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Designing the Ideal Offshore Platform Methane Mitigation Strategy

Carey Bylin, U.S. Environmental Protection Agency; Zachary Schaffer, ICF International; Vivek Goel, ICF International; Donald Robinson, ICF International; Alexandre do N. Campos, COPPE/UFRJ; Fernando Borensztein, Devon Energy do Brasil Ltda.

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Abstract

Description of the Proposed Paper:

Methane is a powerful greenhouse gas and the primary component of natural gas and minimizing methane emissions creates both environmental and commercial benefits. Offshore production platform air emissions have been studied and characterized in detail by the U.S. Minerals Management Service (MMS)[1], and the U.S. Environmental Protection Agency's (EPA) Natural Gas STAR Program has gathered information on methane emission reduction technologies and practices applicable to these facilities. This paper analyzes and summarizes methane emission volumes and sources from offshore production platforms, outlines mitigation technologies and practices, and provides a methodology for conducting full cost-benefit economic analyses to prioritize mitigation actions to yield the maximum environmental benefits at the lowest cost. The information presented can help companies better understand emissions from their offshore facilities and provide guidance they can use to optimize their own operations.

Application:

Worldwide offshore oil and gas production operators can use this approach to improve their current methane emissions inventories and identify mitigation technologies and practices that could be used to reduce emissions at existing facilities or be considered in the design of new platforms as a way to minimize or prevent potential methane emissions.

Results, Observations, and Conclusions:

MMS provides a significant body of knowledge about overall operations and methane emissions from offshore oil and natural gas production platforms. New research and data gathering was utilized to develop a comprehensive analysis of methane emissions from individual platform operations. In doing so, this information was synthesized for the first time in a comprehensive way to identify mitigation technologies and practices that could be applied to the most significant emission sources. Marginal abatement cost curve analyses were then developed to prioritize mitigation actions. This analysis indicated that up to 85% of an individual platform's methane emissions can be reduced cost-effectively through replacement of centrifugal compressor wet seals with dry seals; routing vent sources such as storage tanks, dehydrators, and pig launcher to a vapor recovery system; and implementing a directed inspection and maintenance program to target fugitive emissions.

Significance of Subject Matter:

Optimizing platform design to reduce methane emissions contributes climate change benefits, given methane's role as a greenhouse gas, and also enhances operational safety on offshore platforms. These pillars of environmental and safety benefits, along with economic benefits of conserving and utilizing a valuable clean energy source, contribute to overarching principles of corporate social responsibility.

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[1] The MMS has been collecting detailed air emissions data from Gulf of Mexico production platforms for more than 20 years. The current paper references this data, along with updated emission factors for U.S. and international greenhouse gas inventories

Introduction

The oil and gas industry can benefit from increased revenues, cost savings, enhanced operational efficiency and improved environmental performance by focusing on reducing methane emissions from oil and natural gas operations. Methane is a primary constituent of produced natural gas and a greenhouse gas (GHG) with a global warming potential of over 20 times that of carbon dioxide (Forster, 2007). Worldwide efforts to reduce GHG emissions require significant investment, but GHG emissions reduction projects that target methane emissions present a unique opportunity as methane has considerable value as a source of energy. Annual methane emissions from the global oil and natural gas industry are equivalent to 94 billion cubic meters (m^3) or \$10 to \$23 billion[2] worth of natural gas lost to the atmosphere. By 2020, these figures are anticipated to increase by 35%, reaching 128 billion m^3 of natural gas lost to the atmosphere (EPA, 2006a).

As offshore oil and natural gas production increases worldwide, this sector will increasingly contribute to industry methane emissions. Offshore production platform air emissions in the U.S. Gulf of Mexico have been studied in detail by the U.S. Minerals Management Service (MMS), and these data provide a substantial basis for analyzing methane emission reduction opportunities. Such opportunities are the focus of the U.S. EPA's Natural Gas STAR Program, which during the last sixteen years has gathered information on methane emission reduction technologies and practices applicable to the entire oil and natural gas industry both onshore and offshore. The following analysis references data from these sources, along with updated emission factors, known methane mitigation options, and novel research and data collection in order to summarize methane emission volumes and sources and outline mitigation technologies and practices for offshore production platforms.

The paper details a procedure for 1) identifying and estimating relative volumes of methane emissions from various sources offshore and 2) designing a set of mitigation options that can be implemented to minimize methane emissions at platforms worldwide. An analysis of methane emissions from the operation of example platforms in the Gulf of Mexico and offshore Brazil was conducted to illustrate common reduction opportunities. To select the ideal mitigation options for reducing these emissions, marginal abatement cost curves are utilized to compare the magnitude of the reductions and the natural gas value at which those reductions will be cost-effective. The body of this paper and the example platform analyses illustrate a methodology that can be used by offshore oil and gas producers worldwide to improve estimates of platform emissions, identify potential mitigation technologies and practices, and develop the most cost-effective mitigation strategies.

Significance of Methane Emissions from Offshore Oil and Gas Production

Within the oil and natural gas industry, offshore production is rapidly becoming a major source of energy production worldwide. Significant offshore reserves of oil and gas are currently under exploration and development on nearly every continent. Deepwater oil and gas fields around the world contain significant reserves that will need to be tapped to keep pace with energy demands in the near future.

United States

Natural gas production in the Gulf of Mexico currently supplies 15% of total U.S. production, while offshore production of crude oil makes up 28% of total U.S. petroleum production. The Energy Information Administration's (EIA) Annual Energy Outlook projects that offshore production of natural gas and oil will increase by 39% and 47% respectively by the year 2030, with deepwater oil nearly doubling in total volumetric production (EIA, 2009a).

Latin America

In Latin America, offshore exploration and production comprises 81% of the oil and gas production of Brazil, which has about 90% of its proved oil reserves offshore. New reserves in the pre-salt layer discovered off the coast of Brazil contain approximately 33 to 50 billion barrels of oil equivalent (boe). Oil and gas investments in Brazil are projected to total \$100 billion through 2012 (Hilyard, 2009).

Europe

On the European continent, the Vilje field in the northern part of the Norwegian North Sea is estimated to hold 52 million barrels (MMbbl) of recoverable oil. Oil and gas production from the Volve field in the Norwegian North Sea has already developed reserves of 78.6 MMbbl of oil and 1.5 billion m^3 of gas, with estimated reserves of 154 MMbbl of oil and 6 billion m^3 of gas for the Alvheim field (Hilyard, 2009).

[2] Assuming gas values of U.S. \$106/thousand m^3 to U.S. \$247/thousand m^3

Australia

On the Australian continent, the Ichthys field reserves of the Australian Browse basin are estimated at 362 billion m^3 of gas and 527 MMbbl of condensate. The Turrum field in the Australian Bass Strait is estimated to hold approximately 28 billion m^3 of gas and 110 MMbbl of oil and natural gas liquids, with the Kipper field estimated to hold approximately 18 billion m^3 of recoverable gas and 30 MMbbl of condensate. Drilling and production in the Australian North West Shelf saw approval in late 2008 of a $1.8-billion (Aus.) redevelopment of the Cossack, Wanaea, Lambert, and Hermes oil fields for supporting production beyond 2020 (Hilyard, 2009).

Asia

In Asia Pacific, investments of $311 million were committed for developing natural gas fields on the deepwater Galan block off East Kalimantan in Indonesia, having the capacity to produce an average of 23 million m^3 per day. The Kambuna gas field in the Malacca Straits, off North Sumatra in Indonesia, has proved reserves estimated at 19 million boe. In addition, the Cepu block located on the borders of central Java and East Java is estimated to hold 600 MMbbl of recoverable oil and 48 billion m^3 of natural gas. Further, oil prospects in the Songkhla field in the Gulf of Thailand have been identified with potential oil in place of more than 200 MMbbl (Hilyard, 2009).

Middle East

In the Persian Gulf offshore Iran, a gas field with an estimated 312 billion m^3 in reserves was identified. Further, the Ahdab oil field in Wasit province in Iraq is estimated to contain about 955 MMbbl of recoverable oil in place (Hilyard, 2009).

As offshore oil and gas production increases worldwide, it is important to understand the environmental impacts of this particular energy source. Offshore production is quite energy intensive due to the difficulties in recovering a resource located many miles away from the coast and many thousands of meters beneath the surface of the ocean. The distance from shore increases the difficulty in getting associated gas to the market, resulting in venting and flaring of unutilized gas. Methane emissions from offshore facilities contribute significantly to total greenhouse gas emissions in the U.S.; offshore production of oil and gas makes up one-quarter of total methane emissions from the production sector and 9% of total oil and gas industry methane emissions. As one of the largest contributors of methane emissions in the oil and gas industry, offshore oil and gas production platforms can reap significant economic and environmental benefits by implementing methane emission reduction activities.

Introduction to MMS GOADS Database and the Natural Gas STAR Program

The Clean Air Act Amendments of 1990 required the Minerals Management Service (MMS) of the U.S. Department of the Interior to assess the potential impacts of air pollutant emissions from Gulf of Mexico Outer Continental Shelf (OCS) offshore facilities used for exploration, development, and production of oil, gas or sulfur. The intent was for the MMS to determine if these facilities could influence the air quality attainment status of onshore areas in Louisiana, Texas, Mississippi, Alabama, and Florida (MMS, 2007). Codes 30 CFR 250.302 through 304 outlines the air quality regulations as specified by the MMS.

The Gulf of Mexico Outer Continental Shelf Regional office of the MMS sponsored the Year 2005 Gulfwide Emission Inventory Study with the objective of developing an emissions inventory for all oil and gas production related sources in the OCS of the Gulf of Mexico, including non-platform sources. To develop this inventory, the 2005 Gulfwide Offshore Activities Data System (GOADS-2005) was created to collect monthly emissions activity data from platform sources. The pollutants covered in this inventory include greenhouse gases such as carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O). Operators reported activity data from various process unit sources including amine units, boilers/heaters/burners, diesel engines, and drilling equipment, among several others, using the GOADS software. The 2005 Gulfwide database management system then imports the activity data supplied by the platform operators, and uses emission factors (as published by the EPA, and Emission Inventory Improvement Program (EIIP) emission estimation methods) and emission estimation algorithms to determine the emissions from the platform sources.

The Natural Gas STAR Program of the Environmental Protection Agency is a voluntary program designed to encourage oil and gas companies to adopt proven, cost-effective technologies and practices that reduce methane emissions from their operations. Established in 1993, the Natural Gas STAR Program provides a framework to encourage companies to implement and document their voluntary methane emission reduction activities and has assisted with the technology transfer of innovative options to reduce methane emissions. In 2006 the Natural Gas STAR International Program was launched in support of the Methane to Markets

Partnership[3] to aid in distributing knowledge and experience in cost-effective reductions of methane emissions to oil and gas companies around the world. Through its sixteen-year collaboration with industry, the Natural Gas STAR Program has published over 80 technical documents detailing actual mitigation practices employed by oil and natural gas operators across all sectors of the industry.

Characterizing Representative Offshore Platforms from GOADS Data

The 2005 Gulfwide Emission Inventory Study estimates methane emissions of over 286 million m^3 (214,500 tons per year) from 1,585 platforms in the Gulf of Mexico OCS region. These emissions include sources such as fugitives, natural gas engines, pneumatic pumps, flashing losses, and cold vents. The emissions estimates from the GOADS-2005 report cover all platform structures in the Gulf of Mexico OCS. To enhance the relevance of the current study, a representative sample of platforms was selected for analysis, production data for these platforms was gathered, and revisions were made to take into account the significantly disruptive hurricane activity that occurred in 2005.

The first step in classifying the platforms was to map the Area and Block Number for each platform in the GOADS-2005 database to the corresponding field in Appendix A of the MMS's Field & Reserves Information Database (MMS, 2009), in which the MMS classifies all fields in the Gulf of Mexico OCS as either "oil" or "gas" (MMS, 2005). Each platform that was located above an oil field was designated as an oil platform while each platform located above a gas field was designated as a gas platform. Fields located in water depths of over 200 meters (656 feet) were classified as deepwater and all platforms associated with those fields were subsequently categorized as deep water.

