White Paper on
Risk of a Gas Transmission Pipeline

INGAA Pipeline Safety Committee

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I. INTRODUCTION

The following excerpts were taken from the GTI report titled "The Safety Performance of Natural Gas Transmission and Gathering Systems". This report was prepared by Cheryl Trench of Allegro Energy Consulting and Bernie Selig of HSB Pipelines Consulting and was published as GRI report number GRI-03/0031[1].

> Natural gas is a central and growing part of the U.S. energy supply. According to Energy Information Administration (EIA) data, in 2001 natural gas provided
>
> ⇒ about 43% of the energy delivered to homes, apartments, stores, offices, schools and other commercial buildings (the largest share of any fuel),
>
> ⇒ about 36% of the energy delivered to manufacturing and other industrial plants (again the largest share), and
>
> ⇒ About 14% of the energy used to produce electricity (ranked #2 behind coal).
>
> Thus, natural gas supplies about 28% of the energy consumed by end-users in stationary applications in the United States on an annual basis. (Stationary applications are those where the engine, boiler or furnace is stationary, as opposed to the transportation sector where the vehicle, vessel, plane or train moves. The stationary applications include space heating and cooling, manufacturing and industry, and electricity generation, among others.)
> From the mid-1980's, when legislative constraints on its price expired, to 2001, natural gas consumption in the United States grew by nearly 30%.
>
> Consumption in the latest three-year period (1999-2001), at an average of 21.8 trillion cubic feet ("TCF") annually, was almost 30% higher than the 16.9 TCF annual average over the first three years, 1985-87. Furthermore, consumption growth will continue. Natural gas is also the most popular heating fuel for new homes. It is the fuel of choice for most new power plants in the rapidly expanding electricity market. For instance, the EIA forecasts that the natural gas share of the electric generation market will continue to grow, reaching 20% in 2020.
>
> The United States is a major producer of natural gas, and domestic production supplies 84% of the gas used each year. The remainder of the supply comes almost exclusively as pipeline imports from Canada.[2]

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[1] GRI-03/0031, "The Safety Performance of Natural Gas Transmission and Gathering Systems", Prepared by Cheryl Trench of Allegro Energy Consulting and Bernie Selig of HSB Pipelines Consulting.

[2] A small (but growing) amount of natural gas is imported as liquefied natural gas ("LNG"). These volumes are super-cooled to a liquid state for transport in special tankers. They come to the United States from Algeria and a handful of other countries; LNG is also exported from Alaska to Japan. LNG liquefaction and transportation is expensive. More popular in other global regions than in the United States, it provides an important market alternative for remote producers and for large consumers in regions without indigenous production. It is returned to a gaseous state and transported in pipelines from the receiving facility to a consumer.

