Development of a Criteria Pollutant Emissions Inventory for Sources in the Gulf of Mexico

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ABSTRACT

Measurements of ozone concentrations in onshore areas of Texas and Louisiana periodically exceed the national standard for one-hour ozone in nonattainment areas, with some observations nearly three times the national standard. Shoreline and inland locations in Texas and Louisiana could potentially be influenced by emission sources in the Gulf of Mexico. The Minerals Management Service (MMS) is responsible for determining if air pollutant emissions from (oil and natural gas) platforms and other sources in the Gulf of Mexico influence the ozone attainment (and nonattainment) status of onshore areas. MMS launched a series of studies, beginning in 1993, to assess the emissions of offshore oil and gas platforms and their associated emissions.

The MMS' Gulf of Mexico Outer Continental Shelf Regional office is currently sponsoring Eastern Research Group's (ERG's) work on the *Gulfwide Emission Inventory Study*, which builds upon these MMS studies with the goal of developing a base year 2000 inventory of criteria pollutant emission inventory for all oil and gas production-related sources in the Gulf of Mexico, including non-platform sources. To develop the inventory, ERG created the Gulfwide Offshore Activities Data System (GOADS), which was used to collect monthly activity data from platform sources. The activity data were combined with the most recent *AP-42* emission factors and Emission Inventory Improvement Program (EIIP) emission estimation methods to develop a comprehensive criteria pollutant emission inventory. Non-platform emission estimates were developed for sources such as the Louisiana Offshore Oil Platform (LOOP), commercial marine vessels, and helicopters. Diurnal emission profiles were also developed for the major categories of sources inventoried. The profiles will allow inventory emission estimates for a given category to be temporally allocated, across a 24-hour time period, on a 1-hour basis. Ultimately, State agencies will use this information to perform modeling for ozone and regional haze for use in their State Implementation Plans (SIPs).

INTRODUCTION

The geographic area covered by ERG's MMS Gulfwide study is all of the federal waters in the Gulf of Mexico, west of 87.5 degrees. The base year of the study is 2000; planning for a base year 2005 inventory is currently underway. Pollutants covered in the inventory are the criteria pollutants—carbon monoxide (CO), sulfur dioxide (SO_2), nitrogen oxides (NO_x), particulate matter-10 (PM_{10}), $PM_{2.5}$, total hydrocarbons (THC), and volatile organic compounds (VOC); as well as greenhouse gases—carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O).

The sources covered in the inventory are all oil and gas production platforms. Affected operators are lessees and operators of federal oil, gas, and sulfur leases in the Gulf of Mexico outer continental shelf region. This includes the following platform emission sources:

- Amine units
- Boilers/heaters/burners
- Diesel engines

- Drilling equipment
- Flares
- Flashing losses
- Fugitive sources
- Glycol dehydrators
- Loading operations
- Mud degassing
- Natural gas engines
- Natural gas turbines
- Pneumatic pumps
- Pressure/level controllers
- Storage tanks
- Vents

Non-platform sources covered in the inventory are:

- Biogenic/geogenic sources
- Commercial fishing
- Commercial marine vessels
- Drilling rigs
- The Louisiana Offshore Oil Platform (LOOP)
- Military vessel operations
- Pipe laying operations
- Support helicopters
- Support vessels
- Survey vessels
- Vessel lightering

PLATFORM SOURCES

ERG combined monthly activity data collected from the platform operators for oil and gas production equipment in the Gulf of Mexico with emission factors and algorithms to develop the platform production equipment emission estimates. To collect the activity data, the MMS' Breton Offshore Activities Data System (BOADS) program was the starting point for the Gulfwide Offshore Activities Data System (GOADS) program. GOADS is a Visual Basic application with an Access 2000 backend. Because some platform operators in the Gulf were already using the BOADS software for activity data reporting to MMS, we designed the GOADS program so that it mimicked BOADS, and allowed operators to directly import their monthly BOADS files for 2000. The GOADS program and User's Guide can be downloaded from:
http://www.gomr.mms.gov/homepg/regulate/environ/airquality/goad.html

Data requested included company, structure, and complex ID, lease number, block and area number, and latitude/longitude. For each equipment type, the GOADS software has an equipment screen that contains fields for the parameters to be recorded. As an example, the boiler/heater/burner equipment screen requires operators to enter activity parameters such as equipment ID, hours operated, fuel type, fuel heating value, amount of fuel used, control equipment in place, and equipment elevation. For each piece of equipment, stack parameter information such as outlet height, exit velocity, and exit temperature was also requested. Nearly 3400 oil and gas production platforms submitted monthly equipment activity data files.