Next, oil and gas production values were mapped to each platform. The GOADS-2005 database does not contain oil and gas production data, so these data were taken from the 2005 Oil and Gas Operations Report (OGOR) Part A (MMS, 2008). The hurricane season in 2005 had a major impact on offshore production operations in the Gulf of Mexico. Hurricanes Katrina and Rita were responsible for damage and shut-ins of several offshore platforms and consequently the operations and emissions in the second half of 2005 cannot be considered as typical. For the purposes of this analysis, data taken from the OGOR is limited to the months January through June to eliminate atypical operations during the 2005 hurricane season. Data from these six months has been extrapolated to develop annual estimates of production that may have occurred in the absence of the hurricane and tropical storm activity.

Once the platforms in GOADS-2005 data had been classified and production data were mapped, the data set was then filtered to develop a list of 15 platforms ranging in size from 3.5 million boe to over 40 million boe per year. The platform classification and production estimate for each of the 15 platforms is shown in Table 1. This subset of the GOADS-2005 data was selected as it brackets the approximate range of platforms currently producing deepwater oil and associated gas. The Brazilian offshore production facilities that will be analyzed as examples in this paper also fall in this range at 11 million boe and 7 million boe per year respectively.

With a representative set of deepwater oil platforms from the Gulf of Mexico collected, a source-level estimate of methane emissions from these facilities was developed to identify the major emission sources and opportunities for reductions. The calculation methodologies and activity data (adjusted for hurricane activity) from the GOADS-2005 study were used as a starting point in the development of the source-level estimate. The methane emissions estimate will be described in further detail in the next section of the paper.

[3] The Methane to Markets Partnership is an international public-private initiative that advances cost-effective, near-term methane recovery and use as a clean energy source. More information can be found at: http://www.methanetomarkets.org

Table 1 - Gulf of Mexico Deepwater Oil Production Platforms

Platform Info	Classification		Production Estimate (Adjusted for Hurricane Activity)		
Platform ID	Platform Type	Platform Depth	Oil Production (bbl)	Gas Production (m^3)	Total Production (boe)
Platform #1	Oil	Deep Water	33,719,690	1,109,771,641	40,250,832
Platform #2	Oil	Deep Water	19,359,215	721,169,410	23,603,385
Platform #3	Oil	Deep Water	12,145,724	301,581,109	13,920,566
Platform #4	Oil	Deep Water	8,045,576	426,934,968	10,558,141
Platform #5	Oil	Deep Water	5,581,326	738,016,852	9,924,645
Platform #6	Oil	Deep Water	7,821,533	60,665,994	8,178,559
Platform #7	Oil	Deep Water	5,799,154	182,953,136	6,875,856
Platform #8	Oil	Deep Water	5,298,025	163,920,632	6,262,718
Platform #9	Oil	Deep Water	5,184,926	157,254,309	6,110,387
Platform #10	Oil	Deep Water	5,095,146	139,978,490	5,918,936
Platform #11	Oil	Deep Water	4,500,232	197,163,381	5,660,563
Platform #12	Oil	Deep Water	4,793,769	124,514,923	5,526,554
Platform #13	Oil	Deep Water	3,396,684	149,344,659	4,275,596
Platform #14	Oil	Deep Water	2,669,785	240,551,214	4,085,459
Platform #15	Oil	Deep Water	2,531,803	170,798,259	3,536,972
Total			125,942,589	4,884,618,975	154,689,169

Identifying Major Methane Emission Sources from Individual Offshore Platforms

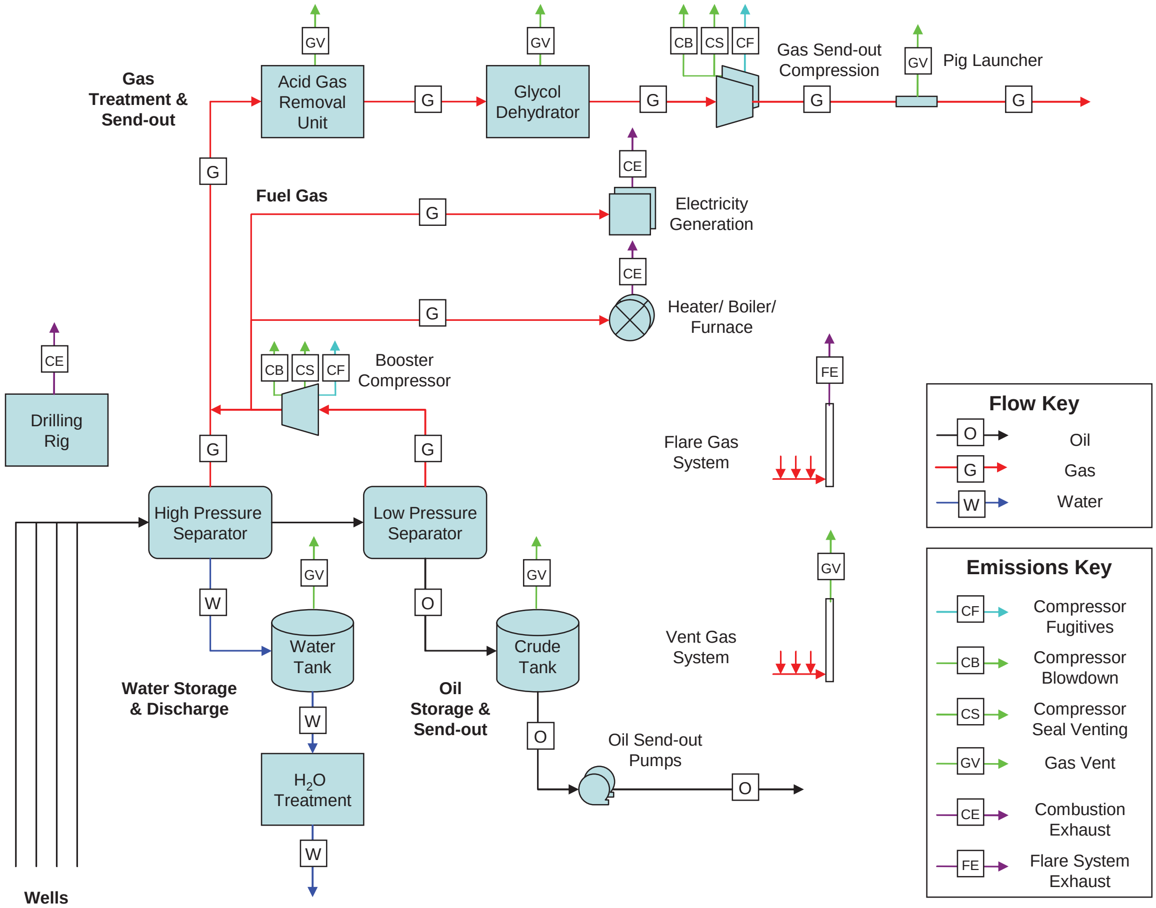
While the GOADS-2005 data is a useful basis for generally understanding major methane emissions sources, additional analysis must be done to apply these results to individual platforms. Development of a platform-level estimate of methane emissions requires understanding of the various operating units installed on the platform and the flow of oil, gas, and other process streams. The process units and emissions sources on an offshore platform are related to each other through the flow of material and energy, as shown in the flow diagram in Exhibit 1.

Sources of methane emissions on an offshore production platform can vary depending on configuration but it is very important to account for all equipment that is routinely vented to the atmosphere as well as non-routine vents from upsets or shutdowns. Common sources of routine venting include compressors, acid gas removal units, glycol dehydrators, liquid storage tanks, and pig traps. Non-routine venting can occur from nearly all pressurized equipment located on the platform during an emergency or shutdown. Routine venting emissions can be directly measured or estimated through engineering calculations or emissions factors. Non-routine vented emissions may be more difficult to characterize as they can occur without warning and vary in frequency and duration of venting. On some facilities, equipment vents can be routed through a common vent stack; it is important to know which individual equipment is manifolded into these systems when attempting to estimate methane emissions.

While venting emissions occur at specific locations on a platform, fugitive emissions occur randomly throughout the platform in components such as valves, flanges, connectors, seals, open-ended lines, and other components. Emissions estimates may be developed from a component count, by type, for all components on the platform. The total component counts can be used with population emissions factors that take into account leak frequency and average leak rates for leaking components. If a fugitive emissions inspection program is in place on the platform, direct measurements can provide a more accurate characterization of fugitive emissions.

Combustion exhaust contains small concentrations of methane due to incomplete combustion of fuel in the process unit. Like vented emissions, combustion exhaust is vented at specific locations. Common combustion equipment on offshore platforms includes gas engines, gas turbines, generators, drilling rigs, and flare stacks. It is important to document which sources of gas are routed to the flare system for combustion. This can minimize confusion over the volumes of gas that are vented versus flared in non-routine system blowdowns.

Exhibit 1 - Flow Chart of Methane Emissions Sources on Offshore Platform Facilities



According to the present analysis, the largest methane emissions sources found in the Gulf of Mexico include:

- Centrifugal compressor wet seal oil degassing: Data reported to the Methane to Markets Partnership as well as assements of processing plants in North America show that wet seal oil degassing methane emissions for a single compressor can range from zero to 2,756 thousand m^3/year (Bylin, 2009). As methane emissions from wet seal oil degassing can vary greatly between compressors, the most accurate way to characterize these emissions is through emissions detection and direct measurement of flow through the degassing vent.
- Cold vents: Methane emissions from common vent stacks that handle routine and non-routine releases of natural gas depend largely on platform configuration and the occurrence of emergencies or shutdowns during the course of the year. The example Gulf of Mexico platforms have reported annual cold vent volumes of 10 thousand m^3 (367 thousand cubic feet, Mcf) to 909 thousand m^3 (32,084 Mcf) of methane
- Reciprocating compressor rod packing emissions: Annual methane emissions from rod packing in a single reciprocating compressor can be as high as 88 thousand m^3 (3 million cubic feet, MMcf) depending on number of cylinders and operating status of the compressor (Howard, 1999)
- Storage tank venting: While storage tank venting emissions are generally well controlled with VRUs in the Gulf of Mexico, methane emissions from storage tank venting would range from 46 thousand m^3 (2 MMcf) to 818 thousand m^3 (29 MMcf) in the absence of any control technology[4]

[4] Calculated using GOADS data and Vasquez-Beggs correlation equation

Development of Source-level Methane Emissions Estimate Based on GOADS-2005 Study

The GOADS-2005 study developed a source-level methane emissions estimate for all platforms in the Gulf of Mexico OCS. The 2005-GOADS study used a variety of industry accepted calculation methodologies from sources such as the EPA's AP-42 and data from the American Petroleum Institute. The calculation methodologies used to estimate methane emissions from the sources in Table 2 are described in the GOADS-2005 study summary report while the activity data for the 15 selected platforms is shown in Appendix A.

The Natural Gas STAR Program has published information that indicates that, in some cases, there may be alternate ways to calculate methane emission volumes from select methane emission sources. The Natural Gas STAR Program works with Partners to collect data so that methane emissions can be better characterized and understood. For some sources, data from Partners suggests that some of the industry-accepted methods of estimating emissions may not accurately capture the magnitude of methane emissions. These sources include centrifugal compressor wet seal degassing vents, centrifugal compressor dry seal vents, reciprocating compressor rod packing vents, and storage tank venting during vapor recovery unit (VRU) downtime. For the purposes of this analysis, modifications were made to methane emissions calculation methodology used by the MMS to arrive at updated estimated emission volumes, referenced below as “new” or “revised.” Table 2 displays a revised estimate of total methane emissions by source for the 15 selected platforms.

