ENERGY MARKET CONSEQUENCES
OF AN EMERGING U.S. CARBON MANAGEMENT POLICY

Gas Flaring and Venting: Extent, Impacts, and Remedies

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About the Study: Energy Market Consequences of an Emerging U.S. Carbon Management Policy

Emerging energy and climate policies in the United States are accelerating the pace of technological changes and prompting calls for alternative energy and stricter energy efficiency measures. These trends raise questions about the future demand for fossil fuels, such that some energy-producing nations are reluctant to invest heavily in the expansion of production capacity. The abundance of shale gas resources in North America could allow the United States to utilize more gas in its energy mix as a means of enhancing energy security and reducing CO_2 emissions. However, this will only occur if U.S. policies promote and allow the benefits provided by natural gas to be realized. To examine these issues and changing trends in the U.S. energy and climate policy, the Baker Institute organized a major study investigating the North American and global oil and natural gas market consequences of emerging U.S. policies to regulate greenhouse gas emissions, as well as the potential role of alternative energy in the U.S. economy.

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Introduction

Associated natural gas is a byproduct of the oil extraction process and is often considered more of a nuisance than an economic resource. In order to get rid of this waste gas, some of it is burned on reaching the surface with a process called flaring, and some of it is directly released into the atmosphere without burning through venting. The potential significance of the associated gas wasted to flaring and venting has recently started to be realized by most countries. Associated gas is very similar in composition to commercial natural gas and is a cleaner source of energy than other fossil fuels. As a feedstock, it has value in the petrochemical and fertilizer industries and as a commercial fuel. The extent of the economic value of the wasted gas to flaring and venting can be approximated by its export value to the U.S. and European markets, which is estimated to be $20 billion (based on the U.S. gas price of $4 per million Btu) (Gerner et al., 2004).

Since methane is the major component of associated gas, direct venting of gas releases a significant amount of methane into the atmosphere. Flaring of associated gas, on the other hand, mainly emits carbon dioxide (CO_2). The National Oceanic and Atmospheric Administration (NOAA) estimates that between 1994-2008, the total amount of global gas flared was 2.4×10^{12} m^3, which corresponds to 70% of total U.S. greenhouse emissions in 2007 (Elvidge et al., 2009a).

A number of institutions are implicated worldwide in the flaring of associated natural gas. The primary players are the oil resource owners, the producing companies, and the local industries that use associated gas or other fuels for heat and power. The World Bank started a public-private partnership initiative called Global Gas Flaring Reduction (GGFR) in 2002 with the purpose of reducing gas flaring and venting worldwide. The current partners of the GGFR are the countries of Algeria, Angola, Azerbaijan, Cameroon, Chad, Ecuador, Equatorial Guinea, Gabon, Indonesia, Iraq, Kazakhstan, the Russian Federation, Mexico, Nigeria, Qatar, the United Arab Emirates (UAE), and Uzbekistan; 18 oil companies including BP, Shell Oil, Chevron, ConocoPhillips, ExxonMobil, Total, and others; donor countries including the United States, United Kingdom, France, Norway, and Canada; and organizations such as the European Union (EU), the Organization of the Petroleum Exporting Countries (OPEC), and the World Bank.

The mission of the GGFR is to address the issue of gas flaring by promoting strong cooperation among the primary players and encouraging regulatory frameworks and gas transmission infrastructure investments. This approach has demonstrated some success in commercial initiatives for using associated gas in certain selected end uses, including electric power generation. However, a demand-pull approach has not generally been successful at the upstream end of the gas value chain, since it does not deal with the fundamental underpricing error that is normally responsible for gas flaring. As such, improvements in sector efficiency have focused on better transmission and distribution of existing associated gas supplies, rather than providing incentives for increasing those supplies (i.e., reducing gas flaring and venting). Recent initiatives to price associated gas at more market-related levels in such major flaring nations as Russia, Nigeria, and Indonesia show positive signs, though it will take time for significant improvements to become clear (GGFR, 2006). This review will assess whether and to what extent such an approach has resulted in (i) efficient use of the gas; (ii) appropriate incentives throughout the gas value chain to supply gas at a price that clears the market; (iii) environmental impacts that are more benign than the use of potential alternative fuels; and (iv) appropriate incentives to reduce the venting and flaring of associated natural gas.

Section 2 of this paper will review self-reported and satellite-estimated countrywide flaring data and the nature of the gas flaring and venting problem—extent, locations, and parties involved, economic and environmental impacts of the gas flared, and an assessment of the reasons for flaring and venting in major oil basins. Section 3 will review approaches to estimating emissions and efforts to mitigate the emissions; identify potential options for reducing gas flaring and venting; and estimate the relative cost-effectiveness of those measures and assess their feasibility. Section 4 explores the best practices from several countries to identify rational approaches that could be implemented in places with the highest flaring and venting volumes. Finally, Section 5 addresses the policy aspects of reducing gas flaring and venting. What tools have been used? What other means may be available? What institutions may provide assistance and financing to reduce flaring and venting?

1. Gas flaring and venting—A worldwide problem

1.1 The role of flaring and venting of associated natural gas as a source of greenhouse gas and air pollution

Associated gas is the raw natural gas that emerges from oil wells and is commonly a mixture of methane and other hydrocarbons—mainly ethane, propane, butanes, and pentanes. Associated gas also contains water vapor, hydrogen sulfide (H_2S), carbon dioxide (CO_2), helium, nitrogen, and other minor compounds. Since methane is the major component of associated gas, direct venting of gas releases a significant amount of methane into the atmosphere along with H_2S and volatile organic compounds (VOC). The amount of these contaminants depends on the chemical composition of the associated gas, which typically shows significant site-to-site variations. Flaring of associated gas, on the other hand, mainly emits CO_2 and carbon monoxide (CO) along with a variety of air pollutants, such as VOCs (which include carcinogens and air toxics), nitrogen oxides (NO_x), sulfur dioxide (SO_2), toxic heavy metals, and black carbon soot. The flaring process is often inefficient, resulting in a mix of constituents that range between vented natural gas and the ideal emissions from burning the gas.

Emissions of potentially toxic air pollutants are highly dependent on the combustion efficiency of the flaring system. The performance of combustion is largely impacted by the energy density of the flare gas stream, design of the flare system, composition of flare gas, and environmental conditions such as ambient temperature, wind speed, and wind direction (Kostiuk et al., 2004). Kostiuk et al. found that the flaring of propane-rich gas produced measurable amounts of soot emissions and many polycyclic aromatic hydrocarbons (PAH) attached to soot particles, including naphthalene, acenaphthalene, fluorene, phenanthrene, fluoranthene, and pyrene. An Alberta Research Council (ARC) study (Strosher, 2000) found more than 150 VOC and PAH species in the plumes of flare products in Alberta oil fields. The amounts emitted were higher for gas streams with a greater content of liquid hydrocarbons, which had combustion efficiencies as low as 62%. The most abundant compounds detected in flare emissions in all conditions tested were benzene, styrene, ethyl benzene, toluene, xylenes, acenaphthalene, biphenyl, and fluorene.

Although most high-flaring oil fields are in remote locations, industrialization at these locations often attracts small local communities in the vicinity of these fields. The air pollution associated with gas flaring and venting poses a significant health risk for local communities and for people who work in these oil fields. A 2005 report by the Environmental Rights Action (ERA) and the Climate Justice Programme (CJP) quantified the impact of toxic air pollutants, including benzene and dioxins, emitted by gas flaring in the Niger Delta. The researchers estimated that gas flaring at 17 onshore flow stations in Nigeria's Bayelsa State is likely to cause 49 premature deaths, respiratory illnesses in 5,000 children, 120,000 asthma attacks, and eight additional cases of cancer each year (ERA and CJP, 2005). These conservative estimates would be amplified if other locations of gas flaring outside Bayelsa State were considered, and other toxic pollutants emitted by gas flaring and venting were included.

Estimates of the roles of various gases in climate change are highly variable. Water vapor is estimated by the Intergovernmental Panel on Climate Change (IPCC) to account for 36%–66% of total greenhouse gas emissions. Of the remaining greenhouse gases, the three principal ones are CO_2, CH_4, and nitrous oxide (N_2O). More exotic compounds, including halomethanes, account for less than 1% of greenhouse gases, though their impact may still be significant. Black carbon particulates in the atmosphere or deposited on soils and ice also enhance global warming. The impact of a particular greenhouse gas is measured by its radiative forcing coefficient and its estimated lifetime in the atmosphere. IPCC conventions normalize CO_2 to a value of 1. On a scale of 100 years, the global warming potential of methane is indexed at 25 times above CO_2 on the IPCC scale; N_2O is 298, and tetraflouromethane compounds are estimated to have 3830-14,800 times the global warming potential of CO_2. Thus, directing resources toward reducing venting vis-à-vis high efficiency flaring is crucial.

1.2 Natural gas: Current demand and expected growth

World natural gas production in 2009 was approximately 2,987 billion cubic meters (bcm) and consumption was 2,940 bcm.[1] Projections from the International Energy Agency (IEA) show an

[1] *BP Statistical Review of World Energy*, 2010.

increasing demand for natural gas by 1.5% per year through 2030.[2] At the present time, natural gas represents 23.1% of total world energy demand on an energy equivalent basis.[3] Over the next 22 years, natural gas use is projected by the U.S. Department of Energy and the International Energy Agency to grow by about 1.9% annually, reaching 4,700 bcm in 2030, and accounting for 24.4% of expected total energy consumption. Therefore, better exploitation of natural gas resources, especially those underutilized in West Africa, would be a significant way to meet the world's increasing natural gas demand.

1.3 Gas flaring data

Data on flaring and venting of associated gas from oil production are very limited due to inaccurate and incomplete self-reporting by individual countries and oil producers. According to the estimates provided by the GGFR and NOAA based on satellite data, global gas flaring volumes were estimated at about 146 bcm in 2009. This figure represents roughly 4.9% of world gas consumption in 2009, about 32% of the European Union's total gas consumption, and 23% of U.S. consumption in 2009, and corresponds to more than 278 million tons of CO2 equivalent (CO2e) (Elvidge, 2009a). This is somewhat less than one percent of global emissions, as world CO2 emissions from the consumption of energy in 2008 were 30,377 million metric tons (EIA, 2010). Total GHG emissions also include issues such as deforestation, so emissions from energy only accounted for 61.4 percent of global CO2e in 2000 (Pravettoni, 2009). Nigeria and Russia alone accounted for 42% of the total flaring volume. Estimates of venting volumes are more difficult to obtain, since current satellite technology is not capable of detecting and tracking venting. However, venting is more damaging environmentally, since unburned CH_4 is approximately 25 times more potent as a greenhouse gas than is CO_2.

1.3.1 Reported data on flaring of associated natural gas

The data on flaring and venting volumes are highly speculative, and order of magnitude errors are within the realm of possibility. The uncertainties in the magnitude of gas flaring and venting

[2] International Energy Agency, *The World Energy Outlook*, 2009.
[3] U.S. Department of Energy, *International Energy Outlook 2007*, Table A.2.

need to be resolved in order to understand the nature of the problem and the impacts of pricing and investment programs on both flaring volumes and total gas supplies.

Based on the reported data by the governments of individual countries, the GGFR has constructed the following table of gas flaring volumes for 2004 and 2005 (see Table 1). The reported data is not available from the GGFR for other years.

According to the reported data, Nigeria, Russia, Iran, Iraq, and Angola are the highest flaring countries. On the other hand, a very large percentage of associated gas (more than 95%) is utilized in countries such as Norway, Canada, the United Kingdom, and the United States. These countries flare less than 2 cubic meters for every barrel of oil produced.

Oil fields scattered over a large area in two regions in West Siberia are responsible for most of Russia's gas flaring. The gas flaring volumes reported by the Russian government increased from a range of 4.3–10 bcm in the 1990s to about 15 bcm in 2005. These figures are not reliable reflections of the actual volumes of gas flared due to the lack of transparency and consistency of the data sources. Regular flare monitoring and measurement via meters are not mandated by the Russian government and are not common practices applied by companies, leading to inconsistent reporting of flare volumes. Thus, flare volumes are usually estimated using mass and energy balances (PFC Energy, 2007; IEA, 2006a).

Table 1. Volume of associated gas flared in 2004 and 2005 in billions cubic meters.[4]

Country	2004	2005
Nigeria	24.1	25.5
Russia	14.7	14.9
Iran	13.3	13.0
Iraq	8.6	7.2
Angola	6.8	6.4
Venezuela	5.4	5.4
Qatar	4.5	3.9
Algeria	4.3	3.5
USA	2.8	3.4
Indonesia	3.7	3.0
Kuwait	2.7	3.0
Kazakhstan	2.7	2.7
Equatorial Guinea	3.6	2.6
Azerbaijan	2.5	2.5
Libya	2.5	2.5
Mexico	1.5	2.5
Brazil	1.5	2.5
Congo	1.2	2.2
UK	1.6	1.6
Gabon	1.4	1.6
Total Top 20	**109.3**	**109.8**
Rest of the World	**40.0**	**40.0**
World Total	**149.3**	**149.8**

1.3.2 Gas flaring estimates from NOAA: Limitations and uncertainties

The NOAA National Geophysical Data Center (NGDC) has made significant improvements in detecting global gas flaring activities and estimating gas flaring volumes in recent years. NGDC uses the data collected by the U.S. Air Force Defense Meteorological Satellite Program (DMSP) Operational Linescan System (OLS) and calibrates it using the most reliable reported gas flaring

[4] Reported Flaring Data—2004-2005. GGFR. (http://web.worldbank.org/WBSITE/EXTERNAL/TOPICS/EXTOGMC/EXTGGFR/0,,contentMDK:21348978~pagePK:64168445~piPK:64168309~theSitePK:578069,00.html).

data from individual countries. The trends in global gas flaring volumes are then estimated from the calibrated results. NGDC has also utilized Google Earth high resolution image data to separate urban lights from the flares, thus improving the satellite-observed detection of gas flaring (Elvidge et al., 2009b).

The 15-year record of global natural gas flaring derived from satellite data is a useful contribution to strategic planning and verification of mitigation of gas flaring. The volume of global gas flaring has remained relatively stable, in the range of 140 to 170 bcm from 1994 to 2009. The most important result of these observations for crafting a mitigation policy targeted at reducing global flaring is the confirmation that a small number of countries are dominant contributors to global flaring emissions. In 2009, Russia had the largest flaring volume, with 46 bcm, followed by Nigeria at 15 bcm; Russia and Nigeria accounted for an estimated 42% of global flaring. Twenty countries accounted for an estimated 85% of the observed flaring.

Table 2 shows the NOAA flaring estimates for 2005–2009. Although the worldwide total is just 7.5% above the GGFR estimate for the year 2005, the top 20 flaring countries account for a greater percentage of total flaring. Moreover, the NOAA list of top flaring countries includes six that are not on the GGFR list and drops seven of the top GGFR flaring countries. For five out of the 20 countries having self-reported data, the reported flaring volumes were less than the satellite estimates. Russia and Kazakhstan in particular may have significantly underreported their flaring volumes. The flaring volumes from NOAA of seven countries were approximately 20% lower than those countries’ self-reported figures. (Figure 1).