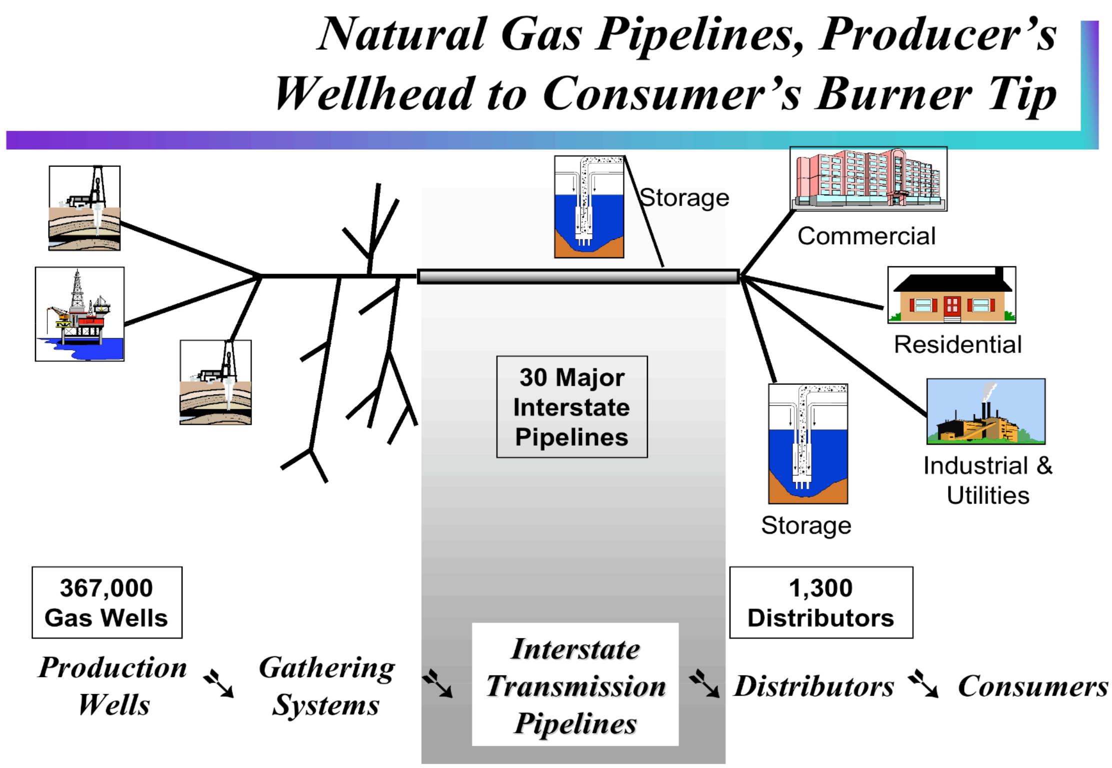

Figure 1
Natural Gas Pipeline Diagram

The journey, depicted in the diagram, begins with a "*gathering system*," where gas from scattered wells or processing facilities is brought in relatively small diameter lines to an interconnection with a "*transmission system*." The natural gas transmission pipelines transport nearly all of the gas consumed in the United States on a portion of its journey. In fact, these large-diameter, high-pressure pipelines ship some gas thousands of miles. For instance, they bring gas from the producing areas at the Gulf Coast to the consuming regions such as the Northeast or the Midwest. They also bring gas from Canada's western producing provinces to the U.S. West Coast, Midwest, and Northeast. In the consuming regions, the transmission lines interconnect with "*distribution systems*." These distributors are the local utility companies, the ones delivering to individual consumers, such as homes, offices, stores, and manufacturing plants. The distributors' lines, accomplishing a different part of the journey, are by definition located in market areas, and hence, often in areas with high population density. These lines are smaller diameter (generally), cover a shorter geographic distance, and are operated at lower pressure than the interstate transmission lines. While some storage exists, the natural gas system is designed to be and is operated continuously.

> The complexity of the natural gas transport infrastructure is seamless and transparent to the consumer. The same molecule of gas is likely to be transported in each of the three types of pipeline systems before reaching a consumer's burner tip.

With the exception of some liquefied natural gas that is transported by ship from foreign ports to US ports, all natural gas in the United States is shipped by pipeline. This remains the only practical way to move the large volumes of gas efficiently and effectively across the country. Gas can be shipped by container in either a compressed or liquefied state.

In a compressed state, it would require approximately 258 million tank truck deliveries per year to transport the necessary volume, assuming that each truck would carry 85,000 cubic feet of gas at a pressure of 1,000 psig. In a liquefied state, it would require approximately 36 million tank truck deliveries per year and in this case the gas is cooled to -250 degrees F and has only a three day life before it begins to vaporize.

II. NATURAL GAS PIPELINE BUSINESS

During the past several years, natural gas has become the lowest cost, most efficient and most environmentally friendly energy source that is readily available in the United States. Natural gas has become the fuel of choice wherever it is available for homes, business, industry and electric generation. The role of natural gas in supplying the nation's energy requirements is widely expected to increase in the years ahead.

Although the benefits of natural gas are well known, an understanding of the critically important role played by the pipelines that transport natural gas is not as well know. Pipelines transport gas from the wells where it is produced to the areas throughout the United States where the gas is distributed and then consumed. The public, media and government become aware of natural gas pipelines only when new pipelines are planned for and built, but when construction is complete and the pipeline is buried; only a few members of the public, the pipeline industry and the pipeline safety regulator are aware of their critically important role.

Pipelines transport nearly all the natural gas used in the United States and pipelines will remain the only practical way of moving the increasing volumes of gas that will be required in the foreseeable future. Pipeline capacity will have to be increased in the years ahead to keep up with the growing demand for natural gas.

The large numbers (trillions) of cubic feet of gas transported per year do not convey the importance of a single pipeline. However, the importance of an individual pipeline can be illustrated by breaking the numbers down to more a meaningful size. For example, a typical new 36" natural gas pipeline could deliver about:

- 292,000,000,000 cubic feet per year,[3]
- 800 million cubic feet per day,
- 555,560 cubic feet per minute, or

[3] If the pipeline operated at 100% of capacity 24 hours per day and 365 days per year, which would be unusual since demand for gas varies by season of the year, day of the week, and time of day. The 800 million cubic feet per day calculation is based on the assumption of a pipeline operating pressure of 800 psi with compressor stations at 90-mile intervals. The remaining numbers in this paragraph are rounded somewhat. The specific calculations are as follows: 800,000,000 cubic feet divided by 1,440 minutes per day (i.e., 24 x 60) = 555,556 cu. ft. per minute. 555,556 divided by 60 (seconds in minute) = 9,259.3 cu. ft. per second. 9,259.3 times 1,028 Btu per cu. ft. =9,518,526 Btu.

- 9,260 cubic feet per second.

Consumers buy natural gas because of its energy or heat value. That value is usually measured in terms of British thermal units, or Btu. The 9,260 cubic feet of gas that can be delivered by a 36" pipeline in one second provides about 9,500,000 Btu. The 9,500,000 Btu can provide each of the following benefits:

- Keep an average home in the Midwest warm for 21 days.
- Dry 475 loads of laundry.
- Cook 730 meals on a stove using gas.
- Heat enough water for 475 showers
- Operate a natural gas fireplace for over 300 hours.
- Fuel a natural gas-powered automobile for about 1,840 miles.
- Fuel a natural gas-powered school bus for 550 miles.
- Provide energy for a restaurant broiler/griddle for 85 hours.
- Generate enough electricity to power a typical home for about 47 days.
- Manufacture enough fertilizer to produce 285 bushels of wheat.

