Methane Emissions from the Oil and Gas Sector

Barriers to abatement and technologies for emission reductions

March 2013

The research for this paper was conducted by ICF International, a leading research and consulting firm for emission reductions from the oil and gas sector.

Founded in 1996, the Clean Air Task Force is a nonprofit organization dedicated to restoring clean air and healthy environments through scientific research, public education, and legal advocacy.

MAIN OFFICE

18 Tremont Street
Suite 530
Boston, MA 02108
617.624.0234
info@catf.us
www.catf.us

Executive Summary

Methane is a unique hydrocarbon in several respects. It is a clean burning fuel, easy to desulfurize, easy to produce, transport to market, easy to use by consumers. It is also a powerful greenhouse gas partially because it is the only hydrocarbon lighter than air, and gravitates up in the atmosphere rather than remain low where pollution causes human health problems. Because it does not significantly participate in photochemical reactions causing smog, emissions have been largely ignored during the past 40 years of the Clean Air Act in the U.S. and other countries of the world following suit with the U.S. environmental movement. Also, because it was third in line after coal and then crude oil for transportation fuel, it has not enjoyed the economic boost of supply and demand pushing oil prices much higher for liquid fuel burning vehicles. Hence, natural gas which is 90% methane is wasted by venting, leaking and flaring throughout the world, even the United States.

Recently, methane has been highlighted by the IPCC 2006 revised guidelines as a much more powerful greenhouse gas, 72 times more powerful than carbon dioxide, the byproduct of all fossil hydrocarbon combustion. What's more, this 72 times factor is based on a 20 year global warming model rather than the 100 year model basis of the 21 times factor used in all United Nations Framework on Climate Change Convention official documents and transactions. Frankly, 20 year planning horizon is more practical than a 100 year planning horizon: just look back 100 year and try to contemplate our society planning for our world today.

This paper provides background on methane emissions from the worldwide oil and natural gas industries, well to burner tip. It presents the estimates of methane emissions from the petroleum industry for each country in the world, with a highlight on the 20 top emitting countries that represent 83% of worldwide methane emissions from this sector. We have sufficient information about the oil and gas industry segments in twelve of those countries to break down the methane emissions by oil and gas production, processing, transmission and distribution, and thereby can relate them to the key technologies and operating/maintenance practices to reduce methane emissions. These technologies and practices are described in detail and the simplistic economics are shown in an appendix plus reference to more complete technical documents available on the U.S. EPA Natural Gas STAR website.

Methane emissions persist throughout the world, including the United States, because of a number of barriers to emissions prevention or capture. These barriers, some real and some perceived, are described in terms of the author's experience worldwide. The question, what can and should be done to mitigate methane emissions and the climate-forcing changes that methane is believed to cause in the atmosphere is addressed at the end with a number of conclusions about what creates these barriers and recommendations to overcome these barriers. The point is made in this paper that, like a clock spring, the worldwide economic and political structure is wound tight over the past century. Therefore, most of the recommendations will take time to sell, to implement, to perfect, to unwind those barriers against methane mitigation. The good news is that a program called the "Global Methane Initiative" has already attracted the membership of 39 countries in the world, representing virtually all of the Americas, Europe and Asia, but not yet significant participation in Africa or the Middle East. Worldwide cooperation is necessary, and has to be a prime objective of any strategy to mitigate methane emissions, and as the most powerful GHG over the next 20 years, impact climate change.

Background

Methane emissions, uniquely among the natural hydrocarbons found in fossil deposits of oil, natural gas and coal, were largely ignored in the 20th century. The 20th century could be considered the century of oil, whereas the 19th century could be called the century of coal and the 21st century is shaping up to be the century of natural gas. The reasons why methane emissions were largely ignored were partially economics and partially ignorance of anthropogenic impact on the Earth's climate. When climate science began unfolding, the first models of climate impact predicted the impact over 100 years, and methane was determined by those models to be 21 times more impactive on global warming than carbon dioxide, the other major anthropogenic gas released to the atmosphere which contributes to the "greenhouse" effect: trapping solar radiation within the Earth's atmosphere causing warming of the planet surface, oceans and atmosphere.

The most recent model analyses of climate impact by the Intergovernmental Panel on Climate Change[1] (IPCC) puts the 100 year global warming potential (GWP) of methane at 25 times carbon dioxide, but also predicts a 20 year GWP of methane at 72 times carbon dioxide. The purpose of these model predictions is to give a measure of relative impact of the different greenhouse gases for planning of worldwide efforts to stop and possible reverse the rate of increase in anthropogenic GHG emissions. In considering forward planning, we can expect little better success in predicting 100 years into the future than the world could have predicted the dawn of the 21st century at the turn of the 20th century. In 1890 to 1910 the world could not have predicted today's many commonplace technologies that completely re-shaped worldwide lifestyle: automobiles, trucks and tractors, air travel, space-based communications providing instant communications anywhere, anytime with anybody in the entire world, just to name a few that rely largely on energy. In 1900, coal powered ocean ships and railroad trains, and coal gas or whale oil supplied light. In 2000, coal is still in common use to generate electricity, but oil has displaced it as a transportation fuel and natural gas is now making the inroads as a primary energy source that oil made 100 years ago displacing coal.

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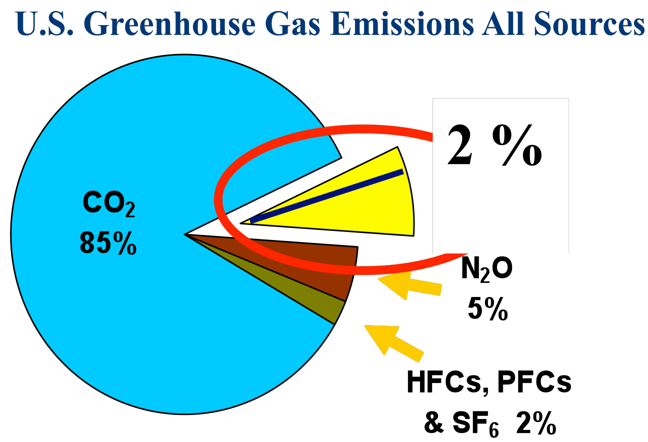
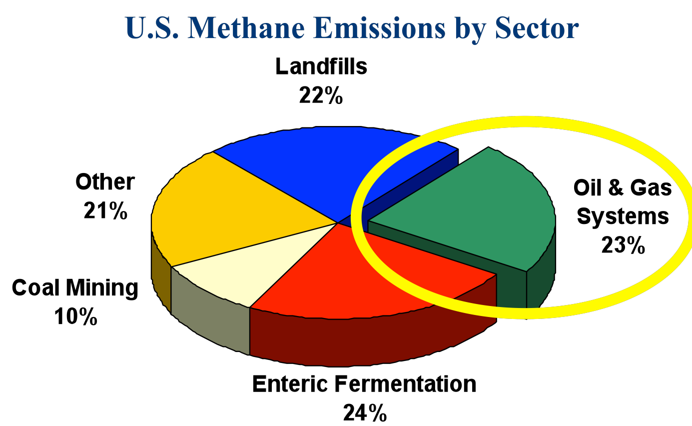
[1] IPCC. *2006 IPCC Guidelines for National Greenhouse Gas Inventories: Volume 2, Energy. Chapter 4, Fugitive Emissions*. <http://www.ipcc-nggip.iges.or.jp/public/2006gl/vol2.html>.

A 20 year planning horizon, on the other hand, is very much more practical, and so the 20 year GWP of methane, 72 times carbon dioxide, presents a more compelling case for considering climate policy. The United Nations Framework Convention on Climate Change (UNFCCC) recently announced that immediate focus should be on methane and "black particulates" (soot, which can precipitate on the surface of ice caps, accelerating absorption of solar radiation which accelerates their melting). So this paper is focused on the short (20 year) term of methane emissions and emissions reduction from the petroleum and natural gas industries worldwide.



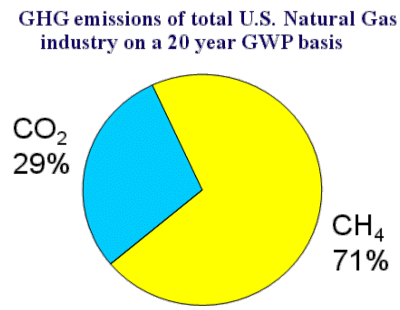
Looking at the U.S. greenhouse gas emissions inventory[2] on a 100 year GWP basis, carbon dioxide (CO_2) at 85% dominates all other GHGs. Methane is second at 8% on a carbon dioxide equivalent basis (i.e. the volume of methane is multiplied by the 21 GWP factor to be on an equivalent global warming potential basis as CO_2. The petroleum and natural gas industry methane emissions are 2 percent of the total U.S. on an adjusted carbon dioxide equivalency basis. The other significant GHGs are nitrous oxide (N_2O), used as an anesthetic and propellant and also a byproduct of air –fuel combustion, refrigerants such as hydro-fluorocarbons (HFCs), perfluorocarbons (PFCs) and sulfur hexafluoride (HF_6) used primarily in the electrical power industry as a gaseous dielectric (resists electrical arcing) insulator in high voltage switch gear. From this chart it would appear logical to base efforts at reducing GHG emissions on CO2 reduction, which means on fossil fuel combustion.



Focusing on methane alone, this chart compares oil and natural gas systems methane emissions to landfills, coal mining, enteric fermentation and other

[2] Source: EPA. Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990 – 2007. April, 2009.

sources methane emissions from the U.S. 2007 National Inventory[1]. Covering landfills sets up an anaerobic breakdown of organic wastes to methane, which, if not captured, escapes to the atmosphere. Coal contains a significant amount of methane adsorbed on the surface of the carbon, which is released to the atmosphere with open-pit mining and vented to the atmosphere in underground mines to avoid explosive build-up where miners are working in an air atmosphere. Enteric fermentation is the regurgitation/exhale of methane from anaerobic breakdown of grasses in the fore-stomach of grazing animals like cattle and sheep. Other smaller sources include manure management, rice growing and unburned hydrocarbon methane from fossil fuel combustion.



This brings us to the petroleum and natural gas industry. The U.S. domestic and worldwide petroleum and natural gas industries are powered largely by natural gas combustion energy. And the prevailing notion is that combustion carbon dioxide far exceeds methane emissions, and thereby should be the focus for climate change mitigation. However, on a 20 year GWP basis, methane emissions are far more impactful as shown in this chart[3] of U.S. natural gas industry emissions. Therefore, on a more tractable 20 year planning basis, and due to the fact that methane, unlike carbon dioxide, has an economic value to recover or prevent emission and add to the supply of clean burning fuel (clean from the standpoint of criteria air pollutants such as sulfur oxides, nitrogen oxides, particulate matter, and carbon monoxide) methane becomes the ideal target for a worldwide GHG emissions reduction program. Most of the methane emitted is from leaks and vents from oil and natural gas production, gas processing, gas transmission and gas distribution to end-user customers. Here leaks are defined as unintentional releases from malfunctioning equipment which, when found, can be repaired and largely stopped. Vented emissions are designed into the equipment or operating practices which open valves to vent natural gas containing methane to the atmosphere. Vent emissions can be excessive, and when this is determined, maintenance, operating practices or alternative equipment designs can largely reduce these emissions.

