Methodology behind "An Irresponsible Energy Future"

There are two separate pieces of research that have resulted in this briefing. One that provided estimates of the carbon intensity of current production and one that estimated the carbon intensity of the companies' total resources.

Using the carbon intensity figures for different forms of oil and gas production given in the HSBC Global Research report[i] and the NETL reports[ii], Trucost, the independent environmental research organisation, was commissioned in April 2009 to analyze the oil and gas production of the top five integrated oil companies: BP, Chevron, Exxon, Shell and Total. Trucost was asked to give a credible estimate of the carbon intensity of the companies per unit of oil and gas production.

The HSBC Global Research report argues that to get a clear picture of the oil companies' future exposure to carbon pricing, it is necessary to examine the companies' 'total resources'.

Total resource figures are estimates companies make of all the oil and gas they own rights to, and which they calculate are likely to be extracted at some point in the future. The standard for this is drawn from guidelines set by the Society of Petroleum Engineers.[iii,iv]

The problem identified by HSBC is that analysing only proven and probable reserves "understates the level of a company's potential reserve base. Also, it does not include projects yet to receive sanction for development."[v]

1. Current Intensity

The Trucost analysis of carbon intensity amongst the top five international oil companies was based on the following sources:

- Company annual reports,
- US Securities and Exchange Commission filings
- Investor presentations.

These were analysed to ascertain the composition of each company's production geographically and thematically. Thematic analysis means, what proportion is oil, gas, LNG or unconventional forms of production such as tar sands, tight gas or deepwater as these forms of production each have different carbon intensities.

1.1 Conventional Oil

Oil production carbon intensity was calculated according to the figures given in two recent reports from the National Energy Research Laboratory.[vi] These provide figures for the carbon intensity per barrel for oil production in a range of countries from which the USA imports oil.

These figures were then used to estimate emissions according to company production in a given country. The sub-total was weighted to reflect the proportion of each company's production in each country. ExxonMobil only reports production in regions; therefore a regional average was used.

1.2 Unconventional Oil / Tar Sands

Tar sands emissions were based on actual reporting where applicable. This is derived from company reporting and/or intensity figures from the Oil Sands Review.[vii] Where emissions were not reported, industry averages derived from the Pembina Institute's analysis were used.[viii]

1.3 Natural Gas

Natural gas intensity estimates were based on information for gas production in Europe, USA and Canada using the data from the European Environment Agency, the US Environmental Protection Agency and Department of Energy.[ix]

2. Total Resources Analysis

The total resources analysis was undertaken by the briefing's authors, analysing company graphs or pie-charts given in company reports or analyst presentations. All the companies were asked for the raw data behind the charts, but were not forthcoming, so the graphs were broken down using a protractor or ruler to calculate the proportion each segment represents. Intensity calculations were then made using the following general assumptions:

2.1 Traditional / Conventional production:

Apart from BP, all companies mixed oil and gas together in this category. With no way to calculate the split we assumed a 50/50 split between oil and natural gas for all companies except BP. We then used the applicable 2008 intensity figure for each company from the Trucost analysis.

2.2 Deepwater and Arctic oil production

We could find no published carbon intensity figures for these categories of production. We know that they are probably above the average for conventional oil, but we conservatively assumed the weighted average for US refinery feedstock in the NETL analysis. This is **40.3**[x]

2.3 Tight / Sour and unconventional gas

We used the figure in HSBC's *Oil & Carbon Report* for Tight Gas: **33.1**

2.4 Heavy Oil and Tar Sands

Each company has reported heavy oil, Enhanced Oil Recovery (EOR) and tar sands slightly differently. To improve accuracy, we have, where possible, broken these segments down using separate company documents. Including:

- *Shell*

We asked Shell to give a numerical break down of what it calls "Heavy Oil and EOR" in its Total Resources pie-chart, but it refused.[xi] This segment made up 34.7 per cent of its pie-chart or 22.9 billion boe out of a total of 66 billion boe. The media release accompanying the presentation, from which this chart was derived, stated: "Canadian heavy oil, where we have some 20 billion barrels of resources, is a classical new technology and integration play that Shell can do well."[xii]

We therefore assume that of the 22.9 billion boe, 20 billion boe is tar sands. We do not know the proportion of this 20 billion boe that will be extracted using mining or in situ methods, and once again we asked Shell and they did not tell us. However, we are aware that 80 per cent of tar sands resources are only accessible through in situ methods.[xiii]

So although Shell's main planned production capacity is in mining which has a lower carbon intensity, we know that in the long term, it will be in situ production that will probably produce the most barrels of oil. We therefore took an average of the carbon intensity figures, including upgrading, for the three main methods of tar sands extraction from the Pembina Institute analysis. These are detailed below in the table. The average of the three including upgrading amounts to **105**.

For the rest of the Heavy Oil and EOR segment we took an average of the figures for EOR and Water Flood Viscous & Heavy Oil from the HSBC *Oil & Carbon Report*. This gives **47.5**.

- *ExxonMobil*

ExxonMobil's graph included a segment called Heavy Oil that accounted for about 20.5 per cent of its resource base. We were able to locate total resource figures for specific tar sands projects in Imperial Oil's (Exxon's Canadian subsidiary, 69.6 per cent owned by ExxonMobil) annual report.[xiv] We cannot be sure that these account for all of ExxonMobil's tar sands resources but, again without further information from the company, it is as close as we were able to get.