Another way to illustrate the significance of gas that could be delivered by a single 36" pipeline is in terms of the kilowatt-hours of electricity that could be generated and the number of homes that could be supplied by that electricity.

In recent years, the average amount of electricity used by residential customers in the US was 10,388 kWh. Therefore, 292,000 MMcf of gas used in a gas-fired combined-cycle generating unit with a 7,500 net heat rate could produce enough electricity to serve 3,551,842 homes for a year.

Still another way to illustrate the significance of the gas that could be delivered by a single 36" pipeline is to calculate the amounts of coal and oil that would be required to provide an equal amount of energy in Btu terms. As shown earlier, such a pipeline operating at full capacity for 365 days could deliver 292,000 MMcf of gas per year, which is roughly equal to about 297,548,000 MMBtu.

The heat value of coal (one measure of coal quality) varies widely depending on the specific geographic location and depth (seam) where it is mined. For purposes of this comparison, the value of 17,000,000 Btu per ton will be used[4]. This value is about average for all coal.

Using these values, the tons of coal required to provide 297,548,000 MMBtu of energy is 17,502,824 tons.

Oil accounts for only about 3% of electric generation in the US. Residual oil-fired steam electric plants still plays a significant role along the East Coast. Distillate oil is used in simple cycle combustion turbines and combined cycle combustion turbines as a back up to natural gas, and as the primary fuel source for simple cycle combustion turbines in areas where gas is not available. Also, diesel generators use distillate oil. The amounts of residual and distillate oil required to equal the Btu content of the natural gas that could be delivered by a 36" pipeline operating at full capacity for 365 days are as follows:

- Residual oil. The Btu content of residual oil is 6,287,000 Btu per barrel.[5] Thus, it would take 47,327,501 barrels of residual oil to equal the energy value of the natural gas.

[4] The value used above is rounded from that shown for Powder River Bituminous Coal in an Energy Information Administration (EIA) document, *State Coal Profiles,* January 1994.

- Distillate oil. The Btu content of distillate oil is 5,825,000 Btu per barrel.[6] Thus, it would take 51,981,202 barrels of distillate oil to equal the Btu content of the natural gas.

A graphic way to illustrate the significance of the energy transportation capacity of a gas pipeline is to compare the energy value that can be delivered by a single pipeline with the railroad transportation needed to deliver an equal amount of coal, and the ship and truck transportation needed to deliver an equal amount of residual and distillate oil. This is shown in Table 1 along with the fatalities in that mode as discussed in Section III of this report.

A large share of the coal used in the United States is moved by rail over some part of its trip from coal mines to electric generating plants. A common rail car size is 100 tons and a unit train often consists of 100 or more cars. Therefore the coal tonnage numbers shown above are divided by 100 to get an approximate number of coal cars required, and the resulting numbers are divided by 100 to get the approximate number of unit trains required. It would take 1,750 one hundred car trains with each car carrying 100 tons of coal to deliver the same amount of energy of just one 36 inch pipeline on an annual basis.

Residual oil is typically moved by ship or barge. A typical oil tanker serving East Coast electric generating plants would carry 200,000 barrels of oil. It would take 237 round trips by a ship carrying 200,000 barrels of oil to deliver the same amount of energy of just one 36 inch pipeline.

Distillate oil is normally moved over long distances by pipelines or barges and over short distances by trucks. Tanker trucks can carry about 10,000 gallons. It would take 214,541 round trips by truck per year to deliver the same amount of energy of just one 36 inch pipeline.

Energy Type	**Transport Equivalent**	**Transport Mode**	**Fatalities in Mode[7]**
Natural Gas	36 inch pipeline	Pipeline	7[8]
Coal	1,750 – 100 car trains	Railroad	795
Residual Oil	237 ships	Waterway	767
Distillate Oil	214,541 tanker trucks	Highway	41,730

Table 1
Comparison of Transportation Mode and Related Fatalities
to the Energy Equivalent of Gas Transported in a 36 Inch Pipeline

[5] US Energy Information Administration (EIA), Monthly Energy Review, Appendix A (Conversion Factors).

[6] Ibid.

[7] The values used in this column were obtained from the Office of Pipeline Safety. They are for illustrative purposes only. For more information on fatalities by mode and by product, see the Gas Technology Institutes report titled "Qualitative Comparison of Coal, Natural Gas and Oil in the Safety, Economic, Environmental and Socio-Political Domains: By Hartford Steam Boiler Insurance and Inspection Company.

[8] In 2001 there were seven pipeline fatalities, 2 involved gas transmission pipelines and 5 involved gas distribution pipelines (such as local gas lines that deliver gas to homes and businesses). This paper primarily addresses gas transmission pipelines but the author wished to show totals by mode in this column.

