

THE REDUCTION OF UPSTREAM GREENHOUSE GAS EMISSIONS FROM FLARING AND VENTING

Report by the International Council on Clean Transportation to the
European Commission Directorate-General for Climate Action

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ACKNOWLEDGMENTS

With thanks to Wojciech Winkler and Lars Müller (DG Clima); Nic Lutsey (ICCT); Francisco Sucre (World Bank); Anders Pederstad and Olga Gassan-zade (Carbon Limits); and the Association of Oil and Gas Producers.

SUGGESTED REFERENCE

ICCT (2014). *Reduction of Upstream Greenhouse Gas Emissions from Flaring and Venting*. Authors: Chris Malins, Stephanie Searle, Anil Baral, Sebastian Galarza, Haifeng Wang, Gary Howorth. Washington D.C.: The International Council on Clean Transportation.

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Abbreviations used

APG	Associated Petroleum Gas
ARB	California Air Resources Board
ARC	Alberta Research Council
ARI	Aerodyne Research, Inc.
BBL	Barrel
Bm ³	Billion cubic meters
BSO	German Biomass Sustainability Ordinance
BTU/ft ³	British Thermal Units per cubic foot
CPX	Capital Expenses
CAR	Corrective Action Request
CDM	Clean Development Mechanism
CER	Certified Emission Reduction
CH ₄	Methane
CL	Clarification Request
CNG	Compressed Natural Gas
CO ₂ e	Carbon Dioxide Equivalent
DIAL	Differential Absorption Lidar
DNA	Designated National Authority
DOE	Designated Operational Entity
DSG	Dry Stripped Gas
EB	CDM Executive Board
EEA	European Environmental Agency
EEX	European Energy Exchange
EPA	US Environmental Protection Agency
ER	Energy Redefined
ERU	Emissions Reduction Unit
ESD	Effort Sharing Decision
EU ETS	EU Emissions Trading Scheme

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EVCI	Electronic Volume Conversion Instrument
FAR	Forward Action Request
FQD	Fuel Quality Directive
FTIR	Passive Fourier Transform Infrared
GGFR	Global Gas Flaring Reduction
GHG	Greenhouse Gas
GIS	Geographic Information System
GOR	Gas-to-Oil ratio
GPP	Gas Processing Plants
GS/MS	Gas Chromatography and Mass Spectroscopy
GTL	Gas to Liquids
H ₂ S	Hydrogen Sulfide
IR	Infrared
IRR	Internal Rate of Return
ISCC	International Sustainability and Carbon Certification
ISO	International Organization for Standardization
ITL	International Transaction Log
JI	Joint Implementation
Km	Kilometer
LCFS	Low Carbon Fuel Standard
LDC	Least Developed Countries
LFLcz	Lower Flammability Limit of the Combustion Zone
LHV	Lower Heating Value
LPG	Liquefied Petroleum Gas
MAC	Marginal Abatement Cost
MFR	Momentum Flux Ratio
MJ	Megajoules
MBTU	Million British Thermal Units
Mm ³	Million cubic meters
MoC	Modalities of Communication

MS	EU Member State
Mt	Million metric tonnes
MWh	MegaWatt hours
N ₂ O	Nitrous Oxide
NGL	Natural Gas Liquids
NIM	National Implementation Measure
NOAA	National Oceanic and Atmospheric Administration
NPV	Net Present Value
NPV/I	Net Present Value divided by Investment
OLS	Operational Linescan System
OPX	Operating Cost
OPGEE	Oil Production Greenhouse Gas Emissions Estimator
PDD	Project Design Document
PJ	Petajoule
PSC/PSA	Production Sharing Contracts/Production Sharing Agreements
RED	Renewable Energy Directive
RFS	US Renewable Fuel Standard
RIN	Renewable Identification Number
RSB	Roundtable on Sustainable Biomaterials
RTFO	UK Renewable Transport Fuel Obligation
SR	Stoichiometric Ratio
UER	Upstream Emissions Reductions
UNEP	United Nations Environment Programme
UNFCCC	United Nations Framework Convention on Climate Change
VIIRS	Visible Infrared Imaging Radiometer Suite

Overview: venting and flaring reduction opportunities

Most oil wells produce not only oil, but also significant volumes of water and of associated petroleum gas. Associated petroleum gas is normally composed principally of methane (natural gas), but can also contain carbon dioxide, hydrogen sulfide, other gaseous hydrocarbons such as propane and butane, and natural gas liquids. Where oil fields are located near to gas distribution infrastructure, it is normal for the associated gas to be captured, processed and shipped to market, typically for use in energy generation or chemicals manufacture. However, where the value of the gas does not make it economically attractive to install infrastructure to take the associated gas to market, it may simply be ‘flared’ – burnt off at the oil field. Some gas can also be lost as fugitive emissions without being combusted, or simply released without being burnt, which is referred to as ‘venting.’ Many countries regulate to prevent or reduce flaring and venting, but these processes remain commonplace in several regions.

Natural gas flaring not only represents a lost economic opportunity but is also a major source of greenhouse gas emissions. Flaring of natural gas releases over 400 million metric tonnes of carbon dioxide equivalent (CO₂e) emissions globally every year, which is comparable to the annual emissions from 125 medium-sized (63 gigawatt) coal plants in the USA (Farina, 2010). At the national level, this represents something close to the entire emissions of Brazil, Australia, France or Italy. In some oil-producing countries this is one of the largest contributors to the national greenhouse gas emissions inventory, such as Nigeria where flaring accounts for over a third of the country’s total CO₂ emissions (GGFR, 2012a). Better utilization of natural gas resources, especially in high-flaring regions—including West Africa and Russia, for example—would not only help in meeting the world’s energy demands but also mitigate climate impacts and reduce air pollution.

There are a number of ways to reduce flared emissions. One way to reduce flaring is by direct regulation. Examples of direct regulation include Norway, where there is an enforced policy of zero flaring (Norwegian Petroleum Directorate, 2013), and North Dakota in the U.S., where oil producers will be required to meet gas capture targets or face having their oil production rates capped (Seeley, 2014). However, in countries where there is a lack of political will or regulatory capacity to reduce flaring, providing financial incentives to oil producers to implement flaring reduction projects can be a valuable tool. The United Nations’ Clean Development Mechanism (CDM) provides such incentives by offering ‘Certified Emissions reductions’ credits to flaring and venting reduction projects. The credits can then be sold, either into compliance markets such as the European Union’s Emission Trading Scheme (ETS), or to companies or individuals looking to invest voluntarily in emissions offsets.

In addition to opportunities to redeem CDM credits in the ETS, Article 7 of the Fuel Quality Directive (FQD) allows for the opportunity to use 'Upstream Emissions Reductions' (UERs) to comply with targets to reduce the carbon intensity of the European Union's transport fuel supply. Because carbon reductions in the transport sector tend to have a high cost relative to the prevailing carbon prices under ETS, the FQD has the potential to be a more powerful incentive to launch new flare reduction projects. Work by ICF (ICF, 2013) suggests that there is an opportunity to deliver tens of millions of tonnes of CO₂e emissions reductions through such incentives. This could make a significant contribution to achieving the FQD target of a 6% reduction in the carbon intensity of European transport fuel. This report was commissioned by the Directorate General on Climate Action of the European Commission to assess the opportunity to reduce upstream emissions associated with venting and flaring as compliance pathway under the FQD. Based on the results of the ICF study and this report, we believe that delivering one sixth of the targeted reductions through upstream credits would be an achievable goal, and the theoretical potential is higher still.

Upstream emissions reductions could be demonstrated through the generation of CDM credits, or through the generation of credits under voluntary schemes. The use of such credits could be managed at either the European level, or by individual Member States (as envisioned under the proposed FQD implementing measure). Alternatively, such reductions could be based on compliance with prescriptive measures set by either the European Commission or Member State regulatory agencies. Whichever of these approaches is implemented, in order to promote quantifiable and reliable climate change mitigation flaring or venting reduction crediting systems should ideally conform to the following principles:

- *Credit gas that is captured and utilized.* Emissions reductions from the projects should be based on measuring the quantity of associated petroleum gas successfully brought to market instead of being flared/vented. Because rates of flaring may vary naturally due to changing conditions in the oil reservoir, it is not enough to simply show a reduction in the rate of flaring at a given well.
- *Continuous measurement at multiple points.* Rates of gas delivery to the market should be continuously measured, with the use of at least two metering points to allow fugitive emissions or faulty measurements to be quickly identified and rectified.
- *Demonstrate "additionality."* It should be demonstrated that credited projects would not have been expected to happen in a business as usual baseline case. This is often referred to as additionality. There are many projects to capture and sell associated gas implemented every year for economic or regulatory reasons, and there would be no environmental goal served by providing credits to these projects. The assessment of additionality by independent auditors should reflect both economic and regulatory factors. The details of this assessment vary between the implementation options discussed in this report.

- *Verification from design to implementation.* All projects should be subject to verification by competent auditors with thorough and transparent documentation. This must include both the initial project design documents, and periodic measurements of emissions reductions once projects are in operation.
- *Data transparency to eliminate double counting across Member States.* Ideally, systems should be in place to ensure that any credits can only be redeemed in one Member State. This could be enabled by the establishment of a central European database, or by other information sharing measures between national regulators.
- *Risk based approach to fraud.* Some types of emission reduction project will be more vulnerable to inaccurate or fraudulent reporting than others. Additional monitoring and verification requirements are appropriate in such cases. Some categories of projects could be excluded from crediting if it is impossible to have confidence that reported savings are real and accurate.

This report outlines and compares four detailed approaches to upstream emissions reduction crediting, all of which would conform to these principles. Two are based on the use of credits from the Clean Development Mechanism (Option 1, ‘the ETS-CDM option’, and Option 2, ‘the standalone CDM option’). The third is a detailed prescriptive measure new to this report (Option 3a, ‘the prescriptive option’). The fourth is based on implementation by a Member State of the requirements outlined in the proposed FQD implementing measure (Option 3b, ‘implementing measure requirements’). In the third or fourth cases, the experience of project implementation and monitoring under CDM should be seen as a valuable reference and resource for the Commission and/or Member States if implementing a new system outside the CDM.

Following this initial overview chapter, the report is structured as follows. A brief executive summary of the results of this work is presented, including assessment of monitoring, reporting, verification, mitigation potential, and policy provisions for venting and flaring. Chapter 1 provides an overview of the project scope and objectives. Chapter 2 details methodologies that could be used to assess and credit emissions reductions from venting and flaring. This includes a review of how calculations and reporting are performed under CDM as well as under a new proposed framework. Chapter 3 presents an analysis of the total size of the emissions reductions potential under each methodology and the relative contribution venting and flaring reductions could have towards meeting the 6% carbon intensity reduction target in the FQD. Chapter 4 details elements of regulatory design, including project eligibility, additionality, verification of projects, and how this crediting scheme might be implemented by Member States. Chapter 5 presents a discussion of the risk of double counting projects within the crediting scheme as well as with other emissions reductions crediting schemes. Potential fraud risk, and measures that can be taken within each framework to minimize fraud, are discussed in Annex A. Annexes B-F provide additional detail on calculations and reporting requirements that are discussed in the main text. Annexes G and H provide an outline of measures necessary to implement Options 3a and 3b, and

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Annex I highlights differences between CDM and the new proposed crediting methodology in Option 3a.

Overview of this report on greenhouse gas emission-reduction opportunities from venting and flaring

CHAPTER	ELEMENTS
Executive summary (pages xxiii-xxxiii)	<ul style="list-style-type: none"> Executive summary of overall findings
Chapter 1 (pages 1-5)	<ul style="list-style-type: none"> Overview of project scope and objectives
Chapter 2 (pages 6-57)	<ul style="list-style-type: none"> Calculation of emissions savings from venting and flaring projects Reporting requirements Stakeholder input to the proposed crediting frameworks Potential for emissions reductions through improving flaring efficiency
Chapter 3 (pages 58-103)	<ul style="list-style-type: none"> Literature review on the cost and size of potential for emissions reductions from venting and flaring Non-cost barriers to engagement in CDM Calculation of the size of the potential for emissions reductions under each crediting option
Chapter 4 (pages 104-153)	<ul style="list-style-type: none"> Additionality requirements for crediting projects Verification requirements Member State implementation of crediting scheme Eligible projects Issues with baseline setting
Chapter 5 (pages 154-159)	<ul style="list-style-type: none"> Risk of double counting projects within each proposed framework and with other crediting schemes
Annex A (pages 170-175)	<ul style="list-style-type: none"> Proposed measures to minimize fraud risk in each proposed crediting framework
Annex B (pages 176-177)	<ul style="list-style-type: none"> Accounting for CDM credit price volatility in calculations
Annex C (pages 178-184)	<ul style="list-style-type: none"> Reporting requirements for innovative upstream emission reductions under the California LCFS
Annex D (pages 185-188)	<ul style="list-style-type: none"> Calculation of emission factors used to calculate emissions savings
Annex E (page 189)	<ul style="list-style-type: none"> Details on CDM project serial numbers
Annex F (page 190)	<ul style="list-style-type: none"> Details on Renewable Identification Numbers
Annex G (pages 191-199)	<ul style="list-style-type: none"> Outline of measures necessary to implement the prescriptive option
Annex H (pages 200-208)	<ul style="list-style-type: none"> Outline of measures necessary for the implementing measure requirements
Annex I (pages 209-211)	<ul style="list-style-type: none"> Summarizes differences between CDM and the prescriptive option

Executive summary

Upstream emissions reductions in the oil industry produced by reducing flaring and venting could make a substantial contribution towards delivering the greenhouse gas emissions reduction target of the Fuel Quality Directive (FQD). In this report, the ICCT has been asked by the European Commission to consider three possible emission-reduction certification and reporting mechanisms that could be implemented to allow flaring and venting reduction projects to be counted for this purpose. The project specification for this report asks for the following options to be considered:

- 1) allowing credits from the UN's Clean Development Mechanism (CDM) and Joint Implementation (JI) programs to be eligible for compliance under the FQD through the existing Union registry that tracks credits used under EU ETS (Option 1, 'the ETS-CDM option'),
- 2) allowing CDM and JI credits to be eligible through a standalone registry (Option 2, 'the standalone CDM option'), and
- 3) a new proposed framework designed to credit venting and flaring reduction projects specifically for the purpose of compliance under the FQD (Option 3).

Under the third option, two distinct cases have been considered. The first (Option 3a, 'the prescriptive option') is an outline for a detailed and relatively prescriptive framework for crediting upstream emissions reductions. Such a framework could in principle be required at the European level by Commission action, but could also be implemented by a Member State as a national interpretation of the option to credit upstream emissions reductions (UERs) or through a voluntary scheme with the intention of generating credits to feed into Member State implementations. The second case (Option 3b, 'the implementing measure requirements') outlines how the requirements for UER reporting contained in the implementing measure for FQD Article 7a proposed to the European Council in late 2014 (European Commission, 2014a) could be implemented at the Member State level. While Option 3a includes detailed specifications intended to be comparable to a CDM methodology document, Option 3b is specified based only on the text of the proposed implementing measure. It is possible that a system based on the specifications in Option 3a could be utilized within the broader framework outlined in Option 3b. At the same time, Option 3b would also support different implementations of crediting, provided they conformed to the requirements of the proposed implementing measure, and would not imply a single prescriptive methodological interpretation. Indeed, credits generated through CDM would likely be considered eligible for compliance reporting within the framework of Option 3b, given a little extra reporting. This executive summary highlights key findings and conclusions drawn from the body of the report.

ES.I. Measurement, reporting and verification

For any emissions reduction crediting, correctly assessing, recording and verifying the emissions reductions achieved is a core requirement.

ES.I.i. The CDM options (Option 1 and Option 2)

For the ETS-CDM option (Option 1) and the standalone CDM option (Option 2), measurement, reporting and verification requirements to register emissions savings are already fully prescribed by CDM and JI. CDM projects must follow approved methodologies to calculate and monitor emissions savings. There are currently three approved methodologies. Participants are able to seek registration of new methodologies but this is a resource intensive process. JI projects may use either approved CDM methodologies or project-specific approaches. In either case, project participants must monitor prescribed parameters relating to the project and have these measurements audited by 'Designated Operational Entities' (DOEs) before credits are awarded.

All three approved methodologies under CDM require participants to demonstrate that venting or flaring would continue if the proposed project were not implemented. Emissions reductions are calculated based on the amount of gas that is recovered by the project and exported and/or utilized in on-site equipment. The premise for crediting such projects under CDM is that the collected gas displaces the combustion of natural gas from gas fields. Crediting is *not* dependent on measuring changes in the average rate at which gas is flared on-site, as this rate is dependent not only on the status of any emissions reduction project but also on external factors including gas-oil-ratio and oil production rate.

The existing requirements for project design, monitoring, and verification under CDM and JI are considered adequate to allow credits to be used under FQD. The measurements required under these methodologies include:

- Continuous measurement of flow rate of the collected gas;
- Periodic measurement of some form of gas composition (calorific value, carbon content and/or methane fraction);
- In some methodologies the following measurements may be required:
 - Temperature and pressure of recovered gas;
 - Flow rate of gas delivered to pipeline from other sources;
 - Operation time of equipment and energy feedstock used;
 - Amount of useful product (if gas is used as a feedstock in a chemical process);

- Changes in energy use and energy feedstocks at the end-use facility;
- Details of vehicle transport of recovered gas, including distance, fuel consumption, and emission factors;
- A suite of measurements to determine fugitive emissions of recovered gas from leaks and accidents.

While CDM/JI registered projects routinely monitor almost all of the data required under FQD, there would be a need for additional data on the issuance year of credits to be reported in order to show FQD compliance. This data, and any other data, such as that identified in the proposed FQD implementing measure, could be verified by DOEs and passed along the chain of custody with the credits themselves.

ES.I.ii.The prescriptive option (Option 3a)

To enact a system of emissions reduction crediting outside CDM, a new comprehensive calculation and monitoring methodology would need to be developed and implemented for the assessment of any venting and flaring reduction projects seeking recognition under the FQD. The proposed prescriptive option (Option 3a) methodology is based on the CDM methodologies, but does contain some differences. For one, whereas each methodology under CDM covers only some specific types of flaring and venting reduction projects, the proposed Option 3a methodology would cover all types of eligible projects. The proposed requirements for eligibility, emissions reduction calculations, and measurements and reporting are very similar to the requirements under CDM, but do include the following differences (cf. Annex I):

- Eligibility of the following types of projects:
 - Cases where gas export capacity is being expanded rather than installed as new;
 - Projects that utilize 100% of recovered gas on-site;
 - Gas recovery at new oil wells;
 - A crediting system for separated natural gas liquids
- Baseline and delta calculation:
 - A simplified definition of the project boundary to exclude any emissions from non-pipeline transport and at the facility where the captured gas is used;
 - No requirement to assess indirect 'leakage' emissions outside the project boundary;
- Monitoring and reporting:
 - A threshold (2%) below which fugitive losses are considered uncertain and are not accounted for;

- Relaxed requirements for small projects (<50 Mm³/yr):
 - Reduced monitoring accuracy requirements;
 - Fugitive emissions threshold raised to 7%;
 - Reduced audit frequency;
 - Periodic measurement of flow rate allowed for very small projects (<10 Mm³/yr).

Monitoring and verification requirements would be relaxed under Option 3a for small-scale projects. The aim of this relaxation would be to encourage engagement from projects that may otherwise not participate due to high measurement and administration costs (for example from implementing continuous measurement of gas flow rates).

Under CDM, validation of emissions reduction projects and verification of the associated emissions reductions is based on assurance by the DOEs, qualified project auditors approved by the CDM Executive Board. A similar system of qualified auditors is proposed for Option 3a, with two possible variations. In the first case, projects would be directly registered with a body appointed by the European Commission (or potentially by a Member State), and that body would have the authority to approve the choice of auditor. In the second, rather than directly administering the emissions reduction crediting system through an appointed body, emissions reductions would be certified by voluntary schemes. In this case, the Commission would approve a set of voluntary schemes, but the approval of auditors would be left up to the administrators of each scheme. It is felt that a single verification approach administered directly by a body appointed by the Commission would better ensure consistency in the quality of emissions reductions, but either of these approaches is considered a viable option.

Beyond measuring the emissions savings achieved by a project, under CDM and JI an important requirement for project registration is that the project should be assessed as 'additional', meaning that it would not have been implemented if not for the value of CDM/JI credits. The assessment of additionality includes a consideration of whether the project would be financially attractive without credit value, whether flaring/venting is regulated in the region in question and whether the project being implemented reflects common practice.

Under Option 3a, it is proposed that as in CDM projects should be required to demonstrate additionality according to well-defined financial and legal criteria. The additionality test under Option 3a differs from the test in place for CDM in the following ways:

- No common practice analysis is required, as it is deemed that common practices can still deliver real greenhouse gas reductions;

- A single defined framework and calculation tool is proposed for the financial analysis. Projects would be allowed a higher internal rate of return than is generally tolerated under CDM, better reflecting a company's internal decision making;
- It is proposed that a database should be kept identifying regions in which flaring is either not legally prohibited, or in which legal prohibitions are not enforced. Projects in these regions would be eligible.

It is intended that this streamlined approach to additionality should minimize uncertainty and encourage more projects to participate, compared to CDM and JI.

ES.I.iii. Implementing measure requirements (Option 3b)

The option reflecting the implementing measure requirements (Option 3b) only reflects requirements specified in the proposed FQD implementing measure, which states that upstream emissions reductions will be estimated and validated in accordance with the international standards ISO 14064, ISO 14065, and ISO 14066, and providing results of equivalent confidence of Commission Regulation (EU) No 600/2012 and Commission Regulation (EU) No 601/2012.

As in the CDM and prescriptive options (Options 1, 2, and 3a), ISO 14064 Part 2 specifies that emissions reductions be calculated as the difference between the emissions in the project scenario and in the baseline scenario. Both scenarios must include all relevant emission sources and sinks and consider all pertinent factors.

Reporting requirements include details required in the proposed FQD implementing measure:

- Starting date of the project (which must be after 1 January 2011);
- Annual emissions reductions (gCO₂e);
- Duration for which the claimed reductions occurred;
- Project location closest to the source of the emissions in latitude and longitude coordinates in degrees to the fourth decimal place;
- Baseline annual emissions prior to installation of reduction measures and annual emissions after the reduction measures have been implemented in gCO₂eq/MJ of feedstock produced;
- Non-reusable certificate number uniquely identifying the scheme and the claimed greenhouse gas reductions;
- Non-reusable number uniquely identifying the calculation method and the associated scheme;
- Where the project relates to oil extraction, the average annual historical and reporting year gas-to-oil ratio (GOR) in solution,

reservoir pressure, depth and well production rate of the crude oil.

ISO 14064 Part 2 requires that monitoring equipment is properly calibrated and that practices pertaining to monitoring, data collection and data storage be documented. A report detailing the reported emissions reductions must be made available to Member States.

Member States and voluntary schemes compliant with the proposed implementing measure may impose additional requirements relating to emissions reductions calculations, monitoring, and reporting, depending on their interpretation of the implementing measure and ISO standards.

ES.II. The size of the potential for emissions reductions

In previous work for the Commission, ICF assessed the level of emissions reductions that could be delivered at a given value of carbon credits by analyzing historical and current CDM and JI projects in Nigeria, Libya, Iran, Yemen, Russia and Azerbaijan. In the present report, the ICF analysis was used to estimate the size of the emissions reductions potential under the CDM options (Options 1 and 2) according to the eligibility restrictions of these options. The ICF analysis was further developed to reflect additional emissions savings that could be achieved under the prescriptive option (Option 3a) and the implementing measure requirements (Option 3b); Option 3a can be expected to attract greater participation of venting and flaring reduction projects because of its more relaxed and streamlined requirements as compared to the CDM process. The potential emissions savings under Option 3b would depend to some extent on Member State implementation, however it is anticipated that requirements under Option 3b are likely to be no more stringent than under Option 3a, and hence given effective implementation by Member States the potential under Option 3a can be treated as a minimum estimate of the potential under Option 3b.

Option 1 would allow credits registered under the ETS to be also used for FQD compliance. Under ETS Phase III, any new CDM projects must be registered in Least Developed Countries (LDCs). Of the countries considered by ICF, only Yemen is currently designated as an LDC. While there would be some opportunities to deliver emissions reductions under Option 1, the geographical limitations on eligibility would make these small compared to reduction targets under FQD. Option 1 is therefore not expected to support significant emissions reductions, and hence would not be expected to support a significant contribution of upstream emissions reductions towards the greenhouse gas intensity reduction target of the FQD.

Options 2, 3a and 3b do, however, offer significant potential emission-reduction opportunities. Under Option 2, a standalone registry would be created for FQD, and the requirements for ETS eligibility need not be

enforced. All of the regions included in ICF's analysis would therefore be eligible to host new CDM and JI projects. Based on ICF's analysis, it is estimated that about 14 MtCO₂e per annum of emissions reductions could be delivered for a persistent and predictable carbon price of \$20/tCO₂e; this is the potential level of emissions reductions that could be achieved under Option 2. Under Options 3a and 3b, a higher level of emissions savings would be achievable under credit prices ranging from \$20-\$200/tCO₂e (Figure A). The additional savings would come from projects that would engage in Option 3a but not CDM/JI due to relaxed additionality requirements, a more streamlined and predictable process, and less stringent requirements for small-scale projects, and for Option 3b these requirements may also be more streamlined, depend on Member State implementation. In reality, this level of savings may not be achieved if credit prices are unpredictable.

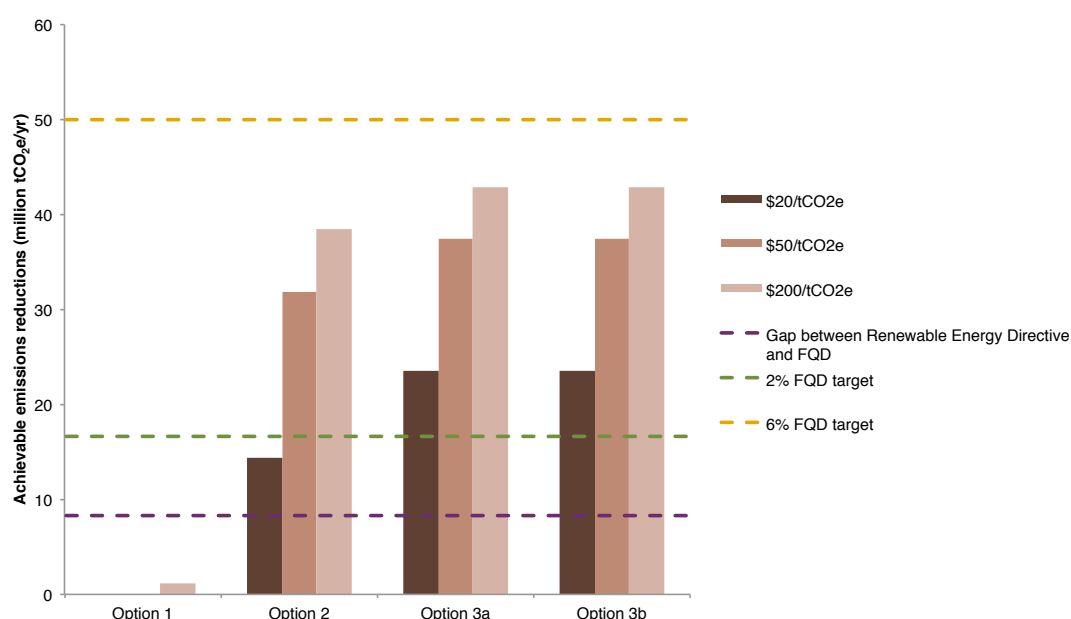


Figure A. Potential emissions reductions from venting and flaring under each option if credits are awarded over the project lifetime

In Figure A, the potentially achievable emissions reductions under Options 1, 2, 3a and 3b are compared to three levels of relevance for the FQD. The venting and flaring emission mitigation Options are compared with the expected gap remaining to the 6% FQD target after the 10% renewable energy target under the Renewable Energy Directive (RED) has been achieved (indicated by the dotted purple line), the 2% optional carbon intensity reduction target set under FQD for CDM credits (dotted green line), and the full 6% target (dotted yellow line). Based on this analysis, there is the potential for Options 2, 3a or 3b to deliver more than half of the emissions reductions required to meet the full 6% GHG intensity reduction target. At \$50 per tonne CO₂e, Option 2 could deliver 65% and Options 3a and 3b could supply 75% of this target. This conclusion is contingent upon an adequate credit price and adequate time (and market confidence) to initiate projects. Uncertainty or lack of confidence in upstream emission reduction credits could substantially reduce the actual level of investment.

Certainly, with a clear framework of incentives, upstream emissions reductions under Options 2, 3a or 3b could be enough to cover the gap between the emissions reductions expected from RED compliance and the FQD target.

However, at the moment the FQD only has a single year (2020) with a binding compliance target, which could significantly reduce the potential to deliver reductions compared to a system that delivered ongoing value. ICF's analysis of the potential assumed that credits would be available for the full project lifetime. If credit value were only available for one year, the potential would be greatly reduced. Figure B presents achievable emissions reductions for each option given a one-year crediting window. In this scenario of single-year crediting, Options 2, 3a and 3b could only make a significant contribution to meeting the 6% carbon intensity reduction target under the FQD if credit prices were high. At \$200/tCO₂e, these options could deliver 31% of the 6% carbon intensity reduction target (i.e. slightly less than a 2% carbon intensity reduction contribution). This has the potential to be a considerable overestimate, as this assessment assumes that investors would treat the carbon price as guaranteed whereas in reality the willingness of oil field operators to invest on the basis of a single year of potential credit value could be limited. In practice, this problem could be largely resolved if Member States implement the optional interim GHG reduction targets, or if Member State implementations of the FQD do not expire in 2020. For instance, the German implementation of carbon reduction targets is expected to take effect at the start of 2015, and is not anticipated to have any built-in expiry date.

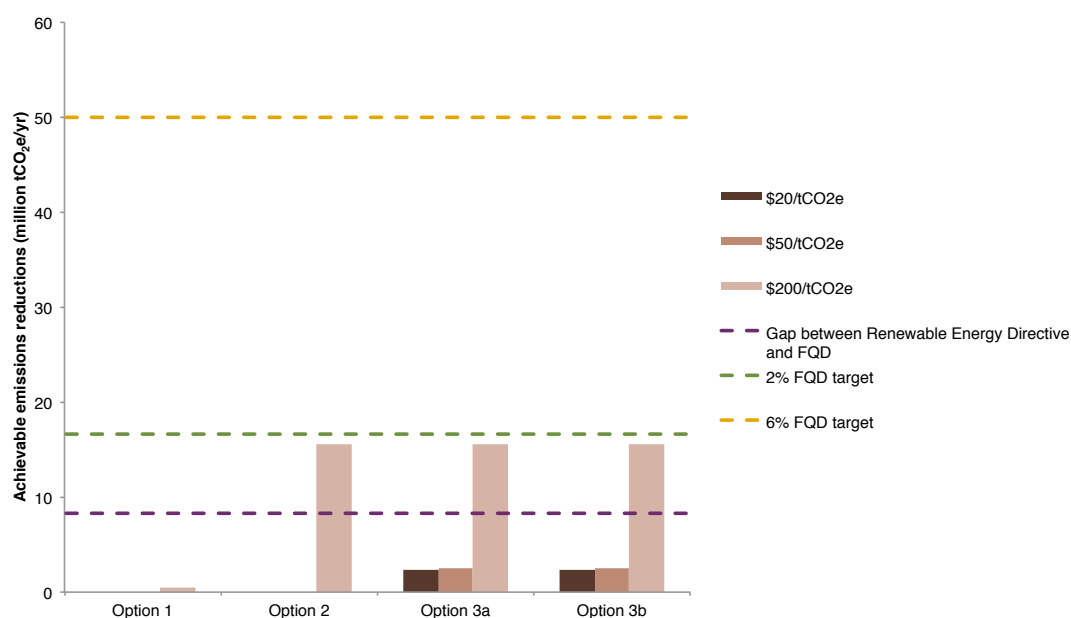


Figure B. Potential emissions reductions from venting and flaring under each option if credits are awarded in one year (2020) only

Source: Energy Redefined calculations based on ICF flaring report

In addition to venting and flaring reductions, in principle additional emissions savings could be achieved by crediting improvements in flare

efficiency. However, flare efficiency improvements are not currently eligible for crediting under existing CDM methodologies, and so are unlikely to be credited under Options 1 and 2. It is not recommended that they be included under Option 3a due to measurement difficulties and fraud potential. Crediting of flare efficiency improvements is not explicitly prohibited under Option 3b, but ISO 14064 includes general requirements for accuracy and conservativeness in reporting emissions reductions. To comply with this requirement, Member States and schemes may choose to limit the eligibility of flare efficiency improvement projects or impose additional monitoring and verification requirements.

ICF's assessment of emission reduction potential assesses the potential for new projects, and does not include the availability of credits from already-approved CDM projects. Based on documents from the CDM pipeline, we believe that existing CDM projects that could be eligible under FQD may generate up to 4 million tonnes of CO₂ reduction credits. This would be enough to contribute about a twelfth of the carbon intensity reduction required by FQD, a 0.5% contribution to reducing the carbon intensity of European transport fuel. These credits could potentially be counted towards compliance under Option 2 or Option 3b.

ES.III. Required measures to implement each option

The three venting and flaring Options that are assessed in this report would require a number of actions related to their implementation. The following measures would need to be taken by Member States and/or the Commission if upstream emissions reductions credits are to be created, traded, and used for compliance with FQD.

ES.III.i. The ETS-CDM option

Under the ETS-CDM option (Option 1), FQD-eligible CDM credits in the EU-centralized registry could be used for compliance under FQD. The existing EU ETS transaction system for credits is robust and includes multiple checks between the point of issuance of credits and their use for compliance. No additional verification of information in the EU registry would be necessary.

As the refining sector is covered by ETS, refiners should be registered on the EU registry. Requiring credits used for FQD compliance to be used in the same country as they are used for ETS compliance would simplify accounting. Member States would need to implement systems so that when a credit is used for ETS compliance and cancelled, a 'new' credit would simultaneously be created in a local account used for demonstration of compliance with FQD.

As noted above, there may be a need under FQD for additional data on credits that is not carried in the CER serial number (such as year awarded) to be passed up the supply chain. Operators would need to arrange for this data to be recorded and verified by the DOEs. The Commission or Member State authorities would need to set up systems for this additional data to be checked before marking credits as FQD-compliant on the EU registry.

ES.III.ii. The standalone CDM option

Under the standalone CDM option (Option 2), FQD-eligible credits would be transferred from national CDM registries to a stand-alone registry at, for example, the European Environmental Agency. This option would require the creation of this centralized registry and the appointment of an administrator. Operators must be allowed to set up accounts at this registry that will enable them to transfer and retire FQD-eligible credits. The International Transaction Log (ITL) that is currently used to verify and facilitate trading of CDM credits between national registries could potentially also be used to transfer credits into the stand-alone central registry. Use of the ITL would help ensure that credits are not double counted under the FQD and other emissions trading systems.

The registry would also be tasked with validating the retirement of credits by ensuring they are cancelled in the central CDM registry and in national registries (so that they can no longer be traded) before issuing the corresponding credits into an operator's account that is used to demonstrate compliance with FQD.

The additional reporting requirements that were discussed above for Option 1 – such as year credits were awarded – would also be necessary under Option 2. These reports would need to be verified by the administrator of the stand-alone registry.

ES.III.iii. The prescriptive option

Under the prescriptive option (Option 3a), a verification body approved by the Commission (either directly or through a voluntary emissions reduction crediting scheme) would approve reported emissions reductions. The administrator of a central registry (comparable to that established under Option 2) would check the documentation provided and confirm the credentials of the verification body, and would then issue credits into an account held by the project operator. Credits would be assigned a unique serial number including all information necessary to demonstrate FQD compliance.

The emissions reduction credits would remain in this central registry at all times. Operators could trade credits by requesting credits be transferred from one account to another. To retire credits for compliance under FQD, the administrator of the registry would remove the credits from an account and report to the operator's Member State

the amount of credits retired. The Member State in question would then recognize these credits as evidence of compliance with the equivalent part of an economic operator's greenhouse gas emissions reduction target under FQD. The use of a single central registry would minimize system administrative costs and fraud risk.

ES.III.iv. Implementing measure requirements

Under this option (Option 3b), approved schemes would verify emission reductions eligible to be used for compliance with FQD. Member States would identify eligible schemes, which could include CDM, and would need to appoint a national administrator to receive, assess, and verify reports of emissions reductions. The European Commission may appoint a central data holder for emission reductions claimed under the FQD; if so, national administrators should report data on approved emissions reductions to this central data holder.

ES.III.v. Member State Implementation

In order for any of these options to have effect, credits from upstream emissions reductions must be eligible to be used for compliance with the FQD in Member States. Member State implementations of each of the options could vary, particularly as regards how a market for upstream emissions reductions is integrated with other FQD compliance options such as biofuel mandates. If any of the Options is implemented, the Commission may consider adopting additional language in the FQD or an implementing measure to clarify the requirement that Member States accept upstream emission reduction credits as showing compliance by operators with the FQD.

1. Project scope and objectives

Natural gas flaring not only represents a lost economic opportunity but is also an important source of greenhouse gas emissions. Flaring of natural gas releases over 400 million metric tonnes of carbon dioxide equivalent (CO₂e) emissions globally every year, comparable to the annual emissions from 125 medium sized (63 gigawatt) coal plants in the USA (Farina, 2010). At the national level, this represents something close to the entire emissions of Brazil, Australia, France or Italy. In some oil-producing countries this is a major contributor to the national greenhouse gas emissions inventory, such as Nigeria where flaring represents over a third of the country's total CO₂ emissions (GGFR, 2012a). Better utilization of natural gas resources, especially in high-flaring regions—including West Africa and Russia—would not only help in meeting the world's energy demands but also mitigate climate impacts and reduce air pollution.

This wasted gas could be recovered and used to generate energy at the site, sold into pipelines or otherwise transported to end-users. Utilizing the recovered gas for a productive purpose saves CO₂ emissions from the production of gas and other fuel that it displaces. Furthermore, recovering gas that would otherwise have been vented as methane reduces CO₂e emissions by an even greater amount than simply displacing gas production, because methane has a (per kilogram) global warming potential (GWP) 25 times that of CO₂ on a 100-year timescale (Huss, Maas, & Hass, 2013).

The EU's Fuel Quality Directive (FQD) targets a 10% reduction in the carbon intensity of transport fuel used in the EU in 2020, compared to a 2005 baseline. This includes a 6% mandatory target, which is expected to be met largely with biofuels. There are two additional and non-binding 2% targets to be met with (a) use of carbon capture and storage and supply of electricity in electric vehicles and (b) the purchase of Clean Development Mechanism (CDM) credits awarded for emissions reductions in the fuel supply sector.

The European Commission is considering the possibility of allowing CDM and Joint Implementation (JI) projects that reduce venting and flaring from oil production to be eligible for compliance with the FQD, or of creating a new crediting mechanism for these projects. CDM is a program born out of the Kyoto Protocol and administered by UNFCCC that supports emissions reductions through a variety of pathways, including renewable energy, energy efficiency, and methane avoidance. Through CDM, "Annex I" countries (this largely refers to developed countries) fund emission reduction projects in non-Annex I countries. Projects approved under CDM generate Certified Emissions Reductions (CERs), which are effectively emission reduction credits. CERs can be used to meet a country's obligation under the Kyoto Protocol, transferred into an emissions trading scheme, such as the EU ETS, otherwise used for regulatory compliance, for instance under the Effort Sharing Decision (ESD), or sold into voluntary

markets. JI is a very similar program that covers emission reduction projects in Annex I countries, although the UNFCCC urges developed countries to partner with countries transitioning to a market economy for these projects (UNFCCC, 2006a), and so JI projects are unlikely to take place in EU countries. Most or all of JI projects that reduce venting or flaring from oil production have taken place in Russia.

To better assess options for how CDM and/or other emission crediting procedures might be utilized in the Fuel Quality Directive context, the European Commission issued a Call for Tenders CLIMA.C.2/SER/2013/0032r that states that:

The European Commission wishes to prepare a regulatory framework that would allow demonstrable reductions in greenhouse gas emissions from venting and flaring to be counted towards the 6% emissions intensity reduction target under the Fuel Quality Directive.

In this context two broad approaches for facilitating the calculation and reporting of upstream emissions appear to have gained interest:

- 1) Voluntary reduction credit certificates (e.g. UN's Clean Development Mechanism or Joint Implementation projects (CDM/JI), and;*
- 2) Prescriptive (regulatory) measures (e.g., Alberta's Specified Gas Emitters Regulation).*

...

The primary deliverable of this work is the development of a regulatory framework (i.e. an outline of legislation/policy proposal) that would allow carbon credits under the Fuel Quality Directive (FQD) to be awarded to global projects that reduce the flaring or venting of associated natural gas from oil production.

This report investigates the possible eligibility under the FQD of CDM and JI credits generated by projects that reduce venting and flaring of gas from oil production (i.e. upstream in the fuel supply chain) and describes a new potential mechanism to assess and verify emissions reductions and issue emissions reduction credits to be used towards FQD compliance. Each of these options could potentially include utilization of associated gas as well as gas-lift gas used in petroleum production that is used for energy at the drilling site or is transported via pipeline, tankers, CNG mobile units or otherwise to end users who may use the gas either for energy or as a chemical feedstock. Here, we focus on three options for awarding and utilizing the credits, as identified in CLIMA.C.2/SER/2013/0032r:

- Option 1 ('the ETS-CDM option'): ETS and FQD compliant CDMs recorded in the Union registry created pursuant to Commission Regulation No. 389/20134. This would only allow suppliers to count CDMs issued for the purpose of the EU Emission Trading System (EU-ETS), the Effort Sharing Decision (ESD) or other Member State (MS) Kyoto obligations (i.e., double counting with EU-ETS or ESD).

- Option 2 ('the standalone CDM option'): All FQD compliant CDMs recorded in a stand-alone registry maintained by e.g. the European Environmental Agency (EEA) or a third party funded by fee-for-use payments (e.g., Google)
- Option 3: All FQD compliant credits issues in accordance with voluntary schemes or a prescriptive measure, recorded in a stand-alone registry maintained by the EEA or a third party funded by a fee for service payments (e.g., Google).

Within Option 3, this report further considers two levels of specificity for possible implementations of UER crediting:

- Option 3a ('the prescriptive option'): a detailed prescriptive specification for a crediting system, comparable in detail to a CDM methodology document. This option could be implemented at the European level as a prescriptive measure, but could also play a role within the proposed FQD implementing measure as part of a scheme at a national level or within one or more voluntary UER crediting schemes.
- Option 3b ('implementing measure requirements'): an outline framework for a Member State implementation of UER crediting based on the text of the proposed implementing measure (European Commission, 2014a). Either or both of crediting under CDM or crediting under an Option 3a based scheme may be eligible as an option to show compliance within this framework. Henceforth, the text of European Commission (2014a) will be referred to as 'the proposed FQD implementing measure.' Because the proposed FQD implementing measure does not require a standalone registry, Option 3b does not make this an explicit requirement, though such a registry could still have a role under this option.

This report follows an earlier report written by ICF for the Commission that studied the Marginal Abatement Cost (MAC) of projects to reduce upstream venting and flaring. That report, titled "Schemes for Fossil Fuel Greenhouse Gas Upstream Reductions – Evaluating and Selecting Schemes and Standards for the Purpose of Article 7a of the FQD" and henceforth referred to as 'the ICF flaring report', was provided to the authors and is a key source for this study.

The tasks that are covered in this report are as follows:

- Task 1: Develop a methodology to assess and credit emissions reductions from gas flaring or venting reduction projects
 - Task 1a: Baseline and delta calculation: review measures outlined in existing CDM methodologies and identify the space and/or need for FQD to impose further specificity on eligible CDM CERs. Propose a methodology to calculate emissions reductions under Options 3a and 3b.
 - Task 1b: Reporting regime: Review reporting requirements outlined in existing CDM methodologies and identify the space and/or need for FQD to impose further specificity on

- eligible CDM CERs. Propose reporting requirements under Options 3a and 3b.
- Task 1c: Methodological validation: Consult with industry and other stakeholders on the suggested calculation and reporting methodology in Options 3a and 3b. Report on the possibility of using satellite technology to verify emissions reductions.
- Task 1d: Flare efficiency improvements: Discuss the extent to which flare efficiency improvements could in principle be used to generate CERs, including a literature review on the efficiency of existing flares and the accuracy of flare efficiency measurements. Make a recommendation on the eligibility of flare efficiency improvements in Options 3a and 3b.
- Task 2: Cost and size of the reduction potential from gas flaring and venting reduction
 - Review previous studies on the cost and size of the reduction potential.
 - Discuss barriers to engagement of venting and flaring reduction projects in CDM.
 - Building upon ICF's work on MAC curves using historical CDM projects, identify the size of the additional reduction potential with varying levels of credit support and with the removal of key barriers to engagement, and assess the size of the reduction potential under Options 3a and 3b.
- Task 3: Regulatory design of systems to credit UERs within the FQD
 - Task 3a: Additionality. Propose three options for additionality requirements with varying levels of stringency and discuss advantages and disadvantages of each. For Option 3a, identify the preferred option.
 - Task 3b: Verification requirements: Review the verification and audit system already in place for CDM, and identify any space and/or need for FQD to impose additional verification requirements on eligible CDM CERs. Propose verification requirements for Options 3a and 3b.
 - Task 3c: Implementation by member states: discuss lessons learned from Member State Implementation of the EU ETS. Discuss the risk of discrepancies between the intent of the three options and the effectiveness of Member State implementation.
 - Task 3d: Eligible projects: Review categories of flaring projects eligible for CERs under CDM and determine any additional conditions on CERs from flaring projects that would need to be imposed under Options 1 and 2. Propose eligibility requirements for projects in Options 3a and 3b.

- Task 3e: Baseline: Explore issues around baseline setting, including associated fraud risk.
- Task 3f: Minimizing fraud risk: Discuss measures that can be taken within each option to minimize the risk of fraud and identify fraud risks that would remain in each option. This section is provided as an Annex.
- Task 4: Pre-regulatory impact analysis
 - Task 4a: Risk/cost of double rewarding projects: Review the potential for CDM CERs and Options 3a and 3b emissions reductions credits to be counted against both FQD and ETS or other emissions trading schemes, and discuss the extent to which double counting might undermine the objective of this or other programs.

2. Task 1: Methodology to assess and credit emissions reductions from gas flaring or venting

The objective of Task 1 is to develop a methodology to assess and credit emissions reductions from projects that reduce venting or flaring of gas in oil production under each of the four options (Options 1 and 2, which both allow emissions reductions from CDM and JI projects to be eligible for FQD compliance, Option 3a, a potential prescriptive crediting framework, and Option 3b, which follows the proposed FQD implementing measure). This task includes an assessment of methodologies to calculate baseline emissions and project emissions reductions under CDM, proposes a new methodology for the prescriptive option and discusses methodological requirements under the implementing measure requirements (Task 1a). It includes a review of CDM reporting requirements, proposes specifications for reporting requirements for Option 3a, and discusses reporting measures that might be required for emissions reduction projects to be eligible for compliance with the proposed FQD implementing measure in Option 3b (Task 1b). Additional reporting requirements for CDM projects to comply with FQD are also discussed. Task 1c presents stakeholder input on these issues and on the possibility of using satellite imaging for validation. Task 1d presents a literature review of flaring efficiency and discusses how this would be incorporated or handled in each option.

2.1. Summary of Task 1

Options 1 and 2 would credit CDM and JI projects that reduce venting and flaring from oil production. There are three such approved methodologies under CDM. All three methodologies share in common that participants must demonstrate that venting or flaring would continue in the baseline (business as usual) scenario, and that emissions reductions are calculated based on the amount of gas that is recovered and exported and/or utilized in on-site equipment. This follows the CDM logic that emissions reductions are generated by the displacement of gas that would otherwise have been combusted. One consequence of this focus on gas displacement is that the emissions reductions credited will not always be reflected by a corresponding reduction in absolute volumes of gas being flared/vented. Indeed, in some circumstances total flaring/venting could even increase, for instance if a large increase in oil production rates resulted in a correspondingly large increase in total gas production. The focus on gas displacement also means that reductions in venting are credited based on avoiding emissions from combustion of the displaced gas, rather than based on the global warming avoided by preventing methane leakage. This means that venting reduction projects **do not** receive additional credits

related to the higher global warming potential of methane under CDM and JI.

Some of the CDM methodologies include additional terms in the calculation, which are offset against the emissions reductions from gas displacement. These can include emissions increases related to the collection, transport and use of associated gas, and indirect emission increases that occur outside the project boundary.

The main requirement for monitoring in the three CDM methodologies is to continuously measure the flow of gas that is exported or utilized by the project. The calorific value (energy content) of the gas must also be measured periodically. The approved CDM methodologies differ somewhat in required gas composition metrics and in how precisely flow must be measured. Monitoring of energy use in the new equipment installed for the project, and any other additional emissions terms, is also necessary.

In some CDM methodologies fugitive emissions from leaks and accidents must be measured, although the stringency of these measurements differs between methodologies. If fugitive emissions are detected, they must be reported and subtracted from emissions savings. Unlike venting reduction, any increases in vented or fugitive emissions must be accounted for using the greater global warming potential of the leaked methane.

The prescriptive option (Option 3a) follows the same principle in calculating emissions reductions based on the amount of gas exported and/or utilized. The tender specifications called for consideration of a mass-balance approach to determine reductions in rates of flaring. However, this approach will generally not calculate emissions reductions accurately as flaring rates vary naturally as a function of oil production characteristics and environmental factors. It is therefore proposed that Option 3a should follow the example of CDM by crediting the volume of gas collected and utilized by the project.

For Option 3a, it is proposed that a system should be implemented that is similar to the CDM methodologies but not identical to any one of them. Rather than creating separate methodology documents for various project-cases, there should be a single unified methodology. This should simplify the process and remove gaps in eligibility. While the basic methodology should be unified, additional reporting requirements should be set for specific categories of projects where there is a need for extra monitoring or a perceived risk of fraud. This includes projects based on expanding or complementing existing gas export capacity, projects that utilize gas on-site and projects that recover imported pressurized lift-gas.

As under CDM, emissions reductions should be based on continuous measurement of recovered gas. Flow monitoring should be imposed at a minimum of two points in the project infrastructure, so that flow rates can be compared in order to a) monitor for gas losses and b) monitor for faulty meters. Fugitive emissions detected in this way should be subtracted from emissions savings if greater than 2% (7% for small projects). This threshold allows for measurement discrepancies that are within the margin of error of the equipment, and is designed to prevent undue burden on participants. As under CDM, Option 3a should require monitoring of emissions from

energy use in new equipment, but should not include indirect emissions changes or emissions at end-use facilities. These terms are formally included in some CDM methodologies, but have not been consistently applied.

It is felt that under existing CDM methodologies measurement costs may have been prohibitive for many potential small-scale projects, and so requirements for these projects are relaxed under Option 3a. The required accuracy of all measurements is reduced for small projects under Option 3a, and very small projects may opt to measure gas flow weekly rather than continuously.

Option 3b is defined by the proposed implementing measure requirements, in particular by ISOs 14064 Part 2, 14065 and 14066, and by Commission Regulation (EU) No 600/2012 and Commission Regulation (EU) No 601/2012. Baseline and delta calculation in Option 3b would be similar to that in CDM, based on calculating the difference between project and baseline emissions. The assessment of both project and baseline scenarios should include all relevant emissions sources and sinks. Member States and compliant voluntary schemes may impose more specific requirements depending on their interpretation of the ISO standards.

Under Option 3b, reporting requirements include details listed in the proposed FQD implementing measure, including project year, project location, reported emissions reductions, and other information. The ISO standards impose some additional requirements relating to the record keeping of monitoring practices and data. A 'GHG report' detailing the reported emissions reductions must be made available to Member State officials and potentially other parties. Member States and compliant voluntary schemes may impose additional reporting requirements. There is no explicit requirement for relaxed requirements for small projects under Option 3b, but they could be implemented at the discretion of Member States.

Beyond the reporting requirements under CDM itself, for Options 1 and 2 additional reporting requirements would be necessary to allow use of credits in the FQD. For instance, it would be important to identify the year in which credits were generated. It is proposed that DOEs (the auditors under CDM) would create a separate report with this information that would be submitted to the European Commission, other central European administrative body and/or Member States. This data reporting would be completely integrated in Options 3a and 3b.

In principle, in addition to gas capture projects improvements in flaring efficiency (i.e. reducing the amount of uncombusted methane released at the flare tip) could be credited. This is because the CO₂ from combusted gas has a lower global warming potential than the uncombusted methane. However, flare efficiency improvements are not currently eligible under any approved CDM methodologies. For Option 3a, a potential calculation and monitoring methodology is described but is not recommended at this time due to the low accuracy of flare efficiency measurements and the relatively high risk of fraud. Crediting of flare efficiency improvements is not prohibited under Option 3b, but Member States and voluntary schemes

may choose to restrict the eligibility of such projects if it is deemed that they do not meet the requirements for accuracy and conservativeness in ISO 14064.

Industry stakeholders and experts on upstream emissions reductions were consulted on the proposed calculation and reporting methodology in Option 3a. These stakeholders generally agreed that crediting based on the amount of gas exported or utilized was the most accurate option. Consultees also felt that satellite measurement of flared volumes would not give an accurate characterization of emissions reductions. The U.S. has recently launched a new, more accurate satellite measuring flaring globally, and satellite measurement of absolute levels of flaring could be valuable as a possible validation test on reported emissions reductions, but this method would require additional investigation. Stakeholders generally agreed that flaring efficiency improvements could not be measured accurately enough for crediting.

There was a range of opinion expressed about the CDM process itself – some stakeholders thought it works reasonably well and indicated they would continue to engage with it in future, but others described it as overly bureaucratic and felt rules were not consistently applied. Others cited low CDM credit (CER) values and the common practice test for additionality as barriers to engagement.

2.2. Task 1a: Baseline and delta calculation

2.2.1. Baseline and delta calculation under the CDM options

Accurate accounting of the emissions saved through reducing the venting and flaring of associated gas from oil production is critical to appropriately and fairly crediting these projects. Savings from avoided venting and flaring could be measured in several ways; for the ETS-CDM option (Option 1) and the standalone CDM option (Option 2) this includes only frameworks for calculating baseline emissions and emissions savings under CDM and JI.

All CDM methodologies, not just those applicable to venting and flaring reduction projects, calculate emissions savings as the difference between a baseline scenario and a project scenario in the project proposal. The baseline scenario is an assessment of the quantity of greenhouse gases that would be emitted in the absence of the project, assuming “business as usual.” The project scenario is an assessment of the amount of greenhouse gases that will be emitted if the project is implemented. If the total amount of emissions under the project scenario is lower than the baseline scenario, the difference is the quantity of greenhouse gases expected to be saved by the project activity. Once the project has been implemented, actual project emissions are measured and credits are awarded on this basis (UNFCCC, 2013b).

Normally, when applying to register a new project under CDM, an applicant must use a methodology that has been approved by the CDM Executive Board (EB) (GGFR, 2005). There are many types of CDM methodologies, from producing renewable energy to increasing the energy efficiency of buildings. The “Fugitive” category of CDM methodologies covers the reduction of unintentional greenhouse gas release. Methodologies that reduce venting and flaring from oil production fall under this “Fugitive” category, and the subcategory “Oil field flaring reduction” (Fenhann, 2014). Approved methodologies define the equations that should be used to calculate emissions under the baseline and project scenarios, as well as details of what measurements should be taken (this is discussed in Section 2.3) (UNFCCC, 2013b). If the new project does not fit within an existing approved methodology, the applicants can propose a new methodology to the CDM EB; if this is approved, the applicants can proceed with applying to register their project (GGFR, 2005). For example, the first CDM project reducing flaring from oil production (“Rang Dong Oil Field Associated Gas Recovery and Utilization Project”) applied to register a new methodology that later became AM0009, now the most commonly used methodology for this project type. Applicants then apply data specific to their project to the equations to calculate baseline and project emissions and the expected emissions savings of that project (UNFCCC, 2008c).

In order to ensure that the baseline scenarios is carefully chosen, an application for a new methodology must list out several alternative baseline scenarios and explain why the chosen scenario is the most likely out of the list (UNFCCC, 2008c). There are three recommended approaches to choosing a baseline: 1. Continuation of historical emissions, 2. The most economically attractive option, 3. Average emissions of similar recent developments (Shrestha, S, GR, & S, 2005). For venting and flaring reduction methodologies, the baseline scenario is typically continuation of venting or flaring.

2.2.1.a. Standardized baselines and small-scale methodologies

In 2011, the CDM EB introduced standardized baselines, which allow the submission of applications without using project-specific data to calculate baseline emissions or to determine additionality. Effectively this creates categories of projects that are pre-approved for additionality. A standardized baseline aggregates projects within a region (this could be a region that is part of a country, a country, or a group of countries) where the legal requirements and enforcement for the relevant type of emissions is the same (UNFCCC, 2011a). As of the time of writing, it is understood that no standardized baselines for venting or flaring reduction projects exist, although such standardized baselines could potentially be proposed and approved in the future. An example of a case where a standardized baseline might be appropriate for venting and flaring reduction would be a region where there are no laws or enforcement regarding flaring, where there is no existing gas export infrastructure and where flaring is demonstrated to be normal practice. For a proposed project within this region, the applicants could assume that the baseline is continued flaring without presenting any

additional evidence or arguments. As long as the project emissions were lower than whatever is legally required in that region, they would be assumed to be additional. Such a system could reduce the administrative burden for some applicants.

