Schemes for Fossil Fuel Greenhouse Gas Upstream Reductions – Evaluating and Selecting Schemes and Standards for the Purpose of Article 7a of the FQD

May 2013

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Task 1

1. Introduction

1.1 Objectives

1.1.1 Objectives of project

The first objective of this study is to describe the technical, economic and regulatory variables that affect the potential for improving/incentivising upstream GHG reductions. This will entail presenting the most economically preferred approaches utilized to date with the use of marginal abatement curves (MACs) for upstream GHG reductions and conducting sensitivity analysis on the pertinent technical, economic and regulatory parameters to highlight potential economic drivers that could facilitate further investment in GHG reductions.

The second objective is to develop guidelines and principles for development of methods/best practices for measuring and verifying GHG emission reductions and guidelines for legislators for screening, evaluating and selecting existing and future schemes, carbon credit standards or certification programmes that ensure that GHG emission reductions are aligned with the requirements prescribed in the draft implementing measure.

1.1.2 Objectives of task

This is the first of three tasks that collectively address the first objective of the study. This task is intended to analyze historical reduction projects that reduce greenhouse gas emissions (GHG) from the flaring or venting of associated petroleum gas. The analysis focuses only on countries from which the European Union imports crude oil, with the primary focus being on the largest crude suppliers. Actual operating projects are the focus, but projects under review and consideration that have adequate data were included as well. In order to be included, the project information must be available for the cost of implementation, GHG reductions achieved, and the amount of crude oil produced at the location of the project.

Once the projects were identified, histograms of the projects were produced. The histograms were based on project type as well as project location. The histograms illustrate which projects have been most successful in reducing emissions per unit of oil production.

Finally, hypothetical pipeline projects were developed to gather, treat, and transport associated petroleum gas. Lack of infrastructure is one of the main reasons associated petroleum gas is vented or flared, wasting potentially recoverable gas that could be sold, and thereby contributing to GHG emissions. These projects exemplify the potential viability of constructing a pipeline to gather, treat, and transport associated petroleum gas. This analysis reviews three potential projects, each located in a different geographic region.

2. Findings

2.1 Selection of projects

Projects selected met several specific criteria to be included on the list. First, the project had to be implemented in a country that exports crude oil to the European Union, with specific focus given to the countries that export the majority of crude oil. Second, the project had to be an implemented project, or a fully designed project with the possibility of implementation. Finally, the project had to include a reasonable level of data. This means that, at a minimum, the project description and data had to include cost of implementation, reductions achieved/projected to achieve, and the location (i.e. in which oil field(s) the project was located). Other relevant data, such as oil field production values, needed to be available as well. In addition, several projects under review and consideration that had adequate data were included. Any project that was externally audited or verified was favored.

In order to carry out this task, many resources were consulted. The prime source for gathering projects was the United Nations Framework Convention on Climate Change (UNFCCC) website. This website provides detailed descriptions for emission reduction projects under the Clean Development Mechanism (CDM). The CDM requires emission reductions projects to be rigorously vetted, ensuring high quality data. Most of the projects presented in this analysis were taken from this source, excluding the theoretical pipeline analysis. For completeness, two other outside sources were consulted. These were the Global Methane Initiative website and the World Bank. While both of these sources contained information on various greenhouse gas emission reduction projects, they did not contain all the data necessary for this analysis. A final source of projects came from ICF's internal records. These projects are under review and consideration and contain confidential information; therefore the country, company, and oil field names have been removed. However, these are relevant projects so they were included in this analysis.

While the CDM projects on the UNFCCC website contain high levels of detail, they do not always contain all the necessary data for this analysis. The most common piece of missing data was the oil production levels. In these instances, other sources were consulted. While not all potential sources are as thoroughly vetted as the UNFCCC website, the data used was from reliable sources. The most common source for the crude oil production values was the Oil and Gas Journal's Worldwide Production survey. This is an annual survey published by the Oil and Gas Journal that documents production levels at all of the known oil fields in the world. However, some of the fields are grouped together, and in those cases, further sources were needed. When this was required, company websites were used whenever possible, as well as any news briefs written about the oil fields. Internet searches were also conducted to locate information. All sources of information used outside of the UNFCCC CDM website have been documented in the analysis spreadsheet.

2.2 Information on projects

2.2.1 List of countries and projects

The list of countries that supply crude oil to the European Union was compiled and is shown in Table 1. The areas of interest were the Middle East, Africa, the former Soviet Union (FSU), and the Americas. For completeness, supplies from Europe were included in this list, but were not focused on in the subsequent study.

Table 1 breaks down the crude oil supply by both region and by specific country in each region. Both the volume of imports is provided, as well as the percentage the imports contribute to the total.

Table 1: Crude Oil Supply to the European Union by Producing Country

Region	Country of Origin	Volume (1000 bbl)	% of Total Imports
Middle East	Abu Dhabi	3 290.	0.09 %
	Iran	212 749.	5.66 %
	Iraq	118 560.	3.15 %
	Kuwait	24 753.	0.66 %
	Oman	1 022.	0.03 %
	Saudi Arabia	226 213.	6.01 %
	Syria	54 463.	1.45 %
	Yemen	1 734.	0.05 %
	Other Middle East Countries	71.	0.00 %
	Middle East Subtotal	**642 855**	**17.09 %**
Africa	Algeria	59 814.	1.59 %
	Angola	58 089.	1.54 %
	Cameroon	14 838.	0.39 %
	Congo	19 223.	0.51 %
	Congo (DR)	1 838.	0.05 %
	Egypt	27 897.	0.74 %
	Gabon	8 125.	0.22 %
	Libyan Arab Jamahiriya	402 980.	10.71 %
	Nigeria	164 245.	4.37 %
	Tunisia	8 839.	0.23 %
	Other African Countries	47 514.	1.26 %
	Africa Subtotal	**813 401**	**21.62 %**
FSU	Azerbaijan	146 742.	3.90 %
	Kazakhstan	224 638.	5.97 %
	Russian Federation	1 117 353.	29.70 %
	Ukraine	590.	0.02 %
	Other FSU countries	105 827.	2.81 %
	FSU Subtotal	**1 595 149**	**42.40 %**
Europe	Norway	492 358.	13.09 %
	Other European countries	93 976.	2.50 %
	Europe Subtotal	**586 334**	**15.59 %**
America	Argentina	4 632.	0.12 %
	Brazil	34 648.	0.92 %
	Canada	4 179.	0.11 %
	Colombia	4 492.	0.12 %
	Ecuador	484.	0.01 %
	Mexico	46 125.	1.23 %
	Venezuela	29 623.	0.79 %
	America Subtotal	**124 184**	**3.30 %**
	WORLD TOTAL	**3 761 923**	**100. %**

(1) Source: Council Regulation (EC) n°2964/95 of 20 December 1995.

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Applicable projects that targeted to reduce GHG emissions from associated petroleum gas were selected, based on the countries and the supply levels outlined in Table 1. These projects, all located in one of the supplying countries, are listed in Table 2.

For a CDM project, emission reductions are calculated using formulae and tools prescribed by an approved CDM methodology. Methodology and tools dictate which parameters need to be monitored, at what frequency and accuracy (where applicable), and which parameters are fixed throughout the crediting period(s). For project registration, ex-ante emission reductions need to be calculated for the entire crediting period. These are described in the project design document (PDD). These calculations are based on historic activity data and documented projections. All assumptions need to have supporting evidence, which are checked thoroughly by a Designated Operational Entity as part of the validation process and again by the UNFCCC during the registration process.

Once a project is registered, it needs to implement and follow a monitoring plan as described in a registered Project Design Document (PDD). Based on monitored data, a monitoring report is developed, which includes project status description and calculations of achieved emission reductions over a monitoring period. This report is submitted for verification and issuance. Again, emission reductions are calculated using the same formulae as described in a registered PDD, and prescribed by the approved methodology. Note that JI projects have a flexibility to use either CDM approved methodologies or a project-specific approach. In any case, JI projects follow the same principles. In general, emissions factors used in CDM and JI projects are consistent with US Environmental Protection Agency (EPA) and the Global Methane Initiative (GMI).

Table 2: Historical Emission Reduction Projects

Country	Project ID	Project Title	Estimated Reductions [tCO_{2e}/year]	Verified Reductions [tCO_{2e}/year]	Production of oil	Reductions per Unit Production (tCO_{2e}/Mbbl)
Iran	1	Soroosh & Nowrooz Early Gas Gathering and Utilization Project (S&N project)	463,122	202,699	87,000 bbl/d	6.38
Qatar	2	Al-Shaheen Oil Field Gas Recovery and Utilization Project	2,957,108 Reduce flaring from 180 MMscfd to 40 MMscfd	N/A	1 Billionth barrel of oil/year (2010) 300,000 barrels a day 260,000 bbl/d in 2006	31.16

Country	Project ID	Project Title	Estimated Reductions [tCO_{2e}/year]	Verified Reductions [tCO_{2e}/year]	Production of oil	Reductions per Unit Production (tCO_{2e}/Mbbl)
Nigeria	3	Recovery and marketing of gas that would otherwise be flared at the Asuokpu/Umutu Marginal Field, Nigeria	256,793	N/A	The JV partners in December 2007 commenced oil production from the Asuokpu/Umutu marginal field at a flow rate of between 3,000 and 4,000 BPD.	201.01
Nigeria	4	Pan Ocean Gas Utilization Project	2,626,735	0	40,000 barrels per day	179.91
Nigeria	5	Recovery of associated gas that would otherwise be flared at Kwale oil-gas processing plant, Nigeria.	1,496,934	555,520	42,000 barrels of crude oil per day	36.24
Equatorial Guinea	6	Reduction of Flaring and Use of Recovered Gas for Methanol Production	2,263,165	N/A	approx. 60,000 bbl/d of condensate	103.34
Angola	7	Angola LNG Project of Capture and Utilization of Associated Gas	13,709,960	N/A	1.542million bbl/d Prod. by Block: 0: 365 Mbbl/d 14: 222 Mbbl/d 15: 490 Mbbl/d 17: 360 Mbbl/d 18: 100 Mbbl/d	24.36
Democratic Republic of Congo (DRC)	8	Recovery and Use of Gas from Oil Wells – Reduction of Gas Flaring by the Compression of Low Pressure Gas for Productive Use at the Libwa, Tshiala and GCO Offshore Oil Fields, Democratic Republic of Congo”	443 305	N/A	28,000 bbl/d	43.38
United Arab Emirates	9	Flare reduction and Utilization of Low Pressure Gas at New Khuff Production Platform -- TOTAL ABK	146,049	N/A	Capacity limited to 30,000 bbl/d	13.34

Country	Project ID	Project Title	Estimated Reductions [tCO_{2e}/year]	Verified Reductions [tCO_{2e}/year]	Production of oil	Reductions per Unit Production (tCO_{2e}/Mbbl)
Confidential - FSU	12	Confidential under review and consideration	445,502	N/A	2489.6mln tons in 2010 and then declining on an annual basis by 6% on average	0.02
Nigeria	13	OML 123 Offshore Associated Gas Capture and Utilization Project, Nigeria	1,702,071	N/A	60Mbbl/d from more than 50 wells.	77.72
Confidential - Middle East	14	Confidential under review and consideration	410,446	N/A	54438 BPD in 2010 and varying across the years, declining from 2014. Average: 40,210.67BPD/annum (over 2008-2019)	27.97
Azerbaijan	15	Capture and processing low pressure associated gas from the Neft Dashlari and Palchiq Pilpilassi oil fields of SOCAR	202,909	N/A	1.2 million tonnes per year in 2008 for Neft Dashlari (assume half that production at Palchiq Pilpilassi field as well [no data exists for this field])	15.03
Oman	16	Associated Gas Recovery and Utilization at Block 9	804,662	N/A	162,400 bbl/d (Combined with all Occidental production, but 105 0f 120 wells are in Safah oil field)	15.51
Ghana	17	Saltpond Oil Field Associated Gas Recovery and Utilization Project	84,360	N/A	550 bbl/d (Included with all offshore production in Ghana)	420.22
Ghana	18	Jubilee Oil Field Associated Gas Recovery and Utilization Project	2,342,845	N/A	Estimated to be 20,000 bbl/d	320.94
United Arab Emirates	19	Flare gas reduction through spiking compressor at Shah	110,055	N/A	70,000 bbl/d	4.31

Country	Project ID	Project Title	Estimated Reductions [tCO_{2e}/year]	Verified Reductions [tCO_{2e}/year]	Production of oil	Reductions per Unit Production (tCO_{2e}/Mbbl)
Egypt	20	Gas Flare Recovery at Suez oil processing company, Egypt	128,447	N/A	66,000 bbl/d This is the refinery throughput	5.29
Russia	22	Associated Petroleum Gas Recovery for the Kharampur oil fields of "Rosneft"	2,280,169	0	60.6 million bbl/y in 2008	37.63
Russia	23	Associated Gas Recovery Project for the Komsomolskoye Oil Field	2,216,946	N/A	Approx. 25 million barrels per year in 2007	88.68
Russia	24	SNG gas gathering	225,666	N/A	750,000 bbl/d	0.82
Russia	25	Utilization of associated petroleum gas (APG) at the Serginskoye oil field	26,969	N/A	Approx. 1 million bbl per year in 2007	26.97
Russia	26	Utilization of Associated petroleum gas (APG) at the Vostochno-Perevalnoye oil field	62,322	N/A	Approx. 3.9 Million bbl per year	15.98
Russia	27	Utilization of associated petroleum gas (APG) at the Sredne-Khulymsk oil field	105,223	N/A	Approx. 7.0 million bbl per year	15.03
Russia	28	Yuzhno Balyksky associated gas recovery project	2,410,210	N/A	580,000 bbl/d	11.39
Russia	29	Low-pressure associated petroleum gas utilization at Enisei Ltd., Usinsk, Komi Republic, Russia	56,036	N/A	73,457 bbl/d	2.09
Russia	30	Utilization of Associated Petroleum Gas at Salym Petroleum Development N.V., Russia	181,847	N/A	120,000 bbl/d in 2007 (160,000 bbl//d in 2010)	4.15
Russia	31	Associated petroleum gas flaring reduction and electricity generation at the Khasyrey oil field.	142,255	N/A	129920 bbl/d	3.00
Russia	32	Associated petroleum gas recovery at Priobskoe oil field of "Rosneft"	780,162	N/A	580,000 bbl/d	3.69
Russia	33	Verkh-Tarskoye Oilfield (VTOF) Gas Utilization	1,736,077	N/A	2.077 million tons in 2008	111.45

Country	Project ID	Project Title	Estimated Reductions [tCO_{2e}/year]	Verified Reductions [tCO_{2e}/year]	Production of oil	Reductions per Unit Production (tCO_{2e}/Mbbl)
Confidential - Africa	34	Confidential under review and consideration	103,623	N/A	No exact details, but flow station has a capacity of 10,000 bbls per day	28.39

Verified emissions reductions in Table 2 originate only from a project that has been successfully registered under a relevant Kyoto flexible mechanism, e.g., Clean Development Mechanism (CDM) or Joint Implementation (JI). A registered project needs to have a monitoring plan implemented, which allows it to regularly monitor and collect data necessary for calculations of emission reductions. Monitoring of a parameter needs to be performed at a frequency prescribed by the selected methodology (e.g. gas flow - continuously and gas composition - monthly). Furthermore, a monitoring report (MR) is developed, describing the project status, its operations, and calculated emission reductions achieved throughout the monitoring period. The frequency of developing a MR is usually annual, yet it can be more or less frequent, depending on the methodology and validated monitoring plan (e.g. some JI Track 1 projects develop a MR on a quarterly basis). A MR is a starting point for next steps: verification and issuance. The MR is submitted to a Designated Operational Entity for verification. Once calculated emission reductions are verified, a request for issuance is submitted to the relevant entity (UNFCCC Secretariat for CDM projects, JICS or a national authority for JI projects). Upon such request being granted, verified emission reductions are issued in the form of carbon credits, which then can be placed on the market, or are traded based on emission reduction purchase agreements. For projects in Table 2, the reasons why there are no verified reductions may include:

- The project hasn't been registered (e.g. validation in process or terminated, project rejected);
- The request for issuance is still being processed (i.e. the Monitoring Report and Verification Report haven't been approved yet);
- No request for issuance has been submitted. On this point, it is worth noting that verification is a relatively costly process (comparable to project validation costs). As such, in the case of registered projects, it is possible that the lack of verified emission reductions stems from project proponents' assessment of effort and cost needed to have carbon credits issued, and deeming them too high compared to the expected returns from carbon credit sales,

Most of the projects identified and shown in Table 2 were taken from the UNFCCC CDM/JI website (confidential projects originate from ICF's work records). Appendix 1 contains specific details on the projects shown in Table 2, including more detailed cost information, project descriptions, gas-to-oil ratios, and other relevant data. Overall, 25 projects were selected for further analysis. In Appendix 1, a total of 33 projects were identified, but not all projects had enough relevant data to merit inclusion in the study.

The final portion of this task involved analysing hypothetical pipeline projects that would gather and transport associated petroleum gas. On the basis of volume of crude imports and volume of flared gas from US National Oceanic and Atmospheric Administration (NOAA) satellite analysis, three project locations were chosen as the basis of this analysis. These were offshore Nigeria, onshore Libya, and onshore Russia. The objective of this analysis was to develop a set of data that represents reasonable assumptions for each scenario. The primary data sources used in the analysis were NOAA satellite photos of flaring in the three countries, oil and gas field maps from the Oil and Gas Journal International Petroleum Encyclopedia and expert judgment on field and well parameters and pipeline length. The combination of the satellite photos and the field maps allowed estimation, based upon actual geographic distribution, of the number and typical areal size of fields, their distance from each other, the total area encompassed by the project, and the likely distance to an assumed market center. Well production rates and number of wells per field assumptions are based upon expert judgment of typical ranges for onshore and offshore fields in these areas.

Table 3 summarizes the three scenarios. For each scenario, maps of oil fields and oil and gas pipelines in areas known to have significant flaring based upon the NOAA satellite shots were reviewed. In each case, a scenario to gather associated gas from a certain number of fields was developed. Estimates were made of the number of wells that would be involved and their average associated gas production rate. The amount of gathering pipeline is based in part on the number of wells and the size of the line depends upon the estimated flow rates. Other estimates were made of the dispersion of field locations, which also impacts the amount of gathering line. A location was selected for which the gathered gas would be transported for processing. Of the various assumptions made, the greatest uncertainty lies in the number of wells and average production rate per well. Information sources on this are available but investigating these was beyond the scope of the current study.

Table 3: Hypothetical Scenarios for Flaring Reduction through Marketing Associated Gas Production

Country	2010 Country Flaring (mmcm/d)	Selected Area	Water depth	Gas composition	Area encompass. fields (sq km)	No. of fields gathered	Wells per field	Gathered Wells	Prod per well (mcm/d)	Assoc. prod. (mcm/d)	Crude. prod. Th BOPD
Libya	10	Onshore	n/a	sweet	2,330	6	20	120	8	1,020	0.50976
Nigeria	41	Offshore	<200m	sweet	260	3	20	60	28	1,699	0.8496
Russia	95	W. Siberia	n/a	sweet	3,885	6	30	180	14	2,549	1.2744

Country	Fraction of country total flaring	Required gathering line (km)	Sales location	Distance from gather point to market (km)
Libya	10%	97	Brega	322
Nigeria	4%	48	Kwa Iboe	48
Russia	3%	145	Strezhevy	241

Gas processing is assumed to be required since all associated gas is wet with hydrocarbon liquids that must be removed prior to long distance pipeline transport. Compression is also required for such associated gas. It is assumed that the gas does not contain CO_2 or H_2S.

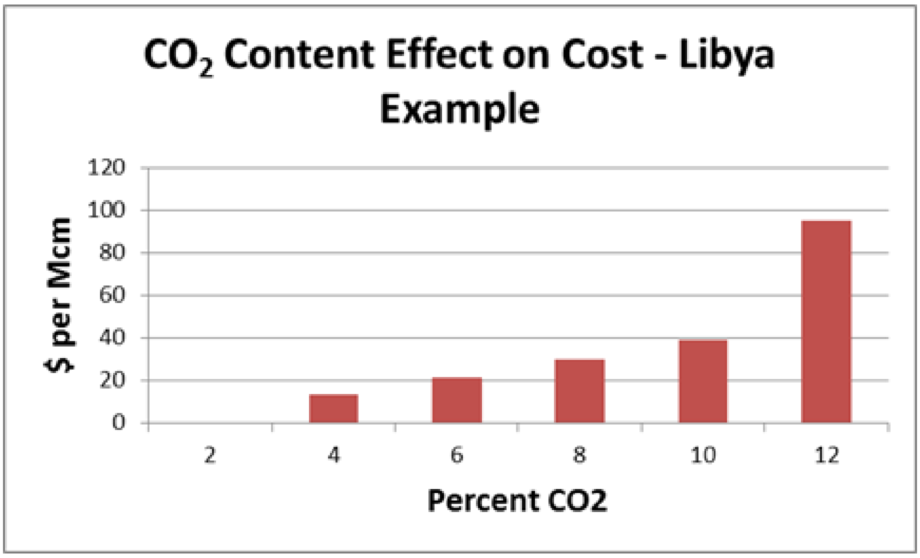
To evaluate the economics of bringing this gas to a market center, ICF employed a proprietary discounted cash flow model called the ICF Gas Gathering Economics Model (GGEM). It looks at gathering, compression, gas processing, and pipeline costs under each scenario. It evaluates required capital and operating expenditures over a thirty year timeframe. Assumptions are made for return on equity, cost of debt, depreciation, rate of inflation, and taxes.

The occurrence of CO_2 and/or H_2S can significantly impact the cost of processing and transporting associated gas. Table 4 and Figure 1 present the results of an analysis with the ICF gathering economics model. Table 4 compares the economic analysis with no CO_2 and with 2%, 4%, and 10% CO2. It also shows a case with 4% CO_2 and 4% H_2S. The lower part of the table shows the differences with the no acid gas cases. In the model, acid gas processing is assumed only if the CO_2 level is 4% or greater. Generally, CO_2 amounts lower than 4% can be accommodated without additional processing. Although not shown in the table, the majority of costs are in the gas processing component. Some additional costs are also in the gas pipeline component. A content of 10 percent CO_2 in the studied cases can result in cost increases of 30 to 90 percent.

Table 4. Effect of Acid Gas Composition on Associated Gas Processing and Transport Costs

Tariff Required - Dollars per Thousand Cubic Meters	0 % CO2 0% H2S	2 % CO2 0% H2S	4 % CO2 0% H2S	10 % CO2 0% H2S	4 % CO2 4% H2S
Libya	$124.26	$124.26	$137.67	$163.44	$145.79
Nigeria	$26.12	$26.12	$34.95	$48.71	$39.18
Russia	$66.01	$66.01	$75.19	$91.78	$80.48
Difference with no acid gas case					
Libya	---	$0.00	$13.41	$39.18	$21.53
Nigeria	---	$0.00	$8.83	$22.59	$13.06
Russia	---	$0.00	$9.18	$25.77	$14.47

Figure 1. Effect of CO2 Composition on Associated Gas Processing and Transport Costs



Using the production rate specified in the scenario, it determines the levelized revenue requirement for each cost component in dollars per thousand cubic foot of gas production. The model results are presented in Table 5. The last column of the table presents the results of the analysis. It shows the price that would have to be paid at the specified market center to make each project economic. The NGL are ethane and heavier and are of LPG quality. The volumes and quantities of the NGLs will be outlined in Task 2. In the three cases evaluated, the price ranges from US$0.74 to US$3.52 per thousand cubic feet of gas, which equates to $25.96 to $124.28 per thousand cubic meters.

Table 5: Summary of Economic Analysis of Three Gathering Scenarios, US$ (Ethane sold as petrochemical feedstock)

	Capital Cost	Annual O&M	Initial Year Throughput (MMcf/ Year)	Tariff Required $/Mcf Throughput	$ Per Th. Cu. Ft Tariff Required $/Mcf Ultimate Gas to Buyer	$ Per Th. Cu. M Tariff Required $/Mcm Ultimate Gas to Buyer
Example Case of Libya						
Gathering	$35,348,471	$919,712	12,960	$0.504	$0.611	$21.59
Field Compression	$2,371,895	$106,735	12,960	$0.027	$0.033	$1.15
Gas Processing	$29,346,952	$733,674	12,809	$0.420	$0.504	$17.80
Gas Pipeline	$133,476,041	$4,004,281	10,784	$2.349	$2.371	$83.74
Gas to Buyer			10,682			
Total	$200,543,359	$5,764,402		$3.300	**$3.519**	**$124.28**
Credit for NGLs (crude oil @$85/bbl)						
Barrels of NGLs recovered initial year		1,264,635				
Value of NGLs per year		$53,702,003				
Value of NGLs per Mcf gas to buyer		$5.03				
Example Case of Nigeria						
Gathering	$5,656,438	$159,411	21,600	$0.049	$0.059	$2.09
Field Compression	$3,953,159	$177,892	21,600	$0.027	$0.032	$1.14
Gas Processing	$41,962,091	$1,049,052	21,348	$0.361	$0.429	$15.15
Gas Pipeline	$20,313,010	$609,390	17,973	$0.214	$0.215	$7.59
Gas to Buyer			17,947			
Total	$71,884,698	$1,995,746		$0.651	**$0.735**	**$25.96**
Credit for NGLs (crude oil @$85/bbl)						
Barrels of NGLs recovered initial year		2,107,725				
Value of NGLs per year		$89,503,338				
Value of NGLs per Mcf gas to buyer		$4.99				
Example Case of Russia						
Gathering	$49,073,429	$1,280,836	32,400	$0.280	$0.339	$11.97
Field Compression	$5,929,738	$266,838	32,400	$0.027	$0.033	$1.15
Gas Processing	$55,734,102	$1,393,353	32,022	$0.319	$0.382	$13.49
Gas Pipeline	$157,147,577	$4,714,427	26,959	$1.106	$1.114	$39.34
Gas to Buyer			26,768			
Total	$267,884,846	$7,655,454		$1.732	**$1.867**	**$65.95**
Credit for NGLs (crude oil @$85/bbl)						
Barrels of NGLs recovered initial year		3,161,587				
Value of NGLs per year		$134,255,007				
Value of NGLs per Mcf gas to buyer		$5.02				

Pipeline costs to the market center represent a large percentage total project costs. Table 6 shows the impact of pipeline length on project cost for the Libya example. The source of this analysis is the ICF cost model. The base case assumption for Libya was 320 kilometers. In that case, total costs were $124.29/1000m^3$ and the pipeline component was $83.69/1000m^3$ or 67 percent of total costs. The table shows the cost impact of different assumptions on pipeline length. In the current model, the levelized pipeline cost is $35.31 per 160 kilometers for shorter pipelines and $42.02 per 160 kilometers for longer lines.

Table 6. Impact of Pipeline Length on Tariff Required – Libya Case

Pipeline Length (km)	Total Tariff Required ($/1000 m^3)	Pipeline Component ($/1000 m^3)	Pipeline Percent of Tariff Required	Pipeline Only Tariff per 160 km ($/1000m^3)
80	$61.09	$17.66	29%	$35.31
160	$81.92	$4202	51%	$42.02
320	$124.29	$83.69	67%	$42.02
480	$167.02	$126.06	75%	$42.02

2.2.2 Emissions reductions

The GHG reductions cited by each of the projects from Table 1 (above) are shown in Figures 2 through 4 (below). GHG reductions are presented per unit of oil production, in this case as tonnes of carbon dioxide equivalent (CO_2e) per thousand barrels (Mbbl) of oil production. Figure 2 shows all of the projects in order from most reductions to the least. Figure 3 shows the reductions per world region of interest. The regions shown are the same regions identified in the first part of this study: the Former Soviet Union, the Middle East, and Africa. Figure 4 shows GHG reductions per project type. Most of the projects involved capturing APG that would otherwise be flared and sending it to an existing pipeline for sale. All of these projects were grouped together in the first graph. The other projects were much more diverse. These included projects to build a liquefied natural gas (LNG) plant, construct a power plant, and to use the APG in enhanced oil recovery (EOR). Since not enough projects of each type existed to make a meaningful comparison, all of these other projects are grouped together in the second graph.

Figure 2: Histogram of all Reduction Projects

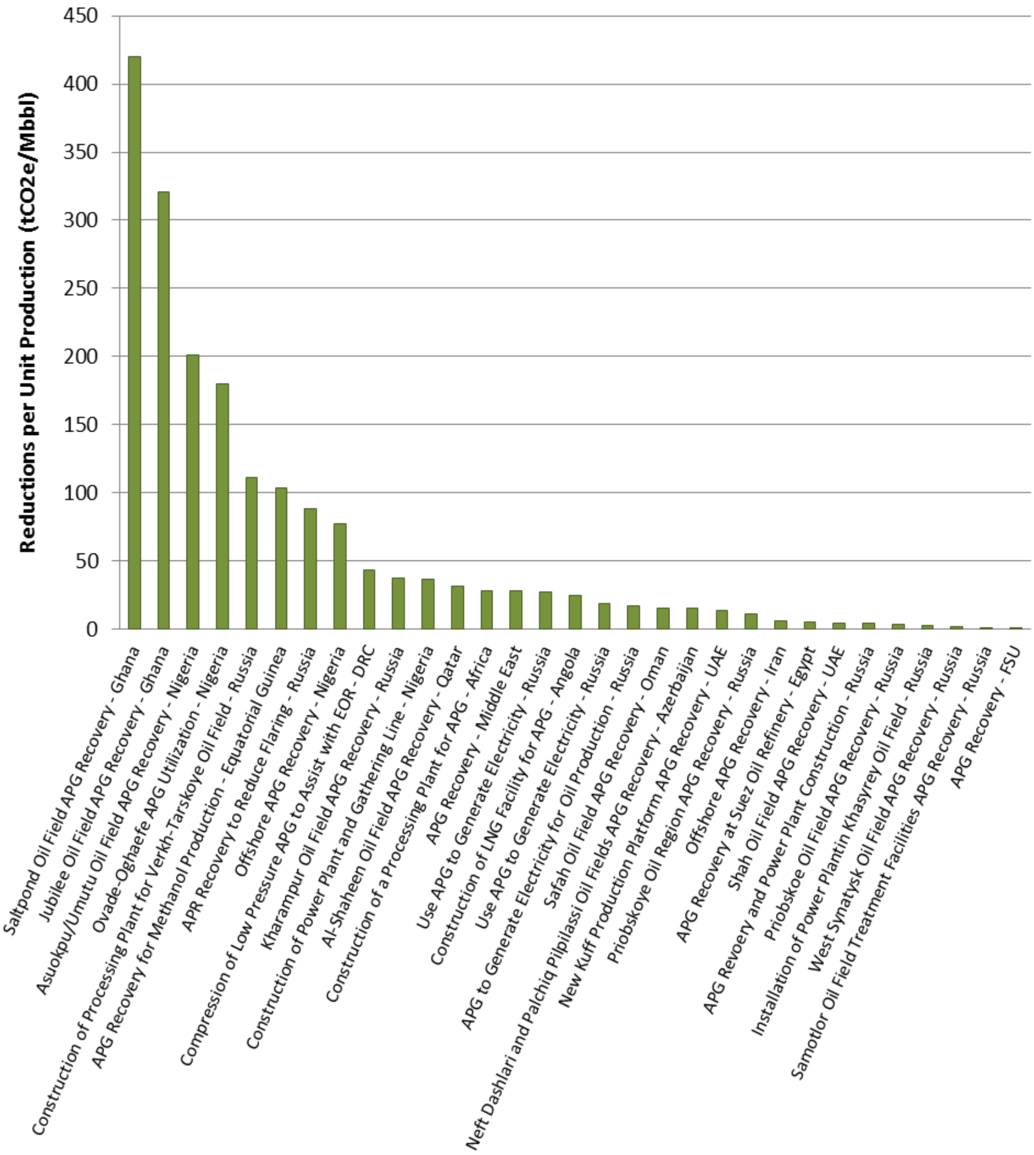
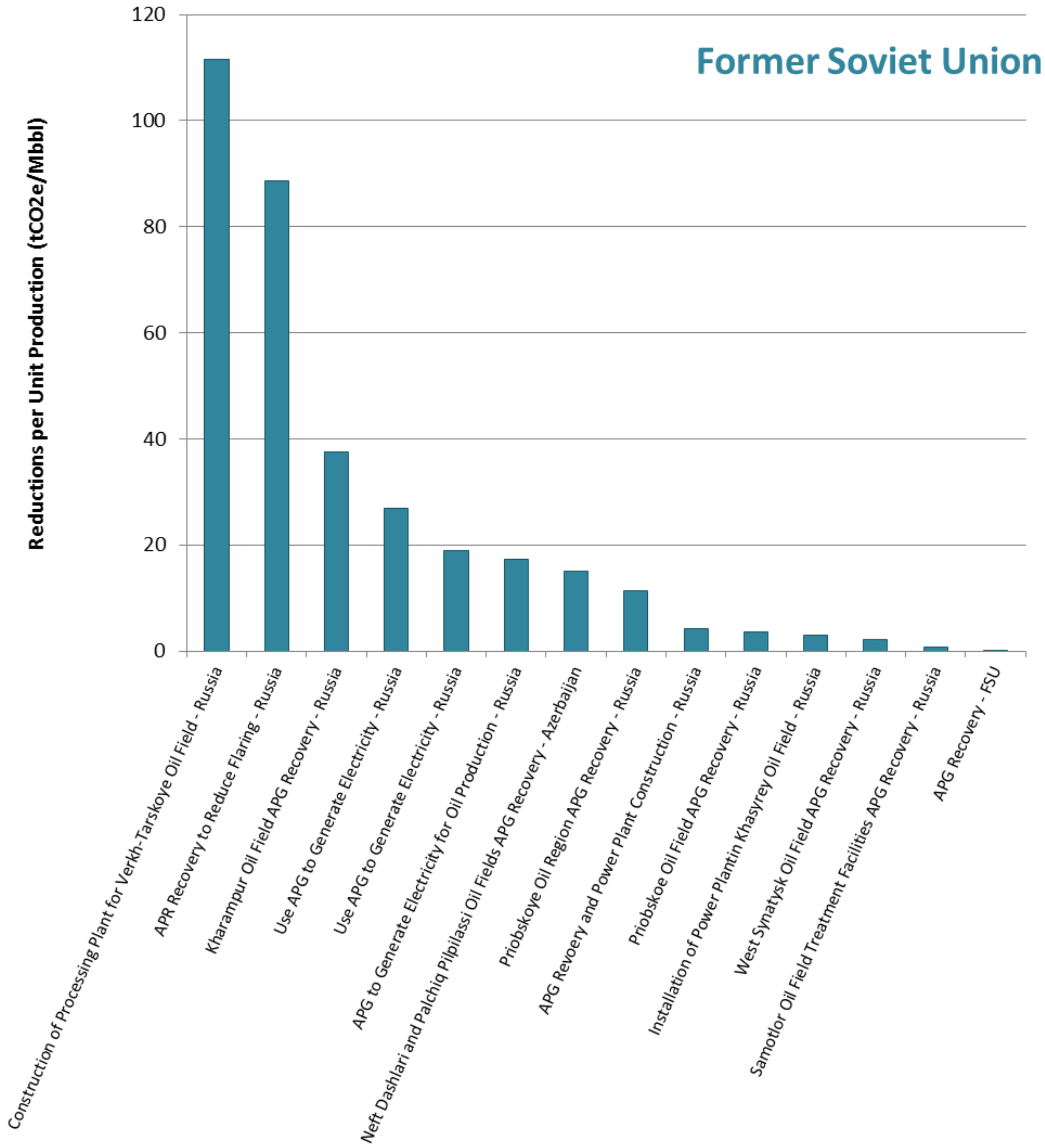
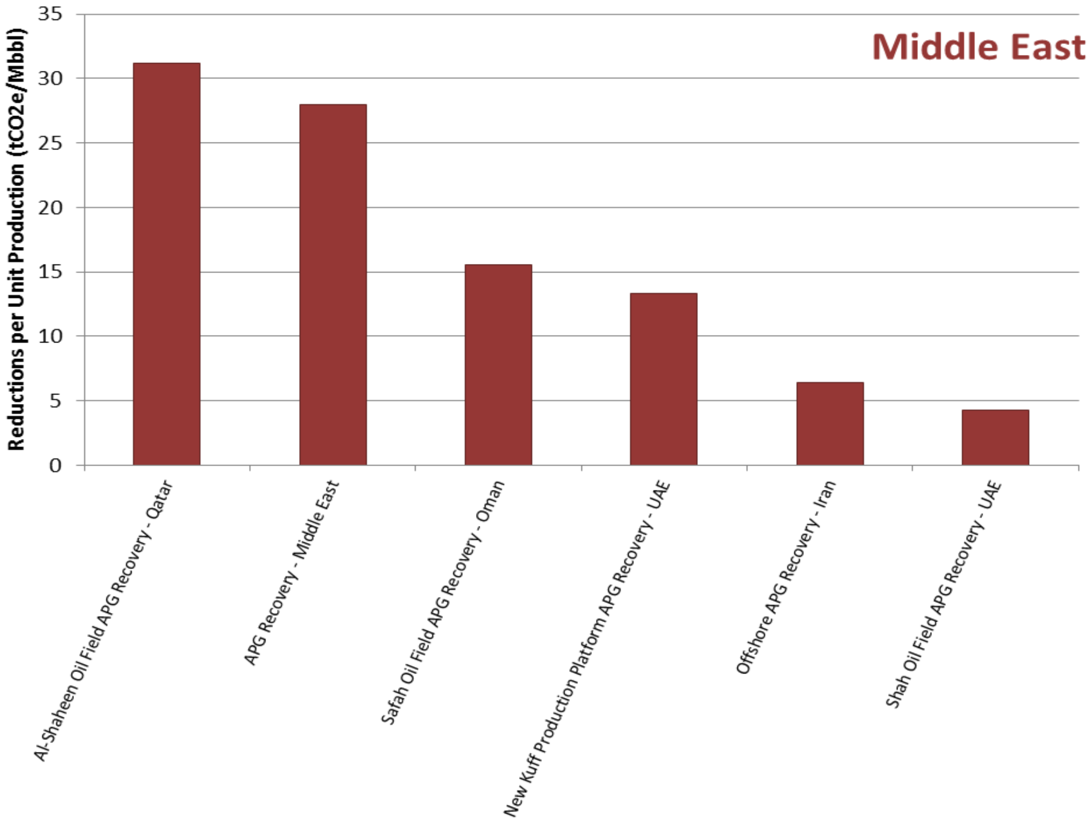


Figure 3: Histograms of Reduction Projects by Region (Former Soviet Union, Middle East, and Africa)




Middle East
Reductions per Unit Production (tCO2e/Mbbl)
35
30
25
20
15
10
5
0
Al-Shaheen Oil Field APG Recovery - Qatar
APG Recovery - Middle East
Safah Oil Field APG Recovery - Oman
New Kuff Production Platform APG Recovery - UAE
Offshore APG Recovery - Iran
Shah Oil Field APG Recovery - UAE

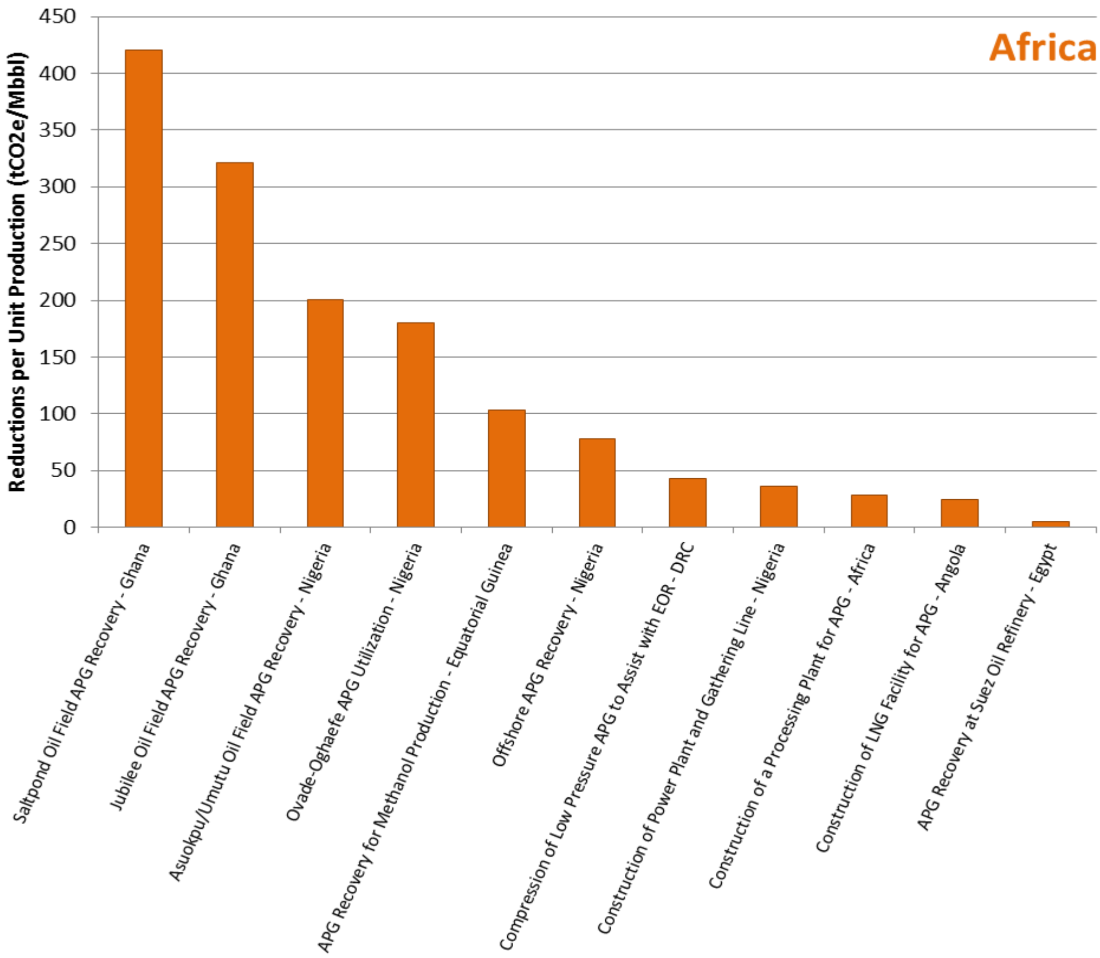
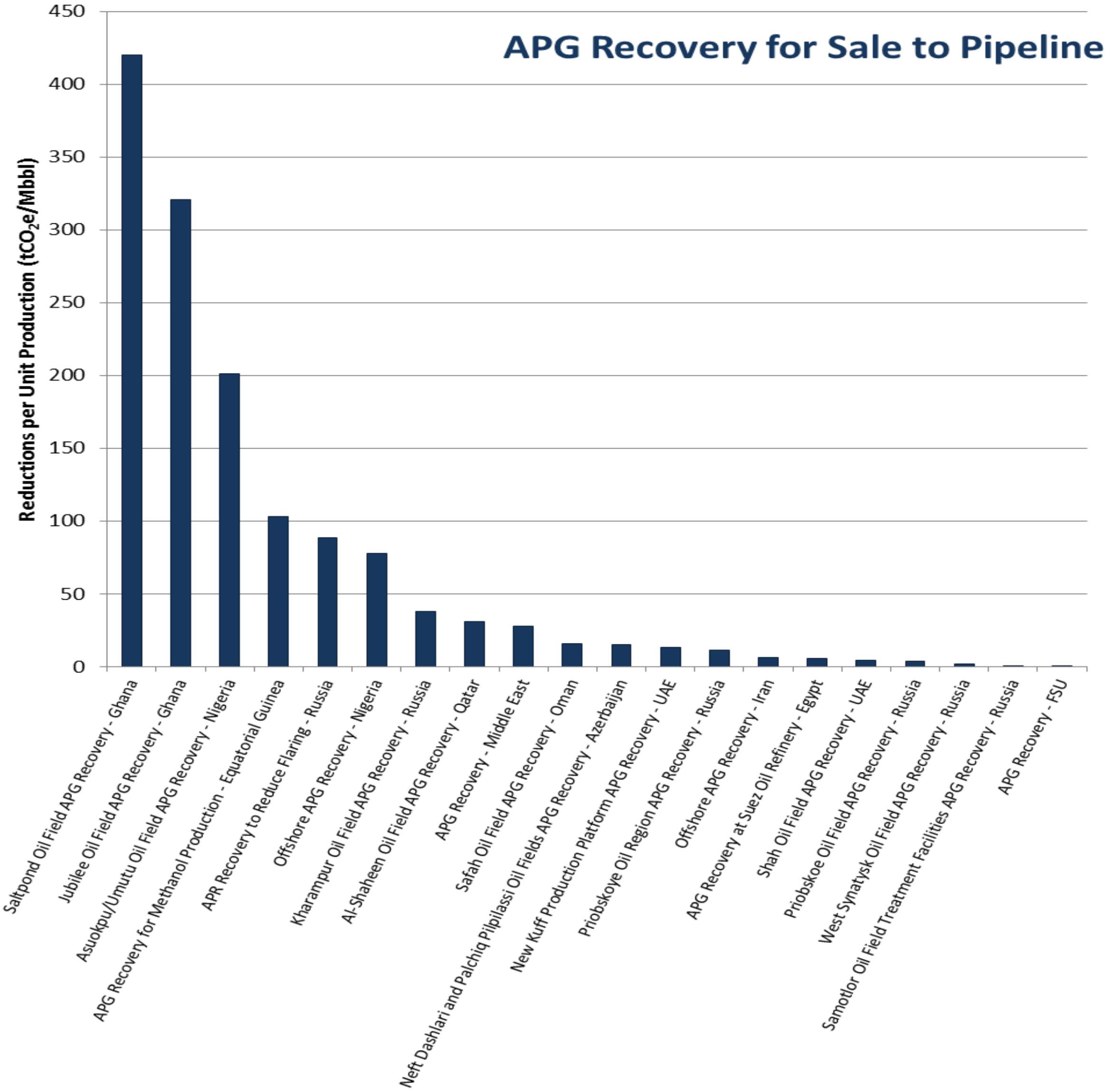
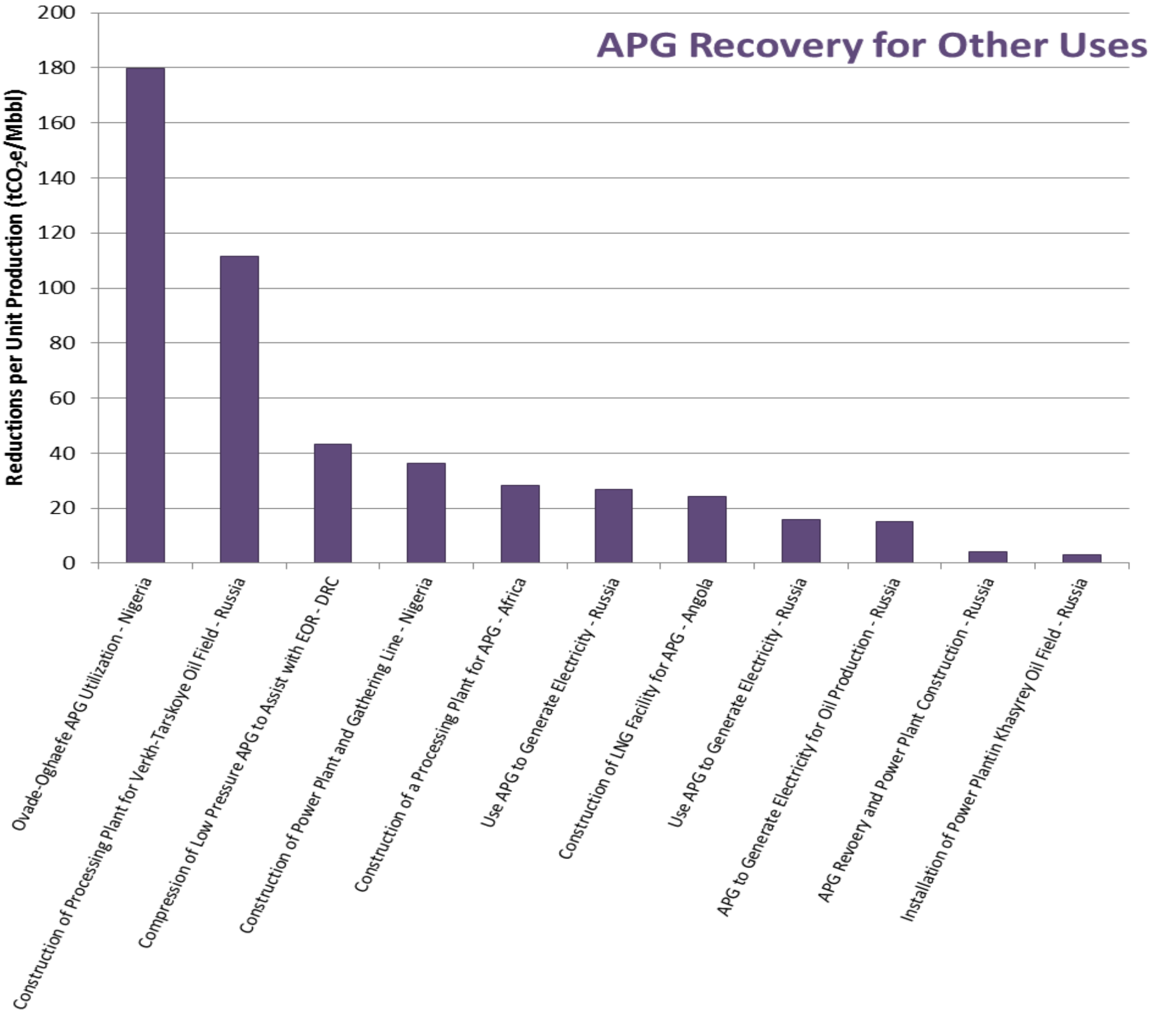

Africa
Reductions per Unit Production (tCO2e/Mbbl)
450
400
350
300
250
200
150
100
50
0
Saltpond Oil Field APG Recovery - Ghana
Jubilee Oil Field APG Recovery - Ghana
Asuokpu/Umutu Oil Field APG Recovery - Nigeria
Ovade-Oghaefe APG Utilization - Nigeria
APG Recovery for Methanol Production - Equatorial Guinea
Offshore APG Recovery - Nigeria
Compression of Low Pressure APG to Assist with EOR - DRC
Construction of Power Plant and Gathering Line - Nigeria
Construction of a Processing Plant for APG - Africa
Construction of LNG Facility for APG - Angola
APG Recovery at Suez Oil Refinery - Egypt

Figure 4: Histograms of Reduction Projects by Type (Recovery for sale, Other – including LNG and Power Generation)





2.3 Discussion

The majority of projects identified by this study focus on capturing associated petroleum gas that otherwise would have been flared and sending it to an existing pipeline for sale, with 20 of the 31 projects identified focusing on this. Results for these types of projects can be wide ranging, with GHG reductions anywhere from 420 tCO_2e per Mbbl down to 0.8 tCO_2e per Mbbl. However, most projects fall in the 1 to 25 tCO_2e per Mbbl range. The other projects identified in this study include sending APG to a power plant to generate electricity, constructing a processing plant to remove hydrocarbon liquids for sale, building a LNG terminal, and using the gas in EOR. These projects seem to indicate better GHG reduction opportunities, with 7 of the 11 projects reporting reductions of 20 tCO_2e per Mbbl or higher.