Table 2 - Total Methane Emissions by Source from 15 Deepwater Oil Platforms in the Gulf of Mexico

Category	Emissions Source	Number of Platforms With Source	Count on All Platforms	CH_4 Emissions (tonnes/year)	CH_4 Emissions (m^3/year)
Venting (new)	Centrifugal compressor wet seal oil degassing	10	148	22,923	33,705,576
Venting	Cold vent	4	4	2,558	3,761,669
Venting	Glycol dehydrator	2	3	260	382,671
Venting (new)	Reciprocating compressor rod packing venting	6	26	133	195,401
Venting (revised)	Storage tank - venting	9	11	95	139,907
Venting (new)	Centrifugal compressor dry seal vent	3	17	92	135,506
Venting	Mud degassing	2	2	5	8,056
Venting	Pneumatic pumps	3	5	2	2,871
Venting	Pressure/level controllers	2	4	1	1,450
Fugitives	Fugitives – other equipment	15	19,840	1,255	1,845,549
Fugitives	Fugitives – valves	15	30,671	726	1,067,724
Fugitives	Fugitives – flanges	14	41,221	79	115,873
Fugitives	Fugitives – connectors	15	34,151	45	65,739
Fugitives	Fugitives – pumps	14	299	10	14,796
Fugitives	Fugitives – centrifugal compressor, wet seal face	6	148	8	14,264
Fugitives	Fugitives – centrifugal pack	8	125	7	10,355
Fugitives	Fugitives – open-ended lines	3	436	4	6,192
Fugitives	Fugitives – centrifugal compressor, dry seal face	3	17	1	1,857
Combustion	Natural gas engine	6	13	1,023	1,504,872
Combustion	Flare	14	47	127	186,859
Combustion	Natural gas turbine	15	70	111	163,294
Combustion	Boiler/heater/burner	5	17	4	5,900
Combustion	Diesel engine	13	116	2	3,086
Combustion	Drilling rig	5	5	0	0
Total Emissions				29,475	43,339,467

Centrifugal Compressor Wet Seals

Centrifugal compressors with wet seals have very low fugitive methane emissions at the seal-face but generally more vented emissions from an open vent connected to the unit that de-gasifies and recirculates compressor seal oil. EPA experience, combined with another assessment of four natural gas facilities (EPA, GTI, Clearstone, 2002), has identified measurements from 48 wet seal centrifugal compressors, with methane emissions totaling 14,860 thousand m^3 methane per year. The data show that seal oil degassing rates for individual compressors could range from 0 to 2,756 thousand m^3 methane per year. These findings point to the potentially large volumes of methane emissions from this source at facilities world-wide and the need to do detection and measurement to identify specific units to target for repair/retrofit when instituting a methane emissions reduction project.

Fugitive emissions calculated in the GOADS-2005 study represent a reasonable estimate for the seal-face emissions, but a separate line item for centrifugal compressor wet seal oil degassing venting has been added in this analysis. Given the variability of wet seal oil degassing emissions, an example emissions rate[5] was selected from the Natural Gas STAR Program technical document "Replacing Wet Seals with Dry Seals in Centrifugal Compressors" and adapted to fit a typical offshore compressor in the Gulf of Mexico. The example calculation in the technical document shows a wet seal oil degassing vent of 1,488 m^3/year (100 cubic feet per minute) of gas or 911 m^3/year of methane at a methane content of 61.2% by volume (EPA, 2006b). The example compressor is a single-stage, beam-type compressor with two seals that is typical of onshore natural gas transmission compressors. To adapt this value to fit an offshore centrifugal compressor, the methane emissions rate was doubled to correspond with a two-stage, beam-type compressor that has 4 seals resulting in 1,822 m^3/year of methane. Centrifugal compressor wet seals (labeled as FCWEg, FCWEo, and FCWEow in the GOADS-2005 study) were treated as follows:

- To calculate wet seal oil degassing emissions the following assumptions were employed:
  - Centrifugal compressors on Gulf of Mexico platforms are two-stage beam-type compressors that have 4 wet-seals each
  - For platforms which report operating gas turbines, but do not specify the number of centrifugal compressors and seal type it was assumed that 50% of the reported turbines powered centrifugal compressors with wet seals. These compressors were also assumed to be two-stage with two wet seals per stage (4 wet seal per compressor)
  - Methane emissions from wet seal oil degassing venting were estimated to be 1,822 m^3/year of methane

$$148 \text{ wet seals} \times \frac{1 \text{ compressor}}{4 \text{ wet seals}} \times 50\% \text{ operating} \times \frac{1{,}822{,}000 \ \text{m}^3 \ \text{CH}_4}{\text{year} \cdot \text{compressor}} = 33 \text{ million m}^3 \ \text{CH}_4$$

Centrifugal Compressor Dry Seals

Centrifugal compressor dry seals are an alternative seal technology to wet seals. Dry seals do not use seal oil and therefore do not have any seal oil degassing emissions. Fugitive emissions from the seal face are still present and have been reported as 0.8 m^3/hour/seal (0.5 cubic feet/min/seal) to 5.1 m^3/hour/seal (3 cubic feet/min/seal). Centrifugal compressor dry seals (labeled as FCDRg, FCDRo, and FCDRow in the GOADS-2005 study) were treated as follows:

- To calculate dry seal emissions the following assumptions were employed:
  - Of the dry seals reported by operators, it was assumed that 50% of these seals (rounded to the nearest whole number) were in operation year round while the rest were in stand-by and therefore have no emissions
  - Dry seal emissions can be estimated as 3.0 m^3/hour/seal (1.75 cubic feet/min/seal), the midpoint of the leak range reported in the Natural Gas STAR document "Replacing Wet Seals with Dry Seals in Centrifugal Compressors" (EPA, 2006b)
  - Methane content of the wet seal degassing vent is assumed to be 61.2% CH_4[6]

$$17 \text{ dry seals} \times 50\% \text{ operating} \times \frac{3.0 \,\text{m}^3 \ \text{gas}}{\textit{hour} \cdot \text{seal}} \times \frac{8{,}760 \text{ hours}}{\text{year}} \times \frac{0.612 \,\text{m}^3 \ \text{CH}_4}{\text{m}^3 \ \text{gas}} = 135 \ \text{thousand m}^3 \ \text{CH}_4$$

Reciprocating Compressor Rod Packing

Reciprocating compressors are sealed through a series of rings within a packing to prevent leakage of natural gas around the rod. Emissions from reciprocating rod packing are not specifically calculated in the GOADS-2005 study and therefore have been treated as follows:

- It is assumed that 50% of gas engines power reciprocating compressors and that reciprocating compressors on deepwater oil platforms have 4 cylinders each
- 50% of reciprocating compressors (rounded to the nearest whole number) were assumed to be operating while the remaining reciprocating compressors were assumed to be idle and depressurized

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[5] The emissions rate used for this analysis is a mid-range emissions rate for wet seal oil degassing as shown in the Natural Gas STAR Lessons Learned document "Replacing Wet Seals with Dry Seals in Centrifugal Compressors"

[6] GOADS-2005 study default methane content for associated gas

- Packing vent emissions are 2.8 m^3/hour/packing (99 cubic feet/hour/packing) for operating compressors. This emissions rate for operating rod packing was developed by the Pipeline Research Council International (Howard, 1999).
- Depressurized reciprocating compressors do not have any associated rod packing emissions. Leaking block valves may contribute to fugitive emissions through the compressor blowdown vent when depressurized.

$$13 \text{ gas engines} \times 50\% \text{ powering reciprocating compressors} \times \frac{4 \text{ cylinders}}{\text{reciprocating compressor}} = 26 \text{ rod packings}$$

$$26 \text{ rod packings} \times 50\% \text{ operating} \times \frac{2.8 \text{ m}^3 \text{ gas}}{\text{hour} \cdot \text{packing}} \times \frac{8{,}760 \text{ hours}}{\text{year}} \times \frac{0.612 \text{ m}^3 \text{ CH}_4}{\text{m}^3 \text{ gas}} = 195 \text{ thousand m}^3 \text{ CH}_4$$

Fugitive Emissions from Platform Components

Fugitive emissions occur randomly from various components installed on an offshore platform and evaluating total methane emissions from randomly occurring leaks in different types of components can be difficult. The most common method for estimating fugitive methane emissions is to use a population emissions factor that can be applied to the count of a component on a platform-wide basis. These population emissions factors are simple to use but do not necessarily help to identify where emissions are occurring on an offshore platform. The GOADS-2005 study uses population emissions factors to characterize fugitives in Gulf of Mexico platforms and activity data is collected for valves, flanges, connectors, pumps, compressor seals, open-ended lines, and other components. The GOADS-2005 study denotes that the “other components” emissions factor includes compressor seals, diaphragms, drains, dump arms, hatches, instruments, meters, pressure relief valves, polished rods, and vents. This one source covers a wide variety of component types and uses a single population emissions factor to estimate fugitive emissions from all component types. It is difficult to determine whether this emissions factor can accurately estimate emissions from these components.

Natural Gas STAR Partners have found that components that contribute significant volumes of fugitive emissions include valves, connectors, compressor seals, and open-ended lines. A 2002 study undertaken by Clearstone Engineering shows that over half of total fugitive emissions in natural gas processing plants were emitted from the top ten largest leak sources (EPA, GTI, Clearstone, 2002). From an emissions reduction perspective, it makes the most sense to target those top leak sources for repair. Using population leak factors to estimate fugitive emissions, however, will not lend any insight into where leaks are occurring. Screening and direct measurement of fugitive emissions on an offshore platform is the ideal method for quantifying methane emissions from platform components as this information can reveal exactly which components are leaking and to what extent. For the purposes of this analysis, it is assumed that the population emissions factors from the GOADS-2005 study reasonably represents total fugitive emissions, but additional screening and direct measurement would be needed to pinpoint the major emitters.

Storage Tank Venting

It is important to note that storage tank venting emissions were estimated by the MMS to be zero for the 15 selected platforms as each one of these facilities reported having an existing vapor recovery system to capture flashing, working, and standing losses from the storage tanks. Vapor recovery systems are common for deepwater oil platforms in the Gulf of Mexico, but may be less so in offshore production facilities worldwide. Emissions from storage tank venting have been revised from the MMS estimate to reflect VRU downtime. All rotating equipment in service must be taken offline for routine maintenance. In the case of vapor recovery units, it is unlikely that a redundant VRU is installed on Gulf of Mexico platforms as they are not necessary to support primary production operations. Therefore, when the VRU is taken offline for maintenance it is assumed that tank vapors are vented to the atmosphere during the maintenance activities. Methane emissions from storage tank venting during VRU maintenance have been calculated using the Vasquez-Beggs correlation for flashing losses as detailed in the GOADS-2005 study and assuming that the VRU has a 95% operating factor (venting for the remaining 5% of the year). The parameters used in the Vasquez-Beggs estimate of tank venting are as follows:

- Crude Gravity: 37º API (GOADS-2005 Default)
- Separator Pressure: 10 psig
- Separator Temperature: 70º F (21.1º C)
- Gas Specific Gravity: 0.93 (GOADS-2005 Default)
- Methane content of flash gas: 27.4% by volume
- VRU Downtime: 5% annually

Offshore production facilities that do not operate vapor recovery units can estimate storage tank venting emissions by applying parameters specific to their operation in the Vasquez-Beggs correlation equation. Without a vapor recovery system in operation it can be assumed that 100% of flashing emissions are vented to the atmosphere.

Identifying and Prioritizing Mitigation Technologies and Practices

There are a number of technologies and practices available for an emissions reduction program that can be applied to offshore platforms. The Natural Gas STAR Program has collected a library of methane emissions mitigation options that have been reported by oil and natural gas operators in the U.S. as well as internationally[7]. Table 3 identifies specific technologies and practices that can target and reduce emissions from offshore production facilities.

Table 3 – Available Technologies and Practices to Target Offshore Emissions Sources

Category	Emissions Source	Technologies and Practices for Reducing Methane Emissions
Venting	Centrifugal compressor wet seal oil degassing	• Replace centrifugal compressor wet seals with dry seals
Venting	Cold vent	• Route individual vented emissions sources to vapor recovery unit (including pig launcher venting) • Route routine compressor blowdowns to fuel gas system
Venting	Reciprocating compressor rod packing vent	• Economic replacement of rod packing
Venting	Glycol dehydrator	• Route non-condensable gas from condenser vent to vapor recovery unit
Venting	Storage tank venting	• Install vapor recovery unit, Scrubber dump valve repair
Venting	Mud degassing	• Route mud degassing vent to vapor recovery unit
Venting	Pneumatic pumps	• Replace natural gas pneumatic pumps with instrument air
Venting	Pressure/level controllers	• Replace high bleed pneumatic devices with low bleed devices • Install instrument air
Fugitives	Fugitives – other equipment	• Directed inspection and maintenance program[8]
Fugitives	Fugitives – valves	
Fugitives	Fugitives – flanges	
Fugitives	Fugitives – connectors	
Fugitives	Fugitives – pumps	
Fugitives	Fugitives – centrifugal compressor, wet seal face	
Fugitives	Fugitives – centrifugal pack	
Fugitives	Fugitives – open-ended lines	
Fugitives	Fugitives – centrifugal compressor, dry seal face	

The mitigation options identified in Table 3 target major sources of methane emissions from the selected Gulf of Mexico platforms. In general the most effective methane emissions reduction options target fugitive and vented emissions sources. Methane emissions from natural gas combustion are difficult to target and reducing these emissions requires reducing the amount of fuel consumed in the combustion device. In some cases, an improvement in efficiency can reduce fuel requirements but these improvements would need to be very significant to impact methane emissions. Detailed descriptions of these emissions mitigation options can be found in Appendix B.