Small-scale methodologies, with simplified baseline calculations, are another avenue for applications for small projects not exceeding 15 kilotonnes CO₂e per year. In principle the CDM board could approve simplified baseline methodologies for small-scale venting and flaring reduction projects, but at the time of writing no applicable methodologies have been approved.

2.2.1.b. Approved methodologies for venting and flaring projects

There are three approved CDM methodologies to credit displacement of gas production through reductions in venting and flaring of gas from oil production: AM0009, AM0037, and AM0077. These methodologies cover different categories of flaring reduction projects in terms of the sources of gas that are eligible to be credited and in transportation and end-use of the collected gas (Table 2.1). These methodologies also differ in whether or not leakage (indirect downstream emission changes that occur outside the project boundary) and fugitives (gas escaped through e.g. pipeline leaks or accidents) must be included in the calculation of project emissions. It should be noted that CDM methodologies can be changed in updated versions; the information provided here represents project eligibility and calculation requirements under the current versions of each methodology at the time of writing (AM0009 v07.0, AM0037 v02.1, AM0077 v01).

Table 2.1. Comparison between approved CDM methodologies to credit reductions in venting and flaring of gas from oil production

METHODOLOGY	PRIOR VENTING/FLARING REQUIRED	ELIGIBLE SOURCES OF GAS	ELIGIBLE TRANSPORT OPTIONS	ELIGIBLE END USES	LEAKAGE IN CALCS	FUGITIVES IN CALCS
AM0009	None (but oil wells must be in operation)	Associated gas + lift gas	Pipeline or by trailer, truck, carriers as CNG	Not specified; partial use on site allowed	Required	Not included
AM0037	3 years	Associated gas	Not specified	Gas used as feedstock and partially as energy source in chemical process	Not included	Required
AM0077	3 years	Associated gas	CNG mobile units or pipeline	Heat (in the case of CNG mobile unit transport)	Required	Not included

For these methodologies, the calculation of emissions savings mainly considers the amount of gas that is recovered, as well as emissions associated with the project activity (e.g. energy use, transporting the recovered gas, fugitive emissions from project infrastructure). It should be understood that under these methodologies it is not the gas that is

recovered from venting and flaring that is credited for reducing emissions, but the gas produced elsewhere that the recovered gas is displacing. These two quantities are for the most part equal, and so at a basic level the amount of gas recovered is what is used to calculate emissions savings.

No currently approved CDM methodologies consider the amount of gas that is **not** collected by the project activity, and thus the total amount of venting or flaring is not directly measured either before or after project implementation (UNFCCC, 2008a, 2009, 2013a). For example, consider a project collecting 0.25 Mm^3 of associated gas per year compared to an initial flare rate of 0.28 Mm^3 per year. If in the same period total associated gas production rose to 0.54 Mm^3 per year due to increased rates of oil production or increase gas-oil ratios, then the total 0.28 Mm^3 of gas flared of would not have changed after project implementation. However, credits would still be awardable for the 0.25 Mm^3 recovered. This example demonstrates that the total amount of gas flared in any period does not matter in calculating the emissions avoided (i.e. the amount of recovered gas), as it is assumed that any extra gas still flared under the project scenario would also have been flared in the baseline.

All of the projects covered in the 4 major regions in the ICF flaring report followed the methodology AM0009. This is the most commonly used methodology for all CDM applications for venting and flaring reduction from oil production.

2.2.1.c. Baseline emissions

For flaring reduction projects, the calculation of baseline emissions must include at a minimum an estimation of the mass of carbon dioxide emitted due to gas combustion. In AM0009, this is done by multiplying together the volume of gas flared, the calorific value of this gas per unit volume and the CO_2 emissions factor for combustion of methane. This calculation could theoretically also include the flare efficiency, i.e. the proportion of the gas that is actually burned as opposed to escaping into the atmosphere. Usually though, project applicants do not include the flare efficiency because it is difficult to measure and validate and because assuming 100% flare efficiency in the baseline gives a conservative estimation of baseline emissions and ensures that the project activity is not over credited (GGFR, 2005). Thus, applications typically only request crediting of avoided CO_2 of flared gas, not unburned methane, although at least one project (“Recovery of vented gas at the Guneshli oil field in Azerbaijan”) has applied to credit reduction of unburned methane (the eligibility of crediting methane in venting reduction projects is discussed further in Task 3d). The CDM EB may be reluctant to credit methane reduction from displacing gas with collection of that which was inefficiently flared because this would significantly increase the number of credits awarded, and may be perceived as creating a risk of fraud or over-reporting of savings. In principle, crediting such improvements in methane destruction efficiency could create perverse incentives for flare efficiency to be underestimated on project applications, or even for flaring to be made

less efficient in the short term in order to allow credits to be claimed later. On the other hand, this conservative approach of only crediting CO₂ but not CH₄ reduction excludes any projects that really would generate significant emissions savings from improving flare efficiency or from collecting gas that was previously inefficiently flared (flaring efficiency is discussed in more detail in Task 1d). For venting reduction projects, the calculation includes at minimum the volume of gas vented multiplied by the fraction of gas that is methane and by the CO₂ emission factor for combustion of methane. Note that even for venting reduction projects, credits are awarded on the basis of the CO₂ that would be released if the methane had been combusted, and there is no credit for the higher global warming potential of methane. This approach is consistent with the underlying philosophy of crediting flaring and venting reduction projects under CDM. In theory, CDM projects do not credit the reduction in emissions from the flare stack, but the displacement of other fuels (natural gas from other sources) when the associated gas is taken to market.

Calculating baseline emissions as the quantity of gas recovered is a potentially conservative approach for methodologies where the collected gas could displace other feedstocks than natural gas. Theoretically, the baseline should reflect the amount and type of energy feedstock that the collected gas is replacing. In many cases it is possible that the associated gas will replace a fuel such as coal or diesel, which have higher emission factors (emissions as CO₂ equivalent per amount of useful energy produced) natural gas. Of course, in reality system expansion assessments to identify which fuels are really displaced are challenging, and the displaced fuels could vary over time. Note that the emissions savings from displacing other energy feedstocks could be partially offset by leakage (e.g. where the influx of gas lowers energy prices and leads to increased consumption); this is addressed in the calculation of project emissions, and is discussed in the subsection on “Leakage emissions” below.

Depending on the project type, baseline emissions may also include electricity or fuel used to transport the gas to the flare site and electricity or fuel used at the end use facility (that the collected gas is intended to displace). For example, if the recovered gas is used in a power plant and the facility’s computers run on electricity, this electricity could be included in the baseline emissions. In this case, this electricity for computers would most likely also be included in the project emissions, and the terms would cancel out.

2.2.1.d. Project emissions

Project emissions include any emissions that occur because of the project activity and would not occur in the baseline. This includes electricity used to process (e.g. compress to CNG) and transport the collected gas to the end use, and may include fugitive emissions that occur due to leaks in the pipeline or accidents (e.g. a broken pipeline seal), and electricity or fuel used at the end use facility. Fugitive emissions are considered in one venting and flaring reduction methodology (AM0037) but not in others (AM0009 and AM0077). Like

other parameters, fugitive emissions are estimated in the project design document and then measured directly after project implementation. Credits are then awarded based on a calculation that includes the measured rates. Unlike the baseline scenario, the project scenario does consider the higher global warming potential of methane emitted from leaks and accidents due to the new project infrastructure. This is to ensure that the emissions savings from flaring reduction aren't compromised by leaking uncombusted methane elsewhere in the system. Again, this is a conservative approach to crediting.

Some project related emissions are dependent on the end use of the collected gas. One typical end use for collected gas in venting and flaring reduction projects is electricity or heat generation; the gas is transported to a facility where it is combusted for electricity or heat that will be used by local consumers. Some of the operations of the facility may be powered by other fuel or electricity from the external grid, and these are included in the project emissions (electricity for computers, using the example above). This is to account for any increases in outside energy use due to the project implementation (e.g. an increase in computer operation to track gas flows). A smaller number of registered venting and flaring reduction projects use the collected gas as a feedstock for chemicals, for example methanol. In these cases, some but not all of the collected gas may be used for electricity to power the chemical production process, and any additional electricity that is brought in from the external grid must be included in the project emissions.

2.2.1.e. Leakage emissions

The last category of emissions calculations is leakage emissions. This refers to changes in emissions that occur because of the project and outside the project boundary. For example, the Rang Dong Oil Field Associated Gas Recovery and Utilization Project calculated leakage as energy used in processing gas beyond the project boundary (in this methodology, AM0009, the project boundary does not include the end use facility). Another example could occur be if an additional supply of gas-generated energy to local consumers were to reduce the local price, incentivizing consumers to increase their energy consumption. One venting and flaring reduction methodology does not include calculation of any leakage emissions (AM0037), and some projects using the methodologies AM0009 and AM0037 calculate leakage emissions as zero.

Emissions reductions from the project are then calculated as:

$$\text{Emissions reduction} = \text{baseline emissions} - \text{project emissions} - \text{leakage emissions}$$

The resulting value is the quantity of emissions reductions that is additional to the baseline and can thus be attributed to the project. This concept is illustrated for the Rang Dong Oil Field project in Figure 2.1.

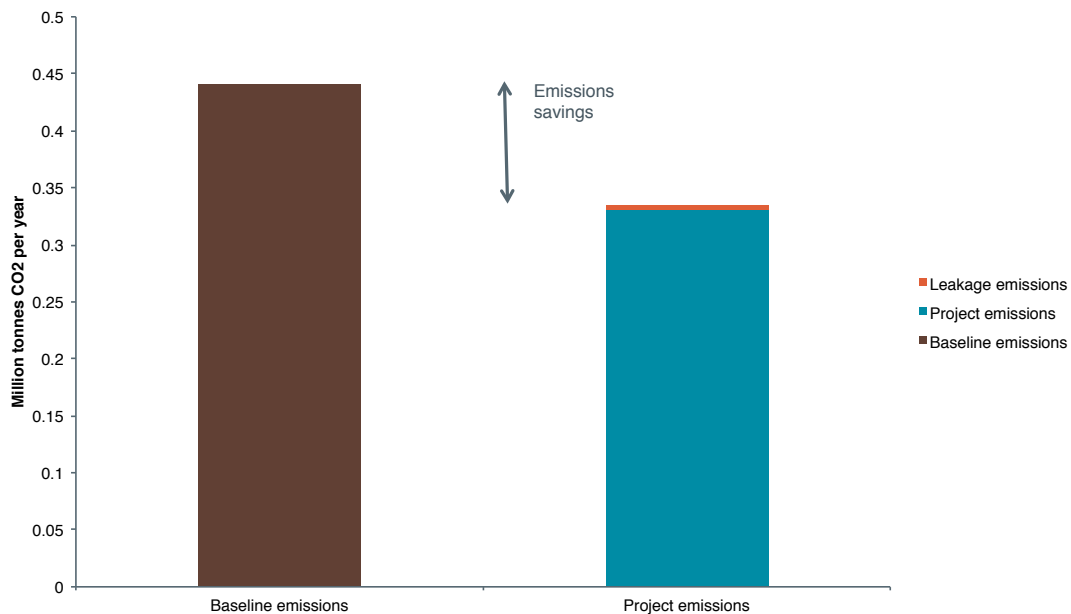


Figure 2.1. Emissions savings for the Rang Dong Oilfield project

2.2.1.f. Joint Implementation

Joint Implementation (JI) is a complementary scheme to CDM. Both programs were created by UNFCCC in response to the Kyoto Protocol. The distinction is that only projects in non-Annex I countries (i.e. developing countries) are eligible to be credited under CDM, and only projects that are in Annex I countries (i.e. developed countries) are eligible for crediting under JI, although the UNFCCC urges developed countries (such as those in the EU) to partner with transitioning countries in conducting JI projects. Projects credited under JI use basically the same approach to calculating emissions savings from venting and flaring reduction as those credited under CDM: calculations include the quantity of gas recovered as well as emissions resulting from transporting the gas, etc., but do not include an estimation of the total amount of associated gas originally flared or vented. JI projects can use any approved CDM methodology or a project-specific approach (UNFCCC). For example, the JI project “Associated Petroleum Gas Recovery for the Kharampur oil fields of ‘Rosneft’” is based on AM0009.

2.2.1.g. Additional measures for CDM projects under FQD

For Options 1 and 2 (i.e. allowing CDM projects reducing venting and flaring from oil production to be eligible for FQD compliance), there is no need to impose further criteria on the baseline and delta calculation currently used in approved CDM methodologies. However, if the Commission aimed to be conservative in allowing FQD compliance for CDM projects, it could require eligible projects to include fugitive emissions from leaks and accidents. This would exclude CDM methodologies AM0009 and AM0077, and projects that are not eligible for AM0037 would have to develop and apply for approval of new methodologies. Applying this more stringent criteria could potentially discourage some legitimate venting and flaring reduction projects due

to the increased administrative cost to applicants in monitoring and calculating emissions savings. Further, the estimation of fugitive emissions has a high level of uncertainty, and thus it cannot be guaranteed that the additional measurements under AM0037 would be effective in ensuring that projects did not result in fugitive emissions. The Commission would have to carefully consider introducing such a restriction.

2.2.2. Baseline and delta calculation under the prescriptive option

2.2.2.a. Crediting displaced gas

For the prescriptive option (Option 3a) the same general approach for calculating emissions savings as is implemented under CDM is proposed. Specifically, the volume of additional gas exported and/or utilized should be measured, with this measurement used as a proxy for the amount of gas displaced. For a simplified example, imagine that a city generates 3 Mm³/yr of demand for natural gas, and that historically that gas has been delivered from a local gas field. If a new flare reduction project results in construction of a pipeline to deliver 1 Mm³/yr of collected associated gas to the city from a separate oil field, but demand remains constant, then delivery of natural gas from the gas field to the city can be reduced to 2 Mm³/yr. In that case, 1 Mm³/yr of natural gas from the gas field need no longer be combusted, and this 1 Mm³/yr is the amount credited. Because the associated gas would presumably have been flared off anyway, there is no increase in associated gas combustion compared to the baseline.

Under this approach, it is not actually necessary to measure the amount of gas being flared before and after the implementation of the project, unless as an additional check on project performance (cf.2.4.2). The assumption is that all associated gas captured and delivered to market displaces gas from other sources, thereby generating emissions savings. It would even be possible for the rate of gas flaring to actually increase after project implementation, if this increase was a result of increased oil production or gas-oil ratio (although such cases might be subject to enhanced audit requirements).

Because both oil production rates and the gas-to-oil ratio can change over time, direct measurement of gas produced and flared may not give a useful indication of delivered emissions savings. There would be no environmental benefit delivered from crediting reduction of flaring at an oil well closed for being commercially non-viable. Crediting based on the quantity of gas collected and transported to an end user is a more accurate and meaningful approach and is easier for project participants to implement (not least because gas taken to market will already need to be metered for sales purposes).

2.2.2.b. Proposed methodology

For Option 3a we propose that a single universal methodology should be used for all flaring and venting reduction projects. Streamlining emissions reduction crediting as much as possible will have the dual benefits of ease of use for project participants as well as being comprehensive. This differs from CDM, under which there are three existing methodologies for reductions from flaring and venting that have inconsistencies and that do not cover all possible reduction projects. For instance, currently a flaring reduction project that utilizes captured gas-lift gas¹ as a chemical feedstock for the production of methanol would not qualify under any approved CDM methodology. This is despite the fact that both elements of the project could be eligible on their own – captured gas-lift gas would be eligible for crediting under AM0009, and gas use as a chemical feedstock qualifies under AM0037. However, these two project components are not covered together by any methodology. Under a single, simplified methodology, there should be no such gaps in applicability (although some project types may still be declared ineligible for other reasons).

It is proposed that the project boundary for an Option 3a project should include the drilling site itself, any existing gas processing infrastructure being used for associated gas handling, and all new infrastructure for gas transportation, compression, and processing developed for the project. The project boundary would end at the point that gas is offloaded into some existing distribution system. For example, if the project involves the construction of a new pipeline from the drilling site connecting to a local trunk line, the newly constructed pipeline would be included in the project boundary but the trunk line (and therefore any leaks, compressors or other emissions sources along it) would not be. If compressors are used at any point along the new pipeline, that energy consumption and the associated emissions must be included within the system boundary. In cases where gas is compressed or liquefied and then transported by container (i.e. via truck, rail, carriers, or CNG mobile units), the project boundary ends at the gate of the compression or processing facility. The end use facility (for example chemical production facility or power plant) is not included in the project boundary, even if it is newly constructed.

The eligible sources and end-uses of the recovered gas in Option 3a would cover almost all those within the scope of approved CDM methodologies. Sources would include associated petroleum gas (APG) and gas-lift gas from an external gas field. Provided that the additionality criteria were satisfied, it would not be required for participants to demonstrate that flaring or venting was occurring before the project start. For gas-lift gas sourced externally, project participants would have to demonstrate that there was a legitimate reason to import lift gas and that the rate of lift gas used was warranted by good reservoir-management practice. They would be

¹ In general, one would expect lift gas to be recycled. In some cases, however, there may be a local supply of high-pressure gas from a separate gas field, the use of which could avoid the need to install gas compression equipment onsite. In such cases, lift gas may be flared as recycling would require compression.

asked to measure continuously the rate of lift gas injection so that it could be checked for consistency with measured gas export. In any case, the amount of recovered gas-lift gas that can be credited shall not exceed 43 m³ per barrel of liquid produced from the well. These additional checks would remove the possibility that gas could be imported ostensibly for use as lift gas but in fact only to be re-exported with credits attached, and discourage a situation where more gas is used for gas-lift than is necessary for oil drilling, for the purpose of generating extra emission reduction credits.

Eligible end-uses in Option 3a would include gas exported to the grid or compressed or liquefied and then exported by pipeline, rail, freight, or any other means of transport. Option 3a would also include gas exported for use as a feedstock in the production of chemicals (e.g. methanol). The use of recovered gas as fuel for on-site equipment is eligible.

Emissions savings under Option 3a would be calculated as:

$$\text{Emissions savings} = \text{baseline emissions} - \text{project emissions}$$

Where:

$$\text{Baseline emissions} = [\text{mass of exported gas} + \text{mass of gas used in new on-site equipment} - \text{baseline gas export capacity}] \times \text{calorific value} \times \text{combusted gas emission factor}$$

And:

$$\text{Project emissions} = [\text{mass of fugitive project emissions} \times \text{uncombusted gas emission factor}] + [\text{energy used in new infrastructure} \times \text{corresponding emission factor}]$$

“Baseline gas export capacity” applies to projects that increase existing export of recovered gas. This may mean expanding a pipeline or adding a liquefaction facility to complement pipeline export capacity. In the case where there was no existing export capacity, this will be zero.

Fugitive emissions are to be measured by comparing metered gas flow into the project infrastructure to metered gas exported, correcting for any removed incombustible components (e.g. CO₂ removal). The threshold on inclusion of this term should be a 2% loss of gas through the infrastructure (i.e. if losses are lower than 2% they can be ignored as measurement error) or 7% for small-scale projects (< 50 Mm³/yr). This should serve to minimize the penalization of participants for discrepancies in values due to slight inaccuracies in measurement equipment given proper calibration and operation. Identification of losses above this threshold should trigger equipment checks by the project participants.

If project participants anticipate fugitive losses of greater than 2% (or 7% for small scale projects), they may choose to include such losses in the calculation of project emissions in the project design document,

taking into account the higher emission factor of uncombusted gas. Additional audits and any punitive measures (such as reduction in credits awarded) would only occur if reported losses were 2% (or 7% for small scale projects) greater than expected in the project design document.

Energy that is used to transport the recovered gas is included in project emissions. This includes e.g. energy use in a compressor along a pipeline or energy use in liquefying gas to be transported via truck. This term does not include energy use at the end use facility or in new equipment that is not involved in transporting the gas (e.g. a new gas generator that is used to power drilling equipment).

Option 3a excludes some terms that are used in CDM methodologies for the calculation of emissions savings; these terms are omitted for the purpose of simplicity, to make engagement in this crediting scheme easier and less burdensome for project participants, and to thus encourage more emissions reductions projects than would otherwise have occurred. These omitted terms include:

- Emissions from use of fossil fuels and electricity at the end use facility
- Leakage, i.e. indirect increases in emissions outside the project boundary as a result of the project

It is proposed that the end use facility be excluded from the project boundary and that energy usage at such facilities therefore be excluded from all calculations. This is because a new end use facility (e.g. power plant) should presumably be displacing an older one elsewhere, and the emissions associated with operating the new facility displace those used to operate the old facility. In practice, it is possible that any new facility would be more or less energy efficient than the facility or facilities being displaced, but it would be extremely burdensome to ask project participants to assess and demonstrate such differences, and subject to the risk of misreporting or fraud.

CDM includes a term for leakage emissions in the calculation of emissions in the project scenario. In this context, leakage refers not to physical leakage of methane, but to indirect impacts on emissions from the project, such as if increased gas availability drove down local energy prices and resulted in increased consumption. It is not proposed to include leakage emissions in Option 3a for several reasons. For one, while this term is included in the CDM calculation in principle, the enforcement of this requirement seems to have been patchy at best and it has generally not been assessed in project design documents. The assessment of leakage emissions is challenging and can be both subjective and contentious. Asking participants to undertake comprehensive leakage studies would be burdensome and may deliver little real benefit. Leakage and energy use rebound effects due to increased energy supply are important topics, relevant not only to gas recovery projects but also to biofuel mandates and efficiency programs, but we do not believe that imposing requirements within an

Option 3a emission crediting framework would be an effective way of addressing these issues.

Following the lead of the CDM, it is proposed that Option 3a would not credit recovery of gas that is currently vented any differently than recovery of flared gas when calculating emissions reductions. That is, Option 3a would assign credits to venting reduction as if it resulted in reduced carbon dioxide emissions, rather than crediting based on reduced methane emissions (methane has a higher GWP than CO₂). This is a conservative approach intended to avoid the creation of perverse incentives for oil producers to increase venting in the short term with the intention of implementing projects to reduce it again later. Methane has a GWP per unit mass twenty five times higher than that of carbon dioxide. This means that for a given carbon atom in an associated gas stream, the climate impact is nine times greater if it is released as methane than if it is combusted and released as carbon dioxide. This higher GWP of methane makes venting reduction especially desirable from a climate perspective, but it may introduce risks in the context of emissions reduction crediting. For current European gas prices, it is estimated that recovering €200 of natural gas would generate about one tonne of carbon dioxide savings if flaring were avoided. For a credit value of €100 to 200 per tonne of carbon dioxide, generating credits is a major boost to the value of an emission reduction project, but does not completely dominate the gas value. Having the gas value itself as an important component of the business case can be a barrier to fraud, as projects that genuinely increase gas capture would be much more profitable than fraudulent projects. However, if the savings were credited as avoided venting at the GWP of methane, the credit value could rise to €900 to 1,800 per tonne of emissions reductions. In this case, the credit value would dominate the gas value, and thus it is much more likely that a fraudulent project (i.e. one in which gas capture was not truly increased) would be financially appealing.

The risk of fraud is considered considerable in this case, and potentially greater than the potential for extra emissions reductions due to the increased credit value from crediting venting projects based on the GWP of methane. Under the CDM, venting reduction projects are credited only as if methane combustion had been avoided, i.e. at the GWP of methane. It is proposed that this conservative approach should also be adopted for Option 3a. It would underestimate the climate benefits of genuine venting reduction projects, but this is considered an acceptable trade off against the risk of false reductions being credited.

While it is not recommended, it would be technically viable to implement Option 3a with venting reduction credits based on the GWP of methane. Should a Member State or other authority decide to implement such crediting, it is recommended that an elevated level of monitoring and verification should be imposed as compared to that imposed on flare reduction projects, in recognition of the uncertainties and risks introduced by methane crediting.

Similarly, it is proposed that emissions savings from flare efficiency improvements should not be creditable under Option 3a. While flare efficiency improvement could in some cases generate real emissions savings, measurement and monitoring of flare efficiency is challenging. Crediting flaring efficiency improvements would introduce the risk of project participants tampering with flare tips or other equipment, selectively assessing flare efficiency only under best-case/worst-case conditions or otherwise taking measures to exaggerate or falsify improvements. There are environmental risks associated with any system that creates a potential financial reward for poor initial performance. There is also substantial uncertainty in flare efficiency measurement, and it is very sensitive to flare rates and environmental conditions. These risks are considered too high compared to the potential benefit of attracting a greater number of projects under Option 3a. This is discussed further in Section 4.5.

2.2.3. Baseline and delta calculation under the implementing measure requirements

The proposed FQD implementing measure specifies the requirement for calculating emissions reductions from upstream emissions reduction projects as follows:

Greenhouse gas reductions associated with oil and gas upstream emissions will be estimated and validated in accordance with principles and standards identified in International Standards and in particular ISO 14064, ISO 14065 and ISO 14066.

ISO 14064 comes in three parts. Part 2 “focuses on GHG projects or project-based activities specifically designed to reduce GHG emissions or increase GHG removals” and is therefore the relevant part for assessing UER projects. ISO 14064 Part 3 sets principles for verifying and validating GHG projects. 14065 and 14066 set requirements for determining the competence of validation and verification bodies and personnel respectively. To meet this requirement therefore, a UER project must be designed and implemented in accordance with ISO 14064 Part 2. This must be validated in accordance with ISO 14064 Part 3 by a team of ISO 14066 competent verifiers working for an ISO 14065 competent organization. The annual emissions reduction claims must then be verified by a separate team of ISO 14066 competent verifiers working for a different ISO 14065 competent organization.²

ISO 14064 Part 2 article 2.7 defines a greenhouse gas emissions reduction as “calculated decrease of GHG emissions between a baseline scenario and the project.” The calculation of emissions reductions therefore requires the assessment of a baseline level of emissions. The baseline is defined as “hypothetical reference case that best represents the conditions most likely to occur in the absence of a proposed

² ISO 14065 (5.4.2 b) states that verification or validation bodies “shall not validate and verify GHG assertions from the same GHG project unless allowed by the applicable GHG programme.” As the proposed Implementing Measure makes no specification on this point, it is assumed that the principle should be applied as indicated in the ISO.

greenhouse gas project.” This is built on the definition of a project, given as: “activity or activities that alter the conditions identified in the baseline scenario which cause greenhouse gas emission reductions.”

This definition of the baseline is very much similar to the definition of the baseline within the CDM methodologies. Because the baseline should represent the ‘conditions most likely to occur in the absence of a proposed greenhouse gas project’, any baseline calculated under a scheme used within the implementing measure requirements (Option 3b) must be based on an assessment of what emissions would be in a business as usual case. ISO 16064 Part 2 “deals with the concept of additionality by requiring that the GHG project has resulted in GHG emission reductions or removal enhancements in addition to what would have happened in the absence of that project” (ISO 14064 Part 2 article 0.3). The baseline assessment must be undertaken by a project participant and validated by the project validator along with other project documentation.

The baseline assessment for such a project should consider, “relevant information concerning present or future conditions, such as legislative, technical, economic, sociocultural, environmental, geographic, site-specific and temporal assumptions or projections” (ISO 14064 Part 2 article 5.4). Further, “The project proponent shall select or establish, justify and apply criteria and procedures for demonstrating that the project results in GHG emissions reductions or removal enhancements that are additional to what would occur in the baseline scenario” (ibid).

The emissions reductions creditable under a scheme eligible under Option 3b must therefore reflect the difference between project emissions and emissions in a baseline scenario as detailed above. In practice, this means that the emissions reduction calculation under Option 3b would need to be broadly similar to that under CDM or Option 3a.

As the baseline scenario must be defined with reference to information including economic and legal projections, we would expect this requirement to be interpreted by a Member State authority as including legal and financial additionality requirements analogous to the specific additionality requirements under CDM. In particular, it would be expected that a project participant should demonstrate either that the baseline case would be permissible under local law, or that local law that ought to prohibit the baseline case is not enforced and that disregard for that local law represents normal business practice. It should also be demonstrated that the baseline case would be considered financially viable – i.e. that financial considerations alone would not have normally caused the project participant to implement the project in question. ISO 14064 Part 2 does not specify the basis for this assessment. Schemes under Option 3b might require financial assessment similar to that under CDM, or similar to that proposed under Option 3a, or some alternative system to make this demonstration. Member State administrators would not recognize an emissions reduction scheme as generating credits eligible for use under the FQD unless they were satisfied that this financial assessment

provided adequate demonstration that, “the project results in GHG emissions reductions ... additional to what would occur in the baseline scenario.”

In order to identify baseline and project emissions, and hence calculate reductions delivered by the project, the project proponent must, “identify all relevant GHG sources and sinks controlled by the project proponent, as well as those related to or affected by the project” (ISO 14064 Part 2 article A.3.3.1). In practice, it should be recognized that “the quantification of GHG emissions and removals generally does not involve all of the potentially large number of GHG sources and sinks” (ibid) and therefore it is appropriate to set criteria to identify relevant sources and sinks.

For a flaring or venting reduction project, most related sources at the oil production facility can be considered irrelevant on the basis that they would not be affected by the project.^{3,4} However, “the project proponent is also accountable for changes in GHG emissions and removals by GHG sources and sinks affected by the project through activity shifting or market transformation” (ibid). These changes are often referred to as ‘leakage’. Between the consideration of sources and sinks controlled by the project proponent or affected by the project, the burden of baseline assessment could be considerable. However, “the criteria may consider a balance between practicality and cost-effectiveness with the GHG project principles” (ibid). A scheme may therefore legitimately permit a streamlined baseline assessment provided that the cost reduction delivered by that streamlining is proportionate to any reduction in accuracy in the emissions assessment.

While CDM does not allow credits for avoided methane venting to be counted based on the GWP of methane, it would be possible to credit avoided venting on that basis within a scheme under Option 3b. The ISO states that, “the project proponent shall use tonnes as the unit of measure and shall convert the quantity of each type of GHG to tonnes of CO₂e using appropriate GWPs” (ISO 14064 Part 2 article 5.8). While this may seem *prima facie* to suggest that changes in vented emissions should always be assessed based on the GWP of methane, and hence contradict the treatment of vented emissions under CDM, the ISO also provides the following guidance for handling uncertainty:

Project proponents should pursue accuracy insofar as possible, but the hypothetical nature of baselines, the high cost of monitoring of some types of GHG emissions and removals, and other limitations make accuracy unattainable in many cases. In these cases, conservativeness serves as a moderator to accuracy in order to maintain the credibility of project GHG quantification (ISO 16064 Part 2 article A.2.5);

³ E.g. energy requirements to extract oil would not be affected unless the project utilized captured gas in a way that affected oil recovery, such as reinjection.

⁴ “Exclusion of GHG sources from regular monitoring and quantification may also be justified when comparisons of the project and baseline sources show no change from the baseline to the project (ibid).

and,

The principle of conservativeness is applied when highly uncertain parameters or data sources are relied upon for the determination of the baseline scenario and the quantification of baseline and project GHG emissions and removals. In particular, the conservativeness of the baseline is established with reference to the choice of approaches, assumptions, methodologies, parameters, data sources and key factors so that baseline emissions and removals are more likely to be under-estimated rather than over-estimated, and that reliable results are maintained over a range of probable assumptions. (ISO 14064 Part 2 article A.2.7).

The requirement under CDM (and Option 3a) that any reduced venting emissions should be credited only by the GWP of carbon dioxide can be understood as an application of this conservativeness principle, given the uncertainty involved in estimation of baseline venting rates. A scheme under Option 3b could therefore follow the precedent from CDM, or otherwise should set clear monitoring and reporting guidelines to ensure the accuracy of crediting of avoided methane emissions.

Under CDM, as discussed in Section 2.2.1.c, there is a logic applied to upstream emissions reduction crediting that the emissions reduction is generated by displacing use of a fuel for an end use, rather than directly from preventing the burning or release of gas at the flare stack. This implies that the project boundary should be drawn to include the end-use facility for captured gas. Under Option 3b, the decision about how widely to draw the project boundary must be taken by the project proponent to the satisfaction of the scheme being used. In turn, the scheme must put in place requirements on identification of relevant sinks and sources that is acceptable to the relevant Member State authorities. In principle, it would be possible to draw a very wide boundary based on the requirements of the ISO – including the end-use facility, and potentially also requiring an assessment of leakage effects in the market. The methodologies under CDM can provide examples in interpreting the ISO in this regard for schemes and Member States, and identifying the appropriate balance between accuracy and cost of reporting. Similarly, our proposals under Option 3a outline a system boundary that we feel finds an appropriate balance between burden and accuracy. It would be possible under Option 3b for a project proponent to argue that the fuel being displaced by increased gas capture had a higher associated emissions factor than natural gas – for instance, in the case of coal displacement. Under CDM, such displacement of higher carbon intensity fuel would not normally be creditable. Under Option 3b, a scheme that allowed enhanced levels of crediting for displacement of higher carbon intensity fuels may be permissible, provided that the level of accuracy was appropriately set and enforced, and that an overall regard to the principle of conservativeness could be shown for the scheme.

Leakage effects are hard to assess in these cases, and while the requirement to assess leakage is also in place under CDM, in practice such emissions have generally been ignored. It may therefore be felt

that ignoring leakage emissions would be appropriate in interpreting the ISO, on the basis that the benefit of assessing leakage may be disproportionate to the cost. Under Option 3b Member State authorities would have to set and communicate their interpretations and requirements on this point.

2.2.4. Flare gas measurement vs. project gas capture measurement

The tender specifications for this report specifically called for consideration of a 'mass balance' calculation approach for assessing reductions in emissions from venting and flaring, whereby volumes of flared gas are estimated as a remainder term:

$$\text{Volume of gas flared} = \text{oil production rate} \times \text{gas-to-oil ratio} - \text{utilized gas volume} - \text{exported gas volume}$$

It is suggested that by comparing the calculated volume of gas flared before project implementation and after project implementation it would be possible to calculate the emissions saved by the project. While such a technique may well give a reasonable estimation of the volume of gas being flared, given continuous or regular measurement of the other gas flows specified, in the context of emissions reduction projects the amount of gas flared before project implementation is not adequate for setting an emissions baseline. The baseline should reflect a business as usual case that may change over time, and thus cannot be fixed based on emissions rates at a given moment. Indeed, the actual amount of gas being flared at an oilfield is sensitive to many more variable factors than the volume of gas associated with a new gas disposition project. In particular, the amount of flared gas will be sensitive (as shown by the equation) to the volume of oil produced and the gas-oil ratio of that oil production. When thinking about a baseline that is dynamic in time, as is required by CDM or by ISO 14064 Part 2, the volume of gas being flared after project implementation actually becomes irrelevant to the saving calculation. Any ongoing flaring in the project scenario would also have been flared in the baseline scenario, and therefore can be cancelled from the equation without ever being measured. It is the volume of gas captured and utilized that is important.

The philosophy of CDM is not in fact to credit a reduction in combustion of gas that goes to the flare – the assumption is that this physical volume of associated gas will be burned either way, whether at the flare for no practical purpose, or at a power generating facility downstream. The credit instead comes from the volume of gas that is displaced at the end use facility. The credit is not for avoiding burning the associated gas, but for avoiding burning gas from some other source. From this perspective, the actual amount of gas being flared either before or after the project is implemented is irrelevant, provided that the correct baseline assumption was that all gas would be flared. This logic applies under Options 1 and 2, which both use the CDM framework, and has been adopted under Option 3a.

This approach of measuring the gas being saved from flaring, rather than the actual amount of gas flared in total, gives a much more useful result than a direct assessment of flared volumes. Direct flaring measurement is highly uncertain; for example, the required measurement accuracy of flared volumes under EU ETS ranges from 7.5%-17.5% depending on project size, which reflects on expectations of how accurately these measurements can be made.

While a measurement approach based entirely on a mass balance assessment of flare rates is inadequate as a full emissions reduction calculation methodology, the assessment of post-project flared gas volume could potentially be relevant to some emissions reduction projects. For instance, there may be cases in which reservoir management could be improved to manage GOR, for instance, and using a mass balance approach may have some value if there was an attempt to credit such reductions. No CDM methodology exists that would allow the crediting of reduced flaring due to improved reservoir management. Such projects would therefore not be eligible for consideration under Options 1 or 2 and are not proposed to be eligible under Option 3a, but under Option 3b a project proponent may be able to make a case for crediting of such a project.

Other than this, in some cases it might be considered desirable to monitor actual flare rates to provide a 'traffic light' to trigger additional auditing of a project. For instance, it might be considered reasonable to impose additional audit on any project that was being awarded emission reduction credits, but where the actual volume of gas flaring had not reduced. This could simply be a sign of natural increases in associated gas production, but might also be suggestive that there was a problem in the calculation of the baseline or in the monitoring of the emissions reductions. Such monitoring could, in principle, be implemented either through some sort of mass balance system, or through satellite measurement or direct instrumental measurement of flare rates.

Satellite measurement of flaring rates is suggested for consideration as a verification technique under Option 3a, but is not required under CDM. However, it would in principle be possible under Option 2 to add some additional requirements beyond the requirements of CDM for CERs to be FQD compliant, such as requiring the reporting to Member States of additional information from the project. Such additional requirements would allow, for instance, the exclusion of projects from the FQD where actual rates of flaring had increased despite the implementation of emissions reduction projects. A secondary benefit of adding data reporting requirements to identify real flare rates would be that the data could be collected by the Commission and integrated in the calculation of upstream fossil fuel emissions for the FQD baseline, and potentially for any more detailed calculation of fossil fuel lifecycle carbon intensity introduced under Article 7a.

2.2.4.a. Applicability of a mass-balance system of emissions reduction estimation under Option 3b

The calculation of emissions reductions based on monitoring changes in actual flare rates, whether through a mass balance based system of observation or through direct measurement, would not be consistent with the requirements for baseline assessment under ISO 14064 Part 2, and would thus not be an appropriate calculation methodology for Option 3b. As described above under Section 2.2.3, ISO 14064 requires the quantification of all relevant GHG sources in both the baseline and project scenarios, which includes all those affected by the project. Reducing the calculation methodology to assessing only flaring emissions would thus not meet the requirements in the proposed FQD implementing measure.

2.3. Task 1b: Reporting regime

Accurate monitoring and reporting of emissions reductions from venting and flaring reduction projects is essential for crediting under each of the options.

2.3.1. Reporting regime under the CDM options

Once a CDM project has been registered and implemented, the project participants must monitor certain parameters used to quantify project emissions. As discussed in Section 2.2 on the baseline and delta calculation above, project emissions are compared to baseline emissions to calculate the emissions reductions attributable to the project. The project participants must report the monitoring data to the Designated Operational Entity (DOE, the project auditor). The DOE then reports to the CDM EB on whether or not the monitoring demonstrates that the project meets the requirements for crediting.

CDM project applicants must monitor and report each measurable parameter included in the calculation of baseline and project emissions under the applicable methodology. For venting or flaring reduction projects, this means measuring the amount of collected gas and its emission factor in combustion, and if applicable, electricity or additional fuel used in the project and/or, fugitive emissions from leaks and accidents (Zakkour, Jakubowski, & Garcia Koch, 2010). Some parameters, such as the CO₂ emission factor for methane in AM0009, are assumed to be default values and not monitored. All monitoring equipment must be maintained and calibrated according to industry standards (Zakkour et al., 2010). All data collected must be recorded, archived electronically, and kept for a minimum of two years after the end of the crediting period.

Each of the CDM methodologies for the reduction of venting and flaring of associated petroleum gas are quite specific about what exactly should be measured, but flexible about how this measurement

is done. For most of the measured parameters, the methodologies do not specify exactly what type of analysis must be done or exactly what type of measuring equipment should be used. The DOE must approve the measurements reported before the project is validated and credited.

The basic measurements to calculate emissions reductions from gas collection include gas flow using a flow meter and the fraction of gas that is methane. Under the three CDM venting and flaring reduction methodologies discussed here, gas flows must be measured continuously (i.e. measurements must be taken at regular intervals throughout the day), but the type of flow meter is not specified.

There are different approaches to monitor the carbon intensity of collected gas. Associated petroleum gas is not pure methane, but contains other substances, which can include ethane, butane, propane, water, carbon dioxide, hydrogen sulfide, and other impurities (FPFC Energy, 2007). Some of these impurities and their combustion products can have a climate forcing impact greater than that of CO₂, but not all of them are included in calculations, and the differential global warming potential is not considered. One methodology (AM0009) requires measurement of the calorific value of the gas, i.e. the amount of energy released when the gas is combusted (typically measured with a calorimeter). Two others (AM0037 and AM0077) call for unspecified measurement of the carbon content of the gas. Both of these approaches would capture ethane, butane, and propane in addition to methane, although how each method estimates the contribution of these other compounds to total gas saved may differ somewhat. Hydrogen sulfide would likely contribute to the calorific value of gas in that type of measurement, but not to the carbon content. These gas composition measurements are required weekly or monthly at a minimum, depending on the methodology.

For the calculation of fugitive emissions from leaks and accidents in applicable methodologies, the global warming potential of the methane leaked is considered under the project scenario (this is also discussed in Task 1a). Thus, it is necessary to measure the actual methane fraction (on a mass basis) as opposed to the calorific value or carbon content. In AM0037, an unspecified chemical analysis is allowed for monitoring of the methane fraction of fugitive gas emissions and this measurement must be made weekly.

Under AM0037, the temperature and pressure of gas in the pipeline are measured and recorded in order to more comprehensively estimate the mass of gas lost in accidents or for fugitive emissions, as well as the duration of this leak or accident. These measurements are only required at the time of the leak or accident.

For methodologies that include calculation of energy used at the drilling and/or end use facility, it is also required to monitor and record the emissions from this energy using a flow meter (in the case of energy from combusting liquid or gaseous fossil fuel, as in AM0077) or a CDM calculation tool ("Tool to calculate baseline, project and/or

leakage emissions from electricity consumption”, in the case of electricity in AM0037).

2.3.1.a. Additional requirements that may be needed under FQD

The Commission’s proposed FQD implementing measure specified information that must be supplied to support reporting of upstream emissions reductions (Annex III). In Table 2.2 these requirements are listed, along with whether they would be met under current CDM reporting (i.e. in materials available on the UNFCCC CDM website⁵) or if additional requirements would have to be imposed. Under Option 1, CDM CERs and JI ERUs issued under EU ETS or other trading systems would be eligible to demonstrate compliance with the FQD; it is also identified whether the information required in the implementation proposal would be available in the CDM project documents and in the serial number for CER/ERU units.

Table 2.2. Reporting requirements for upstream emissions reductions under the proposed FQD implementing measure, and whether these requirements are met by current CDM reporting

REQUIREMENT UNDER IMPLEMENTATION PROPOSAL	INFORMATION AVAILABLE IN CDM/JI DOCUMENTS ON UNFCCC WEBSITE	INFORMATION AVAILABLE IN CER/ERU SERIAL NUMBER
Starting date of the project	Yes	No
Annual emissions reductions (gCO ₂ e)	N/A	Yes (number of CERs retired)
Duration of crediting period	Yes	No
Project location (latitude, longitude)	No	No
Baseline emissions (gCO ₂ e/MJ of feedstock provided)	No	No
Unique identifying number for claimed emissions reductions	Yes	Yes
Unique identifying number for calculation method	Yes	No
Gas-to-oil ratio (GOR)	No	No

Some parameters required in this proposed FQD implementing measure would be adequately covered in CDM reporting, but several would not, and the CER/ERU serial number does not include most of the necessary information. If either the ETS-CDM option (Option 1) or the standalone CDM option (Option 2) were implemented, the Commission would need to impose additional reporting requirements for annual emissions reductions, precise project location, baseline emissions, and GOR or remove these reporting requirements.

The starting date of the project is required in the proposed implementing measure, because projects implemented before 2011 are not considered to contribute towards the target. This information would need to be checked before any CDM credit was determined to be FQD compliant. No additional economic operator reporting would

⁵ <http://cdm.unfccc.int/>

be required, but Member States may want to include this data in a requirement for reporting in order to shift the burden from the public entity to the economic operator.

The duration of the crediting period for CERs identifies the start and end dates for project crediting. While this data is available from the UNFCCC website, identifying the crediting period is not enough to identify whether a given credit was awarded in a specific year. In particular, knowing the crediting period would be inadequate to identify whether a credit had been issued relating to emissions reductions delivered specifically in 2020, the year of the FQD carbon intensity target. Member States would need to put in place an additional reporting requirement for operators to identify the year in which a CER/ERU was awarded.

The project location is not explicit in either the serial number or the UNFCCC website. This data would be most relevant for the purposes of monitoring and verification. However, as CDM already implements robust checks before CERs are issued, additional requirements to report this data would not be necessary under Options 1 or 2. If this data were requested, it would require an additional requirement on economic operators to report to Member States.

The baseline carbon intensity of fuel associated with the location of the emissions reduction projects would not be reported to UNFCCC, and would generally not be available to economic operators without putting additional measurement systems in place. Adding such a requirement within Option 1 or 2 would create a significant administrative burden, but would not provide any extra assurance on the true additionality of reported emissions reductions. Such a requirement may not be productive unless there was a clear regulatory purpose for such a provision.

The calculation methodology under CDM is not explicit from the serial number on a CER/ERU. Under Option 1, the methodology should be reported in the ETS registry, in which case it could be established that the credit was FQD compliant in this respect (i.e. awarded in line with an approved methodology for upstream emissions reductions from flaring or venting reduction). Under Option 2, it would need to be reported and subject to verification.

Finally, the GOR for an oilfield associated with a credited project would not be reported to UNFCCC, and would not generally be known by obligated parties under the FQD. This information would not be necessary to establish that genuinely additional emissions savings had been achieved, but would significantly increase the administrative burden on suppliers. Member States could put in place additional reporting requirements on GOR, but this may not be productive unless there was a clear regulatory purpose for such a provision.

For both Option 1 and Option 2, it is suggested that any additional information required to demonstrate FQD compliance should be verified by the Designated Operational Entity (DOE). As this entity

already validates and verifies the emissions reductions from the project under the CDM process, it should be considered a reliable source of assurance. Guidelines on exactly what information is needed and how to verify it would need to be issued for use by DOEs. The DOEs would then create a document, additional to the CDM process, detailing the required information. This would need to be passed up the chain of custody with the CERs/ERUs. It is suggested that the administrator of the central registry (the Commission in the case of Option 1, some other party in the case of Option 2) should be submitted this document when CERs/ERUs are transferred from a national registry to the central registry. The administrator would then be tasked to check the authenticity of the DOE's opinion (i.e. confirm that it was indeed issued by the same DOE as verified the reductions on the project). The administrator may also choose to undertake additional checks on a risk-based basis on a sample of CERs/ERUs transferred into the registry. The documentation should also be made available to any Member State FQD administrator seeking to perform additional checks on credits being used towards compliance within that Member State.

2.3.2. Reporting regime under the prescriptive option

The prescriptive option (Option 3a) should prescribe a monitoring approach that allows the accurate calculation of emissions savings without undue burden on project participants. With that in mind, it is proposed that the basic measurement approach of CDM – gas flow and composition, with flexibility in type of monitoring equipment – be mirrored in Option 3a. Generally, measurement equipment should be best in class. The calculation of emissions savings above (see Section 2.2.2) depends on five parameters: rate of gas exported, rate of gas used in new on-site equipment, baseline gas export capacity, gas calorific value, and the emission factor of the recovered gas.

Measurement of the volume of gas exported depends on the export method. In cases where the gas is transported via pipeline, gas flow through the pipeline at the edge of the project boundary should be measured *continuously*. Any type of flow meter can be used and for large-scale (>50 Mm³/yr) it should be rated to an accuracy of 99% or more (uncertainty 1% or less) by the manufacturer, for example an ultrasonic meter, Coriolis meter, or a gas meter with Electronic Volume Conversion Instrument (EVCI) (GGFR, 2010; LEVON Group & URS Corporation, 2009). Flow meters in small-scale projects (<50 Mm³/yr) should be rated to an accuracy of 98% or more. When gas is exported in containers via rail, freight, CNG mobile units, etc., the volume of gas in each container, the temperature and pressure, and the number of containers should be measured and reported. Container volume must be measured to an accuracy of 99% or more (98% or more for small-scale projects). In cases where gas is processed before export (e.g. into dry gas), the mass of gas components that are removed (including e.g. NGLs) must be monitored and reported. Energy carriers such as NGLs should be counted towards emissions reductions if they were not previously utilized, and in such cases the mass of separated NGLs should be added to the mass of exported and utilized gas. When gas is

used in new on-site equipment, the rate of this usage in mass (or volume, temperature, and pressure) must be measured.

For projects that utilize gas on-site in the baseline scenario, project participants should be required to report if they intend to continue using gas in the existing equipment or if they intend to switch to a different feedstock. If gas continues to be used in the existing equipment, this amount of gas will not be credited. If the project participants switch to a feedstock with a higher carbon intensity than gas after project implementation, this feedstock type must be reported and the increase in carbon intensity over gas ($\text{gCO}_2/\text{MJ}_{\text{new feedstock}} - \text{gCO}_2/\text{MJ}_{\text{gas}}$) shall be multiplied by the usage capacity of the equipment and subtracted from reported emissions savings.

Crediting on-site energy generation introduces a risk of incentivizing excess energy generation, and a fraud risk that on-site energy generation could be misreported. As an additional check, participants in such projects should be required to report pre-project rates of energy use, and type of energy used – gas, diesel, grid electricity etc. In the event that the gas is to be used to supply energy for some new piece of equipment, the auditor should be provided with the engineering case for introducing that additional equipment.

This level of monitoring is designed to balance adequate oversight with a manageable administrative burden and cost for participants. Since the operator must in any case measure the amount of gas exported for the purposes of sale, this element should not impose any additional burden. At all measurement points, pressure and temperature must be measured (continuously for pipeline export and per batch for container export). This information should be used to calculate the gas volume at standard temperature (with the exception of monitoring via Coriolis flow meter, which measures mass flow instead of volume flow, (GGFR, 2010a)). In cases where pressurized gas-lift gas is imported from outside the project boundary, gas flow must also be measured in this pipeline.

In order to monitor for excessive fugitive emissions or faulty metering, participants should be required to also meter gas at the point(s) it enters the new infrastructure, and this quantity should be compared to the exported quantity. Where there is existing gas-processing equipment the second meter should be placed after that equipment, as any fugitive emissions in existing equipment should be included in the baseline. As with export monitoring, a flow meter, temperature meter, and pressure gauge should be installed in the pipeline at the point gas enters the new infrastructure and should collect measurements continuously. When gas is used in new on-site equipment, it must be monitored to allow accurate tracking of all gas flows. Thus, an additional flow meter, temperature meter, and pressure gauge should be installed at the point where gas is diverted from the main export route to on-site use.

The rate of gas export should be compared to the rate of gas entering the pipeline (minus any gas components such as NGLs that have been

removed, flow to onsite use if applicable, and in all cases corrected to standard temperature and pressure). If the rate of gas flow at the entry point is greater than the rate of gas exported by more than 2% by mass (averaged over a period of one week) or 7% for small-scale projects ($>50 \text{ Mm}^3/\text{yr}$), the operator should be given a month to resolve the issue. If the issue is resolved, credits equivalent to the recorded gas loss (at the uncombusted gas emissions factor detailed in Annex D) should be withheld for that month, after which normal crediting should resume. If the issue is not resolved within a month, an additional audit should be triggered on the measurement equipment. If the measurement equipment at one of the two points is not functioning properly, the operator must immediately repair the equipment, and the measurement from the other point will be used to calculate emissions savings for the period of discrepant measurements. If all equipment is functioning properly, the operator must thenceforth subtract the measured amount of fugitive gas multiplied by an uncombusted gas emission factor of **16.062** (detailed in Annex D from total reported emissions savings. If the rate of fugitive losses recorded rises above 2% for large projects or 7% for small-scale projects ($>50 \text{ mm}^3/\text{yr}$) in any two months in a one-year period, credits should be withheld entirely until the participant is able to demonstrate that they have resolved the leakage issue. In this event, crediting should not resume until after a further equipment audit. As in the approved CDM methodologies, the full emission factor of gas is considered in fugitive emissions, but not in emissions savings for recovered gas. This is a conservative approach that should reduce the risk of over-crediting flaring and venting reduction projects.

The most precise way to allocate an emission factor to the recovered gas would be based on a full gas composition assessment. The other options (as utilized in CDM methodologies) are measurement of calorific value or of methane content in order to calculate metric tonnes of CO_2 avoided by a project. Methane is not the only component of gas that produces CO_2 when combusted. In cases where the NGL content is high, crediting only the methane fraction of recovered gas could substantially underestimate the real benefits. Calorific value, or the amount of energy produced when the gas is combusted, is a closer proxy for CO_2 avoided than the methane fraction, but is still sensitive to compositional variation. Combustion of NGLs produces more CO_2 per BTU than methane, and so for a gas mixture with high NGL content the calorific value measurement would tend to underestimate CO_2 emissions from combustion.

However, by the logic of crediting avoided gas use through gas recovery, the composition (and hence combustion carbon dioxide emissions) of the recovered gas is not the key quantity to consider. Given the philosophy of crediting displacement of other natural gas use, the correct question is what emissions would be associated with the gas displaced. The calorific value of the recovered gas is therefore indeed the most important quantity to measure, as this value (at lower heating value) will determine the amount of fuel displaced.

It is not proposed to determine the exact composition of displaced gas on a project-by-project basis. Such a calculation would require the project participants to identify the alternate (baseline) source of the gas that would be used by the project's end-users and measure its composition. Such an assessment would be subject to change over time and the practical application of such a methodology would contain significant risk of fraud, or at least wishful thinking on behalf of project participants (e.g. incentive to identify a gas source with high NGL content as the displaced material in the baseline scenario). Such a requirement would also create a burden on the project participants in supplying evidence to support their determination of the baseline gas source that would be disproportionate to the potential environmental gains.

Thus, it is proposed that the calorific value of the recovered gas is measured and used to calculate project emissions savings following the equation in Section 2.2.2 and the emission factors in Annex D, which assume a typical processed gas composition. Calorific value can be measured on site or in a laboratory using any method in line with international fuel standards. The measurement technique must have an accuracy of 99% or greater (98% or greater for small-scale projects) according to the equipment manufacturer or laboratory calibration tests. If NGLs are separated and utilized on-site or exported, the mass and calorific value must also be measured and reported in order to be credited, using the NGL emission factor in Annex D.

For projects for which the end-use of the recovered gas is as a feedstock in chemical production (e.g. methanol), CDM requires measurement of the methane fraction (AM0037), presumably because only the methane would be used in that specific chemical process. However, the energy-carrying non-methane components of associated gas are almost entirely hydrocarbons (i.e. ethane, propane, butane, pentane, etc.; (IHRDC, 2014))⁶ that have a significant market value and are usually separated and sold for other processes (IHRDC, 2014). While the non-methane hydrocarbon fraction of the recovered gas may not be displacing methane used at the specific end-use facility, it is very likely displacing hydrocarbon use elsewhere, outside the project boundary. Because of this, it is reasonable to use the calorific value of recovered gas to calculate emissions savings even when the local end-use is a feedstock in chemical production.

For projects recovering gas-lift gas sourced from a high-pressure gas field that was previously vented or flared, the oil production rate must also be measured continuously and reported. The amount of imported gas-lift gas eligible for crediting is capped at 43 m³ per barrel of produced liquid, which should be adequate to provide additional lift for typical projects.

⁶ Associated gas also contains some hydrogen sulfide (usually less than 1%), which produces a relatively low amount of energy upon combustion (about one-third that of methane or other small hydrocarbons by mass (NAO, 2002)).

A summary of monitoring requirements is shown in Table 2.3. Small-scale projects ($<50 \text{ Mm}^3/\text{yr}$) should have less stringent requirements for the accuracy of measurements than for large projects. The risk of over-crediting due to measurement inaccuracy is increased by the adoption of reduced requirements. However the consequence of over-crediting (in terms of excess credit rewards) is proportionally lower for small projects, and the reduced monitoring burden will make it more feasible for these projects to participate in the emissions reduction scheme. This approach mirrors the “Tiers” of required accuracy for reporting of gas flaring under EU ETS depending on the level of total annual emissions.

For very small projects ($<10 \text{ Mm}^3/\text{yr}$), all measurements may be conducted on a weekly basis rather than continuous. While this relaxation in requirements will increase measurement error, it will likely encourage the participation of very small projects that otherwise would not have applied for crediting due to the large monitoring burden relative to the size of the project. Weekly measurements must be typical of flow rates and must be precise and regular. Projects opting for weekly measurements must submit data on annual gas sales (if this data is collected) or on on-site gas usage, which will be checked for consistency. Auditors verifying projects conducting weekly measurements would have additional inspection guidelines (discussed in Section 4.3.3.c).

Table 2.3. Summary of monitoring requirements under the prescriptive option

PARAMETER	REQUIRED ACCURACY (LARGE SCALE PROJECTS)	REQUIRED ACCURACY (SMALL SCALE PROJECTS)	MEASUREMENT FREQUENCY
Flow rate at point of recovery	99%	98%	Continuous (min 10 Hz)
Flow rate at point of export or volume and number of export containers	99%	98%	Continuous (min 10 Hz)
Flow rate at point where gas is diverted to on-site use (if applicable)	99%	98%	Continuous (min 10 Hz)
Flow rate of imported gas-lift gas (if applicable)	99%	98%	Continuous (min 10 Hz)
Volume and number of gas transport containers	99%	98%	Per container
Temperature at all flow rate and volume measurement points	99.9%	99.5%	Continuous (min 10 Hz)
Pressure at all flow rate and volume measurement points	99.75%	99.5%	Continuous (min 10 Hz)
Calorific value of gas at point of export	99%	98%	Weekly
Amount of gas, other fossil fuel, or electricity used in new project infrastructure and facilities	99%	98%	Continuous (min hourly)
Oil production rate (only necessary for projects with imported gas-lift gas)	99%	99%	Continuous (min 10 Hz)

The project operator must electronically submit data to the independent auditor each month of the project for verification. The auditor must visit the project site and examine that each item of measurement equipment is properly installed, maintained, and operated. More detail on monitoring data verification is discussed in Section 4.3.3.c.