Table 2. Estimated flared volumes from satellite data, 2005-2009. Source: NOAA-NGDC website and GGFR Jan-Jul 2010 newsletter.[5]

Volumes (bcm)	2005	2006	2007	2008	2009	Change from 2005 to 2009	Percent of World Total in 2009
Russia	55.2	48.8	50	40.2	46.2	-15	32
Nigeria	21.3	19.3	16.8	14.9	14.9	-6.4	10
Iran	11.3	12.1	10.6	10.3	10.3	-1	7
Iraq	7.1	7.4	7	7	8.3	-0.1	6
Algeria	5.2	6.2	5.2	5.5	5.5	0.3	4
Kazakhstan	5.8	6	5.3	5.2	5.2	-0.6	4
Libya	4.4	4.3	3.7	3.7	3.7	-0.7	3
Saudi Arabia	3	3.3	3.4	3.5	3.5	0.5	2
Angola	4.6	4	3.5	3.1	3.1	-1.5	2
Qatar	2.7	2.8	2.9	3	3	0.3	2
Uzbekistan	2.5	2.8	2	2.7	2.7	0.2	2
Mexico	0.9	1.2	1.7	2.6	2.6	1.7	2
Venezuela	2.1	2	2.1	2.6	2.6	0.5	2
Indonesia	2.7	3	2.4	2.3	2.3	-0.4	2
USA	2	1.9	1.9	2.3	2.3	0.3	2
China	2.8	2.8	2.5	2.3	2.3	-0.5	2
Oman	2.5	2.2	1.9	1.9	1.9	-0.6	1
Malaysia	1.7	1.8	1.7	1.9	1.9	0.2	1
Canada	1.2	1.6	1.8	1.8	1.8	0.6	1
Kuwait	2.5	2.5	2.1	1.8	1.8	-0.7	1
Total top 20	**142**	**136**	**129**	**119**	**126**	**-23**	
Rest of the world	**20**	**21**	**19**	**21**	**21**	**2**	
Global flaring level	**162**	**157**	**148**	**139**	**146**	**-16**	

[5] Global Gas Flaring Estimates, NOAA-NGDC website. 2009. http://www.ngdc.noaa.gov/dmsp/interest/gas_flares.html. The News Flare. GGFR. Issue No. 10, January-July 2010. http://www.siteresources.worldbank.org/EXTGGFR/Resources/ggfr_news_flare_10.pdf.

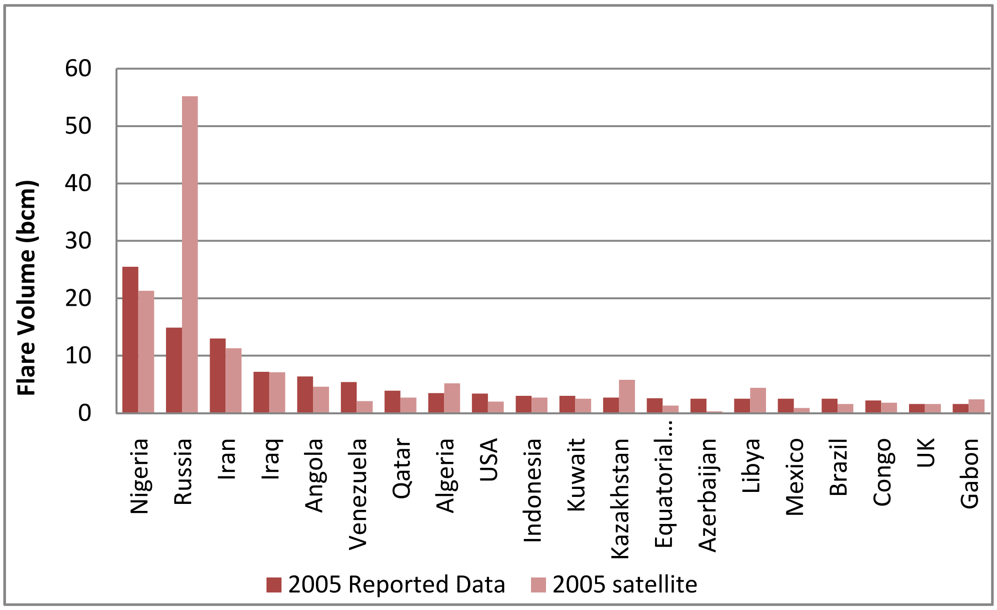

Figure 1. The difference between the self-reported and satellite-estimated flare volumes for 2005. Source: see footnote 5.

The global scale and frequencies of satellite observations have been demonstrated to be an important technology for assessing the magnitude, spatial distribution, and, to a lesser degree, the variability of gas flaring and related emissions to the atmosphere. It is clear that the estimated 140 to 170 bcm of flared gas is sufficiently large to justify mitigation for both environmental and, in some cases, economic reasons.

The developers of the NOAA-DMSP satellite methodologies have noted several factors that currently limit improvements in the quantitative determination of national and/or local gas flaring (Elvidge et al., 2009b). Industry and government cooperation in providing the following data and information will be crucial to improving the capabilities of DMSP and other remote-sensing technologies for future verifications of reductions in flaring: 1) A record reporting flare volumes, the quality of combustion, and instances of flare malfunctions is essential to estimating emissions to the atmosphere. 2) A spatial and temporal record of on-site and adjacent electric or other lighting that might interfere with the remotely sensed detection of individual flares will improve the analysis of remote sensing data.

A recent study that developed models to produce global maps of the fine scale spatial distribution of energy use and fossil fuel CO_2 emissions used gridded satellite observations of nightlights from DMSP-PLS, along with gridded population data and national-level energy and emissions data (Raupach et al., 2010). This effort presents a new approach to interpreting satellite nightlight observations and will also contribute to more accurate estimates of flaring emissions and their potential impacts in the future.

The methodologies for the collection and analysis of remote sensing data on global gas flaring can also be improved by reducing instrument errors associated with aging or replacement sensors. Best practices for remote sensing data analysis also require in situ data and the modeling of environmental variations in the atmosphere immediately above the onshore or offshore gas fields under surveillance. Local atmospheric measurements can be made without interference to oil production.

If the requirement for a quantitative verification of reductions in gas flaring emissions should become sufficiently important to justify assessments at the scale of a small field operation or individual wellhead, ground-based methodologies are available to conduct such high quality emission inventories (e.g., Lamb et. al., 1995; Shorter et. al., 1997). These ground-based methodologies use atmospheric tracer methods utilizing site-specific measurements and modeling to derive state-of-the-art estimates of emissions to the atmosphere across a wide range of scales associated with natural gas production and consumption infrastructure. Direct ground-based measurements of flare volumes can also be taken using flow metering equipment at the wellhead. Some developed countries, Norway for instance, have regularly metered flare volumes; however, those countries do not flare continuously or in sufficient amounts to be actively observed by the NOAA satellites. On the other hand, high flaring countries do not have regular flare monitoring and metering to allow for accurate data input for satellite calibration efforts. A limited number of ground-based investigations using these methodologies could contribute to improvements in the algorithms used for estimated emissions with remotely sensed data.

Currently, satellite technology is not capable of detecting associated gas volumes from venting, which may be significant in some producing regions, especially Russia, Iraq, and Iran. Future developments in satellite technology that can track venting emissions would be an invaluable addition to the efforts to reduce total flaring and venting volumes globally. The venting of associated gas contributes to regional air quality problems and to global changes in the composition of the atmosphere.

1.3.3 Trends in gas flaring

Fifteen years of satellite data have provided the current best estimates for temporal trends in flaring activity globally and by individual country. Global estimates of flaring activity have been relatively stable over the 15-year period, increasing slightly in 2005 to 172 bcm, and decreasing since then (see Figure 2). Despite the reduction efforts of some countries, overall global flaring volumes have seen little improvement, partly because of increasing oil production in those countries responsible for high flaring volumes. The reasons for these high flaring volumes will be discussed in detail in Section 2.4. Within the limitations of the information available, it appears that control of gas flaring remains elusive. Even with unprecedented prices for natural gas traded internationally, several major oil producers and gas traders—including China, Russia, Iraq, Qatar, and Kazakhstan—have increased gas flaring substantially between 1994–2005, although gas flaring has declined slightly in some of these countries since 2005. The predictions of increasing oil production in the future will present another challenge to oil companies and high-flaring countries, and might keep global flaring volumes around the same levels as today (Broere, 2008).

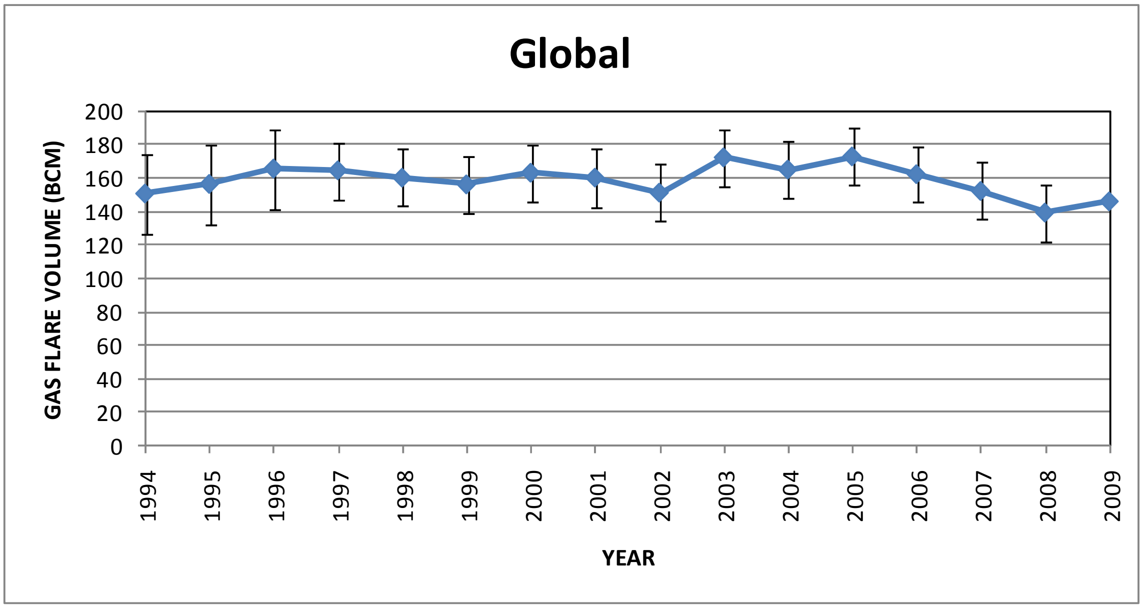

Figure 2. Global trends in gas flaring volumes. Data source: NGDC, 2009.

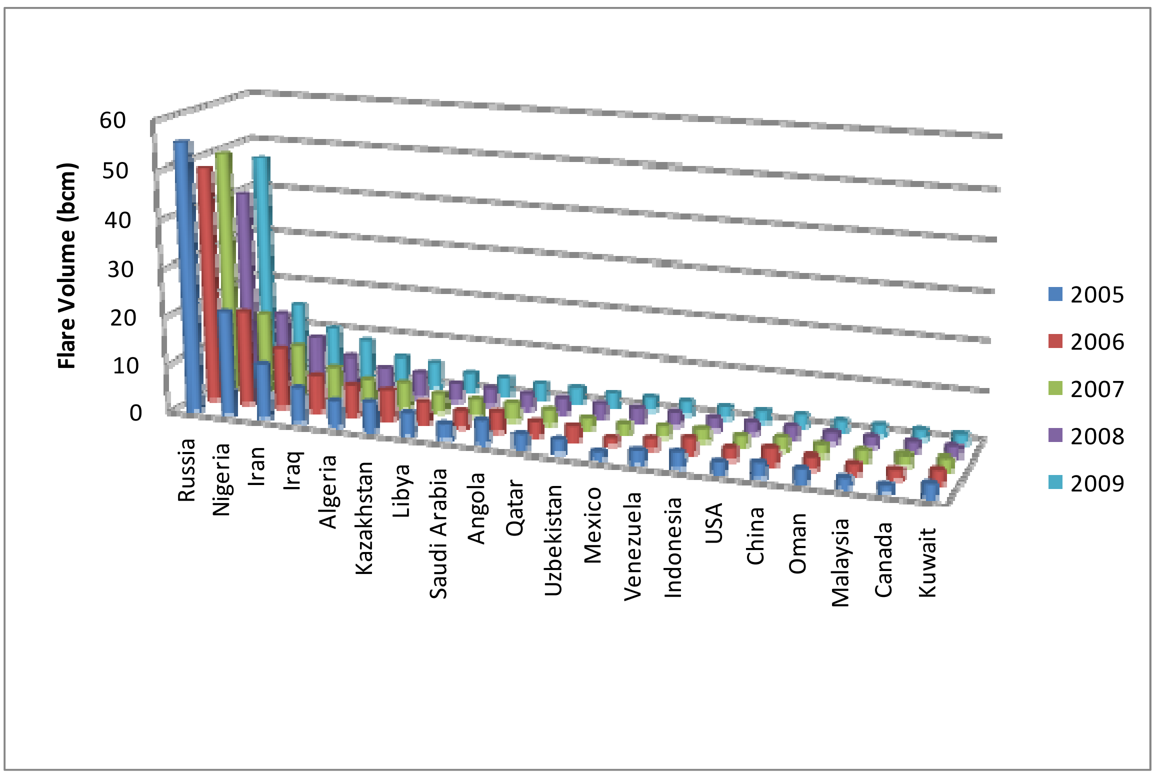

Figure 3. Countrywide trends in gas flaring volumes from 2005 to 2008. Data source: NGDC, 2009.

In addition to global estimates of flaring, the NGDC also analyzed the temporal variations in country flaring over 15 years and found that 17 countries, including Nigeria and Algeria, had downward trends between 1994–2009. The Nigeria data showed a decline of about 15 bcm in flaring volume during this period. The data for nine countries, including Saudi Arabia and Iran, remained stable. Seventeen countries, including Russia, Iraq, and Kazakhstan, had an upward trend until 2005, but gas flaring volumes have generally decreased since 2005. Russia led the worldwide decline between 2005–2008, with its gas flaring falling by about 19 bcm. The decline in flare volumes was achieved despite an increase in oil production. However, in 2009, flaring went up by 6 bcm in Russia and by 1.3 bcm in Iraq, thereby increasing the global gas flaring level to 146 bcm (GGFR, 2010).

