UPSTREAM EMISSIONS OF FOSSIL FUEL FEEDSTOCKS FOR TRANSPORT FUELS CONSUMED IN THE EUROPEAN UNION

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

THE INTERNATIONAL COUNCIL
ON CLEAN TRANSPORTATION

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Abbreviations used

$/MMBtu	U.S. dollar per million BTUs e.g. Gas price
AEGPL	European Association of Liquefied Petroleum Gas
AGO	Australian Greenhouse Office
APG	Associated gas, also called associated petroleum gas
API	American Petroleum Institute
ATVs	Advanced technology vehicles
BAU	Business as usual
bbl	Barrels
bbl/d	Barrels per day
BC	British Columbia
BEV	Battery electric vehicle
BP	British Petroleum
BSO	Biofuel Sustainability Ordinance
BTC	Baku-Tbilisi-Ceyhan pipeline
BTU	British thermal unit
CA	California
CARB	California Air Resources Board
CAPP	Canadian Association of Petroleum Producers
CARBOB	California reformulated gasoline blendstock for oxygenate blending
CBOB	Conventional blendstock for oxygenate blending
CCGT	Combined cycle gas turbine
CCS	Carbon capture and sequestration
CDM	Clean Development Mechanism
CERA	Cambridge Energy Research Associates
CH_4	Methane
CI	Carbon intensity
CIEEDAC	Canadian Industrial Energy End-Use Data and Analysis Centre
CIF price	Cost, insurance and freight price
CIMS	Crude Information Management System
cm/t	Cubic meters per metric tonne
CNG	Compressed natural gas
CO	Carbon monoxide
CO_2e	CO_2 equivalent – includes impact from CO_2, nitrous oxide and methane emissions. Based on 100 year Global Warming Potentials (GWP)
COQG	Crude Oil Quality Group
CPC	Caspian Pipeline Consortium
CSS	Cycle steam stimulation
CWE	Cold water equivalent volume for steam
d	Day
DOGGR	State of California Division of Oil, Gas and Geothermal Resources
DEQ	Department of Environmental Quality
DG	Directorate General of the EU
EER	Energy economy ratio
EC	European Commission
EIA	Energy Information Administration

EISA	Energy Independence and Security Act of 2007
EOR	Enhanced oil recovery
EMFAC	Emissions factors model
EPA	Environmental Protection Agency
ER	Energy-Redefined
ERCB	Energy Resources Conservation Board of Alberta
ESP	Electrical submersible pump
EU	European Union[i]
EUCAR	European Council for Automotive Research and Development
EV	Electric vehicle
FASOM	Forest and agricultural sector optimization model
FAPRI	Food and Agricultural Policy Research Institute
FCC	Fluid catalytic cracker
FCEV	Fuel cell electric vehicle
FEV	Full electric vehicle
FFV	Flex fuel vehicle
FPSO	Floating production storage offshore unit
FQD	Fuel Quality Directive
FQM	Fuel Quality Monitoring
FSU	Former Soviet Union
g	Grams
Gbbl	Billions of barrels
gCO_2e/MJ	Grams CO_2 equivalent per megajoule
GGFR	Global Gas Flaring Reduction partnership of the World Bank
GHG	Greenhouse gas
GJ/t	Giga joules per metric ton - energy
GOR	Gas-to-oil ratio, scf/bbl
GREET	The greenhouse gases, regulated emissions, and energy use in transportation model
GTL	Gas to liquids
GWP	Global warming potential
HCICO	High-carbon-intensity crude oil
ICCT	The International Council on Clean Transportation
IEA	International Energy Association
IHS	Information Handling Services Inc.
ILCD	The international reference lifecycle data system
ILUC	Indirect land use change
IPCC	Intergovernmental Panel on Climate Change
ISAE	International standard on assurance engagements
ISO	International Organization for Standardization
JEC	Joint Research Centre, EUCAR and CONCAWE
JRC	Joint Research Centre
Kbpd	Thousands of barrels per day
kg	Kilograms
$kgCO_2e/bbl$	Kilograms CO_2 equivalent per barrel
kt	Thousands metric tons

[i] Unless otherwise stated, the EU refers to the 27 member countries of the EU. These are: Austria, Belgium, Bulgaria, Cyprus, the Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Ireland, Italy, Latvia, Lithuania, Luxembourg, Malta, Netherlands, Poland, Portugal, Romania, Slovakia, Slovenia, Spain, Sweden, and the United Kingdom.

kWh	Kilowatt hours
LCA	Lifecycle analysis or assessment
LCFS	Low Carbon Fuel Standard
LCI	Lifecycle inventory
LCIA	Lifecycle impact assessment
LNG	Liquefied natural gas
LRT	LCFS reporting tool
MCON	Marketable crude oil name
MJ	Megajoule
MMbbl	Million barrels
MMBtu	Million BTUs
MMscf/d	Million standard cubic feet per day
MMt	Million metric tons
MOVES	Motor Vehicle Emission Simulator
MWh	Megawatt hours
N_2O	Nitrous oxide
NE/MA	Northeast and Mid-Atlantic
NEB	National Energy Board (Canada)
NETL	National Energy Technology Laboratory
NESCAUM	Northeast States for Coordinated Air Use Management
NGL	Natural gas liquids – C3-C5+ (propane, butane, pentanes etc.)
NGPSA	Natural Gas Processors Suppliers Association
NHTSA	National Highway Traffic Safety Administration
NNPC	Nigerian National Petroleum Corporation
NOAA	National Oceanic and Atmospheric Administration
NOx	Nitrogen oxide referring to NO and NO_2
NUTS	Nomenclature of territorial units for statistics
OECD	Organization for Economic Co-operation and Development
OGP	International Association of Oil and Gas Producers
OPEC	Organization of the Oil Exporting Countries
OPGEE	Oil production greenhouse gas emissions estimator
OR	Oregon
ORNL	Oak Ridge National Laboratory
OSR	Oilseed rape
PADD	Petroleum Administration for Defense Districts
PADD1	East Coast: Connecticut, Delaware, District of Columbia, Florida, Georgia, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, North Carolina, Pennsylvania, Rhode Island, South Carolina, Vermont, Virginia and West Virginia.
PADD2	Midwest: Illinois, Indiana, Iowa, Kansas, Kentucky, Michigan, Minnesota, Missouri, Nebraska, North Dakota, South Dakota, Ohio, Oklahoma, Tennessee, Wisconsin.
PADD3	Gulf Coast: Alabama, Arkansas, Louisiana, Mississippi, New Mexico, Texas.
PADD4	Rocky Mountains: Colorado, Idaho, Montana, Utah, Wyoming
PADD5	West Coast: Alaska, Arizona, California, Hawaii, Nevada, Oregon, Washington.
PHEV	Plug-in hybrid electric vehicle

PI	Productivity Index (ratio of the total liquid flow rate to the pressure drawdown)
PLDV	Passenger light-duty vehicle
PSA	Production-sharing agreement
Psig	Pounds per square inch gauge
RED	Renewable Energy Directive
RFA	Renewable Fuels Agency
RFG	Reformulated gasoline
RFS	Renewable Fuel Standard
RIN	Renewable identification number
RLCFRR	Renewable low carbon fuel requirements regulation
RTFCs	Renewable Transport Fuel Credits
RTFO	Renewable Transport Fuel Obligation
SAGD	Steam-assisted gravity drainage
scf	Standard cubic foot
scf/bbl	Standard cubic feet per barrel
SCO	Synthetic crude oil
SOR	Steam-to-oil ratio
ST	Single cycle turbine
t	Metric tons
TEOR	Thermally enhanced oil recovery
toe	Tons of oil equivalent
USGS	U.S. Geological Survey
ULSD	Ultra-low sulfur diesel
VOC	Volatile organic compound
WA	Washington
WB	World Bank
WBCSD	World Business Council for Sustainable Development
WOR	Water-to-oil ratio
WRI	World Resources Institute
wt%	Weight percent
WTT	Well-to-tank
WTW	Well-to-wheel

Executive summary

In 2009, the European Union (EU) amended the Fuel Quality Directive (FQD) to introduce a target for European transport fuel suppliers[ii] to reduce the lifecycle carbon intensity (henceforth 'CI') of their fuel[iii] by at least 6% by the end of 2020. The FQD includes a detailed methodology for assessing the CI of biofuels, and the European Commission is required to develop an Implementing Measure laying out a complementary methodology for the calculation of the greenhouse gas (GHG) emissions from fossil fuels. The Commission has made an initial proposal, but to date nothing has been adopted – an impact assessment of the proposed Implementing Measure was ongoing at the time of writing.

In this context, the International Council on Clean Transportation (ICCT), working with Stanford University, Energy Redefined and Defense Terre, has been contracted by the European Commission's Directorate General for Climate Action (DG Clima) for project CLIMA.C.2/SER/2011/0032r on the *Upstream Emissions of Fossil Fuel Feedstocks for Transport Fuels Consumed in the EU.* This report presents the results of several desk studies for this project on the EU crude oil market and associated empirical and modeled data on GHG emissions; presents a model for lifecycle analysis of crude oil extraction; and provides an estimate of the carbon intensity of oil supplied to the European Union in 2010.

The centerpiece of the project is the 'Oil Production GHG Emissions Estimator', or OPGEE. The model is the result of a project commissioned from Stanford University by the California Air Resources Board (CARB) for its Low Carbon Fuel Standard (LCFS), and supported by the European Commission and the ICCT. The OPGEE model is an open-source, fully public engineering-based model of GHG emissions from oil production operations. It has been peer-reviewed in California by legislators and industry leaders as well as academic experts in the field of petroleum engineering.

The model provides a possible analytical basis for disaggregation of fossil fuel carbon emissions in the FQD. In this report, we will review the legislative and scientific background for such a measure, introduce OPGEE, present the first analysis using OPGEE of the CI of crudes imported into the EU and discuss policy options to allow carbon savings from reduced crude oil carbon intensity to be credited. The report includes: (§2) a review of existing legislation; (§3) a description of crude oil sourcing for the EU; (§4) a review of existing literature and lifecycle analysis (LCA) studies of fossil fuels; (§5) a review of best practices in the construction of LCA models for fossil fuel; (§6) an introduction to the OPGEE model; (§7) a review of available input data for LCA analysis of crude oil; (§8) the resulting EU Baseline calculation based on the OPGEE tool; (§9) policy options to regulate fossil fuel carbon intensity; and (§10) study conclusions.

[ii] The FQD primarily applies to road transport fuel. The precise definition of which fuels are affected by the target is available in the Directive, http://ec.europa.eu/environment/air/transport/fuel.htm
[iii] Including electricity supplied for transportation.

ES.I. Existing legislation

Nine examples of existing or proposed legislation to regulate the lifecycle carbon intensity of fuels were identified:

1. California Low Carbon Fuel Standard (LCFS) (active)
2. Oregon Clean Fuels Standard (CFS) (in reporting phase)
3. Washington Low Carbon Fuel Standard (LCFS) (in development)
4. North-East and Mid-Atlantic States Clean Fuels Standard (CFS) (in development)
5. British Columbia Renewable and Low Carbon Fuel Requirement Regulation (RLCFRR) (active)
6. U.S. Renewable Fuel Standard (RFS2) (active)
7. EU Fuel Quality Directive (FQD) (active)
8. EU Renewable Energy Directive (active)
9. UK Renewable Transport Fuel Obligation (RTFO) (active)

Of these regulations, only the Californian LCFS and British Columbian RLCFRR have measures to regulate fossil fuel carbon intensities. California and in particular British Columbia both consume a relatively narrow set of crudes compared to Europe, with a large fraction of crude coming from the Americas. Still, as shown in Table A, California imports crude from a variety of countries, and the California experience under LCFS is an important example for the European Commission.

Table A Composition of the California crude mix from 2005-2007 by country/state of origin

FEEDSTOCK ORIGIN	2005	2006	2007
Alaska	135,906,000	105,684,000	100,900,000
Angola	12,912,000	14,979,000	21,038,000
Argentina	6,213,000	3,484,000	
Brazil	12,474,000	17,938,000	22,453,000
California	266,052,000	254,498,000	251,445,000
Canada	4,942,000		5,320,000
Colombia	4,180,000	9,362,000	11,813,000
Ecuador	67,705,000	71,174,000	55,456,000
Iraq	34,160,000	56,163,000	57,788,000
Mexico	19,316,000	15,473,000	9,214,000
Nigeria			5,447,000
Oman	2,985,000	6,326,000	
Others	13,707,000	9,311,000	21,313,000
Saudi Arabia	95,507,000	86,976,000	72,296,000
Venezuela		4,120,000	4,706,000
Total	676,059,000	655,488,000	639,189,000

Source: CARB (2009a)

While LCFS and RLCFRR were introduced with methodologies to disaggregate crude oil by emissions intensity, in both jurisdictions those methodologies have been revised since adoption. In California, the initial approach was based on the identification of 'High Carbon Intensity Crude Oils (HCICOs)', defined as crude with an upstream CI of over 15 gCO_2e/MJ, greater than the California baseline. Any oil defined as a HCICO would result in carbon deficits for the company supplying it. However, following stakeholder discussion and consideration by the LCFS Advisory Panel and the HCICO Screening Expert Workgroup, an alternative methodology referred to as the 'California Average' approach was adopted by the CARB Board in December 2011. In this approach, any increase in the average CI of crude oil used in California would result in additional LCFS 'deficits' distributed across **all** fuel suppliers, who would then need to supply additional low carbon fuel to offset the deficit. Because the additional deficits would be applied equally to all fossil fuel suppliers, we do not expect this approach to provide a strong financial signal against the use of higher carbon crudes by any given supplier. It should, however, guarantee that increases in crude carbon intensity will not be allowed to undermine or offset the gains from the deployment of alternative fuels under the CA-LCFS.

In British Columbia, the RLCFRR initially included a hybrid system, allowing reporting of either default emissions or of fuel specific CI values calculated with the GHGenius LCA model. A concern was expressed by industry that within the reporting system it would have been possible to 'shuffle' data such that companies would be reporting only lower carbon crudes in British Columbia. In response to this concern, the option to report actual emissions data for fossil fuels has been discontinued, and as of 1 July 2013 only default fossil fuel CI values will be permitted.