2.3.3. Reporting regime under the implementing measure requirements

As discussed above, the proposed FQD implementing measure lists a number of parameters that must be reported in order for credits from any UER project to be counted towards FQD compliance; these are listed in Table 2.2. In cases where this data was a requirement of the scheme being used to claim credits, presumably, this information would be verified through the normal processes of the scheme. In cases where a certain piece of information was not an explicit requirement of a

scheme, Member States may allow for systems to be put in place for the information to be verified and reported outside of the basic framework. In all cases, these data would require verification in line with ISO 14064 Part 3.

Beyond the data explicitly identified in the proposed implementing measure, ISO 14064 Part 2 imposes some additional requirements on reporting of UER projects. Project proponents must establish and maintain monitoring procedures, including recording the following:

- a) purpose of monitoring;
- b) types of data and information to be reported, including units of measurement;
- c) origin of the data;
- d) monitoring methodologies, including estimation, modeling, measurement or calculation approaches;
- e) monitoring times and periods, considering the needs of intended users;
- f) monitoring roles and responsibilities;
- g) GHG information management systems, including the location and retention of stored data.

The project proponent must make a 'GHG report' available to 'intended users'. In the context of the FQD, intended users should be taken to include national administrators, and any other parties designated by national administrators. For instance, national administrators may require that GHG reports should be made public, but this is not necessary based on ISO 14064 alone. The GHG report must "use a format and include content consistent with the needs of the intended user" (ISO 14064 Part 2 article 5.13). A specification is contained in the ISO for the content of GHG reports in the case that GHG claims are being made to the public. This description of content need not be binding for a GHG report made available to a national administrator, but may provide a useful reference for national administrators and project proponents when determining the content of the GHG report. This specification includes a description of the project, the reported emissions reductions, validation and verification status, and other details (ISO 14064 Part 2 article 5.13).

When monitoring equipment is used, "the project proponent shall ensure the equipment is calibrated according to current good practice" (ISO 14064 Part 2 article 5.10). As the ISO establishes standards for emissions reduction projects in general, and not for venting and flaring projects in particular, it does not specify what parameters must be monitored and reported. The monitoring framework should be defined in the project plan and approved by the project validator, in line with any requirements of the scheme operator and of the Member States.

There is considerable room for interpretation by the scheme operator and by the Member States in setting requirements for monitoring and reporting under the implementing measure requirements (Option 3b). If Member States do not impose additional requirements on UER projects, voluntary schemes could implement highly divergent systems. In the most flexible case, setting a monitoring scheme would be left almost entirely to the discretion of the project proponent and validator. Differences in monitoring regimes could potentially be associated with corresponding varying quality in the accuracy of reported UERs.

In addition to the referenced ISO standards, the proposed FQD implementing measure refers to Commission Regulation (EU) No 600/2012 and Commission Regulation (EU) No 601/2012 in the context of monitoring, reporting and verification. These regulations are focused on emissions reporting for whole installations rather than for projects, but the underlying monitoring, reporting and verification principles should be applied, and may provide additional guidance in setting Member State interpretations of reporting requirements. Commission Regulation (EU) No 600/2012 describes requirements for verification and the accreditation of verifiers, and Commission Regulation (EU) No 601/2012 describes requirements for monitoring and reporting by installation and aircraft operators. The principles and general requirements for the verification process described in Chapter II, Articles 6-33, and those of competence, impartiality, and independence of verifiers in Chapter III, Articles 34-42 of Regulation No 600/2012, are relevant to the verification of upstream emission reductions. The sections of Regulation No 601/2012 relevant to the calculation and reporting of upstream emissions reductions are the Monitoring plan (Chapter II, Articles 11-18, and Annex I); Data Management and Control (Chapter V, Articles 57-66, and Annex IX); and Reporting Requirements (Chapter VI, Articles 67 and 69-70, and Annex X).. The flare reporting requirements in Annexes II and IV are appropriate for flare monitoring at installations but **not** for the assessment of savings from emissions reduction projects.

ISO 14064 Part 2 makes clear that emissions should be reported in line with the complementary principles of accuracy and conservatism. Still, the interpretation of this requirement may differ across Member States, and across schemes. There would be some risk that credits from voluntary schemes built around poor quality or infrequent monitoring could be put forward by regulated parties to contribute towards compliance with the FQD. In order to ensure that the appropriate quality (as defined by the proposed FQD implementing measure and related ISOs) is delivered by all of FQD-eligible UERs across the EU, it will be important for Member States to establish appropriate criteria for measurement and reporting under UER schemes. These criteria could reflect those described for the CDM process under Options 1 and 2 in Section 2.3.1, or those developed for the prescriptive option (Option 3a) in Section 2.3.2.

2.3.4. Reporting requirements for upstream emissions reductions under the California LCFS

The California LCFS allows crediting of upstream emissions reductions. While this policy is somewhat different than the FQD and the prescriptive option (Option 3a), the reporting requirements for the LCFS may be instructive. Under the California LCFS, emissions reductions delivered through innovative upstream technologies are eligible to be counted towards meeting a suppliers' obligation. At the time of writing, the definition of innovative methods was restricted to carbon capture and sequestration and solar steam generation.

The reporting requirements for innovative methods in LCFS are included in full in Annex C. They include the following.

For the project design and approval:

- i) A detailed description of the innovative method proposed and the baseline for comparison;
- ii) Engineering drawing or process diagram illustrating the innovative method;
- iii) Calculation of the CI of produced crude in the baseline case and after implementing the innovative method, including complete lifecycle assessment documentation (e.g. with OPGEE);
- iv) Demonstration of 'scientific defensibility', potentially through academic documentation of the method;
- v) References covering all information sources used in the lifecycle analysis;
- vi) Redacted versions fit for publication of any documents containing confidential business information.

For on-going reporting:

- i) The annual volume of crude oil produced and the volume sold using the approved crude oil production method;
- ii) Confirmation of compliance with any limitations and operational conditions set by the ARB Executive Officer.
- iii) If the crude is supplied to be marketed in a crude blend, details of the other constituents of that blend.

The requirements for project design documents under the LCFS are more detailed than is currently the case in CDM, or is being proposed here under Option 3a. In particular, it is not enough for the supplier implementing the project to assess the new equipment in isolation – a full lifecycle analysis is required of the entire crude production process. By contrast, the CDM and Option 3a methodologies place most of the crude production process outside of the project boundary. It is not considered necessary to assess the whole lifecycle when assessing

venting or flaring reduction projects, as the reduction of gas loss is well defined, and will generally have no significant impact on the rest of the operation. Because the California system is focused on innovation there is an additional requirement to provide supporting documentation for the scientific ‘defensibility’ of the scheme concept. This is not necessary for venting and flaring reduction projects, which are not expected to be scientifically novel.

While the project design documentation requirements are stronger under the LCFS than Option 3a, the requirement to monitor and report data once a project has been accepted are more limited. The California system does not require continuous monitoring of energy or other inputs used in the novel system. The regulation does however require that the applicant should attest that the analysis submitted represents the, “long-term, steady state operation of the innovative crude oil production method.”

The LCFS system puts a great deal of emphasis on direct oversight by the Air Resources Board, rather than the use of qualified auditors as required by CDM and proposed for Option 3a. Keeping the approvals process entirely ‘in-house’ allows the ARB to maintain full control over the approvals process, develop its own internal expertise on the new technologies and avoid issues caused by heterogeneous application of verification rules by different auditors. However, it also requires substantial staff resources. In the European context, with a much larger fuel market and given that there is much greater scope in the short term for venting and flaring reduction projects than for innovative technologies to be deployed, it is felt that the burden of centralizing verification in this way would be too great, both in staff commitment and cost to the public sector.

2.4. Task 1c: Methodological validation

2.4.1. Results of stakeholder consultation

Experts on upstream emissions reductions and other stakeholders in the oil and gas industry were consulted on the appropriateness of the proposed calculation and reporting framework, compared to a mass balance approach and other potential crediting frameworks.

The proposed framework to measure and calculate emissions savings under Option 3a, described as “continuous direct flow measurement of gas utilized by the flare reduction project,” was thought to be an accurate approach by the stakeholders. The mass balance approach was thought to be less accurate. Stakeholders disagreed on the accuracy of other approaches, including direct measurement of flared volumes before and after project implementation, and regular but non-continuous flow measurement. Some stakeholders noted that they would be more comfortable with a requirement for non-continuous flow measurement due to the difficulty in maintaining continuous

measurement equipment, especially in remote areas with limited access to qualified technicians. Satellite measurement of flared volumes was universally rated as not accurate for the purposes of calculating emissions savings, and one stakeholder was concerned that satellite measurement is so fundamentally inaccurate that it should not be used in any context in Option 3a. Stakeholders disagreed on how accurately fugitive emissions from leaks and accidents could be measured. Some stakeholders felt that there is no need to penalize gas losses from leaks and accidents as project operators are incentivized to minimize losses in gas sales regardless of crediting through Option 3a.

A majority of stakeholders thought that the opportunity for crediting flare efficiency improvements was somewhat significant but could not be measured accurately. One stakeholder noted that flare efficiency is affected by varying gas composition, flow rates, and wind conditions, and that is difficult or impossible to determine flare combustion in real time.

Stakeholders who had an opinion on verification requirements thought that a full audit of all projects, including on site examinations and interviews, should be necessary for crediting flaring and venting reduction projects.

Some stakeholders who have direct experience in flaring or venting reduction projects under CDM/JI were fairly satisfied with the process and would engage in it again in the future. However, some stakeholders from industry commented that they found the CDM process bureaucratic, and lacked confidence that rules were consistently applied. One stakeholder commented that the CDM/JI process works well for large-scale projects but not for small-scale projects due to the large burden relative to the amount of credits that could be generated. Low CER values were cited as a barrier to engagement in CDM. This stakeholder also commented that the common practice analysis, required under the CDM process, might be counter-productive as the last remaining flares in a country are often the most expensive projects.

2.4.2. Satellite measurement of flared volumes

As detailed in the previous sections, it is proposed by the authors that a measurement and calculation approach similar to CDM (crediting the amount of gas that is recovered and utilized for a useful purpose) be used as the primary methodology to award credits. Satellite measurements of flared volumes could be used, along with regular audits of measurements and reported data, to verify that emissions reductions have actually occurred. Under such an approach, if the flared volume at a project site, as measured by satellite, appears to significantly decrease after project implementation, the emissions reductions claimed by the project would be verified (note: the project would still be subject to measurement and data audits). If the satellite measurements do not show a significant decrease in flared volumes at the project site, the project would be subject to additional scrutiny, including one or more additional on-site visits by the independent

auditors. It is possible that flaring could increase even with an effective gas recovery project if the oil production rate or the gas-to-oil ratio increased substantially during the project implementation. In such case, the additional audit would verify that the increase in flaring was not a result of a fraudulent or otherwise faulty project.

The U.S. National Oceanic and Atmospheric Administration (NOAA) conducts regular measurements of flaring worldwide using a new satellite with a Visible Infrared Imaging Radiometer Suite (VIIRS) sensor. This technology has higher spectral and spatial resolution than previous sensors (including NOAA's Operational Linescan System (OLS) sensor), allowing for more accurate measurement of flared volumes. NOAA has indicated that a dataset of measured flares in Nigeria over the period 2012-2014 could be provided to the Commission for the purposes of investigating and validating this verification methodology. In principle, such data could be available in future years but individual flare monitoring would require additional proofing that is beyond the capacity of NOAA's current staff; additional funding would likely be necessary to complete this work.

It should be noted that there are limitations to the use of satellite sensors to measure flaring volumes (GGFR, 2012b). These sensors cannot measure venting at all, so venting reduction projects may need to be subject to more stringent auditing requirements. Satellite sensors cannot measure flaring accurately if the flare occurs near other light sources, such as cities, or at high latitudes in the summer where sunlight is present at night. Small flares may be missed completely. Intense flares that are very bright may saturate the sensors, and so the volume of these flares may be underestimated. It is proposed that flares that cannot be confidently measured by satellite be subject to more stringent verification requirements by the independent auditors.

2.5. Task 1d: Flare efficiency improvements

The objective of this subtask is to evaluate the possibility of crediting flaring efficiency improvements for the purpose of FQD compliance. As discussed above in Section 2.2 on baseline and delta calculation and below in Section 4.5 on eligible projects, flaring efficiency is not currently considered under CDM methodologies and flaring efficiency improvements (which would reduce greenhouse gas emissions) are not eligible to be credited. However there is nothing that fundamentally excludes flaring efficiency improvements from being credited under CDM, and it is possible that future methodologies or updates to existing methodologies could allow such crediting. This subsection provides a literature review of flaring efficiency measurements, the accuracy of these measurements, and the efficiency of existing flares. This is followed by a potential framework that could be used to credit flare efficiency improvements.

Flaring is a common way of disposing unwanted gas in the oil and gas extraction and refining industries. The main greenhouse gas released due to flaring is carbon dioxide, produced by the combustion of methane and

other hydrocarbons in the flare gas. However, flaring is not 100% efficient in the destruction of methane – some material normally remains uncombusted. The best flares can achieve high efficiencies, 99% or better, but in the worst cases efficiencies could be as low as 50%. Because methane has a higher global warming potential than carbon dioxide, any release of methane increases the carbon equivalent greenhouse gas emissions from the flare. Therefore, determining the climate impact of flaring requires an understanding of flaring efficiency. For instance, a 95% efficient flare would have a 20% higher climate impact than a 99% efficient one, for the same amount of methane sent to the flare tip.

Flaring efficiency has been shown to be largely determined by wind velocity, gas exit velocity at the tip of the flare, flare tip diameter (tip size), and the energy content of flare gas. Energy content of flare gas depends on its chemical composition of hydrocarbons (methane, butane, pentane, etc.) and the relative amounts of other non-combustible gases present in the flare gas such as nitrogen and carbon dioxide.

Flaring efficiency can be improved by steam injection and air injection, also known as steam-assist and air-assist. Steam-assisted and air-assisted flares produce smokeless flares by adding steam or air into the combustion zone, which creates turbulence for mixing and provides more air for combustion. However, too much steam or air has been shown to have detrimental effects on flaring efficiency.

A number of studies have been carried out in the past to investigate the factors that determine flaring efficiency and to establish the range of efficiencies that are achieved under various conditions.

Flaring efficiency can be defined in a number of ways. One definition is the percentage of carbon present in the associated gas that is converted to CO₂:

$$\tilde{\eta} = \frac{M_{CO_2}}{M_{gas}}$$

Where, M_{CO_2} refers to the mass of carbon in CO₂ produced from combustion and M_{gas} refers to the mass of carbon in the flare gas before combustion. This is the definition used in this chapter unless otherwise stated.

Alternatively, it is possible to define flaring efficiency in terms of sulfur content and methane destruction. In terms of sulfur content, efficiency can be defined as the ratio of the amount of sulfur in the flare gas to the amount of sulfur in sulfur dioxide present in the exhaust gas (analogous to the carbon case). Methane destruction efficiency is defined as the ratio of the amount of combusted methane in the exhaust gas to the amount of methane present in the flare gas before combustion. Although not exactly the same metric as flaring efficiency, methane destruction efficiency is still useful in calculating GHG emissions from flaring since GHG emissions are largely determined by the amount of unburned methane present in the exhaust gas as its global warming potential is 25 times that of carbon dioxide.

2.5.1. Review of Flaring Efficiency Studies

2.5.1.a. Cain et al., 2002

In 2002, Cain et al. performed a very comprehensive review of various studies on flaring efficiency conducted prior to 2002. Below we summarize the main findings from this literature review.

(1) Siegel, K. D., 1980

This is one of the earliest studies estimating flaring efficiency. As part of a PhD dissertation, Siegel measured the efficiency of a refinery relief gas slipstream using an 8-inch tip located at 5 meters above the ground. The tip was also equipped with steam injectors. The flaring efficiency was found to be at least 99% for soot free flare flames, which were presumably obtained from use of steam injection. Some of the tests were carried out in the presence of wind velocity up to 6 m/s.

(2) Chemical Manufacturers Association and EPA, 1983 (as mentioned in Cain et al., 2002)

In this CMA and EPA sponsored study, commercial-size flares were examined to estimate the flaring efficiencies of propylene-nitrogen mixtures. The heat content of the mixtures was varied from 80 to 2183 Btu/ft³. The idea was to infer from this experiment the likely impact of the heat content of the flare gas (associated gas) on flaring efficiency. The impact of steam and air assist was also studied. For steam assist, the steam-to-gas weight ratio was varied from 0 to 123, whereas for air assist the stoichiometric ratios (SR) were higher than 1. The stoichiometric ratio for air assist is defined as the ratio of actual mass flow of assist air to the minimum theoretical stoichiometric mass flow of air needed to combust the flare gas.

Under conditions representing industrial operating practices, flaring efficiencies were found to be more than 98%. The results were based on samples derived using an extractive technique and analyzing them by gas chromatography. With regard to steam assist, a steam-to-gas ratio greater than 5 resulted in reduced combustion due to a flame quench. With regard to air assist, flare efficiency was similarly reduced if the stoichiometric ratio was greater than 0.7.

(3) EPA studies (EPA, 1983-1986, Pohl, 1986)

In 1981, EPA carried out a five-year experimental project to estimate flaring efficiency and quantify GHG emissions using a wide range of fuel mixtures. These include fuels such as propane in nitrogen, natural gas, butadiene, and ethylene dioxide. The experiment was carried out at both lab scale and pilot scale using flare tips diameters up to 12-inches. The project also varied the heat content of the gas ranging from 150 Btu/ft³ to >300Btu/ft³ and flare tip exit velocity from >1 ft/sec to > 400ft/sec, and examined the effect of steam or air injection on soot suppression.

The study showed that if flaring is carried out within operating envelopes specific to each flare head and gas mixture, efficiencies in the range of 98-99% are achievable provided that the flame is stable. However, for a low BTU content flare, the reported efficiency was as low as 62% (McDaniel, 1983).

The study also identified exit velocity and heating values as critical in maintaining the flame stability and hence achieving a >98% flaring efficiency. Flaring efficiency was determined using an extractive sampling technique and analyzing the hydrocarbons using gas chromatography. The study found that higher heat content of the flare gas and lower exit velocity resulted in improved flame stability. Since the experiment was carried out in the stagnant air, lower exit velocity contributed to improved flame stability.

(4) British Petroleum/Statoil study (Boden et al., 1996)

A study carried out by British Petroleum and Statoil analyzed the efficiencies of flares produced in three refineries in Europe. The analyzed gases are the actual gases flared at refineries with varying chemical compositions of hydrogen and heavier hydrocarbons (C_2+) such as propane and butane and heat content ranging from 520 Btu/ft³ to 2460 Btu/ft³. Steam to gas ratios from 0-3 and flare tips of 42 inches and 48 inches were employed. Steam-assisted flares are more common than air-assisted flares in refineries. Flaring efficiencies of 98% were reported for all tests. Efficiencies were derived from measurements of flare emissions using a UV Differential Absorption Lidar (DIAL) system.

(5) Alberta Research Council (ARC) study (Stroscher, 1996, Leahey et al., 2000)

ARC carried out a series of experimental studies to estimate the flaring efficiencies of pure gas streams such as methane, propane, and commercial natural gas beginning in 1990. ARC found that flaring efficiencies for both lab scale and pilot scale tests were 98% or higher under most conditions. Samples were drawn using either onsite analytical equipment or through absorbent samplers and analyzed using combined gas chromatography/mass spectrometry. The study also found the presence of hydrocarbon droplets in the flared gas negatively impacts flaring efficiency. For example, the relatively dry associated sour gas (less hydrocarbon liquids) were found to have a 84% flaring efficiency in field tests whereas the sweet gas with higher hydrocarbon droplets was found to combust at 63-71% efficiencies. Another notable contribution of the study is to demonstrate that crosswinds negatively affect flaring efficiencies.

(6) University of Alberta Studies (Johnson et al., 1998-1999)

In an attempt to reconcile the EPA results (1983-1986) under controlled environments with the ARC field test results, the University of Alberta carried out a research project using scaled-down, generic pipe flares in well-controlled conditions.

In the absence of crosswinds (stagnant air), it found that the gas burns efficiently (>98%). However, the presence of a crosswind decreased flaring efficiency considerably. Other conclusions derived from the study are:

If a crosswind increases, the stack exit velocity should be increased to maintain the flame stability and attain a high flaring efficiency. Large diameter flares also counteract the impact of a crosswind, i.e., large diameter flares burn efficiently even in stronger wind.

Flaring efficiency improves if the heat content of the gas being flared is high. Gas with lower heating content is more susceptible to a crosswind.

With regard to the impact of liquid drops present in the flared gas, contradictory results were obtained. The presence of water droplets (up to 42 wt %) had no impact on flaring efficiency but the presence of octane droplets reduced flaring efficiency from 99% to 93%.

(7) German Aerospace Center/Shell research (UK) study (Haus et al., 1998)

German Aerospace Center/Shell research (UK) chose four natural gas production sites in the Netherlands to measure flaring efficiencies. To determine flaring efficiency, concentrations of various gases including methane and CO₂ were measured using Fourier-Transform Infrared Spectroscopy in flare plumes. The analysis showed flaring efficiencies to be about 99.5%.

(8) Shell Nigeria study on operating flares (Ozumba & Okoro, 2000)

Shell Nigeria carried out flaring tests on eight representative flares with varying designs and flow rates. Using Open-Path Infrared (IR) spectroscopy, flare plume compositions were analyzed and no un-decomposed hydrocarbons were detected. Based on the analysis, flaring efficiencies were estimated to be in the range of 95.7% -98%.

2.5.1.b. Johnson and Kostiuik, 2000

This experimental study examined the effects of crosswinds on flaring efficiency for three types of low momentum flare gas – propane, natural gas and propane/CO₂ in a closed-loop tunnel. To simulate the actual flaring configuration of continuous flaring in the atmosphere, flames were created at the exit of the burner tube, which is perpendicular to the airflow. Samples were analyzed using gas analyzers to identify and measure the concentrations of various carbon containing species. Conforming to earlier studies, it found that crosswinds negatively impact flaring efficiency. The adverse impact of a crosswind has been linked to fuel stripping, i.e., removal of fuel from the flare gas prior to reaching a combustion zone. In addition, the study found that by increasing exit velocity, we could minimize the adverse impact of crosswinds. They also developed a predictive model to estimate flaring efficiency based on heat content and other parameters.

2.5.1.c. Johnson and Kostiuk, 2002

In a follow-up study to the one considered by Cain et al., Johnson and Kostiuk identified parameters that are critical in determining flaring efficiencies, and developed models that can predict efficiencies within a certain range of parameters. The authors used a range of fuel mixtures and crosswinds in a controlled environment to identify a relationship between various parameters and flaring efficiency. The results show that fuel type, wind speed, exit velocity, burner diameter (tip size), and the energy content of the fuel mixture can influence flaring efficiency. The impact of crosswinds is less pronounced as the energy content of flare gas increases. In this experiment, energy content was varied by mixing propane with different amounts of nitrogen. The higher the amounts of nitrogen and the lower the amounts of propane in the fuel mixture, the lower the energy content of the flare gas. This is because nitrogen does not contribute to energy content.

The study by John and Kostiuk (2002) conclusively shows an important role the tip size (burner diameter) can play in influencing flaring efficiency in the presence of crosswinds. The flare associated with a larger tip size (49.8 inch) is less susceptible to higher crosswind speeds and has a higher efficiency than the flare associate with smaller tip size (12.1 inch). This shows that the larger tip size can offset the impact of crosswinds by producing a larger diameter flare.

Although the authors provide a model for predicting flaring efficiency within a range of parameters, they found that it cannot be generalized to all types of flares (mixture of gases) suggesting that there are other mechanisms in play that lead to inefficiency of flaring.

The model is described by the equation shown below.

$$(1 - \eta) \cdot (\text{LHV}_{\text{mass}})^3 = A \cdot \exp\left(B \frac{U_{\infty}}{(gV_j d_o)^{1/3}}\right)$$

where,

U_{∞} , = wind speed,

V_j = exit velocity

d_o = burner diameter

LHV_{mass} = lower heating value

A and B = coefficients

g = acceleration due to gravity, and

$(1 - \eta)$ = inefficiency

2.5.1.d. EPA Report for Flare Review Panel, 2012

In order to identify parameters and conditions that define a stable flame envelope, a condition necessary for achieving a higher flaring efficiency, EPA (2012) analyzed a number of flare efficiency studies and

flare performance test reports in the USA. EPA analyzed flaring efficiency focusing on four main conditions: steam assisted flares with varying levels of steam; air assisted flares with varying levels of air; high wind; and flame lift off. The EPA review study analyzed the data from two types of studies:

- Experimental data from pilot-scale flare tests with flare tip sizes ranging from 3 to 12 inches for steam assisted flares based on two studies (McDaniel, 1983, Pohl et al., 1984) and 1.5 inches for air assisted flares based on a study by Pohl and Soelberg (1985).
- Real data from steam-assisted flares from refineries and chemical facilities. These facilities have flare tip sizes ranging from 16-54 inches.

The EPA report identifies the following parameters and the limits as the requirements for achieving a good flaring efficiency:

- The lower flammability limit of combustion zone gas is an important parameter that determines whether over steaming occurs in flaring leading to a lower flaring efficiency. To achieve a good flaring efficiency, the lower flammability limit of the combustion zone (LFL_{cz})⁷ should be no more than 15.3 % by volume for a steam-assisted flare.
- For air-assisted flares, the stoichiometric ratio (SR) serves as an important parameter to determine when excess aeration occurs. Excess aeration causes a lower flaring efficiency. For achieving a higher flaring efficiency, the SR should not be more than 7. Moreover, for air-assisted flares the lower flammability limit of the gas should be 15.3% or less for maintaining a higher combustion efficiency.

EPA also found that flaring efficiency is not affected as long as crosswinds are no more than 22 miles per hour. Above this speed, a wake-dominated flame may occur resulting in a reduced flaring efficiency. EPA concludes that the momentum flux ratio (MFR) is an appropriate parameter to determine if a wake dominated flame occurs since it takes into account if there is sufficient tip exit velocity to off-set cross wind velocity. The EPA study found that MFR should not be greater than 3 to avoid the formation of a wake dominated flame.

Flame lift off⁸ which results in a reduced flaring efficiency can be avoided by setting the actual flare tip velocity below the maximum allowable flare tip velocity. The maximum allowable flare tip velocity is calculated using the Shore equation that takes into account combustion zone gas composition, the flare-tip diameter, density of the flare gas and density of air (Shore, 2007).

⁷ The lower flammability limit of the combustion zone refers to the concentration (%) of flare gas in the combustion zone below which the gas is too lean to burn.

⁸ Lift off refers to separation of a flame from the tip of the flare due to excessive air induction.

The EPA study also notes that the same operating conditions may apply to no-assisted flares such as keeping the LFL_{CZ} below 15% and keeping MFR no higher than 3 for achieving a high flaring efficiency.

2.5.1.e. Direct measurements of flaring efficiency

To directly measure and monitor flaring efficiency, a number of instrumentation techniques can be used. These techniques are classified into two groups – extractive and non-extractive.

In extractive technique, samples are removed from the flare plumes and analyzed using combined Gas Chromatography and Mass Spectroscopy (GC/MS)⁹. Samples can be collected by “drawing the flare emission sample stream through specific adsorbents, such as Tenax or Carbotrap contained in glass sampling tubes, or by directing the emission sample stream into either Tedlar sample bags or glass sampling bombs” (Storsher, 2000). By comparing the amounts of carbon species in the combusted gas samples with those prior to combustion, we can estimate flaring efficiency.

In non-extractive technique, instead of removing samples from the flare plumes, chemicals present in the flare are identified and quantified using infrared spectroscopy. The commonly used spectroscopic method in measuring flaring efficiency is the Passive Fourier Transform Infrared (FTIR) spectroscopy (Fig. 2.4). In traditional “active” open path absorption techniques, IR light is transmitted through a flare plume. A detector located at the other side of the plume measures the amount of light absorbed by a chemical species of interest. The amount of light absorbed is proportional to the concentration of the chemical species. Passive FTIR, on the other hand, involves observing IR radiation from flare plumes from a distance using an IR instrument coupled with a receiver telescope. This allows identification and quantification of chemical species of interest in flare plumes.

Extractive techniques are shown to provide reliable estimates of flaring efficiency. The EPA sponsored study carried out by Engineering-Science Inc. (McDaniel, 1983) showed that the standard deviations of the consecutive measurements varied from 0.1% to 11.1%. This is considering only two sources of errors – instrument error and calibration error. The study assumed that other errors such as sampling error are negligible. The study also found that errors are sensitive to flaring efficiency. The tests with high flaring efficiency were associated with smaller variances than the tests with low flaring efficiency. For example, the standard deviation of 11.1% was associated with the test flare having 69% efficiency.

Remote sensing techniques have been shown to provide slightly less accurate but still acceptable estimates of flaring efficiency. In these techniques, instruments are mounted on the ground or aerial platforms and are located close to the flare sites. The 2010 TCEQ Flare Study Project (Allen and Torres, 2013) compared the measurement accuracies

⁹ GC/MS is an analytical method that combines gas-liquid chromatography with mass spectroscopy to identify and quantify chemicals in a sample.

of three types of remote sensing technologies for measuring flaring efficiency of flares where flaring parameters were controlled in an uncontrolled ambient environment. These were: Passive Fourier Transform Infrared spectrometer, active Fourier Transform Infrared spectrometer, and Telops Hyper-cam passive imaging radiometric spectrometer. The estimates of flaring efficiency measurements obtained from these techniques were compared to those obtained from the extractive method used by Aerodyne Research, Inc., (ARI) as reference to determine the accuracy of efficiency measurements.

The study found that both passive and active FTIR techniques provide fairly accurate measurements of flaring efficiency. Their mean estimates differed from the ARI estimate by 2 and 2.4 percent, respectively for tests with a flaring efficiency of > 90%. The standard deviations of the differences are likewise small.

On the other hand, efficiency estimates of the hyper-cam passive imaging radiometric spectrometer were less accurate. The average flaring efficiency estimate differed from the average ARI estimate by 19.9%. Moreover, the standard deviation of the difference from the reference ARI estimate was 58.9%.

Another study carried out by URS Corporation (2004) shows that passive FTIR can estimate flaring efficiency with a high degree of accuracy, with uncertainty $\pm 0.3\%$.

Based on the limited published studies to-date, it appears that direct measurement techniques such as FTIR can provide accurate estimates of flaring efficiency on a continuous basis. Most of these studies conducted have analyzed flares with varying levels of efficiency. Since flare plumes can be quite inhomogeneous and velocity profiles can be non-linear and unsteady, one area for further study is to analyze how accurately the sampling techniques can capture such variability.

2.5.1.f. UNFCCC/CCNUCC- Methodological tool “Project emissions from flaring” (Version 02.0.0)

The UNFCCC/CCNUCC has developed a methodology for estimating flare efficiency (defined as methane destruction efficiency) for open flares and enclosed flares. However, the methodology is designed for flare gases that contain only methane, hydrogen and carbon monoxide. It is designed to be used for gas from organic decomposition such as anaerobic digesters or for gas vented in coalmines. Nonetheless, it may be used to derive estimates of flaring efficiency in the oil and gas sector. For the purpose of methodology development, the UNFCCC identifies two types of flares.

An open flare is defined as a “device where the residual gas is burned in an open air tip with or without any auxiliary fluid assistance or a flare with a vertical cylindrical or rectilinear enclosure, for which the flame enclosure is less than 2 times the diameter of the enclosure” (UNFCCC/CCNUCC).

An enclosed flare is defined as a “device where the residual gas is burned in a vertical cylindrical or rectilinear enclosure, where the flame enclosure is more than 2 times the diameter of the enclosure. The device includes a burning system and a damper where air for the combustion reaction is admitted” (UNFCCC/CCNUC).

For open flares, the UNFCCC recommends using a default 50% efficiency, provided the flame is detected. If open flares are not operational as evidenced by the absence of a flame, then a default zero efficiency is used.

For enclosed flares, two options exist. A 90% default flaring efficiency is assigned if the flame is detected and the temperature and the flow rate are within the manufacture’s specification of the flare. If, for a given period, flare parameters are out of the limit or the flame is not detected, a default efficiency value of 0% is used. Assigning a value of 0% flaring efficiency when parameters are out of the limit even when the flame is detected is a conservative approach and is meant to encourage the flare operators to remain within the manufacturer’s specifications. It should not be understood as an estimate of real flare efficiency.

Alternatively, one can directly measure flaring efficiency by monitoring the methane content in the exhaust gas, the residual gas, and the air used in the combustion using analytical instruments such as FTIR. This is allowed in the methodology provided the flame is detected and the temperature and the flow rate are within the manufacture’s specification of the flare.

In any case, the default flaring efficiency of 90% recommended by the UNFCCC can be considered as a conservative value, as it is a priority in these CDM methodologies to ensure that emissions abatement is not over-credited by making aggressive efficiency assumptions.

2.5.1.g. Summary

The literature review shows that flaring efficiency is largely determined by crosswind, exit velocity, tip size (burner tube diameter), and heating value of the gas being flared.

A crosswind can influence flaring efficiency by removing a portion of the flare gas from the flame before it reaches the combustion zone. In a high crosswind and low-exit velocity, wake-dominated flare flame results where a portion of unburned fuel is removed from the flame before it reaches a combustion zone (Johnson et al., 1999; Johnson and Kostiuk, 2000). This leads to lower combustion efficiency.

The tip size matters since it influences the exit velocity of the flare gas depending on the stack diameter and height. Also, the larger tip size can counteract the negative impact of high crosswinds by producing large diameter flares. Too high exit velocity can cause a blow off (i.e., lifting of the flame front) whereas too small exit velocity can damage the tip due to high heat and smoking.

There is a wide variation in the chemical composition and hence the energy content of the flare gas varies from one place to another. Energy content has been shown to determine how efficiently the flare gas burns. Higher flaring efficiencies have been observed for the flare gas with high energy content. Typically, the flare gas (associated gas) consists of combustible hydrocarbons such as methane, ethane, propane, butane, pentane, and non-combustible gases such as nitrogen and carbon dioxide. In some cases, associated gas may also contain hydrogen sulfide. The chemical composition of flare gas used in the OPGEE model is shown below (Table 2.4).

Table 2.4. Flare gas composition used in the OPGEE model (El-Houjeiri and Brandt, 2012)

CONSTITUENTS		MOL%		VOL		ENERGY CONTENT LHV (MJ/KG)
Table A	--	Table B	--	Table C	m³/d	
N₂		2.00		153		
CO₂		6.00		462		
C₁		84.00		6476		50 (methane)
C₂		4.00		309		47.8 (ethane)
C₃		2.00		153		46.4 (propane)
C₄		1.00		76		45.8 (butane)
H₂S		1.00		76		
Total		100.00		7711		

In Table 2.4, C1, C2, C3, and C4 refer to the number of carbon in hydrocarbon molecules in the flare gas. Examples of C1, C2, C3, and C4 are methane, ethane, propane, and butane, respectively. Since methane (C1) has more energy content than other hydrocarbons such as butane, ethane and propane, the higher the % ratio of methane in flare gas, the higher will be the energy content of the gas. The presence of non-combustible gases affects flaring efficiency by lowering the energy content of the flare gas since they do not contribute toward the energy content of flare gas.

If a crosswind is moderate and energy content of the gas is high, efficiencies in the range of 98-99.5% can be obtained. In an uncontrolled environment such as open pit flaring which can be a hole in the ground or just an open pipe, flaring efficiency is reduced significantly. In such a case, the UNFCCC suggests a default value of 50% but the underlying basis for such a recommendation is not that clear.

To ensure that flaring efficiency is high, Johnson recommended a limit on the lower heating value of 12-20 MJ/m³ for flare gas for inclusion in the World Bank voluntary standard for global gas flaring and venting reduction. This also provided a scientific basis for defining the minimum heating value of flare gas under the Directive 60 in Alberta. Flares involving low heating value gases are prone to inefficiency if the exit

velocity is not within a proper range. For example, the EPA study found that flares with low BTU gases exhibited reduced efficiencies when the exit velocity is very high since it can cause a flameout. On the other hand, the University of Alberta found that in the presence of strong wind, low exit velocities can actually lead to a reduced efficiency for low BTU flare gases. Flares involving high heating value gases are generally less sensitive to exit velocity and crosswinds. The studies performed by ARC and the University of Alberta prove that the presence of organic droplets in the gas lowers combustion efficiency.

EPA (2012) has also identified the conditions necessary for obtaining high flaring efficiencies. These conditions are: (a) the lower flammability limit of the combustion zone (LFL_{cz}) should be no more than 15.3 % by volume (b) the stoichiometric ratio (SR) should not be more than 7 for air-assisted flares and (c) the momentum flux ratio (MFR) of a flare should not be more than 3 to avoid the formation of a wake - dominated flame.

Overall, if it can be ensured that the heating value of gases in flares meet the minimum energy content limit provided that other parameters including flaring diameter, exit velocity and cross-wind are kept within the acceptable limits, a flaring efficiency of at least 98% can be assumed in calculating GHG emissions from flaring. Alternatively, it may be possible to predict flaring efficiency using a model provided that data on modeling parameters such as exit velocity, energy content, flare diameter, and crosswind are available. Since parameters such as cross-wind vary from day to day, Johnson (nd) has introduced the concept of yearly averaged efficiency that takes into account the probability distribution function of wind speed:

$$\bar{\eta} = \int_0^{\infty} P(U_{\infty}) \eta(U_{\infty}, V_j, D, HV) dU_{\infty},$$

where,

$P(U_{\infty})$ refers to the probability distribution function of wind speed (U_{∞}).

V_j is the exit velocity,

D is the flaring tip's diameter,

and HV is the heating value of the flared gas.

$\eta(U_{\infty}, D, V_j, HV)$ is the efficiency of flare as function of wind-speed and operating parameters.

However, Johnson and Kostiuk (2002) have pointed out the model may not be universally applied to all flares to get robust estimates of efficiency since there can be factors affecting flaring efficiency other than the modeled parameters. Also lack of field measurement data can limit the use of models to estimate flaring efficiency.

Another alternative to estimate flaring efficiency is to carry out direct measurements on concentrations of combusted products in the flared gas using spectroscopic methods such as Passive Fourier Transform Infrared Technology (FTIR) and differential light absorption techniques. However, it can be costly to carry out such measurements for individual flaring sites.

Since flaring efficiency data are not available at country level (except for Canada, Johnson et al. [2008]), it is not currently possible to estimate the actual levels of efficiencies being achieved at the country level with any degree of certainty, especially because flaring efficiency depends on a number of factors and operating conditions. However, it is possible to provide some qualitative assessment of flaring efficiencies being achieved today by inferring from the stringency/enforceability of air quality regulations in a given region/country, and comparing to the observed flaring efficiencies in Canada.

Using the detailed gas composition data from 2908 locations, wind speed data from 107 Environment Canada Meteorological stations and flaring and venting data from 9767 sites, Johnson estimated average flaring efficiencies in Canada between 2002 and 2005 at about 95% (Johnson, 2008).

Developed countries like the US and the member states of the European Union have air quality regulations that are generally comparable to Canada. It can be surmised that operators in these country would comply with existing air quality regulations as well as the manufacturer's specifications. Therefore, it would be reasonable to believe that flaring efficiencies currently being achieved in these countries could be similar to 95%. Although, as noted above, under favorable conditions and in controlled environments efficiencies of 98-99% have been achieved, in general such high efficiencies are likely to be optimistic for flares in real world conditions.

For developing countries like Nigeria or countries in transition such as Russia, given laxer environmental rules and variable levels of enforcement, operators may have no real incentives to comply with the regulations and operate flares within the range of the specifications recommended by manufacturers. While it is expected that at least some operators still conform to best practice, it seems reasonable to assume that the actual average efficiencies being achieved would be lower than those seen in Canada. For stack flares, typical efficiencies may be expected to range anywhere between 85%-95%. For open pit flaring, efficiencies could be as low as 50%. It would, however, be challenging to identify an average flare efficiency robust enough for use as a parameter in regulation or in efficiency improvement crediting. This will be explored further in the final report.

The ICF flaring report assumes that flaring efficiencies being achieved today range from 90-98%. This range is based on the experimental study carried out by Allen and Torres (2011).

2.5.2. Flare efficiency improvements under the prescriptive option

As discussed above, flare efficiency improvements are not currently eligible for crediting under CDM, and hence would not be eligible for crediting under the CDM options (Options 1 or 2) without the creation of a new methodology. None of the CDM methodologies currently defines a standard to estimate flare efficiency, so any new methodology would have to include new measurement protocols.

As discussed above, the underlying basis for crediting flare reduction under CDM is that combustion of natural gas from other sources will be displaced and avoided. However, there is no basis for crediting flare efficiency improvement on the basis of displacement. The assessment would thus need to be based directly on assumptions about the difference between the global warming effect of uncombusted vs. combusted gases. This would largely follow the methodology to calculate and credit emissions reductions as described in Section 2.2.2.

Emissions savings under this framework would be calculated as follows:

$$\text{Emissions savings} = \text{baseline emissions} - \text{project emissions}$$

Where:

$$\text{Baseline emissions} = \{[\text{mass of flared gas} \times \text{calorific value} \times \text{combusted gas emission factor} \times \text{baseline flare efficiency}] + [\text{mass of flared gas} \times \text{calorific value} \times \text{uncombusted gas emission factor} \times [1 - \text{baseline flare efficiency}]]\}$$

And:

$$\text{Project emissions} = \{[\text{mass of flared gas} \times \text{calorific value} \times \text{combusted gas emission factor} \times \text{post-project flare efficiency}] + [\text{mass of flared gas} \times \text{calorific value} \times \text{uncombusted gas emission factor} \times [1 - \text{post-project flare efficiency}]]\}$$

As with the measurement of all other variables under CDM and under the prescriptive option (Option 3a), the type of measurement equipment for flare efficiency would not be prescribed. Ideally, a demonstrated accuracy of 99% (considering only equipment error) would be required for this measurement. However, this level of accuracy is probably unachievable given existing techniques, and thus it is unlikely that appropriate systems would be readily available by 2020.¹⁰ It is therefore suggested that an achievable accuracy requirement for projects in the 2020 timeframe would be 97%, which should be achievable with current passive and active FTIR technology. Flare efficiency measurements should be required to be conducted

¹⁰ One study described in the literature review above reported passive FTIR to be accurate to 0.3%; however, this result would have to be reproduced by other studies before this level of accuracy could be assumed under Option 3a.

continuously (>1 Hz), as flare efficiency can vary significantly with changes in wind speed, gas flow rate, etc.

If implemented, the measurements of flare efficiency should be reported to the auditors once per month, as with the other required measurements, and would have to be verified similarly.

The main benefit of including an option to credit flare efficiency improvements would be to widen the scope of Option 3a. For projects that currently operate with very low flare efficiency (e.g. pit flares), real emissions reduction should be achievable in principle at modest cost.

While there is certainly an opportunity there, flare efficiency improvement is not currently covered by any methodology under CDM. Following the example of CDM, it is proposed that flare efficiency improvement projects should not be eligible under Option 3a either. The implementing measure requirements do not explicitly exclude flare efficiency improvement projects and in principle they could be credited; this is discussed in more detail below. Without meticulous monitoring and verification allowing flare efficiency improvement to be credited would create an undesirable incentive for project operators to falsify the baseline assessment by taking initial measurements under the least favorable flaring conditions, or even by actively reducing flare efficiency prior to the project start. Such practices would result in overestimated project benefits, and in the worst case could result in pre-project emissions increases.

Additionally, as detailed in the literature review above (Section 2.5.1), the accuracy of flare efficiency measurements limits the confidence with which credits could be awarded. For example, extractive techniques have been found to measure flare efficiency with a standard deviation up to 11%, considering only instrument and calibration error. Greater error could be introduced in the measurement given high or fluctuating wind speeds, or other adverse environmental conditions. Such uncertainty makes it difficult to accurately credit projects.

The overall size of emissions reduction opportunity from flare efficiency improvement is smaller and much more widely distributed than the opportunity to reduce flaring volumes, and it would require many projects to deliver the sort of savings potentially available from a single venting reduction project. Given the modest size of opportunity, the operational challenges of monitoring flare efficiency and the desire to avoid creating perverse incentives, it is recommended that flare efficiency improvements should not be eligible in Option 3a at this time.

2.5.3. Flare efficiency improvements under the implementing measure requirements

There is no explicit text in the proposed FQD implementing measure or in ISO 14064 Part 2 that would preclude the crediting of emissions reductions from flare efficiency improvements. However, the

requirement for conservative estimation of emissions savings in cases where accuracy is difficult to achieve could be interpreted by a Member State as grounds to consider flare efficiency improvements ineligible to generate compliance credits. This is discussed in more detail in Section 4.5.3. If flare efficiency improvement crediting were to be pursued under the option reflecting the implementing measure requirements (Option 3b), the accuracy and reporting requirements discussed above in the context of Option 3a may be a useful reference point for schemes and national administrators.

3. Task 2: Cost and size of the reduction potential

3.1. Summary of Task 2

The purpose of this chapter is to understand how large a contribution upstream emissions reductions credited under each of the options could make towards the 6% greenhouse gas emissions intensity reduction target in the FQD. Flaring and venting projects are usually implemented at a net cost to the operator, and this cost must be offset to encourage participation. The number of projects that may be registered under each option, and thus the level of CO₂ reduction that could be achieved, is therefore heavily dependent on the value of emissions reductions credits. This in turn would be determined by the cost of compliance with the FQD GHG intensity reduction target in each Member State, and by the way that upstream emissions reductions are integrated into each Member State's FQD implementation. For the sake of this chapter, three levels of credit price were considered: a more modest price of \$20 per tonne of carbon dioxide abatement; a moderate price of \$50 per tonne; and a more aggressive price of \$200 per tonne CO₂e. The higher price is consistent with typical estimates given of the cost of carbon abatement through the supply of biofuels, which are likely to be the primary alternative route to FQD compliance.

Several previous studies have estimated the cost and size of reduction potential in various world regions. ICF (2013) looked at four regions (Libya; Iran/Yemen; Nigeria; Russia/Azerbaijan) and estimated that at a carbon price of \$254 per tonne of carbon abatement, 45 million tonnes could be abated, of which 20 million could be achieved at negative cost. Other potential estimates include over 100 MtCO₂e of abatement of methane emissions from fugitives and venting in the U.S. (ICF, 2014) at costs up to \$28/tonne; 28-44 MtCO₂e potential abatement in Alberta Canada (Johnson and Coderre, 2012), of which 17-33 may be achievable at negative cost, with the rest being achievable for a carbon price of \$15/tonne; 70 MtCO₂e of potential abatement from flaring reduction in Russia (PFC Energy, 2007) at unstated cost; 21-26 MtCO₂e of abatement of fugitive methane emissions across the oil and gas sector in Europe (Ecofys, 2009; 2001). This compares to a total emission reduction of about 53 MtCO₂e required in 2020 to meet the FQD GHG intensity reduction target.

While large emissions reductions (on the order of hundreds of millions of tonnes of total annual carbon dioxide abatement potential globally) are possible in principle, only a fraction of this potential is currently being addressed through CDM projects. There are several aspects of the existing CDM process that are seen as barriers preventing larger numbers of projects being registered. These include administrative barriers, such as the

time and cost required for registration under CDM and the burden of demonstrating additionality and undertaking common practice analyses. There is also a sense that in the past the application of CDM methodologies may have been inconsistent and companies have not felt confident in predicting whether their projects will be accepted. In some cases ownership of gas exploitation rights may have been an issue, with operating companies being unable to recoup value from capturing and exporting associated gas. Finally, and importantly, CDM credits currently have a low value on international markets that makes CDM project registration unappealing in most cases. The CDM Board has made some progress with support from the World Bank Gas Flaring Reduction Partnership by approving three generic flaring and venting reduction methodologies and making the process of project registration more participant-friendly, but this improved process cannot deliver projects unless the credits have value.

This report assesses the potential emissions reduction opportunity in each of the options by presenting a modified analysis based on the earlier work for the Commission by ICF (2013). This study utilized data from a number of historical and current CDM and JI projects to establish an overall cost profile, assuming credits are awarded over the entire project lifetime.

The ICF analysis was further developed by Energy Redefined to reflect changes in the cost profile with the removal of various barriers to engagement in CDM, such as relaxing the additionality requirements or reducing capital costs of the project. This approach was used to investigate the potential benefit of implementing the prescriptive option (Option 3a) without the barriers in question. The final design of Option 3a is intended to be similar to but more streamlined than CDM. For instance, Option 3a includes only a single calculation and monitoring methodology, has somewhat relaxed additionality requirements, and offers less stringent monitoring and verification requirements for small-scale projects. Modeling the effects of these changes on ICF's cost profile results in a somewhat larger potential for emissions reductions at a given credit price in Option 3a compared to the standalone CDM option (Option 2). Note that for the ETS-CDM option (Option 1), the potential is very limited as only projects in least developed countries would be eligible for crediting. As Option 3b, reflecting the implementing measure requirements, will depend on Member State implementations and cannot be detailed here in the same way as Option 3a, the potential for emissions reductions under this option cannot be firmly calculated. However, given effective implementation this potential should be on the same order as Options 2 and 3a, and likely slightly larger as more project types would be eligible.

In Figure 3.1 the potentially achievable emissions reductions under Options 1, 2, 3a and 3b are compared to three levels of relevance for the FQD: first, the expected gap remaining to the 6% FQD target after the 10% renewable energy target has been achieved (based on ICF's FQD impact analysis for the European Commission), then the 2% optional carbon intensity reduction target set under FQD for CDM credits specifically, and finally against the full 6% target. Based on this analysis, for an adequate credit price (and given enough time to initiate projects) there is the potential for upstream emissions reductions to deliver most of the emissions reductions required

to meet the full 6% GHG intensity reduction target. Certainly, with a clear framework of incentives, upstream emissions reductions under Options 2, 3a or 3b could be enough to cover the gap between the emissions reductions expected from RED compliance and the FQD target.

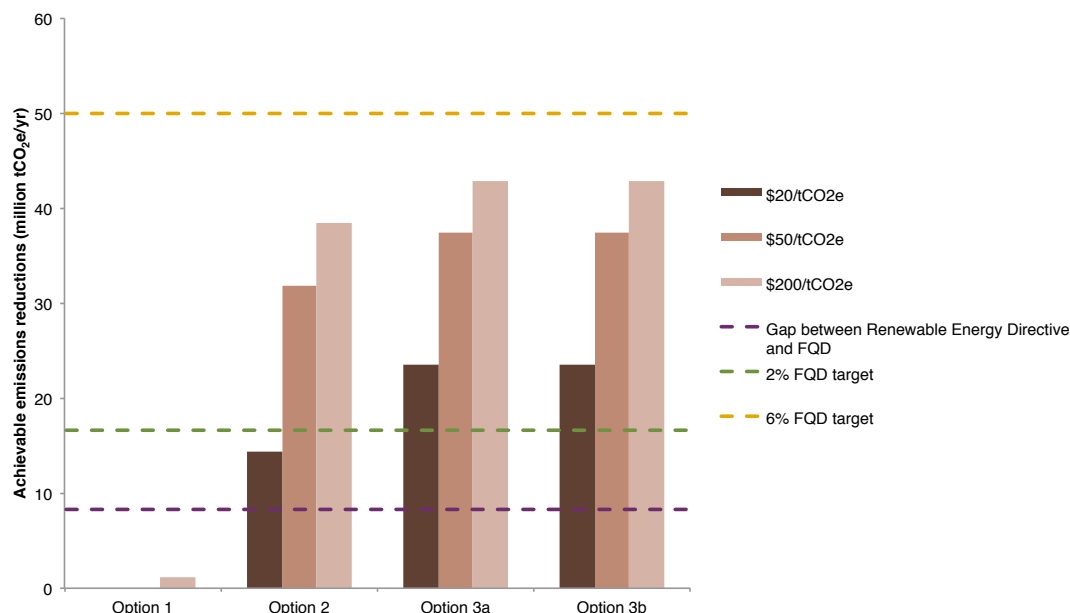


Figure 3.1. Potential emissions reductions from venting and flaring under each of the options if credits are awarded over the project lifetime

While the theoretical potential to deliver economically viable upstream emissions reductions supported by FQD credit values is high, there may be a major barrier to the realistic potential to deliver reductions because at the moment the FQD only has a single year (2020) with a binding compliance target. ICF's analysis of the potential assumed that credits would be available for the full project lifetime. However, if credit value were only available for one year, the potential would be greatly reduced. Figure 3.2 presents achievable emissions reductions for each option given a one-year crediting window. In this scenario, Options 2, 3a and 3b would only make a significant contribution to meeting the 6% carbon intensity reduction target under the FQD if credit prices were high (\$200/tCO₂e). Even this may be a considerable overestimate, as the willingness of oil field operators to invest on the basis of a single year of potential credit value could be limited. In practice, this problem could be largely resolved if Member States implement the optional interim GHG reduction targets, or if Member State implementations of the FQD do not expire in 2020.

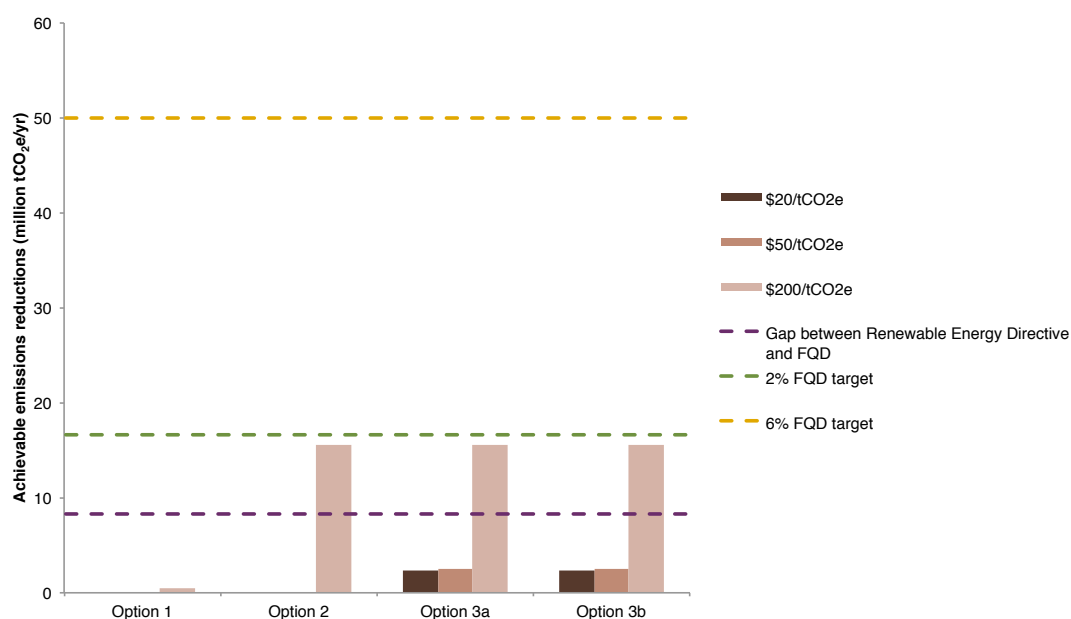


Figure 3.2. Potential emissions reductions from venting and flaring under each of the options if credits are awarded in one year (2020) only

Source: Energy Redefined calculations based on ICF flaring report

3.2. Task objectives: the effects of cost on the size of the potential

The size of the potential for venting and flaring reductions depends largely on how project cost compares to the marginal value of additional FQD compliance. Venting and flaring reduction projects require expenditures on equipment to capture the gas, infrastructure to transport it, staff time to implement, and incur on-going operation and maintenance costs. The projects generate revenue from selling the recovered gas, and in some cases from avoided fines if on-going venting or flaring would violate local regulations. For some projects, the expected revenue exceeds project cost (after accounting for the return on investment normally required by the operator). Such projects would be likely to be implemented regardless of any additional value from FQD compliance. In the language of CDM these projects would normally be considered non-additional (unless it could be demonstrated that they had been subject to significant non-cost barriers). For other projects, the cost greatly outweighs the expected revenue and so these projects are not likely to be implemented even with policy support. The analysis in this task aims to identify those projects that are marginal in terms of cost, i.e. those that have a net positive cost that could be offset by the value of credit support. If operators behave in an economically rational fashion, these are the projects that would be implemented if eligible for FQD compliance but that would not be implemented otherwise. The sum of emissions reductions that would be achieved from this set of projects is

understood to be the size of the reduction potential under the proposed crediting mechanisms.

3.3. Literature review on the cost and size of the reduction potential

Below, we summarize the climate mitigation potential and abatement costs of reducing venting and flaring emissions as well as unintentional emissions reported by a number of studies, using various available technologies and measures.

3.3.1. ICF, 2013

The ICF flaring report is one of the most recent and comprehensive studies to quantify marginal abatement costs of venting and flaring reduction projects. The study selected 23 APG emission reduction projects in four regions/countries-Russia/Azerbaijan, Libya, Nigeria, and Iran/Yemen. These regions and countries account for the majority of EU crude imports (54%). There are two conditions for inclusion of projects for the study: (a) projects that have already been implemented or are fully designed with strong possibility of implementation and (b) detailed data availability including the cost of implementation. At minimum, any included projects have to have a detailed project description including oil field location and oil production, achieved or projected emissions reductions and costs of implementation.

To estimate marginal abatement costs and abatement potentials the ICF flaring report first establishes the baseline AGP emissions.

