Crude Oil Greenhouse Gas Life Cycle Analysis Helps Assign Values For CO2 Emissions Trading

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Emissions of carbon dioxide are already being assigned monetary values. For example, BP is trading CO2 internally, and Suncor has bought CO2 trading credits across the U.S.-Canada border. There is much other rising activity in the greenhouse gas trading game, even before any real formalizing of the Kyoto agreements has been achieved.

This article concentrates on overall crude oil life cycle greenhouse gas analysis-emissions as the oil is produced from reservoir through refining and final consumption, with a brief look at typical natural gas life cycle analysis. We take no sides on the climate change debate, believing politicians are in control and will set the agenda.

The authors' first major excursion into oil and gas greenhouse gas accounting was in the evaluation and short-listing of over 50 energy efficiency and greenhouse gas mitigation and disposal options for the last stages of feasibility studies for a large oil sands-related project. In that program economics and sulfur dioxide emissions were added to greenhouse gas changes per se to give costs in dollar per metric ton of reduction terms.

At the time, greenhouse gas concerns were just starting to arise, and we were surprised at the high degree of interest by all participants once they were fully aware of the exercise. Many companies are now doing the same type of analysis on all new projects to minimize greenhouse gas emissions where economically feasible.

Stepping up in coverage, the authors developed, with Clearstone Engineering, an assessment of the greenhouse gas attributions of Canadian exports and imports of fossil fuels and major fuel derivatives. In that study the emission cycles stopped or started at the national border. For example, most Canadian gasoline, jet, diesel, and low-sulfur heavy fuel oil exports are produced in eastern Canada from imported crude oil-only the Canadian refinery-related emissions were shown as a charge on the product exports.

Ironically, a significant portion of Canadian electricity exports to the U.S. is based on coal imported from the U.S.-the same situation as with the re-refined products. (In the electricity case, we did make preliminary assessments of emissions due to coal production and transport from the U.S.)

However, the bulk of interest in the crude oil greenhouse gas life cycle has come from the Canadian oil sands operators and prospective operators and from the Canadian Association of Petroleum Producers (CAPP). With oil sands production, a portion of refining emissions are released at the site. There is no residue left in the upgraded synthetic crude with no need for coking or other bottom-of-the-barrel processing even in a region with very little heavy fuel oil markets. The oil sands operators wanted to know how their products compare with conventional crudes in greenhouse gas terms, but only full life cycle analysis will provide answers. Also, the qualities of certain synthetic crudes are being improved and lowering overall life cycle emissions-but by how much?

The term "CO2E"-CO2 equivalent-is the proper one throughout crude oil and natural gas life cycle work. In addition to CO2 it includes the other primary officially recognized greenhouse gases-methane (CH4) and nitrogen oxide (N2O).

Metric tons of CO2E = tons of CO2 + 21 × CH4 + 310 × N2O

"C"-carbon-is often used in lieu of CO2, but we recommend use only of CO2E in all oil and gas activities to ensure that CH4 and N2O are not forgotten. Throughout this article unless otherwise noted, CO2E is the discussion basis.
McC+A approach

The International Standards Organization is developing a series of standards on life cycle analysis. These are rather general as they must cover many other aspects of life cycle analysis than just greenhouse gases and must be applicable to many industrial and consumer sectors of very little or no relevancy to crude oil. Perfluorocarbons, hydrofluorocarbons, and hexafluoride are seldom of any importance in oil and gas and are not part of this analysis. McC+A's methodologies are in general accord, rigorously repeated case to case to provide comparison.

McC+A crude oil life cycle analysis considers the major elements through the trail in as much depth as considered appropriate to meet budget and time constraints. One to two days are needed for each routine analysis using easily obtainable data with more time needed if special production, upgrading, or refining issues are present.

The approaches used in McC+A crude oil life cycle analyses provide reasonably fair comparisons between crudes for a specific product end-use area. Close to reality scenarios are used, but the programming does not pretend to develop fully optimized solutions but consistently developed emission totals for each crude per unit of transport fuels for comparison purposes.

Production (including field upgrading) where applicable, transport of crude to refining, refining, and product combustion are analyzed. Natural gas and electricity purchases are added with appropriate local greenhouse gas factors per unit of input.

Greenhouse gas attributions of exploration, capital facility fabrication and construction, and chemical and catalyst inputs are neglected unless of specific importance.

The pseudo-refinery process scheme for each crude is selected as judged most appropriate for that crude in that market area. Often the specific crude is overlaid on a known crude diet for the particular refinery reflecting actuality, but also to avoid process unit limits when a known refinery is being considered. With crudes shipped in diluted form, diluted crude is assumed processed, then product contributions from diluent are netted out. The gasoline to middle-distillate (G/D) ratio is kept close to projected regional levels (but not precisely balanced case by case).

For the comparison, petrochemicals and lubricating oil operations are avoided as being very refinery-specific. Asphalt production was avoided in all the examples shown here, but we have considered it on occasion (without much impact on life cycle emissions attributable to transport fuels).

