# EMISSIONS ACCOUNTING FOR $CO_2$-EOR

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# EMISSIONS ACCOUNTING FOR $CO_2$-EOR

## Key Messages

**(Please also refer to the "Background", "Disclaimer" and "Scope" sections of this overview)**

- The incidental storage of $CO_2$ during $CO_2$ enhanced oil recovery ($CO_2$-EOR) is widely regarded as a co-benefit, if you can appropriately account for, and reward, the net climate benefits arising from such operations.
- The motivation for this study was to build on earlier work on the quantification of life cycle emissions from $CO_2$-EOR but which did not include an extensive discussion of the accounting issues including underlying issues and validity of assumptions.
- This study presents a basis for further discussion and improvement, rather than a definitive view on the matter, and thus should not be seen as a proposed methodology for emissions accounting from $CO_2$-EOR.
- The concept of "emissions leakage (EL)" means the potential for net changes in emissions to occur outside the boundaries and operational control of a particular policy and/or activity, but which arise as a consequence of that policy and/or activity. The potential for EL can increase where no greenhouse gas (GHG) policies and measures are in place to reduce, restrict, or at least account for mid/downstream emissions.
- Emissions can arise along the whole value chain of $CO_2$-EOR, including from the use of incrementally produced oil (IPO).
- EL can occur where IPO adds to the overall supply of oil, rather than substituting parts of the existing supply. A net emissions reduction ("negative EL") can occur where IPO substitutes more emissions intensive supply.
- Stringent/strict GHG emission control schemes will decrease the risk of EL. An analysis using a simplified approach revealed that a significant amount of global oil flows might be at high risk of EL.
- Downstream emissions from end-use are the greatest source of life cycle GHG emissions for gasoline/petroleum, and thus could cause high EL, but are out of direct control of the EOR operation.
- There are significant challenges and uncertainties associated with the development of a methodology to quantify EL from $CO_2$-EOR. For example, the question whether substitution of or addition to oil supply occurs would require a deep analysis of oil markets and demand and supply price elasticity.
- Due to the complexities involved in global trade of oil and refined products, a whole-chain, i.e. cradle-to-grave, assessment of $CO_2$-EOR is generally challenging. It might be necessary and/or more effective to address site-level and mid- and downstream emissions separately. However, diving deeper into this area is not a task IEAGHG would undertake in the immediate future.

## Disclaimer

Due to simplifying assumptions being made, this report does not claim to deliver a definitive view on how to resolve issues of GHG accounting for $CO_2$-EOR but rather provides a first source for ideas on how to establish a framework for considering the issues at hand and "food for thought" in respect of further discussion and debate. IEAGHG acknowledges that in many locations without stringent GHG accounting schemes $CO_2$ emissions reductions cannot be easily credited and that there is still ongoing debate in some cases about who should receive such credits in the EOR chain. Moreover, it will likely be necessary to separate the assessment into two issues:

1. What happens at the site-level

2. What happens at the mid- and downstream level

This is due to the situation that one part of the EOR chain usually does not have control over what happens in other parts, e.g. the EOR operator cannot influence to which country the IPO will finally be exported or how the availability of IPO changes consumers' behaviour. The main reason for this are the complex global trade flows of crude oil and refined products. It is thus difficult to determine the ultimate impact of IPO from $CO_2$-EOR on the environment. This report tries to identify issues in the mid- and downstream areas but does not and cannot attempt to resolve them. It merely presents thoughts on how to approach this challenging topic without wanting to propose a methodology. Although the authors discuss methods of $CO_2$ emissions accounting, this study will not actually quantify those emissions and emissions reductions, as this has been done elsewhere (see e.g. Pembina and IEA reports cited in the "Background" section of this overview). However, it will include ample discussion about the "addition vs substitution" and "emissions leakage" issues, as these were not a focal point of previous reports.

The following sections of the report contain the findings and conclusions of the contractors, Carbon Counts, and do not necessarily reflect the views of IEAGHG and/or its individual member countries and sponsors.

## Background to the Study

The use of $CO_2$ captured from anthropogenic greenhouse gas (GHG) emission sources for tertiary oil recovery as a means to extend the production life of mature oilfields – a technique known as $CO_2$ enhanced oil recovery ($CO_2$-EOR) – has been practised since the early 1970s, mainly in North America. Of the originally injected $CO_2$, typically 60% is retained and hence stored on the first pass through the reservoir, the other 40% is back produced and is re-injected for another pass, when more of it is stored. Thus, well above 95% are stored in total (apart from some minor fugitive emissions). In considering the option of carbon capture and storage (CCS) as a climate mitigation technology, the incidental storage of $CO_2$ during $CO_2$-EOR is widely regarded as a co-benefit. Consequently, $CO_2$-EOR is often viewed as an early opportunity to demonstrate CCS, in particular because the additional costs for capturing, transporting and storing $CO_2$ from anthropogenic sources can be at least partially offset through the sale of incrementally produced oil (IPO). A key issue is how to appropriately account for and reward the net climate benefits arising from such operations. Whilst various methods and approaches have been proposed over the years, some challenges still remain, especially in terms of complexity and political implications.

The main issue for GHG accounting for $CO_2$-EOR operations is the potentially conflicting objective between reducing GHG emissions to the atmosphere through geological storage of $CO_2$ and increasing the production and use of fossil fuels that will ultimately create further GHG emissions along the value chain. The latter includes additional emissions associated with transportation and refining of the IPO ('midstream emissions') and end-use of refined products ('downstream emissions') – see Figure 1[1].

When considering policies and measures to reward the use of CCS with $CO_2$-EOR, this issue might become problematic by posing a risk of "emissions leakage". This can occur where the IPO is used in processes, products, sectors or jurisdictions where no GHG policies and measures are in place to reduce, restrict, or at least account for, mid- and downstream emissions.

It is therefore necessary to review GHG accounting issues around $CO_2$-EOR operations in more detail. IEAGHG commissioned this analysis to Carbon Counts Company (UK) Ltd.

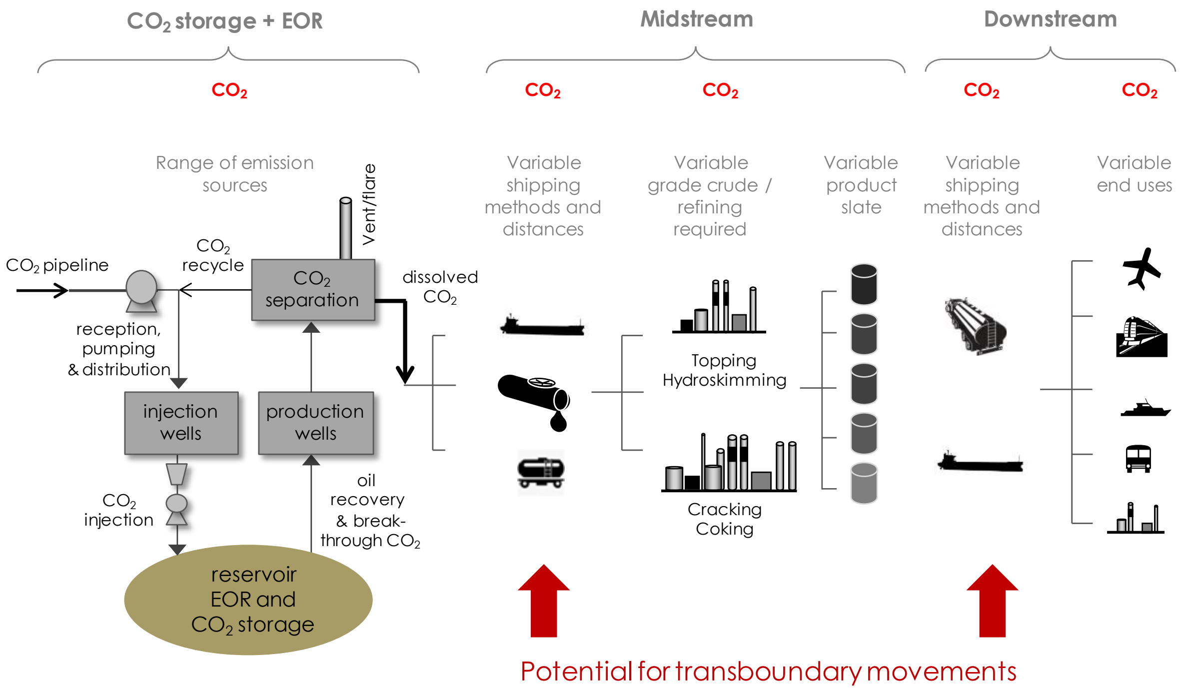


**Figure 1 Site level and downstream $CO_2$ emissions sources from $CO_2$-EOR across the crude oil value chain**

[1] Please note that the use of "midstream" and "downstream" in this study differs from standard oil and gas industry terminology.

In 2013, the Pembina Institute prepared a report for Canada's Integrated $CO_2$ Network ($ICO_2N$) on the net GHG impact of storing $CO_2$ through EOR[2]. The aim of this study was to better understand the GHG impact of $CO_2$-EOR, with two specific objectives in mind:

1. Quantify GHG emissions from $CO_2$-EOR
2. Support a wider discussion of the topic

The analysis uses actual operational data from a single site in Western Canada, and the authors state that the assessment adheres to ISO 14064 but does not strictly follow all procedural requirements. The accounting includes the per barrel emissions intensity of crude oil production, processing and use for the following scenarios (with 1 and 2 being reference storage scenarios):

1. Geological Storage – Net storage through CCS
2. EOR On-site – Net storage through EOR
3. EOR Full Lifetime Emissions – Based on actual emissions data from a Canadian $CO_2$-EOR operation in Alberta
4. EOR Lifetime with Oilsands Offsetting – Offsetting with a barrel of Canadian oilsands syncrude with a 50:50 ratio of mining and in-situ production (steam assisted gravity drainage (SAGD))
5. EOR Lifetime with Average Offsetting – Offsetting with an average barrel of US crude oil

Although site specific factors make generalisations about the GHG performance of $CO_2$-EOR difficult, the authors were able to draw some valuable conclusions from the exercise. Overall, geological storage provides more significant GHG benefits than the EOR scenarios. The results of the quantitative analysis also show that the carbon intensity of oil from this specific site falls somewhere between the intensity of a Canadian oilsands and the US average barrel. Another conclusion is that the EOR performance ratio (in bbl/$tCO_2$ injected) has a very large impact on the overall GHG performance of the process, i.e. higher field productivity leads to higher lifecycle emissions (without offsetting). The final performance also varies greatly depending on the assumptions, i.e. when assuming full substitution of more carbon intensive sources of crude, like in scenario 4, then EOR has a benefit in term of $CO_2$ emissions. The limitations of the study are the following:

- The analysis is site specific and results cannot be easily transferred or generalised.
- The scenarios assume either no or full substitution under an apparently inelastic oil demand.

[2] Wong, Goehner, McCulloch. Net greenhouse gas impact of storing $CO_2$ through Enhanced Oil Recovery (EOR) – An analysis of on-site and downstream GHG emissions from $CO_2$-EOR crude oil production in Western Canada. The Pembina Institute, 2013.

- The actual site data is for a productivity of 1 bbl/t$CO_2$ only, which is well below industry average; the other cases are modelled.

- Due to data limitations, the study assumes that EOR performance is fixed in time.

- $CO_2$ credits are not considered.

- The authors do not provide any particular views on the appropriateness of the different assumptions/approaches.

Some of the caveats outlined above, as well as the conflict between GHG reduction through incidental storage and additional emissions from increased oil use, have been the trigger for the present IEAGHG study.

Another recent study by the IEA CCS Unit, which took place in parallel to the present IEAGHG work, looked at different options to store $CO_2$ through EOR with the aim of achieving a win-win situation for oil production and climate change mitigation goals[3]. For this, existing $CO_2$-EOR practices can be modified to deliver significant capacity for long-term $CO_2$ storage. The assessment uses a hypothetical, representative field and investigates the following three options:

1. Conventional EOR+ – Modification of current practices with the aim to maximise oil production while storing a minimal amount of $CO_2$.

2. Advanced EOR+ – Co-exploit both oil recovery and $CO_2$ storage for profit.

3. Maximum Storage EOR – Focus on the maximising long-term storage of $CO_2$ while maintaining productivity of the Advanced EOR+ case.

The authors find that both Advanced and Maximum Storage EOR+ cases would exceed the $CO_2$ storage requirements in a 2DS scenario. However, adding the necessary practices to conventional processes would require a clear paradigm shift from current practices and the related additional costs might vary greatly for individual sites. Similar to the Pembina report, the IEA report also acknowledges that storing captured $CO_2$ in a saline aquifer would be a more effective means of reducing atmospheric $CO_2$ emissions. Furthermore, the authors look at the substitution issue and conclude that emissions reduction benefits persist for all three options until the rate of displacement reaches 50%, assuming substitution of oil with low $CO_2$ intensity.

## Scope of Work

Given the current gap in the literature, the aim of this report is to consider GHG accounting methods and MRV (monitoring, reporting and verification) rules used to compile inventories of

[3] Heidug, Lipponen, McCoy, Benoit. Storing $CO_2$ through Enhanced Oil Recovery – Combining EOR with $CO_2$ storage (EOR+) for profit. IEA Insight Series 2015.

GHG emissions for projects involving $CO_2$-EOR in combination with CCS. The focus is on addressing emissions in terms of:

1. Whether and when to account for the mid- and downstream emissions associated with the IPO; and

2. How to account for downstream emissions (i.e. ways to quantify such emissions).

The report does not consider "upstream emissions", i.e. emissions associated with the source of $CO_2$ and its capture and transportation. One of the key assumptions in the analysis is that an incentive is applied for capturing the $CO_2$ and storing it in geological formations. As such, it is reasonable to assume that appropriate MRV requirements would be in place for the capture, transport and storage of $CO_2$. The report also does not attempt to provide specific recommendations on how to undertake life cycle assessment (LCA) for $CO_2$-EOR. However, the findings can support development of consistent approaches to LCA by providing insights into boundary settings and emissions quantification.

The following assumptions are made that serve to set out the conditions under which emissions leakage could occur:

1. An incentive, e.g. carbon pricing or mandatory GHG emissions reporting, is in place and applicable to capturing and geologically storing $CO_2$ in conjunction with $CO_2$-EOR. It is further assumed that all site-level emissions must be accounted for under a particular scheme.

2. A risk of emissions leakage is posed where there is asymmetry in GHG emission controls between: (a) where the capture and $CO_2$-EOR operation takes place; and, (b) where IPO is used in processes, products, sectors or jurisdictions. Under these circumstances, the supply of crude oil from $CO_2$-EOR could add to the overall supply of fossil fuels into a market, thereby potentially increasing overall global GHG emissions and driving carbon lock-in. This condition assumes oil supply is elastic.

3. Where GHG emission controls are in place across the whole $CO_2$-EOR value chain, the risk of emissions leakage is reduced. Under these circumstances, the supply of crude oil from $CO_2$-EOR should only substitute supply from other sources, as the controls in place do not allow for an increase in emissions. This reduces the risk of carbon lock-in.

4. GHG accounting/inventory boundaries are critical to understanding the scope for emissions leakage to occur. If a scheme employs sufficiently wide spatial boundaries (e.g. covering the whole oil value chain) then emissions leakage may not pose a risk.

# Findings of the Study

## When and whether to account for emissions leakage

The combination of CCS with $CO_2$-EOR presents some particular challenges that need to be addressed, the most pressing of which is the risk posed by emissions leakage. Since crude oil – and increasingly, refined products – are globally traded commodities, the scope for emissions leakage to occur is primarily governed by the GHG policies and measures that are in place around the world today. Since there is no universal approach to controlling GHG emissions globally and across different sectors, this means that a variable patchwork of policies and measures exists that can drive different types of emissions leakage risk.

1. *Transboundary* emissions leakage i.e. where regions producing and importing IPO have asymmetric controls on GHG emissions; and/or,

2. *Cross-sectoral* emissions leakage i.e. where a policy has fairly narrowly defined boundaries (e.g. sectoral based policies), meaning that mid- and downstream emissions can occur, unregulated, outside the boundaries of the scheme.

Emissions leakage can occur where GHG policies incentivise $CO_2$-EOR deployment in one jurisdiction whilst simultaneously potentially driving longer-term GHG emission increases elsewhere. This can arise due to a lack of stringent GHG emission controls in the markets where the IPO is used. The risk of such emissions leakage occurring is variable because of the variations in the type and stringency of GHG controls in place in different parts of the world. The risk of emissions leakage is also further governed by the characteristics of global oil production, supply and use, and the magnitude of emissions leakage that could actually result from transboundary and cross-sectoral movements of IPO.

Under the current patchwork of GHG emission controls posed by the UNFCCC and Kyoto Protocol and through differential implementation of sectoral policies, both transboundary and cross-sectoral emissions leakage can potentially occur, even where economy-wide emission controls and reporting obligations are in place.
Figure 2 outlines a simplified illustration of the potential for transboundary emissions leakage to occur involving two countries, Country A and Country B. Country A is subject to economy-wide QELROs (quantified emissions limitation and reduction objective) under the Kyoto Protocol, whilst Country B has no obligations in place. The results show a total of eight possible cases where emission leakage from $CO_2$-EOR could arise due to varying combinations in the location of production, refining and end-use combustion.

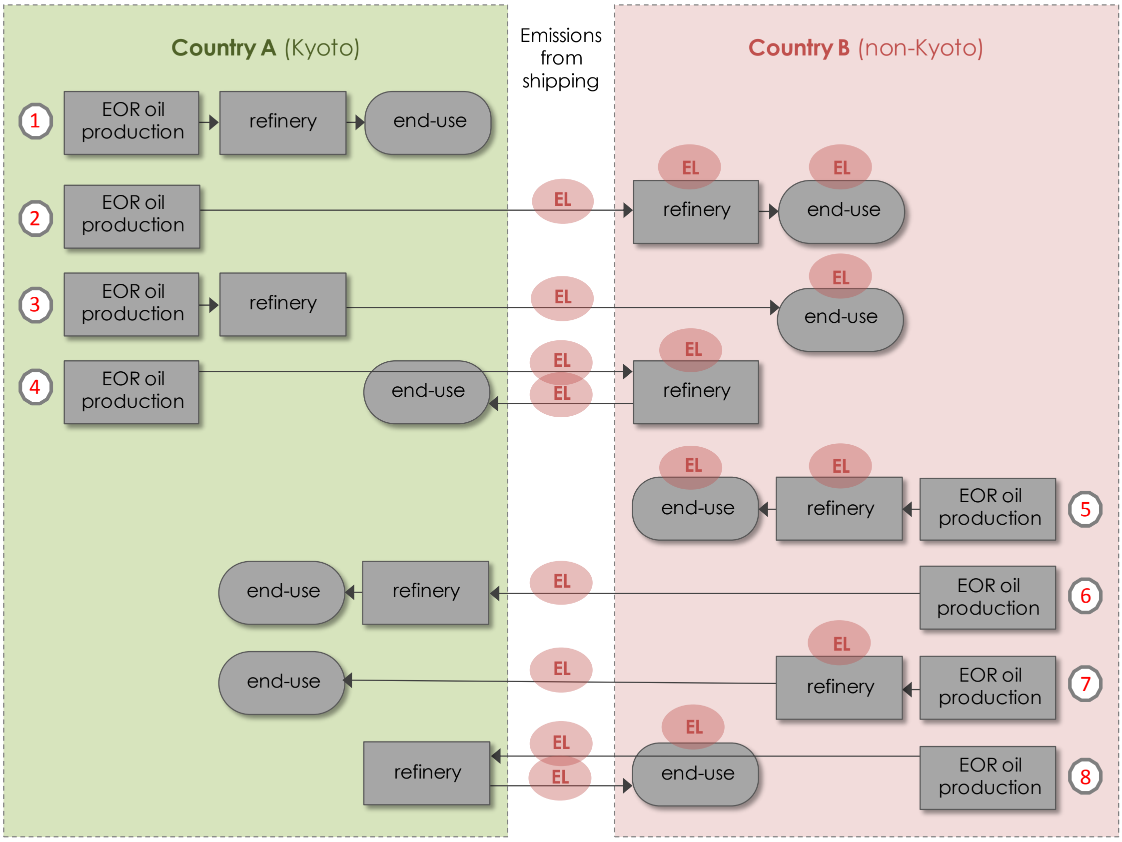


**Figure 2 Potential sources of emissions leakage from $CO_2$-EOR operations**

Only in case 1 all emissions occur within the fully regulated system of Country A. Under these circumstances, it is possible to assume that there is no risk of emissions leakage. This situation might apply in Norway, the European Union or California today, where fairly stringent economy-wide GHG emission controls are in place.

In all other cases there is the potential for both transboundary and cross-sectoral emissions leakage due to the absence of mid- and downstream GHG emission control policies in various parts of the crude oil value chain. An example case could be production of oil in the EU, with refining and end use occurring in North Africa. In particular, the potential remains for cross-sectoral emissions leakage to occur where IPO is used in the international marine or aviation sectors, i.e. bunker and jet fuels.

The above cases illustrate the potential for emissions leakage to occur in fairly simple situations. However, in many countries a variation of policy mixes will exist, falling somewhere between fully-fledged or non-existent emission controls. In addition, QELROs vary significantly between different signatory Annex I Party countries. Another complicating factor is that many countries without economy-wide QELROs have often adopted other measures to control downstream emissions, e.g. through fuel excise duties or vehicle taxes in the road transport sector. The result of this complexity is that emissions leakage could occur, and could occur to different degrees, depending on the status and stringency of GHG emission controls in both oil producing and importing regions.

Figure 3 shows how the risk of emissions leakage could change depending on the final destination (i.e. the point of end-use) of the IPO from a $CO_2$-EOR activity in relation to different types of

GHG emission control policies. It also highlights some example jurisdictions where such conditions exist. The figure is for illustrative purposes only, and does not claim to provide a definitive view on the type and level of emissions leakage risks posed by using oil produced from $CO_2$-EOR.

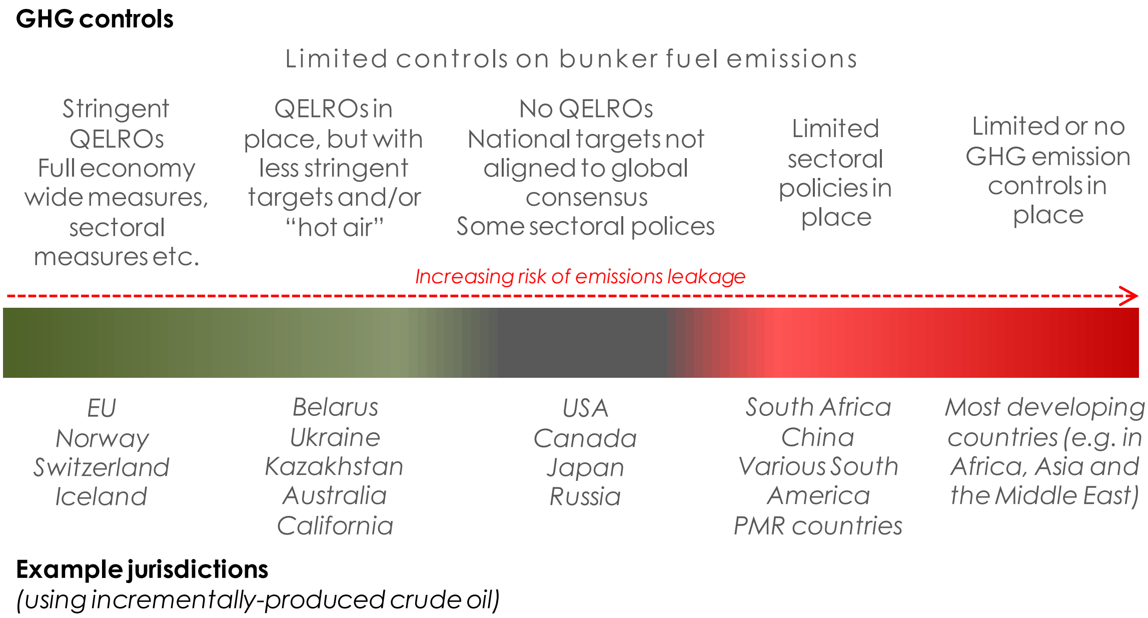


**Figure 3 Risk of emissions leakage for example jurisdictions**

Where the IPO is used in domestic markets, the risk can be easily estimated as only GHG controls in place in a single jurisdiction need be considered. Where the crude oil is traded internationally, the degree of risk is difficult to estimate because of the challenges in comparing different GHG control policies in place. However, the indicative risk can be estimated based on a broad view about the stringency of different GHG control policies in place. Table 1 presents recent data for annual international oil trade flows between sources of production and destinations of consumption. It also highlights the emissions leakage "hot spots", i.e. where the risks and flows are both high.

**Table 1 Major international crude oil and refined products trade flow "hotspots", 2013**

| *Mbbl per day* | To | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | US | Canada | S.America + Mex | Europe | FSU | Middle East | Africa | Aus + NZ | China | India | Japan | Other Asia + | TOTAL |
| **From** | | | | | | | | | | | | | |
| US | - | 298 | 1617 | 674 | 2 | 75 | 136 | 7 | 148 | 40 | 118 | 155 | **3271** |
| Canada | 3125 | - | 22 | 74 | - | 2 | - | - | 34 | 2 | 13 | 4 | **3276** |
| S. America + Mex | 2609 | 40 | 46 | 559 | 2 | 2 | 6 | 1 | 644 | 729 | 47 | 358 | **5042** |
| Europe | 496 | 160 | 266 | - | 104 | 258 | 598 | 2 | 26 | 13 | 28 | 450 | **2399** |
| FSU | 519 | 5 | 15 | 5989 | - | 273 | 36 | 38 | 877 | 42 | 290 | 547 | **8632** |
| Middle East | 2011 | 127 | 139 | 2074 | 9 | - | 334 | 155 | 3097 | 2509 | 3310 | 5672 | **19439** |
| Africa | 821 | 146 | 382 | 2965 | 3 | 25 | - | 139 | 1305 | 642 | 106 | 278 | **6811** |
| Aus + NZ | 2 | 0 | 11 | 2 | - | - | 1 | - | 66 | 3 | 40 | 169 | **294** |
| China | 7 | 1 | 94 | 13 | 10 | 22 | 23 | 1 | - | 12 | 9 | 438 | **631** |
| India | 60 | 2 | 93 | 173 | - | 364 | 177 | - | 13 | - | 64 | 290 | **1235** |
| Japan | 17 | - | 5 | 5 | - | 1 | 2 | 74 | 36 | 1 | - | 181 | **321** |
| Other Asia + S'pore | 126 | 1 | 47 | 110 | 1 | 53 | 102 | 617 | 665 | 101 | 505 | 1993 | **4320** |
| **TOTAL** | 9792 | 781 | 2737 | 12637 | 130 | 1076 | 1416 | 1033 | 6911 | 4094 | 4530 | 10535 | 55670 |
| | **18%** | **1.4%** | **5%** | **23%** | **0.2%** | **1.9%** | **2.5%** | **1.9%** | **12%** | **7%** | **8%** | **19%** | **100.0%** |

*Notes*: Mbbl = thousands of barrels. The shaded cells show emissions leakage risk colour coded according to Figure 3 with flows >300 Mbbl/d in a lighter shade, and flows > 1MMbbl/d in darker shade. Data shown excludes domestic and most intra-area movements. Data for Mexico and Singapore added to S. America and Other Asia respectively.

Table 1 also shows that some of the largest international oil flows are from the FSU, Africa and Middle East to the EU, where the emissions leakage risk is in theory minimal because QELROs and a number of sectoral policies restricting mid- and downstream emissions are in place. In summary, 23% of oil flows are likely to be at low risk, equating to around 1.9 $GtCO_2$. A slightly higher number of 29%, or 2.5 $GtCO_2$, are at medium risk, mainly imports into the US, Japan, Australia and Canada. However, almost half of all oil flows might be at high risk of emissions leakage. This applies to imports into most developing countries and the associated emissions are around 4.2 $GtCO_2$.