The current and projected baseline APG emissions are based on the EPA report titled “Draft Global Anthropogenic Non-CO₂ Greenhouse Gas Emissions: 1990-2030” combined with data from World Bank’s Global Gas Flaring Reduction (GGFR) program. EPA’s report provides a bottom-up calculation of non-CO₂ emissions from the oil and natural gas industries, including emission from flaring, intentional and unintentional venting (leaking equipment and system upsets), and fugitive emissions from processing facilities, natural gas transmission lines and compressor stations, natural gas storage facilities, and natural gas distribution lines. Since the EPA baseline estimates of emissions include more than just APG emissions from venting and flaring, the proportion of emissions in EPA’s baseline that are APG related were estimated from the country level flaring emissions provided by the GGFR. The GGFR program estimates flaring emissions based on the NOAA satellite data. However, using the GGFR data to estimate APG emissions from oil fields can have the following shortcomings.

- The NOAA satellite data do not distinguish flares at oil wells from flares at gas wells. It is reasonable to assume that most flaring occurs at oil wells – the reason most associated gas is flared is because of a lack of gas export infrastructure, but there

is still a limited amount of flaring at gas wells and other installations that could be captured in the satellite analysis. In this respect, the use of NOAA data may overestimate APG emissions associated with oil wells.

- The NOAA data do not capture APG emissions due to venting. The ICF flaring report argues that ‘active’ venting occurs only for short durations and emits only a small amount of methane gas, hence its contribution to APG emissions is likely to be small. While this generalization may be true, there are other fugitive emissions (such as from continuous leakage from equipment), which can be significant. The exclusion of venting emissions will tend to underestimate the overall APG emissions.
- The NOAA data cannot capture flares below a certain intensity. However, the contribution to total flaring of these smaller flares is likely to be small (ICCT 2014).
- Satellite data in general has limited accuracy in measuring flared volumes.

Once the baseline APG emissions are established, potential GHG reductions at country/regional levels are calculated by considering technological applicability (T_{ap}) of a given project, adoption rate (A_r), and efficiency of emission reduction (E_r).

$$\text{GHG reduction} = T_{ap} * A_r * E_r$$

Technological applicability refers to the portion of APG emissions from a country that a mitigation option could feasibly reduce if it was applied. E_r is the reduction achieved from project implementation. Adoption rate (A_r) of a given project is estimated based on the historical trend. It is assumed that the same number of projects will be implemented every 10 years in a given country as there were projects between 2001 and 2010. This may underestimate the APG emission reduction potential that can be realized in a given country, since growing concerns about climate change and increasing adoption of best-practice environmental regulation over the coming decades will likely create a favorable regulatory environment for encouraging flaring and venting reductions. One such example would be revenues generated from selling certifiable emissions credits from venting and flaring reductions.

The ICF flaring report calculates a marginal abatement cost as the value of carbon price at which the present value of total project costs equals the present value of revenues generated over the project period. The periods vary by the project type and are taken from the CDM submission reports. For the main scenario, the study assumes a discount rate of 10% and a tax rate of 33%. The study shows that 19.9 million tonnes of CO₂e can be mitigated in 2020 at the abatement cost of less than \$0/tonne from the four countries/regions analyzed (Libya, Iran/Yemen, Nigeria, Russia/Azerbaijan). If the value of emissions reductions were raised to \$254, 45 million tonnes of CO₂e would be reduced from these countries/regions in 2020.

3.3.2. ICF, 2014

In a recently concluded study, ICF analyses the costs of methane reduction from the US on-shore oil and natural gas industries. It looks into two sources of methane emissions from the oil and gas sector – fugitive emissions (unintentional leakages) from flanges, valves and compressors, etc. and vented emissions such as from pneumatic device bleeds, blowdowns, system upsets, etc. The reductions in vented or fugitive emissions result in the increased recovery of natural gas. The extra natural gas recovered would bring in additional revenues, which offset the costs of reductions. In some cases, the costs are negative because of this. To calculate the cost of mitigation, it does the following.

- The capital cost was amortized over the equipment life. The annual amortized capital cost was combined with annual operating cost to estimate an annual cost.
- The annual revenue generated from the extra-recovered gas is subtracted from the annual cost to calculate the net cost. The cost of mitigation is also calculated without using this credit.
- The net annual cost is divided by annual methane reductions to calculate the cost of mitigation.

The annual methane reductions are estimated against the projected emissions in 2018 and the magnitude of reductions possible from using a given option. To project 2018 emissions, 2011 baseline emissions are estimated using the data available in U.S. EPA's *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990 – 2011* (2013). Only the significant emission sources identified in the projected 2018 inventory are targeted for reductions.

The ICF report does not look into potential emissions reductions and associated costs of utilizing the gas that would be otherwise flared (i.e. flare reductions).

By using the above-mentioned measures, ICF estimates that it is possible to reduce 4.6 bm^3 (116 MtCO_2e) of methane emissions annually in 2018 from the onshore oil and gas industry in the United States. This would require a total capital investment of \$2.2 billion dollars. Of this about 1.0 bm^3 (25.6 MtCO_2e) of methane reductions could be realized from onshore oil production alone. The mitigation costs range from cost effective (i.e. negative cost) -\$143/ Mm^3 (-\$5.7/tonne CO_2e) to \$697/ Mm^3 (\$27.8/tonne CO_2e).

There are five fugitive emissions control options that have negatives costs for methane mitigation – replacing Kimray pumps¹¹ with electric pumps, gas capture from centrifugal compressors¹², leak detection and

¹¹ Kimray pumps are gas-powered pumps used to circulate glycol in gas dehydrators.

¹² Centrifugal compressors use circulating oil, which collects gas as it circulates through the compressor seal. This gas is separated from the oil to maintain proper operation. The common practice is to release the gas to the atmosphere.

repair (LDAR)¹³ at compression stations, replacing high bleed pneumatic devices¹⁴ with low bleed pneumatic devices, and LDAR at reciprocating compressors. These five cost effective options alone account for about 50% (116 Mt) of the total reductions. Of the total reduction, 36% would come from using LDAR to reduce fugitives, 30% from replacement of pneumatic devices, 22% from venting reduction, and 12% from gas capture for wet seal compressors.

3.3.3. Johnson & Coderre, 2012

Johnson and Coderre (2012) examine carbon abatement potential from flaring and venting reductions from oil fields in Alberta, that including both conventional oil fields and the oil sands. The study covers 5945 active oil fields of Alberta that have reported flaring and venting of APG, referred to by this study as ‘batteries’. The total amount of gas flared or vented from these oilfields was 0.687 billion m³. Alberta accounts for 98% of current Canada oil production when oil sands are included, and so the carbon abatement potential estimated by this study can be used as an approximation of the total potential carbon abatement for Canada. However, the paper analyses only one project option, collection and transport of recovered associated gas to the most economical contact point in the existing pipeline infrastructure. Investment costs in all cases are for installing compressors and the additional pipeline needed. No other technology options such as on-site electricity generation, gas-to-liquid conversion, etc., are analyzed, and so additional carbon mitigation that could be economic under current conditions could have been omitted, especially for remotely located oilfields.

Johnson and Coderre (2012) estimate carbon abatement potential for cases where the NPV of the project is zero or less than zero. This is in accordance with Directive 060¹⁵ in Alberta which states that associated gas must be conserved if it is economical to do so on a net present value basis. While estimating net present values for APG recovery, Johnson et al. take into account the following.

- The existing pipeline infrastructure and location of oil fields (based on GIS mapping). This helps determine the most economical entry point for the recovered gas and length of the new pipelines that must be installed.
- Composition of the associated gas that is being flared or vented. This is important for estimating energy content of the gas, which determines the price it gets in the market. On the other hand, information about the H₂S concentration of the gas (sour or sweet) is important in identifying the appropriate pipeline infrastructure for transport.

¹³ LDAR involves IR cameras to detect leaks and repair of equipment.

¹⁴ Pneumatic devices use compressed gas to control and power equipment such as pumps. Pneumatic devices release (“bleed”) methane gas while in operation.

¹⁵ The Directive 060 is a regulation in Alberta that deals with upstream petroleum industry flaring, incinerating, and venting.

- Investment costs for installing compressors and pipelines and rate of production decline, and
- Annual operation costs.

To calculate the economical net present value, Johnson and Coderre followed Alberta's ERCB Directive 60 general guidelines. Based on the guidelines, 1% inflation and discount rate of 6% and the gas price of \$4.19/Mbtu are used in the calculations. The discount rate of 6% is lower than the IRR rates typically used by the oil and gas industry in making decision on project selection. A project period of 10 years is assumed.

The study analyses the net present values for four scenarios- (a) paper batteries¹⁶ which aggregate a number of physically dislocated oil fields (b) disaggregated wells (c) paper batteries with carbon credit of \$15/tonne (d) disaggregated wells with carbon credit of \$15/tonne.

The study estimates that 17-33 million metric tonnes of CO₂e could be mitigated by flaring reduction in Alberta, Canada at zero or negative abatement cost. If the carbon price is set at \$15/tonne, abatement potential would increase to 28-44 Mt.

For most of the sites (81% or corresponding to 77% of the total volume flared/vented), carbon mitigation is profitable as they are located within 1 km of a potential pipeline tie-in point.

In the most cost-conservative (i.e. expensive) scenario, in which wells associated with paper batteries are treated individually, 90% of sites and 54% of the total gas volume could be recovered at a capital cost of less than \$384 thousand per battery.

3.3.4. Ecofys, 2009

The Ecofys study (2009) provides estimates of potential and costs of fugitive emissions reductions from the oil and gas sector in the EU. The report provides cost estimates by project activity rather than by individual projects or oil fields. These activities are broadly categorized into four groups - (a) eliminating chronic leaks from pipelines, distribution facilities, etc. for natural gas, (b) eliminating chronic leaks from pipelines, distribution facilities, etc. for APG from oil production (c) reducing flaring emissions and (d) elimination of venting.

The emission reduction potential for each activity up to 2030 is calculated by comparing the emissions in the project scenario to the emissions in the reference scenario. The reference scenario assumes frozen technology development, i.e. 2005 emissions factor for a given activity will remain the same until 2030. To calculate the emission

¹⁶ Oil and gas wells are connected to primary production facilities for separating oil, water, and associated gas. These primary production facilities are known as batteries. A 'paper battery' on the other hand is a battery that exists on paper only and represents a number of physically disconnected wells as if they were a single entity. The purpose of creating such batteries is to assist the industry by making data reporting flexible.

levels in a given year in the reference scenario, the projected activity level of a given year (e.g., PJ of crude oil extracted) is multiplied by the corresponding but constant emission factor.

Although emissions reductions vary by locations and projects, the study uses weighted average emission reduction efficiency for a given project activity. This is shown in Table 3.1. Weighted emission reduction efficiencies are largely taken from Weyant et al. (2004).

Table 3.1. Emission reduction efficiencies and mitigation costs at different discount rates

PROJECT ACTIVITY	% REDUCTION EFFICIENCY	COSTS (€)/TCO ₂ E			REFERENCE
		D=4%	D=5%	D=10%	
Flaring reduction	95	2.8	3.3	5.7	Weyant, 2004
Venting reduction	81	10.8	11.4	14.3	Weyant, 2004
Chronic leak reduction-oil and gas	66	2.1	2.2	3.0	Weyant, 2004, and Electronic monitoring at large surface facilities

The Ecofys study does not use its own methodology for calculating costs of reductions but rather relies on cost estimates reported by Weyant et al. (2004). The cost estimates are the weighted averages of costs data from Weyant et al. (2004) for a given project activity. Because of this the estimates are crude estimates. Estimates for three discount rates are provided – 4%, 5%, and 10%.

Overall, the study finds that it is possible to reduce GHG emissions by 20.7 million tonnes in 2030 from the oil and gas sector in the EU by implementing the above mentioned measures, with abatement costs ranging from €2.1 (\$2.8)¹⁷/tonne CO₂e to €14.3 (\$19.7) / tonne CO₂e depending on the discount rates and reduction measures.

3.3.5. Ecofys, 2001

In an earlier study carried out by Ecofys for DG Clima, the European Commission, Henderiks and de Jager (2001) also evaluated the EU-15-wide reduction potential and associated cost of emissions reductions from the oil and gas sector. The estimates refer to the year 2010. The authors used bottom up analysis and calculated emissions reductions using an emission reference level based on frozen technology development. As mentioned above, the frozen technology reference level assumes no change in carbon intensities of activities from 1990 to 2010 but assumes changes in physical activities such as changes in production levels of oil and gas.

¹⁷ Based on the US-EU exchange rate of 1.38, March 24, 2014

The study analyses emissions from associated gas, process vents and flares, engines, turbines, compressors and pumps, system upsets, and transmission and distribution activities. Rather than focusing on individual and site-specific projects throughout the EU-15, it identifies methane reduction measures and classifies them into six subsectors – compressors, energy requirements, process vents/flares, associated gas, fugitive emissions, and system upsets. The study then calculates emission reduction potential and costs for each methane reduction measure utilizing average values. The authors also classify methane reductions measures into three broad categories based on the range of abatement costs – (a) economically profitable measures with abatement costs (€/tCO₂e) < 0€, (b) 0€ < 20€ abatement costs and (c) 20 € < 50 € abatement costs.

Cost estimates assume an interest rate of 10% and the project period that is specific to the equipment used for a particular measure. For example, the project period varies from 1 year for maintenance-related options to 50 years for the replacement of the grey cast iron network. It is not clear if cost calculations use investment parameters such as tax rates. Overall the study estimates that it is possible to reduce a total of 25.5 million tonnes of CO₂e in 2010 by implementing fugitive emission reduction measures in the oil and gas sector. This requires a total investment of €0 to €1905 per tonne of CO₂e reduced over the lifetime of the project, depending on the type of project. For a project involving inspection and maintenance, there is a negligible cost whereas for a project involving the replacement of the cast iron network, the investment cost could be as high as €1905. On average, the investment cost for all projects would be €747 per tonne of CO₂ reduced. The investment cost should not be confused with the cost of carbon abatement, which should include revenues from gas sales etc.

3.3.6. GE Energy, 2010

The GE Energy study estimates the costs of flaring reductions at the project level for five projects based on CDM submissions. These five projects and the technology employed are shown below. The technology utilized involves processing of the recovered associated gas and pipeline construction. The study reports that cost estimates are based on the economic data provided in CDM submissions, but it does not tell how they actually estimated them or what assumptions were made. The study also does not provide net abatement costs, although estimates of the ratio of CPX to tonnes of CO₂e annually reduced are provided. However, based on internal rate of returns, it is possible to infer which projects are profitable (negative abatement costs) and which are not. Of the five projects analyzed, all projects except the one in Indonesia are profitable with IRR ranging from 4.5% (Nigeria, Utumu) to 11.8% (Nigeria, PanOcean). The Indonesian project can be profitable with negative abatement cost if there is a carbon credit price of \$15/tonne CO₂e. The IRR for the flaring projects analyzed in this study are below the typical threshold for oil investments. These results are shown in Table 3.2.

Table 3.2. GE Energy estimates of flare gas utilization and CO₂e reduction costs

	INDONESIA 2007 TANBUN	QATAR 2007 AL-SHAHEEN	CHINA- 2009 TARIM	NIGERIA 2008 PANOCEAN	NIGERIA 2010 UTUMU
Flare gas use (Bm ³ /yr)	0.1	1.6	0.2	1.3	0.2
CO ₂ e reduced (Mt)	3.9	17.5	2.4	26.3	2.6
Annual CO ₂ e reduced (Mt/yr)	0.4	2.4	0.3	2.6	0.3
CPX (\$US million)	30	260	32	302	30
IRR w/o credits	-30.4%	9.7%	5.4%	11.8%	4.5%
Technology	Mini LPG plant, pipeline	Processing, NGL, and pipeline	Processing, NGL, pipeline	Processing, NGL, pipeline	Processing, NGL, and pipeline

Source: GE, 2010

Depending on availability of economic data in CDM submissions, it may be possible to project emissions reductions and costs at the national level using the methodology utilized by the ICF study, provided that required data are available.

3.3.7. Carbon Limits, 2013

A study by Carbon Limits (2013) estimates the potential and costs of GHG reductions for four flaring reduction options in Russia, Kazakhstan, Turkmenistan and Azerbaijan, also known as “target countries”. This study is part of the cooperation between the European Bank for Reconstruction and Development and the Global Gas Flaring Reduction Partnership of the World Bank to identify profitable flaring projects in the target countries. *Profitable here means the project should deliver at least a 7% internal rate of return.* The study finds that these countries need to invest US \$8 billion to utilize 95% of associated gas in existing oil fields and additional US \$16 billion for new oil fields.

The investment estimates assume a mix of four technological options available for flare reductions. They are (a) collecting and supplying APG to existing downstream infrastructure, (b) collection, processing and marketing of resulting dry stripped gas (DSG), LPG and natural gas, (c) collection, treatment and onsite electricity generation for export (d) and collection and conversion of APG to diesel and gasoline.

Capital investment estimates are based on a large number of assumptions. They include the “development of Russian oil production, the share of total APG production in 2020 from new developments, the effects of projects under implementation at existing flare sites, the ‘remoteness’ of existing and new APG production sites and new infrastructure, the required installed capacity relative to actual APG recovery, the cost synergies associated with designing integrated APG

solutions for new developments, the size distribution of APG volumes to be recovered at existing and new production sites, the optimal technology mix to utilize gas from existing and new production sites and the unit cost of new infrastructure to utilize APG using alternative technologies at different scales” (Carbon Limits, 2010). *Hence there is a high degree of uncertainty in mitigation potential and costs.*

The study does not provide estimates of carbon abatement costs in the target countries, but estimate the price of output (natural gas, diesel, electricity) that is required to deliver 10% IRR (discount rate) for a given technology. This price is known as the net-back value. For example, the study shows that the net-back value of electricity should be about \$50/MWh and \$40/MWh for electricity generation if the APG is transported by a pipeline by 200 km and 20 km, respectively. For a comparison, the price of electricity in Russia ranged from \$24 to \$140 per MWh in 2013. CPX and OPX data are not provided for all options to derive carbon abatement costs.

3.3.8. PFC Energy, 2007

The PFC study (2007) analyses the cost of reducing flaring emissions from oil production in Russia. This study begins by first estimating how much gas is currently flared. There are various studies giving a wide range of flaring volumes in Russia from 15 Bm³/y of APG (referenced to official reports) to 37 Bm³/y of APG (Hamso, 2013). Since APG is not measured at wellheads in Russia, it is not possible to independently verify how much gas is flared. Nonetheless, the study suggests that it is possible to calculate the amounts of APG produced based on reservoir characteristics, particularly gas-to-oil ratio (GOR) and production profiles of fields. The PFC study estimates the APG volume based on these considerations.

The study then estimates the cost of transporting APG to the market using the existing western Siberia pipeline system. Included in the estimates are the costs of gathering pipelines, gas processing, and trunk-line/transmission. The detailed data and information are provided in appendices as a separate but accompanying document. These costs are compared to the revenues generated from selling oil and gas. The study finds that the revenues from associated gas sale could outweigh the costs, giving a value to reducing flared gas in Russia of \$40,000 per Mm³ suggesting that flaring reduction in Russia can be economically attractive. This is more economically attractive than exploitation of some potential new gas fields. The study also analyses the costs of flaring reduction using various technologies. According to the study, the most promising technologies for commercialization in terms of economic competitiveness are electric power generation and a combination of gas processing plants (GPP) and dry gas sales. The study estimates that about 70 million tonnes of CO₂e can be reduced while generating \$2.3 billion revenues – it is however unclear what the cost of these reductions would be.

3.3.9. PA consulting Group, 2006

The PA consulting Group report (2006) authored by Crosetti & Fuller identified economically attractive flaring projects in Indonesia, but did not explicitly model carbon mitigation potential for flaring reductions or the associated abatement costs. For this, authors gathered production data and identified potential flaring reductions opportunities based on stakeholder discussions and literature review of available technologies. This was followed by a qualitative screening and quantitative screening based on economic and financial criteria to identify economically attractive flaring projects. The study used an economic threshold of \$90 million NPV and a financial valuation of \$15 million for screening, which led to identification of 10 fields with the flaring volume of 1.2 million cubic meter per day (Mm^3/d). For calculating NPV, a discount rate of 10% was used. Since the study provides costs estimates for flaring reduction technologies and production data, one may be able to calculate flaring reduction potentials and abatement costs using the information provided in this study.

3.3.10. Summary of literature review on the cost and size of the reduction potential

Table 3.3 and Table 3.4 summarize cost estimates for emissions reductions from flaring and venting reported by various studies. Table 3.3 lists only the CO_2e reduction potential that can be achieved at negative costs, (i.e. profits) as reported in the literature, for the oil sector only. Table 3.4 reports the reduction potential and associated abatements costs for oil and gas sectors given the availability of carbon prices for credits generated from APG recovery.

As mentioned earlier, some studies such as Johnson and Coderra (2012) and PFC Energy (2007) focus on abatement potential and costs related to oil production only, whereas Ecofys and ICF study (2014) cover both the oil and gas sectors. Total carbon mitigation potential from economically profitable flaring and venting reduction projects in the oil sector in EU-15, Canada, Nigeria, Russia and the US combined can be in the range of 127-143 MtCO_2e per year.

It is to be noted that the magnitude of carbon abatement will increase if the price APG can fetch in the market increases. Moreover, as Table 3.4 indicates, additional reductions can be achieved if the projects can accrue revenues from selling carbon credits. For example, if the carbon credit price is US \$100/tonne CO_2e ¹⁸, carbon mitigation can increase to 41.8 MtCO_2e /yr in 2020 from projects in Libya, Nigeria, Iran/Yemen and Russia/Azerbaijan compared to 20 MtCO_2e /yr in the absence of carbon prices. These countries/regions together account for 54% of total EU crude oil imports. This suggests if flaring and venting

¹⁸ We note that this requires not only that there is a \$100/tonne carbon price, but that oil companies treat that price as reliable when making investment decisions. If the carbon price is discounted for risk, then fewer projects are likely to be considered profitable.

Reduction of upstream greenhouse gas emissions from flaring and venting

reductions are carried out in all the countries exporting crude oil to EU, carbon mitigation would be even more substantial.

Table 3.3. Reported carbon mitigation potential at abatement cost <\$0/tonne CO₂e for the oil sector

STUDY	REGION/COUNTRY	PROJECT TYPE	REDUCTION POTENTIAL (MTCO ₂ E)/YR	INVESTMENT (PER TCO ₂ E)	ABATEMENT COST (PER TCO ₂ E)
Ecofys, 2001	EU-15	Increased gas utilization, maintenance, and improvements of compressors	0.6	€ 0-30 (\$0-41.4)	€ -1 to -4 (-\$1.4 to 5.5)
Johnson and Coderra, 2012	Alberta-CA	Collection, compression and pipeline	17-33		US \$-40 to <0
PFC Energy, 2007	Russia	Variety of projects from electricity generation to a combination of gas processing plants and dry gas sales	70 ^a		
ICF, 2013	Russia/Azerbaijan and Nigeria		20		<0
ICF, 2014	US-onshore oil		25.6	US \$6.9	US \$-5.7 to \$-0.5
Total reduction potential from EU-15, Canada, Nigeria, Russia, and US from profitable projects			127-143 MtCO₂e		

Note: Alberta accounts for 98% of Canada oil production, hence the costs and potential can be considered as representative of the whole of Canada.

^aAt current APG price.

Table 3.4. Mitigation potential and costs for projects that are profitable with additional revenue through carbon prices

STUDY	REGION/ COUNTRY	PROJECT TYPE	REDUCTION POTENTIAL (MtCO ₂ e)/ YR	INVESTMENT (PER tCO ₂ e)	ABATEMENT COST (PER tCO ₂ e)
Ecofys, 2001	EU-15	Various	25.4	N/A	€ 1- 90 (\$1.38-124.2)
Ecofys, 2009	EU	Chronic leaks, flaring and venting reductions	10.3	N/A	€ 2.1-10.8 (\$2.89- 14.9)
GE Energy, 2010 (Project level assessment (not at country level))	Indonesia, Tanbun	Mini LPG plant, pipeline	0.4	\$30	\$15
	Qatar	Processing, NGL and pipeline	2.4	\$260	\$6.5
	Nigeria	Processing-NGL and pipeline	2.6	\$302	\$7.5
	Nigeria	Processing-NGL and pipeline	0.3	\$32	\$10
	China	Processing-NGL and pipeline	0.3	\$30	\$11
ICF, 2013 ¹⁹	Libya	Various options	1.8		Up to \$100
	Nigeria		11.1		
	Iran/Yemen		1.2		
	Russia/Azerbaijan		26.6		
ICF, 2014	US-onshore oil and gas	Fugitive and venting emission control	116	18.9	Up to \$27.8
Johnson and Coderre, 2012	Alberta, Canada	Collection, compression and pipeline	28-46		Up to \$15
Carbon limits, 2013	Russia, Kazak, Turkmin, Azerbaijan	Flaring reductions in existing fields	31.5 ²⁰	US \$8 billion	N/A

¹⁹ 2030 projections.²⁰ Calculated from 16 bm³ avoided gas by increasing gas capture efficiency from 75% to 85%, assuming methane density of 0.717 kg/m³ and conversion ratio of 2.75 gCO₂/gCH₄.

3.4. Barriers to engagement in CDM

The previous subsection reviewed and discussed previous studies estimating the cost and size of potential of flaring and venting emissions reductions. The size of the potential under CDM is constrained by cost in that projects that are cost effective without credit support would not be eligible under CDM's additionality criteria (unless significant non-cost barriers exist), and projects that would not be cost effective even with CDM credit support likely would not be implemented. In addition to the costs of implementing emissions reduction projects themselves, the CDM process is associated with additional barriers, not directly related to project cost. These further limit the number of venting and flaring reduction projects, and the total size of the reduction potential, that are likely to be implemented and utilized for FQD compliance under the CDM options (Options 1 and 2). This subsection discusses these non-cost barriers and explains how they limit engagement of venting and flaring reduction projects in CDM.

3.4.1. Demonstration of additionality

CDM project applicants are required to demonstrate that the proposed project is additional, i.e. that it would not have been conducted in the absence of CDM credit support. They are required to complete:

- An investment analysis to demonstrate that the proposed project is not financially attractive;
- An analysis of other barriers;
- A common practice analysis to determine if the project activity is not common practice in the region (UNFCCC, 2012b).

Project applicants must complete each of these analyses, but are not necessarily required to demonstrate that they meet all three criteria. For instance, a project that is financially attractive but faces substantial non-cost barriers (such as poor national security in the host country) could theoretically be approved. Thus, demonstrating additionality requires the submission of a detailed description of the project, including equipment lists and cost breakdowns. The time and effort to compile and present this information is a cost born by the project applicants.

It may be difficult for the oil and gas industry to demonstrate that a project is not financially attractive without CDM credit support. Although there is no standardized threshold required by the CDM process, the CDM Executive Board appears to typically require the Internal Rate of Return (IRR) for a project should be lower than 10% (e.g. Rang Dong Oil Field Associated Gas Recovery and Utilization Project, Al-Shaheen Oil Field Gas Recovery and Utilization Project). In other words, it is assumed that a project with an IRR above 10% is financially attractive for a company (and would therefore be pursued even without CDM accreditation), and a project with an IRR lower than

10% would not be pursued in the absence of credit support. Note, however, that some flaring reduction projects with an estimated IRR greater than 10% in their PDDs are still approved. For example, one project in Nigeria²¹ calculated an IRR of 13-15% and was later approved and registered, although consideration of the poor security situation in that country may have aided validation.

While 10% is a standard IRR for use in financial analysis, and seems to be favored by the CDM EB, it is understood that the IRR used by oil and gas companies when considering investments is generally higher than 10% in practice.²² More typically, these companies require IRRs of 15-20% before taking on projects, although this hurdle may reach 30% in competitive periods (Ross, 2008; Wood Mackenzie, 2010), depending on the other investment options available. Large oil companies have limited human and financial resources and not all projects can be developed. Projects thus compete with each other, and typically those with the highest IRR are pursued first. Based on these estimates, projects with an IRR lower than 10% would generally not be internally competitive even with credit support (CDM credit value is discussed more below). Thus, the 10% IRR threshold used in the CDM process likely excludes some venting and flaring reduction projects that would not otherwise be pursued, and would hence be genuinely additional.

3.4.2. Inconsistency between methodologies and treatment of additionality

The predictability of the CDM process is closely linked with the consistency of application of CDM decisions, rules, and guidelines. The GGFR writes that inconsistency in terminology and inconsistency between methodologies are significant barriers to the CDM process (Sucre & Rios, 2011).

There are clear differences in requirements in the three approved methodologies for venting and flaring reductions from oil production that can be seen in Table 2.1. AM0037 and AM0077 require venting or flaring to have occurred for three years prior to project start (presumably as a condition to demonstrate additionality) but not in AM0009. AM0009 allows crediting for recovery of non-associated gas-lift gas, but not the other methodologies. AM0009 and AM0077 require calculation of leakage emissions but not fugitive emissions, and the opposite is true for AM0037. There is no clearly documented rationale for these differences in methodologies, and they create gaps that could potentially discourage certain types of projects. For example, a project that captures associated gas for methanol production (applicable under AM0037) and has not vented or flared for 3 years prior (allowed under AM0009) is not eligible for either methodology, even though in principle it appears that taken on their own both lack of prior flaring

²¹ “Recovery of associated gas that would otherwise be flared at Kwale oil-gas processing plant, Nigeria”

²² Expert opinion of Energy Redefined

and using gas for methanol production can be acceptable to the CDM EB.

Furthermore, the way the CDM rules are applied to different project proposals has been alleged to be inconsistent: the World Bank (Platanova-Oquab et al., 2012) writes:

Specifically, the guidance with respect to the determination of additionality still does not provide sufficient objectivity, and its application is often inconsistent.

For instance, the support of national subsidies or tariffs could affect the determination of whether a project is additional, but how the CDM EB treats national support in the determination of additionality has been thought to be inconsistent for different projects. A particularly controversial instance was the rejection of 10 proposed Chinese wind energy projects amid accusations that the Chinese government had recently lowered a subsidized tariff in order to make its projects eligible for CDM (He & Morse, 2010; IETA, 2009); IETA describes it as:

a decision unsupported by evidence and taken behind closed doors.

3.4.3. Length of project registration process

Each step of the CDM process takes a considerable amount of time. Using data from the CDM pipeline (Fenhann, 2014), we show that it can take up to a year for a proposed new methodology to be approved or rejected (Figure 3.3). This length of time is likely to be a barrier to venting and flaring reduction projects because the existing methodologies (AM0009, AM0037, AM0077) are not comprehensive and not all of this type of project would fit in an existing methodology; new methodologies would have to be approved to allow some potential projects to be eligible under CDM. To use the example above, a project recovering associated gas as a feedstock for methanol that had not been venting or flaring this gas for three years prior would not be eligible under any of the existing methodologies. The project participants would have to either propose a new methodology that covers this project type or propose changes to either AM0009 or AM0037. Amending an existing methodology may be quicker than having a new one approved, but would still take time, with no guarantee of being accepted by the EB.

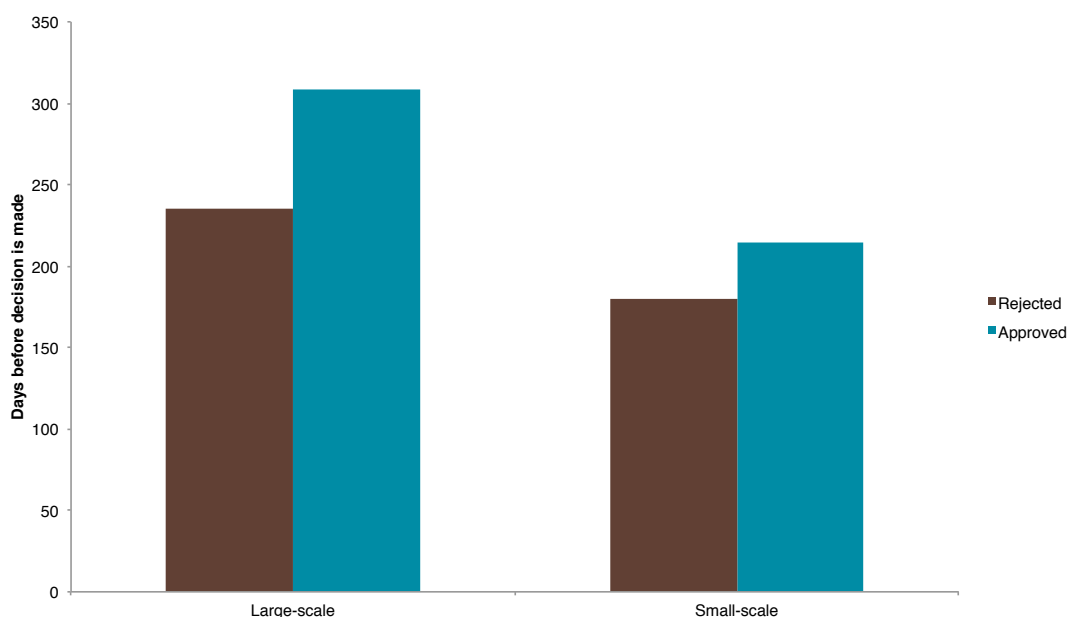


Figure 3.3. The average time for a decision on a new proposed methodology (data from CDMpipeline)

After methodology approval, the process to apply for and register a CDM project takes 1-2 years. This includes time for preparing the project design document (PDD) and other documents (4-6 months), validation (4-12 months), and requesting registration (4-6 months) (Mabanaft/UNFCCC, as cited in Mutriwell, 2011).

Using data from the CDMpipeline, it is calculated that the average time to approve oil and gas projects specifically is similar to the average time for all CDM projects. But for all projects, including those in oil and gas, the average process time has increased between 2002 and 2013.

The long period required to apply for and register CDM projects is a major barrier to engagement. This 1-3 year process (at the long end in the event that a new methodology is required) can conflict with the natural timeline of the project; for example, equipment for the project must be ordered before the end of the approval process. In addition, for some projects gas production and thus flaring naturally declines over time. In that case, a delay in project registration will result in a particularly large loss of credit value to the project participant. Such a reduction in annual credits awards compared to if the project had begun on time, can severely worsen project economics. It is estimated that in some cases a 2-year delay could result in reductions in project value of around 20%.²³

3.4.4. Cost of CDM process

There is a fee to register a project under CDM, but more importantly the process of applying for a CDM project requires substantial

²³ Estimate by Energy Redefined based on expert knowledge.

personnel time that comes at a cost to the project participant(s). The process requires a team within the participant company; these salaries must be paid, as well as administrative support, office space, etc.

UNEP has estimated the administrative costs incurred to obtain credits under CDM. These estimates have been updated to account for inflation, and are shown in Table 3.5. The final column shows estimates from Energy Redefined, based on experience and on data from EPA Energy Star reports on the costs of validation (including e.g. travel costs and staff time). Note that expertise in the oil industry is expensive even in countries with relatively low labor costs, and this is one reason why the costs estimated by Energy Redefined are high.

Table 3.5. Costs of applying for project registration under CDM, estimated by UNEP (UNEP, 2007) and Energy Redefined (ER)

Activity	UNEP		Type of cost	ER COSTS OIL COMPANY BASIS (MEDIUM-LARGE PROJECTS, USD)
	Cost (large-scale, USD)	Cost (small-scale, USD)		
Initial feasibility study,	7,000-35,000	3,000-10,000	Consultancy fee or internal	140,000
Project Design Document PDD	20,000-120,000	12,000-30,000	Consultancy fee or internal	500,000
New methodology if Required	25,000-120,000 (incl. US\$1,000 'UN registration fee)	25,000-60,000	Consultancy fee or internal	500,000
Validation	10,000-35,000	7,000-12,000	DOE fee	30-50,000
Project Registration Fee	10,500-350,000	0-30,000	EB fee	11,000-350,000
UN Adaptation Fund Fee	2% of CERs	2% of CERs	EB fee	2% of CERs, which could be up to \$1.1mill
Initial verification (incl. system check)	5,000-30,000	7,000-20,000	DOE fee	30-50,000
On-going verification (periodically)	5,000-25,000	7,000-12,000	DOE fee	30-50,000

The cost of developing a new methodology is significant (Energy Redefined estimate \$500,000). The impact of this cost on a small CDM project has been estimated by Chadwick (2006). In this project, the total cost of the CDM process was \$387,000 (corrected for inflation), \$234,000 of which was to develop a new methodology. A substantially higher credit price (\$35 vs. \$15) is required to deliver an IRR in the case that a new methodology must be developed for the project.

In addition, registering a project under CDM requires monitoring equipment to measure and demonstrate emissions reductions. This cost may be small relative to the value of gas and CERs generated for very

large projects, but for small projects may be \$500,000 - \$1,000,000, potentially doubling the total project cost.²⁴

3.4.5. Government stake in gas recovery projects

Governments often have a significant financial stake in oil field development, either through owning an equity stake in oil fields and/or production, or because they generate revenue by taxing these projects. When a government has an equity stake, it typically owns all or some of the oil and gas resources under the ground and licenses oil production to private companies. Under Production Sharing Contracts/Production Sharing Agreements (PSC/PSA), the oil company acts as a contractor; it does not own the oil but is allowed to sell some to cover its costs (including a level of profit determined in the contract). In tax royalty or concession systems including the US, Canada, Norway, and the UK, the government licenses an area to an oil and gas company, which exploits and develops it and then pays taxes to the government. In some cases, like the US, the government taxes a fraction of the gross revenue from a project, not profit; this can result in a large total amount of tax being collected. Because governments have such a large stake in oil field development, whether through ownership or taxation, in some cases they will effectively subsidize the cost of development.

In either system, because the government has a major stake in oil production, it shares the same financial interests as the oil companies to some extent. So if a flaring reduction project is not economically attractive for an oil company, the government may have little financial incentive to support the project. That said, it should be noted that governments may have environmental objectives that would cause them to support emissions reductions in general (for example, Norway strongly regulates flaring [Svensen, Simonsen, & Lind, 2014]). In addition, the government of the host country receives 2% of CERs issued for CDM projects to assist in adaptation to climate change (CDM Rulebook). Even in instances where credit value (e.g. CERs) makes a project financially attractive to the government in the long term, the government may still not support it if the government itself is cash constrained in the short term. This could be the case if the government would have to provide tax relief on the up front capital cost for the project, but it would be years before the government was repaid with CER credits.

A converse problem may also exist, where the operator does not have an incentive to reduce flaring. This may occur if the government or some other third party owns some or all of the rights to gas produced from oil drilling. In such a case, the government would receive all revenue from sales of recovered gas that used to be flared, whereas the operator would not receive a financial benefit. If the operator is responsible for paying the capital and operating costs for a gas recovery project, without the revenue from the gas it would not be able

²⁴ Estimate by Energy Redefined based on expert knowledge.

to recoup its costs. Similarly, in some cases the government may receive some fraction of the revenue from gas sales, or the operator may be required to sell at capped prices (or even at 'zero price'). In these cases the reduced revenue for gas sales would make it harder to offset the costs and still provide some margin of profit. Thus, government ownership of gas produced from oil drilling could be a barrier to flaring reduction projects.

A different type of problem with shared ownership of resources is that a potential CDM project may be stalled if one owner (with a stake of around 25% or higher, depending on voting rights) does not agree to proceed with the CDM process. Different owners may have different views due to tax positions or ownership positions in downstream or upstream infrastructure.

3.4.6. Infrastructure

Limited access to infrastructure, such as pipelines, gas processing plants, or electricity grids, can be a barrier to the engagement of oil companies in venting and flaring reduction projects under CDM. Potential project participants may have difficulty accessing existing infrastructure because:

- State entities have sole rights to transport and process (e.g. Russia);
- Natural pipeline monopolies (e.g. Gazprom has a monopoly on gas transportation and exports in Russia (PFC Energy, 2007));
- The infrastructure owners (e.g. Middle East governments, or natural gas companies like Gazprom) offer to buy the gas at a very low price that is uneconomical for the project participants or extract large rents;
- The owners want to use the infrastructure for their own purposes only;
- High tariffs would be charged for use of the infrastructure;
- There is insufficient capacity in the infrastructure to absorb gas from the project;
- Lack of transparency;
- Weak regulators;

If the potential project participants cannot access existing infrastructure, the alternative would be to build new infrastructure. This is usually not economical unless the volumes of gas collected are very high.

Capacity has been a very contentious issue over the years. Infrastructure system operators tend to have a better understanding of any bottlenecks in their systems than project participants who simply

require access to some pipeline space. Similarly, system operators much better understand issues associated with debottlenecking. In some cases government intervention can solve problems with pipeline space; for example, the Norwegian government addressed space allocation issues by creating the GasLed consortium, which is now required to manage all pipeline space in Norway equitably (Statoil, 2010).

3.4.7. CER credit value

CER values are not independently set, but are determined in the marketplace. Regulatory decisions, credit availability and expectations of future emissions reduction goals can all affect expected CER credit values. The European Emissions Trading system, the major market for CERs, has not historically been very stable. Volatility in the early years (2005-2007) ranged from 27-161%, indicating high variation in credit prices. Uncertainty in CER credit value is a significant barrier to engagement in CDM because it limits a company's access to project financing. Although large companies like ExxonMobil or BP might be able to use their own resources to finance CDM projects, many smaller companies require other lenders and project finance. These lenders must have confidence that the project will generate enough revenue to repay the loan, and because a CDM project must rely on credit support in order to meet additionality requirements, credit value is a key component of that expected revenue. Any instability in credit values will normally be reflected by financiers discounting expected credit values and/or requiring higher IRRs when making decisions on whether to invest or not. For example, Park & Jang (2010) estimated the discount rate that should be applied to a CDM project in Indonesia to cover the risk of credit price instability and concluded that credit support should be discounted by 15%. The estimation in this study assumed low volatility; the appropriate discount rate would be higher for a more volatile credit market. Lenders may also raise interest rates to cover the risk of the project.

Project applicants sometimes compare the IRR with and without CDM support to show that the project is only financially attractive with CDM, but for this calculation they do not discount the CER credit value. While a project may appear financially viable to the CDM EB when credit support is included, this does not mean the project will be able to attract financing if credit values are volatile. Thus, CER volatility reduces the pool of projects that can engage in CDM.

Figure 3.4 shows the myriad factors that affect credit price and how it affects financing. A project's chances of attracting financing are influenced by both short and long term expectations of credit price. Expectations of low price or high price volatility (and thus uncertainty in future credit price) make a project less attractive for financing. Short-term credit price volatility is mainly affected by the supply and demand of credits but also external factors like gas prices. Long-term credit prices can be affected by changes CDM rules. Short and long term price expectations are affected by the risk of regulatory change.

Purchasing insurance can help mitigate the risk of changing credit prices.

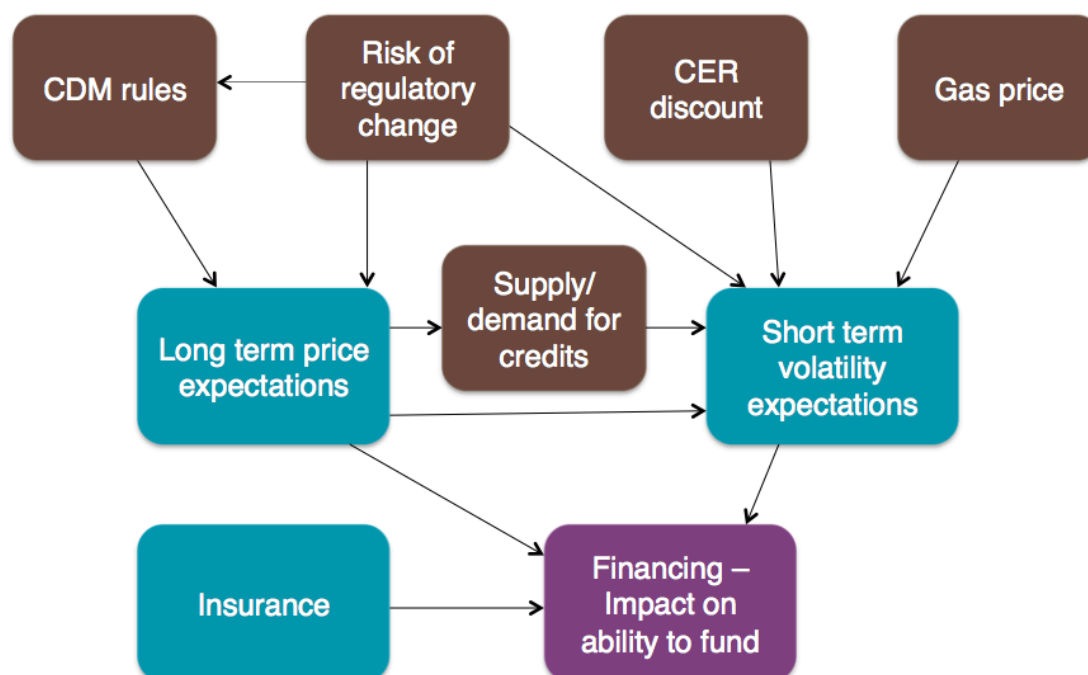


Figure 3.4. Schematic showing factors that affect emission reduction credit prices and how these prices affect project financing

There may be options available to protect a project from the risk of credit uncertainty. For one, project developers could potentially hedge the risk through use of a broker (i.e. accept a discount on expected future CER value in exchange for the broker absorbing the market risk). A second option would be to obtain underwriting from an organization like the World Bank (e.g. Carbon Prototype Fund for Hydro projects), which is essentially a form of insurance. At the current time, it is not believed that either of these options is readily available to operators implementing venting and flaring reduction projects.

3.4.8. Other barriers

In Table 3.6, potential barriers to the engagement of projects in CDM are listed under various categories using a framework from UNEP (2009). These barriers are marked where applicable to oil and gas flaring projects, with relevant comments.

Table 3.6. Potential barriers to oil and gas flaring projects engaging in CDM

BARRIER	APPLICABLE TO OIL/GAS	COMMENT
Technological		
Technology not known	Y	
Technology availability	?	Technology may be owned by others or otherwise unavailable
Adaptation of technology to suit local conditions	?	
Infrastructure requirements	Y	Capacity in existing infrastructure may not be available
Scale of operations	Y	Smaller scale projects face higher relative costs of engaging in CDM
Financial		
High cost of the technology to be implemented.	Y	Import costs on technology for smaller projects may increase the overall project cost
Foreign Ownership Restrictions	Y	Small shares or high taxation of project operator can inhibit projects
Finance availability	Y	Financing may be unavailable for smaller projects
Transaction Cost	?	More significant for smaller projects
Institutional		
Capacity of Designated National Authority (DNA, or national government) / workload on DNA	?	Could potentially be an issue
Large time gap for registration	Y	Interferes with project timeline
Frequent change in methodology by UNFCCC	Y	May increase time required to complete proposal and validation
Long term policy of the local government	?	
Market		
Resource pricing	Y	Low gas prices make projects more difficult financially
Technology replication potential	?	Probably not an issue
Other		
Lack of trained manpower to manage the operations of technology. ;	?	Maybe an issue in certain countries
Limited number of DOE and verification agencies	?	Could be an issue
Lack of in country trained technical/scientific manpower 'for CDM project identification.	?	Maybe an issue in certain countries
Lack of awareness among stakeholders.		Probably not an issue
R and D capacities.		Probably not an issue
Reliability of technology not proven in local conditions	Y	

Framework from UNEP, 2009 and annotated by Energy Redefined

Several of these issues are discussed earlier in this section. Other issues are listed below.

3.4.8.a. Resource pricing

Controlled pricing, or a low price paid to resource owners so that prices can be kept low for consumers, is a barrier to resource development in the oil and gas industry in general. While controlled prices work to the short-term advantage of consumers, if the revenue producers are able to generate from additional production is reduced they are less likely to engage in new projects. This applies to investments in both entirely new sources of gas and to investments in collecting existing wasted gas (flared gas).

3.4.8.b. Frequent changes to CDM methodologies

CDM methodologies are periodically updated. When these changes are either frequent (compared to the timescale for project registration) or involve drawn out discussions, this uncertainty can be a barrier to engagement. For example, AM0009 has undergone several revisions and is currently at version 07.0.0.

3.4.8.c. Technology/First of a kind

The CDM methodology allows projects that are 'first of a kind' to be considered additional, even when other additionality constraints (such as the IRR) do not meet additionality requirements. This would include, for example, projects based on entirely new technologies. There can be significant barriers and inertia against utilizing new technology, especially in larger companies. In the experience of Energy Redefined, oil companies can be reluctant to use new technologies because their internal departments may see themselves in competition with new technology providers and because they are generally risk adverse. In particular, there is a risk of delays with a new technology, which can result in significant project losses of around 20%²⁵ or even project abandonment.

3.4.8.d. Scale of Operations

Capturing relatively small volumes of flared gas is generally difficult to justify economically, as the revenue from gas sales is likely to be overwhelmed by one-off costs (e.g. project registration and infrastructure development). One solution is to cluster small projects to achieve economies of scale. However, this may require coordinating with different operators and developing joint projects, which is not easily accommodated within the current CDM methodology.

3.4.8.e. Taxes

High or discriminatory taxes can be a barrier to investments, as they reduce the effective rate of return. A complex tax system can also be a barrier to investment. Import duties on equipment for a project can also affect the economics of CDM projects and can be a significant cost.

²⁵ Based on a two year delay with a 10% discount rate per year: $1 - (1/(1.1^2)) = 0.17$ or 17%

3.4.8.f. Availability of expertise

Local expertise is necessary to assist with validating and approving projects. This expertise may not always be available, leading to potential delays and/or incorrect assessment of projects.

3.4.8.g. Measurement

The current CDM methodologies for flaring reduction from oil and gas projects are not explicit about what types of measurements are required to monitor emissions reductions, leading to problems in the verification process (Sucre et al., 2011). This may lead to a lack of understanding about what it is important to measure and what it is not, and in particular about the difference between measurement accuracies (for one meter) and system accuracies (the overall error across all measurements in a system). System error is always lower than the sum of measurement error for each meter. The current CDM process focuses on measurement accuracy and not system accuracy, which presents a worst-case view of a project's overall monitoring accuracy and thus makes validation more difficult.

3.5. Calculation of the cost and size of the reduction potential

The previous section detailed barriers (cost and non-cost) to engagement with the CDM process. This section builds on work undertaken for the Commission by ICF (2013) to estimate the cost and size of potential to deliver emissions reductions from venting and flaring reduction projects through the CDM process. The size of the potential opportunity is presented both with and without consideration of these barriers. Failing to recognize that there are restrictions beyond simple financial attractiveness that limit project uptake under CDM would result in a substantial overestimation of the level of project uptake that might be realistic.

3.5.1. The ICF analysis

This analysis is based on the data underlying the ICF flaring report. The analysis involved constructing Marginal Abatement Cost curves (MAC curves) from relevant data on CDM projects.²⁶ MAC curves show the estimated amount of emissions reductions that could be achieved at a particular cost (equivalently, the emissions reductions that would be financially viable for a given predictable carbon price²⁷).

²⁶ <http://cdm.unfccc.int/>

²⁷ As noted above, if the carbon price is variable (as it is in real life), then investment decisions may be based on a discounted expectation of revenue from emission reduction credit sales. One would therefore expect that fewer projects would actually be implemented for an expected carbon price of \$50 per tonne CO₂e, than would be identified as costing less than \$50/tCO₂e on the MAC curve.

The ICF flaring report examined historical CDM projects from regions that supply oil to the EU, including Africa, the Middle East, and the Former Soviet Union. This analysis included projects that have been implemented, as well as some that are still under review and consideration. The project list was limited to those with available data on cost of implementation, projected greenhouse gas emissions reductions, location, and crude oil production rates and were sourced from the UNFCCC CDM website²⁸ and from ICF's internal records. The majority of these projects recovered gas for sale to a pipeline, although a few included construction of a LNG plant or power plant, or used the recovered associated gas in enhanced oil recovery.

A subset of these projects from four specific regions was used to produce the MAC curves in the report: Libya, Nigeria, Iran/Yemen, and Russia/Azerbaijan. Project implementation costs included capital expenditures and operation/maintenance, and revenue included gas sales and avoided fines, but not CER credit value. ICF also calculated the net cost of reduction in \$/tCO₂e for each project. ICF assumed a 10% IRR and a 33% tax rate for all projects (these assumptions are discussed further below). From this, the total amount of reductions (in MtCO₂e) achieved from these historical projects at a net cost below zero²⁹ can be identified, as well as the amount of reductions that would have had below-zero net costs for any given credit value price.

ICF then projected the amount of greenhouse gases that could be avoided through flaring reduction in future years (2020 and 2030) in these four sub regions by comparing a projection of flaring reduction projects that will be implemented with a baseline of flaring emissions. For the baseline, ICF used EPA's 2011 "Draft Global Anthropogenic Non-CO₂ Greenhouse Gas Emissions: 1990-2030" report in combination with some data from the Global Gas Flaring Reduction (GGFR) initiative. To estimate project emissions reductions from future flaring reduction projects, ICF assumed that the future adoption rate of these type of projects would be the same as the historical adoption rate determined through the analysis of CDM projects. The results were that in 2020, 9 MtCO₂e could be abated at zero net cost. At current prices for EU ETS allowances (CDM CERs can be traded into this system), 11 MtCO₂e could be avoided, with the majority of these emissions reductions coming from Nigeria and Russia/Azerbaijan. About 39 MtCO₂e could be abated given unlimited willingness to pay. The results of this analysis for 2010, 2020, and 2030 are shown in Figure 3.5. ICF also presented a sensitivity analysis showing how the results change with varying tax rates and costs. Based on these findings, ICF created a MAC tool, allowing a user to test the impact of varying tax rates and other parameters.

ICF also examined the costs of building new infrastructure to transport recovered gas. As discussed elsewhere in this report, lack of

²⁸ <http://cdm.unfccc.int/>

²⁹ The ICF financial analysis does not precisely match the analysis undertaken in the PDD for each project. Therefore, while a net-cost below zero would normally be an indicator that a project was non-additional, it is possible for some projects analyzed to have been judged additional but still come out at below-zero net cost in ICF's assessment.

infrastructure is a significant barrier to many potential flaring reduction projects. For this task, ICF examined the geographical distribution of oil fields in three areas: offshore Nigeria, onshore Libya, and onshore Russia and calculated how much it would cost to build infrastructure to transport gas from the oil fields to an assumed market center. For this ICF used a proprietary discounted cash flow model to evaluate the economics of gas collection and transport. ICF also considered the impact that removal of CO₂ and H₂S would have on breakeven cost. ICF found that the costs of constructing pipelines to the assumed market center are a large percentage of total costs for such projects.

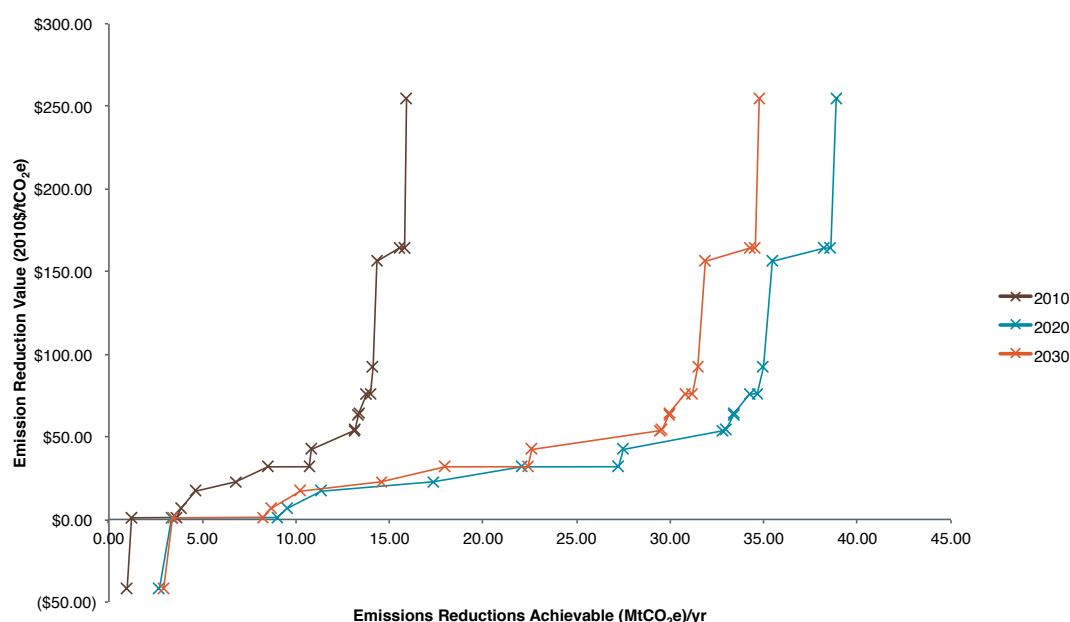


Figure 3.5. MAC curves including all projects for 2010, 2020, and 2030, from the ICF flaring report

3.5.1.b. Observations on ICF flaring report

This report found that approximately 39 MtCO₂e total emissions have been avoided through CDM projects through collection of gas that would otherwise have been vented or flared. This is relatively small compared to the 140 $\text{bm}^3 \text{yr}^{-1}$ (about 400 MtCO₂e yr^{-1}) currently flared (GGFR). ICF report these emission savings to be approximately 2-8% of all oil and gas emissions, which includes venting and flaring and other emission sources.

ICF's adoption rate of 30-40% of all potential projects in Nigeria is consistent with prior work (Cervigni, Dvorak, & Rogers, 2013). However, ICF's adoption rate of 8% for Russian gas is low compared to some estimates; Energy Redefined has previously estimated that at current domestic gas prices 60% of gas could be recovered cost effectively, and this rises to 80% if producers were paid export prices (PFC Energy, 2007).