The reductions per barrel of oil produced will vary based on how much gas is associated with the oil (gas-to-oil ratio and how the ratio changes over time[1]), the CO_2 content[2] and oil extraction techniques utilized. In general associated gas depletes with the oil production over time. As fields mature, and oil production declines; energy-intensive techniques such as water or gas injection must then be used to extend production levels, potentially resulting in increased gas emissions. Most of the projects identified do not have detailed data readily

1 ICCT 2010: http://www.theicct.org/carbon-intensity-crude-oil-europe

2 Jacobs 2009, http://www.eipa.alberta.ca/media/39640/life%20cycle%20analysis%20jacobs%20final%20report.pdf

available across each project that would lend itself to consistent analysis and comparison. However the gas gathering and processing cost drivers for APG recovery projects include the H_2S and CO_2 content of the gas; length of pipeline; and capacity of treatment, dehydration, compression, separation, or condensate fractionation. For offshore projects, space and weight constraints can be prohibitive to APG recovery projects.

Task 2

1. Introduction

1.1 Objectives

1.1.1 Objectives of project

The first objective of this study is to describe the technical, economic and regulatory variables that affect the potential for improving/incentivising upstream greenhouse gas (GHG) reductions. This will entail presenting the most economically preferred approaches utilized to date with the use of marginal abatement cost (MAC) curves for upstream GHG reductions and conducting sensitivity analysis on the pertinent technical, economic and regulatory parameters to highlight potential economic drivers that could facilitate further investment in GHG reductions.

The second objective is to develop guidelines and principles for development of methods/best practices for measuring and verifying GHG emission reductions and guidelines for legislators for screening, evaluating and selecting existing and future schemes, carbon credit standards or certification programmes that ensure that GHG emission reductions are aligned with the requirements prescribed in the draft implementing measure.

1.1.2 Objectives and scope of task

This is the second of three tasks that collectively address the first objective of the study. This task is intended to create MAC curves using the associated petroleum gas emission reduction projects that were identified in Task 1. A tool was developed to produce MAC curves from the identified projects by country, project type, or both.

Based on guidance from the European Commission, this task focused on historical projects with complete data sets, which were identified in Task 1. The historical projects are from regions that supply a significant amount of crude oil to the European Unioin (EU): Africa, the Middle East, and the Former Soviet Union.

There are several inputs used to determine the break even carbon cost of a project, including investment cost, expected revenue, and tax rate. An important aspect of this study was to modify these variables in order to create “sensitivity cases.” In addition, the European Commission requested evaluation of the impact of carbon dioxide and hydrogen sulphide in the produced gas has on the break even costs of a project. Thus, this study developed a theoretical pipeline project to analyse these variables on project costs. A theoretical project was developed as none of the historical projects contained sufficient information carbon dioxide or hydrogen sulphide removal. The project was designed by ICF’s pipeline and natural gas experts.

It should also be noted that the MAC tool was designed to allow the user to create additional sensitivity cases. To facilitate use of the tool, pull-down options were included to enable the user to select projects by region or by type, as well as change variables in the break even cost formula. Further, the tool is capable of analysing additional projects that may be added by the user.

2. Findings

2.1 Selection of projects for inclusion in MAC analysis

In Task 1 of this study, historical associated petroleum gas (APG) emission reduction projects were identified in countries that supply a significant amount of crude oil to the EU. The criteria for selecting these projects in Task 1 were first, the project had to be implemented in a country that exports significant crude oil to the European Union. Second, the project had to be an implemented project, or a fully designed project with the possibility of implementation. Finally, it was necessary that detailed data be available for a project to be included in the study. This means that, at a minimum, the project description and data had to include cost of implementation, reductions achieved/projected to achieve, and the location (i.e. in which oil field(s) the project was located). Other relevant data, such as oil field production values, needed to be available as well.

Only projects that met the above criteria were included in the MAC analysis in Task 2. The countries having projects that met these criteria were Libya and Nigeria from Africa, Iran and Yemen from the Middle East, and Russia and Azerbaijan from the FSU. Together, these six countries account for over 54% of total EU crude oil imports and over 62% of imports from countries outside of Europe. While these countries may not correspond to all the largest suppliers of crude oil from each region, they were the countries that did contain APG emission reduction projects with the most complete data sets. These projects are detailed in Table 2-1, and they contain the same project ID numbers that were assigned to them in Task 1.

Table 2-1: Projects selected for MAC analysis

Project ID	Region	Project Name	Project Description
1	Iran/Yemen	Soroosh & Nowrooz Early Gas Gathering and Utilization Project	This project will collect APG and send it to an existing processing plant.
3	Nigeria	Recovery and marketing of APG that would otherwise be flared at the Asuokpu/Umutu Marginal Field	This project takes APG and sends it to an existing gas pipeline. For this project 45 km of pipeline were installed, as well as three 1,700 HP compressors and a fiscal metering station.
4	Nigeria	Pan Ocean Gas Utilization Project	This project takes APG, treats it, and sends it to an existing pipeline for transport to a power plant. The project also involves the construction of a NGL plant, to be expanded upon as the ability to produce and market LPGs improves. For this project, the compression facility will contain at least four compressors as well as a dehydrator, Joule-Thompson unit, and a stabilizer. The NGL plant will contain conditioning, compression, liquid extraction, and fractionation systems, as well as storage and dispatch facilities.
12	Russia/ Azerbaijan	APG Recovery for Use at Existing Processing Plant	This project collects low pressure APG, compresses it, and sends it to an existing gas processing plant.
13	Nigeria	OML 123 Offshore APG Capture and Utilization Project	This project involves utilizing offshore APG by constructing a platform to treat and compress gas that would otherwise be flared. The gas will then be transported to onshore consumers. The project involves installing two compressors with a 180 MMscf per day capacity, a TEG dehydrator, and a metering system.
14	Iran/Yemen	APG Recovery for Use at a new Power Plant	This project involves recovering APG to be utilized at a new power plant. The power plant will be constructed as part of this project. It also includes necessary infrastructure to gather and transport the APG.

Project ID	Region	Project Name	Project Description
15	Russia/ Azerbaijan	Capture and processing low pressure associated gas from the Neft Dashlari and Palchiq Pilpilassi oil fields of SOCAR	This project will take APG from 8 offshore platforms and send it to a processing facility. Overall, 44 compressors 15.4km of pipeline will be installed.
22	Russia/ Azerbaijan	APG Recovery for the Kharampur oil fields of Rosneft	This project will take APG from 5 processing sites, install a compressor block to pressurize the gas up to 6.0 MPa, and transport it to an existing processing plant.
23	Russia/ Azerbaijan	APG Recovery Project for the Komsomolskoye Oil Field	This project involves installing a new 5.5 km pipeline, along with treatment facilities (dehydration), to treat and sell APG.
24	Russia/ Azerbaijan	SNG gas gathering	This project will collect gas and send it to an existing pipeline after minimal treatment.
25	Russia/ Azerbaijan	Utilization of APG at the Serginskoye oil field	This project will collect APG and send it to an existing 7.5 MW power plant.
26	Russia/ Azerbaijan	Utilization of APG at the Vostochno-Perevalnoye oil field	This project will collect APG and send it to an existing 7.5 MW power plant.
27	Russia/ Azerbaijan	Utilization of APG at the Sredne-Khulymsk oil field	This project will collect APG and send it to an existing 15 MW power plant.
28	Russia/ Azerbaijan	Yuzhno Balyksky APG recovery project	This project will collect APG and send it to an existing processing plant.
29	Russia/ Azerbaijan	Low-pressure APG utilization at Enisei Ltd., Usinsk	This project collects APG and sends it to an existing pipeline. This project will also produce NGLs for sale.
30	Russia/ Azerbaijan	Utilization of APG at Salym Petroleum Development N.V.	The project will utilize APG to produce electric power at a new 45 MW power plant. This project also includes some treatment facilities, including dehydration and heating.
31	Russia/ Azerbaijan	APG flaring reduction and electricity generation at the Khasyrey oil field	The project will utilize APG to produce electric power at a new 33 MW power plant.
32	Russia/ Azerbaijan	APG recovery at Priobskoe oil field of Rosneft	This project involves constructing a 315 MW power plant to generate electricity from APG. The project also involves constructing gathering lines, 2 large compressor stations with a combined capacity of 3.3 Bcm, and treatment equipment for the APG.
33	Russia/ Azerbaijan	Verkh-Tarskoye Oilfield (VTOF) Gas Utilization	This project involves building a processing plant to treat currently flared APG. The treated gas will then be sold. The processing plant will be able to handle in excess of 100 MMcm of gas per year. Also, 1.5 km of pipeline will be installed to transport the gas.
34	Nigeria	APG Recovery for Use at a new Processing Plant	This project involves the construction of a gas processing plant to treat recovered APG and non-associated gas. The processing plant will be constructed as part of this project. This also includes all necessary infrastructure to gather and compress the gas.
35	Libya	APG Recovery (without H_2S and CO_2 Removal) in Libya	This project involves collecting APG from well sites by installing 95 km of gathering lines and 320 km of trunkline. Also, NGLs are extracted, with 80% ethane recovery.
36	Nigeria	APG Recovery (without H_2S and CO_2 Removal) in Offshore Nigeria	This project involves collecting APG from well sites by installing 50 km of gathering lines and 50 km of trunkline. Also, NGLs are extracted, with 80% ethane recovery.
37	Russia/ Azerbaijan	APG Recovery (without H_2S and CO_2 Removal) in Russia	This project involves collecting APG from well sites by installing 145 km of gathering lines and 240 km of trunkline. Also, NGLs are extracted, with 80% ethane recovery.

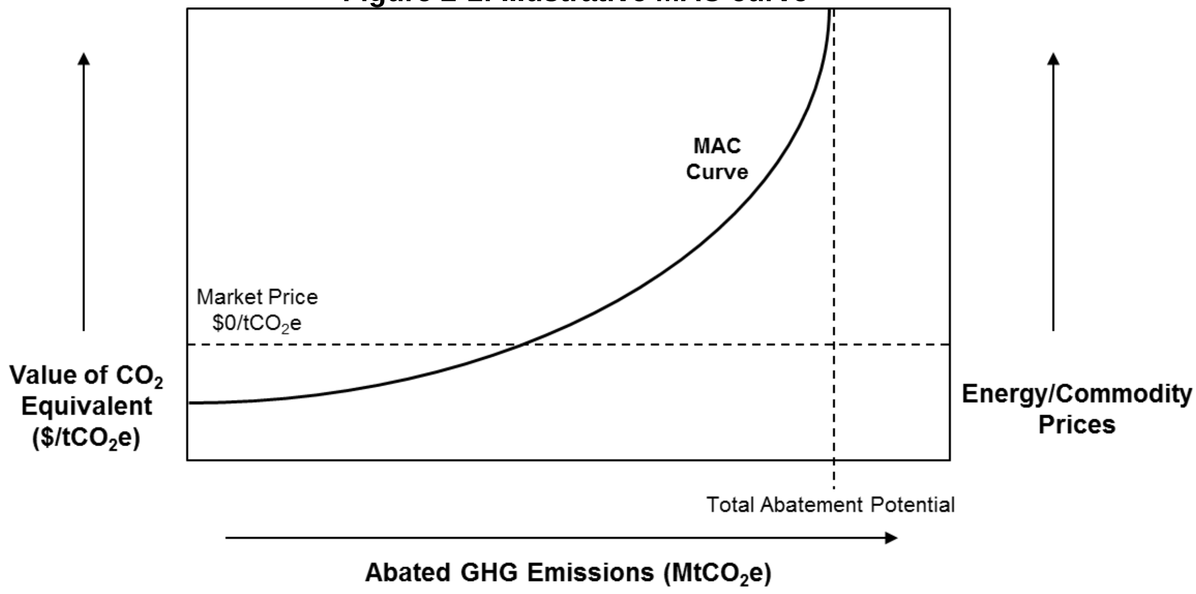
2.2 MAC curve tool development

2.2.1 About MAC curves

MAC curves are used to show the amount of emissions reduction potential at varying price levels. In theory, a MAC curve illustrates the cost of abating each additional ton of emissions. Figure 2-1 shows an illustrative MAC curve. The x-axis shows the amount of emissions abatement in megatonnes of carbon dioxide equivalent ($MtCO_2e$), and the y-axis shows the breakeven price in $\$/tCO_2e$ required to achieve the level of abatement. Therefore, moving along the curve, the lowest cost abatement options are adopted first. The curve becomes vertical at the point of maximum total abatement potential, which is the sum of abatement across all options in the sector/region within the scope of the MAC curve.

In this analysis we constructed MAC curves by estimating the carbon price at which the present value costs and benefits for each selected project equilibrate. The methodology produces a stepwise curve, where each point reflects the price and reduction potential if an APG emission mitigation project were implemented. The following sections describe the components of our methodology. First, we establish the baseline emissions for the countries containing identified projects. Then we describe the methodology used to evaluate the project applicability and adoption rate. Lastly, we describe how we calculate the breakeven price for each option and describe the construction of the MAC curves.

Figure 2-1: Illustrative MAC curve



The results of the analysis are presented as MAC curves by region and by project type and focus on the 2010 to 2030 timeframe. Emissions abatement in the MAC curves is shown as both absolute emissions reductions and as percentage reductions from the baseline.

2.2.2 Baseline emissions for Non-CO_2 Greenhouse Gases

Current and projected (through 2030) emissions estimates are based on emissions projections from the U.S. EPA's 2011 Draft Global Anthropogenic Non-CO_2 Greenhouse

Gas Emissions: 1990-2030 report.[3] The methods used to estimate and project non-CO_2 emissions in the 2011 EPA Draft report are briefly summarized here.

In the 2011 EPA Draft report, natural gas and oil system emissions are combined. In both oil and natural gas systems, methane is a fugitive emission from leaking equipment, system upsets, and deliberate flaring and venting at production fields, processing facilities, natural gas transmission lines and compressor stations, natural gas storage facilities, and natural gas distribution lines. In the EPA Draft report, emissions calculations for natural gas and oil systems utilize international statistics on production and consumption of natural gas and oil. Default emission factors relate emissions to energy product flows through different industry segments. Default emission factors differ between developed and developing countries. The emissions projections presented in the EPA Draft report rely on IPCC Tier 1 calculations and country reported inventory data.

The three primary types of data used to estimate and project emissions are country-prepared emissions reports, activity data, and default emission factors. The preferred source for historical data was the UNFCCC flexible query system[4] since this database provides updated GHG emission estimates for most Annex I Parties and to a lesser extent the latest GHG emission estimates for non-Annex I Parties.[5] National Communications were the preferred source for projections and non-Annex I historical emission estimates. The estimates in the UNFCCC inventory submissions and National Communications for each reporting Party are comparable because they rely on the IPCC methodologies and are reported for IPCC-designated source categories.

For most Annex I Parties, a full historical time series of emissions inventories was available from national inventory reports. In some cases, the EPA Draft report also used emissions projections provided by Annex I Parties in their National Communications. However, in many cases emissions projections from National Communications use aggregated or differing categories which make them difficult to use for disaggregated source-specific projections. Non-Annex I Parties do not file yearly national inventory reports, but they do produce National Communications. Those National Communications include historical inventories and projections in some cases. However, most non-Annex I countries provided their most recent National Communication prior to 2005, meaning some historical period emissions data use projections and calculations.

2.2.3 Project applicability and adoption rate

In this study, for two of the countries (Azerbaijan and Yemen), the EPA Draft report data did not correspond with data reported in the APG historical projects. In the case of Yemen, the emissions reported in the EPA Draft report were less than the base case emissions in the APG emission reduction projects. For Azerbaijan, the emissions listed in the EPA Draft report, the APG GGFR flaring emissions (as described below), and the project reported reductions did not correspond either. Therefore, the baseline emissions for these two countries were combined with the other country from their respective regions (Azerbaijan with Russia, and Yemen with Iran). Within the context of this study, combining the baseline emissions, and subsequently the emission reductions, yields meaningful results.

3 U.S. EPA, 2011. DRAFT: Global Anthropogenic Non-CO_2 Greenhouse Gas Emissions: 1990 – 2030. Available online at: <http://www.epa.gov/climatechange/EPAactivities/economics/nonco2projections.html>.

4 UNFCCC. 2009. United Nations Framework Convention on Climate Change Flexible GHG Data Queries. Available online at: <http://unfccc.int/di/FlexibleQueries/Setup.do>.

5 Annex I Parties include the industrialized countries that were members of the OECD in 1992, plus countries with economies in transition (the CEIT Parties), including the Russian Federation, the Baltic States, and several Central and Eastern European States.

The baseline reductions projected for an option for each country is equal to an option's technical applicability multiplied by its adoption rate multiplied by its reduction efficiency. The technical applicability accounts for the portion of emissions from a country that a mitigation option could feasibly reduce based on its application. The reduction efficiency of a mitigation option is the reduction achieved from project implementation. The technical lifetime of an option (in years) were from the carbon credit project documentation or was determined using ICF's expert knowledge of the technology.

In this study the technical applicability for an option is the percentage of emissions from APG relative to total baseline emissions from a country. The country baseline emissions from the EPA Draft Report contain more than just APG venting and flaring. Therefore, in order to estimate what percentage of country baseline emissions arise from APG, an additional data source was utilized. The World Bank's Global Gas Flaring Reduction (GGFR) program, which estimates countrywide emissions from flaring, was used to approximate the APG emissions. This is shown in Table 2-2. This also avoids double counting by limiting the penetration rate of options relative to each other. The GGFR estimates flaring emissions per country based on satellite images from the U.S. National Oceanic and Atmospheric Administration (NOAA). Several NOAA satellite systems have a capability to detect gas flares based on the radiative emissions from the flames. The estimates are based on a calibration developed with a pooled set of reported national gas flaring volumes and data from individual flares.[6] While flaring can occur in many aspects of oil and natural gas production and processing, most flaring occurs at the wellhead. When the flaring occurs at an oil well, this would be considered APG emissions. Although the majority of flaring occurs at oil wells, some flaring does occur at natural gas wells, but this amount cannot be distinguished in GGFR data. Therefore the emissions reported by the GGFR program are an acceptable approximation for APG flaring emissions. The GGFR data does not include APG venting emissions, however, gas is usually vented for short periods of time, such as in an emergency, and therefore the overall effect vented gas would have on total APG emissions was considered negligible.

Table 2-2: 2010 APG emission percentage of baseline

Emissions Data Source	Regional Emissions ($MtCO_2e$)			
	Libya	Nigeria	Iran/Yemen	Russia/Azerbaijan
GGFR	6.050	24.193	20.143	56.394
Country Baseline	77.390	25.818	45.842	339.224
Percent APG Emissions	**7.8%**	**93.7%**	**43.9%**	**16.6%**

Another important aspect of the MAC analysis was to estimate the future adoption rate of projects. Based on ICF's expert knowledge of emission forecasts, this study used an adoption rate that similar historical APG reduction projects will continue to occur in the future. The historical projects used in this study were developed between 2001 and 2010, a span of ten years. The project adoption rate projected between 2010 and 2030 is the same number of projects in each country between 2001 and 2010, and every subsequent ten year period. Thus, the historical adoption rate is used for the future adoption rate.

[6] The World Bank, 2012. Data retrieved on June 4, 2012. Global Gas Flaring Reduction statistic available online at: <go.worldbank.org/G2OAW2DKZ0>.

2.2.4 MAC curve construction

The MAC curves in this study are constructed from bottom-up breakeven price calculations. The breakeven price is calculated for the abatement potential for each mitigation project. The options are then ordered in ascending order of breakeven price (cost) and plotted against abatement potential. The resulting MAC curve is a stepwise function, rather than a smooth curve as seen in the illustrative MAC curve (Figure 2-1), because each point on the curve represents the breakeven price point for a discrete mitigation project. Conceptually, marginal costs are the incremental costs of an additional unit of abatement. However, the abatement cost curves developed here reflect the incremental costs of adopting the next cost-effective mitigation project.

For each mitigation option, the carbon price (P) at which that option becomes economically viable can be calculated (i.e., where the present value of the benefits of the option equals the present value of the costs of implementing the option). A present value analysis of each option is used to determine breakeven abatement costs in a given region. Revenue from selling credits is not included. Breakeven calculations are independent of the year the mitigation option is implemented but are contingent on the life expectancy of the option. The net present value calculation solves for breakeven price P, by equating the present value of the benefits with the present value of the costs of the mitigation option. Assuming that the emissions reduction, the recurring costs, and the revenue generated do not change on an annual basis, the breakeven price P of the option for a given year is solved:

$$P = \frac{CC}{ER(1-TR)\sum_{t=1}^{T}\frac{1}{(1+DR)^t}} + \frac{RC}{ER} - \frac{R}{ER} - \left[\frac{CC}{ER \times T} \times \frac{TR}{(1-TR)}\right] \qquad (2.1)$$

All costs were scaled to 2010 U.S. dollars by using the Nelson-Farrar index.[7] These costs include capital or one-time costs and operation and maintenance (O&M) or recurring costs. Project revenues include intrinsic cost savings, such as from reduction in flaring fines, as well as the value of the recovered gas. For revenues, project reported gas amounts (i.e. amount of gas sold) and prices were used. These were obtained from the documentation associated with the projects. If a project did not report gas prices, the lowest price from the region was used instead.

2.2.5 Sensitivity case analysis

As noted, the MAC curve spreadsheet is dynamic and allows the user to change many variables for the projects. In order to illustrate this, several sensitivity cases were run. These sensitivity cases were selected based on ICF's expert knowledge of the industry, and include changing the capital costs (±10%), the operating costs (±10%), natural gas price (varied changes), tax rate (±10%), and discount rate (±5%). These changes were made to illustrate the dynamic capabilities of the tool as well as to demonstrate how several common changes can impact the MACs.

A second set of sensitivity cases were also included in the MAC curve spreadsheet. In order to evaluate how CO_2 and H_2S concentrations in recovered APG can affect a project, and subsequently a MAC curve, one of the Libyan pipeline projects was varied to account for the

[7] This index is used to convert costs between years in the energy sector. It can be found in the Oil & Gas Journal, which is available online at: <www.ogj.com>.

processing the gas would need to undergo to remove the CO_2 and H_2S. Since this analysis was done externally, these projects were included in the MAC curve as separate entries. To avoid double counting these projects (they were simply variations of an existing project), these projects are not included in the base case results. However, in subsequent runs, the base case project was removed and replaced by one of the varied projects to create different sensitivity case runs.

2.3 Discussion

2.3.1 Base case results

Table 2-3 presents the breakeven price and the reduction in absolute terms for the mitigation projects that were selected.

The 2010 and 2020 regional baselines and MAC results of this study are presented in Tables 2-4 and 2-5, respectively. For Table 2-5, the MAC results assume a base energy price, a 10 percent discount rate, and a 33 percent tax rate. These MACs represent static reductions in baselines for individual regions/countries. Figure 2-2 provides a MAC curve for all of the selected projects in 2020. Figures 2-3 to 2-5 show the MAC curves for the individual regions (except for Libya, since Libya only contained one project) in this analysis.

The MAC analysis results show that in 2020 approximately 19.9 $MtCO_2e$ of emissions from APG can be cost-effectively abated by adopting these mitigation projects. If additional incentives for emissions reductions (such as carbon price) above the zero break-even price were available to operators, additional emission reductions could be cost-effectively achieved. At the current price for EU Allowances of approximately \$10.54 (or Euro 8.36); approximately 27.1 $MtCO_2e$ of emissions from APG can be cost-effectively abated by adopting these mitigation projects. The MACs illustrate that a significant portion of this mitigation potential can be realized at a zero cost and at low carbon prices. At a break-even price of zero, a project can be installed for a cost exactly equal to the energy or other savings that would be realized; the break-even price of zero is therefore considered to represent the reductions that can be achieved with no net cost. At negative breakeven prices, projects are expected to experience net savings while reducing emissions simultaneously.

Table 2-3: MACs for all included projects

Project ID	Breakeven Cost (2010\$/tCO_2e)	Breakeven Cost (2010\$/Mbbl Production)	Emission Reductions ($MtCO_2e$) 2010	2020	2030
Assuming 10% Discount Rate and 33% Tax Rate					
13	-\$42.10	-\$0.54	1.702	4.713	3.404
36	-\$41.73	-\$0.27	0.976	2.704	2.929
37	-\$35.48	-\$0.09	2.443	5.720	7.330
4	-\$5.89	-\$0.04	2.167	6.000	4.333
29	-\$0.67	-\$0.32	0.056	0.131	0.112
3	\$0.98	\$0.01	0.233	0.646	0.467
28	\$1.17	\$0.10	2.410	5.643	4.820
35	\$4.20	\$0.03	0.585	0.970	1.756
24	\$6.64	\$8.05	0.226	0.528	0.451

Project ID	Breakeven Cost (2010$/tCO2e)	Breakeven Cost (2010$/Mbbl Production)	Emission Reductions (MtCO2e) 2010	2020	2030
12	$17.06	$0.23	0.775	1.815	1.551
23	$31.90	$0.36	2.217	5.190	4.434
27	$42.34	$2.82	0.105	0.246	0.210
22	$53.71	$1.43	2.280	5.338	6.841
26	$54.44	$3.41	0.062	0.146	0.125
30	$63.35	$15.26	0.182	0.426	0.364
25	$64.59	$2.39	0.027	0.032	0.027
14	$75.92	$2.71	0.410	0.815	0.821
1	$76.09	$11.92	0.203	0.402	0.405
31	$92.10	$30.70	0.142	0.333	0.285
15	$156.24	$10.39	0.203	0.475	0.406
32	$164.22	$29.20	1.191	2.787	2.381
33	$164.29	$8.84	0.289	0.339	0.289
34	$254.51	$8.96	0.104	0.287	0.207

.

Table 2-4: Regional baseline emissions for oil and natural gas: 2010-2030

Region	Emissions ($MtCO_2e$) 2010	2020	2030
Libya	77.4	64.1	65.4
Nigeria	25.8	35.7	37.5
Iran/Yemen	45.8	45.5	50.7
Russia/Azerbaijan	339.2	397.1	434.3
All Included Countries	**488.3**	**542.5**	**587.9**
World Totals	**1,595.2**	**1,788.9**	**1,971.6**

Table 2-5: MACs for regions included in the analysis

Region	Emission Reductions at Given Carbon Price Level ($MtCO_2e$)									
	2020					2030				
	$10	$20	$50	$100	$300	$10	$20	$50	$100	$300
Libya	0.97	0.97	0.97	0.97	0.97	1.76	1.76	1.76	1.76	1.76
Nigeria	14.06	14.06	14.06	14.06	14.35	11.13	11.13	11.13	11.13	11.34
Iran/Yemen	0.00	0.00	0.00	1.22	1.22	0.00	0.00	0.00	1.23	1.23
Russia/Azerbaijan	12.02	13.84	19.27	25.55	29.15	12.71	14.26	18.91	26.55	29.63
All Regions	27.06	28.87	34.31	41.80	45.69	25.60	27.15	31.80	40.67	43.95

This analysis does not account for technological change in characteristics as availability, reduction efficiency, applicability, and costs. For example, the same sets of options are applied in 2020 and 2030 and an option's parameters are not changed over its lifetime. This likely underestimates abatement potential because technologies generally improve over time and costs fall.

Figure 2-2: 2020 MAC curve (all projects with percent reduction from baseline)

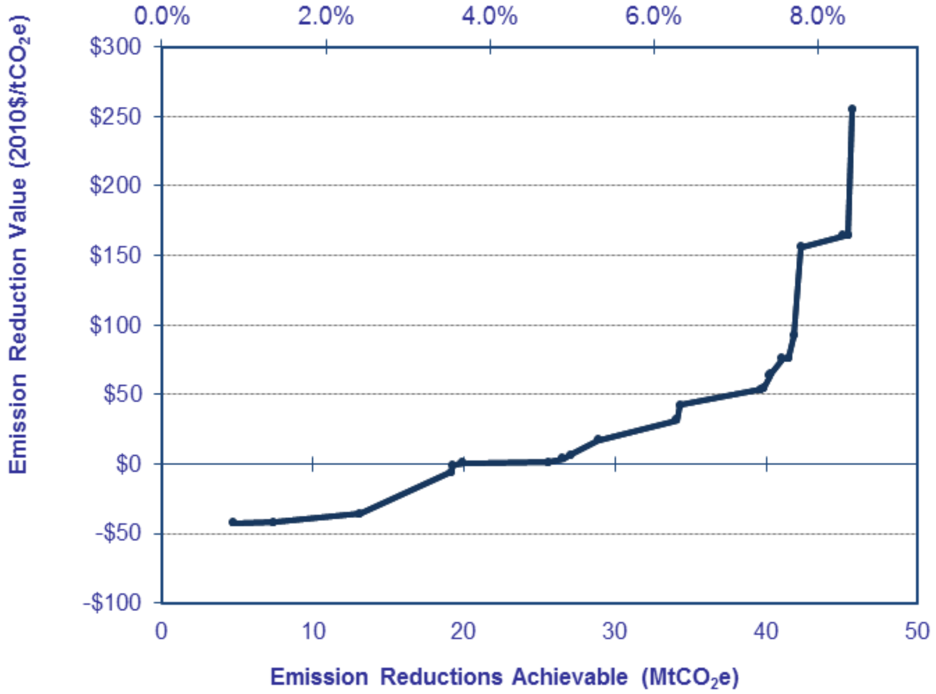


Figure 2-3: 2020 MAC curve for Russia/Azerbaijan (FSU)

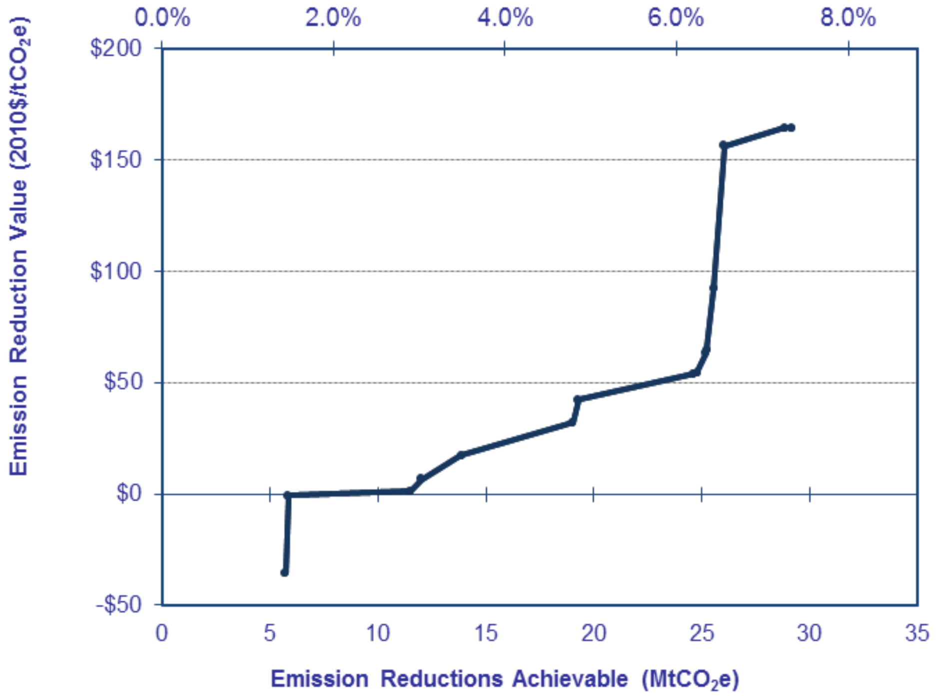


Figure 2-4: 2020 MAC curve for Iran/Yemen (Middle East)

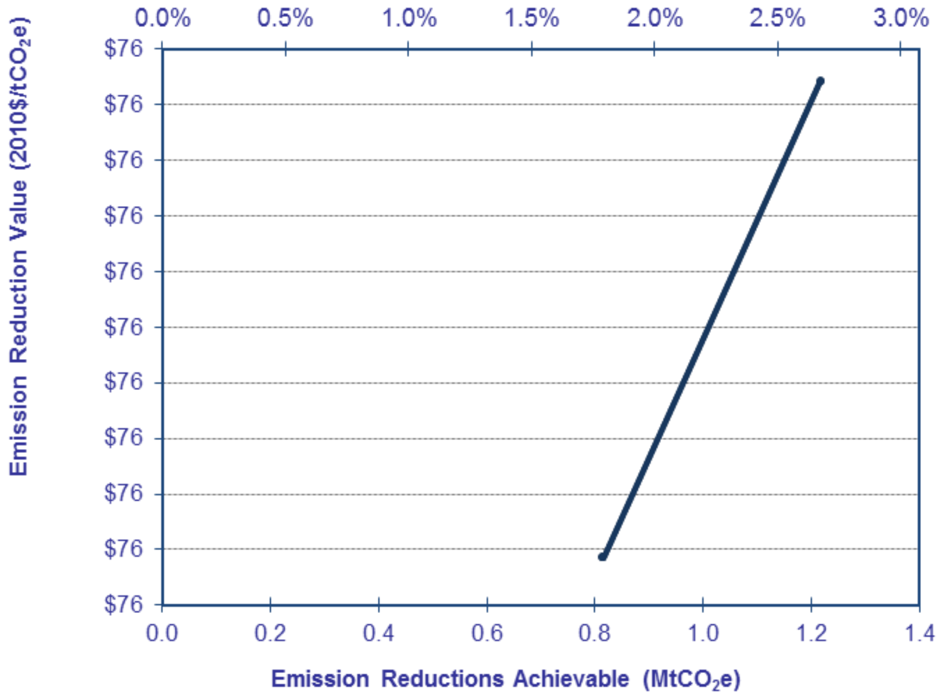
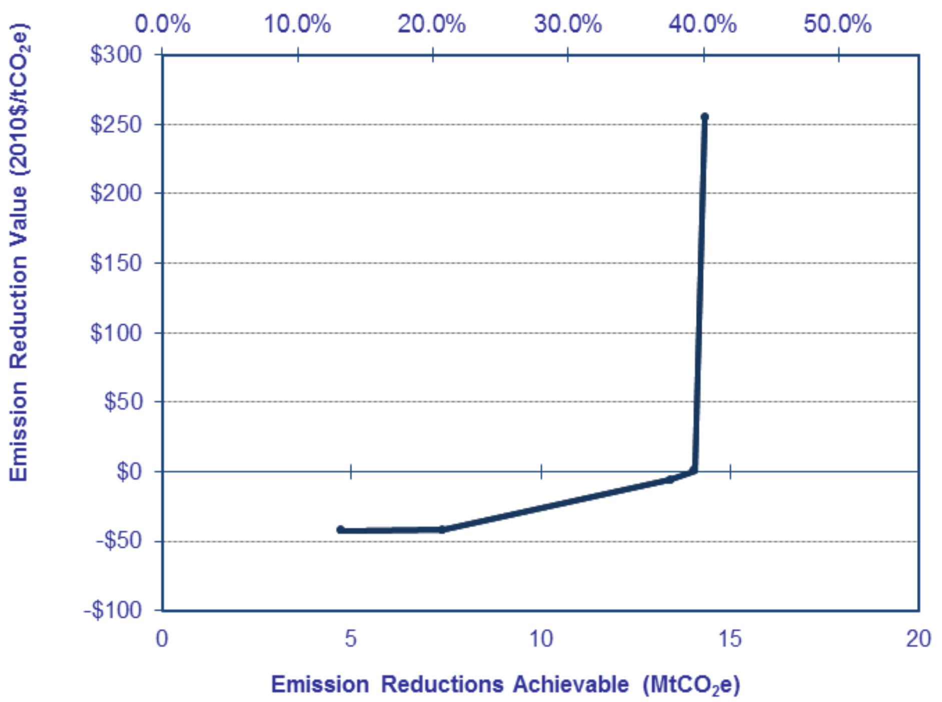


Figure 2-5: 2020 MAC curve for Nigeria (Africa)



2.3.2 Sensitivity case results

A series of sensitivity cases were run in order to illustrate the robustness of the MAC model. The cases that were run were discussed in section 2.2.5, and they are summarized in Table 2-6. For the first five cases (Capital Costs to Discount Rate), all of the projects were included in the analysis. For the two cases varying CO_2 and H_2S content, only one project was used since this project contained sufficient data to model the changing gas composition.

Tables 2-7 to 2-10 show the results from the different sensitivity cases. The results show interesting, yet not unexpected results. As investment and operating costs decrease, tax and discount rate decreases, and APG prices increase the projects become more favourable. One item to note is that the projects do not become uniformly more economical, since each project is different from the others (i.e. increasing APG price will effect projects that produce more APG more favourably than projects that only produce a small amount).

This analysis was not designed to incorporate all possible sensitivity case scenarios. The accompanying MAC tool spreadsheet is very robust. It can be used to create unique sensitively cases or even change the base case if desired. This is discussed further is section 2.4.

Table 2-6: Sensitivity case summary

Parameter	Lower Bound	Base Case	Upper Bound
Capital Costs (CAPEX)	-10%	Project Specific	+10%
Operating Expenses (OPEX)	-10%	Project Specific	+10%
Gas Price	$20/Mcm	Project Specific	$500/Mcm
Tax Rate	20%	33%	40%
Discount Rate	5%	10%	15%
CO_2 Content	N/A	0%	10%
H_2S Content	N/A	0%	4%

Table 2-7: Varying Discount and Tax Rates

Project ID	Breakeven Costs (2010$/t$CO_2$e)				
	Base Case (TR 33%, DR 10%)	Tax Rate		Discount Rate	
		20%	40%	5%	15%
13	-$42.10	-$46.19	-$39.16	-$56.00	-$26.29
36	-$41.73	-$43.03	-$40.80	-$46.24	-$36.65
37	-$35.48	-$37.41	-$34.09	-$42.19	-$27.91
4	-$5.89	-$8.42	-$4.07	-$14.48	$3.87
29	-$0.67	-$0.97	-$0.45	-$1.69	$0.49
3	$0.98	-$1.15	$2.51	-$6.26	$9.20
28	$1.17	$0.21	$1.86	-$2.04	$4.78
35	$4.20	-$1.84	$8.54	-$16.78	$27.85
24	$6.64	$4.95	$7.85	$0.91	$13.16
12	$17.06	$13.87	$19.36	$6.22	$29.39
23	$31.90	$30.56	$32.85	$27.35	$37.07
27	$42.34	$38.64	$44.99	$29.79	$56.60
22	$53.71	$51.32	$55.43	$45.42	$63.05
26	$54.44	$50.71	$57.12	$41.77	$68.84
30	$63.35	$57.06	$67.86	$41.99	$87.62
25	$64.59	$57.14	$69.93	$39.32	$93.30

Project ID	Breakeven Costs (2010$/tCO2e)				
	Base Case (TR 33%, DR 10%)	Tax Rate		Discount Rate	
		20%	40%	5%	15%
14	$75.92	$67.35	$82.07	$46.83	$108.98
1	$76.09	$64.98	$84.06	$38.39	$118.94
31	$92.10	$82.83	$98.76	$60.63	$127.88
15	$156.24	$154.67	$157.36	$151.00	$162.13
32	$164.22	$147.14	$176.48	$105.91	$230.54
33	$164.29	$156.99	$169.53	$141.11	$188.80
34	$254.51	$237.22	$266.92	$195.81	$321.23

Table 2-8: Varying CAPEX and OPEX

Project ID	Breakeven Costs (2010$/tCO2e)				
	Base Case	CAPEX		OPEX	
		-10%	+10%	-10%	+10%
13	-$42.10	-$45.87	-$38.32	-$42.48	-$41.71
36	-$41.73	$11.45	$13.54	$12.29	$12.70
37	-$35.48	-$37.03	-$33.92	-$35.79	-$35.16
4	-$5.89	-$8.22	-$3.56	-$6.62	-$5.16
29	-$0.67	-$0.95	-$0.39	-$0.72	-$0.62
3	$0.98	-$0.99	$2.94	$0.59	$1.37
28	$1.17	$0.17	$2.17	$0.99	$1.34
35	$4.20	-$0.66	$9.07	$3.22	$5.19
24	$6.64	$5.08	$8.19	$5.57	$7.71
12	$17.06	$14.12	$20.00	$15.94	$18.18
23	$31.90	$30.71	$33.08	$29.51	$34.28
27	$42.34	$38.93	$45.74	$41.18	$43.49
22	$53.71	$51.79	$55.63	$49.64	$57.78
26	$54.44	$51.00	$57.88	$52.19	$56.69
30	$63.35	$57.55	$69.14	$62.25	$64.44
25	$64.59	$57.73	$71.44	$59.71	$69.46
14	$75.92	$68.03	$83.81	$75.21	$76.62
1	$76.09	$65.86	$86.32	$74.19	$77.99
31	$92.10	$83.57	$100.64	$90.49	$93.72
15	$156.24	$154.60	$157.87	$139.23	$173.24
32	$164.22	$149.04	$179.40	$161.30	$167.15
33	$164.29	$151.16	$177.43	$159.17	$169.41
34	$254.51	$238.59	$270.43	$240.08	$268.94

Table 2-9: Varying APG price

Project ID	Breakeven Costs (2010$/tCO2e)						
	Base Case (Project Specific)	Gas Price ($/Mcm)					
		$20	$50	$100	$200	$300	$500
13	-$42.10	-$53.03	-$192.64	-$425.33	-$890.71	-$1,356.08	-$2,286.83
36	-$41.73	$2.16	-$13.33	-$39.15	-$90.79	-$142.42	-$245.70
37	-$35.48	$8.37	-$7.10	-$32.90	-$84.49	-$136.07	-$239.25
4	-$5.89	-$7.00	-$18.11	-$36.61	-$73.63	-$110.64	-$184.67
29	-$0.67	-$1.37	-$8.33	-$19.93	-$43.13	-$66.32	-$112.72
3	$0.98	$1.44	-$9.25	-$27.07	-$62.71	-$98.35	-$169.63
28	$1.17	-$0.70	-$19.37	-$50.49	-$112.72	-$174.96	-$299.43
35	$4.20	$48.14	$32.64	$6.79	-$44.91	-$96.60	-$199.99
24	$6.64	$15.65	$3.69	-$16.25	-$56.13	-$96.02	-$175.78
12	$17.06	$33.46	$22.74	$4.88	-$30.85	-$66.58	-$138.04
23	$31.90	$31.22	$24.45	$13.18	-$9.38	-$31.93	-$77.04
27	$42.34	$41.77	$36.06	$26.56	$7.55	-$11.45	-$49.47
22	$53.71	$52.62	$41.68	$23.46	-$12.98	-$49.43	-$122.32
26	$54.44	$54.01	$49.67	$42.45	$28.01	$13.57	-$15.31
30	$63.35	$61.50	$50.45	$32.03	-$4.82	-$41.66	-$115.35
25	$64.59	$63.58	$53.57	$36.89	$3.52	-$29.86	-$96.60
14	$75.92	$75.92	$60.86	$35.77	-$14.42	-$64.61	-$164.99
1	$76.09	$76.09	$54.23	$17.80	-$55.07	-$127.94	-$273.67
31	$92.10	$90.44	$73.78	$46.01	-$9.52	-$65.06	-$176.12
15	$156.24	$172.27	$153.03	$120.96	$56.82	-$7.32	-$135.60
32	$164.22	$172.62	$160.02	$139.02	$97.02	$55.02	-$28.97
33	$164.29	$172.07	$156.52	$130.60	$78.75	$26.91	-$76.77
34	$254.51	$270.31	$239.33	$187.70	$84.44	-$18.82	-$225.33

Table 2-10: Varying CO2 and H2S compositions

Project ID	Breakeven Costs (2010$/tCO2e)							
	Base Case (0% CO_2, 0% H_2S)	CO_2 (mol %)					H_2S (mol %)	
		2%	4%	6%	8%	10%	2%	4%
35	$4.20	$4.20	$8.67	$10.34	$12.02	$13.69	$8.80	$10.67

2.4 MAC tool user instructions

2.4.1 Tool overview

The accompanying MAC tool was designed to model the APG emission reduction projects that were identified in Task 1 of this project. However, the tool was also developed in order to provide the user a high degree of customization. This enables the user to change parameters such as tax rate, operating costs, baseline emissions or even input additional projects. By allowing this, the tool enables the user to create custom scenarios not explored in this report.