Biofuel regulations have a longer history of implementation, with RTFO, RFS and LCFS in particular having been operational for several years. RTFO and LCFS provide useful examples of hybrid carbon intensity reporting schemes, coupling extensive CI lookup tables with well-defined protocols for reporting pathway specific data. In the UK, companies reporting under RTFO are permitted to undertake their own carbon analyses based on the defined methodology – the calculated numbers can then be reported, providing a qualified verifier's opinion to assure data quality and analysis. In California, the regulator (CARB) retains the sole authority to undertake carbon analyses, but fuel companies are able to submit their own process specific data through the 'Method 2A/2B Applications and Internal Priority Pathways'[iv] system. Biofuel reporting systems also provide examples of using fuel and process characteristics to disaggregate emissions values into discrete defaults. In the EU Renewable Energy Directive, for instance, pathways are allocated emissions values based on a combination of feedstocks and process technologies (e.g. palm oil biodiesel without methane capture). This disaggregation is undertaken even though there will be an overlap between some CI ranges – for instance, in RTFO reporting for 2009/10 rapeseed and soy biodiesel have overlapping CI ranges.

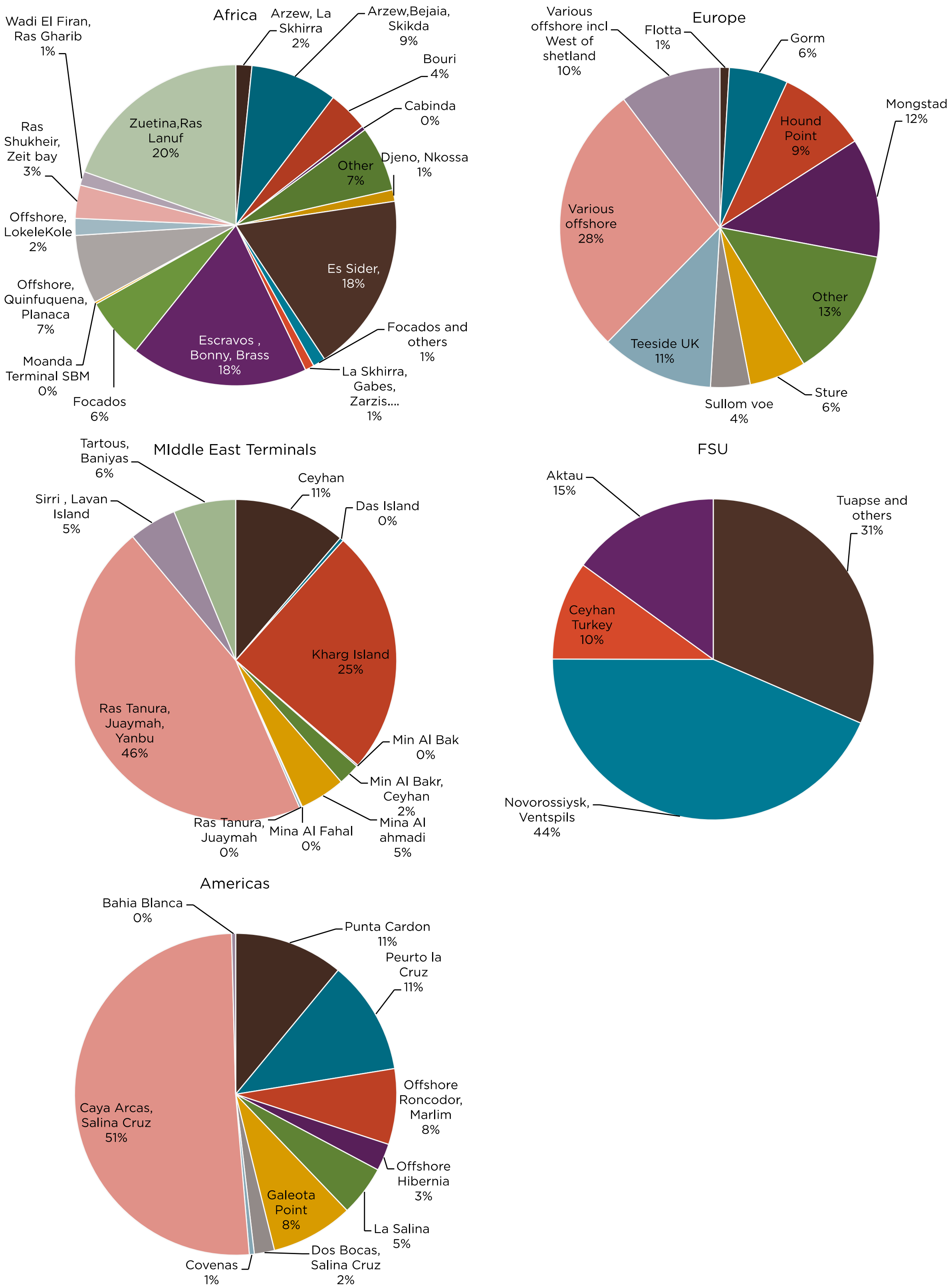
ES.II. Crude oil sourcing

In 2010, global crude oil consumption was growing at a rate of 3.1% per annum, outpacing supply growth (BP 2011b). Oil demand is expected by the International Energy Agency (IEA 2011) to grow to 99 million barrels per day (MMbbl/d) by 2035. Transport is the main source of oil demand. From 2005 to 2011, the European Union has averaged crude imports of about 11.6 MMbbl/d, at a reported average CIF (cost, insurance and freight) price of about $75 per barrel (DG Energy 2012a). The EU is a net importer of crude, supplying only 8% of its crude oil from domestic sources. For the same time period, on average, just under 38% of EU crude came from the Former Soviet Union (FSU), with a further 51% from non-EU Europe, Africa and the Middle East. This oil is supplied to refineries as a range of 'crude-blends' or 'MCONs' (marketable crude oil names).

There are currently up to 3,100 oilfields and another one thousand or so oil fields within the EU and Norway supplying crude to the EU (ICCT/ER 2010; OGJ, 2010). The EU has 104 refineries and a total refining capacity of about 15.5 MMbbl/d (JRC 2012). Europe also imports some refined product, notably diesel from the U.S. and Russia. We estimate that there are 51 terminals (Figure A) currently supplying somewhere between 50 and 70 different crude blends into the European market from 35 different countries.

[iv] This allows suppliers to adjust a pathway to better represent their own processes, or to apply for an entirely new pathway.

Figure A. Crude oil imports into the EU by terminal for 2011 (DG Energy, 2012a; ER, 2012)



Russia is currently the largest exporter of oil to Europe, mostly in the form of Urals Blend and Siberian Light. Close to 80% of Russia's oil is exported through the Transneft pipeline system with the remaining oil shipped via tankers from a number of Black Sea ports, although the latter seem to be in decline (EIA 2012). The Transneft pipeline system spans over 31,000 miles to the ports of Novorossiysk and Primorsk (Transneft 2012).

Norway is the second major exporter to Europe, but as with other North Sea producers, Norwegian oil exports are likely to continue to shrink in the coming decades. Norway is connected by pipeline to a refinery on Teesside in the UK, and also has substantial refining capacity of its own, including at Statoil refinery near the port of Mongstad.

It is difficult to make any detailed, authoritative and reliable prediction about the way EU crude sourcing may change in the coming decades. Crude prices are notoriously difficult to predict, and product flows will be determined by a complex web of interactions including relative economic growth, relative pace of decarbonization, pace of development of unconventional resources and diplomatic relations. Energy Redefined (ICCT/ER 2010) project increases in European oil imports to 2020, with increases in imports from Canada and West Africa in particular. CONCAWE (2008) also predict consumption increases to 2020. They predict increases in Caspian imports to offset falling North Sea production. In both cases, however, the basic structure of EU oil consumption is maintained, with significant imports from the FSU, North and West Africa and the Middle East dominating supplies. Among these regions there seems to be a significant question only about Russia's ability to maintain exports, where there is uncertainty regarding the real size of reserves. It is also likely that more Russian oil will flow to expanding Asian markets in the coming decades, and if the near term trends predicted by CONCAWE and Energy Redefined are continued, we would expect to see Russian crude supplying a smaller fraction of EU needs in the years to come.

In general, we do not feel able to make any strong prediction about how changing oil prices would affect the geographical distribution of European crude sources. In particular, it is difficult to identify which oil sources represent the marginal production. That said, it does at least seem reasonable to expect that low prices would be likely to reduce the rate of expansion of unconventional oil resources. Production of oil from the Canadian oil sands or (especially) from kerogenous oil shales is likely to be more costly than conventional oil extraction, and therefore a low price scenario could significantly inhibit new investment. Oil prices on current levels or higher are probably required for the Energy Redefined prediction of increased imports from Canada to be achieved, however regulatory signals and infrastructure development are potentially as important as the overall oil price. In a very high oil price scenario ($150 per bbl or more) it seems likely that (unless regulatory barriers are put in place) kerogen exploitation may expand and could become an important source, but without such high prices investment may not be appealing. Similarly, as the Canadian experience allows extra heavy oil extraction technologies to mature, relatively expensive bituminous projects in Venezuela or elsewhere could become more appealing in a high oil price scenario. Our analysis is summarized in Table B.

Table B EU crude sourcing trends

SOURCE	CURRENT IMPORTS	COMMENTS
FSU (Russia, Caspian)	41.7%	Russia's reserves may be slightly less certain in nature than those of other regions. There is also competition for Russian crudes from the Asian market. It is possible that in a low ($50) oil price scenario, Russian production could be reduced and we might expect to see the importance of Russian crude to the European market diminish. For a persistent > $100 oil price, however, it seems probable that unconventional reserves will be exploited and will support continued exports to the EU (likely with a different carbon profile). Even with unconventional production, given increasing oil demand from Asia, it seems unlikely that Russian crude will take a significantly larger place in EU imports to 2050 than it does now.
North Africa	12.3%	Given its proximity to the EU, and despite recent political changes, notably in Libya, North Africa is expected to continue being an important partner in oil sourcing. North African reserves are estimated at 69 billion barrels (dominated by Libyan reserves estimated at 47 billion barrels) by the EIA in 2012. This situates the region between Russia and the United Arab Emirates in terms of reserves. Aside from any new political upheavals, sourcing by the EU from the region as a whole is expected to remain broadly stable.
West Africa	7.8%	West African reserves are dominated by Nigeria, which makes up 98% of the region's 38 billion barrels according to the EIA in 2012. It seems likely that the EU will continue to be a key export market, not least given the European refining sector's substantial appetite for the light crude characteristics of Nigerian production.
South & Central America	2.6%	Proven reserves in Latin America have risen dramatically in the last decade, and with extensive unconventional resources production increases seem likely, especially for a high-oil-price scenario ($150), which should allow the national oil companies scope to make serious investments. Energy-Redefined predicts a moderate increase in supply from now to 2020, and it seems reasonable to expect that new South American sources will enter the EU fuel mix in the coming decades–perhaps more so for a high-oil-price scenario.
Middle East	13.8%	Middle Eastern reserves are significant and should sustain production levels to 2050. There seems little reason to expect a major change in European imports, aside from political instability as exemplified by the recent Iranian oil embargo. A high-oil-price scenario might drive more investment elsewhere, though, reducing the fractional importance of these supplies to Europe.
North Sea	20.6%	North Sea oil reserves are diminishing, and we see little reason to expect that to change. North Sea oil will be less important in Europe regardless of oil prices.
Canada	0.07%	Canada has extensive reserves of bituminous oil, which are highly profitable to exploit at $100 a barrel, and would still generate profits at $50. It seems likely that investment will move faster for a higher oil price, so higher prices are likely to make this source more significant for Europe. Given the relatively low gasoline yield from refining bitumen, and the structural shortage of diesel in Europe, one pathway might be for bitumen to be refined in the United States and the excess diesel to be exported as finished product.
Kerogenous oil shales	0%	At $50 a barrel these will not be exploited, and at $100 other unconventional sources (e.g., fracking, tar sands) will probably take precedence in new development in the medium term. However in a $150 scenario these resources, extensive in many areas, will look appealing and, absent prohibitive climate legislation, could become an important source of EU crude.

ES.III. Existing LCA studies

As previously discussed, a number of regulatory frameworks require overall decreases in the lifecycle carbon dioxide emissions of transport fuel, or for alternative fuels to meet some threshold saving compared to a given baseline. These regulations rely on the application of lifecycle analysis (LCA) to determine the CI of each fuel pathway considered. There is no single optimal LCA framework, or single agreed system boundary, but in general the aim of LCA is to account for the energy used and CO_2 emitted by processes related to the production, transport, storage and usage of the fuel. Given the complexity of fuel production processes and the lack of a single unified LCA framework, it is unsurprising that there are diverging CI estimates in the literature, and that the accuracy of the modeling used to determine the CI of fuel sources has come under increased scrutiny.

We reviewed nine key studies on the modeling of lifecycle GHG emissions from conventional crude oil production. These studies have been influential on the discussion of the carbon intensity of crude oil extraction on both sides of the Atlantic. Several of these studies are U.S. focused – nevertheless, there is some overlap of crude sources between the regions, and it is possible to infer conclusions about the CI of comparable processes even when studied in different geographical locations. The studies are:

- Joint Research Centre, EUCAR and CONCAWE (JEC) Well-To-Wheel Study (2011);
- GREET 1 2011;
- GHGenius 4.00c;
- McCann and Associates (2001);
- Energy Redefined/ICCT (2010);
- TIAX (2009);
- Jacobs (2009)[v];
- NETL study (2009);
- IHS CERA (2010a).

