the consolidation of information and of the monitoring of companies, as well as improving the marking of the pipelines. These measures have sometimes been accompanied by regulatory measures;
- maintenance practices: a programme of network inspection by intelligent pig, intensive monitoring of cathodic protection;
- rules of design/construction: the use of new coatings such as polyethylene, intensive monitoring of construction, the development of specific techniques to avoid the risk of ground movement.

Past experience also shows that various faults can occur at different stages in the life of a pipeline. Some faults happen early in the life of a pipeline, such as those caused by construction damage or material defects. Other faults can happen at anytime during the life of a pipeline such as third-party damage. Finally other faults have an incubation period where they can increase to critical proportions and cause an incident. These faults include for instance corrosion.

In practice, maintenance has been adapted to be effective and regular systematic programmes of inspection have been implemented. These checks are adapted to the ageing of certain pipelines. The rate of ageing depends indeed on factors such as the pipeline's own specific design (the grading of steel, coatings, etc.) and operational characteristics.

As is stated in paragraph 5.1, gas companies for the most part, have a great deal of professional experience at their disposal which they put to good use by creating accidents/incidents data bases, for example. In addition, they pool this experience through associations or working groups such as the EGIG[7].

This analysis of their experience allows gas companies to obtain a sound knowledge of the true dangers associated with their work.

Thus, gas companies implement the rules which they have developed, and which have allowed them to obtain good results. The safety results confirm this fact. Indeed, the EGIG[7]'s September 1997 report states, "The overall incident frequency of unintentional gas releases over the period 1970 to 1997 is 0.476 incidents per year (per 1000 km pipeline). However, the figure over the past 5 years is significant lower: 0.215 incidents per year (per 1000 km pipeline)" (See § 4).

6.2 – Effective measures to maintain pipeline integrity

Among the measures implemented in order to maintain pipeline integrity and safety, those which follow are the most commonly applied and appear to be the most effective in response to the potential threats mentioned:

Main threats	Measures commonly applied	Measures implemented by some companies
• External interference	• markers • surveillance of the network (by air, road and on foot) • freephone number linked to the dispatching centre	• legal obligation for inquiry before digging • freephone number for information on every network in the country (One call system) • the placing of concrete slabs and improved marking to limit the risks to pipelines in areas of urban development, instead of replacing the existing pipeline with a pipeline made of thicker steel • increase of depth of coverage in order to avoid the risks caused by work performed by third parties
• Corrosion	• Coating and CP monitoring • systematic diagnosis by intelligent pig or electric surface measurements	
• Construction/material faults	• the use of a design factor • inspections during the construction phases	

Table 5

Other measures and good practices implemented by some gas companies are:

- use of recognised standards, codes, rules;
- implementation of a quality control system (based on ISO 9000);
- systematic procedures to identify threats and suitable safety measures.

6.3 – Imminent developments in practices of Pipeline Integrity Management

We have seen (§ 4) that methods of Pipeline Integrity Management are extremely dependent on the specificities of the local area. Each Gas company adopts its own methods, criteria, procedures, and so on. These are adapted to the huge diversity in their pipelines and their environment.

In some cases, pipelines cross what are essentially uninhabited areas, and in others, they cross very developed regions. Some gas companies are more specifically concerned with the risk of ground movement, etc.

Moreover, the regulations imposed differ greatly from one country to another.

Thus, each country adopts its own particular approach in order to define the design factor used to add extra thickness in specific areas with different risk value (this is in general imposed by regulations). The design factor is often attributed to an area corresponding to a given population density, but with different values attributed. Moreover, certain regulations impose specific design factors for areas where pipelines cross rivers, motorways, etc.

In the same way, the depth of cover required in an urban environment, for example, can vary from 0.8 m to 1.50 m.

In certain countries, the authorities have adopted a "deterministic" approach. Through the installation of appropriate measures ("good engineering practices") the occurrence of any incident should be avoided. Appropriate measures are described in the rules or technical standards of design, construction and operating processes. These are based on consequence analysis and experience. Thus, the high safety record, although many pipelines still in operation were constructed decades ago, indicates that the control measures have proved successful in practice. In these countries, the operator has to prove that practices comply with statutory regulations and with codes.

Certain gas companies must provide probabilistic data, both individual risk and societal risk. Specific measures must be justified within the framework of a systematic risk analysis.

Other operators must have a system of quality or safety management and the regulations state that regular audits must be carried out.

As far as current methods and trends are concerned the following developments seem likely to improve the efficiency of Pipeline Integrity Management.