III. INDUSTRY RISK PROFILE

A. General

Pipelines in general and natural gas transmission pipelines in particular, have an excellent safety record. Since natural gas is lighter than air, in the event of a leak or rupture it dissipates immediately and cannot pool on the ground, form a heavier-than-air vapor cloud, or flow into streams in the way that any of the liquids carried by hazardous liquid pipelines can.[9]

The impact area due to a natural gas pipeline rupture is very limited in size. The impact area can be readily calculated and is dependent on the diameter of the pipeline and the pressure in the pipeline. This provides for an accurate determination of the potential impact of any incident. Buildings and natural barriers provide protection from the rupture and resulting flame.[10]

The impact area can range from a few feet to several hundred feet. For example a 6 inch pipeline operating at 100 psig would have an impact area with a radius of 41 feet. A 30 inch pipeline operating at 1000 psig would have an impact area with a radius of 654 feet.

The OPS maintains records on its website of fatalities caused by natural gas transmission pipelines dating back to 1986. For both on-shore and off-shore lines, the total number of fatalities was 59 in 18 years (1986 - 2003)[11].

Although any fatality is tragic, these statistics nevertheless reveal an excellent safety record. Of the 59 total fatalities over the past 18 years, 39 were on on-shore facilities and three of the onshore were gathering systems. Overall this averages to about 2 fatalities per year for onshore transmission pipelines. One incident, the tragic event in 2000 at Carlsbad, NM, accounted for 12 of the 39 fatalities.

The Carlsbad incident is one of only three incidents in this time period (18 years) where a fatality to the public occurred. All other fatalities were either company employees or saboteurs.[12]

To put this fatality rate into perspective, it is helpful to compare deaths caused by natural gas pipelines with other day-to-day causes of accidental death. Such a comparison demonstrates the relative safety of natural gas transmission pipelines. Figure 2 is illustrative of this comparison.[13]

Other comparisons within the transportation mode show an even more dramatic difference. In 2001, there were 41,730 highway fatalities, 795 rail fatalities, 767 marine fatalities, 1,162 aviation fatalities and 7 pipeline fatalities. Of these seven pipeline fatalities, 2 involved gas transmission pipelines and 5 involved gas distribution pipelines (such as local gas lines that deliver gas to homes and businesses).

[9] WILLIAM C. LYONS, HANDBOOK OF PETROLEUM AND NATURAL GAS ENGINEERING (Gulf Publishing 1996).

[10] CFER study (need the title)

[11] The time period of 1986 through 2003 was selected because it was the only information available for the OPS web-site

[12] The term saboteur is used in this context to identify the third party damage that is inflicted by persons who sabotage the pipeline through negligence or on purpose.

[13] In the above chart, the figure for gas transmission pipelines is the average annual figure calculated above. The source of this data is the National Safety Council, What are the Odds of Dying? (2000), *available at* http://www.nsc.org/lrs/statinfo/odds_072803.htm.

In addition, it is helpful to look at the likelihood of any given person dying as a result of various causes. With an average of 2 onshore fatalities per year for gas transmission pipelines out of the total U.S. population of 275 million, the likelihood of any given American dying from a gas transmission pipeline failure is 1 in 137,500,000. A sampling of other annual likelihood of dying from various everyday risks based on total U.S. population is shown in Table 2.

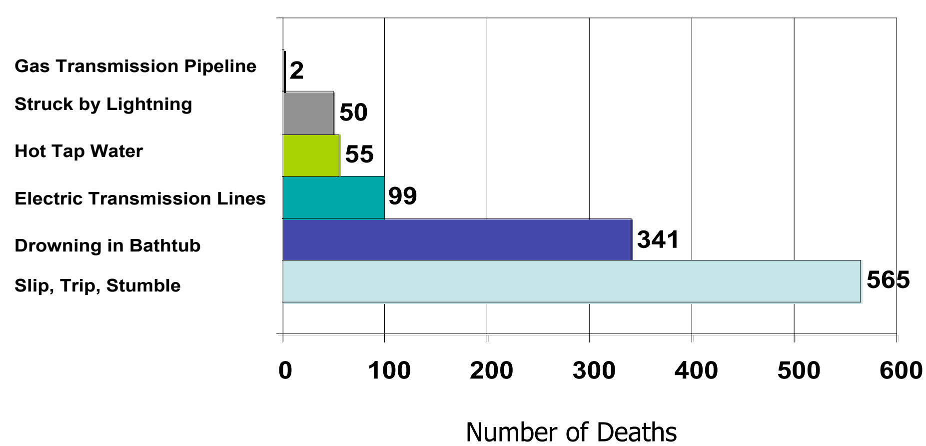

Figure 2

Annual Fatalities from Selected Accident Causes

Gas Transmission Pipeline	1 in 137,500,000
Earthquake and Earth Movement	1 in 7,865,886
Venomous Animals and Plants	1 in 3,441,325
Accidental hanging or strangulation	1 in 826,745
Fall from ladder	1 in 668,218
Inhalation of food	1 in 370,035
Air and Space Transports	1 in 354,319
Pedestrian	1 in 46,901

Table 2

Likelihood of a Person Dying as a Result of Various Causes

Of course, not all Americans have the same risk of being killed by an airplane or pipeline (or any other type of accident). Logically, persons living or working near a pipeline have a greater chance of being killed by a pipeline incident than those who do not, just like those who fly on commercial aircraft have a greater chance of being killed than those who do not.