Another important point for consideration is the materiality of the emissions leakage risk, i.e. the extent of emissions leakage compared to the achievable emissions reduction through the $CO_2$-EOR activity. Recent data from the US Congressional Research Service (CRS) and National Energy Technology Laboratory (NETL) provide can be used to get insight into life-cycle well-to-wheel (WTW) GHG emissions intensity of US gasoline/petroleum. In terms of materiality, the greatest risk is from unmitigated increases in end use, which account for between 60-85% of the life-cycle WTW GHG emissions for gasoline/petroleum. The nature of oil flows mean that downstream emissions from oil exported to countries with limited GHG controls could be up to 60% of worldwide emissions from oil combustion. Refining accounts for around 10% of WTW emissions and transport around 2-3%. Differences in emissions from crude oil extraction may account for up to 17% of the overall WTW emissions associated with petroleum/gasoline. When considering the possibility of negative emissions under scenario's involving substitution, the latter can be considered to be material to the debate. More pertinent, however, is the possibility of refining and end-use emissions increasing on an unmitigated basis if policies and measures are not in place to control their emissions. This could represent a significant source of emissions leakage.

**How to account for emissions leakage**

To account for emissions leakage, it is necessary to develop an emissions factor that reflects emissions from mid- and downstream activities associated with the IPO from $CO_2$-EOR. This typically involves estimating emissions across the value chain and expressing them on an emissions intensity per barrel of oil basis.

Such an approach takes a somewhat simplified view of the leakage effect, however, as in reality, if the new supply of oil displaces other oil sources, the leakage effect may actually be *negative* (i.e. it might actually reduce net emissions by substituting more emissions intensive alternative products). On the other hand, increasing crude oil supply may actually prevent the substitution of oil by less emissions intensive products such as biofuels or electricity. The latter aspect forms the core concern of carbon lock-in. It is therefore challenging to determine whether and what the *substitution* effect of supplying IPO is.

Three possible approaches to estimating emissions leakage can be identified:

- *Project specific* – the approach may be relevant where the supply from $CO_2$-EOR is assumed to be *additional* to existing supply, and would involve adopting a specific set of emissions estimates for mid- and downstream activities for a specific sources of IPO;

- *Marginal supply* – this approach may be relevant in cases where a substitution effect can be identified and linked to displacement of a specific source of oil supply in a given market.

- *Market average* – this approach may be relevant in cases where a substitution effect can be identified, but the specific source of oil displaced by the supply cannot be identified.

In cases where the risk of emissions leakage can be identified as either high or low, the substitution issue is not so relevant since where it is assumed that the risk is low, *no substitution* can occur, and if it is high, then the supply must be *additional*. Consequently, the only relevant approach to accounting for emissions leakage where relevant is to use a product specific emissions factor.

In cases where risk of emissions leakage is considered to lie somewhere between the two extremes, it may be necessary to adopt a combined approach taking account of both addition and substitution. This is similar to approaches adopted under in the CDM for grid connected renewable energy projects, where a combined margin approach is taken.

On a methodological level, there are challenges to implementing such an approach because of the complexity of global oil markets.

**Approaches to $CO_2$-EOR accounting**

A first-pass approach for estimating the risk of emissions leakage is presented, basically consisting of the following steps:

A. Characterise extent and scale of emissions leakage risk

1. *Analyse pathways for oil use including exports.* This is used to determine the range of jurisdictions using the IPO. The analysis can be done on a project-specific or country/regional basis.

2. *Characterise GHG policies and measures in host and receiving countries.*

3. *Estimate the risk of emissions leakage.* The relative percentage of produced oil delivered to each risk category should be established. This provides the basis for pro-rating and allocating production from a $CO_2$-EOR activity to each leakage risk category (i.e. low, medium, high).

B. Calculate emissions factor for leakage

4. *For low or medium risk: Calculate the delta between the site-level emissions associated with the $CO_2$-EOR project and the emission from crude oil extraction for either: (i) the marginal supply, or (ii) the average market supply*. This should be calculated for each jurisdiction in order to establish a weighted average crude oil extraction emissions intensity. The choice of approach depends on whether it is possible to identify the marginal supply for a given jurisdiction or not. The difference between the two provides an estimate of emissions leakage from $CO_2$-EOR, which may be negative where more emissions intensive supply sources are substituted. For countries with a medium risk of emissions leakage, the result should be multiplied by 0.5 to reflect the uncertainty regarding whether substitution of supply is occurring, i.e. only half of any emission reduction benefit is attributable.

5. *For medium and high risk: Calculate the mid- and downstream emissions associated with refining and end-use of crude oil and products.* In the case of countries at a high risk of emissions leakage, this provides the basis for quantifying the risk. For countries with a medium risk of emissions leakage, the result should be multiplied by 0.5 to reflect the uncertainty regarding whether addition to supply is occurring.

A hypothetical worked example is available in the main report. In this example, around 19% of produced oil is assessed to be at low risk of emissions leakage, 41% at medium risk, and the remainder (40%) at high leakage risk.

Table 2 summarises which approaches of calculating emissions leakage factors would be preferable under different risk scenarios.

**Table 2 Approaches for calculating leakage emission factors**

| Emissions leakage risk | Emission factor to apply | Notes |
|---|---|---|
| **Low** | Marginal supply<br><br>or<br><br>Market average | Marginal supply factor may be used on the basis that, in theory, all incremental oil supplied could lead to perfect substitution. This could result in the calculation of a negative emission factor, meaning the amount netted back to the $CO_2$-EOR activity would involve the subtraction of a negative number, leading to a positive increase in the calculated net emission reduction for the particular activity to which the approach is applied.<br><br>Where marginal supply displacement cannot be shown with any confidence, then the market average factor should be applied. |
| **Medium** | Marginal supply<br><br>or<br><br>Market average + product specific | As per Low Risk. However, since it is uncertain whether substitution or addition occurs, it may be necessary to take a combined approach involving an assumption of 50% substitution, and 50% addition.<br><br>The 50% addition component requires the use of a product specific emission factor to be used to calculate mid- and downstream leakage effects, hence it is referred to as a combined approach. |
| **High** | Product specific | As no substitution effect occurs, the delta between the project site level emissions and any substituted supply source is not relevant. Specific emissions associated with mid- and downstream leakage effects should be calculated. |

<u>Limitations of the approach</u>

The approach outlined should be considered as a first-pass attempt that can provide a basis for further work, rather than the definitive approach on the matter.

A key principle to consider in developing an approach to estimate emissions leakage is conservativeness. The principle is of importance in so much as the issues at hand reflect small marginal changes in the emissions intensity of oil extraction and supply on a per barrel basis, set against potentially very large absolute numbers in terms of oil production and trade flows. As such, minor errors in the approach adopted could propagate as a large cumulative error in any leakage emission estimate.

It is important to note that whilst a procedure has been outlined to calculate the relevant emission factor for emissions leakage relating to substitution of other supplies of crude oil, it will be extremely challenging to implement in practice. This is largely due to a lack of high quality data with which to compile the analysis. Moreover, since it is likely that substitution effects cannot be readily measured and attributed with any degree of confidence, such an approach might not be considered as conservative. As such, it is debatable whether it would stand up to scrutiny as an established MRV or accounting approach to calculate emissions leakage from $CO_2$-EOR activities.

Furthermore, there are general practical challenges in implementing such an approach in terms of obtaining the appropriate data, keeping the data up-to-date over time, and equity issues in terms of potential disparities between the inventory quality and transparency of reporting of crude oil extraction and refining emissions across different jurisdictions around the world.

## Expert Review Comments

Four expert reviewers provided feedback on the draft report. Most of them commented the report was well structured, contained a coherent argumentation and provided a nuanced picture of a very complex issue. One reviewer mentioned the report sometimes crossed the line between technology and policy but acknowledged that this was unavoidable due to the nature of the issue. Apart from minor smaller typographic errors and bulky sentence structures, there was a request to add more clarification and description for some of the graphics and calculation, e.g. to provide a decision tree diagram for the calculation steps of emissions leakage. Two reviewers suggested using the Weyburn project as a detailed case study for the report. They also commented that the report should discuss that, according to their opinion, there was no impact of incremental oil from $CO_2$-EOR on the market at present, and thus a risk of emissions leakage would be negligible for the present extent of $CO_2$-EOR operations.

IEAGHG passed the comments on to the contractor and most of them have been addresses in the final report.

## Conclusions

Most jurisdictions around the world that recognise emission reductions from CCS apply the same incentive for storing $CO_2$ as part of $CO_2$-EOR operations. Problematically, there is a paradox presented by, on the one hand, incentivising $CO_2$ stored through $CO_2$-EOR, and on the other, increasing oil production. This may not be an issue if IPO from $CO_2$-EOR substitutes and displaces similar or more emissions intensive sources of crude oil supply. However, in some cases IPO may simply add to overall supply, which could potentially increase lifecycle emissions of $CO_2$-EOR. Gaining a full insight into whether substitution or addition is a very complex topic – and there is currently no scientific consensus.

In case IPO adds to overall supply, this can be considered as a form of "emissions leakage", on the basis that a carbon price incentive for $CO_2$-EOR is driving emissions increases elsewhere, outside of the immediate physical boundaries of the $CO_2$-EOR activity. Conversely, where more emissions intensive supply is substituted and displaced, this can be considered to be a type of "negative emissions leakage" (i.e. resulting in a net overall reduction in emissions).

A proxy measure of assessing emissions leakage risk is the stringency of GHG emission controls present in jurisdictions using IPO. Where stringent emissions controls are in place, it is reasonable to assume that supply of new sources of oil will only substitute existing supplies because the GHG policies and measures in place in theory restrict the scope for using more oil. For jurisdictions with weak or non-existent GHG emissions controls, it is likely that new supplies will add to the overall supply base. However, GHG emission controls are not a perfect measure of risks because a wide range of other factors are at play (e.g. oil price dynamics, subsidies, quotas).

A broad analysis of emissions leakage risk using this approach suggests that whilst a proportion of global oil flows is at low risk of emissions leakage, a significant proportion could be at high risk. (This only considers international trade flows and not domestic production and consumption.)

Variation in the site-level emissions associated with producing different crude oils can account for up to 17-18% of WTW GHG emissions intensity of crude oil products. Refining emissions may account for up to 10% of overall life cycle WTW GHG emissions, whilst transport emissions from both crude oil and refined products may account for as little as 1-2% of overall life cycle GHG emissions. Downstream emissions from the end use of refined products are the greatest source of life cycle GHG emissions, with up to 85% of total emissions from US petroleum/gasoline. The nature of oil flows means that downstream emissions from oil exported to countries with limited GHG controls could be up to 60% of worldwide emissions from oil combustion. However, it is important to note that demand-side changes are out of control of $CO_2$-EOR operators. Thus, approaches separating site-level emissions from mid-/downstream emissions might be necessary to resolve the issues.

There are significant challenges to developing a methodology for estimating and quantifying EL for $CO_2$-EOR operations. These include:

- Uncertainties regarding whether substitution or addition to oil supply is occurring;
- Whether substitution would actually displace marginal oil supply, or whether other sources of supply would be displaced. (i.e. it is often unclear which crude oil extraction emission intensity factor to compare $CO_2$-EOR against);
- Whether an assessment/comparison of GHG policies and measures can provide a suitably robust indication of emissions leakage risk;
- Availability of data from which to quantify the various components of an emissions leakage risk estimate.

Notwithstanding these challenges, this study outlines a first approach. This should be used only as a basis for further debate and consideration, rather than as a definitive view on the matter.

## Recommendations

In order to identify the full range of issues surrounding GHG emissions accounting for $CO_2$-EOR there is a clear need for further discussion and analysis of real world examples. . Concerning the present study, it might be useful to test the discussed approaches in a real world setting regarding their workability, practicality of implementation and limitations. The results from such an exercise could help improve and revise the approach.. It would also be important to consider the full range of political, regulatory and practical challenges presented by the approaches outlined (including complexity, administrative challenges, treatment of different fuels and requirements for successful approval). Another area for further work would be the clarification whether and when substitution or addition take place, which would require a detailed analysis of oil markets, price elasticity and demand/supply conditions.

Due to the complexities involved in global trade of oil and refined products, a whole-chain, i.e. cradle-to-grave, assessment of $CO_2$-EOR is generally challenging. It might be necessary and/or more effective to address site-level and mid- and downstream emissions separately. However, diving deeper into this subject is not an activity IEAGHG would undertake in the immediate future.

IEA Greenhouse Gas R&D Programme

# Quantifying and monitoring emissions reductions from $CO_2$-EOR

(IEA/CON/14/221)

FINAL REPORT

Carbon Counts Company (UK) Ltd

7 April 2015

Prepared by:
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Our Ref: 062 IEAGHG $CO_2$ EOR Accounting

## PREFACE

This report was prepared by *Carbon Counts Company (UK) Ltd* ("Carbon Counts") under contract to the IEA Greenhouse Gas R&D Programme ("IEAGHG"). The lead authors were Paul Zakkour and Greg Cook.

The report attempts to review issues associated with greenhouse gas emissions accounting where anthropogenic carbon dioxide is captured and used for enhanced oil recovery ($CO_2$-EOR) in conjunction with long-term geological storage of $CO_2$. Whilst this suggests a fairly narrow scope of research, it in fact opens up several lines of complex enquiry, requiring a strong understanding of global oil production, trade, supply and demand. This is a topic to which countless hours of debate and consideration are made on an ongoing basis, generally without any clear consensus in respect of matters such as 'peak oil', 'carbon lock-in' and fossil fuel 'demand destruction'. It is also a topic that is highly political, with oil being at the heart of economic activity and life-style behaviour. As such, the analysis presented herein has required some simplifying assumptions in order to provide limits to the discussions presented. This has been carried out to the best of the authors' capacity, commensurate with the time and resources available for the study. The report does not claim to provide a definitive view on how to resolve issues of greenhouse gas emissions accounting for $CO_2$-EOR, but rather provides a source of ideas on how to establish a framework for considering the issues at hand, and food for thought in respect of further discussion and debate.

The project team would like to thank Tim Dixon and Jasmin Kemper of the IEAGHG for their excellent oversight and inputs during the development of the report. We are also grateful to Dr. Malcolm Wilson, Anastassia Manuilova (ArticCan Energy Services Inc.), Paulo Negrais Seabra (Petrobras) and Dr. Wolfgang Heidug (International Energy Agency) who peer reviewed draft versions of the manuscript.

## CONTENTS

## ACRONYMS AND ABBREVIATIONS

| | |
|---|---|
| ACR | American Carbon Registry |
| Bbl | Barrel of oil |
| CCS | Carbon dioxide capture and storage |
| CDM | Clean development mechanism (under the Kyoto Protocol) |
| EOR | Enhanced oil recovery |
| EPA | US Environmental Protection Agency |
| EU | European Union |
| EU ETS | EU Emissions Trading Scheme |
| FQD | EU Fuel Quality Directive |
| GHG | Greenhouse gas |
| GHGRP | Greenhouse Gas Reporting Program (US EPA) |
| INDC | Intended nationally determined contribution (an emission reduction “pledge”) |
| IPCC | Intergovernmental Panel on Climate Change |
| LCA | Life cycle assessment |
| LULUCF | Land use, land use change and forestry |
| MRV | Measurement (or monitoring), reporting and verification |
| MRR | EU Monitoring and Reporting Regulation (under the EU ETS) |
| PMR | Partnership for Market Readiness (under the World Bank) |
| QELRO | Quantified emission limitation and/or reduction obligation |
| $tCO_2$ | Tonne of carbon dioxide |
| UNFCCC | United Nations Framework Convention on Climate Change |
| WTT | Well to tank (LCA approach for crude oil life cycle emissions, up to point of end use) |
| WTW | Well to wheels (LCA approach for crude oil life cycle emissions, including end use) |

## GLOSSARY OF TERMS

A number of terms are used throughout this report defined as:

*'Carbon leakage'* is widely used to refer to situations where production cost increases due to climate policies drive a transfer in production to jurisdictions with lower (or no) greenhouse gas (GHG) emissions constraints, potentially resulting in a net emissions increase. Whilst related, this report does not consider leakage in this context, but rather the issue of 'emissions leakage' described below.

*'Carbon lock-in'* is a *'path dependency'* argued by Unruh (Unruh, 2000) that:

> *"…industrial economies have been locked into fossil fuel-based energy systems through a process of technological and institutional co-evolution driven by path-dependent increasing returns to scale. It is asserted that this condition, termed* carbon lock-in*, creates persistent market and policy failures that can inhibit the diffusion of carbon-saving technologies despite their apparent environmental and economic advantages"*

*'Conservative'* is used in the report drawing on the CDM definition of*:*

> *"In case of uncertainty regarding values of variables and parameters the establishment of a baseline is considered* ***conservative*** *if the resulting projection of the baseline does not lead to an overestimation of emission reductions attributable to a CDM project activity (that is, in the case of doubt, values that generate a lower baseline projection shall be used)."*

The purpose is to avoid overestimating the level of emission reductions that may be achieved by a CDM project activity.

*'Credible'* means whether any greenhouse gas emissions accounting framework and the results of its application would stand up to rigorous scrutiny by e.g. a regulator.

*'Downstream'* refers to the combustion and/or use of crude oil and/or refined products in end-use processes and products, such as transport fuels or petrochemical feedstocks.

*'Emissions leakage'* means the potential for net changes in emissions to occur outside the boundaries and operational control of a particular policy and/or activity, but arising as a consequence of the policy and/or activity. Its use in the report is similar in context to that applied under the Kyoto Protocol's clean development mechanism (CDM). Where a GHG-based incentive is applied to a particular activity, such as a 'carbon credit' or carbon tax offset, emission leakage can potentially undermine its environmental integrity because of its effects on net emission reductions arising from the activity.

*'Fair'* refers to e.g. whether an operator has taken suitable steps to provide assurances that the result of measurement is as close to the true value as possible.

*'Midstream'* refers to the activities involved in the transportation and refining of crude oil.

*'Path dependency'* is the idea that decisions we are faced with depend on past knowledge trajectory and decisions made, and are thus limited by the current competence base. In other

words, history matters for current decision-making situations and has a strong influence on strategic planning (from: www.ft.com/lexicon). The theory was originally developed by economists to explain technology adoption processes and industry evolution.

*'Permanence'* relates to the risk that some geologically stored $CO_2$ in a CCS or $CO_2$-EOR project could seep from the subsurface back to the atmosphere at some future point in time. Permanence compromises the environmental objective of CCS and any climate mitigation policies that support its development. It also compromises the environmental integrity of any incentives such as tax relief or carbon credits provided for the avoidance of emissions by the use of CCS. It can be addressed through appropriate means of recourse and/or remediation.

*'Price elasticity'* is the response in supply and demand of a particular product to changes in price. *'Demand elasticity'* is a measure of the relationship between a change in the quantity demanded of a particular product to a change in its price. *'Supply elasticity'* is a measure of the responsiveness of producers to change the supply of a particular product in response to a change in its price. A product is referred to as *elastic* is where there is only a limited change due to price increase or decrease, and *inelastic* where the opposite effect occurs.

*'Seepage'* refers to slow or rapid physical leakage of $CO_2$ from geological storage sites. It is used in this report to avoid confusion with the term leakage, which is used in the context of emissions leakage. It is also applied in the same context under the CDM to avoid similar confusion.

*'True'* refers to principles of measurement regarding how close a measured and/or calculated value might be to the actual, real value.

*'Upstream'* refers to the generation, capture and transport of $CO_2$ to a $CO_2$-EOR site.

## EXECUTIVE SUMMARY

The use of carbon dioxide ($CO_2$) to enhance oil recovery from mature fields has been practiced since the early 1970's, primarily in the United States: a process known as "$CO_2$-EOR". Today, over 100 such oilfields are in existence, injecting around 50 million tonnes $CO_2$ per year. Much of the $CO_2$ used is mined from natural sources, although around 12 $MtCO_2$ is derived from anthropogenic sources. With the emergence of carbon dioxide capture and geological storage (CCS) as a climate mitigation technology, $CO_2$-EOR has been seen as a potential early opportunity to catalyse wider uptake of the technology. In order to recognise the emission reduction benefits potentially arising from $CO_2$-EOR, appropriate greenhouse gas (GHG) emissions accounting approaches are required in order that the net abatement effects be appropriately quantified and attributed to the technology and its operators. Most of the GHG accounting issues presented by CCS – such as seepage and permanence – apply also to $CO_2$-EOR operations. These issues have largely been addressed in GHG regulatory frameworks in place around the world today. However, there are additional issues presented by $CO_2$-EOR compared to 'pure' geological storage projects, principally how to account for the emissions from transport, refining and end-use of the incrementally-produced crude oil. This is a topic that has proved contentious, with some arguing that $CO_2$-EOR can never reduce emissions because it produces additional oil, and others asserting that it is a relevant emission reduction technology. Core to this discussion is whether the incrementally-produced crude oil *substitutes* other sources of crude oil supply, thereby resulting in a minor or negative net change in emissions, or whether it *adds* to supply, thereby creating new sources of emissions. There is also a temporal dimension to the debate, relating to long-term elasticity of demand for oil, and the risk of path dependency on fossil fuels and carbon "lock-in". This paper sets out to address these issues.

The approach taken looks as the problem in terms of "emissions leakage". This term is used because if a carbon price incentive is provided to undertake $CO_2$-EOR as an emission reduction technology, but concurrently the incrementally-produced crude oil drives increases in emissions elsewhere, this can be considered as a leakage problem. To address emissions leakage in this context, the report considers the following:

1. Whether and when to account for emissions leakage
2. How to account for emissions leakage, and
3. A first-pass methodological approach to account for emissions leakage from $CO_2$-EOR

A proxy measure of leakage risk is the stringency of GHG controls in place in the jurisdiction refining and using the crude oil; such policies can restrict increases in emissions thereby limiting the effect, in theory, to *substitution* rather than *addition*.

In terms of **whether and when to account for emissions leakage**, it finds that the risk of emissions leakage occurring is variable because of the variations in the type and stringency of GHG controls in place in different parts of the world. Where the incrementally-produced crude oil is used in domestic markets, the risk can be easily estimated as only GHG controls in place in a single jurisdiction need be considered. However, where the crude oil is traded internationally, the degree of risk is difficult to estimate because of the challenges in comparing GHG control policies in place in different parts of the world – indicative risk can be estimated based on a broad view about the stringency of different GHG control policies. The scale of the risk is fairly large because of the nature of global oil trade flows, with imports into developing countries – jurisdictions largely absent of GHG emission controls – accounting for almost half of all oil trade internationally. The materiality of the risk is variable: variations in the site-level emissions associated with producing different crude oils can account for up to 17-18% of the well-to-wheel (WTW) emissions intensity of crude oil products. Refining emissions may account for up to 10% of overall lifecycle WTW GHG emissions, whilst transport emissions from both crude oil and refined products may account for as little as 1-2% of overall lifecycle GHG emissions. Downstream emissions from the end use of refined products are the greatest source of lifecycle GHG emissions (up to 87% of the WTW emissions). The nature of oil flows mean that downstream emissions from oil exported to countries with limited GHG controls could be up to 60% of worldwide emissions from oil combustion.

With respect to **approaches to account for emissions leakage**, it is necessary to develop an emissions factor that reflects emissions from mid- and downstream activities associated with the incrementally produced crude oil from $CO_2$-EOR. This factor can be used to "net-back" these emissions to the activity producing the crude oil from $CO_2$-EOR. This typically involves estimating emissions across the value chain and expressing them on an emissions intensity per barrel of oil basis. Such an approach takes a somewhat simplified view of the leakage effect, however, as in reality, if the new supply of oil displaces other oil sources, the leakage effect may actually be *negative* (i.e. it might actually reduce net emissions by substituting more emissions intensive alternative products). On the other hand, increasing crude oil supply may actually prevent the substitution of oil by less emissions intensive products such as biofuels or electricity, a complex matter to consider. The latter aspect forms the core concern of carbon lock-in. It is therefore challenging to determine whether and what the *substitution* effect of supplying incrementally produced crude oil might be. Three possible approaches to estimating emissions leakage are identified:

- *Product specific* – the approach may be relevant where the supply from $CO_2$-EOR is assumed to be *additional* to existing supply, and would involve adopting a specific set of emissions estimates for mid- and downstream activities for a specific source of incrementally produced crude;
- *Marginal supply* – this approach may be relevant in cases where a substitution effect can be identified and linked to displacement of a specific source of oil supply in a given market.
- *Market average* – this approach may be relevant in cases where a substitution effect can be identified, but the specific source of oil displaced by the supply cannot be identified.

In cases where the risk of emissions leakage can be identified as either high or low, the substitution issue is not so relevant since where it is assumed that the risk is low, *no substitution* can occur, and if it is high, then the supply must be *additional*. Consequently, it could be concluded that the only relevant approach to accounting for emissions leakage, where relevant, is to use a product specific emissions factor. In cases where risk of emissions leakage is considered to lie somewhere between the two extremes, it may be necessary to adopt a combined approach taking account of both addition and substitution. This is similar to approaches adopted under in the CDM for grid connected renewable energy projects, where a combined margin approach is used. On a methodological level, there are challenges to implementing this because of the complexity of global oil markets.

A first-pass **methodology for calculating emissions leakage** risk is presented, covering several steps:

- Firstly, the characteristics of oil supply from the country hosting the $CO_2$-EOR activity needs to be analysed. This is used to determine the range of jurisdictions using the incrementally-produced oil, and the emissions leakage risk for each country, classified in terms of low, medium and high risk.
- Secondly, the volume of oil received by each jurisdiction in each risk category should be calculated. The relative percentage of produced oil delivered to each risk category should be established. This provides the basis for pro-rating and allocating production from a $CO_2$-EOR activity to each leakage risk category (i.e. low, medium, high).
- Thirdly, for jurisdictions at either low or medium risk of emissions leakage, the delta between the site-level emissions associated with the $CO_2$-EOR project and the emission from crude oil extraction for either: (i) the marginal supply, *or* (ii) the average market supply, is calculated.
- Fourthly, mid- and downstream emissions associated with refining and end-use of crude oil and products should be calculated for jurisdictions at medium and high risk of emissions.
- A 50:50 combined approach using both the *substitution* effect (i.e. the delta between the actual site-level emissions and the site level emissions from the marginal or average supply) and the *addition* effect is proposed for countries where there is a medium risk of emissions leakage. Where there is a high risk of emissions leakage, the substitution effects are not considered relevant, and all emissions are considered to be additional and therefore the actual emissions should be used.

The approach outlined is untested, and is really designed only to foster further debate on the matter.

The report also reviews the current approaches to calculating GHG emissions from site-level operations in $CO_2$-EOR projects under different GHG regulatory schemes around the world. In the concluding chapter consideration is made of the challenges for implementing emissions leakage estimates in practice.

# 1 INTRODUCTION

The injection of carbon dioxide ($CO_2$) captured from anthropogenic emission sources into hydrocarbon-bearing geological reservoirs can provide a means of tertiary oil recovery to extend the production life of mature oilfields – a technique known as $CO_2$ enhanced oil recovery ($CO_2$-EOR). $CO_2$-EOR has been practised since the early 1970s, mainly in North America, where today more than 100 commercial miscible $CO_2$ floods are in operation, purchasing $CO_2$ at prices up of to US$40-45 per tonne (t) $CO_2$ (UNIDO, 2011).[1] These projects are utilising around 47 million t$CO_2$ per year (of which 12 million tonnes are supplied from anthropogenic sources; UNIDO, 2011; US EPA, 2014), and producing around 282,000 barrels of oil per day (bbl/day; NETL, 2014). Estimates of global potential for $CO_2$-EOR production are in the order of 470 billion barrels of additional oil globally (UNIDO, 2011). Despite a financial incentive to recover and recycle as much of the injected "breakthrough" $CO_2$ as possible,[2] empirical evidence shows that around 60% of the injected $CO_2$ never re-emerges at the production wellhead (Bachu and Shaw, 2002), and as a result is geologically stored.

