*Egypt. J. Chem.* **Vol. 64,** No. 3 pp. 1421 - 1431 (2021)

# Egyptian Journal of Chemistry

**http://ejchem.journals.ekb.eg/**

## $CO_2$ Emissions, Green House Gas Calculations and Controlling in the Gas Plant

**Ebrahiem E. Ebrahiem[1, *], Abdelaziz A. Noaman[1], Tarek M. Aboul-Fotouh[2], Moustapha S. Mansour[3], Yassin A. Hakim[1]**

[1]*Chemical Engineering Department, Faculty of Engineering, Minia University, Minia, Egypt.*

[2]*Mining and Petroleum Engineering Department, Faculty of Engineering, Al-Azhar University, Cairo 11884, Egypt.*

[3]*Chemical Engineering Department, Faculty of Engineering, Alexandria University, Alexandria 21544, Egypt.*

**Abstract**

Gas flaring is one of the most challenging energy and environmental problems facing the world today whether regionally or globally. Gas flaring becomes a public concern and a priority issue because it's waste of a non-renewable source in addition to environmental problems due to gas emissions that produce greenhouse effects. Also, it represents definite risks to human health. Air emissions calculations were conducted based on the international guidelines and found that $CO_2$ pollutant is the main source of the emissions in the gas plant, the yearly emissions of $CO_2$ are 343.3 Ton /year. The second source of emissions in the gas plant is $CH_4$. The yearly emissions from methane CH4 is 3.3 Ton/year. The other sources of emissions in the gas plant include CO, NOx and VOC.

Total GHG emissions from the gas project Facilities during normal operation are estimated to be 55,133 Ton/year $CO_2$ equivalents. $CO_2$ is the main GHG pollutant, which contributes over 91% of the GHG. The calculated GHG intensity of the gas project facilities is 0.05 Tons of $CO_2$ equivalents per ton of the total production.

To minimize the emissions and GHG in the process facilities of the gas plant waste heat recovery unit must be installed, Ultra-Low NOx Burners is recommended for minimizing NOx emissions, $CO_2$ Gas injection to the reservoir to be installed and finally the energy efficiency of the project facilities should be improved by enhancing heat integration and recovery throughout the plant

***Keyword***: flared gas, emission, GHG, fired heater, $CO_2$ injection.

## 1- Introduction

Gas flaring, the process of burning-off associated, unwanted, or excess gases released during normal or unplanned over-pressuring operation in many industrial processes [1, 2]. The impact of gas flaring on man and his environment has become a problem over the years [3].

Gas flaring consist of a mixture of different gases. The composition will depend upon the source of the gas going to the flare system. Associated gases released during oil-gas production mainly contain natural gas. Natural gas is more than 90 % methane ($CH_4$) with ethane and a small number of other hydrocarbons; inert gases such as $N_2$ and $CO_2$ may also be present [4, 5].

Gas flaring contributes to climate change, which has serious implications for the world [6]. Gas flaring is a major source of greenhouse gases (GHG) contributing to global warming which could accelerate the problem of climatic change and harsh living conditions on earth. Flaring releases carbon dioxide and methane, the two major greenhouse gases[7-9].

Globally over 150 billion cubic meters (bcm) of natural gas associated with crude oil production is being flared and vented annually. This volume represents 5% of the global natural gas production and adds the equivalent of 400 million tons of $CO_2$ in annual emissions. It is also a loss of valuable resources which, in many cases, could be used for the benefits of local communities or for export projects. Overall, the loss of revenues through global gas flaring is estimated at approximately US$ 25 billion per year at $5.00 per

*Corresponding author e-mail: prof.ebrahiem@mu.edu.eg; (Ebrahiem E. Ebrahiem).
Receive Date: 27 October 2020, Revise Date: 25 November 2020, Accept Date: 29 November 2020
DOI: 10.21608/EJCHEM.2020.47850.2978

MMBTU. Figure 1 displays the global gas flaring and oil production in the world [10-13].

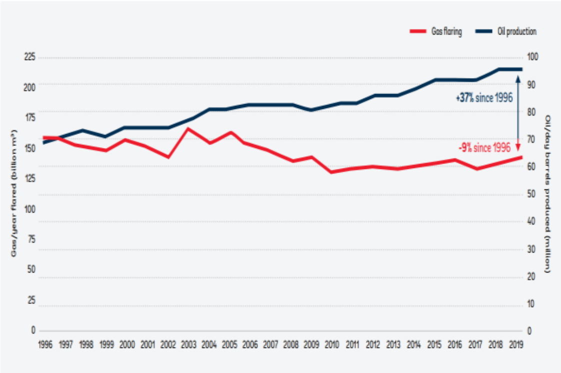


**Figure 1: Global Gas Flaring and Oil Production in the World [1].**

Ovuakporaye et al., [14] showed that gas flaring leads to the presence of air pollutants hazardous that have serious effects on human health such deformities in children, lung damage and skin problems.

Ajugwo [15] discussed that acid rain is resulted from gas flaring also discussed its environmental effects such as vegetation damage and acidizing lakes beside to contribution to degradation and other harms of public health. Moreover, he stated that air pollution subsequent from gas flaring may cause diseases such as cancer, neurological, reproductive, and developmental effects.

Yabin Weng et al., [16] studied the greenhouse- gas emissions measurements and reduction- potential evaluation during oil and gas production in China, the measured GHG emissions showed that the evaporation and flashing loses from the storage tanks were the largest source accounting 86% of the total methane emissions and 42% of the total GHG emissions. Flaring was the second in the overall emissions, accounting for 32 and 8 % of GHG and $CH_4$ emissions, respectively.

Emn et al., [17] studied how to estimate oil flashing losses emissions factor (FLEF) percentage for crude oil storage tanks by using the new equation technique to minimize human errors. This statistical technique is a linear association between possible variables to assess flashing loss percentage as a function of operating temperature, sample point height (H1), oil tank height (H2), gas/oil ratio, gas gravity and oil gravity.