ERG programmed automatic quality assurance (QA) procedures into the software in an effort to minimize the submittal of incomplete and erroneous activity data by the platform operators. These QA procedures focus on the critical activity data that are needed to develop emission estimates. The software also automatically runs a series of quality control (QC) checks on the data every time the operator saves it. If the operator leaves a field blank, provides data that is out of range, or enters a value that is not consistent on a month-to-month basis, an error message will appear. The operator can either: correct the problem, override the QA/QC check (and provide a comment), or ignore the message and save the file. When operators entered data that appeared in the QA/QC results, we attempted to reconcile the missing, atypical, or suspect data by reviewing the comments, developing surrogate data, and working with the MMS field officer to obtain data from the operators.

ERG performed rigorous QA/QC of the activity data collected from platform operators. We completed tasks to correct the number of operating hours provided for a given month, filled in missing monthly operating data (if equipment was operational), verified and corrected activity values such as fuel heating value, made sure that the equipment shown to be vented included a vent ID and activity record, filled in missing stack parameters with surrogates, and double checked exit velocity and fuel usage totals by recalculating the parameters.

The activity data were then uploaded into an Oracle database management system (DBMS) to develop monthly emission estimates. ERG modified a previously-developed DBMS so that the most current emission factors and calculation methods were used to calculate and archive emissions estimates. The following discussion briefly describes the emission sources and calculation methods we used for oil and gas production platform equipment. The emission estimation methods are discussed in more detail in a 1996 emissions inventory conference paper written by Brian Boyer and Kenneth Brodnax.[1]

Amine units are used for natural gas that contains unacceptable amounts of hydrogen sulfide (H_2S). While most platform operators pipe the sour gas onshore for sulfur removal, a few remove the sulfur on the platform using the amine process. Various amine solutions are used to absorb H_2S. After the H_2S has been separated out, it is vented, flared, incinerated, or used for feedstock in elemental sulfur production.[2] Operators were given the option of simply entering the activity data needed to develop emission estimates using AMINECalc; they were not required to run the program themselves. ERG's subcontractor COMM Engineering, of Lafayette, LA, developed the THC, CH_4, and VOC emissions estimates using AMINECalc, and we loaded the data directly into the DBMS. Emissions were adjusted for any control devices that were reported, such as a flare, vapor recovery system/condenser, or sulfur recovery unit.

Boilers, heaters, and burners provide process heat and steam for many processes such as electric generation, glycol dehydrator reboilers, and amine reboiler units.[3] AP-42 emission factors were used to estimate emissions for these combustion units.[4] All boilers were assumed to be wall-fired boilers (no tangential-fired boilers). Emission factors for No. 6 residual oil were used to estimate emissions from waste-oil-fueled units.

Diesel and gasoline engines are used to run generators, pumps, compressors, and well-drilling equipment. Most of the pollutants emitted from these engines are from the exhaust. Evaporative losses are insignificant in diesel engines due to the low volatility of diesel fuels.[4] AP-42 emission factors were used to estimate emissions from these diesel and gasoline engines.[4]

Drilling activities associated with an existing facility or from a jack-up rig adjacent to a platform are included because of their emissions associated with gasoline, diesel, and natural gas fuel usage in engines. Total emissions were checked to insure that they equaled the sum of emissions associated with gasoline, diesel, and natural gas fuel usage. AP-42 emission factors were used to estimate emissions.[4]

Diesel engines were assumed to be ≥ 600 hp. Natural gas engines were assumed to be 4-cycle and evenly distributed between lean and rich burns (by averaging).

A flare is a burning stack used to dispose of hydrocarbon vapors. Flares can be used to control emissions from storage tanks, loading operations, glycol dehydration units, vent collection system, and amine units. Flares usually operate continuously; however, some are used only for process upsets.[2] AP-42 emission factors for industrial flares were used to estimate emissions.[4]

Flash gas is associated with high, intermediate, and low pressure separators, heater treaters, surge tanks, accumulators, and fixed roof atmospheric storage tanks. Flash gas emissions were only estimated for gas that is vented to the atmosphere or burned in a flare. No emissions are associated with flash gas that is routed back into the system (e.g., sales gas). If a pressure drop occurs between upstream pressure vessels, flash gas emissions were estimated using the Vasquez-Beggs correlation equations to estimate tank vapors in standard cubic feet per barrel of oil produced.