Five of these studies (JEC, GREET, GHGenius, McCann and PE International) are based on reported oil industry energy consumption and emissions data combined with regional flaring estimates. The JEC study and GHGenius are based on data reported by the International Association of Oil and Gas Producers (OGP) and NOAA flaring data (GHGenius does however have a more detailed treatment of Canadian crudes). McCann and PE International (used in NETL) have proprietary upstream models, while in GREET the upstream part of the lifecycle is reduced to an energy efficiency value and assumptions regarding fuel types. The results of these studies are

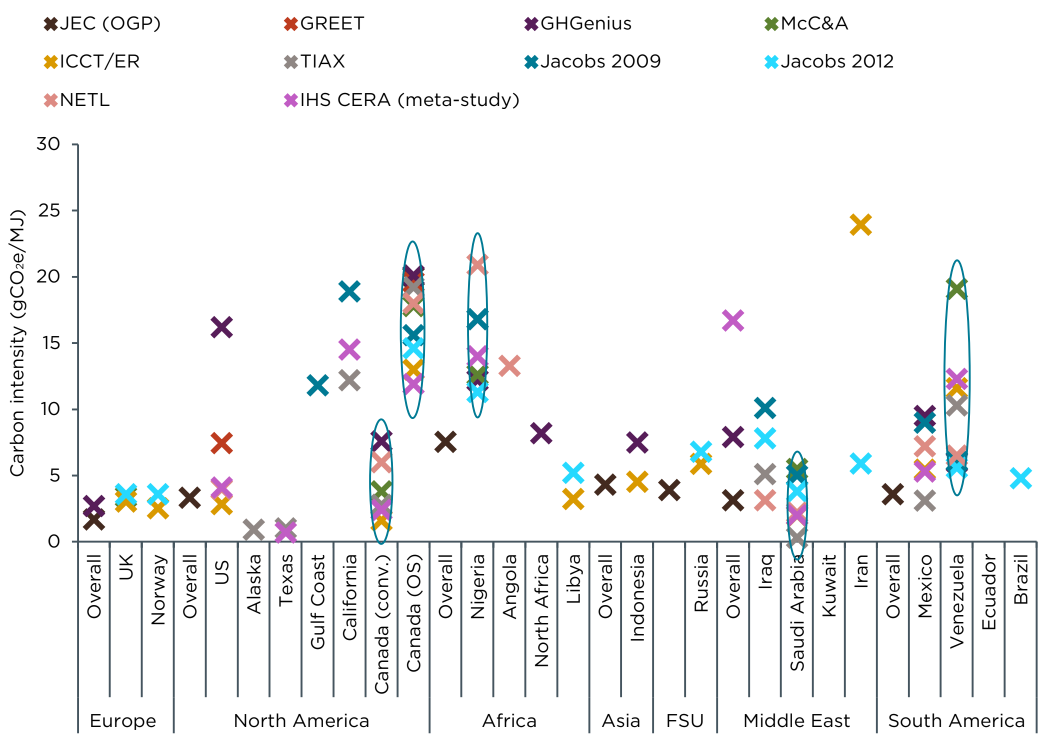
[v] We also note LCA results from Jacobs (2012)

useful comparison points, however the methodologies used are not directly comparable to the engineering approach of OPGEE.

Three studies are based on engineering models (TIAX, Jacobs, Energy Redefined). These studies all provide some degree of sensitivity analysis and discuss the role of key parameters in determining emissions. TIAX and Jacobs use well-documented data for a limited set of fields, while Energy Redefined use an extensive but proprietary dataset.

Finally, IHS CERA undertook a meta-study based on several of the studies mentioned above (IHS CERA, 2010a).

Figure B. Upstream crude oil CI from studies in the literature



The results of the reviewed studies are grouped by region in Figure B (note that Canadian oil is split into conventional and oil sands). In most cases, values are not intended to represent regional averages. As is noted by ICCT/ER (2010), national origin is in general not an accurate way to characterize emissions for regulatory purposes, because production practices can very markedly between fields within a given country. That said, the various studies do show broad consistency on crude from some regions – for instance, in Figure B the relatively tight grouping at lower CIs for Saudi Arabian production is highlighted. Similarly, Canadian oil sands are uniformly assessed as having high emissions, generally above 15 gCO_2e/MJ upstream, while estimates for Canadian conventional are all in the range 0-10 gCO_2e/MJ. Nigerian crude is also consistently assessed as high emissions because of high flaring, but with a larger range, due to the uncertainty around flaring. Venezuelan production, on the other hand, has a very wide range of estimated emissions from below 5 to nearly 20 gCO_2e/MJ, reflecting the differences between extra heavy oils that need to be upgraded and lighter crudes that go straight to market. Similarly, the upstream carbon intensity of U.S fuel varies from very low (for Texan light oil) to very high (for Californian thermally enhanced heavy). The CI values are also tabulated in Table C.

Table C Comparison of oil production emissions in gCO_2e /MJ from the reviewed LCA studies, by region

REGION		JEC (OGP)	GREET	GHGenius	McC&A	ER**	TIAX	JACOBS 2009	JACOBS 2012	NETL	IHS CERA (META-STUDY)	% OF EU CRUDE
EU		1.7		5.3								9.0%
	UK				3.4	3.0			3.6[α]			5.0%
Norway						2.5			3.6			11.6%
North America		3.3										0.1%
	U.S.		7.45	14.8^^		2.8				4.0	4.1	Imports of refined diesel
	Alaska						0.9					
	Texas						1				0.7	
	Gulf Coast							11.8				
	California						12.2	18.9			14.5	
	Canada (conventional)			8.8	3.8	1.6	2.8			5.7	2.4	0.07%
	Canada (oil sands)	20.0	19.6[a]	19.1^	17.8	13.0	19.2[a]	15.6[a]	14.6 (6.1-21.1)[a]	18.0	11.9[a]	Believed to be negligible
Africa		7.6										21.3%
	Nigeria			14.8	12.6		16.8	16.8	11.3	20.9	14.0	5.4%
	Angola									13.3		1.6%
	North Africa			9.1								12.3%
	Libya					3.2			5.2			8.9%
	Algeria									5.7		2.2%

REGION		JEC (OGP)	GREET	GHGenius	McC&A	ER**	TIAX	JACOBS 2009	JACOBS 2012	NETL	IHS CERA (META-STUDY)	% OF EU CRUDE
Asia		4.3										0%
	Indonesia			12.0		4.5						0%
FSU		3.9										41.7%
	Russia					5.9			6.8			29.1%
Middle East		3.1		11.0							16.7	13.8%
	Iraq						5.1	10.1	7.8	3.1		1.9%
	Saudi Arabia				5.5	2.0	0.3	5.0	3.8	2.2	2.0	6.3%
	Kuwait									2.7		0.6%
	Iran					23.9			5.9			4.1%
South America		3.6										2.5%
	Mexico			9.5		5.4	3.1	9		6.3	5.3	1.4%
	Venezuela			6.0	19.1	11.6	10.3	6.1	5.6	3.9 (15.5)β	12.3^	0.7%
	Ecuador									5.0		< 0.2%
	Brazil								4.8	20.8		0.62%

**JEC revise the OGP emissions upwards based on higher flaring estimates from satellites. This is only captured for the global average.*
***Energy Redefined give example crudes, not national averages, and only well to refinery gate values. We have used their approximately linear scaling of refinery emissions to API to back refining out, but transport to refinery is still included.*
ªThis model covers a number of oil sands pathways - this is a simple arithmetic average, including upgrading where appropriate.
^GHGenius includes both bitumen and SCO pathways. This is the average for the production GHGenius models in 2011.
^^GHGenius reports relatively high U.S. emissions because U.S. heavy and offshore production are modeled as being very energy intensive.
αJacobs (2012) have two UK crudes – Forties and Mariner. This is an arithmetic average.
βNETL (2009) report a separate value for Venezuelan extra heavy, shown in parentheses.

ES.IV. Best practices for oil and gas GHG estimation tools

There is no single specification for the 'ideal' modeling tool for upstream oil and gas emissions. Building a tool that estimates greenhouse gas (GHG) emissions from oil and gas operations could be done at a variety of levels of detail and using an assortment of approaches, tools, and modeling frameworks. The ideal qualities for such a model would include (i) rigor, complexity and calculation detail; (ii) transparency of data sources and modeling equations; (iii) completeness in coverage of sources and types of emissions; (iv) usability of model and controls by outside parties; (v) choice and quality assessment of data, defaults and model parameterization; and, (vi) consistency in the presentation of model output and results. Some of these qualities are in tension i.e. a more complete and rigorous model is generally more complex and less easy to use. Guidelines such as the International Organization for Standardization (ISO) 14040 lifecycle assessment (LCA) framework, the International Reference Lifecycle Data System (ILCD) Handbook (European Commission 2010) and the American Petroleum Institute (API) compendium of GHG emissions estimation methodologies for the oil and gas industry (API 2009) provide additional guidance on good practice. An LCA exercise should be accompanied by a consideration of data quality.

ES.V. Predictive model: OPGEE

The Oil Production Greenhouse Gas Emissions Estimator (OPGEE) is an engineering-based lifecycle assessment (LCA) tool for the measurement of greenhouse gas (GHG) emissions from the production, processing, and transport of crude petroleum. It is a project of Stanford University administered by Dr. Adam Brandt. The lead modeler is Dr. Hassan El-Houjeiri. The modified version of OPGEE used to calculate the EU Baseline in this report (OPGEE v1.0.ICCT), was developed by Dr. Chris Malins and Sebastian Galarza of the ICCT (see Annex C).

OPGEE has been developed to fill a gap in the set of currently available public tools for GHG analysis of oil production. Tools like GREET and GHGenius have broad scope, are publically available and transparent, but do not include process-level details. Models such as those used by Jacobs and Energy Redefined, model processes but are proprietary, so that the public cannot reproduce results from these models. The goals of the OPGEE project are to:

1. Build a rigorous, engineering-based model of GHG emissions from oil production operations.

2. Use detailed data, where available, to provide maximum accuracy and flexibility.

3. Use public data wherever possible.

4. Document sources for all equations, parameters, and input assumptions.
5. Provide a model that is free to access, use, and modify by any interested party.
6. Build a model that easily integrates with existing fuel cycle models and could readily be extended to include additional functionality (e.g. refining).

In developing OPGEE, the following principles have been observed:

- A model should have clear system boundaries, based on significance criteria;
- A model should follow established guidance in areas where there is more than one methodological option (e.g. co-product treatment);
- A model should use fundamentals of petroleum engineering where possible;
- The level of detail should be appropriate to the uncertainty and accuracy of data inputs – an LCA model need not reflect the level of detail required in an industrial model;
- A model should have rigorous default values included;
- A model should be transparent with comprehensive documentation and clear citations;
- A model should be freely available for download by interested parties;
- A model should be as complete as possible in its coverage of significant emissions sources;

The OPGEE model is built in the spreadsheet application *Microsoft Excel*. Excel is a widely owned and used software application, and the use of Excel makes the workings of the model (including all calculations) accessible to most users, and opens the possibility of customization under the open source license.

The system boundary of OPGEE extends from initial exploration to the refinery gate, and the processes modeled and parameters included are based on a sensitivity assessment. All emissions sources expected to be of order 1 gCO_2e/MJ are included in the modeling, as are most sources greater than 0.01 gCO_2e/MJ) – smaller sources are excluded unless they have incidental importance in the process modeling. OPGEE includes seven process stages in its scope: Exploration; Drilling and Development; Production and Extraction; Surface Processing; Maintenance; Waste Disposal; Crude Transport – the significant emissions sources are listed by process stage in Table D.

Table D Upstream oil production emission sources > 0.1 gCO_2e/MJ (OPGEE v1.0)

MAIN STAGE	PROCESS	SUB-PROCESS	EMISSIONS SOURCE	ESTIMATED MAGNITUDE (gCO_2e/MJ)
Drilling and development	Developmental drilling	Terrestrial drilling	Prime mover emissions	~ 0.1 g
			Vents and upset emissions	~ 0.1 g
			Land use impacts	~ 0.1 g
		Oceanic drilling	Prime mover emissions	~ 0.1 g
			Vents and upset emissions	~ 0.1 g
Production and extraction	Lifting	Pumping	Combustion for pump driver	~ 1 g
			Electricity for pump driver	~ 1 g
			Casing and wellhead fugitive emissions	~ 1 g
		Gas lift	Compressor prime mover emissions	~ 1 g
			Compression electricity emissions	~ 1 g
			Casing and wellhead fugitive emissions	~ 1 g
	Injection	Gas injection	External gas processing (e.g., N2 production)	~ 0.1 g
			Gas compression energy	~ 1 g
			[-] Gas sequestration credit (CO_2 flood)	~ 1 g
			OTSG fuel combustion	~ 10 g
			Turbine gas consumption (combined cycle)	~ 10 g
			HRSG duct firing (combined cycle)	~ 1 g
			[-] Electricity co-production offsets (combined cycle)	~ 10 g
Separation and surface processing	Fluid separation	Oil-water-gas separation	Oil-water-gas separation	~ 0.1 g
			Oil-water-gas separation with heater-treaters	~ 0.1 g
			Associated gas venting	~ 10 g
			Associated gas flaring	~ 10 g
			Produced gas venting and flaring	~ 1 g
		Water treatment	Produced water cleanup	~ 0.1 g

MAIN STAGE	PROCESS	SUB-PROCESS	EMISSIONS SOURCE	ESTIMATED MAGNITUDE (gCO_2e/MJ)
	Water treatment and disposal		Produced water handling and pumping	~ 0.1 g
		Water reinjection and disposal	Produced water reinjection	~ 1 g
			Produced water disposal	~ 0.1 g
			Evaporative and fugitive emissions	~ 0.1 g
			Fugitive emissions during workover	~ 0.1 g
			Fugitive emissions during workover	~ 0.1 g
Crude product transport	Pipeline transport	Pipeline transport	Combustion for pump prime mover	~ 1 g
			Electricity for pump use	~ 1 g
			Leaks (pipeline losses)	~ 1 g
	Tanker transport	Tanker transport	Combustion in tanker prime mover (bunker fuels)	~ 1 g
			Evaporative and fugitive emissions	~ 0.1 g

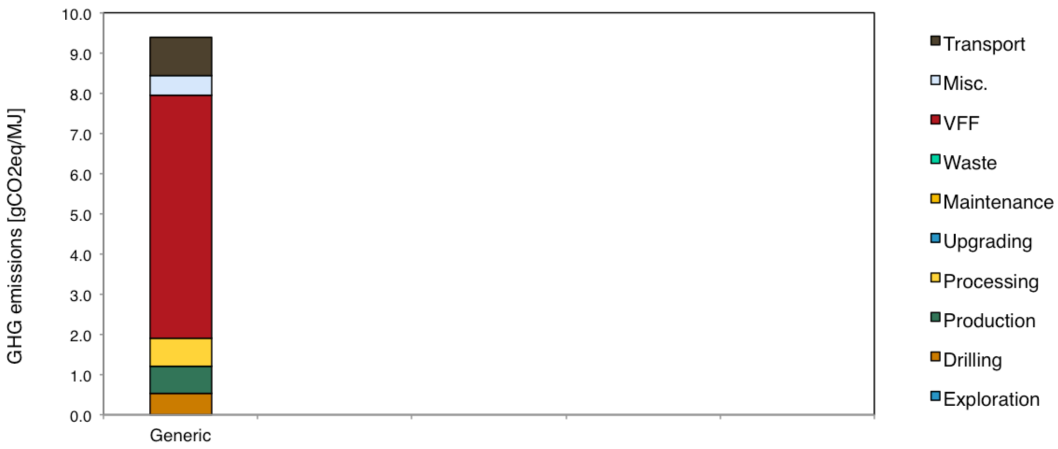
For most users, the simplest way to control OPGEE is via a 'User Inputs and Results' worksheet. On this worksheet, the user can specify key parameters based on either their own data or the OPGEE defaults (Table E), and can see the results of the OPGEE analysis in summary emissions and energy consumption charts (Figure C). Users with a more detailed understanding of the petroleum engineering principles characterized in OPGEE, and/or with access to detailed industry data, can also amend the various secondary input parameters.