The objective of this work is to study the emission from natural gas facilities and its calculations and reduction in the gas project, including emissions calculation based on the international guidelines, Green House Gas (GHG) emissions , reduction of emissions to air (fired heater, routine venting of natural gas, non-routine & emergency flaring of natural gas and storage tank venting), $CO_2$ Gas injection to the reservoir and improving energy efficiency of the process facilities in the gas plant.

## 2. Gas Project Description

### 2.1 Central Process Facilities (CPF)

Figure 2 reveals the major processing units which make up the central processing facility CPF. The gas project consists of eight wells, a gathering system and CPF, where the production stream from the various fields will be separated into condensate and dew pointed gas products for export. The gas processing involves inlet facilities for liquid separation, mercury removal unit, $CO_2$ removal unit, dehydration unit, and a hydrocarbon dew-pointing unit to meet the export gas specifications.

The condensate separated from the gas in the inlet facilities is stabilized to meet the RVP specification for export condensate. The gas will be exported via export gas pipeline and treated in a dedicated Liquefied Petroleum Gas (LPG) extraction facility to commercial specification required for end user consumption. The condensate will be exported via export pipeline to the oil terminal.

Mercury has been detected up to 70 ng/Sm$^3$ in some well samples. Well samples are reported to contain no elemental Sulphur, no wax, and no paraffin. Also, the $H_2S$ content of the wells is zero

### 2.2 Wellhead Flowlines

Eight producing wells are initially considered for the gas project. Figure 3 demonstrates the wells and the length for each wellhead flow line. A wellhead pressure of 267 bara, wellhead temperature of 50°C and the flowline pressure of 56 bar at the design flow rate of 0.425 MSCMD (15 MMSCFD) shall be used.

The all eight gas wells have the same design flowrate which is 0.425 MSCMD. A range of compositions of different condensate gas ratios (CGRs) can be delivered by each well depending on the layer being produced.

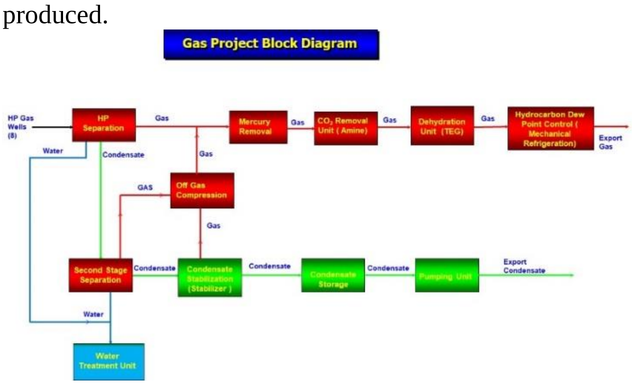


**Figure 2: Schematic of the CPF Process Units.**

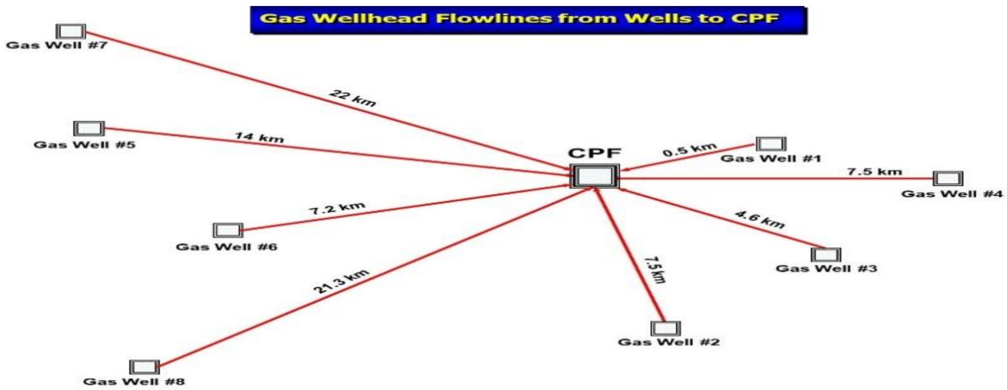


**Figure 3: Gas Wellhead Flowlines from Wells to CPF.**

### 3. Gas Project Design Capacities

The gas project is designed for a production of 2.7 MSCMD export gas and 10,000 STB/day export condensate. Table 1 explore the design flowrates for the for the process facilities of the gas project.

**Table1: Flowrates Design Production**

| Design Capacity | Unit | Value |
|---|---|---|
| Production from wells (Note 1) | MSCMD | 2.9 (Lean Gas)<br>3.3 (Rich Gas) |
| Gas Export (for gas pipeline design) | MSCMD | 2.7 |
| Condensate Export, maximum | STB/d | 10,000 |
| Water Production, water-cut | % Vol. | 10 |

Note1- Includes 0.1 MSCMD of fuel gas.

### 3.1 Product Specifications

The following are the gas and condensate specifications for pipeline export and water specification for disposal.

#### 3.1.1 Export Gas Specifications

The export gas specifications for gas are:

- Water dew point: -12°C.
- Hydrocarbon dew point at 35 barg: +10°C.
- $CO_2$ content: < 1.0 mole %.
- The pressure of the export gas is 44 barg.

#### 3.1.1 Export Condensate Specifications

The condensate export specification requires removal of water and light hydrocarbons to meet the BS&W (< 1 %v/v) and RVP (< 0.8 bar & 37.8 °C) specifications.

### 4. Calculation Method

Emissions to air consist of exhaust gases containing carbon dioxide ($CO_2$), carbon Monoxide (CO), nitrous oxide ($N_2O$), nitrogen oxides ($NO_X$), and methane ($CH_4$), volatile organic compounds (VOC), Sulphur dioxide ($SO_2$) and hydrogen sulphide ($H_2S$) from various types of combustion equipment, vents and flares.