Fugitive emissions are leaks from sealed surfaces associated with process equipment. Specific fugitive source types include equipment components such as valves, flanges, and connectors.[3] Operators were required to delineate the stream type (i.e., gas, heavy oil, light oil, or water/oil) and average VOC weight percent of fugitives, and provide an equipment inventory (e.g., number of components). Table 1 presents the THC emission factors used for equipment leaks. The default values in Table 2 were assigned for the average VOC weight percent.

Glycol dehydrators remove excess water from natural gas streams to prevent the formation of hydrates and corrosion in the pipeline.[3] Emission estimates for this source were calculated using regression predictive equations based on a series of GLYCalc program runs, developed by ERG's subcontractor COMM Engineering, to predict lbs/hr-MMSCFD for VOC and CH_4.

Loading operation emissions are from the displacement of the vapor space in the receiving cargo hold by liquid product. Loading losses are due to: 1—liquids displacing vapors already residing in the cargo tank, and 2—vapors generated by the liquid being loaded into the cargo tank.[1,3] The calculations below assume that ships arrive in uncleaned, ballasted condition and that the previously carried loads were crude oil. These evaporative emissions were calculated using the AP-42 equations.[4]

Hydrocarbon emissions from mud degassing occur when gas that has seeped into the well bore and dissolved or become entrained in the drilling mud is separated from the mud and vented to the atmosphere.[3] For water-based and oil-based muds, hydrocarbon emissions are estimated using emission factors provided in the 1977 EPA report: *Atmospheric Emissions from Offshore Oil and Gas Development and Production*.[5]

Like diesel and gasoline engines, natural gas engines are used to run generators, pumps, compressors, and well-drilling equipment. Most of the pollutants emitted from these engines are from the exhaust.[4] AP-42 emission factors were used to estimate emissions.[4]

A gas turbine is an internal combustion engine that operates with rotary rather than reciprocating motion. Turbines are primarily used to power compressors rather than generate electricity.[1] A turbine's operating load has a considerable effect on the resulting emission levels. With reduced loads, there are lower thermal efficiencies and more incomplete combustion.[4] AP-42 natural gas turbine emission factors were used to estimate emissions.[4]

Table 1. THC emission factors for oil and gas production operations (lb/component-day)[6]

Component	Gas	Natural Gas Liquid	Heavy Oil (<20 API Gravity)	Light Oil (≥ 20 API Gravity)	Water/ Oil	Oil/Water/ Gas[c]
Connector	1.1E-02	1.1E-02	4.0E-04	1.1E-02	5.8E-03	1.1E-02
Flange	2.1E-02	5.8E-03	2.1E-05	5.8E-03	1.5E-04	2.1E-02
Open-end	1.1E-01	7.4E-02	7.4E-03	7.4E-02	1.3E-02	1.1E-01
Other[a]	4.7E-01	4.0E-01	1.7E-03	4.0E-01	7.4E-01	7.4E-01
Pump	1.3E-01	6.9E-01	6.9E-01	6.9E-01	1.3E-03	1.3E-01
Valve	2.4E-01	1.3E-01	4.4E-04	1.3E-01	5.2E-03	2.4E-01
Centrifugal Comp/Wet Seals[c]	6,675	N/A[d]	N/A	N/A	N/A	N/A
Centrifugal Comp/Dry Seals[c]	400	N/A	N/A	N/A	N/A	N/A
Centrifugal Comp/ Shaft Packing Seals[c]	78	N/A	N/A	N/A	N/A	N/A
Other Compressor Seals[c]	2,385	N/A	N/A	N/A	N/A	N/A

[a] Includes diaphragms, drains, dump arms, hatches, instruments, meters, pressure relief valves, polished rods, and vents.
[b] Assumed to be equal to either gas or water/oil, whichever is greater.
[c] Source: EPA Gas Star Program (www.epa.gov/outreach/gasstar/).
[d] N/A: Not applicable.