In considering the option of carbon dioxide capture and storage (CCS) as a climate change mitigation technology, the incidental storage of $CO_2$ during $CO_2$-EOR is widely regarded as a co-benefit, especially if the technique can be optimised to increase amounts of $CO_2$ that are geologically stored. Consequently, $CO_2$-EOR is often viewed as an 'early opportunity' to demonstrate CCS, in particular because the additional costs for capturing, transporting and storing $CO_2$ from anthropogenic sources can be at least partially offset through the sale of incrementally-produced oil. At the time of writing, ten CCS projects involving $CO_2$-EOR are in operation, and at least twenty are in various stages of planning around the world (GCCSI, 2014).

In considering the co-benefits of $CO_2$ storage with $CO_2$-EOR, a key issue is how to appropriately account for and reward the net climate benefits arising from such operations. There has been some debate amongst stakeholders about whether $CO_2$-EOR is the same as geological storage or not, primarily predicated on the GHG accounting requirements applicable to $CO_2$-EOR versus $CO_2$ storage (e.g. see Dooley *et. al*., 2010; IEA, 2012). Whilst various methods and approaches have been proposed over the years to address these concerns, some challenges still remain. This report aims to consider options to address these challenges.

## 1.1 Challenges in greenhouse gas emissions accounting for $CO_2$-EOR operations

In the early 2000's – at the time when CCS began to be more widely considered as a viable option for climate change mitigation – several concerns were raised about the risks to the environmental integrity of policies and measures designed to promote and incentivise its use. These centred on two issues: *seepage* and *permanence*. More recently, these concerns have been largely overcome in various applicable GHG policy frameworks through development of

[1] Two types of $CO_2$ floods can be used to mobilise residual oil in geological reservoirs: miscible and immiscible. The former is by far the most common technique. It utilises the capacity of supercritical $CO_2$ to act as an emulsifying agent with crude oil, thereby reducing its viscosity and aiding production. Immiscible $CO_2$ flooding involves using $CO_2$ to physically force out residual oil without miscibility (e.g. for heavier oils in low pressure environments). It is fully not proven as an effective EOR technique. Either method can result in incidental geological storage of $CO_2$.

[2] $CO_2$-EOR techniques lead to re-emergence of injected $CO_2$ dissolved in produced oil, widely referred to as *breakthrough* $CO_2$.

measurement, reporting and verification (MRV)[1] guidelines and supporting legal frameworks to manage liability and long-term stewardship of geological storage sites. These are also applicable to $CO_2$-EOR in combination with $CO_2$ geological storage, as described below and in Annex B. However, the combination of $CO_2$-EOR with geological storage for climate mitigation purposes still presents some additional challenges compared to 'pure' geological storage activities. These include:

1. Site-level emissions
2. Subsurface monitoring
3. Incrementally produced crude oil

These discussed in turn below.

### 1.1.1 Site-level emissions

$CO_2$-EOR surface operations result in additional site-level emissions compared to 'pure' geological storage activities. These include emissions from energy used in the treatment of the produced crude at the wellhead (covering both onsite combustion and potentially bought-in electricity), emissions from the treatment, recycling and recompression of breakthrough $CO_2$, and other fugitive emission sources associated with handling hydrocarbon gases (e.g. leaks and flaring or venting of $CO_2$ and methane).

Approaches to measuring these emission sources have been established (e.g. Zakkour, 2007; McCormick, 2012), and consequently all are now covered by various GHG regulatory schemes (see Annex B).

### 1.1.2 Subsurface monitoring

There has been some contention regarding the level of subsurface monitoring required for $CO_2$-EOR projects in order to recognise the GHG emission reductions benefits of $CO_2$ storage. Nearly all $CO_2$ floods in operation today around the world do not undertake extensive monitoring of the injected $CO_2$, and consequently, there is uncertainty whether long-term retention of $CO_2$ in the subsurface, and therefore isolation from the atmosphere, is being comprehensively achieved and demonstrated; it has been suggested that this should not be a reason to preclude such activities from claiming emission reductions.

From a regulatory perspective, this debate has largely been resolved, however, as there is general agreement that the same MRV requirements applicable to geological storage sites should also apply to $CO_2$-EOR operations in order to claim emission reductions. This is evidenced in the differential GHG monitoring rules applicable to $CO_2$-EOR projects that wish to claim GHG emission reductions, and those that do not. For example, in the US the *GHG Reporting Program* (GHGRP) contains clear differences with respect to subsurface monitoring stringency required for $CO_2$-EOR under:

a) *Subpart UU* – basic monitoring; $CO_2$ geological sequestration is *not* recognised as a "non-emissive end-use"; and,
b) *Subpart RR* – extensive monitoring; $CO_2$ geological sequestration *is* recognised "non-emissive end-use" (see Annex B).

[1] Sometimes also referred to as measurement, monitoring and verification, or "MMV".

If a $CO_2$-EOR operator in the US wishes to claim emission reductions, then it must following the monitoring and reporting rules in *Subpart RR*.[1] Similarly, if a $CO_2$-EOR project in Europe wished to account for emission reductions from $CO_2$ storage under the EU Emissions Trading Scheme (EU ETS), the $CO_2$-EOR site would need to be permitted under the EU CCS Directive, and the site monitored in accordance with both the Directive and EU ETS's *Monitoring and Reporting Regulation* (MRR) requirements. These requirements are described further in Annexes A and B.

### 1.1.3 Use of incrementally-produced crude oil

A significant outstanding issue for GHG accounting for $CO_2$-EOR operations is treatment of the emissions arising from use/combustion of the incrementally-produced crude oil. This presents the potentially conflicting objective of, on the one hand, reducing GHG emissions to atmosphere through geological storage of $CO_2$, and on the other, increasing the production and use of fossil fuels that will ultimately create further sources of GHG emissions along the crude oil value chain. The latter relates to additional emissions associated with transportation and refining of the incrementally-produced crude oil ('*midstream* emissions') and end-use of refined products ('*downstream* emissions') – see Figure 1.1.

The topic consistently proves to be contentious: $CO_2$-EOR protagonists typically assert that the technology delivers net GHG emission reductions in the same way as CCS, whilst others assert that $CO_2$-EOR can only ever drive a net increase in GHG emissions because more crude oil is produced. The central axiom of this debate lies in the way in which the GHG emissions from incrementally-produced crude oil from $CO_2$-EOR processing and combustion are considered. This matter has yet to be fully considered and addressed, and forms the focus of this report.

When considering policies and measures to reward $CO_2$ storage with $CO_2$-EOR, the issue is fundamentally one of *boundaries* and *emissions leakage*. Boundaries relate to the sources of GHG emissions that are included within a particular GHG emissions inventory – sometimes also referred to as *scope*. These can be set very narrow e.g. to include only site-level emissions, or very wide, covering e.g. the sources of $CO_2$ ('upstream'), its transportation, site-level emissions and mid- and down-stream emissions. Using narrow boundaries can lead to the risk of *emission leakage* (see *Glossary of Terms* used in this report). Typically GHG polices and measures such as emission trading schemes apply only to discrete installations or facilities, and as such, the boundary for regulated emissions is limited to the geographical limits of the site e.g. a petroleum production facility.

For $CO_2$-EOR value chains, the risk of emission leakage risk is limited if all other system elements are also subject to GHG emission controls, such as refining, transport and e.g. vehicle emissions from use of road transport fuels. It can occur, however, where the incrementally-produced oil is used in processes, products, sectors or jurisdictions where no GHG measures are in place to reduce, restrict, or at least account mid- and downstream emissions. A lack of emission controls can in theory lead to unmitigated increases in global GHG emissions due to the burning of extra oil. The problem is relevant to consider for oil supply since it is a commodity that is traded globally. This means that there is the possibility that one jurisdiction could provide a GHG emission reduction incentive for storing $CO_2$ in conjunction with $CO_2$-EOR, but the incrementally

[1] As well as permit the site in accordance with the *US Underground Injection Control* Class VI well rules

produced oil is refined and used in other jurisdictions with limited or no controls on GHG emissions.

Such a view also relies on the assumption that the cost of oil supplied from $CO_2$-EOR is similar or lower than the marginal cost of oil supply in the global market, and thereby adds to the economically-viable global oil supply base.[1] In these circumstances, emissions leakage effects may not be apparent in the short-term due to constraints on oil consumption (e.g. infrastructure bottlenecks etc.). But over the longer term, the addition of new sources of economically-viable oil may – because of demand elasticity – present a risk of 'carbon lock in' by further promoting *path dependency* on oil as a source of energy.[2] On the other hand, there is a contrasting view that oil supply is becoming increasingly inelastic, with new sources of oil being more complex, slow and costly to develop (e.g. unconventional oils such as Albertan oil sands or deep water pre-salt developments in West Africa and Brazil; see, e.g. Cooke, 2007; Konrad, 2012). Under these circumstances, there is a competing view that oil production from $CO_2$-EOR would act to reduce the price of oil and therefore displace marginal production and expensive new oilfield development projects. This substitution of supply could also drive net reductions in global GHG emissions from oil production as $CO_2$-EOR is potentially a less emissions-intensive method of crude oil production relative to some conventional and unconventional sources in the global oil supply base.

Consequently, there is a debate to be had as to whether oil supplied from $CO_2$-EOR would either (a) add to overall supply, thereby driving the risk of emissions leakage; or (b) displace more costly marginal production, thereby not increasing supply and therefore not leading to any risk of emissions leakage. The latter could potentially lead to net reductions in GHG emissions from global oil supply, or *negative leakage*, insomuch as it might displace more emissions-intensive production. Sitting alongside these complex competing views is the effect of political interventions on oil supply and pricing. Examining the role of $CO_2$-EOR and GHG emissions against this backdrop is a challenge, requiring deep analysis of e.g. global oil supply options and costs and the role for $CO_2$-EOR globally within this supply 'curve', the price effects on the demand curve etc., all of which is too big a subject to consider within the scope of this report.

Notwithstanding this complex backdrop, adopting the view of the *International Monetary Fund* (IMF) that both supply and demand for oil is fairly elastic over the longer-term (IMF, 2011),[2] then it is possible to assume that there is a commensurate risk of emission leakage occurring over the same time-scale: as mentioned previously, both crude oil and refined products are traded globally with daily movements within and between all world regions, and with numerous and complex combinations of flows from well to final product(s) (Figure 1.1). In some cases, it may or may not be relevant to account for all GHG emissions arising across this value chain within the boundary of a particular $CO_2$-EOR activity; a question that will depend on a number of factors. Given the potential differences of opinion regarding the scope for $CO_2$-EOR to drive emissions leakage, the analysis presented here is underpinned by a specific set of assumptions (Section 1.4).

[1] In addition to oilfield development and operation costs etc, the cost of $CO_2$-EOR oil supply will be affected by both the cost of bought-in $CO_2$ and the related carbon price that might be attained for capturing and storing $CO_2$.
[2] The IMF has reported that a 10% permanent price increase in oil reduces demand by only around 0.7% over a 20 year period, meaning that oil prices are highly elastic over the long term (IMF, 2011).

## 1.2 Approaches to address GHG emissions from $CO_2$-EOR

A range of research has considered GHG accounting approaches and methods for $CO_2$-EOR operations, mainly adopting two different approaches:

- Using full lifecycle assessment (LCA) to estimate an inventory of net GHG emissions, using wide boundaries that take into account all upstream, operational (site-level), mid- and downstream emissions arising from a $CO_2$-EOR project (e.g. Jaramillo et. al., 2009; Wong *et. al.*, 2013; Stewart, 2013; Marriot, 2013); or,
- Considering only GHG accounting or MRV methods that operators should apply when compiling a site-level GHG inventory. These approaches employ narrow boundaries and therefore do not generally account for emissions from up-, mid- or downstream activities (e.g. Loretti and Grygar, 2005; API Compendium, 2009; Zakkour, 2007; McCormick, 2012).

Both approaches are relevant to climate policy considerations: LCA calculations can reveal whether $CO_2$-EOR techniques are able to deliver overall net emission reductions, thereby helping policy-makers to take a view on whether it is a valid GHG emission reduction technology. MRV methods provide guidance on how to enforce rules for measuring the effectiveness of a $CO_2$-EOR project under policies or measures that support GHG emission reduction technologies. Problematically, neither technique has fully resolved methodological approaches for estimating GHG emissions for mid- and downstream use that fully account for the potentially complex and variable crude oil value chains that the incrementally-produced crude could enter (Figure 1.1).

By employing wide boundaries and hypothetical scenarios, LCA approaches in the literature have generally been forced to make assumptions about the mid- and downstream value chain for the produced oil in order to generate net emissions estimates; these may either over- or underestimate the actual level of emission reductions achievable through $CO_2$-EOR.[1] On the other hand, approaches involving MRV techniques for $CO_2$-EOR have generally avoided the issue of whether and how to monitor and report downstream emissions.[2] What is missing in the literature to date is a systematic review of whether and how to measure and report downstream emissions from $CO_2$-EOR under specific GHG emission reduction policies and measures. This is paramount to ensuring that a true and fair reflection of the net emission reduction benefits delivered by the technology is accounted for and rewarded under a particular policy or measure. In its absence, the environmental integrity of the supporting policy or measure, as well as any financial incentives, carbon tax relief, tradable emission rights (or 'credits') generated by $CO_2$-EOR under a particular scheme, will be compromised.

[1] For example, Wong *et. al.* (2013), in their comparative analysis of lifecycle emissions from Canadian $CO_2$-EOR operations assume that all incrementally produced crude oil would be refined in a PADD II (US Midwest) oil refinery, all with the same end use; Jaramillo *et. al.* (2009) also made similar assumptions regarding refinery and end use emissions by using published averages of refinery emission factors.

[2] This is because in most cases these emissions are difficult to monitor and report due to the variability in the oil value chain, or fall outside of the scope and boundary of the particular system under consideration. For example, Zakkour (2007) considered only MRV requirements for $CO_2$-EOR under the European Union's greenhouse gas emissions trading scheme, which has defined boundaries for MRV at the installation level, therefore excluding mid- and downstream emissions. Other efforts, e.g. API (2009), focus only on providing support to corporate entities wishing to calculate the *direct* emissions associated with their activities, therefore excluding *indirect* emissions outside of their control (e.g. downstream emissions of the incrementally-produced crude oil).

### 1.3 Objectives, scope and approach

Given the current gap in the literature, the aim of this report is to consider GHG accounting methods and MRV rules used to compile inventories of GHG emissions for projects involving $CO_2$-EOR in combination with $CO_2$ storage. The focus is on addressing emissions leakage in terms of:

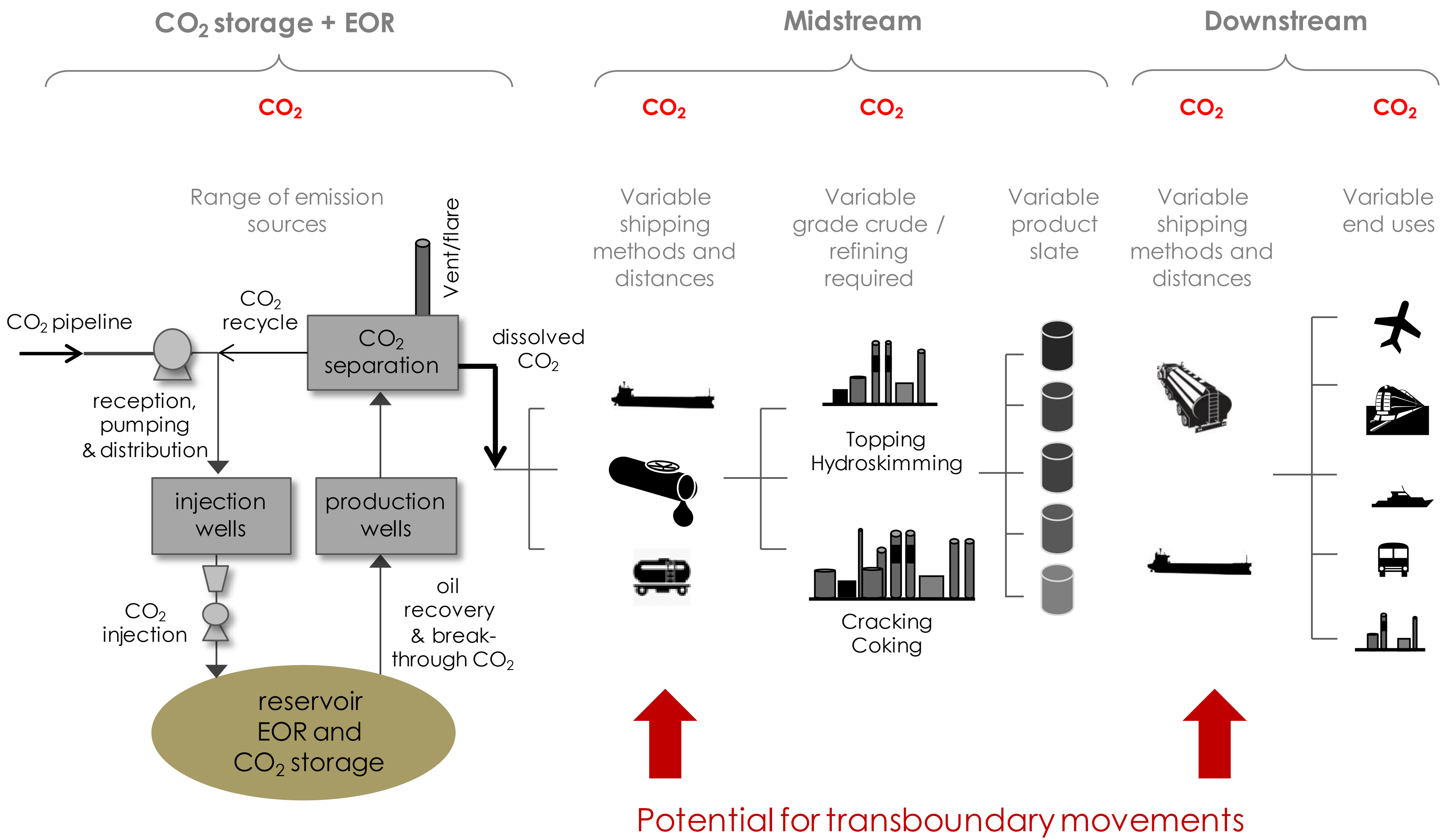
1. Whether and when to account for the mid- and downstream emissions associated with the incrementally-produced oil; and
2. How to account for downstream emissions (i.e. ways to quantify such emissions).

Annexes A and B set out part of the evidence base for the study by providing a review of GHG emissions monitoring and reporting requirements for sites undertaking $CO_2$-EOR, and requirements for measuring and reporting mid- and downstream emissions as applied in various jurisdictions.

The report does not consider the upstream emissions i.e. emissions associated with the source of $CO_2$ and its capture and transportation. One of the key assumptions in the analysis is that an incentive is applied for capturing the $CO_2$ and storing it in geological formations (see Section 1.4 below). As such, it is reasonable to assume that appropriate MRV requirements would be in place for the capture, transport and storage of $CO_2$. The report also does not attempt to provide specific recommendations on how to undertake LCA for $CO_2$-EOR. However, the findings can support development of consistent approaches to LCA by providing insights into boundary setting (i.e. the 'whether and when' to account for emissions) and emissions quantification (i.e. the 'how' to account for emissions).

The final chapter considers the options for developing or modifying GHG accounting rules to take account of mid- and downstream emissions from $CO_2$-EOR.

**Figure 1.1** **Site level and downstream $CO_2$ emissions sources from $CO_2$-EOR across the crude oil value chain**



## 1.4 Conditions for emissions leakage

As highlighted previously, there is significant uncertainty as to whether supporting $CO_2$-EOR through carbon pricing could drive emissions leakage, based on differing views about oil supply and the price elasticity of demand and supply (Section 1.1). In order to underpin the remainder of the analysis presented in this report, several assumptions are made that set the conditions under which emissions leakage could occur. These are as follows:

1. That an incentive, be it carbon pricing or mandatory GHG emissions reporting, is in place and applicable to capturing and geologically storing $CO_2$ in conjunction with $CO_2$-EOR. This is important since it means that a GHG policy incentive is acting to promote the use of $CO_2$-EOR and therefore fossil fuel production. In the absence of any incentive or requirement to monitor and report GHG emissions from $CO_2$-EOR operations, there is little point in considering whether and how to account for downstream emissions as potential sources of emissions leakage. It also means that for the purpose of this analysis, it is assumed that all site-level emissions must be accounted for under a particular scheme;
2. That a risk of emissions leakage is posed where there is asymmetry in GHG emission controls between: (a) where the capture and $CO_2$-EOR operation takes place; and, (b) where incrementally-produced oil is used. Such asymmetry means that GHG policies and measures act to drive investment into $CO_2$-EOR in one sector/jurisdiction whilst simultaneously posing the risk of emissions leakage due to unmitigated emissions arising during the handling and end use of incrementally-produced oil in another. Under these circumstances the supply of crude oil from $CO_2$-EOR could *add* to the overall supply of fossil fuels into a market over the longer-term, thereby potentially increasing overall global GHG emissions and driving carbon lock-in. This condition assumes oil supply and demand is fairly elastic;
3. That conversely, where GHG emission controls are in place across the whole $CO_2$-EOR value chain, either in a single jurisdiction or across multiple jurisdictions, the risk of emissions leakage is reduced. Under these circumstances, GHG emission controls should mean that the supply of crude oil from $CO_2$-EOR should only *substitute* supply from other sources, as the controls in place do not allow for an increase in emissions over the longer-term.[1] This reduces the risk of carbon lock-in; and,
4. That GHG accounting/inventory boundaries are critical to understanding the scope for emissions leakage to occur.[2] If a scheme employs sufficiently wide spatial boundaries (e.g. covering the whole oil value chain, as in LCA approaches) then emissions leakage may not pose a risk in so much as all emissions associated with $CO_2$-EOR would need to be taken into account under the scheme, and *vice versa*.

[1] As noted by Wong *et. al.*, 2013, the assumptions regarding substitution and addition to oil supply are respectively subject to conditions of short-term inelasticity versus longer-term elasticity (i.e. longer-term market changes driven by supply). The actual overall net change in emissions will vary depending on the relative emissions across the $CO_2$-EOR value chain compared to the marginal source of crude oil that is substituted.

[2] The *boundary* determines the scope of gases and emission sources and/or removals by sinks to be included within the GHG inventory submitted as part of the MRV requirements for a particular scheme.

# 2 WHETHER AND WHEN TO ACCOUNT FOR EMISSIONS LEAKAGE

The conditions for assessing emissions leakage were set out previously (Section 1.4). On this basis, since crude oil – and increasingly, refined products – are globally traded commodities, the scope for emissions leakage to occur is primarily governed by the GHG policies and measures that are in place around the world today. Since there is no universal approach to controlling GHG emissions globally and across different sectors, this means that a variable patchwork of policies and measures exists that can drive different types of emissions leakage risk. These can be summarised as:

1. *Transboundary* emissions leakage i.e. where regions producing and importing incrementally-produced crude oil have asymmetric controls on GHG emissions; and/or,
2. *Cross-sectoral* emissions leakage i.e. where a policy has fairly narrowly defined boundaries (e.g. sectoral based policies), meaning that mid- and downstream emissions can occur, unregulated, outside the boundaries of the scheme.

The risk of emissions leakage is also further governed by the characteristics of global oil production, supply and use, and the magnitude of emissions leakage that could actually result from transboundary and cross-sectoral movements of incrementally produced oil. The former can provide an insight into the scale of the risk whilst the latter can provide a view on whether the risk is worth addressing (i.e. is it material?).

To address these questions, the following issues are reviewed in this section of the report:

1. The role of GHG policies and measures in place around the world and across different sectors in potentially driving emissions leakage;
2. Potential scenarios under which both transboundary and cross-sector emissions leakage from $CO_2$-EOR could occur; and,
3. The likelihood and scale of emissions leakage risk based on the international trade flows of crude oil and refined products.

These can help provide a view on whether and when it may be relevant to account for emissions leakage from $CO_2$-EOR projects under certain circumstances.

## 2.1 GHG controls and effects on emissions leakage

GHG polices and measures in place around the world today include economy-wide controls, sectoral schemes and project-based incentives (see Annexes A and B). All of these can act to incentivise $CO_2$-EOR, and to variable degrees place controls on mid- and downstream emissions across the $CO_2$-EOR value chain. Their different design features can also potentially drive leakage in different ways, as described further below.

### 2.1.1 Economy-wide policies

Economy-wide policies and measures apply to the full portfolio of GHG emission sources within a national economy. Where such policies are applied universally to all jurisdictions or countries around the world, there is, in principle, no scope for emissions to go unaccounted for in different products, processes, sectors, or jurisdictions. This means that under such circumstances the risk of emission leakage is zero.[1] In other words, a global harmonized system of GHG emissions controls with uniform carbon pricing would mean that there is zero risk of emissions leakage arising from any activity.

The UNFCCC and the Kyoto Protocol are the only such schemes in operation today. However, the principle of *common but differentiated responsibility* enshrined in the UNFCCC means that such obligations are not universally applied, and there are differential requirements imposed on developed (Annex I Parties) relative to developing country Parties (non-Annex I Parties). The former face obligations to measure and report emissions on an annual basis and put in place policies to restrict and reduce emissions. On the other hand, whilst most developing country Parties will, from 2015 onwards, be required to submit biennial update reports ('BURs') of national GHG emissions, they do not face such strict obligations to take action to reduce emissions within their economies.

The 1997 Kyoto Protocol enhanced the UNFCCC's emission reduction obligations by imposing economy-wide quantified emission limitation and reduction obligations (QELROs) at a national level for thirty-seven Annex I Parties – the US being the exception by not ratifying the agreement in the first commitment period (2008-2012) – Canada also withdrew in 2011. Of the developed country Parties to the UNFCCC, the European Union (28 countries), Australia, Belarus, Iceland, Kazakhstan, Liechtenstein, Monaco, Norway, Switzerland and Ukraine have all agreed to participate in a second commitment period (2013-2020) with associated QELROs, although Japan, Russia, Canada and New Zealand – as well as the US – have stated their intentions not to.

Under the UNFCCC and Kyoto Protocol accounting rules (see Annex A and B), $CO_2$-EOR can be counted as an emission reduction technology, as $CO_2$ injected into geological formations for the purpose of $CO_2$-EOR does not need to be reported as an emission in a country's national GHG inventory. This is subject to applying the relevant GHG accounting and MRV rules as developed by the *Intergovernmental Panel on Climate Change* (IPCC; see Annexes A and B). Mid- and downstream emissions, from e.g. refining and road transport, are also counted within a country's QELROs. Therefore, in principle, the domestic use of incrementally produced crude oil or products in countries bound by QELROs, or its movement between such countries, should not pose any risk of transboundary emissions leakage. This is because all mid- and downstream emissions arising from the handling and end use of crude oil and/or refined products are regulated by the applicable QELRO in those jurisdictions.

On the other hand, movement of incrementally-produced crude oil between Kyoto signatory countries (with a QELRO) and either non-Kyoto signatory countries or non-Annex I Party countries (without QELROs) would pose a risk of transboundary emissions leakage.

There are variations within this simplified view, however. Firstly, there is variable stringency in the QELROs set for Kyoto signatory countries. This can mean that in some cases the actual net reduction effort a country needs to make may be quite limited, or even allow for emissions to increase. Several factors can affect this, including:

[1] Subject to the proviso that they include an appropriate absolute national emission limitation target that are set in an equitable way based on scientific consensus for global reductions and employ comparable MRV methods to ensure appropriate accounting for emissions in each jurisdiction.