How much methane emissions are from worldwide oil and natural gas operations?

So far, the U.S. National Inventory representation of the oil and gas industry has been used to illustrate some key principles. Those principles are:

- On a 100 year GWP basis, methane emissions are approximately 8% of the total U.S. national GHG emissions;

[3] EPA. Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990 – 2007. April, 2009. Updated with 20-year GWP from IPCC. Changes in Atmospheric Constituents and in Radiative Forcing. 2007.

- Oil and gas industry methane emissions are approximately 25% of the total U.S. methane emissions; and
- On a 20 year GWP basis, methane is over 70% of the oil and gas industry GHG emissions.

The U.S. methane emissions from the oil and gas industry are largely determined from a comprehensive study of the natural gas industry conducted in 1992 and published in 1996 by the U.S. EPA and Gas Research Institute (GRI, now the Gas Technology Institute, or GTI)[4], and a companion study of the oil industry based on 1995 data available from EPA[5]. These studies form the backbone of the IPCC GHG estimating guidelines, which are largely used by the U.S. and many countries around the world. In recent years EPA has determined that a few emission sources are under-estimated in the GRI/EPA 1996 study as a result of obtaining better field measurement data through the EPA's voluntary Natural Gas STAR Program and companion international Methane to Markets (now Global Methane Initiative, GMI) program. Some of these sources are more unique today to North America, but others are common worldwide. The overall impact from correcting these few sources is to approximately double the U.S. oil and gas industry emissions estimates.

The total methane emissions estimated for the worldwide oil and gas industry in 2010 is 1554 MMTCO2e (the full list of 190 countries and methane emissions from oil and gas operations for years 1990 through 2030 are shown in Appendix 1).The table shown here is an extract for the top 20 countries of methane emissions from oil and gas operations. These estimates are made from three different methodologies as follows:

Methane Emissions from Top 20 Oil and Gas Systems (MMTCO2e)		
Country	MMTCO2e	Percent
Angola	85	5.5
Azerbaijan	24	1.6
Canada	56	3.6
India	23	1.5
Indonesia	36	2.3
Iran	48	3.1
Kuwait	107	6.9
Libyan Arab Jamahiriya	78	5.0
Malaysia	20	1.3
Mexico	31	2.0
Nigeria	26	1.7
Oman	36	2.3
Qatar	73	4.7
Russian Federation	311	20.0
South Korea	50	3.2
Turkmenistan	35	2.3
Ukraine	22	1.4
United States	113	7.3
Uzbekistan	83	5.4
Venezuela	31	2.0
TOTAL	1288	82.9

1. Most rigorous tier 3 (by source category) estimates for the United States inventory;
2. Where a country did not submit an inventory to the UNFCCC, EPA used public data on the oil and gas industry configuration from public records to apply an IPCC tier 1 (broad country-wide factors) or tier 2 (broad industry-wide factors) to estimate methane emissions; and
3. Some countries submitted inventories to the UNFCCC, but the methods have not been determined in this work.

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[4] GRI/EPA, Methane Emissions from the Natural Gas Industry, June 1996.
[5] EPA, Estimates of Methane Emissions from the U.S. Oil Industry, draft, October 1999.

Tier 1 has factors based, for example, on how much total gas and oil a country produces, imports, and exports. Tier 2 has factors based on gross industry measures such as, for the oil and gas industries, the number of oil wells, gas wells, miles of gas transmission pipelines, number of gas processing plants and number of gas customers served. Tier 3 for the U.S. Inventory has approximately 70 individual sources replicated in the 7 NEMS (National Emissions Modeling System) regions and factors based on source average emission factors and the estimate of the number of sources in the original 1992 GRI/EPA study. This 1992 base data year is "driven" to prior and succeeding years with activity driver factors based on the ratio of broad, applicable measures reported in the public record for the current year relative to the base year (e.g. for 2010, number of wells, miles of pipelines, amount of gas produced in 2010 divided by these statistics in 1992 is multiplied by the emissions estimated for each relevant source in 1992). These emission estimates are offset by the amount of methane emissions reported to be recovered by the 130 Natural Gas STAR Program partner companies. In 2008, these companies reported reducing 39 MMTCO2e of methane emissions, and from 1990 through 2008, they have cumulatively reduced 280 MMTCO2e of methane emissions. Presently, 13 international oil and gas companies have joined this voluntary partnership and 36 countries have signed an agreement with the U.S. State Department to participate in the Global Methane Initiative.

Recent refinements of the U.S. methane inventory for the oil and gas industries are based in part on emission factors that had poor data support in the 1992 EPA/GRI study and on a gas production technology that was not common in 1992 (and thereby, not covered at all): namely, hydraulic fracturing of tight gas formations such as coal bed, tight sands and shale gas. These tight gas formations are not being exploited aggressively outside North America, so these factors do not affect present estimates from other countries. However, they do impact the U.S. inventory, increasing the estimate in 2010 by about 300% to 300 MMTCO2e, raising the percent of worldwide oil and gas industry emissions to 17%. Tight gas is found in large quantities throughout the world, as shown in Appendix 2[6], and it is entirely reasonable to assume that energy deficient countries such as China, India and Eastern Europe will (and are) aggressively developing these tight gas resources like North America.

To understand where methane emissions abatement opportunities lie, it is necessary to look at emissions by industry sector, as different technologies apply to the equipment common to different sectors. The table below shows data that we have, or could readily generate from public information on how much of the total GHG emissions for each listed country are from each of the industry sectors: oil production, oil tanks, gas production, gas venting, gas flaring, gas processing, gas transmission and gas distribution. All values are expressed in million tonnes of carbon dioxide equivalent based in a 100 year GWP for methane of 21. The total MMTCO2e values are all taken from the individual countries' reported GHG emissions to the UNFCCC with

[6] V.A. Kuuskraa, Advanced Resources International, Inc., *WORLDWIDE GAS SHALES AND UNCONVENTIONAL GAS: A Status Report*, December 12, 2009.

exception of Russia and the United States. In the case of Russia, who reported 311 MMTCO2e for 2010, which included 15 billion cubic meters (BCM) of gas flaring and zero emissions from oil tanks, the IEA independently estimated from satellite photography that Russia is actually flaring approximately 60 BCM of gas[7]. ICF is well aware that flaring wellhead gas provides no incentive to capture the gas that will flash off the crude oil when pressured from the gas-liquid separator to the field stock tanks. Therefore, ICF proportioned the U.S. oil tank methane emissions to Russian production by the ratio of Russia's 10.5 million barrels per day of oil production to the U.S. 5.6 MMBPD oil production. This is probably conservative given the U.S. does have some vapor recovery and does not flare a significant amount of associated gas.

The United States methane emissions are also adjusted by ICF to best represent recent estimates used in the U.S. EPA's Mandatory Reporting Rule, Subpart W[8], with adjustments for tight sand hydraulic fracturing emissions and all emission reductions both reported to EPA's Natural Gas STAR Program as well as anecdotal information from methane capture equipment vendors and oil/gas companies NOT participating in the voluntary Gas STAR Program. ICF does not believe for a minute that every one of these county methane emissions inventories is absolutely correct, or developed with the same rigor as the U.S. National Inventory. However, this table serves as an example of where methane emissions abatement technologies can be focused to best advantage and across the worldwide oil and gas industry.

Country	Total MMTCO2e	Oil Production	Oil Tanks	Gas Production	Gas Venting	Gas Flaring	Gas Processing	Gas Transmission	Gas Distribution
Russia	327.5	0	8.4	131.3	0	8.5	0.5	153.9	24.9
United States	300.3	36.8	4.4	172.7	0	0	15.8	40.6	29.9
Uzbekistan	83.4	0	0	34.8	0	0	0	40.9	7.6
Canada	56.4	0.8	0	23.9	2.3	0.8	5.7	10.6	12.2
Turkmenistan	35.2	0	0	15.7	0	0	0	18.5	1.1
Venezuela	30.6	0.3	0	13.2	9.1	3.2	3.5	0.4	0.9
India	23.1	0.5	0	2.6	5.2	1.8	10.5	0	2.5
Ukraine	21.8	0	0	6.5	0	0	0	7.6	7.7
Argentina	11.1	0.1	0	1.3	2.6	0.9	2.3	2.9	1.1
Thailand	3.7	0	0	0.4	0.8	0.3	1.7	0	0.5
Colombia	3.1	0.6	0	0.4	0	0	1.7	0	0.5
China	2.6	0.2	0	0.3	0.6	0.2	0	1.1	0.2

Methane Emission Reduction Opportunities

The EPA voluntary Natural Gas STAR Program partners have identified and implemented over 80 technologies and practices to cost-effectively reduce methane emissions from the oil and gas industries. These are discussed at length on the EPA website: http://www.epa.gov/gasstar/tools/recommended.html . In the interest of

[7] http://www.iea.org/textbase/npsum/opt_russ_gas.pdf
[8] ***www.epa****.gov/climatechange/emissions/****subpart/w****.html*

brevity and to put the focus on those with the greatest impact on worldwide methane emission reduction, this section lists those most significant sources and provides a brief explanation of the technologies and their economics.

The major sources of worldwide methane emissions, and the associated cost-effective abatement technologies are listed in Appendix 3. Note that the total 2010 worldwide methane emissions in this table are 1,354 MMTCO2e as opposed to the estimate in Appendix 1 of 1,554 MMTCO2e. This is because Appendix 3 was developed six months prior to Appendix 1, and some of the bases (e.g. GHG inventories submitted to the UNFCCC, IEA statistics) have changed as well as views on emission factors and existing abatement measures. It is important to note that these are all just estimates, and the exact number is not as important as the principles underlying methane abatement opportunities. Following is a discussion of the top ten most impactful abatement technologies and practices from a worldwide and forward planning basis. All of these methods are being implemented by U.S. Natural Gas STAR Partners.