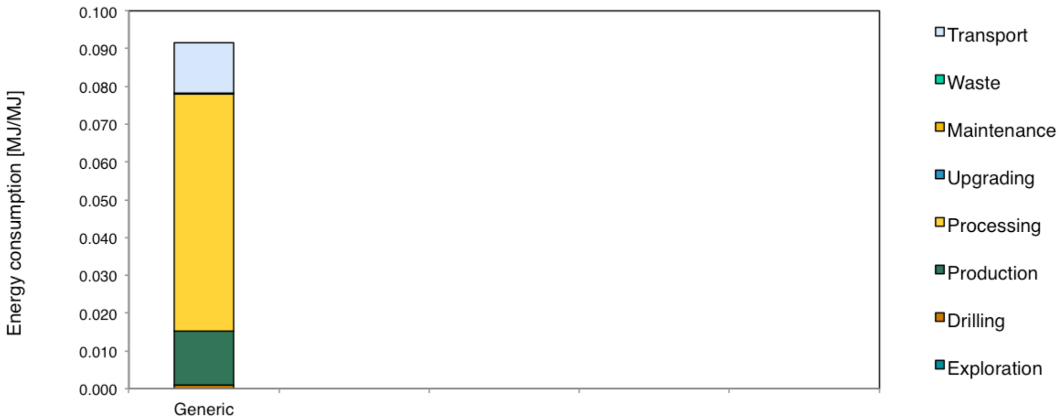
Table E OPGEE Primary Data Inputs (Brandt 2012)

GENERAL FIELD PROPERTIES	PRODUCTION PRACTICES
Field Location Field Depth Field Age Reservoir Pressure Oil Production Volume Number of Producing Wells	Gas to Oil Ratio (GOR) Water to Oil Ratio (WOR) Steam to Oil Ratio (SOR) Water Injection (Y/N, Quantity) Gas Injection (Y/N, Quantity) N_2 Injection (Y/N, Quantity) Steam Injection (Y/N, Quantity) Onsite Electricity Generation
PROCESSING PRACTICES	**FLUID PROPERTIES**
Heater-Treater (Y/N) Stabilizer Column (Y/N) Flaring Volume Venting Volume	API Gravity of Produced Fluid Associated Gas Composition

For all inputs, user data can be entered but the model also includes default values for use in the absence of user data. These defaults are based on review of the available petroleum engineering literature, and are intended to represent typical values. In some cases rather than specifying a default parameter as a single number, it is more appropriate to base the default on a relationship. As an example, the water-oil-ratio (WOR) for a field will generally increase with age, and so the default for WOR is an exponential relationship parameterized by the age of the field.

Figure C. Example of summary GHG emissions (above) and energy consumption (below) for 'default' oilfield (graphs taken directly from OPGEE v1.0)[1]





[1] *VFF is short for 'venting, flaring and fugitive emissions'.*

As with any model, OPGEE has limitations and areas where there are opportunities for additional development. Some production technologies are not explicitly modeled – for instance Canadian bitumen extraction is currently characterized by reference to results from the GHGenius model (based on company reporting) rather than assessed using process modeling. The GHGenius-based approach should give a good approximation (see Brandt, 2011a), but it would be more consistent with the treatment of conventional oil to adopt a petroleum engineering approach. There are also areas in which a more sophisticated physical model could give a more accurate characterization of real emissions. For instance, OPGEE currently models single-phase fluid flow in the well bore. This is likely to be a good approximation to real flow for most fields, but in cases such as fields with very high gas-oil-ratio (GOR) fields a two phase flow model would be likely to provide greater accuracy.

The greatest challenge to improving the accuracy of results, especially in the context of attempting to estimate a European baseline fuel carbon intensity, is the availability of data. While it would be ideal for all parameters to be reported based on real data, the priority in developing the modeling framework through consultation with industry should be to improve coverage of the most important input parameters. The key drivers of energy use are: gas-oil-ratio and gas processing decisions; water-oil-ratio; steam-oil-ratio in the case of thermally enhanced recovery; depth and pressure of reservoir; and identification of the processes used for each field. In addition to energy use, the key driver of carbon intensity is the rate of gas flaring – for fields with very high flared volumes, the flare rate is the primary driver of the carbon intensity. In general, if these parameters are well characterized for a given field, then a more accurate estimation of the CI of the field can be derived.

Priorities for OPGEE development in the short to medium term are:

- Developing a two-phase flow-lifting model. This adds complexity to model calculations but does not increase the number of input parameters.
- Building an engineering-based model for the calculation of GHG emissions from oil sands production (current module is derived from GHGenius [see http://www.ghgenius.ca/]).
- Building modules for innovative production technologies such as solar steam generation and CO_2 flooding.
- Making the modeling sensitive to the secondary effects on fluid flow due to steam injection and gas injection.
- Adding flexibility to the gas-processing scheme to allow the options of removing the gas dehydrator and/or AGR unit.
- Collecting more data and improving the correlations of WOR and GOR defaults.
- Calculating field-level flaring rates following completion of ongoing work by Elvidge (NOAA) and Hart (UC Davis).
- Using technical reports and workbooks to update fugitive and venting emission factors.

ES.VI. Data availability and collection

As part of this study, an analysis was conducted to determine the quantity, quality and (in certain cases) cost of available data on crude oil production, focused on the main data requirements of the OPGEE tool – and to collect this data to undertake an assessment of the baseline CI of the European crude slate. Given limitations in data access and transparency within the oil industry, many oilfields have little or no information readily accessible in the public domain - while publically available data sources have been prioritized, we have also identified proprietary datasets.

The default values in OPGEE were constructed based on public data available through the California State Department of Oil, Gas, and Geothermal Resources (DOGGR) Report (2007) and the CARB survey

(2011), national authorities like the EIA and a broad range of sources from existing literature. The default values are detailed with sources in the OPGEE model (OPGEE 1.0.ICCT) and OPGEE documentation (Annex D).

Estimating CIs of oil field-by-field requires identifying sources for the input data. In the case of oil entering the EU, only Britain, Denmark and Nigeria publish extensive national oil production statistics at the field level. These datasets contain detailed (monthly) time series data at the field level across a number of parameters included in the OPGEE model. These datasets do not however include information on oilfield characteristics such as depth and pressure, or on processes used for oil extraction – this information has to be sourced from a combination of proprietary datasets and the available literature.

The data collection for the EU baseline has concentrated on the following parameters that are identified as key inputs by El-Houjeiri et al. (2013):

- Field depth –referenced for 81% of fields in the EU Baseline.
- Reservoir pressure – referenced for 32% of fields in the EU Baseline.
- Oil production volume – referenced for all fields in the EU Baseline.
- API gravity – referenced for 98% of fields in the EU Baseline.
- Gas-oil-ratio – referenced for 68% of fields in the EU Baseline.
- Water-oil-ratio – referenced for 76% of fields in the EU Baseline.
- Flaring-oil-ratio – referenced for 56% of fields in the EU Baseline (otherwise based on national flaring averages from NOAA).

El-Houjeiri et al. also identify productivity index and steam-oil-ratio as key parameters. Productivity index is difficult to find recorded in the public domain, and has been set based on defaults. The EU Baseline does not currently include any fields that use steam injection, and hence no steam-oil-ratios have been identified. In addition to these input parameters, emissions can be sensitive to assumptions about production processes. For instance, thirty fields have been identified as using gas lift, while for other fields where the reservoir pressure does not supply adequate lifting force the default assumption is that a downhole pump is used. Confirming production processes for most fields is likely to require industry consultation.

Overall, we have been able to obtain adequate data to perform an initial analysis of over 300 oil fields – many more than covered in any previous crude oil CI analysis of which we are aware, with the exception of ICCT/ER (2010). Importantly, the EU sources a significant portion of its crude from Russia and FSU countries, where crude production data is particularly difficult to obtain. The extent to which these countries are accurately covered in proprietary datasets is unclear. For the North Sea, in contrast, data availability is very good – the UK and Denmark publish extensive datasets, and it seems likely that access to additional data for Norway may be negotiable in future. The key data sources are summarized in Table F[vi]. Where data is not available or has not yet been identified, defaults are used. While in many cases OPGEE's defaults will provide reasonable answers, reliance on these values necessarily introduces an additional degree of uncertainty to the model.

[vi] A full bibliography is given in the body of this report, §11.

Table F Summary of available input parameters by data source

INPUT PARAMETER	EIA	DG ENER	DOGGR	CARB	ERCB	NOAA/ WORLD BANK	ER	OGJ	DECC (UK)	DEA (DK)	NNPC (NG)	CIMS	WORLD ENERGY ATLAS
API Gravity	✓						✓	✓			✓	✓	
Reservoir Pressure			✓				✓						
Reservoir Depth	✓		✓	✓			✓						
Reservoir Temperature			✓				✓						
Viscosity							✓					✓	
GOR			✓	✓	✓		✓		✓	✓	✓		
WOR			✓	✓	✓		✓		✓	✓	✓		
Age of Field			✓		✓		✓	✓					
Flaring Rate				✓		✓	✓		✓		✓		
Venting Rate				✓		✓	✓		✓		✓		
Fugitive Emissions				✓		✓	✓				✓		
Type of Lift				✓			✓						
Development Type				✓			✓						
Field Location			✓	✓	✓		✓	✓	✓	✓	✓	✓	✓
Field Depth			✓	✓			✓	✓					
Number of Wells							✓	✓			✓		
Associated Gas Composition	✓		✓	✓	✓		✓		✓		✓		
Production Volumes	✓	✓	✓	✓	✓		✓	✓	✓	✓	✓	✓	
Water Injection			✓	✓	✓		✓		✓		✓		
Gas Injection			✓	✓	✓		✓		✓		✓		
Nitrogen Gas Injection			✓	✓	✓		✓						
Steam Injection			✓	✓	✓		✓						
Onsite Electricity Gen.			✓	✓			✓						
MCON/Blend												✓	

ES.VII. The EU baseline

In order to generate an estimate of the carbon intensity of the EU fossil fuel baseline, we have used a 'representative fields' approach to approximate the carbon intensity of the crudes consumed in Europe. In this approach we have taken the list of crudes consumed in Europe published by DG Energy for 2010[vii], and compared it to the 265 oilfields we have analyzed with OPGEE. For each field, we have determined based on location, API and information from the Crude Information Management System (CIMS) database which crude stream that field would most likely be feeding (it is not possible to directly determine from the DG Energy data exactly which fields have supplied Europe). Where we have data on many oilfields supplying a given crude, we have calculated a production-weighted average of the CIs of those fields to describe the crude stream as a whole. Where we have data for only one field, we have taken the CI of that field and treated it as representative of the entire crude stream. Using this approach, we have estimated CIs for crude streams representing up to 93 percent of European crude consumption. There is necessarily more uncertainty in the estimated CI for crudes associated with only one field, than for crudes associated with large numbers of fields.

This assessment represents the most comprehensive attempt to date to characterize the carbon intensity of crude oil entering Europe using a public model and public data.[viii] In particular, it is a more detailed analysis than the JEC Well-to-Wheels report (JEC, 2011), in the sense that it considers hundreds of oilfields individually rather than relying on aggregated industry reporting. Based on our analysis, the average upstream carbon intensity of oil supplied to Europe is estimated to be 10.2 gCO_2e/MJ. This is higher than previous assessments from JEC (2011) and ICCT/ER (2010). JEC (2011) suggested an average upstream CI of about 6 gCO_2e/MJ, based on energy consumption data from the International Association of Oil and Gas Producers (OGP) and regional flaring data. OPGEE models somewhat higher average upstream energy requirements[ix] in each region than are reported by OGP, and this is the primary reason for the difference between the EU baseline presented here and the JEC WTW value. Additional calibration against industry data would be appropriate to ensure OPGEE is not systematically overestimating energy needs. Note that reported energy consumption rose by 16% in OGP's 2011 data (OGP 2012) compared to the 2004 data referenced by the JEC WTW report, although this increase would still not fully explain the difference between JEC and OPGEE. The carbon intensities by crude stream are detailed in Table G.

[vii] We have excluded from the analysis crude oil sources making a very small contribution to EU imports, and crude streams defined very loosely in the DG Energy reporting (such as 'Other Africa').
[viii] We have referenced a substantial amount of data from paid-for sources, notably the Oil and Gas Journal (OGJ). While this data is not in the free public domain, it is readily available at relatively modest cost.
[ix] Note that the system boundary for OPGEE is drawn wider than for OGP, but this alone does not explain the gap.