- *The QELRO agreed under the Kyoto Protocol*. In the first commitment period these ranged from a 10% increase to a 9% reduction for the period 2008-2012 against a 1990 base-year. For the second commitment period, this ranges 0.5% to 20% reductions against a 1990 base year amongst Parties over the period 2013-2020. These variations will have material effects on the stringency of GHG reduction targets introduced by different countries.
- *Accounting rules for land use, land use change and forestry (LULUCF) under the Kyoto Protocol*. These allow for optional reporting of only some parts of LULUCF activities, which allows for some countries to leave large portions of emissions unaccounted and therefore not included in their QELRO commitment, whilst in others, credits may be received for some LULUCF removals that may have occurred since 1990;
- *The effect of economic decline since the base-year in countries with economies in transition (EITs)*. In EITs, national emissions reduced significantly between 1990 and 2008 as a result of declining economic activity, leading to the creation of surplus AAUs, often referred to as "hot air". Similar effects may potentially occur for Western European countries in the second commitment period of the Kyoto Protocol as a result of the economic downturn since 2008;
- *The carry-over of surplus assigned amount units (AAUs)* – or "hot air" – from the first to the second commitment period of the Kyoto Protocol, particularly for EITs. This again can weaken the actual reduction effort required to meet any reduction commitment.

Consequently, there is a risk that transboundary emission leakage can occur between Kyoto Parties, as a "weak" QELRO could allow for emissions increases to occur (see also Section 0).

Moreover, as Parties to the UNFCCC move towards a future agreement under the *Ad hoc Durban Platform* – scheduled to be agreed at the 21st Conference of the Parties (COP21) of the UNFCCC in Paris in late-2015, and to enter into force in 2020 – prospects for globally harmonised economy-wide emission limitation and reduction targets looks weak. The current approach agreed at the Warsaw Climate Conference[1] invites Parties to submit unilateral *intended nationally determined contributions* (INDCs) that set out their climate mitigation objectives. Such a bottom-up "pledge and review" system leaves significant latitude for countries to adopt whatever targets and priorities suit their own national circumstances, rather than one that aims to reach a global temperature increase limitation and/or emission reduction goal.

Secondly, some non-Kyoto signatory Parties have created, or are in the process of creating, domestic or regional GHG emission control policies, such as emission trading schemes or carbon taxes. Examples include a proposed carbon tax in South Africa, and various other activities in e.g. the 18 or so regions of China developing emissions trading schemes (ETS), and proposals for ETS's Mexico, Chile, Brazil, etc. and various other activities such as those taking place under the auspices of the World Bank's *Partnership for Market Readiness* (PMR).[2] The latter has 17 'implementing country participants' exploring options for different types of market-based mechanisms that can provide a carbon pricing signal to emitters in their respective jurisdictions.

[1] The 19th Conference of the Parties to the UNFCCC (COP19).

[2] The PMR is a partnership between developed and developing countries, aiming at building capacity for and piloting new carbon market based mechanisms.

Thirdly, some Kyoto Parties – primarily Australia – are actually abolishing strict national GHG emission controls in favour of other, non-quantitative, emission reduction support mechanisms. All of these variations tend to challenge the simplified view outlined previously, making a complex backdrop for considering the scope for emissions leakage.

Lastly, despite the economy-wide nature of the UNFCCC and Kyoto Protocol requirements, cross-sectoral emissions leakage can still potentially occur. This is because emissions from bunker fuels used in international aviation and international maritime transport are not governed under the UNFCCC or Kyoto Protocol.[1] The mandate for addressing these emissions lies with the *International Civil Aviation Organisation* (ICAO) and *International Maritime Organisation* (IMO) respectively. To date, neither organisation has made much progress in establishing GHG reduction measures or emission limitation targets for these sectors.

### 2.1.2 Sectoral policies

In response to obligations under the UNFCCC and Kyoto Protocol, most Annex I Parties and several non-Annex I Parties have enacted national policies and measures to address GHG emissions. For large point sources occurring within a jurisdiction where $CO_2$ capture could be applied – mainly large emitting sectors such as power generation, cement production, iron & steel production and petroleum refining etc. – policy approaches include the following:

- Emissions trading based on cap-and-trade principles – e.g. as in the European Union and California and various pilot schemes in non-Annex I Party countries such as China and under the PMR;
- Targets with taxes or penalties – e.g. as in Alberta or under development in South Africa;
- Mandatory reporting – e.g. as in Canada, the US, and Australia.[2]

Facilities meeting qualifying requirements, either through exceeding an emissions threshold – typically where annual emissions in excess of 25,000 $tCO_2$ per year – or through direct nomination in the relevant legislation (see Annex A), must annually monitor and report GHG emissions. Where applicable, these reports provide the basis for compliance with any targets or other obligations imposed under the relevant scheme.

With the exception of the California ETS, which does not yet allow for the use of CCS to meet emission reduction targets,[3] all of these schemes generally allow regulated entities to deduct from their emissions inventory amounts of $CO_2$ captured and injected for geological storage. This includes for the purpose of $CO_2$-EOR, subject to monitoring of the relevant emissions sources (see Annexes A and B). Therefore, to obtain recognition of $CO_2$ stored through $CO_2$-EOR as an emission

[1] As they occur in international airspace and waters, and are therefore not assignable to any individual Party

[2] Australia also enacted the Carbon Pricing Mechanism (CPM) in 2011 with a view to establishing a national cap-and-trade scheme for large emitters from mid-2015 onwards. However, following a change of government, the CPM was abolished in favour of the Direct Action Plan. The monitoring and reporting obligations imposed under the National Greenhouse and Energy Reporting Act still apply to large GHG emitters, however (see Annex A and B).

[3] This is on the basis that no California Air Resources Board (ARB)-approved CCS "*quantification methodology that ensures that the emissions reductions are real, permanent, quantifiable, verifiable, and enforceable*" is in existence. CCR Title 17, Subchapter 10, Article 5. §95852(g). For this reason, with respect to 'Conditions for emissions leakage' (Section 1.4), California is excluded from the remaining analysis. This exclusion notwithstanding, the C-ETS imposes obligations on operators to monitor all emission sources from Petroleum Systems (CCR Title 17, Chapter 10, Art. 2, Subarticle 5) as well as refineries as "Suppliers of Transportation Fuels" (CCR Title 17, Chapter 10, Art. 2, Subarticle 2, §95121), and would therefore cover most emissions sources associated with $CO_2$-EOR.

reduction under these schemes, an operator would need to employ a suite of monitoring technologies to the oilfield to provide assurances over permanence and to detect seepage. This situation is correct since the reporting framework under the UNFCCC and the Kyoto Protocol allows for the county hosting the $CO_2$-EOR project to not report $CO_2$ emissions that are captured and geologically stored, subject to applying appropriate monitoring and reporting (as described in Section 2.1.1). As such, most developed countries provide a GHG-related incentive to capture anthropogenic emissions of $CO_2$ and use it for the purposes of $CO_2$-EOR.

As the schemes tend to apply to large point source emissions, GHG emission controls are generally in place for midstream emissions associated with refining of incrementally-produced oil, provided that the crude oil is *not exported outside of the schemes' jurisdictional boundaries*, be it sectoral or geographical. Where incrementally-produced oil or refined products are exported outside of a scheme's boundaries, there is, however, a risk of transboundary emissions leakage. This is dependent on the status of GHG controls in the importing country. In general terms, as outlined in the previous section, if these countries are subject to stringent QELROs, or have implemented sectoral polices to regulate emissions, this risk is minimised. In all other cases, there is a risk of transboundary emissions leakage occurring.

In terms of cross-sectoral emissions leakage risk, scheme boundaries are important. For midstream (transport) and end use emissions, some jurisdictions have extended the scope of cap-and-trade and mandatory reporting policies to cover fleet emissions from mobile emissions sources. For example, in Australia, GHG emissions monitoring requirements also extend to large liquid fuel consumers, and in the EU, the EU ETS now also applies to emissions from the aviation sector. As such, in some schemes there is the possibility that GHG emission controls are in place for some mid- and downstream emission sources. More generally though, mobile emissions sources in developed countries are typically addressed through other types of approaches. These include:

- Vehicle taxes (e.g. variable road taxes based on average emissions);
- Fuel taxes and levies;
- Portfolio standards for vehicle producers – for example:
    - US *Corporate Average Fuel Efficiency* (CAFE) standards;
    - EU's emission performance standards for cars and vans and $CO_2$ labelling of cars;
    - Japan's *Top Runner Program* for manufacturers and importers of new cars.
- Portfolio standards for fuel suppliers – involving requirements for suppliers and retailers in certain markets to improve the overall lifecycle emissions of the transport fuels they supply (e.g. under the EU Renewable Energy Directive and EU Fuel Quality Directive (FQD) and California's Low Carbon Fuel Standard).

In cases where countries are bound by QELROs, the risk of cross-sectoral emissions leakage should be minimised because downstream GHG emissions are typically regulated. On the other hand, few non-Annex I developing countries have policies in place to regulate emissions from mobile emissions sources such as trucks and cars. In fact, several developing country governments actually subsidise petroleum products to promote affordability for the general population (e.g. in India, Egypt or Indonesia); thereby incentivising the increased use of these products – and by extension, increased transport sector emissions.

As a consequence of variations in scheme coverage and transboundary movements of crude oil and products, there is in some cases a risk that $CO_2$-EOR could be incentivised in one jurisdiction through sectoral GHG policies, whilst downstream emissions could occur unregulated in other sectors or jurisdictions.

### 2.1.3 Project-based approaches

Often GHG policies and measures such as those described in previous sections include the scope for using "offsets" or "credits" towards compliance with scheme obligations. These are typically generated through undertaking emissions reduction projects in sectors or jurisdictions outside of the direct control of the scheme, or in other unregulated sectors.[1] Project-based schemes in existence globally today include:

- Clean development mechanism (CDM);
- Joint implementation (JI);
- Domestic offsets under the EU ETS;
- Various offset schemes under the California-ETS;
- Alberta-based Offset Credits; and,
- The Australian Carbon Farming Initiative.

Further details on these schemes are set out in Annex A. Most of these schemes operate according to a bottom-up process whereby proponents wishing to develop a certain type of emission reduction project may propose methodologies by which the net emission reductions achievable by the project may be quantified. This typically involves defining, *inter alia*:

- The activity type to which it is applicable,
- The baseline scenario and baseline emissions; and,
- The monitoring methodology to be used to calculate project emissions.

Several project-based GHG accounting methodologies have been developed for CCS and $CO_2$-EOR, including under the *Alberta-based Offset Credit* scheme and under the *American Carbon Registry* (ACR; linked to the California ETS; see Annex A). Although GHG accounting rules for CCS projects have been agreed under the CDM (UNFCCC, 2011), to date no relevant project-type methodologies have been developed applicable to CCS or $CO_2$-EOR.[2]

Under typical project-based scheme rules, any methodology applicable to $CO_2$-EOR should include a monitoring methodology to measure and calculate project emissions for all site-level GHG emission sources, including bought-in electricity, onsite electricity generation and fugitive emissions. Both the Albertan and ACR methodologies include such methods, and similar approaches would be required under any CDM methodology (see Annex B).

Since project-based schemes have narrowly defined GHG accounting boundaries determined by the actual site where the project takes place, there is a risk that the project could drive emission

[1] In some cases it can also include GHGs outside the scope of a scheme (e.g. the EU ETS covers on $CO_2$ emissions, and not other GHGs). In the case of Alberta, eligible offset projects also includes $CO_2$-EOR projects and potentially other types of $CO_2$ geological storage projects, subject to approval of relevant Quantification Protocols (see Annex A).

[2] Two CCS CDM methodologies were proposed in 2005 (NM0167 and NM0168), but rejected subject to further considerations by Parties to the UNFCCC. This culminated in approval of the CCS M&Ps in 2011. However, since then, no proposed New Methodologies have been submitted to the CDM Executive Board.

changes outside of the project developer's immediate control. An example might be where a project has effects on energy markets by changing the supply or price, leading to increases in consumption. This poses a risk for scheme operators in that the level of GHG emission reduction credit awarded may not be commensurate with the actual GHG emissions impact associated with the project, and could therefore affect the environmental integrity of the scheme and its credits. Consequently, methodological guidance usually requires "leakage emissions" to be taken into account, variously defined as:

> *"…a decrease in sequestration or increase in emissions outside project boundaries as a result of project implementation"* (ACR, 2010); or
>
> *"…the net change of anthropogenic emissions by sources of greenhouse gases which occurs outside the project boundary, and which is measurable and attributable to the CDM project activity"* (UNFCCC, 2005)
>
> "No leakage" as eligibility criterion for projects as under the *Alberta-based Offset Credit Scheme* (AESRD, 2013).

These requirements relate to both transboundary and cross-sectoral emissions leakage. With the exception of the *Alberta-based Offset Credit Scheme*, where emissions leakage can be identified and measured, these must be subtracted from the overall level of emission reductions calculated for the project.

In $CO_2$-EOR projects, mid- and downstream emissions pose a risk of emissions leakage as described previously. However, to date no project-based schemes have proposed any methods to take into account such emissions leakage (see Annex B). Under the CDM, leakage emissions have been a particular concern, principally because projects take place in non-Annex I Party developing countries where economy-wide or sectoral GHG emission controls are typically absent (see above). In fact, such concerns formed much of the debate concerning the inclusion of CCS activities within the CDM. It has also affected the inclusion of new 'supercritical' coal-fired power stations within the mechanism.[1] In both cases, the view has been expressed that incentivising mitigation projects based on the continued use of fossil fuels leads to 'lock-in' of carbon-intensive technology and/or deters investment in low carbon alternatives. The assumption inherent in such a claim is that the use of energy/fuels used in the absence of $CO_2$-EOR would be less carbon-intensive. However, determining whether this is the case or not is highly complex, requiring an analysis of product substitution effects e.g. what would be used in the absence of the incrementally produced oil. This issue is partly considered in the next chapter.

As a consequence of such concerns, it is likely that a CDM methodology applicable to $CO_2$-EOR would need to consider the scope for emissions leakage to occur. This would need to be made in the specific context of the market into which the incrementally-produced crude oil is sold, recognising that:

[1] Approved consolidated baseline and monitoring methodology ACM0013 "Consolidated baseline and monitoring methodology for new grid connected fossil fuel fired power plants using a less GHG intensive technology"; the CDM Executive Board approved six coal plants for CDM registration before agreeing in November 2011 to suspend and review the methodology that outlines how many credits the schemes could earn, effectively stopping new projects from earning credits.

- If it enters the domestic market, or is exported to a different non-Annex I developing country Party, there may be no GHG emission controls on the handling or end-use emissions. Consequently, there is a risk of emissions leakage; or
- If it is exported to an Annex I Party, handling and end use may be subject to GHG emission controls. In these circumstances, the risk of emissions leakage is reduced.

Finally, emissions leakage concerns as described throughout need to be taken in the context of the likelihood that they might occur, and the material risk they pose to the overall emission reduction benefit achievable by a particular $CO_2$-EOR activity.

## 2.2 Scenarios for emissions leakage

### 2.2.1 Simplified cases

Under the current patchwork of GHG emission controls posed by the UNFCCC and Kyoto Protocol and through differential implementation of sectoral policies, both transboundary and cross-sectoral emissions leakage can potentially occur, even where economy-wide emission controls and reporting obligations are in place.

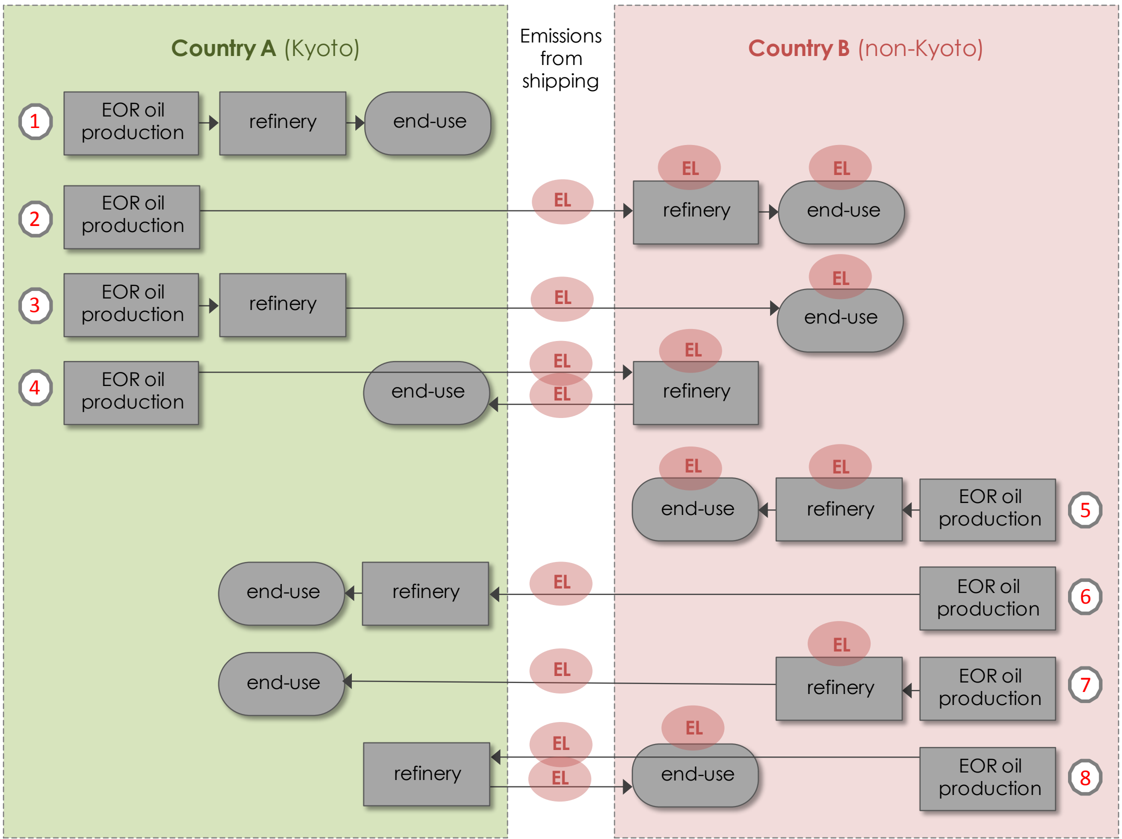
A simplified illustration of the potential for transboundary emissions leakage to occur involving two countries, *Country A* and *Country B*, is outlined below (Figure 2.1). In the figure, *Country A* is subject to economy-wide QELROs under the Kyoto Protocol, whilst *Country B* has no such obligations in place (and also has no national-level GHG emission control policies or mandatory reporting requirements in place). The results show a total of eight possible cases where emission leakage from $CO_2$-EOR could arise due to varying combinations in the location of production, refining and end-use combustion.

It can be seen that in only one case (1) all emissions occur within the fully regulated system of *Country A*. Under these circumstances, it is possible to assume that there is no risk of emissions leakage. This situation might apply in Norway, the European Union or California today, where fairly stringent economy-wide GHG emission controls are in place (see Annex B).

Under these simplified circumstances it is reasonably straightforward to determine various situations whereby, if a carbon price incentive is applied for $CO_2$-EOR, emissions leakage could arise. An example case could be production of oil in the EU, with refining and end use occurring in North Africa. It is also reasonably straightforward to identify the possible emission sources that might need to be accounted for as leakage. Under this scenario, as bunker fuels are not covered by QELROs, the potential remains for *cross-sectoral emissions leakage* to occur where incrementally-produced oil is used as the international marine or aviation sectors.

In all other cases there is the potential for both *transboundary* and c*ross-sectoral* emissions leakage to occur due to the absence of mid- and downstream GHG emission control policies in various parts of the crude oil value chain.

**Figure 2.1 Sources of emissions leakage arising from $CO_2$-EOR production (eight cases)**




*Note*: EL = emissions leakage; the eight cases shown all assume that all upstream (CCS and $CO_2$-EOR-related) emissions are accounted for within the relevant incentivising carbon scheme(s). See Condition No. 1 in Section 1.4.

### 2.2.2 Complex cases

The above cases illustrate the *potential* for emissions leakage to occur in fairly simple situations between countries or regions with and without economy-wide GHG emission limitation controls. However, *Country A* and *B* represent only the two ends of a broad spectrum, and in many cases, these extremes will not necessarily apply. Many countries – as outlined in the previous section – have to varying degrees adopted some policies and measures to limit or reduce GHG emissions in various sectors of the economy. As a result, in many countries a variation of policy mixes exists, falling somewhere between having either fully-fledged absolute economy-wide emission controls in place, or having none at all. As such, the factors affecting the scope for emissions leakage from $CO_2$-EOR are complex and not necessarily comparable and consistent.

An obvious complicating factor is that many countries without economy-wide QELROs under the Kyoto Protocol have often adopted policies and measures to control downstream emissions in the road transport sector, such as through fuel excise duties or vehicle taxes. Such measures have not necessarily been driven by climate change concerns – rather by economic or energy security goals – but the net result may be the same. Other measures can include emission intensity targets (rather than absolute targets such as QELROs), which would allow overall emissions to increase, but at the same time promote efficiency improvements. Furthermore, there is also variation within the stringency in both economy-wide and sectoral policies in place around the world. For example, the

QELROs imposed by the Kyoto Protocol vary between different signatory Annex I Party countries, as described previously (Section 2.1.1). The result of this complex tapestry of emission control policies is that emissions leakage could occur, and could occur to different degrees, depending on the status and stringency of GHG emission controls in both oil producing and importing regions.

In trying to simplify this complexity, it is possible to consider three types of factors affecting the degree to which emissions leakage could occur.

*1. Differential obligations posed by economy-wide policies*

National and regional targets adopted within the Kyoto Protocol are the result of political negotiations. This invariably results in different obligations for different countries, with some QELROs ostensibly being 'weaker' than others (Section 2.1.1). For example, in the case of several Former Soviet Union countries, including Ukraine, Belarus and Kazakhstan, the choice of a 1990 base year has created significant "hot air" (Section 2.1.1).[1] As such, emissions leakage could be considered an issue where crude oil or refined products are shipped to these countries, as essentially they face no material requirements to adopt measures to reduce national GHG emissions, and therefore fossil fuel consumption. Other factors also affect the stringency of commitments, as described previously. Furthermore, the "pledge and review" approach of INDCs under a future climate change agreement will also inevitably result in variations in the levels of emission reduction effort between countries. Attempts have been made to assess the relative effectiveness of differing post-2012 commitments made by various Parties to the UNFCCC, which clearly highlights the range of, and variations in, the level of stringency in the positions taken by various Annex I Parties. (Figure 2.2).

*2. Differential targets in sectoral-based policies*

Sector-based policies can differ widely in terms of how targets are set, including their relative stringency and design details. For example, when comparing different emissions trading schemes currently in place, there is often variation in the level of reductions actually required to be made by e.g. refineries. Furthermore, in the case of vehicle emissions standards there is significant variation between the stringency of standards applied in different jurisdictions. For example:

- In the EU, the limit currently set for cars is 130 $gCO_2$/km, which is to be reduced to 95 $gCO_2$/km from 2020;[2]
- In the US standards, the equivalent limits for cars are 140 $gCO_2$/km in the base year 2016, falling to around 113 $gCO_2$/km in 2020.[3]

As such, whilst in both cases it could be assumed that emissions leakage does not pose a risk due to the presence of the policies in place to restrict emissions from road vehicles, the variation in

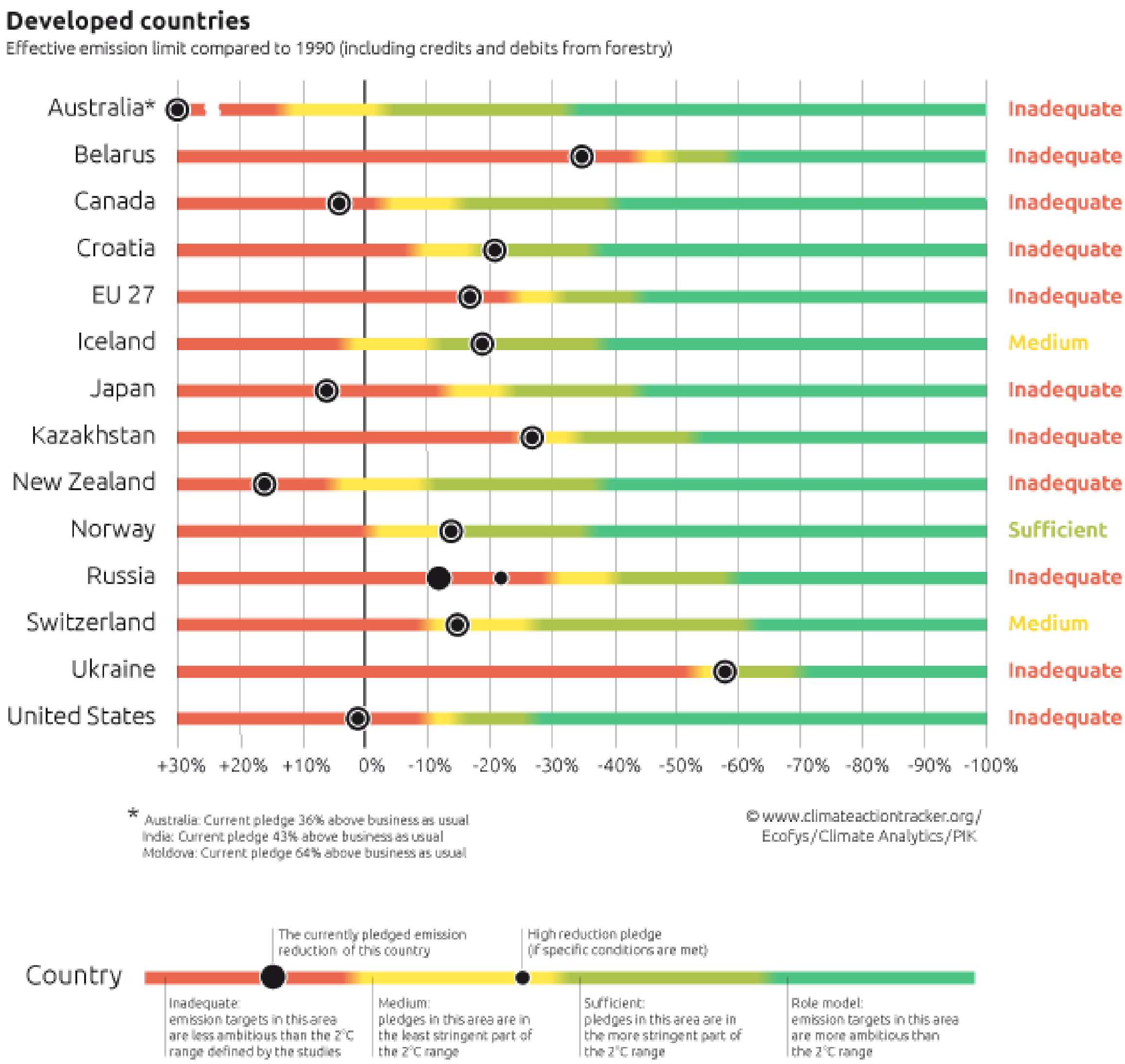
[1] This is a problem that has been widely termed "hot air", allowing these countries to hold and trade surplus Assigned Amount Units under the Kyoto Protocol without taking any actions to address national GHG emissions.

[2] On April 23, 2009, the EU legislation on $CO_2$ emissions for passenger cars was published in Regulation (EC) No 443/2009 of the European Parliament and of the Council Regulation (EC) No 443/2009 of the European Council: Setting emission performance standards for new passenger cars as part of the Community's integrated approach to reduce $CO_2$ emissions from light-duty vehicles. See: http://ec.europa.eu/clima/policies/transport/vehicles/cars/index_en.htm

[3] The US Environmental Protection Agency (EPA) and the Department of Transportation's National Highway Traffic Safety Administration (NHTSA) issuing final rules in 2012 extending the National Program to further reduce GHG emissions and improve fuel economy for model years (MYs) 2017 through 2025 light-duty vehicles. See: http://www.epa.gov/otaq/climate/documents/420f12051.pdf

requirements poses a question about whether they achieve the same net result, which is clearly not the case.

**Figure 2.2 Relative effectiveness of pledges and commitments to 2020**




*Source*: www.climateactiontracker.org from Ecofys, Climate Analytics and the Potsdam Institute for Climate Impact Research (PIK). Only developed country Parties shown.