The comparison of the changes in flaring estimates with trends in oil production over the same period of time reveals whether the reductions in flaring could be attributed to decreasing oil production in some countries or not. The NGDC's analysis of flaring efficiencies, which are the ratio of flared gas volume per barrel of oil produced, found that there are considerable differences among countries, although in general most countries have been improving their efficiencies (Elvidge et al., 2009a). The study concluded that decreasing trends in flaring volumes were due to decreasing oil output in some countries, while other countries—especially Russia and Nigeria—improved their efficiencies consistently over recent years (see Figure 4). The efforts to reduce flaring volumes made by Russia and Nigeria were also effective and will be discussed later in this report.

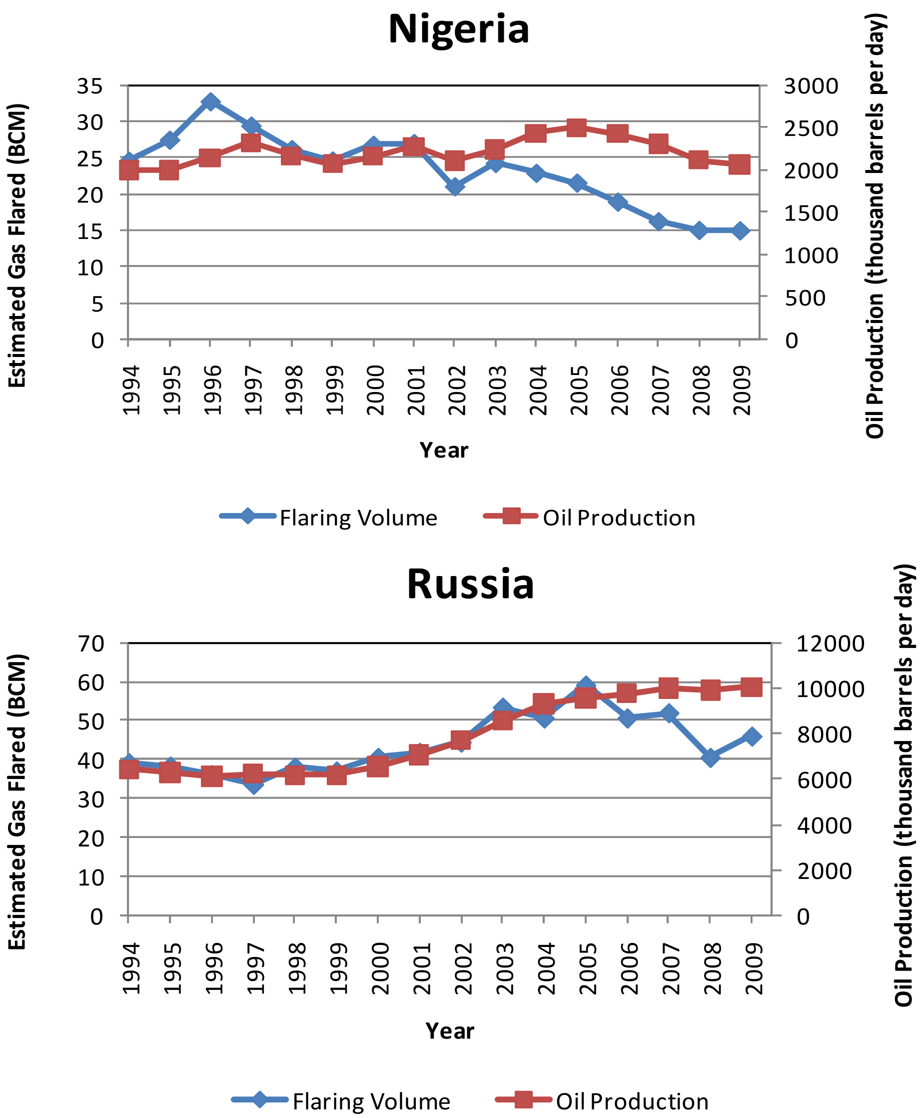

Figure 4. Comparison of oil production and flaring volumes over a 15-year period for Nigeria and Russia. Source: Oil production data is from BP Statistical Review of World Energy, June 2010; Gas flaring data is from NOAA-NGDC.

1.4 Reasons for high flaring and venting volumes

Associated gas co-produced during oil production is often flared due to safety concerns, financial barriers to implementing flare reduction projects, low domestic gas prices, lack of incentives and efficient regulations on flaring activities, or market barriers (GGFR, 2002). Safety is an issue during process malfunctions and emergency shutdowns due to the risk of the release of high pressure in the well. Also, the associated gas composition might pose a safety hazard to the facility and to the workers. For example, the gas from Shell's Shearwater oil field in Britain contains a large percentage of highly toxic hydrogen sulfide, and therefore burning the gas is the only safe option to get rid of the acidic component (Broere, 2008).

Associated gas is also flared because it is economically not feasible to remove sulfur and other contaminants, and to pressurize and transport the commercial product to the customer. Transmission of any appreciable distance also requires removal of the liquid fractions (the LPGs), again at some cost. Use by industry, households, or utilities requires a distribution system.

The remote locations of oil fields and offshore platforms from energy consumption points also make it impractical to build pipelines or electricity transmission lines to utilize associated gas. In some cases, although the oil field is close to a local market, the markets are too small or nonexistent, or the amount of associated gas is insufficient to allow for viable energy infrastructure development.

The geophysical nature of the oil fields can be inappropriate for the re-injection of associated gas into the subsurface. In some cases, re-injection adversely impacts oil recovery rather than increasing oil production efficiency and is not an economically valid process (IEA, 2006a).

In some countries, Nigeria for example, unanticipated interruptions due to economic and social instabilities discourage secondary recovery projects that produce relatively minor economic returns.

In other cases, associated gas is flared due to the structure of markets that limit new investments or the right to use existing infrastructure, as in the case of Gazprom's monopoly on gas pipeline and exports in Russia (see Section 4.4) (IEA, 2006a).

Another and rather important factor hindering gas flaring reduction efforts, especially in developing countries, is the absence of an efficient and effective regulatory framework and powerful authorities to enforce the regulations. Gas flaring reduction efforts have been proven successful in countries that have a strong cooperation between the governments and the oil and gas companies, and where technologies are complemented by supportive government policies. The regulatory institutions in developed countries, such as Norway, the United States, the United Kingdom, and Canada, have the authority to monitor flaring levels; enforce emission permits; and monitor the health, safety, and environmental impact of flaring and venting activities. However, without strongly enforced regulations, oil companies may neglect activities that in any way diminish attention to oil production and project profitability.

In some developing countries, oil producers are given permission to use associated gas to increase oil production efficiency by re-injecting back to the well, or to utilize the gas for operational activities in the facility; however, they are often limited by preemptive rights imposed by the host governments to sell associated gas to third parties. Since local governments do not have the economic and technical means and necessary infrastructure to transport and sell the associated gas by themselves, oil producers do not have options other than flaring or venting the associated gas. In countries where preemptive rights are not common, oil producers sell associated gas only if it is financially advantageous (Gerner et al., 2004).

As one of the highest flaring nations, Nigeria faces significant challenges in reducing flaring volumes. The most important barriers are: the lack of local gas and gas product markets; low gas prices; a lack of gas pipelines and electricity transmission lines; the amount of investment needed for flaring reduction projects; public unrest and security issues; lack of regulatory, fiscal, and legal frameworks; and capacity to attract investment and to enforce regulations and gas flaring policies (ICF, 2006).

The structure of the oil and gas sector in Russia, specifically the monopoly of Gazprom, is a major barrier to utilizing associated gas. Gazprom has a monopoly over the gas transmission network, hindering transparent and reliable third-party access to pipelines by other oil companies. Gazprom only allows associated gas that meets certain criteria to flow through its pipelines; therefore, most oil producers cannot sell their gas to Gazprom without further processing, and there is no other entity that can purchase their gas. Their only option is to send the associated gas to one of the Gazprom-owned gas processing plants or build their own gas processing plants. Gazprom also has a monopoly on Russia's exports of natural gas to European markets. It sells West Siberian gas to European markets at high prices of around $140-280 per million cubic meter (mmcm); however, other producers are not allowed to do so. Other producers are free to sell their gas to domestic markets using Gazprom's pipelines but at much lower prices (around $45/mmcm). A Gazprom-owned company called Sibur Holding controls all independent gas processing operations in West Siberia. Other factors limiting the options to reduce the flaring of associated gas in Russia are low domestic gas prices; low associated gas flow rates in some fields; insufficient capacity of the existing pipelines; and the high cost of gas infrastructure and transmission lines from remote locations to consumption points (IEA, 2006a; PFC Energy, 2007).

2 Review of technologies to measure and reduce gas flaring volumes

Gas Flow Meters

The available methods to measure flared and vented gas flow rates associated with oil production include ultrasonic flow meters, optical flow meters, insertion turbines, averaging pitot tubes, and thermal mass meters. Some of these traditional technologies— such as insertion turbines, pitot tubes, differential pressure flow meters, and thermal mass meters—are limited by such factors as high flow velocities, large pipe diameters, changing gas composition, low pressure, dirt, wet gas, wax, condensate, and high concentrations of contaminants such as CO_2 and H_2S.

Ultrasonic flow meters have been in use since 1987. They measure flow velocity by determining the time it takes for an ultrasonic pulse to travel between two fixed transducers located in the pipe. Ultrasonic meters are a cost-effective solution for measurement of flare gas volumes. They are independent of pipe size and are not affected by extreme flow velocities and changing gas composition. They have no mechanical moving parts and their maintenance is minimized through self-diagnostics. Their measurement accuracies range from 2.5% to 5% of the actual values.[6]

[6] Curtis Gulaga, *Flare Measurement Best Practices to Comply with National & Provincial Regulations*, available at *http://www.cbeng.com/resources/whitepaper/Flare_Measurement_Prov_Reg.pdf.*

Orifice and venturi meters can be used instead of ultrasonic meters for stable gas flows, and they are applicable to wet and dry gas streams containing contaminants. However, they do not perform well for a broad range of flow rates, and need to be calibrated frequently for changing gas composition (Clearstone Engineering, 2008).

Optical flow meters are devices capable of deployment in harsh oil field conditions. They use laser or LED light and determine the flow velocity by measuring the time between two perturbations in light beams using the small particles in the gas stream. The perturbations are detected using two optical sensors separated by a known distance. Optical flow meters are independent of gas composition, flow characteristics, pressure, and temperature. Their measurement accuracies range from 2.5%–7%.

Smart automation systems

In an effort to reduce emissions of gas by venting, BP developed a "Smart Automation Well Venting System" technology that combines remote terminal units (RTU) and programmable logic controllers (PLC) with artificial intelligence software in the gas wells. The software monitors and analyzes data from wellhead instruments and lets the PLC optimize well performance by adjusting the gas lifting cycle.[7] BP installed pilot systems starting in 2000 on about 2,200 wells, and reduced venting by about 50% between 2000–2004 with about 114 bcm of associated gas savings in total (EPA GasStar).

Re-injection

Re-injection is a commonly used method to preserve gas for future use or to increase the efficiency of the oil production process while utilizing the associated gas that otherwise would be flared or vented. The technology involves the installation of a gas compressor to re-pressurize areas of low-pressure formation gas, enhancing oil production. As an alternative to gas compressors, multiphase pump systems—in which oil and gas can flow together—have a smaller equipment size and allow determination of the flow characteristics without the need to separate

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[7] Reduced Emission Completions/ Plunger Lift and Smart Automation. Methane to Markets. Oil and Gas Subcommittee Technology Transfer Workshop, January 28, 2009. Monterrey, Mexico (*http://methanetomarkets.org/documents/events_oilgas_20090127_techtrans_day2_robinson1_en.pdf)*

oil and gas. These pump systems can also be powered by gas-fired generators to conserve more energy in the oil fields (Tengirsek and Mohamad, 2002). The re-injection option is not applicable in some geological formations. For example, adding too much pressure to shallow reservoirs can initiate an uncontrolled flow of oil, gas, or water (PFC Energy, 2007).

A successful re-injection project at an oil field in Southeast Asia aims to reduce GHG emissions by 2.65 million tons of CO_2e by conserving the gas from the oil field for sale, or for use in additional electric power capacity in the field. The project is expected to demonstrate the relevant technology, especially for applications in remote oil fields in Southeast Asia (GGFR, 2003).

A new technology using multiphase pumps and testers to return oil and gas together to the production line without the need for separation has been applied in Abu Dhabi oil fields and has demonstrated zero oil flaring. The project is expected to completely eliminate gas flaring as well in Abu Dhabi (Tengirsek and Mohamad, 2002).

Another successful application of the re-injection technique has been demonstrated in a Gabon oil field, where CO_2 emissions were reduced by a total of 1.1 million tons and flaring volumes reduced by 97% after the installation of new re-injection equipment and gas compressors (Broere, 2008).

Liquefied petroleum gas (LPG)

LPG is an attractive way of utilizing associated gas because of its easy storage and transport to local markets, and due to the higher percentage of propane and butane (liquefiable petroleum gases) in associated gas composition compared to non-associated gas.

Before extracting the liquefied petroleum gases, associated gas must first be treated for removal of impurities including water vapor, CO_2, mercury vapor, and H_2S. Conventional LPG processes treat the whole gas stream before extracting the LPG content. These processes are not economical and practical for associated gas, which is produced in much lower volumes and has a lower pressure than non-associated gas from gas wells. Therefore, some companies have developed technologies to treat only the recovered LPG content of associated gas to remove the contaminants and thus to reduce the plant size and associated capital costs. [8]

The LPG is produced in a three-step process involving the compression of the associated gas; condensation of the heavy carbon fraction by cooling the compressed gas; and separation of the heavy fraction to produce LPG. LPG production does not require extreme cooling temperatures or extreme pressures, chemicals, and cooling agents. Some commercially developed LPG units provide certain advantages in utilizing the associated gas. For example, Membrane Technology & Research's LPG-SEP unit is completely automated so it can easily be operated at remote locations and can be shipped to the site easily.[9]

In many developing countries, especially Africa, LPG would provide an attractive alternative to domestic use of biomass fuels, and to conventional automobile fuels (GGFR, 2002). In Nigeria, although the price of LPG bottles is fixed by the Petroleum Equalization Fund Act of 1975, LPG suppliers do not usually comply with the regulations and market the bottles at higher prices to the public. Besides, even at higher prices, gas bottled as LPG is frequently exported and not always available to the public, leading to shortages of domestic cooking gas (Sonibare, 2006).

LPG was also recommended as the best option for mid-size oil fields in Russia by PCF Energy in a study for the World Bank (PFC Energy, 2007). A GGFR study (2004c) found LPG use economically beneficial if LPG prices are at a level of $300 per ton and if the raw flare gas contains at least 15% LPG.