Table 2. Default speciation weight fractions for total hydrocarbon (THC) emissions by stream type[6]

THC Fraction	Gas	Natural Gas Liquid	Light Oil (≥ 20 API Gravity)	Heavy Oil (<20 API Gravity)	Water/Oil[a]	Oil/Water/Gas
Methane	0.945	0.612	0.612	0.942	0.612	0.612
VOC	0.0137	0.296	0.296	0.030	0.296	0.296

[a] Water/oil refers to water streams in oil service with a water content greater than 50% from the point of origin to the point where the water content reaches 99%. For water streams with a water content greater than 99%, the emission rate is considered negligible.

A readily-available supply of compressed natural gas is used to power gas actuated pneumatic pumps. There is no combustion of the gas because the energy is derived from the gas pressure. These pumps include reciprocating pumps such as diaphragm, plunger, and piston pumps. Most gas-actuated pumps vent directly to the atmosphere.[1] CO_2, CH_4, THC, and VOC emission estimates for pneumatic pumps were developed using the following equation[3]:

Equation (1) E = Hrs operated × fuel usage rate (SCF/hr) × (mole weight of gas, lbs/lb-mole) × (1 lb-mole/379 SCF)

Where

E = emissions

Devices that control both pressure and liquid levels on vessels and flow lines are used extensively in production operations. The units are designed to open or close a valve when a preset pressure or liquid level is reached. The valves are automatically actuated by bleeding compressed gas from a diaphragm or piston. The gas is vented to the atmosphere in the process. Most production facilities use natural gas to actuate the controllers. The amount of gas vented is dependent on several factors, including the manufacturer and application.[1] CO_2, CH_4, THC, and VOC emissions estimates (in pounds) for pressure and level controllers were developed using the equation shown above.[3]

VOC and THC may be lost from storage tanks as a result of flashing, working, and standing losses. This discussion only addresses working and standing losses; flashing losses were estimated separately. Standing losses result from the expulsion of vapors due to vapor expansion and contraction resulting from temperature and barometric pressure changes. Working losses result from filling and emptying operations.[1] Working and standing loss emissions were calculated using the AP-42 equations.[4]

Production facilities often discharge natural gas to the atmosphere via vents. The discharges can be due to routine or emergency releases. A vent may serve one or several pieces of equipment through a header system. Emissions from vents were calculated based on the volume of gas vented and the chemical composition of the gas.[1]

NON-PLATFORM SOURCES

ERG compiled base year 2000 activity data and developed emission estimates for a number of non-platform source categories. Following is a brief description of the source categories, the source of our activity data, and the emission factors we used to develop the estimates. For the most part, the emission factors used to calculate the emissions from all of the engines for these sources were obtained from the EPA's Office of Transportation and Air Quality (OTAQ) in Ann Arbor, Michigan. OTAQ published the emission equations along with their Diesel Marine Vessel Rule in 2002. The activity data and resulting emission estimates will be disaggregated in the future to MMS lease blocks or GIS data sets, depending on MMS's program needs.

For biogenic/geogenic sources, we were able to estimate emissions for crude oil seeps and subsurface bacterial processes. Subsurface seeps of oil occur when oil deposits beneath the ocean floor escape into the ocean waters through cracks and vents in the floor. The volume of oil seeping into the ocean can be relatively significant, although the total amount of oil that is released into the ocean does not find its way to the surface. Mitchell and coworkers developed an estimate of the quantity of oil seeping into the Northern Gulf of Mexico ranging from 2.5 to 6.9×10^5 barrels per year based on studies of oil slicks both at the ocean level and from satellite and space shuttle photography.[7] A report by the National Research Council cites a possible seep rate for the entire Gulf of Mexico to be 1.05×10^6 barrels per year.[8] Emissions were estimated using the oil seepage VOC emission factor (105 lbs/barrel oil released) developed by the California Air Resources Board.[9] Nitrous oxide (N_2O) is produced by deep-water bacteria, and is transferred to the atmosphere through upwelling and air-sea transfer mechanisms.[10] Bouwman and co-workers compared several earlier inventories of ocean N_2O to create a gridded annual N_2O inventory available as part of the Global Emission Inventory Activity (GEIA) data set.[11] Based on this information, total annual emissions for the GOM study area have been estimated to be 3,710 tons N_2O –N/year.