A survey of the interstate gas pipeline industry did show that there are approximately 35 persons per mile, who live or office within 660 foot of a pipeline. With a 305,000 mile transmission pipeline infrastructure, the resulting population is over 10 million. These risks will be discusses in more detail in Subsection C of this Section. No publicly available information on population near pipelines was found.

B. 2002 and 2003 Incident Statistics

It is very difficult to garner any statistically relevant information due to the very few number of incidents and the resulting limited amount of incident data. Looking in more detail at the available data shows some interesting facts:

1) When looking into internal corrosion failures for the past two years (this time period was chosen because of the more detailed information available, however review of all information shows the same statistical relevance) like the one that occurred near Carlsbad, NM, we find the following:

In 2002 there were 14 internal corrosion incidents. Four of these were on gathering lines offshore. Seven of these were on transmission pipelines offshore. Of the three remaining, the causes were as follows:

- One was on an offshore platform
- One was on a drip in a well meter building
- One was onshore transmission

In 2003 there were 13 internal corrosion incidents. One of these was on gathering lines offshore. Six of these were on transmission lines offshore. Of the six remaining, the causes were as follows:

- Two were in compressor buildings
- One was an condenser in a compressor station
- One was onshore gathering
- Two were onshore transmission

When you take away gathering and offshore where internal corrosion is expected and managed accordingly, there were only 3 incidents in two years or about 1.5 per year. This number matches the historical numbers for this threat. From 1986 through 2002 the average of internal corrosion leaks onshore, non-gathering was 1.6 per year.

2) The data for the higher population density areas, where the potential impact of an incident may be greater, shows the following:

In 2003 there were 12 reportable incidents in class 3 areas. Class 3 areas to date, are synonymous with high consequence. Of the 12 incidents, 8 were caused by saboteurs. The four remaining incidents are as follows:

- Power line fell on pipeline facility causing an arc burn that leaked
- Airplane hit pipeline facility causing a rupture
- Atmospheric corrosion on a _ inch pipe in a compressor building
- Ground settling caused structural member to move which damaged a valve assembly which then leaked

There were no fatalities and one injury to a company employee caused by a sabotage incident.

In 2002 there were 12 reportable incidents in class 3 areas. Of the 12 incidents, 6 were caused by sabotage. The remaining six incidents are as follows:

- Car/Truck hit valve vault, no leak
- Internal Corrosion Pitting from MIC, no leak
- Operator Excavation Damage, no leak
- Crack in valve body with leak
- External Corrosion Pitting leak from Bacteria
- Lap weld pipe seam rupture

There were no fatalities and one injury to a company employee and one injury to the general public caused when the vehicle operated by the public person ran off the road and hit a valve vault.

3) The data for costs from these incidents is also very revealing. In the past these costs were identified as "property damage". In 2002, these costs were divided into three categories instead of just one. These categories are:

- Gas Loss
- Operator Damage
- Public/Private Property Damage

The values for each of these categories for 2002 and 2003 are as follows:

2002

Gas Lost Cost	$ 7,053,818
Operator Property Cost	$12,830,217
Public/Private Property Cost	$ 837,862
Total Property Cost	$20,721,897[14]

2003

Gas Lost Cost	$10,879,699
Operator Property Cost	$23,116,221
Public/Private Property Cost	$ 5,546,701[15]
Total Property Cost	$39,542,621[16]

As can be seen from this data, nearly all of the costs associated with a natural gas transmission incident are either the cost of gas lost or the repair cost of the damage to the operators facilities. Property damage to the public/private is relatively small.

Another issue with these statistics is the variability in the cost of gas. In 2003 the cost of gas nearly doubled from the 2002 level. This variability tends to skew the numbers as well as it

[14] There are errors in the DOT data. The total of each column equates to the number shown. However, the total column in the data base shows about $4.74 million more. In addition, the total of several lines are off by as much as $2.5 million. DOT has not rectified this discrepancy as of the date of this report.

[15] Public/Private includes one incident from Mitchel Energy where they reported a $1,378,360 lease compressor unit as private costs (it probably should have been reported as operator cost). Southern California Gas Company reported one incident with a cost of $2,395,000 for clean up of liquid hydrocarbons after a blow-down of a storage field. Removing these two data points leaves actual public/private costs related to safety at $1,773,341.

[16] There are errors in the DOT data. The total of each column equates to the number shown. However, the total column in the data base shows about $10 thousand less. In addition, the total of several lines are off by as high as $400 thousand. DOT has not rectified this error as of the date of this report

requires more leaks to meet the incident reporting threshold of $50,000 of total cost. Therefore in 2003 more incidents were reported than in 2002.

4) Depth of cover is an item often discussed in relation to pipeline safety. Since the beginning of 2002, 23 third party damage incidents have been recorded. Seven of these do not have depth of cover information provided. They include 2 entries of "Open Ditch", 2 entries for "Road Work", 1 entry for "Sewer" and two say nothing at all. Of the remaining 16 depth of cover is provided and the depths range from 6 inches to 156 inches. The average depth is 51 inches.