Table G EU Crude Carbon Intensity Baseline (as estimated using OPGEE and the 'representative crudes' methodology)

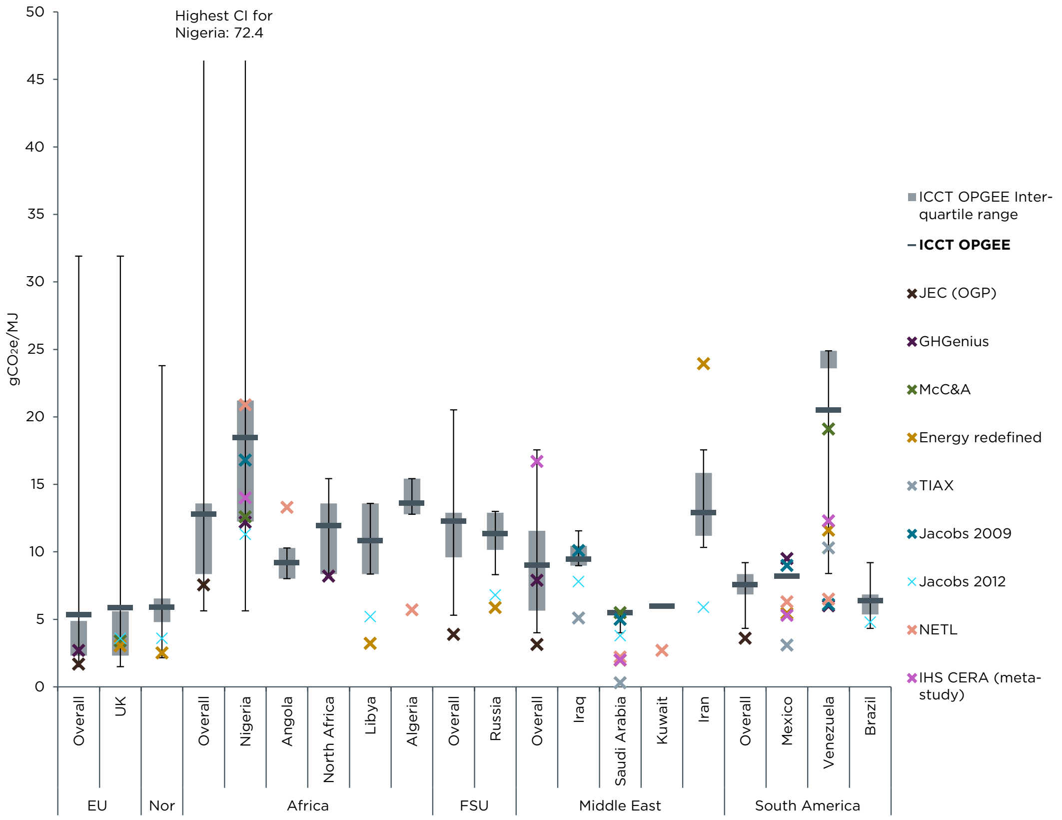
REGION	COUNTRY	CRUDE	CRUDE CARBON INTENSITY (gCO_2e/MJ)	2010 CONSUMPTION IN EU (1,000 BBL)	% OF EU CRUDE
Africa	Algeria	Other Algerian Crude	15.4	19,076	0.4%
Africa	Algeria	Saharan Blend	12.8	40,738	0.9%
Africa	Angola	Other Angolan Crude	9.2	58,089	1.3%
Africa	Cameroon	Cameroon Crude	23.3	14,838	0.3%
Africa	Congo	Congo Crude	13.0	19,223	0.4%
Africa	Egypt	Egyptian Medium/Light (30-40°)	8.9	19,429	0.4%
Africa	Libyan Arab Jamahiriya	Libyan Heavy (<30° API)	8.9	14,992	0.3%
Africa	Libyan Arab Jamahiriya	Libyan Light (>40°)	8.3	196,971	4.6%
Africa	Libyan Arab Jamahiriya	Libyan Medium (30-40°)	13.6	191,018	4.4%
Africa	Nigeria	Nigerian Light (33-45°)	18.5	120,680	2.8%
Africa	Nigeria	Nigerian Medium (<33°)	18.3	32,989	0.8%
America	Brazil	Brazil Crude	6.5	34,648	0.8%
America	Mexico	Maya	8.2	39,729	0.9%
America	Venezuela	Venezuelan Extra Heavy (<17°)	8.4	16,036	0.4%
Europe	Denmark	Denmark Crude	3.2	89,133	2.1%
Europe	Norway	Ekofisk	2.8	86,989	2.0%
Europe	Norway	Gullfaks	8.8	44,408	1.0%
Europe	Norway	Oseberg	6.4	57,310	1.3%
Europe	Norway	Other Norwegian Crude	6.3	249,212	5.8%
Europe	Norway	Statfjord	6.4	54,439	1.3%
Europe	United Kingdom	Brent Blend	8.8	57,589	1.3%
Europe	United Kingdom	Flotta	10.4	17,907	0.4%
Europe	United Kingdom	Forties	3.4	152,792	3.5%
Europe	United Kingdom	Other UK Crude	6.7	144,748	3.4%
FSU	Azerbaijan	Azerbaijan Crude	5.4	146,742	3.4%
FSU	Kazakhstan	Kazakhstan Crude	17.7	224,638	5.2%
FSU	Other FSU countries	Other FSU Crude	20.5	105,827	2.5%
FSU	Russian Federation	Other Russian Fed. Crude	9.8	480,350	11.1%
FSU	Russian Federation	Urals	12.5	637,003	14.7%
Middle East	Iran	Iranian Heavy	11.5	110,759	2.6%
Middle East	Iran	Iranian Light	16.2	61,179	1.4%
Middle East	Iran	Other Iran Crude	11.7	40,811	0.9%
Middle East	Iraq	Basrah Light	10.4	22,885	0.5%
Middle East	Iraq	Kirkuk	9.0	85,192	2.0%

REGION	COUNTRY	CRUDE	CRUDE CARBON INTENSITY (gCO_2e/MJ)	2010 CONSUMPTION IN EU (1,000 BBL)	% OF EU CRUDE
Middle East	Iraq	Other Iraq Crude	11.5	10,483	0.2%
Middle East	Kuwait	Kuwait Blend	6.0	24,753	0.6%
Middle East	Saudi Arabia	Arab Light	5.5	219,859	5.1%
Middle East	Syria	Souedie	7.8	40,661	0.9%
Middle East	Syria	Syria Light	10.1	13,802	0.3%
EU baseline average CI:		**10.2**	**Total crude modeled (1,000 bbl):**		**3,997,924**

The EU Baseline calculated here is based on a much broader analysis of world crude production than most previous studies. Figure D shows that for most regions, the average values estimated with OPGEE are comparable to estimates from previous LCA studies.[x] The range of emissions estimates, especially where access to data is best, tends to be much wider than in the literature. This is largely because previous studies have generally modeled a single average or a single representative crude, rather than average CIs across many analyzed crudes, and have used different methodologies. In several cases, production processes vary significantly within a given region. In general, for the crude producing nations most often considered in the literature, such as Mexico, Saudi Arabia, Iraq and Nigeria, the OPGEE average values from the EU Baseline fall within the previously reported range.

[x] Note that for comparative purposes we have included Venezuelan upgraded heavy oil in Table D, but these fields are not part of the EU baseline.

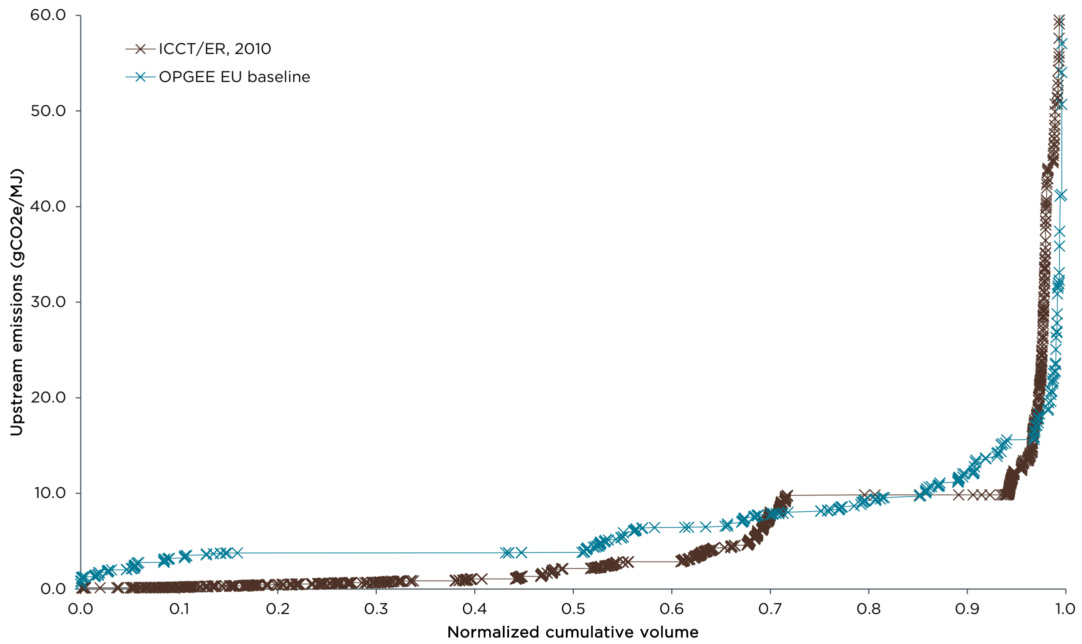
Figure D. OPGEE estimated average and range for regional oil production CI with values reported by previous LCA studies



The CI range for Nigerian fields goes up to 72 gCO_2e/MJ for Tapa, which reports nearly 5000 scf/bbl of gas flaring.
Note that where literature estimates have been associated with an overall region, this is because that is how they were reported in the relevant report – whereas the 'overall' values and ranges reported for OPGEE represent the full range of fields within that region.

The only study with a broader coverage of crudes than the EU Baseline in this report is ICCT/ER (2010), where over 3,000 fields were assessed. That study had different system boundaries than OGPEE (it included refining, and excluded sources such as drilling and exploration). For purposes of a fair comparison, in Figure E the carbon emissions from production only are compared for ICCT/ER against the OPGEE EU baseline. ICCT/ER find an average production CI of 5.3 gCO_2e/MJ, while OPGEE gives an average using the representative fields methodology of 8.5 gCO_2e/MJ. Both studies show a similar pattern of CI values – the first half of production is at relatively low CIs, followed by another 40-45% that are higher and a final 5-10% of fields with very high emissions, due to high flaring, high WOR (OPGEE), upgrading, thermally enhanced production (ICCT/ER) and so on. In the case of wells with high WOR, in many cases reservoir depletion may be making the wells progressively less economically viable, and these may be relatively marginal oil resources. In other cases, such as large Nigerian fields with high volumes of gas flaring, high carbon intensity cannot be taken to imply marginality of production. The similarities in results between the two modeling efforts suggest that the EU Baseline from OPGEE is delivering a good characterization of the CI of crude entering Europe.

Figure E. Comparing the ICCT/ER (2010) and OPGEE carbon intensity values – production emissions only*, by normalized cumulative volume of oil



**OPGEE normally includes transport, drilling and exploration in the system boundary. ICCT/ER included transport and refining. The values charted here are for production only for purposes of comparison.*

The EU Baseline presented here represents the best estimate with the data available. The results suggest that the EU crude slate may be somewhat more carbon intensive than has been previously assessed – further data collection will help to confirm that conclusion, or to produce a more accurate alternative value. For this report we have used typical (rather than actively conservative) default values. For a regulatory implementation, it might be appropriate to consider being systematically conservative[xi] in the estimation of CIs, as has been done for biofuels under the Fuel Quality and Renewable Energy Directives (FQD and RED).

ES.VIII. Comparative analysis of policy options

The availability of OPGEE to the regulatory community introduces the option to regulate the upstream carbon intensity of crude oil production at a greater level of detail and accuracy than would previously have been possible. Accurate estimation of crude CI can be important both in regulations aiming to manage carbon emissions from crude production itself, and also in regulations to encourage the use of alternative fuels, which are often based on comparisons to conventional fossil fuel baselines.

Any system that attributed a higher CI to a given crude under the Fuel Quality Directive would reduce the value of that fuel to refiners (as the

[xi] Issues relating to conservatism are discussed in §9.1.3.a.

higher emissions would need to be offset). Similarly, assigning a particular crude a lower CI would provide increased value, creating an incentive for producers to reduce emissions. Depending on relative cost, fuel suppliers could respond by using larger quantities of alternative fuels to offset the use of higher carbon crudes, invest in reducing carbon emissions from existing crude streams or switch to alternative lower carbon crudes (reducing the incentive for further investment in high carbon extraction processes).

There are several precedents that suggest the types of policies that could be implemented to control fossil fuel carbon intensity. This report discusses the following approaches:

- Full reporting and accounting;
- Hybrid reporting approach analogous to biofuel reporting under RED/FQD, RTFO;
- Feedstock defaults approach outlined in DG Clima implementing proposal for Fuel Quality Directive;
- High Carbon Intensity Crude Oil (HCICO) approach adopted by CARB in 2011 for the LCFS;
- California average approach adopted in 2012 by CARB to replace HCICO approach;
- Other approaches proposed for discussion by CARB;
- British Columbian treatment under the RLCFRR;
- Country/region specific default values approach (RTFO 2008/10);
- Emissions reduction credits approach modeled on the Clean Development Mechanism (CDM).

The highest level of disaggregation and accuracy would be available through a full reporting and accounting system, in which fuel suppliers were required to either report a defined set of OPGEE inputs to an administrator, or to arrange for verifiable OPGEE calculations to be made independently and report the results. Such a system would provide the most accurate possible market signals, as each crude would be assigned its own specific carbon intensity.

In biofuel regulations, several regulators have looked to minimize the burden of CI reporting by adopting hybrid reporting systems, in which the option to report detailed values is complemented by conservative lookup values for each pathway. A hybrid regulation for fossil fuels would have similarities to existing regulations. The biofuel treatment under LCFS and RTFO (and other RED implementations), plus the fossil fuel treatment under RLCFRR and several proposed California approaches to fossil fuel accounting are all variations on hybrid reporting. Under such a hybrid regime, lookup tables would be provided for a specified set of crude categories but an option would be allowed for fuel suppliers to demonstrate better performance. If the intention is to generate value for lower carbon crudes and for emissions reduction projects, it is important that the option to demonstrate better-than-default performance exist, as this is allows suppliers to achieve value by showing improved performance. OPGEE provides an ideal analytical framework for a hybrid regime, as fuel suppliers would be able to determine the carbon saving offered by a given emissions reduction strategy and use OPGEE emissions estimates to guide their decision-making. Under a hybrid scheme, defaults could be set at a variety of levels. They could be based on feedstock, as in the existing Fuel Quality Directive proposed Implementing Measure. Alternatively, further disaggregation could be achieved, especially for conventional fuels, by identifying a broader range of categories. Further analysis with OPGEE could be undertaken to identify the most effective characteristics that could be used to apply a disaggregation. Opportunities for disaggregation of conventional crudes include splitting out thermally enhanced oil production or the use of upgraders.