The main sources of emissions identified for this gas project are emissions from gas combustion equipment, this include Gas Turbine Generators (GTG), fired heater , emissions from $CO_2$ venting, emissions from gas flaring and emissions from diesel combustion equipment ( emergency diesel generator and firewater pumps).

### 4.1. Emissions Estimation Methodology

International guidelines for estimating emissions and discharges have been followed to estimate the emissions. The emission factors approach has been adopted to calculate the emissions in the gas plant. Some activities in the gas plant have been exempted , these activities include fugitive emissions (including storage tanks), emissions from produced water storage (Evaporation pond), transportation including transportation of personnel, after sales metering devices, storage of refined products (condensate storage tanks), venting and purging for jobs executions.

Table 2 reveals the calculations of gas emissions from combustion equipment. The fuel gas physical properties (molecular weight, density, ----) were obtained from the simulation of the gas plant by using Aspen HYSYS software, version 10. 1[18]. The operating days per year for the gas plant was assumed to be 354 days.

**Table 2 Emissions from Gas Combustion Equipment**

| Input Data | Turbines | Heater | Remarks |
|---|---|---|---|
| Fuel gas molecular weight, kg/kgmol | 19.99 | 19.99 | Based on the rich gas compositions |
| Fuel gas density, Kg/Sm$^3$ | 0.844 | 0.844 | |
| Fuel gas requirement, Sm$^3$/hr. | 1250.8 | 546 | Based on the rich gas compositions |
| Fuel gas requirement, kg/hr. | 1056 | 461 | |
| Operating days/yr. | 354 | 354 | Emissions are calculated based on plant operation of 354 days/yr. |
| Sulphur Content of gas (Wt. fraction), Ton/Ton | 0 | 0 | |

Table 3 displays the emissions calculations from gas combustions equipment, from the table it can be noticed that. The emission factors for the turbines and heaters were taken from the international guidelines, the total emissions calculations of the heaters and turbines were calculated by multiplying the factor and fuel gas during the operational days which is 354 days ( example: 2.75 X 1056 X 24 X 354/ 1000).

Table 4 illustrate emissions from Diesel Combustion Equipment. The physical properties of the diesel (molecular weight, density, ----) was assumed. The operating hours of the diesel combustion equipment were assumed. The diesel use per year was estimated based on the international best practice in similar projects.

Table 5 displays the emissions calculations from diesel combustions equipment, from the table it can be noticed that the emission factors for the diesel combustion equipment were taken from the international guidelines, the total emissions calculations of the heaters and turbines were calculated by multiplying the factor and fuel gas during the operational days.

**Table 3 Emissions Calculations from Gas Combustions**

| Pollutant | Emissions Factors (Ton emission/Ton gas burnt) | | Estimated Emissions (Ton/yr.) | |
|---|---|---|---|---|
| | Turbines (international guideline) | Heaters (international guideline) | Turbines | Heater |
| $CO_2$ | 2.75 | 2.75 | 24674 | 10771 |
| CO | 0.0027 | 0.0008 | 24.2 | 3.1 |
| NOx | 0.0067 | 0.0031 | 60.1 | 12.1 |
| $N_2O$ | 0.00022 | 0.00022 | 1.97 | 0.86 |
| SO2 | 0.0 | 0.0 | 0.00 | 0.00 |
| $CH_4$ | 0.00042 | 0.00007 | 3.77 | 0.27 |
| VOC | 0.000051 | 0.00062 | 0.46 | 2.43 |

**Table 4 Emissions from Diesel Combustion Equipment**

| Input data: | Emergency Diesel Generator | Fire Water Pumps | Remarks |
|---|---|---|---|
| Peak diesel use, m$^3$/hr. | 0.455 | 0.135 | |
| Operating hours, Hr./Yr. | 168 | 17 | - It is assumed that emergency diesel generator will operate for 7 days/year including test.<br>- It is assumed that the firewater pump will be tested once/week for 20 minutes. |
| Diesel density, Kg/l | 0.83 | | Diesel density is assumed 0.83 kg/l |
| Estimated Diesel use / year, Ton/Yr. | 63.45 | 1.94 | |
| Sulphur Content of diesel (Weight fraction Ton/Ton) | 0.00005 | | Diesel Sulphur content has been considered 50 ppm |

**Table 5 Emissions Estimation**

| Pollutant | Emission Factors (Ton emissions/ Ton gas burnt) (international guideline) | Estimated Emissions from Emergency Diesel Generator (Ton/yr.) | Estimated Emissions from Fire Water Pumps (Ton/yr.) | Total Estimated Emissions from Diesel Combustion (Ton/yr.) |
|---|---|---|---|---|
| $CO_2$ | 3.2 | 203 | 6.22 | 209 |
| CO | 0.019 | 1.21 | 0.04 | 1.25 |
| NOx | 0.07 | 4.44 | 0.14 | 4.58 |
| $N_2O$ | 0.00022 | 0.014 | 0.0004 | 0.014 |
| $SO_2$ | 0.0001 | 0.006 | 0.0002 | 0.007 |
| $CH_4$ | 0.00014 | 0.009 | 0.0003 | 0.009 |
| VOC | 0.0019 | 0.121 | 0.0037 | 0.124 |

Table 6 shows the emissions from gas flaring, the physical properties of the flared gas (molecular weight, density, ----) were obtained from the simulation of the gas plant by using HYSYS simulation program, version 10. 1. The operating days per year for the gas plant was assumed to be 365 days. The LP fuel gas for pilot was estimated.