Commercial fishing activity data were provided by the National Oceanic & Atmospheric Administration. Emissions are associated with vessel propulsion, and operation of generators, cranes, and winches.

The commercial marine vessel source category includes vessels that transport goods through the Gulf, along with cruise ships. Most of these emissions are from vessel propulsion. In addition to OTAQ's emission equations, we calculated steamship emissions by extrapolating those in the EPA's National Emissions Inventory (NEI), and applying them to shipping-lane activity data provided by the Corps of Engineers.

Emissions associated with exploratory drilling are from the vessel engines, and from generating electricity and operating mud pumps and draw works. We were provided activity data from MMS's Operation and Analysis Branch, by lease block.

The Louisiana Offshore Oil Port, or the LOOP, is located 40 miles offshore, allowing large oil tankers to offload their product without entering port. Emissions from the LOOP are from the tanker engines, support vessel engines, and pumps and a generator located on the platform. We obtained operating data directly from the LOOP. There are also ballasting evaporative emissions, which we estimated based on the amount of product transferred and EIIP guidance.

Military vessel activity in the Gulf is from Navy and Coast Guard patrols and maneuvers. We were able to get Coast Guard data for 2000, but not Navy data. The Navy data we used were taken directly from the MMS 1995 study. Emissions were estimated for a variety of engines, including older residual fueled steam turbines. For the older engines, we used AP-42 emission factors, and factors from EPA's National Emissions Inventory.

Emissions from pipe laying operations are associated with the vessel engines, and smaller engines that run generators, compressors, welding equipment, cranes, and winches. We were provided activity and locational data by MMS's Pipeline Section.

The source of our support helicopter activity data was the "Helicopter Safety Advisory Conference's Gulf of Mexico Offshore Helicopter Operations Safety Review" report.[12] Emissions were estimated assuming short landing and takeoff cycles. We developed the emission factors for this source category based on a variety of published test reports-- from EPA, engine manufacturers, and the Navy.

Emissions from support vessels--crew boats, tugs, and barges that transport heavy equipment--are associated with the vessel engines, and smaller engines that run generators, cranes, and winches. We were unable to find activity data specific to the year 2000 for this source category. We extrapolated the activity data presented in a 1995 MMS study (for 1992) based on the increase in the number of platforms operating in 1992 and 2000 years.[2] MMS developed the 1992 activity data by surveying industry.

Survey vessels are used to map geologic formations and seismic properties in the Gulf. MMS provided aggregated permitted survey activity (not company specific) in total miles or surface area covered. The emissions are from the vessel engines, and from generating electricity and compressor air.

Vessel lightering emissions occur when oil is transferred from one vessel to another. Emissions are associated with vessel engines, secondary engines that operate pumps and winches, and ballasting and product transfer evaporative losses during lightering activities. The Coast Guard monitors lightering operations at 3 sites in the Gulf, and provided activity data for the year 2000. Evaporative losses were estimated using the EIIP recommended emission factor of 0.86 lb TOC per 1000 gallons of crude oil.

DIURNAL PROFILES

ERG also developed diurnal emission profiles for the source categories inventoried in the MMS Gulf of Mexico study. The profiles will allow inventory emission estimates for a given category to be temporally allocated, across a 24-hour time period, on a 1-hour basis. Hour-by-hour emission estimates of this nature are required in order to run advanced photochemical simulation models (such as the Urban Airshed Model).

Diurnal curves are expressed as the percentage of total emissions that occur at each 1-hour interval for each emission source. We obtained the temporal profiling data from a number of sources. Direct monthly survey data were available for platform equipment, as the monthly hours of operation for each piece of equipment were provided by platform operators through the GOADS program.

For non-platform sources, information was derived from published industry statistics and the 1995 MMS study. Our subcontractor COMM Engineering also provided information on the daily operational patterns and characteristics of the sources based on their permitting experience with offshore oil and gas operations. Lastly, default allocation algorithms and values were obtained from EPA guidance documents dealing with modeling inventories and modeling requirements for the new ozone and PM-2.5 National Ambient Air Quality Standards (NAAQS).[13,14,15]

The NAAQS guidance document containing specific procedures was used to temporally allocate point, area, and mobile source emissions for comparison to the patterns developed from survey data and with guidance from COMM Engineering.[14] Primarily the 1999 report was used, as it contains multiple algorithms and factors that were used to verify temporal profiles.