Liquefied natural gas (LNG)

LNG technology uses a straightforward refrigeration process (Tusiani and Shearer, 2007). The gas is pre-treated for impurities such as sulfur, CO_2, water, and other contaminants, transformed into liquid by being cooled to -162^{o}C, and stored until it is shipped onboard LNG tankers. New technologies are emerging to reduce the capital costs of the LNG process by eliminating this pre-

[8] Microlex LPG Extraction Process. The IOR Energy. (*http://www.tiruwell.com.au/oilgas/2.htm)*

[9] LPG Recovery from Associated Gas: LPG-Sep™. Membrane Technology & Research. *http://www.mtrinc.com/natural_gas_liquids_recovery.html*

treatment step and incorporating it into the liquefaction process. An example of such a process, called Micro-cell, was developed by Curtin University in Australia and is expected to reduce the capital costs of the conventional LNG process by 20%–40%. The resulting volume of the liquefied gas is about 1/600 of the original volume in the gas phase (Lichun et al., 2008). After transport to a receiving terminal, the liquefied gas is re-gasified for use in gas markets.

A new LNG technology concept that has yet to be developed and proven commercially is called floating LNG (FLNG). This process is a combination of conventional LNG and floating deepwater offshore production technologies. The combined FLNG vessels will contain liquefaction facilities onboard, and can be moved to small and remote oil fields easily, without having the need to build large, new facilities at each location. This concept is largely advocated by Shell (Marcano and Cheung, 2007) and the first commercial applications are likely to be in Australia at remote Browse Basin gas fields.[10] The relatively low concentrations of gas associated with oil production may still fall below the commerciality threshold of FLNG, which requires inputs of about 10 mmcm per day.

LNG products are generally used as fuels in power generation, heating, and industrial processes. The most important markets for LNG produced in West Africa are in Europe and the Americas (Lichun et al., 2008).

Compressed natural gas (CNG)

CNG is natural gas compressed to a much lower volume (1/200 of the original volume) at pressures between 8,300 and 30,000 kilopascals (kPa) (Economides and Mokhatab, 2007). CNG is stored and transported in cylinders. The most advanced cylinders are made with fiber reinforced plastic (FRP), which has certain advantages over metal/steel gas containment systems including light weight, corrosion resistance, durability and safety, and lower capital and operational costs. Trans Ocean Gas is developing a technology using FRP cylinders to further compress gas at lower temperatures to 1/500 of its original volume and, in turn, achieve

[10] Floating LNG Technologgy for Australia's Northwest Coast. Investor Updates. Australian Government Trade Commission. 22 October 2009. http://www.austrade.gov.au/Invest/Investor-Updates/091022-Floating-LNG-technology-for-Australias-northwest-coast/default.aspx.

increased efficiency in gas transport. The technology is presented as a future cost-effective alternative to LNG, because it provides a similar reduction in gas volume without the need to build high cost liquefaction plant.

Although CNG technology has been well established for ground transport by trucks over short distances, no major CNG projects have been in operation to utilize stranded gas in locations far from required infrastructure using seaborne transport. CNG technology has the potential to become the preferred method of utilizing associated gas in offshore platforms where building pipelines or LNG plants are not economical and practical. Since CNG is transportable, and therefore easily re-deployable, it can be used in fields with relatively short production horizons. CNG is used primarily as a transport fuel and in small scale transport road projects.

Trans Ocean Gas is in the process of commercializing its CNG transport technology. Developments in CNG technology are supported by Statoil, TransCanada, and ExxonMobil (Marcano and Cheung, 2007).

Natural gas hydrates (NGH)

NGH is crystallized natural gas, which is a solid material in an ice state and chemically stable at -20^{o}C. The stabilizing temperature is considerably higher than the LNG temperature of -162^{o}C, which leads to lower capital, transportation, and storage costs. However, NGH is far less dense than LNG and the quantity of gas transportable in hydrate form is correspondingly lower than LNG technology. NGH as a method to utilize associated gas is still in the research phase, but Mitsui and Mitsubishi, the BG Group, and Marathon Oil are leading the efforts to develop gas-to-solids technology to produce and transport NGH (Marcano and Cheung, 2007).

Gas-to-liquids (GTL) technology

GTL technology is a chemical process that converts methane gas into transportation fuels, naphtha, and other specialty liquid chemicals. After the removal of impurities in the original gas stream, the GTL process involves multiple steps in converting natural gas to liquids:

1. Natural gas reforming converts natural gas (mostly methane) mixed with oxygen into synthesis gas (also called syngas, which is a mixture of carbon monoxide and hydrogen).

Syngas production in this step involves technologies of steam reforming, partial oxidation, or both integrated into one reforming reactor (auto-thermal reforming [ATR, Haldor Topsoe] technology). Steam reforming processes are considered very productive, but highly energy- and capital-intensive. A partial oxidation process consumes considerably less energy, but the high outlet temperature from the reactor results in a higher cost of reactor materials and soot formation (Keshav and Basu, 2007). ATR technology produces syngas of higher pressure, but it also produces large amounts of CO_2 and the combustion compartment reaches very high temperatures.

Other methods of syngas production, including compound reforming and catalytic partial oxidation (CPOX), are also in development. The compound reforming method combines steam reforming with ATR and has a lower production cost (no compressor is required) but a higher capital cost (two reactors are needed). In CPOX, because reactions occur in a catalytic bed membrane reactor, no burner is used. According to Keshav and Basu (2007), CPOX ranks as the best syngas production technology in terms of relative costs, CO_2 emissions volume, and oxygen and natural gas consumption volume. However, the partial oxidation technology had the best reactor performance in terms of CO yield and H_2 to CO ratio.

2. Fischer-Tropsch conversion converts syngas into a broad range hydrocarbon stream using catalysts.
3. Product upgrading unit upgrades the raw reactor products from the previous step to end products such as GTL diesel and GTL naphtha.

The GTL technology is often called Fischer-Tropsch–Gas-to-Liquids (FT-GTL) technology because the Fischer-Tropsch chemical conversion is the main process in converting the gas into liquid hydrocarbons. FT-GTL technology is still in development. Since GTL has not been economically feasible and has involved more technical risks until recently, the well-established LNG technology has dominated the commercial markets for utilizing associated gas. However, new and more efficient GTL technologies, which produce high quality end products in smaller sized plants, are emerging as an alternative to LNG for oil and gas producers. GTL capacity is estimated to increase to 1–2 million barrels per day by 2015, utilizing 0.3–0.6 bcm per day of natural gas (Fleisch et al., 2003).

The FT unit in the FT-GTL process, which requires the conversion of the gas into syngas, is the most capital- and energy-intensive part of the process (Keshav and Basu, 2007). A new GTL process developed by researchers at Texas A&M University (Hall, 2005) and commercialized by Synfuels International, Inc. bypasses this step, which makes the process more energy efficient and profitable at a much lower capacity (~0.3 million cubic meters per day, or mcm per day) than the FT plants (which usually have a capacity on the order of 30 mcm per day). The cost for the new process was calculated at $25 per barrel of liquid product for a 1.4 mcm per day plant (Hall, 2005). The new technology cracks methane in high combustion temperatures into acetylene and hydrogen, and then catalytically hydrogenates acetylene to ethylene. The resulting end products are either ethylene and hydrogen (GTE), or other liquid products, including transportation fuels or chemical feedstocks (GTL) (Hall, 2005).

Another new technology developed by Velocys, called microchannel technology, reduces the overall system volume by a factor of 10 to 100 by using parallel arrays of microchannels. The efficiency of steam formation and FT processes are increased by using more active catalysis, and capital costs are reduced by using smaller equipment.

The utilization of associated gas through GTL processes is more challenging and capital intensive for offshore production facilities. A new technology, which is still in the development phase, combines the floating, production, storage, and offloading (FPSO) vessel with GTL-FT technology and in this sense shows similarities to the concept of FLNG. Syntroleum Corp. and Bluewater Energy Services BV formed a joint venture to develop world's first GTL FPSO vessel for use in remote and small oil and gas fields in an offshore environment (Marcano and Cheung, 2007).

GTL diesel is a low sulfur, low aromatics, and high cetane number fuel, providing high combustion quality and significant emission reductions and is compatible with existing diesel engine technology. Likewise, GTL naphtha, having a high quality chemical composition free of metals, aromatics, and sulfur, is an ideal feedstock for petrochemical production (Lichun et al., 2008). GTL kerosene blends, also called GTL jet fuel, have significantly lower emissions of particulate matter and other pollutants and higher energy density, and have recently been approved for use in commercial aircraft.[11]

Qatar is a leader in the world with the most GTL projects, which produce 330,000-500,000 barrels per day, followed by Australia with 120,000 barrels per day (Fleisch et al., 2003).

Shell and Qatar Petroleum's GTL project will be completed by the end of 2010 and is expected to produce around one million tons of GTL kerosene per year (will be available in 2012), sufficient fuel for a commercial aircraft to travel 500 million kilometers (Shell media release, Sept. 29, 2009). Other than the jet fuel, the facility will produce GTL diesel, GTL base oils, GTL paraffin, and GTL naphtha.

SasolChevron's project of GTL conversion using Sasol's slurry phase distillate (SPD™) technology in Nigeria involves building a 34,000 barrel-per-day GTL products plant in Escravos, Nigeria. When completed, the plant will convert 15% of total flaring to low emissions GTL diesel (~70% of product) and GTL naphtha (~30% of product) (Oguejiofor, 2006).

A number of GTL plants are in the demonstration phase. For example, the new GTL or GTE technology by Synfuels International has been tested in a demonstration plant in Robertson County, Texas, and plant modifications and testing to improve reduction efficiency and cost-effectiveness are ongoing (Hall, 2005).

Technologies that convert gas to-dimethyl ether, and ammonia

Methane in natural gas and associated gas can also be converted to methanol. Methanol is further used to produce dimethyl ether (DME) and olefins such as ethylene and propylene in simple reactor systems, conventional operating conditions, and commercial catalysts. Lurgi's MegaMethanol, MTP, and MegaSyn technologies and Topsoe's DME process provide cost-

[11] Shell Oil Company, "GTL Jet Fuel approved for use in civil aviation," news release, Sept. 29, 2009.

effective and large economy-of-scale solutions to gas conversion. Methane in associated gas can also be converted to ammonia via the Haber process to produce nitrogen fertilizers. This method is quite common in Persian Gulf oil-producing states, especially in Saudi Arabia, Qatar, and the UAE,[12] as well as Trinidad, another major methanol and ammonia producer.

Gas-by-wire (gas-to-power) technologies

Gas-by-wire technology is an emerging alternative to associated gas utilization. Gas-fired power plants built near oil and gas fields generate electricity, which is transported by transmission lines to consumers. Due to the limitations in installing power lines over long distances, especially in remote areas in developing countries, this technology is profitable when applied to distances less than 2,000 km (IEA, 2006a). A far better option is to use the generated power in oil field operation and production processes.

Microturbines are one way to generate small-scale electricity using associated gas as fuel. They are combustion turbines that produce lower emissions and are more reliable and economic than other small-scale power generation technologies due to their smaller size, reduced number of moving parts, and similar efficiency to conventional small-scale power generation technologies. A oil field flare gases (OFFGASES) project funded by the Department of Energy (DOE) explored practical ways to utilize the stranded gas in oil wells in California and found that the best way of accomplishing that is by using microturbines. With emerging microturbine technologies, stranded or flared gas in California oil fields can be utilized to generate 4,000 MW of electricity (The Interstate Oil and Gas Compact Commission, April 2008).

Flex-microturbine technology, recently developed as part of the OFFGASES project, is suitable for extreme oil field conditions and capable of converting a wide range of gases of different pressures and quality (high BTU, low- and ultra low-BTU, and harsh gas) into electricity generation at the same power plant. The flex-microturbine technology also eliminates the need to install compressors because it accepts fuel gas at atmospheric pressure. This technology produces substantially lower NO_x, CO_2, and VOC emissions than its traditional counterparts.

[12] The Gulf Petrochemicals & Chemicals Industries - A Brief Chronology. Gulf Petrochemicals and Chemicals Association, (*www.gpca.org.ae/newgpca/historicalbackground.asp).*

Despite these advantages, this new technology is currently too costly to be commercially feasible and needs further development to reduce costs (The Interstate Oil and Gas Compact Commission, April 2008). Capstone microturbines cost about $30,000 while the flex-microturbine costs about $300,000. Furthermore, many small oil producers have greater associated or stranded gas volumes to meet their electricity needs and currently there are no regulations to allow them to sell their excess power to the local grid. BP has also started trials with microturbines in a Wyoming oil field to generate energy for use in the oil field and for distribution to a local grid.[13]

Combined heat and power (CHP), also called cogeneration, is also an efficient, clean, and reliable alternative for utilization of associated gas to generate electricity and heat simultaneously. CHP plants capture and utilize heat that is generated as a byproduct of electricity generation and is normally wasted in conventional power plants.[14] In 2007, Norway's state-owned Statoil started the construction of a CHP station with 280 MW electricity and 350 MW heat capacity that also included a full-scale carbon dioxide capturing facility. The facility is scheduled to start operations in 2010 (IEA, 2006b).

Combined cycle gas turbine (CCGT) units provide energy-efficient electricity, have good operating flexibility, short installation time, low NOx, SOx, and CO_2 emissions, and are suitable for use in cogeneration with fuel energy utilization up to 80-90% and electric power generation efficiency of more than 55%. The Tomsk power plant in the Urals-West Siberian region of Russia expanded its generation capacity by installation of a CCGT unit fueled by associated gas that would have otherwise been flared or vented. The project is expected to achieve CO_2e emission reductions of 1,922,415 tons CO_2e per year from the reductions in gas flaring and venting (GGFR, 2003).

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[13] Jonah Field. September 2009 Case Study. Capstone Turbine Corp. *http://www.capstoneturbine.com/_docs/CS_CAP384_JonahField_lowres3.pdf*

[14] What is Combined Heat and Power? Texas Combined Heat & Power Initiative. Gulf Coast Clean Energy Portal, *http://www.texaschpi.org/content/future/future.asp.*

2.1 Comparison of technology options

According to the IEA (2006a), none of the current gas utilization technologies and methods are economical if the associated gas volumes are below 10 mcm per day and the oil field is located more than 2,000 km from the closest market. In such situations, IAE (2006a) recommends economic incentives and governmental regulations to prevent the flaring activities. In the case of relatively short distances to markets and low gas volumes, electricity generation or pipeline transport of the gas might become economical alternatives to flaring. If the gas volumes are higher than 10 mcm per day and distances to markets are greater than 2000 km, there are some other options to utilize the gas, including LNG or GTL plants, and transporting the liquids produced via tankers to the market locations (IAE, 2006a).

As for the comparison of well-established LNG and newly emerging GTL technologies, LNG has higher plant efficiency and less complex infrastructure needs. However, both LNG and GTL have comparable full-life cycle capital costs. Although LNG has slightly lower operating costs than GTL, the overall production cost for LNG and GTL products for the same amount of natural gas is quite similar (on the order of $2.5 billion) (Lichun, 2008). Both LNG and GTL products are environmentally friendly alternatives to coal and crude oil. LNG products are generally used as fuels in power generation, heating, and industrial processes. GTL serves a different energy market than LNG, with most of the GTL plant yield as low sulfur transportation fuels. Due to their highly desirable emissions characteristics, GTL products occupy a valuable niche market, especially for blending into more conventional fuels to meet increasingly stringent emissions regulations. The pricing for LNG products requires long-term contracts (more than 20 years) between suppliers and the consumers, and the actual price is adjusted according to the price of the crude oil (Zhang and Pang, 2005 in Lichun, 2008). GTL products, on the other hand, can be sold in open markets with no requirement of long-term contracts. Therefore, in the end, the decision to install either an LNG or GTL unit will be dependent on other factors such as local market needs, available resources, and companies' and governments' priorities, etc.