**Table 6 Emissions from Gas Flaring**

| Input data: | HP and LP Flare | Remarks |
|---|---|---|
| Fuel gas molecular weight, kg/kgmol | 19.99 | |
| Fuel gas density, Kg/Sm$^3$ | 0.84 | |
| Estimated LP fuel gas for pilot, Sm3/hr. | 2.0 | |
| Estimated LP fuel gas for pilot, kg/hr. | 1.7 | |
| Operating days/yr. | 365 | |
| Worst case flaring scenario flow, Ton/Yr. | 93.2 | De-pressurization at maximum plant capacity with export route blocked for 15 minutes is assumed the worst case-flaring event. Frequency is assumed to be 4 times a year. |

Table 7 shows the gas flaring calculations, from the table it can be noticed that the emission factors for the gas flaring equipment were taken from the international guidelines, the total emissions calculations of the gas flaring equipment were calculated by multiplying the factor and fuel gas during the operational days .

Table 8 reveals the emissions from gas venting in the process facilities of the gas plant. Vent gas flow rates have been taken from process simulation data. From the table 8, it can be noticed that the main component in the gas venting is $CO_2$ and the amount of emission per year is 14426 Ton/Year. The other sources include $CH_4$ and VOC. The calculations of the emission resulting from the vent gas is based on plant operation 354 days /year

Table 9 displays the Green House Gas Intensity Calculation: GHG intensity = Tones of $CO_2$ equivalent / Tones of production = 55133 / 1060230 = 0.05 Ton $CO_2$ Equivalent / Ton production

## 5. Results & Discussions

### 5.1 Air Emissions Calculations

Table 10 provides air emissions summary based on sources and the respective calculation details stated in the previous section. From table 10, it can be noticed based on the flare worst scenario the following: -

-The yearly emissions of $CO_2$ are 343.3 Ton /year. $CO_2$ pollutant is the main source of the emissions in the gas plant. The sources of $CO_2$ emissions are turbines, heaters, diesel generators and $CO_2$ venting from the gas sweetening stage.

- The second source of emissions in the gas plant is $CH_4$. The yearly emissions from methane $CH_4$ is 3.3 Ton/year. The source of $CH_4$ emissions in the gas plant are turbines, heaters, diesel generators and $CO_2$ venting from the gas sweetening stage.

The other sources of emissions in the gas plant include CO, NOx and VOC.

**Table 7 Gas Flaring Emissions Calculations**

| Pollutant | Emission Factors (Ton emissions/ Ton gas burnt) (international guideline) | Estimated Emissions from Flare Pilot (Ton/Yr.) | Emissions from Worst Case Flaring Scenario (Ton/Yr.) |
|---|---|---|---|
| $CO_2$ | 2.61 | 38.6 | 243.3 |
| CO | 0.0087 | 0.13 | 0.8 |
| NOx | 0.0015 | 0.022 | 0.1 |
| $N_2O$ | 0.000081 | 0.0012 | 0.008 |
| SOx | 0.0000128 | 0.0002 | 0.001 |
| $CH_4$ | 0.035 | 0.52 | 3.3 |
| VOC | 0.015 | 0.22 | 1.4 |

**Table 8 Emissions from $CO_2$ Venting**

| Vent Gas Compositions | Estimated Emissions (Ton/Yr.) | Remarks |
|---|---|---|
| $CO_2$ | 14426 | Emissions are calculated based on plant operation of 354 days/year. |
| $H_2S$ | 0 | The $H_2S$ content of the wells is considered zero. |
| $CH_4$ | 192 | Emissions are calculated based on plant operation of 354 days/year. |
| VOC | 58 | Emissions are calculated based on plant operation of 354 days/year. |

**Table 9 Green House Gas Intensity Calculation**

| | |
|---|---|
| The overall yearly GHG emissions, Ton $CO_2$ equivalent/year | 55133 |
| Export Gas design flow, MSCMD | 2.7 |
| Condensate export design flow bbl./day | 7000 |
| Export gas density, kg/Sm$^3$ | 0.8 |
| Condensate density, kg/Sm$^3$ | 750 |
| Export gas mass flow rate, Ton/day | 2160 |
| Export condensate mass flow rate, Ton/day | 835 |
| Total daily mass flow rate of gas and condensate, Ton/day | 2995 |
| Total yearly mass flow rate of gas and condensate, Ton/year (Considering 354 days plant availability) | 1060230 |

**Table 10 Air Emissions Summary**

| Pollutant | Yearly Estimated Emissions - Normal Operations (Ton/yr.) | | | | | | Yearly Estimated Emissions - Non-Routine Operations (Flare Worst Case Scenario) (Ton/year) |
|---|---|---|---|---|---|---|---|
| | Turbines | Heater | Diesel Combustion | Flare Pilot | $CO_2$ Venting | Total Emissions | |
| $CO_2$ | 24674 | 10771 | 209 | 38.6 | 14426 | 50119 | 243.3 |
| CO | 24.2 | 3.1 | 1.2 | 0.13 | 0.0 | 28.7 | 0.8 |
| $NO_x$ | 60.1 | 12.1 | 4.6 | 0.022 | 0.0 | 76.9 | 0.1 |
| $N_2O$ | 1.97 | 0.86 | 0.014 | 0.0012 | 0.0 | 2.85 | 0.008 |
| $SO_2$ | 0.00 | 0.00 | 0.007 | 0.0002 | 0.0 | 0.007 | 0.001 |
| $CH_4$ | 3.77 | 0.27 | 0.009 | 0.52 | 192 | 197 | 3.3 |
| VOC | 0.46 | 2.43 | 0.124 | 0.22 | 58 | 62 | 1.4 |
| $H_2S$ | 0.00 | 0.00 | 0.00 | 0.00 | 0.0 | 0 | |
| GHG - $CO_2$ Equivalent | 25365 | 11044 | 214 | 50 | 18461 | 55133 | 18461 |

Figure 4 reveals the estimated percentages (by weight) of yearly pollutant emissions during normal plant operations in the process facilities of the gas plant. $CO_2$ is the major pollutant followed by $CH_4$ and $NO_X$.