### *3. Differential carbon price signals*

Where carbon price signals exist, for example within carbon tax schemes or emissions trading schemes, these will usually differ between jurisdictions. As such, the level of emission reductions that may be achieved by the policy could vary. Even where such schemes might be compared on a crude price basis, it must be considered that different carbon pricing policies may create additional asymmetries, for example, when comparing market-based schemes (with associated price volatility) with typically more stable carbon taxes. The potential use of scheme exemptions, free allocation and other compensatory measures further complicates the matter. As such, the basis upon which assumptions about the risk, and degree, of emissions leakage may be made is again unclear.

To illustrate the issue further, in making comparisons of countries with and without QELROs it is possible to see situations where sectoral policies are in effect more stringent in the latter. For example, although the EU ETS places a cap on emissions, the carbon price level within the scheme has recently been lower than the equivalent carbon price level proposed under the South African carbon tax.[1] Similarly, many non-Kyoto developing countries have energy and carbon reduction policies in place, including national targets, irrespective of their reduction obligations under the UNFCCC, for example, the activities under the PMR described previously (see Section 2.1.1). It is possible that these could result in the establishment of GHG emission policies that are more effective than those in place in, for example, the EU.

It also useful to note that other political factors may also play a role, such the US ban on the export of crude oil, although the export of refined products does occur. This means that the scope for leakage to occur due to downstream emissions outside of the US is limited. Various other political factors may influence the scope for emissions leakage, such as those affecting crude oil supply and price e.g. the OPEC quota system.

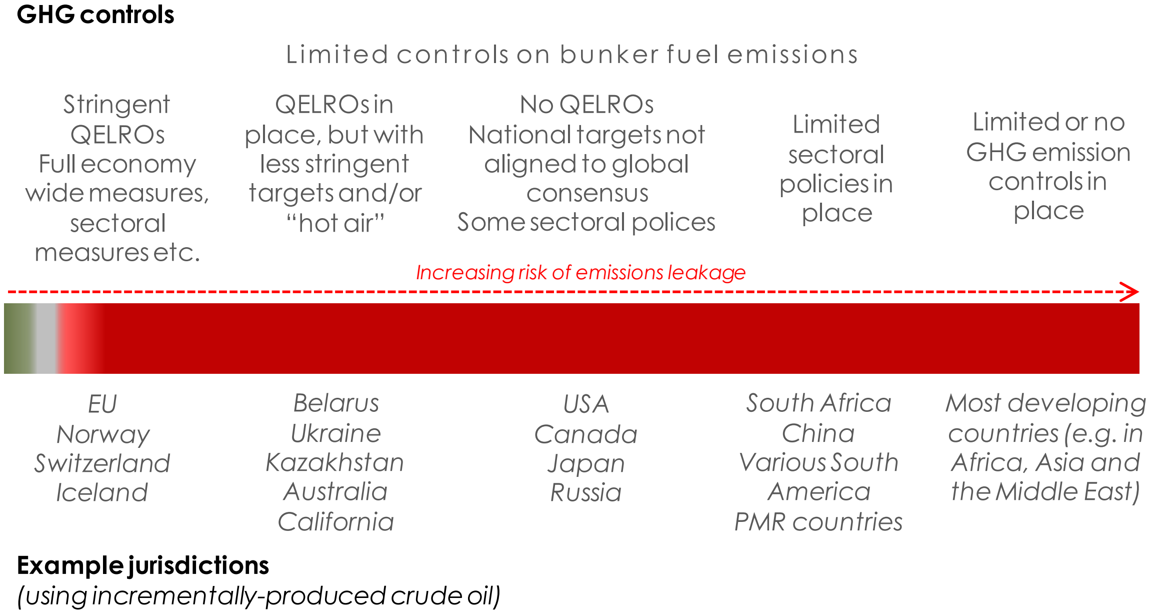
## 2.3 Estimating the risk of emissions leakage

Whilst it can be reasonably concluded that emissions leakage *could* occur as a result of mid- and downstream emissions associated with $CO_2$-EOR projects, it is more challenging to be definitive about whether it is actually occurring and to what degree. The previous discussion has considered the stringency of different GHG emission control policies as a proxy measure of the risk of emissions leakage, based on the conditions described. To take a more refined view would, however, require international benchmarking to compare the relative stringency of GHG emission control policies and measures in place in different countries, a complex task due to the challenges in making a fair comparison between different policy instruments.

However, notwithstanding the shortfalls in the approach, it is possible to make inferences about the scale of emissions leakage risk, as outlined below (Figure 2.3). The graphic depicts how the risk of emissions leakage could change depending on the final destination (i.e. the point of end-use) of the incrementally produced crude oil from a $CO_2$-EOR activity in relation to different types of GHG emission control policies. It also highlights some example jurisdictions where such conditions exist.

[1] Data provided by Thompson Reuters Point Carbon, as presented in World Bank (2014), highlights that the EUA price barely exceeded €7 over the period April 2013 to April 2014, with it mainly in the range €3 to €5 per EUA over the period. This compares to the initial tax rate proposed by the South African Treasury of ZAR 120/t$CO_2$-e (RSA National Treasury, 2013), equivalent to around €8.5 to €10 at 2013-2014 exchange rates.

**Figure 2.3 Varying risk of emissions leakage from $CO_2$-EOR projects**




*Source*: Carbon Counts analysis. The figure is for illustrative purposes only, and does not claim to provide a definitive view on the type and level of emissions leakage risks posed by using oil produced from $CO_2$-EOR. PMR = World Bank Partnership for Market Readiness.

## 2.4 Likelihood and scale

Whilst the risk of emissions leakage can, to an extent, be identified and described, it is important to place these considerations within the context of real-world characteristics of crude oil production and use, in particular international trade movements. This can allow the scale and nature of the risk of emissions leakage to be assessed.

Where the $CO_2$-EOR activity is constrained to domestic production, refining and end-use, the risk of emissions leakage will be based on the characteristics of the policy incentivising $CO_2$-EOR use (e.g. CDM in developing countries, or the EU ETS in Europe), and the risk of cross-sectoral emission leakage occurring. In most circumstances it should be possible to readily identify these situations on a case-by-case basis, based on an understanding of domestic polices and measures to control GHG emissions in mid- and downstream sectors.

The risk of transboundary emissions leakage associated with international trade movements presents a more complicated situation. Figure 2.4 and Table 2.1 present recent data for annual international oil (crude and products) trade flows between sources of production and regions of consumption.

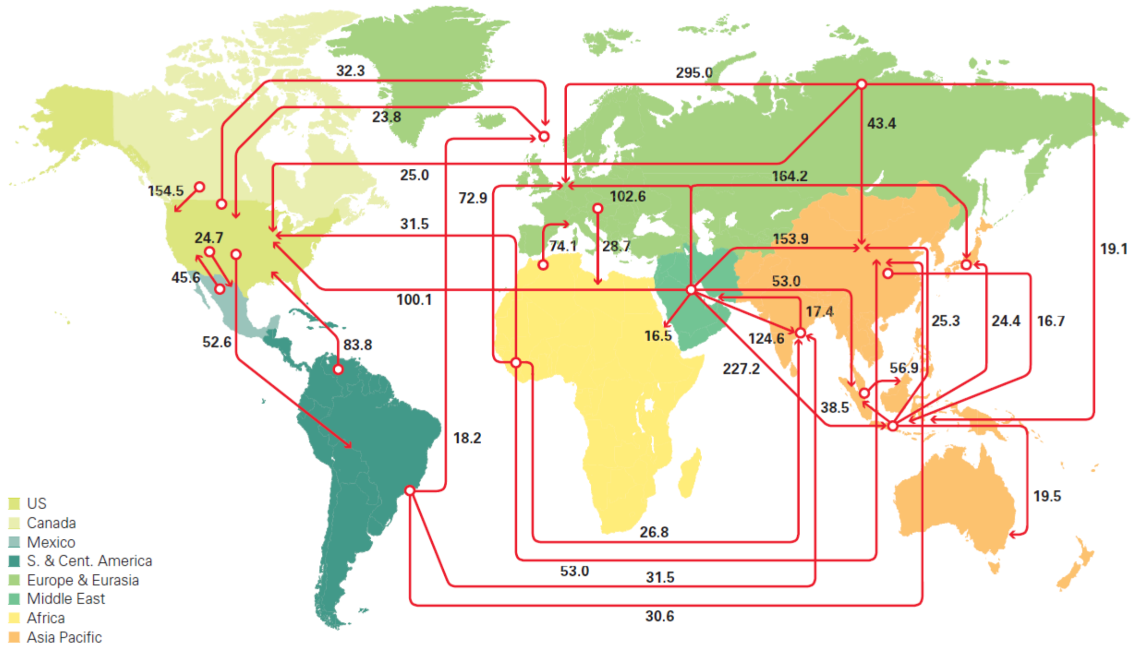
Firstly, it can be seen that all world regions engage in oil trade imports and exports. Oil trade has increased dramatically over recent years, partly fuelled by rising demand in the emerging economies of Asia: at 2.7 billion tonnes (55.6 million barrels per day), trade in global oil in 2013 accounted for 64% of global consumption, up from 57% a decade ago (BP, 2014). Secondly, the table also shows the emission leakage "hot spots" highlighting the largest flows at risk of emission leakage, as well as those at lesser risk.

Whilst the figures shown are a somewhat simplified summary of a single situation in time (for 2013), they do serve to show that, on the basis of existing trade patterns, some potential combinations of production and use could pose a risk of transboundary emissions leakage. This is of course predicated on the possibility that $CO_2$-EOR could be incentivised in producing regions through GHG policies and measures. Based on the spectrum of leakage risk summarised in Figure 2.3, circumstances where this could arise include projects developed under *inter alia*:

- the CDM in non-Annex I developing countries:
    - Exports from Middle East to countries with no QELROs and limited sectoral policies (e.g. Africa, South America, India, China, other Asia)
    - Exports from Middle East to developed countries without QELROs but with sectoral and MRV requirements (e.g. US, Canada, Japan)
    - Exports from Africa to countries without QELROs (e.g. US, China, India, Other Asia)
- JI in FSU countries:
    - Exports to countries without QELROs (e.g. China, Other Asia)
- US, Canadian, Albertan or California incentives:
    - Exports to South America
- the incentive under the EU ETS in Europe:
    - Exports to Africa and other parts of Asia (e.g. Central, South and South East Asia)

In many CDM cases, there is also the risk of emissions leakage where the incrementally-produced crude oil is refined and used domestically. Conversely, some of the largest international flows of oil are from the FSU and Middle East to the EU, where the risk of emissions should in theory be minimal as the receiving jurisdiction faces QELROs under the Kyoto Protocol and have enacted a range of sectoral policies to restrict mid- and downstream emissions.

## Figure 2.4 Major international crude oil and refined product trade flows 2013 (megatonnes)




## Table 2.1 Major international crude oil and refined product trade flows 2013 (Mbbl/d)

| *Mbbl per day* | US | Canada | S.America + Mex | Europe | FSU | Middle East | Africa | Aus + NZ | China | India | Japan | Other Asia + | TOTAL |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | To | | | | | | | | | | | | |
| **From** | | | | | | | | | | | | | |
| US | - | 298 | 1617 | 674 | 2 | 75 | 136 | 7 | 148 | 40 | 118 | 155 | **3271** |
| Canada | 3125 | - | 22 | 74 | - | 2 | - | - | 34 | 2 | 13 | 4 | **3276** |
| S. America + Mex | 2609 | 40 | 46 | 559 | 2 | 2 | 6 | 1 | 644 | 729 | 47 | 358 | **5042** |
| Europe | 496 | 160 | 266 | - | 104 | 258 | 598 | 2 | 26 | 13 | 28 | 450 | **2399** |
| FSU | 519 | 5 | 15 | 5989 | - | 273 | 36 | 38 | 877 | 42 | 290 | 547 | **8632** |
| Middle East | 2011 | 127 | 139 | 2074 | 9 | - | 334 | 155 | 3097 | 2509 | 3310 | 5672 | **19439** |
| Africa | 821 | 146 | 382 | 2965 | 3 | 25 | - | 139 | 1305 | 642 | 106 | 278 | **6811** |
| Aus + NZ | 2 | 0 | 11 | 2 | - | - | 1 | - | 66 | 3 | 40 | 169 | **294** |
| China | 7 | 1 | 94 | 13 | 10 | 22 | 23 | 1 | - | 12 | 9 | 438 | **631** |
| India | 60 | 2 | 93 | 173 | - | 364 | 177 | - | 13 | - | 64 | 290 | **1235** |
| Japan | 17 | - | 5 | 5 | - | 1 | 2 | 74 | 36 | 1 | - | 181 | **321** |
| Other Asia + S'pore | 126 | 1 | 47 | 110 | 1 | 53 | 102 | 617 | 665 | 101 | 505 | 1993 | **4320** |
| **TOTAL** | 9792 | 781 | 2737 | 12637 | 130 | 1076 | 1416 | 1033 | 6911 | 4094 | 4530 | 10535 | **55670** |
| | **18%** | **1.4%** | **5%** | **23%** | **0.2%** | **1.9%** | **2.5%** | **1.9%** | **12%** | **7%** | **8%** | **19%** | **100.0%** |

*Source*: BP Statistical Review of World Energy 2014. *Notes*: Mbbl = thousands of barrels. The shaded cells in Table 2.1 show emissions leakage risk colour coded according to *Figure 2.3* with flows >300 Mbbl/d in a lighter shade, and flows > 1MMbbl/d in darker shade. Data shown excludes domestic and most intra-area movements of oil - for example, crude oil and products moving between countries within Europe. Data for Mexico and Singapore added to S. America and Other Asia respectively. Also they do not capture the full potential range of movements between countries and facilities e.g. the refining of crudes of different origin, or the re-importing of refined products; some countries serve as major refining locations whilst being only minor end users of oil-derived fuels.

To put the scale of this issue in context: using the data shown in Figure 2.4 and Table 2.1, and the varying risk of emissions leakage for different oil importing regions shown in Figure 2.3, the following applies:

- 23% of oil flows are at *limited* or *low risk* of emissions leakage (e.g. imports to Europe where most countries face QELROs). This equates to emissions of around 1.9 billion $tCO_2$.[1]
- 29% of oil flows are at a *moderate* or *medium risk* of emission leakage (based on the regions shown in the centre of Figure 2.3, e.g. US, Canada, Japan and Australia). This equates to emissions of around 2.5 billion $tCO_2$.
- 46% of oil flows are at a *higher risk* of emission leakage (based on the regions shown towards the right of Figure 2.3, e.g. most developing countries). This equates to emissions of around 4.2 billion $tCO_2$.

The total of 6.7 billion $tCO_2$ potentially at risk of emissions leakage compares to total global emissions from oil combustion of around 11 billion tonnes, or about 60% of all global oil emissions. Whilst it is also important to note that $CO_2$-EOR counts for less than 0.03% of global oil production today, if the high-end estimates for $CO_2$-EOR reserves were to be realised and produced over the next 40 years, crude oil from $CO_2$-EOR could constitute as much as half of global oil production.[2]

Based on the analysis presented, there are a number of circumstances where there is a potential risk of transboundary emissions leakage, in particular for $CO_2$-EOR projects promoted under the CDM in the Middle East and Africa, and JI projects in the FSU. $CO_2$-EOR projects undertaken in Europe or the US also pose a minor risk of emissions leakage, as only minor trade flows occur from these regions to areas with only limited GHG controls in place.

## 2.5 Materiality

The previous discussion suggests that there is a risk of emissions leakage when GHG policies provide support to $CO_2$-EOR activities. The *materiality* of this risk – or in other words, the significance of the potential levels of emissions leakage that could occur compared to the emission reductions achievable through $CO_2$ storage compared on a per barrel crude oil produced basis – is also a relevant consideration. This can help provide a view on which are the most significant elements of site-level, mid- and downstream emissions, and therefore whether they are important to the overall emissions profile calculated for $CO_2$-EOR activities.

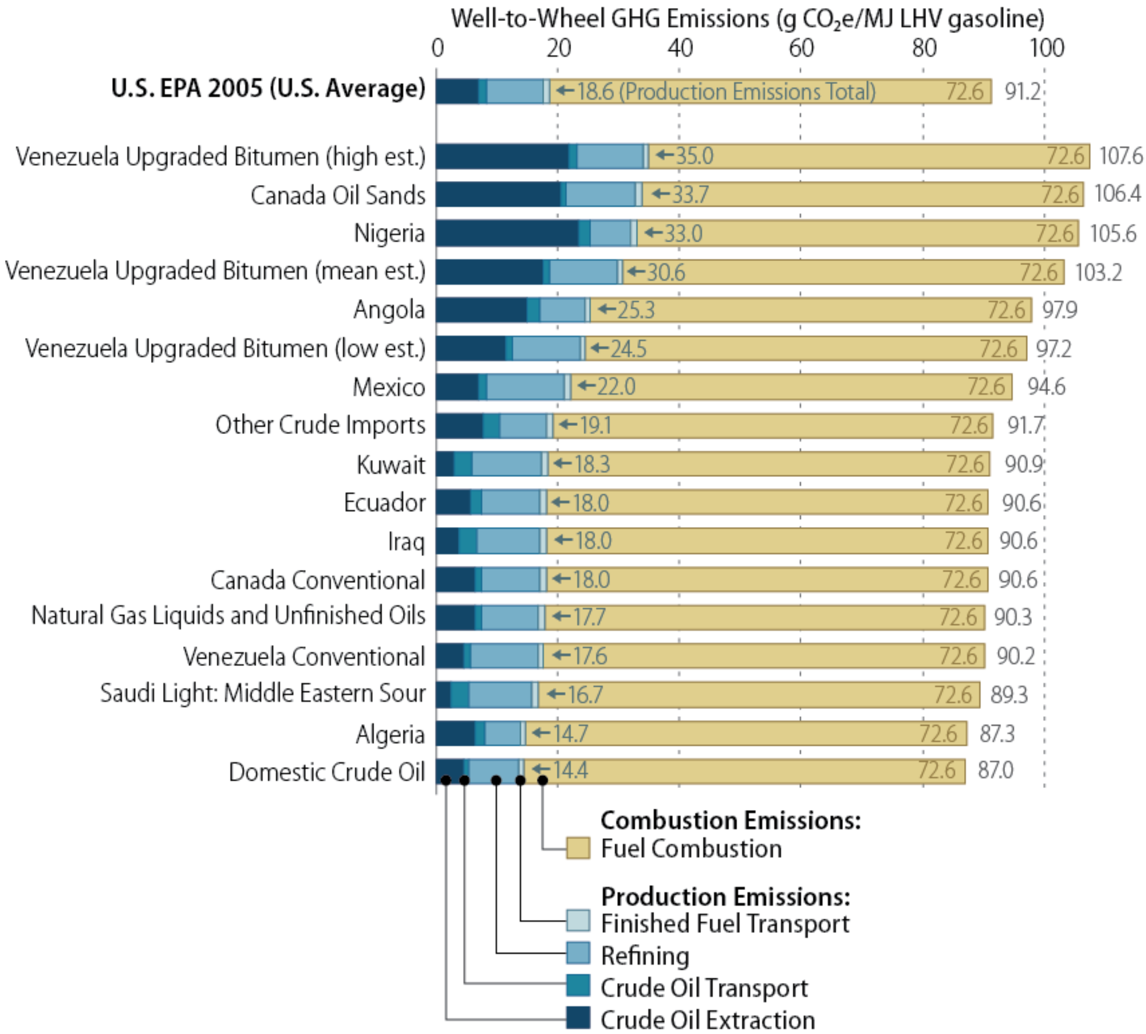
As mentioned in Section 1, a number of studies have considered the lifecycle GHG emissions of fuel produced from various crude oils, covering emissions from both *well-to-tank* (WTT i.e. from production to the point of use) and *well-to-wheels* (WTW i.e. also including end-use). These analyses often produce similar albeit varying results depending on the assumptions made in performing such assessments, and it is beyond the scope of this paper to provide a comprehensive review of this body of work (see also Section 1.1). However, irrespective of the details, results of such analyses can provide insight into the relative size of the variations that exist for site-level, mid-

[1] Emissions estimate based on assuming 0.43 metric tonnes $CO_2$ per barrel (EPA, 2013) where 7.37 barrels = 1 tonne of crude oil (IEA, 2011) and that the fraction oxidized is 100% (IPCC, 2006).

[2] Based on global oil production of around 86 million barrels per day in 2013 (BP, 2013), daily production from $CO_2$-EOR of 282,000 barrels, and high-end estimate of $CO_2$-EOR potential reserves of 470 billion barrels (see Section 1), which, if it was all to be produced over 40 years, would be equal to more than 32 million barrels per day of crude oil supply.

and downstream emissions from different crude oil sources, thereby providing insight into whether certain sources of emissions leakage are actually worth trying to measure, i.e. material to the overall emission reduction estimate delivered by a particular $CO_2$-EOR activity. Of the body of research, a recent paper from the US Congressional Research Service (CRS, 2014) using data from the US National Energy Technology Laboratory (NETL, 2009), provides a useful insight into the WTW GHG emissions intensity of US gasoline from various global production sources (Figure 2.5).

**Figure 2.5 Well-to-Wheels GHG Emissions Estimates for Global Crude Resources**




*Source*: CRS, 2014. Based on data from NETL, 2009

Of the emissions data shown, those from *Crude Oil Extraction* are most relevant with respect to variations in emissions possible between different crude oil supply sources. When considering leakage effects, if it is assumed that supply of incrementally produced oil from $CO_2$-EOR could substitute and displace more emissions intensive production sources, then a net emissions benefit could be achieved. This would in essence result in a *negative* leakage effect i.e. a positive number. The data shown in Figure 2.5 show a variation of between around 4 $gCO_2/MJ$ (Saudi Light) to over 20 $gCO_2/MJ$ (Nigerian and Venezuelan) for crude oil extraction emissions, giving a difference of up to 16 $gCO_2/MJ$. Assuming that site-level emissions from $CO_2$-EOR would be at the lower end of this scale,[1] and could potentially substitute crude supplies at the upper end, it would be material to consideration of emissions leakage as it represents a reduction in emissions intensity of over 17% relative to the average crude oil supplied to US markets (i.e. 16 $gCO_2$/MJ compared to an average WTW intensity of 91.2 $gCO_2$/MJ)

This effect is actually materially greater than the variations shown for mid- and downstream emissions from *Transport*, *Refining* and *Combustion* (i.e. end use) combined. In terms of the midstream emissions, the analysis suggests that refining can account for approximately 10% or less of the overall WTW emissions, whilst transport of crude and refined products is much lower at around 1-3% of overall emissions. The analysis also shows that the GHG emissions levels attributable to refining are variable, which will depend on, *inter alia*, the type of crude feedstock being refined, the type and age of refinery, and any GHG emission abatement measures employed. In undertaking its analysis, NETL (NETL, 2009) made several assumptions to develop a heuristics (i.e. rule of thumb) model to make these estimates, and the reader is referred to that report for a fuller description of the approach taken.

Whilst the variation in site-level emissions and refining could lead to variations of up to 25% of total WTW emissions, thereby making them material for consideration, it is debatable whether emissions from transport of crude are material to the overall level of reductions achievable from $CO_2$-EOR. For example, Jaramillo *et. al.* (2009) showed that in general terms emissions from the transport of crude oil and refined products are extremely low in certain conditions, the former accounting for around 0.5% of the total mid- and downstream emissions in their analysis, and the latter being excluded on the basis that it accounted for only 1% of total emissions.[2] Wong *et. al.*, 2013, also showed similar results when examining the lifecycle emissions of various crude oils used in Canada and the US, including $CO_2$-EOR activities. It is important to note that in both cases the analysis was confined to Canadian or US production, refining and use – whereas in the cases discussed in this report, emissions from shipping of crude oil from e.g. the Middle East to South or East Asia, and refined product transport emissions in some parts of the world, may be higher. Notwithstanding these potentially higher emissions, the evidence presented in Figure 2.5, for e.g. Kuwaiti or Saudi Arabian crude oil transport, suggests crude oil shipping emissions are a relatively small portion of the overall WTW emissions from crude oil use.

As is to be expected (and as shown in Figure 2.5), the greatest contribution to overall lifecycle GHG emissions comes from the downstream end-use (or combustion) of refined products, accounting for in the range 67-83% of total emissions from gasoline in the US. Similar figures are also shown in NETL (2009) for diesel and jet fuel. These emissions therefore represent a potentially large source of emissions leakage from $CO_2$-EOR projects if they are allowed to occur unregulated.

LCA studies can also provide useful insight into the significance of such emissions relative to the overall emission reductions achievable from $CO_2$-EOR, albeit also with some limitations set by the underlying assumptions and the way in which results are presented. For example, according to

[1] Wong *et. al.* 2013 analysis suggests that site level emissions from a $CO_2$-EOR operation are around 100 kg/bbl produced, equal to around 16 $gCO_2$/MJ. The same analysis presented as net emissions i.e. including both site-level plus $CO_2$ injected (i.e. stored) gives a negative figure of around -150 kg/bbl, equal to approximately -24 $gCO_2$/MJ of oil produced (based on data shown in Figure 7 of that report).

[2] Based on data presented in the *Greenhouse Gases, Regulated Emission, and Energy Use in Transportation* (GREET) model, developed by the Argonne National Laboratory in the US.

Jaramillo (*op. cit.*) each $tCO_2$ injected in $CO_2$-EOR operations today in the US produces around 3.7-4.7 $tCO_2$ of emissions (i.e. emissions from the sources of $CO_2$ used for $CO_2$-EOR). Wong *et al.* (*op. cit.*) provided estimates somewhat lower at around 0.5 $tCO_2$ per $tCO_2$ brought to site – the differences being attributable to the different boundaries used in the studies, with Jaramillo taking account of the upstream emissions including form coal mining, transport, combustion and $CO_2$ transport, whereas Wong only considered site level, mid- and downstream emissions. In any case, as transport of crude and refined products could account for around only 2% of the WTW $CO_2$ emissions, this could equate to around 10 $kgCO_2$ per $tCO_2$ stored. Consequently, it is debatable whether they are sufficiently material to include in any estimate of emissions leakage. Emissions of end use combustion are obviously a different proposition, accounting for perhaps as much as 0.4 $tCO_2$ per $tCO_2$ stored.

The levels of potential emissions leakage will be important to any discussion regarding whether to account for emissions leakage, and if so how, and which elements, should be the focus of efforts.

**Whether and when to account for emissions leakage**

**Summary of findings**

- Emissions leakage can occur where GHG policies incentivise $CO_2$-EOR deployment in one jurisdiction whilst simultaneously potentially driving longer-term GHG emission increases elsewhere. This can arise due to a lack of stringent GHG emission controls in the markets where the incrementally-produced crude oil is used;
- The risk of such emissions leakage occurring is variable because of the variations in the type and stringency of GHG controls in place in different parts of the world;
- Where the incrementally-produced crude oil is used in domestic markets, the risk can be easily estimated as only GHG controls in place in a single jurisdiction need be considered;
- However, where the crude oil is traded internationally, the degree of risk is difficult to estimate because of the challenges in comparing GHG control policies in place in different parts of the world. However, the indicative risk can be estimated based on a broad view about the stringency of different GHG control policies in place;
- The scale of the risk is fairly large because of the scale and nature of global oil trade flows, with imports into developing countries – jurisdictions largely absent of GHG emission controls – accounting for almost half of all oil trade internationally;
- The materiality of the risk is variable: variation in the site-level emissions associated with producing different crude oils can account for up to 17-18% of the WTW emissions intensity of crude oil products. Refining emissions may account for up to 10% of overall lifecycle WTW GHG emissions, whilst transport emissions from both crude oil and refined products may account for as little as 1-2% of overall lifecycle GHG emissions;
- Downstream emissions from the end use of refined products are the greatest source of lifecycle GHG emissions (up to 87%). The nature of oil flows mean that downstream emissions from oil exported to countries with limited GHG controls could be up to 60% of worldwide emissions from oil combustion.

The methodological options available to account for these emissions, and their relative merits - including their political acceptability/expediency – are assessed in the remaining sections of this report.