It would be desirable for the risk analysis approach to be more readily accepted by the authorities and better understood by the public.

As specified in paragraph 5.3, an analytical tool for performing safety analysis can be an element of a company's Pipeline Integrity Management System. Regardless of whether it has deterministic or probabilistic roots or whether it produces qualitative or quantitative results, it definitely makes the status of a pipeline more transparent and contributes to fostering the awareness of potential danger and risk.

For many companies, it is difficult to evaluate the efficiency of those measures which have been adopted. Every measure seems to be important. Value analysis to rank those measures adopted (to define recognised performance criteria and to measure performance) would complement the risk analysis. It would then be possible to choose the most effective measures against a certain threat and to implement them in those places where they are most needed.

Work performed by third parties in the proximity of gas structures poses the main risk to the natural gas transmission network. It is upon this risk that gas companies currently focus most all of their attention. Efficient prevention in this area can only be achieved with the help of the authorities. Thus, a plan of land coverage accompanied by stricter regulatory measures involving local authorities, landowners and gas companies would be desirable.

Currently several developments directly concerning Pipeline Integrity Management are expected.

The implementation of Pipeline Integrity Management Systems over the next few years seems essential for gas companies to further improve integrity. This would allow a systematic approach to pipelines integrity and safety and would therefore lead to improved structure and more formal Pipeline Integrity Management.

The pipeline risk management demonstration program conducted by the US Department of Transportation allows operators flexibility in allocating resources by risk management (i.e. risk assessment, risk control and performance measures) to verify that it is an effective way to improve safety, environmental protection, and reliability.

Although this program is still in progress, and it is to early to talk about the lessons learned, risk management appears to be a proactive tool which will be used more and more.

Standardisation projects are currently under way involving the ISO[6] and the CEN[9]. The purpose of these projects is to define the minimum specifications for the design, operation and maintenance of natural gas transmission systems.

Reference standards will therefore soon be available. They will enable gas companies to share their professional experience and put them to good use.

The implementation of new and more successful techniques is likewise to be seen as a possible source of development. They will allow better risk prevention and a reduction in possible consequences at low cost.

In the near future one will also see:

- new repair methods;
- more successful internal inspection techniques (intelligent pigs);
- external (aboveground) inspection techniques.

In the same way, current research to better understand risk factors, such as stress corrosion, will also be a source of progress.

The changes in the commercial environment predicted, in particular in Europe, will also have consequences for Pipeline Integrity Management. Deregulation will lead operators to implement techniques and utilise tools which provide the most cost effective prevention schemes possible. Pipelines made of polyethylene or other composite materials, with increasing design pressure are already being envisaged as a means of supplying industrial customers.

It is very likely that the creation of market regulators will result in operators having to justify the methods of Pipeline Integrity Management they use in order to maintain and even develop their legitimacy in this field.

7 - CONCLUSION

This report highlights the Pipeline Integrity Management methods being implemented by gas companies.

These aim at maintaining the current high safety level, prevent major hazards, ensure the integrity of the pipeline and protect people and environment in the vicinity of the pipeline in the most cost effective way.

It should be noticed that Pipeline Integrity Management aspects are included in the more general framework of the Safety Management System. Currently, more and more gas companies implement such a system on the basis of standards like ISO 9000 and so on.

Considerable knowledge and information is available within gas companies, however that harmonisation of the information is very difficult because different standards and codes are being used in design phase and different preventive measures are currently used in the construction, commissioning and operational phase of a pipeline for cross country gas transportation.

In this way, it can be seen how practices of Pipeline Integrity Management are continually developing in order to adapt to their environment, and to improve performance.

Past experience and imminent developments show that Pipeline Integrity Management is a flexible and efficient approach to improve safety in the long term. Consequently, Pipeline Integrity Management Systems are, under the control of authorities, the best alternative to additional safety regulations.

Within the context of deregulation of the European markets and globalisation, Pipeline Integrity Management appears to be a tool to promote the gas industry in the eyes of the authorities, the market regulators and the customers (industrials, ...).

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Abbreviations:

[1] ANSI : American National Standard Institute

[2] API : American petroleum institute

[3] ASME : American society of mechanical engineers

[4] DIN : Deutsches Institut für Normung

[5] EN : European normalisation

[6] ISO : International standard organisation

[7] EGIG : European Gas pipelines Incident Data Group

[8] DOT : US Department of Transportation

[9] CEN : of European Committee for standardisation