Typical examples

Table 1 summarizes seven crude oil life cycle cases (courtesy of oil sand producers and CAPP), all with the final products being consumed in the region encompassing Minneapolis, Chicago, Detroit, and Toronto. The total emissions have all been normalized to a fixed volume of transportation fuels (1 cu m=6.3 bbl).

The analyses all assumed that the “refinery” existed only to produce such transportation fuels with other products as byproducts. Thus, the data of the various cases were normalized to a constant volume of transportation fuels.

In these examples, the production emission data were drawn from surface oil sands operator data (mostly black box but generally vetted with occasional change recommendations) from Clearstone Engineering estimates for Alberta production, North Sea Operators Association data, Carbon Dioxide Information Analysis Center (Oak Ridge) data, and various other sources.

The marine emissions are based on tanker fuel models developed by a marine consultant and former tanker captain who also provides mileage between ports and recommended tanker sizes. The pipelines-related emissions are based on major Canadian pipeline energy input data.

The refinery (and upgrader) modeling used in the life cycle analyses is based on a selected truncated version of McC+A's 70-80 spreadsheet refinery capital planning model program. In certain instances a more complex set of spreadsheets was needed, or special models had to be developed. For example, the Venezuelan heavy crude field and related partial upgrader was modeled from literature data with some help from a co-owner. For Canadian upgraders, clients have been providing data but with McC+A review for reasonableness.

The modeling and presentation formats used in these examples resulted from discussions with many oil sands industry representatives with an agreement to have an annual review in order that the best data and newest factors are incorporated. For example, refining models must be upgraded to match new U.S. gasoline sulfur specifications when they are finalized.
In the example shown, the lighter crudes were assumed processed in a conventional catalytic cracker-equipped refinery with visbreaking for low sulfur crudes-Brent and Canadian Light—but a coker for Saudi due to a perceived lack of regional high-sulfur heavy fuel oil markets. The synthetic crudes did not require bottom-of-the barrel processing as there is only decant oil from catalytic cracking.

The heavy crudes were coker-processed at the Venezuelan upgrader or at a Chicago area heavy-crude refinery. The Venezuelan partially upgraded crude was assumed processed in a specific sister Lake Charles refinery on top of an assumed normal crude diet. Hydrocrackers were assumed only at that site.

For natural gas inputs the byproduct equivalent line is discussed below—as it requires much more explanation than the other elements in the chain.

The specific cases have used average Alberta natural gas processing estimates by Clearstone Engineering adjusted for pipeline fuel use (following TransCanada pipelines fuel consumption reports) for gas delivered beyond Alberta. Electricity inputs were assessed at 1 kg CO₂E/KW-hr-Alberta’s average delivered electricity factor and considered reasonable for U.S. Midwest average supply.

**Other regions, petrochemicals**

The examples shown are specific to the Chicago-area transportation fuel markets. But the McC+A methodologies are generally applicable and have been used for non-North American applications.

In such cases much local data are essential for a valid comparison-local coal mining methane releases, future G/D ratios, existing refinery configurations, future gasoline and diesel specifications, current crude diets, etc.

Petrochemical production at refineries does create challenges with crude oil life cycle analyses relative to appropriate apportionment of greenhouse gases. (We have tried modifying reformer and gasoline yields to avoid benzene-toluene-xylene production for actual refinery data but are not satisfied with the results.)

Apportionment is the major challenge in all life cycle work; for example, McC+A allocates all refinery emissions to transport fuels, but this leaves heavy fuel oil without any attributions. In one study we back-calculated heavy fuel oil attributions for Canadian exports and asphalt allowing for tank heating and other refinery utilities specific to heavy fuel oil. Generally, process emissions are allocated to desired distillate products, partly consistent with their distillation and reaction heat needs.

Asphalt production can be handled, requiring just more crude to produce the base transport fuel volume.

Major examination of all bases and methodologies is essential when considering refining in other areas. As a footnote to Table 2 indicates, “formal” national fuel-combustion CH₄ and N₂O factors can introduce major apparent differences in total CO₂E, even for the same crude in the same refinery, the same G/D and gasoline and diesel qualities. This makes interregional comparison difficult at best.

Currently, an African crude is assumed to be used in the normal pseudo-U.S. Midwest refinery with products used nearby to avoid such problems, although it is very unlikely ever to be processed there.

**Byproduct equivalent**

Our first trials resulted in differing byproduct energy inputs into the regional economy for each crude.

The current methodology balances the energy contributed by nontransportation fuel products with natural gas. A base case is selected, and the differences in byproduct energy from that case are adjusted by the addition or subtraction of natural gas. This results in a new byproduct equivalent CO₂E figure for all but the base crude.

There have been questions as to whether natural gas is the most appropriate byproduct-balancing fuel. Data on Wyoming and South American coals have been provided one client where refinery coker was the principal byproduct. (Specific delivered coal CO₂Es are needed due to varying mine-site CH₄ emissions by Northwest Mine Services and transport fuel use.) However, McC+A still believes natural gas is correct at least in areas where it is available.
Hydrogen production impact

As noted above, hydrocracking has been used only sparingly in the selected pseudo-refineries. But that does not fully agree with reality (although most regional hydrocrackers are associated with aromatics production).