Figures 5, 6,7,8,9 and 10 provide a picture of major pollutant emissions from various sources. These yearly emissions figures will help in the understanding of the main source of pollution for each pollutant.

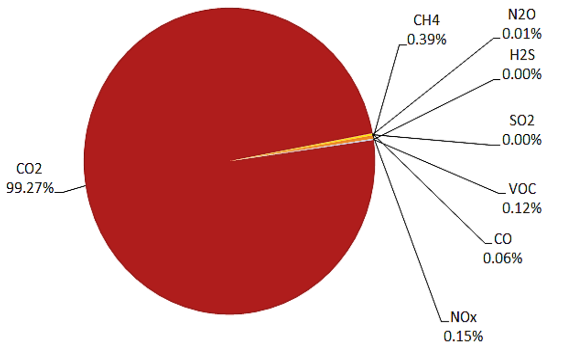


**Figure 4: Percentage Yearly Air Pollutant Emissions during Normal Operations**

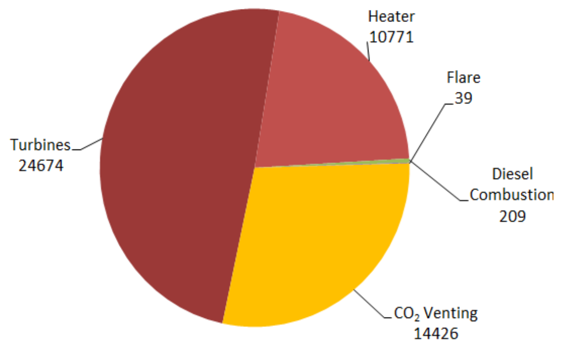


**Figure 5: Estimated Yearly $CO_2$ Emissions per Ton**

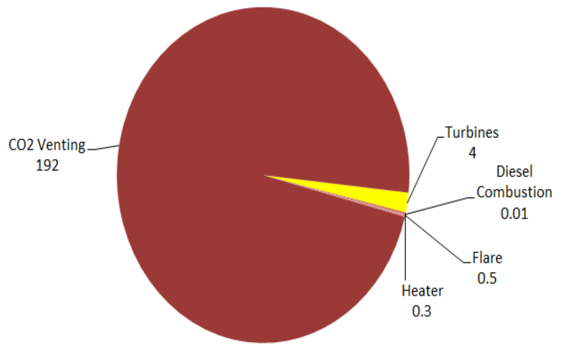


**Figure 6: Estimated Yearly $CH_4$ Emissions per Ton**

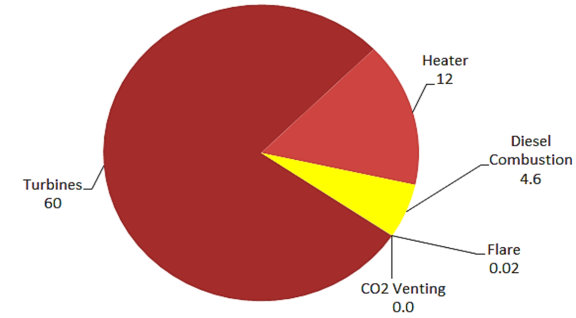


**Figure 7: Estimated Yearly $NO_X$ Emissions per Ton**

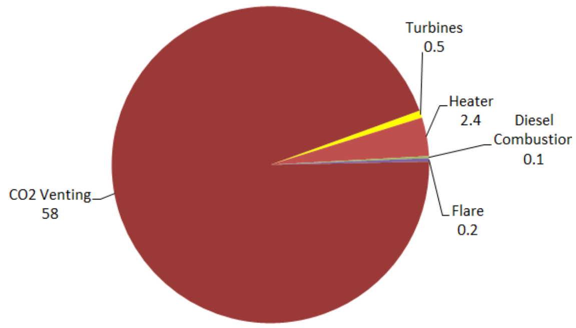


**Figure 8: Estimated Yearly VOC Emissions per Ton**

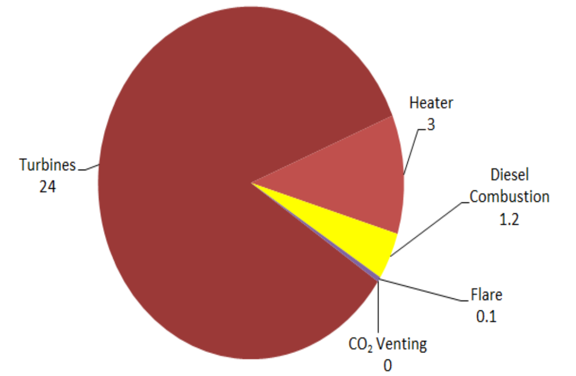


**Figure 9: Estimated Yearly CO Emissions per Ton**

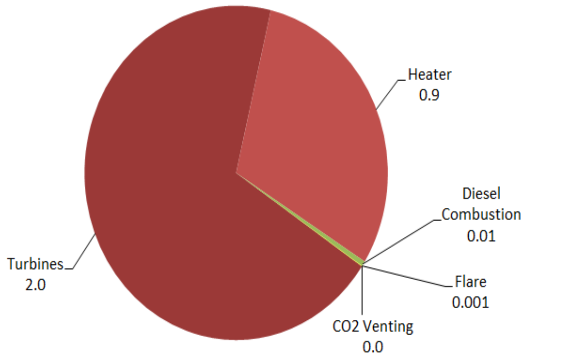


**Figure 10: Estimated Yearly $N_2O$ Emissions per Ton**

### 5.2. Green House Gas (GHG) Emissions

The main six GHG's, as listed in the Kyoto protocol, are carbon dioxide ($CO_2$), methane ($CH_4$), nitrous oxide ($N_2O$), hydrofluorocarbons (HFCs), perfluorocarbons, and Sulphur hexafluoride and emission of these gases shall be minimized as much as reasonably practicable [20].