How to Select Potential Mitigation Options

Mitigation options should be evaluated according to an analysis of the major emission sources from a given platform as well as the cost-effectiveness of each mitigation option. The major emissions sources on an individual platform may be different from those listed above. Table 2 on page 8 includes the number of sample platforms that contain each methane emissions source as well

[7] Many of the most commonly reported and effective technologies and practices have been documented as Lessons Learned studies and Partner Reported Opportunities (PRO) fact sheets which are available at: http://www.epa.gov/gasstar/tools/recommended.html
[8] Fugitive emissions from the thousands of components which are present on offshore production facilities can be targeted for reduction by a general program of directed inspection and maintenance (DI&M). In such a program, components would be efficiently screened for leaks using infrared detection equipment, any leaks detected would be quantified, and where it is cost-effective leaking components would be fixed or replaced.

as the total count of the source on all platforms. This table illustrates the fact that even between platforms with similar general characteristics (deepwater, oil with associated gas production in the range of 3 million – 40 million boe per year) there can be significant differences in the processing equipment installed on each platform. To estimate methane emissions from a given platform, an operator can do the following:

- Determine methane emissions sources on the platform
    - The emissions source list from the GOADS-2005 study can be used as a starting point
    - Review the process flow diagram of the platform for emissions sources that are not covered by GOADS-2005
- Decide upon methane emissions calculation methodology for sources on the platform
    - Emissions estimates can be arrived at through direct measurement, engineering calculations, or application of emissions factors
    - The GOADS-2005 study presents calculation methodologies for many common sources offshore and can be used as a starting point; additional calculation methodologies used to revise methane emissions estimates from the GOADS-2005 study are discussed in this paper (MMS, 2007)
- Collect activity data and supporting measurement necessary for the defined calculation methodologies
    - Collecting gas composition analyses in different process streams will aid in determining methane emissions as the methane content of associated natural gas can change at various points in the process flow
- Calculate methane emissions estimates for each source using the collected activity data and following the chosen calculation methodologies
- Review calculated emissions for gaps or errors

Mitigation options that target the largest sources of methane emissions will, in general, result in the greatest volumes of emissions reductions. However, it is also important to review the operational considerations and cost-effectiveness of each mitigation option to optimize the mix of reductions selected for implementation. There are a number of technologies and practices available for an emissions reduction program that can be applied to offshore platforms. The Natural Gas STAR Program has collected a library of methane emissions mitigation options that have been reported by oil and natural gas operators in the U.S. as well as internationally. Mitigation options on the EPA's website are organized in terms of process unit to which they are applied; general categories such as compressors/engines, dehydrators, pneumatics/controls, pipelines, tanks, valves, and others. Using a detailed source-level estimate of methane emissions on an offshore platform, the library of mitigation technologies can be narrowed to include only those options which target the major methane emissions sources on the platform.

The Natural Gas STAR technical documents can provide additional background information to help determine whether these options would be technically feasible for application offshore. In some cases, additional equipment must be available on the platform so that gas can be captured and utilized rather than emitted to the atmosphere. A careful study of Natural Gas STAR technical documents will point out any prerequisites and help to eliminate options that may not be suitable on a particular platform. After identifying the pool of mitigation options that are available to reduce methane emissions and eliminating any options that are not technically feasible, the next step is to collect the costs and savings associated with implementing each mitigation option.

Cost Estimates[9]

The Natural Gas STAR Program technical documents report ranges of costs and savings for these emissions mitigation options, but they are generally applicable to onshore installations. Costs for applying the same reduction technologies/practices offshore can be significantly higher than an onshore application. General factors that contribute to higher costs offshore include:

- Capital costs can be inflated as the equipment may need to be more robust to tolerate marine and harsh weather conditions or reduced in size to conserve limited deck space.
- Installation costs can be much higher due to the transport of people and equipment offshore, lifting the equipment up to the platform deck, and moving existing equipment to accommodate new installations.
    - A derrick barge for lifting heavy equipment of up to 45,000 kg (100,000 lb) can cost up to $70,0000 per day
    - Smaller modular cranes can lift lighter equipment onto a platform at a cost of $5,000 per day
- Operating and maintenance costs are inflated due to transportation of maintenance materials and personnel offshore and more frequent maintenance requirements in an adverse operating environment.
    - In the Gulf of Mexico, labor rates for operators offshore are generally 30% higher than those of onshore operators

[9] These scaling factors are based off of rule-of-thumb estimates of onshore costs versus offshore costs from Natural Gas STAR Partners and offshore service providers who work with Natural Gas STAR Partners.

For the purposes of this analysis, the following inflation factors were implemented to translate reported onshore costs into projected costs for the same practices offshore:

- Capital cost inflation: 3 x onshore capital costs
- Installation costs (general): 3 x onshore installation costs
- Operating and maintenance (O&M) costs: 1.3 x onshore O&M costs

A breakdown of onshore versus offshore costs for the mitigation options show in Table 3 is available in Appendix C.

Savings Estimates

To estimate emissions reductions, each mitigation option must be examined individually. Some options such as installing instrument air to power pneumatic devices can eliminate 100% of methane emissions as the motive fluid is switched from natural gas to air. Other options such as Directed Inspection and Maintenance (DI&M) have been well documented and have been reported to reduce between 60 – 80% of total fugitive methane emissions when properly implemented. Each mitigation option considered in this analysis was assigned a reduction efficiency (shown in Appendix C) based on reported reductions to the Natural Gas STAR Program. These reduction efficiencies are applied to the methane emissions from the source targeted by the mitigation options to determine the total achievable methane emissions reductions. Actual measurement of natural gas savings after implementing mitigation options can be achieved by installing meters to measure gas flow of recovered vent streams or through "before and after" direct measurement of fugitive emissions from a repaired component. Actual savings from each installed mitigation option should be recorded to track effectiveness of the project.

Marginal Abatement Cost Development

After identifying the largest and most prevalent methane emissions sources on typical deepwater oil production platforms, and matching these sources to potential technologies and practices that can reduce methane emissions, further analysis must be conducted to maximize emissions reductions in a cost-effective manner. Large sources of methane emissions such as compressor seals and storage tank venting will generally require complicated and expensive mitigation options to reduce these emissions. While the reductions achieved may be large in magnitude, the cost of reducing these emissions may also be large. The key to evaluating the various mitigation options available is to determine which options will achieve emissions reductions at the lowest cost per unit over the lifetime of the project.

A marginal abatement cost (MAC) curve is a graphical tool that can be used to prioritize which mitigation options should be implemented and estimate the level of methane emissions reductions that can be achieved. Each mitigation option is ranked according to the break-even cost per unit of natural gas saved and plotted to show what level of cumulative reductions may be achieved and at what price. The break-even price of natural gas savings is the price at which the discounted costs and savings are equal over the project time horizon. This break-even price must be calculated for each mitigation option that is under consideration for the platform. Each option should then be organized by ascending break-even gas price and can be plotted in a step function where the X-axis represents the total volume of methane emissions reductions achievable and the Y-axis represents the price of natural gas at which that mitigation option breaks even.

For the purposes of this paper, the following are the parameters used in the discounted cash flow analysis:

1. Project time horizon for each mitigation option: 5 years
2. Discount rate of 10%
3. Salvage Cost (if any, for replacement of existing equipment with newer technologies)
4. Capital Cost for the new equipment as applicable for an offshore installation
5. Installation cost for the equipment as applicable for an offshore platform
6. Operating and maintenance (O&M) cost differentials for the mitigation option as applicable for an offshore platform, taking into account net changes in overall O&M costs when an older technology is replaced. These costs may increase or decrease with the application of new mitigation options.
7. Methane emissions reductions and the total volume of natural gas that is saved through the implementation of each mitigation option.

In the following section of the paper, mitigation options for three example offshore production facilities were evaluated, and two were plotted on a MAC curve. A range of natural gas prices were also plotted on the MAC curve to show which mitigation options are cost-effective based on natural gas prices alone. All mitigation options that fall below a certain price of natural gas will pay back, with the value of the natural gas saved, all costs prior to the end of the 5 year time horizon. Mitigation options that fall above the chosen price of natural gas should not be dismissed however. As gas prices fluctuate, additional mitigation options may be come cost-effective in the future so it is important to continually evaluate which options can be implemented. Additionally, these options may be candidates for carbon credit projects where the GHG reductions achieved (in terms of carbon equivalent) may be sold to supplement the revenue achieved from the natural gas savings alone. When evaluating the feasibility of carbon credits to supplement revenue from natural gas savings it is important to consider the costs of documenting such a project. Carbon credit registries require project documentation, validation, and verification before credits are issued. The cost of bringing carbon credits to market can be as much as $100,000 and should be factored into MAC analysis along with actual capital, installation and O&M costs.

Application of Findings to Offshore Platforms

To further examine these tools, three offshore production facilities were selected as examples for this analysis; two floating production storage and offloading (FPSO) facilities from Brazil as well as a theoretical composite Gulf of Mexico platform which was developed from the 15 deepwater oil platforms shown in Table 1. The total methane emissions from these example facilities were calculated using a modified estimate applying the suggested revisions to the GOADS-2005 study as detailed in previous sections of the paper. Table 4 below shows both methane emissions estimates as well a total production from each example platform or FPSO.

Table 4 – Example Platform Methane Emissions Estimates

Platform Info		Classification		GHG Emissions Estimate		Production Estimate		
Area and Block	Platform ID	Platform Type	Platform Depth	CH_4 Emissions (tonnes)	CH_4 Emissions (m^3)	Oil Production (bbl)	Gas Production (m^3)	Total Production (boe)
GoM	Ex. Platform	Oil	Deep Water	4,595	6,757,215	22,959,398	691,782,990	27,030,625
Brazil	FPSO #1	Oil	Deep Water	624	918,176	10,541,930	162,287,760	11,497,013
Brazil	FPSO #2	Oil	Shallow Water	448	659,455	6,657,753	15,220,500	6,747,328

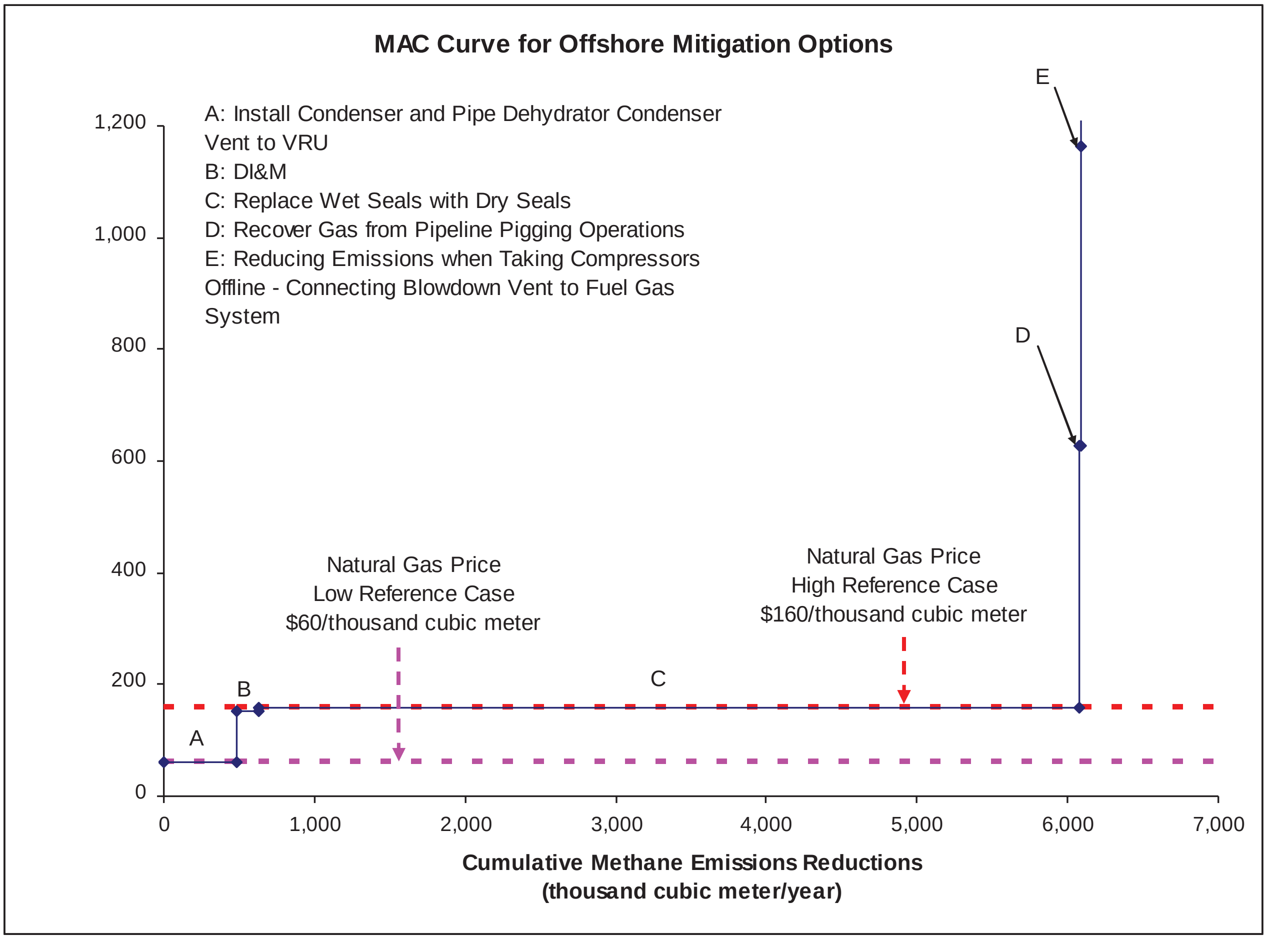
Emissions from fugitive and vented sources again dominate the total volume of methane emissions from these example facilities. A breakdown of methane emissions by source level for each example platform is available in Appendix D. Upon identification of major sources of methane emissions, the next step is to identify reduction options that specifically target the major sources.