From this limited data it appears that there is no correlation between depth of cover and pipeline safety. Damage prevention may best be covered through prevention, including participation is state required one-call organizations and use of other appropriate methods as identified by the Common Ground Alliance.[17]

5) The data provides an opportunity to distinguish between interstate transmission facilities and intrastate. Although conclusions have not been made, the data is interesting. For example sabotage incidents for intrastate account for about 1/3rd of the incidents where for interstate it accounts for only 1/10th. External and internal corrosion for intrastate facilities accounts for 1/10th of the incidents whereas they account for 1/5th of the interstate incidents.

These differences are not really unexpected. Interstate pipelines, which deliver large volumes of gas across long distances and which operate at higher pressures would more easily reach the reportable threshold for a corrosion leak than would intrastate pipelines operating at lower pressures. Intrastate pipelines at either the gathering end of the network or near the delivery end of the network tend to operate at lower pressures. Likewise sabotage incidents on intrastate pipelines are expected to be more due the proximity of population whereas the interstate pipelines tend to be in more rural areas.

As one final measure of relative risk, the National Transportation Safety Board ("NTSB") investigates transportation accidents on airplanes, railroads, highways, the marine environment, and pipelines that result in fatalities, significant injury or substantial property damage. Since its inception in 1967, the NTSB has investigated more than 124,000 aviation accidents and over 10,000 surface transportation accidents. To put this in context, only 104 of the more than 134,000 total investigations were related to pipelines, and only 15 of the 104 pipeline-related investigations were related to on-shore natural gas transmission lines.

C. Six-Sigma

Six sigma in many organizations and for other entities means a measure that strives for near perfection. Six sigma drives for six standard deviations between the mean and the nearest acceptable limit. The statistical representation of Six sigma describes in a quantitative manner how a given process is performing whether that process is pipeline integrity or widget manufacturing. To achieve Six sigma, the process must not produce or allow more than 3.4 failures per million opportunities (3.4E-6). The concept provides for the comparison of outcomes for whatever is being measured.

The commercial airline industry operates very close to Six sigma. As shown in table three, the odds of dying from an airline accident is approximately 1 in 354,319. Six sigma has an equivalent value of 1 in 294,117. The gas transmission industry is significantly better than Six sigma with a

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[17] The Common Ground Alliance recommended 132 measures to help prevent third party damage (sabotage) to pipelines. The report is entitled "".

fatality rate of 1 in 137,500,000. These are societal risks however and do not address the concerns of individual risk.

As discussed previously, it is estimated that approximately 10 million persons live or office near transmission pipelines. With 2 fatalities per year, the odds of dying are 1 in 5 million or 2E-7.

For purposes of this subsection of this report, the data used involves incidents that have occurred along the natural gas pipeline corridor (660 feet on either side of the centerline of a pipeline) that are onshore (near public) and involve a pipeline (i.e. event along the right-of-way) rather than an incident at a location such as a compressor or meter station that has restricted access to the public (i.e. fence and intrusion detection). This clarification in the data addresses the individual risks.

These results only reflect the probability that an event may occur in the future based on historical trending of past events. If practices change, such as the new natural gas pipeline integrity rule, then this forecast can be low or high.

1. Probability of a Reportable Leak Occurring on a Onshore Natural Gas Transmission Pipeline

As mentioned previously, when an incident occurs on a pipeline facility that has resulted in a death, injury requiring hospitalization, cost over $50,000 including natural gas lost, or was significant; it must be reported to the OPS. This analysis only includes reportable incidents where there is a release of natural gas. The rate shown in the following table has been normalized by the % of pipe in class location categories in the year 2002 (i.e. surrogate for the breakdown of class location mileage in years 1984-2001) in combination with the average number of onshore transmission pipeline miles in operation in the U.S. in the years 1990-2002 (285,636 miles).

The results are also not shown on a per mile basis. As previously discussed, the impact area due to a natural gas release is limited and can be calculated. Most transmission lines in the US have an impacted area of less than 500 feet in radius or 1,000 feet in diameter. There then are at least 5 such circles per mile. With this adjustment, the data is as follows:

Probability of a Onshore Reportable Failure with Gas Being Released (events per 1/5 mile per year)				
Cause	**Class 1**	**Class 2**	**Class 3**	**Class 4**
Construction / Material	5.2E-06	2.1E-06	4.5E-06	8.3E-06
Corrosion	9.8E-06	4.7E-06	8.1E-06	2.5E-05
Outside Force	1.1E-05	1.1E-05	1.8E-05	4.2E-05
Other	4.2E-06	5.1E-06	3.8E-06	2.5E-05

Table 3
Probability of an Onshore Reportable Failure

Outside Force damage is the highest probability cause where gas is released in all class locations. The next highest probability cause is corrosion.

2. Probability of a Rupture Occurring on a Onshore Natural Gas Transmission Pipeline

Not all reportable incidents that have the loss of natural gas involve the rupture of the pipeline. In many cases, a leak may occur, significantly reducing the risk to the surrounding public.

Probability of a Onshore Rupture (events per 1/5 mile per year)				
Cause	**Class 1**	**Class 2**	**Class 3**	**Class 4**
Construction / Material	2.6E-05	4.3E-07	1.5E-06	8.3E-06
Corrosion	5.8E-06	3.4E-06	2.2E-06	0.0E+00
Outside Force	5.5E-06	6.4E-06	9.0E-06	1.7E-05
Other	2.2E-06	2.5E-06	3.8E-07	8.3E-06

Table 4
Probability of an Onshore Rupture

There is a positive correlation in the rate of reportable incidents that result in a rupture with the design, construction and operating practices of higher population density class location areas for Construction / Material and Corrosion causes. The rate of incidents in which a rupture occurs and caused by "Other" also decreased significantly in Class 3 areas.