Full heavy-crude upgrading via any residual hydrocracking route requires very appreciable hydrogen—well over 1 Mscf/bbl and CO$_2$ from steam methane reforming is roughly 0.4-scf/scf of hydrogen indicating over 21 kg of CO$_2$/bbl just due to hydrogen from natural gas (more for LNG or naphtha). And this number doesn't cover the added CO$_2$E due to extensive compression and hydprocessor related emissions.

While our pseudo models assume no catalytic reformer limits, actual refineries often are limited; the necessary hydrogen production thus can be very pronounced. As gasoline and diesel sulfur contents go down and cetane up, hydrogen production will become even more common. Obviously, hydrogen recovery must be maximized if one is to minimize greenhouse gas emissions.

On the plains of the U.S. and Canada the G/D ratio is near 1, and gas oil hydrocracking starts to become essential in lieu of catalytic cracking in low-sulfur heavy fuel oil market areas. The same is true of many countries outside the U.S. and Canada, with the odd exception such as Colombia.

A few older hydrogen units are also sources of merchant CO$_2$, but very few merchant CO$_2$ sources are true sinks. Like dry ice, most end-uses disappear back into the air; even urea is only a short-term sink, the CO$_2$ re-evolving when the urea is placed on the soil. Thus, no greenhouse gas credits for CO$_2$ capture or use have been included to date.

Natural gas examples

Several example calculations developed by Clearstone Engineering and McC+A for various natural gases in various markets are presented in Table 3.

About the only conclusion is that all natural gases are not equal. These variants can be important in crude oil life cycle work wherever hydrogen production from natural gas is involved. (Normally, natural gas makeup to refinery fuel gas is minor compared to input to steam methane reformer feed.)

The Russia to Germany and LNG examples are considered realistic, but much more analysis is needed to refine the totals. In Russia, the major accounting challenges are in CH$_4$ emissions in the field and at compressor stations, both direct leakage and unburned CH$_4$ in flaring.

Losses and fuel in marine transport are major question marks with LNG. A logistics consultant and tanker captain provided consistent estimates, but the LNG transport CO$_2$E may be only +50%.

Storage-related emissions are already important in the U.S. and growing in Canada. Peak-shaving LNG storage appears to be making a comeback and appreciably enhances gas-related greenhouse gas estimates.

McC+A has compared natural gas with diesel in a new technology transportation scenario where both crude oil and gas life cycle models were integrated. This was at the request of a prospective user of the new technology.

The natural gas life cycle models have also been used in developing greenhouse gas balances with and without over 600 MW of proposed cogeneration capacity. In such cases, regional gas production and only local pipeline-related emissions were assumed.

Trading and uncertainties

McC+A does not pretend that its current set of programs and data bases are suitable for CO$_2$ trading.

While our work to date provides many clues, much more detailed analysis is needed to define both the starting points and the appropriate ground rules for benefit accounting and auditing.
Uncertainty analysis is essential in any trading situation. One current crude oil life cycle analysis will have error bars shown in its graphical output. McC+A and M. Nosal developed uncertainty analyses for Environment Canada for both 1990 greenhouse and criteria pollutant national inventories. However, at this time estimating uncertainties adds too much time and cost for normal life cycle needs.

Trading contracts are a totally different matter, where +8-10% overall accuracy is not acceptable. (In comparing results of different crude oil life cycle cases, McC+A believes differences over +5% are significant due to common approaches.)

In more-detailed analysis, uncertainties should be developed separately for CO₂, CH₄, and N₂O for each element in the analysis. For example, CH₄ and N₂O become extremely important wherever biological activity is involved, as evidenced by a trial life cycle on ethanol from corn, with the ethanol added to a base gasoline.

**Guides, ground rules**

Crude oil greenhouse gas life cycle analyses provide guides to determine where emphasis is best put on greenhouse gas emission reduction or trading opportunities. But as can be seen there are many ground rules for suitable methodology for even one market region.

Not least of the complications is a variety of national or regional CH₄ and N₂O emission factors (generally based on very limited data) for the transportation fuel combustion portions of the analysis, where the country-to-country variations can be almost as large as producing field or refining emissions in total.

With the monetizing of CO₂ and CO₂E emissions, full life cycle and partial life cycle-type comparisons will become more universal. Detailed breakdowns at the plant or even project become essential in accounting and defining trading potential.

The approaches discussed here must be appreciably expanded to fully provide answers as CO₂ and CO₂E emissions become costs and trading opportunities.

**The Authors**

Tom McCann and Phil Magee together have more than 70 years of Canadian and world refinery planning, operations, and capital experience. Their models have been used for capital planning at over 1 million b/d combined, existing refinery capacity in the past 5 years. Over the past 10 years they have evolved a series of regional and national greenhouse gas emission inventories, inventory quality assurance and methodologies, and data bases for crude oil and natural gas greenhouse life cycle analyses.

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