To reduce GHG emission there shall be no continuous and routine venting or flaring of associated gas GHG emissions have been estimated as $CO_2$ equivalent. $CO_2$ equivalent is a measure for describing how much Global Warming Potential (GWP) a given type and amount of greenhouse gas may cause, using the functionally equivalent amount or concentration of $CO_2$ as the reference. $CO_2$ equivalent of $CH_4$ and $N_2O$ have been considered as 21 and 310 respectively based on 100 years Global Warming Potential (GWP).

The highest potential to reduce greenhouse gas emissions are operations include flaring and/or venting of hydrocarbons and $CO_2$, significant fugitive emissions and combustion emissions from power generation.

Total GHG emissions from the gas project Facilities during normal operation are estimated to be 55,133 Ton/year $CO_2$ equivalents. $CO_2$ is the main GHG pollutant, which contributes over 91% of the GHG. Figure 11 reveals the percentage yearly GHG emissions for different pollutants. Figure 12 highlight the main sources, which contribute towards GHG pollution.

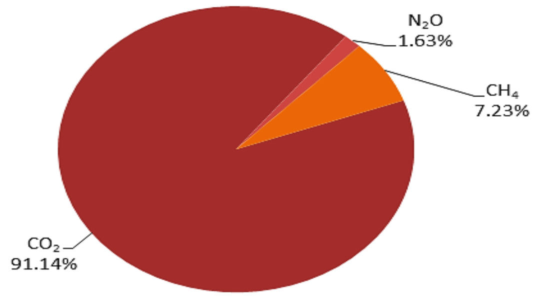


**Figure 11: GHG Contribution during Normal Operations**

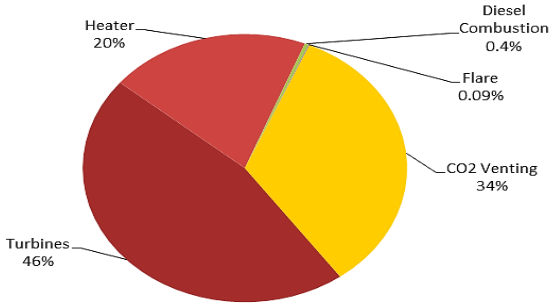


**Figure 12: GHG Emissions based on Sources**

### 5.3. GHG Intensity

The GHG intensity is defined as the tones of $CO_2$ equivalent emissions in the facility per ton of total gas and condensate production. The calculated GHG intensity of the gas project facilities is 0.05 tons of $CO_2$ equivalents per Ton of the total production.

### 5.4. $CO_2$ Injection

Sweeting unit by amine in the gas plant is used to remove $CO_2$ from the natural gas to meet the export gas specifications. The export gas specification for $CO_2$ content should be less than 1 mole%. The feed gas composition has an inlet concentration of 2.51 mole% which exceed the specification for export gas. Therefore, $CO_2$ removal is required to meet the gas export specification. The amount of $CO_2$ released to the atmosphere will therefore be equivalent to 1.63%. Compression package should be used to reinject this $CO_2$ in the wells.

Aspen HYSYS version 10.1 steady state was used to simulate the compression skid and pipeline needed to inject the $CO_2$ in the well. The composition of the $CO_2$ feed stream to the compression package was taken from the simulation of the process facilities in the gas plant and confirmed by Bryan Research and Engineering "ProMax" ® version 5 []. Peng-Robinson equation of state with modified interaction parameters fluid package was used to simulate the compression package needed to inject the $CO_2$ in the well.

The main process simulations in the gas plant have been carried out with AspenTech Process Modelling Aspen "HYSYS" version 10.1. A supporting simulation for the amine (MDEA) and TEG systems has been developed using Bryan Research and Engineering "ProMax" ® version 5[19] . This is a specialist amine and TEG package which is considered to give more accurate predictions of performance of $CO_2$ removal systems. It is used to provide input to Aspen HYSYS regarding the process outlet temperature from both columns, as well as estimating the amine circulation rate, TEG circulation rate and duties for heat exchangers in the respective regeneration packages.

The selected physical property package for the Aspen HYSYS model developed for the gas project is the Peng-Robinson equation of state with modified interaction parameters fluid package. ProMax uses the amine sweetening – SRK and SRK equations of state for vapour phase properties, and the electrolytic ELR and SRK models for liquid phase properties, of the amine and TEG simulations respectively. The binary coefficients in Aspen HYSYS and ProMax have been selected as recommended by the software.

Units are based upon the metric system, with pressures quoted in barg. Standard conditions are defined as 15.6°C (60°F) and 1.01323 bara (1 atm).

The compression system contains 4 stages to increase the pressure of the acid gas from 5 psig to up to 2000 psig. A suction scrubber will remove any residual liquid in the stream. The material used for the compression system should be designed to resist the corrosion, Pipelines will be used for $CO_2$ transport to the well for injection. Figure 13 displays the simulation of the $CO_2$ Injection by using Aspen HYSYS simulation software.