We calculated that about 35 per cent of the Heavy Oil resource could be accounted for with tar sands mining resources and about 9.4 per cent in Imperial Oil's main in situ project that uses Cyclic Steam Simulation (CSS). We therefore applied Pembina figures to the mining segment (**80**) and CSS segment (**135**) and HSBC's Heavy Oil figure (**55**) to the remainder. This gave us a total intensity figure for the Heavy Oil segment of **71.3**.

- Chevron

Chevron reported Heavy Oil in a separate segment to Oil Sands. We applied the HSBC Heavy Oil figure to Heavy Oil (**55**) and the Pembina average of the three production methods to the oil sands (**105**)

- *BP*

BP reported Heavy Oil and Viscous Water Flood together. BP at present has one planned tar sands project, but it does not disclose the total resources for it. We used the HSBC Heavy Oil figure for this (**55**). If we had added BP's tar sands project to the analysis, (which as a SAGD project does have high intensity) BP's figure may have changed by a point or so. This however would not make much difference to the overall comparison between companies.

Tar Sands carbon intensity figures from which we derived an average of 105[xv].

Activity	GHG intensity (kg CO_2e/barrel)	GHG intensity (kg CO_2e/barrel) including 45 kg CO_2e/barrel for upgrading of bitumen
Mining of bitumen	35	80
SAGD extraction of bitumen (in situ)	55	100
Cyclic Steam extraction of bitumen (In situ)	90	135

2.5 Other general assumptions

That the Total Resources measurement and definition is the same for all companies.

We are forecasting 40+ years into the future based on 2008 data; therefore figures are highly susceptible to unforeseen events (political, economic, geographic etc), plus technological improvements to efficiency.

The development of these resources is dependent on the trajectory of crude oil prices. The higher the oil price, the more oil is available for drilling as more expensive methods become economical. In general as the oil price rises, heavier and more difficult oil, which usually requires more energy intensive production methods, is increasingly likely to be exploited.

We have no timeline for the development of these resources – the figures are an estimate of intensity based on 100 per cent of Total Resource development.

Questions regarding the research methodology behind this analysis should be directed to Lorne Stockman, lorne {AT} priceofoil DOT org

[i] Paul Spedding, Nick Robins & Kirtan Mehta, *Oil & Carbon: Counting the Cost*, HSBC, September 2008.
[ii] NETL, *Development of Baseline Data and Analysis of Life Cycle Greenhouse Gas Emissions of Petroleum-Based Fuels*, November 26, 2008. www.netl.doe.gov/energy-analyses/trend.html; NETL, *An Evaluation of the Extraction, Transport and Refining of Imported Crude Oils and the Impact on Life Cycle Greenhouse Gas Emissions*, March 29, 2009. http://www.netl.doe.gov/energy-analyses/pubs/PetrRefGHGEmiss_ImportSourceSpecific1.pdf

[iii] See http://www.spe.org/spe-app/spe/industry/reserves/index.htm
[iv] We were not able to locate comparable data for Total so omitted it from this analysis. Additionally, the companies have not released detailed figures for the composition of these resources. Instead the data has to be deciphered from graphs published in the companies' annual strategy updates or other presentations for investors. We phoned the companies to request the figures behind the charts. They all refused. BP told us to "get a protractor out" in order to analyse its pie chart. So we did.

[v] Paul Spedding, Nick Robins & Kirtan Mehta, *Oil & Carbon: Counting the Cost*, HSBC, September 2008.
[vi] NETL, *Development of Baseline Data and Analysis of Life Cycle Greenhouse Gas Emissions of Petroleum-Based Fuels*, November 26, 2008. www.netl.doe.gov/energy-analyses/trend.html; NETL, *An Evaluation of the Extraction, Transport and Refining of Imported Crude Oils and the Impact on Life Cycle Greenhouse Gas Emissions*, March 29, 2009. http://www.netl.doe.gov/energy-analyses/pubs/PetrRefGHGEmiss_ImportSourceSpecific1.pdf

[vii] http://www.oilsandsreview.com/report.asp?id=osr%2Femission-intensity-GHG-2007.html
[viii] http://www.oilsandswatch.org/pub/586

[ix] http://www.eea.europa.eu/publications/technical_report_2008_6/Annual-European-Community-greenhouse-gas-inventory-1990-2006-and-inventory-report-2008; http://www.epa.gov/climatechange/emissions/downloads09/07Inventory.pdf; www.netl.doe.gov/energy-analyses/trend.html
[x] All figures in kg co_2e/boe (kilograms of carbon dioxide equivalent per barrel of oil equivalent.)
[xi] S. Wiggins, *Email to Andy Rowell*, May 11, 2009
[xii]http://www.shell.com/home/content/media/news_and_library/press_releases/2008/strategy_update_17032008.html
[xiii] See for example: Canadian Association of Petroleum Producers, February 2009: Canada's Oil, Natural Gas and Oil Sands Overview and Outlook. http://www.capp.ca/getdoc.aspx?DocID=147850&DT=PDF
[xiv] http://www.imperialoil.ca/Canada-English/Files/Investors/2008_AR_Upstream.pdf
[xv] Pembina Institute, *The Climate Implications of Canada's Oil Sands Development,* November 29, 2005. http://pubs.pembina.org/reports/oilsands-climate-implications-backgrounder.pdf page 10.