Tank vapor recovery:

The World Bank Global Gas Flaring Reduction (GGFR) puts global natural gas flaring at 400 MMTCO2e. In this case, the emission is actually carbon dioxide as the gas is burned in a flare. Virtually all of this flared gas is "associated" gas, i.e. gas produced in association with crude oil. Each location where associated gas is flared, the oil production is provided with a means to take it to market (e.g. pipeline) but the gas is not, and therefore must be either vented or flared. Actually, flaring is less impactive of global warming than venting because of the high GWP of methane. A very small fraction of the flared gas emission is actually methane, estimated at 1 to 1 ½ percent, which represents the unburned hydrocarbon in a field flare. The more significant source of methane emissions in these operations is the vapor vented from the crude oil field stock tank. These tanks are most commonly fixed roof, atmospheric pressure tanks which receive crude oil from a wellhead gas-liquid separator under slight pressure (25 to 50 pounds per square inch gauge, psig). This pressure is akin to pneumatic gas "pumping" (actually pushing) the oil in the separator as necessary to fill a field stock tank. Many of these remote production sites are not electrified, and even those that are prefer to pressure the crude oil into the stock tank rather than purchase and maintain a mechanical pump. The gas released from the oil at atmospheric pressure vents from the tank roof, and is typically 50 to 75% methane. Where the associated gas from the gas-liquid separator is flared for lack of a means of transporting it to market, this situation leaves the tank vapor also "stranded." Finding a means of collecting and transporting the associated gas that is flared enables capture of the methane rich gas that is vented. The methane gas vented from oil tanks in Russia and the United States sector breakdown of their respective inventories shows the magnitude of this opportunity. Other major oil producing countries, such as the Middle East and South America likely have similar methane emissions from production tanks, but this is not broken out of their GHG emissions reports to the UNFCCC. ICF has assisted the EPA Natural Gas STAR International Program in designing economic tank vapor capture projects for Colombia, Argentina and India, some of which have been implemented.

Vapor recovery units consist of a low pressure compressor and necessary delicate controls designed to capture most of the gas off the tank without drawing air-oxygen into the tank and into the recovered hydrocarbon gas. The vapor recovery compressors are typically driven by electric motors, but can also be driven by natural gas fired engines. These units typically cost from $50 to $100,000 and pay-back the investment in less than one year. An example application of this technology would be the Russian oil industry, which flares from 30 to 50% of the associated gas mainly because of politics (see the next section on policy and barriers).

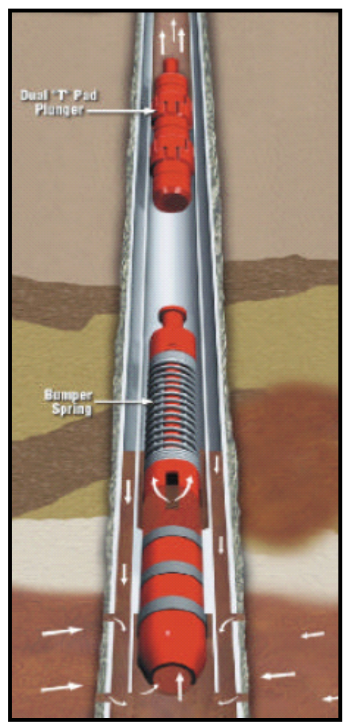
Gas well completion vent gas recovery after hydraulic fracturing:

This is a major source of methane emissions, and emission abatement, uniquely in North America because of the rapid growth in tight gas production. The expansion of tight gas production to other parts of the world are expected to greatly increase this methane emission source UNLESS other countries, like the United States, employ a new technology called "Reduced Emissions Completion" (REC) or "Green Completions." The photo on the right shows

hydraulic fracture water and excess sand, used to prop open the fractured reservoir rock, backflow into a metal bin (larger fractures backflow into a surface impoundment. The methane rich gas pushing the water out of the well escapes to the atmosphere.

Alternatively, as shown in the photo on the left, special purpose designed equipment is temporarily used at the wellhead during well completion to capture this gas. In this photograph, the portable black tanks on the right store the water used for fracture. The trailer in the middle stores the sand mixed with water when a well is fractured. The pair of small, vertical vessels to the right of the pick-up truck are the REC sand separators (left vessels) and gas-liquid separators (right vessels) which capture the backflow gas and route it to a gas sales pipeline. The black tank between the REC vessels and the sand trailer receives the liquid, which includes water, pumped back to the temporary tanks, and hydrocarbon gas liquids which can be sold at a premium price enhancing the economics of REC. Natural Gas STAR Program partner companies who developed this REC technology report capturing 0.5 to 2 million cubic feet of gas per day per well plus 0 to 600 barrels of gas condensate, worth an average of $20,000 per day per well in sales revenue. When this technology is applied to many wells in a field drilling program, it is very cost-effective because the portable equipment is moved from well completion to the next well completion, up to 25 wells per year. The United States relatively high gas production methane emissions are partially a result of this hydraulic fracturing completion emissions without the full proliferation of REC technology. [Author's note: the "Lessons Learned Study" explaining this technology will be published by EPA in April 2011.]

Gas well liquids unloading with a plunger lift:



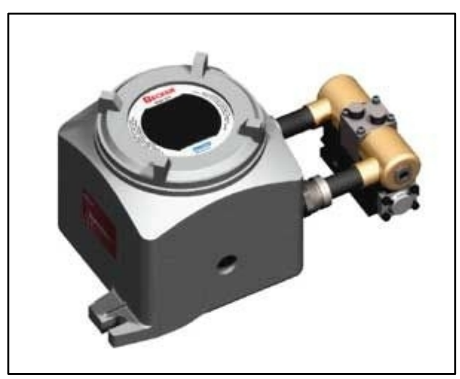
Also somewhat unique to the United States gas production is a major emission source associated with expelling liquids, primarily water, out of a producing well. This problem of water accumulation in the gas flow tubing is typical of depleted gas reservoirs where the water underlying the gas contained in the reservoir rock is sucked-up with the gas production. As the gas cap in a natural gas reservoir is removed, water pushes upward, eventually moving closer to the well perforations (which allow the gas to flow into the well casing and up the tubing). Also, as the gas is depleted from the reservoir, the pressure in the reservoir declines. Just one barrel of water will stand approximately 250 feet in the typical gas well tubing, exerting 125 psig pressure on the bottom of the well in addition to the sales line pressure at the wellhead. So a 100 psig sales line pressure plus one barrel of water in the tubing puts 225 psig pressure at the bottom of the well. If the depleted gas reservoir “shut-in” pressure is only 225 psig, this one barrel of water will stop gas production. Pumping the water out of the well is very expensive, between $25 and $50,000 for a beam pump. Operators try “blowing” the water out of the well tubing, sort of like “coughing-up” fluid from your lungs, by shutting off the sales line and opening the well to the atmosphere. This relieves the sales line 100+ psig back pressure and allows a rush of gas to push the water the 1 to 2 miles up the well tubing to the surface. This practice, called “blowing” the well, or “liquids unloading” vents a lot of methane gas to the atmosphere. Gas STAR Partner companies have measured the effectiveness of this well blowing practice and found that it removes only about 15% of the water.

The solution to this problem is a “plunger lift.” The photo shows a metal plunger that is dropped down the well tubing, resting on the bottom of the well on a bumper. As gas flows around this plunger and up the tubing, entrained water also flows past the plunger and accumulates above it in the tubing, impeding gas flow. A mechanical timer or programmable logic controller or just a field operator manually shuts-in the gas flow to the sales line, building gas pressure in the well casing outside the tubing. Once reservoir shut-in pressure is achieved, the well is opened to the sales line or atmosphere so that the gas pressure in the casing can push the plunger and liquids efficiently pushed ahead of it up the well tubing to the surface. This increases the efficiency of liquids unloading to near 100% while either avoiding methane gas venting altogether or minimizing it to less than 5% of blowing the well to the atmosphere without a plunger lift. One Gas STAR Partner company, who pioneered the programmable logic controller, dubbed “smart automation plunger lift” reduced their well venting in one field by 4 billion cubic feet per year, a 50% reduction. To date, their success has increased to over 90% venting reduction using smart automation well venting.

As gas production in other parts of the world mature to the state that the United States conventional gas production is, this technology will avoid the substantial methane emissions experienced in the U.S. just one decade ago. Natural Gas STAR International partner companies in Russia, India and Latin America have shown interest in learning more about this technology.

Low-bleed pneumatic controllers:

Many parts of the oil and natural gas production, gas gathering and gas transmission sectors of the industry are in remote locations that do not have electric power. The remote, un-manned operations must be automatically controlled to keep liquid levels, temperatures, pressures and flow rates within proper operating ranges. This is accomplished in the absence of electricity



with “gas pneumatic valve controllers.” The production gas pressure is used as a power source to relay signals from the process measurement (i.e. liquid level, gas pressure, heater temperature, fuel gas flow rate) to a valve actuator. This signal must keep flowing, so the gas is “bled” to the atmosphere at the valve controller. This is called the “bleed” and older models of pneumatic controllers have a higher bleed rate, averaging 130 cubic feet per hour (CFH) than newer controllers designed for a low bleed (less than 6 CFH). This is not a lot of gas loss, but there are an estimated 400,000 of these pneumatic controllers in the production and gas gathering sectors of the industry, and another 200,000 pneumatic controllers in gas transmission. With the large number of such devices, this source is one of the highest contributions to methane emissions in the United States natural gas industry. This type of remote control is common throughout the world, and replacing older high-bleed devices with low-bleed or retrofitting bleed reduction kits has proven a cost-effective way to reduce this emission by about 90%.

Gas dehydration using a flash tank separator or electric pump:

Produced natural gas is normally saturated with water; as a matter of fact, water is often produced along with the natural gas and phase separated in a wellhead gas-liquid separator. The common technology to reduce water vapor from the natural gas is to pass the gas through a contactor where a deliquescent chemical, normally triethylene glycol (TEG) absorbs the water. This chemical circulates from the gas contactor to a “reboiler” which heats the chemical driving off the water as steam which is vented to the atmosphere. TEG also absorbs a little methane and heavier hydrocarbons such as volatile organic carbon (contributor to air pollution) and benzene, toluene, ethylbenzene and xylene (BETX) which are “hazardous air pollutants.” These organic chemicals, including methane, are also boiled out of solution with the water and vented to the atmosphere. Furthermore, at remote, un-manned production wellheads, the controls for these dehydrators are powered by pneumatic gas controllers and also the TEG circulation pump is powered by gas pressure. This pump power gas also vents to the atmosphere, contributing even more methane emissions. One solution is to install a gas-liquid separator on the TEG stream before it enters the reboiler. This vessel captures the entrained gas at a lower pressure so that it can be routed to fuel gas or a compressor to pump the gas to sales. This “flash tank separator” (FTS) is not expensive, can be retrofitted to nearly any dehydrator, and reduces methane emissions by 90%, VOC and HAP emissions by 50 to 70%. The U.S. EPA has made this technology mandatory on larger gas dehydrators, such as are found in gas gathering/booster stations and gas processing plants, but wellhead dehydrators, of which there are approximately 40,000 in the U.S. commonly do not have this technology, sometimes because there is not a use for the recovered low pressure gas.