Gulf of Mexico – Composite Platform

This theoretical platform is a composite of the activity data for the 15 selected Gulf of Mexico platforms in Table 1. The emissions from this composite were estimated from the most commonly occurring equipment on deepwater oil production platforms in the U.S. to demonstrate specific mitigation opportunities. The composite platform was configured to produce 63 thousand barrels of oil per day along with 2 million m^3 of natural gas per day. There is a vapor recovery system to capture storage tank venting emissions. Vents from the dehydrator, wet seal degassing, compressor blowdown, and pig launcher vents all are released to the atmosphere. The platform has a flare gas system for handling well venting and upsets. Centrifugal compressors with wet seals are used for gas compression. There are a small number of gas pneumatic controllers and pumps on board. The platform also operates a drilling rig with synthetic based mud degassing.

The main methane emissions sources identified on this platform are methane emissions from centrifugal compressor wet seal oil degassing, gas emitted from the cold vent, and venting from the glycol dehydrator. For those mitigation technologies that were identified as viable options, specific project costs and methane emissions savings that correspond with the given level of emissions on the platform were developed. These parameters were assembled to develop a marginal abatement curve which can aid in the decision making process to determine the ideal options for reducing methane emissions. Exhibit 2 represents the MAC generated from the application of viable reduction options, as selected from Table 3 and applied to the theoretical platform from the Gulf of Mexico.

Exhibit 2 – Gulf of Mexico Example Platform Marginal Abatement Cost Curve



In this example, the most cost effective methane emissions reduction option is to recover methane from the glycol dehydrator vent using the existing vapor recovery system, followed by the implementation of a directed inspection and maintenance program. As shown in Natural Gas STAR technical documents, the conversion from wet seals to dry seals will result in substantial methane emissions reductions; the majority of methane emissions reductions in this theoretical Gulf of Mexico example were achieved through seal conversion. Installing dry seals on this example platform is an expensive project with one-time costs estimated to be $9.7 million for replacing all 20 wet seals. This investment can be repaid within the 5 year time horizon for the project due to O&M cost savings estimated to be $1.1 million per year as well as the large volume of natural gas that is no longer lost from the wet seal oil degassing vent. The significant O&M cost savings derive primarily from reduced downtime related to seal oil system problems, power savings from elimination of seal oil pump and cooling fans, and increased flow efficiency in pipelines[10]. At a gas price of $160/thousand m^3 ($4.50/Mcf), a total of 6.1 million m^3 of methane emissions can be recovered from this platform, this means that over 85% of total estimated methane emissions can be recovered at recent U.S. wellhead natural gas prices (EIA, 2009b).

Brazil – FPSO #1

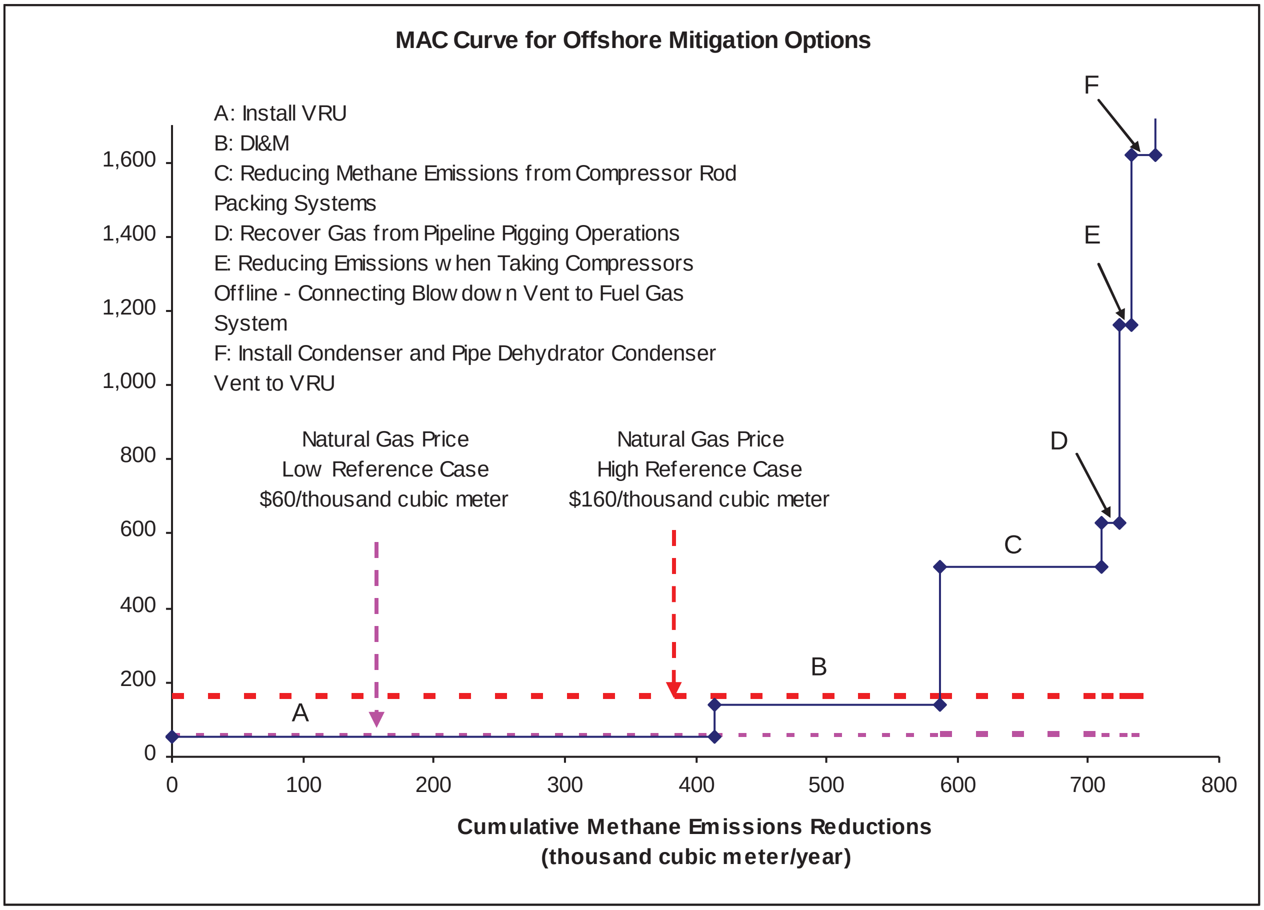
This FPSO has several sub-sea oil and associated gas producing wells as well as gas-only producing wells. Crude oil is produced at a rate of nearly 30 thousand barrels per day with a gravity of 29º API along with 450 thousand m^3 of daily natural gas production. Crude oil is stored onboard in atmospheric tanks that are vented to the atmosphere. Exhaust from an inert gas generator is used to disperse hydrocarbons from the crude storage tanks. Crude oil is offloaded from the FPSO once every four to six weeks.

[10] Operators of wet seal compressors have found that seal oil can mix with the compressed gas and be sent with the gas into the pipeline, thus building up fluid in the pipeline and reducing pipeline efficiency. Converting to dry seals removes the potential for seal oil to be released into the pipeline.

Natural gas is dehydrated in a glycol unit with an electric pump and no flash tank separator and then sent out for sale. Gas turbine generators produce electricity to run the 6 reciprocating compressors and 6 oil send-out pumps.

The main methane emissions sources identified on this platform are methane emissions from reciprocating compressor rod packing, crude oil storage tank venting, and fugitive emissions from valves and other equipment. As shown in Exhibit 3, the majority of potential emissions reductions are due to the installation of a 40 kW (50 hp) vapor recovery system to capture the estimated 4,000 m^3 of vapors that are estimated to be flashing off of the crude and venting to the atmosphere. Other significant emissions reductions are from implementing a DI&M program on the FPSO as well as economic replacement of rod packing on the six reciprocating compressors. In this example, 45% of total methane emissions from the platform can be recovered at a typical Brazilian natural gas price (not including transportation) of \$60/thousand m^3 (\$1.70/Mcf). Exhibit 3 represents the MAC generated from the application of viable reduction options selected from Table 3, as applied to FPSO #1.

Exhibit 3 – Brazil FPSO #1 Marginal Abatement Cost Curve



Brazil – FPSO #2

The configuration of this FPSO is quite different than the first example. This FPSO is an oil and associated gas production facility in shallow water. Crude oil is produced at a rate of 18 thousand barrels per day with 42 thousand m^3 of daily associated gas production. Crude oil is stored onboard with no vapor recovery system. No infrastructure exists for delivering the produced gas for sale so it is used as fuel with the excess associated gas flared. One reciprocating compressor is located on the FPSO for boosting gas to fuel pressure and the gas is not dehydrated prior to combustion. Instrument air is used for control devices.

Reducing methane emissions from this FPSO presents different challenges than in the other example analyses. Some produced natural gas is consumed onboard to satisfy fuel requirements of the oil production operations. The excess gas not consumed cannot be delivered to markets onshore as there is not a sufficient volume to support the installation of a sub sea pipeline. In this situation, the excess produced gas has no outlet and is flared. It is still possible to achieve emissions reductions of fugitive and vented methane emissions, but these projects cannot be paid back through increased sales as the gas essentially has no value in this situation. As such, alternative cost recovery mechanisms must be explored.

One opportunity for recovering value from the stranded gas is to recover natural gas liquids from the unprocessed associated gas. Compared to non-associated natural gas, associated gas that is produced with crude oil has a larger fraction of heavier hydrocarbons that can be recovered and blended back into the crude oil. The recovery of natural gas liquids would require the installation of processing equipment, but the cost of this installation could be offset by revenue from increased crude oil sales.

One method of recovering gas liquids from the associated gas is to boost the gas to high pressure, cool the high pressure stream in an air cooler, then expand the high pressure gas to lower the temperature to sub-ambient and condense the heavy hydrocarbons. This process requires additional equipment including a booster compressor and a fin-fan heat exchanger which are not currently available on the FPSO. The addition of a vapor recovery unit to capture storage tank vapors and put them into the gas liquid recovery system would increase the volume of liquids recovered as well as reduce direct venting of methane.

Implementing a gas liquids recovery project on this FPSO would result in the changes of gas flow as shown in Table 5. In this example project, it was assumed that all pentane+ hydrocarbons in the associated gas and a portion of the butanes would be condensed when expanded from 600 psig to fuel gas pressure (~200 psig) and blended back into the crude. The reduced heat content of the lean gas as well as additional fuel requirements for the booster compressor, air cooler fan, and vapor recovery unit result in increased fuel consumption and decreased gas flaring. Total gas liquids recovered from the rich associated gas amount to 110 bbl per day or over 40,000 bbl per year of additional volume to blend in with the produced crude oil.