There are four distinct sections to the tool. The main tab is called “Control” and is where the MAC curves are displayed. The next tab is called “Results” and is where detailed data from the MAC analysis are displayed. This includes project titles and descriptions, breakeven costs, and reductions. The third tab is called “Baselines” and is where the country baseline emissions are input. The final section is comprised of three tabs called “Inputs_Middle_East,” “Inputs_FSU,” and “Inputs_Africa.” This is where the individual projects and project parameters are displayed.

While the tool allows the user to change many parameters, it is only capable of showing one set of results at a time. If multiple different scenarios are desired, each one must be run and saved separately. Also, in order to restore default values, the tool needs to be closed and reopened.

2.4.2 Changing parameters

There are three main areas where the user can customize the tool. These are the “Control” tab, the “Baselines” tab, and the “Inputs” tabs. On these tabs, any cells that are white or drop down menus can be changed. Once modified, the user will need to hit the “Update Results” button on the Control tab to make sure the changes are displayed.

The Control tab is where the MAC curves are produced. On this tab, the user can choose certain countries or project types to focus on, which year to produce the MAC curve for (2010, 2020, or 2030), and can modify the tax and discount rates. Any changes made on this tab will apply to all projects in the tool.

The Baseline tab is where country baseline emissions are input. By default, the baseline emissions are based on the U.S. EPA’s 2011 Draft Global Anthropogenic Non-CO_2 Greenhouse Gas Emissions: 1990-2030 report. However, if the user wishes to use a different set of baseline emissions, these can be input on this tab.

The Inputs tabs enable the user to make edits to the tool. Here, the project costs, project revenues, project lifetime, and implementation year can all be changed. The user can also remove any of the default projects as well as input any additional projects they would like displayed on the MAC curve. In order to remove projects, the box located in column A needs to be unchecked for each project to be removed. To add projects, the user needs to input the project data on one of the blank rows at the bottom of the spreadsheet and make sure to check the box in column A to include the project in the analysis. A more detailed explanation is provided below.

2.4.3 Additional projects

When adding projects to the Inputs tabs, there is a procedure the user needs to follow to ensure the project shows up in the MAC analysis. First, the user must title the project. Second, the user needs to specify the project as a certain project type from the dropdown list. If the added project doesn’t match any of the options exactly, the closest match should be used. Third, the country and country group need to be input. The tool is only designed to show country level results for the four country groupings on the Baselines tab, but any country can be used and displayed on the Results tab. (Note: in order to get an additional country to display on the Results tab, the “All Included Countries” option needs to be selected on the Control tab.) Finally, the project data must be input. Mandatory data includes implementation year, project lifetime, project baseline emissions, and project reductions. All other data elements are optional, but will give more accurate results if included.

Once desired projects are added, make sure the box in column A is selected. Then the “Update Results” button on the control tab needs to be pressed. The new projects will now be incorporated into the MAC curve results.

Task 3

1. Introduction

1.1 Objectives

1.1.1 Objectives of project

The first objective of this study is to describe the technical, economic and regulatory variables that affect the potential for improving/incentivising upstream greenhouse gas (GHG) reductions. This will entail presenting the most economically preferred approaches utilized to date with the use of marginal abatement cost (MAC) curves for upstream GHG reductions and conducting sensitivity analysis on the pertinent technical, economic and regulatory parameters to highlight potential economic drivers that could facilitate further investment in GHG reductions.

The second objective is to develop guidelines and principles for development of methods/best practices for measuring and verifying GHG emission reductions and guidelines for legislators for screening, evaluating and selecting existing and future schemes, carbon credit standards or certification programmes that ensure that GHG emission reductions are aligned with the requirements prescribed in the draft implementing measure.

1.1.2 Objectives and scope of task

This is the third of three tasks that collectively address the first objective of the study. This task will look at current and future crude oil production in the pertinent regions, as identified in the first and second tasks of the first objective. As discussed and agreed upon with the European Commission, the future crude oil production projections will be taken from an established report rather than being developed independently.

This task will also identify publically announced projects that may potentially result in reduced emissions from associated petroleum gas production. These projects are to include, but are not limited to pipelines, expansion of enhanced oil recovery (EOR), power plants, and offshore pipelines to LNG/LPG plants. Suggestions will also be made on how these projects could be incorporated into the MAC tool previously provided in the second task.

2. Findings

2.1 Current and Future Oil Production

2.1.1 Oil Production Forecast

In order to understand the emissions reduction potential from associated petroleum gas (APG), a production outlook is needed. However, a worldwide APG production forecast does not exist. This can be attributed to several factors. While APG forecasts for individual fields are often performed, these results are usually not made public. Also since no two oil fields are exactly the same, it is impractical to apply any type of correlation to estimate APG levels in a given reservoir. Further, APG production volumes can vary greatly over the life of a field, and depending on the exact geology of the field, can either decrease or increase on an annual basis.

As an example, we examined the Levelland Oil Field located in western Texas. This is one of the larger conventional fields located in the state, and the field contains no gas wells to otherwise deplete the gas. Oil and APG production values are available from 1993 to the present, and are plotted in figure 2-1 along with the gas-to-oil ratio (GOR). As the figure shows, the amount of APG produced per year initially increases, then decreases sharply, and then levels out for the last 10 years.

Figure 2-1: Annual Oil and APG Production for the Levelland Oil Field in Texas

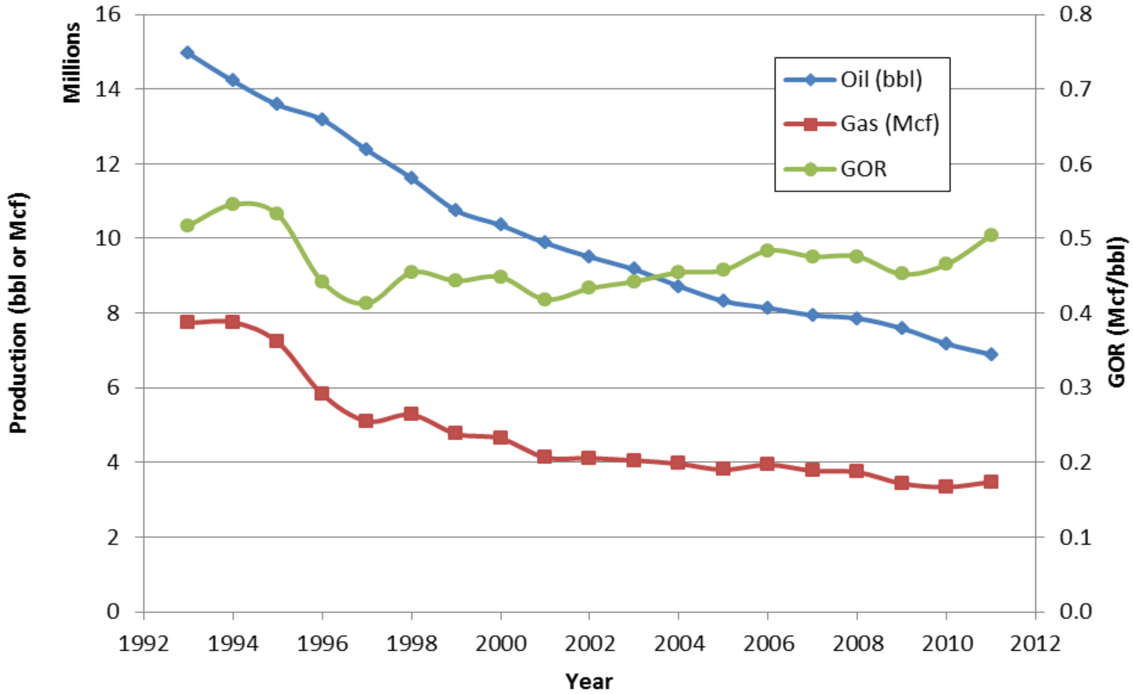
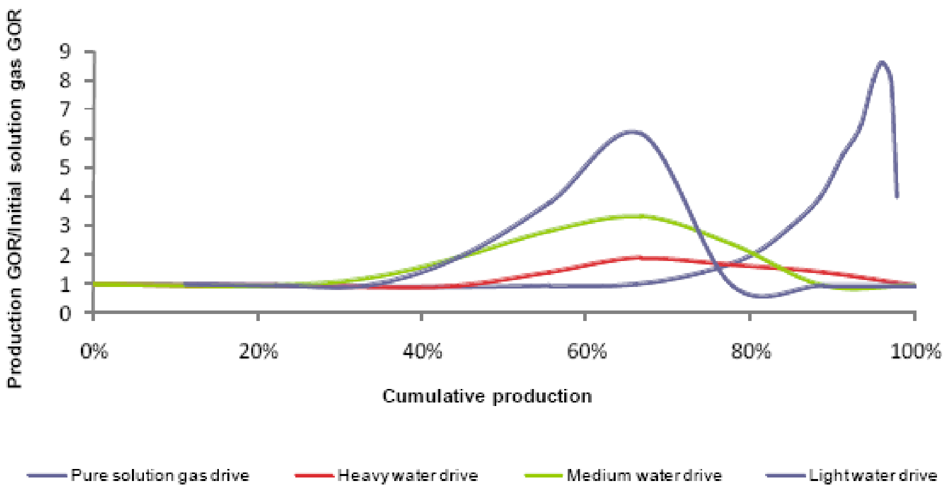


Figure 2-2: Ratio of Produced Gas Throughout Field Life



Source: Energy Redefined 2010[8]

[8] http://www.theicct.org/carbon-intensity-crude-oil-europe

While estimating APG production values can be difficult, Figure 2-1 does show that APG production is related to the amount of oil produced. This is evident in the fact that the GOR stays relatively constant between 1993 and 2011. Other studies suggest that GOR can increase significantly with field age. Energy Redefined (Fig. 2-2) suggests that GOR may increase up to 9 times of the initial value. In general, the higher the production of oil, the higher the overall production of APG will be. This is not a perfect correlation, since, as described above, the amount of APG produced depends on a variety of factors that can vary widely, not only from field to field, but even well to well; but, in general the correlation remains proportional. Therefore, a country's oil production is only somewhat indicative of the relative amount of APG produced.

Table 2-1 shows the U.S. Energy Information Administration's forecast (and historical data) of oil and liquids production from the countries of interest as identified in Tasks 1 and 2. The table is taken from data from the 2011 International Energy Outlook[9]. The table includes all conventional liquids production.

Table 2-1: Liquids Production Forecast by Country (MMbbl/day)

Country	2010 % EU Oil Imports*	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Russia	29.70%	3,468	3,541	3,614	3,577	3,577	3,650	3,687	3,760	3,796	3,869	3,942
Libya	10.71%	621	657	657	694	657	657	329	329	329	329	329
Saudi Arabia	6.01%	4,052	3,906	3,723	3,906	3,504	3,687	4,088	4,161	4,198	4,198	4,234
Kazakhstan	5.97%	475	511	511	511	548	584	621	657	694	694	730
Iran	5.66%	1,533	1,497	1,460	1,533	1,497	1,533	1,533	1,533	1,497	1,497	1,460
Nigeria	4.37%	949	876	876	803	803	876	949	986	1,022	1,059	1,095
Azerbaijan	3.90%	146	219	292	329	365	365	438	438	438	475	475
Iraq	3.15%	694	730	767	876	876	876	949	986	986	1,022	1,059
Yemen	0.05%	146	146	110	110	110	110	110	110	73	73	73

* These values represent the percentage of total crude oil imports to the EU broken out by country for 2010.

The top eight oil importers (by percentage of total oil imports to the EU) were included in this task. Yemen was also included because it was one of the countries containing a project focusing of APG emission reductions that was detailed in Task 2. Collectively in 2010, these nine countries supplied over 69% of crude oil imported to the EU. Together these countries are predicted to increase oil production by 11% in 2020 compared to 2010. Therefore the APG from these countries is likely to increase as well. According to GGFR data for 2011, Russia and Nigeria are the top two flaring countries in the world, and are respectively forecast to increase oil production by 14% and 15% by 2020.

Table 2-1 shows production through 2020, but the International Energy Outlook has forecast data out to 2035. This information is included in Appendix A.

2.2 Barriers to APG Utilization

There several factors that affect utilization rates of APG. While economic and geography are certainly linked in some scenarios, not all will be applicable to every country and company. In addition Government regulations and policy are important to APG flaring reductions. Governments can assist by setting up a regulatory framework that encourages companies to limit unnecessary flaring. In addition, governments can shape investment with

[9] International Energy Outlook 2011. U.S. EIA. 19 September 2011. Available online at: http://www.eia.gov/forecasts/ieo/

tax policy and fuel price reforms. High oil prices have created more opportunities for flare gas to displace energy from an alternative fuel source (such as oil-fired power generation). Reduction of flaring of associated gas, generally with a high content of ethane and heavier hydrocarbons, contributes further to production of NGLs. Investment in gas processing plants recover the NGLs and can be a positive addition to project economics, particularly if there is access to export markets.

In Russia to promote utilization of associated gas, the government plans to significantly increase the fee paid by companies for flaring. The regulatory authorities' aim to reach 95% utilization of APG, most likely by 2014. Some incentives to reduce flaring have also advanced. The process of fuel price reforms for domestic end-use is ongoing. The government has liberalized associated gas prices allowing parties to negotiate terms. In addition, a program is in place to increase domestic gas sales prices across all sectors. The government has also allowed preferred access to the electricity grid for power generated from flare projects. In Nigeria, a number of factors have driven investment to reduce flaring, including: higher oil prices, increased government stability, additional regulatory oversight, pressure from NGOs, and international focus on sustainability practices of the regions oil companies. In the Middle East, many governments have either directly or indirectly set the price of gas at very low levels. Associated gas gathering has been practiced for decades at the supergiant oil fields of Saudi Arabia, Iran, Iraq, and Kuwait. The issue for flare gas reduction is prices are typically administered at an average level based on the average costs of the giant concentrated gas resources. However, at sites where gas is sour, or at isolated smaller sites, gas gathering and processing costs are higher than average. As a result, often it has been more economical to flare hard-to-handle gas than to develop it into gas systems.

Task 4 and 5 has additional analysis regarding developing guidelines for a scheme to support APG flaring reduction.

2.2.1 Economic Concerns

Economic concerns focus mainly on profitability of using APG. This has to do with the market price of natural gas and the amount of APG produced. In many countries, especially those with large national oil and gas companies, commodity prices are fixed. Even in countries where prices aren't fixed, natural gas prices have fluctuated widely over the past few years, making investing in bringing more gas to market difficult to economically justify. For example, a project might be profitable at a natural gas price $10/MMBTU, but highly unprofitable at $3/MMBTU.

It requires a substantial amount of capital investment to bring APG to market. A company may need to install gas gathering lines, compressor stations, and gas treatment facilities at a minimum. For example, Shell is investing U.S.$2 billion in Nigeria to install and upgrade gas gathering lines at 26 of its production facilities. This is in addition to the U.S.$3 billion Shell has already spent installing associated gas gathering infrastructure at 32 flowstations in Nigeria.[10]

Additionally, investing in APG recovery infrastructure can be difficult because the amount of APG in an oil well is often unknown and hard to predict. The gas-to-oil ratio (GOR) of a field is not constant, but usually increases during a field's early life and decreases near the end. However, this depends on the nature of the way in which pressure is maintained in the

[10] "Shell to spend $2 billion reducing Nigeria gas flaring." Reuters. 19 May 2010. Available online at: http://www.reuters.com/article/2010/05/19/us-nigeria-shell-idUSTRE64I2XD20100519

reservoir. This fluctuation in production values can make estimating profitability of APG recovery projects difficult.

The supply of gas is only part of the economic issue. In addition, market demand for the captured APG can be difficult to predict. In many countries, especially developing nations, the demand for natural gas and natural gas products is far lower than production. In these instances, a demand for gas must be created to develop a viable economic recovery project. This is particularly true in Nigeria. For example, Nigeria requires 6,000 MW of electricity capacity nationally. However, at any one point in time, only 2,000 MW is available for generation. The reason for this is because Nigeria's current power generation capacity is in a poor state of repair. On top of this, Nigeria only has 5,950 MW of installed capacity – 50 MW less than what is required.[11] So, even if captured APG was available for use by electricity generators, the country is incapable of using this gas. In order to utilize the currently flared APG, Nigeria needs major expansion in its end users' markets or exports.

Production Sharing Agreements (PSAs) between the oil producer and the government or licensor must also be considered. Many PSAs only provide a license for oil production, which may inhibit or prohibit the developer to undertake any APG emission reduction projects, as it covers only the ownership of oil produced from these fields. Thus, the oil producer wouldn't have any legal right to draw any economic benefit from the recovery of APG, and would either only vent APG or flare it.. In many instances as well, the PSA is valid only for a certain number of years, inhibiting long term investment options. Often times PSAs allow the oil producer to reimburse capital costs through increased share of production but that often relates only to capital costs associated with oil production and may not cover investments made for APG flaring reduction.

2.2.2 Geographical Concerns

Geographic concerns relate to where the associated gas is produced in relation to where pipelines for transport and the end user are located. Many oil fields are located in highly remote areas. For example, there are many small oil fields that produce a substantial amount of APG scattered throughout Western Siberia in Russia. These fields can often be hundreds of kilometers from the nearest major natural gas market. This results in two issues for gas producers. First, the majority of the gas cannot be used locally. This is mainly because the power needs of the area are quite small, and these areas almost always lack the necessary treatment facilities to be able to either extract natural gas liquids (NGLs) or produce saleable gas. Second, a tremendous amount of investment in gathering infrastructure is required in order to transport the gas to a major market.

Another issue is the market area where the gas is produced. In many cases, it may be neither feasible nor reasonable to try to expand the gas market. In these cases, the gas will need to be transported to a distant location or exported. This again results in major infrastructure investments to either develop transnational pipelines, or potentially even liquefied natural gas (LNG) facilities. Both of these options are very complicated logistically, as well as costly. Couple this with the fact that APG production rates can fluctuate widely and the investment outlook may not be favorable.

This issue ties back in with the economic concerns as well. When developing a project for APG, whether in the form of a gas processing plant or an electric power generation facility,

[11] CDM Project 0553: Recovery of associated gas that would otherwise be flared at Kwale oil-gas processing plant. 1 July 2004. Available online at: http://cdm.unfccc.int/Projects/DB/DNV-CUK1155130395.3/view

the largest capital expenditure involves constructing the facility itself. Choosing the appropriate location for the facility is no small task. The facility must be located near a long term gas supply such as major APG producing fields to ensure that the facility can have a steady supply of gas. As one field declines in APG, another field needs to be available to provide gas. This can be difficult as most of these facilities are assumed to have a lifetime of at least 30 years. Therefore ensuring adequate supply to any new plant is critical when siting a new project. Periodic investment in new gas pipelines from new fields to the plant will probably be required over the decades.

2.3 Options for Increasing APG Utilization

Even though there are several barriers to reducing emissions from APG production, there are still many options available to companies. While these scenarios may not be feasible in all cases, many will be potentially applicable.

2.3.1 Existing Technology for Reducing APG Emissions

There is technology available that offers options for capturing and reducing emissions from APG. Table 2-2 describes some of the advantages and disadvantages of these choices. These options fall into three categories based on how and where the captured APG is used: local, regional, and regional with transmission. Local options, which include gas reinjection and on-site power generation, require the least investment in infrastructure. The other two options, which include large-scale power generation and gas processing, may require substantial investment in new infrastructure to come to fruition.

Table 2-2: Options for Utilizing Produced APG

Technology	Advantages	Disadvantages
Gas Reinjection for Future Use	Preserves value of gas	Capital cost; not all formations suited for reinjection
Gas Reinjection for Enhanced Oil Recovery (EOR)	Revenue through increased oil production; possible future recovery of some reinjected gas	Capital cost; not all formations suitable for gas EOR
Local Electricity Generation for Field Use	Reduce purchased electricity	Capital cost
Regional Electricity Generation (Power Plant)	Income from gas sales to electricity generators	Substantial capital cost of gathering and processing infrastructure; possible inadequate generating capacity demand
Process APG and Sell Dry Gas, NGLs	Income from processed APG, as NGLs, Chemical Feedstock, or dry gas sales	Capital cost of gathering infrastructure; possible inadequate plant capacity and access; possible limits on pipeline capacity

The list in Table 2-2 is not comprehensive, but is designed to show that there are a range of options available to companies in order to increase the utilization of APG. In many cases, a combination of these technologies may be needed in order for a project to be economically feasible. Some projects will not be feasible without outside investment. These cases offer the opportunity for outside investment, through such mechanisms as the Clean Development Mechanisms from the United Nations Framework Convention on Climate Change.

2.3.2 Publically Announced Projects

In Tasks 1 and 2, implemented projects, or fully designed projects with the possibility of implementation, for APG emission reductions were examined. The goal of this task is to examine projects in the countries identified in Tasks 1 and 2, with the objective of identifying publically announced projects. Projects that are discussed below could be potentially added to the MAC tool, as designed in Task 2. The process of adding new projects is discussed in section 2.4.

This task focused on projects that could potentially reduce emissions from APG flaring. It includes projects that are not explicitly for reducing emissions from APG, but that could use the APG at some point in the future. As explained in section 2.2, the main issues with increasing APG utilization are economics and geography. Announced projects that transport, treat, or consume natural gas (e.g. a pipeline, processing plant, or power plant) could potentially use APG. This would depend wholly on the economics of the project, but with economic incentive, the project may be feasible. Therefore, announced projects that utilize natural gas were included. The announced projects are broken out by country. However, typically only a fraction of announced projects are eventually fully implemented, as gas market prices, available company capital and economics can change over the period of front end engineering and design, leading to project cancellations. Many of the projects below are complex, multi-billion dollar projects that would take years to implement

Russia

- Murmansk-Vokhov gas pipeline, Gazprom. In March 2012, Gazprom sequestered 500 million rubles for design and survey work on the Murmansk-Vokhov gas pipeline. The pipeline will supply gas from the Shtokman field to customers in Northwestern Russia and for export via the Nord Stream Pipeline. The pipeline, which is still in the feasibility stage, is expected to total 1,265 km in length and have a carrying capacity of 50 Bcm of gas per year. Also planned are 10 compressor stations. (Pipeline News – Future Jobs, Aug 2012).
- South Stream gas pipeline, Gazprom. In February 2012, Gazprom announced it would begin construction on the South Stream gas pipeline by the end of the year. The pipeline, which will total 2,237 miles (3,600 km) is intended to supply Italy and Austria with Russian gas via the Black Sea. Gazprom estimates that the project will cost U.S.$11.6 billion, and should be completed by 2015. (Pipeline News – Future Jobs, Aug 2012)
- Berezovskaha-Spasskaya Guba pipeline, Gazprom. In March 2012, Gazprom set aside 230 million rubles in order to construct the second phase of the 23 mile (37 km) long Berezovskaha-Spasskaya Guba inter-settlement gas pipeline. This project is part of the gasification of the Karelia Republic. (Pipeline News – Contracts Let, Aug 2012)
- Northern Caspian Sea subsea pipelines, Saipem. In June 2012, LUKOIL-Nizhnevolzhskneft signed Saipem to construct two subsea pipelines in the Northern Caspian Sea. The pipelines, which will each be 70 miles (114 km) long, will transport both oil and gas. The pipelines will connect the offshore Vladimir Filanovsky field with the onshore hub of plugging devices. The work is scheduled to be completed in 2015. (Pipeline News – Contracts Let, Aug 2012)
- Shtokman Gas Project, Technip. In 2009, Technip was awarded a contract for the front-end engineering design for the onshore portion of the Shtokman Gas Project. This project is looking to develop the gas reserves below Russia's Barents Sea for LNG production. It is predicted that gas sales could come online in 2012 and LNG production could begin in 2017. (Pipeline News – Contracts Let, Aug 2012)

- LPG Rospan Project, TNK-BP and SIBUR. In July 2012, TNK-BP and SIBUR announced they would continue a joint venture started back in 2007. As part of this agreement, SIBUR will purchase LPG produced by TNK-BP. The LPG will be produced from a condensate stabilization unit which will be built as part of the Rospan Project. The LPG will be produced from APG in TNK-BP's oil fields.[12]

Libya

- Bouri Gas Utilization Project, Tecnomare. In September 2008, Tecnomare announced the Bouri Gas Utilization Project. This project aims to install three offshore pipelines connecting three platforms located in the Bouri field. The pipelines will transport raw gas, dry gas, and condensate from the platforms to help reduce APG flaring.[13]

Saudi Arabia

- Al Wasit Gas Program, Saipem. In August 2011, Saudi Aramco award Saipem a contract for the Al Wasit Gas Program and development of the Arabiyah and Hasban offshore fields. The project will encompass 12 wellhead platforms, 2 tie-in platforms, and 1 injection platform. 260 km of offshore export trunkline and 40km of offshore flowline will be installed. In addition, 120 of onshore pipelines will be constructed. Completion is scheduled for 2013-2014. (Pipeline News – Contracts Let, Aug 2012)
- Gas and Condensate Export System (GCES), The Penspen Group and Technip. In May 2012, Penspen and Technip were engaged to manage and construct a new GCES on the Saudi Arabia/Kuwait border. The new export system will include gas facilities carrying 1.1 million cubic meters of gas per day to Kuwait as well as110 km of export pipeline, of which approximately 47 km will be offshore. The project is scheduled to be completed in 2014. (Pipeline News – Contracts Let, Aug 2012)

Kazakhstan

- Pre-Caspian gas pipeline, Gazprom. In October 2007, a trilateral agreement was signed between Kazakhstan, Turkmenistan, and Russia to build a pipeline to supply Russia with gas from the Caspian Sea region. As of October 2011, the feasibility study and engineering design data was approved, and the legal and contractual framework for constructing the pipeline was being finalized. Upon completion, the pipeline will cover 1,056 miles (1,700 km) in total, with 311 miles (500 km) in Turkmenistan and 746 miles (1,200 km) in Kazakhstan. The pipeline is expected to carry 40 Bcm of gas per year, with 30 Bcm and 10 Bcm coming from Kazakhstan and Turkmenistan, respectively. (Pipeline News – Future Jobs, Aug 2012)

Iran

- Gas export pipeline to Syria, Gov. of Iran. In March 2011, Iran signed an initial agreement to build a pipeline to export fuel gas to Syria via Iraq. The agreement also provided cooperation on the construction of a 140,000 barrel per day oil refinery in Syria. The pipeline would feed into the Arab regional gas network. Initially, the gas will be

12 "SIBUR and TNK-BP have signed agreements." 4-Traders. 25 July 2012. Available online at: http://www.4-traders.com/TNK-BP-HOLDING-OAO-6498768/news/TNK-BP-Holding-OAO-SIBUR-and-TNK-BP-have-signed-agreements-on-strategic-partnership-in-the-product-14430078/

13 "Bouri Gas Utilization Project." SPS Fano. Available online at: http://www.spsfano.com/joomla/index.php?option=com_content&view=article&id=127&Itemid=191&lang=en

supplied to Syria, Lebanon and Jordan, with some quantities to be exported to Europe in the future. The pipeline is expected to have a capacity of 100 million cubic meters per day. (Pipeline News – Future Jobs, Aug 2012)

- Gas mainline installation, Gov. of Iran. In April 2011, Iran announced that it would spend U.S$6 billion to install 1,678 miles (2,700 km) of new high pressure gas mainlines, as well as 19 new compressors. The project is aimed at expanding many of Iran's current gas mainlines. (Pipeline News – Future Jobs, Aug 2012)

Nigeria

- Nigerian Otumara-Saghara-Escravos Pipeline, Saipem. In September 2011, Shell Petroleum Development Co. awarded Saipem an EPC contract that includes engineering, procurement, fabrication and commissioning of a network of pipelines to help Shell comply with Nigeria's anti-flaring regulations. The 26 mile (42 km) pipeline will collect about 0.8 thousand cubic meters of associated gas per day. The contract is valued at U.S.$101 million, and there is no timeline on the project. (Pipeline News – Contracts Let, Aug 2012)
- Trans-Saharan Gas Pipeline (TSGP), Nigerian National Petroleum Co. In January 2011, Nigeria, Niger, and Algeria signed an agreement to move forward with the construction of the TSGP. The 2,565 mile (4,128 km) pipeline will take gas from the Niger Delta and move it through Nigeria and Algeria to the coast. It is projected to supply Europe with 20 Bcm of gas per year. The pipeline is expected to cost in the U.S.$10 billion range, with another U.S.$3 billion for upstream gas development, and should come online in 2015. (Pipeline News – Future Jobs, Aug 2012)
- Ofon Phase 2 development, Total. In February 2012, Total announced that contracts have been awarded for the second phase of the offshore Ofan field development. The project will see the installation of two production platforms, a processing platform, and an accommodation platform. While the project will increase oil production in the field, the main focus is on recovering the field's natural gas. The project is scheduled to come onstream in 2014. (Pipeline News – Contracts Let, Aug 2012)
- Forcados Yokri integrated project and the Southern Swamp associated gas gathering project, Shell Nigeria. In July 2012, Shell Nigeria announced a couple additional projects to further reduce APG flaring at its production sites. The Forcados Yokri integrated project and the Southern Swamp associated gas gathering project, which will cost U.S.$4 billion, are expected to produce 100,000 barrels oil equivalent per day (BOE/d) and 85,000 BOE/d, respectively, at peak production and reduce flaring intensity per barrel of oil produced.[14]

Azerbaijan

- Azerbaijan-Georgia-Romania Inter-connector (AGRI), Gov. of Azerbaijan, Georgia, and Romania. In September 2011, Romania, Georgia, and Azerbaijan signed an MOU for the AGRI to supply gas from the Caspian region to Europe. The project would utilize an already existing trans-Caucasus pipeline to take Azeri gas to Georgia. A LNG terminal will be constructed in Georgia, most likely in the port of Kulevi. The LNG would then be shipped to the Romanian port of Constanta to be regasified and subsequently enter the Romanian transmission system. The capacity is expected to reach 7 Bcm of gas per

[14] "Shell okays $4 billion to further cut Nigeria gas flaring." Oil & Gas Journal. 27 July 2012. Available online at: http://www.ogj.com/articles/2012/07/shell-okays-4-billion-to-further-cut-nigeria-gas-flaring.html

year, with about 5 Bcm going to the EU. The project, which has no timeline at this point, is expected to cost U.S.$26 billion.

- Trans Anatolian gas pipeline, Gov. of Azerbaijan and Turkey. In May 2012, Turkey and Azerbaijan announced of a new joint gas pipeline which would facilitate the export of Azerbaijani natural gas to Europe via Georgia and Turkey. Total E&P Azerbaijan, BP, and Statoil have been invited to participate in the project. The pipeline will be 2,000 km in length, is expected to cost around U.S.$7 billion, and should be commissioned in 2017. The line is projected to carry upwards of 10 Bcm of gas per year.
- Gas export pipeline, SOCAR. In March 2010, SOCAR announced that would build a pipeline to export gas to Iran. The pipeline is expected to have a capacity of 6.57 Bcm per year, and should be completed by the end of 2012. (Pipeline News – Future Jobs, Aug 2012)
- BP plans to increase the compressor capacity at one of their gas compressor in order to increase the amount of APG reinjected into the strata by 40%.[15]
- Japan Oil Engineering Co. will providing consulting to reducing flaring at the Guneshli oil field and to help the country's electric power plants switch from coal and heavy oil to natural gas and APG for power generation. The project is aiming to reduce emissions by 2.5 million tonnes CO2e per year.16

Iraq

- Zubair field export pipeline, South Oil Company of Iraq. In March 2011, the South oil Company of Iraq announced that it was taking bids for a contract to build a 108 km pipeline to connect the Zubair field in southern Iraq with the Fao depot, north of the Arabian Gulf. The pipeline will transport 2.8 million cubic meters of gas per day. (Pipeline News – Future Jobs, Aug 2012)

Yemen

- No announced projects were found. Many oil companies appear to be pulling out of the country due to the recent unrest in the country as well.

2.4 Incorporation into MAC Tool

The MAC tool developed in Task 2 was designed with the ability to allow projects to be added. The projects discussed in section 2.3.2 can be inserted into the MAC tool to show what affect they might have on the reduction of emissions from APG. In order to be included in the tool, the user needs to know start date, the cost of the project, and emission reductions achievable. There are more inputs for the MAC analysis, as discussed in depth in Task 2, but they are not required in order to run the model. The additional inputs provide a more refined analysis of the projects.

[15] "BP plans to cut associated gas flaring to 200,000-300,000 cu m a day." ABC.az. 14 February 2012. Available online at: http://abc.az/eng/news/62352.html

[16] "Project aims to cut Guneshli gas flaring." PennEnergy. 7 February 2012. Available online at: http://www.pennenergy.com/index/petroleum/display/220818/articles/oil-gas-journal/drilling-production/project-aims-to-cut-guneshli-gas-flaring.html

Appendix 1

Table A-1: Conventional Liquids Production Forecast by Country to 2035 (MMbbl/year)

Country	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Russia	3,468	3,541	3,614	3,577	3,577	3,650	3,687	3,760	3,796	3,869
Libya	621	657	657	694	657	657	329	329	329	329
Saudi Arabia	4,052	3,906	3,723	3,906	3,504	3,687	4,088	4,161	4,198	4,198
Kazakhstan	475	511	511	511	548	584	621	657	694	694
Iran	1,533	1,497	1,460	1,533	1,497	1,533	1,533	1,533	1,497	1,497
Nigeria	949	876	876	803	803	876	949	986	1,022	1,059
Azerbaijan	146	219	292	329	365	365	438	438	438	475
Iraq	694	730	767	876	876	876	949	986	986	1,022
Yemen	146	146	110	110	110	110	110	110	73	73

Country	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Russia	3,942	3,979	4,052	4,088	4,125	4,161	4,198	4,234	4,271	4,344
Libya	329	329	292	292	292	256	256	256	256	256
Saudi Arabia	4,234	4,307	4,417	4,490	4,563	4,672	4,745	4,818	4,891	5,001
Kazakhstan	730	730	767	767	803	803	840	876	876	913
Iran	1,460	1,424	1,424	1,424	1,387	1,387	1,351	1,351	1,314	1,314
Nigeria	1,095	1,132	1,168	1,168	1,168	1,168	1,168	1,168	1,168	1,205
Azerbaijan	475	475	475	475	475	475	475	475	438	438
Iraq	1,059	1,132	1,168	1,241	1,278	1,314	1,351	1,424	1,497	1,570
Yemen	73	73	73	73	73	73	73	73	73	37

Country	2030	2031	2032	2033	2034	2035
Russia	4,453	4,526	4,563	4,599	4,636	4,672
Libya	256	292	292	292	292	292
Saudi Arabia	5,074	5,147	5,220	5,256	5,293	5,329
Kazakhstan	949	986	986	1,022	1,022	1,059
Iran	1,351	1,351	1,351	1,387	1,387	1,387
Nigeria	1,205	1,205	1,205	1,241	1,241	1,205
Azerbaijan	438	438	438	438	402	402
Iraq	1,643	1,716	1,825	1,898	1,935	2,008
Yemen	37	37	37	37	37	37

Source: International Energy Outlook 2011. Conventional Liquids Production, Reference Case Scenario.

Task 4

1. Introduction

1.1 Objectives of project

The first objective of this study is to describe the technical, economic and regulatory variables that affect the potential for improving/incentivising upstream GHG reductions. This will entail presenting the most economically preferred approaches utilized to date with the use of marginal abatement curves (MACs) for upstream GHG reductions and conducting sensitivity analysis on the pertinent technical, economic and regulatory parameters to highlight potential economic drivers that could facilitate further investment in GHG reductions.

The second objective is to develop guidelines and principles for development of methods/best practices for measuring and verifying GHG emission reductions and guidelines for legislators for screening, evaluating and selecting existing and future schemes, carbon credit standards or certification programmes that ensure that GHG emission reductions are aligned with the requirements prescribed in the draft implementing measure.

1.2 Objectives of task

This task aims to identify and analyse methodologies and initiatives for GHG emission reductions monitoring, verification and reporting. To meet this objective the following tasks have been performed:

Sub-task 1 - Identification of methodologies and initiatives under study;
Sub-task 2 - Definition and validation of the analysis criteria;
Sub-task 3 - Analysis and description of methodologies and initiatives; and
Sub-task 4 - Comparison of methodologies and initiatives.

1.3 Overview of tasks performed

Sub-task 1 - Identification of methodologies and initiatives under study:
A comprehensive review of existing legislative and voluntary schemes was conducted to identify schemes relevant to this study. The schemes were selected based on their relevancy to upstream oil operations, and associated gas flaring/venting reduction activities. The initial list included the following schemes:

- Argentina: hydrocarbons legislation (Law No. 17,319 (Hydrocarbons Law) Resolution 143/98 regulating natural gas flaring); environmental legislation (Resolution 236/93 on Gas Flaring and Venting);
- Australia: hydrocarbons legislation (Petroleum Act 1967), environmental legislation (Environmental Protection Impact of Proposals Act 1974; Schedule 1997; Petroleum Submerged Lands Management of Environment Regulations 1999);
- Canada: Canada Oil and Gas Operations Act (COGO Act);
- Canada (Alberta): Directive 060 Upstream Petroleum Industry Flaring, Incinerating, and Venting;
- Canada (Alberta): Specified Gas Emitters Regulation;
- Canada (British Columbia): Flaring and Venting Reduction Guideline (Under OGAA);

- Canada (Saskatchewan): Directive S-10 and Directive S-20; Oil and Gas Conservation Act and Oil and Gas Conservation Regulations, 1985;
- Canada (Manitoba): Oil and Gas Act;
- Canada (Newfoundland and Labrador and Nova Scotia): Offshore Areas Drilling and Production Regulations;
- Kazakhstan: Law “On introducing modifications and amendments in some legislative acts of the Republic of Kazakhstan concerning subsoil use and carrying out petroleum operations in the Republic of Kazakhstan”, № 79-III;
- Nigeria: hydrocarbons legislation (1969 Petroleum Act and Regulations, as amended; Model Petroleum Contract; Associated Gas Reinjection Act 1979; Associated Gas Reinjection (Continued Flaring of Gas) Regulations 1985; The Petroleum (Drilling and Production) Amendment Decree 1988); environmental legislation (Effluent Limitation Regulations 1991; DPR Environmental Guidelines and Standards for the Petroleum Industry 1991; FEPA EIA Guidelines for E&P Projects 1994, Decree No. 58/88);
- Norway: Petroleum Activities Act; CO_2 Tax Act;
- Peru: hydrocarbons legislation (Hydrocarbons Law 1993; Model Petroleum); environmental legislation (Environment Code 1990);
- Russia: Legislation on the limitations of associated gas flaring (Government's decree n°7)
- United Kingdom:
  - Primary legislation: Energy Act 1976, Petroleum Act 1998; Petroleum (Current Model Clauses) Order 1999; Environmental Legislation applicable to the Onshore Hydrocarbon Industry (England, Scotland, and Wales); The Offshore Petroleum Production and Pipelines (Assessment of Environmental Effects) Regulations 1999;
  - Key instruments for invoking primary legislation: Onshore (that is, Petroleum Exploration and Development Licenses); Offshore (that is, Exploration100 and Production Licenses101); Guidance Notes on Procedures for Regulating Offshore Oil and Gas Field Developments; Field Development Program; Venting and Flaring Consents; Offshore Pipeline Works Authorizations.
- USA: Petroleum Refinery National Initiative, The New Source Performance Standards (40 CFR part 60, subpart Ja);
- USA (California): Rule 1118 - Control of Emissions from Refinery Flares, Regulation 12, Rule 11 and Regulation 12, Rule 12
- The UK Quality Assurance Scheme for Carbon Offsetting
- The EPA Climate Leaders Offset Guidance
- Australia’s Greenhouse Friendly/National Carbon Offset Standard
- Japan’s Certification Center on Climate Change
- Clean Development Mechanism;
- Verified Carbon Standard;
- EU ETS Monitoring Reporting and Verification Guidelines

Based on the EC's feedback, several schemes out of those listed above were shortlisted for more in-depth analysis[17]. The final selection was based on following factors: schemes requiring estimation of APG flaring/venting, their robustness, extent of use, and the level of detail publicly available.

These schemes include:

- UNFCCC Clean Development Mechanism (CDM) – it is one of the flexible mechanisms introduced by the Kyoto Protocol. The scheme encourages project-based emission reductions in developing countries, while at the same assisting industrialized countries to meet their GHG emission reduction commitments.
- Verified Carbon Standard (VCS) – it is a quality standard for the voluntary carbon offset industry. Based on the Kyoto Protocol's Clean Development Mechanism, VCS establishes criteria for validating, measuring, and monitoring carbon offset projects.
- Alberta Specified Gas Emitters Regulation (SGER) – it is a strategic regulation requiring compliance installations to reduce Alberta emissions intensity by 12%, as of July 1, 2007.
- Alberta Offset Scheme (AOS) and "Quantification Protocol For Solution Gas Conservation" – this scheme provides flexibility for entities covered by the Specified Gas Emitters Regulation (SGER) to meet their compliance obligations. The following two directives have been included in the review, as the offset protocol makes key references to these documents.
    - Directive 060: Upstream Petroleum Industry Flaring, Incinerating, and Venting
    - Directive 007: Volumetric and Infrastructure Requirements.
- EU Emission Trading Scheme Monitoring Verification and Reporting Guidelines (MRV Guidelines 2007) – these guidelines have been adopted by the European Commission (EC) to help regulated entities meet their compliance requirements under the EU ETS Phase I and Phase II. NB: the EC has developed and recently issued Monitoring and Reporting Regulation (MRR) and Regulation for verification of emissions and accreditation of verifiers (AVR)[18], which have not been analysed in this report.

Sub-task 2 - Definition and validation of the assessment criteria:
The EC approved criteria used for the in-depth analysis of the shortlisted schemes consist of the following subsections:

- General characteristics;
- Compliance requirements;
- Methodology for emission reduction calculations;
- Monitoring requirements;
- Reporting requirements,
- Verification requirements, and
- Other interesting characteristics noted through research.

[17]Several schemes were listed in the Terms of Reference, including the UK Quality Assurance Scheme for Carbon Offsetting; the EPA Climate Leaders Offset Guidance; Australia's Greenhouse Friendly/National Carbon Offset Standard; and Japan's Certification Center on Climate Change. These schemes were not shortlisted as they were deemed not relevant. However, general observations on these schemes are presented in Appendix 3.

[18] Available at http://ec.europa.eu/clima/policies/ets/monitoring/documentation_en.htm

Appendix 1 presents the criteria used to evaluate the shortlisted schemes.

Sub-task 3 - Analysis and description of methodologies and initiatives
Each shortlisted methodology was researched thoroughly to address the assessment criteria. Information was taken from publicly available documents. Appendix 2 presents the results of this analysis.

Sub-task 4 - Comparison of methodologies and initiatives:
Following the analysis of the specified methodologies/ initiatives (Appendix 2), the next step was to compare criteria, highlighting similarities and differences across different methodologies / initiatives. The results of this assessment are presented in Section 2.1.

Section 2.2 presents the strengths and weaknesses of the different methodologies / initiatives and their advantages and disadvantages relative to each other.

Section 2.3 presents the initial list of recommendations for a potential scheme to be set by the EC, which will be discussed in more detail under Task 5 of the project.

2. Observations

2.1 Comparison of methodologies and initiatives

General:

Five schemes have been analysed in detail (Appendix 2). Three of them are voluntary programmes (i.e., Clean Development Mechanism (CDM); Verified Carbon Standard (VCS); and Alberta's Offset Scheme (AOS)), the remaining two are legally-binding (i.e., Specified Gas Emitters Regulation (SGER); and Monitoring Reporting Verification (MRV) Guidelines for activities covered by the EU ETS). In fact, due to this distinction, the majority of similarities and differences are noted between these two wider groups – legislative and voluntary – rather than on an individual scheme basis.