Reciprocating compressor rod packing economic replacement:

Reciprocating compressors have a large share of the population of gas movers from wellhead to gas processing and transmission, and a significant share of gas movers in processing plants and transmission compression stations. The most significant methane emission source from reciprocating compressors is the seal around the piston rod that prevents high pressure gas compressed in the cylinder from escaping around the rod. This seal is called a "rod packing" and is designed to have a little bit of leakage to minimize wear on the components and not bind the piston rod. The packing rings must be replaced periodically because of wear, and a common practice in field production compressors is to replace the rings when natural gas leakage is obviously excessive. The Natural Gas STAR Program partners have reported replacing rings when it is economical (i.e. when the value of gas leakage exceeds the cost of replacing the rings. This maintenance practice is fully explained in a Gas STAR Lessons Learned study[9]. It requires measuring the packing leakage shortly after new packing rings are installed, and then periodically (annually or semi-annually) afterwards to determine how much the leakage has increased. This information, along with the typical cost of replacing packing rings, using an economic capital recovery factor equation, allows a company to determine when it is economical to replace the packing rather than a fixed schedule or when it is obviously necessary to replace it (which would be long beyond the time when it was economic). Some Gas STAR Partner companies have reported success installing "low emission packing" (LEP) which greatly reduce rod packing leakage starting with new packing installation. The program does not, however, have sufficient data on the relative wear rate of LEP to determine if it is a long term economic solution. LEP replaces one cup in the packing case with a deeper cup and three specially designed rings which are "axially" loaded, and fill the cup, hence avoiding gas slippage around the rings with each piston stroke.

Centrifugal compressor oil seals vent gas capture or replacement with dry seals:

Centrifugal compressors elevate gas pressure with high speed rotating wheels rather than reciprocating pistons. Each end of the compressor shaft typically has a seal to keep high pressure gas inside the compressor case from leaking out around the spinning shaft. The traditional type of seal circulated a lubricating seal oil through a seal case with three rings, the middle one attached to the spinning shaft and the outer two stationary with rubber O-ring seals around the outside and springs pushing these stationary rings against the spinning ring. The seal oil is pumped into the seal at a pressure slightly higher than the compressed gas. The seal oil pushes the stationary rings slightly apart and flows between them and the spinning ring, creating a barrier to gas leakage. This is a very good seal from the standpoint of gas leakage down the shaft and out of the compressor case. However, natural gas is readily absorbed in the seal oil under high pressure, and must be removed to maintain seal oil lubricity and viscosity to avoid ring wear. Absorbed gas is typically "flashed" off the seal oil at atmospheric pressure and often vented to the atmosphere.

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[9] http://www.epa.gov/gasstar/documents/ll_rodpack.pdf.

There are two solutions to this large emission source: replace wet (i.e. oil) seals with dry (no seal oil) seals or capture the gas vented off the seal oil and recycle for beneficial use, such as fuel gas. The diagram shows in red a seal oil capture system that routes a substantial fraction of the gas to fuel and emits about 1 percent of the gas, thus reducing emissions by 99 percent. Dry seal, which cost approximately $500,000 to retrofit, also reduce emissions by about 99 percent but also reduce annual operating costs by about the same amount. The seal oil capture system costs less than $50,000 to retrofit. This technology is described in a Natural Gas STAR Lessons Learned study[10].

Compressor through leaking valves leakage detection:

Gas compressor stations and gas processing plants typically have several compressors in parallel, so that some can be shut down for routine maintenance or standby during low throughput while others continue to operate. Compressors that are shut down are isolated from the system with suction and discharge isolation valves. These valves are typically large and isolate the compressor from high pressures, ranging from 300 to 1000 psig. A very small deformity or debris in the valve sealing surface or seat can result in a large amount of gas leakage through the compressor and through an open blowdown vent that is intended to keep the compressor case depressurized.

Further, all compressors receive suction gas from a vessel that is designed to separate even very small amounts of liquids. This vessel is called a "suction scrubber" or "liquid knock-out" vessel, and is typically fitted with a de-mister screen on the top and an automated liquid "dump valve" on the bottom to discharge liquids when they accumulate to a pre-set level. On occasion, these liquid dump valves stick open or closure may be fouled by debris in the valve seat. Like unit isolation valves, they typically have a large pressure drop across the valve, between 300 and 600 psig, and even a small opening or valve stuck open will discharge all accumulated liquid and then blow high pressure gas through the liquid line to a condensate tank and out the roof vent. Leak surveys of compressor stations as shown in this chart have found these sources to be up to 80% of total fugitive emissions from compressor stations, which can represent almost $15 million of lost gas at customer gas prices.

In both of these cases of through valve leakage, the discharge is far away from the valve itself, typically out a compressor building roof vent for unit isolation valves or a tank roof vent for scrubber dump valve. Because of this dislocation of vent from source, they often go unnoticed. The solution is to repair or clean the valve seat, which can be very expensive, given isolation valves are typically very large and to fully isolate them for repair may require a full compressor station shut-down. Scrubber dump valves are less expensive to repair, simply requiring the one, connected compressor to be shut down. To justify the cost of repair, it is necessary to first detect the leakage, which can be done easily with an infrared leak imaging camera

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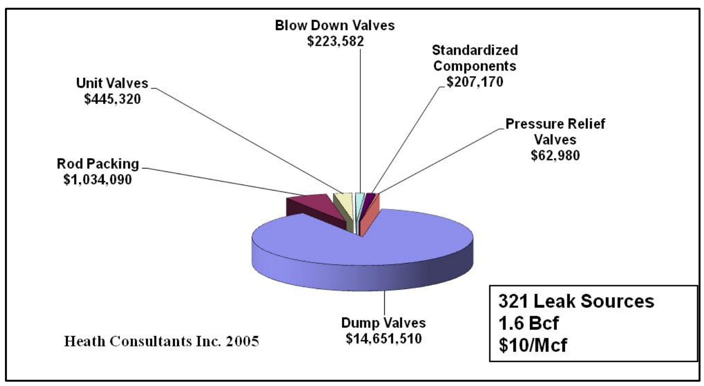
[10] http://www.epa.gov/gasstar/documents/ll_wetseals.pdf

viewing the roof or tank vents, or acoustic leak detection instrument applied to the suspected leaking isolation valve or scrubber dump valve. Some acoustic detectors come with an algorithm that estimates the quantity of gas leaking through the valve based on the valve size, pressures upstream and downstream of the valve, valve type (ball, gate, plug) and decibel reading from the acoustic detector. Another more accurate, but more expensive method is to measure the leakage at the vent with methods such as "bagging" (shown in the photo) or other flow measurement instruments. A good practice is to inspect these vents before a compressor or station shut down so that repairs can be planned and performed as part of routine maintenance.

Another solution for isolation valves is to route a compressor blowdown vent to the station fuel gas system rather than vent to the atmosphere. This reduces the pressure downstream of a unit isolation valve to fuel gas pressure, between 50 and 260 psig for reciprocating engines and combustion gas turbine drivers, respectively. This alternative puts leaking gas to beneficial use rather than venting it to the atmosphere until the isolation valves can be repaired. This practice is outlined in a Natural Gas STAR Lessons Learned study[11].

Leak detection and repair:



Natural gas leak detection took a giant leap forward with the invention of the infrared gas leak imaging camera. This technology brings the world of equipment leaks and vents into clear focus for operators as well as regulators. Whereas natural gas emissions have been plausibly denied by operators, the gas being colorless, often odorless, and in the din of operating equipment often not detectible by sound, the camera makes this ignorance impossible. EPA has adopted this technology for petroleum refinery and chemical plant leak detection and repair programs controlling volatile organic compounds (VOC) and hazardous air pollutant (HAP) emissions. The technology works equally well with methane rich natural gas emissions. Over the past decade, the IR leak imaging camera has gone from a research bench-top concept to commercial availability. Although expensive to

[11] http://www.epa.gov/gasstar/documents/ll_compressorsoffline.pdf

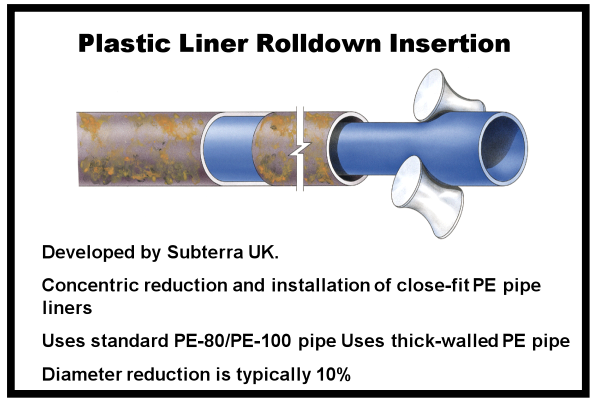
purchase, the labor time saved by being able to screen thousands of potentially leaking components per hour rather than days, pin pointing the exact location of leaks to facilitate repair, pays for the investment. Most Natural Gas STAR partner companies who performed processing plant leak surveys claimed that the gas saved paid for the camera in the initial survey. The photos below show a tank as viewed in visible light with the naked eye, and through the IR camera, revealing a very large cloud of methane gas being released to the atmosphere.

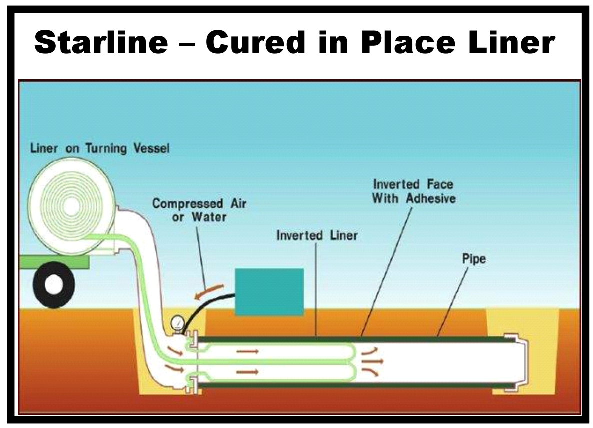
Many studies have shown that over 90% of leaking gas comes from less than 1% of the total components (valves, piping connectors, open ended lines, compressor and pump seals). The trick is to find those less than 1% needles in the haystack of potential leaking components. The IR camera has been shown to screen thousands of components an hour, picking out just the few that have significant leaks.