There are also options for regulatory frameworks with fewer opportunities for suppliers to report oilfield specific values. Under the FQD proposed Implementing Measure, only fuel-feedstock combinations with default CI higher than fuels from conventional crude would be permitted to report actual emissions data – credits would not be available for conventional crudes with a lower CI than the default. Similarly, under the California HCICO screening approach, most crudes would have been in a single emissions bin with no benefit from reporting lower-than-default CI for a given field. Options with less disaggregation may be most appropriate if the priority is to set an accurate baseline to measure alternative fuels, to reduce the risk of having the very highest CI streams enter the market or to move through a reporting and data gathering phase before a more stringent future measure.

An alternative or complement to a hybrid-reporting scheme would be to directly offer incentives for performance improvements. In California, for instance, credits can be earned under the LCFS for the adoption of innovative oil extraction processes that reduce emissions. Similarly, flaring reduction projects are already eligible in principle for crediting under the United Nations Clean Development Mechanism (CDM). The FQD proposed Implementing Measure envisions credits being made available for upstream emissions reduction projects. Where any emissions reductions are being achieved through changes that can be modeled by OPGEE (e.g. reduced flare rate, change of lift method, implementing gas export etc.), then the credits that should be awarded to the project could also be calculated with OPGEE. In the case that innovative technologies not yet modeled by OPGEE were being implemented, either an expansion of OPGEE to include a new module or an alternative credit calculation methodology would be necessary.

Any crude oil carbon intensity regulation needs to be consistent with existing legal obligations. There should be no fundamental legal barriers to adopting any of the policy options discussed in this report at the European Union or Member State level, especially given that the FQD has already been adopted. The most likely legal barrier to adoption of one of these policies would come from international trade law and the WTO treaties. International trade law provides explicitly for the application of regulations to protect the environment, including to manage greenhouse gas emissions – however, such measures must conform to the General Agreement on Tariffs and Trade (GATT).

Normally, the GATT prohibits the discrimination of 'like' products, where likeness is determined by end use, physical properties, tariff classification, and consumer tastes and habits. A regulation such as the FQD proposed Implementing Measure that discriminates only between feedstocks with clearly different physical properties would be relatively unlikely to be successfully challenged as discriminating between like products, but a measure disaggregating among conventional crudes may be more vulnerable. Fortunately, Article XX of the GATT provides exceptions to the likeness principle for "*measures for the conservation of exhaustible natural resources*". It is likely that measures to protect the climate fall under this exception, in which case the key criterion for any regulation is that, "*measures are not applied in a manner which would constitute a means of arbitrary or unjustifiable discrimination between countries where the same conditions prevail, or a disguised restriction on international trade*."

ES.IX. Conclusions

The experience of biofuel regulation through policies such as Europe's RED, the UK's RTFO, California's LCFS and the U.S. federal RFS has demonstrated that effective regulation of the climate impact of transportation fuels is possible, but requires a solid basis in lifecycle analysis. Until now, while there have been many studies of the lifecycle emissions of fossil fuel extraction, there has been no transparent analytical framework available to regulators that is able to provide detailed, process based analysis of different oil extraction pathways. A full process-based modeling framework is less necessary when the primary purpose is to set a baseline fuel carbon intensity against which to compare alternative fuels (NETL, 2009; JEC, 2011). In those cases, the task is to provide a reasonable characterization of the average (or marginal) emissions of fossil fuel, against which thresholds may be set for alternative fuels. A certain amount of disaggregation of fossil fuels can be achieved without full process modeling, for instance by focusing on clearly defined fuel categories with distinctly different carbon footprints, such as the different feedstock pathways in the FQD draft implementing measure. However, a more sophisticated tool is necessary to accurately disaggregate the emissions intensity of *prima facie* similar crude oils, or (as in the California average approach under LCFS) to accurately capture year on year changes in the CI of the fuel mix.

In this report we have presented the Oil Production Greenhouse Gas Emissions Estimator (OPGEE), a spreadsheet model that uses engineering principles to assess the carbon intensity of oil production. Like Biograce or CA-GREET for biofuels, providing an adequate set of inputs for use with OPGEE can provide an accurate assessment of the CI of a given crude oil pathway, and determine with reasonable certainty which of two crude oil pathways is the more carbon intensive. OPGEE v1.0 is able to provide a reasonable assessment of the CI of most current crude oil production, but there remain additional processes to model and areas to further improve OPGEEs accuracy – priority areas to enhance OPGEE include modeling two-phase fluid flow and adding a module for the process modeling of bitumen extraction.

Once a model has been built, the greatest challenge for any LCA exercise on the scale of calculating the CI of the European crude oil baseline is the collection of robust data. In general, it is difficult to find field-specific oil production data, especially for oil fields in countries like Russia with limited transparency. Nevertheless, this report analyses a set of 265 separate oil fields, which represents significant progress compared to studies such as the JRC WTW report which relies on highly aggregated reported data. Where specific data is not available, the OPGEE model is populated with default assumptions sourced from the literature for all data points, allowing estimates to be made even where data is limited to a few key parameters.

The 265 oil fields assessed for the EU Baseline have been associated with crude blends being supplied into Europe (covering 93 percent of European oil consumption) – we estimate that the volume weighted average CI of the oil used in Europe is 10.2 gCO_2e/MJ. This is lower than the baseline of 11.39 gCO_2e/MJ calculated with OPGEE by CARB for crude oils used in California, but somewhat higher than previous JEC and ICCT/ER estimates for EU crude. This assessment is a substantial advance in terms of data coverage and transparency on any previous published work. Additional consultation and data collection from industry would allow this result to be confirmed, or the value to be improved and made more representative of the actual crude used in European refineries.

With respect to data, the situation for European regulators is particularly challenging. While California and British Columbia, both regions that have implemented LCFS-type regulations, are heavily reliant on crude from North America where data is relatively rich, Europe is highly import dependent and imports crude from all over the world. Indeed, the largest single exporter of crude to Europe is Russia – with other countries in the Former Soviet Union being significant suppliers. In these regions data acquisition is likely to be persistently difficult in the short to medium term. Even in areas for which production data is available (e.g. the UK North Sea fields) there is space for input from industry to improve the accuracy of the analysis.

Despite the challenges, there are many examples of transport fuel CI regulation to draw on. Even where data is sparse, a hybrid reporting system with conservative default values could be used to incentivize reporting, gather data and provide real value to good performers. Upstream emissions reductions credits could be made available on the basis of field level reporting, and thus do not rely on a full characterization of the CI of every crude blend or every field. The high emissions coming from some oilfields are indicative of a significant opportunity to deliver carbon savings. For example, incentives to eliminate gas flaring in a country like Nigeria could clearly deliver large GHG benefits, as well as helping it to exploit the value in an important natural resource. As action to address climate change accelerates, it is certain that the significant carbon emissions resulting from extracting crude oil will come under increasing regulatory pressure in the years ahead. Through the FQD, and with analytical tools like OPGEE, the European Union is in a position to set a benchmark for best practice in effective regulation of fossil fuel carbon intensity.

1. Introduction

In 2009, the European Union's Fuel Quality Directive (FQD) was amended and expanded, introducing a requirement for road transport fuel suppliers to reduce by 6 percent the lifecycle greenhouse gas (GHG) intensity (emissions per unit energy) of fuel and other (electric) energy supplied for use in road vehicles, as well as fuel for use in non-road mobile machinery, by the end of the compliance period in 2020. In addition to setting a binding GHG reduction target, the directive includes a detailed methodology for assessing the carbon intensity (CI)[1] of alternative fuels and requires the European Commission to propose an implementing measure for the calculation of the GHG emissions of fuels and other energy from fossil sources. The European Commission has proposed an Implementing Measure, and at the time of writing the Commission had been tasked to undertake an impact assessment of this proposal by the end of 2012.

In this context, the International Council on Clean Transportation (ICCT), together with Stanford University, Energy-Redefined, and Defense Terre, was contracted by the European Commission's Directorate-General for Climate Action (DG Clima) to undertake project CLIMA.C.2/SER/2011/0032r on the *Upstream Emissions of Fossil Fuel Feedstocks for Transport Fuels Consumed in the EU*. This project has three major deliverables. First, several desk studies on the EU fossil fuel feedstock market and associated empirical and modeled data on GHG emissions. Second, the development of an open-source predictive model for estimating the GHG intensity of upstream emissions of fossil fuels delivered to the European market, based on a tool being developed by Stanford University for the California Air Resources Board (CARB). This model is the 'Oil Production GHG Emissions Estimator' (OPGEE). The OPGEE model is an open-source, fully public, engineering-based model of GHG emissions from oil production operations. It has been peer-reviewed in California by legislators and industry leaders as well as academic experts in the field of petroleum engineering. Results generated using the OPGEE model have also been published in the peer reviewed academic literature (El-Houjeiri et al., 2013). Third, we were asked to use the tool, if appropriate, to estimate the CI of the European fossil fuel Baseline (the crudes consumed in Europe in 2010) and to discuss options for using this information in a regulatory context, such as under the FQD.

The current report presents the results of several desk studies on the EU fossil fuel feedstock market and associated empirical and modeled data on GHG emissions; presents a new model for lifecycle analysis of crude oil extraction; and provides an estimate using that model of the carbon intensity of oil supplied to the European Union. The report is structured into the following sections: (§2) a review of existing legislation; (§3) a description of crude oil sourcing for the EU; (§4) a review of existing literature and lifecycle analysis (LCA) studies of fossil fuels; (§5) a review of

[1] Throughout this report, we follow the convention of implicitly including the carbon-equivalent emissions from other greenhouse gases when we use the term 'carbon intensity', based on 100-year global warming potentials (GWPs).

best practices in the construction of LCA models for fossil fuel; (§6) an introduction to the OPGEE model; (§7) a review of available input data for LCA analysis of crude oil; (§8) the resulting EU Baseline calculation based on the OPGEE tool; (§9) policy options to regulate fossil fuel carbon intensity; and (§10) study conclusions.

2. Existing legislation

2.1. Introduction

The transportation sector is a significant source of greenhouse gases, contributing about 12 percent of global anthropogenic GHG emissions to the atmosphere (World Resources Institute [WRI], 2005). This contribution from the transport sector is expected to grow in coming years as the use of personal cars in developing countries increases. Governments around the world are responding to this challenge by introducing stringent fuel economy standards and by devising and implementing low carbon fuel policies to promote alternative fuels with lower carbon intensities. In some cases, governments have also begun to introduce policies designed to reward the use of fossil fuels with relatively low lifecycle carbon emissions, and to discourage the use of fossil fuels with relatively high lifecycle emissions.

There are three major categories of low carbon fuel policies. First, there are volumetric standards that require minimum amounts of renewable fuel to be used in transport based fuels either on volume or on energy content, with no mandatory standard for carbon performance and no additional value assigned to lower carbon fuels. Two examples in this category would be the UK Renewable Transport Fuel Obligation (RTFO), introduced in 2008, and the Canadian Renewable Fuel Regulations. A second category can be thought of as hybrid policies that have volumetric targets but also impose some sort of mandatory performance expectations. Examples of these policies include the Renewable Fuel Standards in the U.S. (RFS2) and the European Union's Renewable Energy Directive (RED), both of which have minimum carbon performance standards for certain fuel categories.[2] The EU RED requires biofuels to reduce GHG emissions by at least 35 percent compared to gasoline or diesel (rising later in the mandate) by 2020. The U.S. RFS2 also sets minimum GHG reduction thresholds for each category of biofuels, with the lowest qualifying threshold being 20 percent for 'renewable fuel.'[3]

The final set of policies consists of performance-based standards sometimes referred to collectively as 'low carbon fuel standards' (LCFS). The most notable examples in this category are the California Air Resources Board's (CARB) Low Carbon Fuel Standard, British Columbia's Renewable and Low Carbon Fuel Requirements Regulation, and the Fuel Quality Directive (FQD) in the EU. An LCFS sets the carbon intensity (CI) reduction target for the fuel mix used in transport and determines the contribution of different fuels to that target via lifecycle analysis. The California LCFS requires a 10 percent reduction in the CI of the fuel mix by 2020, and the EU's FQD mandates a 6 percent reduction by 2020.

[2] Note that the UK's RTFO is in this category since it was adapted to implement the RED.
[3] It is generally expected that the 'renewable fuel' category will be dominated by corn ethanol, which is excluded from the advanced biofuel category.

An accurate accounting of the lifecycle emissions of fossil fuel extraction is important for both hybrid and performance-based standards. This assessment (together with downstream emissions from refining and distribution) is necessary to set the petroleum baselines against which alternative fuels are compared. A differentiated accounting of various fossil fuel pathways opens the possibility of generating value not only for low carbon alternative fuels but also for reductions in the carbon intensity of fossil fuel extraction and refining. In this section, a review of low carbon fuel policies in North America and Europe is conducted to highlight their main features, with emphasis on the methodology and data used in estimating the GHG emissions of petroleum fuels–mainly diesel and gasoline. In all cases but one, the carbon intensities reported for these programs are given in terms of lower heating value. The exception is the British Columbian Renewable and Low Carbon Fuel Requirements Regulation, for which values are given in higher heating value terms.

2.2. California LCFS

2.2.1. Type of legislation, targets, and size of the affected market

The California Low Carbon Fuel Standard (CA-LCFS) is a fuel (and technology[4]) neutral, GHG performance-based standard that seeks to reduce GHG emissions from the transport sector by 10 percent by 2020. The standard would result in an approximate reduction of 16 million metric tons CO_2e per year compared to 2010 baseline emissions. These savings come from increasing the use of alternative fuels, including biofuels, compressed natural gas (CNG), hydrogen, and electricity, which all have lower carbon intensities than gasoline and diesel, in the California fuel mix. The CA-LCFS was implemented in 2010, with the compliance period beginning in 2011.[5] Table 2.1 shows the carbon intensity reduction target for each year under the CA-LCFS. The required percentage reduction in CI is modest in the earlier part of the program and becomes progressively more stringent in the latter years.