Economides and Mokhatab (2007) compared LNG technology to pipeline and CNG alternatives for exploitation of stranded gas. The full chain cost of a typical CNG process—including compressing, loading, shipping, and unloading—is substantially cheaper than that of an LNG process at moderate distances (up to 3,000 km) and for smaller fields (less than 100 mmcf per day). A CNG plant with loading facilities, compressors, pipelines, and buoys costs $30 to $40 million. CNG ships, with chillers and fluid displacement onboard, cost about $230 million (Economides and Mokhatab, 2007), but also carry less gas than do LNG tankers. For smaller fields or longer distances CNG becomes uneconomical. CNG facilities require a shorter construction time frame (30–36 months) than LNG and GTL facilities, which are usually completed in 4–5 years.

IAE (2006a) performed an assessment of the cost-effectiveness of several options to increase the associated gas utilization rate in a typical oil field in West Siberia. The options studied included the local use of the associated gas as an energy source, building pipelines, GTL plants, and re-injection. The calculations revealed that the energy demand from oil field processes and by local communities was equivalent to approximately 30% of the associated gas supply. The remaining 70% of the gas volume would have to be utilized by other means or flared.

The option to build a pipeline connecting the oil field to the nearest Gazprom pipeline network would need additional infrastructure such as a gas treatment plant, and compressor stations to keep the gas pressure steady enough to transport through the pipelines over long distances. The low level of current domestic gas prices and the difficulty in gaining access to Gazprom's gas pipeline network are the main barriers to this option. However, at higher gas prices, similar to what Gazprom charges to export customers, the internal rate of return might approach 25%, which would make this option economically attractive.

On the other hand, financial returns for GTL projects using remote gas are generally lower than for efforts to market the gas itself as a fuel. If the additional carbon revenues are considered in the amount of $7 per ton of CO_2, the internal rate of return (IRR) increases to 8%; however, it is still not sufficient enough to conquer the capital and operating costs of the whole project.
The re-injection option was not cost-effective without considering the carbon revenues. Even with an emission reduction unit price of $7 per ton of CO_2, the IRR was only 8%, which was not sufficient to overcome the investment costs.

Greenhouse gas emission reductions were estimated at a range of 2.0-2.5 kg CO_2e per m^3 of gas for each alternative.

PFC Energy (2007) concluded that the use of Russian associated gas for electric power generation and combination gas processing plants would be the most efficient ways to utilize Russia’s associated gas. For large fields with flaring volumes of greater than 0.5 bcm per year, the most economically feasible option would be power generation in CCGT for sale to the power grid. The study also predicted $2.3 billion in annual revenues and 70 million tons of CO_2 reductions per year from the utilization of 30% of the associated gas currently flared at current gas prices. These predictions were based on the assumption that the existing gas pipeline network and the infrastructure were accessible by third parties.

A GGFR (2006) study compared several gas utilization technologies for Indonesia and found that electricity generation is the most favorable option at low natural gas market prices among gas pipelines, CNG, and LNG technologies. For higher gas prices, pipeline and electricity generation options were more advantageous than CNG and LNG for a range of distances and gas volumes. The choice between pipelines and power generation at high gas value strongly depends on the distances implicated. LNG is generally preferable to CNG due to greater storage and transportation costs for CNG; however, at high gas prices, CNG becomes competitive with LNG for the specific conditions considered in the study.

In summary, the decision to invest in a certain technology can be challenging. Many factors—including capital investment, technology risks, domestic market structure, political environment, strategies of investing companies, existing infrastructure, distance to markets, and existing infrastructure—need to be considered in decision-making. An overall comparison of all available alternatives is difficult to make, and site-specific assessments are recommended in order to choose the best practice.

3 Best practices of flare reduction technologies, regulatory measures, and fiscal incentives

Flaring and venting are key factors that separate associated gas from non-associated natural gas. If the government as resource owner and/or regulator fails to strike an appropriate and beneficial pricing and regulatory package with potential producers or users, then non-associated gas can be shut in, to be produced at another time without diminution of the recoverable reserves.[15] However, associated gas cannot be shut in so easily, since that would curtail the generally more valuable oil production. Once associated gas is flared or vented it is no longer available for any beneficial purpose, including field pressurization.[16]

In looking at how associated gas is used when it is not flared or vented, it is necessary to consider two key factors that will impact the decision to flare gas. These are: (i) the incentives in place, mostly gas pricing, for effective and efficient use of the gas; and (ii) the regulatory apparatus for implementing policy with respect to natural gas pricing, transmission, and use.

In the sections that follow, the cases of Norway, the United States, and Canada—countries utilizing almost all of the produced associated gas—will be highlighted with regard to the regulatory framework and fiscal incentives they offer to oil producers.

3.1 GGFR voluntary standard

GGFR's voluntary standard for reducing global gas flaring and venting is being implemented by GGFR partners with the goal of reducing barriers to the utilization of associated gas in developing countries through markets and infrastructure, the commercialization of associated gas, strengthening of regulations, and trading of carbon credits.

The voluntary standard recommends consistent use of mass and energy balances to estimate flare and vent volumes in the existing wells; and the installation of flow meters in newly developed

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[15] This statement is not always true. In Russia, some non-associated gas is stripped of condensates, used for oil blending, and the remaining light fractions, methane and ethane, are then flared. However, this practice is unusual elsewhere.

[16] Flaring of associated gas was seen as problematic and wasteful long before GHG concerns came to the fore. One of the first significant initiatives of the Gulf Cooperation Council (GCC) was a regional gas gathering project with the aim of capturing associated gas for use in field pressurization or petrochemicals. Of course, the natural gas industry in the United States got its start from capturing associated gas at the wellhead.

wells and in existing facilities with large flaring volumes. GGFR recommends continuous metering of the gas volume flared at the source or flare gas burners, and the measurement of associated gas composition and heating values, which are essential to determining greenhouse gas emission rates (GGFR, 2004b).

3.2 Fiscal incentives

Taxation and emission fees, introduced in some countries, have not been proven effective as means of reducing flaring. In some countries, most notably Nigeria and Russia, the emission fees were too low and remained affordable for companies that did not change their practices. In some other countries, fees cannot be enforced due to the lack of monitoring and metering as well as the lack of authority. However, other fiscal incentives such as tax reductions, duties, and government share in production are usually more effective in reducing flaring and venting activities when they are financially attractive to the oil producing entities. Some examples include the petroleum tax incentives in Nigeria, the CO_2 tax in Norway, and a royalty waiver program in Alberta, Canada (GGFR, 2004a).

Carbon-reduction credits that can be sold on an emissions trading market under the Kyoto Protocol's Clean Development Mechanism can also serve as a potential financial incentive supporting projects and investments for reducing flaring and venting. Nigeria, Algeria, and Indonesia are taking steps to achieve emission reductions that will make them eligible for carbon trading with developed countries (Gerner et al., 2004).

3.3 Examples of best practices

Norway

Despite increasing levels of oil production, Norway reduced gas flaring and venting significantly through successful implementation of regulations and close cooperation between the authorities and the industry. Norway's regulatory institution, the Norwegian Petroleum Directorate (NPD), along with the Ministry of Petroleum and Energy (MPE), strictly regulate emissions from oil production and gas flaring and venting operations, and oversee the safety and energy efficiency of petroleum production facilities.

The oil producers operating in Norway's oil fields are not allowed to flare gas without getting approval from NPD except for releases for safety during normal operations. The operators are required to prepare an installation and operation plan, and an environmental impact assessment for air emissions related to flaring and venting; they must also obtain a permit from the MPE that specifies the type and level of air emissions, technology to circumvent and mitigate emissions, and flaring equipment (GGFR, 2004a).

The NPD also oversees the measurement and monitoring of the volumes of gas flared or vented thorough the use of an internal control system. The oil producing companies are required to check the sensors of the internal metering system every six months, submit an emissions inventory once a year, and ensure the regulations are being met.

Norway widely uses incentives and penalties, such as a CO_2 tax on emissions to encourage oil producers to reduce gas flaring volumes (GGFR, 2004a).

Canada

In 2007, the total associated gas production for Canada was 23.7 bcm, 94% of which was utilized in domestic heating and power generation as well as industrial and commercial use. The associated gas is re-injected in some oil fields, and is also used as fuel in industrial processes, and in oil field operations. The well-developed pipeline and transportation infrastructure in Canada and the United States also allows distributing the associated gas to North American gas markets.[17]

Other than the availability and accessibility of flare reduction technologies, the commercial and regulatory regimes play a significant role in the high percentage of associated gas utilization in Canada. Gas flaring is regulated by individual provinces rather than the federal government. The government of Alberta, where Canada's major oil reserves are located, and industry partners set voluntary targets through a Clean Air Strategic Alliance for oil producers to eliminate or reduce flaring of associated gas by 25% between 1996 and the end of 2001. Otherwise, regulatory

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[17] *World Bank GGFR-Private Public Partnership Implementation Plan for Canadian Regulatory Authorities June 2008,* available at *http://siteresources.worldbank.org/EXTGGFR/Resources/canada_cip.pdf*.

maximum limits for flaring would have been imposed on individual sites. The voluntary target effort was successful in cutting flaring by about 50% by 2001. The regulators and companies performed site-specific evaluations for options to achieve gas flaring reductions.

Canadian provincial regulators require annual and public reporting of flaring volumes from each oil producer, and strict compliance with fines and license cancellations. Alberta also has unregulated gas markets and open access to gas infrastructure, and designed royalty waivers to reduce gas flaring.

United States

Although greenhouse gas emissions are not regulated in the United States, other constituents of associated gas are strictly regulated by the Environmental Protection Agency (EPA). The EPA requires companies to report gas flaring volumes and regulates their emissions from flaring activities. Onshore and offshore producers of oil and associated gas are required to manage associated gas through transportation to a market, power generation, or re-injection. The well-established gas pipeline system and high national demand for gas makes it economically feasible to use associated gas instead of flaring it. The federal Minerals Management Service (MMS) regulates offshore oil and gas operations and requires a report of monthly flaring volumes from offshore operators. Individual states may also have their own regulations for gas flaring and venting (GGFR, 2004a).

3.4 Efforts to reduce flaring volumes in the highest flaring nations

The GGFR projects that future flare reduction projects around the world have the potential of eliminating 32 million tons of greenhouse gas emissions by 2012 (Broere, 2008).

Russia

The largest companies in Russia are starting to realize the economic benefits of associated gas utilization, especially after recent increases in Russian domestic gas prices, and are considering viable options for their oil fields. Some oil producers are already using associated gas with fuel cogeneration plants and some utilize gas processing plants. Surgutneftegas, which is one of the largest companies, largely invests in gas turbine power generators and pipelines, and plans to increase gas utilization rates to 95% in the near future, thereby accessing the benefits of carbon revenues. However, the levels of gas or electricity demand in oil fields and local communities are often much less than the amount of associated gas produced. Companies are looking for other options to make use of their gas, though they are often limited by Gazprom's monopoly on the pipeline network, gas processing, and gas exports (IEA, 2006a).

In Russia, the absence of competitive markets for gas and other fuels has retarded efforts to value associated gas at its opportunity cost. With wellhead prices significantly below US$1/GJ in mid-decade,[18] there has been little financial incentive for oil producers to re-inject, sell, or otherwise make more beneficial uses of the country's abundant associated gas. If, as is indicated by NOAA data, Russia also flares a significant volume of gas at its condensate separation plants, then the absence of appropriate upstream pricing for natural gas may lead to flaring of non-associated gas fractions as well.

The Russian government increased methane emission fees from associated gas flared starting in 2005. However, it is not yet clear how effectively these regulations are being implemented and enforced by the government. Fees based on each unit volume of gas flared instead of concentration of methane emissions would be more effective in discouraging companies to flare associated gas (IEA, 2006a).

The Ministry of Natural Resources issues licenses to oil and gas producers that include permission to process and sell associated gas, re-inject, use in the facility or produce electricity, or flare in specified amounts. However, there is no specific legislation to regulate flaring or venting, nor any limits on gas flaring levels. The responsibilities of federal and regional authorities are not well defined and oftentimes overlap, making them ineffective in enforcing regulations on gas flaring (IEA, 2006a).

[18] According to the World Bank's 2004 "Reform of the Russian Natural Gas Sector" prices to industrial users in Russia were below $1/GJ in 2003-04, with transmission and distribution costs accounting for more than 80% of the price to consumers. These prices were in effect as recently as early-2007.

Some regional governments in Russia such as the Khanty-Mansiysk administration have their own mandates regarding utilization of associated gas. The region has a cap of 5% flaring of gas produced by the license-holding company. Other measures proposed by the administration include fiscal incentives such as tax reductions or exemptions for companies that develop new technologies to reduce flaring; and new legislation specific to associated gas utilization that defines the responsibilities and rights of all parties, including government agencies, oil companies, and gas processing plants. The administration also proposes to introduce significant change to the national gas sector structure by introducing a form of open access for non-Gazprom entities to Gazprom's gas pipelines and gas processing plants (IEA, 2006a).

The transport of associated gas to markets is not currently a reliable way of utilizing the gas due to the uncertainties related to Gazprom's pipeline operations; however, carbon credits under the Kyoto Protocol's Clean Development Mechanism may serve as a potential financial incentive supporting re-injection, GTL, and LNG projects for reducing flaring and venting. If Gazprom becomes more cooperative with the oil companies and accepts buying associated gas or transporting it via its pipelines, it will mitigate Russia's increasing gas demand and moderate domestic gas price increases (IEA, 2006a). PFR Energy (2007) estimates 18 bcm per year of dry gas recovery if the following steps are taken by Russia: include requirements for gas utilization in licenses; set higher site-specific fines for flaring; require monitoring and metering of flaring volumes and enforce these requirements; allow reliable third-party access to Gazprom's existing transmission network; deregulate gas and gas product markets; add associated gas capacity when building new pipelines and gas processing plants; and use carbon financing.

It is important to consider that much of Russian gas development is in remote regions that challenge traditional environmental monitoring methods. Significant efforts will be required to design an effective and efficient strategy for monitoring both venting and flaring activities.

Nigeria

In Nigeria, 17% of total daily gas production is re-injected, 33% is used commercially, and the remaining 50% is wasted by flaring (GGFR, 2003). Nigeria's annual flaring of about 19 bcm in 2006 amounts to 44 million tons of CO_2e emissions (ICF, 2006).