## 3 HOW TO ACCOUNT FOR EMISSIONS LEAKAGE

The risk, scale and materiality of emissions leakage considered previously can provide a view on whether and when to account for such emissions under different GHG policy incentives for $CO_2$-EOR. However, it does not provide any indications regarding the appropriateness of different methods to calculate emissions leakage. In considering such methods, two factors are paramount:

1. Which GHG emission factor or GHG emissions estimate to use;
2. How to calculate the emission factor or compile the emission estimate.

These are considered further below.

### 3.1 Selecting an emissions factor

In order to account for emissions leakage, it is necessary to develop an emissions factor that can account for the following elements associated with potential sources of emissions leakage:

- Site-level emissions, and in particular the variation – or *delta* – between a these emissions for a crude oil originating from $CO_2$-EOR operations and an alternative source of oil supply that might be *substituted*; and
- Mid- and downstream emissions, and in particular where these may occur unmitigated due to an absence of polices or measures to control their emissions, thereby *adding* to overall supply and potentially driving longer-term carbon lock-in.

Establishing an emissions factor that can reflect these two elements allows these additional emissions sources to be netted-back and subtracted from the emissions reductions calculated for upstream and site-level operations in a $CO_2$-EOR project, thereby providing a means to account for emissions leakage. This would typically involve expressing the emissions factor as an emissions intensity per barrel of oil or on an energy content basis i.e. $tCO_2$/bbl or $tCO_2$/MJ.

Developing an appropriate emissions factor that reflects these two elements requires a view to be taken on the effects of the supply of incrementally-produced crude oil to a particular market, as discussed in Section 2. As highlighted there, the core of concerns over emissions leakage and carbon lock-in is primarily one involving an evaluation of whether incrementally produced crude oil from $CO_2$-EOR effectively *substitutes* and *displaces* existing/other oil production or whether it is simply *additional* to these sources. The lock-in discussion is predicated on the view that energy/fuels used in the absence of $CO_2$-EOR would be less carbon-intensive, and by supporting $CO_2$-EOR, investment into other low carbon technology alternatives is reduced. The corollary is that any new supply would simply substitute existing oil supply. This makes for a complex backdrop against which to evaluate the two elements of emissions leakage outlined above.

Determining whether substitution or addition occurs is highly complex, requiring an analysis of marginal oil supply economics, product substitution effects, and price elasticity of supply and demand e.g. what would happen in the absence of the incrementally produced oil? Crude oil is used in a wide range of applications and end products, each with its own set of alternative products which may vary considerably by region, sector etc. There is generally no clear consensus in the literature on these matters: whereas in the short term it appears likely that demand for oil is relatively fixed (i.e. inelastic), and so incrementally produced oil may *substitute* and *displace* other sources, over the longer term this is less clear. This also needs be framed in the context of price elasticity of oil supply – or inelasticity – in terms of whether additional supplies of crude oil can be brought forward in reasonable time and at acceptable cost to meet changes in demand (see also Section 1.1). The lack of consensus in the literature reflects the large number of complexities and uncertainties involved in making such considerations, which include economic, policy and even behavioural/societal factors. Whilst noting the wider importance of this debate, its further consideration lies outside of the scope of the current study. Suffice to say, either case has implications for the appropriateness of any emissions estimate and emissions factor used to calculate an apparent emissions leakage effect.

The following discussion considers what type of emissions factor could be applied for estimating emissions leakage effects of crude oil supply from $CO_2$-EOR. The issue can be simplified to three basic cases regarding whether, for a given market, a barrel of oil from $CO_2$-EOR would:

- *Add to the existing oil supply* – in this case, the actual mid- and downstream emissions associated with the particular $CO_2$-EOR activity would seem an appropriate means by which to estimate emissions leakage, as no substitution effect occurs. As no substitution effect occurs, considerations regarding the delta between the project emissions and the emissions associated with any displaced crude oil supply do not apply. This can be referred to as a "product specific" emissions factor;
- *Substitute and displace marginal oil supply* – in this case, the factor used to estimate emissions leakage would need to take account of the delta between the project emissions and the displaced *marginal* supply, as well as the mid- and downstream emissions intensity of the displaced crude oil relative to the same scope of emissions associated with the new $CO_2$-EOR supply.[1] This is because it could be assumed that the additional barrel of oil from $CO_2$-EOR displaces the marginal source of crude oil supplied to a market. This can be referred to as a "marginal supply" emissions factor;
- *Substitute and displace an unknown source of oil supply* – this case is the same as the "marginal supply" above, but because marginal supply displacement can't be determined with any confidence, it may be more appropriate to consider substitution effects relative to the *average* emissions intensity of oil supplied to the whole market rather than the *marginal* supply.[2] The market average emissions intensity would in effect provide the best proxy measure of displacement effects. This can be referred to as a "market average" emissions factor.

If this potential effect can be identified, then an appropriate emissions factor for estimating leakage emissions can be developed.

Similar approaches were developed by Wong *et. al.* (2013) in accounting for the per barrel emissions intensity of crude oil production, processing and use associated with $CO_2$-EOR in North

[1] Taking the example shown in Figure 2.5, this would involve calculating the delta between the $CO_2$-EOR project emissions and whichever supply source was determined to be marginal (e.g. Venezuelan bitumen)
[2] Again, referring to Figure 2.5, this would be the US Average shown at the top of the graph.

America. Their study covered the following scenarios (excluding two scenarios covering storage only):

- *Scenario 3: EOR Barrel* – this approach involved using actual emissions based on operational data from the specific case study used in the report (a Canadian $CO_2$-EOR operation);
- *Scenario 4: Oilsands Barrel* – this approach involved using an emissions intensity estimate of a barrel of Canadian oilsands syncrude, based on a 50:50 ratio of emissions from mining and *in situ* production (e.g. steam assisted gravity drainage; SAGD). The approach drew on values from the literature on the subject. It is based on a similar view as the "marginal supply" emission factor described above; and,
- *Scenario 5: Average Barrel* – this approach involved using a calculated value for the emissions intensity of an average barrel of US crude oil, drawing on various life-cycle studies on the subject. This used an average emissions factor for the crude oil supplied to the whole market as per the "market average" emissions factor described above, rather than the marginal barrel as used in *Scenario 4*.

The approach of Wong *et. al.* (2013) relied on making assumptions about mid- and downstream processing and use in order to generate full LCA GHG emission estimates. It was considered relevant as the authors of that report made the assumption that oil demand is inelastic at least in the short-term, and therefore $CO_2$-EOR supply can only *substitute* other sources (whilst noting the longer-term potential for effects on the price elasticity of demand). They did not express any particular views on the appropriateness of the different approaches used.

In taking this type of approach, where *substitution* does occur then it is relevant to consider the emissions associated with the marginal source of supply that could be displaced by $CO_2$-EOR (such as in *Scenario 4* above). For arguments sake, the view could be taken that the most GHG intensive production source would be displaced based on emissions being a proxy for energy intensity or complexity of production, and therefore costs; for example, Canadian oilsands syncrude as applied in *Scenario 4* above or Venezuelan Bitumen (as shown in Figure 2.5). This is likely to result in a reduction in overall net emissions intensity of crude supply if such sources are displaced by supply from $CO_2$-EOR, as it is likely to have lower emissions across the oil value chain compared to, for example, Canadian syncrude (as shown by Wong *et. al*, 2013). This outcome would result in *negative* emissions leakage.

However, such an assumption is far from certain due to the variability of global oil market supply and trading, which may not wholly be influenced by production economics, but also by trading behaviour and political factors etc. It is also important to note that in the case of energy products, it is generally not the product that influences consumer behaviour and demand, but rather the service or "utility" it provides. As such, in the case road transport fuels, the utility provided is "transportation" and similar services could be provided by biofuels or electricity (e.g. buses, trains or electric vehicles). For these reasons it is difficult to be certain about substitution effects in energy markets as the scope for product substitution covers a wide range of options that can provide a similar utility or service. Therefore, a more conservative or prudent approach might be to assume the market average emissions factor for the crude oil supplied into it. Taking this approach, the measure of emission leakage would likely be lower than when assuming displacement of the marginal supply, as typically, marginal supply is likely to be more emission intensive.

These options notwithstanding, for the present purposes, the report authors have taken the view that the stringency of GHG controls in place in a jurisdiction can provide a proxy measure for the likelihood of emissions leakage and the risk of longer-term carbon lock-in occurring or otherwise. Whilst not ideal, this approach formed the basis of the analysis of emissions leakage risk set out in the previous chapter.[1] Based on the spectrum of risk presented there (Figure 2.3), the following logical assumptions can be applied: the likelihood of *substitution* occurring is higher where stringent GHG controls are in place; and, the risk of *addition* increases in circumstances where less stringent or no controls are in place. Taking a polarised view of leakage risk leads to a view that there can only be cases where either there is a risk of emissions leakage, or there is not. Where there is a high risk, crude oil supply can only be *additional*, and where there is not, *substitution* must occur i.e. perfect substitution. Consequently, adopting this view means that there would only be a need to consider emissions leakage where crude oil supply is *additive* – and arguments concerning *substitution* effects are therefore immaterial to the discussion. On this basis the actual *product specific* emissions from $CO_2$-EOR would need to be used, and not marginal or market average emission factors.

On the other hand, however, given the uncertainties over the degree of risk of emissions leakage presented by supplying incrementally-produced oil to different markets (as shown in the central area of Figure 2.3), it is also debatable whether this view is a sound one, and it may be that certain other approaches could be used. This may involve adopting a combined approach taking account of both supply *addition* and supply *substitution*, and adopting a combined emissions factor for the two.

## 3.2 Calculating a leakage emission factor

On a methodological level, the situation reflects something similar to that faced by grid-connected renewable energy projects under the CDM in the early 2000's. For such projects, it is assumed that emission reductions are achieved through the substitution and displacement of fossil fuel power plants connected to the power grid, i.e. the baseline would be a fossil fuel fired power plant. This resulted in significant debate about which grid emissions factor to apply for the relevant electricity grid in the baseline: either the *build margin* or the *operating margin*; the former being the emissions intensity of a new power plant that would have been built but is subsequently displaced by the renewable source; and the latter relating to existing plants connected to the grid that might be switched off to accommodate the new plant i.e. the marginal plant or MWh generated. The build margin is reflective of the longer-term implications of the project activity (e.g. investment in new capacity), whilst the operating margin reflects the shorter-term changes in electricity supply driven as a result of the project. These discussions resulted in the agreement of CDM Approved Consolidated Methodology ACM0002,[2] which generally applies a *combined margin* approach, consisting of the average grid emission factor of both the build and operating margin for a given

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[1] Such an approach can only provide a proxy measure of the risk as the stringency of policies can change over time, as seen with the progressive weakening of the impact of the EU ETS since its inception, or as currently occurring in Australia with the abolition of the CPM.

[2] The approach is now set out the latest version of the "Tool to calculate the emission factor for an electricity system" under the CDM. However, the basic elements described broadly apply.

electricity system.[1] Such an approach was taken due to uncertainties about the appropriateness of either the build or operating margin in reflecting the effects of adding new renewable energy (or other low carbon energy) supplies to an electricity grid.

Taking this analogue to a discussion on $CO_2$-EOR, the build margin could equate to oil fields that wouldn't be developed due to incremental supply from $CO_2$-EOR, and the operating margin could be existing fields that are shut-off due to increased supply. Problematically, the markets for crude oil and liquid fuels are far more complicated than for grid electricity. Furthermore, in a similar way to electricity grids, since oil is only one type of energy carrier among many, the marginal supply could be other types of energy carrier such as biofuels, electricity or even more emissions intensive products such as coal-to-liquids. As such, trying to draw direct parallels with the approach in ACM0002 can only partially address the issues presented. Since development of ACM0002 took several years of discussion and analyses to arrive at the combined margin approach, it is conceivable that similar effort will be needed to arrive at a satisfactory generalised methodological approach to address emissions leakage from $CO_2$-EOR.

That said, on a case-by-case basis it may be more straightforward to develop specific approaches to calculating mid- and downstream emissions for a given incrementally produced crude that could be used to estimate emissions leakage effects. This could be the case, for example, where domestic refining and use or export to a single identifiable market can be ascertained. Even then, if emissions leakage estimation methodologies could be readily developed, there could be challenges for implementation in practice. Under ACM0002, the build margin requires information about the last five power plants built that are connected to the relevant grid, whilst the combined margin requires detailed information, *ex post*, on the dispatch of power plants to the grid over the previous year. Trying to apply similar principles to crude oil supply would therefore require detailed knowledge of the fields supplying crude oil to a given market for a given period of time, both historically and on an annual basis thereafter in order to make *ex post* estimates of emissions.

However, since the oil market is global, with ownership of the crude and products potentially changing hands several times through the value chain via many intermediaries, trying to establish such information on the traceability of supply and use is challenging. These types of challenges have been experienced in Europe with the development of the EU Renewable Energy Directive and Fuel Quality Directive, which requires fuel suppliers in Europe to meet a portfolio standard for the LCA GHG emissions of fuel supplied. In meeting such a requirement, suppliers must have detailed information on both the source of crude oil imported, and also the relevant emissions across the value chain. The resulting complexity has led to long delays in implementation, and at present remains unresolved. As such, experience suggests that it could be extremely difficult to apply a similar approach for emissions leakage and $CO_2$-EOR.

On a case-by-case basis it may be possible, but would likely require complex monitoring approaches in order to provide assurance that any assumptions about oil supply made in year 1 of the project remain relevant across its lifetime.

Potential approaches to address these issues are described in the next section.

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[1] In fact the approach is more complicated than described here, with a variety of approaches being allowed to calculate build, operating and combined margin.

## How to account for emissions leakage

### Summary of findings

- To account for emissions leakage, it is necessary to develop an emissions factor that reflects emissions from mid- and downstream activities associated with the incrementally produced crude oil from $CO_2$-EOR. This typically involves estimating emissions across the value chain and expressing them on an emission intensity per barrel of oil basis.
- Such an approach takes a somewhat simplified view of the leakage effect, however, as in reality, if the new supply of oil displaces other oil sources, the leakage effect may actually be *negative* (i.e. it might actually reduce net emissions by substituting more emissions intensive alternative products). On the other hand, increasing crude oil supply may actually prevent the substitution of oil by less emissions intensive products such as biofuels or electricity. The latter aspect forms the core concern of carbon lock-in. It is therefore challenging to determine whether and what the *substitution* effect of supplying incrementally produced crude oil might be.
- Three possible approaches to estimating emissions leakage can be identified:
  - *Product specific* – the approach may be relevant where the supply from $CO_2$-EOR is assumed to be *additional* to existing supply, and would involve adopting a specific set of emissions estimates for mid- and downstream activities for a specific source of incrementally produced crude;
  - *Marginal supply* – this approach may be relevant in cases where a substitution effect can be identified and linked to displacement of a specific source of oil supply in a given market.
  - *Market average* – this approach may be relevant in cases where a substitution effect can be identified, but the specific source of oil displaced by the supply cannot be identified.
- In cases where the risk of emissions leakage can be identified as either high or low, the substitution issue is not so relevant since where it is assumed that the risk is low, *no substitution* can occur, and if it is high, then the supply must be *additional*. Consequently, the only relevant approach to accounting for emissions leakage, where relevant, is to use a product specific emissions factor.
- In cases where risk of emissions leakage is considered to lie somewhere between the two extremes, it may be necessary to adopt a combined approach taking account of both addition and substitution. This is similar to approaches adopted under in the CDM for grid connected renewable energy projects, where a combined margin approach is taken.
- On a methodological level, there are challenges to implementing such an approach because of the complexity of global oil markets.

# 4 APPROACHES TO $CO_2$-EOR ACCOUNTING

The previous sections of this report considered issues for $CO_2$-EOR emissions accounting in the context of:

- Whether and when to account for emissions leakage from $CO_2$-EOR. This concluded that there is a spectrum of emissions leakage risk according to the stringency of climate change policies and measures in place in jurisdictions where the incrementally produced oil is used; and,
- How to account for emissions leakage. This discussion showed that emissions leakage should to be considered in the context of market effects of new oil supplies. It also highlighted the challenges for doing so.

In addition, various approaches applied to $CO_2$-EOR site-level GHG accounting and MRV are set out in Annex B.

Based on the findings of the review and discussions, this section of the report attempts to put forward a framework that can be applied on a project-, country- or region-specific basis for the following:

1. Establishing approaches to site-level emissions accounting for $CO_2$-EOR;
2. Characterising the extent and scale of emissions leakage risk; and,
3. Calculating the emission factor to apply for estimating emissions leakage.

The approach outlined should be considered as a first-pass methodological attempt that can provide a basis for further work, rather than the definitive approach on the matter.

A key principle to consider in developing an approach to estimate emissions leakage is *conservativeness.* The principle is of importance in so much as the issues at hand reflects small marginal changes in the emissions intensity of oil extraction and supply on a per barrel basis, set against potentially very large absolute numbers in terms of oil production and trade flows. As such, minor errors in the approach adopted could propagate as a large cumulative error in any leakage emission estimate.

## 4.1 Approaches to site-level emissions accounting

A review of various GHG accounting rules and their approaches for site-level $CO_2$-EOR emissions accounting is presented in Annex B. The analysis there highlights that many schemes around the world include approaches to $CO_2$ emissions accounting for $CO_2$-EOR at a site-level, covering MRV methods to estimate emissions from the following sources:

- Fugitive emissions related to surface infrastructure
- Indirect emissions related to the use of bought-in electrical energy
- Seepage emissions related to leakage from the storage complex
- Additional energy use for oil recovery
- Emissions associated with the use of incrementally-produced oil ('downstream emissions')

- Other

For any particular scheme, the scheme's MRV and accounting rules would need to be followed to estimate such emissions. For example, the EU MRR provides guidelines for how such emission should be quantified for an installation undertaking $CO_2$-EOR that is covered by the EU ETS. Similarly, in the US, the Environmental Protection Agency's (EPA's) GHGRP includes a range of subparts applicable to various aspects of $CO_2$-EOR operations including:

- *Subpart C*: *General Stationary Fuel Combustion Sources* – to calculate emissions from onsite energy generation, which would include any additional energy used for the purposes of $CO_2$-EOR;
- *Subpart W: Petroleum and Natural Gas Systems* – to calculate emission from surface activities, including fugitive emissions, venting and flaring, and any losses of breakthrough $CO_2$ etc.;
- *Subpart RR: Geologic Sequestration of $CO_2$* – to calculate amounts of $CO_2$ geologically sequestered, and also to calculate any $CO_2$ leaking from the site (i.e. seepage).

Any electricity bought-in to a $CO_2$-EOR site will need to be counted on a site-specific basis according to e.g. supplier records or estimates of grid emissions intensity factor for the particular grid that is supplying the site, where required by the scheme's specific MRV rules. These data may be published in some jurisdictions. In addition, where an oil facility carries out both $CO_2$-EOR and non-EOR production, the various emissions would likely need to be pro-rated to account for the relative energy use for the different operations.

For the purposes of brevity, details of the specific methods applicable under different schemes have not been set out here, and the reader is referred to Annex B to locate relevant sources of information. Annex B describes the MRV approaches for $CO_2$-EOR activities applicable under various policies and measures across a range of jurisdictions, and Table B-1 provides information on where to find relevant MRV and accounting rules for each part of the $CO_2$-EOR value chain.

## 4.2 Characterising the extent and scale of emissions leakage risk

The type of emissions leakage risk posed by $CO_2$-EOR was described in Section 2, and summarised in Figure 2.3. Based on the discussion there, it is possible to conclude that in some circumstances there is a risk of emission leakage occurring due to $CO_2$-EOR as a result of the risk of unmitigated increases in downstream crude oil use. Similarly, there is the possibility of *negative* emissions leakage occurring where the incrementally-produced oil from $CO_2$-EOR displaces more emissions intensive supplies of crude oil.

To address these aspects of emissions leakage, it may be possible to develop an accounting methodology to quantify the level of emissions leakage that might occur. The estimated level of leakage emissions may be subsequently subtracted from the total emission reductions estimated for the upstream and site-level components of a $CO_2$-EOR activity to provide an overall estimate of the net emission reductions achieved by a $CO_2$-EOR activity.

In practice, the most practical way to do this is to calculate the following:

1. The delta between the $CO_2$-EOR site-level emissions and the emissions associated with crude oil extraction for any displaced oil supply source; and,
2. The mid- and downstream emissions intensity on a per barrel basis.

Such an approach could be applied at an individual project level, or for a whole jurisdiction in the case of regional cap-and-trade type policies (see Annex A and B).

The remainder of this section considers a step-wise approach to characterising the risk of emissions leakage occurring. The approach outlined relies on pro-rating the characteristics of all oil produced in a jurisdiction to allocate the relevant leakage emissions to a specific $CO_2$-EOR project.

### 4.2.1 Step 1 – Characterising the pathways for oil use including exports

The first step is to identify the way in which incrementally produced oil from $CO_2$-EOR will be used, either at a project level or regional level. It can include domestic refining and use, and exports for refining and end use in another jurisdiction. This can be achieved through the following approaches:

1. *On a project specific basis* – identifying the main markets that oil is sold to by the firm undertaking the $CO_2$-EOR project, which may be obtainable from sales and trading departments. These records could provide information on the countries where the oil is to be refined and used. In reality this is likely to be difficult to obtain as crude oil is typically traded through a number of intermediaries, meaning that it may not be possible to identify the specific markets into which the oil is supplied. As such, a country or regional approach will need to be adopted.
2. *On a country or regional basis* – identifying the volume of crude oil production at a national level that is used domestically and the amounts exported. For the latter, the full range of countries and the amount exported to each should be listed.

Based on the data collected, a list containing each receiving country (including the host country for domestic use), the amount of oil used/exported to each in a calendar year, and the relative percentage for each location should be developed.

Identifying the export pathways for refined products is likely to be extremely challenging, and has been excluded from this methodology for the time being, subject to further consideration.

### 4.2.2 Step 2 – Characterising GHG policies and measures in place in receiving countries

Using the list developed in Step 1, an assessment should be made of the GHG policies and measures in place in each country identified. This should draw on the discussion outlined in Section 2 and summarised in Figure 2.3. It must include the host country. In some cases there may be many countries involved. Therefore, in order to rationalise the level of effort needed, where more than 8 countries are identified, the focus of efforts should be on the top 80 percentile of countries using oil produced from the host country or the top 8 countries using oil. This may or may not include the host country.

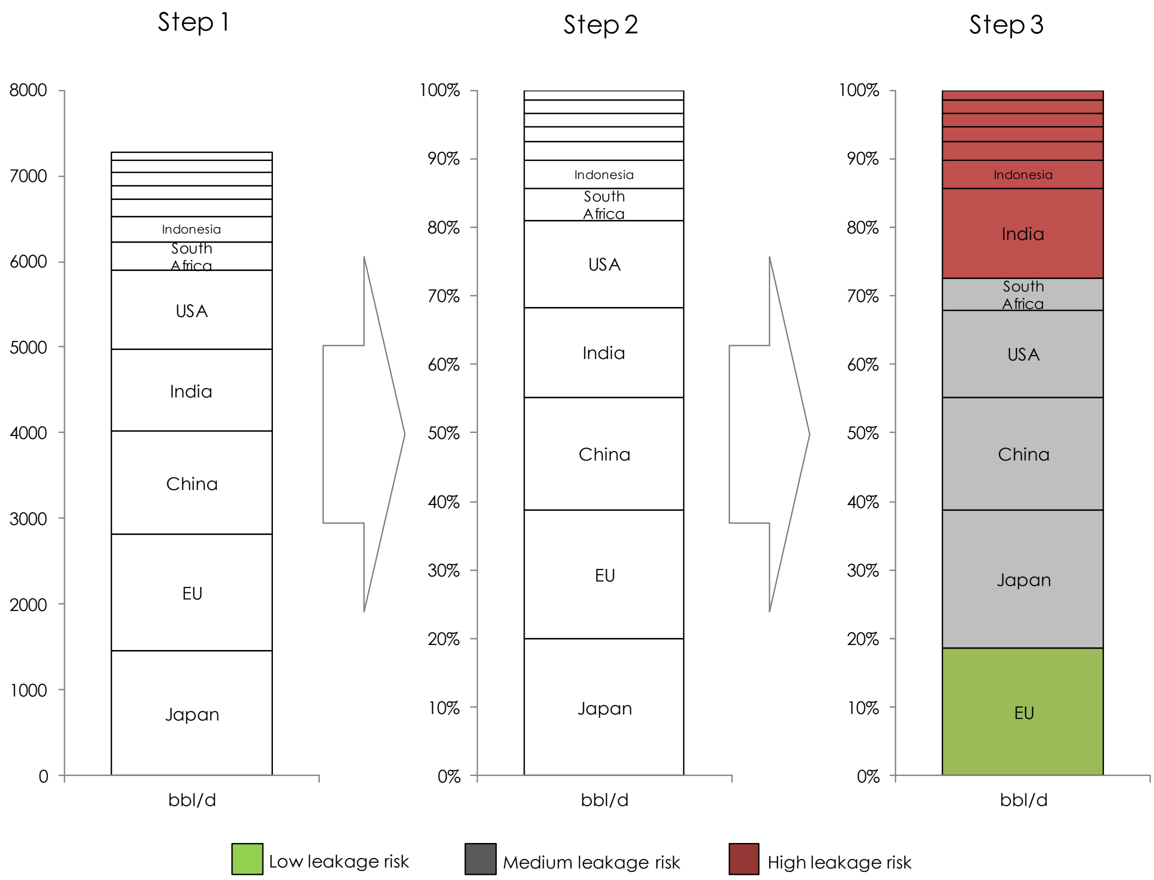
### 4.2.3 Step 3 – Estimating the risk of emissions leakage

Based on the analysis undertaken in Step 2, the risk of emissions leakage for each country should be categorised as high, medium or low. This should then be compiled into a composite description of the emissions leakage risk covering for the project or country covering:

- The percentage and total volume of oil at *low risk*. This may be used to estimate any emissions reductions achieved by displacing more emission intensive sources of crude oil.
- The percentage and total volume of oil at *medium risk*. This will be subject to a combined approach to calculating an emission factor for emissions leakage.
- The percentage and total volume of oil at *high risk*. This will be subject to a full emissions leakage risk estimation.

A hypothetical worked example is shown in Figure 4.1. In this example, around 19% of produced oil is assessed to be at low risk of emissions leakage, 41% at medium risk, and the remainder (40%) at high leakage risk.

**Figure 4.1 Hypothetical example of emissions leakage risk characterisationWhether and when to account for emissions leakage**




The ratios established should be used to pro-rate the risk of emissions leakage at a project- or jurisdiction specific level.

Using the information about leakage risk characterisation, an indicative quantitative estimate of emissions leakage risk can next be calculated as described below.

## 4.3 Calculating the emission factor to apply for estimating emissions leakage

Three possible approaches to calculating an emission factor to quantify leakage risk were set out in Section 3.2, covering *product specific*, *marginal supply* and *market average*. In taking the risk categories of high, medium and low established under Section 4.2, the approaches outlined in Table 4.1 could be applied to each of these different cases.

**Table 4.1 Approaches to calculating leakage emission factors**

| Emissions leakage risk | Emission factor to apply | Notes |
|---|---|---|
| Low | Marginal supply or Market average | Marginal supply factor may be used on the basis that, in theory, all incremental oil supplied could lead to perfect substitution. This could result in the calculation of a negative emission factor, meaning the amount netted back to the $CO_2$-EOR activity would involve the subtraction of a negative number, leading to a positive increase in the calculated net emission reduction for the particular activity to which the approach is applied.<br><br>Where marginal supply displacement cannot be shown with any confidence, then the market average factor should be applied. |
| Medium | Marginal supply or Market average + Product specific | As per Low Risk. However, since it is uncertain whether substitution or addition occurs, it may be necessary to take a combined approach involving an assumption of 50% substitution, and 50% addition.<br><br>The 50% addition component requires the use of a product specific emission factor to be used to calculate mid- and downstream leakage effects, hence it is referred to as a combined approach. |
| High | Product specific | As no substitution effect occurs, the delta between the project site level emissions and any substituted supply source is not relevant. Specific emissions associated with mid- and downstream leakage effects should be calculated. |

The following sections set out a step-wise approach to calculating the relevant leakage emissions factor to apply in each case.