Three schemes, CDM, VCS and SGER, target emissions associated with both flaring and venting of associated petroleum gas (APG). The AOS Solution Gas Conservation Protocol addresses only small vents (<500m^3/day), while MRV covers only flares. All voluntary schemes[19] have methodologies/protocols for a project type that utilises APG and reduces associated emissions within the upstream petroleum industry[20]. Legislative schemes, on the other hand, consider flares and/or vents being one of many sources of emissions at an installation-level. Moreover, they target large industrial facilities (MRV: combustion installations >20MW and mineral oil refineries; SGER: installations emitting >100,000tCO_2/year).

The reduction target is solely linked to legislative schemes, with the difference that under SGER each installation has the same target (-12% in emission intensity compared to baseline), whereas under the EU ETS there is one common target for all activities covered by the scheme.

[19] Note: VCS accepts methodologies developed specifically for the scheme, as well as methodologies of Clean Development Mechanism (CDM) and California's Climate Action Reserve (CAR). Neither VCS nor CAR have their own methodologies targeting emissions linked to flaring/venting of associated petroleum gas. As such, often in the text CDM and VCS are treated as one and the same (this is marked by "CDM/VCS").

[20] CDM/VCS: oil wells; AOS: oil & bitumen extraction

Compliance:

The level of complexity and detail in applicability conditions is the highest in CDM methodologies. This is followed by AOS Solution Gas Conservation Protocol, where requirements for projects are less stringent. Legislative schemes are more straightforward, as the decision to include a particular flare/vent is dependent on the level of combustion emissions from the installation.

Under the voluntary schemes, all applicability conditions (those listed in methodologies/protocols and in referenced tools) have to be fully met; otherwise a project is excluded from the scheme. Moreover, an emission reduction has to be *additional*: in principle it means that it has to be beyond regulatory requirements, be real, measurable and verified[21]. Voluntary schemes do not recognize any emissions from project types for which there is no approved methodology/protocol.

The legislative schemes have a wider set of compliance options: internal emission reduction, use of offsets, trading of allowances (EUAs under EU ETS) or Emission Performance Credits (EPCs under SGER). Moreover under the SGER, operators can also make a contribution to the Climate Change and Emissions Management Fund ($15 per 1t$CO_2$). Thus, legislative schemes provide flexibility to operators in deciding which action is more cost-effective to comply with requirements. The legislative schemes exclude particular emission types, but none of these types relate to APG emissions (e.g. biomass emissions under EU ETS, emissions linked to district energy under SGER).

Schemes differ in how they treat new entrants. In general, under the voluntary schemes there is no such term as “new entrants”. Methodologies can be used by any operator whose project meets the required criteria. Also, it is possible to develop a new methodology/protocol, or revise/update an existing one. Worth mentioning, VCS allows the additions of new project activities into a grouped project, provided certain conditions are met[22]. New entrants are an integral part of legislative schemes; yet there is no unanimous approach. The EU ETS sets aside a pool of EUAs, forming a New Entrant Reserve; while SGER introduces a phased reduction target (i.e. -2% starting with the fourth year of commercial operation, and then by 2% every year after, until the 12% reduction target has been achieved).

Monitoring plans are required by all schemes, except SGER. The general content is very similar: description of emission sources, parameters to be monitored, data collection and management systems, roles and responsibilities, and data storage and archiving. A monitoring plan is required as part of the project registration (voluntary schemes) or permitting procedures (EU ETS).

Costs associated with schemes vary. They include:

- costs of implementation of a project or internal improvement in operations, which are unique to a facility;
- costs associated with administration of a scheme (e.g. under the CDM – registration fee, issuance fee which are based on a validated volume of estimated emission reductions);

[21] The concept of additionality is discussed in more detail later in this section, under “Other” heading.

[22] Under VCS, a grouped project combines multiple project activities: http://v-c-s.org/faqs/what-are-grouped-projects. It is similar to Programme of Activities (PoA) under the CDM. Yet, under PoA no new project activity can be added after its validation and registration.

- costs associated with validation and/or verification, which are project- or installation-specific.

Also, under legislative schemes, the cost of compliance depends on a matrix of compliance options chosen by an operator.

All schemes have control systems in place. They can be grouped as follows:
- Project- or installation-level: validation (CDM, options under VCS), registration checks (CDM only), and verification of emission reductions or emissions (CDM, VCS, AOS, SGER, and MRV);
- Scheme-level: supervisory body or enforcement authorities performing regular or spot audits: CDM, VCS, AOS (as part of SGER checks), and SGER[23]. The frequency and process for undertaking these checks is scheme-specific (see Appendix 2).

As opposed to legislative schemes, voluntary schemes by nature do not include any penalties, such as fines, for non-compliance. Incentives for developing a project lie in the potential revenue stream, which depends on an offset price and demand. In the AOS case, which is linked to the legislative scheme as opposed to CDM and VCS, another incentive can be a cheaper compliance option to meet regulatory requirements, provided that offsets are used for internal purposes. For the legislative schemes, the main incentive is cost-saving, e.g. lower emissions correlate to lower compliance cost, such as the purchase of EUAs and/or eligible offsets to cover emissions under EU ETS.

Methodology:

The voluntary schemes address emission reductions from APG projects. As such, their emission reductions estimation methodology is based on calculating baseline emissions, project emissions and, if applicable, leakage emissions. Each component has a specific formula provided by a methodology/protocol (see Appendix 2 for details). Sources of emissions captured by these formulas depend on project design and end-use of APG.

In legislative schemes, emissions related to an activity (flaring and/or venting), rather than emission reductions, are targeted. Under MRV, the formula is simple:
Activity (amount of gas flared) x Emission Factor x Oxidation Factor.

SGER, on the other hand, provides a list of recognized calculation methods eligible for determining emissions associated with each emission source category, including flaring and venting (e.g. EC sector specific guidance, American Petroleum Institute 2004, and GHG Protocol).

The coverage of gases differs across the schemes. MRV considers only CO_2, CDM/VCS – CO_2 and CH_4, and AOS – CO_2, CH_4, and N_2O. SGER has the most comprehensive coverage of gases (CO_2e being the sum of direct emissions of carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulphur hexafluoride); yet these relate to all emission source categories. Therefore, it is possible to assume that gases related to flaring and venting are the same as under AOS.

Unavailability of data is not directly addressed by the schemes. Voluntary schemes rely on the project company's internal procedures, including the monitoring plan developed and implemented to support the project. Yet, it is worth mentioning that AOS Solution Gas Conservation Protocol includes contingent data collection procedures for cases when more

[23] Information on audits under EU ETS and MRV has not been identified.

accurate and precise methods cannot be used. In general, MRV also refers to "good professional practice", while simultaneously requiring the operator to take into account the provisions of the Integrated Pollution Prevention and Control Reference Document on the General Principles of Monitoring. MRV is more specific, when it comes to measurement-based methodology[24] - an operator is provided with three options on how to determine an appropriate substitution value (e.g. the arithmetic mean of the concentration of the specific parameter and standard deviation – for a parameter directly measured as concentration). SGER does not describe missing data treatment; however, relevant procedures are covered by the specific calculation method (e.g., American Petroleum Institute 2004, GHG Protocol).

Calculations of emissions or emissions reductions are updated on an annual basis. For legislative schemes this coincides with obligatory reporting; whereas in voluntary schemes this is often linked to verification[25] (i.e., carbon credit issuance). Additionally, for CDM projects, calculations are made at the validation stage and registration if relevant requests for review are raised by the CDM Executive Board.

Regarding updates to a calculation methodology, the frequency varies across the schemes. Only AOS revises its methodologies according to a defined timeline (every 5 years or sooner). Other schemes are not that specific. In CDM and VCS, it is possible to submit a request for methodology revision or clarification anytime. Methodological changes in SGER are triggered by operators following major modifications in a facility. Any such changes are subject to approval. Under MRV, the calculation methodology may change only upon revisions to the MRV Guidelines[26].

All schemes refer to world-recognized standards, but they differ in whether these standards are for overall processes (e.g. verification, additionality demonstration) or calculation/measurement methods (e.g. sampling, determination of carbon content). Usually, these include ISO standards (CDM, VCS, AOS, and MRV). MRV also relies on CEN standards (i.e. those issued by the European Committee for Standardisation) and national standards (e.g. German DIN standards). VCS and SGER make references to other known guidelines, such as GHG Protocol, American Petroleum Institute guidelines, and Canada Standards Association.

Every scheme prefers actual measurement as a source of data for calculating emissions, deeming it the most accurate method. However, CDM/VCS allow different data sources (one or several alternatives), depending on their availability, for those parameters that do not need to be monitored regularly over the crediting period. In each case, a project proponent needs to provide documentary evidence and justification for the chosen data.

In MRV, there is a more systemized approach – taken from IPCC Inventory Guidelines - based on Tiers (Tier 1 to 3, with 3 being the most accurate), which are applicable to all parameters used in the calculation of emissions. The "Tiers" reflect the materiality of the uncertainty levels on overall error in reported data; i.e. the bigger the emissions, the smaller the overall uncertainty should be. However, this does not directly correlate with CDM approaches, although the annual emissions could be considered as equivalent to annual emission reductions under the CDM in terms of materiality to the net result.

[24] This is one of the methods to calculate emissions allowed under MRV. It is discussed in detail further in this section, under the "Monitoring" heading.

[25] Note: emission reductions are calculated per year; however, they do not need to be reported annually. As such, verification is only conducted when reports are submitted.

[26] Note: Currently, the EC is in the process of revising the existing guidelines. Information can be found at: http://ec.europa.eu/clima/events/0050/index_en.htm

A Tier 3 approach is commonly considered more difficult and costly to meet than lower Tiers (e.g. due to the need for in-line, continuous measurements, which depending on the metering device, can be costly). As such, although an operator in principle must apply the highest tier level; if he can demonstrate to the competent authority that this is technically not feasible or would lead to unreasonably high costs, he may be allowed to apply a lower tier. When even Tier 1 cannot be achieved, an operator is allowed to develop a customized monitoring methodology (a so-called "fall-back" approach), subject to authorities' approval. The Tier approach was introduced to provide flexibility for monitoring for different types, sizes and ages of installations.

SGER highlights the accuracy of different sources of measured and calculated data. In particular, any data estimated on design requirements or from agreements, as well as top-down emission factors will not be approved by SGER (as they fall below the required accuracy level), unless an operator demonstrates that the low level of accuracy will not materially affect the facility's submission.

An emission factor based on measured and analyzed composition data is the preferred approach. Yet, recognizing that such data may not always be available, the schemes provide a level of flexibility; for example, generic/default values (such as national, IPCC) can be applied if properly justified.

All schemes, except MRV, provide tools and guidelines for project developers/operators to manage all or some requirements of a given scheme. Details are provided in Appendix 2.

In general, an uncertainty assessment is required by all schemes, yet they differ in the extent and detail of the assessment to be performed. The uncertainty assessment should take into account the cumulative effect of uncertainty associated with all parameters used to calculate the emissions.

AOS and SGER are the least detailed in that respect. AOS requires project developers to address uncertainty in project calculations, but no guidance is provided in the Solution Gas Conservation Protocol. In SGER, the main document does not specify how to treat uncertainty; however, uncertainty is generally defined by the chosen emission calculation methodology. On the other hand, VCS has set criteria for the use of models to estimate processes that generate GHG emissions. It also requires that methodology elements provide a means to estimate a 90-95% confidence interval.[27]

In CDM, this requirement is specific to a methodology, but both AM0037 and AM0077 describe reporting procedures if uncertainty is low (<10%), medium (10-60%) or high (>60%).[28] Specifically, if uncertainty is medium or high then quality control/assurance procedures need to be documented and parameter sensitivity analyses is required to determine the potential of the parameter to affect the emission reduction calculation. The authenticity of these uncertainty levels would be verified by an independent auditor (Designated Operational Entity). However, the methodologies suggest that if uncertainty is less than ±10% (i.e., low), then this is acceptable for CDM reporting. In comparison, MRV

[27] Confidence interval = mean value ± (standard error x t statistic); it defines the confidence that the true value will be within the defined interval. The standard error includes two types of error: systematic and random. Systematic errors may be caused by fundamental flaws in the equipment, the observer, or the use of the equipment. Depending on the measurement equipment (flow meters; gas analysers) used, precision and accuracy will vary; however, the low error (uncertainty) thresholds defined by the schemes are fully achievable.

[28] CDM methodology AM0009 does not prescribe how to address uncertainty.

uncertainty requirements are more onerous, as they require higher accuracies for data parameters collected to calculate emissions. Overall, the requirements defined for “low” permissible uncertainty within the CDM in both AM0055 and AM0077 equate to the less than the Tier 1 requirement under the MRV. Consequently, the overall uncertainty described by the MRV can be considered as best practice for operators. Finally, MRV asks for regular uncertainty assessment only in case of a measurement-based methodology; since uncertainty in case of calculation-based methodology is assessed and approved once, at the stage of permit issuance.

Quality assurance and control of methodology is addressed by various means: use of standards (VCS, AOS), validation (CDM, optional in VCS and AOS), verification (all schemes), and registration checks (CDM), as well as audits (SGER) and placing of a number of obligations on an operator/project owner such as equipment calibration, implementation of robust data collection system (CDM, VCS, AOS, MRV).

Monitoring:

Monitoring boundaries are similar across the schemes, as they include a facility (all schemes) and other elements depending on a project design (CDM and VCS). The general idea is to cover, where applicable: flares, vents, APG capture and processing facilities, as well as uses of APG (e.g. fuel for equipment, on-site electricity generation, feed for other products manufacture). In any case, emission sources are project/facility specific, and they are described in advance (e.g. at the stage of project validation/registration or at the time of permit issuance). Abnormal events (e.g. shutdown, emergency) are specifically addressed in CDM methodology AM0037, which requires calculating fugitive (CH_4) emissions in case of accidents, and in MRV where emissions from flares include routine and operational flaring (start-up, shutdown etc.).

Monitoring frequency is determined for a particular parameter, but in all cases, APG flow should be measured continuously. The monitoring methodology is governed by an approved monitoring plan, where each parameter has a defined measurement method. Furthermore, voluntary schemes allow revisions to monitoring plans, but in the case of CDM a revision has to be first approved by the CDM Executive Board before being applied to a project. Under MRV, the following monitoring methods are allowed:

- a calculation-based methodology, in which emissions are calculated using measurement systems and additional parameters from laboratory analyses or standard factors;
- a measurement-based methodology, in which emissions are determined through continuous measurement of the concentration of the relevant greenhouse gas in the flue gas and of the flue gas flow. In this case the use of continuous emission measurement systems (CEMS) is required. Yet, this method can be applied only under certain conditions and upon authorities’ approval. MRV provide a set of specific requirements for an operator to follow;
- a customized monitoring methodology – yet this is allowed only in exceptional cases and is subject to authorities’ approval.

SGER allows a number of measurement approaches, simultaneously determining their level of accuracy.

Considering that monitoring and emission calculation methodologies are closely linked, the use of standards, uncertainty treatment and quality assurance in monitoring are the same or very similar to those described under the “Methodology” section. An exception is AOS. For monitoring requirements it refers to the Alberta's Directive 017 "Measurement Requirements for Oil and Gas Operations"[29], and this in turn refers to other standards or guidelines for determining and combining uncertainties, such as ISO 5168 and American Petroleum Institute manual. The Directive 017 specifies also the confidence level around monitored/measured data (95%) and provides uncertainty levels associated with measurement devices, device calibration, sample gathering and analysis etc. Worth mentioning is also the fact that AOS encourages the use of Data Management Systems, while VCS requires a quality management system to be established and applied.

Reporting:
All the schemes require a set of documents being presented to competent authorities. The main information that the scheme applications require are: a description of a project/facility, sources of emissions, calculation methods, and monitoring. Voluntary schemes do not have a reporting requirement as such. Yet, upon project registration, emission reductions need to be verified before they can be issued. For this purpose, a monitoring report with emission calculations is developed. It needs to be noted that there is a limited time over which emission reductions can be claimed (e.g. in CDM 10 years or 3x7 years). The situation is different in legislative schemes, as they require annual reporting. All schemes provide standard forms (templates) in which data should be submitted. SGER requires using Electronic Data Reporting System. As for scheme transparency, there is either a publicly available registry or database. Also, under SGER, the following points are worth mentioning:

- It is possible to request keeping certain information in the Baseline Application confidential for a period of up to 5 years on the basis that the information is commercial, financial, scientific or technical information that would reveal proprietary business, competitive or trade secret information about a specific facility, technology or corporate initiative. Confidentiality cannot be granted for the entire application form and cannot be given retroactively. Such request is subject to approval by the enforcement authorities.
- Anyone wishing to access baseline or compliance information that has not been deemed confidential may submit written requests for information directly to the facility. The facility must respond in writing within 30 days of receiving the request. If requested information is not provided then a person may appeal to the enforcement authority.
- Authorities publish annual results of compliance in a compiled (aggregated) version (short version is given on the website, whereas much more comprehensive information can be found in uploaded reports).

Verification:

Verification is obligatory in all schemes. The process is similar, covering the following main stages: employing a third-party verifier, submitting documentation, verification including site visit, and finally issuance of a verification report/statement. In addition, legislative schemes require from a verifier to undertake risk assessment. Moreover, under SGER, although verifiers are not required to actively monitor the validity of their reports after issuance, if it is brought to their attention that previous statements are no longer accurate, they must notify the facility. The facility then has to notify the relevant authorities to discuss further follow-up actions that might be required. AOS requires a peer-review of a verification report before issuance.

[29] Available at: http://www.ercb.ca/docs/documents/directives/Directive017.pdf

Verification is taken in accordance with a specific manual or recognized standard (e.g. ISO 14064). CDM and SGER provide also a number of additional resources, with which verifiers should be familiar with, for example, CDM Executive Board's decisions or Alberta's Climate Change and Emissions Management Act. The materiality thresholds usually are: 5% for projects/installations with smaller volume of emissions, and 1% or 2% for the others. Only CDM methodologies do not prescribe materiality thresholds. Verification under AOS and SGER is very similar, as these two schemes are closely linked. Thus, both allow grouping errors into quantitative and qualitative errors, and indicate that materiality is assessed on their individual as well as aggregated basis.

Three schemes (VCS, AOS, and MRV) require a reasonable level of assurance. SGER is less strict, and asks for limited assurance with three sub-categories (limited, qualified limited and adverse assurance statement). Under CDM and VCS, verifiers have to have appropriate accreditation, and the list of approved verification bodies is publicly available. Also, their work is supervised by scheme's competent entities and is subject to spot checks or regular audits. In legislative schemes, criteria for verifiers and their areas of expertise are specified in regulations. Interestingly, SGER permits the facility to engage the same lead verifier and/or verification company to undertake verification process for a maximum of 5 compliance cycles, with a mandatory two compliance cycle break.

Double counting is avoided by a variety of means, namely:

- Emission reductions (carbon credits) are serialised (all schemes);
- An owner of a carbon credit needs to have an account in a dedicated registry/log (all schemes), in which any transfer, cancellation or retirement of a carbon credit is captured (all schemes);
- Emission reductions are only valid for a defined crediting period (voluntary schemes);
- Project proponents have to submit Proof of Right, demonstrating the entity's right to all and any GHG emission reductions or removals generated by the project (VCS);
- Project proponents have to provide evidence that GHG reductions or removals generated by the project have not and will not be otherwise counted or used under another programme or mechanism (VCS, AOS);

Retention of information:

All schemes require retention of information, but they differ in associated periods of time. The shortest period is under CDM/VCS (i.e. at least 2 years after the end of crediting period), whereas the longest is under MRV (10 years).

Additionality:

Under voluntary schemes, projects need to demonstrate additionality, which in principle means demonstration that emission reductions would not occurred under the business-as-usual (BAU) scenario. In the AOS, the additionality for a reduction/removal activity is typically assessed through a simple *standardised* approach, which means that projects only need to ensure that emission reductions exceed existing legal requirements, are real, demonstrable and quantifiable. In contrast, the VCS and CDM follow stricter *project-specific* approaches as defined by the CDM "Tool for the demonstration and assessment of additionality". Experience has shown that the interpretation of the tool is subjective, depending on the project type, which has inevitably resulted in project registration delays/issues (NB: VCS allows for a performance-based approach, yet no such test has ever been used[30]).

One of the main components of CDM additionality demonstration is the use of either the Investment Analysis (e.g. calculation of a project/equity IRR and its comparison to a selected benchmark) or Barrier Analysis (e.g. description of technological or institutional barriers preventing the implementation of a project) or both. The majority of projects apply Investment Analysis only, as it provides a quantitative approach, which is easier to interpret and verify compared to the Barrier Analysis.

In addition, as part of the additionality demonstration, CDM project proponents need to demonstrate a prior consideration of CDM in decision-making process whether to pursue/implement the project.

Although additionality is an important tool to test whether a project would not have occurred under a BAU scenario, the application of the test is not the key barrier to project implementation. The primary barriers are 1) economic (project costs; i.e., gas gathering lines, compressor stations, and gas treatment facilities); 2) geographic (i.e., lack of a local end user); and 3) contractual issues (i.e., production sharing agreements)). As such, weaker additionality requirements (e.g., as defined in the CDM); would not necessarily lead to windfall profits for project proponents. A fact reflected in the low number of APG projects in the CDM pipeline.

Additionally, within the voluntary markets where credits are primarily purchased to meet carbon neutrality requirements[31], APG projects do not provide a strong stakeholder story to support an organisation's corporate social responsibility, ethics and risk management (or even have a good resale value for anticipated mandatory commitments or commodity investment purposes). A situation reflected by the fact that no APG-related credits were purchased on the voluntary markets in 2010 and 2011.[32]

Other:

Under MRV, small emitters can be exempted from the EU ETS and its requirements.

[30] WWF *"Making Sense of the Voluntary Carbon Market A Comparison of Carbon Offset Standards"*: http://www.wwf.org.uk/filelibrary/pdf/carbon_offset_long.pdf

[31] In 2011, 54% of voluntary credits were purchased for corporate CSR, branding and reputational benefits; 22% transacted for resale; 17% in anticipation of regulation or commodity investment purposes; and 7% for supply chain "greening". Ecosystem Marketplace and Bloomberg (May, 2012) Developing Dimension: State of the Voluntary Carbon Markets 2012

[32] ibid

2.2 Strengths and weaknesses

Voluntary Schemes (CDM, VCS, AOS)

Strengths	Weaknesses
General: ▪ They provide level of flexibility to operators/project owners in choosing data source for required parameters, depending on information availability.	
CDM: ▪The scheme is recognized worldwide. CERs can be used for compliance and voluntary purposes in different national/regional emission reduction programmes. ▪Robust ▪**AM0077 includes instructions for uncertainty assessment**	**CDM:** ▪Stringent applicability conditions are often prohibitive. Requesting revision or clarification to a methodology, not to mention development of a new methodology is time- and cost-consuming. ▪Administration is a heavy burden for project development. ▪Rules and methodologies are not always clear, and leave room for interpretation. UNFCCC staff is not consistent in their assessment of projects (very subjective). ▪Validation/verification bodies (DOEs) vary in terms of: number of review steps and time taken to complete project validation. ▪CDM Additionality Tool does not guarantee that only additional projects are approved[1]. Its stringency and project-specific application has been the main reason for project registration reviews[2]. ▪In all, it takes far too long to validate and subsequently to register projects, often well over 12 months. ▪A CDM project development cycle involves three parties: project proponent, DOE and CDM EB. The latter two form the review process of project design and compliance with CDM rules. Having these two review steps has significantly lengthened the time needed to register a project. It has also introduced the opportunity for disagreement between DOE and CDM EB. Positive validation does not guarantee a positive decision of CDM EB. In other words, after years spent on validation, there is still a risk that the project registration will consume more time and money, and may even fail to get registered. ▪It is very sensitive to price of CERs – too low hinders project development and CDM uptake.
VCS ▪It allows adding new project instances to a grouped project; thus avoiding unnecessary cost and delays like in the case of CDM, where new project instances would have to go through validation and registration processes. ▪Less stringent assessment of additionality demonstration than in the case of CDM. VCS also allows for performance-based additionality demonstration (although this has not been applied, so far). ▪The scheme holds validation/verification bodies liable for over-issuance. ▪There is a Compensation Mechanism Steering Committee established to explore ways to incentivize the development of new, streamlined and broadly applicable methodologies. Currently, VCS rebates 20% of the levy on every VCU issued to methodology developers when a project uses the methodology they developed.	**VCS** ▪It is less complex than CDM, and has a lower admin burden (e.g. positive validation automatically results in acceptance by VCS, provided documents submitted for registration meet the schemes requirements). At the same time, this is one of the main criticisms of the scheme, that it is not stringent enough, thus not providing needed assurance that achieved emission reductions are real and additional. ▪Like CDM, the uptake of the scheme is very sensitive to offset price.
AOS ▪It is linked to the existing regulation, which obliges a covered installation to reduce their emissions intensity. Offsets are a means to comply with the legislative requirements. ▪Linked to the point above, the main incentive is compliance (cheaper option) than actual price of a carbon credit (as opposite in the case of VCS or CDM).	**AOS** ▪The particular protocol is limited to small vents (<500m^3 per day). Yet, other offset types can be used for compliance.

[1] WWF *"Making Sense of the Voluntary Carbon Market A Comparison of Carbon Offset Standards"* http://www.wwf.org.uk/filelibrary/pdf/carbon_offset_long.pdf

[2] IGES "*CDM Reform 2011*": http://enviroscope.iges.or.jp/modules/envirolib/upload/3327/attach/cdmreform2011.pdf

Legislative Schemes (SGER, MRV)

Strengths	Weaknesses
General: ▪ They are a stronger incentive for covered entities to comply, compared to voluntary schemes. ▪ They provide several ways to comply with requirements: internal abatement measures, offsets, trading of allowances (EU ETS) or Emission Performance Credits (EPCs). Moreover under the SGER: contribution to the Climate Change and Emissions Management Fund. ▪ Methodologies are straightforward and are not subject to frequent revisions. ▪ They provide a level of flexibility to operators/project owners in choosing data source for required parameters, depending on information availability.	**General:** ▪ They need to include some enforcement measures (e.g. fines). However, based on the experience of EU ETS and aviation, it is very likely that any legally-binding scheme will meet with strong opposition.
SGER: ▪ As opposed to EU ETS, there is no free allocation. Thus, if the cost of making payment for one tonne of CO2 to the Fund is set high enough, it is more likely that compliance players will either make improvements in their own operations or buy offset credits – both ways resulting in emission reductions.	**SGER** ▪ Although the emission reduction target in absolute terms is facility-specific, it relates to an overall facility. Thus, similarly to the EU ETS, emission reductions occur where they are cost-effective, not necessarily meaning they will relate to flaring or venting emissions. In the context of this study, it is not a desired outcome.
EU ETS & MRV ▪ Tiered approach provides building blocks to determine the appropriate monitoring methodology for each installation. It allows accommodating different sectors and technologies with the need for a level playing field for operators across the EU. It also enables improving the quality of the monitoring system over time to reach the required tier level. ▪ A systematic approach to uncertainty assessment. Specific uncertainty levels associated with tiers for activity data.	**EU ETS & MRV** ▪ Due to free allocation and possibility to bank allowances, there is less incentive to reduce emissions internally. ▪ One target for all installations covered by the EU ETS – thus, emission reductions occur where they are cost-effective, not necessarily meaning they will relate to flaring emissions. In the context of this study, it is not a desired outcome

In general, the voluntary schemes (i.e., CDM, AOS) are compliance tools for their associated legislations (i.e., EU ETS, SGER). In its general structure, Article 7a of the FQD mirrors the SGER compliance regime, where an emissions intensity reduction target is set, and compliance tools are provided to meet the target. For the SGER, these compliance tools include: 1) Making improvements to the installation's operations; 2) Purchasing Alberta-based offset credits, through the AOS; 3) Contributing to the Climate Change and Emissions Management Fund at $15/ tonne; and 4) Purchasing or using Emission Performance Credits from installations that have exceeded their targets. In comparison, Article 7a represents a more stringent legislation with less leeway (i.e., compliance tools) for suppliers to meet their targets. Nonetheless, the proposed carbon credit scheme for upstream APG projects has a similar role to the AOS.

Although the AOS has not resulted in any APG project, a combination of the best elements of the CDM/JI and AOS schemes could provide an effective blueprint for the proposed scheme. The EC will be responsible for drafting the scheme's guidelines, but utilising the CDM project methodology, while applying the AOS additionality, MRV definitions could ensure an efficient and effective project mechanism. As experienced with the CDM, additionality and administrative burdens have proved the biggest factors in low and slow project success rates. Consequently, it seems advisable that project assurance, validation and verification activities should be undertaken by the MS, using systems in-place for the EU ETS (e.g., existing MS accredited EU ETS verifiers could take up the role of the project validator/verifier). These ideas are further discussed in the following section.

2.3 Recommendations

Following the comparison and analysis of the schemes above, several recommendations for a potential EC scheme have been drawn. Yet, the list below is not exhaustive. A more detailed discussion on the potential EC scheme will be undertaken under Task 5 of the project.

Compliance

- The principles of any potential scheme, either voluntary or prescriptive, shall adhere to the legislative requirements of the Fuel Quality Directive, Article 7a. The scheme should be treated as one of the compliance options within the regulation, giving the targeted parties flexibility in choosing the most cost-effective approach for compliance, similar to the SGER and EU ETS.

Additionality

- The additionality requirements should follow a *standardised* approach (e.g., AOS), rather than a stricter *project-specific* approach (e.g., such as the CDM) to ensure that the project approval process is streamlined and transparent, and not prohibitive. Assuming a *standardised* approach, similar to the AOS, implies that additionality should be based on simple, but robust criteria, such as 1) reductions exceed legal requirements; 2) reductions are real (i.e., specific and identifiable actions that reduce or remove GHGs); 3) reductions demonstrate a net reduction in GHGs; and 4) reductions are quantifiable.

Methodology

- Considering that the CDM provides the only scheme where APG projects have been developed and submitted for registration, it provides a good baseline to assess the anticipated size of projects that could be submitted to a potential EC scheme. In March 2013, there have been 10 projects registered, 1 project requesting registration, and 20 projects at validation. Assuming the MRV installation categories: 6 projects have emissions *<50ktCO2/yr* (Category A); 14 projects have emissions of *>50<500 ktCO2/yr* (Category B); and 11 projects have emissions of *>500 ktCO2/yr* (Category C). As such, the existing MRV installation categories provide a good starting point for the EC scheme.
- Project emission reductions (ER) can be defined as:

  ER = BEy – PEy; where:

  BEy = Baseline emissions in year y (tCO2e), which is the sum of emissions associated with the transportation and flaring of the associated gas in year y

  PEy = Project emissions in year y (tCO2e), which is the sum of emissions associated with fuel (including electricity) consumed by the project activity in year y

  Emissions should be estimated using a calculation-based methodology, similar to the MRV. That is,

  CO2 emissions = Activity data (gas flow to flare) x Emission factor x Oxidation factor
- Although the MRV applies calculation Tier levels for different installation categories, we recommend a slightly adapted approach (Figure 1), which recognises the need

for field data rather than default factors (for gas flow rates to the flare and flaring emission factors) to ensure the accuracy of emission reduction estimates.

Figure 1: MRV estimation and accuracy requirements for emitting installations

Annual Emissions (installation category)	*Gas flow to flare*		*Combustion emission factor*		*Oxidation factor*	
	Tier	*Accuracy*	*Tier[33]*	*Accuracy*	*Tier*	*Accuracy*
<50 ktCO2/yr (A)	*3*	*± 7.5%*	*2b*	*Operator measured or laboratory analysis*	*1*	*Reference value*
>50<500 ktCO2/yr (B)	*3*	*± 5%*	*3*	*Operator measured or laboratory analysis*	*1*	*Reference value*
>500 ktCO2/yr (C)	*3*	*± 2.5%*	*3*	*Operator measured or laboratory analysis*	*1*	*Reference value*

- Uncertainty assessment principles should be set in the proposed scheme. Such principles should be modelled on the basis of the MRV, with accuracy requirements for calculation parameters defined by the installation category (i.e., Category A, B or C).
- Methodology(ies) for APG flaring/venting reduction should have robust applicability criteria, allowing different project designs to use it, instead of developing a new methodology for each specific situation (which is the case with CDM).
- Monitoring plans should be developed before project implementation, and subject to validation of the project.
- Use of international standards should be encouraged for monitoring and sampling.

Structure and Responsible Parties

- The EC, as the regulating authority, will be responsible for defining the harmonised guidelines for the proposed scheme, which will include the project methodology, GHG calculation methodology, additionality, and MRV requirements. The EC should aim to review and update the guideline, where necessary, every 5 years[34].
- The project's approval process needs to be straightforward, with minimised administrative burden. Similar to the AOS, one party should be involved in the assessment of a project's eligibility. For the proposed scheme, an entity certified by a professional MS accreditation body (e.g., the UK Accreditation Service (UKAS)) can be responsible for project validation.
- Verification entities should be certified under a professional MS accreditation body (e.g., the UK Accreditation Service, (UKAS) accredits companies for EU ETS verification). Entities already certified for EU ETS verification should be applicable. At a minimum, it is expected that verification entities should be trained in ISO 14064 Part 3 – Greenhouse Gases: Specification with guidance for the validation and verification of greenhouse gas assertions.
- Validation and verification can be provided by the same accredited body.

[33] Tier 2b uses installation-specific emission factors derived from an estimate of the molecular weight of the flare stream, with use of process modelling based on industry-standard models. By considering the relative proportions and the molecular weights of each of the contributing streams, a weighted annual average figure is derived for the molecular weight of the flare gas. Tier 3 is calculated from the carbon content of the flared gas applying the specific provisions given in the MRV Guidelines (Section 13 of Annex I).

[34] Similar to the AOS

- The designated MS authority should form the last stage of approval, which would include the confirmation that all procedures have been fulfilled in issuing a validation decision, and whether the project documentation is complete and consistent.
- To ensure double counting is avoided, emission reductions (carbon credits) should be serialised. The owner of a carbon credit needs to have an account in a dedicated registry/log, in which any transfer, cancellation or retirement of a carbon credit is captured. This should be the responsibility of the designated MS authority (e.g., environment departments/ agency within MS governments).
- It is advised to introduce a specific limit on the time that validation/verification bodies can take to assess a project, after which time the project is deemed acceptable by default. This would require senior management accountability within the validation/verification bodies if errors are made by their teams, which should in turn ensure adequate resourcing. The work of these bodies should be subject of regular audits and spot checks.

Appendix 1: APG Project Success Rate

The following table presents the success rate for the APG project-based schemes evaluated: CDM; JI; VCS; and AOS. The table highlights the number of APG projects that have been submitted to each scheme since their inception, and the quantity of issued credits. The final column summarises the approximate maximum, minimum and average annual emission reductions from projects that have issued verified credits.

The table illustrates that the CDM and JI pipelines represent the only conduit for APG projects to date.

In meeting the SGER's annual 12 percent intensity reduction target, installations can:

- Make improvements to their operations
- Purchase Alberta-based offset credits (from the AOS)
- Contribute to the Climate Change and Emissions Management Fund
- Purchase or use Emission Performance Credits (from installations that have exceeded their targets)

There is little information on how installation specific reductions have been met, other than aggregated compliance results. For example, in 2011, operational improvements resulted in 1.5 million tons in reductions. As such, it is not possible to indentify whether APG projects contributed to these totals.

Figure 2: Summary of APG project success rates across

Scheme	Registered	Reg. Request	Validation	Rejected/ terminated	Issued credits (Million tCO2e)	Annual issuance (ktCO2e) (max, min, average)
CDM	10	1	20	19	13.8	1,100; 200; 700 [a]
JI	19	0	3	0	100	19,000; 50; 2,200 [b]
VCS	0	0	0	0	0	0
AOS	0	0	0	0	0	0

[a] Only 5 of the 10 registered projects have issued credits
[b] Only 12 of the 19 registered projects have issued credits

Appendix 2: Template with analysis criteria

Name of regulatory Scheme	*XXXX*
General characteristics	
Objectives of regulation	
Country / language	
Web site	
Implementation/enforcement entity	
Targeted sector(s)	
Reduction target	
Compliance	
Installation types and thresholds	
Options for compliance	*E.g. reporting only; flare/venting reduction targets, credits*
Exclusions	
Treatment of new entrants	
Monitoring plan or flare/vent management plant	*If required, as part of the permit procedure – what it needs to cover*
Incentives for APG reduction or use	
Costs	
Control system	*Audits (scheduled, ad-hoc)*
Consequences of non-compliance	*E.g. fine, permit withdrawal*
Methodology	
Estimation approach	*Emission calculation formula; parameters monitored/fixed*
Gases included in the reporting	
Treatment of missing data	*E.g. how to address unavailability of data (e.g. meter failure)*
Calculation update frequency	
Methodological changes	*E.g., how to manage future changes in boundaries, calculation approach, oil field practices such as EOR*
Consistency with international standards	
Levels of accuracy (sources of data)	*E.g. tiers of approaches for activity data, composition data, and conversion factors); is the selection of tiers subject to approval?*
Sources for emission factors	*E.g. tiers of approaches (default/ company-specific)*
Any tools provided?	*E.g. tool for emission calculation; tool for emission reduction calculation*
Uncertainty Treatment	
Quality Assurance	
Monitoring	
Boundaries	*E.g. what sources are monitored continuously, regular operations/ abnormal events (shutdown, emergency, start-up)?*
Frequency	

Name of regulatory Scheme	***XXXX***
Methodology	*E.g. prescribed (one-fit-all) or customized (site/installation specific); measurement-based or calculation-based*
Use of standards	*E.g. ISO 10715 for sampling; ISO 6974 for compositional analysis*
Uncertainty treatment	*E.g. allowed measurement/ equipment uncertainty threshold for each source; uncertainty calculation approach*
Quality assurance	*E.g. what are the operator responsibilities (e.g. measuring equipment to be calibrated, adjusted and checked)?*
Reporting	
Scope	*E.g. information disclosure for small installations, full reporting for others*
Frequency	
Form (reporting format)	*What data supplied with certification*
System transparency (public database, information disclosed)	
Verification requirements	
Process	*E.g. what is the verification procedure, what needs to be covered/ checked; is a site visit required?*
Methodology	*E.g. materiality levels; risk analysis*
Assurance requirements	*E.g., reasonable, limited*
Avoiding double counting	*Mechanisms for making sure that credits are not used more than once or re-certified somewhere else*
Third party	*If required, accredited verifiers? Recommended verifiers?*
Other requirements	
Retention of information	*E.g. how long should the data be stored on site; is an electronic database required?*

Appendix 3: In-depth analysis of schemes

Clean Development Mechanism

Name of regulatory Scheme	***Clean Development Mechanism and selected approved methodologies:*** ***"Recovery and utilization of gas from oil wells that would otherwise be flared or vented" (AM0009)*** ***"Flare (or vent) reduction and utilization of gas from oil wells as a feeds" (AM0037)*** ***"Recovery of gas from oil wells that would otherwise be vented or flared and its delivery to specific end-users"(AM0077)***
General characteristics	
Objectives of Scheme	*The Clean Development Mechanism (CDM) encourages emission reductions in developing countries, at the same providing industrialized countries with some flexibility in meeting their emission reduction limitation targets. Approved methodologies are associated with specific sectoral scopes and activities – see* http://cdm.unfccc.int/DOE/scopes.html. *The three selected methodologies particularly aim to recover and utilize associated gas from oil wells that would otherwise be flared or vented. Yet, they differ in how associated gas is utilized (see "Installation types and thresholds" under Compliance below).*
Country / language	*Non-Annex I countries*
Web site	*CDM:* cdm.unfccc.int *Methodologies:* http://cdm.unfccc.int/methodologies/PAmethodologies/approved
Implementation/enforcement entity	*Project Proponents; Designated Operational Entities, UNFCCC CDM Secretariat, UNFCCC CDM Registration and Issuance Team, UNFCCC CDM Executive Board*
Targeted sector(s)	*Upstream Petroleum Industry*
Reduction target	*N/A*
Compliance	
Installation types and thresholds	*In general, CDM excludes nuclear energy, new HCFC-22 facilities and avoided deforestation (REDD).* *AM0009, AM0037 and AM0077 are applicable to large-scale projects.*[35] *Each methodology list a number of applicability conditions which need to be fulfilled by the project proponents, if the project using a given methodology is to be validated, registered and later verified.* ***AM0009*** *is applicable to project activities that recover and utilise associated gas and/or gas-lift gas from oil wells. The associated gas and/or gas-lift*

[35] Note: Large-scale projects are those that do not meet eligibility criteria of a small-scale project, which are: a) type (i): renewable energy project activities with a maximum output capacity equivalent to up to 15 megawatts (or an appropriate equivalent); b) type (ii): energy efficiency improvement project activities which reduce energy consumption, on the supply and/or demand side, by up to the equivalent of 60 gigawatt hours per year; and c) type (iii): other project activities that both reduce anthropogenic emissions by sources and directly emit less than 60 kilotonnes of carbon dioxide equivalent annually (17/CP.7, paragraph 6(c) as amended by 1/CMP.2, paragraph 28). Furthermore, a small-scale project has to conform to one of the project categories in appendix B to Annex II of COP Decision 4/CMP.1, and cannot be a debundled component of a larger project activity, as determined through appendix C to Annex II of 4/CMP.1.