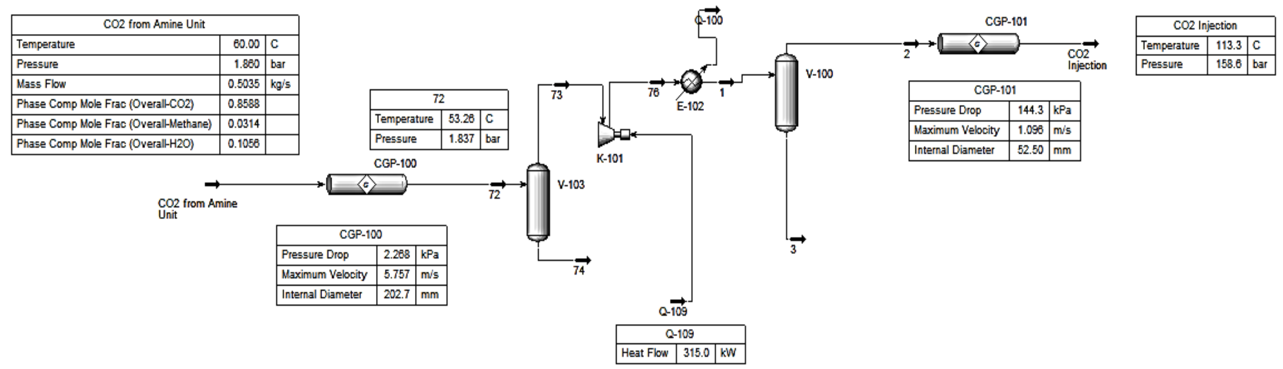


**Figure 13: Aspen HYSYS Software for Gas for $CO_2$ Injection in Reservoir**

The pipeline should be short as possible, the disposal well should be near to the plant as possible. Stainless steel (316 L) should be used for the pipeline construction for corrosion resistance and injection system: The injection system comprises surface facilities at the injection site, e.g. storage facilities (if required), distribution manifold at end of transport pipeline, distribution pipelines to wells, additional compression facilities (if required), measurement and control systems in the wellhead(s) and the injection wells .Aspen HYSYS simulation software was used to design the compression system needed for the injection of $CO_2$ in the disposal well as shown in Figure 11. From the simulation results, the duty of the compressor needed for the injection is 315 kW and 2'' pipeline will be required.

## 6. Conclusions

Routine air emissions from process facilities of the gas plant will arise from fired heaters used for heating process fluids/utilities, compressor seal gas vents, power generation, waste incineration and amine regeneration overhead column ($CO_2$).

Non-routine and emergency emissions will arise from emergency blowdown (via a flare stack), vents from well site, process plant pressure relief devices, maintenance requiring plant blowdown, pipeline pigging operations and storage tank venting.

Air emissions calculations were conducted based on the international guidelines and found that $CO_2$ pollutant is the main source of the emissions in the gas plant, the yearly emissions of $CO_2$ are 343.3 ton /year. The second source of emissions in the gas plant is $CH_4$. The yearly emissions from methane $CH_4$ is 3.3 Ton/year. The other sources of emissions in the gas plant include CO, NOx and VOC.

Total GHG emissions from the gas project Facilities during normal operation are estimated to be 55,133 Ton/year $CO_2$ equivalents. $CO_2$ is the main GHG pollutant, which contributes over 91% of the GHG. The calculated GHG intensity of the gas project facilities is 0.05 Tons of $CO_2$ equivalents per ton of the total production.

### 6.1. Fired Heaters

Fired heaters for heating media e.g. TEG, hot oil and any other process/utility heaters will burn natural gas as fuel. Hence the emissions will comprise the normal combustion products associated with natural gas combustion. Burner management systems will be provided to maximize combustion efficiency thus minimizing emissions of carbon monoxide, particulates (PM10) and unburned hydrocarbons. In line with the Indicative BAT, low $NO_X$ burners will be installed to minimize $NO_X$ emissions. Ground level concentrations of those pollutants which are covered by an air quality standard ($NO_X$, $SO_X$, PM10 and Carbon Monoxide) will be further controlled by discharging the flue gases through suitably sized stack. This will prevent or minimize emissions to air from the Project facilities.

### 6.2. Natural Gas Venting

The venting of natural gas containing methane to atmosphere must be minimized. The main source of continuous venting will be associated with the seal system on the natural gas compressors. If the compressors selected are reciprocating type, venting of natural gas through seal system will not be an issue. Natural gas dissolved with purge gas (nitrogen) will be directed to flare. It is feasible to reduce the greenhouse gas emissions associated with the gas leakage from the primary gas seals by recompression of the seal gas and return to the gas supply. However, this is uneconomic for the small quantity of release expected and problematic due to increasing the operating complexity of the system, reducing the reliability of the system and the requirement for a minimal backpressure on the seal.

### 6.3. Gas Flaring

Flare systems are provided for abnormal (start-up, shutdown) and emergency conditions. In the event of a plant emergency, a fire or a confirmed loss of containment of gas, an emergency shutdown (ESD) of the CPF will occur. Releases from PSVs are likely to be infrequent, of relatively short duration and have minimal impact. Precautions will be taken to prevent fugitive emissions from relief valves.

### 6.4. Storage Tanks

Condensate will be stabilized to low TVP to eliminate the potential for fugitive emissions from the condensate storage tanks. The main chemicals stored in tanks at site will be methanol and TEG. TEG is less volatile (the boiling point is 278°C) than methanol (boiling point is 64.7 °C) hence air emissions of TEG via the tank vents will be very low.

### 7. Recommendations

To minimize the emissions from the process facilities of the gas plant, the following items should be considered: -

- The energy efficiency of the project facilities should be improved by enhancing heat integration and recovery throughout the plant. Cold process gas should be used to cool the hot process gas before it is processed in the gas treatment plant.
- In the glycol and amine regeneration systems, cooler rich streams should be used to cool the hotter lean streams to minimize heating and cooling demand. A Waste Heat Recovery System (WHRS) and co-generation system should be considered as part of the optimization of the plant heat balance.
- Ultra-Low NOx Burners (recommended for minimizing NOx emissions) have limited turndown capability and should be used instead of the conventional one. Ultra-low NOx burners are less reliable than the more conventional low NOx burners and both these limitations motivate the use of WHRS.
- A waste heat recovery unit (WHRU) can be considered to transfer waste heat produced by gas turbine compressors and use it to heat the heating medium utility required to process gas. By transferring and re-using the waste heat, the project can reduce its fuel gas consumption and subsequent $CO_2$ emissions. The main advantages of the WHRU are reduced fuel gas consumption, a reduction in greenhouse gas emissions of about 7000 tons per annum of $CO_2$ equivalent during the early years of field life.
- 3.8 to 6.5 MW of heat can be extracted from the turbine exhaust gases. However, during the winter case, when the demand on heating medium is at its peak only about 3.8 to 4.7 MW heat can be extracted. Accordingly, a supplementary firing system supplied with fuel gas will be required to provide the balance heating duty.