Table 5 – Gas Liquid Recovery Project – Annual Associated Gas Flows

Current FPSO Operation	Gas Flow (m^3)	CH_4 Emissions (m^3)
Storage Tank Venting (crude oil flash gas only)	1,004,848	275,328
Associated Gas Flaring	4,015,000	45,856
Associated Gas Fuel Consumption	10,950,000	-
Total	**15,969,848**	**321,184**

Gas Liquid Recovery Scenario	Gas Flow (m^3)	CH_4 Emissions (m^3)
Storage Tank Venting (crude oil flash gas only)	50,242	13,766
Associated Gas Flaring	1,949,190	23,728
Associated Gas Fuel Consumption	12,521,203	-
Total	**14,520,636**	**37,494**

Methane Emissions Reductions	**283,690**	**m^3**
Total Liquids Recovered	**40,167**	**bbl**

The liquid recovery project eliminates 95% of storage tank venting through the installation of the vapor recovery unit and is the primary source of methane emissions reductions. Additional methane emissions reductions are achieved through the minimization of flaring on the FPSO. Flaring has a 98% hydrocarbon combustion efficiency which results in 2% of methane in the flared gas being emitted in the exhaust. In this scenario, flared gas is consumed as fuel in gas engines which, depending on the engine, can have a near 100% combustion efficiency. The shift in volume between flaring and combustion in a gas engine accounts for 8% of total methane emissions reductions from this project. Over 40% of total methane emissions from the FPSO (as shown in Table 4) can be reduced through the implementation of this liquids recovery project.

A rough cost estimate for implementing this project was developed from basic sizing assumptions as well as previous feasibility studies of natural gas liquid recovery projects undertaken by Natural Gas STAR International. The following assumptions were used to estimate the total project costs shown in Table 6:

- Vapor recovery unit capacity: 200 Mcf per day
  - Driver: electric power

- Booster compressor size: 200 hp
    - Driver: gas engine
- Air cooler: 1,600 ft^2 heat transfer area
- Onshore-to-offshore equipment capital cost multiplier is assumed to be 5x to account for increased equipment cost in a sour gas environment

Table 6 – Brazilian FPSO #2 - Estimated Emissions Reduction Project Costs

Offshore Gas Liquids Recovery Project Costs	
Capital Cost	$3,243,130
Installation Cost	$1,437,160
O&M Cost	$108,281
Break-even liquids price	$34/bbl

The break-even liquids price of $34 per barrel of liquid was calculated using a 10% discount rate over a 5 year project lifetime. As these liquids are blended into the crude and sold at crude oil prices, this project would prove cost-effective at current crude prices of $70/bbl. This gas liquids recovery project offers favorable economics despite the fact that the stranded associated gas has no value and is also able to reduce nearly half of methane emissions from the FPSO.

Summary Statement and Conclusions

The GOADS-2005 study was used to select a group of representative deepwater oil and associated gas production platforms in the Gulf of Mexico and estimate methane emissions from those facilities. The source-level methane emissions estimate revealed that the largest sources of methane emissions from platforms in the Gulf of Mexico include centrifugal compressor wet seal oil degassing venting, natural gas released from cold vents, methane emissions from reciprocating compressor rod packing, and venting from glycol dehydrators. Fugitive leaks from components on a typical offshore platform are also a significant source of emissions, and methane emissions from crude oil storage tanks may also be a significant source if vented gas is not captured with vapor recovery units. Technologies and practices to reduce methane emissions on offshore platforms were selected and analyzed using marginal abatement cost curves to determine which options are most cost-effective for reducing methane emissions.

For a composite (hypothetical) Gulf of Mexico platform, over 85% of methane emissions could be reduced at or below typical U.S. wellhead natural gas prices by recovering methane from the glycol dehydrator vent using the existing vapor recovery unit, undertaking directed inspection and maintenance of fugitive emissions and replacing wet seals with dry seals on centrifugal compressors. Replacing wet seals with dry seals on centrifugal compressors was the largest source of methane emissions reductions on the Gulf of Mexico example platform. Approximately 45% of methane emissions could be reduced from the Brazil FPSO #1 example at typical Brazilian natural gas prices (without transportation costs). The major sources of emissions on this FPSO were storage tank venting and equipment leaks, which can be reduced by installing a vapor recovery unit and implementing a directed inspection and maintenance program, respectively. The Brazil FPSO #2 example is unique in that the natural gas produced onboard is stranded and has no value beyond that of fuel to power the oil production and offloading operations. It was found that recovering the gas vented from the oil storage tanks also recovered valuable liquids, which provide economic benefits for reducing methane emissions. This process involved installing a VRU to capture vented gas as well as a booster compressor and air cooler. A basic cost analysis of this project revealed that it is possible to payback the investment for this methane emissions reduction project through gas liquids sales alone.

Following the analysis laid out in this paper, a strategy to minimize methane emissions from offshore platform includes 1) estimating source-level methane emissions on the platform, 2) identifying methane emissions reductions technologies which target the largest emissions sources, 3) researching costs and savings potential for the mitigation options that target major methane emissions sources, and 4) developing marginal abatement cost curves to determine what level of methane emissions reduction can be achieved cost effectively. The examples shown in this analysis achieved methane emissions reductions between 40% and 85% cost-effectively, demonstrating that economic methane emission reduction projects can be successfully implemented at offshore production facilities despite the increased costs and unique challenges of offshore operations. Offshore production platform operators may therefore benefit both the environment as well as their own economic bottom line by evaluating their own operations and implementing methane emission reduction projects when cost-effective.

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Appendix A – Gulf of Mexico Platform Activity Factors

		Platform														
Equipment	Activity Units	AC025 183-1	EB643 822-1	EW873 24129-1	GB426 24080-1	GB668 1288-1	GB783 1218-1	GC205 67-1	GC237 735-1	GC338 1290-1	GC782 1215-1	MC127 876-1	MC773 1175-1	MC807 24199-1	MC809 70004-1	VK826 24235-1
centrifugal pack, natural gas stream	component count			12			4			8	15	11	6			
centrifugal pack, oil stream	component count			6			4				12	6	2			
centrifugal pack, oil/water stream	component count		12				4				11	4				8
centrifugal, dry seal, natural gas stream	component count									8						
centrifugal, dry seal, oil/water stream	component count										1					8
centrifugal, wet seal, natural gas stream	component count	20		8	24			13	8			10	8	36	20	
centrifugal, wet seal, oil/water stream	component count										1					
connectors, natural gas stream	component count	696	1,107	697	1,269		409	1,133	737	3,439	647	1,000	628	1,396	928	1,518
connectors, oil stream	component count	1,092		742	476	9,194	334		160	1,832	362	561	461	591	528	
connectors, oil/water stream	component count	296		328	182		152				216	335	286	250	169	
flanges, natural gas stream	component count	1,451	2,354	1,827	2,019		822	1,641	1,258	811	1,262	1,951	1,178	2,096	1,760	3,303
flanges, oil stream	component count	1,655		2,370	1,318		865		359	432	727	1,126	977	1,240	1,395	
flanges, oil/water stream	component count	564		1,198	370		397				424	659	588	523	301	
open-ended lines, natural gas stream	component count									98						
open-ended lines, oil stream	component count					285				52						
open-ended lines, oil/water stream	component count										1					
other equipment, natural gas stream	component count	794		757	1,043		368	780	519	717	526	809	561	1,160	860	
other equipment, oil stream	component count	837		1,013	585	228	428		191	713	359	558	381	535	529	
other equipment, oil/water stream	component count	202	993	431	123		145				152	233	239	177	104	1,790
pumps, natural gas stream	component count	19	20					71	2	5	9	14				32
pumps, oil stream	component count			17	13		11		6		11	16	5	14	7	
pumps, oil/water stream	component count	4		3	1		2				5	7	3	1	1	
reciprocating compressor rod packing	component count		4		4	4	4	4								6
valves, natural gas stream	component count	978	1,596	1,205	1,545		592	1,332	924	811	843	1,303	875	1,627	1,246	2,241
valves, oil stream	component count	1,277		1,413	851	1,713	566		241	432	296	767	716	894	913	
valves, oil/water stream	component count	415		732	239		287				303	471	449	373	205	

		Platform												
		AC025	EB643	EW873	GB426	GB668	GB783	GC205	GC237	GC338	GC782	MC127	MC773	MC807
Equipment	**Activity Units**	183-1	822-1	24129-1	24080-1	1288-1	1218-1	67-1	735-1	1290-1	1215-1	876-1	1175-1	24199-1
Boiler/heater/burner: <10 MMBtu/hr, natural gas	Mscf, natural gas consumption						4,939	3,649						
Boiler/heater/burner: >100 MMBtu/hr, natural gas	Mscf, natural gas consumption								1,769,746					
Boiler/heater/burner: 10-100 MMBtu/hr, natural	Mscf, natural gas consumption		2,743						36,490					
Cold vent	Mscf, natural gas vented									28,966			52,426	1,055
Diesel engine: <600 hp, diesel fuel	gallons, diesel consumption	209	182	3,180	1,995	111	7,023	132,175	22,515	38,259	20,499	24,458	12,945	890
Diesel engine: >600 hp, diesel fuel	gallons, diesel consumption	5,115	12,524	858	97,285	1,403	449,312	122,971	140,907	20,846	300,213		94,461	726,639
Drilling rig, diesel fuel	gallons, diesel consumption						212,097			165,128			84,291	266,459
Flare: light smoke, with continuous pilot,	Mscf, natural gas flared			34,608										
Flare: light smoke, with continuous pilot, pilot	Mscf, natural gas flared			815										
Flare: no smoke, no continuous pilot, flare	Mscf, natural gas flared						111,676	48,132						
Flare: no smoke, with continuous pilot, flare	Mscf, natural gas flared	21,145	24		56,317	1,900			36,274	49,338	84,490	181,467		313,190
Flare: no smoke, with continuous pilot, pilot	Mscf, natural gas flared	434	2,537		5,647	2,537			869	391	434	434		2,172
Glycol dehydrator triethylene glycol	MMscf, natural gas throughput					18,032								
Mud degassing, synthetic-based mud	days drilling				18									18
Natural gas engine: 2-stroke, lean-burn	Mscf, natural gas consumption													
Natural gas engine: 4-stroke, clean-burn	Mscf, natural gas consumption						265,482							
Natural gas engine: 4-stroke, lean-burn	Mscf, natural gas consumption		201,178		12,435	128,836								
Natural gas engine: 4-stroke, rich-burn	Mscf, natural gas consumption				30,373			53,147						
Natural gas turbine	Mscf, natural gas consumption	1,354,682	761,199	391,055	1,036,227	507,464	358,116	457,425	417,604	266,920	1,713,428	1,018,844	312,788	2,232,479
Pneumatic pumps	Mscf, natural gas vented													
Pressure/level controllers	scf, natural gas vented							128,520	15,120					
Storage tank - condensate	bbl, condensate throughput	174												
Storage tank - crude oil	bbl, crude oil throughput		5,477,250		26,631,551	2,820,365		4,161,346		1,732,871				25,111,285

Appendix B

Reducing Methane Emissions from Rod Packing Systems:

Reciprocating compressor rod packing consists of a series of rings, held by a set of packing cups that are fitted around the piston shaft. These rings are lubricated to reduce wear and also to help withdraw heat. The compression chamber pressures will determine the number of cups and rings. Leakage around packing cups is prevented by a gasket installed at the end of the packing case. Correctly installed new packing cases, can be expected to leak at a minimum of 11.5 cubic feet per hour, with higher leakage rates depending upon the correctness of alignment of the packing, as also wear. The leakage can occur through the gasket, between cups, around the rings inside the cups, and between the rings and the shaft, with the leakage gases vented to the atmosphere through packing vents on the flange. As the system ages, increased leak rates can occur from wear on the packing rings and piston rod. Emissions as high as 900 cubic feet per hour from one compressor rod have been reported. To reduce methane emissions, realize gas savings through lower leakages, and also for extending the service life of the compressor rods, monitoring and replacing compressor rod packing systems is a viable practice, on a regular basis. An economic replacement threshold approach using company-specific financial objectives and monitoring data and determining emission levels at which it is cost-effective to replace rings and rods, can result in operational benefits, including a longer life for existing equipment, improvements in operating efficiencies, and long-term savings.