The ICF analysis is historical and, by definition, considers only CDM projects that have been implemented or entered the pipeline. All these

projects can be considered 'large scale' (with estimated emissions savings of at least 25,000 tCO₂e yr⁻¹). One drawback to this approach is that potential small-scale projects, which may have different marginal abatement costs, are not included, although as discussed above specific small-scale methodologies may be required to make such projects more appealing.

Finally, recovered gas is not 100% methane, and may contain other substances with economic value, such as natural gas liquids (NGL). ICF do not include revenue from NGL in their cost calculations, which may be substantial in countries like Nigeria and Russia. This could potentially reduce the marginal abatement costs considerably. However, it is possible that some projects had initiated NGL recovery prior to commencement of gas recovery, in which case this revenue would not be attributable to the flaring reduction project.

3.5.2. Potential under the ETS-CDM option

Under Phase III of the ETS (2013 – 2020), in order for credits from newly registered CDM projects to be eligible, they must have been earned in the Least Developed Countries (LDCs³⁰). Under the ETS-CDM option (Option 1; credits recorded in the Union Registry used for EU ETS), only projects in LDCs would therefore be eligible for FQD as well. Given that Yemen is the only one of the six countries considered by ICF that is an LDC, and that ICF studies only one project in Yemen, this is a major limitation on the potential to deliver emissions reductions under Option 1. CERs and ERUs from projects commencing outside the LDCs in 2012 or earlier may be eligible to be carried over for compliance in Phase III (for more on carry-over, see Section 5.2.2). While establishing more precisely the potential for emissions reductions in the LDCs would require additional data, it is clear that the potential under Option 1 is only a small fraction of the potential if countries like Nigeria, Russia and Libya are allowed to participate.

3.5.3. Potential under the standalone CDM option

Under the standalone CDM option (Option 2; credits recorded in a stand-alone registry independent of EU ETS), all of the regions included in the ICF analysis would be eligible to host CDM/JI projects for FQD compliance. In order to estimate the potential for emissions reductions from venting and flaring under Option 2, the ICF analysis is used.

3.5.4. Reanalysis of ICF's MAC curves with consideration of barriers related to the additionality requirement

The ICF analysis was developed to reflect the estimated implied cost of the barriers to engagement in CDM discussed above. Energy Redefined

³⁰ <http://unctad.org/en/pages/aldc/Least%20Developed%20Countries/UN-list-of-Least-Developed-Countries.aspx>

has further developed this analysis to reflect several scenarios for the way that CDM registration could be implemented. ICF's MAC curves have been remodeled, with and without accounting for barriers to project registration, in the following scenarios:

- Total removal of additionality requirement, improving adoption rates by 100%³¹;
- Raising the IRR threshold from 10% to 30% for additionality criteria, which would allow more projects to qualify as additional;
- Relaxation on Type I/Type II error certainty for additionality;
- Removal of additionality criteria but with no increased adoption rate (i.e. no IRR threshold);
- Cost reduction of \$700,000 with removal of additionality criteria³²;
- Cost reduction of \$1,200,000 with removal of additionality criteria;
- Inclusion of small projects.

Some of these barriers interact and are in effect cross-correlated. In some cases, the modeling by Energy Redefined for this report models change to multiple barriers through varying a single cost parameter. For example, removing additionality criteria and including small projects are both modeled by increasing the adoption rate. The interaction of these elements, as well as those modeled in the next section on non-additionality barriers, is shown in Figure 3.6.

³¹ Energy Redefined indicative estimate of increase in adoption rates with removal of additionality criteria.

³² The administrative cost of demonstrating additionality was shown to be \$700,000-1,200,000 in Section 3.4 on barriers to engagement in CDM above.

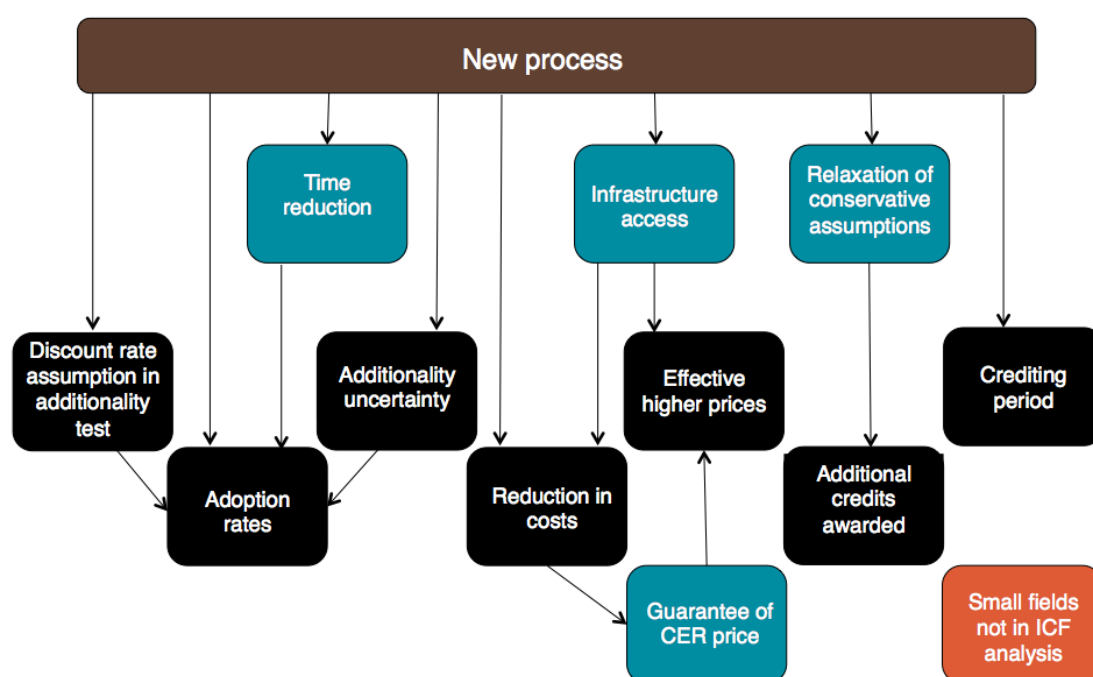


Figure 3.6. Schematic showing interactions between elements that affect marginal abatement costs

The boxes in black represent the variables in the model that have been changed here in order to evaluate the effects of removing these barriers. Some of these factors could be directly affected by changes in process or legislation, whilst others could be changed indirectly (e.g. using a higher discount rate would affect those projects deemed to be additional). The boxes in blue represent policies that would have an effect on abatement potential (e.g. guaranteeing a “high” and constant carbon price would have the same effect as a high gas price).

Having made these adjustments, Energy Redefined then created new MAC curves accounting for the various changes in variables in these scenarios, and compared them with the CDM base case in the ICF flaring report.

It is important to note that projects with a marginal abatement cost less than zero at a 10% discount rate would be considered non additional based only on a financial criterion alone (<10% IRR). However, some of these may still be additional due to substantial non-cost barriers or if the project is ‘first of a kind.’ These below-zero cost projects are shown in the purple box in Figure 3.7. A less conservative approach to additionality would capture many of the projects that should be delivered for around \$0 tCO₂e⁻¹ or just over – this could be of the order of 7-8 million tCO₂e yr⁻¹ in the 2020 timeframe.

As noted above, it is also important to note that the ICF financial analysis is not identical to the financial analysis submitted to the CDM EB for each project – for instance the ICF analysis was performed assuming a uniform tax rate of 33%. In practice the tax rate in many of these countries may be higher, in part due to complicated tax regimes

that mask the true tax rate. Because of this, in some cases actual abatement costs may be higher than stated by ICF. Note that the same tax rate of 33% is assumed in the analysis by Energy Redefined shown below.

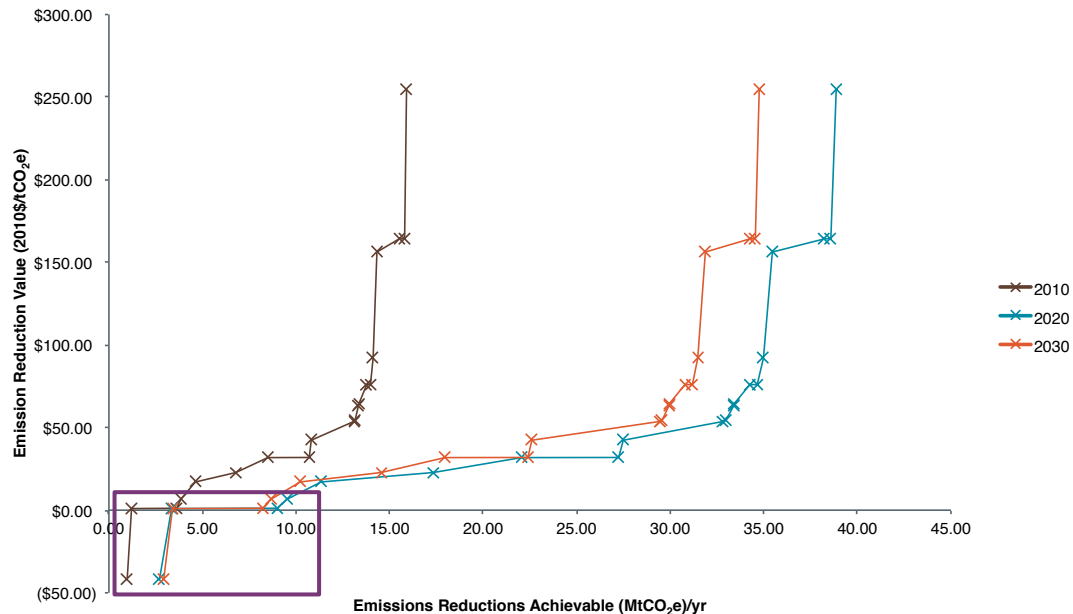


Figure 3.7. Marginal abatement cost curves, with purple box highlighting those projects that would not be considered additional at a 10% discount rate

Table 3.7 shows the results that removing some barriers related to additionality have on the amount of emissions reductions that could be achieved cost effectively, compared to ICF's projections. The barriers that had the largest effect when removed were the additionality test (with and without a corresponding doubling of adoption rates) and the inclusion of small projects. Relaxation of certainty in the additionality determination and increasing the IRR threshold to 30% also had substantial effects on the size of the potential for emissions reductions from CDM venting and flaring projects. Reducing administrative costs associated with demonstrating additionality alone did not have a significant effect. Note that these calculated changes in the size of the potential are not additive, and that this analysis reflects only large projects – reducing administrative costs would have an even greater effect on small projects.

Table 3.7. Additional emissions reductions (in million tonnes CO₂e yr⁻¹ and in million dollars in gas value) that could be achieved cost effectively without credit value with the removal of various barriers related to additionality, shown for different years

	ADDITIONAL EMISSIONS SAVED OVER BASE CASE (MILLION TCO ₂ E YR ⁻¹)			TOTAL VALUE OF GAS RECOVERED AT \$2 PER MBTU (MILLION DOLLARS)		
	2010	2020	2030	2010	2020	2030
Doubling adoption rates	0	10.05	9.12	0	236.5	214.6
Allow 30% IRR	2.87	6.29	5.29	67.5	148.0	124.5
Relaxation on Type I/Type II errors for additionality	2.41	5.64	4.65	56.7	132.7	109.4
No additionality test, but no increased adoption	3.62	8.99	8.22	85.2	211.6	193.4
Cost reduction of \$0.7 million	0	0	0	0	0	0
Cost reduction of \$1.2 million	0	0	0	0	0	0
Inclusion of small fields	0.77	7.70	10.00	18.1	181.2	235.3

Figure 3.8 and Figure 3.9 show the effect that increasing the IRR threshold, or the discount rate, has on the size of the potential to cost effectively reduce venting and flaring emissions through CDM. For this large project based database it appears that a discount rate above 17% should be chosen if a primary objective was to maximize collection potential. Including smaller projects could increase this 'optimal' discount rate.

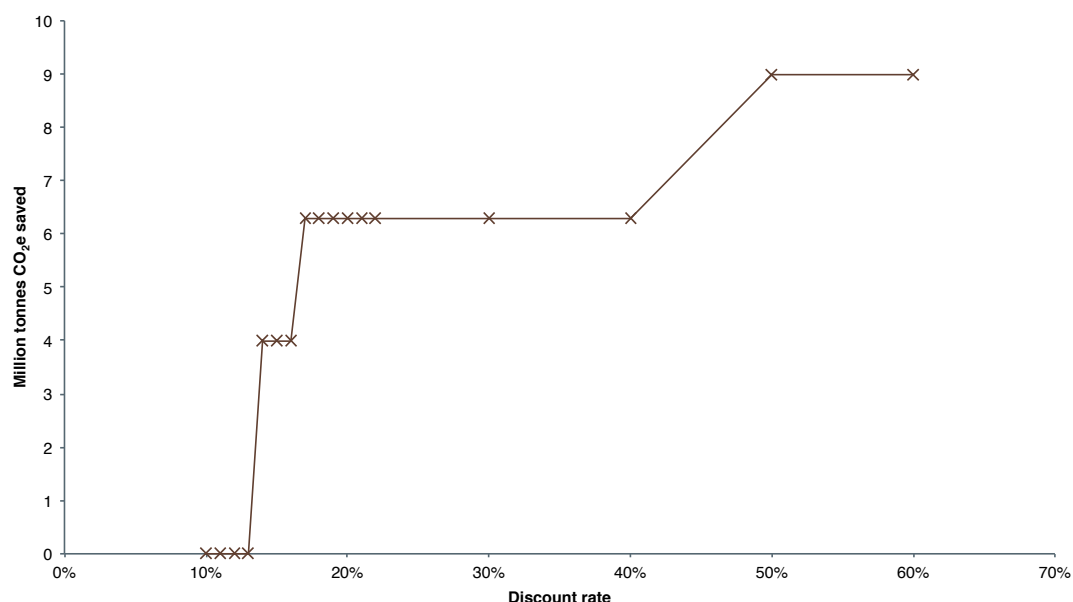


Figure 3.8. Size of the potential to reduce venting and flaring emissions through CDM projects (in MtCO₂e yr⁻¹ reduced through 2020) at varying discount rates, or IRR

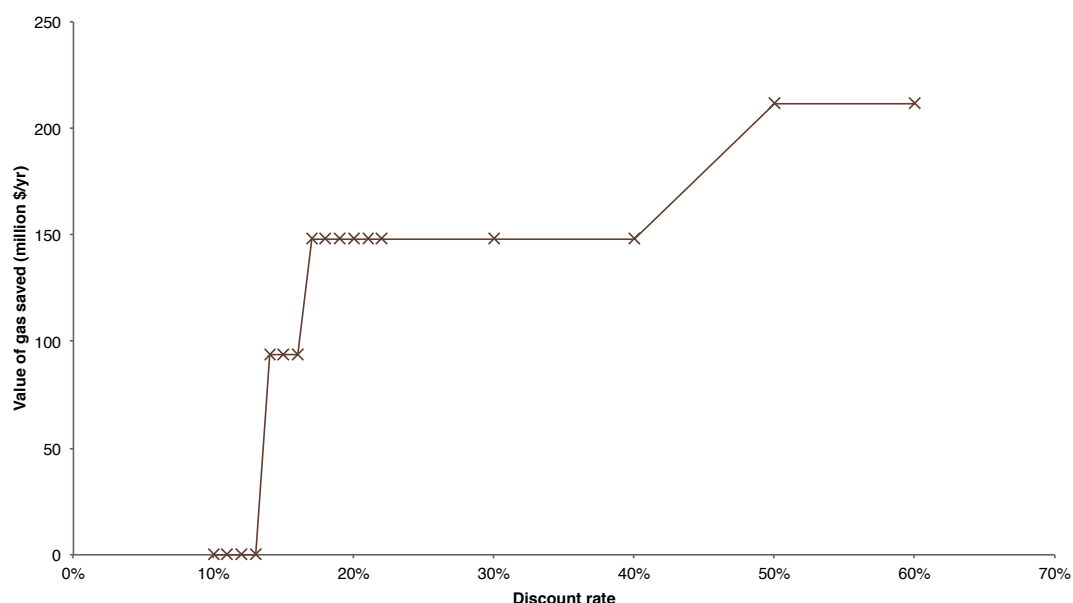


Figure 3.9. Size of the potential to reduce venting and flaring emissions through CDM projects (in millions of dollars worth of gas saved through 2020) at varying discount rates, or IRR

3.5.5. Reanalysis of ICF MAC curves with consideration of other barriers

Having reassessed the potentials given variations in implementation of additionality criteria, the effect of removing other barriers on the cost and size of potential from CDM venting and flaring projects is modeled. The following scenarios are considered here:

- Higher gas price. This would include resolving situations where infrastructure owners demand to buy gas at a lower-than-market price.
- Reducing capital costs by 30%³³ through clustering and access to technology.
- Removing \$1.2m of PDD development costs to reflect savings under no additionality criteria (this was effectively already accounted for above in the additionality section but is provided here as a comparison). Note this may overestimate the savings of removing the additionality criteria as some sort of PDD would still have to be produced.
- Allowing the use of 98% flaring efficiency in the baseline calculation (Edwards, Larive, Rickeard, & Weindorf, 2013)³⁴, which would increase calculated emissions reductions and thus credit support.

³³ Determined by prior analysis by Energy Redefined.

³⁴ Note that in reality some flare efficiencies maybe lower than this.

- Accounting for recovery of NGL, based on a case where the gas is 40% NGL by volume (following PFC, 2010). This would increase the emissions factor of flaring. This factor has a similar effect as reducing the assumption for flare efficiency.

The results of these scenarios are shown in Table 3.8. The scenarios that would have the greatest impact on the size of the emissions reduction potential are doubling the adoption rate and allowing higher access to infrastructure. Note that the additional potential reductions in these scenarios are not additive. For factors that improve the economics of projects (e.g. higher gas price, or reducing costs with project clustering and technology access), the increase in the emissions reduction potential over the baseline decreases with increasing credit price (i.e. a high credit price compensates for high project expenses). This is because as revenues per tonne of CO₂e reduction increase, projects are less reliant on the minimizing upfront costs to make them viable.

Table 3.8. Additional emissions reductions (in million tonnes CO₂e yr⁻¹ and in million dollars in gas value) that could be achieved cost effectively with the removal of other barriers, shown in 2020 at varying carbon prices

EXTRA M TONNES CO ₂ e	SAVED OVER BASE CASE			GAS VALUE \$ MILLIONS APPROX @\$2/MBTU		
Carbon price:	\$20/ tCO2e	\$50/ tCO2e	\$200/ tCO2e	\$20/ tCO2e	\$50/ tCO2e	\$200/ tCO2e
Higher gas prices (\$4/Mbtu)	17.46	2.48	0.29	822.0	116.8	13.5
Capital costs reduced 30%, clustering and access to Technology	4.71	1.67	0.29	110.9	39.3	6.9
PDD costs reduced by \$1.2m	0.00	0.00	0.00	0.0	0.0	0.0
Assumption of 98% flare efficiency	1.51	2.71	3.67	35.5	63.7	86.3
Accounting for higher emissions factor for NGL (40% by volume)	1.51	2.71	4.31	35.5	63.7	101.5

The results of achievable emissions savings at \$20/tCO₂e from Table 3.7 and Table 3.8 are also shown in Figure 3.10. For comparison, the dashed lines represent first the additional emissions savings required to meet the FQD once the biofuel used to meet the Renewable Energy Directive has been taken into account (as calculated in ICF FQD impact analysis), and then 2% and 6% carbon intensity reduction targets in FQD. From this figure it is apparent that the potential for emissions reductions through venting and flaring reduction is large. The 2% target for additional emissions reductions via CDM should in principle be almost achievable. Alternatively, flaring and venting reductions could

make a substantial contribution towards the FQD's 6% carbon intensity reduction target.

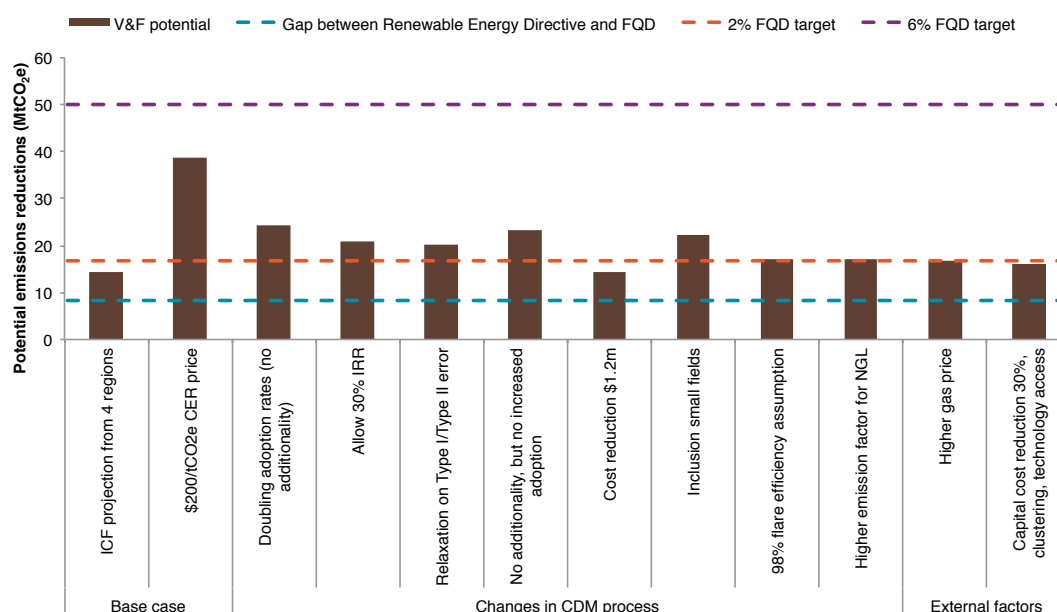


Figure 3.10. Potential emissions reductions from venting and flaring under the standalone CDM option

Source: Energy Redefined calculations based on ICF flaring report

3.5.6. FQD credit support in the year 2020 only

The analysis above assumes that credit value is persistently available over the lifetime of an emission reduction project, i.e. it assumes that the FQD would be extended and credit value would be moderately stable beyond 2020. The FQD is, at the European level, currently only binding in the year 2020. While Member States have the option to introduce interim targets, which would effectively make the FQD binding on economic operators in earlier years in those States, there is a possibility that compliance will only be required in the year 2020, and hence that the FQD would only deliver value to upstream emissions reduction projects in the year 2020. This would effectively reduce the value of credit support over the project lifetime, as the type of project considered here is usually in operation for several years. The reduced credit support available from a one year credit value opportunity would substantially reduce the amount of emissions reductions that could be achieved at any given credit price. The results of this one-year scenario are shown in the MAC curve in Figure 3.11. For a carbon price of \$200, the effect of reducing the crediting period to a single year would be to reduce the opportunity by about 27 MtCO₂e yr⁻¹ to about 12 MtCO₂e yr⁻¹. At \$2/MBTU this would equate to \$682 million in lost gas revenue per year. A single year of value support would also make the potential savings very sensitive to a lower carbon price – at \$50/tCO₂e a one-year credit window would not support any projects. This also ignores the potentially higher uncertainty associated with a one-year policy

window. It is likely that a one-year window would create a high perception of uncertainty among investors, and thus even for a high expected carbon price, it is unclear that any significant investment would occur.

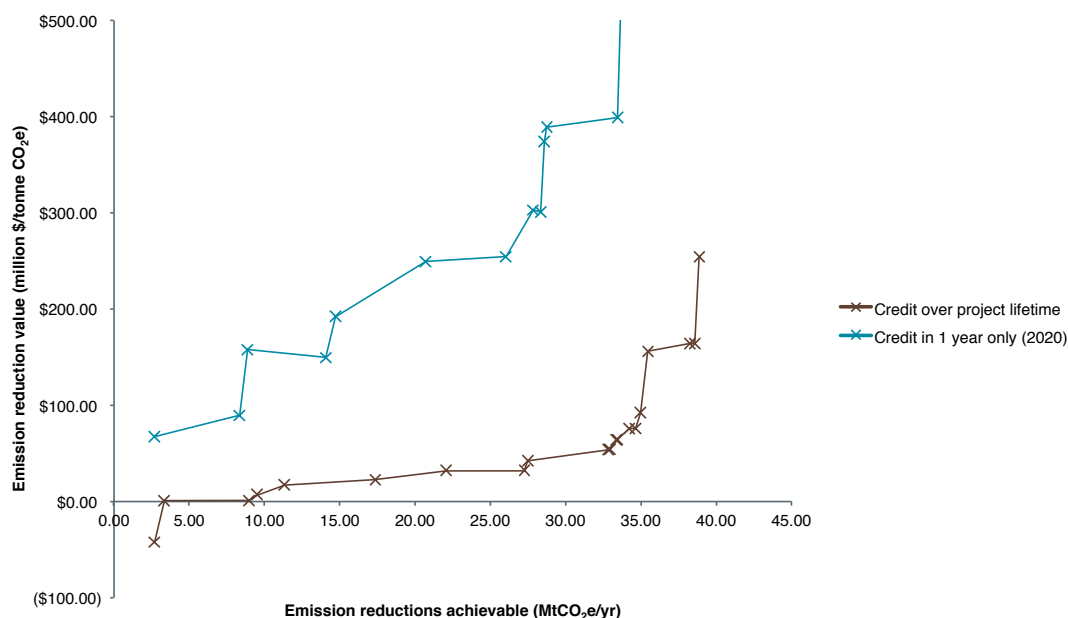


Figure 3.11. MAC curve in scenario where FQD credits are required in the year 2020 only, compared to the base case

It is unsurprising that an FQD under which credits only have value for a single year greatly decreases the amount of emissions reductions achievable for any given marginal abatement cost. Figure 3.12 shows the sensitivity of the potential for emissions reductions while varying the number of years for which credit value would be achievable. This response is also shown at varying marginal abatement cost. Note that gas volumes captured (and hence emissions avoided) in each year are assumed to be the same. The figure shown is for 2020, the year of the FQD target. Note that at \$200/tCO₂e, the full volume potential in the ICF analysis can be saved after about 6 years.

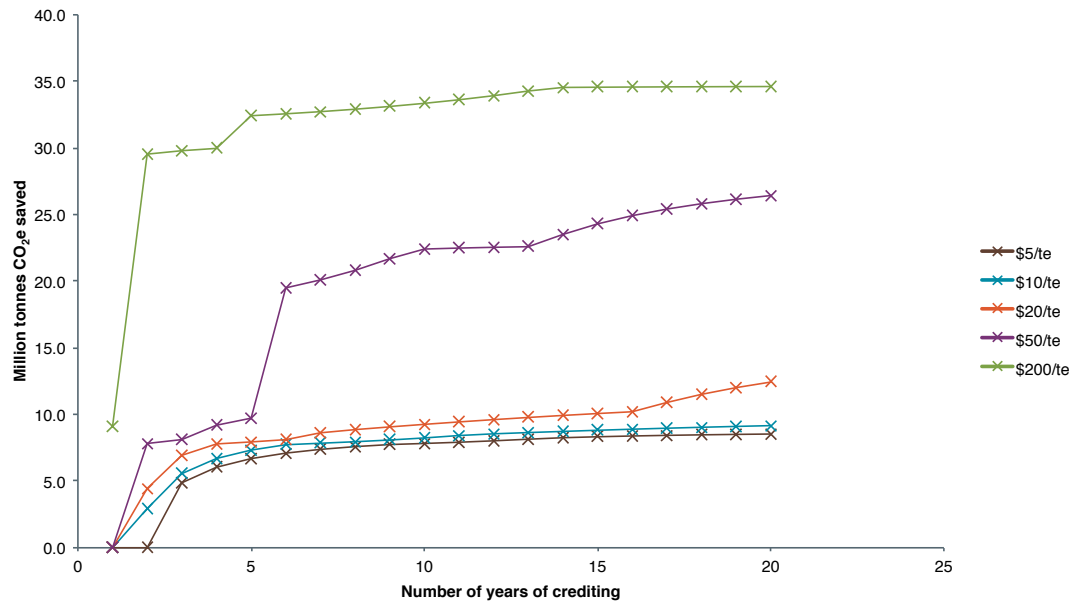


Figure 3.12. Emissions reductions at varying numbers of years for which credit support is active, at varying marginal abatement cost

Figure 3.13 and Figure 3.14 show the same analysis, but excluding projects that are likely not to be considered additional (i.e. that are cost effective at $\$0 \text{ tCO}_2\text{e}^{-1}$ given a 10% discount rate). As would be expected, the potential emissions reductions at any given number of years for active credit value is lower than in the previous figures. This suggests that under current CDM additionality rules, a single year window for credits to be eligible for compliance could struggle to incentivize emissions reductions for any expected carbon price below $\$100/\text{tCO}_2\text{e}$.

Reduction of upstream greenhouse gas emissions from flaring and venting

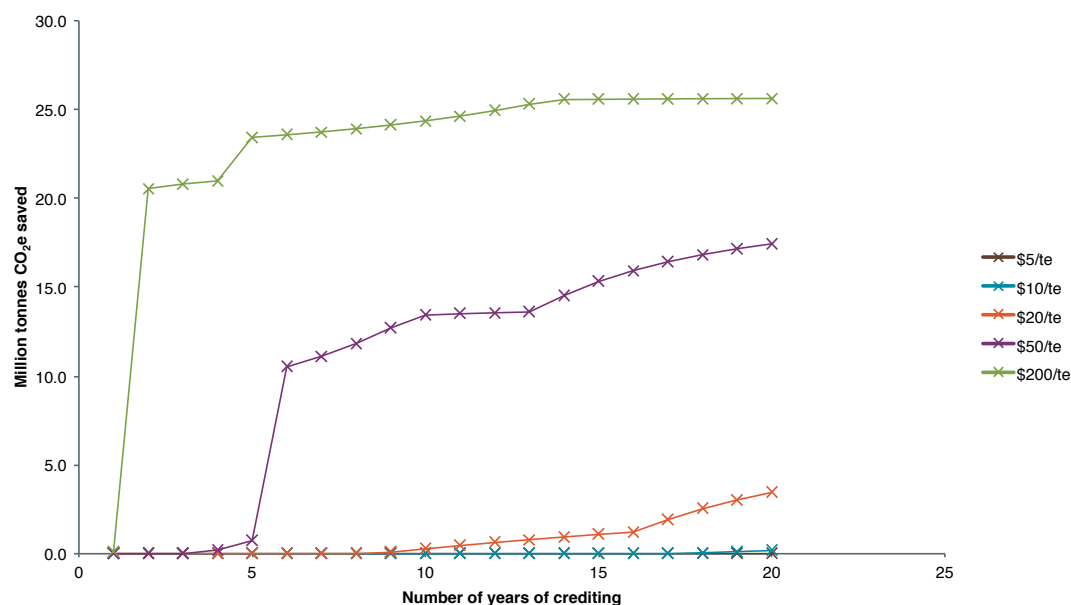


Figure 3.13. Emissions reductions at varying numbers of years for which credit support is active, at varying marginal abatement cost, excluding non-additional projects

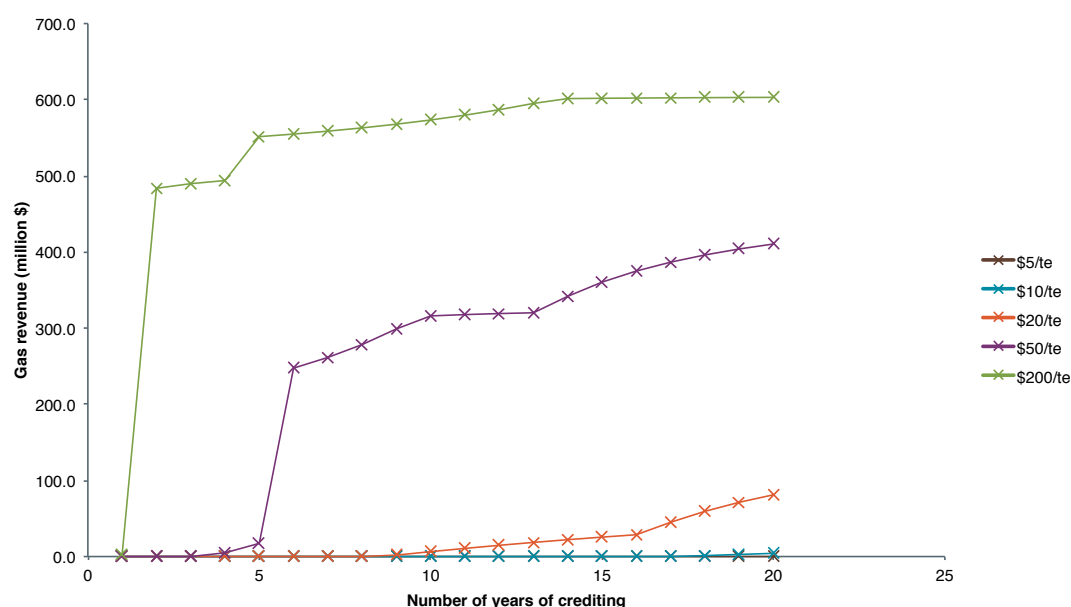


Figure 3.14. Value of recovered gas at varying numbers of years for which credit support is active, at varying marginal abatement cost, excluding non-additional projects

3.5.7. Cost and size of potential under the prescriptive option

The prescriptive option (Option 3a) is similar to the CDM options (Options 1 and 2) in many ways, but introduces a more streamlined process with less burdensome additionality requirements (see Section

4.2.2). As such, the opportunity for carbon savings under Option 3a should be somewhat greater compared to Option 2.

In the previous section, the estimation of potential carbon savings under Option 2 follows the results of the ICF analysis, which was conducted based on real CDM projects. Energy Redefined further developed this analysis to estimate the additional emissions savings that could be achieved with different implementation options; the calculations of achievable emissions savings under Option 3a was performed using the same methodology. The number of new projects and the corresponding magnitude of associated emissions reductions was estimated at varying carbon prices for a more streamlined Option 3a, compared to CDM.

Table 3.9 and Table 3.10 present the additional emissions savings that could be achieved with Option 3a, compared to Option 2, assuming full project lifetime and 1 year crediting periods, respectively. In particular, additional emissions savings with Option 3a are a result of streamlined additionality requirements (relaxation of some assumptions in financial calculation; no common practice analysis requirement; the availability of a financial additionality calculator and legal status database, etc.) and certain rules that encourage the participation of small projects (relaxed measurement and reporting requirements). The values shown here could underestimate the real differential in achievable emissions savings that could be achieved through increased participation in Option 3a. This is because the benefits of some of the measures proposed here (e.g. one comprehensive methodology, no calculations for end-use facilities or leakage, etc.) are difficult to evaluate within this analytical framework, but we believe they could be important in encouraging project applications. .

Table 3.9. Additional emissions savings that could be achieved with the prescriptive option (Option 3a), compared to the standalone CDM option (Option 2), with a 15-20 year crediting period. Savings are presented both in million tonnes CO₂ and in savings in gas value in million dollars

	ADDITIONAL SAVINGS OVER OPTION 2 (MILLION TONNES CO ₂)			ADDITIONAL SAVINGS OVER OPTION 2 (MILLION \$ GAS VALUE AT \$2/MBTU)		
	\$20/tCO ₂ e	\$50/tCO ₂ e	\$200/tCO ₂ e	\$20/tCO ₂ e	\$50/tCO ₂ e	\$200/tCO ₂ e
Credit price						
Additionality simplification	4.50	4.50	4.50	106.0	106.0	106.0
Increase in small field participation	4.66	1.08	1.07	109.8	25.4	25.2
Total	9.15	9.67	8.66	215.5	227.7	203.9

Table 3.10. Additional emissions savings that could be achieved with the prescriptive option (Option 3a), compared to the standalone CDM option (Option 2), with a 1 year crediting period. Savings are presented both in million tonnes CO₂ and in savings in gas value in million dollars

	ADDITIONAL SAVINGS OVER OPTION 2 (MILLION TONNES CO ₂)			ADDITIONAL SAVINGS OVER OPTION 2 (MILLION \$ GAS VALUE AT \$2/MBTU)		
	\$20/tCO ₂ e	\$50/tCO ₂ e	\$200/tCO ₂ e	\$20/tCO ₂ e	\$50/tCO ₂ e	\$200/tCO ₂ e
Credit price	\$20/tCO ₂ e	\$50/tCO ₂ e	\$200/tCO ₂ e	\$20/tCO ₂ e	\$50/tCO ₂ e	\$200/tCO ₂ e
Additional simplification	0	0	0	0	0	0
Increase in small field participation	2.30	2.58	0	54.1	60.7	0
Total	2.30	2.58	0	54.1	60.7	0

The total estimated emissions savings that could be achieved with Option 3a are shown in Table 3.11. This represents the achievable emissions savings calculated by ICF plus the additional emissions savings that could be achieved as a result of more streamlined requirements under Option 3a.

Table 3.11. Total emissions savings that could be achieved with the prescriptive option for both 15-20 and 1 year crediting periods. Savings are presented both in million tonnes CO₂ and in savings in gas value in million dollars

	TOTAL SAVINGS (MILLION TONNES CO ₂)			TOTAL SAVINGS (MILLION \$ GAS VALUE AT \$2/MBTU)		
	\$20/tCO ₂ e	\$50/tCO ₂ e	\$200/tCO ₂ e	\$20/tCO ₂ e	\$50/tCO ₂ e	\$200/tCO ₂ e
Credit price	\$20/tCO ₂ e	\$50/tCO ₂ e	\$200/tCO ₂ e	\$20/tCO ₂ e	\$50/tCO ₂ e	\$200/tCO ₂ e
15-20 year crediting period	23.57	37.44	42.94	555.0	881.7	1010.3
1 year crediting period	2.30	2.58	15.55	54.1	60.7	366.2

3.5.8. Cost and size of potential under the implementing measure requirements

As the option reflecting the implementing measure requirements (Option 3b) is not detailed in the same way as the prescriptive option (Option 3a) and depends greatly on Member State implementation of the proposed FQD implementing measure, we do not have the basis for a firm calculation of the potential emission reduction under this option.

Assuming the process of registering schemes and projects under Member State implementations is not more burdensome than CDM, the potential emission reduction under Option 3b should be greater than Option 3a as more project types would be eligible.

3.5.9. Risk of fraudulent crediting under the prescriptive option and the implementing measure requirements

In any emissions offset system, there is always some risk of credits being fraudulently claimed and awarded. However, with proper implementation and enforcement of the safeguards outlined in the prescriptive option (Option 3a) proposal, the emissions savings achievable under Option 3a should be much larger than the potential for fraudulent crediting. Anecdotal evidence suggests that fraudulent crediting under CDM could potentially represent a significant fraction of all credits awarded (Drew & Derw, 2010; McDermott, 2012), although we are not aware of any robust assessment of this fraction. These examples are sometimes reported to be a result of corrupt validation/verification and enforcement, but could also represent companies taking advantage of loopholes in the CDM process. In the experience of Energy Redefined, less than 5% of CDM projects are found to be actually fraudulent (compromised auditors, etc.), but this does not include fraudulent projects that are not caught.

Option 3a may be less prone to fraudulent crediting than CDM because the more streamlined additionality criteria may leave less space for deceit. In particular, introducing a clearly defined financial calculation that more closely resembles that which the companies would perform internally and that leaves less space for subjective decisions (see Section 4.2.2 for details) may reduce the scope and incentive for fraudulent financial reporting. Based on experience with CDM, Energy Redefined estimates that of the order of one in twenty projects proposed under Option 3a could turn out to be fraudulent. In practice, the risk of fraud will be strongly correlated to the quality of oversight exerted over and by the project auditors. It will also relate to the type of penalties that can be brought in the event that a fraudulent project is uncovered. It may be difficult to apply penalties directly to upstream operators. Applying penalties to obligated suppliers in Europe registering fraudulent upstream emissions reductions may be simpler, but risks punishing operators acting in good faith. Appropriate measures to respond to fraud would depend strongly on whether UER crediting is implemented at the European or national level, and would warrant consultation with industry and other stakeholders.

All told, while there is a risk of fraudulent applications or reporting, the opportunity should be relatively limited within the Option 3a framework described here. Given an appropriate commitment to enforcement (details of which are beyond the scope of this report), the potential for real emissions savings to be delivered from UERs is very much greater than the risk of rewarding fraudulent projects.

The risk of fraudulent crediting under the implementing measure requirements (Option 3b) will depend on the strength of requirements for schemes set by Member States in conforming to the proposed FQD implementing measure. If Member States require schemes to conduct adequate due diligence and on-going monitoring and verification, as well as implement strong enforcement and penalties (for instance, suspending schemes with repeated violations), the risk of fraudulent crediting under Option 3b should be no greater than under Option 3a.

3.5.10. Potential contribution of credits from existing projects

ICF's assessment of emission reduction potential assesses the potential for new projects, and does not include the availability of credits from already-approved CDM projects. The analysis we have presented above follows this example. However, under Option 2 (the standalone CDM option) and Option 3b (the implementing measure requirements) credits from existing CDM projects may be eligible for use towards compliance. Based on documents from the CDM pipeline, we believe that existing CDM projects that could be eligible under FQD may generate up to 4 million tonnes of CO₂ reduction credits in 2020. This would be enough to contribute about a twelfth of the carbon intensity reduction required by FQD, a 0.5% contribution to reducing the carbon intensity of European transport fuel.

3.5.11. Potential contribution of venting and flaring reduction to FQD 6% reduction target

3.5.11.a. The ETS-CDM option

As discussed above, the potential for emissions reductions from venting and flaring projects is severely limited. Nearly all of the reduction potential identified in the ICF flaring report and in this re-analysis would thus not be eligible under this option. The LDC restriction in EU ETS effectively renders the ETS-CDM option (Option 1) unviable.

3.5.11.b. The standalone CDM option

Under the standalone CDM option (Option 2), the LDC restriction would not apply as credits would be recorded in a stand-alone registry independent of EU ETS. In this context, this subtask has evaluated the total amount of emissions reductions that could be achieved through venting and flaring reduction projects in four sub-regions supplying oil to the EU. The total size of this potential reduction is large and is significant. The top credit price modeled, \$200/tCO₂e, is high compared to current ETS prices, but moderate compared to estimates of the carbon abatement costs of using biofuels (the primary alternative emissions reduction strategy under FQD). In its 2013 Impact Analysis for DG CLIMA of implementing options for the FQD, ICF estimated marginal abatement costs of biofuels in the EU as being at least €200/tCO₂e (ICF, 2013b, Table 5.5). If upstream emissions

reductions compete in the market with biofuels as an FQD compliance pathway, a \$200/tCO₂e credit price is therefore very plausible.

At a credit price of \$200/tCO₂e, the potential reduction in 2020 is projected to be about 16 MtCO₂e/yr with a one-year credit window, or about 39 MtCO₂e/yr with a persistent credit window. This represents approximately **1.9%** and **4.7%** of all projected road transport emissions in the EU for the one-year and persistent credit windows,³⁵ respectively, and could deliver **31%** and **78%** of the required carbon savings in the EU fuel mix in 2020 as required by the 6% reduction target in the FQD. This is a highly significant potential, and is roughly equivalent to the emission savings that would be achieved by replacing 2.2% and 5.4% respectively of road fuel with cellulosic biofuel.³⁶ As noted in section 3.5.10, there may be an additional contribution of up to 0.5% from credits generated by existing projects.

3.5.11.c. The prescriptive option and the implementing measure requirements

The emission reduction potential under the prescriptive option (Option 3a) is somewhat higher than under the standalone CDM option (Option 2) at each credit price. At a credit price of \$200/tCO₂e, the potential reduction in 2020 is 16 MtCO₂e/yr for a one-year credit window and 43 MtCO₂e/yr for an extended credit window, representing **1.9%** and **5.4%** of all projected road transport emissions in the EU for the one-year and extended credit windows respectively. This level of reductions could deliver **31%** and **86%** of the required 6% carbon intensity reduction in the FQD.

The emission reduction potential under the implementing measure requirements (Option 3b) is not as clear but would likely be greater than that under Option 3a. As noted in section 3.5.10, there may be an additional contribution of up to 0.5% from credits generated by existing projects.

Allowing venting and flaring emissions reductions to be eligible for compliance under FQD could potentially make the 6% reduction target much more easily achievable, assuming a robust credit price. For investment to happen, it is not only necessary that the credit price should be high, but that as projects are conceived investors should be confident that it will be high several years in the future.

³⁵ Size of potential from Figure 3.11. Calculations used the following assumptions and sources. Total projected road transport emissions in 2020 assumed to be about 11.4 PJ with a 60/40 diesel/gasoline split (personal communication with Ian Hodgson at DG Clima). Emission factors of 73.25 kgCO₂/MBTU for diesel and 70.22 kgCO₂/MBTU from EPA (<http://www.epa.gov/climateleadership/documents/emission-factors.pdf>).

³⁶ Assuming emissions savings of 45% for rapeseed biodiesel, not including indirect land use change emissions, and 85% for a generic cellulosic biofuel. Values taken from Annex V of the Renewable Energy Directive.

4. Task 3: Regulatory design

Tasks 1 and 2 discussed how emissions reductions from venting and flaring reduction projects can be calculated, what the cost and non-cost barriers to these projects are, and what level of emissions savings might be achievable through implementing each option under the FQD. Task 3 provides additional detail of how these options could be implemented.

Task 3a describes three potential options for additionality requirements of varying stringency. Task 3b provides an overview of existing validation and verification requirements under CDM (which would apply under the CDM options, Options 1 and 2) and proposes similar requirements for the prescriptive option (Option 3a) and the implementing measure requirements (Option 3b). It further discusses what additional measures would need to be taken by Member States to verify the emissions reductions for the purposes of the FQD, given the Commission's proposal to implement Article 7a.

The overall success of the crediting mechanism will be greatly affected by how Member States implement this measure and how much control over the credit trading market is given to them. Task 3c examines lessons learned from the experience of Member State implementation of the EU ETS, and explores how upstream emission reduction crediting could be integrated into different FQD implementations.

A successful mechanism to credit emissions reductions must clearly identify what types of projects are eligible to be credited. Task 3d discusses the eligibility requirements under the FQD and the proposed FQD implementing measure and how this will influence the set of venting and flaring projects that may be eligible for crediting. This task then clearly specifies what types of projects are eligible under Options 1, 2, 3a and 3b.

Task 3e explores issues around baseline setting and what measures are taken within Options 3a and 3b to ensure baseline emissions are calculated accurately and conservatively.

A successful regulation minimizes administrative burden while also minimizing the risk of crediting fraudulent projects. To this aim, Task 3f, which is included as a separate Annex (Annex A), outlines measures that can be taken within Options 1, 2, 3a and 3b to minimize fraud risk and identifies remaining fraud risks that cannot be addressed within these options.

4.1. Summary of Task 3

Under the Clean Development Mechanism, emissions reductions may not be credited unless they are above and beyond what might have been expected in a business as usual case. This is called the principle of

‘additionality’. Additionality is also an important requirement if emissions offsets are to be included under the FQD, to ensure that the recorded emissions reduction represent real savings rather than simply registering the many associated gas collection projects that occur each year due to normal business considerations or regulatory action.

Three alternative levels of additionality are discussed. The first alternative (strict) mirrors the CDM approach. The second (moderate) introduces a streamlined approach designed to more closely reflect the oilfield operator’s internal decision making. The third alternative reflects the additionality requirements in ISO 14064 Part 2, which would apply under the proposed FQD implementing measure.

Under the moderate approach, a defined calculation based on gas value, capital expenditure and operational expenditure would be used to assess financial additionality. Only projects that calculate a net present value to investment ratio of 0.5 would be deemed financially additional. This approach would assume a higher discount rate than typically allowed in CDM and would allow operators to predict changing gas revenues over time – measures that more closely reflect an operator’s internal decision about project financial viability. This would replace the vague and stricter financial test in CDM. Projects may optionally demonstrate prohibitive non-cost barriers to project implementation as an alternative to the financial analysis, but it is anticipated that project auditors would only accept arguments regarding non-cost barriers in exceptional circumstances.

In addition to the financial additionality test, projects under the moderate approach would not be considered additional if they would have occurred anyway due to local laws. In general, projects could not be additional in jurisdictions where flaring is illegal or regulated – however, exceptions could be made if the law is not enforced. This is similar to the strict, CDM-based approach. To streamline the process of testing additionality and provide certainty to project applicants, it is proposed that the administrator of a prescriptive option (Option 3a) emissions reduction crediting scheme (either the European Commission or appointed body) should make available an online tool to perform the standardized financial analysis and a list of jurisdictions in which it is known that there is no enforced prohibition on flaring.

One measure that is required under the strict criteria but would not be required under the moderate approach is a common practice analysis. This analysis would exclude projects in regions where the chosen emissions reduction approach was already common practice. However, for flaring and venting reduction projects, no reason is seen to enforce this rule. Gas collection may be common practice in a region but still not financially viable for a particular project – under the moderate additionality approach, that project could still count as additional.

The moderate additionality proposal would minimize crediting of projects that would have occurred under business as usual, but should still be less burdensome than CDM. This proposal is made for Option 3a because a reduced burden of additionality demonstration should help support higher levels of project registration. As noted above, an approach with no additionality rules at all is not considered appropriate.

In the third additionality approach based on requirements in ISO 14064, eligible projects must demonstrate that the baseline case would not be prevented by the law and would be financially rational. These requirements are broadly similar to the financial analysis and legal requirements under CDM and Option 3a, but ISO 14064 does not detail how these determinations would be made. This additionality approach would be required under the proposed FQD implementing measure. Member States would need to provide further guidance in implementing this additionality approach, and could choose to specify requirements similar to CDM or Option 3a.

Another important aspect of emission reduction crediting is validation of project designs and verification of claimed emissions reductions. Under the CDM options (Options 1 and 2), in line with the CDM rules, an independent auditor (known as the designated operational entity, or DOE) accredited by the CDM Executive Board would validate whether the project meets additionality and other eligibility criteria. The DOE would review the project design document (PDD) and all supporting documentation and would conduct a site visit and interviews with relevant participants and stakeholders. This would result in a validation report submitted to the CDM Executive Board with an opinion on the project. The Executive Board would then make the final decision. If the project was approved, the DOE would regularly review monitoring data from the project to verify that the reported emissions reductions are real and accurately calculated.

Under a prescriptive approach, Option 3a would closely mirror these requirements. The Commission would appoint a body that would have approval authority and would oversee the crediting of all projects. This body would approve independent auditors who would validate project applications in much the same way as CDM. Once a project was approved, the auditor would review all monitoring data submitted monthly and would conduct on-site visits once per year (once every three years for small projects). If monitoring data indicated fugitive emissions above 2% (7% for small projects), or in the event of any other data inconsistencies, site visits would be triggered unless the project participant was able to explain and resolve the discrepancies within one month.

As an alternative to a prescriptive measure centrally administered, Option 3a could be implemented through compliant voluntary emission reduction schemes. In that case, the Commission would approve eligible schemes and those schemes would then be responsible for accrediting individual auditors and for making determinations on the approval and crediting of projects. The voluntary emissions schemes would be expected to enforce the same basic guidelines on how emissions reductions should be calculated, monitored, and verified. Under this approach, the Commission would avoid the need to set up a body to administer the Option 3a system, but would have little control over the consistent application of calculation, monitoring and verification requirements. There would also be a risk that no compliant schemes would come forward to register and verify Option 3a projects.

Under both the prescriptive and voluntary schemes approaches, it is suggested that credits should be awarded with serial numbers containing

all the information necessary to demonstrate compliance with FQD requirements, and to link an individual credit to an individual project and crediting year.

Under the implementing measure requirements (Option 3b), all validation and verification would take place within schemes approved by Member States. This could include CDM. Auditors within these schemes would perform validation and verification in accordance with the requirements in ISO 14064 Part 3, 14065 and 14066. Member States may impose specific requirements on schemes based on their interpretation of the requirements of these ISOs. Member States would need to appoint an administrator responsible for receiving reports of UERs approved by auditors and confirming they comply with the requirements of the FQD. Systems would need to be put in place to hold data on reported UERs used for compliance with FQD. If set up appropriately, these systems could be used to verify that UERs are not double counted across multiple Member States.

Any of these implementation approaches assumes that there would be central oversight of the use of UERs, either through a central body or through Commission identification of acceptable voluntary schemes. However, in practice any implementing measure to introduce upstream emissions crediting will also need to be transposed and implemented by Member States into local law. The experience of Member State implementation of the EU Emissions Trading Scheme provides a useful example for reference when considering UERs under FQD. EU ETS has recently moved from a distributed crediting system to a centralized approach with a single Union registry, and now has standardized monitoring, reporting and verification procedures among Member States. These measures help facilitate credit trading, ensure consistency in the quality of emissions reductions, and reduce fraud potential. It is suggested that the centralized system under ETS should be taken as an example for the implementation of crediting under FQD, whether through Option 2, Option 3a or Option 3b.

If an Option 3a system were introduced with Member States rather than the Commission taking responsibility for approving schemes or auditors, this would introduce the potential for differences in implementation across Europe. Similarly, under Option 3b it would be likely that there would be variation in interpretation across Member States. Member States might differ on interpretation of eligibility and additionality requirements (e.g. on the analysis of non-cost barriers) or on verification requirements. Member State implementation of RED sustainability criteria has been variable, and if upstream emissions reductions are confirmed and claimed at the Member State level there could be similar variability in quality control of credits from venting and flaring reduction.

Another important question, which applies under all options, is how Member States will integrate crediting of upstream emissions reductions into their existing FQD implementation strategies. For Member States that plan to comply with the FQD via a carbon market like a low carbon fuel standard, incorporating upstream emission reduction credits would be straightforward. For other policy types however (e.g. biofuel mandates or quotas), integration could be more complicated. There would be solutions to integrate a market for upstream emissions reductions as a way to fill any

gap between the level of emissions reductions achieved under the biofuel policy and the 6% target, but whether and how this was implemented could make a great difference to the value of the credits. If any of the Options is implemented, the Commission may consider adopting language requiring that Member States accept UER credits as showing compliance by operators with the FQD.

As well as considering the mechanics of a potential upstream emissions crediting scheme, we were asked to consider which venting and flaring reduction projects should be eligible for crediting. Firstly, it is proposed that under Options 1, 2, and 3a, only projects that reduce venting and flaring from oil drilling sites be eligible for upstream emission reduction crediting under the FQD. Gas sites would be excluded from these options as gas is not generally a transport fuel. It is further suggested that refinery reductions should be excluded as refineries are already regulated by EU ETS.

Projects under Options 1 and 2 are additionally constrained by the eligibility requirements in approved CDM methodologies. Most projects that are relevant would be covered by at least one CDM methodology. However, as each methodology covers a specific subset of projects there are some eligibility gaps. This means that a particular combination of gas source, field age and recovered gas end use may not be eligible without a new methodology being registered. In contrast, because Option 3a uses only one comprehensive methodology, there would be no gaps in coverage. Unlike some CDM methodologies, there would be no requirement under Option 3a for projects to have flared or venting prior to the project start; it is assumed that if projects satisfactorily meet additionality requirements, this measure is unnecessary. It would therefore be possible to register projects on newly developed fields.

Under Option 3b, eligible projects could potentially include other types of upstream emission reductions, including at gas extraction sites. Emission reduction methods other than reductions in venting and flaring could be considered, for example through fuel switching or through innovative measures such as carbon capture and storage. While other project types could be eligible, it is expected that venting and flaring reductions offer the greatest potential for UERs under Option 3b.

Flare efficiency improvements would not be eligible under Options 1, 2, and 3a. There is no direct restriction on the eligibility of emissions savings through improved flare efficiency under Option 3b, however ISO 14064 Part 2 states requirements for accuracy and conservativeness of all GHG emissions savings. Member States may decide to restrict the eligibility of flare efficiency improvements if they determine that emissions reductions from such projects could not be accurately and conservatively reported and credited.

The final issue of regulatory design considered under Task 3 is the setting of the emissions baseline. Underreporting of baseline emissions would result in over crediting of venting and flaring reduction projects. Several safeguards are proposed under Option 3a to ensure accurate and conservative reporting of baseline emissions. Validation and verification by

independent auditors should protect against the risk of fraudulent and erroneous reporting in general. For projects with existing gas export infrastructure, the pre-project export capacity is subtracted from measured gas export with project implementation, preventing underreporting of baseline exports. Gas use in existing gas equipment on-site is not eligible; only use in new equipment is.

Safeguards to ensure accurate baseline reporting under Option 3b are indicated in the ISO standards. Baseline settings must consider all relevant information, including reasonable legislative and economic assumptions, as well as all relevant emission sources and sinks. Specific measures to ensure accurate baseline reporting may be imposed by Member States and by voluntary schemes, and could potentially include safeguards detailed in Option 3a.

4.2. Task 3a: Additionality

Additionality requirements in carbon offsetting programs such as the Clean Development Mechanism are designed to ensure that the program is a genuine driver of new emissions reductions, rather than simply providing a windfall to emissions reductions that would have taken place anyway. In the context of the Kyoto agreement and the Clean Development Mechanism, additionality is particularly important because CDM credits are to be used within national emissions inventories as an alternative to delivering reductions in Annex 1 countries. Business as usual *domestic* emissions reductions are eligible towards Kyoto targets, but for emissions reductions elsewhere to be creditable it is important that they have been driven by specific investments.

The goal of The Fuel Quality Directive greenhouse gas intensity reduction commitment is identified as contributing to the European Commission's post-Kyoto greenhouse gas reduction targets. The recitals to the FQD include the following:

(3) The Community has committed itself under the Kyoto Protocol to greenhouse gas emission targets for the period 2008-2012. The Community has also committed itself by 2020 to a 30 % reduction in greenhouse gas emissions in the context of a global agreement and a 20 % reduction unilaterally. All sectors will need to contribute to these goals.