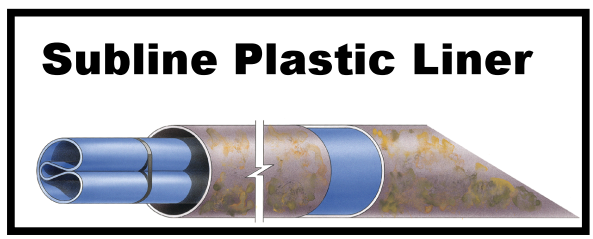
Cast iron distribution main piping joint sealing or plastic liners:

Older natural gas distribution systems used 19th century technology cast iron pipe for underground distribution mains. Cast iron is very corrosion resistant, but is brittle and joints must be made by a "bell and spigot" design where a tapered nozzle (i.e. spigot) is inserted in an expanded bell and sealed originally with hemp and lead infusion packed tightly between the spigot and bell. This type joint cannot hold gas pressure over a few inches of water head, and the joints are also prone to leakage with movement of the pipe in the ground. Digging up t he pipe and replacing it with protected steel or modern plastic pipe is very expensive because of the city street repair not to speak of the traffic detour. Two techniques have been developed to repair or prevent joint leakage in cast iron mains. The repair technique is called CISBOT (Cast Iron Sealing Robot). As shown in the

picture, a robotic sealing element with camera and light source is snaked into the cast iron pipe and moved to each join. The camera allows inspection with advantage of the lighting. If the joint appears to be leaking, the robot injects the joint with a sealing compound. From one excavated entry point, the robot can inspect several joints in each direction from the entry.







There are several techniques developed to insert plastic liners inside the cast iron pipe. These can be regular thick walled polyethylene pipe or very thin walled to fit snugly into the cast iron pipe, using the hoop strength of the cast iron to hold pressure. One technique pictured below rolls regular thick walled plastic pipe down to a smaller diameter which can be pulled through the cast iron pipe. The plastic pipe will slowly regain its diameter, and does not depend on the cast iron pipe for gas pressure support. Each service line connection with this and all plastic liners require individual excavations in addition to the excavations and removal of a cast iron pipe joint to enter the parent pipe.

Another plastic liner technique, called the “Starline cured in place liner,” requires the cast iron pipe to be cleaned on the inside with an abrasive-blasting method, like sand blasting, to assure good bonding between a flexible polyester woven liner and polyurethane coating. The abrasive is vacuumed out of the pipe and the liner is coated with adhesive and “inverted” through the cast iron pipe (i.e. turned inside out with compressed air or water inflating the soft liner coated with adhesive as it is pushed through the cast iron pipe). This liner fits snugly and has minimal loss of pipeline internal diameter.

The third technique folds the thin walled plastic liner so it can be pulled through the cast iron pipe. It does not require internal pipe cleaning as there is no bonding to the parent pipe, and it can negotiate bends up to 22 ½°.

This liner is inflated with cold water pressure and relies on the hoop strength of the parent cast iron pipe to hold pressure. It is available in diameters from 3 inch to 59 inch and can be pulled through up to 1000 feet of cast iron pipe.

Con Ed of New York City as well as European cities such as London and Paris are experimenting and developing these plastic liner techniques to reduce the single largest source of methane emissions in gas distribution: cast iron pipe.

Policy drivers and barriers

This section of the paper discusses several non-technical factors that drive behavior of oil and gas operating companies either to invest in methane reduction technologies and practices, or not. A number of examples of each policy driver or barrier are explained in terms of this author's opinions of what are "perceived" factors as opposed to "actual" factors. In this context, "perceived" is applied to either actual statements made by operating companies to justify their actions, or this author's attempt to explain why actions, or inactions, are taking place in the face of what would otherwise seem to be obvious business decisions. On the other hand, "actual" factors are those which appear to be real and which do justify actions or inactions. As with any business decisions, a combination of policy drivers and barriers might be at the root of actions, given that a consensus of business managers in a company combine on any decisions.

This latter point is important to explain further. The oil and gas industry is very complex and largely decentralized. Field operating managers carry great weight in decision-making, for if they don't support a decision, it is destined to fail, no matter how good an idea it was. Furthermore, field operating managers are greatly influenced by field technical and engineering personnel. Many good ideas originate with field engineers and geologists, which depending on their historical record of success, ideas are tried or ignored by operating managers. Field engineers know best their own facilities, and second best, their "neighbor's" facilities. There is a natural, built in disincentive to be the first one to try something new (lest it fails, and detracts from the field technical expert's credibility). This latter point is why the U.S. EPA Natural Gas STAR Program has been so successful: because one operator is telling his neighbors and peers about his successes (and sometimes failures) … there are ample examples of both. The real mechanism of this Gas STAR Program is "technology transfer."

Now above the field operating and technical managers, the purse strings and budgets are generally controlled by business managers: general managers. Capital and operating/maintenance budgets are developed in advance for the following fiscal year, and certainly have production and compliance with regulations at the heart of the objectives. It is very common that there are more good ideas on how to spend the budget than money to spend. Because of this, only the most profitable and mandatory compliance projects can be specifically named in a budget plan. This is the primary reason why "one year payback" projects are most attractive, because they generally fall under the radar: the revenue making it to the bottom line obscures the costs that may not have been specifically mentioned in the budget. This is where field engineers and operating managers can "take a flier" on a new technology without fighting for a place in the operating division's annual budget. Such "fliers" are going to have to be virtual sure bets for field managers to spend their operating and maintenance money.

So, with this brief background in oil and gas company decision making, let's examine some of the policy drivers and barriers.

Gas price, or price controls:

Oil and gas companies generally work to a profit motive. This is why oil production earns greater attention and investment than gas production in most of the world. When transportation around the world is powered more by gas than gasoline and transportation demand outstrips supply, then natural gas may drive industry investments. For now, however, gasoline, jet kerosene and diesel fuel move the world.

In some parts of the world, Venezuela and Argentina for example, gas price is controlled low by the government to insulate their voting public from rising world energy prices. This is a REAL barrier, and a real price control which the gas producing companies are all too aware of. It not only stifles investment in new gas production, but even more stifles investment in methane emissions abatement. Argentina's gas demand has outgrown their in-country supply and import of natural gas carries a higher price. This situation is driving discussions between the industry and government on raising the controlled price such that it encourages in-country supply without "gouging" the consumers. Higher the gas prices justify more methane emission abatement. In 2010 ENAP Sipetrol's General Manager in Argentina approved one methane abatement project that had positive economics even at the controlled gas price, but chose to defer other methane abatement projects that, while economic, were not AS economic as the one chosen. Note: the field operating and engineering managers were presented these opportunities by the EPA Natural Gas STAR International program, and approved them before the projects could be presented to the general manager, and the general manager needed to know that his field management supported the projects. A sister project for ENAP in Chile is hung-up with the field engineering manager refusing to believe in the methane emissions even though they were measured in the field.

Russia, on the other hand, has had more than ample gas production for their markets. However, Russia is making the transition from a state run society wherein all utilities were provided by the central government, to a market society, wherein citizens pay for their utilities. This transition is incomplete, and many in the society cannot (or will not) pay for their gas. The monopoly gas transmission and distribution company, Gazprom, is not allowed to cut-off gas supply to citizens who "can't" pay for their consumption. Gazprom points to this situation as justification for why they cannot derive "western" economics for methane abatement investments. At the same time, Gazprom has exported gas to Eastern Europe and former Soviet Union (FSU) countries such as Ukraine. For these exports, Gazprom commands a world-scale gas price (or attempts to negotiate a world-scale gas price, e.g. in Ukraine). In this case, it is this author's opinion that Gazprom's position that their average, across the entire operation gas price is very low has been a "perceived" barrier. Since one can assume that the domestic market will be fully supplied before the export market, any investment that retains more gas in the pipeline (i.e. does not allow it to escape to the atmosphere) adds gas to the export market at a premium price. Gazprom has in recent years began to invest in the most cost-effective methane abatement projects, namely, replacement of "wet seals" in their 4000 compressor infrastructure.

Interestingly, the U.S. also suffers from a form of gas price control. The natural gas transmission and distribution companies generally do not own the gas they transport. The public utility agreements regulate prices for transporting gas including a "fuel factor" (since the transported product itself powers the transportation engines) and a "lost and unaccounted-for" factor to cover "fugitive" losses and meter differences between supply and customers. In other words, the customers are paying for lost gas. Therefore, if a company "loses" less gas, the PUC wants to pass this savings along to the customer. This common situation provides gas transmission and distribution companies with no economic incentive to "lose less gas." The industry and rate regulators have been aware of this issue, and some companies such as Pacific Gas and Electric (PG&E) has developed an agreement with their regulators to solve this dilemma. PG&E is allow to show a "voluntary" one dollar contribution on their gas bills, that money being tightly controlled with oversight by the PUC such that it is spent on energy efficiency and emissions abatement. To date the customers of PG&E have been more than generous in voluntarily adding $1 to their gas bills for this purpose.

Preferential interest in crude oil revenues:

As pointed out above, the world moves on oil: primarily gasoline in North America and China, primarily diesel in Western Europe, and jet kerosene for virtually all air transportation. Because demand growth continually presses supply, and for the major international oil corporations like ExxonMobil, Shell, Chevron, and BP, puts stress on their efforts to grow reserves faster than consumption, oil prices continue to dominate the energy markets in all parts of the world. In the United States, government prohibition of flaring associated natural gas with the Alaska North Slope oil production results in that gas being re-injected back into the reservoir. This is doubly expensive and wasteful, not only because it requires significant energy to pump that gas back down in the reservoir, but it will require energy again to bring that gas back up for supplying a market when a gas pipeline is built. Note that the industry and government could muster the investment to bring the oil to market with the Trans-Alaskan Oil Pipeline, but could not quite muster the capital to bring the gas down to market. This same situation is playing out in Montana, where the Bakken oil is being produced and pipelines are built to bring the oil to markets, but the associated gas is being flared. The State is not insisting that the gas be brought to market at the same time as the oil, and in this case, the tight shale oil does not offer a repository for re-injecting the associated gas. When gas is being flared, there is no economic incentive to reduce methane emissions from oil or gas operations, the largest contributors to methane emissions.

Russia oil production flares approximately half of the associated natural gas, not because there is no means of transporting this gas to market, but because the means, the Gazprom transmission pipeline, doesn't have capacity for this "extra" gas. This is discussed further below under "vested interests of monopoly enterprises," but here it is important to understand that the oil operations, primarily the field oil stock tanks, could not justify installing vapor recovery just to have the gas flared. It would be technically feasible to route tank vapors to the flare, but again, there is no revenue to drive this and no environmental regulation demanding it.