Directed Inspection and Maintenance (DI&M) Programs:

Directed Inspection and Maintenance (DI&M) is aimed at surface facilities that contain equipment components that include pipes, valves, flanges, and various fittings, meters and controllers. Over a period of usage due to a variety of process and environmental stimuli such as temperature and pressure fluctuations, corrosion and normal wear, these components can develop leaks, thereby releasing gas to the atmosphere. The size of the facility would determine the number of active equipment components that can be expected to leak, as well as process parameters, such as pressure in service lines. Typically, a small percentage of equipment components have measurable leakage, and of those normally a small percentage contributes to the majority of the emissions. Thus, fugitive emissions can be controlled by minimizing the potential for big leaks and performing early detection and repair.

A DI&M program is a cost-effective method to help mitigate methane losses from such equipment component leakages. It consists of a comprehensive baseline survey of all surface facilities, where operators identify and measure leakages at all leaking components. The inability to quickly detect, and subsequently quantify the emissions has been a key to addressing methane emissions reductions programs. A variety of leak detection methods are available including soap bubble screening, electronic screening (sniffers), Toxic Vapor Analyzers (TVAs) and Organic Vapor Analyzers (OVAs), ultrasound and acoustic leak detection, and in addition more recent technology such as the infrared (IR) camera and the Remote Methane Leak Detector (RMLD) which is another infrared emission screening device, is helping improve operators' ability to comprehensively identify methane emissions sources. After emissions identification, the next step is to quantify the emission levels and analyze costs, benefits and outcomes of mitigation options. High volume samplers that work by pulling the emissions, and also a large volume sample of the air around the leaking component into the instrument through a vacuum sampling hose, can be used to accurately quantify emission rates. Sample measurements are corrected for ambient hydrocarbon concentration. High volume samplers can measure leak rates up to 0.2 cubic feet per minute, equivalent to 326 cubic feet per day. Leak rates higher than 0.2 cubic feet per minute can be measured using bagging techniques or flow meters. Quantitative leak rate measurements made using bagging techniques employ bags of known volumes (e.g. 1 m^3, 2 m^3), made from antistatic plastic. Measurements are performed by sealing the bag around the emissions and measuring the time to inflate the bag to full capacity. For much higher flow rates, flow meters such as rotameters are used. In addition to identifying emissions and quantifying the leak rates, a key element to accurately calculate methane emissions rates is knowing the composition of the gas stream, which can allow the calculation of leakage volumes of methane and other hydrocarbons to be made, in order to facilitate an economic analysis of mitigation options.

Routing Glycol Dehydrator to Vapor Recovery Unit:

Glycol dehydration units that use gas-assist pumps for recirculation of lean glycol back to the gas contactor, have the pumps driven by expansion of the high pressure gas entrained in the rich glycol. Flash tank separators are installed to recover the entrained gas, for potentially beneficial uses such as injection to a fuel gas system. Routing the recovered gas via piping to a vapor recovery unit (VRU) can recover more gas, by adding to the gas that is collected through other vents that are similarly routed to the VRU. As a design consideration, the VRU should be sized to sufficiently capture the glycol dehydrator vent load, along with other vent sources. Routing of the gas from flash tank separator can recover all of the gas.

Recovering Gas from Pipeline Pigging Operations:

Pigging operations are performed when gathering lines accumulate condensable liquids in pipelines, which can reduce pipeline efficiency. It consists of using spherical or bullet shaped plugs, called pigs, to push accumulated liquids through the pipeline to a shore pig catcher where liquids are diverted to low pressure storage tanks. Before launching the pig, a section of specialized piping called the pig launcher must be isolated and pipeline pressure natural gas vented to the atmosphere to load the pig. Vented gas from the pig launcher can be recovered by routing the vent into the vapor recovery system. When connecting the pig launcher vent to the VRU, the connection should be engineered to keep a pressure relief safety valve in place for emergency blowdown of this equipment.

Converting Gas-Driven Chemical Pumps to Instrument Air:

Pressurized natural-gas driven pumps driving glycol circulation in glycol dehydration units and chemical transfer pumps, normally vent methane gas to the atmosphere. Natural gas pumps can be replaced with instrument air pumps for glycol circulation and chemical transfer pumps. This results in an increase in operational efficiency and reductions in maintenance costs and vented emissions.

Convert Gas Pneumatic Controls to Instrument Air:

Natural gas-powered pneumatic instrument systems are often used in the natural gas industry to operate a variety of process control devices for regulating pressure, flow, temperature and liquid levels. As a part of normal operation, these devices bleed natural gas into the atmosphere, and are a major source of methane emissions. Constant bleeding of natural gas from these gas-powered pneumatic controllers is collectively reported as being one of the largest sources of methane emissions in the natural gas industry, with an annual estimation of approximately 51 billion cubic feet in the production sector, 14 Bcf in the transmission sector, and <1 Bcf from the processing sector. Pneumatic control systems that are powered by natural gas emit methane from tube joints, controls, and numerous other points within the distribution tubing network. The bleed rate depends on the design of the device, as also on process conditions such as pneumatic gas supply pressure, actuation frequency, and age of the equipment. It has been found economical to substitute compressed air for natural gas in pneumatic systems, leading to elimination of methane emission and also increase in the volume of sales gas. The major components involved in the conversion of natural-gas based pneumatic controls to instrument-air based ones are the compressor used for instrument air delivery, a reliable power source required to operate the compressor, dehydrators or air dryers to dry the instrument air to prevent problems of corrosion of the instrument parts and blockages of instrument air piping and controller orifices, and a volume tank that can hold enough air to allow a large withdrawal of compressed air for a short time, such as for start-up functions, without affecting process control functions.

Replace Wet Seals with Dry Seals:

Centrifugal compressors are widely used in the processing and transmission of natural gas. These compressors have a rotating shaft with seals that prevent the high-pressure natural gas from escaping the compressor casing. These seals traditionally use rings that are lubricated by circulating high-pressure seal oil as a barrier from escaping gas, and are referred to as “wet seals”. Although very little gas escapes through the oil barrier, the gas comes into contact with the seal oil under high pressure at the compressor side seal oil/gas interface, thus resulting in a significant amount of gas being absorbed by the seal oil. Methane emissions occur from wet seals when the absorbed high-pressure gas is flashed off the circulating oil, and these can range from 40 to 200 cubic feet per minute. This de-gasification is done to maintain the viscosity and lubricity of the seal oil (using heaters, flash tanks, and degassing techniques), and the seal oil is then recirculated. The mechanical dry seal system is an alternative to this traditional wet (oil) seal system, and does not use any circulating seal oil. These dry seals operate mechanically under the opposing force created by hydrodynamic grooves which are etched into the surface of the rotating ring fixed on the compressor shaft, and spring pressure on an opposing stationary ring. During the time the compressor is not rotating, the stationary ring in the seal housing is pressed against the rotating ring by springs. When the compressor shaft is rotating at high speed, the compressed gas is pumped between the rings by the hydrodynamic grooves in the rotating ring. The opposing forces of high pressure gas pumped between the rings and springs trying to push the rings together tightens the gap between the rings thereby allowing very little gas to leak. During normal operation, these dry seals can leak at a rate of 0.5 to 3.0 cubic feet per minute across each seal, depending upon the size of the seal and also the operating pressure. Dry seals are normally tandem (two or three) sets of rings.

Reducing Emissions When Taking Compressors Off-Line:

Natural gas is transported from production and processing sites to transmission and distribution systems through compressors. Fluctuating demand for gas cause compressors to cycle on- and off-line, and maintenance and emergencies can cause compressors to be taken off-line. When compressors are offline, natural gas leakage can occur from a number of sources, and the leakage volumes depend on the pressure of the compressor system. In a depressurized system, methane emissions result from venting of the high pressure gas left within the compressor and also from continued leakage of unit isolation valves, while in a fully pressurized system, natural gas can leak from the closed blowdown valve and the compressor rod packings. The number of times a compressor is blown down depends on its operational mode. Compressors that are base-loaded operate most of the time, and are typically blown-down only three times per year, with downtime averaging 500 hours per year. Other compressors can be peak-load service operated, with their services being used depending on market demand. Such compressors can be off-line on average 40 times per year, for approximately 4,000 hours. The ratio of the number of base load to peak-load compressors can vary widely between pipeline companies due to a difference in operating strategies, system configurations, and markets. When taking compressors off-line, the largest source of methane emissions is from the venting of gas that is left within the compressor, with a single blowdown releasing approximately 15 Mcf of gas into the atmosphere, on average. Unit isolation valves, which isolate the compressor from the pipeline, are another source of emissions from off-line compressors, and they can typically leak at 1,400 cubic feet per hour. Natural Gas STAR Partners have reported unit valve leaks of up to 24 Mcf per hour in transmission compressor stations. Other emissions sources from off-line compressors are compressor rod packings and blowdown valves. Blowdown valves can leak from pressurized systems at a typical rate of 150 cubic feet per hour. Seals on compressor piston rods can leak approximately four-fold higher than during normal operations, to about 75 cubic feet per hour per rod. Operational measures that have been reported to significantly reduce methane emissions include keeping compressors pressurized, which does not require any modifications and which will significantly reduce the leak rate from 1,400 cubic feet per hour at the unit valve to approximately 450 cubic feet per hour from the blowdown valve and rod packings. Another measure is to route the blowdown vent lines to the fuel gas systems, allowing the vented gas to be used as fuel when taking the compressor off-line. This reduces the leakage from the compressor packings and blowdown vent to about 125 cubic feet per hour. When routing the blowdown vent into the fuel gas system, the connection will be engineered to maintain pressure relief safety valves so that the compressor can still be quickly vented to the atmosphere in case of emergency. A third operational practice is to install a static seal on each compressor rod shaft outside conventional packing, which can eliminate leaks from rod packings when the compressor is kept pressurized, during shutdown. In this case, leakage would occur from the blowdown valve only, at a typical rate of 150 cubic feet per hour at system pressure.

Appendix C

Table 7 – Mitigation Option Costs and Savings

Technological Options	Capital Cost (Onshore)	Capital Cost (Offshore)	Installation Cost (Onshore)	Installation Cost (Offshore)	New Equipment Delta O&M Cost (Onshore)	New Equipment Delta O&M Cost (Offshore)	Reduction Efficiency (%)	Conditions of Application for Costs
Install vapor recovery unit	$59,405	$178,215	$59,405	$178,215	$16,839	$21,891	95%	500 Mcf per day VRU
Optimize Glycol Circulation and Install of Flash Tank Separators in Dehydrators	$18,794	$56,382	$0	$0	$13,140	$17,082	90%	Horizontal Flash Tank for 450 gallon/hour TEG Circulation rate
Pipe Glycol Dehydrator to Vapor Recovery Unit	$8,750	$26,250	$8,750	$26,250	$0	$0	95%	250 feet length of pipe
Recover Gas from Pipeline Pigging Operations	$26,250	$26,250	$8,750	$26,250	$0	$0	95%	250 feet length of pipe
Replace Wet Seal with Dry Seals	$162,000	$486,000	$162,000	$486,000	-$88,300	-$114,790	94%	6-inch Shaft Beam Type Compressor 2 wet seals
Reducing Emissions When Taking Compressors Off-Line	$1,688	$5,064	$1,688	$5,064	$0	$0	90%	Cost corresponds to option of connecting blowdown vent to fuel gas system
DI&M	$0	$50,000	$0	$0	$0	$0	70%	One-time costs for a third-party contractor
Reducing Methane Emissions from Compressor Rod Packing Systems	$1,620	$4,860	$1,620	$4,860	$0	$0	65%	Teflon or moly-based 8 to 10 cup ring set for a three-inch rod, including cups and cases
Convert Gas-Driven Chemical Pumps to Instrument Air	$10,000	$30,000	$10,000	$30,000	$1,000	$1,300	100%	gas-assisted glycol pump sized for a gas dehydration unit that processes 10 MMcf of wet gas per day
Convert Gas Pneumatic Controls to Instrument Air	$69,823	$209,469	$69,823	$209,469	$32,850	$42,705	100%	Screw-type air compressor with a capacity of 350 cubic feet per minute of air, Volume tank of capacity 1,000 gallons of air, and alumina bed desiccant dryer with an air volume capacity of 350 cubic feet per minute
Replace High Bleed with Low Bleed Devices	$1,809	$5,427	$1,809	$5,427	-$36	-$47	75%	Replacing high-bleed pressure controller to low-bleed (implementation costs represent average costs for Fisher brand pneumatic instruments installed)