(4) One aspect of greenhouse gas emissions from transport has been tackled through the Community policy on CO₂ and cars. Transport fuel use makes a significant contribution to overall Community greenhouse gas emissions. Monitoring and reducing fuel life cycle greenhouse gas emissions can contribute to helping the Community meet its greenhouse gas reduction goals through the decarbonization of transport fuel.

Although the FQD does not include a discussion of additionality, the same logic should be applicable: offsets used to meet the GHG reduction target

should be additional to business as usual, just as CDM credits must be additional.

Before moving on to the discussion of different potential levels of additionality assessment, it is useful to reflect on what the implications would be of a crediting system in which there was no requirement for additionality, i.e. that projects should not need to demonstrate any change from business as usual practices. The expected advantage of eliminating additionality requirements would be that it should encourage greater participation. Administrative burden would be greatly reduced, as would the risk of a project application being rejected. A wide range of gas capture projects would be eligible for crediting that would not otherwise have been; for instance any gas capture projects undertaken in response to local legislation or cases where gas capture is highly profitable.

While this would certainly generate additional credits for use in compliance, and offer potentially significant reductions in compliance costs, the downside from a policy viewpoint could be profound. For instance, any new oil-drilling project that recovers gas would be eligible for crediting. Even gas captured at fields that are essentially gas wells with some associated liquids production might be entirely eligible for avoided flaring credits. As an example of the potential scale of credits entering the system in such a case, the entire 6% carbon reduction target of the FQD could be met by existing associated gas recovery in Russia alone.³⁷ If the market for FQD compliance were swamped by the inclusion of tens of millions of tonnes of carbon reduction credits from projects that were going to happen anyway, then the policy would deliver no real environmental benefit. As well as undermining the environmental goals of the FQD, excessive cheap credits could drive a crash in the value of other low carbon fuels under FQD. This would effectively remove the FQD as a driver of low carbon biofuel use, or the use of electricity in vehicles.³⁸ An absence of any additionality criteria whatsoever is therefore not considered an appropriate option for the policy.

In the remainder of this chapter, we consider three options for the level of additionality requirement that may be applied for UERs under FQD. First, a strict additionality requirement is outlined based on current CDM rules. Second, a reduced additionality requirement is suggested built around a simplified financial calculation. Finally, and with particular reference to Option 3b, an additionality requirement based only on the content of ISO 14064 Part 2 is considered.

³⁷ Currently around 50 million tonnes of associated gas are recovered in Russia, according to official sources (calculated from <https://www.kpmg.com/RU/en/IssuesAndInsights/ArticlesPublications/Documents/WWF-and-KPMG-survey-eng.pdf>). The amount of APG recovery necessary to meet the 6% target is about 50 million tonnes (see calculations in Section 3.5.11). A density of 30.15 g/ft³ for APG was assumed (default value in OPGEE).

³⁸ Biofuels would still receive support to ensure compliance with the Renewable Energy Directive, but without the focus on delivering emissions reductions.

4.2.1. Strict additionality requirement

The strictest alternative for additional requirements would be similar to the additionality assessment required under CDM. Project applicants would have to perform a scenario analysis, listing out all potential scenarios for the baseline and project emissions. The applicants would then have to undertake a process of elimination to arrive at the most likely pair of scenarios.

For the selected project scenario, projects would then have to demonstrate:

- Either:
 - Project is not required under local laws and regulations
 - Project is required under local laws and/or regulations, but evidence is provided that these rules are routinely unimplemented and that operators do not face action in the event of non-compliance.
- As well as at least one of:
 - Project is not financially attractive without credit support
 - Project faces non-cost barriers
- And the common practice analysis demonstrating that recovery of associated gas is not the typical practice in the region at the time of project application.
- After any project had been accepted, there would be an annual requirement to reassess the local regulatory framework. In any case where the project auditors determined that the legal framework has changed such that a project would no longer pass an additionality test, then crediting for that project should be discontinued.

All projects would be required to undertake a full balance sheet financial analysis. This would involve documenting all costs (capital, operating, and maintenance costs) and revenues associated with the project and calculating the IRR (or similar benchmark) with and without credit support. CDM requires that the IRR without credit support must be below 10% for the project to be considered additional. For the strict additionality case, we propose following this example.

The non-cost barrier analysis is used to describe reasons the project would not occur without credit support, and could be invoked if the project fails the financial analysis test (i.e. if the analysis shows that the project should be financially viable without credit support). This could include investment barriers (e.g. capital is not available in the host country), technological barriers, lack of infrastructure, etc. It would be necessary for the project applicant to explain why access to credit support allows non-cost barriers to be overcome. In general, DOEs

should be cautious of claims that non-cost barriers justify an assessment that a project is additional.

Finally, the regulatory reassessment would be used to ensure that oil producers did not take advantage of crediting under Option 3a to reduce the cost of forthcoming regulatory action. Any savings delivered by a project after regulatory enforcement has been tightened up would not be truly additional, and would therefore be excluded from crediting.

The main drawback to a stricter additionality approach is that the burden of the assessment and possibility of failing the financial test in particular are likely to exclude some projects that are only marginally additional, and could discourage applications in general. For instance, it is known that many (perhaps most) oil and gas exploration companies require IRRs higher than 10% in internal assessment of investment opportunities. Projects showing IRR of 10-15% (or even 15-20%) in the additionality assessment would register as non-additional, but may then still be unlikely to happen without credit support. This could curtail the contribution of venting and flaring reduction to meeting the FQD target. In the case of CDM, which has a similar set of criteria, there is considerable burden and cost of time required to complete all the required analyses. As detailed in Table 3.5, the cost of preparing the all the documentation for the application may be around 500,000 USD and up to 1 million USD if a new methodology is required (mostly for staff time). Much of this time is spent conducting the additionality analyses and compiling the necessary documentation and evidence.

Furthermore, it can be difficult for a project applicant to know from conducting these analyses whether their project will qualify for support. Some of these criteria (especially the non-cost barriers) are subjective. Project applicants must consider the risk of investing time and money into the process and not being credited for the project.

4.2.2. Moderate additionality requirement

This additionality requirement aims to be less burdensome than the current CDM approach. The main elements of this requirement are as follows:

- Project is not required under local laws and regulations, unless these are generally unenforced; and
- Either:
 - Project is not financially attractive without credit support
 - Project is subject to significant non-cost barriers

The financial analysis used to demonstrate additionality under this approach is similar to that used under CDM, but would allow for a higher discount rate and for accounting of declining gas production over time. As industry stakeholders responded that the CDM financial

analysis is not very burdensome (see Section 2.4.1), the reporting requirements under this approach are not likely to discourage potential project operators from applying for crediting. However, allowing participants to use a higher discount rate and to project the decline of future gas production in the financial analysis will likely allow the approval of some marginally additional projects that would fail the additionality test under CDM.

In this financial calculation, Net Present Value as a ratio to Investment (NPV/I) of 0.5 would be used as the benchmark to determine additionality. In CDM, project participants may report either the NPV (not as a ratio of investment) or the internal rate of return (IRR); venting and flaring project design documents tend to report IRR. NPV/I is likely to better reflect the calculation upon which the company would make its decisions on whether or not to pursue a project; companies are not likely to pursue projects requiring very large investment with small net profit. For Option 3a, NPV/I would be roughly calculated as:

$$\text{NPV/I} = [(\text{decline-adjusted revenue} - \text{OPX}) \times \text{annuity factor} - \text{CPX}] / \text{CPX},$$

where:

CPX = capital costs,

OPX = operating costs.

Revenue is calculated as:

$$\text{Revenue} = [\text{Volume gas sold} \times \text{gas price}] + [\text{volume NGLs sold} \times \text{NGL price}]$$

and is adjusted for any expected decline in oil production over the duration of the project. A linear decline may be assumed; this would simplify the calculation. This approach reduces expected revenues over time (reflecting a real expectation of declining gas production over time). As a result, NPV appears to be lower than it would if the decline were not considered; this will result in the approval of projects that are marginally additional that would not be approved under the CDM approach. Project applicants will be required to submit a reservoir simulation and engineering estimates to support the assumed decline in gas production over time. For existing fields, historical oil production rates and GOR ratio must be submitted. These documents will remain confidential and will not be made public by the auditors. If project applicants opt not to submit such estimates, the rate of decline assumed in their calculations will be zero.

OPX and revenue would be subject to a discount rate of 20%, which is likely more representative of discount rates used internally by the companies than the apparent 10% IRR threshold in CDM venting and flaring projects. This discount rate is represented in the annuity factor

Projects with a calculated NPV/I less than 0.5 would be considered additional. It is proposed that NPV/I is used rather than NPV because project operators are likely to compare a project's expected return to

the size of its investment, even if the overall return is positive. For example, a project with NPV of \$500,000 requiring \$200 million in CPX may not be worth implementing, even though technically the project may be profitable. The suggested benchmark of $NPV/I < 0.5$ is based on the expert judgment and industry experience of Energy Redefined; projects with NPV/I lower than 0.5 are not likely to be pursued by operators.

For projects that expand existing export and on-site usage capacity, this financial analysis is applied in a similar way to new infrastructure. The CPX of installing new equipment/infrastructure or of upgrading or expanding this equipment/infrastructure, and the changes in OPX and revenue, shall be used in the calculation.

It is proposed that the Commission produce or commission the production of a simple, public tool that can be used by project operators to determine whether a proposed project is likely to satisfy the financial additionality requirement under Option 3a.

As in CDM, it is proposed that projects must not be required under local laws and regulations. Such projects would likely have occurred in the absence of crediting, even if they are not financially attractive. It is proposed that an option is provided for project applicants to demonstrate that local laws and regulations are not enforced; if this is true, the project may be deemed additional pending the financial analysis or non-cost barriers assessment. If a proposed project is in the same jurisdiction as another project previously approved under Option 3a, the new project may simply refer to the approved project's demonstration of non-enforcement of local laws instead of repeating the demonstration, combined with any necessary updates in the enforcement of that jurisdiction. The Administrator may create and maintain an online and publicly available database with a list of jurisdictions in which flaring and/or venting is illegal but unenforced. It is understood that producing a comprehensive database would be a very large task; a partial database that covered some regions would still be of benefit to some applicants. Satellite images of flaring could potentially be used to help determine whether flaring is still occurring in jurisdictions where it is illegal, and hence whether it could be reasonably concluded that the law is unenforced in that region. Applicants in regions that are not covered in the database and where flaring or venting is illegal but unenforced could still apply for crediting and provide justification; if this justification is accepted, the Commission or appointed database administrator would then add this jurisdiction to the database. This would provide project applicants in such jurisdictions certainty that their applications will not be denied on the grounds on legality.

For projects that do not satisfy the financial requirement, an optional assessment of non-cost barriers may be completed. The independent auditors must rigorously examine such assessments and projects should only be approved if it is clear that the non-cost barriers would prohibit the implementation of the project in the absence of crediting, and that crediting would overcome these barriers. The burden in

preparing the application and in reporting and verification of such projects is likely to be high; however, only a small fraction of all projects under Option 3a are expected to follow this approach.

4.2.3. Additionality requirement based on ISO 14064 Part 2

As noted in Section 2.2.3, ISO 14064 “deals with the concept of additionality by requiring that the GHG project has resulted in GHG emission reductions or removal enhancements in addition to what would have happened in the absence” (ISO 14064 Part 2 article 0.3). It is also required that the baseline scenario must be defined with reference to information including economic and legal assumptions or projections.

We interpret the requirements of ISO 14064 as implying that some sort of legal assessment and economic assessment must be required before identifying emissions reductions as additional, and thus eligible for credits. In particular, in establishing the baseline case it would be expected that a project participant should demonstrate either that the baseline case would be permissible under local law, or that local law that ought to prohibit the baseline case is not enforced and that disregard for that local law represents normal business practice. It should also be demonstrated that the baseline case would be considered financially viable – i.e. that financial considerations alone would not have been reasonably expected to cause the project participant to implement the project in question. These requirements are very much analogous to the requirements from CDM that have already been discussed (Section 4.2.1), but with the difference that ISO 14064 does not specify exactly the basis upon which such a determination should be made. In practice, this means that a system of additionality requirements based on ISO 14064 would determine additionality at the discretion of the qualified validator appointed for the project, and with reference to any guidelines set in place by the body administering the crediting scheme in question, whether a private entity or a national administrator. Providing additional discretion to scheme administrators and qualified validators may be expected to reduce the burden of demonstrating additionality, and provide some increase in flexibility to project proponents in determining the basis upon which to make the case that a project is indeed additional. The net effect should, however, be broadly similar to application of the CDM rules, in terms of which projects would be accredited as additional and which would not.

4.2.4. Additionality criteria for the prescriptive option

The moderate additionality approach would ensure that the prescriptive option (Option 3a) deliver real emissions savings without overly discouraging engagement by operators. This approach is somewhat less burdensome than CDM (no common practice analysis, more lenient financial test) and the proposed tools would facilitate the application process; these advantages which would save application

costs (less staff time required in preparing the application) and reduce uncertainty, and would likely encourage more projects to participate in Option 3a.

The consideration of higher discount rates and of declining gas production rates would more accurately reflect project dynamics and would allow crediting of some projects that would be rejected under CDM. This approach may result in greater emissions reductions from projects that are additional but would not have been implemented under the CDM framework.

Inclusion of some additionality criteria ensures the integrity of Option 3a. Removing all additionality requirements could result in the FQD being satisfied entirely by flaring and venting reduction projects that would have happened anyway – in this case, the FQD would not result in any real emissions reductions.

4.2.5. Additionality criteria under the implementing measure requirements

Under the implementing measure requirements (Option 3b), it would be incumbent upon schemes seeking to provide certified emissions reductions eligible for use in compliance under the FQD to demonstrate to the satisfaction of Member States that their procedures for assessing the additionality of a project were consistent with the additionality requirements of ISO 14064 Part 2. Schemes under Option 3b might require financial assessment similar to that under CDM, or similar to that proposed under Option 3a, based on some alternative defined calculation or else based on engagement between the project proponent and the validator, and relying on the validator's discretion. Systems reliant on the discretion of the qualified validator in this way may provide more flexibility to project proponents, and assessments better tailored to the specific characteristics of the project in question, but would also be more subject to inconsistent treatment and at risk of fraudulent activity than more clearly defined systems. As a minimum, it is likely that the Member State would need to be shown that the validators were provided with clear and extensive guidelines for making such a discretionary adjudication. Member State administrators could not recognize an emissions reduction scheme as generating credits eligible for use under the FQD unless the administrator was satisfied that this financial assessment provided adequate demonstration that, "the project results in GHG emissions reductions ... additional to what would occur in the baseline scenario."

Note that under the proposed implementing measure it is explicit that it is not necessary that it should be demonstrated that the project would not have occurred in the absence of the FQD. This means that while the project proponent must show that the project would not have been implemented under business as usual assumptions, there is no need to show that the value specifically available through FQD was a driver of project development.

Similarly, the Member State administrator would need to be satisfied that any scheme seeking to generate credits under Option 3b contained adequate systems to ensure that legal additionality was demonstrated. It may often be possible in specific cases for Member States to identify whether the region in which a project was undertaken had laws against flaring and/or venting in place, and to develop an understanding of which of the regions where flaring is formally outlawed do not effectively enforce those requirements. Checking for consistency between validators determinations and the Member State's understanding could be a useful check on the quality of the validation process. As in the moderate additionality case suggested as the basis of additionality rules in Option 3a, this determination by Member States (and project validators) might be assisted if the European Commission or its appointed body would maintain a central database identifying regions in which project could or could not be considered additional.

4.3. Task 3b: Verification requirements

4.3.1. Verification requirements for the CDM options

This section describes validation and verification requirements under CDM that would apply under the ETS-CDM option (Option 1) and the standalone CDM option (Option 2). It then discusses what additional verification steps would be necessary for CERs used for FQD compliance.

All CDM projects must be 'validated' and 'verified' in order to be eligible for registration and to receive credits. The validation process occurs after the project participants submit the Project Design Document and before the project commences³⁹ (Kamel, 2005) and ensures that the information supplied in the PDD is accurate. Once a project has been validated, it is registered and may proceed with implementation. The verification process takes place after project implementation and ensures that the project is proceeding as planned and that the emissions reductions are properly monitored and reported. Verification is necessary before CERs are issued to the project participants.

Validation and verification must be completed by a Designated Operational Entity (DOE), an independent auditor accredited by the CDM Executive Board. DOEs must follow all CDM requirements to validate project proposals (CDM Rulebook).

Much of the validation process focuses on ensuring that the project design document (PDD) accurately represents the project. This is the start of the CDM process and includes validating the PDD's demonstration of additionality, including checking the project applicants' barrier analyses (CDM Rulebook). The DOE must also ensure that the designated national authority (DNA, or government of

³⁹ Note that some projects may commence gas recovery and start the crediting period before registration has been completed.

participating countries) have signed off on the project. The DOE submits a validation report to the CDM Executive Board, and if approved, the project is registered under CDM. Specific details that must be included in the validation report are listed in Table 4.1.

Table 4.1. Details included in validation report (UNFCCC, 2011b)

VALIDATION REQUIREMENT	REPORTING REQUIREMENT
Designated Operational Entity (DOE) conduct independent assessment of proposed project activities against CDM requirements	DOE report assessment results in a validation report. A negative opinion (non-compliance with CDM requirements) must be provided to project participants and Board informed
Global stakeholder consultation: DOE take into account all comments received during project validation	Report details of actions taken to take the comments into account
DOE determine whether the designated national authority (DNA) of each Party involved in activity has written a letter of approval	Indicate whether letter has been received, whether it was from project participants or directly from DNA; include statement of whether letters are in accordance, and if needed the means of validating authenticity of letters.
DOE validate whether each project participant has been authorized by at least one Party to the Kyoto Protocol involved in the approval letter	Validation report indicating whether each participant authorized by a Party and means of validation used to come to this conclusion
DOE confirm that DNA has considered whether proposed CDM project activity assists Host Party in sustainable development	DOE state whether Party's DNA confirmed contribution of project to sustainable development in the host country. May be reported together with assessment of validity of host Party's approval (action 3).
DOE validate corporate identity of all project participants and focal points included in the Modalities of Communication (MoC) statement, plus personal identities including specimen signatures and employment status	DOE confirm in writing that it has performed due diligence on the MoC statement
DOE validate MoC statement correctly completed and duly authorized	DOE confirm in writing that MoC statement complies with forms and requirements
DOE determine whether Project Design Document (PDD) completed using latest version of the PDD form	DOE provide statement regarding this compliance
DOE determine whether description of project activity in PDD is accurate, complete, etc.	DOE describe process taken to validate accuracy and completeness of project description, provide opinion on accuracy and completeness, provide justification if it has not conducted a site visit
DOE determine whether baseline and monitoring methodologies are valid versions of those approved by Board	DOE describe steps taken to assess information in PDD against criteria, and provide validation opinion
Project boundary: DOE determine whether all main GHG sources, physical project boundary, and baseline emission sources are included within project boundary	DOE describe how validation of project boundary was performed, and state whether boundary and source gases are justified for the project activity
DOE determine whether baseline is the scenario that reasonably represents GHG emissions that would occur without project	DOE describe steps taken to assess requirements, provide opinion whether everything is reasonable
DOE determine whether steps taken and	DOE describe steps taken to assess

equations and parameters comply with requirements	requirements and provide opinion whether everything is correct and complete
DOE validate additionality	DOE describe steps taken to cross-check info in PDD and how it determined evidence is credible
DOE determine whether CDM benefits were necessary in decision to undertake project (i.e. additionality)	DOE describe validation of project start date; describe evidence that the CDM was necessary; provide opinion on where project complies with requirements
DOE assess list of identified credible alternatives to project activity to determine most realistic baseline scenario	DOE describe whether alternatives are credible and complete
DOE determine whether project would not be financially attractive without CERs	DOE describe how parameters used in financial calculations have been validated; describe suitability of benchmark used; confirm if assumptions to calculations are appropriate and calculations are correct
DOE determine whether non-cost barriers would prevent implementation of the project	DOE describe how it has validated each barrier and provide determination of credibility
For large scale projects, DOE assess whether project participants have conducted a common practice analysis (unless this is a first of kind)	Describe how geographical scope validated; how assessment of existence of similar projects; describe how assessed essential distinctions between this project and other similar ones; confirm whether the project is not common practice
DOE determine whether description of monitoring plan in PDD is based on approved monitoring methodology including applicable tools	DOE give opinion on compliance of monitoring plan; describe steps to assess whether monitoring arrangements feasible; state opinion on project participants ability to implement monitoring plan
Determine whether project participants conducted analysis of environmental impacts; determine whether participants conducted an environmental assessment	DOE indicate whether participants have done analysis and if it meets requirements
DOE determine if participants have completed local stakeholder consultation process	Describe steps taken to assess the adequacy of stakeholder consultation; provide opinion on such adequacy

Following the audit, the DOE must take one of the following actions:

- Verify that the project meets all CDM requirements.
- Terminate the project with a negative opinion.
- Raise a Corrective Action Request (CAR) if the project participants have made mistakes, the CDM requirements are not met, or if there is a risk the emissions reductions cannot be monitored or calculated.
- Raise a Clarification Request (CL) if the audited information is insufficient or unclear.
- Raise a Forward Action Request (FAR) to identify issues that require further review

- Resolve or “close out” CARs and CLs only if the project participants have modified the project design, rectified the PDD or provided satisfactory explanations or evidence.

All Corrective Action Requests, Clarification Requests, and Forward Action Requests must be reported in the validation report. DOEs must provide an update within 180 days after the start of the validation process and must specify if the validation contract has resulted in a positive opinion (or approval of registration), terminated in a negative opinion (denial of registration) or if corrective, clarification, or forward actions are requested. After this point, the DOE must provide updates on the status of the validation process every 3 months.

DOEs must deliver a validation report to the CDM Executive Board. The validation report includes:

- A summary of the validation process and conclusions.
- All of the DOE’s approaches, findings and specific conclusions, especially on the baseline selection, justification of additionality, use of emission factors, and monitoring plan.
- Information on the stakeholder consultation.
- List of interviewees and documents reviewed.
- Details of the validation team, technical experts, and internal technical reviewers, with details on each person’s role in the validation process.
- Information on how quality control and the validation process were conducted within the validation team.
- Appointment certificates or Curriculum Vitae of the DOE validation team members, technical experts, and internal technical reviewers.

After the project has been validated and registered and the project activity has commenced, the verification process begins. The DOE audits the monitoring data collected and archived by the project participants in order to verify emissions reductions and to check that measurements do not deviate significantly from one month to the next or other issues that could indicate measurement error (Zakkour et al., 2010).

CDM guidelines outline a standard auditing technique the DOEs can use in both validation and verification (UNFCCC, 2011b). As needed, DOEs can:

- Review documents including data and information. Can use independent background investigations.
- Follow up with actions including on-site visits, telephone or email interviews, including with stakeholders in the host country and personnel with knowledge of the project.

- Review available information on other similar projects or technologies.
- Review formulae and accuracy of calculations.
- Other actions as needed

If the DOE approves the project following the verification process, the DOE issues a certification:

*Certification is the written assurance by the designated operational entity that, during a specified time period, a project activity achieved the reductions in anthropogenic emissions by sources of greenhouse gases as verified.*⁴⁰

A certification is a request for the Executive Board to issue CERs for the emissions reductions achieved by the project. We are not aware of any instances where the Executive Board rejected a certification from a DOE, and it does not appear that the Executive Board performs substantive additional checks on a project's validity before issuing CERs.

The UNFCCC secretariat then processes the request for the issuance of CERs. Within 7 days after starting the process, the secretariat must conduct a completeness check on the request for issuance to ensure that it is in accordance with the latest available version of the completeness checklist. Within 23 days following this process, the secretariat must complete an information and reporting check. Following each check, the secretariat will then notify the project participants and the DOE and make the conclusion of this check public. If the request for issuance does not meet the requirements of either check, the DOE may submit revised documentation. A party involved in the CDM project may submit a request an additional round of review (CDM rulebook).

If the request for issuance passes both checks, the secretariat approves it. The Executive Board then makes the final determination at an Executive Board meeting, and if positive, requests the CDM registry administrator to issue the CERs. CERs are then issued by the CDM registry administrator on behalf of the Executive Board (CDM rulebook). The CDM registry administrator then transfers CERs from the Executive Board's pending account to the accounts of the project participants and other parties involved (including 2% of CERs that are issued to the government of the host country to assist with adaptation to climate change). CERs are forwarded to holding accounts held by project participants in the national registry in the Annex I country that authorized their participation in the CDM project (CDM Rulebook).

4.3.1.b. Verification requirements under FQD

As the existing CDM framework already has in place a system of audit and verification that ensures credited projects are real, are additional,

⁴⁰ 3/CMP.1, Annex, paragraph 61, which can be found at <http://unfccc.int/resource/docs/2005/cmp1/eng/08a01.pdf#page=6>

and achieve the reported level of emissions saving, there is no need for Member States to perform additional verification of these elements. This includes the regularity of reporting and the nature and duration of measurements and estimates – all these parameters are specified by CDM and appear to be adequate for the purposes of Options 1 and 2. A properly issued CER can be considered as adequate evidence of real emissions savings. A parallel can be drawn between the way that the CDM verification framework could be relied upon under Options 1 and 2, and the way that the European Commission has endorsed sustainability schemes for biofuels reporting under the RED/FQD. For biofuels, the Commission has assessed schemes like the International Sustainability and Carbon Certification (ISCC), and Member States are now expected to accept properly awarded certificates from those schemes as adequate evidence of sustainability compliance. .

Under Option 1 and 2, CERs would go through the process described above of being checked by the Executive Board and the UNFCCC secretariat, and would be issued to a holding account in the national registry of the Annex I country that authorized the project. Under Option 1, CERs used for FQD compliance would also be used towards a Member State's obligation under EU ETS. In such case, the CERs would be transferred from the national registry to the Union registry (the central EU registry for all allowances and emissions reduction credits used towards the EU ETS). Under Option 1, the Union registry would need to implement some system for marking CERs and ERUs as counting towards compliance under FQD (e.g. an "FQD tickbox") and upon retirement issue credits into an obligated party's FQD account under the applicable Member State's system for tracking FQD compliance. Any obligated party wishing to use a CER or ERU for compliance with FQD must request this of the registry administrator. No additional verification checks would be needed to ensure these CERs were valid, as the systems in place for ETS are already adequate. We propose that operators should be required to use any such credits for FQD compliance in the same country as they are used for ETS compliance. In that case, there would be no need to put in place further checks to avoid having credits counted in more than one jurisdiction, as the systems in place for ETS are already adequate.

Under Option 2, the CERs would be transferred from the national registry to a stand-alone third party registry, administered by a government body (e.g. the European Environmental Agency) or a private entity. These CERs would still have gone through the entire verification process within the CDM process as well as multiple checks by the Executive Board and the UNFCCC secretariat, and thus would not likely need additional checks up to the point they are transferred from the national registries. Because these credits would be handled by a single central registry, it would be relatively simple to assure that credits were only used for FQD compliance in a single EU Member State, by requiring that Member State authorities confirm validity with the central registry before counting any credit for compliance. The credits should be retired from the UNFCCC CDM registry at the point that they are transferred from national registries. Unlike Option 1, under

Option 2 it is suggested that credits should be usable only under the FQD, not under the ETS. This would simplify the cancellation process, and avoid the situation where a single credit is active in more than one registry at a time. When CERs or ERUs were transferred into the central registry under Option 2, it would be necessary to place an additional reporting requirement upon the party transferring them to identify the date of issue of the credits, the methodology used, the start date of the project and any additional necessary information. Ideally, this data would be verified by the DOE for the project alongside the reports submitted to the CDM EB, and this assurance would be passed along the chain of custody with the CERs themselves and subject to verification by Member States or the central registry managers as appropriate.

In the Commission's proposal to implement Article 7a of the FQD, there are a number of reporting requirements for suppliers who claim reductions in upstream emissions, such as the exact project location and the gas-to-oil ratio (these are listed in Table 2.2), that are not currently included in reporting under existing CDM methodologies. It is proposed that the DOE who validates and verifies an FQD-compliant CDM or JI project also verify this additional information and include it in a separate document. It is also proposed that the Commission issue guidance on the additional reporting required and methods that should be used to verify it.

4.3.2. Verification requirements under existing biofuel regulations

Parallels can be drawn between the verification of emissions reductions claims under FQD and the verification of biofuel sustainability claims. Looking at the California LCFS and the British and German implementations of RED suggests three differing verification approaches, any of which could be applied to upstream emissions reductions. These are:

1. Verification through approved voluntary schemes (Germany);
2. Verification through qualified auditors (UK);
3. Verification through direct engagement with the regulator (California).

4.3.2.a. Voluntary schemes

The German Biomass Sustainability Ordinance (BSO) requires that any biofuel supplied in Germany must be certified to meet an approved sustainability standard by an approved sustainability auditor. In principle, the use of voluntary schemes can reduce the startup time and administrative burden for setting up a new regulation, although in practice the first scheme certified by the German Government as meeting its requirements for biofuel certification was the International

Sustainability and Carbon Certification (ISCC)⁴¹, which was set up specifically with the requirements of the BSO in mind. The BSO sets clear requirements for schemes, in terms of coverage and audit standard, adding additional detail beyond the basic requirements specified in the RED and FQD. Under the BSO, as well as under the UK RTFO, which in its original form included a meta-standard for biofuel sustainability against which existing schemes were rated, extensive engagement between the government and the schemes being used has always been an important element of the process.

The use of voluntary schemes for demonstration of performance has several advantages in the case of biofuel sustainability. For one, it shifts the cost burden of verification away from the government, and onto the fuel supplier through charges leveled by the scheme. The scheme administrators can be looked to to develop staff expertise and capacity that it may be difficult to sustain within the public sector. The use of a limited number of defined schemes should hopefully also improve the consistency of verification practice as compared to a system where any qualified auditor is permitted to produce a sustainability opinion, as in the UK. Most voluntary schemes will provide extensive verification guidelines, run verification training and work with a limited number of verification companies.

From the social and environmental point of view, voluntary schemes can deliver benefits through adding additional requirements that would go beyond the minimum requirements imposed by legislation. For instance, the sustainability requirements of the ISCC scheme are much more comprehensive than the minimum set mandated by the RED and FQD. Because ISCC has become a preferred route to gain entry to the German biofuel market, many suppliers are therefore engaged on a range of sustainability issues beyond the minimum specified by legislation. Such indirect benefits cannot be guaranteed, but the interaction of BSO and ISCC is a good example where this has taken place.

One challenge in the context of flaring is that, to the best of our knowledge, there are no voluntary sustainability or offsetting schemes beyond CDM/JI that are currently applied to venting and flaring in the oil and/or gas sector. If UERs are implemented under the FQD through voluntary schemes, either new bodies would need to be set up or existing carbon offsetting systems would need to expand coverage into the oil and gas sector. It may be difficult to develop the necessary sectoral expertise on the short timescale required to start delivering projects before 2020.

4.3.2.b. Qualified auditors

The UK RTFO allows for and encourages the use of voluntary schemes, but it does not follow the German system in insisting that voluntary schemes should be used. One reason for this is a concern that certification through voluntary schemes may be unduly burdensome in

⁴¹ <http://www.iscc-system.org/>

some cases, in particular small to medium enterprises producing biodiesel from waste oil. The formal requirement under the RTFO is therefore not that a sustainability scheme should have been applied, but that a auditor competent to perform a sustainability assessment should certify that sustainability requirements have been met. The auditor may be satisfied that the standard has been met by seeing evidence of certification to a voluntary scheme, but this is at the auditor's discretion, not the national administrator's. By analogy, for upstream emissions reductions the equivalent of this would be to allow reductions to be certified outside of the confines of formal schemes. This would give operators more flexibility in terms of the number of bodies able to certify reductions, but may leave additional space open for inconsistency in treatment. In the worst case, there may be an increased risk that some auditors could systematically falsifying their reports in order to favor their clients and generate more business for themselves.

Under the RTFO, the requirement for auditors is that they should be competent to give an ISAE 3000 limited assurance statement.⁴² This is similar to the proposed requirement in the proposed FQD implementing measure that emissions reductions should be demonstrated in accordance with ISO 14065.

4.3.2.c. Direct regulator verification

Under the Low Carbon Fuel Standard in California, the Air Resources Board (ARB) plays a much more active role in the verification of carbon intensity claims, and indeed the verification of upstream emissions reductions claims. Extensive documentation must be submitted to the regulator to support any request for an altered lifecycle emissions pathway, and there is no necessary engagement of a third party auditor. This approach is the most administratively intensive, but it does allow the ARB to maintain a higher level of control over the process and a higher level of confidence that verification is carried out to the required standard. It also allows ARB to develop expertise internally.

There are two primary drawbacks to considering such a centrally verified system for upstream emissions reductions in FQD. The first is that it would be administratively intensive to set up a body or department with the capacity to handle a potentially large number of UER project requests, more so if site visits were to be used as part of the verification process. The ARB under LCFS predominately has to deal with applications related to facilities in or near California, whereas under an oil sector flaring reduction incentive projects are likely to be spread across the world. The second drawback is that there may be limited internal expertise on UERs and verification within the administrative body, especially at first. Often, private sector bodies have more flexibility in hiring new staff, and a private-sector system based on voluntary schemes or qualified auditors may be better able to

⁴² See the RTFO Guidance for Verifiers, https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/301082/part-3-guidance-for-verifiers-yr7.pdf

recruit experienced people than the public sector equivalent (although this is not guaranteed).

There is a possible middle ground between direct regulator verification and the use of qualified auditors that can be seen in action in CDM. Thinking about the CDM Executive Board is considered in the role of the regulator, you have a case where the regulator requires significant data submission and takes an active role in assessing project registration, but where the specifics of data registration are outsourced to the designated operational entity (DOE). In any of these three types of framework, the level of engagement by the central regulatory body will always be guided not only by what is most effective but also by what is within the practical capacity of the body in question. In the case that verification is distributed to the Member States, this balance becomes that much harder to find. It is not a coincidence that Germany and the UK, with relatively high capacity for sustainability work, have been leaders in setting biofuel sustainability verification systems, and that other EU countries have often drawn from these experiences. In the case of UERs, the challenges that the European Commission might face in putting together a team with significant oil industry experience would be magnified if each of 28 Member States faced the same challenge.

4.3.3. Verification requirements under the prescriptive option

As in CDM, the prescriptive option (Option 3a) would require that both the information provided in project applications and the on-going measurements of emissions savings be verified by an independent auditor. There are two pathways identified for the application of verification requirements. In the first, they would be laid out in detail in a single prescriptive measure (i.e. an approach fully regulated by the Commission).⁴³ In the second, they would be implemented through approval of independent crediting schemes.⁴⁴ In either version, the following verification requirements are proposed.

4.3.3.a. Requirements for accreditation of auditors

The independent auditors should be accredited by a body or committee established by the Commission. The criteria for accreditation should resemble those of CDM for DOEs (UNFCCC, 2012a) (these criteria are very similar to those in ISO 14065):

- The auditor must be a legal entity under applicable national and international law.
- The auditor must not have any conflicts of interest and must be independent from project operators.

⁴³ In principle, the same type of prescription could be imposed at the Member State level; however this would introduce a considerable risk of differing interpretations and levels of reporting burden across the Union.

⁴⁴ This would be analogous to the way that certification be approved sustainability schemes for biofuels is accepted as proof of compliance with sustainability criteria under RED/FQD.

- Independence and impartiality is verified internally through a committee within the auditing organization that is separate from the verification and certification functions. This is in line with the goals of independence and impartiality for accreditation in the Commission Regulation on verification of reporting pursuant to the ETS.⁴⁵
- In particular, the auditors may not belong to a different department or subsidiary of the same company applying for the project.
- The auditor must have necessary expertise in the Option 3a crediting regime, in emissions accounting, and in regional and sectoral aspects. The auditor must demonstrate sufficient knowledge in baseline setting, calculation of emissions savings, required measures, and fraud risk.
- The auditor must establish, document, and implement procedures for determining competence and independence of all involved personnel, and must continually monitor and maintain these procedures.
- The auditor must conduct internal audits at least once a year and submit an annual function report to the CDM Executive Board.

As an alternative approach, the Commission could simply allow any CDM-accredited DOE working in the oil and gas field to validate Option 3a projects, on the basis that the CDM Executive Board would already have established the fitness of that DOE to perform project assessments. This approach would reduce the potential burden to the Commission of implementing an accreditation scheme.

4.3.3.b. Validation of project proposals

As in CDM, under Option 3a the auditor would be responsible for making a recommendation to the Commission on whether a project should be credited. This process would involve:

- Reviewing the project proposal document and all relevant supporting documents. Emphasis should be placed on:
 - Validating the additionality analysis.
 - Checking accuracy of the calculation of expected emissions savings.
 - Checking that the monitoring plan is robust and meets requirements.
 - Confirming the existing availability of any relevant infrastructure.

⁴⁵ http://ec.europa.eu/clima/policies/ets/monitoring/docs/swd_impact_assessment_en.pdf

- At least one on-site visit to verify project plan and existing infrastructure (or lack thereof).
- Interviews with stakeholders and personnel with knowledge of the project, as necessary.

In a validation report, the auditor would inform both the Commission and the project operator of the opinion: positive, negative, or requires changes to the proposal. If changes are required to the project proposal document or to the project plan itself, the project applicants would be allowed to resubmit the proposal.

It is proposed that the validation report be published in the public domain on a website maintained by the auditing company. The auditors should redact the validation report to remove any financial or other information the project participants reasonably consider proprietary or confidential. Concerns about the confidentiality of documentation provided in relation to the additionality analysis in particular were raised by stakeholders who were consulted about this project. It is felt that any public interest in full disclosure of such information is outweighed by the legitimate commercial interest of project participants in keeping detailed financial data confidential.

The validation report should also include details about the auditing team, the validation process, documents reviewed and interviews held, details of the site visit, and how quality control was conducted within the auditing team. Additionally, the exact location of the project (latitude and longitude to four decimal places) should be included in the validation report for the purposes of satellite verification of reported emissions reductions (discussed below).

The body or committee established by the Commission would make the final decision in whether or not to register the project for crediting under Option 3a.

4.3.3.c. Verification of project implementation, monitoring and reporting

After a project has been registered for crediting under Option 3a, the auditor must continue to monitor the project to verify that the reported emissions savings are correct.

Monitoring data must be submitted electronically to the auditor monthly within two weeks of month-end. The auditor should check these data within one month of receipt for discrepancies from the original project plan and for discrepancies between measurements of gas flow at different points within the project boundary. If problems are detected, the project participants should be allowed a two-month period to identify and correct the problem. If problems persist beyond two months, a site visit and audit is required. The auditor must check if all monitoring equipment is operating correctly and is correctly calibrated.

If some monitoring equipment is not functioning or calibrated correctly, and this is likely the cause of the data discrepancies, the project operator would be required to fix the problem immediately. In the case that one gas flow measurement point is operating correctly and the second is not, the measurements from the first point shall be used to determine crediting for that month. If the problems with the monitoring equipment are so severe that emissions savings cannot be calculated, credits shall be awarded on the basis of 50% of the average emissions savings of the previous three months. If problems with monitoring equipment cannot be resolved within two months, crediting of the project shall cease at that point until measurement resumes to the auditors' satisfaction.

If the monitoring equipment is deemed to be functioning and calibrated correctly, the auditor shall determine the cause of the discrepancy. If the problem is that measurement of downstream gas flow is lower than the upstream gas flow by more than 2% for large scale projects or 7% for small scale projects, the discrepancy should be reported as fugitive emissions and subtracted from total project emissions savings according to the calculations detailed in Section 2.2.2.b. If the problem is that measured emissions savings deviate significantly from the project plan, the auditor shall investigate what the reason is for this departure from expected emissions savings, and should make a determination of whether crediting of the project should continue. In particular, in the case that emissions savings are much higher than initially anticipated, the auditor should undertake a secondary additionality test to check that the project can still be considered additional at the elevated rate of gas recovery. A determination of deliberate tampering of monitoring equipment should result in termination of crediting of the project, and should be reported to the European Commission.

If no problems occur with the monitoring data, the auditor shall conduct an on-site visit once per year for large scale projects and once every three years for small-scale projects, followed by an annual report to both the Commission and the project operator containing the verified emissions reductions.

For very small projects ($<10 \text{ Mm}^3/\text{yr}$) opting for weekly measurements instead of continuous, auditors should pay particular attention to the following issues: that the reported measurements are characteristic of typical flows, that the data are consistent with other elements of field operation, and that gas measurement is not being skewed purposefully (e.g. selectively reporting particularly high flows). Auditors will check these measurements against annual reported gas sales for consistency.

It would be possible to perform an additional check on the level of reported emissions savings using satellite measurement. Using the exact project location as reported in the validation report, the body or committee established by the Commission could compare light intensity in the vicinity of the flare in night time satellite images of the project before and after project implementation. As flare intensity will normally vary over time, it would be important to take several

instantaneous images and average the results. While satellite imaging is not to be used to determine the magnitude of emissions reductions for a project (as the key question is not the absolute change in flaring rate, but the amount of gas recovered), it should provide confirmation as to whether or not a project is performing in line with expectations in the project plan. If levels of flaring observed through satellite imaging are inconsistent with the project plan (allowing for inaccuracy in measurement and for normal variation from predicted gas production rate), an additional on-site audit should be required. If there is a reasonable and verifiable explanation for the inconsistency (e.g. the oil production rate or gas-to-oil ratio increased unexpectedly over time), the auditor should confirm the reported emissions savings. If the auditor determines that flaring reduction has not occurred and that this has not been reported to the auditor by the project participant, the project should be terminated.

While such satellite checks may prove valuable in the long term, currently the accuracy of such individual flare assessments has not been fully investigated. This measure should therefore only be introduced at some future at the discretion of the Commission once it has been adequately demonstrated that such measurements can deliver adequate accuracy to be useful.

For venting reduction projects, satellite checks would not be viable. Satellite verification is further discussed in Section 2.4.2.

4.3.3.d. Crediting projects

Following data verification, the auditor shall make a recommendation to the body or committee established by the Commission on whether the project should be awarded emissions reduction credits under Option 3a, and if so, how many. The body or committee shall perform any additional checks on the project as deemed necessary.

The body or committee established by the Commission would then issue a request for credits to be issued to a central database (comparable to the registry referred to under Option 2) into an account held by the project operator. The administrator of this database would check the documentation provided with the request for credits for authenticity and consistency before issuing credits.

The credits would remain in the database at all times. The project operator may choose to retire the credits for compliance under FQD, in which case the administrator would report to the operator's Member State the amount of emissions credits retired, which the Member State would then be obliged to count against compliance with that operator's GHG emissions reduction target under FQD. Alternately, the credits could be traded to another operator, in which case they would simply be transferred to another account, based on agreement of both parties. In all events, in order to use these credits for compliance they would eventually have to be retired from the database and used in a Member State implementation of the FQD.

Keeping all Option 3a credits within one database should minimize administrative costs and fraud potential. The database could be very easily checked to ensure that credits are unique, and no false credit numbers (i.e. from projects that have not occurred) could be generated. It is proposed that even if several independent crediting schemes are considered eligible, that credits from all these schemes should be recorded into a single FQD database if they are to be used for FQD compliance.

Within a database, each credit should be assigned a unique serial number. Credit serial numbers should also contain information tracking the credit to a specific project, project operator, and year of achieved emissions reductions to enable tracking and verification. The number of serial numbers for a particular project held by one obligated party can also be tracked. Thus, credit serial numbers in an Option 3a database should contain more information than EU ETS serial numbers.

Renewable Identification Numbers (RINs) used to demonstrate compliance with the U.S. Renewable Fuel Standard (RFS) can be used as an example of the way that unique credit codes could be structured, given in **Error! Reference source not found.** (US EPA, 2010).

The proposed serial number structure for credits under Option 3a is as follows:

AYYYYO000PPPPSSSSSSSSSEEEEEEE

Where:

A = Status (Active, Retired, or Cancelled)

YYYY = Calendar year in which emissions reductions were achieved

O000 = Unique Operator ID (who generated the emissions reductions)

PPPP = Unique Project ID

SSSSSSSS = Start of credit block

EEEEEEEE = End of credit block

In the event that several third-party emissions reduction schemes are made eligible, then the credit number should also record the originating scheme.

In the Commission's proposal to implement Article 7a of the FQD, there are a number of reporting requirements for suppliers who claim reductions in upstream emissions. that are not currently included in reporting under existing CDM methodologies or Option 3a. These include exact project location and the gas-to-oil ratio (these are listed in Table 2.2 in Section 2.3.1.a on reporting requirements). If such reporting requirements are implemented, the auditor should be required to verify this information and include it in the annual verification reports. Given an individual credit serial number, the

administrator of the central database could then match the credit with the annual verification report for that project and verify this additional information.

4.3.3.e. Verifying through voluntary sustainability schemes

Instead of the prescriptive measure detailed above, the Commission could choose to implement Option 3a through independent emissions reduction crediting schemes. Under this approach, the Commission would approve an emissions reduction crediting scheme and the scheme would approve individual auditors to verify projects. An example from the implementation of RED sustainability criteria would be the Roundtable on Sustainable Biomaterials (RSB) EU RED, an organization that certifies a biofuel meets the land use and greenhouse gas requirements under RED.

Direct management by the Commission of a prescriptive measure for Option 3a would require considerable capacity building and a significant investment of staff time. Approving independent certification schemes to handle the burden of data management and project assessment would present advantages in terms of reducing the burden on the European and/or Member State institutions, but would reduce the level of control of the Commission over project quality. This may be considered a reasonable trade off.

Use of voluntary emissions reduction crediting schemes under Option 3a should broadly follow the guidelines and requirements for such schemes under RED, which are as follows (European Commission, 2010).

Schemes may be governmental, private, or of any other origin, and multiple schemes may assess the same types of projects. There is a maximum period of recognition of 5 years for a sustainability scheme, after which the scheme can presumably reapply for permitting following reassessment. If the scheme makes changes to their processes, they must notify the Commission, which will assess if the scheme is still valid.

The scheme must ensure that its auditors are independent and have the necessary general and specialized skills related to the scheme's criteria. The scheme must create a verification plan that corresponds to the risk profile, scope, and complexity of the activity being verified, and must carry out the verification plan by gathering the necessary evidence. Schemes should ensure that project operators are audited before allowing them to participate in the scheme, and must conduct regular (at least yearly) audits of a sample of claims (e.g. monitoring data) made under the scheme. Evidence must be retained for a minimum of 5 years.

The Commission assesses each new scheme and, if it meets the criteria of the RED (in this case, of Option 3a) and the standard for audit quality, the Commission adds it to the list of recognized schemes for the appropriate elements of sustainability reporting.

4.3.4. Verification requirements under the implementing measure requirements

Under the implementing measure requirements (Option 3b), UER projects would be assessed and verified within schemes approved by Member States. Competent auditors compliant with any requirements set by the scheme would validate and verify projects. These audit bodies and their staff must also meet the requirements listed in ISO 14065 and 14066 respectively. Member States may impose specific requirements on schemes based on their interpretation of the requirements of these ISOs. Because the requirements for validation and verification processes will depend on Member State implementation as well as on the practices established by specific voluntary schemes, these requirements cannot be detailed here with the same specificity with which they have been detailed for Option 3a in Section 4.3.3.

The requirements for validators and verifiers under the ISOs are broadly similar with those described for CDM in Section 4.3.1 and for Option 3a in Section 4.3.3.a. Auditors must “remain independent of the activity being validated or verified, and free from bias and conflict of interest,” “demonstrate ethical conduct,” “exercise due professional care and judgment,” and “have the necessary skills and competencies to undertake the validation or verification” (ISO 14064 Part 3, Article 3).

Verification in Option 3b must meet the requirements listed in ISO 14064 Part 3. The auditor must develop a validation and verification plan (Article 4.4.2 and Article A.2.4.5), assess emissions data and information from the project as well as the information system controls in place⁴⁶ against the criteria established by the voluntary scheme, evaluate the emissions reductions reported by the project participants (Article A.2.8), and finally issue a validation or verification statement (Article A.2.9). The boundaries of the validation and verification processes should be determined based on the organization of the UER project, its baseline scenarios, its physical, legal, financial, operational and geographic boundaries, the emissions sources and sinks, the types of GHGs included, the time period of the project, and the frequency of subsequent verification processes as required by the scheme (Article 4.3.4). Auditors must retain records to demonstrate conformity with ISO 14064 Part 3 (Article 4.10).

There are a number of elements of the validation and verification process that are specified under Options 1, 2, and 3a that cannot be specified here and are thus would be subject to the discretion of the voluntary schemes and to Member States. These elements include the specific actions taken by auditors (e.g. site visits, interviews with project employees and stakeholders) and the frequency of follow-up audits.

Member States would need to appoint an administrator responsible for receiving reports of upstream emissions reductions from regulated parties and confirming they comply with the requirements of the FQD.

⁴⁶ E.g. monitoring equipment and data storage; Article 4.5.

This administrator would also be responsible for identifying that any other requirements imposed by that Member State on UER projects had been fulfilled. Only reported UERs approved by that administrator would be eligible to count towards final compliance.

The specification for Option 3 from the tender specifications for this contract specifies that credits should be recorded in a standalone registry. This requirement for a central registry is not explicit in the proposed FQD implementing measure however, and thus it is possible that Option 3b could be implemented without any centralized data repository. Nevertheless, appointing a single body (e.g. the European Environment Agency) to act as a centralized data holder for data on reported UERs used for compliance with FQD would have considerable advantages in supporting Member State implementation. In particular, such a body could verify that UER projects are not double counted across multiple Member States and would be able to identify any discrepancies to the national administrators for the affected regulated parties. Without such a centralized body, it may be cumbersome and difficult for each Member State administrator to coordinate such basic verification checks with every other Member State.

4.4. Task 3c: Implementation by Member States

If any of the options presented here for crediting upstream emissions reductions is adopted at the European level, it will not be enough for it to be passed as a European Directive – the practical implementation will fall on the European Member States. In this section, we review issues that may be faced by Member States in implementing each option. In the following subsections, we consider: experiences and lessons from implementation of the ETS; questions around the integration of UER crediting in FQD implementations; and potential concerns of Member States in relation to the implementing measure.

4.4.1. Experience from the ETS

The EU Emissions Trading Scheme (ETS) was established in 2005 to help meet the EU's emission reduction targets. The EU ETS covers selected sectors including power plants and factories and works as a 'cap and trade' system: the number of 'allowances' for greenhouse gas emissions is capped and businesses in regulated sectors can buy and sell allowances from and to each other.

Prior to 2013, the EU ETS operated as a decentralized system, with Member States leading many decisions about implementation within their own borders. This system allowed differences between Member States in target setting and methodologies (Kruger et al., 2007), which some commentators have argued may have contributed to an oversupply of allowances and to low and volatile prices for ETS credits (Ellerman & Joskow, 2008). Member States' monitoring, reporting and verification procedures were highly varied (EDF & IETA, 2014; Kruger et

al., 2007). In addition, some emission allowances were stolen through hacking, which may in some cases have been enabled by inadequacies in the security of secure online trading systems (Carney, 2011). In response to these problems, the European Commission introduced major changes to the EU ETS in 2013. The total emissions caps are now centralized through the European Commission, and national registries have been replaced with a single, centralized Union registry (European Commission, 2014b). Practices for monitoring, reporting and verification have been harmonized (EDF & IETA, 2014). To combat low prices and price volatility, the Commission has proposed establishing a 'market stability reserve.' (European Commission, 2014c).

4.4.2. Integration of UER crediting with Member State FQD implementations

In order to have legal effect on economic operators in the Member States, the Fuel Quality Directive must be transposed into national law by each state and implemented. The structure of the measure as a Directive (as opposed to a Regulation) leaves considerable discretion on the part of the Member States as to how each element of the FQD is handled, and the greenhouse gas emissions element is no exception. Depending on the level of detail in prescriptions set for the implementation of upstream emissions reductions crediting under the FQD, Member States may have considerable leeway of interpretation. In some cases, such leeway could lead to optional enhanced verification and monitoring (imposing additional requirements not intended by the Commission). In others, it could lead to a weakening of intended verification, monitoring and/or anti-fraud systems.

Examples of quite different Member State implementations are available in the existing implementations of the RED and FQD, in particular as regards the sustainability criteria. The German system, for instance, imposes a requirement that all biofuel must be certified through an approved voluntary scheme, while other implementations such as the UK RTFO allow for sustainability data to be verified outside of formal sustainability schemes. The stringency of sustainability checks is understood to vary somewhat between Member States. There are also differences between the policy types used to achieve the targets. Germany will from 2015 move to a system of carbon reduction targets aligned to the carbon reduction target of FQD. This is expected to bring adequate quantities of renewable energy into the German transport fuel market to meet the RED, and therefore Germany will no longer impose direct volume requirements. In contrast, the Spanish system currently works through biofuel quotas with no direct incentives for carbon performance. Spain, and other Member States currently implementing volume rules, may introduce complementary or superseding carbon targets between now and 2020 – but it seems likely that in some countries the FQD target will be approached entirely through volume incentives, in a reversal of the German approach.

In the specific context of upstream emissions reductions, we see three areas in which Member State implementations could differ:

1. Eligibility of projects;
2. Verification of reductions;
3. Integration of market for UERs with other compliance options.

4.4.2.a. Eligibility of projects

Under the CDM options (Options 1 and 2), the eligibility of projects would be heavily prescribed by the existing requirements of CDM. Member States would therefore have limited scope to adopt differing approaches to project acceptance. One potential area of discrepancy would be the identification of which projects would be considered to be oil sector rather than gas sector, as many gas fields may also produce liquids, either small volumes of conventional crude or condensates/natural gas liquids. This could be resolved through setting a definition of 'oil' and 'gas' installations within any implementing measure.

Under the prescriptive option (Option 3a), there could be much more potential for variation in eligibility assessments, depending on whether project registration was managed centrally or deferred to the Member States. If deferred to the Member States, differences in interpretations of additionality requirements and other eligibility criteria would be possible. It has been proposed (Section 4.2.2) that the financial additionality test under Option 3a would be based on a clearly defined equation. Implementing additionality in that way would reduce the scope for difference in interpretation between Member State authorities. However, Option 3a allows the option to demonstrate substantial non-cost barriers as an alternative to the financial test, and the determination of whether such barriers sufficiently demonstrate additionality could be highly subject to differences in Member State implementation as well as auditor practices. There would also be scope for differences of opinion between Member States regarding regulatory frameworks – for instance, whether projects in Nigeria can be additional given that the Nigerian Government has in the past passed laws against flaring. Under Option 3a, the Commission should consider publishing a list of regions in which existing regulation is not considered adequate to preventing flaring, as a way to encourage consistency. As eligibility rules would be clearly specified under Option 3a, there would be limited scope for different interpretations. For instance, it is recommended that flare efficiency improvements should not be creditable.

Under Option 3b, Member States would have the greatest leeway in determining project eligibility. In the proposed FQD implementing measure, eligible projects are not limited to those reducing venting and flaring emissions, and could potentially include other types of upstream emission reductions. ISO 14064 Part 2 limits the scope of eligible projects to those that deliver system-wide greenhouse gas reductions that are additional to the appropriately defined baseline scenario, but does not preclude any particular type of project. Flare efficiency projects could in theory be eligible under ISO 14064, which does not

explicitly prohibit them, but such projects would have to meet acceptable standards of measurement accuracy in order to allow conservative crediting. This is discussed further in Section 4.5.3.

4.4.2.b. Verification of reductions

As noted above, the approach to verification of sustainability claims for biofuels differs markedly between Member States, and there is similarly considerable scope for variation in the verification of upstream emissions reductions. Under Options 1 and 2, this is limited by the use of the CDM framework to verify reductions at the project level. The key task for national administrators would then be simply to confirm that claimed credits are real and that they are correctly retired from the central registry being used. Given that a central registry is set up, there would be limited scope for inconsistent implementation.

Under Option 3a, the primary question is whether confirmation of claims would be done by a central administrator managing a central database, or whether reductions would be claimed and confirmed at the Member State level with this information then being passed to the Commission. In the latter case, there would be a risk that inadequate checks by some Member States could allow either double counting or fraudulent generation of credits. Implementing a system under which reductions are assigned unique identification numbers would help limit the risk of fraudulent generation, as it would allow retired credits to be directly associated to registered projects. The use of such identification measures is envisaged by the proposed FQD implementing measure. Without a central system in place for recording serial numbers on emissions reductions, the burden of monitoring and coordinating between Member States to avoid double counting could become quite substantial. National administrators would need to engage with their (up to) 27 counterparts and undertake some sort of end of year reconciliation and comparison of submitted credits. While a central database would imply set-up and operating costs for the European Union, it is felt that this would be the most efficient way to manage these risks. In the absence of a central database run by the European Commission, one alternative would be for Member States to define a single protocol for allocating and recording serial numbers, and to set up databases of recorded UERs that could be readily queried by other national administrators. While this would be a technically very feasible solution, coordinating decision making among all Member States may be difficult.

Another question would be whether a central administrator or the Member States individually are given responsibility to confirm the qualifications of project auditors. Under CDM, the CDM Executive Board must approve the DOE. Under Option 3a, the most streamlined system would be to have a central administrator approve projects including the selection of auditors. If instead Member States were given the responsibility of approving project design documents and choice of auditors, it would be more difficult to ensure a consistent level of oversight. There are international standards (ISO 14066, ISO 14065) outlining the competences required from and the process that should

be followed by auditors of carbon emissions reduction claims. Imposing these (or similar) guidelines on Member States should provide a degree of consistency. Nevertheless, the level of oversight applied could vary a great deal, with self-certification at the minimal end and extensive paperwork submission requirements at the maximal end. Given differences between Member State capacity and appetite to undertake these sorts of checks, it is to be expected that if approval of auditors is left to Member States there would be some variation in robustness of application.