In 1979, the Nigerian government passed the Associated Gas Re-Injection Act, which stated that "No company engaged in the production of oil or gas shall, after 1 January 1984, flare gas produced in association with oil without the permission in writing of the Minister." Since then, government ministers have not been capable of standing strong against the lobbying efforts of the oil companies. The government has been setting new deadlines every year to completely stop flaring; the latest one was December 31, 2009. However, the government has not been successful in enforcing these deadlines on the oil producing companies. On the other hand, the companies, especially Shell, are complaining about cuts in government funding in flare out projects and claim that despite these cuts and the disruptions caused by security problems, they reduced flaring by 60% in Nigeria from 2002 to 2008. Gas gathering and associated gas utilization projects accounted for 30% of the reductions, and reduced production due to security issues accounted for another 30% reduction in flaring (Shell Sustainability Report, 2008). However, the level of flaring in 2008, when scaled to 1999 production levels, is only 12% lower than 1999 levels, showing an insignificant amount of reduction in nine years despite years of promises to reduce gas flaring in the delta.

The main reasons for continued flaring in Nigeria are the economic and fiscal concerns of the oil and gas companies and the inability of the government to enforce laws and regulations that set strict permits and penalties against flaring practices.

The West African Gas Pipeline Company (WAPCo)—which is mostly owned by Chevron, the Nigerian National Petroleum Corporation, and Shell—is promoting a new 425-mile gas pipeline to connect onshore and offshore fields across Nigeria, Ghana, Benin, and Lagos. The so-called West African Gas Pipeline (WAGP) would be the first international gas transmission network in Sub-Saharan Africa (Focus, 2006). The completed project is expected to significantly reduce gas flaring in Nigeria (approximately 78 million tons CO_2e reductions).

Nigeria has several LNG plants producing liquefied natural gas that is exported to Europe and the United States in volumes of 1.2 bcf per day. Nigeria is the seventh-largest LNG exporter in the world. The country is planning to increase LNG exports to 10 bcf per day by 2012 (Focus, 2006). However, the problem with the LNG plants is that thus far they have only used non-associated gas, and therefore have not had any impact in reducing the associated gas amounts that are being flared despite the promises of the operating companies.

Nigeria's declining electricity-generation levels and ongoing power shortages have stimulated efforts to reduce gas flaring. Currently, 81 million people do not have access to electricity and live in the dark, and average per capita electricity consumption is among the lowest in the world.[19] The goal is to increase the number of gas-fired power plants across Nigeria and other West African countries. The gas-to-power program intends to build several new gas-fired power plants and transmission lines across West Africa from Nigeria and Niger to Senegal (Focus, Oil and Energy Trends, November 2006). The planned installation of a new transmission system will be a part of the West African Power Pool, a cooperation of national electricity companies in West Africa. Gas-fired power plant development in the region would be a significant alternative to existing and future hydro-electric power plants developments, which are often adversely affected by seasonal flow reductions and droughts.

The SasolChevron project of gas-to-liquid (GTL) conversion in Escravos, Nigeria, was one of the earliest GTL projects proposed for Nigeria. When completed, the plant will convert 300 mcf per day of gas (15% of total flaring) to low emissions GTL diesel (~70% of product) and GTL naphtha (~30% of product) for sale in the European and U.S. markets (Oguejiofor, 2006). Several other GTL plants are proposed, including a floating GTL facility; however, GTL technology is still in development and it will take time before these projects are completed (Focus, 2006).

In order to promote investments in flaring reduction projects, the Nigerian government has introduced fiscal incentives. The National Petroleum Investment Management Services (NAPIMS) listed the following fiscal incentives to stimulate associated gas utilization efforts (Oguejiofor, 2006):

1. a value added tax (VAT) and customs-duty exemptions on plant, machinery, and equipment;

[19] Country Analysis Briefs. U.S., Energy Information Administration, Independent Statistics and Analysis. Updated in July 2010, available at http://www.eia.doe.gov/cabs/Nigeria/Background.html.

2. a five-year tax holiday;
3. an accelerated capital allowance after the tax-free period in the form of 90%, with 10% retention on the books for investment in plant and machinery;
4. a 15% investment capital allowance that shall not reduce the value of the asset;
5. tax-free dividends during the tax-free period; and
6. tax-deductible interest on loans for associated gas utilization projects.

More recently, Nigeria has produced a Gas Master Plan (Yar'adua, 2007) that is aimed largely at promoting the domestic use of natural gas as a means to end flaring. This plan, introduced in 2007, aims to couple power sector reform with increased domestic gas prices to create improved incentives to natural gas producers. Nigeria envisions a quintupling of domestic gas utilization by 2013, from less than 2 bcf per day in 2007 to about 11 bcf per day (114 bcm per year).

Half the demand growth, about 5 bcf per day (52 bcm per year), comes from the power sector. Other major growth sectors are ammonia and methanol (~1.5 bcf per day or 15.6 bcm per year), GTL (~2 bcf per day or 20.8 bcm per year), and CNG (~1.5 bcf per day). The Nigerian government intends to bolster its institutions and infrastructure so that greater competition and open access can be introduced, underwriting a more robust economic demand for natural gas.

In particular, the Gas Master Plan looks at initial increases in high-pressure transmission and better utilization of existing gas transmission capacity by the international oil companies (IOCs) producing oil in Nigeria. The gas sector regulator is also looking to create a more secure transactional environment for gas sales to domestic entities. In the past, nonpayment by government and parastatals has reduced the enthusiasm of the IOCs to make significant investments in supply to the domestic market.

Other countries

Iraq's South Oil Company recently formed a joint venture with Shell to invest in infrastructure to reduce flaring in southern Iraq's oil and gas fields. The joint venture aims to sell associated gas in Iraq's domestic markets, use it to generate power, and export it to other countries.

Iran's AMAK project, claimed to be the most extensive environmental project implemented by the National Iranian South Oil Company, started in February 2005 to collect associated gas from one of the carbonate reservoirs in the Ahwaz oil field in Southern Iran. The project involved the construction of seven sour gas compressors, one acid gas compressor, a sweetening plant, 280 km of gas pipeline, and 100 km of power lines. The project aims to prevent flaring of 7 mcm per day of sour gas, and has achieved the collection of 2.1 bcm of gas in the two years since it started operations in 2005.[20]

Chevron in Angola has several associated gas management projects. The Flare and Relief Modifications (FARM) project, along with the offshore Gas Processing Platform and Cabinda Gas Plant, upgrades and modifies the flare gas and relief systems on 14 offshore facilities, processes offshore natural gas liquids, and produces LPG for export by using floating production, storage, and offloading vessels. The project will eliminate 708,000 m^3 of flared gas per day (Christiano, 2008).

By increasing domestic gas prices, Algeria and Egypt have extended their gas infrastructure, developed domestic gas markets, and allocated a considerable share of domestic production for export (Gerner et al., 2004).

4 Why utilize associated gas? The market and policy perspectives

In the analysis that follows, the cases of Indonesia and Russia, both significant gas flaring countries, along with Egypt, a declining flarer, will be highlighted with regard to the factors that lead to gas flaring in their countries, and the possible remedies for such flaring.

4.1 The "chicken and egg" nature of gas pricing, gas production, and gas demand

In a gas system that is export oriented, the objective of the foreign buyer normally is to minimize the wellhead price of energy, essentially by convincing the producer or resource owner that no alternative uses for the gas are viable. The domestic producer, on the other hand, will attempt to

[20] Amak Plan: Blue Skies, Clean Air. Shana, November 12, 2007 (http://www.shana.ir/118705-en.html)

convince the buyer that no other source of gas can be found at quite so attractive a price as the one on offer for these exports. The role of the host government is often limited to that of (economic) rent collector, and domestic market considerations play a secondary role.

A low price approach may seem valid, and may indeed provide a useful impetus to resource development by priming demand for the fuel. For example, the development of the Arun LNG complex in Sumatra in the 1970s permitted the government of Indonesia to earn significant revenues from a resource that was “stranded” in the economic geography of those times. As a secondary benefit, the country was able to divert a portion of the gas stream to some domestic industries (fertilizer, steel, and plywood) at cut-rate prices. A similar argument was used to support the initial Egyptian strategy toward gas exports at the expense of domestic use. For many years the consumption of natural gas in Egypt had been limited largely to the utility sector, while industry still relied primarily on fuel oil.

The paradox of natural gas starts from the assumption that associated gas has a low return on investment and can be characterized as follows:

1. The oil producer should receive something close to the marginal cost of “producing” associated gas—i.e., close to zero.
2. This gas is not tradable. That is to say, there is a zero or very low opportunity cost for the country with regard to the supply of such gas.
3. The price of natural gas for industrial and utility consumers does not need to be related in some essential manner to the value of the fuel in opportunity cost terms because it is “non-tradable.”
4. Associated gas can be used to develop industries where demand for market-priced fuels would prove uneconomic.
5. The government, through its control of pricing of this “non-tradable” resource, can maintain control of associated gas pricing, and even keep it distinct from the pricing of non-associated gas. This price discrimination will ensure that only government as the resource owner and its chosen industries will receive the economic rent from the production of the gas.

The argument that associated gas is a non-tradable good has its origin in the traditional definition of non-tradable goods—a product with a high transportation cost and short shelf life. It is usually applied to perishable commodities, commodities that must be fabricated close to the source of consumption (e.g., restaurant meals), and those that cannot be replaced easily by traded goods. There are several reasons to believe that this line of thinking has led to significant misallocation of resources in developing countries, as well as Russia, in regard to associated gas. Contrary to the beliefs prevalent for a number of years regarding associated gas, natural gas has the following attributes:

1. Natural gas can be stored. This has been true for more than 60 years.
2. Natural gas can be transported reasonably economically over significant distances.
3. Natural gas directly substitutes for such “tradable” goods as fuel oil.
4. Technology that is widely available increases the degree of substitutability of gas for oil continually (e.g., compressed natural gas in transport).

These points regarding Indonesia’s associated gas were made in the Indonesia Associated Gas Survey.[21] In addition, there exist scarcity values (economic rent) that are derivative of the scarcity value of the oil itself through the point of a field’s ultimate exhaustion. It is also widely ignored that most of the cost of materials and labor in the gas value chain consists of tradable machinery, parts, and skills, which makes associated gas commensurate with non-associated gas and oil products regardless of the trading status of the gas itself.[22]

In Indonesia, the associated gas in Java was seen to have two outlets: (i) as flare gas at the production platform; and (ii) for localized low-value use directly onshore of the production platforms. The prospect of pricing the gas at its market energy equivalent was simply not explored for many years. For an oil producer faced with the options of flaring or low-value end use,[23] the possibility of investing in compression, treatment, storage, or other ways to increase the tradability of the gas will generally not be undertaken with much enthusiasm. That lack of

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[21] PA Consulting and Pendawa Associates. *Indonesia Associated Gas Survey*, Jakarta, 2006.

[22] A similar error is often made in the analysis of “non-tradable” coal, which features costs of production that are almost entirely tradable commodities, machinery, and labor.

[23] For many years the price of associated gas in West Java was below US$0.50/mmbtu, equivalent to oil at $3/bbl.

enthusiasm will be shared by the host government if reduction in gas flaring is accompanied by temporary reductions in oil output.

At the user end, the supply of non-tradable gas to a state enterprise at a controlled (low) price removes any incentive to seek more valuable end uses or improved efficiency and technology. Ultimately, this creates a positive feedback loop—low input prices, poor technology, price controls on output, unknown supply elasticity—that hampers more market-oriented approaches.[24]

Absent from the approach of the Indonesian government, and many others, was the recognition of the value of substituting natural gas for fuel oil, especially for the heavy fuel oil that was produced in such abundance from the relatively unsophisticated refining system.[25] The opportunity cost that matters when setting the price of natural gas is not a built-up cost from the wellhead to the burner tip, it is the value of the alternative fuel at the burner tip. So if heavy fuel oil (HFO) is used industrially at the same efficiency as natural gas (though it seldom is), then users will be willing to pay at least as much as they pay for HFO on an energy-equivalent basis at the burner tip.[26] In the past 10–15 years, with crude prices fluctuating around $25-30/bbl (prior to 2004), this would place the value of natural gas at more than US$4/gigajoule (GJ), compared to an average price in Indonesia of less than $3/GJ, and in Russia of just $1.20/GJ.

Were more associated gas used in electricity generation and industry, then additional oil exports would be possible. As Egypt learned in the 1990s, the value of the gas is the price that the redundant HFO will fetch in the export market. Had Indonesia taken advantage of the trading opportunities presented by surplus fuel oil, it might have been possible for Indonesia to open up a second line of feedstock exports to refineries in Singapore and elsewhere instead of looking at

[24] Production sharing contracts with a very high country share may also be a factor. In many such contracts there is little incentive for the producer to economize on the use of "cost" gas, which is completely chargeable against the production cost of oil. In a typical 85:15 production share, the contractor would receive just 15% of the value of the saved gas for its share of the profit production. If this gas is sold at a very low, controlled price, then the incentive to produce additional gas is largely absent.

[25] Throughout the 1980s there was far more concern with the negative impacts on oil product markets of "surplus" HFO in Southeast Asia than there was interest in the use of that HFO as a feedstock in complex refineries.

[26] In electricity production, a modern gas-fired power plant converts fuel to electricity at an efficiency of roughly 55-57%. In contrast, an HFO-fired steam turbine plant achieves a conversion efficiency of about 38-40%. Since the generation equipment costs roughly the same per unit of capacity, a gas-fired plant can pay about 40% more per GJ for fuel than can an HFO plant.

HFO as a fuel only. Such HFO feedstocks are commonly traded throughout the world, but especially where there exists a technically sophisticated refining sector.

From the standpoint of GHG reduction, the chief benefits of replacing fuel oil with natural gas are two-fold: (i) direct reduction in GHG emissions at the point of end use due to the lower carbon content of the gas; and (ii) displacement of crude oil inputs to refineries with the HFO used as a feedstock. A potential reduction in end use of HFO translates directly into lower crude oil throughput, as long as markets for these products are allowed to operate effectively.[27]

Note 1. How does replacement of HFO reduce CO_2 output?
The argument that is made here is that greater encouragement of associated gas exploitation has two environmental benefits. The first is the reduction in flaring, which amounts to a direct diminution of CO_2 and methane emissions to the atmosphere. The second is the displacement of heavy fuel oil by associated gas. In conjunction with high conversion refining methods (low HFO output), significantly less crude oil would be needed to supply light product markets. The argument is really quite simple. Suppose that the demand for light products (LPG, gasoline, kerosene, diesel, etc.) is 75 million barrels per day. The remainder of the oil consumed, some 11 million barrels per day, is HFO.[28] If almost all of the HFO were converted to light products, say 9 million barrels per day, then the products market would be oversupplied by that amount, unless crude oil runs to refineries were reduced by a roughly

[27] For example, in the U.S. refining sector, total net production of heavy fuel oil (#6) is about 650,000 barrels per day, around 4% of total refinery output, compared to 20% or more (depends on crude oil type) at refineries without upgrading facilities. In addition, the United States imports about 300,000 barrels per day of HFO. Total consumption of HFO outside the refining sector in the United States is only 230,000 barrels per day, meaning that the remainder, more than 700,000 barrels per day, is used as refinery feedstock, replacing crude oil on an almost 1:1 basis. If the demand for HFO as a final product falls as a result of environmental concerns, then refiners will have the option of (i) accepting far lower prices for HFO; (ii) converting the remainder of that fuel oil to lighter products in their own refineries; (iii) selling the HFO as a feedstock to high conversion refineries at a steep discount; or (iv) gasifying their own HFO or coke for electricity generation and steam/heat cogeneration.