In Class 1 areas, the individual risk of a rupture due to an "Other" cause is greater than a Outside Force cause. This phenomenon can best be explained by the likelihood of pipeline company employees being involved in an incidents in the "Other" cause category.

The only causes that do not show a decrease in rate for higher population density class location areas are incidents caused by Outside Force. In fact, based on this data the probability increases when an incident occurs in a higher population density location that a rupture will occur.

3. Probability of an Injury During a Reportable Incident Involving a Gas Release on an Onshore Natural Gas Transmission Pipeline

Based on the injury statistics contained in the reportable natural gas transmission incident data, it appears that injuries have occurred during the release of gas whether there is a rupture or just a leak. However, based on the information available in the OPS data files, it can not be determined if the injury occurred at the outset of the incident or during the mitigation efforts (voluntary action) that occur after the initial event. This information is important in understanding the ranking of proposed solutions. Since the time of the injury occurrence is not readily determinable from the data, I have chosen to describe the probability in terms of events per 1/5th mile per year in order to give a relative concept of the probability.

One distinction in this table from the other two tables is that multiple injuries can occur per incident. One purpose of this study is to look at the probability of an incident occurring and measuring the success of the present program to prevent such incidents. While it is very important to prevent multiple injuries from occurring during an incident, the use of this measure will skew the measurement of the success of the procedures and practices to prevent an event in which an injury occurred.

Probability of a Injury due to an Event (event with injury per 1/5 mile per year)				
Cause	**Class 1**	**Class 2**	**Class 3**	**Class 4**
Construction / Material	2.0E-07	8.6E-07	3.8E-07	0.0E+00
Corrosion	4.0E-07	0.0E+00	7.5E-07	0.0E+00
Outside Force	1.2E-07	2.1E-06	5.7E-06	8.3E-06
Other	1.7E-06	0.0E+00	0.0E+00	0.0E+00

Table 5
Probability of an Injury Due to an Event

The probability of an injury due to a Construction / Material or Corrosion cause are significantly less in class 2, 3, and 4 location areas than the Outside Force cause. No particular trend occurs in the Construction/Material category as the class location increases. A trend does occur for the Outside Force category as the class location increases.

4. Information on Fatalities for Gas Transmission and Gathering Pipelines

As discussed earlier, the probability of a fatality along the pipeline is on the order of 1 in 5 million. The Office of Pipeline Safety maintains records on its website of fatalities caused by natural gas transmission pipelines dating back to 1986. For both on-shore and off-shore lines, the total number of fatalities was 59 in 18 years (1986 - 2003). Table 6 below shows the information on fatalities for this time period (1986 through 2003).

From this table is can be seen that the fatalities are basically in two groups. One group is company employees; where an event occurred during operation or maintenance of these facilities. The second group is saboteurs; who chose to risk their lives and others through the conductance of dangerous excavation activities. Of the 30 incidents involving a fatality, only three incidents involved fatalities of the public, all the others involved employees or saboteurs.

If one looks at the number of incidents involving members of the public for the past 18 years we find that the odds of a member of the public dying from a gas transmission incident is 1.17E-7 for about 30 times better than Six sigma.

	Year	Fatalities	Company	Location	Cause	Category
			Natural Gas Transmission and Gathering Fatalities			
1	1986	1	Panhandle Eastern Pipeline	Onshore	Other	Employee
2	1986	1	El Paso Natural Gas	Onshore (gath)	Outside Force	Excavator
3	1986	1	Phillips Petroleum	Onshore (gath)	Other	Employee
4	1986	1	Northwest Gas	Onshore	Outside Force	Excavator
5	1986	1	Enserch	Onshore	Outside Force	Excavator
6	1986	1	Rocky Mountain Natural Gas	Onshore (gath)	Other	Employee
7	1987	0				
8	1988	1	Delhi Gas	Onshore	Other	Employee
9	1988	1	ANR Pipeline	Onshore	Outside Force	Excavator
10	1989	2	Consolidated Edison	Onshore	Outside Force	1 Employee
						1 Public
11	1989	11	Natural Gas Pipeline	Offshore	Outside Force	Ships Crew
12	1989	7	Southern Natural Gas	Offshore	Outside Force	Contractor
13	1989	1	Illinois Power	Onshore	Material	Employee
14	1989	1	Northern Natural Gas	Onshore	Other	Employee
15	1990	0				
16	1991	0				
17	1992	2	Texas Eastern	Onshore	Outside Force	Excavator
18	1992	1	United Gas	Onshore	Mech Joint	Employee
19	1993	1	Texas Eastern	Onshore	Other	Employee
20	1994	0				
21	1995	2	Chevron	Offshore	Other	Employee
22	1996	1	Delhi Gas	Onshore	Outside Force	Excavator
23	1997	1	Citizens Gas	Onshore	Outside Force	Public
24	1998	1	Lonestar Gas	Onshore	Outside Force	Excavator
25	1999	1	Pacific Gas & Electric	Onshore	Other	N/A
26	1999	1	Northern Natural Gas	Onshore	Outside Force	Employee
27	2000	12	El Paso Natural Gas	Onshore	Internal Corrosion	Public
28	2000	1 *	Pacific Gas & Electric	Onshore	Outside Force	Excavator
29	2000	1	El Paso Natural Gas	Onshore	Outside Force	Excavator
30	2000	1	Columbia Gas	Onshore	Outside Force	Excavator
31	2001	1	Williams Gas Central	Onshore	Other	Employee
32	2001	1	Northwest Gas	Onshore	Other	Employee
33	2002	1	Enogex (Mustang Fuel)	Onshore	3rd Party Damage	Excavator
34	2003	1	Pacific Gas & Electric	Onshore	3rd Party Damage	Excavator
	S-total	59	* Not an Incident			
	Less	20	Offshore			
	Less	3	Gathering			