There could also potentially be differences in verification requirements and practices among Member States, in addition to differences in the selection of auditors. Section 4.3.3 outlined a prescriptive verification approach that detailed audit frequencies and the types of actions that should be undertaken by auditors. Adopting this prescriptive approach would limit the extent to which verification practices could vary between Member States. If instead voluntary sustainability schemes are utilized for verification, auditing practices could vary substantially.

Under Option 3b, competent auditors would validate and verify UER projects in line with any guidelines set by schemes and Member States. To be eligible under FQD, this process must follow the requirements for auditors and verification practices described in the ISO standards and discussed in Section 4.3.4. Beyond this, specific requirements for verification actions would be at the discretion of the schemes and that of the Member States, should they choose to impose additional requirements. This approach would potentially allow the highest degree of variation in verification practices of any of the Options discussed in this report. In some cases, this could also be associated with variability in the quality of reported emissions reductions used for compliance with FQD. It is expected that a national administrator would need to be appointed in each Member State to verify that reported UERs conform to FQD requirements; differences in mandates and legal powers given to these bodies could result in discrepancies in stringency of anti-fraud enforcement, and may create a window for lower quality UERs to be reported in certain Member States. Member States may find it useful to create information exchange mechanisms to share experiences of implementation and discuss best practices. Appointing a central EU data repository for data on reported UERs in Option 3b could be helpful to national administrators; without such a central data holder or alternative measures, there would be considerable risk of double counting emissions reduction projects across multiple Member States.

4.4.2.c. Integration of market for UERs with other compliance options

A third area of potential difference relates not so much to the details of project oversight, but to the way that upstream emissions reduction credits would be integrated into Member State policy support for other compliance options under the FQD GHG reduction target. To give a simple example, consider the case that in the UK the RTFO remains in place to 2020 as the primary biofuel support mechanism in the UK. As the RTFO is a volume mandate and does not generate a price on

carbon, UER credits could not be directly integrated for compliance under the RTFO. The UK Government would therefore need to introduce some complementary system in order for it to be possible to redeem credits towards compliance with the FQD.

Suppliers would only need to use UERs if the biofuel supplied under the RTFO was not adequate to deliver compliance with the FQD. In that case the size of the UER market in 2020 would be heavily determined by the GHG reductions delivered by biofuels. It may be difficult to predict the value of UERs in 2020. This could undermine the likelihood of investments in UER projects being made.

Under an integrated carbon market, on the other hand, the use of UERs would be relatively straightforward. As noted above, the German system will move to carbon incentives from 2015, and it would be trivial to integrate the redemption of UER certificates in such a system. The California Low Carbon Fuel Standard is a good example of an operational scheme that already combines the possibility of delivering emissions reductions through biofuels with crediting of upstream emissions reductions projects. The only risk in the RED/FQD context of an implementation entirely through carbon reductions is that if the supply of UERs was very high it could reduce the actual volume of biofuel used, and this could threaten achievement of the 10% renewable energy target.

The proposed FQD implementing measure does not include any language that would prescribe a single approach to the integration of UER credits into national implementations of FQD. The only pertinent requirement is that the national implementation should allow regulated parties to include reported UERs in the calculation of the specific GHG intensity of the fuel they supply. As Member States have considerable flexibility in determining the practical details of integrating UERs into local implementations of the FQD, in the short term there will be a degree of uncertainty for regulated parties about whether UERs will have value in all Member States. Additional clarity about the details of implementation would help support assessments of the value of UER credits, and therefore support potential project proponents in taking investment decisions. It is likely that significant differences in national approaches to market integration will contribute to uncertainty in the value of UERs, and that some Member State markets will offer higher value than others. Member States in which value certainty is established more quickly may find that they attract a higher fraction of eligible UERs than Member States where uncertainty persists longer.

4.4.3. Potential concerns of Member States

As part of the stakeholder consultation, the following points were raised as potential concerns some Member States may have about the implementation of UER crediting schemes.

- If upstream emissions reductions were being credited through multiple voluntary frameworks, there could be some variation

in quality of implementation. Some Member State officials may be more comfortable with a single framework applied across Europe, either through a prescriptive measure or a central administrator.

- The idea of having a central emissions reduction credit database may be preferred by some Member States as a way of managing the risk of credits being counted in more than one jurisdiction.
- With the possibility of credits being eligible for only one year, it was suggested that it could be appropriate to allow credits to be accumulated over several years and redeemed against the 2020 target.
- Some Member States are likely to be concerned over opportunities for double counting of emissions reductions, whether in two Member States, in FQD and in ETS (especially under Option 1) or in FQD and some other system were introduced with Member States.

4.5. Task 3d: Eligible projects

4.5.1. Eligible projects under the CDM options

Under the ETS-CDM option (Option 1), credits would be recorded in the Union registry, effectively double counting credits with EU ETS. New rules severely limit the eligibility of CERs and ERUs in EU ETS (European Commission, 2009). For new projects registered in 2013 or later years, only projects in LDCs are eligible for the use of offset credits under EU ETS. Emissions reductions from non-LDC CDM and JI projects from 2012 and before are still eligible to be carried over for compliance in the 2013-2020 period (for more on carry over, see Section 5.2.2), but new projects from non-LDCs are not. No JI projects are eligible in 2013 and beyond. As discussed in Section 4.5.1, this greatly limits the overall potential for emissions reductions from venting and flaring to be used towards FQD compliance under Option 1, as it excludes high-potential countries such as Russia and Nigeria.

From 2020 onwards, it is not currently anticipated that any emissions reductions from CDM projects will be eligible for use in EU ETS at all.

The standalone CDM option (Option 2) is not constrained by the list of LDCs, as under this option credits would be recorded in a stand-alone registry independent of EU ETS. Project eligibility under Option 2 is also constrained by the requirements for existing CDM methodologies, and those are described here.

Under the FQD, eligible projects include those that reduce the lifecycle greenhouse gas intensity of fuel and energy used in road transportation in the year 2020 (also applicable in 2014 and 2017 for Member States

that implement intermediate targets). At the broadest level, this could include any projects that reduce upstream emissions from the production of petroleum that is used in transport fuel.

Upstream emissions reductions in any country can be additional, but as the FQD target is for the carbon intensity of fuel supplied within the European Union, one option would be to look to restrict the eligibility to projects associated with oil streams coming to Europe. At the moment, there is no chain of custody in place to allow national or EU regulators to determine whether oil from a given oilfield is consumed in Europe. It would be possible to put such a requirement in place, and force economic operators looking to use CERs for FQD compliance to prove that the CERs are associated with oil actually supplied to Europe. This would however, represent an additional administrative burden, and may be a discouragement to project registration. The global oil market is fungible, and oil field operators may be less willing to invest in CDM projects if they would be forced to arrange to sell their oil into the European market to earn credits. There may therefore be limited environmental benefit available from restricting national eligibility to use CDMs under FQD in such a way. The proposed FQD implementing measure implies a number of other eligibility criteria on venting and flaring reduction projects. Table 2.2 lists the proposed reporting requirements and indicates those that are not currently included in CDM reporting. The eligibility of projects for FQD compliance would be predicated on whether any additional information required under a final rule could be verified and submitted to national/EU authorities as appropriate. For example, under the proposed implementing measure only projects that monitor and report the gas-oil ratio would be eligible.

CDM imposes a number of eligibility criteria on all projects, including venting and flaring reduction projects. The general requirements for eligibility under CDM apply to Options 1 and 2; these are (Shrestha et al., 2005):

- The participation of national governments of project partners is voluntary;
- The project results in real, measureable GHG emissions reductions and long term benefits;
- The GHG emissions reductions are additional to what would have happened without the project.

It should be noted that there is also a broad geographical requirement that CDM projects must be in non-Annex I countries. Joint Implementation (JI) acts as a geographically complementary scheme to CDM; only projects in Annex I countries are eligible for crediting under JI. The list of Annex I countries generally includes developed nations.⁴⁷ It is, however, generally understood that JI projects will be put in place in 'transition economies.' From the point of view of JI venting and flaring reduction projects, the Russian Federation is certainly the most

⁴⁷ The list of Annex I countries can be found at:
https://unfccc.int/parties_and_observers/parties/annex_i/items/2774.php.

important country. Non-Annex I countries generally include developing nations.⁴⁸

For projects that reduce venting and flaring from oil wells specifically, eligible projects are defined in the approved methodologies below. In each of these methodologies, only collected gas that would otherwise have been vented or flared is eligible for crediting; this is a central additionality requirement within CDM. All of these projects cover upstream emissions reductions from petroleum production and thus would in principle be eligible for compliance under FQD. New venting and flaring reduction projects that fit the general CDM eligibility criteria, but do not fit under one of these approved methodologies, can apply for approval of a new methodology that includes this project type.

Methodology AM0009: Projects that recover associated and/or gas-lift gas and export it via a gas pipeline. Lift gas from outside the project boundary (e.g. gas produced from a separate gas field for the purpose of enhanced oil recovery) is eligible in principle. A partial amount of the recovered gas can be used to meet energy needs on site. The gas may be compressed into CNG or processed into hydrocarbon products (e.g. liquefied petroleum gas) prior to export. The oil well must be producing oil at the time of project start. There is no requirement that flaring or venting must have occurred prior to the project start, although presumably any on-going oil production would be associated with some flaring or venting. If gas recovery was already in place, the project would not be deemed additional and would thus not be eligible for crediting under CDM.

Methodology AM0037: Projects that recover associated gas from oil wells and utilize this gas to produce a useful chemical product. Flaring and/or venting must have occurred for the last 3 years prior to the project start. The recovered gas may be partly used as an energy source in the chemical process to produce the useful product (e.g. methanol, ethylene, ammonia).

Methodology AM0077: Projects that recover associated gas from oil wells and deliver this gas to a clearly identifiable end-user either through a pipeline (as in AM0009) or by CNG mobile units (high strength pressure vessels designed to transport CNG from a large CNG station to smaller stations⁴⁹). The oil well must be producing oil at the time of project start, and flaring and venting must have occurred for the last 3 years prior. If the gas is delivered by CNG mobile units, there is an additional requirement that it must be delivered to end users who were already generating heat with existing equipment at the delivery site prior to project commencement. The recovered gas must be utilized within the same country as the project, although it is not clear why this requirement is in place. If gas-lift gas is recovered by the

⁴⁸ The list of Non-Annex I countries can be found at:
http://unfccc.int/parties_and_observers/parties/non_annex_i/items/2833.php

⁴⁹ Defined in GGFR (2010b).

project, it must be from associated gas within the project boundary, and not gas imported from a separate gas field.

The eligibility requirements in these methodologies differ mostly by the specified end use, in whether gas-lift gas is eligible, and in whether flaring and venting must have occurred prior to the start of the project.

Each of these three methodologies specify that CO₂ emissions from combusted methane are included in the baseline scenario, but not uncombusted CH₄ emissions. For flaring reduction projects, this assumption means that 100% flaring efficiency is assumed in order to credit emissions reductions conservatively (i.e. to avoid over-crediting projects). For venting reduction projects, vented gas is assumed to be flared in any baseline scenario; i.e. reduction of methane, which has a global warming potential 25 times that of CO₂ on a 100-year timescale (IPCC, 2007), is credited as CO₂ and the higher real savings (from a climate perspective) are not recognized (although this difference is partially offset by the higher density of CO₂; one tonne of methane produces several more tonnes of CO₂ when combusted, and it is the number of CO₂ tonnes that is credited). AM0077 actually explicitly states that all venting reduction must be credited as CO₂ and not methane. Earlier versions of AM0009⁵⁰ did allow higher crediting of methane avoidance from venting reduction, and at least one CDM project has applied to be credited for reduction of methane using that methodology (“Recovery of vented gas at the Guneshli oil field in Azerbaijan”) but this project is still in the validation process and so it is not yet known whether the CDM EB will approve it and fully credit the methane reduction. AM0009 has since been updated to 07.0.0 and in this version, the higher crediting of methane avoidance is not eligible.

One notable issue is how gas-lift gas is treated under these different methodologies. Gas-lift gas is not eligible to be credited under AM0037 in any circumstance. In AM0077, gas-lift gas is eligible *if* it originated as associated gas from an oil well within the project boundary, so in essence all credited gas must be associated petroleum gas from the project oilfield in this methodology. AM0009 is the most generous with respect to gas-lift gas, and gas-lift gas from any source appears to be eligible.

The specified end use of the gas is also different in each of these methodologies. AM0077 is highly specific, as the end-user must be identifiable (and if CNG mobile units are used to transport the gas the project applicants are required to identify the end users prior to project application), which indicates the project participants must be able to guarantee the end use. Furthermore, the gas must be used to generate heat within the same country as the project. These conditions should make an additionality assessment more tractable, but are restrictive to the project participants. AM0037 applies to projects that use the gas as a feedstock in a chemical process, but not when the primary use of the gas is for energy. Again, AM0009 is the most broad and does not

⁵⁰ The current version at time of writing is AM0009 v0.7.0. The eligibility of crediting methane from venting reduction was removed in the revision from AM0009 v0.3.0 to AM0009 v0.4.0.

specify what the end use must be, although it is restrictive in transportation and LNG and other conversion routes are not eligible.

These three approved methodologies are specific about the types of projects they apply to, but there is clearly scope for new methodologies to deal with additional gas utilization cases, providing they fit the general CDM criteria. For example, a new methodology to recover associated gas and gas-lift gas and transport via CNG mobile units to a chemical plant in a different country where the gas is used as a feedstock for the production of methanol, could in principle be approved and used to register this type of project under CDM. However, a project applicant would have to apply to register this new methodology as well as apply for their specific project to be credited, which would certainly be a longer process than using a previously approved methodology (the additional time for the approval of a new methodology is discussed in Section 3.4). This additional wait time as well as administrative burden could discourage some projects that could in principle be eligible for crediting under CDM.

As well as being most broadly applicable methodology, AM0009 is also by far the most widely utilized methodology for venting and flaring reduction projects under CDM (Fenhann, 2014). This suggests that more generally applicable methodologies are seen as more useful by potential project participants, and furthermore that the approval of more generally applicable methodologies in the future would likely attract more project applications.

In principle the CDM EB could approve small-scale methodologies for venting and flaring reduction projects. Small-scale projects are defined as projects that do not exceed emissions of 15 kilotonnes CO₂e per year. Small-scale projects are classified into broad categories, and it appears that small-scale venting and flaring reduction methodologies could potentially be eligible under the “methane reduction” sub-category of “other projects” (i.e. not renewable energy or energy efficiency projects) (UNFCCC, 2006b). The advantage of using small-scale methodologies is that they allow use of a simplified baseline and monitoring methodology, which may reduce administrative costs for project participants. However, at the time of writing no small scale methodologies for the reduction of venting and flaring from oil production have been approved.⁵¹ If applicable small-scale methodologies are developed and approved in the future, this could encourage the participation of small venting and flaring reduction projects that would otherwise not be worth the effort of registering as a large scale CDM project.

New rules under CDM limit projects that reduce certain industrial gases (namely N₂O and HFC-23) and projects related to land use change. These restrictions do not apply to venting and flaring reduction projects.

⁵¹ Currently approved small scale methodologies can be found at the UNFCCC CDM website: <http://cdm.unfccc.int/methodologies/SSCmethodologies/approved>

4.5.2. Eligible projects under the prescriptive option

4.5.2.a. Type of extraction facility

It is proposed that only projects reducing venting and flaring of associated gas from oil wells should be included under the prescriptive option (Option 3a). Under this recommendation, projects at gas fields would be excluded because gas is not typically a transport fuel. It is also noted that most flaring occurs due to lack of infrastructure for gas export, and thus the opportunity to deliver emissions reductions at such gas production facilities is likely to be much more limited. By definition, gas fields are already connected to gas export infrastructure so there should be no reason to systematically flare gas (although some flaring could still occur for pressure management etc.). Downstream emissions reductions (e.g. flaring at oil refineries) are not recommended for eligibility because downstream emissions are not under the purview of FQD, the size of the opportunity is relatively small, and emissions at refineries are already regulated under EU ETS.

4.5.2.b. Source of gas

It is proposed that projects from all countries be eligible for crediting under Option 3a. As noted above (Section 4.5.1), there would not be a clear environmental benefit to restricting crediting to oilfields that could be demonstrated to be supplying crude to the EU. Restricting eligibility to projects in given regions, or where fuel can be traced back to source, would introduce additional burden and exclude projects that could deliver genuine savings.

4.5.2.c. Single methodology for all project types

In general terms, Option 3a provides one single methodology that covers all possible gas sources, transport modes, and end-uses that are eligible under any of the three existing CDM methodologies for venting and flaring reductions from oil wells, as well as some cases that are not currently eligible. It is intended that Option 3a should be less burdensome for participants than the current CDM process. As such, this proposal for Option 3a aims to be as broad as possible in applicability, while at the same time reducing the risk of fraud by excluding high-risk categories of project (discussed further in Section 4.5.2). Where additional monitoring and verification requirements are suggested for specific project types, this is intended to protect against specific risks. There are clear benefits to this approach of one overarching methodology. Importantly, no projects should fall through the cracks because of combining elements eligible in different methodologies. For instance, as discussed above, a new project to recover associated gas and gas lift gas (eligible under AM0009 but not others), transport it via CNG mobile units (eligible under AM0077 but not others), and use it as a feedstock in a chemical plant (eligible under AM0037 but not others) would not be eligible under any existing CDM methodology. There are no such gaps when only one methodology is used. This simplified system also reduces the potential for confusion among project applicants about whether or not their project is eligible, potentially saving administrative time. It should generally be clear

whether a project is eligible in principle for crediting, simplifying project appraisal for potential participants and removing entirely the threat of having to develop a whole new methodology.

4.5.2.d. Crediting of existing projects

In general, it would not be possible to have existing emissions reduction projects credited under Option 3a. Where projects are already in effect, the presumption is that continuing that project could not be additional. The only exception to this rule would be the case that an existing project is at risk of being shut down without additional credit support, for instance an existing CDM project suffering from low CER prices. It is suggested that such cases should be considered further by the Commission before they would be made eligible for crediting, and that there should be a relatively challenging burden of proof to show additionality for such cases (i.e. strong requirements to show that a project could not continue without access to FQD credits). Nevertheless, given the low value of CERs such cases may well come up, and it would be appropriate to consult further with the industry to establish how much interest there would be in such a facility to recognize existing projects. Allowing CDM registered projects to generate FQD credits in exchange for giving up rights to CERs could potentially be a way of bringing more credits into the FQD system.

4.5.2.e. Flare efficiency

As noted above, it is recommended that improvements in flaring efficiency should not be creditable. Such crediting could incentivize operators to reduce flare efficiency prior to applying for credit support. Furthermore, the high uncertainty in flare efficiency measurements (see Section 2.5) would undermine confidence in such credits.

4.5.2.f. Lift gas

In addition to associated gas from the local oil well, it is proposed that pressurized gas-lift gas imported from independent gas fields should be eligible for crediting if that gas was previously being flared but can be captured by the project. In most cases where gas-lift gas is necessary, associated gas from the same oil well is compressed and effectively “recycled” as gas-lift gas. In some cases where a high-pressure gas field is located nearby, operators import this gas to use as gas-lift gas in the oil well because it is less expensive than compressing and recycling associated gas. At least one project applied to be credited under CDM for switching from this practice to using compressed associated gas (“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”; validation negative).

The crediting of imported lift-gas introduces an additional risk of fraud (as detailed in **Error! Reference source not found.**), and therefore it is proposed that additional conditions should be imposed on such projects before they can be credited:

- (1) the project participants supply a financial analysis demonstrating that it was more economical to import high-pressure gas from the gas field than to compress associated gas from the oil well;
- (2) the project participants supply an engineering assessment of the rate of lift-gas injection required (m^3/bbl), and only this much gas use should be eligible for crediting;
- (3) in addition to the requirement for an engineering assessment, there should be a general maximum on the amount of recovered gas-lift gas that can be credited of 43 m^3 per barrel of liquid produced.

These three conditions must be verified by the independent auditors.

4.5.2.g. Transport to market

No restriction is proposed on the way that recovered gas is transported to market. This includes transport by pipeline, trailers, trucks, carriers, and CNG mobile units. The gas may be processed into dry gas, LPG, etc. or compressed into CNG before transport (although in such cases some additional monitoring and reporting is required). Other forms of gas transport not listed here may be considered by the independent auditors and should generally be approved. The only case in which a transport system should be rejected would be if the independent auditor deemed that the risk of leakage/accidents was so great as to substantially undermine the savings delivered by the project.

4.5.2.h. End use

Similarly, all productive end uses for the recovered gas should be eligible under Option 3a. This includes use of gas for heat, electricity generation, industrial energy applications, domestic gas supply, transport fuel and as a feedstock in the production of a product (e.g. methanol). Where gas is exported to existing gas distribution systems with no ring-fencing of end use, this is acceptable for crediting. Any other end uses for the recovered gas should generally be approved, provided that it is expected that the use of the gas would displace another feedstock of equal or greater carbon intensity.

It is proposed that use of the recovered gas for energy on-site should be eligible for crediting under Option 3a, but subject to additional reporting requirements under Section 2.3.2. Where some gas is already used for on-site energy generation, the existing rate of usage should not be creditable.

4.5.2.i. Capacity expansion

In addition to entirely new infrastructure, it is proposed that projects that increase existing export capacity should be eligible under Option 3a. This could include, for example, increasing capacity for gas compression to boost CNG exports, or increasing pipeline export capacity. As detailed under Sections 2.2.2.b and 2.3.2, the amount of gas creditable in such projects would equal measured gas export minus previous export capacity, which should represent a conservative

determination. There could potentially be a case where an operator seeks to replace existing gas export capacity with export capacity by an alternative mode, e.g. replacing pipeline export capacity with liquefaction capacity. This could happen if existing markets are oversupplied or otherwise access is limited, or if a large spread opens in price between liquefied, compressed and piped gas. While it is possible in principle for such projects to meet additionality criteria (if the baseline would include discontinuing existing exports for financial reasons), it is proposed that such cases should not be eligible. This is because the challenges around demonstration of additionality would be exaggerated in such a case, in particular as regards convincingly demonstrating that discontinuation of export is the correct baseline assumption. Being seen to credit projects that involve no actual increase in gas recovery could undermine the credibility of the crediting system.

4.5.2.j. Prior flaring

Under some CDM methodologies, under Option 3a it is proposed that there be no requirement that projects vented or flared prior to applying for crediting. This will allow Option 3a to incentivize gas capture at new oil wells and oil wells where production is increasing. The auditor should however be provided with a declaration of whether flaring/venting is currently in effect at the field, and a clear explanation of why flaring/venting would commence in the baseline scenario. The additionality requirements under Option 3a, and other measures in the Option 3a methodology, should satisfactorily protect against the risk of crediting non-additional projects.

4.5.3. Eligible projects under the implementing measure requirements

The option reflecting the implementing measure requirements (Option 3b) is more open with regard to project eligibility than what has been outlined for Option 3a. In the proposed FQD implementing measure, eligible projects are not explicitly limited to those reducing venting and flaring emissions, and could potentially include other types of upstream emission reductions. The proposed implementing measure states (European Commission, 2014a):

Voluntary greenhouse gas emission reductions at oil and gas production and extraction sites shall only be applied to default values derived from solid, gaseous or liquid feedstock sources such as petrol, diesel, CNG or LPG.

Upstream greenhouse gas emission reductions originating from any country may be counted as a reduction in greenhouse gas emissions against fuels from any feedstock source supplied by any fuel supplier.

Upstream greenhouse gas emission reductions shall only be counted if they are associated with projects that have started after 1 January 2011

It is not necessary to prove that upstream emission reductions would not have taken place without the Article 7a reporting requirement.

In addition to the types of venting and flaring reduction projects at oil extraction sites that would be eligible under Option 3a, this language allows for upstream emissions reductions at gas extraction sites to be reported. In general, rates of flaring at gas production sites are expected to be much lower than at oil sites without gas capture infrastructure, and therefore the overall opportunity for emissions reductions in the gas sector are likely to be less. It also allows for upstream emissions reductions to be delivered through methods other than reductions in venting and flaring. For instance, fuel switching at an oilfield from a high carbon intensity fuel such as petroleum coke to a lower carbon intensity power source such as wind energy would be creditable if additional and appropriately reported. These other upstream emissions opportunities are beyond the scope of this report, however it is believed that venting and flaring reduction projects offer by far the largest opportunity for cost-effective UERs in the upstream sector.

There is to be no geographical restriction on the countries in which UERs may take place, distinguishing Option 3b from approaches within the CDM. Under the reporting requirements imposed in the proposed implementing measure, any projects must start after 1 January 2011, so credits still being generated by legacy projects would not be allowable.

There are no restrictions on eligibility with regard to whether flaring or venting occurred prior to the project start, what types of gas (i.e. associated gas, gas-lift gas) may be credited, what modes of transport are used, and the end-use of the gas. Voluntary schemes used to award credits for UERs may of course choose to impose additional eligibility criteria on these and other aspects. In all cases, projects must conform to the requirements for showing that emissions reductions are additional as identified in ISO 14064 Part 2. Member States may wish to impose additional eligibility restrictions in line with their assessment of which types of project can meet those additionality requirements.

Under Option 3a, it was recommended that projects to improve flare efficiency should not be eligible for credits under the FQD. ISO 14064 Part 2 on the other hand does not directly prohibit projects that improve flare efficiency and thus such projects could in theory be eligible under Option 3b. Certainly, the ISO allows for “appropriate GWPs” to be used in the assessment of emissions reductions (ISO 14064 Part 2 article 5.8). This would support the possibility of crediting methane destruction based the difference between the GWP of the combusted methane and that of the resultant CO₂.

Although there is no direct restriction on the eligibility of emissions savings delivered through improved flare efficiency, there are requirements for treatment of accuracy and uncertainty that might limit

the possibility to credit such projects. ISO 14064 Part 2 article A.2.5 states that, “Accuracy and conservativeness are interrelated principles. Once a project proponent has reduced uncertainty to the extent practicable, the value chosen within that range should result in a conservative estimate of the GHG emission or removal.” As discussed in Section 2.5, there are considerable uncertainties associated with measuring flare efficiency at all, and greater uncertainties when assessing the difference between emissions in a project and baseline case. If flaring efficiency improvements were to be credited under Option 3b, it would be necessary for the validator and verifier to confirm that there was an adequate certainty that emission reductions had been achieved given uncertainty and inaccuracy in the system. The project proponent would need to agree a methodology with the validator for assessing emissions reductions that was conservative by design. The awarded credits for a flaring efficiency project should therefore always be below the best estimate of the emissions reductions achieved. Given the considerable challenges in accurately assessing such emissions reductions, a Member State may feel that this is an example of a case in which eligibility should be restricted in order to comply with the principles of accuracy and conservatism in the ISO standard.

On a similar note, while under Option 3a it was proposed that all venting reductions should be awarded based on the GWP of CO₂, Option 3b would in principle allow additional credit to be given for avoided methane. Again, it would be important to ensure that the accuracy of the assessment of reduced venting, and accuracy of the identification of the composition of vented gas, were adequate to support the award of credits using the GWP of methane. As with flare efficiency, schemes, validators, verifiers and national administrators should have regard to the principle of conservatism when crediting such emissions reduction. The final judgment about how such projects are credited will be at the discretion of Member States.

4.6. Task 3e: Baseline

4.6.1. Baseline setting under the prescriptive option

Correct baseline setting is vital to accurate crediting of emissions savings. A robust crediting system must have in place safeguards to ensure accurate and truthful reporting of baseline emissions. Several such safeguards are proposed for the prescriptive option (Option 3a).

As under CDM, validation of the reporting and calculation of baseline emissions is required by independent auditors under Option 3a. This is discussed in Section 4.3.3.b and includes a site visit to ensure that the baseline infrastructure is reported correctly. Minimum accuracy of all measurement equipment is specified in Section 2.3.2 in order to ensure accurate reporting of both baseline and project emissions.

Projects that increase existing rates of gas recovery and usage should be eligible under Option 3a. This would include projects that already export or utilize some gas in the baseline, and would be increasing export or on-site usage with project implementation. Including such projects widens the scope of emissions reductions deliverable under this mechanism, but it introduces additional challenges in baseline setting when compared to wholly new infrastructure. In particular, there is a risk of fraudulent reporting in baseline setting with these projects. For example, a project could be over credited if the applicants claimed falsely low exports in the baseline and very high exports in the project scenario, when in fact the project would not result in such a great increase in gas export. This type of fraudulent reporting would be prevented under Option 3a by defining the baseline scenario by gas export *capacity* rather than *consumption*. Thus, the amount of emissions reduction delivered by the project activity would be defined based on *measured* gas recovery after project implementation minus gas export *capacity* before project implementation. For on-site gas usage, only gas consumed in *new* on-site equipment would be eligible for crediting. This is a conservative approach that should virtually eliminate the possibility of underreporting baseline emissions in these types of projects.

Another case that could introduce complexity to the baseline is the recovery of gas-lift gas sourced from a separate pressurized gas field. Such projects could occur if already pressurized gas is being imported for gas-lift to avoid the need for installing gas compressors. Whereas normally lift-gas would be recycled into the well, in these cases this does not occur as it would need recompression first, and the equipment is not available. Capturing this used lift-gas rather than flaring it would therefore result in real emissions reductions. However, inclusion of these types of projects could create an incentive to import more pressurized gas than is actually necessary for oil recovery. In principle, an operator could either inject more lift gas than necessary, or simply connect a gas import line directly to the export line and pretend that the gas had been used for lifting. In such a case, the excess imported gas would generate credits that were not associated with any real emissions reduction. As a measure to protect against this type of fraud, it is proposed that there should be a cap on the amount of gas-lift gas that is eligible is proposed, and that project auditors should be shown engineering assessments of the amount of lift-gas required.

For potential projects improving the combustion efficiency of gas flares, the challenges in baseline setting are considered so significant that it is recommended that such projects are ineligible for credits. Such projects would have an incentive to misreport baseline flare efficiency or even to purposefully reduce it prior to the project start. It would be difficult to impose proportionate reporting requirements that would protect adequately against these fraud risks. For similar reasons, it is proposed that there should be no additional credit for venting reduction projects to account for the global warming potential of methane. While an argument could reasonably be made that reducing venting delivers greater benefits than reducing flaring, such

opportunity would introduce perverse incentives to increase the proportion of gas being vented as opposed to flared. By crediting venting reduction only at the same rate as flaring reduction, such incentives would be eliminated.

Under any of the three options for upstream emissions reduction crediting, the emissions reductions achieved (in tonnes of carbon dioxide equivalent) would be offset against the emissions assigned to fuel supplied by a supplier. For this sort of crediting, it would not be necessary to assess the full lifecycle carbon intensity of production of oil at the project field, for instance by modeling with OPGEE. While there will be many emission sources outside the project boundary that could be assessed, such as energy to pump produced oil up the well, it is assumed that these are not affected by the project. It would be possible to require reporting of such information as a criterion for eligibility, but it would not affect the environmental benefits of the crediting regime.

If full reporting of crude oil carbon intensity were introduced, or a hybrid system allowing suppliers to report actual data on an opt-in basis, then upstream emissions reduction projects could deliver value as part of a full lifecycle assessment. This could obviate the need for the type of credit-and-offset scheme detailed here.

4.6.2. Baseline setting under the implementing measure requirements

Safeguards to ensure accurate baseline reporting under the implementing measure requirements (Option 3b) are indicated in the ISO standards, which states that baseline setting should consider, “relevant information concerning present or future conditions, such as legislative, technical, economic, sociocultural, environmental, geographic, site-specific and temporal assumptions or projections” (ISO 14064 Part 2 article 5.4). Within this statement, the requirements that the baseline scenario consider legislative and economic assumptions suggests that venting or flaring cannot be included in the baseline scenario if such activities are not permitted under local laws and regulations (unless unenforced) or if gas collection is financially favorable to the project operator. ISO 14064 Part 2 also requires that the baseline (and project) scenario include all relevant emissions sources and sinks related to the project.

Specific measures to ensure accurate baseline reporting may be imposed by Member States and by voluntary schemes; such measures may include any or all of the safeguards detailed in Option 3a.

4.7. Task 3f: Minimizing fraud risk

Potential fraud risks to each of the options, as well as measures that have been taken within each proposal to limit fraud are discussed within Annex A.

5. Task 4: Risk/cost of double rewarding projects

5.1. Summary of Task 4

This subtask discusses the potential for CERs and ERUs to be double counted for compliance with both FQD and EU ETS, and under FQD and some another emissions trading system.

Under any of the options discussed, with some basic controls implemented there should be limited risk of credits being double-counted under the FQD. Under the CDM options (Options 1 and 2), double-counting projects within CDM/JI should be prevented by the verification process and by checks within the current trading system for CDM and JI credits. Within the prescriptive option (Option 3a), the central database and detailed project serial numbers should prevent double counting. Under the implementing measure requirements (Option 3b), there could be greater potential for projects to be double counted across multiple schemes, or in multiple Member States. However, if UERs are assigned unique and detailed serial numbers, double counting could be detected either through the operation of a central database or through bi- or multi-lateral data sharing between Member States.

Beyond the FQD, under Option 1, double-counting projects with EU ETS is actually required, as only credits used under FQD would be in the ETS registry. Under Options 2, 3a and 3b, double-counting with EU-ETS could be avoided by establishing regular communication between the central registry for crediting venting and flaring projects and the Union Registry (EU ETS).

It is difficult to assess the risk of double counting projects for compliance under FQD and emission trading schemes in other world regions as no such issue has yet arisen. The central data holder in Options 2, 3a and 3b (and the Commission in Option 1) could publish an annual list of descriptions and serial numbers of projects used for compliance with FQD; other emission trading schemes could check this list before issuing other credits.

5.2. Risk of double counting under the CDM options

5.2.1. Preventing CER double counting in transaction

The UNFCCC's International Transaction Log (ITL) is the most important mechanism to reduce the risk of double counting CER and ERU (JI) credits. The ITL was established by the UNFCCC Secretariat to verify transactions of units used for to demonstrate emissions reductions for compliance with the Kyoto Protocol, including issuance, transfer and acquisition between registries, cancellation and retirement of CERs, and the carry-over of CERs. CERs and ERUs used under both EU ETS and ESD are traded through the ITL. The ITL connects the central CDM registry and national registries, and ensures credit transactions are consistent with rules agreed under the Kyoto Protocol. All approved CERs are recorded in the CDM Registry account. This can be found at the UNFCCC website.⁵² The ITL checks the units to see if they have been previously retired in a nation's registry for compliance with emissions targets or cancelled (if found to not be in compliance with UNFCCC rules, in which case the units are removed from the trading system), if units exist in more than one registry, units for which a previously identified discrepancy has not been resolved and units improperly carried over. It also validates the eligibility of Parties involved in the transaction to participate in the CDM.

Participation in a CDM project must be authorized by an Annex I country (developed country).⁵³ A holding account is established by the project participants at the national registry in that country, and CERs are issued into that account. CERs are transferred from this account to another account in this country or another Annex I country when another party purchases the credits. The purchaser proposes a CER transaction and initiates the transaction with the ITL. The ITL checks each proposal in terms of quantity, type and serial numbers of units, relevant account types and numbers, and transaction status, and validates the transaction before passing to the relevant acquiring overseas registry. The registries will undertake their own validation checks before accepting the transaction. Figure 5.1 below illustrates the process. In the event that a transaction is rejected, the ITL sends a code indicating which ITL check has been failed and the registry terminates the transaction (UNFCCC, 2004).

⁵² All data is available at <http://cdm.unfccc.int/Registry/index.html>

⁵³ The non-Annex I country where the project actually takes place is then known as the host party.

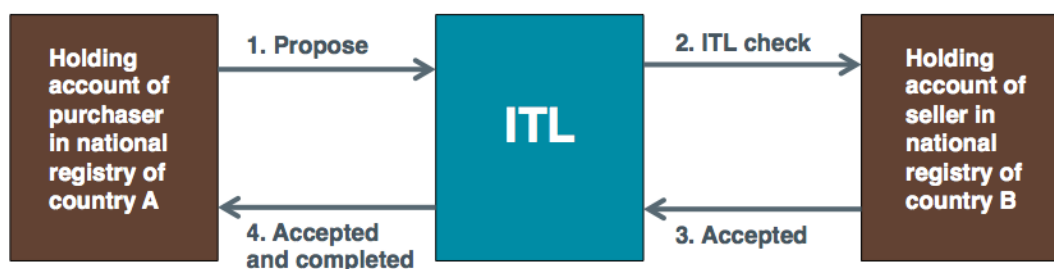


Figure 5.1. Schematic of the transaction process of a CER between the purchaser of CERs (in country A) and the seller (in country B) through the International Transaction Log (ITL)

In order to facilitate tracking, each unit in each carbon trading market under the Kyoto Protocol is given a unique serial number. The serial number comprises the commitment period for which the CER is issued, the country which hosts the CDM project activity, the type of unit (i.e. CER or ERU, the equivalent credit under JI), a unit number that is unique to the CER for the identified commitment period and Party of origin, and a project identifier that is unique to the CDM project activity for the Party of origin (CD Rulebook). A sample serial number is shown in Annex E (Carbon Fix).

Since the EU ETS and ESD were implemented, a few countries and regions that are outside the Kyoto Protocol, including California, Quebec and six provinces in China, have established emissions trading systems that potentially presents a double counting problem. Such a problem has reportedly not occurred yet and the EB is discussing technical solutions to prevent double counting. One potential solution for the purposes of the EU ETS and ESD would be that if a country that is not a member of the Kyoto Protocol, say China, decides to accept CERs but is not connected to ITL, China could open an account through their embassy in the registry of a European nation to handle transactions, and by proxy connect to the ITL. For units used for compliance with FQD specifically, one solution could be to establish a public list of CERs and ERUs retired under FQD so that countries participating under other emission reduction schemes could in principle check to prevent double counting. Member States could also check any available public lists of units retired under other emission reduction schemes to reduce the risk of double counting units used for their compliance with FQD.

5.2.2. Preventing CER double counting in retirement and carry-over

The ITL also plays an important role in retiring CERs and validating use of the carry-over CERs from previous compliance periods. When a CER or ERU is retired, it can no longer be traded or used for compliance in another scheme or for another jurisdiction. Prior to 2013, retirement involved the internal transfer of units from a holding account in a national registry of an Annex B country (essentially the same list as

Annex I countries) to that country's retirement account, which was used to demonstrate compliance with emissions targets. Since 2013, all allowances and offset credits are retired in the centralized Union registry (European Commission). The ITL approves the retirement of a CER if the Party involved in the transaction meets all the eligibility criteria for participation in the Kyoto Protocol (UNFCCC, 2008b).

To add flexibility within the ETS and the ESD, no more than 2.5% of a country's CERs may be carried over from the first Kyoto commitment period (2008-2012) to the second commitment period (2013-2020; note, Kyoto commitment periods are separate from EU ETS Phases). Carry-over refers to the process by which a unit that was issued and valid for one commitment period becomes valid for transactions during the subsequent commitment period. The total quantity of units available and eligible for carry-over is reviewed by the ITL. The ITL then sends a notification to each registry, indicating the total number of units that the registry may carry over. The registry must then initiate carry-over transactions, subject to the carry-over limitations. The CER units will remain in the same account and the serial numbers will remain unchanged, except that the applicable commitment period identifier will be updated to the subsequent commitment period. The serial number also contains an original commitment period identifier that will identify these units as carried-over from the prior commitment period (Annex E).

Carry-over units from the first commitment period would not be eligible for FQD compliance. This can be easily checked in the unit serial number, which specifies the commitment period in which the unit originated. However, the serial number does not specify the year the unit was generated, which would likely be necessary for FQD compliance. As discussed under 2.3 on "Reporting Regime," CER serial numbers do not contain the necessary reporting information for FQD.

5.2.3. Concerns about double counting CERs with FQD

Option 1 would allow CERs and ERUs used for compliance with EU ETS and other emission reduction goals to be eligible also for compliance under FQD. By definition, Option 1 would allow double counting (only credits used for ETS compliance would be placed on the ETS register). It is not clear if such double counting would be seen as problematic for the EU ETS (or other emission reduction schemes) as this situation has not yet arisen. There are already sufficient checks to ensure that a single CER or ERU could not be counted towards the EU ETS for two separate jurisdictions (e.g. Spain and France claiming the same CER), as all transactions are checked by the ITL and all CERs used for EU ETS compliance are retired in the central Union registry.

Under Option 2, CERs and ERUs used for compliance with FQD would be retired under a standalone registry and would not be eligible for compliance with EU ETS or other emission trading systems. As the existing system for trading CERs precisely identifies and tracks each CER, there is likely no need for the FQD to impose additional measures

on CERs to prevent double counting with EU ETS. As discussed above, a public list of CERs and ERUs used for FQD compliance could allow other emission trading schemes to check for double counting, and Member States could check with any publically available lists of CERs and ERUs used for emission reduction targets in other countries. Double counting CERs and ERUs for FQD compliance in different jurisdictions could be avoided if the standalone registry performs a simple check that all CERs and ERUs have unique serial numbers during the retirement process.

5.3. Risk of double counting under the prescriptive option

The risk of double counting under the prescriptive option (Option 3a) would be similar to that under the CDM options (Options 1 and 2), with the additional risk that projects could be double counted under Option 3a and CDM, if a project proponent registered a single project under both schemes.

The risk of double counting projects under both Option 3a and CDM is expected to be relatively small. It is anticipated that Option 3a credits would be more valuable than CERs, from the CDM. Given this, the burden of registering a project under CDM as well as Option 3a may not be considered worthwhile even if it would in principle make double-crediting possible. Such a risk could be minimized or eliminated by an annual communication between the central database (or Member State databases) under Option 3a and the central CDM registry. The Option 3a database could supply a list of all project locations (by country, state or province, and nearest town) and a short description of each project. This should be sufficient information for the CDM registry to cross-check these projects with the CDM list of venting and flaring reduction projects. The converse (CDM registry supply a list of projects to the Option 3a database) could occur instead. In any case, the number of new CDM projects that reduce venting and flaring from oil wells is fairly small, so the burden on the administrators to perform this cross-check would be limited.

As under Options 1 and 2, there is a risk under Option 3a of double counting projects under FQD and emissions reductions schemes in other jurisdictions, or with voluntary markets. This situation has not yet arisen and so it is difficult to estimate how great the risk is. Within the 2020 timeframe, it is not anticipated that this will be a major risk. Placing an obligation on project participants that they should not register project savings in any other scheme should be adequate to ensure that a framework for handling such issues (for instance through project disqualification) is available if cases arise. The central database for Option 3a could publish a list of project locations with a short description for other emissions reduction schemes to cross-check with their own registries. However, without a comprehensive list of all frameworks and projects there is no way to absolutely guarantee that such double counting cannot occur.

5.4. Risk of double counting under the implementing measure requirements

The proposed FQD implementing measure does not explicitly specify any steps that must be taken to prevent double counting. Depending on whether Member States feel that it is necessary to implement measures to prevent double counting, there may be a high risk of it happening. If Member States do however choose to prevent double counting, the requirement that all emissions reductions should be accompanied by a non-reusable certificate number would be a valuable tool.

Under the implementing measure requirements (Option 3b), it is expected that each Member State would appoint a national administrator responsible for receiving and confirming reports of emissions reductions from regulated parties. Such an administrator would be expected to verify that UER projects are not double counted *within* a Member State.

It is envisioned in the specification for Option 3 (a and b) that a single body (such as the European Environment Agency) should act as a centralized data repository for reported UERs in the EU. Should such a central data repository be established, the administrator of this body could use non-reusable certificate numbers associated with UERs (as required in the proposed implementing measure) to verify that UERs are not double counted within or between Member States. This would be a key step to prevent double counting of eligible UERs. Without such a centralized body it would be difficult to ensure double counting does not occur: national administrators in each Member State (assuming they are established) would have to establish procedures to check all reported UERs with the administrators of all other Member States, a system that could potentially be difficult to implement.

As with Options 1, 2, and 3a, there would remain the risk of UERs being double counted first in FQD and then under emission reduction schemes in other jurisdictions. Some schemes may place requirements on credit holders and/or maintain credit registries that would prevent such double counting. Member States may choose to approve credits only from schemes that implement adequate systems to ensure that awarded credits could only be redeemed in a single credit market.

Member States could impose a legal requirement that project participants not register their UER projects under any other scheme, with enforcement penalties for any party found not to have complied. In addition, a central European data holder or national administrators could publish lists of all UER projects credited under FQD, which could be queried by other jurisdictions or participants in voluntary carbon markets.

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Annex A Minimizing fraud risk

This Annex details additional measures that can be taken to minimize fraud risk in crediting venting and flaring reduction projects for FQD compliance.

A.1 CDM options

Under the ETS-CDM option (Option 1), no additional measures to prevent fraud have been identified at the project or credit-trading levels. As Option 1 utilizes existing crediting (CDM/JI) and trading (EU ETS) schemes, there would be little opportunity to impose additional restrictions or other measures.

Under the standalone CDM option (Option 2), no additional anti-fraud measures are recommended at the project level as the existing CDM and JI schemes address such risks sufficiently. New measures are proposed for verification of CERs and ERUs entered into the European registry for compliance with FQD and for the trading of such credits.

The stand-alone third party central registry established under Option 2 would be able to check CER and ERU serial numbers upon retirement to ensure that credits were not used for compliance by two different Member States.

Under both Option 1 and 2, there would be additional requirements for projects to demonstrate FQD compliance beyond the information submitted to the CDM board. It is proposed that the project's DOE submit an additional document to provide information needed for FQD compliance. At the minimum, this document should detail in which year emissions reductions were achieved and which methodology was used for each CER or ERU serial number resulting from the project. This should protect against the risk of parties utilizing emissions reductions from non-eligible projects and from non-eligible years for the purpose of FQD compliance. The DOE should be the entity most familiar with the project, and have been vetted by the CDM board, and is therefore considered qualified to submit this additional information with no further checks.

Under Option 1, Member States would need to check the authenticity of the DOE's report and confirm that it was issued by the same DOE who verified the emissions reductions for the project. In the case of Option 2, the administrator of the central registry would perform this task. The administrator may also undertake additional checks on a risk-based basis on a sample of CERs/ERUs transferred into the central registry. These measures should reduce the risk that DOEs willfully submit false reports.

A.2 The prescriptive option

In the prescriptive option (Option 3a), several measures are proposed to reduce the risk of fraudulent reporting. Some of these measures are also used in CDM, and some are additional.

Option 3a provides an equation with which to calculate NPV/I, the measure of financial attractiveness. It is proposed that the Commission make available a computer tool to facilitate and standardize this calculation in project design documents. This standardized approach differs from CDM, which does not prescribe the financial calculation method, and reduces the potential for fraudulent or incorrect calculation.

It is also proposed that the Commission create and maintain a public online database listing jurisdictions under which flaring or venting is illegal but unenforced. This database may be complete or partially complete in geographical coverage. Such a tool would allow consistency in approving project applications and would reduce the scope for fraudulent projects that are not actually additional. Auditors would be able to quickly check the legal status of the project's region in the database and would be less likely to wrongly approve a project where a flaring or venting ban is in fact enforced.

As under current CDM methodologies, Option 3a would not credit improvements in flare efficiency. Similarly, emissions reductions from reduced venting would be credited the same as flaring reductions, and 100% flare efficiency would be assumed. While improving flaring efficiency and reducing venting have real climate benefits, crediting such projects would create a substantial risk of fraudulent reporting and could potentially increase emissions. A project could temporarily reduce flaring efficiency by tampering with the flare tip or by replacing it with a less efficient one in order to measure high baseline emissions, and then restore the system to its original state to claim emissions reduction credits. If high crediting for venting reduction and flare efficiency projects were available, operators of new projects would have an incentive to flare inefficiently or vent from the start of the project for a period of time instead of flaring efficiently. This perverse incentive could potentially result in a greater increase in emissions than are reduced by the credited project. By not allowing crediting of flare efficiency improvement or higher crediting for venting reduction than flaring reduction, Option 3a would eliminate these sources of fraud risk.

It is recommended that Option 3a provide as wide an opportunity to flaring reduction projects as possible in order to incentivize greater emissions savings. In this vein, Option 3a would allow crediting of both associated gas and gas lift gas under Option 3a. There may be some cases where gas is imported from a high-pressure reservoir to use for gas-lift without further compression. If the gas-lift gas in such cases is recovered along with associated gas, it would be eligible for crediting. This type of project carries a risk that project operators could use more gas-lift gas than necessary in order to 'launder' the high-pressure gas through a crediting route. As a measure to protect against the risk of such fraud, it is suggested that project participants should be required to provide documentation of the engineering case for the use of the reported volume of imported gas-lift

gas, and that in any case the amount of recovered gas-lift gas that could be credited should be subject to a cap of 43 m³ per barrel of liquid produced from the well.

Option 3a would allow crediting of projects with existing gas recovery infrastructure that increase recovery and of projects that previously utilized some gas on-site. Like gas-lift gas, these types of projects are included in order to broaden the opportunity for emissions reductions under Option 3a. The most accurate calculation of emissions savings in these cases would be to subtract actual baseline gas export or usage from current recovery – this presumes that some amount of gas export or usage that occurs after project implementation would have occurred anyway in the baseline. However, this approach carries the risk that project operators would falsify measurements of gas export and usage prior to the project start (i.e. decrease the amount of exported and utilized gas reported in the baseline). Since auditors cannot check in situ measurements before a project application has been submitted, there is little recourse to ensure fraudulent reporting has not happened. Thus, it is proposed to instead subtract the baseline export *capacity* of a project from total measured gas recovery after project implementation. On-site gas usage would only be creditable when used in new equipment. This ensures that baseline gas export and utilization cannot be underreported.

The primary measure to reduce fraud risk is the auditing process. Under Option 3a, this would be similar to CDM, with an independent auditor tasked with validating the information provided in project applications and verifying measured emissions savings. As an additional measure to ensure the independence and impartiality, auditors are prohibited from working for the same company as the project applicants, even if in a separate department or subsidiary of the same parent company.

A full review of project applications, accompanying documents, and a site visit and stakeholder interviews would be conducted by an auditor prior to recommending registration of a project. It is proposed that project operators report monitoring data to the auditor once per month and that full on-site audits occur at minimum once per year for large scale projects and one per three years for small scale projects once a project has been registered.

For flaring (but not venting) reduction projects, reported emissions reductions would be further checked through comparing satellite images of the flaring site over time to ensure that flaring is reduced. If no significant reduction in flaring is observed in the satellite images after project implementation, an additional on-site inspection by the auditor would be triggered. This step serves as a check against both false reporting and fraudulent or compromised verification.

It is proposed that emissions reduction credits under Option 3a be created, administered, and retired under one body, the central stand-alone database. All credit trading would take place within this database. An administrator would oversee the database and upon retiring credits for a project operator to show compliance could easily check that the credit was real and connected to a valid and verified project, and that the credit is not

a duplicate of another. It is proposed that credit serial numbers contain more information than is found in EU ETS serial numbers (including the year of issuance, identification numbers for the project and project operator, and number of credits for this project held by an obligated party) to facilitate verification of the credits. There would be very low risk of double counting credits or of retiring false credits under this system.

A.3 The implementing measure requirements

The ISO standards referred to in the proposed FQD implementing measure provide general requirements for accurate reporting of emissions reductions and for schemes and verifiers (e.g. verifiers must be independent and avoid conflicts of interest). If these requirements are rigorously enforced on UER projects, it should minimize the opportunity for fraud at the project level (i.e. fraud through false reporting of emissions reductions related to a given project). The quality of the validator and verifier are central to ensuring that reported emissions reductions are genuine. ISO 14065 and 14066 provide clear guidance for the appointment of competent validators and verifiers, but without oversight by the associated scheme and by Member States there is some risk of poor quality or even fraudulent auditing. Member States and schemes could limit this risk by imposing comprehensive documentation requirements on audit bodies, by undertaking review assessments of the audit documentation for some sample of audits, and by ensuring that poor or fraudulent performance by specific bodies is recorded and that additional oversight is applied to projects audited by those bodies in future. In some cases, it may be appropriate to implement a system to suspend or disqualify specific audit bodies.

The proposed FQD implementing measure requires all UERs to be associated with a non-reusable certificate number that uniquely identifies the scheme, the claimed GHG reductions, and the calculation method. This certificate number would allow national administrators or other bodies to check that reported UERs are associated with real projects and are not double counted. Implementing systems to allow reported certificate numbers to be confirmed with the administrators of emissions reduction schemes would be a relatively simple check to reduce the risk of fraudulent reporting of emissions reductions.

In principle, ISO 14064 would allow methane reductions from venting reduction and flare efficiency improvement projects to be counted on the basis of the higher GWP of methane compared to CO₂ of combusted gas. Such accounting could create incentives for fraudulent projects that artificially increase venting of associated gas before the baseline is defined in order to create a baseline scenario with high emissions, when operators otherwise would otherwise have flared or utilized the gas. Similarly, if flare efficiency improvement is eligible for credits under a given scheme, operators could have an incentive to reduce the efficiency at flare tips before the project start in order to allow them to record a high emissions baseline. Member States and voluntary schemes could impose restrictions on the accounting of methane, similar to CDM and Options 3a, to protect

against this fraud risk. There may also be an opportunity to impose additional requirements on baseline assessment to reduce the opportunity for this type of activity. For instance, in the case of flare efficiency projects it should be possible to establish whether the flare tip being used at a given project is consistent with normal practice in the industry in that region. A specification could be imposed requiring that a standard practice analysis should be undertaken for any such project, and that no credits should be allowed in cases where the project baseline falls short of standard practice. Similarly, for venting reduction projects it would be possible to require the validator to confirm that rates of venting in the baseline are consistent with standard practice in the industry in that region.

The fraud-risk reduction measures proposed for specific project types under Option 3a above could also be considered by Member States and/or schemes implementing crediting under the implementing measure requirements (Option 3b).

A.4 Remaining fraud risk in all options

Crediting of fraudulent venting and flaring reduction projects could undermine the purpose of incentivizing these types of reductions under the FQD. This subsection discusses potential fraud risks that could occur in all options discussed in this report.

One potential fraud risk is the integrity of the DOEs or auditors. The verification of projects could be outsourced to companies that may have relationships with the project participants, resulting in a conflict of interest. Additionally, there are currently no penalties for the DOE or to the project participants for false reporting under CDM, other than the removal of credits or the suspension of the DOE. Such penalties are not prescribed in Option 3b but could be established by Member States under this option, as in any of the others.

Another potential issue is “false reporting,” associated with mis-identification of the baseline scenario used to determine additionality in any of the options. In some cases, project participants claim that a project would not be implemented in the baseline scenario (i.e. without credit support) when it actually would be implemented regardless. Previous studies have estimated that 15-40% of reported emissions reductions from CDM projects may not be properly additional (Schneider, 2007; Yang, 2001). In 2007, a UN official estimated that 15-20% of all CDM carbon credits were issued inappropriately due to incorrect additionality assessment (Schapiro, 2010). Another study found that almost three-quarters of oil and gas CDM projects were complete at the time of approval for carbon credits, indicating they were not actually additional (Burnett, 2009), although it is not clear from this study if these projects had applied for registration before implementation, or otherwise had planned on credit support.

For Options 1 and 2, low CER prices may indicate that some projects have been approved without actually meeting the financial additionality criteria.

Given the current low CER prices, it can be expected that many CDM flaring reduction projects are marginal in terms of the financial demonstration of additionality (i.e. when the value of CERs is low, only projects that are already on the cusp of profitability will be moved forwards). Given the uncertainties implicit in the financial assessment of proposed CDM projects, it is likely that the CDM EB may have approved projects that may not strictly have met the additionality criterion. Such over crediting may be far in excess of any over crediting through measurement errors⁵⁴.

Sometimes a project could be approved when it is not truly additional because government policies distort the calculation of IRR for the financial requirement of additionality. This is relevant for Options 1, 2, 3a, and potentially Option 3b depending on how it is implemented. There are many countries in the world where it is required that gas is sold to a government at low prices (e.g. \$0.5/Mbtu), and the government then uses the gas to produce high value products. The “project boundary” usually does not include these downstream positions, particularly if the operator itself has no downstream position. In such cases the government does not own the gas production but effectively gains value from emission credits generated by the gas collection via increased supply of low-priced gas – but this benefit is not considered in determining additionality. If these downstream benefits to government were included in the project boundary, the project may not be deemed additional. On the other hand, it could be argued that additional government revenue in developing countries could contribute to the development objectives of the CDM program, for example.

Another potential area for fraud is that carbon reductions could be exaggerated due to measurement error or tampering. For example, it is possible that meters could be tampered with to increase measured gas flows, and then repaired before the auditor verifies measurements. Project participants could in principle also distort their analysis by only measuring certain variables at selected sites, or by adopting calculations that may skew the result. It is also possible that auditors could be bribed or placed in untenable positions. In addition, in many developing countries there is a lack of reliable data and poor institutional capacity to monitor the data collection process, providing opportunity for project participants to manipulate measurements to their advantage. It is not clear if any of these types of fraud have actually taken place under CDM.

In a recent Point Carbon survey (Tvinnereim & Røine, 2010), 15% of 890 respondents from organizations covered by carbon regulation said they had seen fraud, embezzlement, or corruption in a CDM or JI project. This survey highlights the need to develop, implement, and enforce mechanisms such as those described above.

⁵⁴ Estimation by Energy Redefined based on expert judgment.

Annex B Accounting for Risk in Credit Price

There has been significant volatility of the carbon price in the ETS. Investors will view this as additional risk or may in theory account for the price of risk with a discount. In addition prices have also fallen sharply in the past. Here we discuss the level of discount that should be applied to the price.

Simplistically one could buy an option to cover the downside risk, so that one always received the amount expected. We can value the price of this insurance using option theory. As the CDM process provides credits each year one would need to buy an option for year 1, 2 and so on, so the value of this option is dependent on number of years and the level of volatility.