[28] The HFO number is actually higher, probably by 50%, since some countries categorize HFO as a distillate oil.

equivalent amount.

With associated natural gas replacing HFO or naphtha[29] for electricity and industry in most countries, the CO_2 reduction can be calculated as follows:

CO_2 per kWh: Gas = 525 g, HFO = 815 g

CO_2 of all HFO used in industry/electricity: 1.55 billion tons per year

CO_2 emissions of substitution by associated gas: 1.06 billion tons per year

CO_2 emissions for 20% efficiency improvement for natural gas: 0.85 billion tons per year

This substitution will make sense as long as there is a beneficial alternative use for the HFO as a feedstock.

4.1.1 General policy framework for associated gas production

As noted above, both Indonesia and Russia have considered associated gas to be a byproduct rather than a co-product. This means that little upstream investment was justified for this nonessential and "non-tradable" commodity.

Both countries have now come around to a more appropriate recognition of the value of associated gas in final energy markets. However, this new appreciation of the end-user value of gas has yet to be fully felt at the producer's end; the lack of recognition continues to hamper the upstream development and sustainability of the product.

4.1.2 Pricing

Current pricing for utility and industrial users in Indonesia's West Java Regency averages about \$4/GJ, up from below \$3/GJ in 2005. This gas price nets back to about \$1.25/GJ at the wellhead in South Sumatra and a bit over \$2/GJ at the wellhead for West Java offshore associated gas.[30]

[29] Naphtha is also treated as something of a market stepchild in many countries. With heavy taxes on gasoline the norm, along with either subsidies for diesel or minimal taxation, the pricing gap per GJ between naphtha and diesel is often considerable. Nevertheless, with gas not always available, power plant operators with CCGT units may be forced to use naphtha at prices well above the cost of flare gas reduction.

[30] Associated gas producers do not receive this netback price and are still subject to tiered pricing.

Netbacks for LNG are considerably higher than this such that, absent domestic marketing obligations, gas producers would prefer to export this gas.

One point of entry to remedy the market defects that encourage gas flaring has been a series of gas network infrastructure projects supported by the World Bank and the Asian Development Bank (ADB). The key pricing focus of both banks' West Java network projects, in both transmission and distribution, was recovery of the costs of the network investment and operation through tariffs charged by a monopoly state-owned company. The type of open access to the network that might otherwise stimulate further domestic markets for gas has been limited since the borrower, Perusahan Gas Negara (PGN), acts as both the network owner/operator and gas seller. More access to the gas transmission system by both sellers and customers, thereby reducing the role of PGN as a merchant gas seller, could allow customers to offer higher prices for associated gas than they are now permitted under the government's controlled pricing system.[31]

A similar situation is found in Russia, albeit with even greater disparities between domestic and international prices for the same gas. The World Bank has calculated that the domestic price of gas that is needed to allow Russia's gas industry to develop sustainably is about twice the current level or about $1.75/GJ ($50/mcm).[32]

While there is not a generalized supply function for natural gas, especially for associated gas, given the dependence on local geology and infrastructure, there are some generalizations that can be deduced from producer behavior regarding the nature of the supply function. These are:

1. Gas gathering and compression cost at least US$2.50-3/GJ as a new investment in Indonesia (GGFR, 2006)[33] and probably US$2.50-4/GJ for new investments in Russia.

[31] Were a better functioning market in fuels to exist in Russia or Indonesia, there would be no need for CCGT plant operators to purchase naphtha at prices of ~$20/GJ when direct negotiation of supply terms with gas flarers would result in energy supply at a lower price. Unfortunately, such transactions are not permitted, even with a willing buyer and a willing seller.

[32] Reform of the Russian Gas Sector, page 6. The long run marginal cost (LRMC) for Russian gas is estimated at ~$40/mcm (~$1.40/GJ) provided there is no scarcity value attributed to the gas. This is a strict accounting cost.

[33] GGFR (2006), page 4-3.

2. In the current industry environment, the private producer expects a profit of more than US$0.50-0.75/GJ to undertake investments that will primarily benefit the host country.[34]
3. To make this profit hurdle, host governments may need to find a way to increase the producer's share of the profit, or raise wellhead prices to market levels.

In Egypt, the national gas company purchases both associated and non-associated gas at the same (low) price of $1/million Btu (mmbtu) ($0.95/GJ) from the state-owned oil company, EGPC. The state-owned oil company purchases gas from private producers at $2.65/mmbtu ($2.51/GJ) and the government pays a subsidy for the difference between the consumer price and the wholesale price.[35] Unlike Indonesia and Russia, oil producers in Egypt are willing to make the types of production, compression, and treatment investments that permit increased gas use in the future. According to the NOAA, gas flaring in Egypt—with newer oil fields than Indonesia's, and similar daily output—is about 1.7 bcm per year, less than 60% of Indonesia's level, and has featured a steady downward trend since the mid-1990s.

The government of Egypt had promised that by 2009/2010, natural gas prices to final consumers will reach an acquisition cost of $2.65/mmbtu. Further specific structural reforms of the gas supply system have not yet been proposed.

4.1.3 Infrastructure

A highly regulated system, operating without significant economic incentives, such as the historic associated gas systems of Indonesia and Russia, will tend to be a point-to-point system, with little flexibility as to the uses of the gas. Indeed, both countries have historically featured such systems in the domestic market.

In its policy dialogues for the gas industry, the World Bank has urged that domestic markets be restructured such that the gas commodity and the network assets are priced separately to end users. Indonesia has started to do this, with recent network investments and the initiation of

[34] Based on alternative gas prospects in Australia, Brazil, Canada, and the North Sea.
[35] Egypt News, April 2009/Issue 28, available at http://www.egyptoil-gas.com/admin/industry/News%20EOG%20Newspaper%20April%2009%20Issue.pdf..

pressure from both gas producers and gas consumers for open access to the gas transmission system.[36]

Russia has moved away from competition in its domestic gas sector. As such, the country's outside advisers, including the International Financial Institutions (IFIs), have urged that the country adopt financial unbundling of the various gas segments along with specific pricing reforms suggested in the 2004 Russia Gas Policy Study. At the same times, as stated in Note 2, Russia has found that its low-price gas strategy has not proved capable of providing adequate resources for upstream investments, including flare reduction.

4.2 How has the international community engaged on associated gas flaring issues?

By the late-1990s there was an emerging consensus that associated gas flaring was a directly harmful, wasteful, and easily delimited resource issue that could be addressed by the international community. With that in mind, several of the world's major oil producing countries, along with most of the major international oil companies, joined the World Bank's Global Gas Flaring Reduction Initiative in 2002. However, this formation period for the GGFR coincided with a near-cessation of direct lending by the IFIs for gas production in their developing member countries (DMCs). Consequently, the World Bank and other IFIs had little to say on the subject of associated gas during this period unless the associated gas was flared or vented and somehow fell under the purview of the GGFR. Though the World Bank's portfolio of gas lending is once again on the rise, most of the current involvement of the IFIs in gas sector issues arises from either policy dialogue or network infrastructure lending. Most of the international community's current gas projects result from one or more of the following rationales:

1. Improve gas network infrastructure to better take advantage of associated or other "non-tradable" gas supplies.
2. Improve gas network equipment to reduce venting and other releases of natural gas to the environment.

[36] This point is made strongly in GGFR (2006). See especially pages 3-6 and 4-3.

3. Provide an environment that is conducive to increased domestic use of natural gas so as to reduce gas flaring.
4. Replace coal and heavy oil in power and industry with natural gas to improve general economic efficiency.
5. Replace oil use in power and industry to make this oil available to export markets.

Although most of the extensive record of engagement by the international community on Russian gas issues was motivated largely by the desire to reduce gas flaring,[37] many of the recommendations of the Russian gas policy projects are indistinguishable from policy prescriptions to improve the overall efficiency of energy use in the Russian economy.[38] It is important to note this since a key theme of this paper, enunciated in Section 3.1, is that uneconomic energy pricing often goes hand-in-hand with physically wasteful energy production and use. For example, most of the economic analysis surrounding the West Africa Gas Pipeline, and certainly the World Bank's role in providing for a partial credit guarantee for the Ghana pipeline terminus, has little or nothing to do with reducing gas flaring at the wellheads in Nigeria. Their analysis is focused instead on sound pricing in the receiving country and cost recovery for the network infrastructure. At the same time, the initial motivation for the regional pipeline project in Nigeria, the producing country, is at least partially, if not mostly, GHG-related.

4.2.1 Project lending as a motivator to reduce gas flaring

As noted above, most of the recent project lending in natural gas by the World Bank and ADB has involved gas infrastructure: transmission and distribution systems. As is normal in such projects, a bank will take steps to ensure that the tariffs charged for the use of the network infrastructure can cover the costs of the investment. The pricing of the upstream gas, the rights of

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[37] The international financial community's only current operation in Russian gas aims explicitly at reducing flaring. At the same time, the World Bank has engaged recently in policy dialogue with the Russian Federation on gas pricing in a manner consistent with economic efficiency alone. See "Reform of the Russian Gas Sector," World Bank, 2004.

[38] Indeed, it may be argued that improving Russia's overall economic efficiency, in part through increasing the effectiveness of fuel use, was the primary goal of the international community's gas sector engagement. Environmental concerns would have been secondary in this interpretation. Nevertheless, such concerns were voiced specifically in the early engagements of the World Bank in Russia's gas sector.

access to the transmission system by suppliers and customers, and other issues tend to remain in the background in such network infrastructure lending projects.

For Indonesia, the recent lending projects that have reached completion include gas distribution in West Java (which started in 1997) and gas transmission from Sumatra to Java (which also started in 1997). Other, more recent, projects on gas distribution are still underway and their impacts cannot yet be fully evaluated.[39] However, the Infrastructure Development Policy Loan (IDPL 1) builds on previous policy initiatives, especially with regard to gas pricing and the substitution of gas for oil among power and industrial users in West Java.

In the aftermath of the 1997-98 Asian financial crisis, which hit Indonesia particularly hard, the immediate plans for the Sumatra-Java pipeline were scrapped. However, the project was ultimately completed in 2006 with financing from the Asian Development Bank and Japanese sources, among others.

4.2.2 Policy dialogue

Policy dialogue on the use of associated gas has been a recent and strong element of IFI activities in Russia, Indonesia, and Egypt during the past decade. Although such activities are of short duration, involve no financial commitment by the DMC, and stand alone as technical assistance efforts, policy dialogues may result in important changes if the country has played a role in the initiation of the activity.

In Egypt, Indonesia, and Russia, the GGFR forms the basis for some of the policy dialogues that the international community undertakes with oil producing countries, especially where associated gas is not used as effectively as it might and significant volumes are flared as a result.[40]

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[39] Most significant in this list of new projects is the World Bank's Infrastructure Development Policy Loan I (IDPL1), which started in October 2007. This project was influenced by the GGFR report, *Indonesia Associated Gas Survey – Screening & Economic Analysis Report (Final)*, 2006.

[40] Additional bank documents were used in this review, including:

- GGFR (2004a)
- Loan number 3354 EGT, (Gas Investment Project) between the International Bank for Reconstruction and Development and the Egyptian General Petroleum Corporation, 1991.
- Loan number 3354 EGT, (Gas Investment Project) between International Bank for Reconstruction and Development and Petroleum Gas Company, 1991.

In both Russia and Egypt, there has been no real need for the World Bank to be engaged in upstream gas lending activities in the past decade.[41] However, in both countries there has been internal discussion of whether and to what extent the countries' export-oriented policies were optimal, whether the pricing of the gas resources internally was sustainable, and whether regulation of the sector was appropriate.

The two policy dialogues arose differently. The "Reform of the Russian Gas Sector" report was an outgrowth of a larger study of that country's development strategy as of 2003 (World Bank, 2004). However, there had been prior World Bank involvement in Russia's gas sector. The IFIs are not likely to have further operational involvement in Russia's gas sector, given the putative ability of the country to finance its own energy sector infrastructure needs (see Note 2).

In Egypt, conversely, the policy engagement, after years of quiescence on that score, resulted from an agreement between the international community (specifically, the World Bank) and the government of Egypt that certain policy issues in the gas sector warranted reexamination. One of the net outcomes of this policy review was new gas lending activity—a direct implementation of some of the policy dialogue recommendations.

Note 2. Can Russia really finance its own upstream gas sector?

Strictly speaking, Russia is not able at present to replace its gas production with new discoveries and production. It is for this reason that Russia currently imports gas from Turkmenistan in order to fulfill certain export delivery obligations. Russia makes no profit on these transactions. Just over 25% of total Russian gas production is exported, at prices that comport with world oil prices. However, the 75% of Russian gas that is sold on the domestic market is priced at just 10-15% of world levels (~US$1-1.25/GJ). Such prices can barely cover network infrastructure and will not support significant upstream activities in the Arctic or polar regions in either non-associated gas or in gas gathering and compression of

[41] For Russia, this means once the 1998 financial crisis was resolved. However, Russia remains either the largest or second-largest source of flare gas in the world. See Yuriy Myroshnychenko, "Natural Gas as Climate Change Solution: Breaking down the barriers to methane's expanding role". Also see footnote 5.

associated gas.

Wellhead netback values used to justify current upstream gas projects fall generally into the US$2-3/GJ range in less challenging climates than the Arctic. Russia has committed to bringing domestic gas prices up to parity by 2012 or 2013. However, it is still unclear what this will imply for wellhead netback values. Apparently alarmed by the prospect of falling non-associated gas production due to low-price-driven underinvestment, the government of Vladimir Putin suggested in February 2008 that it might scrap price controls on associated gas.

This proposal was made during the oil price run-up in 2008. However, the subsequent fall in world oil prices, from over $125/bbl in 2008 to less than $75/bbl throughout 2009, has reduced Gazprom's (oil-price-linked) revenues and eliminated some of the financing cushion that was going to be used to finance improved domestic infrastructure for gas utilization.

4.2.3 What issues were identified in lending projects and policy dialogues?

For the two Indonesia gas network projects, the key concerns that were identified included: (i) liberalizing the investment climate for gas to bring in new investors; (ii) liberalizing prices for gas; (iii) supporting the additional supplies of gas for the Java market through various means; and (iv) reducing reliance on coal by industry and power generators, thereby reducing emissions of particulates, hydrocarbons, and CO in West Java.