Name of regulatory Scheme	***Clean Development Mechanism and selected approved methodologies:*** ***"Recovery and utilization of gas from oil wells that would otherwise be flared or vented" (AM0009)*** ***"Flare (or vent) reduction and utilization of gas from oil wells as a feeds" (AM0037)*** ***"Recovery of gas from oil wells that would otherwise be vented or flared and its delivery to specific end-users"(AM0077)***
	gas was flared, vented and/or partially utilized on-site to meet energy demands prior to the implementation of the project activity. ***AM0037*** *is applicable to project activities that recover associated gas from oil wells. which was previously flared, and utilize this associated gas in an existing or a new end-use facility, to produce a useful chemical product.* ***AM0077*** *is applicable to project activities that recover associated gas from oil wells that would otherwise be flared or vented. A new gas processing plant is installed in which the associated gas and, optionally, non-associated gas and/or combined gas are processed. The processed gas is (i) delivered to clearly identifiable specific end-user(s) by means of CNG mobile units and/or (ii) delivered into an existing natural gas pipeline in the host country(ies).* *Furthermore, each methodology includes a list of specific criteria that a given project needs to meet.* *Also, applicability conditions of tools referenced in a given methodology have to be met:* ▪ *For AM0009, AM0037, AM0077: <u>Tool to calculate project or leakage CO_2 emissions from fossil fuel combustion:</u> The Tool is only applicable when CO_2 emissions from fossil fuel combustion are calculated based on the quantity of fuel combusted and its properties. Consequently, project proponents need to monitor(measure) the quantity and properties of gas being combusted.* ▪ *For AM0009, AM0037, AM0077: <u>Tool to calculate baseline, project and/or leakage emissions from electricity consumption</u>: The Tool is only applicable if one out of the following three scenarios applies to the sources of electricity consumption:* ○ *Scenario A: Electricity consumption from the grid. The electricity is purchased from the grid only. Either no captive power plant is installed at the site of electricity consumption or, if any on-site captive power plant exits, it is not operating or it can physically not provide electricity to the source of electricity consumption.* ○ *Scenario B: Electricity consumption from (an) off-grid fossil fuel fired captive power plant(s). One or more fossil fuel fired captive power plants are installed at the site of the electricity consumption source and supply the source with electricity. The captive power plant(s) is/are not connected to the electricity grid.* ○ *Scenario C: Electricity consumption from the grid and (a) fossil fuel fired captive power plant(s). One or more fossil fuel fired captive power plants operate at the site of the electricity consumption source. The captive power plant(s) can provide electricity to the electricity consumption source. The captive power plant(s) is/are also connected to the electricity grid. Hence, the electricity consumption source can be provided with electricity from the captive power plant(s) and the grid.* ▪ *For AM0037: <u>Tool to calculate the emission factor for an electricity system:</u> The tool can be applied to determine an emission factor required for calculations of baseline emissions for a project activity that substitutes grid electricity, i.e. where a project activity supplies electricity to a grid or a project activity that results in savings of electricity that would have been provided by the grid (e.g. demand-side energy efficiency projects).*
Options for compliance	*All applicability conditions being met. Otherwise, it is possible to submit a clarification request regarding the applicability of a methodology; or request for revision of an approved methodology. Also, it is possible to develop a new methodology. There are special CDM procedures on how to make such submissions and what the associated timeline with processing them is.*
Exclusions	*Only if applicability conditions – listed under "Installation types and thresholds" above – are NOT met.*

Name of regulatory Scheme	***Clean Development Mechanism and selected approved methodologies:*** ***"Recovery and utilization of gas from oil wells that would otherwise be flared or vented" (AM0009)*** ***"Flare (or vent) reduction and utilization of gas from oil wells as a feeds" (AM0037)*** ***"Recovery of gas from oil wells that would otherwise be vented or flared and its delivery to specific end-users"(AM0077)***
Treatment of new entrants	*N/A (A methodology only applies to project implementation; new entrants (project proponents) need to meet the methodological criteria)*
Monitoring plan or flare/vent management plant	*Each methodology requires the project proponents to develop and implement a Monitoring Plan, of which key aspects are:* *a) Parameters monitored, including measurement procedures, QA/QC procedures, and monitoring frequency* *b) Data collected and calculation methodologies* *c) Management Structure for the overall project activity* *d) Staff training* *e) Data storage and Archiving.* *The first two points have to comply with monitoring requirements given in a methodology. The development of a Monitoring Plan is essential for validation and registration, and its implementation is checked at the verification stage.*
Incentives for APG reduction or use	*Potential revenue stream from selling Certified Emission Reductions (CERs),* *Price of CER and demand*
Costs	*There are admin costs associated with CDM (e.g. registration fee, issuance fee)* *Project-specific*
Control system	*Documentation is checked by a Designated Operational Entity, the UNFCCC entities*
Consequences of non-compliance	*Lack of project validation; rejection of the request for registration; no CERs issued and available for monetization.*
Methodology	
General estimation approach	*Annual emission reductions (ER) equal:* $ER = BE_y – PE_y – LE_y$*; where:* *BEy = Baseline emissions in year y* (tCO_{2e}) *PEy = Project emissions in year y* (tCO_{2e}) *LEy = Leakage emissions in year y* (tCO_{2e}) *Yet, a methodology provides specific equations for each component, as presented below.*
AM0009	***Baseline emissions (BE):*** *BE are caused by combustion of fossil fuels at end-users that are produced from non-associated gas or other fossil sources. This methodology assumes that the use of recovered gas displaces the use of methane - the fossil fuel with the lowest direct* CO_2 *emissions. Emissions from processing and transportation of fuels to end-users are neglected for both the project activity and the baseline scenario, as it is assumed that these emissions are similar in their magnitude and level out.* $BE_y = V_{F,y} \times NCV_{RG,F,y} \times EF_{CO2,\ Methane}$*; where* $V_{F,y}$ *= Volume of total recovered gas measured after pre-processing and before the part of the recovered gas may be used on-site, in year y, (Nm³)* $NCV_{RG,F,y}$ *= Average net calorific value of recovered gas in year y, (TJ/Nm3)* $EF_{CO2,\ Methane}$ *=* CO_2 *emission factor for methane* (tCO_2/TJ)

Name of regulatory Scheme	***Clean Development Mechanism and selected approved methodologies:*** ***"Recovery and utilization of gas from oil wells that would otherwise be flared or vented" (AM0009)*** ***"Flare (or vent) reduction and utilization of gas from oil wells as a feeds" (AM0037)*** ***"Recovery of gas from oil wells that would otherwise be vented or flared and its delivery to specific end-users"(AM0077)***
	Project emissions (PE): *The following sources of PE are accounted for in this methodology:* ▪ *CO_2 emissions due to consumption of fossil fuels for the recovery, pre-treatment, transportation, and, if applicable, compression of the recovered gas;* ▪ *CO_2 emissions due to the use of electricity for the recovery, pre-treatment, transportation, and, if applicable, compression of the recovered gas.* *PE are the sum of emissions from both sources.* *(i) Emissions due to consumption of fossil fuels, including the recovered gas, if applicable for the recovery, pre-treatment, transportation and, if applicable, compression of the recovered gas are calculated applying the latest approved version of the "Tool to calculate project or leakage CO_2 emissions from fossil fuel combustion":* o *Quantity of fossil fuel combusted x emission factor* *(ii) Emissions due to the use of electricity for the recovery, pre-treatment, transportation, and, if applicable, compression of the recovered gas are calculated applying the latest approved version of the "Tool to calculate baseline, project and/or leakage emissions from electricity consumption"* o *Generic approach: Quantity of electricity consumed by the project electricity consumption source j in year y (MWh/yr) x Emission factor x(1+Average technical transmission and distribution losses for providing electricity to source j in year y)* o *Alternative approaches (provided that electricity consumption is from (an) off-grid fossil fuel fired captive power plant(s) and the electricity consumption source is a project source):* i. *Project emissions from consumption of electricity are determined by calculating the CO_2 emissions from all fuel combustion in the captive power plant. These emissions should be calculated using the latest approved version of the "Tool to calculate project or leakage CO_2 emissions from fossil fuel combustion";* ii. *Project emissions from consumption of electricity are determined based on the rated capacity of the captive power plant(s) ($PP_{CP,j}$), an emission factor of 1.3 tCO_2/MWh and an operation of 8,760 hours per year at the rated capacity:* *11,400tCO_2/MW x $PP_{CP,j}$* *(j = project electricity consumption sources that are supplied with power from captive power plant(s) installed at one site.* ***Leakage emissions (LE):*** *LE are the sum of leakage emissions due to fossil fuel consumption in year y and of leakage emissions due to electricity consumption in year y.* *(iii) Emissions due to the use of electricity for the recovery, pre-treatment, transportation, and, if applicable, compression of the recovered gas are calculated applying the latest approved version of the "Tool to calculate baseline, project and/or leakage emissions from electricity consumption"* o *Generic approach: Net increase in electricity consumption of source l in year y as a result of leakage (MWh/yr) x Emission factor x(1+Average technical transmission and distribution losses for providing electricity to source l in year y); where "l" = Leakage*

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	sources of electricity consumption *Alternative approaches: the same as in the case of project emissions.*
AM0037	***Baseline emissions (BE)*** *BE is the sum of emissions associated with the transportation and flaring*[36] *of the associated gas ($BE_{CO2,flaring,y}$ and $BE_{T,CO2,y}$) emissions from the production of the useful product in the absence of the project activity ($BE_{CO2,product,\ y}$), and fugitive emissions associated with transportation of associated gas ($BE_{T,CH4,y}$).* $BEy = BE_{CO2,flaring,y} + BE_{T,CO2,y} + BE_{T,CH4,y} + BE_{CO2,product,\ y}$ *For each component, calculation formulas are given.* *Project proponents are allowed to either assume $BE_{T,CO2,y}$ equal 0 or calculate these emissions according to formulas provided. Similarly for $BE_{T,CH4,y;\ a}$s a conservative simplification, project participants may assume this emission source as zero.* *In case of calculating CO_2 emissions from the production of the useful product in the absence of the project activity ($BE_{CO2,product,y}$), the formula depends on the scenario listed in Table 2 of the methodology that is applicable to a proposed project activity* ***Project emissions (PE)*** *PE are the sum of CO_2 emissions from energy required for transporting the associated gas to the end-use facility ($PE_{CO2,T,y}$), fugitive emissions from transportation of the associated gas to the end-use facility ($PE_{CH4,T,y}$), including any accidental release, and CO_2 emissions at the end-use facility as a result of the project activity ($PE_{CO2,facility,y}$).* $PE_y = PE_{CO2,T,y} + PE_{CH4,T,y} + PE_{CO2,facility,y}$*; where:* *<u>$CO_2$ emissions from energy required for transportation of the associated gas to the end-use facility ($PE_{CO2,T,y}$)</u> are based on monitored quantities of fossil fuels and/or electricity that are required for that purpose. "Tool to calculate project or leakage CO_2 emissions from fossil fuel combustion" and the "Tool to calculate baseline, project and/or leakage emissions from electricity consumption" should be applied.* *<u>Fugitive CH4 emissions from transportation of the associated gas to the end-use facility ($PE_{CH4,T,y}$)</u> are calculated using the same procedure as provided in the baseline emissions section.* *Note: this source can be ignored, provided that (i) a pipeline transporting the associated gas to the end-use facility is identical (in terms of length, design, and other characteristics likely to affect fugitive emissions and energy demands for compressors) to the pipeline used to transport the associated gas to the flare in the baseline scenario or that (ii) fugitive CH_4 emissions can clearly be expected to be lower in the project case. In case the project activity assumes extending the pipeline to the flare in the baseline scenario, so that associated gas could be transported to the end*

[36] Under AM0037, if the associated gas was vented in the baseline, the baseline emissions are still estimated as under the assumption that the gas is flared.

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	use facility , baseline emissions along the existing pipeline can be ignored and PE only need to be estimated for the pipeline extension. *Furthermore, $PE_{CH4,T,y}$ need to include fugitive emissions from accidents. There are calculation formulas provided, which are based on the principle that in case of gas leakage the gas volume is calculated as the sum of (1) the total amount of gas flow from the time the accident occurred until gas flow was shut off, and (2) the total amount of gas remaining in the pipeline at time of shut off.* *<u>CO_2 emissions occurring at the end-use facility as a result of the project activity ($PE_{CO2,facility,y}$)</u> are calculated using specific formula depending on the applicable scenario.* ***Leakage emissions (LE)*** *No LE are considered in this methodology.*
AM0077	***Baseline emissions (BE)*** *This methodology assumes that all associated gas is flared (and not vented) in the baseline scenario and carbon is converted into carbon dioxide. The calculation formula is:* *$BE_y = (\sum V_{E,y} * w_{carbon,E,y} + V_{F,y} * w_{carbon,F,y}) * \lambda_y *44/12 *1/1000$; where* *olume of the processed gas measured at discharge point of CNG product at a CNG daughter station in year y (m^3)* *$V_{F,y}$ = Volume of the processed gas measured at point, where the associated gas or combined gas enters the existing natural gas pipeline in year y (m^3)* *$w_{carbon,E,y}$ = Average content of carbon in the processed gas measured at discharge point of CNG product at a CNG daughter station in year y (kgC/m^3)* *$w_{carbon,F,y}$ = Average content of carbon in the processed gas measured at point point, where the associated gas or combined gas enters the existing natural gas pipeline in year y (kgC/m^3)* *λ_y = Fraction of the associated gas used in the project activity in year y (Note: it equals 1 if only associated gas is used in the project activity. Otherwise, if associated gas is mixed with non-associated gas, then this parameter needs to be calculated according to the formula provided in the methodology.* ***Project emissions (PE)*** *PE are the sum of (i) CO_2 emissions due to consumption of fossil fuels for the project activity ($PE_{CO2,fossilfuels,y}$), (ii) CO_2 emissions due to the use of electricity for the project activity ($PE_{CO2,elec,y}$), and (iii) CO_2 emissions from transport of the processed gas in CNG mobile units ($PE_{CO2,transport,y}$):* *$PE = PE_{CO2,fossilfuels,y} + PE_{CO2,elec,y} + PE_{CO2,transport,y}$; where y refers to a year.* *<u>$PE_{CO2,fossilfuels,y}$</u> – from the use of fossil fuels for the collection, recovery, treatment, transportation and processing of the associated gas, non-associated gas or combined gas and, if applicable, compressing the processed gas to CNG – are calculated using the latest approved version of*

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	the "Tool to calculate project or leakage CO_2 emissions from fossil fuel combustion". *$\underline{PE_{CO2,elec,y}}$ – from the electricity consumption for the collection, recovery, treatment, transportation and processing of the associated gas, non-associated gas and combined gas and, as applicable, electricity consumption from compressing the processed gas to CNG and/or compression of natural gas into a pipeline – are calculated applying the latest approved version of the "Tool to calculate baseline, project or leakage emissions from electricity consumption".* *$PE_{CO2,transport,y}$ – from the transportation of the associated or combined gas in mobile units by means of trucks – can be calculated using one of the options provided: an approach based on distance and vehicle type (option 1) or on fuel consumption (option 2). For both approaches calculation formulas are provided.* ***Leakage emissions (LE)*** *The methodology requires project proponents to assess:* ▪ *Whether the end-user(s) opted for a lower efficiency of the equipment as a result of the project activity;* ▪ *Whether the supply of the processed gas by the project activity to the market will lead to additional fuel consumption.* *If such leakage effects result from the project activity, then they should be included in the emission reductions, accordingly. Where the fuels of the project activity substitute fuels with higher carbon intensity, leakage can be ignored.*
Gases included in the reporting	*AM0009: CO_2 only* *AM0037: CO_2, CH_4 (fugitives emissions resulting from associated gas transport)* *AM0077: CO_2, CH_4 (fugitive emissions during treatment and transportation of the associated gas, non-associated gas, combined gas or processed gas; yet the methodology deems these emissions negligible)*
Treatment of missing data	*The methodologies do not directly prescribe how to address unavailability of data.* *They rely on project company's internal procedures, as well as on the monitoring plan specifically developed and implemented for the purpose of CDM project.* *It is an obligation of project proponents to ensure that equipment is properly maintained and calibrated, as based on measurements emission reductions are calculated and CERs are verified.*
Calculation update frequency	*At the stage of PDD development, validation and registration* *Once the project is registered: at the stage of verification (usually undertaken annually)*
Methodological changes	*If the methodological requirements on monitoring or emission reduction calculation change, they only apply to projects that have entered the validation process and haven't gone through the public stakeholder consultation.*
Consistency with international standards	*Application of international standards is required when taking measurements for some parameters. See "Use of standards" below*
Levels of accuracy (sources of data)	*<u>AM0009 & AM0077:</u>* *Projection and adjustment of project and baseline emissions on the basis of oil production:*

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	The methodology acknowledges that project as well as baseline emissions, which depend on the quantity of associated gas and gas-lift gas recovered, are linked to oil production. As such, it allows oil production projections using reservoir simulators, reflecting the rock and fluid properties in the oil reservoir. Yet, once the project is registered, the quantity and composition of the recovered gas are required to be monitored ex post and baseline and project emissions are adjusted respectively during monitoring. *Methodologies allow using different sources of data (site-specific, regional/national, IPCC or other internationally recognized sources, default values). Yet, the most accurate and preferred sources include: measurement/analysis information and project company documents. All sources are subject to checks and approval by a DOE.*
Sources for emission factors	*Emission factors are either:* *1. Default values, fixed by a methodology: e.g. in AM0009 - $EF_{CO2,Methane}$ (CO_2 emission factor for methane in tCO_2/TJ), which is used to calculate baseline emissions);* *2. Default values, fixed by the Tools referenced in a methodology (see "Any tools provided?" below), if specific conditions are met;* *3. Calculated values, as per calculation requirement of a given methodology: e.g. in AM0037 - $EF_{CO2,BL,product}$ (CO_2 emission factor for the production of the useful product in the baseline situation)* *4. Calculated values, as per requirements of the Tools, either based on the chemical composition of the fossil fuel type (Option A) or based on net calorific value and CO_2 emission factor of the fuel type (Option B). These apply to fossil fuel emission factors. Option A is preferred. Information can be taken from the following sources:* *a) Values provided by the fuel supplier in invoices* *b) Measurements by the project participants (if a) is not available)* *c) Regional or national default values (if a) is not available). These sources can only be used for liquid fuels and should be based on well-documented, reliable sources (such as national energy balances)* *d) IPCC default values at the upper limit of the uncertainty at a 95% confidence interval as provided in table 1.4 of Chapter1 of Vol. 2 (Energy) of the 2006 IPCC Guidelines on National GHG Inventories (if a) is not available).* *Where applicable, the preferred option for emission factors calculations is to use measured data. Otherwise, project proponents should use accurate and reliable local or national data where available. Where such data is not available, IPCC default emission factors (country-specific, if available) could be apply if they are deemed to reasonably represent local circumstances. Any value should be chosen in a conservative manner and justified.* *The emission factor for an electricity system (so-called grid emission factor) has to be calculated using "Tool to calculate the emission factor for an electricity factor". There is a range of parameters needed for calculations. Sources of data are parameter-specific, and they include: utilities or governmental records, official publications; default values (e.g. fixed by the Tool to calculate the emission factor for an electricity factor, IPCC, national/regional), or values given by fuel suppliers.*

Name of regulatory Scheme	***Clean Development Mechanism and selected approved methodologies:*** ***"Recovery and utilization of gas from oil wells that would otherwise be flared or vented" (AM0009)*** ***"Flare (or vent) reduction and utilization of gas from oil wells as a feeds" (AM0037)*** ***"Recovery of gas from oil wells that would otherwise be vented or flared and its delivery to specific end-users"(AM0077)***
Any tools provided?	*The following tools are referenced in methodologies:* ▪ *Tool for the demonstration and assessment of additionality* ▪ *Tool to calculate project or leakage CO_2 emissions from fossil fuel combustion* ▪ *Tool to calculate baseline, project and/or leakage emissions from electricity consumption* ▪ *Tool to calculate the emission factor for an electricity factor" (in AM0009 and AM0037)* ▪ *Tool to assess the validity of the original/current baseline and update of the baseline at the renewal of the crediting period (only in AM0009)* ▪ *Combined tool to identify the baseline scenario and demonstrate additionality (only in AM0077)*
Uncertainty Treatment	*Specific to methodology, and parameter – see the Monitoring section below.*
Quality Assurance	*Emission calculations have to be based on credible evidence and all assumptions should be clearly described. It is essential to follow methodological requirements. These calculations are subject to checks and reviews by a validation/verification team and UNFCCC entities.*
Monitoring	
Boundaries	*Methodology-specific.* *In AM0009, the project boundary encompasses:* ▪ *The project oil reservoir and oil wells where the associated gas and/or gas-lift gas is collected;* ▪ *The site where the associated gas and/or gas-lift gas was flared or vented in the absence of the project activity;* ▪ *The gas recovery, pre-treatment, transportation infrastructure, including where applicable, compressors;* ▪ *The source of gas-lift gas.* *In AM0037, the project boundary includes:* ▪ *The site where the associated gas would be flared in the absence of the project activity;* ▪ *The pipeline from the site of the previous associated gas flaring to the end-use facility;* ▪ *The end-use facility using the associated gas in the project activity;* ▪ *The facility(ies) where the useful product would be produced in the absence of the project activity.* *In AM0077, the spatial extent of the project boundary encompasses:* ▪ *Project oil wells where the associated gas is collected;* ▪ *Natural gas wells where the non-associated gas is produced;* ▪ *The site where the associated gas was flared or vented in the absence of the project activity;* ▪ *The gas recovery infrastructure;* ▪ *The gas treatment and transportation infrastructure;* ▪ *The gas processing plant;* ▪ *If applicable: CNG mother and daughter stations;* ▪ *If applicable: Specific end-user(s) and gas utilizer(s) of the associated or combined gas.*

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	AM0009 and AM0077 do not directly address abnormal events (e.g. shutdown, emergency). Yet, they are indirectly captured by the calculations of emission reductions (e.g., higher diesel use in generators in case of emergency situation or back-up need is reflected in higher project emissions due to fossil fuel consumption; volumes of gas flared/vented are not included in calculations of either baseline and project emissions, therefore the more gas is flared/vented the less emission reductions can be expected due to lower amount of associated gas used. *AM0037 does require including fugitive emissions in case of accidents in the calculations of project CH_4 emissions from transportation of the associated gas to the end-use facility – see "AM0037" above under the Estimation Approach.* *The project proponents keep a log of abnormal events anyway, so that they are able to explain relatively large differences between estimated and achieved emission reductions. Such explanation is given in a Monitoring Report for a given monitoring period.*
Frequency	*Parameter-specific, for example:* ▪ *Volume of the total recovered gas, after pre-treatment and before the part of the recovered gas is used on-site, in year y = continuously* ▪ *Sampling and compositional analysis and calculation of net calorific value= at least weekly or monthly* ▪ *Quantity of fossil fuel consumption = continuously* ▪ *Quantity of electricity consumption = continuously*
Methodology	*Requirements for monitoring need to be met by all projects that use a given methodology* *Each parameter has defined measurement procedures.*
Use of standards	*AM0009: for the volume of the total recovered gas - The measured volume should be converted to the volume at normal temperature and pressure using the temperature and pressure at the time to measurement.* *AM0009: for onsite gas measurement (Chemical analysis of gas samples):.* *Sampling in accordance with ISO 10715 or equivalent standard. Compositional analysis in accordance with ISO 6974 or equivalent standard. Routine maintenance and calibration in accordance with ISO 10723 or equivalent standard. GC calibration gases certified to ISO 6141 or equivalent standard. Annual manufacturer servicing and calibration to ISO17025 or equivalent standard. In case third party laboratories are used, these should as a minimum have ISO17025 accreditation or justify that they can comply with similar quality standards* *Based on the molar composition, the Net Calorific Value on a volumetric basis should be determined for each sample in line with ISO 6976 or an equivalent standard for a combustion reference temperature of 250C and the same metering reference condition used for the total volume of the recovered gas.* *AM0037: The laboratories in (b) should have ISO17025 accreditation or justify that they can comply with similar quality standards. Also, for measurements of mass fraction of carbon in a fossil fuel type should be undertaken in line with national or international fuel standards.*

Name of regulatory Scheme	***Clean Development Mechanism and selected approved methodologies:*** ***"Recovery and utilization of gas from oil wells that would otherwise be flared or vented" (AM0009)*** ***"Flare (or vent) reduction and utilization of gas from oil wells as a feeds" (AM0037)*** ***"Recovery of gas from oil wells that would otherwise be vented or flared and its delivery to specific end-users"(AM0077)***
	AM0077: Sampling equipment, sampling procedure, gas analyser and analysis procedures shall comply with appropriate reference standards and where laboratory analysis is used the laboratory shall comply with national accreditation standards.
Uncertainty treatment	*AM0009: the methodology does not directly prescribe how to address uncertainty.* *AM0037: for measurements of mass fraction of carbon in a fossil fuel type, the methodology requires verifying if values provided by a fuel supplier or from measurements by project proponents are within the uncertainty range of the IPCC default values as provided in Table 1.2, Vol. 2 of the 2006 IPCC Guidelines.* *AM0077: in the Monitoring Methodology section, the methodology specifies 'permissible uncertainty' to be expressed as the 95% confidence interval around the measured value, for normally distributed measurements. Furthermore, the uncertainty associated with each parameter should be assessed, for example, by calculating the probable uncertainty as the mean deviation divided by the square root of the number of measurements. If a resulting this uncertainty is within the 95% confidence interval, then no further action needs to be taken.* *Otherwise, the uncertainty should be assessed as low (<10%), medium (10-60%) or high (>60%). Percent uncertainty may be calculated by dividing the mean of the parameter by the probable uncertainty and multiply by 100% to get percent uncertainty. If case when a resulting uncertainty is <10%, then project proponents can consider the uncertainty low.* *For parameters with medium or high uncertainty, project proponents are requested to describe in detail quality control procedures and to provide explanation of quality assurance. Also, when a parameter has a medium or high uncertainty, a sensitivity analysis should be performed to determine the potential of the uncertainty of the parameter to affect the emissions reduction calculation.* *All assessments of the uncertainty levels are subject to third party's verification at the project verification stage.* *For gas, CNG volume or mass measurement, the metering systems needs to be designed, installed and maintained to the requirements of the appropriate metering reference standards for the installed technology so that the uncertainty in measurement can be calculated in a fully traceable manner with reference to such standards.* *Similarly, for gas sampling, the sampling equipment and sampling procedure needs to comply with appropriate reference standards so that allowing calculating that uncertainty in sample extraction.* *Uncertainty associated with each parameter is to be maintained through a calibration program designed to ensure individual parameter uncertainties are maintained at a level ensuring the combined overall uncertainty in emission reductions can be shown to be within a commonly acknowledged 5% verification materiality threshold.*

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Quality assurance	*The project proponents have to maintain and calibrate measuring equipment regularly.* *The gas compositional analysis should be taken in line with national or international fuel standards.* *The project proponents have to demonstrate that they developed (and implemented) a robust monitoring plan, which is described in detail in the PDD (also refer to "Monitoring plan or flare/vent management plant" above).* *Methodologies specify for almost all parameters QA/QC procedures; for example cross-checks of electricity consumption measurements with invoices.* *Any deviation in a monitoring plan described in the Project Design Document needs to be subject to either:* ▪ *request for revision: this is in case a monitoring plan needs to be amended to comply with the monitoring methodology or aims to improve accuracy and/or completeness of monitoring. A set of documents needs to be submitted to the CDM Executive Board: a request for revision of monitoring plan form (F-CDM-REVMP);a revised monitoring plan (in clean and track change versions);the DOE's validation opinion; and other relevant documents;* ▪ *request for deviation: it is appropriate when project proponents make a formal request for guidance from the CDM Executive Board regarding deviations from provisions of the registered project documentation for the verified period only. To make such request, a request for deviation form (F-CDMDEV-ISS); and other relevant documents have to be submitted. A request for deviation must be submitted prior to submitting a request for issuance. The procedure for making such request is described in "Procedures for requests for deviation prior to submitting request for issuance"[37].*
Reporting	
Scope	*There is no reporting requirement as such; yet in order to register the project it is necessary to develop a Project Design Document (PDD), CER calculation spreadsheet, investment model (if applicable), follow the requirements of a methodology and associated tools, and collect documentary evidence.* *To have CERs issued, the above is also applicable, except that no PDD and investment model is required, instead a Monitoring Report together with CER calculations need to be submitted for verification.* *To renew the crediting period it is necessary to submit a revised PDD and associated evidence, which are subject to validation.*
Frequency	*At the validation stage, registration stage and verification stage*
Form (reporting format)	*See "Scope" above*
System transparency (public database, information disclosed)	*PDD is uploaded on the UNFCCC website at early stage of the validation process, for the purpose of stakeholder consultation.* *Once the project completes the validation and is submitted for registration, additional project-specific documents are uploaded on the UNFCCC website: validation report, letter(s) of approval, Modalities of Communications.*

[37] Available at: http://cdm.unfccc.int/Reference/Procedures/iss_proc07.pdf

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	Similarly, when the project seeks CERs issuance, then Monitoring Report and Verification Report are also published.
Verification requirements	
Process	*Verification process resembles validation process and covers the following steps:* ▪ *Documentation submission (PDD and CER spreadsheet in case of validation; Monitoring Report and CER calculation spreadsheet in case of verification);* ▪ *Completeness check;* ▪ *Site visit;* ▪ *Development of draft Validation/Verification Report (VR); list of Corrective Action Requests and Clarification requests submitted to project proponents;* ▪ *Submission of responses to DOE's queries* ▪ *Follow-up requests by DOE and responses* ▪ *Issuance of Final Draft VR* ▪ *Technical Review of Final Draft VR and project documentation* ▪ *Requests by Technical Reviewer and responses* ▪ *Issuance of Final VR*
Methodology	*Validators and verifiers follow the Manual ("Clean Development Mechanism Validation and Verification Manual" available at: http://cdm.unfccc.int/Reference/Manuals/index.html)*
Assurance requirements	*Validators and verifiers are accredited by the UNFCCC.* *Two methods of monitoring the performance of DOEs are provided for in the accreditation rules - regular on-site surveillance and spot-checking. As a result of non-compliance, a given DOE may be suspended or its accreditation can be withdrawn.* *DOE's work is also checked on a project basis by the UNFCCC CDM entities during processing of request for registration and request for issuance. An investigation into DOE's work can be triggered by the UNFCCC in case requests for registration or issuance are rejected relatively often.*
Avoiding double counting	*All projects are logged in the UNFCCC system (whether registered, rejected, withdrawn, or with validation terminated). CERs issued are serialised and registered in the CDM Registry, administered by the UNFCCC secretariat.* *Upon authorization from the EB to issue CERs for a project activity, the secretariat forwards the issued CERs into a Pending Account until it receives instructions to forward CERs into the relevant Holding Account. Project participants may have a Holding Account either in the CDM Registry or in the National Registry of an Annex I country. For CERs to be transferred from an account in the CDM Registry to a National Registry account, they must pass through the International Transaction Log (ITL). The ITL, which still awaits connection to the European's Community ITL, already recorded transactions of CERs from the CDM registries to some Annex I National Registries. These transactions include issuance, cancellation, replacement, retirement and the transfer of CERs. Once the CERs are received in a National Registry account they may be traded or used for complying with national or regional targets. At present, CERs cannot be transferred between National Registries but internal transfers within a National Registry are possible.*

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	No emission reductions can be claimed by a registered project, prior to the date of submitting a complete request for registration.
Third party	*The UNFCCC accredits Designated Operation Entities (DOEs) which are eligible to carry out validation and verification services. The UNFCCC maintains a publicly available list of DOEs together with information on sectoral scopes they are accredited for: http://cdm.unfccc.int/DOE/list/index.html.* *There are two procedural documents regarding DOE accreditation:* ▪ *Accrediting operational entities by the Executive Board of the CDM* ▪ *Performance monitoring of designated operational entities*
Other requirements	
Retention of information	*All data collected as part of monitoring should be archived electronically and be kept at least for 2 years after the end of the last crediting period.* *AM0009: If renewed crediting period chosen (CERs could be generated for 21 years, 3 x 7years, as opposed to fixed crediting period of 10 years), then it is necessary to follow "Tool to assess the validity of the original/current baseline and to update the baseline at the renewal of a crediting period".*
Additionality	*All projects seeking CDM registration have to demonstrate that they are additional compared to a business-as-usual scenario. There is a very specific and rigorous procedure for demonstrating the additionality as described in the "Tool for the demonstration and assessment of additionality" and/or "Combined tool to identify the baseline scenario and demonstrate additionality"[38]. Also, a methodology can also include a specific guidance.* *In general, these steps need to be followed:* *1. Define plausible alternatives to a proposed project activity* *a. Check their consistency with applicable laws and regulations* *2. Investment analysis* *a. Determine appropriate analysis method (Option I - Simple Cost Analysis, Option II - Investment Comparison Analysis or Option III - Benchmark Analysis)* *b. Calculation and comparison of financial indicators, only applicable to Options II and III* *c. Sensitivity analysis, only applicable to Options II and III;* *3. Barrier analysis* *a. Identify barriers that would prevent the implementation of the proposed CDM project activity (technological barriers, investment barriers, barriers due to prevailing practice, other)* *b. Show that the identified barriers would not prevent the implementation of at least one of the alternatives (except the proposed project activity)*

[38] Available at: http://cdm.unfccc.int/Reference/tools/index.html

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	4. Common practice analysis *a. Analyze other activities similar to the proposed project activity;* *b. Discuss any similar Options that are occurring* *As part of the additionality demonstration, project proponents are also required to demonstrate prior-consideration of CDM in their decision-making to pursue a project. The "Guidelines on the demonstration and assessment of prior consideration of the CDM" is available on the UNFCCC website[39].*

Verified Carbon Standard

Name of regulatory Scheme	***Verified Carbon Standard (VCS)***
General characteristics	
Objectives of regulation	*The Verified Carbon Standard is a greenhouse gas accounting program used by projects to verify and issue carbon credits in voluntary markets.*
Country / language	*World*
Web site	*http://v-c-s.org/*
Implementation/enforcement entity	*Project Proponents; VVB (Validation/Verification Bodies), VCS registry*
Targeted sector(s)	*Similar to CDM, there are 15 sectoral scopes under which projects, activities or methodologies can be developed. They are listed at: http://v-c-s.org/node/448* *VCS accepts methodologies developed specifically for the scheme, as well as methodologies of Clean Development Mechanism (CDM)[40] and California's Climate Action Reserve (CAR)[41]. Neither VCS nor CAR have their own methodologies targeting emissions linked to flaring/venting of associated petroleum gas.*
Reduction target	*N/A*
Compliance	
Installation types and thresholds	*Same as under the CDM:* *Specific to a methodology and referenced tool (if applicable).*

[40] Source: http://cdm.unfccc.int/methodologies

[41] Source: http://www.climateactionreserve.org/how/protocols/

Name of regulatory Scheme	*Verified Carbon Standard (VCS)*
	A potential VCS project should face one or more distinct barrier(s) compared with barriers faced by alternatives to the project: investment barrier; technological barriers; institutional barriers.
Options for compliance	*All applicability conditions listed in a methodology and associated tools or modules have to be met.* *Deviations from the methodology applied to a project are permitted where they represent a deviation from the criteria and procedures relating to monitoring or measurement (but not quantification) of GHG emission reductions or removals set out in the methodology.* *VCS also allows revisions to an existing methodology and development of a new methodology. Procedures for each are described in the "Methodology Approval Process"[42].*
Exclusions	*In general, the scope of the VCS Program excludes:* *1) Projects that can reasonably be assumed to have generated GHG emissions primarily for the purpose of their subsequent reduction, removal or destruction.* *2) Projects that reduce hydrofluorocarbon (HFC) emissions from the production of HCFC-22 in Kyoto Protocol Annex B countries.* *Like under CDM, a potential VCS project cannot be mandated by any law, statute or other regulatory framework, or for UNFCCC non-Annex I countries, any systematically enforced law, statute or other regulatory framework. Also, the project should not be a common practice.*
Treatment of new entrants	*VCS allows for new methodology development under any of 15 sectoral scopes.* *Under a grouped project (i.e. a project that combines multiple project activities), it is possible to add a new project activity instance, provided a number of conditions is met, for example: it occurs within one of the designated geographic areas specified in the project description, it complies with at least one complete set of eligibility criteria for the inclusion of new project activity instances etc. (refer to the VCS Standard document, section 3.4.10).*
Monitoring plan or flare/vent management plant	*Similar to CDM:* *Monitoring Plan is required as part of a project development. The VCS Standard Guide specifies that:* ▪ *The project proponent shall establish a GHG information system for obtaining, recording, compiling and analyzing data and information important for quantifying and reporting GHG emissions and/or removals relevant for the project (including leakage) and baseline scenario.* ▪ *A monitoring plan for the project that includes roles and responsibilities shall be established.* ▪ *Where measurement and monitoring equipment is used, the project proponent shall ensure the equipment is calibrated according to the equipment's specifications and/or relevant national or international standards.*
Incentives for APG reduction or use	*Potential revenue stream from selling Voluntary Carbon Units (VERs),* *Price of VCU and demand*
Costs	*Project-specific* *Admin costs*
Control system	*Project is validated by a Validation Body, and achieved emission reductions have to be verified by a Verification Body. Validation and verification can be provided by the same body.* *Generally, validation should be completed within 2 years of the project start date.*

[42] Available at: http://v-c-s.org/program-documents

Name of regulatory Scheme	*Verified Carbon Standard (VCS)*
	The VCS Association has a right: ▪ *To oversee and ensure the integrity of projects and VCUs in the VCS registry system;* ▪ *To undertake an annual review of projects and VCUs in the VCS registry system based on which it may undertake additional periodic reviews.* ▪ *To oversee the validation/verification bodies operating under the VCS Program.* ▪ *Not to register projects or issue VCUs where it deems that they are not in compliance with the VCS rules, and to delist projects and VCUs where it deems that they have not been registered or issued in accordance with the VCS rules.* ▪ *To take action against validation/verification bodies and VCS registries in accordance with the provisions set out in the agreements signed with the VCSA.* *Validation/verification bodies are liable for any over-issuance of VCUs in accordance with the provisions in the agreement signed with the VCSA.*
Consequences of non-compliance	*Lack of project validation; no VCUs issued and available for monetization.*
Methodology	
Estimation approach	*Methodology-specific (see summary tables of CDM methodologies for flaring/venting related emission reductions). For projects not related to Agriculture, Forestry and Other Land Use: crediting period is maximum 10 years and can be renewed twice.*
Gases included in the reporting	*The scope of the VCS Program includes:* *1) The six Kyoto Protocol greenhouse gases.* *2) Ozone-depleting substances as set out in VCS document ODS Requirements.* *Emission reductions are expressed in* tCO_{2eq}.
Treatment of missing data	*Similar to CDM; it is case-specific.* *Reasonable assumptions backed with credible evidence; or a different set of data should be applied.*
Calculation update frequency	*At the stage of Project Description development, validation & verification* *Note: positive validation automatically results in acceptance by VCS, provided documents submitted for registration meet the schemes requirements. In other words, under VCS there are no equivalents of separate project assessments under CDM by the UNFCCC Secretariat (reporting and information check) and reviews by CDM Executive Board.* *Once the project is registered: calculations of achieved emission reduction are done at the stage of verification.* *Note: under the VCS, a project start date is the date when emission reductions started being generated. As such, it is allowed to undertake simultaneously project validation and first verification of emission reductions achieved to date. Then, a project proponent submits together request for registration as well as request for issuance to the VCS Registry.*
Methodological changes	*The VCS allows methodology revisions.*
Consistency with international standards	*1) ISO 14064-2:2006, Greenhouse gases - Part 2: Specification with guidance at the project level for quantification, monitoring and reporting of greenhouse gas emission reductions or removal enhancements, ISO, 2006.* *2) ISO 14064-3:2006, Greenhouse gases - Part 3: Specification with guidance for the validation and verification of greenhouse gas assertions, ISO 2006.* *3) ISO 14065:2007, Greenhouse gases - Requirements for greenhouse gas validation and verification bodies for use in accreditation or other forms*

Name of regulatory Scheme	*Verified Carbon Standard (VCS)*
	of recognition, BSI, 2007 *4) The GHG Protocol for Project Accounting (Chapter 7, guidance related to additionality and common practice), WRI, 2005.* *The VCS Program Guide explains that since the four standards above are part of the requirements of the VCS, their requirements need be met either by the project proponent (ISO 14064-2:2006) or validation/verification body (ISO 14064-3:2006 and ISO 14065:2007). The VCS Standard document states that The validation/verification body and validation and verification team shall meet the competence requirements set out in ISO 14065:2007, mutatis mutandis.*
Levels of accuracy (sources of data)	*The VCS recognizes two types of projects:* *1) Projects: Less than or equal to 1,000,000 tCO2e per year; and* *2) Mega projects: Greater than 1,000,000 tCO2e per year.* *The threshold for materiality with respect to omission or misstatement concerning reported quantities shall be five percent; except for mega-projects where it shall be one percent.* *The level of assurance in validation/verification shall be reasonable, with respect to material errors, omissions and misrepresentations, for both validation and verification.* *A methodology specifies sources of data for each parameter (see summary tables of CDM methodologies for flaring/venting related emission reductions)*
Sources for emission factors	*Methodology-specific (see summary tables of CDM methodologies for flaring/venting related emission reductions)* *The VCS Standard document states that: standards and factors used to derive GHG emission data shall meet the following requirements:* *1) Be publicly available from a reputable and recognized source (eg, IPCC, published government data, etc).* *2) Be reviewed as part of its publication by a recognized competent organization.* *3) Be appropriate for the GHG source or sink concerned.* *4) Be current at the time of quantification.*
Any tools provided?	*Methodology-specific (see summary tables of CDM methodologies for flaring/venting related emission reductions)*
Uncertainty Treatment	*According to the VCS Standard document:* *Where models are used to estimate processes that generate GHG emissions, model parameters shall be derived from scientifically peer-reviewed studies that identify the parameters as important drivers of GHG emissions. Furthermore, methodologies that rely on models to estimate GHG emission reductions and/or removals are required to meet the following requirements:* *a) All plausible sources of model uncertainty, such as structural uncertainty or value uncertainty, shall be assessed using 2006 IPCC Guidelines for National Greenhouse Gas Inventories, Volume 1, Chapter 3, as may be updated from time to time.* *b) The model shall have strict requirements for estimating uncertainty, and the model shall be calibrated by variables such as geographic location and local climate data.* *c) The model shall apply conservative factors to discount for model uncertainty in accordance with VCS project requirements. The model shall also use conservative assumptions and parameters that will underestimate, rather than overestimate, the net GHG emission reductions and removals.*

Name of regulatory Scheme	*Verified Carbon Standard (VCS)*
	The VCS requires methodologies to clearly state the assumptions, parameters and procedures that have significant uncertainty, and describe how such uncertainty shall be addressed. Where applicable, methodology elements should provide a means to estimate a 90 or 95 percent confidence interval. Where a methodology applies a 90 percent confidence interval and the width of the confidence interval exceeds 20 percent of the estimated value or where a methodology applies a 95 percent confidence interval and the width of the confidence interval exceeds 30 percent of the estimated value, an appropriate confidence deduction should be applied. Methods used for estimating uncertainty shall be based on recognized statistical approaches such as those described in the IPCC Good Practice Guidance and Uncertainty Management in National Greenhouse Gas Inventories. Confidence deductions shall be applied using conservative factors such as those specified in the CDM Meth Panel guidance on addressing uncertainty in its Thirty Second Meeting Report, Annex 14.
Quality Assurance	*A number of principles are in place to ensure that GHG-related information is a true and fair account: (these principles are taken from ISO 14064-2:2006, clause 3): relevance, completeness, consistency, accuracy, transparency, and conservativeness.* *If a project is validated under the CDM, applicants for VCS registration have to complete only selected sections of the Project Description Template. A validation/verification body is then required to carry out a validation of same, which shall be accompanied by a validation representation, to provide a gap validation for the project's compliance with the VCS rules.* *Projects rejected by other GHG programs due to procedural or eligibility requirements cab be considered under the VCS Program, but the following conditions have to be met:* *1) The project description (where the other GHG program has rejected the project before VCS validation) or monitoring report (where the other GHG program has rejected the project after VCS validation) shall clearly state all GHG programs to which the project has applied for registration and the reason(s) for rejection. Such information shall not be deemed as commercially sensitive information.* *2) The validation/verification body shall be provided with the rejection document(s), including any additional explanations.* *3) The project shall be validated against the VCS rules. For projects where the other GHG program has rejected the project after VCS validation, this means a complete revalidation of the project against the VCS rules.* *The validation report and the verification report contain a statement, in which a validation/verification body needs to describe the level of assurance of the validation or verification.* *According to ISO 14064-3:2006, the level of assurance of the validation/verification is to be agreed with the client at the beginning of the validation/verification process (in general, there are two levels: reasonable assurance engagements and limited assurance engagements allowed by the standard, but VCS requires reasonable level of assurance).*
Monitoring	
Boundaries	*Methodology-specific (see summary tables of CDM methodologies for flaring/venting related emission reductions)*
Frequency	*Parameter-specific (see summary tables of CDM methodologies for flaring/venting related emission reductions)*
Methodology	*Methodology-specific (see summary tables of CDM methodologies for flaring/venting related emission reductions)* *The VCS allows deviations from the monitoring plan (i.e., the procedures for monitoring and measurement) as set out in the project description*

Name of regulatory Scheme	*Verified Carbon Standard (VCS)*
	provided that the project remains in compliance with the applied methodology. Any deviations have to be described and justified in the monitoring report, which then are subject to validation at the time of verification. Also, consequences of applied deviations have to be reported in all subsequent verification reports.
Use of standards	*Specific to a parameter and methodology (see summary tables of CDM methodologies for flaring/venting related emission reductions)*
Uncertainty treatment	*The VCS Standard requires that, where applicable, procedures to account for uncertainty in data and parameters shall be applied in accordance with the requirements set out in the methodology.*
Quality assurance	*The VCS Standard requires that quality management procedures to manage data and information shall be applied and established.*
Reporting	
Scope	*Same as under the CDM*
Frequency	*At the validation stage and verification stage*
Form (reporting format)	*Same as under the CDM*
System transparency (public database, information disclosed)	*There is a VCS Project Database, where information on all projects registered under VCS can be found (for each project registration and issuance documents, information on VCUs can be accessed):* *http://www.vcsprojectdatabase.org/*
Verification requirements	
Process	*Verification process resembles validation process and covers the following steps:* ▪ *Documentation submission to VVB (Monitoring Report, CER calculation spreadsheet and accompanying documents);* ▪ *VVB assesses GHG emission reductions or removals in accordance with VCS rules, including site visit and interviews* ▪ *VVB requests and response* ▪ *Issuance of the Verification Report and verification representation (Deed representation)* ▪ *Project proponent(s) submits project documents (including project proponent representations) to VCS Registry* *Templates for Verification Report and representations can be downloaded from: http://v-c-s.org/program-documents/find-program-document*
Methodology	*Materiality thresholds are: 1% for mega projects and 5% for the others.* *See "Assurance requirements" below*
Assurance requirements	*Validators and verifiers need to have appropriate accreditation (see "Third party" below).* *Their work has to comply with international standards (see "Consistency with international standards" above).* *In addition to the requirements set out in ISO 14064-3:2006, the following apply to validation and verification processes:* *1) The level of assurance shall be reasonable, with respect to material errors, omissions and misrepresentations, for both validation and verification. (The validation report and the verification report contain a statement, in which a validation/verification body needs to describe the level of assurance of the validation or verification)* *2) The validation or verification shall ensure conformance of the project with the VCS rules, or rules and requirements of the approved GHG program, as applicable.* *3) The objective of validation or verification shall be in conformance with the VCS rules and the methodology applied to the project.* *4) The threshold for materiality with respect to omission or misstatement concerning reported quantities shall be five percent except for mega-projects where it shall be one percent.*

Name of regulatory Scheme	*Verified Carbon Standard (VCS)*
	The VCSA is responsible for overseeing the work of Validation/Verification Bodies; and has a right to take an action in accordance with the provisions set out in the agreements signed with the VCSA
Avoiding double counting	*Projects must open an account with a VCS-approved registry to be issued Verified Carbon Units, or VCUs. They are serialised.* *The VCS does not permit claiming credit for the same GHG emission reduction or removal under the VCS and other GHG programs.* *Projects registered under other GHG programs are not eligible for VCU issuance beyond the end of the total project crediting period under those programs* *The VCS Standard document specifies that:* *Where projects reduce GHG emissions from activities that are included in an emissions trading program or any other mechanism that includes GHG allowance trading, the VCS requires evidence demonstrating that the GHG emission reductions or removals generated by the project have not and will not be otherwise counted or used under the program or mechanism. Such evidence may include:* *1) A letter from the program operator, designated national authority or other relevant regulatory authority that emissions allowances (or other GHG credits used in the program) equivalent to the reductions or removals generated by the project have been cancelled from the program or national cap, as applicable.* *2) Evidence of the purchase and cancellation of GHG allowances equivalent to the GHG emissions reductions or removals generated by the project related to the program or national cap.* *3) Evidence from the program operator, designated national authority or other relevant regulatory authority stating that the specific GHG emission reductions or removals generated by the project or type of project are not within the scope of the program or national cap.* *Where projects have created another form of GHG-related environmental credit, such as renewable energy certificates, the VCS requires evidence demonstrating that such environmental credits which have been issued during that monitoring period have not been used and have been cancelled from the environmental credit program. Note that this requirement does not apply to non-GHG related environmental credits, such as water or biodiversity credits.* *At the validation stage, project proponents have to provide Proof of Right, which includes document(s) demonstrating the entity's right to all and any GHG emission reductions or removals generated by the project during the project crediting period or verification period, as the case may be. Yet, it is distinct from right of use.* *If a project proponent transfer its project from VCS to another GHG program, he is obliged to notify the VCS registry administrator of same.*
Third party	*Validation/verification bodies are eligible to provide validation and verification services under the VCS Program if they have signed the required agreement with the VCSA and are:* *1. Accredited under a VCS-approved GHG program (i.e. CDM, JI and California's CAR);* *2. Accredited under ISO 14065 for scope VCS by an accreditation body that is a member of the International Accreditation Forum; or* *3. Approved under the VCS temporary accreditation program.* *The VCS maintains the publicly available list of VVBs and information on sectoral scopes each VVB is accredited for:* *https://vcsprojectdatabase2.apx.com/myModule/Interactive.asp?Tab=VVBs&a=1*

Name of regulatory Scheme	*Verified Carbon Standard (VCS)*
	The VCS allows for temporary accreditation, provided an entity' application for accreditation under the three schemes listed above is in the process. Such temporary accreditation is granted for a period of 12 months, with a possibility of extension by further 6 months but only if a delay in issuing accreditation is due to internal procedures of a relevant accreditation body.
Other requirements	
Retention of information	*Like in the CDM: all documents and records should be kept in a secure and retrievable manner for at least two years after the end of the project crediting period.* *The validation/verification body need to keep all documents and records in a secure and retrievable manner for at least two years after the end of the project crediting period, even where they do not conduct verification for the whole project crediting period.*
Additionality	*The VCS, like CDM, requires project proponents to demonstrate additionality of their projects. Demonstration and assessment of additionality should be done in accordance with the requirements set out in the methodology applied to the project or in the standalone module (additionality test) applicable to a given methodology.* *For baseline selection and additionality demonstration, the VCS allows two approaches: activity method and performance method. They are defined as follows:* *<u>Performance methods:</u> These methods establish performance benchmark metrics for determining additionality and/or the crediting baseline. Projects that meet or exceed a pre-determined level of the metric may be deemed as additional and a pre-determined level of the metric may serve as the crediting baseline. A performance method is an integral part of a methodology.* *<u>Activity methods:</u> These methods pre-determine additionality for given classes of project activities using a positive list. Projects that implement activities on the positive list are automatically deemed as additional and do not otherwise need to demonstrate additionality. One of three options (namely, activity penetration, financial viability or revenue streams) is used to qualify the project activity for the positive list. An activity method can be integrated into a methodology as well as be approved as a stand-alone module (additionality test), which can be used in conjunction with applicable methodologies.* *Furthermore, a methodology establishes procedure for demonstration and assessment of additionality amongst one of the below possible approaches:* *1) Project method: step 1 – regulatory surplus; step 2 – implementation barrier (investment barrier, technological barriers, and institutional barriers); step 3 – common practice* *2) Program test: step 1 – regulatory surplus; step 2 – performance benchmark (the emission reductions achieved per unit shall be below (or above, for sequestration) the prescribed performance benchmark metric or proxy for such metric)* *3) Technology test: step 1 – regulatory surplus; step 2 –positive list:* *a. Option A - activity penetration (demonstration that the project activity has achieved a low level of penetration relative to its maximum adoption potential); and/or* *b. Option B – financial viability (demonstration that the project activity is less financially or economically attractive than the alternatives to the project activity using the procedures for investment analysis set out in the CDM Tool for the demonstration and assessment of additionality); and/or*

Name of regulatory Scheme	*Verified Carbon Standard (VCS)*
	c. Option C – revenue stream (demonstration that the project activity does not have any significant sources of revenue other than revenue from the sale of GHG credits *A VCS methodology can either reference and explicitly require the use of the CDM Tool for the Assessment and Demonstration of Additionality, or it can develop its own approaches and tools for demonstrating and assessing additionality.*

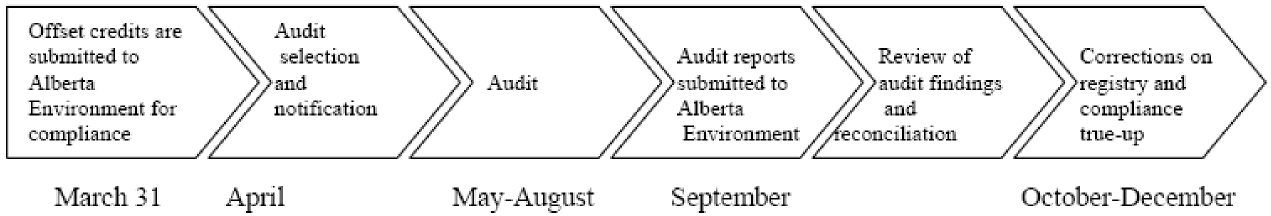
Alberta's Offset Scheme

Name of regulatory Scheme	***Alberta's Offset Scheme*** ***Quantification Protocol For Solution Gas[43] Conservation***
General characteristics	
Objectives of regulation	*This scheme provides flexibility for entities covered by the Specified Gas Emitters Regulation (SGER) to meet their compliance obligations. Also, it supports Alberta's commitment to reducing provincial greenhouse gas emissions (50MtCO_2 reduction by 2020, and 200MtCO_2 reduction by 2050).* *The specific protocol aims to capture small, uneconomic vent streams released as part of oil and bitumen extraction processes by sending the captured solution gas to flare.*
Country / language	*Canada (Alberta) / English*
Web site	*Offset scheme: http://environment.alberta.ca/0923.html* *Protocol for Solution Gas Conservation: http://environment.alberta.ca/03954.html*
Implementation/enforcement entity	*Alberta Environment and Water*
Targeted sector(s)	*Protocol- specific. A complete list of approved protocols is available at: http://environment.alberta.ca/1238.html* *For the Solution Gas Conservation Protocol: extraction of crude oil and bitumen.*
Reduction target	*N/A*
Compliance	
Installation types and thresholds	*Facilities and sectors not subject to the SGER that are able to reduce their greenhouse gas emissions according to a government approved protocol and that meet the following requirements:* *a. the specified gas emissions reduction must occur in Alberta;* *b. the specified gas emissions reduction must be from an action taken that is not otherwise required by law at the time the action is initiated;* *c. the specified gas emissions reduction must (i) result from actions taken on or after January 1, 2002, and (ii) occur on or after January 1, 2002;* *d. the specified gas emissions reduction must be real and demonstrable;* *e. the specified gas emissions reduction must be quantifiable and measurable, directly or by accurate estimation using replicable techniques;* *f. the specified gas emissions reduction has to be be third party verified; and registered on the Alberta Emissions Offset Registry.*

[43] Solution gas is defined as dissolved gas in well bore or reservoir fluids. This gas is largely comprised of methane and remains in solution until the pressure or temperature conditions within the reservoir change at which time it may break out of solution to become a free gas.