Some parts of the major Middle Eastern oil production used to flare virtually all associated natural gas, but have since made major investments to capture that gas and either use it for electrical power generation (often for sea water desalination) or re-inject the gas back into the reservoir where that is technically feasible. Saudi Aramco invested over $15 billion in the 1970s to capture virtually all associated gas from their major Arab Light production, most of it used for enhanced oil recovery by water flood. Some of this gas found its way into electrical energy supply to major Saudi cities and other industrial enterprises. The Middle East is generally less candid about their methane emissions from oil and gas operations, although it can be generally said that the equipment used in the Middle East is state of the art.

Access to gas markets:

In some regions of the world, natural gas has no market, and thereby has no market value. This is called "stranded gas." Africa has been such a region until the past decade when Chevron invested billions of dollars in Angola to bring liquefied natural gas (LNG) to markets. Just three years ago the United States had plans to build 49 LNG import terminals[12]. Today, with the technical advancements in hydraulic fracturing, which unlocked vast reserves of tight shale gas to economic production, some of the current 9 U.S. LNG import terminals have filed permit applications to export LNG. England, Western Europe and Japan have emerged as the predominant LNG importing regions for African, Southeast Asia, Middle East and Eastern Russia stranded natural gas.

Associated gas production can be stranded in offshore production operations. One such example in Brazil was analyzed by the Natural Gas STAR International program for a floating production storage and offtaking (FPSO) operation that transported oil by tanker, but had no gas pipeline and flared the gas. A design was developed to separate gas liquids from associated gas vapors captured by a vapor recovery unit, using a Joule-Thompson expansion. The gas liquids blended with the crude oil brought revenues which paid out the vapor recovery and J-T equipment, thus

[12] http://intelligencepress.com/features/lng/terminals/lng_terminals.html

minimizing methane gas flaring and venting. The point of this project was that it is not always necessary to pump recovered gas to market if there is an alternative beneficial use for it in the stranded gas location.

In virtually all cases where associated gas is stranded, and flared or vented, there is sure to be methane emissions from the oil operations that can be recovered when the stranded gas finds a beneficial use or market access.

Vested interests of monopoly enterprises:

The classic example of this is Gazprom, which controls its own natural gas production, gas transmission and gas distribution: end-to-end operations in natural gas supply to the Russian population as well as Eastern Europe, FSU, and now China export markets. Gazprom is producing natural gas wells while the major oil producers in Russia are flaring associated gas. Gazprom makes the legitimate point that the oil companies have not installed gas processing plants such that their associated gas meets pipeline specifications. Oil companies are reluctant to make the major investment without a firm commitment that Gazprom will take their gas at a fair price. This stalemate is a real barrier that can be resolved politically. The fact that Gazprom's production is lagging demand, and becoming more expensive to maintain, plus competition with LNG and Turkmenistan's rapidly growing natural gas supply, may cause economic drivers to help resolve this stalemate with associated gas producers.

India avoids this problem by not allowing the state owned gas transmission/distribution company, Gas Authority of India Limited (GAIL) to produce oil and gas, and the state owned oil and natural gas company (ONGC) that produces oil and gas cannot transport or distribute gas. Brazil and Mexico avoid this problem by the state owned company, Petrobras and Pemex, respectively, own and operate both oil and gas enterprises, end-to-end.

Capital costs and investment climate:

While some methane abatement technologies have relatively low implementation costs and quick pay-back, others require a substantial up-front investment. This requires an investment climate with "proper, consistent, legal, fiscal and approved" framework for investment (i.e. one that avoids graft and bribery). This should include developed institutions, including environmental and energy authorities to ensure sensible development of policies. This barrier is prevalent in a number of developing nations with oil and gas resources and stifles capital investment from outside the country.

Lack of knowledge of emissions and abatement technologies:

Lack of knowledge of emissions is a factor in almost all oil and gas field operations. The industry has a very strong sense of denial about methane emissions, partly because methane gas is odorless, colorless and non-toxic, and over the normal din of machinery in an operating environment emissions cannot be heard. It is further complicated by the natural motivation to not acknowledge emissions of any kind if they are not toxic. Finally, there is a general sense of denial in the industry about man-caused climate change. Again, the EPA Natural Gas STAR voluntary methane program has been successful largely because it does not depend on industry believing in climate change, but rather believing in the profit motive.

From a realistic point of view, many methane emission sources are positioned out of sight and reach by operators for safety considerations. For example, many emission sources associated with compressors are piped to vent stacks out the roof of a compressor building or at least high in the air so that the emissions will disperse in the air. Methane, being the only hydrocarbon lighter than air will disperse upward rather than sink down to the ground level like propane or butane gases. Safety instruments that detect explosive gas build up (lower explosive limit, LEL, detectors) are generally located at ground level where operating personnel work. These often do not detect methane emissions that are discharged high in the air. The invention of the infrared optical leak imaging camera has revolutionized this aspect of the industry and taken away the natural sense of denial. Time and again both U.S. and international operators have stated that their facilities have no leaks or vents before an IR leak imaging camera is brought to the facility. These operators express amazement (and instant buy-in) when they, themselves, view the leaks live through the camera. Some Gas STAR Program partners have reported purchasing a dozen cameras, outfitting the field "pumpers" with a camera to look at the facility immediately after stepping out of their pick-up truck. They report finding all kinds of unexpected leaks which they can walk right up to and often stop with the simple tightening of a valve or connector with a wrench.

Like color or flat screen TVs, the IR leak imaging cameras are presently expensive, but competition between vendors and increasing demand is expected to bring the unit price down … like color and flat screen TVs. This technology is valuable for all oil, gas, refinery, petrochemical and chemical industries seeking to detect and control hydrocarbon and some chemical emissions. For example, the very powerful GHG sulfur hexafluoride (SF_6) was one of the first commercial applications of IR leak detection cameras for the electrical power industry.

Not far behind denial of methane emissions is the lack of knowledge of methane abatement technologies and operating/maintenance practices. The need for technology transfer continues to be strong throughout the worldwide oil and gas industry. Since many of the technologies and practices were first developed in U.S. operations, and the U.S. has a generally negative international reputation when it comes to climate change policy (for refusal to ratify the Kyoto accord), many international companies are suspicious about the validity of the U.S. EPA Natural Gas STAR Program promoted technologies and practices. The Global Methane Initiative (formerly Methane to Markets) now has 39 partner countries and a growing number of international partner oil and gas companies including Gazprom of Russia[13].

[13] *www.**globalmethane**.org/gmi/*

The technical documents for over 80 Natural Gas STAR Program technologies and practices are available in English, Spanish, Russian, Chinese and now Arabic, posted on the Natural Gas STAR website[14]. Continued promotion of these methane voluntary programs, and especially participation by international partner companies, is gradually gaining respect and interest in the methane abatement technologies. However, it is still a challenge to bring this information down to the field operations and engineering level, given anything with the lable "U.S. Environmental Protection Agency" is thought of as an air pollution matter to be considered by a company's environmental personnel. It is not uncommon that the environmental personnel in operating companies, both U.S. and international, have very limited field experience and even less technical knowledge of exactly how the equipment works and where methane emissions come from. This is one of the key features of the Gas STAR technology transfer workshops and "Lessons Learned" studies (full length technical documents).

Inertia for the way it has always been done:

This is human nature: "if it ain't broke, don't fix it." Many methane abatement technologies are "new and different." As mentioned above, field engineers and operators are naturally reluctant to be the first to try something new. Some vendors provide their technology to the first time users "for free" to gain the endorsement of an industry user. This is well known, too, and propagates the suspicion of anything new: the fact that a company might promote a technology that worked for them, but they didn't have to pay for it. Further complicating this issue is the fact that competing vendors are quick to make claims that their technology "does the same thing" as a truly new and effective methane abatement technology. This has been going on with the IR leak imaging cameras for about 10 years, as one vendor makes claims that are frankly false, casting doubt in industry users whether all claims are false. The claim that an IR leak imaging camera or IR laser leak detector can "quantify" leaks is one good example of this false advertising. The trick is in what is meant by "quantifying." Some IR laser leak detectors have a digital read-out in ppm-meters, which is the amount of the laser beam that was absorbed by the gas cloud. It does not relate in any way to the size or amount of gas in the cloud, let alone how much gas in volume or mass is leaking from the source.

The way to overcome this inertia is honest reporting, multiple industrial representatives reporting and follow-up verification of results after a technology is tried. The most valuable representations of methane abatement projects are those where the industry had a third party company with no stake in the outcome perform the emissions detection and measurement before and after several applications, and report the results publicly. Some international companies have been reluctant to do this for reasons discussed below under Competition with other government emissions programs.

[14] *www.epa.gov/**gasstar**/*

Hopes for outside investment through Kyoto CDM and JI projects:

This issue is best epitomized by the Indian oil company, ONGC's approach to methane mitigation. While this is an affluent company, it is also very aggressive in seeking all advantages that may be gained through international programs. If carbon credits will sell to Kyoto Annex I countries, ONGC (and other Annex II developing country companies) will seek to package their projects to gain CDM approval. In many cases, methane mitigation technologies can be applied to some operations economically and others less economically. If several similar applications are packaged together such that the whole is not economical (i.e. meets the CDM "additionality" test) then there is hope that the whole project will be approved for carbon credits.

Another way of looking at this is the opposite: a company in the Middle East would naturally include gas recovery as a small fraction of a larger production project. But if the gas is vented, and then has to stand-alone in retrofitting the gas recovery equipment, it can be packaged to appear un-economic. The fact that the oil and gas industry is so technologically and organizationally complex makes it particularly difficult for verification and validation of CDM projects. Further complicating this is the natural bias of the CDM Methodology Panel (Meth Panel) in favor of non-fossil fuel projects, and accordingly opposed to any project that enables more fossil fuel supply. By its general nature, any methane emissions abatement technology sounds like a fossil fuel supply increase. The CDM Meth Panel seeks to know specifically (for verification) exactly WHAT methane supply is reduced with the abatement of a certain methane emissions. In the worldwide natural gas market, it is not possible to finger a specific well that will be shut in or well that will not be drilled because a significant methane emission source is eliminated or captured.

This very issue, satisfying the CDM Meth Panel on a specific natural gas supply source that will NOT be produced when a gas flare project recovers the wasted gas and directs it into the market, has delayed gas flare reduction for years. The World Bank Global Gas Flare Reduction program (GGFR) has combined forces with the Global Methane Initiative (GMI) to attempt to influence the CDM Meth Panel to take a different tact on verification of flared gas recovery projects similar to the tact taken with alternative electrical power generation projects. In this latter example, it was impractical if not impossible to finger the exact power plant that would burn less coal when a wind energy or solar energy supply project put power on a national electrical grid. This issue was successfully overcome with the Meth Panel, but gas flare reduction (not involving the supply of a renewable energy source) is struggling.