For the two policy dialogues, the major concern was how to create a long-term sustainable market in natural gas that would satisfy both domestic and export needs. In each case, the balance between domestic demand and exports was considered to be biased toward exports. No explicit connection to gas flaring or venting was made in either policy dialogue description. By stressing the longer-term sustainability of the gas resource and by making explicit the opportunity cost of inefficient use of gas in the presence of increasingly costly oil, it became possible for the World Bank to argue for a revised gas sector policy without recourse to GHG issues.

The Indonesia Associated Gas Survey arrived at valuations for flared gas that were equivalent to tradable gas, and netted back to US$5-6/1000 standard cubic feet (mscf) at the wellhead (see discussion on pages 3 and 4). However, the experiences of the production sharing contractors (PSC) that must sell associated gas to PGN, the state-owned gas distribution company, differed greatly. One PSC, whose gas production would be worth $125-$150 million at market prices, received less than $40 million for its gas output in 2007 ($1.54/mscf). The company's oil output was worth more than $500 million, even though the energy produced as gas was more than 50% of the oil energy produced.[42] It should be noted that generally 80%–90% of the "profit" oil or gas goes to the Indonesian government under the country's production-sharing contract regime, so the company's share amounts to less than $15/barrel for oil or $0.40/mscf for gas at current prices.

Under the terms of Indonesia's production sharing contracts, associated gas in each oil field is priced separately, on a cost-plus basis. Prices are fixed for the duration of the contract for sales to the domestic market. Typical sales prices for selected domestic users are shown in the table below:

Domestic natural gas prices in Indonesia for associated gas (US$/mmbtu)		
End Use	**Price Range**	**Implied Wellhead Price Range**
Fertilizer	$1.00-2.00	$0.60-1.50
Steel	$0.65	$0.25
Plywood	$0.97	$0.50
Source: U.S. Embassy-Jakarta; Petroleum Report, various years		

Many of the older PSC agreements contain wellhead pricing for associated gas that is below US$1.00/mscf (mmbtu). Prices this low do not create sufficient incentives to make aggressive moves to end flaring and increase marketable output. This is because under both the cost-plus and profit split provisions of current production sharing agreements, the producer will only receive a fraction of the profit gas, with the remainder going to the government. If a PSC gas producer offshore Java is working on the basis of an 85% government/15% company profit split,

[42] Harvest Resources, *Investor Relations Report*, page 1.

then the company will receive just a few pennies for every dollar of additional gas produced, once costs are accounted for.

The Associated Gas Survey (see Section 4) indicates that investment costs per mmbtu are 2.5 to 3 times the current controlled prices[43] for associated gas users and about the same as the retail price of natural gas for industrial users. Such a pricing policy seems to ignore the clear economic benefits of a supply cost of less than US$5/GJ for natural gas, including network infrastructure, when world oil prices are well above US$10/GJ even for heavy fuel oil.

4.3 Who are the stakeholders for the gas sector dialogue on flaring?

4.3.1 International financial institutions

The international community, through its development banks, sees its involvement in gas normally involving one or more of four domestic institutions. These are:

1. The Ministry of Energy
2. The state-owned gas company (production, transmission, distribution)
3. The gas regulator
4. The state-owned electricity company

In order to reduce gas flaring and provide incentives for market participants to use gas for productive purposes, the government will need to make its policies accordingly. Project lending, along the lines of what the World Bank and ADB attempted in Indonesia in the late-1990s, did not fully address such issues. In fact, it was not until the country completed a new natural gas policy in 2000 that non-export (largely at the expense of LNG exports) options started to come to the fore.

The IFIs' emphasis in Indonesia continued to focus on building credibility and competence in those energy sector institutions still functioning reasonably well in the wake of the 1997-98 financial crisis. Correspondingly, the gas distribution company, PGN, the gas regulator, and the major domestic end user, PLN, were all objects of the IFIs' attentions during this period.

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[43] On page 4-3 of the Associated Gas Report, these costs are estimated to fall into the $3/mmbtu range for recovering associated gas. This means that gas could be delivered to an industrial estate in Jakarta for less than $5/mmbtu.

In Russia, the major stakeholder is Gazprom. Regulatory institutions are weak and play minor roles in the gas sector. The major factor influencing Gazprom's domestic policy is its obligation to supply gas to domestic heating and electricity consumers. With the World Bank phasing out of most of its Russian projects, there is scarcely any direct program lending that would be persuasive to such a large and profitable company. Therefore, the international community has opted for persuasion in the form of its Russia Gas Policy report.

Egypt's case is perhaps the most interesting of the three. Egypt is reorienting its gas market and reforming the pricing structure simultaneously. Upstream gas rights above 28˚N are the province of the Egypt General Petroleum Company (EGPC). Gas transmission is handled by the Egyptian Holding Company for Natural Gas (EGAS), a subsidiary of EGPC. Gas rights south of 28˚N are the province of a third entity, Ganoub El Wadi Holding Petroleum Company (GANOPE), which is a state-owned company. There is no independent regulator for gas pricing or distribution.

Policy decisions are made by the Ministry of Energy, which supervises both EGPC and EGAS. The IFIs' primary policy involvement is with the Ministry of Energy currently, though the natural gas distribution project will be implemented by EGAS.[44] The current gas project does not require that Egypt establish an independent regulatory body for natural gas. However, there is some intention to strengthen the country's gas institutions.

4.3.2 International oil and gas companies

The IOCs have generally responded to either incentives or regulations from the host country governments to undertake (or cease) certain activities in their upstream operations. As a general rule, though, the IOCs have been less than enthusiastic until recently about associated gas recovery projects that marketed to the host-country market in Indonesia and Russia. The perceived obstacles to increased gas recovery included the following:

- Currency risk: Oil is marketed in U.S. dollars, but the additional associated gas volumes would probably be priced in local currencies or, at best, a mix of local currency and hard currency.

[44] This is a $150 million gas distribution project approved by the World Bank's board in January 2008.

- Exposure to domestic regulatory agency decisions: At present, the IOCs generally operate under the supervision of a special purpose agency. Enhanced domestic gas marketing would bring other, purely domestic, government agencies into the mix.
- Low prices in the domestic market: Why incur costs of $3-4/GJ to sell for $2/GJ?
- Financial exposure to domestic market entities, including state-owned electricity generation companies: IOCs were reluctant to take on additional financial risk by selling to state-owned companies with limited financial resources and weak balance sheets.

In recent years, the environment for an increased IOC role domestically in some of the oil producing countries has improved. In Egypt, the marketing of associated gas has been taken out of the hands of the IOCs through a transfer (in US$) to a domestic oil company. This feature makes the sale of gas by the IOC to the state-owned company virtually riskless for the IOC.

Indonesia still resists the kind of open access to the gas network that might make associated gas transactions at market-related prices feasible. At oil prices down to about US$35/bbl, the $2.50-3.00/GJ required to reduce flaring and market the associated gas would probably be feasible, provided the production sharing contracts could be more flexible at lower oil prices.

There is currently little appetite by most IOCs for major new investments in Russia’s gas sector, given the recent difficult history. The Russians will either have to provide some firm financial guarantees of cost recovery by IOCs for gas flaring reduction projects or they will have to undertake such investments entirely by themselves.

4.3.3 State-owned national oil companies

The national oil companies in major flaring countries have played a relatively minor role in the reduction of gas flaring through investments and operations outside the NOC members of the Gulf Cooperation Council countries, Algeria, and perhaps one or two other NOCs. In this regard, the NOCs are proving themselves little different from the IOCs in terms of their willingness to invest in associated gas gathering, compression, and re-injection or transmission without appropriate pricing and regulatory arrangements.

In addition, where the NOC is treated as a cash resource for the government, there is generally little desire to invest billions of dollars in a "free good." In Russia, the national gas company, Gazprom, was more willing to purchase gas from Turkmenistan at market rates than it was to invest in flare reduction in order to sell into a domestic market at very low prices. In Indonesia, Pertamina, long the resource owner for associated gas as well as the regulator of the sector, showed little interest in encouraging investments in improved supplies of associated gas with its concomitant reduction in flaring.

4.4 What were the impacts of the international community's engagement in gas flaring and associated gas issues?

The international community has been an important partner for each of the three countries in their gas sector development. However, in no case was this engagement regarding gas use or pricing dispositive for the patterns of use of natural gas or its relative absence in each country.

Discussions with IFI project officers involved with energy and fuels provide a consistent story of a certain disengagement from the gas sector between the mid-1990s and the early part of this decade. The World Bank's general exit from hydrocarbons and extractive industries had the effect of removing that institution from ongoing policy debates in many of its DMCs on gas policy.

The dearth of upstream oil and gas projects during this period resulted in less gas usage than might otherwise have been the case. For Indonesia and Egypt, the absence of an IFI lending and advisory role in the gas sector contributed to an instrumental view of network investment projects. As long as the tariffs could cover network costs, then the project was considered by the lenders to be successful. Significant expansion in gas use and creation of a domestic gas market, as opposed to regulated sales, was not considered part of the project design.

A longer view of the development of the sector and of the types of investment and pricing policies required to accomplish the country's objectives with regard to fuel production and end use efficiency might have been the outcome of a more involved international community, especially its IFIs.

4.4.1 Role of gas in the power and industrial fuels mix

In both Indonesia and Russia, gas use has been highly regulated over the years, with multiple prices and significant price discrimination/distortion with regard to end user price levels. This issue was engaged in Russia's case by the World Bank's Russia Gas Policy report, but the IFIs have yet to tackle this issue head on for Indonesia.

In Russia, there seems to be a growing realization of the value of "right pricing" natural gas, whether from associated or non-associated sources. Certainly if the internal Russian figures of 160 bcm per year of flared gas are correct, then the problem is far more severe than has been acknowledged thus far. Indeed, the Russian government itself seems to have moved into agreement with more market-oriented gas pricing at the wellhead, at least for associated gas fields.

Tight regulation of domestic gas in terms of both prices and quantities can lead to significant economic imbalances and resource misallocations. Indonesia was certainly so affected over the past 10 years. While natural gas from associated wells was going to state companies at very low prices, creating dubious value added for the economy (see Section 2.1.3, above), the state power company, PLN, was using liquid fuels in power plants designed for natural gas and purchasing these fuels at international prices. During the same time, one of the factors discouraging further private investment in power generation was the lack of gas for CCGT plants. If private power plant operators had been able to contract directly with IOCs then flare gas offshore of West Java, perhaps a more reasonable market-oriented outcome could have followed.[45]

As of this writing, the international community's engagement with Indonesia has resulted in some positive changes in that country's approach to associated gas. But what has mostly changed is the market environment in which the country now operates. High overall energy prices and the country's increasing inability to underwrite domestic consumption subsidies have created a highly unstable policy environment in which new proposals for domestic gas exploitation have received increasingly favorable attention. New projects by the World Bank and the ADB,

[45] For example, the gas flared offshore West Java, roughly 1 bcm per year, is sufficient to provide fuel for about 700 MW of CCGT electricity generation.

including a gas network infrastructure investment program, are intended to put into place certain regulatory reforms; without such reforms, a new approach to the domestic gas market would continue to progress in fits and starts, restrained by gas supplies.[46]

In Egypt, the Ministry of Energy is working with the international community to gradually reform the country's approach to domestic gas use, increasing its role not only in power production, but also in industry, commercial, and household end uses.

5 Recommendations and conclusions

This review of the venting and flaring of associated natural gas in producing oil fields has confirmed the need to recommit to an aggressive global mitigation program. The local environmental and public health impacts together with contributions to the potential for global warming make a strong case for accelerated programs, especially in countries with the technical capacity to effectively participate jointly with industry and sponsoring organizations.

Consideration should be given to the fact that the international community will have less effect when a country graduates from its lending programs, as has Russia's hydrocarbons sector with regard to the European Bank for Reconstruction and Development (EBRD) and the World Bank. Technical support is especially needed in poorer countries to develop the scientific and engineering skills necessary to verify mitigation programs. In the case of Russia, the technical assistance provided by the IFIs does not seem to be valued to the same degree as it is in Indonesia and Egypt.

The case in Indonesia has shown that it is necessary to remain in the field to hold sway on the country's policy circles. Indonesia remains a poor country, its energy institutions and policy apparatus are challenged, and its hydrocarbons fortunes are shifting rapidly. As with Egypt, well-timed intervention could prove highly beneficial in both economic and environmental terms. One of the key impressions left after looking at the changing situations in both Indonesia and Egypt is that it is very possible to reach both economic and environmental goals in tandem. Efforts to

[46] Indonesia's short run solution to this issue is to restrict exports of gas to several LNG customers in favor of domestic market uses. As of this writing, the Minister of Energy, Dr. *Purnomo* Yusgiantoro, has announced that exports of LNG to North America from the Tangguh development will be redirected to Japan and Thailand while the domestic demand of equivalent volumes (~3 million t per year) will be supplied from Kalimantan development.

control both prices and resource allocation in the two countries have led to serious distortions and missed opportunities to replace oil products with gas. In the case of Indonesia, it has led to a rebirth of coal as a main fuel for power generation.

The most important element of the international community's initiatives in Egypt and Indonesia will be consistent progress toward achievable and clear goals: (i) increased use of gas wherever it can reasonably replace fuel oil; (ii) improvements in distribution and transmission to promote conversion of customers; (iii) pricing policies that provide for a financially healthy and self-supporting industry from the consumer back to the wellhead; (iv) nondiscriminatory pricing between associated and non-associated gas; and (v) environmental policies that support gas conversion wherever feasible and that are consistent with supply conditions.

In Nigeria's case, although flare volumes have decreased somewhat, the majority of the decrease is likely due to the decreased oil production caused by civil unrest. Both regulatory enforcements and financial incentives are proving insufficient in Nigeria. Several gas utilization projects are underway; however, the completed projects have not been as successful in reducing gas flaring volumes as claimed. In Nigeria, less complicated and lower cost technologies, such as LPG and gas-to-power, could be put in place to utilize associated gas locally, as most flaring fields are very close to poor local communities that are in desperate need of basic energy sources.

Regardless of who is flaring the gas, whether it is an NOC or an IOC, the incentives for investment in flaring reduction must be appropriate and clear. To the greatest extent possible, regulations need to encourage willing buyers and willing sellers to make beneficial economic use of the great volumes of flared gas that are vented and flared each year. Gas flaring reduction regulations and technologies adopted by the countries should be site-specific. No single option is best for all oil fields. Each field has its own characteristics, size, local market conditions, and infrastructure needs; each country has its own political, institutional, and financial framework.

Finally, the methodologies for estimating gas flaring and venting need to be updated, improved, and made consistent. Satellite data needs improved calibration through more accurate actual flaring volume data from countries with large flare volumes. There is no good reason, 10 years after interest in mitigations of gas flaring ramped up, that there should be serious information anomalies and discrepancies. An accurate flaring database needs to be maintained, and there needs to be a concerted effort to estimate gas venting, potentially a far more serious global environmental threat.

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