Name of regulatory Scheme	***Alberta's Offset Scheme*** ***Quantification Protocol For Solution Gas[43] Conservation***
	Section 7 of SGER provides also specific requirements for a geological sequestration and capture of specified gas. *Emission reductions have to have a clearly established ownership.*
Options for compliance	*The same as in the case of CDM and VCS, a project needs to meet protocol-specific applicability criteria. In addition, conservation of solution gas has to be achieved in three ways:* *a. injection into a natural gas pipeline;* *b. on-site use as fuel gas; and/or* *c. combustion to generate electrical power.* *Projects must be implemented according to the conditions outlined in the offset project plan and associated monitoring plan. In case of changes in operations, these have to be documented in the offset project report which is prepared annually or prior to a third party verification.*
Exclusions	*Offset credits cannot be generated for an activity that does not have a government approved quantification protocol.* *Also, like in other offset schemes, a potential project cannot be mandated by any law, statute or other regulatory framework.* *As such, the Solution Gas Conservation Protocol is only applicable to solution gas conservation, where vented flow rates do justify combustion as outlined in Section 8.1.2 in Directive 060.In other words, vented solution gas emissions higher than 500 m^3 per day are excluded.* *Furthermore, the Protocol excludes flared solution gas.*
Treatment of new entrants	*The scheme allows for development of a new protocol. There is a specific guidance available for protocol developers.*
Monitoring plan or flare/vent management plant	*A project developer must prepare a detailed offset project plan, covering:* *1. Project Scope and Site Description* *2. Inventory of Sources and Sinks* *3. Identification of Baseline and Project* *4. Quantification Plan* *5. Monitoring Plan* *6. Data Management System and Records* *The template with instruction on how to fill each section is available at: http://environment.alberta.ca/02275.html* *A monitoring plan is required as part of the project plan. The monitoring plan includes information on: the measured parameters required for calculating the emission reduction or removals; methods and procedures on making measurement, specifications for monitoring equipment to be used, locations of sampling points, frequency of sampling events, data collection methodology, and other details.*
Incentives for APG reduction or use	*Meeting compliance targets under SGER*
Costs	*There are admin costs associated with the offset scheme (e.g. registration fee)* *Costs of implementation are project-specific.* *Yet, the Protocol acknowledges that projects will be small sites and that a number of sites will need be aggregated to create projects of sufficient volume to support verification, registration and transaction costs..*

<table>
<tr><th>Name of regulatory Scheme</th><th>Alberta’s Offset Scheme
Quantification Protocol For Solution Gas[43] Conservation</th></tr>
<tr><td>Control system</td><td>A percentage of facility compliance submissions is audited by Alberta’s authorities annually. As part of this auditing exercise, a percentage of offset credits submitted by facilities as compliance options are also audited, so that facility’s compliance with the SGER is checked.
See the “Control system” section in the summary table for SGER for details on auditing process.



Also, auditors are required to use one of the following three audit methodologies consistent with verification methodology requirements:
ISO 14064 Part 3 – Greenhouse Gases: Specification with guidance for the validation and verification of greenhouse gas assertions
Standards for Assurance Engagements, Canadian Institute of Chartered Accountants (CICA) Handbook – Assurance Section 5025
International Standard on Assurance Engagements (ISAE) 3000 – Assurance Engagements Other Than Audits or Reviews of Historical Financial Information.
If discrepancies are identified during the audit, then Alberta’s authorities work with a project developer to address these. The “Technical Guidance for Offset Credit Providers” describes the specific process with associated timeline.
If discrepancies are not met, then the affected offsets (the serial number range in which the problem occurred) are rectified as follows:
If unpurchased offset tonnes exist, correction may first be taken from unpurchased tonnes held by the project developer. In this situation, the project developer will be required to initiate transfer of ownership to the affected facilities, and request retirement of the credits required to replace revoked credits.
If all credits from the project have been sold, Alberta Environment and Water will accept unretired offset credits to replace the revoked credits if it can be demonstrated that the replacement credits were verified, serialized and owned by the facility at the March 31 compliance deadline.
If all credits have been retired and submitted for compliance, facilities will be required to make a payment into the Climate Change and Emissions Management Fund at the rate applicable at the compliance deadline.</td></tr>
<tr><td>Consequences of non-compliance</td><td>Providing false or misleading information will result in actions taken by Alberta’s authorities, which can include but are not limited to revoking all offset credits associated with the affected offset project. Companies that have submitted revoked credits will be required to seek alternate compliance through payment into the Climate Change and Emissions Management Fund.</td></tr>
<tr><td>Methodology</td><td></td></tr>
<tr><td>Estimation approach</td><td>The scheme allows for 8-year crediting period, with a possible 5-year extension for most project types, excepting soil sequestration projects, which may have a longer credit duration period.</td></tr>
</table>

Name of regulatory Scheme	***Alberta's Offset Scheme*** ***Quantification Protocol For Solution Gas[43] Conservation***
	The Protocol requires to quantify reductions achieved by the project to be based on actual measurement and monitoring and must be done in accordance with the Energy Resources Conservation Board Directive 017: Measurement Requirements for Upstream Oil and Gas Operations[44].Details of measurement and monitoring requirements for volumes of solution gas are described in the summary table for Alberta's Directive 060. *The Protocol excludes sources that are not expected to change between baseline and project condition from quantification of emission reductions. Assumption being that excluded activities will occur at the same magnitude and emission rate during the baseline and project and so will not be impacted by the project.* *As described in "Boundaries" below under Monitoring, out of identified baseline and project sinks and sources, the following are included in the quantification of emission reductions:* ▪ *Solution Gas Capture (baseline) - The compressor and dehydration systems may be fuelled by fossil fuels; these additional greenhouse gas emissions are incremental to the project. Quantities and types for each of the energy inputs may need to be tracked.* ▪ *Thermal Energy Production (baseline) - The production of thermal energy may be required to meet the demands of facilities being provided with thermal energy from the project site. This thermal energy may have been derived from waste heat recovery systems resulting in an energy burden on the systems from which the heat is being recovered or directly from combustion of fossil fuels. Energy requirements, fuel volumes and fuel types will need to be tracked.* ▪ *Electricity Production (baseline) - Electricity may be produced off-site to match the electricity being produced by the energy from the solution gas net of parasitic loads. This electricity will be produced at emissions intensity as deemed appropriate by the Program Authority. Measurement of the gross quantity of electricity produced by the facility will need to be tracked to quantify this source. The gross quantity of electricity produced should be net of any electricity sold as Renewable Energy Credits (RECs) as defined by the Environmental Choice Program.* ▪ *Solution Gas Capture /Processing (project) - A processing system may be required to refine the solution gas prior to injection into a natural gas pipeline. The compressor, processing equipment and dehydration systems may be fuelled by fossil fuels; these additional greenhouse gas emissions are incremental to the project. Quantities and types for each of the energy inputs may need to be tracked.* ▪ *On-Site Thermal Energy/Electricity Production (project) - Captured solution gas may be used to generate on-site thermal energy and/or electricity. The quantity of solution gas or other fuel types used must be tracked.* ▪ *Solution Gas Venting (baseline and project) – under baseline this is a direct release of solution gas to the atmosphere post capture. Under the*

[44] Available at: http://www.ercb.ca/docs/documents/directives/Directive017.pdf.

Name of regulatory Scheme	***Alberta's Offset Scheme*** ***Quantification Protocol For Solution Gas[43] Conservation***
	project non-routine venting of solution gas may occur during compressor maintenance or other scenarios. The quantity and characteristics of the vented solution gas would need to be tracked in both cases. ▪ *Fuel Extraction / Processing (baseline and project) - Each of the fuels used throughout the on-site component of the project will need to be sourced and processed. The total volumes of fuel for each of the on-site sources/sinks are considered. Volumes and types of fuels are the important characteristics to be tracked in both cases.* *Emission reductions (ERs) are calculated by deducting project emissions (Emissions $_{Project}$) from baseline emissions (Emissions $_{Baseline}$):* *ERs = Emissions $_{Baseline}$ – Emissions $_{Project}$* ***Baseline emissions** (Emissions $_{Baseline}$)* *Baseline emissions are the sum of emissions from baseline sources as described above:* *Emissions $_{Baseline}$ = Emissions $_{Solution\ Gas\ Capture}$ +Emissions $_{Solution\ Gas\ Venting}$ + Emissions $_{Fuel\ Extraction\ and\ Processing}$ + Emissions $_{Thermal\ Energy\ Production}$ + Emissions $_{Electricity\ Production}$* ***Project emissions** (Emissions $_{Project}$)* *Project emissions are the sum of emissions from project sources as described above:* *Emissions $_{Project}$ = Emissions $_{Solution\ Gas\ Venting}$ + Emissions $_{Solution\ Gas\ Capture/Processing}$ + Emissions $_{Fuel\ Extraction\ /\ Processing}$ + Emissions $_{On\text{-}Site\ Thermal\ Energy/Electricity\ Production}$* *For each component in these equations, a separate calculation formula is provided.*
Gases included in the reporting	*The same as under SGER: CO_2, CH_4, N_2O, HFC, PFC, and SF_6.* *Protocol-specific: CO_2, CH_4, N_2O*
Treatment of missing data	*The Protocol does not directly prescribe how to address unavailability of data.* *It relies on project company's internal procedures, as well as on the monitoring plan specifically developed and implemented for the purpose of a project.* *It is an obligation of project proponents to ensure that equipment is properly maintained and calibrated, as based on measurements emission reductions are calculated.* *The Protocol provides contingent means for calculating or estimating the required data for the emission reduction equations.*
Calculation update frequency	*Emission reductions are calculated on an annual basis.* *Note: verification can take place in longer intervals.*
Methodological changes	*Protocols are reviewed at a maximum every 5 years, or sooner as deemed needed by authorities to ensure protocols continue to reflect best available science and quantification methodologies. If a protocol changes, but the project was already initiated, then project developers may continue to implement, quantify, monitor and verify the project against the previous version of the protocol.*

Name of regulatory Scheme	***Alberta's Offset Scheme*** ***Quantification Protocol For Solution Gas[43] Conservation***
Consistency with international standards	*The scheme uses the ISO 14064-2 platform for establishing and quantifying greenhouse gas reduction projects.*
Levels of accuracy (sources of data)	*Measurements are the preferred source of data.*
Sources for emission factors	*Protocol-specific.* *The Protocol on solution gas conservation provides a degree of flexibility, i.e. project proponents may use generic emission factors indicated in the Protocol instead of site-specific emission factors. However, if site-specific factors are to be used, the approach used to develop these factors must comply with Directive 017 methodology in order to ensure a reasonable level of accuracy.* *The values of generic emission factors are taken from Environment Canada reference documents, and adjusted annually as part of Environment Canada's emissions inventory.*
Any tools provided?	*The following are publicly available:* ▪ *Technical Guidance for Protocol Developers* ▪ *Guidance for developing custom coefficients* ▪ *Additional guidance for tillage management systems* ▪ *Offset project template* ▪ *Technical Guidance for Offset Project Developers* *All these can be found at: http://environment.alberta.ca/02275.html* *The Protocol includes the following references:* ▪ *ERCB Directive 007: Volumetric and Infrastructure Requirements, September 2011* ▪ *ERCB Directive 017: Measurement Requirements for Oil and Gas Operations (April 2011)* ▪ *ERCB Directive 060: Upstream Petroleum Industry Flaring, Incinerating, and Venting (November 2011)* ▪ *International Standards Organization ISO 14064 -2:2006 Specification with Guidance at the 21 Project Level for Quantification, Monitoring and Reporting of GHG Emission Reductions or 22 Removal Enhancements*
Uncertainty Treatment	*The guidance document on an offset project states that:* ▪ *The accuracy of the project calculations varies depending on the methodology being used.* ▪ *Accuracy associated with quantification methodologies is assessed during protocol development.* ▪ *Project developers must address the uncertainty in the project calculations to ensure that emission reductions being calculated represent actual emission reductions.* *No specific instructions on uncertainty treatment are given in the Protocol.*
Quality Assurance	*Protocols and offset projects are required to be developed and implemented according to ISO 14064-2.* *Alberta's authorities reserve the right to review offset credits submitted for compliance and, as such, can request a supplemental government audit on one or more offset projects where credits have been used as a compliance option.*

Name of regulatory Scheme	***Alberta's Offset Scheme*** ***Quantification Protocol For Solution Gas[43] Conservation***
	Note: under the Alberta's offset scheme, validation is optional. For project proponents that wish to pursue validation, they should refer to ISO 14064 and guidance available from the Climate Change and Emissions Management Corporation at www.ccemc.ca. *Under the scheme, there is no negligible emissions limit set for offset projects. Negligible emissions are emission sources that are extremely small (on the order of tonnes per year) that are difficult to quantify and unlikely to change over time. Emission sources, regardless of size, that are integral to the offset project quantification cannot be excluded. Project developers are requested to identify negligible emissions in the offset project plan, and reassess these emission sources periodically to make sure the assumptions made in the project plan remain valid.* *Material errors that result in an overstatement in credits may result in the project and all associated offset credits being revoked from the registry. The Alberta Emissions Offset Registry will be up-dated to reflect the status the changes in the offset project.* *For Quality assurance/quality control (QA/QC), the Protocol suggests to project developers to include:* ▪ *Ensuring that the changes to operational procedures continue to function as planned and achieve greenhouse gas reductions* ▪ *Ensuring that the measurement and calculation system and greenhouse gas reduction reporting remains in place and accurate* ▪ *Checking the validity of all data before it is processed, including emission factors, static factors, and acquired data* ▪ *Performing recalculations of quantification procedures to reduce the possibility of mathematical errors* ▪ *Storing the data in its raw form so it can be retrieved for verification* ▪ *Protecting records of data and documentation by keeping both a hard and soft copy of all documents* ▪ *Recording and explaining any adjustment made to raw data in the associated report and files.* ▪ *A contingency plan for potential data loss.*
Monitoring	
Boundaries	*Protocol-specific.* *The Protocol identifies a number of baseline sinks and sources (upstream, onsite and downstream), and groups them into controlled, related and affected ones[45]. Similarly, the Protocol prescribes project sinks and sources. For each a flow diagram is provided.*
Frequency	*Frequencies are parameter-specific:* *Volumes of each fuel type – continuous metering or monthly reconciliation* *Volumes of solution gas – measured continuously* *Methane composition of fuel gas – annual sampling*
Methodology	*Protocol-specific.* *For the solution gas conservation project: Project and baseline measurements must be from direct metering of the conserved solution gas*

[45] **Controlled:** The behaviour or operation of a controlled source and/or sink is under the direction and influence of a Project Developer through financial, policy, management, or other instruments. **Related:** A related source and/or sink has material and/or energy flows into, out of, or within a project but is not under the reasonable control of the project developer. **Affected:** An affected source and/or sink is influenced by the project activity through changes in market demand or supply for projects or services associated with the project.

Name of regulatory Scheme	***Alberta's Offset Scheme*** ***Quantification Protocol For Solution Gas[43] Conservation***
	supported by periodic gas analyses following the requirements of Directive 017.
Use of standards	*The Protocol itself does not refer to any standards for measurements/monitoring. Yet, it refers to Directive 017.*
Uncertainty treatment	*Measurements/monitoring needs to be taken in accordance with Directive 017.* *The confidence level is 95%.The Directive specifies uncertainty levels associated with measurement devices, device calibration, sample gathering and analysis, variable operating conditions, etc.*
Quality assurance	*The offset scheme encourages project proponents to introduce data management system (manual, automated, or combination of two), including data controls.* *Project proponents need to include data flow charts and sample calculations in the offset project plan and to make supporting records available to the third party verifier/government auditor as part of the project documentation.* *The Solution Gas Conservation Protocol prescribes that data quality management must be of sufficient quality to fulfil the quantification requirements and be substantiated by company records for the purpose of verification. Also, The project developer must establish and apply quality assurance and quality controls (QA/QC) management procedures to manage project data and information. Written procedures must be established for each measurement task outlining responsibility, timing and record location requirements.*
Reporting	
Scope	*The offset project report includes:* ▪ *The time period covered by the report;* ▪ *Project details and information demonstrating how the project was implemented relative to the project plan ad approved quantification protocol;* ▪ *Any changes in details and/or implementation of the project that arose during the reporting period. The third party verifiers will verify changes against the project plan to support the project review;* ▪ *Calculation methodology for greenhouse gas reductions and removals in tonnes CO_{2e} with clearly identified inputs, emission factors, equations and methodologies used and a sample calculations;* ▪ *Quantified emissions reductions clearly articulated as tonnes removed or reduced per vintage year; and* ▪ *Be signed by the project developer(s).* *The report is subject to verification, and is necessary for registering the project under the Scheme.*
Frequency	*Annual or prior to verification*
Form (reporting format)	*The project report template is available at: http://environment.alberta.ca/03323.html*
System transparency (public database, information disclosed)	*The Alberta's scheme favours full transparency on offset project documentation including the offset project plan, offset project report, greenhouse gas assertion, and verification report including the signed conflict of interest, statement of verification, and statement of qualifications.* *If a project is required to make corrections, the original documentation and the revised documentation, including rational for the change, will be displayed on the registry. Removed and revoked serial ranges will also be displayed to maintain full transparency of the offset credits.*
Verification requirements	
Process	*The process is the same as under SGER.* *Frequency of verification is specified in the offset project plan - this could be annual or at longer intervals up to the maximum credit duration period*

Name of regulatory Scheme	***Alberta's Offset Scheme*** ***Quantification Protocol For Solution Gas[43] Conservation***
	set as 8-years for most project types. *Also, the verification report has to undergo peer review prior to being finalized. The peer reviewer must have relevant audit and technical expertise and cannot be the same person as the lead verifier. The peer reviewer may also be the signing authority for the verification report.*
Methodology	*The same standards as for SGER.* *Additional guidance is found in:* ▪ *Climate Change and Emissions Management Act* ▪ *Specified Gas Emitters Regulation* ▪ *Guidance for Third Party Verifiers* ▪ *Government approved Offset Quantification protocol (see http://environment.alberta.ca/1238.html for a complete list)* ▪ *Technical Guidance for Offset Project Developers* *Material errors are errors over 5% on an individual or aggregated basis. The magnitudes of the errors, both positive and negative, are summed to determine the total project error. Immaterial errors are assessed on a case-by-case basis to understand their impact on the overall project and determine appropriate corrective actions.* *Errors can be further broken into quantitative and qualitative errors. Within the latter group, materiality assessment is based on a Verifier's judgement.*
Assurance requirements	*As of January 2012, reasonable level of assurance will be required.* *An original statement of qualification (SoQ), statement of verification, and conflict of interest to the project developer need to be provided as part of the verification report.* *Third party verifiers cannot issue a verification finding for projects with incomplete or missing raw data and/or supporting information.*
Avoiding double counting	*The offsets are serialized and registered in the scheme's registry. Any transfer of ownership of credits is tracked by the registry. When an offset is used for compliance, it is retired from the registry and removed from circulation.* *As of January 1, 2012, offset projects can no longer claim credits for greenhouse gas reductions that occurred historically (prior to project creation on the registry).* *Also, offset project developers are required to complete and submit a statutory declaration as part of the project registration on the Alberta Emissions Offset Registry. This document is a legally binding assertion stating that all offset credits being serialized for the project have only been listed on the Alberta Emissions Offset Registry and have not been registered in any other offset system.*
Third party	*The same as for SGER.*

Name of regulatory Scheme	***Alberta's Offset Scheme*** ***Quantification Protocol For Solution Gas[43] Conservation***
Other requirements	
Retention of information	*Supporting information for the project including all raw data should be maintained for a period of 7 years after the end of the project credit duration period.* *The Protocol provides record keeping requirements:* ▪ *Raw baseline period data, independent variable data, and static factors within the measurement boundary* ▪ *A record of all adjustments made to raw baseline data with justifications* ▪ *All analysis of baseline data used to create mathematical model(s)* ▪ *All data and analysis used to support estimates and factors used for quantification* ▪ *Expected end of life date of equipment removed or renovated under the project* ▪ *Common practices relating to possible greenhouse gas reduction scenarios discussed in this protocol* ▪ *Metering equipment specifications (model number, serial number, manufacturer's calibration procedures)* ▪ *A record of changes in static factors along with all calculations for non-routine adjustments* ▪ *All calculations of greenhouse gas emissions/reductions and emission factors* ▪ *Measurement equipment maintenance activity logs* ▪ *Measurement equipment calibration records* ▪ *Initial and annual verification records and audit results* *Furthermore,* ▪ *All records must be kept in areas that are easily located;* ▪ *All records must be legible, dated and revised as needed;* ▪ *All records must be maintained in an orderly manner;* ▪ *All documents must be retained for 7 years after the project crediting period;* ▪ *Electronic and paper documentation are both satisfactory; and* ▪ *Copies of records should be stored in two locations to prevent loss of data.*
Additionality	*Additionality for a reduction/removal activity is typically assessed during protocol development and is reassessed periodically during the protocol review. Therefore, the project proponents do not need to perform a separate additionality demonstration on top of protocol's applicability criteria.*

Specified Gas Emitters Regulation

Name of regulatory Scheme	***Greenhouse Gas Reduction Program (Specified Gas Emitters Regulation)***
General characteristics	
Objectives of regulation	*The Specified Gas Emitters Regulation is to help Alberta in delivering on the current Alberta climate change action plan.*
Country / language	*Canada (Alberta) / English*
Web site	*http://environment.alberta.ca/01838.html*
Implementation/enforcement entity	*Alberta Environment and Sustainable Resource Development Ministry*

Name of regulatory Scheme	*Greenhouse Gas Reduction Program (Specified Gas Emitters Regulation)*
Targeted sector(s)	*Large industrial facilities that emit more than 100,000 tonnes of greenhouse gases a year.* *Sectors covered include (but are not limited to): Chemicals; Forest Products; Fertilizer; Gas Plants; Heavy Oil; Landfills; Minerals (including cement, lime and metals manufacturing sectors); Oil Sands; Petroleum Refining; Power Plants.*
Reduction target	*Reduction of emissions intensity (i.e. total annual greenhouse gas emissions by the total annual production) by 12% compared to a baseline. This target is referred as Net Emissions Intensity Limit (NEIL) and is facility-specific.* *Baseline for established facilities: average intensity of 2003-2005* *Baseline for new facilities: based on the third year of commercial operation* *Baseline for in-situ Oil Sands Extraction facilities: based on multi-year baselines*[46] *Baseline for cogeneration: two baseline intensities are established; one for electricity produced by the cogen and one for the other products of the plant (e.g. heat).* *Note: It is possible to agree on an alternate baseline if a "standard" one does not represent normal operations, as for example temporary shutdown or operation below capacity took place. Also, it is possible to re-establish a facility baseline if changes in methodology or operations (expansion, decommissioning etc) occurred.*
Compliance	
Installation types and thresholds	*Established industrial facilities which completed their first year of commercial operation before January 1, 2000, or have completed eight years of commercial operation.* *If facility's Total Direct Emissions (TDE), including biomass and industrial process emissions, were equal to or greater than 100,000 tonnes CO2e in any single calendar year starting in 2003, then it is subject to Regulation. Facilities that have exceeded the reporting threshold must submit a Baseline Emissions Intensity Application by June 1 of the year following the year they exceeded the compliance threshold.* *If TDE are higher than 50,000 tCO_{2e}, a facility is subject to Specified Gas Reporting Regulation*[47]*. These facilities have to submit annual reports on their emissions but do not need to comply with specific target.*
Options for compliance	*A number of documents should be submitted together with the facility's baseline application:* ▪ *Third Party verified Baseline Emissions Intensity Application form (Electronic),* ▪ *Third Party Verifier's Report (Electronic),* ▪ *Simplified process flow diagram,* ▪ *The signed Conflict-of-Interest Checklist,*

[46] Note: In the fourth year of commercial operations, the baseline emissions intensity is calculated based on the facility's third year of commercial operations. In the fifth year, the baseline is calculated based on the third and fourth years. In the sixth year and beyond, the baseline is calculated based on the third, fourth and fifth years. All averaging of multi-year baselines will be on a production basis rather than a time basis. Calculation of multi-year baselines is automatically completed by Alberta Environment using the information submitted in compliance reports (as per *Technical Guidance for Completing Specified Gas Baseline Emission Intensity Applications*, 2010).

[47] Source: http://environment.alberta.ca/02166.html

Name of regulatory Scheme	*Greenhouse Gas Reduction Program (Specified Gas Emitters Regulation)*
	▪ The signed Statement of Certification form, *▪ The signed Statement of Qualification form,* *▪ The signed Statement of Verification form, and* *▪ If required, a signed Confidentiality Request and supporting documentation* *Furthermore, the Reporter is encouraged to attach additional supporting documents including detailed emissions calculations, supporting data, emissions calculation methodologies, etc. with their application, so that the authority can understand the application.* *A facility subject to the Emitters Regulation may utilize the following compliance tools:* *1. Make improvements in its operations* *2. Contribute to Climate Change and Emissions Management Fund: Pay $15 per tonne of CO_{2e}, (Fund Credits) to meet reduction requirements.* *3. Purchase Alberta based offsets generated from projects by facilities not subject to the Regulation. The offsets must be from Alberta-based projects which occurred after January 1, 2002.* *4. Purchase Emissions Performance Credits (EPCs) from a different Alberta facility. EPCs are generated by facilities that exceeded their 12% mandatory intensity target. EPCs can be banked for future use or sold to other facilities that need to meet the reduction target.*
Exclusions	*Emissions linked to district energy are exempted from the Regulation. They are defined as:* *"District energy is the direct provision of non-industrial heating or cooling to multiple buildings from a central plant(s) through a distribution network. Multiple heating or cooling sources will be considered part of the same district energy system if they serve a common distribution network."*
Treatment of new entrants	*New facilities are those that completed the first year of commercial operation on December 31, 2000 or a subsequent year and have completed less than eight years of commercial operation.* *They are required to reduce emissions starting with the fourth year of commercial operation by 2%, and then by 2% every year after, until the 12% reduction target has been achieved.*
Monitoring plan or flare/vent management plant	*Monitoring approach is part of the baseline application*
Incentives for APG reduction or use	*Flaring/Venting is only part of emissions subject to reporting and compliance.* *An incentive for a facility to implement improvements in its internal operations (e.g. reduction of Flaring/venting) is to reduce the cost of paying for offset credits, Emissions Performance Credits or into the Climate Change and Emissions Management Fund – see "Options for compliance" above.*
Costs	*Facility-specific* *Also, depending on the compliance option(s) chosen by a facility – see "Options for compliance" above*
Control system	*The enforcement authority audits approximately 10% of baseline emissions intensity applications annually. These audits are to check the accuracy of the reported information and to identify anomalies.* *The following criteria are applied to choose facilities for auditing:* *▪ Coverage across sectors;* *▪ A range of facility sizes and complexity;* *▪ New and established facilities;* *▪ A cross-section of verifiers hired to review third party submissions;* *▪ Anomalies or issues encountered during the desktop review; and*

Name of regulatory Scheme	*Greenhouse Gas Reduction Program (Specified Gas Emitters Regulation)*
	▪ *Random selection.* *Based on the criteria above, it is possible that some facilities are audited more than once or be audited several times in succession.* *The audit process is similar to third-party verification process, with a few key differences. The steps are:* *1. Selection of facilities for auditing* *2. Issuance of request for proposal to select auditors* *3. Checking Conflict of Interest between auditors and facilities to be audited* *4. Issuance written notice to facilities informing about an audit and auditing team* *5. Undertaking an audit (site visit is encouraged)* *6. Submission of an audit report to the enforcement authority* *7. Review of audit finding by the enforcement authority and determination of next steps.* *The same materiality threshold for audits is required as for third party verification. Auditors must assess both quantitative and qualitative errors associated with a baseline application; and are required to identify in the Audit Report all material and immaterial errors discovered during the audit.* *Material errors exceeding 5% on an individual or aggregated basis must be corrected in the same period. Generally, material errors need to go through re-verification by a Third Party Verifier, and a corrected baseline application must be re-submitted. Immaterial errors are assessed on a case-by case basis.* *All audits are required to be performed to at least a limited level of assurance. Yet, some audits may be requested to be performed to a more rigorous reasonable level of assurance; provided facilities demonstrate sufficient data management, quality assurance, and access to information to support such reasonable assurance.*
Consequences of non-compliance	*The Climate Change and Emissions Management Act (Sections 44 and 45) governs consequences for providing false or misleading information. These can include even imprisonment.* *Furthermore, the Specified Gas Reporting Regulation specifies that for lack of report's submitting; incomplete reporting and/or wrong emission calculations (not in compliance with the Specified Gas Reporting Standard) the following fines will apply:* *(i) not more than $50 000, in the case of an individual, and* *(ii) not more than $500 000, in the case of a corporation.*

Name of regulatory Scheme	*Greenhouse Gas Reduction Program (Specified Gas Emitters Regulation)*
Methodology	
Estimation approach	*For determination of threshold (Total Direct Emissions), the Regulation requires using the following formula:* $$Total\ Emissions = \sum_{i=1}^{n}(E_{CO_2 i} \times GWP_{CO_2}) + \sum_{i=1}^{n}(E_{CH_4 i} \times GWP_{CH_4}) + \sum_{i=1}^{n}(E_{N_2O i} \times GWP_{N_2O}) + \sum_{v=1}^{m}(E_{PFC_v} \times GWP_{PFC_v}) + \sum_{v=1}^{m}(E_{HFC_v} \times GWP_{HFC_v}) + (E_{SF_6} \times GWP_{SF_6})$$ *Where:* *"i" is a particular source category;* *"v" is a particular PFC or HFC species;* *"n" is the number of source categories;* *"m" is the number of species;* *E_{CO2} is the direct emissions of CO_2, in the calendar year, measured in tonnes for each source category; (Note: CO_2 emissions from the combustion of biomass and CO_2 emissions from decomposition of biomass are included in determining whether the facility exceeded the 100,000 tonne CO_{2e} threshold but are not included in the calculation of the Baseline Emissions Intensity (BEI) for the facility).* *GWP_{CO2} is the global warming potential of CO_2=1;* *E_{CH4} is the direct emissions of CH_4 in the calendar year, measured in tonnes for each source category;* *GWP_{CH4} is the global warming potential of CH_4 =21;* *E_{N2O} is the direct emissions of N_2O in the calendar year, measured in tonnes for each source category;* *GWP_{N2O} is the global warming potential of N_2O =310;* *E_{PFC} is the total of industrial process emissions and industrial product use emissions restricted to PFC species, in the calendar year, measured in tonnes;* *GWP_{PFC} is the global warming potential of PFC species as set out in the Regulation.* *E_{HFC} is the total of industrial process emissions and industrial product use emissions restricted to HFC species, in the calendar year, measured in tonnes;* *GWP_{HFC} is the global warming potential of HFC species listed in the Regulation* *E_{SF6} is the total of industrial process emissions and industrial product use emissions restricted to SF_6, in the calendar year, measured in tonnes;* *GWP_{SF6} is the global warming potential of SF_6 =23900* *There are several measurement and calculation options available for the different categories of emission sources. Each has an associated level of accuracy depending on the measured parameter data (e.g., fuel consumption) and the calculation method (e.g., mole balance) – see "Levels of accuracy (sources of data)" below.* *Description of calculation approaches allowed by calculation:*

Name of regulatory Scheme	*Greenhouse Gas Reduction Program (Specified Gas Emitters Regulation)*

- *Mole balance with efficiency factors determines an emission factor based on the mole balance of carbon between the input and the output of a source, with some assumed efficiency factor.*
- *Equipment-specific emission factors are determined based on the measurement of the input and output of the equipment at an operating condition similar to normal operations.*
- *Manufacturer's emission factors are determined based on manufacturer testing.*
- *Models based on surrogate parameters can derive emission factors based on scientific models that do not have a parameter directly related to the emission (e.g. soil surface temperature and methane emissions from a coal pile).*
- *Generic emission factors based on a sample of equipment.*
- *Top-down emission factors based on the aggregate numbers averaged over a large population.*

The Regulation specifies which Emission Calculation methods[48] are acceptable for each source category:

Reference	Method	Stationary Fuel Combustion	Industrial Process	Fugitive	Biomass Combustion	Other (incl. Flaring and Venting, Mobile)
1	EC Sector-Specific Guidance	✓	✓			✓
2	CAPP 2005	✓	✓	✓		✓
3	CAPP 2003	✓	✓	✓		
4	CAPP 1999	✓	✓			
5	SGA 2000	✓				
6	CSA 2007	✓		✓	✓	✓
7	ICFPA 2005a	✓	✓		✓	✓
8	ICFPA 2005b	✓	✓		✓	✓
9	US EPA AP 42	✓				
10	API 2004	✓	✓	✓		✓
11	GRI-GLYCalc			✓		
12	GHG Protocol	✓	✓		✓	✓

The Regulation provides specific guidance on calculating emissions from cogeneration.

[48] Acronyms: CAPP – EC – Environment Canada; Canadian Association of Petroleum Producers; SGA – SGA Energy Limited; CSA – Canada Standards Association; ICFPA - the International Council of Forest and Paper Associations; US EPA - United States Protection Agency; API - American Petroleum Institute; GRI-GLYCalc software by Gas Technology Institute; GHG Protocol by World Business Council for Sustainable Development (WBCSD)/World Resources Institute (WRI).

Name of regulatory Scheme	***Greenhouse Gas Reduction Program (Specified Gas Emitters Regulation)***
Gases included in the reporting	*CO_{2e} being the sum of direct emissions of carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFC), perfluorocarbons (PFC), and sulphur hexafluoride (SF_6).* *CO_{2e} emissions must be disaggregated and reported according to source categories.* *Note: emissions from some source categories are excluded from calculating baseline threshold (Total Direct Emissions) and/or determining baseline (Total Annual Emissions) – see "Scope" under Reporting below for details.*
Treatment of missing data	*Not addressed in the Regulation.* *Likely it is specific to Emission Calculation method applied (see the table in "Estimation approach" above)*
Calculation update frequency	*Baseline calculation remains unchanged, unless changes in the methodology and operations occurred.* *Emissions are to be calculated each year for the compliance report.*
Methodological changes	*A methodology has to be consistent between baseline and compliance cycles. If new methodologies become available, or if the facility implements changes that require updating its methodology, the facility is requested to inform the authorities and discuss the impacts of the methodology on the approved baseline. Any changes in methodology are subject to approval and the baseline must be restated before the methodology can be used in compliance reports.* *A methodology can change due to major modifications (e.g. instalment or replacement of equipment to broaden the capacity and suite of products produced at the facility); phased expansion; and decommissioning.*
Consistency with international standards	*A number of recognized emission estimation methods is allowed by the Regulation. See "Estimation approach" above.*
Levels of accuracy (sources of data)	*Below, the table presents emission estimation methodologies and associated level of accuracy:*

Measured Data	Accuracy*	Calculation
Monitoring or direct measurement	Most	Mole balance with efficiency factors
Intermittent (periodic) direct measurement		Equipment-specific emission factors
Calculated based on measured surrogate parameters		Manufacturer's emission factors
Extrapolated from historical data		Models based on surrogate parameters
Estimated from design requirements		Generic emission factors
Estimated from agreements	Least	Top-down emission factors

** Enforcement authorities do not support measured data or emissions calculations that fall below the black line for the respective categories unless*

Name of regulatory Scheme	***Greenhouse Gas Reduction Program (Specified Gas Emitters Regulation)***
	it can be demonstrated that this level of accuracy will not materially affect the facility's submission.
Sources for emission factors	*See "Levels of accuracy (sources of data)" above*
Any tools provided?	*There are following guidance documents available for industry:* ▪ *Technical Guidance for Completing Baseline Emissions Intensity Application* ▪ *Draft Baseline Verification Templates* ▪ *Technical Guidance for Completing Specified Gas Compliance Reports* ▪ *Guidance for Landfill Emissions Quantification*
Uncertainty Treatment	*Specific to method applied (see "Estimation approach" above for methods allowed under the Regulation)*
Quality Assurance	*Baseline application is subject to third-party verification as well as auditing by the enforcement authority.*
Monitoring	
Boundaries	*Facility-specific* *A facility is required to provide a description of its boundaries and operations. This should include general information about what the boundaries of the facility are, operations and activities included at the facility, if something is excluded (i.e. power plant - coal from a mine and the emissions associated with the mine are reported by the mine not the power plant) and any other relevant boundary or operational information.*
Frequency	*The Regulation does not directly prescribe monitoring frequency.* *Yet, it considers monitoring and direct measurement of data using Continuous Emissions Monitoring Systems the most accurate and preferred approach.*
Methodology	*<u>Description of measurement approaches allowed by the Regulation:</u>* ▪ *Monitoring or direct measurement uses Continuous Emissions Monitoring Systems (CEMS). Where greenhouse gases are directly measured, a calculation methodology does not need to be specified.* ▪ *Intermittent (periodic) direct measurements use source (stack) testing, which is a "snapshot measurement in time". Several measurements are taken periodically over the year, and each measurement is extrapolated over a period of time to determine emission values for that period of time. Intermittent (periodic) direct measurement is only considered acceptable if the frequency of measurement is sufficient to quantify all emissions sources in the category and reflect variability in the emission source better than alternative methods.* ▪ *Calculated based on surrogate measures uses correlations developed between measured emission rates and related parameters. This is the most common form of measurement (e.g., fuel consumption).* ▪ *Extrapolation from historic data uses past information to determine current operating conditions (e.g., runtime and loads).* ▪ *Estimates from design requirements uses design information and facility configuration to determine likely values (e.g., power requirements for equipment determine fuel consumption).* ▪ *Estimates from agreements use contractual arrangements to provide a product or service to determine likely values (e.g. power supplied, fuel delivered).* *The level of accuracy grows from the bottom to top in above list (see "Levels of accuracy (sources of data" above).*
Use of standards	*Not specified*

Name of regulatory Scheme	Greenhouse Gas Reduction Program (Specified Gas Emitters Regulation)
Uncertainty treatment	*Not addressed in the Regulation.* *Likely it is specific to Emission Calculation method applied (see the table in "Estimation approach" above)*
Quality assurance	*Not directly addressed by the Regulation; but a baseline application is subject to third-party verification as well as auditing by the enforcement authority.*
Reporting	
Scope	*The Baseline Application should include the following sections:* *Section A: Administrative Information* *Section B: Emissions, Production and Intensity Information* *Section C: Calculation Methods* *Section D: Cogeneration Information* *Section E: Baseline Calculation* *Section F: Additional Comments* *Section G: Third Party Verifier Information* *Submission of Information* *Submission Checklist* *Conflict-of-Interest Checklist* *Statement of Qualification* *Statement of Verification* *Statement of Certification* *Below table presents emissions reporting requirements under the Regulation (source: Technical Guidance for Completing Specified Gas Baseline Emission Intensity Applications, 2010):*

Name of regulatory Scheme	*Greenhouse Gas Reduction Program (Specified Gas Emitters Regulation)*

Source Category	Specified Gas	Reported	Threshold (TDE)	Baseline (TAE)
Stationary Fuel Combustion (Includes CH_4 and N_2O emissions from the combustion of biomass)	CO_2, CH_4, N_2O	✓	✓	✓
Industrial Process	All	✓	✓	×
Venting (Does not include Formation CO2)	CO_2, CH_4, N_2O	✓	✓	✓
Flaring (Does not include flaring of landfill gas)	CO_2, CH_4, N_2O	✓	✓	✓
Other Fugitive	CO_2, CH_4, N_2O	✓	✓	✓
Formation CO_2	CO_2	✓	✓	✓
Waste and Wastewater (Includes emissions from incineration of non-biomass waste and CH_4 & N_2O emissions from decomposition of waste and CH_4 & N_2O emissions from flaring of landfill gas)	CO_2, CH_4, N_2O	✓	✓	✓
On-site Transportation	CO_2, CH_4, N_2O	✓	✓	✓
CO_2 Emissions from the Combustion of Biomass (Includes CO_2 emissions from combustion of biomass, incineration of waste biomass and flaring of landfill gas)	CO_2	✓	✓	×
CO_2 Emissions from the Decomposition of Biomass	CO_2	✓	✓	×
CO2 related to capture and storage activities	CO_2	✓	×	×

All sources of HFCs, PFCs, and SF6 associated with facility production have to be calculated and reported in the facility's threshold calculation and baseline emissions calculations. Yet, these emissions associated with emergency equipment and such sources as office fridges and building air conditioning are not directly related to production and therefore, are excluded from threshold and baseline emissions calculations.

All CO_2 emissions are reported; whereas the Total Annual Emissions (TAE), which excludes industrial process emissions and CO_2 emissions from the combustion of biomass, are automatically calculated in the reporting form.

Facilities with negligible emissions sources (i.e. total aggregate annual emissions from such sources are less than 100 toCO_{2e} per year) should report these sources and provide supporting calculations in their baseline application. If the total aggregate emissions fall below the negligible emissions threshold, emissions may be excluded in the facility's annual compliance report. Facilities are requested to check these emissions sources periodically to determine whether the emissions source remains negligible.