In Figure A, we estimate the discount that would need to be applied to the price by using a Black Scholes valuation model for different maturities (years). Note a detailed valuation is beyond the scope of this project. This model does not account for price jumps.

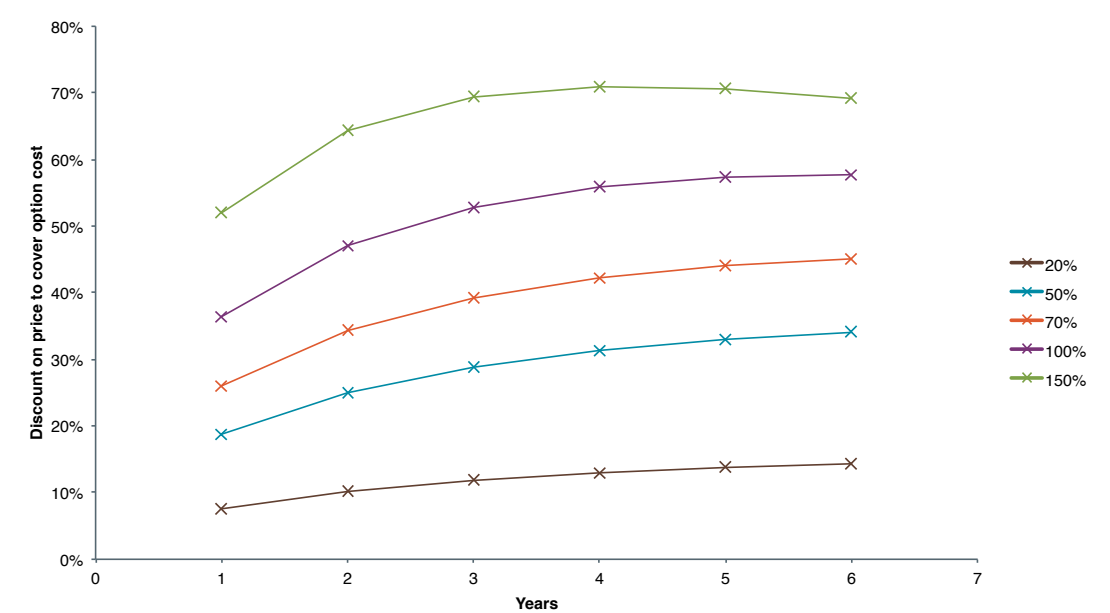


Figure A. The necessary level of discount applied to CDM credits to cover volatility risk, at varying levels of volatility

The values over time average 12-66% for different volatilities. That is one would have to discount the price by 12-66%.

By modifying the Black Scholes model we can estimate the effect of a major jump in the price process, (e.g. a price jump from \$20/tCO₂e to \$10/tCO₂e, or a 50% drop) – using a Merton Price diffusion model.⁵⁵

In Figure B, we show the additional discount that one would have to apply for the jump process modeled. This would be added to the discount above to account for normal volatility with a jump once in the period.

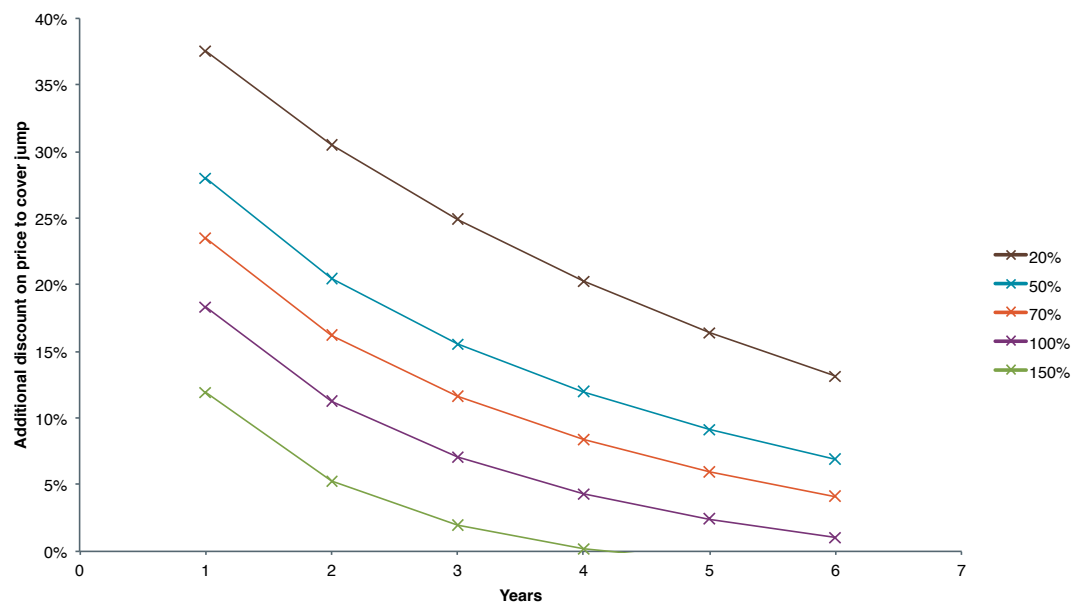


Figure B. The necessary additional level of discount applied to CDM credits to cover the risk of price jumps, at varying levels of volatility

⁵⁵ Note there are many models we could have used but chose this for its relative simplicity

Annex C Reporting requirements for innovative upstream emission reductions under the California LCFS

The regulatory text related to the option to report innovative upstream emissions reductions under California LCFS is as follows:

C.1 Credit for Purchasing Crudes Produced using Innovative Crude Production Methods.

A regulated party may receive credit for fuel or blendstock derived from petroleum feedstock which has been produced using innovative methods. For the purpose of this section, an innovative method means crude production using carbon capture and sequestration or solar steam generation that was implemented by the crude producer during or after the year 2010 and results in a reduction in carbon intensity for crude oil recovery (well to refinery entrance gate) of 1.00 gCO₂e/MJ or greater. The crude oil producer must submit to ARB carbon intensity values for petroleum feedstock recovered both with and without implementation of the innovative method. Credits for CARBOB, gasoline, or diesel derived from this petroleum feedstock must be calculated as specified below:

$$Credits_{Innov}^{XD}(MT) = (CI_{Without}^{XD} - CI_{With}^{XD})_{Innov} \times E_{Innov}^{XD} \times C$$

where,

$Credits_{Innov}^{XD}(MT)$ mean the amount of LCFS credits generated (a positive value), in metric tonnes, by the volume of a fuel or blendstock produced in California and derived wholly from petroleum feedstock which uses the innovative production method;

CI_{With}^{XD} means the carbon intensity value, in gCO₂e/MJ, of the petroleum feedstock produced with the innovative method;

$CI_{Without}^{XD}$ means the carbon intensity value, in gCO₂e/MJ, of the petroleum feedstock produced using a similar process but without the innovative method (hereafter referred to as the comparison baseline method);

E_{Innov}^{XD} is the amount of fuel energy, in MJ, from CARBOB (XD = "CARBOB") or diesel (XD = "diesel"), determined from the energy density conversion factors in Table 4, produced in California and derived wholly from petroleum feedstock produced with the innovative method;

C has the same meaning as specified in section 95485(a)(3)(A).

- a) General Requirements. The innovative crude oil production method must be approved for use pursuant to this section before a regulated party can receive credit under the LCFS regulation for producing fuels or blendstocks from the innovative crude. This regulatory approval must be initiated by the crude oil producer through a written application to the Executive Officer. The application must contain at least the following:
 - i) A description of the innovative method, the comparison baseline method, and how emissions are reduced;
 - ii) An engineering drawing(s) or process flow diagram(s) that illustrate the innovative method;
 - iii) Calculations using the OPGEE model, or alternative model approved by the Executive Officer, to estimate the carbon intensities for the production of the crude using the innovative method and the comparison baseline method. The calculations must identify all modified parameters in the model and demonstrate that the inputs to the model accurately reflect the conditions specific to the crude production process;
 - iv) Any other technical documentation to support the applicant's claim that emissions will be reduced from the use of the innovative method.
- b) Scientific Defensibility and Substantiality. For a proposed application for the use of innovative crude oil production methods to be approved, the applicant must demonstrate both that the innovative method is scientifically defensible and that it meets a substantiality requirement. These requirements are specified below:
 - i) Scientific Defensibility. A crude oil producer that seeks approval for an innovative crude oil production method bears the sole burden of demonstrating that the proposed innovative crude oil production method is scientifically defensible. Proof that a proposed innovative crude oil production method is scientifically defensible may rely on, but is not limited to, publication of the proposed innovative crude oil production method in a major, well established and peer-reviewed scientific journal (e.g., Science, Nature, Journal of the Air and Waste Management Association, Proceedings of the National Academies of Science).
 - ii) Substantiality Requirement. For each of its crude oils for which a crude oil producer is seeking approval as an innovative crude oil production method, the applicant must demonstrate that the proposed innovative crude oil production method has a well-to-refinery gate carbon intensity that is at least 1.00 gram CO₂-eq/MJ less than the well-to-refinery gate carbon intensity for the crude oil produced using the comparison baseline method. "Well-to-refinery gate" means all the steps involved in the extraction, production and transport of the crude oil to California, but it does

not include the carbon intensity due to refining the crude oil, transporting the fuel, or the vehicle's use of the fuel.

- c) Application and Data Submittal. A crude oil producer may apply to the Executive Officer for approval of an innovative crude oil production method under the LCFS. Unless otherwise noted, all applications for an innovative crude oil production method shall comply with the requirements below.
 - i) i. An applicant that submits any information or documentation in support of a proposed innovative crude oil production method must include a written statement clearly showing that the applicant understands and agrees to the following:
 - (A) The applicant must specifically identify all information submitted pursuant to this provision that is a trade secret; "trade secret" has the same meaning as defined in Government Code section 6254.7;
 - (B) All information in the application not identified as trade secrets are subject to public disclosure pursuant to title 17, CCR, sections 91000-91022 and the California Public Records Act (Government Code sec. 6250 et seq.); and
 - (C) If the application is approved, the carbon intensity values will be incorporated into the Crude Lookup Table and LCFS Reporting Tool
 - ii) All applications shall include a detailed description of the innovative method and its comparison baseline method. The description must include:
 - (A) Schematic flow charts that identify the system boundaries used for the purposes of performing the life cycle analyses on the proposed innovative crude oil production method and the comparison baseline method. Each piece of equipment or stream appearing on the process flow diagrams shall be clearly identified and shall include data on its energy and materials balance. The system boundary shall be shown in the schematic.
 - (B) A description of all feedstocks used, including their points of origination, all feedstock transportation distances and modes, and all processing to which feedstocks are subject. This discussion shall cover energy and chemical use, transport modes and distances, storage, and processing. A description of all non-feedstock inputs used in the crude production process.
 - (C) A description of all co-products, byproducts, and waste products.

- (D) A description of all facilities involved in the production of the crude oil and other byproducts, co-products, and waste products.
 - (E) A list of all combustion-powered equipment, along with their respective capacities, sizes, or rated power, fuel utilization type, and proposed use throughout the crude production lifecycle.
 - (F) A description of the thermal and electrical energy consumption that occurs throughout the crude production life cycle. All fuels used (natural gas, biogas, coal, biomass, etc.) must be identified. The regional electrical energy generation fuel mix used in the analysis must be identified. Internally generated power such as cogeneration and combined heat and power must also be described.
 - (G) A description of the transportation modes used throughout the crude production life cycle. This discussion must identify origins and destinations (at least on a regional basis), cargo carrying capacities, fuel shares, and the distances traveled in each case.
- iii) The application shall include complete life cycle assessments performed on the proposed innovative crude oil production method and its comparison baseline method using OPGEE or an alternative model approved by the Executive Officer. Electronic copies of the models shall be provided. The descriptions of the life cycle assessment results must provide
- (A) Detailed information on the energy consumed, the greenhouse gas emissions generated, and the final carbon intensity.
 - (B) Documentation of all non-default model input values used in the carbon intensity calculation process. If values for any significant crude oil production parameters are unknown, the application shall so state and model default values shall be used for these parameters in the analysis.
 - (C) Detailed description of all supporting calculations that were performed outside of the model.
 - (D) Documentation of all modifications other than those covered by item (II) above, made to the model. This discussion shall include sufficient specific detail to enable the Executive Officer to replicate all such modifications and, in combination with the inputs and supporting calculations identified in items II and III above, replicate the carbon intensity results reported in the application.
- iv) A list of references covering all information sources used in the preparation of the life cycle analysis. All reference citations in the lifecycle analysis report shall include in-text parentheticals stating the author's last name and date of publication. All in-text

parenthetical citations shall correspond to complete publication information provided in the list of references, and complete publication information shall at a minimum, identify the author(s), author's affiliation, title of the referenced document, publisher, publication date, and pages cited. For internet citations, the reference shall include the universal resource locator (URL) address of the citation, as well as the date the website was last visited.

- v) A signed transmittal letter from the applicant attesting to the veracity of the information in the application packet and declaring that the information submitted accurately represents the long-term, steady state operation of the innovative crude oil production method described in the application packet. The transmittal letter shall be the original copy, be on company letterhead, be signed by an officer of the applicant with authority to attest to the veracity of the information in the application and to sign on behalf of the applicant, and be from the applicant and not from an entity representing the applicant (such as a consultant or legal counsel).
 - vi) All documents (including spreadsheets and other items not in a standard document format) that contain confidential business information (CBI) must prominently display the phrase "Contains Confidential Business Information" above the main document title and in a running header. Additionally, a separate, redacted version of such documents must also be submitted. The redacted versions must be approved by the applicant for posting to a public LCFS web site. Within redacted documents, specific redactions must be replaced with the phrase "Confidential business information has been deleted." This phrase must be displayed clearly and prominently wherever CBI has been redacted.
 - vii) All applications, supporting documents, and all other relevant data or calculation or other documentation, except for the transmittal letter described in paragraph (v) above, shall be submitted electronically such as via e-mail or an online-based interface unless the Executive Officer has approved or requested in writing another submission format.
- d) Application Approval Process. The application must be approved pursuant to this section before a regulated party may obtain credit under the LCFS regulation for producing fuels or blendstocks from the innovative crude.
- i) Within 30 calendar days of receipt of an application designated by the applicant as ready for formal evaluation, the Executive Officer shall advise the applicant in writing either that:
 - (A) The application is complete, or
 - (B) The application is incomplete and the Executive Officer will identify which requirements of section 95486(b)(2)(A)(4)a-c.

above have not been met.

- (1) The applicant will be permitted to submit additional information to meet the requirements to section 95486(b)(2)(A)(4)a-c.
 - (2) If the applicant is unable to achieve a complete application within 180 days of the Executive Officer's receipt of the application, the application will be denied on that basis, and the applicant will be informed in writing.
- ii) Once the Executive Officer has deemed an application to be complete, it will be posted for public comment at <http://www.arb.ca.gov/fuels/lcfs/lcfs.htm>. Comments will be accepted for 10 calendar days following the date on which the application was posted. Only comments related to potential factual or methodological errors may be considered. The Executive Officer will forward to the applicant all comments identifying potential factual or methodological errors. Within 30 days, the applicant shall either make revisions to its application and submit those revisions to the Executive Officer, or submit a detailed written response to the Executive Officer explaining why no revisions are necessary.
 - iii) An application submitted pursuant to this section shall not be approved if the Executive Officer determines:
 - (A) Based upon the application information submitted pursuant to this section, the proposed crude production method is not innovative, as that term is defined in this section.
 - (B) Based upon the application information submitted pursuant to this section, the applicant's carbon intensity calculations cannot be replicated using the ARB OPGEE model.
 - iv) If the Executive Officer finds that an application meets the requirements set forth in subsection 95486(b)(2)(A)4, the Executive Officer will take final action to approve the crude oil carbon intensity value and the associated innovative crude oil production method, describing all limitations and operational conditions to which the innovative crude oil production method will be subject, by amending this section 95486 in accordance with Government Code section 11340, et seq. If the Executive Officer finds that an application does not meet the requirements of subsection 95486(b)(2)(A)4, the application will not be approved, and the applicant will be notified in writing and the basis for the disapproval shall be identified.
 - v) Recordkeeping. Each crude oil producer that has crude approved as innovative must maintain records identifying each facility at which it produces crude oil for sale in California under the approved innovative crude oil production method. For each such facility, the crude oil producer must compile records for at least

three years showing:

- (A) The annual volume of crude oil produced using the approved innovative crude oil production method and the annual volume of crude subsequently sold in California under the approved innovative crude oil production method.
- (B) Compliance with all limitations and operational conditions identified by the Executive Officer in paragraph iv, above.

If the crude oil approved as innovative is marketed as part of a crude blend, the crude oil producer must also maintain for at least three years annual records identifying the constituent crudes that comprise the blend and the percentage that each constituent crude contributes to the blend.

These records shall be submitted to the Executive Officer within 20 days of a written request received from the Executive Officer or his/her designee, provided the request is made before the expiration of the period during which the records are required to be retained.

Annex D Calculation of emission factors

D.1 Combusted processed gas and natural gas liquids

This section details the calculation of emission factors for processed gas and natural gas liquids in kgCO₂/MBTU. These factors can then be multiplied by the calorific value and mass of exported gas and NGLs.

Processed gas is somewhat variable in composition. For this emission factor we assume the processed gas composition reported by Enbridge, a North American oil company (Enbridge). This composition and other information used to calculate the emission factor are shown in Table D. Lower heating values (LHV) are used (NAO Inc.) as well as standard gas densities (The Engineering Toolbox). C1 compounds include primarily methane; C2 ethane; C3 propane; C4 butane and iso-butane.

This calculation assumes that recovered associated gas is processed into dry gas before export. If NGLs are also exported, this mass can also be credited using the NGL emission factor detailed below. To calculate the NGL emission factor, it was assumed that the NGL composition reflects the relative proportions of ethane, propane, and butane removed from associated gas when processed into dry gas. The proportion of larger hydrocarbons was assumed to be negligible. The original composition of associated gas was taken from OPGEE (El-Houjeiri & Brandt, 2012). For projects that export associated gas without processing, use of these emission factors may underestimate emission savings.

CO₂ is typically removed from gas during processing. We assume that this removed CO₂ would be released into the atmosphere without displacing CO₂ from a useful purpose. Thus, we have added this component back into the processed gas composition in order to account for its contribution to the overall emission factor. Nitrogen and hydrogen sulfide removed were ignored.

Table D Parameters used to calculate emission factor of combusted associated petroleum gas

GAS COMPONENT	% OF GAS ON MOLAR BASIS	MOLECULAR WEIGHT (G/MOL)	LHV (BTU/G)	DENSITY (KG/M ³)	CO ₂ PRODUCED IN COMBUSTION (MOL/MOL)
N ₂	0	28.0	0	1.165	0
CO ₂	6.0	44.0	0	1.842	1
C ₁	89.8	16.0	47.5	0.668	1
C ₂	2.4	30.1	45.0	1.264	2
C ₃	0.2	44.1	43.7	1.882	3
C ₄	0	58.1	43.7	2.489	4
H ₂ S	0	34.1	14.4	1.434	0

The molecular weight of each processed gas component was used to calculate the mass fraction of each component in the total mixture. The mass fraction was then multiplied by each component's LHV to arrive at the weighted average LHV of the mixture (39.40 BTU/g). The molar fraction of each component and its CO₂ factor (mol CO₂ produced per mol gas in combustion) were multiplied and summed to calculate the CO₂ factor of the total mix (1.01 molCO₂/mol gas) which was then converted to a mass basis (2.44 gCO₂/g gas). This factor was then divided by the LHV of the APG mix to arrive at 0.061851 gCO₂ produced per BTU of APG combusted, equivalent to **61.1851 kgCO₂e/MBTU**. This emission factor can then be multiplied by the calorific value of recovered gas (in MBTU/t APG), the total mass of recovered APG (in tonnes) and 1/1000 t/kg to calculate total emissions savings in tCO₂e.

Table E Parameters used to calculate emission factor of combusted NGLs

GAS COMPONENT	% OF GAS ON MOLAR BASIS	MOLECULAR WEIGHT (g/MOL)	LHV (BTU/g)	DENSITY (kg/M ³)	CO ₂ PRODUCED IN COMBUSTION (MOL/MOL)
C ₂	34.5	30.1	45.0	1.264	2
C ₃	43.0	44.1	43.7	1.882	3
C ₄	22.5	58.1	43.7	2.489	4

The NGL emission factor was calculated in the same way as the emission factor for dry gas above. The molecular weight of each processed gas component was used to calculate the mass fraction of each component in the total mixture. The mass fraction was then multiplied by each component's LHV to arrive at the weighted average LHV of the mixture (43.99 BTU/g). The molar fraction of each component and its CO₂ factor (mol CO₂ produced per mol gas in combustion) were multiplied and summed to calculate the CO₂ factor of the total mix (2.88 molCO₂/mol gas) which was then converted to a mass basis (2.99 gCO₂/g gas). This factor was then divided by the LHV of the APG mix to arrive at 0.0679406 gCO₂ produced per BTU of APG combusted, equivalent to **67.9406**

kgCO₂e/MBTU. This emission factor can then be multiplied by the calorific value of recovered gas (in MBTU/t APG), the total mass of recovered APG (in tonnes) and 1/1000 t/kg to calculate total emissions savings in tCO₂e.

D.2 Uncombusted associated petroleum gas

Fugitive APG escaped from leaks and accidents is not combusted and thus the global warming potential (GWP) of the individual gas components must be considered. Table F lists the 100-year GWP of each of the components in D.1Table E (from IPCC, 2007).

Table F Components of associated petroleum gas and their global warming potentials

GAS COMPONENT	100-YEAR GWP
N ₂	0
CO ₂	1
C ₁	25
C ₂	5.5

Reduction of upstream greenhouse gas emissions from flaring and venting

C ₃	3.3
C ₄	4
H ₂ S	0
H ₂ O	0

As above, the molar fraction of each gas component was converted to a mass fraction using the molecular weight of each gas. This was done because GWP are reported on a mass basis. The average GWP, weighted by mass fraction of each gas component, was then calculated as **16.062 tCO₂e/tAPG**. This emission factor can then be multiplied by the total mass of escaped APG to calculate fugitive emissions. Fugitive emissions are then subtracted from project emission savings.

Annex E CER/ERU serial number

The serial number is a unique identification number for CERs and ERUs. The detailed description of the serial number is shown in Table A below. The example comes from IGES (2013).

Table A Example CER or ERU serial number

1	2	3	4	5	6	7	8	9	10	11
XX	1		000,000,000,001	999,999,999,999	01	01	1	0000000 1	1	XX/YY/ZZ

	IDENTIFIER	RANGE OR CODES
1	Originating Party	The hosting country code according to ISO
2	Unit Type	1= AAU, 2=RMU, 3=ERU from AAU, 4= ERU from AAU, 5 = CER
3	Supplementary Unit Type	Blank for Kyoto-only units
4	Unit Serial Block Start	Unique numeric value assigned by registry
5	Unit Serial Block End	Unique numeric value assigned by registry
6	Original Commitment Period	1-99
7	Applicable Commitment Period	1-99
8	LULUCF Activity	About afforestation and reforestation
9	Project Identifier	Numeric value assigned by registry for Project; unique per originating registry. The project number is a combination of the originating party and the public identifier
10	Track	1 or 2
11	Expiry Order	Expire dates for tCERs or ICERs (both are About afforestation and reforestation)

With the project identifier, one can look up the project through the UNFCCC CDM registry.⁵⁶

⁵⁶ <http://cdm.unfccc.int/Projects/projsearch.html>

Annex F Renewable Identification Numbers (RINs)

A RIN code has the following structure:

RIN: KYYYYCCCCFFFFFFBBBBBRRDSSSSSSSSEEEEEEEE

Where:

K = Code distinguishing assigned RINs from separated RINs

YYYY = Calendar year of production

CCCC = Company ID

FFFFFF = Facility ID

BBBBB = Batch number

RR = Code identifying the Equivalence Value

D = Code identifying the renewable fuel category

SSSSSSSS = Start of RIN block

EEEEEEEE = End of RIN block (tracks which credits from a project and how many are held by a single obligated party. Using one number for a batch of credits can lead to easier trading and accounting than listing out all of the serial numbers for a lump sum of emissions reductions).

Annex G Outline of the prescriptive option (3a)

The prescriptive option (Option 3a) represents the authors' outline of a prescriptive UER crediting system. This is designed to provide a level of detail comparable to the detail in a CDM methodology document. These details are reflected throughout this report in the appropriate sections. This annex does not present a comprehensive delineation of Option 3a, but rather an overview of actions necessary for key players in order to implement Option 3a. It is our intention that the detailed specification for Option 3a presented in this report would allow this option to be directly implemented.

In line with the scope of this project, we have primarily focused on the potential for Option 3a to be implemented at the European level. However, we believe that it could equally be implemented by a single Member State (as a national scheme under the proposed FQD implementing measure), or as the methodology used for a voluntary scheme. There are elements of this outline scheme that go beyond the minimum requirements of the proposed FQD implementing measure (cf. Option 3b). The key characteristics of this option are:

- Emission reductions shall be calculated as the difference in emissions between a 'business-as-usual' baseline scenario and a project implementation scenario. The amount of emission reductions shall be calculated based on the quantity of gas recovered by the project and productively utilized.
- Eligible projects should demonstrate additionality, meaning that it should be demonstrated that the project would not have been expected to happen without enrolment in the crediting scheme and access to the value of the credits. The assessment of additionality by independent auditors should consider financial and regulatory factors.
- All projects should be subject to verification by competent and independent auditors. Two sub-options are discussed in the report: (i) accreditation of auditors through a centralized scheme at either the EU or Member State level with specified verification and validation criteria and practices, and (ii) accreditation of auditors through voluntary emission reduction schemes.
- All emissions reduction credits for flaring and venting reductions should be created, traded, and retired within a centralized database. Ideally, this database would operate at the EU level to allow the prevention of double counting across Member States.

The following sections detail actions by key parties that would support a successful implementation of upstream emissions reduction reporting

under Option 3a. The actions are detailed for the case in which an Option 3a scheme would be implemented at the central European level. The actions necessary for implementation at either the Member State or voluntary scheme level would be analogous. If implemented at the Member State level, the national authorities would inherit all responsibilities allocated to the European Commission in the text below. In the case of implementation through a voluntary scheme, many responsibilities would be inherited by the scheme coordinator, but of course there would also be actions incumbent upon national administrators in order to make credits acceptable for use under FQD (cf. Annex H).

G.1 Actions for the European Commission

In order to put in place an EU level prescriptive measure for UER crediting, the European Commission could do the following:

G.1.1 Establish a central administrator

The appointment of a central body will be necessary to oversee validation and verification of all eligible UER projects under the scheme, and to ensure that all emissions reductions are centrally registered correctly. This body would be expected to confirm that all auditors used for validation or verification met the necessary competence requirements. The administrator would assess reported data and check that validation and verification reports submitted by auditors are compliant with the requirements of the FQD. For some aspects of reporting (such as ensuring that reports meet all minimum data requirements) these checks would be necessary on all project reports. For other aspects, such as quality assurance of auditors' opinions, a sampling strategy may be appropriate. This central body must approve all reported emission reductions before credits are issued. The central administrator could be within the European Commission itself, could be a division of an existing European agency such as the European Environment Agency, or could be an entirely new administrative body established for the purpose. Depending on levels of uptake for UER crediting, the workload for the administrator could be quite substantial, especially in 2020 but also earlier as schemes would need to be validated in advance. It will be difficult to anticipate the precise level of demand for UER schemes. There would therefore be some appeal in funding the administrator through charges on project participants, allowing its staffing to be more responsive to demand. It should be understood that the role of the central administrator under Option 3a will be large and central to the success of the implementation of the option. In particular, under Option 3a implemented at the European level, the central administrator would take on several responsibilities (and the associated workload) that under Option 3b could potentially be placed on scheme administrators outside of the public sector.

G.1.2 Establish a central UER database

In addition to the central administrator, the Commission would need to establish a central database of UER credits. This database could be maintained by the same central administrator described above, but could also be held by a third party. The database could equally be maintained by a public body or by contract with a private body, provided that necessary data security arrangements are developed and adhered to.

When any validated project recognized by the central administrator generated verified emissions reductions, this database would issue UER credits with unique serial numbers. Credits would only be issued after confirmation by the central administrator. All project proponents and regulated parties under the FQD emission reduction requirement would have accounts on this database, and all credit trading would take place within this database. Accounts would only be created with the approval of the central administrator. Provided all credits were pre-verified, and all accounts were legitimate, there would be no need for the central administrator to intervene in credit trades – simply a requirement that they should be confirmed by authorized persons acting for both parties to the trade.

Using a single central database would prevent double counting across Member States. In the case of a single Member State implementing the Option 3a scheme, a national database would still be required, but additional checks would be necessary to avoid double counting of projects across different Member States. With coordination by Member States, it would be technically possible to establish a network of national registries with the possibility for trading between national accounts. However, this may be complicated to implement in practice.

Whether the DATABASE was held at the European or Member State level, the central administrator would be given the power to ‘retire’ eligible UERs following requests from regulated parties. These retired credits would be reported by the central administrator to national administrators of the FQD, and they could then be counted by those national administrators against an individual company’s carbon intensity reduction requirements, and hence allow companies comply with their FQD targets.

G.2 Actions for the central administrator

In order to facilitate the use of Option 3a upstream emissions reduction credits for compliance with the FQD, the central administrator could do the following:

G.2.1 Provide guidelines and other reporting tools

The central administrator should provide detailed guidelines for project participants. These would include all of the requirements outlined within this report, and any additional guidance necessary for the specifics of implementation, such as instructions for reporting data to the central DATABASE and instructions for auditors on how to be accredited.

The central administrator could also provide additional tools to assist project participants. For instance, to assist in additionality checks by project participants, it would be useful for the administrator to publish a list of jurisdictions where flaring or venting is known to be prohibited under local laws or where existing regulations are unenforced. The administrator could make available a programmatic tool to calculate financial additionality. In all cases, the administrator should ensure that clear guidance on requirements is available, including providing responses to frequently asked questions about the scheme. The availability of such resources may encourage project operators to participate and should reduce the number of submitted applications that do not meet the additionality criteria and other requirements under Option 3a.

G.2.2 Coordinate with Member State authorities

Ideally, the credits generated through an implementation Option 3a would be accepted for FQD compliance in the maximum possible number of Member States, in order to give project proponents flexibility in finding markets for credits. As Member States have the prerogative to set local interpretations of the requirements of the FQD for UERs, it would be appropriate for the central administrator (if operating at the EU level) to communicate with Member State governments in order to identify any potential inconsistencies between local requirements and the details of an Option 3a implementation. This may be less relevant if Option 3a were to be implemented as a national scheme, but would certainly be appropriate for an implementation of Option 3a through a voluntary scheme.

G.2.3 Accredite validators and verifiers for competence

For any project registered with the central administrator, the project proponent should identify auditors to act as project validator and verifier. The central administrator should develop criteria and procedures for accreditation of auditors (cf. section 4.3.3.a), and in order for credits to be generated by any scheme both the verifier and validator must go through this accreditation process. If Option 3a is being implemented as a scheme within the legal framework of the proposed FQD implementing measure (Option 3b), then the detailed competence requirements should refer directly to ISO 14065 and ISO 14066, and the central administrator would need to develop a process

on that basis. If Option 3a were to be implemented outside of the legal framework of the proposed FQD implementing measure, then the central administrator would have additional leeway in defining the accreditation process. In that case, the requirements of ISO 14065, ISO 14066 and of the CDM DOE accreditation process should be used as a guide to good practice. The central administrator could consider establishing a register of pre-accredited auditors to reduce the administrative burden for new projects.

G.2.4 Establish a system of oversight for validation and verification reports

The central administrator should arrange for two levels of checks to be made to validation and verification reports. The first level, which should be made to all reports, would be a set of checks for consistency and accuracy of data. For instance, in the validation report the central administrator should confirm that the financial additionality test has been correctly implemented. In verification reports, reported emissions reduction should be compared to anticipated emissions reductions, with a system of red flags for cases where results are apparently inconsistent with project plans. For these basic checks, the central administrator should withhold project approval/emissions reduction credits as appropriate until any issues have been resolved with the validator/verifier and project proponent.

The second level of checks would be more involved, and may be applied through sampling and on a risk based basis. For instance, the central administrator might decide to implement site checks for some fraction of project proposals to assure that project design documents represented a true reflection of project plans and that baseline assessments had been correctly carried out. In the case that such site checks revealed some irregularity, then it may be appropriate for the central administrator to carry out additional checks on a risk-based basis – for instance checking additional projects with the same proponent or auditor. Detailed procedures would need to be developed by the central administrator when appointed and designed to balance administrative burden (on both the administrator and the projects) with the need to ensure the environmental integrity of the scheme. Where appropriate, CDM could be used as an example of potential oversight systems.

G.2.5 Establish or coordinate with the central database

If the central administrator is also to administer the UER database, then a key initial task for the administrator would be to design and procure that database, ensuring that it supported all the necessary reporting functionality to allow streamlined reporting compliant with the requirements of the FQD. If the database were to be established and run by some other body (public or private), then the central administrator should coordinate with that database owner to set the

specification for the database to ensure that it will meet the needs of the central administrator.

Whichever body has ownership of the central database, it will be paramount to ensure that it reflects good practice in terms of information security, but also that it can be accessed by relevant parties through accounts. In particular, the central administrator would need access to all information and to be able to approve credit creation and retirement. Depending on how the system is implemented, the verifier may be given an account to register 'provisional' credits on the database pending confirmation by the central administrator (this could also be done through direct submission of verification reports to the central administrator). At the discretion of the central administrator, the database could be set up as a comprehensive system for handling all validation and verification report data, or set up as a system solely to award, transfer and retire credits (with validation and verification reports submitted separately). Finally, the project proponents and obligated parties under the FQD would need to access database accounts to trade credits.

G.2.6 Implement a system for managing incorrect or fraudulent reports

Checks by the central administrator on validation and verification reports may in some cases reveal incorrect or inadequately supported information. In some cases, this could be a sign of attempted fraud. The central administrator would need to develop a program for fraud handling, building on the system of checks of validation and verification reports. Such a system would provide guidelines for the identification of potential cases of fraud, and define appropriate follow up steps to apply in these cases. Where fraud is identified, the central administrator would need to take steps to impose appropriate penalties on the party attempting the fraud. These penalties would need to be set at the Member State level, and be consistent with any European Commission guidance. The central administrator may need to coordinate with national FQD administrators in applying such penalties.

To handle the case that incorrect or fraudulent reporting is identified after credits have been awarded in the central database, the central administrator will need to put in place a system for certificate revocation, and in particular put principles in place to handle any need for revocation of certificates that have already been traded onwards. If incorrectly awarded certificates have already been used for compliance with a national implementation, then the matter should be passed to the national FQD administrator for any appropriate action to be taken.

G.3 Actions for the Member State

In order to implement Option 3a, Member States could take the following action:

G.3.1 Implement UER crediting in national legislation

As for the other options, national legislation will be necessary to allow eligible UER credits to be counted towards regulated parties' obligations under FQD in each Member State. How UERs are integrated will depend on each Member State's system of FQD implementation. Where carbon markets are created (as anticipated in Germany starting in 2015), it should be simple to integrate UERs into those markets. Where RED/FQD are implemented through other measures such as biofuel volume mandates, it will be necessary to create a pathway for UERs to count towards FQD compliance and clarify this pathway with regulated parties. The success of UER crediting under Option 3a will depend to some extent on the confidence that regulated parties have in the value of UERs under the FQD. Participation in the UER market can be encouraged through providing clear guidance on how UERs can be used and how the market for UERs will interact with the national measures under FQD to credit carbon savings from alternative fuels (biofuels, electricity in transport, hydrogen etc.).

G.3.2 Establish appropriate measures to control the risk of fraud

The FQD itself does not set penalties to be applied in the event of fraudulent reporting. In order to provide disincentives to fraudulent activity, Member States may find it appropriate to put in place defined penalties for fraudulent reporting.

G.3.3 Case of a Option 3a as a prescriptive national scheme

In the case of a scheme based on Option 3a being implemented at the national level, the national government would need to take on the roles detailed above for the European Commission, and the 'central administrator' would need to be replaced by a national administrator.

G.4 Actions for the project participant

In order to generate upstream emissions savings that can be used by regulated parties towards compliance with the GHG intensity reduction target of the FQD, project participants could take the following actions:

G.4.1 Identify FQD as a market for credits

Before starting a project, the participant may benefit from clearly identifying whether the FQD is considered a desirable market for generated credits. If so, this should be clearly indicated to validators and verifiers, and the participant should take steps to identify any requirements resulting from engagement in the FQD. This could include identifying which Member State market is preferred for eventual use of the credits.

G.4.2 Confirm eligibility of project

If a project participant anticipates generating FQD-compliant UERs from a venting or flaring reduction project, then it should take care to ensure that project is eligible under Option 3a. This would include undertaking a financial additionality assessment using the Option 3a financial additionality test.

G.4.3 Appoint competent auditor

To guarantee eligibility under the FQD, the project participant should take care to appoint an auditor accredited by the verification body or committee established by the Commission or by eligible voluntary schemes.

G.4.4 Submit project application

Project participants must submit an application (project design document) to a qualified auditor and this application must be validated prior to the generation of UERs. The application must include a project plan, an emissions reductions monitoring plan, and an additionality assessment.

G.4.5 Comply with monitoring and verification process

Once a project application has been validated, the project participant must comply with monitoring requirements under Option 3a. Monitoring data must be submitted to the auditors monthly. Project participants must comply with the verification process, including on-site audits, requests for additional documentation or monitoring data, and requests to change the monitoring plan or equipment.

G.4.6 Make commercial arrangement to transfer credits to regulated parties

In general, the legal entities that are upstream oil and gas producers, the participants in upstream emissions reduction projects, may not be

regulated parties under the GHG intensity reduction target of the FQD. The upstream operator delivering the emissions reductions will therefore need to make a commercial arrangement to transfer emissions reduction credits to parties regulated in a EU Member State in which UERs are eligible towards FQD compliance. In some cases, it may be possible to identify traders interested in acting as intermediaries between the project proponents and the regulated parties, but this is not guaranteed. The project participant must then submit a request to the central EU database to transfer credits to the recipient.

G.5 Actions for regulated parties

In order to count report upstream emissions savings towards compliance with the GHG intensity reduction target of the FQD, regulated parties could take the following action:

G.5.1 Make commercial agreement to transfer credits from project participants

In cases where the regulated party is not itself a project participant, it must purchase UER credits. Once an agreement is confirmed, the project participant should submit a request to the central EU database to transfer credits to the regulated party.

G.6 Actions for auditors

In order to ensure that upstream emissions savings recorded under a given scheme will be eligible towards compliance with the GHG intensity reduction target of the FQD, the auditor for given projects could take the following action:

G.6.1 Seek approval from the central validation and verification body

In order to perform validation and verification for Option 3a-eligible emissions reduction projects, auditors must be approved by the central EU validation and verification body. Qualified auditors must meet the requirements under Option 3a, including independence and competence in the area of venting and flaring emission reductions.

Annex H Outline of the option reflecting the implementing measure requirements

This option (Option 3b) is designed to be compatible with the Commission's proposed Implementing Measure for Article 7a of the FQD. In line with the Implementing Measure, under this option it is assumed that the Member States will take on all responsibility for monitoring and verification of emissions reduction claims, and that the only central role (to be played presumptively by the European Environment Agency) will be one of data sharing.

The key characteristics of an emissions reduction system compatible with the proposed Implementing Measure are as follows:

- Emissions reduction projects assessed based on schemes approved by Member state administrators shall be considered eligible to contribute towards compliance under the FQD. Emissions reductions achieved outside of approved schemes cannot be considered (although at the discretion of a Member State it may be allowable for projects to commence before a specific scheme has been approved).
- Emissions reductions shall be calculated in accordance with guidelines set in ISO 14064, Part 2. This means that reductions shall be calculated based on the difference between emissions after the project has been implemented and the emissions that would have been expected in a 'business-as-usual' baseline.
- Emissions reduction projects (including the definition of the baseline) must be validated by competent bodies before they are implemented in order to be eligible.
- Emissions reduction claims must be verified by competent bodies once they have been implemented.
- The competence of validators and verifiers should be established based on the requirements of ISOs 14065 and 14066.
- Upstream emissions reduction projects can already be registered under the CDM and JI schemes as long as they started after January 1, 2011. Subject to Member State approval, with some additional data tracking, and some specific additions to monitoring, reporting and verification guidelines, credits for upstream emissions reductions awarded under these schemes could in principle be eligible for compliance under FQD.

- A single body (presumptively the European Environment Agency) should act as a centralized data repository for reported upstream emissions reductions in Europe.

The following sections detail actions by key parties that would support a successful implementation of upstream emissions reduction reporting for compliance with the carbon intensity reduction target of the FQD.

H.1 Actions for the Member State

In order to implement the option to report upstream emissions savings towards compliance with the GHG intensity reduction target of the FQD, Member States could take the following actions:

H.1.1 Transpose and implement the Implementing Measure

In general, additional local legislation is likely to be required in each Member State to allow UER credits to be counted towards regulated parties' obligations under FQD. Where legislation creates a market in carbon savings from alternative fuels (for instance as anticipated in the German RED/FQD implementation from 2015 onwards) it should be a simple matter to integrate UERs into the existing scheme. Where RED/FQD are being implemented through other measures, such as volume mandates, it will be important to clarify with regulated parties how UER credits will be integrated into compliance reporting. For instance, UERs may be an option to allow regulated parties to cover any gap between the carbon savings achieved by compliance with a biofuel volume mandate, and the carbon savings required to comply with the FQD. Clear guidance on how UERs can be used and how the market for UERs will interact with any market for carbon savings from alternative fuels will help provide regulated parties with confidence to act in the UER market. It will also help potential upstream emissions reduction project proponents to understand the potential value of the emissions reductions generated, and thus support investment.

H.1.2 Appoint an administrator

Appoint an administrator responsible for receiving reports of emissions reductions from regulated parties, and for confirming that reported emissions reductions comply with the requirements of the FQD. During and/or at the end of any year for which a carbon intensity reduction target has been set in the Member State implementation of the FQD⁵⁷, each regulated party should report to the national administrator detailing how it has complied with its carbon intensity reduction target. If the option of upstream emissions reduction crediting has been implemented, this reporting should include reporting on any GHG

⁵⁷ At a minimum a reduction target should be implemented in 2020, and Member States may implement interim reduction targets in preceding years.

intensity reductions achieved through the use of alternative fuels, and reporting on any upstream emissions reductions that the regulated party proposes to count towards compliance.

H.1.3 Identify eligible emissions reduction schemes

Any reported upstream emissions reductions must have been registered with some scheme set up for that purpose. This could include but need not be restricted to the reporting of credits awarded under the Clean Development Mechanism or the reporting of credits awarded by independent emissions offset certification schemes. The scheme may already be active, or may be introduced between now and 2020. In some cases, an emissions-reduction crediting scheme may be fully compatible with the requirements outlined in the proposed FQD implementing measure. However, in other cases, additional reporting might be required. For instance, credits under CDM will not necessarily specify the year of project commencement, which is required under FQD. The national administrators will need to assess each emissions reduction scheme under which a regulated party would like to report emissions reductions, and assess whether it is compliant with the requirements of the FQD and whether any additional data must be reported beyond the data usually included in a credit awarded under that scheme.

The national administrator may consider identifying a list of eligible schemes and any associated additional data reporting requirements in advance of the reporting period. The national administrator may also consider engaging with the industry and with the administrators of crediting schemes to support the development of protocols that allow credits generated to be eligible for use to comply with the FQD.

H.1.4 Assess reported data

Where emissions reductions have been reported under an allowable scheme, the national administrator must then assess whether all required data has been reported, and whether the data reported is compliant with the requirements of the FQD. The FQD requires the following data to be reported:

- Starting date of the project (which must be after 1 January 2011);
- Annual emissions reductions (gCO₂e);
- Duration for which the claimed reductions occurred;
- Project location closest to the source of the emissions in latitude and longitude coordinates in degrees to the fourth decimal place;

- Baseline annual emissions prior to installation of reduction measures and annual emissions after the reduction measures have been implemented in gCO₂eq/MJ of feedstock produced;
- Non-reusable certificate number uniquely identifying the scheme and the claimed greenhouse gas reductions;
- Non-reusable number uniquely identifying the calculation method and the associated scheme;
- Where the project relates to oil extraction, the average annual historical and reporting year gas-to-oil ratio (GOR) in solution, reservoir pressure, depth and well production rate of the crude oil.

In most cases, the primary task of the national administrator will be to verify that credits have indeed been correctly awarded, i.e. to check the reporting of annual emissions reductions in gCO₂e. Any credits awarded should have been subject to monitoring and verification consistent with the requirements of ISO 16064 Part 3 as applied to the reporting requirements outlined in ISO 14064 Part 2, and the verifiers should have been competent under ISO 14065 and 14066. If the national administrator determines that a scheme already applies adequate safeguards to ensure that this is the case, it may not be necessary to undertake any additional confirmation activity. However, if the minimum requirements of a scheme fall short of the requirements of the ISOs, or if the national administrator determines that it is appropriate to undertake additional checks, then the national administrator may consider additional verification action, which could include:

- Requiring additional documentation of the competence of project verifiers or validators;
- Requiring additional evidence of data monitoring processes;
- Verifying the veracity of reported credit serial numbers;
- Undertaking independent validation of project baseline assumptions.

In any case where the national administrator is not satisfied that the credits awarded by the scheme meet the requirements of the ISO standards, those credits should not be counted towards compliance with the GHG intensity target of the FQD.

H.1.5 If appropriate, report data to a central data repository appointed by the European Commission

It may be that the European Commission appoints a central data holder for information on upstream emissions reductions claimed under the FQD. If so, where the national administrator accepts emissions reduction claims, data on these claims should be reported to the

central data holder for the European Union. This data should include unique serial numbers identifying claimed emissions reductions.

H.1.6 Take action to prevent double counting within the FQD of emissions reduction credits

If there is an appointed central data holder, then in the event that the same serial numbers are reported by more than one national administrator, the data holder should notify the respective administrators. These administrators should then coordinate to undertake an investigation to determine which (if either) of the regulated parties is entitled to count the reductions towards its compliance target. If a regulated party is found to have incorrectly claimed emissions reductions in a Member State, the national administrator should take appropriate enforcement action. If the revocation of emissions reduction claims results in a regulated party or the Member State as a whole being out of compliance with the GHG intensity reduction target of the FQD, this should be reported to the Commission.

If there is no central data holder appointed by the Commission, then it would be incumbent on the Member States to implement an alternative system to detect whether identical credits have been reported in more than one jurisdiction. This might involve Member States coordinating to agree a single central data holder to which data could be passed, or a system of bilateral checks between Member States. A system built around a single central data control point is likely to be the least administratively burdensome.

H.2 Actions for the project participant

In order to generate upstream emissions savings that can be used by regulated parties towards compliance with the GHG intensity reduction target of the FQD, project participants could take the following actions:

H.2.1 Identify FQD as a market for credits

Before starting a project, the participant may benefit from clearly identifying whether the FQD is considered a desirable market for generated credits. If so, this should be clearly indicated to validators and verifiers, and the participant should take steps to identify any requirements resulting from engagement in the FQD. This could include identifying which Member State market is preferred for eventual use of the credits.

H.2.2 Confirm eligibility of project

If a project proponent⁵⁸ anticipates that it may want to use credits from the project to demonstrate compliance with an FQD GHG intensity reduction target⁵⁹ then it should take care to ensure that project is eligible and that it meets any additional data collection requirements imposed by the FQD beyond the requirements of the emissions reduction scheme. It may be advisable for project participants to seek confirmation in advance from national administrators that a given scheme is expected to be considered eligible under FQD in that country.

H.2.3 Appoint competent validator and verifier

Where a validation/verification body is acceptable under a specific scheme, this may not guarantee that the body is ISO 14065 competent, and/or that its personnel are ISO 14066 competent. To guarantee eligibility under the FQD, the project participant should take care to appoint appropriately qualified auditors.

H.2.4 Demonstrate additionality of project

Emissions reductions may only be counted towards compliance with the FQD if the project generating them can be demonstrated to be additional in the context of ISO 14064 Part 2. The project proponent should therefore develop a case to argue that the project is additional, in particular with regard to any legal obligations on the company, and to the question of whether the project would have occurred anyway for commercial reasons regardless of emissions concerns.

H.2.5 Make commercial and legal arrangement to transfer credits to regulated parties

In general, the legal entities that are upstream oil and gas producers, the participants in upstream emissions reduction projects, may not be regulated parties under the GHG intensity reduction target of the FQD. The upstream operator delivering the emissions reductions will therefore need to make an arrangement to transfer emissions reduction credits to parties regulated in a EU Member State in which UERs are eligible towards FQD compliance. These arrangements should cover both commercial terms and key legal issues, such as establishing responsibilities in the event that UER credits should be revoked for any reason. Arrangements are likely to take the form of sales of credits, and accompanying transfers of data. Where credits are held on registries

⁵⁸ I.e. an upstream oil or gas operator considering entering into an upstream emission reduction project.

⁵⁹ Or trade the credits from the project onwards with a view to being used eventually for compliance with the FQD.

(e.g. CDM) it may be necessary to make formal arrangement for the transfer to be reported to the registry. In some cases, it may be possible to identify traders interested in acting as intermediaries between the project proponents and the regulated parties, but this is not guaranteed.

H.3 Actions for the regulated party

In order to count report upstream emissions savings towards compliance with the GHG intensity reduction target of the FQD, regulated parties could take the following actions:

H.3.1 Confirm eligibility of credits

When considering making a commercial arrangement to receive UER credits from an upstream operator, the regulated party could seek confirmation in advance from the national administrator that those credits can be expected to be eligible to show FQD compliance (given that the appropriate data is reported etc.).

H.3.2 Collect required data

In some cases (such as CDM), emission reduction schemes may not require the reporting of the full set of data required for the FQD. In those cases, regulated parties should coordinate with upstream operators to ensure that additional required data is passed up the supply chain and subjected to chain of custody and verification in line with the requirements of FQD.

H.3.3 Avoid double reporting

A given emissions reduction should only be reported in a single Member State. Regulated parties should take care to ensure that if they intend to report UERs towards compliance with their carbon intensity reduction targets, those reductions will not also be reported by another regulated party, or by the same party in a different Member State. This due diligence may be supported by emissions reduction registries, if such registries are maintained by the schemes being used.

H.4 Actions for emissions reduction crediting schemes

In order to maximize the likelihood that upstream emissions savings recorded under a given scheme will be eligible towards compliance with

the GHG intensity reduction target of the FQD, the administrators of emissions reduction crediting schemes could take the following actions:

H.4.1 Align requirements to the requirements of the FQD

The proposed Implementing Measure for Article 7a of the FQD sets certain requirements for upstream emissions reductions to be eligible to be counted towards compliance with the FQD's GHG intensity reduction target. Credits generated under a given scheme will only be eligible to the extent that regulated parties are able to demonstrate that reported UERs meet these criteria. Requirements include but are not limited to:

- Data reporting requirements;
- Requirement on project start date;
- Assessment of the baseline and emissions savings in line with ISO 14064 Part 2 (including as relating to the assessment of additionality);
- Monitoring and verification in line with ISO 14064 part 3;
- Validation and verification by separate bodies competent according to ISOs 14065 and 14066.

Where the requirements of the crediting scheme guarantee compliance with the FQD requirements without any need for additional verification or reporting, credits for the scheme are more likely to be considered eligible by national administrators.

H.4.2 Provide guidance on any additional requirements for credits to be counted towards FQD

Where there are requirements of FQD that go beyond the requirements of a scheme, the scheme administrator could support participants by providing clear guidance on any additional data collection etc. This could be extended to providing a bolt-on additional certification designed to close the gap between the basic requirements of the scheme and the requirements of the FQD. In the case of biofuel sustainability schemes used to show compliance of biofuels with the sustainability criteria of the RED and FQD, some schemes (e.g. the Roundtable on Sustainable Biomaterials) have a separate implementation available tailored to the RED.

H.4.3 Implement serial numbers

Eligibility of credits under the FQD requires unique serial numbers to be assigned to each batch of emissions reductions. Schemes should therefore consider implementing systems to assign serial numbers to units of emissions reductions, and ensure that such numbers carry the

requisite information. Without such systems being implemented by schemes, it may be difficult or impossible for regulated parties to use the credits for compliance under FQD.

H.4.4 Liaise with national administrators

Scheme administrators should consider maintaining a dialogue with national administrators to identify any issues that could prevent certificates from that scheme from being deemed eligible. This will help provide confidence to regulated parties to engage in the UER market.

H.5 Actions for the validator and verifier

In order to ensure that upstream emissions savings recorded under a given scheme will be eligible towards compliance with the GHG intensity reduction target of the FQD, the validator and verifiers for given projects could take the following actions:

H.5.1 Develop a clear understanding of FQD requirements, and of any variation in the expectations of different national administrators

Where a project proponent identifies that it intends to trade generated credits into the FQD compliance market, the validator and verifier should be careful to review requirements additional to the requirements of the scheme in use. While Member State implementations will all be based on the same Implementing Measure, there is room for legitimate differences in interpretation (for instance types of documentation required) so where possible the validator/verifier should aim to assess the requirements in the specific Member State identified as the target market.

H.5.2 Document any additional data

Where additional data (such as project start date) is required for FQD, the validator/verifier should take care to document this data alongside documentation of data required by the scheme itself, and ensure that it is subjected to the appropriate level of audit.

Annex I

Differences between CDM and the prescriptive option

This Annex highlights differences between CDM and the new proposed methodology in the prescriptive option (Option 3a) for ease of comparison.

I.1 Eligible projects

Under CDM, there are currently three approved methodologies to credit venting and flaring reduction from oil fields, and project applicants must propose new methodologies to cover projects that are not eligible under these existing methodologies. In Option 3a, there is only one methodology that covers all eligible projects comprehensively.

Projects that are explicitly eligible under Option 3a but may not be eligible under current CDM projects:

- Projects that previously utilized or exported gas that are increasing export or utilization capacity.
- Projects that utilize 100% of recovered gas on-site.
- Projects that import gas-lift gas from nearby pressurized gas fields and recover and export this gas.
- No requirement that venting or flaring occurred prior to project start or that oil wells be in production at the time of project application.

I.2 Baseline and delta calculation

Elements in the baseline and delta calculation under Option 3a that differ from CDM are:

- One comprehensive methodology
- The project boundary explicitly includes all existing gas recovery infrastructure and all new recovery, export, and utilization infrastructure. When gas is exported by methods other than pipeline, the project boundary ends at the gate of the processing or compression facility.
- No consideration of “leakage” emissions, i.e. indirect emission changes outside the project boundary.

- No consideration of emissions at the end-use facility, even if this facility is new.
- Existing export and utilization capacity at the time of project application are included in the baseline scenario.
- Fugitive emissions from leaks and accidents are only included in the delta calculation if the measured losses exceed 2% for large-scale projects ($> 50 \text{ Mm}^3/\text{yr}$) and 7% for small-scale projects ($< 50 \text{ Mm}^3/\text{yr}$).

I.3 Monitoring and reporting

Elements of monitoring and report in Option 3a that differ from CDM are:

- One comprehensive methodology with required measurements and measurement accuracy specified.
- Measurement accuracy requirements are relaxed for small-scale projects ($< 50 \text{ Mm}^3/\text{yr}$)
- Gas flows reported in mass instead of volume.
- Separated natural gas liquids (NGLs) are eligible for crediting if exported or utilized.
- Emissions savings are calculated on the basis of energy content multiplied by an emission factor for processed gas and NGLs, separately (detailed in Annex D).
- Very small-scale projects ($< 10 \text{ Mm}^3/\text{yr}$) may opt to measure gas flows weekly rather than continuously.

I.4 Additionality

This report detailed three potential levels of additionality. The moderate additionality level is proposed for Option 3a. Elements of this moderate additionality proposal that differ from CDM are:

- No common practice analysis required.
- The financial analysis more closely resembles that which the project applicants are likely to use for internal decision making purposes.
 - Assumption of a 20% discount rate (or IRR) is assumed.
 - It may be assumed that profits will decline over time if supported by documentation, for instance due to expectations of declining oil production rates.

- The metric upon which to determine additionality is net present value divided by investment (NPV/I).
- The calculation of financial viability is more clearly specified than in CDM.
- It is proposed that a computer tool be provided so that project applicants can easily know if their project will meet the financial additionality criteria.
- Projects in jurisdictions where flaring and/or venting is prohibited under local laws and regulations but this prohibition is unenforced are explicitly allowed.
 - It is proposed that a public database of such jurisdictions is maintained to ease the application process.

I.5 Validation and verification

In CDM, validation of the project design document and verification of project monitoring and reporting are conducted by an independent auditor (the DOE) who reports to the CDM Executive Board. For Option 3a we describe two potential validation and verification frameworks: (a) these checks would be performed by independent auditors accredited by a body appointed by the Commission according to specified validation and verification procedures, and (b) validation and verification would be performed by voluntary emission reduction schemes approved by the Commission according to basic guidelines provided by the Commission, but specific procedures would not be centrally prescribed.

Under the prescribed validation and verification framework, some specific measures that may deviate from DOE practice include:

- On-site audits are required annually for large-scale projects (>50 Mm³/yr).
 - On-site audits every three years for small-scale projects (<50 Mm³/yr).
- All monitoring data must be submitted electronically to the auditors monthly.
- Additional audits are triggered by:
 - Discrepancies between flow measurements at different points along the recovery and processing infrastructure, if not resolved within 1 month.
 - Failure to detect a significant reduction in flaring via satellite images after project implementation, for flaring projects.



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