**Nomenclature**

| **Abbreviation** | **Description** |
|---|---|
| BAT | Best Available Technologies |
| BCM | Billion Cubic Meters |
| BTU | British thermal unit |
| CPF | Central Process Facilities |
| EDP | Emergency Depressurization |
| ESD | Emergency Shutdown |
| FGR | Flare Gas Recovery |
| GHG | Greenhouse Gas |
| GTL | Gas to Liquid |
| GTG | Gas Turbine Generators |
| GWP | Global Warming Potential |
| HFCs | Hydrofluorocarbons |
| Kg | Kilogram |
| LPG | Liquefied Petroleum Gas |
| MMSCFD | Million Standard Cubic Feet |
| MW | Mega Watt |
| ng | Nanogram |
| NGL | Natural Gas Liquid |
| NOx | oxides of nitrogen |
| PR | Peng-Robinson |
| PM10 | Particulate Matter |
| RVP | Reid Vapor Pressure |
| SRK | Soave-Redlich-Kwong |
| SOx | sulfure oxides |
| TEG | Tri Ethylene Glycol |
| TVP | True Vapour Pressure |
| VOCs | volatile organic compounds |
| WHRS | Waste Heat Recovery System |
| SCF | Standard Cubic Feet |
| UNEP | United Nations Environment |

Yr. Year

## 8. Conflicts of interest

There are no conflicts to declare.

## 9. Funding sources

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

The authors will be responsible for their financial interest

## References

[1] Kidnay, A.J., Parrish, W.R., McCartney, D.G., " Fundamentals of Natural Gas Processing", CRC Press, Boca Raton, FL, USA, 2011.

[2] Christopher D. Elvidge, Morgan D. Bazilian, Mikhail Zhizhin, Tilottama Ghosh, Kimberly Baugh, Feng-Chi Hsu, "The Potential Role of Natural Gas Flaring in Meeting Greenhouse Gas Mitigation Targets", Energy Strategy Reviews 20, pp. 156-162, 2018.

[3]Davoudi M, Rahimpour M R, Jokar S M, Nikbakht F, Abbasfard H , "The major sources of gas flaring and air contamination in the natural gas processing plants: a case study", Journal Natural Gas Science Engineering 13 7–19,2013

[4] Younessi S., Omidkhah, M., Tarighaleslami, A., Study on flare gas recovery (FGR) to minimize wastes and economic benefits., The 17th Regional Symposium on Chemical Engineering (RSCE2010), November 1, 2010.

[5] Zadakbar O., Vatani, A., Karimpour, K., "Flare gas recovery in oil and gas refineries", Oil Gas Sci. Technol. - Rev. IFP 63, pp. 705-711, 2008

[6] Al-Bidaiwi, M. S., Beg, M. S., Al-Muhannadi, M. I., "Qatar Petroleum, Gas Flaring Reduction Initiatives in Dukhan Oil & Gas Field", Society of Petroleum Engineers International Production and Operations Conference and Exhibition, Qatar, 2012.

[7] Orimoogunje, O.I., Ayanlade, A., Akinkuolie, T.A., Odiong, A.U., "Perception on the Effect of Gas Flaring on the Environment", Research Journal of Environmental and Earth Sciences, 2, pp. 188-193, 2010.

[8] O. Anomohanran, "Determination of Greenhouse Gas Emission Resulting from Gas Flaring Activities in Nigeria", Energy Policy 45, pp. 666–670, 2012.

[9] United Nations Environment Program, "Natural Allies: UNEP and Civil Society", Nairobi: United Nations Foundation, 2004.

[10] Elvidge, C.D., Ziskin, D., Baugh, K.E., Tuttle, B.T., Ghosh, T., Pack, D.W., Erwin, E.H., Zhizhin, M., "A Fifteen-year Record of Global Natural Gas Flaring Derived from Satellite Data", Energies 2, pp. 595-622, 2009.

[11] International Energy Agency, "3rd IEA Unconventional Gas Forum", Chengdu, China: April 10, 2015.

[12] World Bank, "Regulation of Associated Gas Flaring and Venting. A Global Overview and Lessons from International Experience" World Development Report, Washington, 2000/2001.

[13] BP Statistical Review of World Energy, June 2019 $68^{th}$ edition. Available at: www.bp. Com/statistical review.

[14] Ovuakporaye, S., Aloamaka, C. P., Ojieh A., Ejebe D., Mordi, J. C., "Effects of Gas Flaring on Lung Function Among Residents in Gas flaring Community in Delta State", Nigeria, Res. J. Environ. Earth Sci., vol. 4, pp. 525-528, 2012.

[15] Ajugwo, A. O., "Negative Effects of Gas Flaring: The Nigerian Experience", Journal of Environment Pollution and Human Health, vol.1 (1), pp. 6-8, 2013.

[16] Yabin Weng, Ming Xue, Xiangyu Cui," A Case Study of Greenhouse- Gas Emissions Measurements and Reduction – Potential Evaluation During Oil and Gas Production in China", SPE International Conference and Exhibitions on Health, Safety , Environment and Social Responsibility, Abu Dhabi, , SPE-19502,2019.

[17] Eman M., Mansour, Saad M., Desouky, Mohamed Elail, "Flashing Losses Emission Evaluation from Crude Oil Storage Tanks", Egyptian Journal of Chemistry, April 2020

[18] Aspen Tech., "Advanced Process Modeling Using HYSYS", 2015.

[19] BR&E ProMax® Version 3.1. Bryan Research & Engineering, Inc. P.O. Box 4747 Bryan, Texas, 2008.

[20] United Nations Kyoto Protocol to the United Nations Framework Convention on Climate Change, 1998