Name of regulatory Scheme	*Greenhouse Gas Reduction Program (Specified Gas Emitters Regulation)*
	The Regulation provides also specific reporting requirements for facilities with cogeneration.
Frequency	*Every year, by June 1*
Form (reporting format)	*Facilities report their emissions through an Electronic Data Reporting System (https://ec.ss.ec.gc.ca/).*
System transparency (public database, information disclosed)	*It is possible to request keeping certain information in the Baseline Application confidential for a period of up to five years on the basis that the information is commercial, financial, scientific or technical information that would reveal proprietary business, competitive or trade secret information about a specific facility, technology or corporate initiative. Confidentiality cannot be granted for the entire application form and cannot be given retroactively. Such request is subject to approval by the enforcement authorities.* *Anyone wishing to access baseline or compliance information that has not been deemed confidential may submit written requests for information directly to the facility. The facility must respond in writing within 30 days of receiving the request. If requested information is not provided then a person may appeal to the enforcement authority.* *Each year, results of the compliance with Regulations are published; yet they are on the aggregated (not facility) basis. The following information are provided: improvements to operations expressed in $MtCO_2$ reductions; amount of money paid into the Fund; number of Alberta-based offset credits purchased expressed in $MtCO_2$; number of Emission Performance Credits purchased expressed in $MtCO_2$; and statement on how total reductions have been calculated – see http://environment.alberta.ca/01838.html.* *In addition, under the Alberta's Greenhouse Gas Reporting Program, annual Greenhouse Gas Emissions Summary Reports are developed and published – see http://environment.alberta.ca/02166.html.*
Verification requirements	
Process	*Facility-specific verification criteria are established by the Lead Verifier prior to the site visit; and they have to be described in the Verification Report. These criteria aim to test whether the facility's baseline emission intensity application adheres to the regulatory requirements in the Regulation, that all emission sources are included and negligible emissions sources are clearly documented, that the appropriate calculations, emissions factors etc, for the emission sources are being used, and that baseline emission intensity calculations are correctly calculated with no material errors.* *Verification process covers the following:* *1. Engaging a Third Party Verifier (including completing the Conflict-of-Interest Checklist)* *2. Planning the Verification, i.e. the Verifier needs to determine:* *a. Objectives of the verification* *b. Assessment methods of the potential risks in the greenhouse gas data management system* *c. Assessment methods of the potential magnitude of any errors, omissions and misreporting* *d. Setting initial quantitative materiality level for any errors, omissions or misreporting* *e. Designing and documenting of a verification plan (which documents the terms of the engagement and the potential verification procedures) and risk-based sampling plan (which is a supporting document developed on-site after the verifiers have done an initial*

Name of regulatory Scheme	*Greenhouse Gas Reduction Program (Specified Gas Emitters Regulation)*
	assessment of the robustness of the facility's greenhouse gas emissions data and emission management systems). *f. Timeframe and schedule for the verification* *3. Conducting site visit(s) covering:* *a. Site tour, identification of GHG sources* *b. Confirm facility boundary* *c. Meet personnel* *d. Identify fuel inputs and products* *e. Identify key measurement meters* *f. Look for additional GHG sources* *g. View random samples of records* *h. Review data management system* *i. Visit on-site laboratories* *4. Reviewing documentation and supporting materials* *5. Verification Report[49] which needs to contain:* *a. the final verification plan;* *b. the final sampling plan;* *c. a complete verification schedule;* *d. names and roles of verification team members;* *e. a risk assessment;* *f. findings identifying and quantifying any material and immaterial discrepancies found; and* *g. a limited level assurance statement for the baseline application.* *6. Closing meeting* *7. If applicable, Verification for resubmissions* *Also, although Third Party Verifiers are not required to actively monitor the validity of their reports after issuance; if it is brought to their attention that previous statement is no longer accurate, they must notify the facility. The facility then must notify the relevant authorities to discuss further follow-up actions that may be required.*
Methodology	*Third Party Verifiers must use one of the following verification standards and must be able to demonstrate how they meet the qualifications for the standard being used:* ▪ *ISO 14064 Part 3 – Greenhouse Gases: Specification with guidance for the validation and verification of greenhouse gas assertions* ▪ *Standards for Assurance Engagements, Canadian Institute of Chartered Accountants (CICA) Handbook – Assurance Section 5025* ▪ *International Standard on Assurance Engagements (ISAE) 3000 - Assurance Engagements Other Than Audits or Reviews of Historical Financial Information*

[49] There is Verification Report Template Available: http://environment.alberta.ca/01091.html

<table>
<tr><th>Name of regulatory Scheme</th><th>Greenhouse Gas Reduction Program (Specified Gas Emitters Regulation)</th></tr>
<tr><td></td><td>In addition, the Regulation provides a list of documents that include additional guidance for verifiers:
▪ Climate Change and Emissions Management Act
▪ Specified Gas Emitters Regulation
▪ Technical Guidance Document for Completing the 2008 Specified Gas Compliance Reports
▪ Technical Guidance Document for Completing Baseline Emissions Intensity Applications
▪ Additional Guidance on Cogeneration Facilities
▪ Alberta Environment's guidance documents for Offsets projects (see Related Alberta Environment publications for a complete list).
▪ Technical Guidance for Quantifying Specified Gas Emissions from Landfills

Materiality levels acceptable under the Regulation are given in the table below:
<table>
<tr><th>Total Annual Emissions (ktonne CO_2e)</th><th>Materiality Threshold (% of Total Annual Emissions or Total Annual Production)</th></tr>
<tr><td>≤ 500
> 500</td><td>5
2</td></tr>
</table>

Materiality is assessed on the total magnitude of the errors, omissions or misrepresentations regardless of the combined effect of overstatements and understatements. Any errors below thresholds are considered immaterial, and even if unresolved, they do not prevent issuance of a Statement of Verification. They have to be described in the Verification Report.
On the other hand, all material discrepancies have to be resolved before the issuance of a Statement of Verification.

Errors can be further broken into quantitative and qualitative errors. Within the latter group, materiality assessment is based on a Verifier's judgement.

Moreover, the authorities consider materiality on an aggregate basis across the program. As such, although a large emission source may have a small error (below a quantitative material threshold); it in fact can result in a large, financial cost relative to total program compliance costs. In such cases, the facility is required to correct the error. In all, all immaterial errors are assessed to understand both facility and program materiality, and corrections are prescribed accordingly.</td></tr>
<tr><td>Assurance requirements</td><td>Baseline applications have to be verified to a limited level of assurance. Furthermore, there are three possible verification statements that can be issued for a limited level of verification:
▪ a limited level assurance statement
▪ a qualified limited level assurance statement - if the verifier is unable to form an opinion on certain aspects of the baseline application due to circumstances beyond the control of the Third Party Verifier or the facility.
▪ an adverse assurance statement – if there are outstanding, unresolved, and undisclosed material discrepancies.</td></tr>
</table>

Name of regulatory Scheme	*Greenhouse Gas Reduction Program (Specified Gas Emitters Regulation)*
	The Statement of Verification must be completed, printed, signed and submitted to relevant authorities and is the assurance statement for the third party verification.
Avoiding double counting	*Emission Performance Credits must be serialized through the relevant Alberta's authorities before they can be used as a compliance option and must represent real intensity reductions at the facility.*
Third party	*The lead verifier must be an accountant registered under the Alberta Regulated Accounting Profession Act, or professional engineer under the Engineering Geological and Geophysical Professions Act, in good standing and be trained in one of the three acceptable verification methodologies as listed in "Methodology" under Verification requirements.* *A member of a profession that has substantially similar competence and practice requirements as a registered profession mentioned above - in a province or territory of Canada, or approved by the director, in a jurisdiction outside of Canada – is eligible to be a third party auditor.* *The verification team should have technical expertise and detailed knowledge in the following areas:* ▪ *Data audit practices and data verification standards* ▪ *The Specified Gas Emitters Regulation and associated requirements* ▪ *Verification criteria and their appropriate application within the defined scope of the verification* ▪ *Sector-specific areas including:* o *The specific greenhouse gas activity and technology* o *Identification and selection of greenhouse gas sources, sinks, reservoirs* o *Quantification, monitoring and reporting, including relevant technical and sector issues* o *Situations that may affect the materiality of the greenhouse gas assertion, including typical and atypical operating conditions* o *Be able to operate as a business including policies, finances, and quality review of products or services* *The lead verifier must sign and submit the original Statement of Qualification, Statement of Verification, and Conflict of Interest.* *The Third Party Verifier must be able to demonstrate independence and have the appropriate systems in place to document this independence in order to be qualified for third party verification. Therefore, the facility can engage the same lead verifier and/or verification company to undertake verification process for a maximum of 5 compliance cycles, with a mandatory two compliance cycle break. Note: the initial baseline application for a facility is considered a compliance cycle. Baseline restatements will be assessed separately. The Regulation recognizes that in some cases, for example correcting adverse audit reports, or in situations where a facility has undergone multiple baseline restatements, the authorities may request a facility to use a new verifier as part of the condition for restatement.* *Alberta is working with national accreditation bodies and will require accreditation of verifiers as these programs become available.* *It is a responsibility of an engaging facility to ensure that a chosen Verifier meets all the requirements.*
Other requirements	
Retention of information	*All records, data and other information used in the preparation of a report for should be kept for at least 3 years after the report is submitted under this Regulation.*

EU ETS MRV Guidelines

Name of regulatory Scheme	*European Union Emissions Trading Scheme (EU ETS)* *Guidelines for the monitoring and reporting of greenhouse gas emissions pursuant to EU ETS Directive (MRV Guidelines 2007) – Phase I and Phase II*
General characteristics	
Objectives of regulation	*In line with the EU ETS Directive, the adopted guidelines for the monitoring and reporting of greenhouse gas emissions aim to help regulated activities meet the compliance requirements.*
Country / language	*European Union, Norway, Iceland and Liechtenstein*
Web site	*http://ec.europa.eu/clima/policies/ets/monitoring/index_en.htm*
Implementation/enforcement entity	*Competent authorities in Member States, European Commission*
Targeted sector(s)	*The EU ETS Directive provides a list of activities covered by the scheme (Annex I). Flaring emissions are targeted under the combustion activities and mineral oil refineries.*
Reduction target	*21% by 2020 (the scheme-wide reduction target)*
Compliance	
Installation types and thresholds	*Combustion installations: combustion of fuels in installations with a total rated thermal input exceeding 20 MW (except in installations for the incineration of hazardous or municipal waste)* *Mineral oil refining*
Options for compliance	*Installations covered by the EU ETS have to following options to comply with the regulations:* ▪ *Implementing emission reduction measures ;* ▪ *Emissions trading* ○ *Through organized exchanges: The Nordic power exchange, Nord Pool, provides a market place for trading in physical and financial contracts in the Nordic countries (Finland, Sweden, Denmark and Norway). The Nord Pool trading also provides a carbon market containing trading, clearing and delivery of emission allowances as well as certified emission reductions (CERs);* ○ *Through brokers or other intermediaries;* ▪ *Bilateral transactions carried out directly between a buyer and a seller* ▪ *Use offset credits: Certified Emissions Reductions (CERs from CDM projects); and Emission Reduction Units (ERUs from JI projects but only in Phase II).* ▪ *Any surplus allowances can be banked between trading periods. Borrowing from the following year within a trading period is also allowed.*
Exclusions	*Under the EU ETS Phase III (2013-2020):* *Small emitters - which have been part of the EU ETS scope during Phase I and II - will be eligible for exclusion, under the following conditions: (i) an installation carries out an activity listed in Annex 1; (ii) reported emissions were lower than 25,000 tCO2eq in each of the 3 years preceding the year of application, excluding emissions from biomass; (iii) for combustion installations, an additional capacity threshold of 35MW applies; and (iv) such installation is subject to measures that will achieve an equivalent contribution to emission reductions.* *Installations exclusively burning biomass are not covered by the EU ETS Directive.*
Treatment of new entrants	*New Entrant Reserve is set aside, from which new entrants receive free allowances, provided they meet eligibility criteria.*

Name of regulatory Scheme	***European Union Emissions Trading Scheme (EU ETS)*** ***Guidelines for the monitoring and reporting of greenhouse gas emissions pursuant to EU ETS Directive (MRV Guidelines 2007) – Phase I and Phase II***
Monitoring plan or flare/vent management plant	*Permits to installations covered under the EU ETS have to contain monitoring requirements, specifying monitoring methodology and frequency. The MRV Guidelines provide a list of information that such monitoring plan needs to cover.*
Incentives for APG reduction or use	*Emission reductions achieved internally result in lower number of allowances needed to be purchased.* *Also, if internal reductions are below an allocated number of allowances, then an installation can trade the surplus of allowances.*
Costs	*Site-specific* *Admin costs* *Price of allowances*
Control system	*Not addressed in the MRV Guidelines*
Consequences of non-compliance	*Fines, imprisonment (e.g. Germany for a fraudulent application submitted for extra allowances)*
Methodology	
Estimation approach	*CO_2 emissions are calculated from the amount of gas flared [Nm^3] and the carbon content of the flared gas [tCO_2/Nm^3] (including inherent CO_2).* *CO_2 emissions = Activity data x Emission factor x Oxidation factor* *Emissions can be determined either via:* *1. a calculation-based methodology - based on activity data obtained by means of measurement systems and additional parameters from laboratory analyses or standard factors;* *2. a measurement-based methodology, based on continuous measurement of the concentration of the relevant greenhouse gas in the flue gas and of the flue gas flow. An operator is required to use continuous emission measurement systems (CEMS) and follow the specific guidelines given in the MRV document.* *A measurement based methodology is allowed only if an operator can demonstrate that:* ▪ *this method reliably results in a more accurate value of annual emissions of the installation than an alternative calculation based methodology, while avoiding unreasonable costs; and* ▪ *the comparison between measurement and calculation-based methodology is based on an identical set of emission sources and source streams.* *Yet, a measurement based methodology is subject to the approval by a competent authority; and for each reporting period an operator is required to confirm the measured emissions by means of calculation-based methodology, as prescribed in the MRV Guidelines. Annual emissions of each considered GHG shall be determined with use of one of the following options:* *(a) calculation of emissions as laid down in the respective activity-specific Annex For the calculation of emissions, lower tiers (i.e. Tier 1 as a minimum) can generally be applied or;* *(b) calculation of emissions as laid down in the 2006 IPCC Guidelines, e.g. Tier 1 methods may be used.*
Gases included in the reporting	*CO_2*

Name of regulatory Scheme	***European Union Emissions Trading Scheme (EU ETS)*** ***Guidelines for the monitoring and reporting of greenhouse gas emissions pursuant to EU ETS Directive (MRV Guidelines 2007) – Phase I and Phase II***
Treatment of missing data	*The MRV Guidelines state that the treatment of minor data gaps which result from downtimes of measurement systems should follow good professional practice ensuring a conservative estimation of emissions, considering the provisions of the Integrated Pollution Prevention and Control (IPPC) Reference Document on the General Principles of Monitoring of July 2003).* *In case of measurement based methodology, when data is not available, a substitution value should be calculated based on:* ▪ *the arithmetic mean of the concentration of the specific parameter and standard deviation – for a parameter directly measured as concentration;* ▪ *a mass balance model* ▪ *or the energy balance approach of process – for parameters not directly measured as concentrations*
Calculation update frequency	*Annually, at the submission of report*
Methodological changes	*Changes are induced only by revisions to the MRV Guidelines.*
Consistency with international standards	*For measurement based methodologies;* 1. *CEN standards (i.e. those issued by the European Committee for Standardisation),* inter alia: 2. *If CEN standards are not available, suitable ISO standards,* inter alia: o *ISO 12039:2001 Stationary source emissions — Determination of carbon monoxide, carbon dioxide and oxygen — Performance characteristics and calibration of an automated measuring method,* o *ISO 10396:2006 Stationary source emission — Sampling for the automated determination of gas* o *concentrations,* o *ISO 14164:1999 Stationary source emissions. Determination of the volume flow rate of gas streams in ducts — automated method.* 3. *Where no applicable standards exist, procedures can be carried out where possible in accordance with suitable draft standards or industry best practice guidelines.* *For determining Net Calorific Values and emission factors for fuels:* 1. *CEN standards (i.e. those issued by the European Committee for Standardisation),* inter alia: o *EN ISO 6976:2005 Natural gas — Calculation of calorific values, density, relative density, and Wobbe index from composition,* o *EN ISO 4259:1996 Petroleum products — Determination and application of precision data in relation to methods of test.* 2. *If CEN standards are not available, suitable ISO standards,* inter alia: o *ISO 13909-1,2,3,4:2001 Hard coal and coke — Mechanical sampling,* o *ISO 5069-1,2:1983 Brown coals and lignites — Principles of sampling,* o *ISO 625:1996 Solid mineral fuels — Determination of carbon and hydrogen — Liebig method,* o *ISO 925:1997 Solid mineral fuels — Determination of carbonate carbon content — Gravimetric method,* o *ISO 9300:1990 Measurement of gas flow by means of critical flow Venturi nozzles,* o *ISO 9951:1993/94 Measurement of gas flow in closed conduits — Turbine meters* 3. *Where no applicable standards exist, procedures can be carried out where possible in accordance with suitable draft standards or industry*

<table>
<tr><td>Name of regulatory Scheme</td><td>European Union Emissions Trading Scheme (EU ETS)
Guidelines for the monitoring and reporting of greenhouse gas emissions pursuant to EU ETS Directive (MRV Guidelines 2007) – Phase I and Phase II</td></tr>
<tr><td></td><td>best practice guidelines.
Supplemental national standards for the characterization of fuels are:
o DIN 51900-1:2000 Testing of solid and liquid fuels — Determination of gross calorific value by the bomb calorimeter and calculation of net calorific value — Part 1: Principles, apparatus, methods,
o DIN 51857:1997 Gaseous fuels and other gases — Calculation of calorific value, density, relative density and Wobbe index of pure gases and gas mixtures,
o DIN 51612:1980 Testing of liquefied petroleum gases, calculation of net calorific value,
o DIN 51721:2001 Testing of solid fuels — Determination of carbon and hydrogen content (also applicable for liquid fuels).

The laboratory used to determine the emission factor, net calorific value, oxidation factor, carbon content, the biomass fraction or composition data should be accredited according to EN ISO 17025:2005 (General requirements for the competence of testing and calibration laboratories).
If a non-accredited laboratory is used, a list of requirements needs to be met, as specified in the MRV Guidelines.

For online gas analysers and gas chromatographs, the requirements EN ISO 9001:2000 should be met by an operator operating such systems. Calibration services and the suppliers of calibration gases shall be accredited against EN ISO 17025:2005.</td></tr>
<tr><td>Levels of accuracy (sources of data)</td><td>
<table>
<tr><td>Annual Emissions (installation category)</td><td colspan="2">Fuel flow</td><td colspan="2">Emission factor</td><td colspan="2">Oxidation factor</td></tr>
<tr><td></td><td>Tier</td><td>Accuracy</td><td>Tier</td><td>Accuracy</td><td>Tier</td><td>Accuracy</td></tr>
<tr><td><50 ktCO2/yr (A)</td><td>1</td><td>± 7.5%</td><td>1</td><td>Reference value</td><td>1</td><td>Reference value</td></tr>
<tr><td>>50<500 ktCO2/yr (B)</td><td>2</td><td>± 5%</td><td>2</td><td>Reported by MS or purchasing records</td><td>1</td><td>Reference value</td></tr>
<tr><td>>500 ktCO2/yr (C)</td><td>3</td><td>± 2.5%</td><td>3</td><td>Operator measured or laboratory analysis</td><td>1</td><td>Reference value</td></tr>
</table>

The choice of tiers is subject to the approval by a competent authority. Any change in tiers is allowed only if an operator can demonstrate to the satisfaction of the competent authority that such change will lead to a more accurate monitoring and reporting of the emissions of the relevant activity.</td></tr>
</table>

Name of regulatory Scheme	***European Union Emissions Trading Scheme (EU ETS)*** ***Guidelines for the monitoring and reporting of greenhouse gas emissions pursuant to EU ETS Directive (MRV Guidelines 2007) – Phase I and Phase II***
	The highest tier approach should be applied by all operators to determine all variables for all source streams for all category B or C installations[50] *(unless if demonstrated that the highest tier approach is technically not feasible or will lead to unreasonably high costs, a next lower tier can be applied for that variable within a monitoring methodology).* *Also, the highest tier level following the specific requirements in the MRV Guidelines should be used in case of determining relevant greenhouse gas emissions with measurement based methodology (CEMS).* *Subject to approval by a competent authority, a minimum (Tier 1) level for the variables can be applied in case of minor source streams. Alternatively, operator's own no-tier estimation method for de minimis source streams can be used.* *If at least Tier 1 cannot be used, then the MRV Guidelines provide Fall-back Approaches, which allow an operator to be exempted from the application of MRV requirements on tiers and design a fully customized monitoring methodology.*
Sources for emission factors	***Emission factor*** *Tier 1* *Using a reference emission factor of 0.00393tCO_2/m^3 (at standard conditions) derived from the combustion of pure ethane used as a conservative proxy for flare gases.* *Tier 2a* *Using country-specific emission factors for the respective fuel as reported by the respective Member State in its latest national inventory submitted to the Secretariat of the United Nations Framework Convention on Climate Change.* *Tier 2b* *Using installation-specific emission factors derived from an estimate of the molecular weight of the flare stream, with use of process modelling based on industry-standard models. By considering the relative proportions and the molecular weights of each of the contributing streams, a weighted annual average figure is derived for the molecular weight of the flare gas.* *Tier 3* *Using emission factor [tCO_2/Nm^3 flare gas] calculated from the carbon content of the flared gas applying the specific provisions given in the MRV*

[50] Category B installation: an installation with average reported annual emissions over the previous trading period (or a conservative estimate or projection if reported emissions are not available or no longer applicable) of greater 50kt and equal to or less than 500kt of fossil CO_2 before subtraction of transferred CO_2. Category C installation: an installation with average reported annual emissions over the previous trading period (or a conservative estimate or projection if reported emissions are not available or no longer applicable) of greater than 500kt of fossil CO_2 before subtraction of transferred CO_2.

Note: transferred CO_2 is CO_2 not emitted from the installation but transferred out of the installation as pure substance, or directly used and bound in products or as feedstock, provided the subtraction is mirrored by a respective reduction for the activity and installation which the respective Member State reports in its national inventory submission to the Secretariat of the United Nations Framework Convention on Climate Change.

Name of regulatory Scheme	***European Union Emissions Trading Scheme (EU ETS)*** ***Guidelines for the monitoring and reporting of greenhouse gas emissions pursuant to EU ETS Directive (MRV Guidelines 2007) – Phase I and Phase II***
	Guidelines (Section 13 of Annex I).
Any tools provided?	*N/A* *Some Member States have issued supporting materials, e.g. the Swedish Environmental Protection Agency has developed a report: "Measuring Technique for emission of carbon dioxide – principles and costs for monitoring within the framework of the EU Emissions Trading Scheme". This document describes different methods to monitor the variables, used to calculate the emission of carbon dioxide, within the framework of the Emissions Trading Scheme.*
Uncertainty Treatment	*Uncertainty is defined as "a parameter, associated with the result of the determination of a quantity, that characterises the dispersion of the values that could reasonably be attributed to the particular quantity, including the effects of systematic as well as of random factors and expressed in per cent and describes a confidence interval around the mean value comprising 95 % of inferred values taking into account any asymmetry of the distribution of values."* *When the <u>calculation-based methodology</u> is used, then there is no need to report on uncertainty, as this has been assessed and approved by a competent authority at the stage of permit issuance. [Refer to "Levels of accuracy (sources of data)" above for uncertainty levels associated with each tier for the activity data.]* *The uncertainty determined for the measurement system within the tier system comprises the specified uncertainty of the applied measurement instruments, uncertainty associated with the calibration and any additional uncertainty connected to how the measurement instruments are used in practice. The stated threshold values within the tier system refer to the uncertainty associated to the value for one reporting period.* *Where required, the operator shall base the calculation on the specifications as provided by the supplier of the measurement instruments. If the specifications are not available, the operator shall provide for an uncertainty assessment of the measurement instrument. In both cases, he shall take into account necessary corrections of these specifications from effects resulting from the actual use conditions like ageing, conditions of the physical environment, calibration and maintenance. These corrections may involve conservative expert judgement.* *If measurement systems are applied, the operator needs to take into account the cumulative effect of all components of the measurement system on the uncertainty of the annual activity data using the error propagation law (as per Annex 1 of the 2000 Good Practice Guidance and in Annex I of the Revised 1996 IPCC Guidelines)* *In case of the <u>measurement system</u> the uncertainty within the tier system needs to comprise the specified uncertainty of the applied measurement instruments, uncertainty associated with the calibration and any additional uncertainty connected to how the measurement instruments are used in practice. The uncertainty assessment needs to be performed annually and take into account the cumulative effect of all components. The MRV Guidelines provide equations on determining uncertainty of a sum (e.g. of individual contributions to an annual value) and for uncertainty of a product (e.g. of different parameters used to convert a meter reading into mass flow data).*
Quality Assurance	*See "Quality Assurance" under Monitoring section below.*

Name of regulatory Scheme	***European Union Emissions Trading Scheme (EU ETS)*** ***Guidelines for the monitoring and reporting of greenhouse gas emissions pursuant to EU ETS Directive (MRV Guidelines 2007) – Phase I and Phase II***
Monitoring	
Boundaries	*Flares as a source of emissions are addressed under the combustion of fuels in installations with a total rated thermal input exceeding 20 MW (except in installations for the incineration of hazardous or municipal waste) and under refining of mineral oil.* *As listed and described in the GHG emission permit.* *Emissions from flares should include routine flaring and operational flaring (trips, start-up and shutdown as well as emergency relieves).*
Frequency	*Depending on a methodology applied, for example:* ▪ *A measurement based methodology uses a continuous emission measurement system. Sampling rate is based on hourly averages.* ▪ *Samples of natural gas for the purpose of determining emission factor, oxidation factor etc. – at least weekly.*
Methodology	*As described above ("Estimation approach" under Methodology), there are two methods to determine emissions:* ▪ *a calculation-based methodology, in which emissions are calculated using measurement systems and additional parameters from laboratory analyses or standard factors;* ▪ *a measurement-based methodology, in which emissions are determined through continuous measurement of the concentration of the relevant greenhouse gas in the flue gas and of the flue gas flow. In this case the use of continuous emission measurement systems (CEMS) is required. Yet, this method can be applied only under certain conditions and upon authorities' approval. MRV provide a set of specific requirements for an operator to follow.* *The monitoring methodology is part of the monitoring plan subject to the approval by a competent authority. An operator is required to follow the requirements of the MRV Guidelines; however in exceptional cases, it is possible to design and implement a fully customized monitoring methodology (see "Levels of accuracy (sources of data)" above under the Methodology section).* *The monitoring methodology should be changed if this improves the accuracy of the reported data, unless this is technically not feasible or would lead to unreasonably high costs.* *A substantial change to the monitoring methodology as part of the monitoring plan shall be subject to the approval of a competent authority if it concerns:* ▪ *a change of the categorisation of the installation as laid down in Table 1,* ▪ *a change between the calculation-based or the measurement-based methodology used to determine emissions,* ▪ *an increase of the uncertainty of the activity data or other parameters (where applicable) which implies a different tier level.*
Use of standards	*See "Consistency with international standards" under the Methodology section above.*
Uncertainty treatment	*See "Uncertainty Treatment" under the Methodology section above.*
Quality assurance	*Monitoring and reporting are based on seven principles: completeness, consistency, transparency, trueness, cost effectiveness, faithfulness, and improvement of performance in monitoring and reporting of emissions.*

Name of regulatory Scheme	***European Union Emissions Trading Scheme (EU ETS)*** ***Guidelines for the monitoring and reporting of greenhouse gas emissions pursuant to EU ETS Directive (MRV Guidelines 2007) – Phase I and Phase II***
	An operator is required to: ▪ *clearly state, justify and fully document in internal records changes to the monitoring plan* ▪ *without undue delay propose changes to the tiers applied when:* ○ *accessible data has changed, allowing for higher accuracy in the determination of emissions,* ○ *previously non-existent emission has started,* ○ *the range of fuels or relevant raw materials has substantially changed,* ○ *errors were detected in data resulting from the monitoring methodology,* ○ *the competent authority has requested a change.* ▪ *document and archive monitoring data for the installation's emissions from all emission sources and/or source streams* ▪ *establish, document, implement and maintain effective data acquisition and handling activities for the monitoring and reporting of GHG emissions in accordance with the approved monitoring plan, the permit and these guidelines;* ▪ *establish, document, implement and maintain an effective control system to ensure that the annual emissions report, resulting from the data flow activities does not contain misstatements and is in conformance with the approved monitoring plan, the permit and these guidelines;* ▪ *assign responsibilities to all data flow activities and to all control activities;* ▪ *ensure that relevant measuring equipment is calibrated, adjusted and checked at regular intervals including prior to use, and checked against measurement standards traceable to international measurement standards where available, in accordance with the risks identified;* ▪ *If the operator uses information technology, including process-control computer technology, it shall be designed, documented, tested, implemented, controlled and maintained as a way to ensure reliable, accurate and timely processing of data in accordance with the risks identified;* ▪ *design and implement reviews and validation of data in accordance with the risks identified. These validations may be conducted either manually or electronically.* ▪ *where an operator chooses to outsource any process in the data flow, the operator shall control the quality of these processes;* ▪ *where necessary, take appropriate corrections and correct the rejected data.*
Reporting	
Scope	*The MRV Guidelines specify the content of the emission report,* inter alia*:* ▪ *for all emissions sources and/or source streams the emission totals, chosen approach (measurement or calculation), chosen tiers and method (if applicable), activity data, emission factors, and oxidation/conversion factors. The following items, which are not accounted for in terms of emissions, shall be reported as memo items: amounts of biomass combusted [TJ] or employed in processes [t or Nm3]; CO_2 emissions [tCO2] from biomass where measurement is used to determine emissions; CO_2 transferred from an installation [tCO_2]; inherent CO_2 leaving the installation as part of a fuel;* ▪ *temporal or permanent changes of tiers, reasons for these changes, starting date for changes, and starting and ending dates of temporal changes.* *The "Reporting" section in the MRV Guidelines list also specific reporting requirements, such as: fuels and resulting emissions shall be reported using the IPCC fuel categories; emissions shall be reported as rounded tonnes of CO_2; emissions occurring from different emission sources or*

Name of regulatory Scheme	***European Union Emissions Trading Scheme (EU ETS)*** ***Guidelines for the monitoring and reporting of greenhouse gas emissions pursuant to EU ETS Directive (MRV Guidelines 2007) – Phase I and Phase II***
	source streams of the same type of a single installation belonging to the same type of activity may be reported in an aggregate manner for the type of activity.
Frequency	*Annually (by 31 March)*
Form (reporting format)	*Tabular form and plain text (where applicable).* *The Format is provided in the MRV Guidelines (Annex I, para 14).*
System transparency (public database, information disclosed)	*Emission reports held by a competent authority are required to be made available to the public.* *There is a Community Transaction Log, where information on Member States' registries, National Allocation Plans, compliance, accounts and transactions can be found.*
Verification requirements	
Process	*Verification is undertaken annually, on each emission report.* *The MRV Guidelines require that a verifier shall carry out the following steps* *1. Strategic analysis, including* *a. verify whether the monitoring plan has been approved by the competent authority and whether it is the right version.* *b. understand each activity undertaken by the installation, the sources, source streams within the installation, the metering equipment used to monitor or measure activity data, the origin and application of emission factors and oxidation/conversion factors, any other data used to calculate or measure the emissions, and the environment in which the installation operates,* *c. understand the operator's monitoring plan, data flow, as well as its control system, including the overall organisation with respect to monitoring and reporting,* *d. apply the materiality level.* *2. Risk analysis, including:* *a. analyse the inherent risks and control risks related to the scope and complexity of the operator's activities and emission sources and source streams, and which could lead to a material misstatements and non-conformities,* *b. draw up a verification plan which is commensurate with this risk analysis. The verification plan describes the way in which the verification activities are to be carried out. It contains a verification programme and a data sampling plan. The verification programme describes the nature of the activities, at what times they must be carried out and their scope in order for the verification plan to be completed. The data sampling plan sets out what data is to be tested in order to reach a verification opinion.* *Moreover, the verifier shall:* ▪ *carry out the verification plan by gathering data in accordance with the defined sampling methods, walkthrough tests, document reviews, analytical procedures and data review procedures, including any relevant additional evidence, upon which the verifier's verification opinion will be based,* ▪ *confirm the validity of the information used to calculate the uncertainty level as set in the approved* ▪ *monitoring plan,* ▪ *verify that the approved monitoring plan is implemented and seek understanding whether the monitoring plan is up to date,* ▪ *request the operator to provide any missing data or complete missing sections of audit trails, explain variations in the emissions data, or revise*

Name of regulatory Scheme	***European Union Emissions Trading Scheme (EU ETS)*** ***Guidelines for the monitoring and reporting of greenhouse gas emissions pursuant to EU ETS Directive (MRV Guidelines 2007) – Phase I and Phase II***
	calculations, or adjust reported data, before reaching a final verification opinion. The verifier should, in any form, report all non-conformities and misstatements identified to the operator. *Site visit is required to inspect the operation of meters and monitoring systems, conduct interviews, and collect sufficient information and evidence.* *Internal verification report is developed at the end of verification process. Final Verification Report is submitted by an operator together with the annual emission report to a competent authority. Member States shall ensure that the operator addresses non-conformities and misstatements after consultation of the competent authority in a timeframe set by the competent authority.*
Methodology	*Methodology is based on strategic analysis, process analysis, and risk analysis, as described in the "Process" above.* *Materiality level depends on a installation category[51]:* ▪ *Category A and B installations – 5%* ▪ *Category C installations – 2%*
Assurance requirements	*Reasonable assurance whether the data in the emissions report is free from material misstatements and whether there are no material non-conformities.*
Avoiding double counting	*Since Phase I of the EU ETS began in 2005, national registries were in place tracking allowances issued and ownership.* *However, national registry systems have been closed to all account transactions since the 3 June 2012. The Consolidated System of European Union Registries (CSEUR) has been fully activated on the 20 June 2012.* *Appointed by the European Commission, the Central Administrator will conduct an automated check on each transaction in registries through the independent transaction log to ensure there are no irregularities in the issue, transfer and cancellation of allowances.*
Third party	*Minimum requirements for the verifier are specified in the EU ETS Directive and are as follows:* *The verifier shall be independent of the operator, carry out his activities in a sound and objective professional manner, and understand:* *(a) the provisions of this Directive, as well as relevant standards and guidance adopted by the Commission pursuant to Article 14(1);* *(b) the legislative, regulatory, and administrative requirements relevant to the activities being verified; and* *(c) the generation of all information related to each source of emissions in the installation, in particular, relating to the collection, measurement, calculation and reporting of data.*
Other requirements	
Retention of information	*The following information should be retained for at least ten years after the submission of the emission report:*

[51] Category A installation: an installation i with average reported annual emissions over the previous trading period (or a conservative estimate or projection if reported emissions are not available or no longer applicable) equal to or less than 50kt of fossil CO_2 before subtraction of transferred CO_2.. Category B installation: an installation with average reported annual emissions over the previous trading period (or a conservative estimate or projection if reported emissions are not available or no longer applicable) of greater 50kt and equal to or less than 500kt of fossil CO_2 before subtraction of transferred CO_2. Category C installation: an installation with average reported annual emissions over the previous trading period (or a conservative estimate or projection if reported emissions are not available or no longer applicable) of greater than 500kt of fossil CO_2 before subtraction of transferred CO_2.

Name of regulatory Scheme	***European Union Emissions Trading Scheme (EU ETS)*** ***Guidelines for the monitoring and reporting of greenhouse gas emissions pursuant to EU ETS Directive (MRV Guidelines 2007) – Phase I and Phase II***
	<u>For calculation-based methodologies:</u> ▪ *the list of all source streams monitored,* ▪ *the activity data used for any calculation of the emissions for each source stream, categorised by process and fuel, or material type,* ▪ *documents justifying the selection of the monitoring methodology and the documents justifying temporal or non-temporal changes of monitoring methodologies and tiers approved by the competent authority,* ▪ *documentation of the monitoring methodology and results from the development of activity-specific* ▪ *emission factors and biomass fractions for specific fuels, and oxidation or conversion factors, and respective proofs of approval from the competent authority,* ▪ *documentation of the process of collection of activity data for the installation and its source streams,* ▪ *the activity data, emission, oxidation or conversion factors submitted to the competent authority for the national allocation plan for years preceding the time period covered by the trading scheme,* ▪ *documentation of the responsibilities in connection to the emissions monitoring,* ▪ *the annual emissions report, and* ▪ *any other information that is identified as required for the verification of the annual emissions report.* *<u>The following additional information shall be retained for measurement-based methodologies:</u>* ▪ *the list of all emission sources monitored,* ▪ *documentation justifying the selection of a measurement-based methodology,* ▪ *the data used for the uncertainty analysis of emissions from each emission source, categorised by process,* ▪ *the data used for the corroborating calculations,* ▪ *a detailed technical description of the continuous measurement system including the documentation of the approval from the competent authority,* ▪ *raw and aggregated data from the continuous measurement system, including documentation of changes over time, the log-book on tests, down-times, calibrations, servicing and maintenance,* ▪ *documentation of any changes of the continuous measurement system.*
Exemption	*From specific requirements for the Monitoring Plan, Tiers of Approaches, Calculation of uncertainty, Control and verification, Determination of activity-specific data and factors – as described in relevant sections above – installations with average verified reported emissions of less than 25 000tCO_2 per year during the previous trading period can be exempted.*

Directive 60: Upstream Petroleum Industry Flaring, Incinerating and Venting

Name of regulatory Scheme	***Directive 060: Upstream Petroleum Industry Flaring, Incinerating, and Venting***
General characteristics	
Objectives of regulation	*The aim of the Directive 060 is to eliminate or reduce flaring, venting and incinerating in order to ensure Alberta Ambient Air Quality Objectives (AAAQOs)[52] are met and where required to meet health and safety objectives.*
Country / language	*Canada, Alberta Province, English*
Web site	*http://www.ercb.ca/docs/documents/directives/Directive060.pdf*
Implementation/ enforcement entity	*The Energy Resource Conservation Board (ERCB)*
Targeted sector(s)	*Upstream Petroleum Industry*
Reduction target	*1) The Alberta solution gas flaring limit is 670mln m^3 per year (50% of the revised 1996 baseline of 1340mln m^3/year) effective immediately.* *2) If solution gas flaring exceeds the above limit in any year, the ERCB will impose reductions that will stipulate maximum solution gas flaring limits for individual operating sites based on analysis of the most current annual data so as to reduce flaring to less than annual limit. For example, solution gas flaring could be limited to a maximum of 500thousand m^3/year at any one site.*
Compliance	
Installation types and thresholds	*Wells and facilities, including pipeline installations that convey gas (e.g., compressor stations, line-heaters, etc.) licensed by the ERCB in accordance with the Pipeline Act.* *For gas plants processing less than 1.0 billion m^3 per year (raw gas inlet volume), flaring, incinerating, and venting must not exceed 1% of raw gas receipts in the first year of operation and must not exceed 0.5% of receipts in any year thereafter.* *For gas plants processing more than 1.0 billion m^3 per year, flaring, incinerating, and venting must not exceed the greater of 0.2% of receipts or 5.0 million m^3 per year.* *Gas containing more than 5ppm H_2S must not be released from a pipeline without the approval of the ERCB, unless the gas is burned such that it meets the specific requirements provided in Section 7.*
Options for compliance	*The licensee, operator, or approval holder must notify the appropriate ERCB Field Centre in advance of planned flaring, venting, or incinerating operations. To notify an ERCB Field Centre, the licensee, operator, or approval holder must complete and submit an ERCB Flaring/Incinerating/Venting Notice Form via the ERCB's Digital Data Submission system.* *Venting is not deemed an acceptable alternative to flaring. If gas volumes are sufficient to sustain stable combustion, the gas must be burned (or conserved)[53]. If venting cannot be avoided, it must meet the specific requirements (Section 8 in the 060 Directive).*

[52] *Existing ambient air quality objectives*: http://environment.alberta.ca/01005.html

Name of regulatory Scheme	*Directive 060: Upstream Petroleum Industry Flaring, Incinerating, and Venting*
	The licensee or operator is required to use the Solution Gas Flaring and Venting Decision Tree (Section 2.3 of the 060 Directive) to all flares and vents greater than 900m³/day. Consideration of each element of the decision tree needs to be demonstrated. Conservation economics must be updated every 12 months. *The 060 Directive (Section 2.5) specifies under which conditions solution gas has to be conserved at existing oil and bitumen sites, for example:* *a) combined flaring and venting volumes are greater than 900 m³/day per site and the decision tree process and economic evaluation result in a net present value of greater than –$50 000Cdn;* *b) the gas to oil ratio is greater than 3000 m³/m³; all wells producing with a GOR greater than 3000 m³/m³ at any time during the life of the well must be shut in until the gas is conserved; or* *c) flared volumes are greater than 900 m³/day per site and the flare is within 500 m of an existing residence, regardless of economics.* *i) If a new residence is constructed or relocated within 500 m of an existing solution gas flare after the effective date of this directive, the licensee or operator must consult with the new residents to provide information about the flaring operation.* *The 060 Directive requires also considering clustering of production facilities operating within 3km of each other, when assessing economics of solution gas conservation opportunities. In the case of a multiwell oil or bitumen development, conservation on a project or development area basis must be evaluated regardless of distance. Further details are provided in Section 2.6.* *Section 2.9 describes requirements of public consultation and notification requirements (which are in agreement with the Directive 056[54]).* *Section 2.11 describes limitations and notification requirements for nonroutine flaring, incinerating, and venting during solution gas conserving facility outages.* *Section 3 regulates temporary flaring and incinerating activities, which include well testing, well cleanup, well servicing, sour gas pipeline blowdown, coalbed methane well testing, underbalanced drilling, maintenance blowdowns, and emergency blowdowns through temporary or permanent flare or incinerator equipment.* *Licensees must use the Temporary Flaring and Incinerating Decision Tree Process to evaluate all opportunities to eliminate or reduce flaring and incinerating, regardless of volume (Section 3.1). There are time limits defined for temporary activities, as well as conditions that require permits.* *The 060 Directive provides requirements (decision trees, notification ad reporting) for flaring, incinerating and venting*

[53] The Directive 060 defines *conservation* as "the recovery of solution gas for sale, for use as fuel for production facilities, for other useful purposes (e.g., power generation), or for beneficial injection into an oil or gas pool (e.g., pressure maintenance, enhanced oil recovery)."

[54] The Directive 056 *Energy Development Applications and Schedules* prescribes the requirements and procedures for filing a licence application to construct or operate any petroleum industry energy development that includes facilities, pipelines, or wells (Available at: http://www.ercb.ca/docs/documents/directives/Directive056.pdf).

Name of regulatory Scheme	*Directive 060: Upstream Petroleum Industry Flaring, Incinerating, and Venting*
	▪ of gas from gas battery, dehydrator, and compressor station (Section 4); *▪ of natural gas from gas processing plants (Section 5)* *▪ of natural gas from gas gathering and transmission lines (Section 6)* *Section 7 defines performance requirements, which apply to flares and incinerators in all upstream industry oil and gas systems for burning sweet, sour, and acid gas, including portable equipment used for temporary operations including well completion, servicing, and testing. The ERCB highlights that this directive identifies minimum ERCB regulatory requirements but it should not be treated as a substitute for comprehensive engineering design codes and guidelines* *Section 7 provides sulphur recovery requirements and sour gas combustion.*
Exclusions	*Fuel gas used for pilots or flare system purge, as well as acid gas volumes from gas sweetening (which are normally continuously flared) are excluded from the annual volume limits.*
Treatment of new entrants	*New sites need to perform tests determining whether combined flaring and venting volumes will exceed 900m^3/day. If yes, then the opportunities for solution gas conservation must be evaluated as per the economic evaluation criteria described in Section 2.8 of the 060 Directive. If the limit is not reached, economic evaluation of conservation is recommended but not legally required.* *There are separate time limits for test periods for new crude oil and bitumen sites.* *A multiwell bitumen site must prebuild solution gas conservation lines to one common point on the lease as part of initial construction.*
Monitoring plan or flare/vent management plant	*Licensees must provide a documented system for measurement and/or estimation of flared and vented gas volumes upon ERCB Technical Operations Group request. All flare events both minor and major must be logged and provided upon request.*
Incentives for APG reduction or use	*The Royalty Waiver Program: the royalty on solution gas is waived, if productively used instead of being flared. The waiver lasts for ten years from the first day in the month in which the application is received. The program covers all methods of conserving solution gas.* *Further details: http://www.energy.alberta.ca/NaturalGas/1139.asp*
Costs	*Admin costs*
Control system	*The ERCB is allowed to obtain different sets of information, upon requests, for example:* *▪ conservation economics assessment (annual updates), economic evaluation audit packages;* *▪ information on ambient air quality impact evaluations* *▪ after the flaring/incinerating event, information on dispersion assessments for flares or incinerators that require dispersion modelling but do not require a flaring permit* *▪ solution gas flared at gas plants during plant shutdowns lasting more than seven days* *▪ equipment and controls design information* *▪ justification for volumes not combusted* *The ERCB annually inspects a portion of Alberta's operating wells, production and processing facilities, and pipelines.* ***Field inspections*** *are*

Name of regulatory Scheme	*Directive 060: Upstream Petroleum Industry Flaring, Incinerating, and Venting*
	prioritized based on the weighting of three key criteria: operator history, site sensitivity, and inherent risk of the facility or operation. *In addition to inspections, ERCB carries out **audits**. Initially, these are conducted during the application process, yet post-application operational audits are also conducted under certain conditions. Selection criteria for these audits include inspection results, public complaints, and risk potential related to a facility's operations.* [55]
Consequences of non-compliance	*Non-compliant events associated with D060 are included in the table compiled by the ERCB and available at: http://www.ercb.ca/docs/enforcement/riskassessednoncompliances.pdf* *The response to a non-compliant event is governed by D019 "Compliance Assurance"[56]. Consequences are described as Low Risk Enforcement Action, High Risk Enforcement Action (persistent non-compliance), High Risk Enforcement Action (Demonstrated Disregard), and High Risk Enforcement Action (Failure to Comply). The enforcement consequences include:* *• noncompliance fees* *• self-audit or inspections* *• increased audits or inspections* *• third-party audits or inspections* *• partial or full suspension* *• suspension and/or cancellation of permit, licence, or approval* *Also, The ERCB may refer a matter to prosecution when it believes a licensee has acted with demonstrated disregard.* *Directive 019 assumes also Voluntary Self-Disclosure. One of its advantages is no enforcement is taken if a licensee corrects or addresses the noncompliant events during the time agreed upon with the ERCB.*
Methodology	
Estimation approach	*The 060 Directive lists measurement and reporting requirements for <u>volumes of gas</u> flared, incinerated, and vented, which are in addition to those given in:* ▪ *Directive 017 "Measurement Requirements for Oil and Gas Operations"[57],* ▪ *Directive 007 "Volumetric and Infrastructure Requirements"[58],and* ▪ *the Oil and Gas Conservation Regulations (OGCR)[59].*

[55] *Inspection and audits:* http://www.ercb.ca/portal/server.pt/gateway/PTARGS_0_0_321_0_0_43/http%3B/ercbContent/publishedcontent/publish/ercb_home/public_zone/public_safety/inspections_and_audits/

[56] Directive 019: http://www.ercb.ca/docs/documents/directives/Directive019.pdf

[57] Directive 017: http://www.ercb.ca/docs/documents/directives/Directive017.pdf

[58] Directive 007: http://www.ercb.ca/docs/documents/directives/directive007.pdf

[59] Alberta's OGCR: http://www.ercb.ca/docs/requirements/actsregs/ogc_reg_151_71_ogcr.pdf

Name of regulatory Scheme	*Directive 060: Upstream Petroleum Industry Flaring, Incinerating, and Venting*
	Well test results and information required by flaring and incinerating permits must be submitted in accordance with the requirements of ▪ *Directive 040 "Pressure and Deliverability Testing Oil and Gas Wells",* ▪ *Bulletin 2004-15 "New Well Test Capture (WTC) System Implementation Date Reminder: Changes to Final WTC Pressure ASCII Standard (PAS) Formats and Version 4.0 PAS File Business Rules Implications",* ▪ *the applicable permit, and* ▪ *Section 10 of the 060 Directive.* *The 017 Directive includes requirements on proration and allocation factors (Section 3). Proration is an accounting system or procedure where the total actual monthly battery production is equitably distributed among wells in the battery.* *If measurement and accounting procedures meet applicable requirements, metering differences[60] up to ± 5.0% of the total inlet/receipt volume are deemed to be acceptable.* *Standard or base conditions for use in calculating and reporting gas volumes are 101.325 kPa (absolute) and 15°C.*
Gases included in the reporting	*Not applicable* *Reporting covers relevant volumes of gas flared, vented and incinerated (please refer to the section Reporting-Boundaries below).*
Calculation update frequency	*Monthly gas volumes must be reported in units of 10^3 m^3 and rounded to 1 decimal place.*
Consistency with international standards	*The 017 Directive states that "the methods to be used for determining and combining uncertainties are found in the latest edition of the American Petroleum Institute (API) Manual of Petroleum Measurement Standards (MPMS), Chapter 13: Statistical Aspects of Measuring and Sampling or the latest edition of the International Standard Organization (ISO) Standard 5168: Measurement of Fluid Flow—Estimation of Uncertainty of a Flow-rate Measurement."*
Levels of accuracy (sources of data)	<u>*Oil systems - Total battery gas[61]*</u> *Single point uncertainty[62]:* *> 16,900 m^3/d = 3.0%* *> 500 m^3/d but ≤ 16,900 m^3/d = 3.0%* *≤ 500 m^3/d = 10.0%*

[60] A "metering difference" is used to balance, on a monthly basis, any difference that occurs between the measured inlet/receipt volumes and the measured outlet/disposition volumes at a facility. Metering difference is generally acceptable as an accounting/reporting entity if a difference results from two or more measurements of the same product.