So in this issue, there are problems on both sides if the fence: the companies aggressively (perhaps over aggressively) seeking CDM carbon credit project approvals (and not investing in those fractions of the project that are separately economical), and the Clean Development Mechanism not working well for gas flare reduction with accompanying methane emissions abatement once the flared gas has a market.

Government segregation of oil, gas and coal enterprises:

This is a problem where one national company owns and operates one part of the industry, say oil, and another owns and operates a related industry, say gas. Russia has this issue between Gazprom who owns and operates the gas business well to gas customer, and the oil companies like TNK-BP who own and operate the oil business from well to refinery. When the two enterprises must interrelate to optimize methane gas use, and minimize emissions, the structure of the companies can get in the way. Mexico experienced something similar with Pemex having jurisdiction in oil and gas production, transmission and distribution, but coal mine methane that could be captured could not be managed by Pemex. In this case, the coal mine had no choice but to vent the methane that it could capture.

While it does not directly relate to just methane, even the U.S. has this policy barrier in that the coal industry has a lock on solid fuel fired electrical power plants and does not "make room" for petroleum coke, manufactured as a by-product in petroleum refineries. Hence, most of the petroleum coke produced in the coastal refineries of the U.S. is exported to foreign markets such as China. The indirect aspect of this petroleum coke barrier as it relates to methane emissions is the impediment it causes in importation of low methane emission crude oil sources such as synthetic crude oil (SCO) produced from upgraded oil sands.

Competition with other government emissions programs:

The EPA Natural Gas STAR Program has be so successful because for 15 years, methane has been un-regulated under the Clean Air Act. Hence, anything oil and gas companies did to abate methane emissions was considered beneficial. Part of the "Memorandum of Understanding" that the U.S. EPA signed with oil and gas companies included the EPA using its influence to obtain credit for those investments that U.S. companies made voluntarily if methane should ever be regulated. That time is now, and the U.S. oil and gas companies are frankly suspicious of the EPA. This suspicion has stifled continued investment in methane abatement technologies by some companies. It is a credit to other operating companies that they continue to invest and even innovate in methane abatement projects as they await EPA's forthcoming regulations. To be fair to the U.S. EPA, their regulation of GHG emissions under the Clean Air Act was contested with states up to the Supreme Court, and EPA lost. So the forthcoming regulations are court ordered.

In a similar vein, Russia has an issue between a government pollution tax and methane mitigation projects. In the absence of the IR leak imaging camera, neither the government regulators nor the gas companies were very aware of certain methane emission sources. The position this puts an operating company in is that if they abate a huge methane emission, this is tantamount to providing evidence of "fugitive" emissions far above what they have been paying the pollution tax on, and exposing them to increased tax for past emissions. An operating company would have to "trust" the government NOT to come after them for past emissions. There are cases just the opposite, wherein U.S. States such as Louisiana and Alabama successfully settled with oil companies on excessive, non-reported flaring and venting emissions, causing the company to pay back-royalties. Such cases get the attention of the worldwide oil and gas industry (which is surprisingly well informed of industry events around the world through such periodicals as the Oil & Gas Journal).

State owned oil and gas companies have this issue where some parts of their operating area have emissions regulations, but no enforcement. Being a state entity, these companies consider it an obligation to comply with state mandated emissions regulations even if there is not enforcement. For this reason, some companies have been reluctant to allow the IR leak imating cameras into their operations (presumably out of concern that what they find they will have to abate even if it is not economical): what you don't know won't hurt you.

In the United Nations Framework Convention on Climate Change (UNFCCC), the emphasis until recently has been on CO_2 emission reduction. Perhaps for this reason, several countries, including the United States, have created laws to reduce CO_2 emissions, in the U.S. through, e.g. Corporate Average Fuel Economy (CAFÉ) regulations. The proposed carbon tax legislation by McCain/Lieberman and Bingaman/Specter dealt with CO_2 emissions, "leaving methane to be regulated by EPA." The United Nations Environmental Program (UNEP) recently came out with a recommendation to focus GHG emissions control on black carbon and methane[15] because of the much higher short term GWP of methane versus CO_2. This is where this paper started, making the case for abating methane because of its 20 year GWP. Now government programs around the world should embrace this and remove those barriers that stifle oil and gas companies from investing and innovating technologies and practices to avoid methane emissions.

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[15] http://www.washingtonpost.com/wp-dyn/content/article/2011/02/23/AR2011022306885.html

The following table cross-walks these ten policy/barrier issues with the companies listed in the top 20 methane emissions.

Policy/Barrier -> / Country	Gas Price	Crude Oil	Markets	Monopoly	Investment	Knowledge	Inertia	CDM/JI	Segregation	Government
Russia	P	R		R		R	R	R	R	R
United States	R					R	R			R
Uzbekistan		R			R	R				
Canada										R
Turkmenistan						R		?		
Venezuela	R	R			R	R				
India						R	R	R		
Ukraine						R		R		
Argentina	R					R	R			
Thailand						?				
Colombia		R			R	R	R			
China	R	R				R				

Note: R = Real; P = Perceived by Country; ? = Possibly

Appendix 1: Estimate of Worldwide Oil and Gas Methane Emissions

Methane Emissions from Oil and Gas Systems (MMTCO2e)

Country	1990	1995	2000	2005	2010	2015	2020	2025	2030
Afghanistan	0.88	0.06	0.07	0.01	0.01	0.01	0.01	0.01	0.02
Albania	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Algeria	10.59	11.42	14.18	17.54	19.13	23.28	25.19	26.06	26.86
Angola	17.93	24.34	28.12	47.45	84.91	92.31	88.70	92.44	99.85
Antigua and Barbuda	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Argentina	8.25	10.23	10.78	11.57	12.71	12.65	13.66	15.56	17.72
Armenia	1.68	1.68	1.68	1.68	1.61	1.56	1.70	1.91	2.02
Australia	6.96	7.04	5.85	4.95	5.45	5.75	6.20	6.45	6.80
Austria	0.37	0.47	0.56	0.67	0.81	0.77	0.78	0.79	0.82
Azerbaijan	9.31	6.47	8.51	11.91	24.34	31.47	33.95	35.58	37.97
Bahamas	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Bahrain	0.48	0.54	0.64	0.76	1.06	1.20	1.26	1.38	1.41
Bangladesh	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01
Barbados	0.05	0.05	0.07	0.05	0.05	0.05	0.06	0.06	0.07
Belarus	1.23	1.23	1.46	1.59	1.59	1.34	1.43	1.55	1.61
Belgium	0.53	0.52	0.45	0.41	0.65	0.64	0.66	0.69	0.73
Belize	0.00	0.00	0.00	0.00	0.11	0.11	0.11	0.13	0.16
Benin	0.15	0.11	0.03	0.00	0.00	0.00	0.00	0.00	0.00
Bhutan	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Bolivia	0.75	1.58	0.67	1.89	2.20	2.28	2.47	2.76	3.04
Bosnia and Herzegovina	0.00	0.38	0.02	0.02	0.02	0.02	0.02	0.03	0.03
Botswana	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Brazil	1.00	1.18	1.97	2.61	3.58	4.90	6.40	7.28	8.11
Brunei	8.43	9.10	10.71	11.13	11.38	12.19	12.73	13.15	14.11

Brunei Darussalam	8.43	9.10	10.71	11.13	11.38	12.19	12.73	13.15	14.11
Bulgaria	0.62	0.65	0.59	0.63	0.96	0.94	0.99	1.03	1.08
Burkina Faso	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Burundi	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Cambodia	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Cameroon	0.03	0.02	0.01	0.01	0.01	0.02	0.02	0.02	0.02
Canada	30.15	40.70	47.70	48.46	56.38	63.69	67.58	73.41	78.90
Cape Verde	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Central African Republic	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Chad	0.00	0.00	0.00	6.61	5.61	5.81	6.02	6.44	6.64
Chile	1.92	1.60	1.22	1.62	1.88	1.94	2.18	2.46	2.71
China	2.42	2.69	3.09	3.73	4.35	4.29	4.45	4.81	5.18
Colombia	2.44	2.78	2.99	8.43	8.81	8.47	9.03	10.45	12.25
Comoros	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Congo	0.02	0.02	0.02	0.02	0.02	0.02	0.03	0.03	0.03
Cook Islands	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Costa Rica	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Côte d'Ivoire	0.06	0.33	0.90	1.91	2.64	2.80	3.01	3.27	3.45
Croatia	1.20	1.15	1.11	1.33	1.24	1.15	1.11	1.12	1.13
Cuba	0.01	0.40	1.32	1.48	1.45	1.39	1.48	1.71	2.02
Cyprus	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Czech Republic	0.90	0.67	0.69	0.68	0.81	0.78	0.80	0.83	0.87
Democratic Republic of Congo (Kinshasa)	1.09	1.12	0.97	0.74	0.86	0.89	0.93	0.99	1.02
Denmark	0.04	0.06	0.08	0.10	0.08	0.07	0.06	0.06	0.06
Djibouti	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Dominica	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Dominican Republic	0.00	0.00	0.00	0.00	0.05	0.05	0.06	0.07	0.07
Ecuador	0.44	0.61	0.61	0.82	0.79	0.63	0.63	0.63	0.63

El Salvador	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Equatorial Guinea	0.00	0.19	6.28	14.48	14.90	15.51	16.18	17.35	17.98
Eritrea	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Estonia	0.79	0.38	0.43	0.52	0.53	0.40	0.42	0.44	0.45
Ethiopia	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fiji	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Finland	0.01	0.08	0.06	0.06	0.09	0.09	0.09	0.09	0.09
France	2.79	2.25	2.02	1.91	2.58	2.49	2.55	2.65	2.76
Gabon	10.13	13.69	11.81	9.99	9.40	10.09	9.87	9.88	9.89
Gambia	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Georgia	0.17	0.16	0.16	0.17	0.13	0.14	0.15	0.16	0.17
Germany	7.48	7.71	7.46	7.04	7.20	6.89	6.49	6.70	6.94
Ghana	0.00	0.15	0.27	0.28	0.28	0.29	0.30	0.32	0.33
Greece	0.09	0.06	0.14	0.15	0.21	0.20	0.20	0.21	0.22
Grenada	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Guatemala	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Guinea	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Guinea-Bissau	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Guyana	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Haiti	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Honduras	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Hungary	1.54	1.96	2.05	2.05	2.22	2.13	2.15	2.21	2.28
Iceland	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
India	11.77	14.44	15.54	18.12	23.07	26.23	29.85	34.95	36.49
Indonesia	36.87	42.50	41.67	33.78	35.86	38.09	39.63	40.89	43.88
Iran	25.65	31.44	34.98	43.51	48.11	48.21	48.28	50.93	54.21
Ireland	0.13	0.11	0.09	0.06	0.10	0.10	0.10	0.11	0.11
Israel	0.04	0.12	0.14	0.43	0.61	0.69	0.74	0.81	0.82
Italy	7.30	6.82	6.35	5.65	7.12	6.85	6.96	7.17	7.42
Jamaica	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Japan	0.23	0.27	0.27	0.32	0.46	0.47	0.60	0.63	0.64
Jordan	0.06	0.10	0.08	0.16	0.47	0.51	0.58	0.66	0.70
Kazakhstan	12.57	6.75	5.24	5.19	6.22	8.06	8.70	9.12	9.74
Kenya	0.02	0.02	0.02	0.02	0.04	0.04	0.04	0.04	0.05