Source operations (and in turn their emissions) are, by nature, either inherently continuous and reasonably uniform, or intermittent and non-uniform. For example, production processes are typically continuous (24 hours/day) and consistent because companies want to maximize the utilization of resources and obtain as much return on their investment as possible. Fluctuating operational levels are not consistent with these missions. Other source types that are not directly product-driven such as helicopter flights may only occur to fulfill a specific need and may have an operation that is limited by other physical conditions (e.g., is only done in daylight). Meteorological conditions, for example, may also affect a source's daily temporal profile (e.g., higher temperatures at mid day mean higher emissions than emissions at midnight).

Since the objective of having the diurnal profiles is to support photochemical modeling, the temporal profiles presented here were developed for a typical day in the ozone season. In a typical summer day, activity for production platforms, drilling, tanker-shipping, space cooling, drill rig mobilization, and setting of new platforms were expected to be fairly continuous on a 24-hour basis. This would be especially true for the latter two categories, since companies want to maximize such activities during the summer months when seas are relatively calm. Activities such as helicopter traffic and supply boats are not continuous and generally cycle in conjunction with daylight hours.

The following platform operations have essentially constant operation, with no variation in emissions throughout a 24-hour ozone season day:

- Amine units
- Drilling
- Flares
- Flashing
- Fugitives
- Glycol dehydrators
- Mud degassing
- Pneumatic pumps
- Pressure and level controllers
- Vents

The following non-platform operations also have essentially constant operation:

- Commercial marine vessels
- LOOP activities
- Military vessels
- Oceangoing barges
- Pipe laying
- Survey and exploration vessels

The diurnal pattern for boilers/heaters/burners, and turbines has slight diurnal variation. For biogenic ocean processes, internal combustion engines, loading losses, oil seeps, and storage tanks, the pattern is temperature-driven throughout a 24-hour ozone season day. The curve is based on the fluctuation in average air and water temperature in the Gulf.[16]

The diurnal pattern for two non-platform operations average 21 hours of operation per day. The curve assumes no significant activity between the hours of midnight and three am for helicopters and support vessels (crew boats, supply boats, tugs, and barges).

LIMITATIONS

As with the development of any inventory of activity data or emission estimates, the accuracy can vary considerably depending upon the accuracy of the activity data obtained and the emission factors used.

The key limitation and source of uncertainty associated with this inventory effort pertains to the completeness of the platform activity data gathered and used to develop emission estimates. It is difficult to confirm that all affected lessees and operators of federal oil, gas, and sulfur leases in the Gulf of Mexico OCS region provided GOADS files to MMS as required. It is also difficult to track active versus inactive platforms on an annual basis. For example, operators were told to submit records for "satellite" platforms that have no emission sources on them. There may have been no equipment activity data records associated with these platforms, but MMS records show the platform as active in 2000. Platform ownership changes make it difficult to track month-to-month completeness. Lastly, we have no way of knowing how well the operators understood what activity data were being requested. For example, losses from flashing occur at all points where an oil stream undergoes a pressure drop. Operators were asked to determine all sources of flash gas that are vented or flared. Each point of separation/treatment had to be examined as a potential source of flash gas. Flash gas can be vented to the atmosphere or burned in flares from the following equipment: high, intermediate, and low-pressure separators; heater treaters; surge tanks; accumulators; and fixed roof atmospheric storage tanks. It is believed that emissions from flashing are underestimated because operators did not completely report the sources.

Our estimates for some non-platform source categories such as support vessels and naval operations were based on adjustments made to activity data that were included in the 1995 MMS study. Much of the non-platform activity data used in the 1995 study were derived from a 1992 Survey of Offshore Operators undertaken by the Offshore Operators Committee. This 1992 report contains useful information, and it would have been helpful if a similar study could have been performed for this 2000 inventory effort. In addition, most of the non-platform sources are powered by marine diesel engines. In this study, marine diesel emission factors were developed using recent EPA emission equations derived from a large number of "in use" vessel test data. These emission equations require horsepower and operating load factors. Typical horsepower and load factors were obtained from the 1995 MMS report. These values are averages, such that actual emissions from specific vessels may be significantly different.

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KEY WORDS

Emission inventory
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