[61] It includes produced gas that is vented, flared, or used as fuel), including single-well batteries—also referred to as "associated gas," as it is the gas produced in association with oil production at oil wells.

[62] Single Point Uncertainty is defined as the limits applicable to equipment and/or procedures used to determine a single-phase specific volume at a single measurement point.

Name of regulatory Scheme	*Directive 060: Upstream Petroleum Industry Flaring, Incinerating, and Venting*
	Maximum uncertainty of monthly volume (M) *> 16,900 m^3/d = 5.0%* *> 500 m^3/d but ≤ 16,900 m^3/d = 10.0%* *≤ 500 m^3/d = 20.0% (NB: these volumes can be determined by using estimates.* *Gas systems – Fuel gas* *Single point uncertainty:* *> 500 m^3/d = 3.0%* *≤ 500 m^3/d = 10.0%* *Maximum uncertainty of monthly volume (M)* *> 500 m^3/d = 5%* *≤ 500 m^3/d = 20.0% (NB: if the annual average fuel gas meets this condition on a per-site basis, the gas volume may be determined by using estimates).* *Gas systems – Flare gas* *Single point measurement uncertainty = 5.0%* *Maximum uncertainty of monthly volume = 20.0% (NB: In some cases if flaring is infrequent and no measurement equipment is in place, flare volumes must be estimated)*
Sources for emission factors	*Not applicable*
Any tools provided?	*Not applicable*
Monitoring	
Boundaries	*The following flare and vent streams need to be measured:* ▪ *continuous or intermittent flare and vent sources at all oil and gas production and processing facilities (excluding cold heavy oil and crude bitumen) where annual average total flared and vented volumes per facility exceed 500 m^3/day (excluding pilot, purge, or dilution gas); if all solution gas is flared or vented from any production facilities, the measured produced gas (less fuel gas use) may be used to report volumes flared or vented; in such situations, specific flare or vent gas meters are not required;* ▪ *acid gas flared, either continuously or in emergencies, from gas sweetening systems regardless of volume; and* ▪ *fuel (dilution or purge) gas added to acid gas to meet minimum acid gas heating value requirements or AAAQO.* *Volumes < 500 m^3* *The ERCB recommends to meter total flare streams in larger oil and gas batteries, pipeline facilities, and gas processing plants where there could be multiple connections to the flare system from sources such as process equipment, storage tank vents, pressure-relieving valves, manual blowdowns, and emergency vent valves, even when the volume is less than 500m^3/d on a yearly average.*

Name of regulatory Scheme	*Directive 060: Upstream Petroleum Industry Flaring, Incinerating, and Venting*
	The 060 Directive also specified that a licensee, operator, or approval holder must also: ▪ *minimize fuel gas use for flare header purge, flare and incinerator pilots (at gas plants);* ▪ *log and monitor non-routine flaring events.*
Frequency	*According to the Directive 017 "Measurement Requirements for Oil and Gas Operations:* *All gas production and injection must be continuously and accurately measured with a measurement device or determined by engineering estimation if exception conditions described below are met or site-specific ERCB approval has been obtained.* *The frequency of gas meter element calibration must be* *• within the first calendar month of operation of a new meter,* *• immediately (by the end of the calendar month) following service or repairs to the meter,* *• semiannually thereafter if the meter is used in a gas plant or for sales/delivery point (royalty trigger points), see Section 1.7.2 for details, and* *• annually for all other meters.* *The required frequency for inspection of the gas meter primary measurement element is semiannually for gas plant accounting meters and sales/delivery point (royalty trigger point) meters and annually for all other gas meters.* *The Directive 017 also specifies calibration requirements for other devices, such as orifice meters, and defines exceptions from these requirement, regulates proving[63] of meters*
Methodology	*Conservation facilities must be designed for a minimum of 95% conservation. Dispersion modeling can be done with the ERCB's ERCBflare.xls and ERCBincin.xls spreadsheets, available on the ERCB website. This is to help the user and the ERCB determine if there are any risks to exceeding the AAAQOs.* *Meters designed for the expected flow conditions and range must be used.* *Estimates are allowed only If the measurement is not required (as listed in the Boundaries section above) and the following conditions are met:* *1) reliable and consistent flared, incinerated, and vented gas estimating and reporting systems are in use, including:* *a. Estimating systems account for all gas flared, incinerated, and vented from the facility (expressed to the nearest 100 m^3/month) during routine, emergency, and maintenance operations, well deliverability testing, and the depressurising of vessels, compressors, and pipelines.* *b. Volume estimates are based engineering calculations.* *c. Procedures or use of software for estimating flare and vent volumes have been developed by a technically knowledgeable person.*

[63] Proving is defined as the procedures or operations whereby a prover volume is compared to an indicated meter volume (both corrected to applicable pressure and temperature conditions)

Name of regulatory Scheme	*Directive 060: Upstream Petroleum Industry Flaring, Incinerating, and Venting*
	d. A formal system for consistently estimating and reporting is in place for flared volumes that are not captured by existing flare meters. *2) documentation describing flared and vented gas estimating and reporting procedures, as well as related operating logs are made available for review by the ERCB upon request.* *3) estimating requirements for heavy oil/oil sands operations are provided in the Directive 017.* *4) installation of meters may be requested by the ERCB in case where there are failures to demonstrate adequate flare or vent gas estimating and reporting systems.* *Directive 017 specifies gas measurement and accounting requirements for various battery/facility types, meter selection, design and installation standards*
Use of standards	*Directive 017 provides design and installation standards for each meter type.* *General Calibration Requirements for gas meters state that calibration procedures must be in accordance with the following (as available and applicable):* ▪ *procedures specified by Measurement Canada,* ▪ *procedures described in the API Manual of Petroleum Measurement Standards (MPMS),* ▪ *the device manufacturer's recommended procedures, or* ▪ *other applicable industry-accepted procedures* *Inspections must be done in accordance with procedures specified by the API, the American Gas Association (AGA), or other relevant standards organizations, other applicable industry-accepted procedures, or the device manufacturer's recommended procedures, whichever are most applicable and appropriate.* *The Canadian Association of Petroleum Producers (CAPP) has developed for reducing flaring/venting, for example:* ▪ *Best Management Practices (2006) – the document presents a recommended approach to identify routine and non-routine flare sources and quantities, as well as assess the opportunity for reduction of flare volumes and frequency at their operated facilities. It can also apply to routine and nonroutine venting.*[64] ▪ *Guide for Estimation of Flaring and Venting Volumes from Upstream Oil and Gas Facilities (2002) – it describes flaring and venting sources together with suggested estimation methods and sample calculations.*
Uncertainty treatment	*According to the Directive 017 "Measurement Requirements for Oil and Gas Operations:*

[64] Available at: http://membernet.capp.ca/raw.asp?x=1&dt=NTV&dn=114231

Name of regulatory Scheme	Directive 060: Upstream Petroleum Industry Flaring, Incinerating, and Venting
	Oil systems/Total battery gas -Single point measurement uncertainty for the equipment and/or procedures used to determine: ▪ the measured gas volumes (when measurement is required) - 3.0% ▪ gas-oil ratios or other factors to be used in estimating gas volumes ≤ 500 m^3/d – 10.0% Gas systems/Flare gas-Single point measurement uncertainty for the equipment and/or procedures used to determine the measured gas volumes = 5.0% NB: The Directive provides uncertainty requirements for a number of items within oil and gas systems, for example: acid gas[65], well gas.
Quality assurance	Licensees must investigate and correct causes of repeat nonroutine flaring, incinerating, and venting. The licensee, operator, or approval holder must be able to demonstrate that volumes of gas are accurately and consistently determined.
Reporting	
Scope	Measurement and reporting requirements apply to the licensee, operator, or approval holder of oil, bitumen, and natural gas production and processing facilities. Incinerated gas must be reported as flared, if an incinerator is used in place of a flare stack. This is not applicable to acid gas streams at a gas plant that are flared or incinerated as part of normal operations; in these cases the flared or incinerated acid gas should be reported as acid gas shrinkage, not flared. Fuel gas that is flared, incinerated, or vented (e.g., flare pilot gas, header purge gas, storage tank blanket gas) must be reported as fuel gas, not flared gas. For facilities that do not require a licence (such as small booster compressors), the flared and vented volumes must be reported at the nearest upstream reporting well, battery, or pipeline facility. Flared, incinerated, and vented solution gas: ▪ volumes of gas greater than or equal to 100m^3/month (adjusted to 101.325kPa and 15°C) that are flared, incinerated, or vented from routine operations, emergency conditions, and the depressurizing of pipeline, compression, and processing systems ▪ all new oil well production, including the test period; a battery code needs to be obtained for any new oil wells before production, including flaring, can be reported. Solution gas flared at gas plants during plant shutdowns lasting more than seven days can be deducted in calculating the annual flared volumes. Yet, these solution gas volumes must be documented and provided to the ERCB upon request.

[65] Acid gas is defined as gas separated in the treating of solution or non-associated gas that contains hydrogen sulphide (H_2S), totally reduced sulphur compounds, and/or carbon dioxide (CO_2).

Name of regulatory Scheme	*Directive 060: Upstream Petroleum Industry Flaring, Incinerating, and Venting*
	Major flaring events must be flagged (Section 5.3 provides a definition of a major flaring event). If a sixth major flaring event occurs within any consecutive (rolling) six-month period, a written "exceedance" report must be submitted to the appropriate ERCB Field Centre and copy of this report needs to be sent to the ERCB Technical Operations Group within 30 days of the occurrence of the sixth flaring event. The report needs to *i. provide data on all flaring events (volume and duration) for the consecutive (rolling) six-month period in question and their possible causes.* *ii. propose a plan and corresponding timeline for implementing corrective actions to ensure that frequent major nonroutine flaring does not recur.* *Well test data:* ▪ *Any produced volumes, including those flared, incinerated, or vented,* ▪ *fluid volumes and fuel consumption;* ▪ *all gas analyses from samples gathered at the wellhead.* *Furthermore, well tests that require permits must submit a Sour Gas Flaring/Incineration Data Summary Report to the ERCB Technical Operations Group.* *Non-routine production and cases of total volumes < 500 m^3:* *The reporting requirement may be waived.* *Fuel gas used for pilots and flare header purge gas:* ▪ *Fuel gas used in flare systems (including fuel gas make-up to acid gas flares) is to be reported as part of the total fuel gas volume on the Petroleum Registry of Alberta.* ▪ *Fuel gas added to flare systems must be subtracted from the measured flare volumes if total flare gas measurement is used downstream of the fuel gas entry point.* *Gas well tied into an oil battery: this gas needs to be reported on a separate production statement (for a gas battery) showing the gas delivery to the oil battery. A similar requirement is in place for oil well gas delivered to a gas battery.*
Frequency	*Flared, incinerated, and vented solution gas: monthly through the Petroleum Registry of Alberta (PRA) as described in Section 10 and in accordance with the Directive 007.* *Well test data: within three months of completing the fieldwork. The same applies to Sour Gas Flaring/Incineration Data Summary Report.* *Fluid volumes and fuel consumption must be recorded and reported on the monthly production submissions*
Form (reporting format)	*The licensee, operator, or approval holder must notify the appropriate ERCB Field Centre in advance of planned flaring, venting, or incinerating operations. To notify an ERCB Field Centre, the licensee, operator, or approval holder must complete and submit an ERCB Flaring/Incinerating/Venting Notice Form within FIS3 of the ERCB's Digital Data Submission system.*

Name of regulatory Scheme	Directive 060: Upstream Petroleum Industry Flaring, Incinerating, and Venting
	Flared, incinerated, and vented solution gas: through the Petroleum Registry of Alberta (PRA). Flaring of sour gas must also be reported on the S-30 Monthly Gas Processing Plant Sulphur Balance Report. *Well test data: submissions must be in a pressure ASCII standard (PAS) format and submitted via the Well Test Data Capture system in DDS.*
System transparency (public database, information disclosed)	*The ERCB compiles data from monthly reports into an annual report and publishes it in "ST60B: Upstream Petroleum Industry Flaring Report" (available on the ERCB website).* *Copies of "ST60: Crude Oil and Crude Bitumen Batteries Monthly Flaring, Venting, and Production Data" and "ST60A: Crude Oil and Crude Bitumen Batteries Annual Flaring, Venting, and Production Data" can be viewed in the ERCB Library or purchased.*
Verification requirements	
Process	*The verification of a report is not required.* *Any enclosed combustion technology not meeting the 060 Directive requirements (minimum exit temperature and minimum residence time) must submit third-party verified conversion efficiency test results to the ERCB Technical Operations Group for approval, unless the facility is subject to an EPEA approval. Test programs and submissions must be provided by a qualified technical professional[66].*
Methodology	*Not applicable*
Assurance requirements	*Not applicable*
Third party	*Not applicable*
Other requirements	
Retention of information	*A log of flaring, incinerating, and venting events and responses to public complaints has to be maintained. This log needs to:* ▪ *describe each non-routine flaring, incinerating, and venting incident and any changes implemented to prevent future non-routine events of a similar nature from occurring;* ▪ *the date, time, duration, gas source or type (e.g., sour inlet gas, acid gas), and volumes for each incident.* ▪ *be kept for a minimum of 12 months.*

[66] The 060 Directive specifies *a qualified technical professional* as a Professional Engineer, Certified Technician, Certified Engineering Technologist, or Registered Engineering Technologist, as recognized by APEGGA or ASET, or the equivalent.

Appendix 4: Comments on non-shortlisted schemes

The UK Quality Assurance Scheme for Carbon Offsetting:

- Already closed by the UK Government, but a coalition of carbon offset providers tries to keep it alive (http://www.qascarbonoffsetting.com/).
- The scheme was introduced to provide a straightforward way for consumers and businesses to identify quality offsets.
- The approved offsets under the Scheme included: CERs (from registered CDM projects), ERUs (from registered JI projects), Assigned Amount Units (AAUs) and phase 2 European Union Allowances (EUAs). VERs have been under consideration.
- Emission calculation methods that have been allowed under the scheme: Defra Voluntary Registry Guideline, WCI GHG Protocol, ISO standards.
- Sources for emission factors: Defra/DECC's GHG Conversion Factors.
- This scheme does not target industrial sectors. It is mainly for individual consumers and businesses.

US EPA Climate Leadership Offsets

- Terminated in 2010.
- Available methodologies (types of qualifying projects): captured methane end use, commercial boiler, industrial boiler, landfill methane, manure management, reforestation/afforestation, and transit bus efficiency.

Australia's GHG Friendly/National Carbon Standard

- This mark/brand is used to demonstrate carbon neutrality of a product, organisation or part of an organisation.
- Qualifying offset schemes include: CERs (except long-term CERs and temporary CERs); ERUs, Removal Units (generated & issued by Kyoto Protocol Annex I Parties for carbon absorption by LULUCF activities); AAUs; VERs (Gold Standard credits), VCUs, and Australian credits.
- Requirements for applicants:
    - measure the carbon footprint,
    - monitor and reduce emissions (to the extent possible),
    - purchase and cancel sufficient eligible offsets to offset remaining emissions associated with an organisation or product.
- Approaches allowed under the scheme: GHG inventory for an organisation; and Life-Cycle Assessment for a product.

Japan's Certification Centre on Climate Change

- Plays a role of the secretariat for various schemes in Japan, namely:
    - Carbon Offset Providers' Disclosure Programme – this is to review whether offset providers run their business along the guidelines for carbon offsetting introduced by Japanese gov.)
    - Japan Verified Emission Reduction (J-VER) Scheme – this scheme is based on verification & certification process according to ISO 14064:2; ISO 14064:3, and ISO 14065 (NB: the same as VCS for which we already developed the table)
    - Public Certification Scheme for Carbon Offsetting – this programme is to encourage GHG emission reductions credible carbon offsetting serviced by providing the third party check. It is like a labelling scheme applicable to products & services; meetings & events; buildings, retail & consumer goods manufacturers.

Task 5

1. Introduction

1.1 Objectives of project

The first objective of this study is to describe the technical, economic and regulatory variables that affect the potential for improving/incentivising upstream GHG reductions (Task 1, 2 and 3). This entails presenting the most economically preferred approaches utilized to date with the use of marginal abatement curves (MACs) for upstream GHG reductions and conducting sensitivity analysis on the pertinent technical, economic and regulatory parameters to highlight potential economic drivers that could facilitate further investment in GHG reductions.

The second objective is to develop guidelines and principles for the development of methods/best practices for measuring and verifying GHG emission reductions and guidelines for legislators for screening, evaluating and selecting existing and future schemes, carbon credit standards or certification programmes that ensure that GHG emission reductions are aligned with the requirements prescribed in the draft implementing measure (Task 4 and 5).

1.2 Objectives of the task

This task aims to provide the EC with an overview of a potential scheme for estimating and verifying emission reductions resulting from projects reducing Associated Petroleum Gas (APG) flaring/venting in the oil & gas sector. Guidelines on key aspects of the potential scheme and critical issues therein have been prepared to assist legislators in the decision-making process. These guidelines have been developed to meet the purpose of Article 7a of the amended Fuel Quality Directive (FQD), 2009/30/EC.

To meet this objective the following tasks have been performed: desk-based analysis of potential projects based on the results of Task 1 and Task 2, and exploration of lessons learned from Task 4.

2. Observations

2.1 Introduction to the oil & gas industry and flaring/venting activities

Global flaring and venting of gas associated with petroleum production is a significant source of greenhouse gas emissions and airborne pollutants. According to estimates from satellite data, global flaring levels rose by 1.9% in 2011, compared to the 2010 level[67]. In 2011, 140 billion m^3 of gas was flared, an amount equivalent to 4.3% of world natural gas consumption which totalled ca. 3,200 billion m^3 in 2011[68]. This amount of flaring produces approximately 250 million tonnes of CO_2 emissions annually, comparable in magnitude with total CO_2

[67] Global Gas Flaring Reduction (GGFR), Estimated Flared Volumes from Satellite Data, 2007-2011: http://web.worldbank.org/WBSITE/EXTERNAL/TOPICS/EXTOGMC/EXTGGFR/0,,contentMDK:22137498~pagePK:64168445~piPK:64168309~theSitePK:578069,00.html

[68] BP, World Natural Gas Consumption – Historical Data, http://www.bp.com/extendedsectiongenericarticle.do?categoryId=9041231&contentId=7075259

emissions in a medium-sized country, such as Spain[69]. Flaring can also be a source of pollutants such as particulate soot, sulphur dioxide (in cases where the flare gas contains sulphur compounds such as hydrogen sulphide, H_2S), unburned fuel, and other undesirable by-products of combustion.

In addition to flaring, direct venting of gas is a significant source of emissions during oil production. Over 100 billion m^3 of gas is estimated to be lost annually by the global oil and gas industry[70]. Given that the principle constituent of associated gas from oil production is methane, and that methane has a global warming potential that is 25 times greater than CO_2 over a 100-year period[71], the global GHG emissions from venting are significantly greater than flaring (i.e., on the order of 2.6 billion tonnes CO2 equivalent).

More than 80% of global venting and flaring occurs in fewer than 15 countries, including Nigeria, Russia, Iran, Iraq, Angola, Qatar, Algeria, Venezuela, Equatorial Guinea, Indonesia, Brazil and Mexico.

There has been an international push to reduce gas flaring and venting through the World Bank's Global Gas Flaring Reduction (GGFR) partnership and the Global Methane Initiative (GMI). The majority of GGFR partners have endorsed a voluntary standard for flare and vent mitigation, and both the GGFR partnership and GMI actively promote demonstration projects to reduce flaring and venting. However, in mid-2012 the World Bank called for strengthening and even scaling up efforts to reduce flaring in light of the latest increase[72].

2.2 Characteristics of flaring/venting projects, emission reduction potential and impact on targets

In principle, there are a range of alternatives for dealing with surplus APG that would otherwise be directed to a flare or vent. These can include the collection and compression of gas into pipelines for processing and sale; the generation of electricity or co-generation of heat and electricity using conventional gas turbines, microturbines, or other gas-fired engines; and the compression and reinjection of the gas back into an underground reservoir for enhanced oil recovery (EOR). For very large volumes of remotely located associated gas, gas-to-liquid (GTL) conversion of natural gas into more valuable and more easily transported liquid fuels, or production of liquefied natural gas (LNG) to facilitate transport to distant markets, are also potential options.

Task 1 analysed historical projects that reduce greenhouse gas (GHG) emissions from APG flaring or venting. 31 projects were identified in countries from which the European Union imports crude oil, with the primary focus being on the largest crude suppliers.

The majority of projects focus on capturing APG that otherwise would have been flared and sending it to an existing pipeline for sale. The GHG reduction potential of these types of projects was estimated to range from 0.8 tCO_2e per Mbbl to 420 tCO_2e per Mbbl. Yet, most projects fell in the 1 to 25 tCO_2e per Mbbl range.

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[69] Trends in global CO_2 emissions; 2012 Report, http://edgar.jrc.ec.europa.eu/CO2REPORT2012.pdf

[70] Global Methane Initiative Oil and Gas Subcommittee: Achieving Environmental, Economic and Operational Benefits by Reducing Oil & Natural Gas Sector Methane Emissions, October 2011: http://www.globalmethane.org/documents/events_oilgas_101411_tech_bylin.pdf

[71] 2007 IPCC Fourth Assessment Report (AR4): http://www.ipcc.ch/publications_and_data/ar4/syr/en/contents.html

[72] World Bank, *World Bank Sees Warning Sign in Gas Flaring Increase*, July 2012, http://www.worldbank.org/en/news/2012/07/03/world-bank-sees-warning-sign-gas-flaring-increase

The remaining projects identified in the study include routing APG to a power plant to generate electricity, constructing a processing plant to remove hydrocarbon liquids for sale, building a Liquefied Natural Gas terminal, and using gas in enhanced oil recovery operations. These projects highlighted GHG reduction opportunities of 20 tCO_{2e} per Mbbl or higher.

In all, the GHG reduction potential per barrel of oil produced varies based on how much gas is associated with the oil (i.e., gas-to-oil ratio (GOR) and how the ratio changes over time), the CO_2 content and oil extraction techniques utilised. Generally, APG volume decreases with the oil production over time. As oil fields mature and oil production declines; energy-intensive techniques such as water or gas injection must then be used to extend production levels, potentially resulting in increased gas emissions.

The capital cost varies significantly across the projects (i.e., based on available data, costs can range from ca. 1 million USD to hundreds of USD millions). Costs typically depend on the planned APG end use, gas separation and gathering infrastructure, length of transportation pipelines to the end-users, and quality (purity) of gas and required treatment facilities, to name a few factors.

2.2.1 Overview of the potential windfall profits

In Task 2, the *Financial Viability and Historical MAC Curve Analysis* demonstrated that in 2020 approximately 19.9 $MtCO_2e$ of emissions from APG flaring/venting can be cost-effectively reduced. Moreover, if additional incentives for emissions reductions were available, such as a carbon price, further emission reductions could be cost-effectively achieved. In summary, the MACs illustrate that a significant portion of the identified mitigation potential can be realized at a zero cost (i.e., a project can be installed for a cost equal to the energy or other savings that would be realized). This, on the other hand, suggests that operators could potentially benefit from windfall profits, if the EC were to develop an offset scheme with a carbon pricing to meet the objectives of the FQD, Article 7a.

However, the risk of windfall profits can be deemed low, considering that the MAC analysis assumes that high project costs (i.e., gas gathering lines, compressor stations, and gas treatment facilities) are offset by gas sales to market. The MAC analysis assumes a constant gas price per country over the project lifetime. In reality, gas prices will fluctuate over time, along with gas volumes[73], and in many regions the identification of a local end user who can utilise all the gas is not so straightforward[74]. Thus, APG investment decisions can be highly complex and uncertain.

This is supported by the fact that representation of APG projects in the voluntary market is non-existent, and in the CDM and JI pipelines it is very low (10 projects registered out of total 6,556 (0.15%) and 19 projects registered out of total 495 (4%), respectively). The

[73] The gas-to-oil ratio (GOR) of a field is not constant, but usually increases during a field's early life and decreases near the end. However, this depends on how pressure is maintained in the reservoir. This fluctuation in gas production can make estimating profitability of APG recovery projects difficult.

[74] In many countries, especially developing nations, the demand for natural gas and natural gas products is far lower than production. In these instances, a demand for gas must be created to develop a viable economic recovery project. If the gas needs to be transported to another market, then this will result in additional major infrastructure investments to either develop transnational pipelines, or potentially even liquefied natural gas (LNG) facilities. Both of these options are very complicated logistically, as well as costly.

anticipated GHG reductions per year from the CDM and JI registered projects are 8.8 million tCO_2e/yr and 27.2 million tCO_2e/yr, respectively.

3. Simplified checklist with guidelines for policy makers

3.1 Lessons learned from Task 4: recommendations for a potential EC scheme

Under Task 4, several legislative and voluntary schemes for GHG emission reductions (i.e., UNFCCC Clean Development Mechanism (CDM), Verified Carbon Standard (VCS), Alberta Specified Gas Emitters Regulation (SGER), Alberta Offset Scheme (AOS), and EU ETS) monitoring, verification and reporting were analysed against a variety of features, such as:

- Compliance, including *inter alia* options for compliance, exclusions, and incentives;
- Methodology, including emission reductions estimation approaches;
- Monitoring, including *inter alia* boundaries, frequency, and uncertainty treatment;
- Reporting, including scope, and frequency;
- Verification, including approach and assurance requirements; and
- Other, such as addtionality requirements.

Other than the EU ETS, which has been included as a benchmark for EC monitoring, verification and reporting compliance requirements; only the UNFCCC's CDM has registered flare reduction projects.[75]

The Task 4 comparison enabled the assessment of each scheme's strengths and weaknesses, and the drafting of preliminary recommendations for a potential EC scheme. These lessons learned included:

Compliance

- The principles of any potential scheme, either voluntary or prescriptive, shall adhere to the legislative requirements of the Fuel Quality Directive, Article 7a. The scheme should be treated as one of the compliance options within the regulation, giving the targeted parties flexibility in choosing the most cost-effective approach for compliance, similar to the SGER and EU ETS.

Additionality

- The additionality requirements should follow a *standardised* approach (e.g., AOS), rather than a stricter *project-specific* approach (e.g., such as the CDM) to ensure that the project approval process is streamlined and transparent, and not prohibitive. Assuming a *standardised* approach, similar to the AOS, implies that additionality should be based on simple, but robust criteria, such as 1) reductions exceed legal requirements; 2) reductions are real (i.e., specific and identifiable actions that reduce or remove GHGs); 3) reductions demonstrate a net reduction in GHGs; and 4) reductions are quantifiable.

Methodology

- Considering that the CDM provides the only scheme where APG projects have been developed and submitted for registration, it provides a good baseline to assess the

[75] As of March 2013, 10 flare reduction projects have been registered out of a total 50 projects submitted into the CDM pipeline (i.e., a 20% success rate). These registered projects have an *ex-ante* reduction potential of 8.8 million tCO_2e per year.

anticipated size of projects that could be submitted to a potential EC scheme. In March 2013, there have been 10 projects registered, 1 project requesting registration, and 20 projects at validation. Assuming the MRV installation categories: 6 projects have emissions *<50ktCO2/yr* (Category A); 14 projects have emissions of *>50<500 ktCO2/yr* (Category B); and 11 projects have emissions of *>500 ktCO2/yr* (Category C). As such, the existing MRV installation categories provide a good starting point for the EC scheme.

- Project emission reductions (ER) can be defined as:

  ER = BEy – PEy; where:

  BEy = Baseline emissions in year y (tCO2e), which is the sum of emissions associated with the transportation and flaring of the associated gas in year y

  PEy = Project emissions in year y (tCO2e), which is the sum of emissions associated with fuel (including electricity) consumed by the project activity in year y

  Emissions should be estimated using a calculation-based methodology, similar to the MRV. That is,

  CO2 emissions = Activity data (gas flow to flare) x Emission factor x Oxidation factor

- Although the MRV applies calculation Tier levels for different installation categories, we recommend a slightly adapted approach (Figure 1), which recognises the need for field data rather than default factors (for gas flow rates to the flare and flaring emission factors) to ensure the accuracy of emission reduction estimates.

Figure 1: MRV estimation and accuracy requirements for emitting installations

Annual Emissions (installation category)	*Gas flow to flare*		*Combustion emission factor*		*Oxidation factor*	
	Tier	*Accuracy*	*Tier*[76]	*Accuracy*	*Tier*	*Accuracy*
<50 ktCO2/yr (A)	*3*	*± 7.5%*	*2b*	*Operator measured or laboratory analysis*	*1*	*Reference value*
>50<500 ktCO2/yr (B)	*3*	*± 5%*	*3*	*Operator measured or laboratory analysis*	*1*	*Reference value*
>500 ktCO2/yr (C)	*3*	*± 2.5%*	*3*	*Operator measured or laboratory analysis*	*1*	*Reference value*

- Uncertainty assessment principles should be set in the proposed scheme. Such principles should be modelled on the basis of the MRV, with accuracy requirements for calculation parameters defined by the installation category (i.e., Category A, B or C).
- Methodology(ies) for APG flaring/venting reduction should have robust applicability criteria, allowing different project designs to use it, instead of developing a new methodology for each specific situation (which is the case with CDM).
- Monitoring plans should be developed before project implementation, and subject to validation of the project.
- Use of international standards should be encouraged for monitoring and sampling.

Structure and Responsible Parties

[76] Tier 2b uses installation-specific emission factors derived from an estimate of the molecular weight of the flare stream, with use of process modelling based on industry-standard models. By considering the relative proportions and the molecular weights of each of the contributing streams, a weighted annual average figure is derived for the molecular weight of the flare gas. Tier 3 is calculated from the carbon content of the flared gas applying the specific provisions given in the MRV Guidelines (Section 13 of Annex I).

- The EC, as the regulating authority, will be responsible for defining the harmonised guidelines for the proposed scheme, which will include the project methodology, GHG calculation methodology, additionality, and MRV requirements. The EC should aim to review and update the guideline, where necessary, every 5 years[77].
- The project's approval process needs to be straightforward, with minimised administrative burden. Similar to the AOS, one party should be involved in the assessment of a project's eligibility. For the proposed scheme, an entity certified by a professional MS accreditation body (e.g., the UK Accreditation Service (UKAS)) can be responsible for project validation.
- Verification entities should be certified under a professional MS accreditation body (e.g., the UK Accreditation Service, (UKAS) accredits companies for EU ETS verification). Entities already certified for EU ETS verification should be applicable. At a minimum, it is expected that verification entities should be trained in ISO 14064 Part 3 – Greenhouse Gases: Specification with guidance for the validation and verification of greenhouse gas assertions.
- Validation and verification can be provided by the same accredited body.
- The designated MS authority should form the last stage of approval, which would include the confirmation that all procedures have been fulfilled in issuing a validation decision, and whether the project documentation is complete and consistent.
- To ensure double counting is avoided, emission reductions (carbon credits) should be serialised. The owner of a carbon credit needs to have an account in a dedicated registry/log, in which any transfer, cancellation or retirement of a carbon credit is captured. This should be the responsibility of the designated MS authority (e.g., environment departments/ agency within MS governments).
- It is advised to introduce a specific limit on the time that validation/verification bodies can take to assess a project, after which time the project is deemed acceptable by default. This would require senior management accountability within the validation/verification bodies if errors are made by their teams, which should in turn ensure adequate resourcing. The work of these bodies should be subject of regular audits and spot checks.

The above preliminary findings formed the basis for developing comprehensive guidelines for a potential EC scheme, which are presented in the subsequent section of the report.

3.2 Key aspects of a potential scheme

This section provides guidelines on a potential scheme design. The checklist given in the table discusses several aspects and for each indicates key features, which should be treated as suggestions for further discussion and wider stakeholder consultation. Moreover, it should be noted that the lists of aspects and points to consider within each aspect are not exhaustive.

[77] Similar to the AOS

General characteristics	*Checklist*
Objectives of a scheme	▪ *Linked to the legislative requirement of the Fuel Quality Directive (FQD), Article 7a;* ▪ *Aimed to help suppliers meet the 6% reduction target of life cycle GHG intensity (emissions per unit of energy) of fuel supplied by the end of 2020;* ▪ *Voluntary or prescriptive scheme* ▪ *Reductions claimed are eligible towards the supplier's EU-ETS or the Member State's Kyoto obligations, provided they meet the necessary requirements set by the EC.*
Implementation/enforcement entity	▪ *European Commission (e.g., DG Clima) to be responsible for harmonised guidelines (covering, project methodology, GHG calculation methodology, additionality, and MRV requirements)* ▪ *Authority designated by the Member State (e.g., environment departments/ agency within MS governments) to be responsible for approval of project applications, registering the projects and managing the log of reductions achieved and claimed towards the FQD target.*
Targeted sector(s)	▪ *Upstream emissions of fossil fuels: extraction and processing of oil* ▪ *Sites located in countries supplying a significant proportion of EU oil consumption*
Start date	▪ *Reductions to be claimed from the date of a project becoming operational*
Compliance	
Applicability criteria	▪ *Associated Petroleum Gas (APG) flaring/venting reduction projects that utilise APG for onsite/offsite energy generation, fuel for equipment operation e.g. compressors, feed for other products manufacture, enhanced oil recovery;* ▪ *Reductions achieved after start of FQD, Article 7a* ▪ *Reductions claimed under the scheme have not been claimed and retired under any other scheme (e.g., CDM, VCS, EU ETS)* ▪ *Reductions must be real (i.e., specific and identifiable actions that reduce or remove GHGs)* ▪ *Reductions must demonstrate a net reduction in GHGs* ▪ *Reductions must be quantifiable* ▪ *Reductions have to be third party verified; and registered on the designated registry.*
Additionality criteria and demonstration	▪ *Additionality requirements not to be prohibitive, i.e., building on approach/requirements developed by the AOS and VCS;* ▪ *Reductions achieved to be beyond the current and planned (known to be implemented) requirements of national legislation;*
Exclusions	▪ *Applicability conditions not being met;* ▪ *Projects using non-approved methodology/protocol*
Options for compliance	▪ *All applicability conditions are met* ▪ *Projects to be implemented according to the conditions outlined in the project plan and associated monitoring plan. In case of changes in operations, these have to be documented in the offset project report which is prepared annually or prior to a third party verification.*
Control system	▪ *Projects to be subject to validation by a designated MS authority;* ▪ *Achieved emission reductions subject to verification by a designated third-party body. NB: validation and verification can be provided by the same body;* ▪ *Time limit to be introduced for validation/registration process (e.g. no more than 6 months) from the submission of a project*

<table>
<tr><td></td><td>application to the scheme;
▪ The work of validation/verification bodies should be subject of regular audits and spot checks;
▪ A percentage of supplier's compliance submissions to be audited by EC authorities annually.</td></tr>
<tr><td>Consequences of non-compliance</td><td>▪ Revoking of reductions towards the supplier's claim of target achievement;
▪ Fine paid into a specified fund (similar to Alberta's Climate Change and Emissions Management Fund)</td></tr>
<tr><td>Monitoring plan or flare/vent management plan</td><td>▪ A monitoring plan to be developed as part of the project validation/registration and subsequently subject to verification; the content requirements can be borrowed from existing schemes, e.g. CDM or EU ETS.</td></tr>
<tr><td>Methodology</td><td></td></tr>
<tr><td>Emissions measurements and calculation methods</td><td>▪ Either a crediting period is established (e.g., (8-10 years) or it applies to the project lifetime (i.e., APG projects have a relatively short lifetime, as the amount of gas reduces over time. So, the project could claim credits as long there is sufficient APG to meet project operational requirements).
▪ Emission reductions to be estimated using a calculation-based methodology (CO_2 emissions = Activity data (gas flow to flare) x Emission factor x Oxidation factor), where activity data and emission factor are calculated based on field data (e.g., flow meters, laboratory analysis), not defaults.
▪ Emission reductions to be a result of deducting Project Emissions from Baseline Emissions;
▪ Emissions sources to be accounted include: APG capture, processing, transportation and use (including flaring/venting in routine and non-routine situations)
▪ Methodology(-ies) for APG flaring/venting reduction to have flexible scope, allowing different project designs to use it, instead of developing a new methodology for each specific situation – for example, simplify and combine CDM methodologies into one protocol.</td></tr>
<tr><td>Levels of accuracy (sources of data)</td><td>
<table>
<tr><td>Annual Emissions (installation category)</td><td colspan="2">Gas flow to flare</td><td colspan="2">Combustion emission factor</td><td colspan="2">Oxidation factor</td></tr>
<tr><td></td><td>Tier</td><td>Accuracy</td><td>Tier</td><td>Accuracy</td><td>Tier</td><td>Accuracy</td></tr>
<tr><td><50 $ktCO_2$/yr (A)</td><td>3</td><td>± 7.5%</td><td>2b</td><td>Operator measured or laboratory analysis</td><td>1</td><td>Reference value</td></tr>
<tr><td>>50<500 $ktCO_2$/yr (B)</td><td>3</td><td>± 5%</td><td>3</td><td>Operator measured or laboratory analysis</td><td>1</td><td>Reference value</td></tr>
<tr><td>>500 $ktCO_2$/yr (C)</td><td>3</td><td>± 2.5%</td><td>3</td><td>Operator measured or laboratory analysis</td><td>1</td><td>Reference value</td></tr>
</table>
▪ Accuracy requirements based on installation category (A, B or C), i.e., the emissions associated with the flared gas.
▪ Recommended to follow the approach of AOS with regards to negligible emissions. That is, AOS defines negligible emissions as emission sources that are extremely small (on the order of tonnes per year) that are difficult to quantify and unlikely to change over time. Emission sources, regardless of size, that are integral to the offset project quantification cannot be excluded. Project developers are requested to identify negligible emissions in the offset project plan, and reassess these emission sources periodically to make sure the assumptions made in the project plan remain valid.</td></tr>
</table>

Sources for emission factors	▪ *Tier 1 (oxidation factor) is estimated based on IPCC default values.* ▪ *Tier 2b uses installation-specific emission factors derived from an estimate of the molecular weight of the flare stream, with use of process modelling based on industry-standard models. By considering the relative proportions and the molecular weights of each of the contributing streams, a weighted annual average figure is derived for the molecular weight of the flare gas.* ▪ *Tier 3 (emission factor) is calculated from the carbon content of the flared gas applying the specific provisions given in the MRV Guidelines (Section 13 of Annex I).Tier 3 (flow rate) is calculated from meter data, purchasing records.*
Uncertainty Treatment	▪ *Accuracy requirements as presented in the ETS MRV to be followed, as it is sufficiently comprehensive in this respect.* ▪ *Uncertainty to be assessed and approved once, at the stage of permit issuance (i.e., verification)*
Quality Assurance	▪ *The project proponents have to maintain and calibrate measuring equipment regularly.* ▪ *The gas compositional analysis should be taken in line with national or international fuel standards.* ▪ *The project proponents have to demonstrate that they developed (and implemented) a robust monitoring plan, which is described in detail in the project plan* ▪ *Quality management procedures to manage data and information shall be applied and established.*
Monitoring	
Boundaries	▪ *Depending on the project design, but should include emissions associated with the transportation and flaring of the associated gas, as well as the sum of emissions associated with fuel (including electricity) consumed by the project activity.* ▪ *Recommended to follow the approach of CDM with regards to abnormal events (e.g. shutdown, emergency) – they are indirectly captured by the calculations of emission reductions (e.g., higher diesel use in generators in case of emergency situation or back-up need is reflected in higher project emissions due to fossil fuel consumption; volumes of gas flared/vented are not included in calculations of either baseline and project emissions, therefore the more gas is flared/vented the less emission reductions can be expected due to lower amount of associated gas used).* ▪ *Yet, project proponents to keep a log of abnormal events to be able to explain relatively large differences between estimated and achieved emission reductions. Such explanation should be given in a Monitoring Report for a given monitoring period.*
Frequency	▪ *Parameter-specific, for example* o *Volumes of APG – measured continuously by meters* o *Volumes of each fuel type – continuous metering or monthly reconciliation* o *Sampling of APG composition – at least weekly by laboratory analysis*
Methodology	▪ *Parameter-specific – i.e., activity data obtained by means of measurement systems, purchasing records; emission factors from laboratory analyses, and oxidation factors from reference.* ▪ *Use of international standards to be encouraged for monitoring and sampling, like in the case of existing schemes;* ▪ *Monitoring methodology to be part of the monitoring plan.*
Uncertainty treatment	▪ *Same as described in the "Methodology" section*
Quality assurance	▪ *Obligations of a project operator as set in the EU ETS to be followed;* ▪ *Following national or international standards to be encouraged where possible, for example for gas compositional analysis.*

Reporting	
Scope	▪ *The project's approval process to be straightforward, with minimised administrative burden: an accredited body should assess the project's eligibility (validation); the approval by the designated MS authority should be focused on checking whether all procedures have been fulfilled in issuing a validation decision, and whether project documentation is complete and consistent.* ▪ *Level of assurance to be determined by the EC* ▪ *Recommended to set a limit on the time that validation entities can take to assess a project, after which time the project is deemed acceptable by default.* ▪ *The set of documents required for validation/approval and verification similar should include: project design document, emission reductions calculation model, and validation report needed for project approval/registration, monitoring report, and verification report). The content of documents could be based on CDM or AOS templates.*
Frequency	▪ *At validation/approval and verification stages*
Verification requirements	
Process	*Project-specific verification criteria to test whether all emission sources are included and negligible emissions sources are clearly documented, that the appropriate calculations, emissions factors etc, for the emission sources are being used.* *Verification process covers the following:* *8. Engaging a Third Party Verifier (including completing the Conflict-of-Interest Checklist)* *9. Planning the Verification, i.e. the Verifier needs to determine:* *a. Objectives of the verification* *b. Assessment methods of the potential risks in the greenhouse gas data management system* *c. Assessment methods of the potential magnitude of any errors, omissions and misreporting* *d. Setting initial quantitative materiality level for any errors, omissions or misreporting* *e. Designing and documenting of a verification plan (which documents the terms of the engagement and the potential verification procedures) and risk-based sampling plan (which is a supporting document developed on-site after the verifiers have done an initial assessment of the robustness of the facility's greenhouse gas emissions data and emission management systems).* *f. Timeframe and schedule for the verification* *10. Conducting site visit(s) covering:* *a. Site tour, identification of GHG sources* *b. Confirm facility boundary* *c. Meet personnel* *d. Identify fuel inputs and products* *e. Identify key measurement meters* *f. Look for additional GHG sources* *g. View random samples of records* *h. Review data management system* *i. Visit on-site laboratories*

	11. *Reviewing documentation and supporting materials* 12. *Verification Report which needs to contain:* a. *the final verification plan;* b. *the final sampling plan;* c. *a complete verification schedule;* d. *names and roles of verification team members;* e. *a risk assessment;* f. *findings identifying and quantifying any material and immaterial discrepancies found; and* g. *a limited level assurance statement for the baseline application.* 13. *Closing meeting* 14. *If applicable, Verification for resubmissions* ▪ *Also, although Third Party Verifiers are not required to actively monitor the validity of their reports after issuance; if it is brought to their attention that a previous statement is no longer accurate, they must notify the project proponent. The project proponent then must notify the relevant authorities to discuss further follow-up actions that may be required.*
Frequency	▪ *Verification to be performed as specified in the project plan – ideally, this should be annually*
Third party	▪ *Minimum requirements as in the EU ETS* ▪ *Use of verifiers approved by the designated MS authorities to be used.*