### 4.3.1 Step 1 – Calculating the delta between the project site-level emissions and substituted supply

Following the approach set out in Table 4.1, for oil supply to low and medium emissions leakage risk jurisdictions, a $CO_2$-EOR project operator may wish to estimate the potentially positive emissions leakage effects arising from substituting more emissions intensive oil supply. This may be achieved by the following:

1. Using the information for each relevant jurisdiction gathered in accordance with Section 4.2, identify the marginal crude oil supply for the each receiving jurisdiction.
2. Calculate the crude oil extraction emissions intensity of that supply based on publically available information about the crude oil supplied to those jurisdictions, where available (i.e. in a similar way as shown in the dark blue bars in Figure 2.5). The data should be used to compile a weighted average crude oil extraction emissions intensity for marginal supply sources for each receiving jurisdiction.
3. Calculate the site-level emissions for the specific $CO_2$-EOR project.
4. Calculate the delta between the weighted average marginal crude oil extraction emissions intensity for marginal supply sources from (2) above and the project site-level emissions from (3) above.
5. Where marginal supply cannot be identified, follow the same procedure but use the weighted market average crude oil extraction emissions intensity for the indentified jurisdictions.

For jurisdictions with medium emission leakage risk, the calculated figure should be multiplied by 0.5 to allow for a combined approach to be applied, consisting 50% of the emissions leakage from supply substitution, and 50% arising from mid- and downstream emissions described under Step 2 below.

### 4.3.2 Step 2 – Calculating mid- and downstream emissions

For cases where emissions leakage risk is considered to be medium or high, the mid- and downstream emissions from crude oil refining and end-use of products should be calculated. As the emissions from transport of crude oil and refined products are likely to be small and therefore immaterial to the estimate, they are excluded (see Section 2.5).

The following steps should be followed to estimate mid- and downstream emissions:

**Step 2.1 – Calculating emissions from crude oil refining**

Where data is available, country specific crude oil refining emission intensity figures should be sought. These may be publically available or derived from publically available information sources including:

- National GHG inventory reports and/or National Communications submitted to the UNFCCC;
- Any regional or national sectoral policies which require data to be collected on crude oil refining emissions (for example, the EU ETS or US GHGRP);
- Other relevant data sources where available.

Where absolute numbers on refinery emissions are obtained, these should be divided by data on total crude oil refined or consumption in the relevant jurisdiction, based on internationally recognised information sources (e.g. the BP Statistical Review of World Energy; the US Department of Energy, Energy Information Administration, or the International Energy Agency Statistics).

The results of this analysis should be presented on a $tCO_2$ per barrel basis.

**Step 2.2 – Calculating emissions from end-use**

The IPCC default factor of 73 300 $kgCO_2$/TJ energy content may be used to estimate emissions from the end-use of crude oil products (IPCC, 2006). This equates to 0.46 $tCO_2$/barrel based on 6.3 GJ/barrel oil equivalent. Alternatively, the US EPA employs a figure of 0.43 $tCO_2$/barrel.[1]

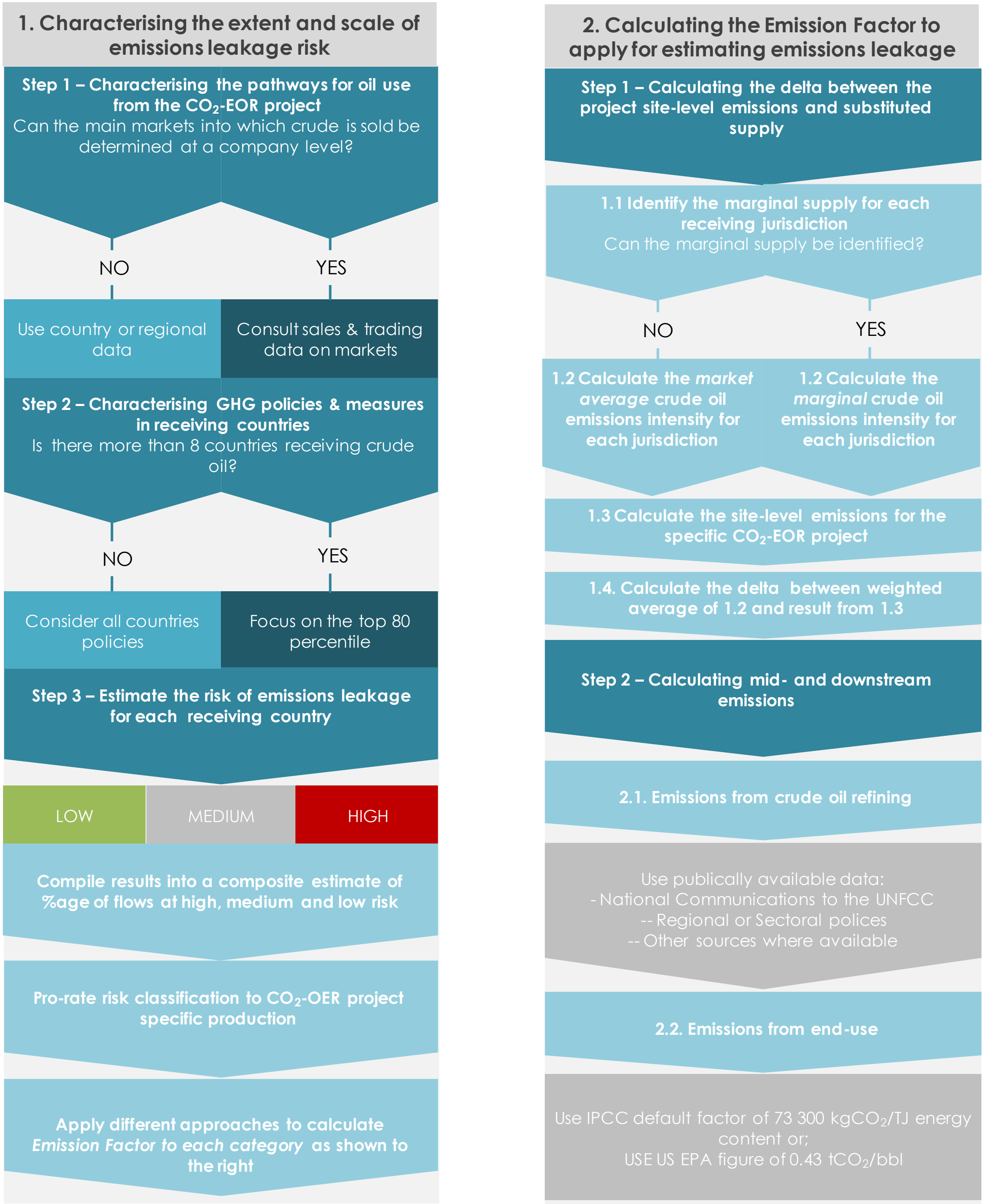
This data should be used to estimate end-use emissions from incrementally-produced crude oil.

The result of Step 2.1 and 2.2 should added together to provide a composite figure for mid- and downstream emissions leakage. In the case of medium emissions leakage risk jurisdictions, the number should be multiplied by 0.5, and added to the result of Step 1.

The various steps described are set out schematically overleaf (Figure 4.2).

[1] From: http://www.epa.gov/cleanenergy/energy-resources/refs.html

**Figure 4.2 Proposed approach to $CO_2$-EOR emissions leakage accounting**




## 4.4 A note on the approach outlined

It is important to note that whilst a procedure has been outlined to calculate the relevant emission factor for emissions leakage relating to substitution of other supplies of crude oil, it will be extremely challenging to implement in practice. This is largely due to a paucity of high quality data with which to compile the analysis. Moreover, since it is likely that substitution effects cannot be readily measured and attributed with any degree of confidence, such an approach might not be considered as *conservative*. As such, it is debatable whether it would stand up to scrutiny as an established MRV or accounting approach to calculate emissions leakage from $CO_2$-EOR activities.

Furthermore, there are general practical challenges in implementing such an approach in terms of obtaining the appropriate data, keeping the data up-to-date over time, and equity issues in terms of potential disparities between the inventory quality and transparency of reporting of crude oil extraction and refining emissions across different jurisdictions around the world. These matters are considered further in Section 5.

**Approaches to $CO_2$-EOR emissions accounting**

**Summary of findings**

A first-pass methodology for calculating emissions leakage risk is presented, covering several steps:

- Firstly, the characteristics of oil supply from the country hosting the $CO_2$-EOR activity needs to be analysed. This is used to determine the range of jurisdictions using the incrementally-produced oil, and the emissions leakage risk for each country, classified in terms of low, medium and high risk.
- Secondly, the volume of oil received by each jurisdiction in each risk category should be calculated. The relative percentage of produced oil delivered to each risk category should be established. This provides the basis for pro-rating and allocating production from a $CO_2$-EOR activity to each leakage risk category (i.e. low, medium, high).
- Thirdly, for jurisdictions at either low or medium risk of emissions leakage, the delta between the site-level emissions associated with the $CO_2$-EOR project and the emission from crude oil extraction for either: (i) the marginal supply, *or* (ii) the average market supply, is calculated. This should be calculated for each jurisdiction in order to establish a weighted average crude oil extraction emissions intensity. The choice of approach depends on whether it is possible to identify the marginal supply for a given jurisdiction or not. The difference between the two provides an estimate of emissions leakage from $CO_2$-EOR, which may be negative where more emissions intensive supply sources are substituted. For countries with a medium risk of emissions leakage, the result should be multiplied by 0.5 to reflect the uncertainty regarding whether substitution of supply is occurring i.e. only half of any emission reduction benefit is attributable.
- Fourthly, mid- and downstream emissions associated with refining and end-use of crude oil and products should be calculated for jurisdictions at medium and high risk of emissions. In the case of countries at a high risk of emissions leakage, this provides the basis for quantifying the risk. For countries with a medium risk of emissions leakage, the result should be multiplied by 0.5 to reflect the uncertainty regarding whether addition to supply is occurring.
- For countries at medium risk of emissions leakage, a combined approach to quantifying emissions leakage risk is proposed, consisting 50% of any benefits of substituting more emissions intensive oil supplies and 50% of the risk of unmitigated increases in mid- and downstream emissions.

# 5 Conclusions

## 5.1 Summary of findings

The analysis undertaken can be used to draw a number of conclusions about emissions accounting for $CO_2$-EOR. These are as follows.

Most jurisdictions around the world that recognise emission reductions from CCS apply the same incentive for storing $CO_2$ as part of $CO_2$-EOR operations. This includes the EU Emissions Trading Scheme, and potentially the Clean Development Mechanism. In the US, $CO_2$ stored as part of a $CO_2$-EOR operation can be reported as geologically sequestered if the appropriate monitoring techniques are employed, whilst other parts of the Greenhouse Gas Reporting Programme allow for emissions accounting of various site level emissions. The one exception is the California ETS, which does not yet have a recognised monitoring methodology in place to allow for CCS to be included in the scheme. Approaches are under development to support improved emissions reporting of CCS and $CO_2$-EOR in Australia.

Each scheme sets out specific rules for quantifying $CO_2$ emissions (and emission reductions) arising from $CO_2$-EOR site level operations. These are summarised in Annex B.

Problematically, there is a paradox presented by, on the one hand, incentivising $CO_2$ storage through $CO_2$-EOR, and on the other, increasing oil production. This may not be an issue if the incrementally-produced oil from $CO_2$-EOR *substitutes* and *displaces* similar or more emissions intensive sources of crude oil supply. However, in some cases the incrementally-produced crude oil may simply *add* to overall supply, which could potentially increase oil use and lead to carbon lock-in over the longer-term. Gaining a full insight into whether substitution or addition takes place requires a deep analysis of oil markets and in particular demand and supply price elasticity – the literature on the matter is somewhat unclear, with indications being that the price elasticity of demand is high, whereas others argue that the price elasticity of supply low, which serves to constrain increases in oil consumption. Further challenges to this view arise due to political interventions in oil markets.

Where incrementally produced oil *adds* to overall supply, this can be considered as a form of emissions leakage, on the basis that a carbon price incentive for $CO_2$-EOR is driving emissions increases elsewhere outside of the immediate physical boundaries of the $CO_2$-EOR activity. Conversely, where more emissions intensive supply is substituted and displaced, this can be considered to be a type of *negative* emissions leakage (i.e. leakage resulting in a net overall reduction in emissions).

Given the high levels of complexity involved, a proxy measure of assessing emissions leakage risk is provided by the stringency of GHG emission controls present in jurisdictions using the incrementally-produced oil. Where stringent emissions controls are in place, it is reasonable to assume that supply of new sources of oil will only substitute existing supplies because the GHG policies and measures in place, in theory, restrict the scope for more oil to be burned. The corollary of this is that for jurisdictions with weak or non-existent GHG emissions controls, it is likely that new supplies will add to the overall supply base.

A broad analysis of emissions leakage risk using this approach suggested that 23% of global oil flows are at low risk of emissions leakage, 29% are at medium risk, and 46% are at high risk. This only considered international trade flows and not domestic production and consumption.

In terms of materiality, the greatest risk is from unmitigated increases in end use, which account for between 60-85% of the life-cycle well-to-wheels (WTW) emissions for petroleum/gasoline (based on US data). Refining accounts for around 10% of WTW emissions and transport around 2-3%. Differences in emissions from crude oil extraction may account for up to 17% of the overall WTW emissions associated with petroleum/gasoline. When considering the possibility of negative emissions under scenario's involving substitution, the latter can be considered to be material to the debate. More pertinent, however, is the possibility of refining and end-use emissions increasing on an unmitigated basis if policies and measures are not in place to control emissions from such activities. This could represent a significant source of emissions leakage.

There are significant challenges to developing a methodology for estimating and quantifying emissions leakage for $CO_2$-EOR operations. These include:

- Uncertainties regarding whether *substitution* or *addition* to oil supply is occurring;
- Whether substitution would actually displace marginal oil supply, or whether other sources of supply would be displaced. And as such, it is unclear which crude oil extraction emission intensity factor to compare $CO_2$-EOR against;
- Whether an assessment, and comparison, of GHG policies and measures can provide a suitably robust indication of emissions leakage risk;
- Availability of data from which to quantify the various components of an emissions leakage risk estimate.

Notwithstanding these challenges, a first pass methodological approach is outlined. This should be used only as a basis for further debate and consideration on the matter, rather than as a definitive view on the matter.

## 5.2 Issues for further consideration

Whilst this paper has set out a range of arguments regarding the risk of emission leakage from $CO_2$-EOR in terms of, *inter alia*, whether and when it could occur, the likelihood and materiality of it occurring and subsequently how it may be accounted for, further discussions are required to identify the full range of issues involved in providing carbon price incentives for the technology. This includes engaging with policy-makers at various national, regional and international levels, and industry and non-governmental organisations. There may be other concerns and conceptual ideas that have not been indentified and addressed in this report.

Furthermore, given the potential complexities involved in indentifying emission leakage risk and subsequently quantifying it, it will also be important to consider the full range of political, regulatory and practical challenges presented by the approaches outlined. These include:

- *Complexity versus workability* – whilst it may be possible in some circumstances to calculate the relative emission reductions benefits arising from substituting certain types of crude oil supply, there are also significant challenges to doing so in terms of data collection and analysis. Therefore, even if issues of emissions leakage are of concern to policy-makers, any action to address them will need to be carefully thought through to ensure that they can be applied in practice. For example, in the CDM, concerns were raised over emissions leakage from capturing and utilising natural gas that was previously flared; however, most recent revisions to the methodology now do not include any requirements to account for emissions leakage. This is because of uncertainties about whether the effects could actually be readily identified and quantified.
- *Administrative challenges* – if for example, a methodology for calculating emissions leakage risk from $CO_2$-EOR activities is introduced in the EU ETS, it is likely to present significant effort for implementation. This could include presenting member states with the requirement to provide information on all oil imports and export pathways, and the crude oil extraction emissions intensity of each source. On the other hand, member states are already collecting similar information for the purpose of implementing Article 7(a) of the EU Fuel Quality Directive (FQD) regarding the life-cycle GHG emissions intensity of fuels sold in EU markets. It would likely add to the complexity of verifications for installations undertaking $CO_2$-EOR under the scheme.
- *Equity and fairness*– one of the challenges highlighted in implementing Article 7(a) the EU FQD has been concerns over the asymmetry of data availability, and therefore the subsequent treatment of different fossil fuels regulated by the scheme. For example, the Government of Alberta and the Canadian Federal Government have expressed reservations about the treatment of oilsand syncrude under the scheme compared to other sources of crude oil, claiming that it is being punished as a result of transparent reporting of GHG emissions in the country relative to other jurisdictions (e.g. see Oliver, 2013).
- *Likelihood of success* – based on these considerations, it is debatable whether approaches to determining emissions leakage from $CO_2$-EOR would have much near-term success in gaining successful approval by regulators (e.g. the European Commission or CDM Executive Board). It is likely that further consultations will be needed to determine a clear view on the matter.

In terms of the methodological approach outlined in Section 4, it will be important to test the proposed approach in a real world setting for an actual project in order to gain a better view on whether it is workable, how practical it is to implement, its limitations and any revisions that may be needed.

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# **Annex A** – Summary of GHG schemes and accounting rules reviewed

| Scheme | Description | GHG Accounting / MRV Rules |
|---|---|---|
| UNFCCC reporting of national GHG inventories | Under the UNFCCC, all Parties must develop, periodically update, publish and make available to the Conference of Parties (COP), national inventories on GHG emissions and removals by sinks using comparable methodologies as agreed by the COP (*Articles 4* & 12). Reporting requirements vary between Parties: Annex I Parties are obliged to annually report national GHG inventories of anthropogenic emissions and removals by sinks in a common reporting format (CRF): non-Annex I Parties are only required to report periodically. Since COP17, both Annex I, and all but the Least Developed Countries and small island states non-Annex I Parties are obliged to report biennial updates of National Communications, including national GHG inventories. | The Intergovernmental Panel on Climate Change (IPCC) is mandated by the COP to develop appropriate national GHG inventory compilation guidelines. Currently three guidelines are applicable in the first commitment period of the Kyoto Protocol (CP1; 2008-2012), namely the:<br>• Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories (1996 GLs)<br>• IPCC Good Practice Guidance and Uncertainty Management in National Greenhouse Gas Inventories (2000 GPG)<br>• IPCC Good Practice Guidance for Land Use, Land Use Change and Forestry (2003 GPG LULUCF)<br>In the future (likely applicable from 2015 onwards during Kyoto Protocol CP2, 2013-2020), Annex I Parties will need to use the *2006 IPCC Guidelines for National Greenhouse Gas Inventories* (2006 GLs) and also publish Biennial Reports using a CRF. In addition, Biennial Update Reports containing national inventories following the 1996 GLs, the 2000 GPGs and the 2003 GPG LULUCF is encouraged for non-Annex I developing countries Parties from December 2014, excluding the least developed country Parties. Scope for future reporting by non-Annex I Parties using 2006 GLs is also foreseen.<br>The 2006 GLs outline a modified approach to inventory compilation compared to the 1996 GLs, which followed the Kyoto Protocol CRF (see left). The 2006 GLs are organised as follows:<br>Vol 2: Energy (CRF 1)<br>Vol 3: Industrial Processes and Product Use (CRF 2 & 3)<br>Vol 4: Agriculture, forestry and land use (AFOLU; CRF 4 & 5)<br>Vol 5: Waste |
| Kyoto Protocol compliance with assigned amounts and IET | The Kyoto Protocol sets quantified emission limitation or reduction obligations (QELROs) for Annex B Parties, which are measured in assigned amount units (AAUs) equal to 1 $tCO_2$-e; AAUs are determined by the country's national GHG inventory. It is essentially a *GHG cap-and-trade scheme*, with AAUs being tradable between Annex B Parties. "Offset" units from the project-based CDM and JI may also be used to meet compliance requirements (see below). Annex I Parties may also issue Removal Units (RMUs; equal to 1$tCO_2$-e) where there is a net increase in the carbon stock of the relevant sink from Land Use, Land Use Change and Forestry (LULUCF) activities under Article 3.3 and 3.4 of the Protocol. RMUs can be used towards compliance with QELROs. National GHG inventories under the KP must be reported in accordance with the CRF by sectors covering:<br>Sector 1 – Energy (fuel combustion; fugitive emissions)<br>Sector 2 – Industrial Processes<br>Sector 3 – Solvents and other product use<br>Sector 4 – Agriculture<br>Sector 5 – LULUCF<br>Sector 6 – Waste<br>Sector 7 – Other<br>A range of supplementary information must also be provided, e.g. for LULUCF. | |
| Kyoto Protocol clean development mechanism (CDM) | The CDM is a *project based mechanism*. Under the Kyoto Protocol, Parties with a QELRO may acquire Certified Emission Reductions (CERs) from CDM projects undertaken in developing countries. CERs, which equal 1$tCO_2$-e, can be used towards a Party's reduction target, and as such act as an "offset" mechanism by reducing the Party's obligation to reduce emissions domestically.<br>In the EU, the approach has been privatised to an extent by allowing regulated entities in the EU ETS to surrender CERs towards their obligations. | The CDM modalities and procedures (CDM M&Ps) is the rulebook for CDM (UNFCCC, 2005). It sets out, *inter alia*, governance, participation, verification requirements for CDM projects. To date, four CDM M&Ps have been established for different project types, including specific M&Ps for Afforestation/Reforestation and CCS (CCS M&Ps). At a project level, specific *Approved Methodologies* (AMs) must be developed according to the M&Ps that set out the project-type specific GHG accounting rules, the basis for calculating the CERs generated by a project. The approach to implementing the AM for a project must be set out in a Project Design Document (PDD), which must be submitted to the CDM Executive Board for *Registration*. |
| EU GHG emissions trading scheme (EU ETS) | The EU ETS implements a *GHG cap-and-trade scheme* across the EU-27 plus 4 non-EU countries, covering more than 11,000 large GHG emitting installations such as power stations, cement plants, steel works etc. Allowances (EUAs) are auctioned by the EC, with certain trade exposed sectors receiving a free | Regulation No. 601/2012 on monitoring and reporting (the "MRR") sets down rules for MRV for qualifying installations in Phase III of the scheme.<br>The EU CCS Directive establishes a legal framework for the environmentally safe geological storage of $CO_2$ in the EU-27, which includes MRV requirements for $CO_2$ |

| Scheme | Description | GHG Accounting / MRV Rules |
|---|---|---|
| | allocation against a benchmark. It is currently in Phase III, running 2013-2020.<br>ERUs from JI and CERs from the CDM may be used for compliance purposes, subject to EU enforced *quantitative* and *qualitative* restrictions on certain types of CERs e.g. large hydro; afforestation/reforestation; industrial gas projects are all banned, whilst CERs from projects registered *after* December 2012 are only eligible when located in a Least Developed Country or country with a bilateral agreement with the EU (none of the latter yet exist). | storage sites in the EU, and underpins inclusion of CCS in the EU ETS. |
| US EPA GHG Reporting Program (GHGRP) – 40 CFR Part 98 | The US EPA GHGRP is designed to help the EPA better understand sources of GHGs to help make informed policy, business, and regulatory decisions. Any facility in the US which emits > 25 kt$CO_2$-e/year is required to annually report its emissions of relevant gases. Presently nearly 8,000 facilities in the US are reporting GHG emission under the rule. *NOTE: the GHGRP covers only reporting requirements, and does not impose caps or reduction targets on facilities.* | The GHGRP has a wide number of subparts which set out the accounting rules applicable to different GHG emitting facilities (see *Table B-1* below). Two subparts pertain directly to $CO_2$ storage activities: subpart RR and subpart UU.<br>Only subpart RR allows amounts of $CO_2$ injected to be reported as sequestered, and applies to wells regulated under the US EPA UIC Class VI, which also includes extensive provisions relating to MRV for $CO_2$ storage sites. Subpart UU requires only the amounts of $CO_2$ received to be reported; it does not allow operators to claim a $CO_2$-EOR operation as a "non-emissive end-use". EOR operators may report under subpart UU, or opt-in to report under subpart RR. In cases of the latter, a UIC Class VI well permit must be obtained. |
| California Emission Trading Scheme | Assembly Bill (AB) 32 – the Global Warming Solutions Act – sets down the basis for a *GHG cap-and-trade scheme* in the US State of California. It applies to a range of activities including power plants, refineries, cement kilns and various other industrial plants that emit >25 kt$CO_2$-e/year in the State, covering around 350 installations. The scheme involves the use of auctioning and free allocation to distribute the trading units (California GHG Allowances) in the cap. It includes provisions for linkages (none are yet established) and allows the use of offsets from various domestic schemes, such as Forest and Livestock Projects, as well as projects developed by Air Resources Board (ARB)-approved Offset Project Registries: currently the American Carbon Registry (ACR) and the Climate Action Reserve (CAR). Credits from these registries must be converted to ARB-approved units for use in the ETS. | MRV rules are set out in California Code or Regulation, Title 17, Division 3, Chapter 1, Subchapter 2, Article 2: Mandatory Greenhouse Gas Emission Reporting. This includes a range of provisions including MRV rules for 'Carbon Dioxide Suppliers' and guidance on 'Biomass derived fuels'.<br>The ACR and CAR have so far established around 30 offset methodologies covering a range of activities. The ACR recently approved an offset methodology for *CCS in Oil and Gas Reservoirs*, although this will not be able to directly link to the California ETS until approved by the ARB. |
| Canada GHGRP | Environment Canada sets down mandatory reporting requirements for facilities emitting >50,000 t$CO_2$ equivalent per year. | Aside from some limited additional guidance for certain types of facilities, measurement and reporting is to be carried out in line with IPCC Guidelines. |
| Alberta Specified Gas Emitters Regulation | Alberta requires facilities that emit more than 100,000 tonnes of GHGs a year to reduce emissions intensity by 12%, as of July 1, 2007.<br>Companies have four choices to be in compliance:<br>• Make improvements to their operations<br>• Purchase Alberta-based offset credits<br>• Contribute to the Climate Change and Emissions Management Fund<br>• Purchase or use Emission Performance Credits<br>Under the Specified Gas Reporting Regulation and associated Standard, facilities emitting in excess of 50,000 tonnes measured in $CO_2$e, based on the sum of direct emissions of $CO_2$, $CH_4$, $N_2O$, HFCs, PFCs, and $SF_6$, must submit a | The Specified Gas Reporting Standard sets out monitoring and reporting requirements for qualifying facilities. It requires that GHG emissions are calculated using methods that are:<br>(a) widely accepted by the industry to which the facility belongs; or<br>(b) consistent with the guidelines approved for use by the UNFCCC for the Preparation of National GHG Emission Inventories by Annex 1 Parties (Decision 18/CP.8), and the annex to that decision contained in FCCC/CP/2002/8.<br>The Alberta-based Offset Credit Systems includes over 30 Approved Quantification Protocols applicable to various emission reduction activities. This includes protocols for $CO_2$-EOR. A draft Quantification Protocol has also been under consideration |

| Scheme | Description | GHG Accounting / MRV Rules |
|---|---|---|
| | specific gas report to the regulator. These reports are used to enforce the emission intensity reduction obligations. | since 2011, for the *Capture of $CO_2$ and Permanent Storage in Deep Saline Aquifers* |
| Quebec cap and trade system | In December 2011 the Quebec Assembly adopted a Regulation respecting a cap-and-trade programme, which commenced on 1 January 2013. It is structured as follows:<br>• First compliance period (2013-2014) electricity generators and emitters >25 kt$CO_2$/year.<br>• Second compliance period (2015-2017) – as for First, plus distribution and importing of fossil fuels and consumption in the transport and building sectors and SMEs. | In Quebec, under the *Regulation respecting mandatory reporting of certain emissions of contaminants into the atmosphere (RRMRCECA)*, large emitters of GHGs have been required to report emissions since 2007. The regulation provides the basis for MRV under the cap-and-trade scheme.<br>The RRMRCECA allows for amounts of $CO_2$ captured and stored to be deducted from a facility's GHG report, thereby recognising CCS as an eligible emission reduction technology under the cap-and-trade system. |
| Australia Carbon Pricing Mechanism (CPM)<br><br>National Greenhouse Gas and Energy Reporting (NGER) scheme | The CPM is a carbon tax that was planned to transition to a *GHG cap-and-trade* scheme for large emission sources in Australia, covering approximately 60% of the country's emissions including electricity generation, stationary energy, landfills, wastewater, industrial processes and fugitive emissions. It involved two stages:<br>• *Fixed price*—The carbon price is fixed for the first three years. In 2012–2013 it is \$23/t$CO_2$-e, in 2013–2014 it is \$24.15/t and in 2014–2015 it is \$25.40/t. Liable entities can purchase units up to their emissions levels. Purchased units cannot be traded or banked.<br>• *Flexible price*—From 1 July 2015 the price will be set by the carbon market, with allocation based on auctioning of units up to a cap set by regulation.<br>A link of the CPM to the EU ETS was planned, also the use of CERs as well as domestic Australian Carbon Credit Units (ACCUs) generated under the Carbon Farming Initiative (CFI). Offset use is restricted to 50% of an entities total liability.<br>**Under the new administration, the CPM was abolished on 1 July 2014.**<br>The NGER also imposes mandatory GHG and energy monitoring and reporting obligations for businesses, irrespective of the abolition of the CPM. | CPM liable entities must monitoring and report emissions to the Clean Energy Regulator under the *National Greenhouse and Energy Reporting Act* (2007) and related implementing provision (e.g. the *National Greenhouse and Energy Reporting Regulations*, 2008; and the *National Greenhouse and Energy Reporting (Measurement) Determination*, 2008 (NGER).<br><br>Projects developed under the CFI are required to develop specific GHG accounting methodologies, which are subject to approval by an appointed Board, in a similar ways as for CDM.<br><br>Under the NGER, all businesses must measure and reporting emissions where the following thresholds are exceeded:<br>• Emitting >25,000 t$CO_2$e/yr<br>• Consuming > 25,000 MWh/yr of electricity; and/or<br>• Consuming >2.5 million litres of fuel/yr |
| | | |