Appendix D

Gulf of Mexico Composite Platform

		Count	Activity Factor		Emissions Factor		CH4 Emissions		CH4 Emissions	
Emissions Type	Source		AF	Units	EF	Units	Emissions	Units	Emissions	Units
Venting	Wet seal degassing	20	3	compressors	619,291	m^3 CH4/compressor	65,603	Mcf	1,857,873	m^3
Venting	Cold vent	1	41,867	Mscf	0.612	scf CH4/scf gas	25,449	Mcf	720,710	m^3
Venting	Glycol dehydrator triethylene glycol	2	26,651	MMSCF	0.3357	lb VOC/hr-MMcfd	4,779	Mcf	135,338	m^3
Venting	Mud degassing, synthetic-based mud	1	36	days	198.41	lb THC/day	104	Mcf	2,940	m^3
Venting	Pressure/level controllers, gas bleed	2	144,830	scf	0.612	scf CH4/scf gas	88	Mcf	2,493	m^3
Venting	Pneumatic pumps	2		Mscf	0.612	scf CH4/scf gas	17	Mcf	475	m^3
Venting	Storage tank - crude oil throughput	1	22,959,398	bbl	0	scf of CH4/bbl crude	0	Mcf	0	m^3
Fugitive	Fugitives – other equipment, natural gas stream	741	741	other components	0.4704	lb THC/component-day	1,834	Mcf	51,933	m^3
Fugitive	Fugitives – valves, natural gas stream	1,223	1,223	valves	0.24	lb THC/component-day	1,544	Mcf	43,731	m^3
Fugitive	Fugitives – other equipment, oil/water stream	417	417	other components	0.7392	lb THC/component-day	1,622	Mcf	45,925	m^3
Fugitive	Fugitives – other equipment, oil stream	530	530	other components	0.4008	lb THC/component-day	1,118	Mcf	31,649	m^3
Fugitive	Fugitives – valves, oil stream	840	840	valves	0.13008	lb THC/component-day	575	Mcf	16,280	m^3
Fugitive	Fugitives – flanges, natural gas stream	1,695	1,695	flanges	0.021	lb THC/component-day	187	Mcf	5,303	m^3
Fugitive	Fugitives – connectors, natural gas stream	1,115	1,115	connectors	0.010992	lb THC/component-day	64	Mcf	1,826	m^3
Fugitive	Fugitives – connectors, oil stream	1,361	1,361	connectors	0.010992	lb THC/component-day	79	Mcf	2,229	m^3
Fugitive	Fugitives – centrifugal, wet seal, natural gas stream	20	12	wet seals	0.4704	lb THC/component-day	30	Mcf	841	m^3
Fugitive	Fugitives – pumps, oil stream	11	11	pumps	0.6912	lb THC/component-day	40	Mcf	1,133	m^3
Fugitive	Fugitives – flanges, oil stream	1,133	1,133	flanges	0.005808	lb THC/component-day	35	Mcf	980	m^3
Fugitive	Fugitives – centrifugal pack, natural gas stream	9	9	packing	0.4704	lb THC/component-day	22	Mcf	631	m^3
Fugitive	Fugitives – centrifugal pack, oil/water stream	8	8	packing	0.7392	lb THC/component-day	31	Mcf	881	m^3
Fugitive	Fugitives – pumps, natural gas stream	22	22	pumps	0.13008	lb THC/component-day	15	Mcf	426	m^3
Fugitive	Fugitives – centrifugal pack, oil stream	6	6	packing	0.4008	lb THC/component-day	13	Mcf	358	m^3
Fugitive	Fugitives – valves, oil/water stream	386	386	valves	0.005208	lb THC/component-day	11	Mcf	300	m^3
Fugitive	Fugitives – connectors, oil/water stream	246	246	connectors	0.005808	lb THC/component-day	8	Mcf	213	m^3
Fugitive	Fugitives – flanges, oil/water stream	558	558	flanges	0.00015	lb THC/component-day	0	Mcf	12	m^3
Fugitive	Fugitives – pumps, oil/water stream	3	3	pumps	0.0013008	lb THC/component-day	0	Mcf	1	m^3
Combustion	Natural gas engine: 4-stroke, lean-burn	2	228,024	Mscf	1.25	lb CH4/MMBtu	7,049	Mcf	199,614	m^3
Combustion	Flare: no smoke, with continuous pilot, flare gas consumption	2	156,809	Mscf	0.126	lb CH4/MMBtu	489	Mcf	13,837	m^3
Combustion	Natural gas turbine, gas fuel consumption	5	1,793,720	Mscf	0.0086	lb CH4/MMBtu	381	Mcf	10,803	m^3
Combustion	Drilling rig, diesel fuel consumption	1	433,097	gallons	0.008	lb CH4/MMBtu	11	Mcf	317	m^3
Combustion	Diesel engine: >600 hp, diesel fuel consumption	5	324,678	gallons	0.008	lb CH4/MMBtu	8	Mcf	237	m^3
Combustion	Diesel engine: <600 hp, diesel fuel consumption	3	35,621	gallons	0.008	lb CH4/MMBtu	1	Mcf	26	m^3
Combustion	Flare: no smoke, with continuous pilot, pilot gas consumption	2	3,263	Mscf	2.3	lb CH4/MMcf	0	Mcf	5	m^3
					Total Methane Emissions:		**111,205**	**Mcf**	**3,149,319**	**m^3**

Brazil – FPSO #1

	Count	Activity Factor		Emissions Factor		CH4 Emissions		CH4 Emissions	
Source		AF	Units	EF	Units	Emissions	Units	Emissions	Units
Storage tank - crude oil throughput	8	10,541,930	bbl	5.33	scf/bbl crude	15,392	Mcf	435,889	m^3
Rod packing venting	24	12	packing	122	scf/hour-packing	6,660	Mcf	929,776	m^3
Cold vent	1	1,315	Mscf	0.64	scf CH4/scf gas	553	Mcf	15,675	m^3
Glycol dehydrator triethylene glycol	1	5,731	MMSCF	0.3357	lb VOC/hr-MMcfd	696	Mcf	19,708	m^3
Mud degassing, synthetic-based mud	1	15	days	198.41	lb THC/day	45	Mcf	1,270	m^3
Fugitives – other equipment, natural gas stream	823	823	other components	0.4704	lb THC/component-day	2,130	Mcf	60,318	m^3
Fugitives – valves, natural gas stream	1,358	1,358	valves	0.24	lb THC/component-day	1,793	Mcf	50,780	m^3
Fugitives – other equipment, oil/water stream	463	463	other components	0.7392	lb THC/component-day	1,883	Mcf	53,324	m^3
Fugitives – other equipment, oil stream	589	589	other components	0.4008	lb THC/component-day	1,299	Mcf	36,781	m^3
Fugitives – valves, oil stream	933	933	valves	0.13008	lb THC/component-day	668	Mcf	18,909	m^3
Fugitives – flanges, natural gas stream	1,883	1,883	flanges	0.021	lb THC/component-day	218	Mcf	6,161	m^3
Fugitives – centrifugal pack, natural gas stream	48	48	packing	0.4704	lb THC/component-day	124	Mcf	3,518	m^3
Fugitives – connectors, natural gas stream	1,239	1,239	connectors	0.010992	lb THC/component-day	75	Mcf	2,122	m^3
Fugitives – connectors, oil stream	1,512	1,512	connectors	0.010992	lb THC/component-day	91	Mcf	2,589	m^3
Fugitives – flanges, oil stream	1,259	1,259	flanges	0.005808	lb THC/component-day	40	Mcf	1,139	m^3
Fugitives – pumps, natural gas stream	24	24	pumps	0.13008	lb THC/component-day	17	Mcf	486	m^3
Fugitives – pumps, oil stream	6	6	pumps	0.6912	lb THC/component-day	23	Mcf	646	m^3
Fugitives – valves, oil/water stream	429	429	valves	0.005208	lb THC/component-day	12	Mcf	348	m^3
Fugitives – connectors, oil/water stream	273	273	connectors	0.005808	lb THC/component-day	9	Mcf	247	m^3
Fugitives – flanges, oil/water stream	620	620	flanges	0.00015	lb THC/component-day	1	Mcf	14	m^3
Fugitives – pumps, oil/water stream	3	3	pumps	0.0013008	lb THC/component-day	0	Mcf	1	m^3
Flare: no smoke, with continuous pilot, flare gas consumption	1	182,500	Mscf	0.126	lb CH4/MMBtu	569	Mcf	16,104	m^3
Natural gas turbine, gas fuel consumption	4	1,001,000	Mscf	0.0086	lb CH4/MMBtu	213	Mcf	6,029	m^3
Drilling rig, diesel fuel consumption	1	178,974	gallons	0.008	lb CH4/MMBtu	5	Mcf	131	m^3
				Total Methane Emissions:		**32,421**	**Mcf**	**918,176**	$\mathbf{m^3}$

Brazil – FPSO #2

	Count	Activity Factor		Emissions Factor		CH4 Emissions		CH4 Emissions	
Source		AF	Units	EF	Units	Emissions	Units	Emissions	Units
Storage tank - crude oil throughput	8	6,657,753	bbl	5.329	scf/bbl crude	9,721	Mcf	275,285	m^3
Rod packing venting	4	4	packing	99	scf/hour-packing	7,692	Mcf	217,837	m^3
Cold vent	1	90	Mscf	0.64	scf CH4/scf gas	407	Mcf	11,527	m^3
Mud degassing, synthetic-based mud	1	15	days	198.41	lb THC/day	45	Mcf	1,270	m^3
Fugitives – other equipment, natural gas stream	483	483	other components	0.4704	lb THC/component-day	1,250	Mcf	35,400	m^3
Fugitives – valves, natural gas stream	797	797	valves	0.24	lb THC/component-day	1,052	Mcf	29,802	m^3
Fugitives – other equipment, oil/water stream	272	272	other components	0.7392	lb THC/component-day	1,106	Mcf	31,327	m^3
Fugitives – other equipment, oil stream	346	346	other components	0.4008	lb THC/component-day	763	Mcf	21,607	m^3
Fugitives – valves, oil stream	548	548	valves	0.13008	lb THC/component-day	392	Mcf	11,106	m^3
Fugitives – flanges, natural gas stream	1,105	1,105	flanges	0.021	lb THC/component-day	128	Mcf	3,615	m^3
Fugitives – connectors, natural gas stream	727	727	connectors	0.010992	lb THC/component-day	44	Mcf	1,245	m^3
Fugitives – connectors, oil stream	887	887	connectors	0.010992	lb THC/component-day	54	Mcf	1,519	m^3
Fugitives – centrifugal pack, natural gas stream	8	8	packing	0.4704	lb THC/component-day	31	Mcf	879	m^3
Fugitives – pumps, oil stream	7	7	pumps	0.6912	lb THC/component-day	27	Mcf	754	m^3
Fugitives – flanges, oil stream	739	739	flanges	0.005808	lb THC/component-day	24	Mcf	669	m^3
Fugitives – pumps, natural gas stream	14	14	pumps	0.13008	lb THC/component-day	10	Mcf	284	m^3
Fugitives – valves, oil/water stream	252	252	valves	0.005208	lb THC/component-day	7	Mcf	204	m^3
Fugitives – connectors, oil/water stream	160	160	connectors	0.005808	lb THC/component-day	5	Mcf	145	m^3
Fugitives – flanges, oil/water stream	364	364	flanges	0.00015	lb THC/component-day	0	Mcf	9	m^3
Fugitives – pumps, oil/water stream	2	2	pumps	0.0013008	lb THC/component-day	0	Mcf	0	m^3
Flare: no smoke, with continuous pilot, flare gas consumption		141,773	Mscf	0.126	lb CH4/MMBtu	442	Mcf	12,510	m^3
Natural gas turbine, gas fuel consumption		386,653	Mscf	0.0086	lb CH4/MMBtu	82	Mcf	2,329	m^3
Drilling rig, diesel fuel consumption		178,974	gallons	0.008	lb CH4/MMBtu	5	Mcf	131	m^3
				Total Methane Emissions:		**23,286**	**Mcf**	**659,455**	**Mcf**