To achieve the required percent CI reduction, regulated parties can blend gasoline and diesel with low carbon intensity biofuels or sell other alternative fuels such as electricity and hydrogen. The regulated parties are upstream producers and importers of gasoline, diesel, biofuels, electricity, liquefied natural gas (LNG), compressed natural gas (CNG), and hydrogen. Alternatively certain fuels that have inherently low carbon intensities and can meet the required percentage reduction through 2020 are not required to comply with CA-LCFS reporting requirements. These fuels include electricity, hydrogen and

[4] LCFS is not strictly technology neutral in the area of upstream emissions reductions, see §2.2.3.c.
[5] In 2010, participants were asked to report on fuel CI but had no mandatory targets to achieve.

hydrogen blends, fossil CNG derived from North American sources, biogas CNG, and biogas LNG. However, these fuels can opt into the program to generate credits. In such a case, these fuels need to comply with CA-LCFS requirements. Liquefied petroleum gas (LPG, or propane) is exempted from the CA-LCFS. The standard also does not apply to fuels that have niche uses, for example, for use in aircraft, military vehicles and equipment, and oceangoing vessels.

If a fuel supplier delivers a fuel that has a lower CI than baseline gasoline or diesel, this generates credits. Total credits and deficits are calculated by taking into account the CI differential and the volumes of fuel supplied. For fuel cell and electric vehicles, the system also takes into account the 'energy economy ratio' (EER). EER is a measure of the efficiency of converting energy in the fuel into usable energy in a given vehicle. For instance, electric vehicles (EVs) tend to be 2.5 to 3.5 times more efficient than conventional gasoline or diesel engines; however, each EV is likely to differ in efficiency. The EER used for electric vehicles in the CA-LCFS calculations is set to a typical value of 2.7 (California Air Resources Board [CARB], 2009a).

If the CI of a fuel supplied is higher than the baseline CI of gasoline or diesel, this results in deficits. For each compliance year, regulated parties need to generate enough credits to meet the carbon intensity target for that year. The CA-LCFS is a flexible standard that allows compliance through credit trading, so that obligated parties are able to pay for a third party to introduce low carbon fuels to the California market rather than supplying those fuels themselves.[6] For example, regulated parties with excess deficits can purchase credits from other regulated parties with excess credits. However, regulated parties are not allowed to buy credits generated in climate change mitigation programs outside of the CA-LCFS program in California. Excess credits can also be banked for use in future years. Deficits of up to 10 percent may also be carried forward to the next year. If deficits are not remedied within a specified year, the regulated parties will face penalties commensurate with the size of their deficits. Fuels suppliers may also be allocated additional deficits if the California crude slate has grown more carbon intensive, under the 'California average' system for assessing the CI of the crude oil used in California. Under this system, if the average CI of California crude in a given year is higher than the baseline CI, all fossil fuel suppliers are allocated deficits in proportion to the volume of fossil fuel supplied.

There are two options for reporting CI values. Regulated parties may use the default intensity values given for their alternative fuel pathways in the lookup tables generated by the California Air Resources Board (CARB). Alternatively, these regulated parties may use the '2A/2B' method to determine new CI values. The 2A method is used to request an amended pathway based on an existing default pathway. If a fuel does not have a defined default pathway, that company must make a new 2B application. The 2A method involves changing the input data in the Greenhouse Gases, Regulated Emissions, and Energy Use in

[6] At the time of writing, the credit trading mechanism has not yet been implemented.

Transportation (GREET) model for a particular fuel pathway. For example, if corn ethanol production uses biogas instead of coal and natural gas as energy inputs, then the energy input data will be changed to reflect the new processing method. The 2B method applies to a new fuel pathway not reported in the lookup tables. In such a case, a regulated party needs to conduct a thorough lifecycle analysis and submit an application to CARB for executive approval. Once approved, the new fuel path will be added to the lookup table. Both the 2A and 2B methods need to go through staff reviews and public comment periods before their final approval. For crop-based fuels, the CI values provided in the lookup tables include GHG emissions from indirect land use change in addition to direct emissions from well-to-tank (WTT) lifecycle assessments.

Following in the footsteps of European regulations (the Renewable Energy Directive and Fuel Quality Directive) CARB is considering how sustainability criteria might be represented in this legislation. For this purpose, CARB has set up a sustainability expert workgroup to consider sustainability provisions.

Table 2.1. CI reduction requirements under LCFS[7,8]

YEAR	CI TARGET FOR GASOLINE AND ITS SUBSTITUTES (gCO_2e/MJ)	CI TARGET FOR DIESEL AND ITS SUBSTITUTES (gCO_2e/MJ)	% REDUCTION
2010	Reporting only		
2011	95.61	94.47	0.25%
2012	95.37	94.24	0.50%
2013	97.96	97.05	1.00%
2014	97.47	96.56	1.50%
2015	96.48	95.58	2.50%
2016	95.49	94.60	3.50%
2017	94.00	93.13	5.00%
2018	92.52	91.66	6.50%
2019	91.03	90.19	8.00%
2020	89.06	88.23	10.00%

The pre-regulatory economic analysis of the CA-LCFS suggests that it will reduce imports of high carbon crude oil by an amount resulting in savings of up to $11 billion (maximum) in California during the program period (CARB, 2009a). The analysis also finds that increasing the use of biofuels might lower revenues for the state owing to lost transportation fuel taxes. The potential loss in revenues could range between $80 million and $370 million in 2020 (CARB, 2009a).

California accounts for 10.8 percent and 6.8 percent of U.S. motor gasoline and distillate (diesel) fuel consumption, respectively. About

[7] Final Regulation Order, sub article 7. Low Carbon Fuel Standard. Available at http://www.arb.ca.gov/fuels/lcfs/lcfs.htm
[8] The compliance schedule was updated to reflect the 2010 California baseline calculated with OPGEE as of 26 Nov 2012.

358 million barrels of gasoline and 90 million barrels of distillate fuel were used in California in 2009.[9] When the regulation was introduced, CARB analyzed four scenarios to meet the 10 percent CI reduction target and their corresponding market impacts.

- In Scenario I, corn ethanol is blended at 10 percent with gasoline until 2015. After 2015, the share of low CI advanced ethanol and the number of flex fuel vehicles (FFVs; vehicles that can run on gasoline blended with a gas substitute such as ethanol) increases. This scenario also assumes that the number of electric (plug-in hybrid electric vehicles [PHEVs] and battery electric vehicles [BEVs]) and fuel cell electric vehicles (FCEVs) will increase to about a half million.
- Scenario II considers a wider mix of cellulosic ethanol, advanced renewable ethanol, and sugarcane ethanol than in Scenario I.
- In Scenario III, the number of advanced vehicles increases to 1 million, while the use of FFVs decreases compared to Scenario II.
- Scenario IV assumes that the number of advanced technology vehicles (ATVs) increases to 2 million.

2.2.2. Methodology and data in petroleum GHG emissions calculations

As mentioned earlier, credits and deficits of the fuels supplied are calculated by comparing their CIs with those of the gasoline or diesel they will replace. Until the 26th of November 2012, the CA-LCFS required that the CIs of gasoline and diesel should be calculated using the California GREET model (CA-GREET). This model is a modified version of the GREET model administered by Argonne National Laboratory in the United States. The reason for choosing the GREET model is that it is a transparent, publicly available model. It allows users to modify input values, using California-specific data for extraction, refining, and transport, to calculate the CI of gasoline and diesel produced in California. The model has gone through periodic technical reviews and is widely used across the world for lifecycle analysis studies of fuels and vehicles. The decision to choose the GREET methodology for California was not based on an impact assessment but on the fact that it is publicly available and transparent.

The modified CA-GREET model used the 2006 crude mix supplied to California refineries as the basis for estimating upstream and refinery GHG emissions. The 2006 crude mix accounts for all crudes that contributed at least 2 percent of the crude volume used in California. About 655 million barrels of crude oil were refined in 2006. Most of the crude oil brought into California in 2006 came from Alaska, Saudi Arabia, Ecuador, Iraq, and Brazil, accounting for 16 percent, 13 percent, 11 percent, 9 percent, and 3 percent of the total crude oil supplied,

[9] U.S. Energy Information Administration (EIA). Available at: http://www.eia.gov/state/seds/hf.jsp?incfile=sep_sum/plain_html/sum_use_tot.html

respectively (CARB 2009b). In calculating the baseline CI, GHG emissions of various crude feedstocks were averaged. That is, there is no differentiation in the baseline for individual regulated parties by crude type, so a supplier using high carbon crudes would have the same baseline as a supplier of lower carbon crudes.

From 2013, the methodology for fossil fuel emissions calculations has been revised to use the Oil Production Greenhouse gas Emissions Estimator (OPGEE) model.[10] The OPGEE model is detailed elsewhere in this report as well as its accompanying documentation (see §6 and Annex D). In California, OPGEE is used as the basis for implementing the 'California average' fossil fuel accounting methodology (see §2.2.3.b). Using this methodology, CARB has generated a lookup table of carbon intensity values for different crude marketing names, also known as marketable crude oil name (MCON), entering the California market (see Table 2.5).

2.2.2.a. Extraction

For the initial implementation of the CA-LCFS, CARB used a detailed breakdown of crude slates[11] obtained from the California Energy Commission to calculate extraction GHG emissions (Table 2.2). In general, crude slates were divided into three categories: primary, secondary, and tertiary, based on the API gravity of the crude. The higher the API gravity, the lighter the crude, and in general the less energy it takes to refine and to extract it.[12] Crude produced in California accounted for 38 percent of the total used in California refineries in 2006. Of this volume, 38 percent was heavy crude recovered by a 'tertiary method,' i.e., thermally enhanced oil recovery (TEOR). Such 'tertiary methods' require more energy than primary and secondary production–using natural gas (95 percent) as their primary source of energy, with the remaining energy supplied from coal. In 2006, about 40 percent of TEOR production co-generated electricity, which in turn was used in extraction operations and exported to the grid. The GHG credits from the exported electricity were counted in the GHG emissions analysis.

CARB used data obtained from the state's Division of Oil, Gas, and Geothermal Resources (DOGGR) and the California Energy Commission to calculate energy use for domestic crude production. For all crude slates, GHG emissions were based on the types of energy consumed, the equipment used (for example, boilers, motors, etc.), and the corresponding emission factors. In addition to carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O) emissions, volatile organic compounds (VOC) and carbon monoxide (CO) emissions were included in the GHG estimates since they would ultimately be converted into CO_2 equivalents. GHG emissions from flaring were included as well. The breakdown of fuel shares used in crude extraction is given in Table 2.3. The sources for emissions factors are derived mainly from the U.S.

[10] http://www.arb.ca.gov/regact/2011/lcfs2011/lcfs2011.htm
[11] Crude slate refers to the different types of crudes (by origin) that are supplied to refineries.
[12] For extraction in particular, there are many exceptions to this principle.

Environmental Protection Agency (AP 42 Compilation of Air Pollutant Emission Factors) as well as other publicly available sources. CARB used the weighted average crude recovery efficiency of 93 percent as opposed to the GREET default value of 98 percent for the entire United States to account for efficiency of crude extraction in California, Alaska, and exporting countries.

From 2013, this calculation was replaced by a detailed crude-by-crude calculation performed with OPGEE.

Table 2.2. Composition of the California crude mix from 2005-2007 by country/state of origin (bbls)

FEEDSTOCK ORIGIN	2005	2006	2007
Alaska	135,906,000	105,684,000	100,900,000
Angola	12,912,000	14,979,000	21,038,000
Argentina	6,213,000	3,484,000	
Brazil	12,474,000	17,938,000	22,453,000
California	266,052,000	254,498,000	251,445,000
Canada	4,942,000		5,320,000
Colombia	4,180,000	9,362,000	11,813,000
Ecuador	67,705,000	71,174,000	55,456,000
Iraq	34,160,000	56,163,000	57,788,000
Mexico	19,316,000	15,473,000	9,214,000
Nigeria			5,447,000
Oman	2,985,000	6,326,000	
Others	13,707,000	9,311,000	21,313,000
Saudi Arabia	95,507,000	86,976,000	72,296,000
Venezuela		4,120,000	4,706,000
Total	676,059,000	655,488,000	639,189,000

Source*: CARB (2009b)*

Table 2.3. Share of fuels in crude extraction for California crude mix

FUEL TYPE	FUEL SHARES
Crude oil	0.2%
Residual oil	0.2%
Diesel	2.5%
Gasoline	0.3%
Natural gas	94.3%
Coal and petroleum coke	2.4%
Electricity	0%
Feed Loss	0.10%

Source: CARB (2009b)

2.2.2.b. Crude transport

In the original LCFS analysis, instead of using default values for transport modes and corresponding emission factors in the CA-GREET model, CARB estimated these factors for the three modes of crude transport—tanker, pipeline, and barge. This analysis was carried out using energy consumption data, distance traveled, and emissions factors obtained from publicly available sources including the EPA, the American Petroleum Institute, and the U.S. Energy Information Administration.

The OPGEE treatment of crude transport is described in Annex D.

2.2.2.c. Refining

Since California refineries are generally ‘complex’ and are designed to process heavy crudes and produce fuels with stricter fuel specifications than in other U.S. states, CARB adjusted the refining efficiency used in the GREET model. The values of refining efficiency used for California reformulated gasoline blendstock for oxygenate blending (CARBOB) and diesel are 84.5 percent and 86.7 percent (CARB, 2009c), respectively. CARB also adjusted the values for fuel share, equipment used for energy generation, and associated emissions factors to estimate GHG emissions. Table 2.4 shows the fuel shares in California refineries. OPGEE does not assess refining emissions.

Table 2.4. Fuel shares in California refineries

FUEL TYPE	FUEL SHARES
Residual	3%
Natural gas	30%
Petroleum coke	13%
Electricity	4%
Still gas	50%
Total	100%

Source*: CARB (2009b)*

2.2.2.d. Transport and storage of refined products

In California, diesel and gasoline are transported by truck and pipeline. The average pipeline distance is 50 miles, and electric motors are used to generate power for pipeline transport. Eighty percent of refined products were assumed transported by pipeline and 20 percent by tanker truck running on diesel. The type of energy used for transport, percentage share, distance traveled, and emissions factors were used to calculate GHG emissions from transport of diesel and gasoline.

2.2.2.e. Fuel combustion

When a fuel is combusted in a vehicle, it emits CO_2 and other tailpipe emissions. GHG emissions from fuel combustion in a vehicle were calculated using the carbon content and other tailpipe emissions–CH_4, N_2O, VOC, and CO. As mentioned earlier, VOC and CO were assumed converted to CO_2 through oxidation. The data for other tailpipe emissions were derived from the EMFAC (CARB)[13] and MOBILE6 (EPA)[14] models.

The total well-to-wheel (WTW) GHG emissions were calculated by summing GHG emissions in extraction, crude transport, refining, refined product transport, and fuel combustion and expressed in units of gCO_2e/MJ.