# **Annex B** – GHG accounting requirements for $CO_2$-EOR under different schemes

The purpose of this Annex is to outline how existing GHG emissions accounting rules, as applicable under various policies and measures that incentivise the deployment of $CO_2$-EOR as a climate mitigation technology, account for all relevant emissions sources across a $CO_2$-EOR value chain. The analysis does not consider GHG accounting rules for the capture, transport or geological storage of $CO_2$, as these have been widely covered elsewhere in the literature (e.g. see Zakkour, 2005; Zakkour 2007; Zakkour and Cook, 2014; Jaramillio, 2009). Rather, the focus is on understanding whether the existing GHG accounting rules effectively determine a true, credible and realistic estimate of the net emissions attributable to a $CO_2$-EOR operation. The GHG policies and accounting rules covered by the review are summarised in Annex A. Each scheme's rules are reviewed in the context of the following $CO_2$ emissions sources:

- Site-level operational emissions
  - Indirect emissions related to the use of bought-in electrical energy
  - Additional energy use for oil recovery
  - Fugitive emissions related to surface infrastructure
  - Seepage emissions related to leakage from the storage complex
- Mid- and downstream emissions
  - Transport of incrementally-produced crude oil and refined products (midstream)
  - Refining emissions (midstream)
  - Emissions associated with the end use of product (downstream)

## B-1 INTERNATIONAL – IPCC GHG GUIDELINES

Under the UNFCCC, all Parties must employ comparable methodologies to compile national inventories of anthropogenic GHG emissions to atmosphere and removals by sinks, and report these to the Conference of the Parties (COP). The methodologies are produced by the Intergovernmental Panel on Climate Change (IPCC; see Annex A), the latest version being the *2006 IPCC Guidelines for National Greenhouse Gas Inventories* (IPCC, 2006; "2006 GLs"; see Annex A). The 2006 GLs are expected to be binding for Annex I Parties to the UNFCCC from 2015.[1]

The 2006 GLs introduced GHG accounting approaches for CCS in national GHG inventories for the first time, thereby allowing $CO_2$ to be deducted from the sector inventory totals where it is captured and geologically stored, as long as the site is monitored in accordance with 2006 GLs, *Volume 2, Chapter 5: Carbon Dioxide Transport, Injection and Storage*. This applies equally to $CO_2$ geologically stored through $CO_2$-EOR, provided that all related emissions sources are accounted for following guidelines in the 2006 GLs. As a result, countries with QELROs under the Kyoto Protocol are effectively allowed to deploy CCS and/or $CO_2$-EOR technologies as a means to meet their target.[2]

Under the 2006 GLs, monitoring and estimation of all emissions from $CO_2$-EOR site-level operations would need to be included in a country's national GHG inventory using methods under the various source categories as follows:

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[1] Subject to the conclusion of a work programme by the UNFCCC that started in 2010.
[2] Although Norway has been reporting amounts of $CO_2$ stored at its Sleipner CCS facility in its national GHG inventory since 1996 following the 1996 IPCC Guidelines and recording it as a memo item.

- On site fuel use: *Volume 2, Chapter 2: Energy*
- Flaring, venting and other fugitive emissions (e.g. equipment leaks): *Volume 2, Chapter 4: Fugitive Emissions*.
- Emissions of $CO_2$ leaking from the geological storage site: *Volume 2, Chapter 5: Carbon Dioxide Transport, Injection and Storage*

Similarly, activities involving the transporting, refining and end use of incrementally produced oil should also generally be included in a country's national GHG inventory irrespective of the process or sector in which it is used, and compiled in accordance with various volumes of the 2006 GLs. For example, any combustion emissions associated with refining are covered using methods outlined in *Volume 2, Chapter 2: Energy*. Similarly, fugitive emissions from refining, transport, loading or offloading of oil is covered under *Volume 2, Chapter 4: Fugitive Emissions*, and end use emissions in the transport sector under *Volume 2, Chapter 3: Mobile Combustion* or *Volume 3: Industrial Processes and Product Use* for various industrial uses of oil.

As a result, the various relevant chapters provide guidance for an inventory compiler at a national level as to how to produce full estimates of all GHG emissions from $CO_2$-EOR activities – both site-level and downstream.[1] This means that countries facing QELROs should, in principle, be taking actions to address these emissions, and as a result, the scope for emissions leakage to occur is eliminated. However, this applies only where the oil is produced, refined and used in countries with QELROs. Given the differential requirements and the differential status of participation in the second commitment period of the Kyoto Protocol, issues arise in respect of GHG accounting for $CO_2$-EOR where transboundary movements of crude oil and products occur between countries facing differential obligations. This issue was discussed in Section 2 of this report.

It is also important to note that there is scope for *cross-sectoral* emissions leakage to occur within countries with QELROs. Although the 2006 GLs set down approaches for calculating emissions arising from international marine and aviation bunker fuels in national GHG inventories of Parties, these emissions should be *excluded* from national totals, reported separately, and are *not* subject to QELROs of Annex I Parties under the Convention and the Kyoto Protocol.[2] This is because they take place in international waters and airspace, and therefore are not attributable to any single Party. The Kyoto Protocol mandates signatory Annex I Parties to work with the International Maritime Organisation (IMO) and the International Civil Aviation Authority (ICAO) to pursue emissions limitation or reduction efforts for emissions from marine and aviation bunker fuels respectively. Despite several efforts to date, little progress on the matter has been made by the IMO or ICAO.

## B-2 UN Clean Development Mechanism

The UN Clean Development Mechanism (CDM) is a project-based emissions trading scheme that allows emission reduction credits to be generated for projects that reduce emissions in developing

[1] Note the US EPA National Inventory Report (EPA, 2014) includes a source category 2B5 covering "Carbon Dioxide Consumption". This source category is generally reserved for "Other" emission sources in the Chemical Sector.
[2] From: http://unfccc.int/methods/emissions_from_intl_transport/items/1057.php

countries (see Annex A). Although GHG accounting rules for CCS projects have been agreed under the CDM (UNFCCC, 2011), no relevant project-type methodologies have been developed.

Under the CDM, the project boundary defines the emissions that must be included when calculating the emission reductions achievable by the project. It is defined as encompassing:

> *"…all anthropogenic emissions by sources of greenhouse gases under the control of the project participants that are significant and reasonably attributable to the CDM project activity"* (UNFCCC, 2005)

Consequently, any CDM methodology developed for $CO_2$-EOR would be required to include a monitoring methodology to measure and calculate project emissions for all emissions from $CO_2$-EOR site level operations covering bought-in electricity, onsite electricity generation and vented and fugitive emissions etc.

Since CDM projects take place exclusively in developing countries with limited economy-wide policies and measures to control emissions, emissions leakage has been a major concern for CDM policy-makers. Leakage emissions under the CDM are defined as:

> *"…the net change of anthropogenic emissions by sources of greenhouse gases which occurs outside the project boundary, and which is measurable and attributable to the CDM project activity"* (UNFCCC, 2005)

Based on this definition, the question of whether mid- and downstream emissions arising from incrementally produced oil should be accounted for is dependent on the terms "measurable" and "attributable". The CDM Executive Board has attempted to further define these terms as:[1]

- Measurable = "which can be measured"
- Attributable = "directly attributable"

The main body of this report has extensively considered the scope for measuring and attributing mid- and downstream emissions from $CO_2$-EOR and may be used to inform discussions in these contexts.

## B-3 EUROPEAN UNION

All 28 Member States of the European Union will ratify the second commitment period of the Kyoto Protocol, and are therefore bound by QELROs imposed under the amendments to the Kyoto Protocol agreed at the Doha Climate Change Conference in 2012. In complying with these requirements, all Member States are obliged to follow IPCC Guidelines in compiling national GHG inventories, as described above (Section 0).

In addition, since 2005, the EU has imposed a regional GHG emissions cap-and-trade scheme for operators of installations that are major point sources of GHG emissions in the European Union (the EU ETS; see Annex A). Since the EU ETS is designed to help Members State governments meet their obligations under the Kyoto Protocol, the MRV requirements of the scheme are designed to be

[1] 5th Meeting of the CDM Executive Board, Annex 3, para. 10(d).

consistent with IPCC Guideline requirements so that emission reductions achieved under the scheme may be recognised in national GHG inventories.

The EU ETS Monitoring and Reporting Regulation (MRR) sets out how GHG emissions from qualifying installations are to be monitored, and includes MRV rules applicable to both CCS and $CO_2$-EOR. These set out requirements for monitoring all relevant emission from $CO_2$-EOR site level operations, including:

- Amounts of $CO_2$ injected;
- Amounts of $CO_2$ vented, including any $CO_2$ entering a flare or dedicated $CO_2$ purge system;
- Fugitive emissions of $CO_2$, including from oil-gas separation units (this can include breakthrough $CO_2$ that returns to the production well dissolved in oil); and
- Emissions of $CO_2$ leaking from the geological storage site.

Under the EU ETS, the scheme boundaries are defined by the physical limits of the qualifying installation. Therefore, all mid- and downstream emissions associated with incrementally produced oil from a $CO_2$-EOR operation could potentially lead to emissions leakage, as they fall outside of this boundary. However, the possibility of emissions leakage is dependent on the market into which the crude oil or product is sold. Where the crude oil is refined in EU refineries or used in EU industry (e.g. in petrochemical production), the mid- and downstream emissions associated with refining and manufacturing would be covered under the EU ETS as refineries and most large industrial installations are qualifying installations under the scheme. Where refined products are sold in the EU, then downstream emissions from road transport and aviation would also be covered by regulation. In the case of the former, the EU's emission performance standards for cars and vans and $CO_2$ labelling of cars would apply, whilst the aviation sector is now included under the EU ETS. Emissions arising from the use of incrementally-produced crude oil in marine shipping are not covered by regulations in the EU.

Regarding imported fuels, the EU Renewable Energy Directive (RED) and the related EU Fuel Quality Directive (FQD) amendments require entities importing crude oil and refined products into the EU to take account of upstream and midstream emissions arising in their production. These regulations act as an anti-leakage border adjustment measure by requiring operators to account for emissions from operations in the fuel cycle value-chain occurring outside of the EU.

## B-4 UNITED STATES (FEDERAL)

The United States has not ratified the Kyoto Protocol and is therefore not bound by any QELROs thereunder; it must report emissions to the UNFCCC following IPCC Guidelines as set out previously (Section 0). The development of national policies to regulate GHGs has been a challenging subject in the US, although in June 2014 The US Environmental Protection Agency (EPA) announced the Clean Power Plan regulations to reduce GHG emissions from existing electricity production facilities in the US. Further, it has also proposed Carbon Pollution Standards for New Power Plants.

Although the US EPA only recently introduced federal regulations that mandate emission reductions in the power sector (the Clean Power Plan, 2014), the EPA passed the *Greenhouse Gas Reporting*

*Program* (GHGRP) rule several years ago, which requires facilities to measure and report GHG emissions (see Annex A). It sets out differential requirements for operators of $CO_2$-EOR operations, based on applying either *Subpart RR* or *Subpart UU* of the rule.

Under *Subpart RR - Geologic Sequestration of Carbon Dioxide* – operators injecting anthropogenic $CO_2$ including for the purpose of $CO_2$-EOR may report the amounts of $CO_2$ *geologically sequestered*, where:

1. The owner or operator injects the $CO_2$ stream for long-term containment in geological formations and has chosen to submit a proposed monitoring, reporting, and verification (MRV) plan to the EPA and received an approved plan from the EPA.
2. The well is permitted as Class VI under the Underground Injection Control program.

Where this option is not taken, operators must report emissions relating to $CO_2$-EOR operations following *Subpart UU* (see below). Operators adopting *Subpart RR* are required to apply the following to estimate emissions from $CO_2$-EOR site level operations:

- Mass of $CO_2$ injected and emissions from geological storage leaks: *Subpart RR*
- Emissions from site electricity or heat generation: *Subpart C – General Stationary Fuel Combustion Sources.*
- Other site level emissions such as flares, vents and fugitive emissions (equipment leaks): *Subpart W – Petroleum and Natural Gas Systems*.

As such, operators reporting under *Subpart RR* would be required to report all site level emissions.

Operators of $CO_2$-EOR sites reporting under *Subpart UU – Injection of Carbon Dioxide* – must report only the amounts of $CO_2$ received, and are exempted from any other emission reporting requirements such as those under *Subpart RR* and from fuel combustion (under *Subpart C*) and other site level emissions (e.g. under *Subpart W*). Operators employing Subpart UU cannot claim emission reductions from geological sequestration of $CO_2$.

In terms of mid- and downstream emissions, petroleum refineries and other large industrial facilities are required to report under the GHGRP (e.g. under *Subpart MM* and *Subpart X*). However, since the US is not subject to economy-wide restrictions or QELROs under the Kyoto Protocol, all mid- and downstream emissions may pose the risk of emissions leakage unless they are used in regulated jurisdictions (e.g. California). This absence notwithstanding, it is important to note that:

- The US, under a set of complex rules, bans the export of crude oil, although the export of refined products does occur. This means that the scope for leakage to occur due to downstream emissions outside of the US is limited.
- The US imposes various regulations to reduce emissions from road transport, including the US *Corporate Average Fuel Efficiency* (CAFE) standards for vehicle manufacturers and importers.
- Various State-level measures are being taken to reduce GHG emissions, including in California (see below).

As such, the scope for emissions leakage to occur from incrementally produced crude oil $CO_2$-EOR in the US is somewhat nuanced by the confined nature of the market.

## B-5 US (STATE)

In addition to the US Federal rules described above, several States have enacted policies and regulations aimed at cutting GHG emissions.

California has established a state-wide GHG cap-and-trade programme covering around 350 entities that emit over 25,000 t$CO_2$ per year (C-ETS; see Annex A). Presently the use of CCS, and therefore $CO_2$-EOR, is not a recognised emission reduction technology under the scheme on the basis that no California Air Resources Board (ARB)-approved CCS *"quantification methodology that ensures that the emissions reductions are real, permanent, quantifiable, verifiable, and enforceable"* is in existence.[1]

This exclusion notwithstanding, the C-ETS imposes obligations on operators to monitor all emission sources from "Petroleum Systems" (CCR Title 17, Chapter 10, Art. 2, Subarticle 5) as well as refineries as "Suppliers of Transportation Fuels" (CCR Title 17, Chapter 10, Art. 2, Subarticle 2, §95121), and would therefore cover most emissions sources associated with $CO_2$-EOR, were it to be included as a recognised emission reduction technology.

The C-ETS also allows for the use of offset credits for compliance (see Annex A). The American Carbon Registry (ACR) includes a methodology for *CCS in Oil and Gas Reservoirs*, which requires operators to monitor and report all site-level GHG emission sources, including bought-in electricity, onsite electricity generation and fugitive emissions.

For midstream and downstream emissions, the ACR requires that "leakage emissions" be taken into account, defined as:

> *"…a decrease in sequestration or increase in emissions outside project boundaries as a result of project implementation"* (ACR, 2010);

Incrementally-produced crude oil in projects adopting the *CCS in Oil and Gas Reservoirs* methodology could potentially form such a source of emissions leakage. However, the methodology does not propose any methods to take account of such emissions, but suggests that:

> *"In this methodology, the project boundary is intentionally drawn broadly to avoid unaccounted emissions associated with capturing and storing $CO_2$. Specifically it covers the full CCS value chain, including emissions from $CO_2$ recovery and re-injection operations at enhanced oil and gas recovery sites"*

The absence of emissions leakage accounting may be to an extent correct since, under a range of complex legal rules, crude oil exports from the US are prohibited. As such, midstream and potentially downstream emission associated with $CO_2$-EOR projects using the ACR methodology would take place in the US. A lifting of this ban is currently being discussed in the US Government, whilst the export of refined products is not prohibited. However, the absence of economy-wide controls on GHG emissions across most of the US means that these emissions may occur unrestricted or unaccounted for.

[1] CCR Title 17, Subchapter 10, Article 5. §95852(g).

In terms of imported fuels, the California Low Carbon Fuel Standard requires entities importing crude oil and refined products into the State to take account of upstream and midstream emissions arising in their production. These regulations act as an anti-leakage border adjustment measure in the same way as the EU RED/FQD, as described above.

The US Regional Greenhouse Gas Initiative (RGGI) is a cap-and-trade scheme applicable to electricity generators in the states of Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont. It began operation in 2009. As the scheme is only applicable to electricity generation, and of the participating states only New York has some small oil production, further consideration of emissions from $CO_2$-EOR is not covered in this report.

## B-6 CANADA (FEDERAL)

Canada originally ratified the Kyoto Protocol in 2002, although later withdrew in 2011 before the end of the first commitment period. It has also stated its intention not to participate in the second commitment period to 2020. As such, it is not subject to QELROs thereunder.

Several regulations to control emissions of GHGs have been introduced at a Federal level, including a target to restrict emissions of GHGs from fossil fuel fired power generation for new units commissioned after July 1 2015[1], and a mandatory GHG Reporting Program (GHGRP). The former recognises the role that CCS can play in meeting the target, whilst the latter inherently recognises CCS and $CO_2$-EOR through the general application of IPCC Guidelines or other relevant guidelines to calculate GHG emissions (see Annex A). The Federal government provides only limited additional specific guidance for GHG accounting and MRV under the GHGRP. As such, $CO_2$-EOR site level operational emissions, and mid- and downstream emissions would be monitored and reported following the approach described previously (Section 0).

The Federal government has set emission limits for passenger vehicles, light trucks and heavy-duty vehicles. This means that in theory the risk of emissions leakage from downstream emissions in these sectors is limited by such restrictions. Canada is, however, a major exporter of crude oil, principally to the US.

## B-7 CANADA (PROVINCIAL)

At a Provincial level, various actions have been taken to reduce GHG emissions from large point source emissions including:

- Alberta – the Specified Gas Emitters Regulation and GHG Reporting Program (see Annex A)
- Quebec – Provincial cap and trade scheme, in operation since January 1, 2013 (see Annex A)
- British Columbia, Manitoba and Ontario – all have signed up to the Western Climate Initiative (WCI)

[1] Proposed *Reduction of Carbon Dioxide Emissions from Coal-fired Generation of Electricity Regulation, 2012*

Under the Albertan Regulations, monitoring is to be carried out using industry or UNFCCC guidelines (see Annex A). As such, the approach to measuring $CO_2$-EOR site level emissions and mid- and downstream emissions described in Section 0 would be applicable.

The Alberta Specified Gas Emitters Regulation allows for the use of offset credits generated under the Alberta-based Offset Credits scheme to be used for compliance with emission reduction targets (see Annex A). Presently, one offset protocol is applicable for EOR, and a proposed protocol for CCS is under consideration. The former sets out monitoring requirements for a wide range of emissions sources from $CO_2$ site-level operations, including flares, vents and equipment leaks. However, neither protocol considers mid- and downstream emissions potentially arising from $CO_2$-EOR, primarily because under the scheme "No Leakage" is an eligibility criterion for projects (AESRD, 2013). Consequently, the Alberta-based Offset Scheme does not provide guidance on accounting for emissions leakage from mid- and downstream emissions potentially arising from such projects.

In Quebec, the RRMRCECA sets down monitoring rules for various GHG emitting activities in the Province (see Annex A). However, Quebec does not have any domestic oil production, and therefore the rules are not considered relevant in the context of GHG accounting for $CO_2$-EOR operations.

## B-8 AUSTRALIA

Australia has agreed to participate in the second commitment period of the Kyoto Protocol, and is therefore bound by its QELRO under the Doha Amendment to the Kyoto Protocol, as agreed in 2012. It also enacted domestic policies to limit emissions of GHGs, the flagship of which was the Carbon Pricing Mechanism (the CPM; see Annex A). However, since a change of administration following elections in September 2013, the present government abolished the CPM on 1 July 2014.[1] Despite withdrawing the CPM, Australia will continue to require mandatory GHG reporting for wide number of entities in accordance with the *National Greenhouse and Energy Reporting (Measurement) Determination, 2008* (the NGER; see Annex A).

The NGER allows for $CO_2$ that is captured for permanent storage to be deducted from a regulated entity's emissions inventory. However, the current version of the regulation does not specifically address emissions from $CO_2$ storage operations. To address this gap the Government issued a proposed amendment in May 2014 (Commonwealth of Australia, 2014.), under which $CO_2$-EOR site level operational emissions, such as flaring, venting and other fugitive emissions, would need to be estimated using the American Petroleum Institute (API) Compendium (API, 2009; specifically section 5-77 and Appendix C).

As the NGER applies to large emitters in the country, midstream emissions from refining of incrementally-produced crude oil taking place in Australia would be subject to reporting under the NGER, and therefore included in the national GHG inventory, and counted towards the country's QELRO under the Kyoto Protocol. Presently the country does not impose any restrictions on vehicle greenhouse gas emissions, meaning that downstream emissions could occur unregulated.

[1] Information from Australia Department of Environment http://www.climatechange.gov.au/

Australia is presently a net importer of crude oil, meaning that the scope for emissions leakage to occur through export of incrementally-produced crude oil to unregulated jurisdictions is limited.

A summary of applicable GHG accounting and MRV rules applicable across each stage of the $CO_2$-EOR value chain is provided below (Table B-1).

## Table B-1 Summary of selected GHG accounting and MRV rules applicable to $CO_2$-EOR

| $CO_2$-EOR value chain element | | | Economy-wide | Sectoral-based | | | | Project-based |
|---|---|---|---|---|---|---|---|---|
| | | | 2006 IPCC Guidelines | EU ETS | US GHGRP | Canada GHGRP* | Australia NGER | CDM/Alberta Offsets/ACR |
| **Site operations** | Site-level operation emissions | Bought in electricity | Stationary Combustion (V.2, Ch.2 - 1A1a) | Combstn of fuel >20MW. MRR Anx. IV | Subpart D – Electricity Generation | Emissions from stationary combustion, venting, flaring, other fugitive emissions, etc. to be reported using methods based on (a) widely accepted industry standards; or, (b) consistent with IPCC Guidelines applicable to Annex I Parties to the UNFCCC. | Covered under the NGER | Covered – based on specific methodological guidance provided under the respective schemes. |
| | | Onsite generation | Stationary Combustion (V.2, Ch.2 - 1A1c ii) | Combstn of fuel >20MW. MRR Anx. IV, §1 | Subpart C – General Stationary Fuel Combustion Sources *(excluded for EOR facilities reporting under Subpart UU)* | | Covered under the NGER | |
| | | Fugitive emissions | Fugitive emissions (V. 2, Ch.4)<br>• Venting (1B2ai)<br>• Flaring (1B2aii)<br>• Others (e.g. equipment leaks etc 1B2aiii) | Combstn of fuel (flares). MRR Anx. IV, §1,D. Geological storage of GHGs. MRR, Anx. IV, §23 (Vented and fugitive emissions from injn & EOR) ($CO_2$) | Subpart W – Petroleum and Natural Gas Systems Subpart RR – Geologic Sequestration of $CO_2$ *(Subpart UU – Injection of $CO_2$, only requires reporting of mass injected)* | | To be covered using API Compendium approaches. Based on proposed modifications to NGER. | |
| | | Seepage | $CO_2$ Trans. Injn. & Stor. (V.2, Ch. 5)<br>• Injection (leaks 1C2a)<br>• Storage (seepage 1C2b) | Geological storage of GHGs. MRR, Anx. IV, §23 (Leakage from storage complex) ($CO_2$ only) | Subpart RR – Geologic Sequestration of $CO_2$ *Subpart UU exclusions apply* | Emissions of "vented formation $CO_2$" to be reported using methods outlined above. | To be covered using API Compendium approaches. Based on proposed modifications to NGER. | |
| **Midstream** | Refining emissions | | Stationary Combustion (V2, Ch.2 - 1A1b). Fugitive emissions (V. 2, Ch.4)<br>• Flaring and venting (as above)<br>• Leaks etc. (1B2aiii4) | Mineral oil refinery. MRR Anx. IV, §2 | Subpart MM – Suppliers of Petroleum Products | Covered as above | Covered under the NGER | May be covered as "leakage" emissions under CDM, but not for Alberta or ACR. (see Section **Error! Reference source not found.**) |
| | Transport emissions (oil and product) | | Mobile Combus'n (V.2 Ch.3)<br>• Water-borne Navigation (1A3d)<br>• Railways (1A3c)<br>• Trucks<br>Fugitive emissions (V. 2, Ch.4) – transport; loading and offloading, pipelines etc. | *Not covered.* | *Not covered.* | *Not covered.* | Partial. Large users of fuel (>2.5 million litres/yr) must monitor and report energy and emissions under the NGER. | May be covered as "leakage" emissions under CDM, but not for Alberta or ACR. (see Section **Error! Reference source not found.**) |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| **Downstream** | End use emissions | Mobile Combustion (V.2 Ch.3)<br>Industrial Process & Product Use (V.4, Ch.1-4) | Most industrial uses covered (e.g. carbon black prod'n; MRR Anx. IV, §15).<br>Aviation covered (MRR Anx. III).<br><br>*Road transport and marine bunker fuels not covered. Some sectoral polices in place to address such emissions.* | Most industrial uses covered (e.g. under Subpart X – Petro-chemical Production).<br><br>*Road transport and marine bunker fuels not covered.*<br>*Some sectoral polices in place to address such emissions.* | Most industrial uses covered.<br><br>*Road transport and marine bunker fuels not covered.* | Most industrial uses covered under the NGER.<br><br>Transport emissions captured in Australian national GHG inventory via NGER reporting, but not directly regulated by the Government. | May be covered as "leakage" emissions under CDM, but not for Alberta or ACR.<br>(see Section **Error! Reference source not found.**) |

* In Alberta, the Alberta-based Offset Credit System also allows for $CO_2$-EOR projects and potentially 'pure' $CO_2$ geologic storage projects to generate credits which may be used for compliance under the Specific Gas Emitters Regulation (see Annex A). Where applicable, to avoid double counting, emission reductions from $CO_2$ capture and geological storage should not be counted in the Specified Gas Report filed by the operator (as required under the $CO_2$-EOR Quantification Protocol for Alberta-based offset credits).

CARBON COUNTS

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