Kiribati	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Kuwait	48.01	82.73	85.48	103.99	107.16	108.07	105.23	109.87	117.71
Kyrgyzstan	1.12	0.44	0.34	0.37	0.27	0.31	0.33	0.36	0.38
Laos	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Latvia	0.27	0.22	0.17	0.15	0.14	0.13	0.14	0.16	0.17
Lebanon	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Lesotho	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Liberia	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Libyan Arab Jamahiriya	54.60	55.42	56.89	67.75	77.66	70.85	64.32	65.13	65.87
Liechtenstein	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Lithuania	0.36	0.16	0.18	0.21	0.17	0.14	0.15	0.16	0.16
Luxembourg	0.02	0.02	0.03	0.05	0.09	0.09	0.09	0.10	0.10
Macedonia	0.00	0.00	0.02	0.03	0.03	0.03	0.03	0.04	0.04
Madagascar	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Malawi	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Malaysia	10.49	13.43	17.14	18.92	20.49	21.84	22.90	23.90	25.81
Maldives	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mali	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Malta	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Marshall Islands	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mauritania	0.00	0.00	0.00	0.00	0.58	0.60	0.63	0.67	0.69
Mauritius	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mexico	30.56	33.98	38.28	39.13	31.20	25.99	24.32	26.06	29.67
Micronesia (Federated States of)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Moldova	1.08	0.53	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Monaco	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mongolia	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Montenegro	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Morocco	0.00	0.00	0.17	0.18	0.18	0.19	0.21	0.22	0.23
Mozambique	0.00	0.00	0.02	0.06	0.57	0.68	0.82	0.91	1.00
Myanmar	0.88	0.91	1.48	4.42	5.23	5.80	6.28	6.85	7.54
Namibia	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Nauru	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Nepal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Netherlands	1.64	1.63	0.80	0.75	0.86	0.84	0.85	0.86	0.87
New Zealand	0.32	0.30	0.40	0.43	0.67	0.71	0.77	0.80	0.85
Nicaragua	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Niger	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Nigeria	17.29	19.19	21.91	27.73	25.99	33.26	35.86	37.30	37.73
Niue	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
North Korea	0.02	0.02	0.03	0.00	0.00	0.00	0.00	0.00	0.00
Norway	0.32	0.56	0.68	0.62	0.47	0.41	0.38	0.37	0.37
Oman	26.87	33.47	39.15	34.95	36.16	39.58	35.60	36.98	35.66
Pakistan	3.94	5.00	6.28	7.93	12.85	13.70	15.08	17.09	19.30
Palau	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Panama	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Papua New Guinea	0.00	3.78	2.66	1.54	1.65	1.71	1.72	1.68	1.74
Paraguay	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Peru	0.14	0.15	0.11	0.14	0.15	0.15	0.16	0.18	0.21
Philippines	0.01	0.01	0.00	0.12	0.13	0.14	0.14	0.15	0.17
Poland	3.10	3.19	3.54	4.32	5.25	4.38	4.85	4.97	5.69
Portugal	0.05	0.06	0.21	0.87	1.31	1.27	1.30	1.34	1.40
Qatar	19.27	23.02	41.25	54.69	73.00	95.56	106.04	116.51	125.11
Romania	19.41	12.83	9.21	8.83	9.19	8.63	8.45	8.51	8.65
Russian Federation	335.07	274.61	280.34	311.53	310.60	318.79	358.50	377.70	393.34
Rwanda	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Saint Kitts and Nevis	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Saint Lucia	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Saint Vincent and the Grenadines	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Samoa	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Sao Tome and Principe	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Saudi Arabia	1.60	2.10	2.20	2.62	2.46	2.70	2.75	2.85	3.02

Senegal	0.00	0.01	0.01	0.01	0.02	0.02	0.02	0.02	0.03
Serbia	0.86	1.23	0.88	0.79	0.19	0.19	0.21	0.23	0.24
Seychelles	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Sierra Leone	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Singapore	0.00	0.05	0.58	0.72	1.64	1.57	1.77	2.15	2.54
Slovak Republic	0.51	0.61	0.72	0.67	0.74	0.74	0.74	0.78	0.81
Slovenia	0.06	0.05	0.04	0.03	0.05	0.05	0.06	0.06	0.06
Solomon Islands	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Somalia	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
South Africa	0.01	0.23	0.22	0.24	0.25	0.26	0.28	0.30	0.31
South Korea	0.34	1.80	3.26	5.72	49.62	49.62	58.15	66.68	70.94
Spain	0.63	0.82	0.78	0.91	1.36	1.33	1.38	1.44	1.50
Sri Lanka	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Sudan	0.00	0.00	7.00	13.19	18.16	18.83	19.50	20.85	21.52
Suriname	0.15	0.26	0.36	0.35	0.49	0.46	0.49	0.57	0.67
Swaziland	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Sweden	0.00	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00
Switzerland	0.38	0.27	0.22	0.18	0.20	0.20	0.20	0.20	0.20
Syrian Arab Republic	15.35	22.80	22.43	19.33	18.48	19.97	17.33	17.79	16.93
Tajikistan	0.78	0.29	0.13	0.12	0.11	0.11	0.12	0.13	0.14
Thailand	2.40	4.08	7.57	10.79	14.52	15.17	16.11	17.36	19.14
Togo	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Tonga	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Trinidad and Tobago	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01
Tunisia	0.63	0.58	0.69	0.73	0.89	0.94	1.02	1.12	1.19
Turkey	1.09	1.15	1.23	1.58	2.29	2.22	2.27	2.36	2.46
Turkmenistan	22.09	16.16	24.23	32.43	35.21	40.42	43.46	44.63	46.05
Tuvalu	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Uganda	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Ukraine	31.34	23.59	21.90	23.95	21.76	19.46	20.71	22.16	22.91
United Arab Emirates	7.75	8.65	9.52	10.76	12.16	12.48	12.44	12.74	12.86

United Kingdom	10.30	9.71	7.95	5.76	4.10	3.70	3.30	3.27	3.30
United Republic of Tanzania	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
United States	163.45	164.60	161.10	134.56	113.03	125.03	138.45	150.23	153.69
Uruguay	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.02
Uzbekistan	45.67	62.83	70.02	76.33	83.39	92.84	99.84	102.83	105.65
Vanuatu	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Venezuela	27.97	36.29	41.74	35.70	30.55	30.80	35.73	39.54	43.24
Viet Nam	0.05	0.19	0.34	0.47	0.47	0.49	0.50	0.50	0.53
Yemen	0.04	0.07	0.09	0.09	0.07	0.07	0.06	0.06	0.06
Zambia	0.00	0.01	0.00	0.01	0.01	0.01	0.01	0.01	0.01
Zimbabwe	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TOTAL	1,139	1,186	1,277	1,407	1,554	1,650	1,745	1,855	1,950

Appendix 3: 2010 Worldwide Methane Emission Sources and Mitigation[16]

Source	Methane Emissions ($MtCO_2e$)	U.S. EPA Natural Gas STAR (NGS) Mitigation Technology or Practice[1]	Nominal NGS Cost ($/tonne)[2]
Natural Gas Production	688.8		
Pneumatic devices	260.4	Retrofit or replace with low-bleed devices	-39
Dehydrators	75.5	Optimize circulation rate, install flash tank	-42
Offshore	75.3		
Gas engines	59.7	Automated air/fuel ratio controllers	-46
Well blowdowns	43.6	Install plunger lifts and "smart" automation	-12
Flaring	0.36		
Other	174.0		
Oil Production	35.9		
Pneumatic devices	6.41	Retrofit or replace with low-bleed devices	-39
Oil tanks	2.08	Install vapor recovery units	-34
Gas engines	1.10	Automated air/fuel ratio controllers	-46
Chemical injection pumps	0.76	Convert to air, solar, or mechanical control	-33
Oil wellheads	0.35	Leak inspection and repair	-44
Offshore	12.6		
Flaring	0.08		
Associated gas venting	2.34		
Other	10.2		
Oil Transportation	0.98		
Oil Refining	1.75		
Natural Gas Processing	66.4		
Reciprocating compressors	32.2	Economic replacement of rod packing	-42
Gas engines	13.6	Automated air/fuel ratio controllers	-46
Centrifugal compressors	9.83	Replace wet seals with dry seals	-35
Plant blowdowns/venting	3.86	Alter testing practices, test with air, move-in isolation valves	-37

[16] EPA. ICF Revised: Global Anthropogenic Emissions of Non-CO_2 Greenhouse Gases 1990-2020 <http://www.epa.gov/climatechange/economics/international.html>.

Plant leaks	2.74	Leak inspection and repair	-44
Flaring	0.08		
Other	4.21		
Natural Gas Transmission/Storage	194.7		
Reciprocating compressors (transmission)	55.9	Economic replacement of rod packing	-42
Pneumatic devices (transmission)	16.0	Retrofit or replace with low-bleed devices	-39
Gas engines (transmission)	15.9	Automated air/fuel ratio controllers	-46
Other transmission fugitives	27.2	Leak inspection and repair	-44
Pipeline venting (transmission)	34.3	Pipeline pump-down, hot taps, composite wrap	-45
Other transmission maintenance venting	28.0	Alter testing practices, test with air, move-in isolation valves	-37
Reciprocating compressors (storage)	7.84	Economic replacement of rod packing	-42
Other storage	9.50		
Natural Gas Distribution	365.9		
Metering & regulating stations	147.8	Leak inspection and repair	-44
Pipeline mains	115.7	Leak inspection and repair, flexible plastic liners	-36
Pipeline services	61.1	Leak inspection and repair, flexible plastic liners	-36
Other	41.3		
TOTAL OIL & GAS	1,354.5		

Notes: 1: U.S. EPA Natural Gas STAR Program technologies and practices at www.epa.gov/gasstar.
2: Net present value of costs from a five year, 10% discounted cash flow with natural gas valued at $5 per thousand cubic feet.