Table 6

Fatalities on Natural Gas Transmission and Gathering Pipelines by Cause and Category

	Description of Event
1	Contract Employee was clearing a freeze when condensate ignited, due to operator error.
2	Excavator ran over pipeline causing a rupture.
3	Employee was operating sphere facility.
4	Damage to pipeline by outside forces cause failure.
5	Vacuum Truck hit pipeline causing a rupture
6	Employee was removing fitting which struck him.
7	N/A
8	During depressurization of pipeline, accumulation of gas ignited.
9	Truck driver ran off road hitting meter station which ruptured.
10	Frost heave cause pipe to fail at coupling. Public individual was passing by.
11	Fishing vessel repeatedly struck pipeline that was exposed after a hurricane.
12	Cold cut of platform riser caused liquid to spray onto work boat The liquid ignited.
13	Material failed while employee was working on pipeline.
14	Employee entered building where gas was present and was asphyxiated.
15	N/A
16	N/A
17	Contractors performing excavation work for a optic cable company ruptured pipeline.
18	Mechanical joint came loose while pipeline was exposed.
19	Employee struck by valve operator hand wheel during pig launch operation.
20	N/A
21	Two employees opened pig trap door that was under pressure.
22	Excavator struck and ruptured pipeline.
23	Delayed rupture from directional drill hit on pipeline.
24	Excavator severed pipeline while trenching.
25	This was not a reportable incident, it is to be removed from the OPS data base.
26	Third party hit pipeline, employee attempted to disengage equipment when pipeline ruptured.
27	Internal corrosion failure of pipeline.
28	Excavator operating a bulldozer operator hit pipeline which ruptured.
29	Gravel pit heavy equipment operator struck pipeline which ruptured.
30	Excavator working in coal strip mine, using large front end loader ruptured pipeline.
31	Construction worker in Meter Station trapped by backhoe, no release of gas.
32	Employee overcome by gas when pack and purge occurring in Compressor Station.
33	Excavator struck and ruptured pipeline, no one-call was made.
34	Contractor ripping an agricultural filed hit pipeline.

Table 7

Description of Event for Fatalities Shown in Table 6

D. Continual Improvement

The natural gas pipeline industry has always been committed to research and technical development. This commitment began in the mid 1950"s with the development of the ASME B31.8 Code for Gas Transmission and Distribution Piping Systems and the Organization of the Pipeline Research Committee. This commitment to research and development of technically based standard's, has been a major factor in achieving the level of safety exhibited. This commitment is expected to continue n the future providing for continual improvement.

The Office of Pipeline Safety and the pipeline industry have recently enacted programs to track safety performance in an effort to improve safety. A recent study conducted for the Gas Technology Institute showed that incidents per unit of natural gas transported fell by 40% from the three years 1985-1987 to the three years 1999-2001. Other information is expected to be gathered in order for trends to be determined,

In 2002 the Office of Pipeline Safety issued a new set of regulations for integrity management of transmission lines in high consequence areas (HCA's). The new integrity management program will focus a significant amount of resources on reducing the probability of corrosion failures in HCA locations (similar to Class 3 and 4 areas), resulting in a reduction of the probability of corrosion failures occurring in those locations. On the interstate pipeline system there will be a significant amount of over-testing (i.e. additional pipeline is tested/inspected during the test/inspection of the HCA area) during the IMP program resulting in 50 % (estimate) of the Class 1 and 2 piping being inspected and mitigated for corrosion. This should reduce the probability of corrosion incidents within those areas.

The integrity management program addresses other threats as well including construction and material threats as well as outside force threats; however the greatest improvement expected from this program is in the area or corrosion control.

Outside force damage remains the most significant issue for operators of underground utilities including gas pipelines. Research continues in this area but improvement can not be accomplished by pipeline operators alone. The issue is systemic across the US for all operators of underground facilities including communication, water and electricity.

Within the operators realm of control is the issue of operator injury and fatality. Although once again the statistics are exemplary, operators are doing more to safeguard their employees including instituting operator qualification programs.

Many new consensus standards have recently been created with several more in various stages of completion. These standards will help guide operators in every aspect of managing pipeline integrity.