2.2.3. HCICO screening vs. California average approach

2.2.3.a. Proposed treatment of high-carbon-intensity crude oil in 2010 rule

California has relatively complex refineries with high utilization rates. These refineries can produce producing a high share of lighter petroleum products from a wide range of crudes, including heavy crudes (Worrell and Galitsky, 2004). California refineries are heavily dependent on imported crude oils, which account for about 60% of the total crude oil refined in California. There is therefore a concern among some stakeholders that increased supplies of high-carbon heavy oils could undermine the carbon reduction goals of the LCFS if the carbon intensity of fossil fuels is not managed under the program. For example, during the consultation period various stakeholders expressed a concern about the increasing supply of tar sands (CARB, 2009c). The initial regulatory response to these concerns was to propose a system for screening and accounting for any increase in 'High Carbon Intensity Crude Oils' (HCICOs) entering California.

The CA-LCFS as enacted in 2010 identified a 2006 California basket of crude oil, including all crudes meeting more than 2 percent of California demand in that year. Crudes in the California basket were to be effectively grandfathered in, as the CI of those fuels had already been included in the baseline. However, any new crudes entering California were to be screened against a set of criteria for identifying HCICOs. Crudes deemed potential HCICOs would then have a full lifecycle analysis undertaken–any fuel with upstream CI above the 15 gCO_2e/MJ threshold would be assigned its actual CI for CA-LCFS accounting and would therefore result in deficits being generated for the company supplying it.

Some high-CI crudes, notably those extracted in California via thermally enhanced oil recovery, were included in the baseline and hence not subject to HCICO status or the generation of deficits. Others, such as Venezuelan heavy crude, Canadian oil sands crude, and crude oil from Nigeria with high flaring and venting emissions, were not included in the 2006 crude mix and hence would potentially incur deficits under the HCICO screening system. The HCICO provision was designed to protect the overall carbon reduction target of the CA-LCFS by discouraging the supply of HCICOs but also to provide a signal for oil producers to engage in upstream emission reduction activities, such as

[13] EMFAC 2011 is available at http://www.arb.ca.gov/msei/modeling.htm
[14] MOBILE6 is available at http://www.epa.gov/otaq/m6.htm

reducing flaring, improving energy efficiency, and using carbon capture and sequestration (CCS).

2.2.3.b. 'California average' methodology

At the end of 2011, it was recommended to the CARB governing board that the HCICO treatment (described above) should be replaced. This was in the context of substantial opposition from industry to the application of any accounting methodology that differentiated between crudes. The proposed options for revised treatment of fossil fuel carbon intensity were as follows (CARB, 2011):

- *Current provisions with amendments* — The suggested amendments include a screening process for non-HCICOs and refraining from retroactively applying penalties if a fuel initially deemed to be non-HCICO is later deemed to be HCICO. If an HCICO is later found to be non-HCICO, credits can be applied retroactively.

- *'California average' approach* — This approach involves calculating the yearly average CIs of gasoline and diesel based on the crude oil mix, including HCICO used in the prior year. If the use of HCICO in the mix increases, all the regulated parties will use the same new average CI to calculate deficits against the target. However, the regulated parties can get credits if they demonstrate that the oil is extracted using new methods such as CCS.

- *Hybrid 'California average'/company-specific approach* — In this approach, the regulated parties are allowed to use the default CI values from the lookup table if their own crude slates do not become more intensive overtime. If they do, the parties are required to calculate their deficits using the CI of the crude oil and volume of HCICO used in the prior year relative to the CI required for the target year.

- *Company-specific approach* — Each regulated party has its own baseline CI for its crude slates and carbon reduction targets for each year. The baseline deficit is calculated through the difference between the baseline CI and the target-year CI. If the regulated party's crude slate becomes more CI intensive compared to its own baseline year, incremental deficits need to be calculated by comparing the current year's CI (based on the crude slates) to the CI of the target year. The party is allowed to shift its crude slates without penalty if its CI does not increase.

- *Worldwide average* — This approach is similar to the 'California average' approach. Here, the baseline CI values of CARBOB, gasoline, and diesel in the lookup table are based on the worldwide crude oil mix and refining emissions. As usual the base deficit would be the difference in the baseline CI and target year CI. If world average crude extraction and refining emissions become more intensive, incremental deficits are calculated in the manner suggested above.

- *California baseline year* — This is the most elementary approach, in which the baseline CIs for gasoline and diesel reported in the lookup table are used to calculate the base deficit. The baseline CI values are the same throughout the program period so that the regulated party is not subjected to incremental deficits even if the crude slates become more carbon intensive.

At the December 2011 meeting of the CARB governing board, it was agreed that CARB would accept a staff recommendation to adopt the 'California average' approach in the short term. In this approach, as detailed above, fuel suppliers would no longer be assessed CA-LCFS deficits in proportion to the CI of the fuels they had individually supplied. Rather, deficits would be assigned to all participants in proportion to the carbon performance of the California crude slate as a whole. This effectively decouples the value signal of the CA-LCFS deficits generated by supplying high CI crudes from the decision by an individual entity to supply them. As a result, if one firm increased its CI in a given year, the carbon penalty for that increase would be spread evenly across all market participants supplying fossil fuels. It should be noted, however, that while adopting an approach in which the carbon penalty for switching to a higher carbon crude slate is divorced from the individual operator, CARB asserted its commitment in principle to move to a system with greater crude differentiation by company in due course, presuming an appropriate system can be proposed.

The California average approach requires lookup tables detailing the upstream carbon intensity of the MCONs being consumed in California. The lookup values by MCON as proposed by CARB in March 2013 are listed in Table 2.5.

Table 2.5. MCON carbon intensity values assessed for the CA-LCFS (March 2013 preliminary draft)

REGION	CRUDE NAME	2010 BASELINE CI (gCO_2e/MJ)[26]	LOOKUP TABLE CI (gCO_2e/MJ)[27]
California Crude Average		**11.44**	
Algeria	Saharan		10.13
Angola	Cabinda		8.41
	Dalia	8.03	8.33
	Gimboa		8.14
	Girassol	8.42	8.74
	Greater Plutonio	7.96	8.23
	Hungo		7.56
	Kissanje		8.14
	Mondo		8.25
	Nemba		8.55
	Pazflor		7.38
Argentina	Canadon Seco	7.59	7.68
	Escalante	7.61	7.7
	Hydra	6.38	6.52
	Medanito		8.23
Australia	Pyrenees	4.39	4.52
	Stybarrow		4.89
	Van Gogh		4.68
	Vincent		3.63
Azerbaijan	Azeri		6.48
Brazil	Albacora Leste	5.09	5.05
	Bijupira-Salema		6.39
	Frade	4.69	4.64
	Jubarte		6.7
	Lula		8.11
	Marlim	6.07	6.11
	Marlim Sul	6.81	6.81
	Ostra	5.1	5.03
	Polvo	4.96	4.88
	Roncador		5.76
	Roncador Heavy		5.46
	Sapinhoa		6.81
Cameroon	Lokele	23.8	21.46

[26] 2010 data used when available to estimate CI values.
[27] 2011 data used when available to estimate CI values.

REGION	CRUDE NAME	2010 BASELINE CI (gCO_2e/MJ)[26]	LOOKUP TABLE CI (gCO_2e/MJ)[27]
Canada	Albian Muskeg River Heavy		19.76
	Albian Heavy Synthetic	19.86	19.76
	Cold Lake	17.53	17.48
	Federated	7.54	8.16
	Koch Alberta	7.4	8.01
	Lloydminster		8.43
	Mixed Sweet	7.51	8.14
	Peace River Heavy		19.47
	Peace River Sour		7.99
	Shell Synthetic		20.74
	Suncor Synthetic (all grades)	23.39	24
	Surmont		19.33
	Syncrude Synthetic	20.81	20.74
	Wabasca		14.31
Chad	Doba		6.58
Colombia	Cano Limon		7.83
	Castilla	7.42	7.35
	Magdalena		18.97
	Rubiales		6.99
	South Blend		7.63
	Vasconia	7.88	7.76
Congo	Azurite		10.12
	Djeno		10.46
Ecuador	Napo	8.51	8.18
	Oriente	9.88	9.58
Equatorial Guinea	Ceiba		9.41
Iraq	Basra Light	11.67	11.6
Kuwait	Kuwait		8.82
Libya	Amna		12.57
Malaysia	Tapis		9.48
Mexico	Isthmus		8.61
Neutral Zone	Eocene	5.72	5.88
	Khafji		7.26
	Ratawi	7.53	7.74
Nigeria	ABO		7.55
	Agbami		20.35
	Amenam		15.97
	Antan		37.35
	Bonga		5.23
	Bonny	16.93	16.12
	Brass		74.27
	EA		3.65
	Erha		8.27
	Escravos		21.57

REGION	CRUDE NAME	2010 BASELINE CI (gCO_2e/MJ)[26]	LOOKUP TABLE CI (gCO_2e/MJ)[27]
	Forcados		18.17
	Okono		26.27
	OKWB		39.75
	Pennington		23.13
	Qua Iboe		15.28
	Usan		15.97
	Yoho		15.28
Oman	Oman	10.95	10.89
Peru	Loreto	7.2	6.75
	Mayna	8.8	8.38
Russia	ESPO	12.07	12.3
	M100		14.61
	Sokol		9.13
	Vityaz		9.27
Saudi Arabia	Arab Extra Light	7.45	7.45
	Arab Light	7.39	7.32
	Arab Medium		6.84
Thailand	Bualuang		3.5
Trinidad	Calypso	5.48	5.84
	Galeota		7.56
UAE	Murban		8.25
	Upper Zakum		7.26
Venezuela	Boscan	8.58	9.03
	Hamaca		22.27
	Hamaca DCO		5.92
	Mesa 30		9.7
	Petrozuata (all synthetic grades)	22	22.29
	Zuata (all synthetic grades)	21.98	22.27
US Alaska	ANS	13.67	14.88
US Colorado	Niobrara		3.63
US New Mexico	Four Corners		6.06
US North Dakota	Bakken		9.76
	North Dakota Sweet		9.76
US Texas	WTI		11.59
US Utah	Covenant		2.12
US California	Aliso Canyon	2.08	3.15
	Ant Hill	22.13	29.05
	Antelope Hills	2.89	4.85
	Antelope Hills, North	12.76	17.48
	Arroyo Grande	27.38	28.47
	Asphalto	9.78	13.42
	Bandini	7.48	7.09
	Bardsdale	5.4	4.23
	Barham Ranch	2.79	2.93

REGION	CRUDE NAME	2010 BASELINE CI (gCO_2e /MJ)[26]	LOOKUP TABLE CI (gCO_2e /MJ)[27]
	Belgian Anticline	3.78	4.46
	Bellevue	8.62	7.54
	Bellevue, West	8.76	6.26
	Belmont, Offshore	3.22	3.38
	Belridge, North	4.54	4.6
	Belridge, South	13.49	14.28
	Beverly Hills	4.25	4.5
	Big Mountain	3.3	3.36
	Blackwells Corner		4.48
	Brea-Olinda	2.99	3.11
	Buena Vista	13.93	7.68
	Cabrillo	2.88	2.98
	Canal	4.13	3.91
	Canfield Ranch	3.67	3.54
	Carneros Creek	2.99	3.17
	Cascade	2.22	2.27
	Casmalia	7.48	9.11
	Castaic Hills	2.92	2.29
	Cat Canyon	3.92	3.93
	Cheviot Hills	3.09	3.2
	Chico-Martinez		3.07
	Cienaga Canyon	4.24	3.87
	Coalinga	25.3	24.34
	Coalinga, East	20.25	20.85
	Coles Levee, N	4.22	4.35
	Coles Levee, S	4.98	5.11
	Coyote, East	5.65	5.97
	Cuyama, South	12	10.92
	Cymric	20.17	20.17
	Deer Creek	9.49	10.47
	Del Valle	4.43	4.36
	Devils Den	5.28	4.69
	Edison	8.63	12.82
	El Segundo	3	3.21
	Elk Hills	6.4	7.44
	Elwood, S., Offshore	3.99	3.93
	Fruitvale	10.33	3.58
	Greeley	8.25	8.59
	Hasley Canyon	1.99	2.05
	Helm	3.44	3.52
	Holser	3.05	3.04
	Honor Rancho	2.86	4.15
	Huntington Beach	5.14	4.94
	Hyperion	1.73	1.78
	Inglewood	8.87	8.91

REGION	CRUDE NAME	2010 BASELINE CI (gCO_2e /MJ)[26]	LOOKUP TABLE CI (gCO_2e /MJ)[27]
	Jacalitos	2.24	2.13
	Jasmin	11.82	11.95
	Kern Front	22.05	22.69
	Kern River	8.61	8.3
	Kettleman Middle	3.83	4.03
	Kettleman North	5.01	5.77
	Landslide	10.67	11.48
	Las Cienegas	4.64	4.53
	Livermore	2.2	2.3
	Lompoc	31.6	15
	Long Beach	5.99	6.2
	Long Beach Airport	3.76	3.5
	L.A. Downtown	4.16	4.33
	Los Angeles, East	8.42	7.28
	Lost Hills	10.9	9.89
	Lost Hills, Northwest	4.42	3.87
	Lynch Canyon	7.21	6.97
	Mahala		2.86
	McDonald Anticline	4.97	4.29
	McKittrick	16.14	18.98
	Midway-Sunset	21.48	22.41
	Monroe Swell		2.02
	Montalvo, West	2.68	2.76
	Montebello	11.16	13.16
	Monument Junction	3.74	3.92
	Mount Poso	12.95	10.65
	Mountain View	4.69	3.54
	Newhall-Potrero	2.82	2.94
	Newport, West	3.82	3.96
	Oak Canyon	3.51	3.56
	Oak Park	2.15	2.38
	Oakridge	2.59	2.45
	Oat Mountain	1.9	2.02
	Ojai	3.47	3.64
	Olive	1.87	1.97
	Orcutt	11.77	12.07
	Oxnard	15.64	11.47
	Paloma	3.82	3.83
	Placerita	29.37	30.71
	Playa Del Rey	6.67	4.26
	Pleito	4.21	2.78
	Poso Creek	23.08	23.38
	Pyramid Hills	2.75	3.11
	Railroad Gap	9.27	8.52
	Raisin City	7.44	8.4

REGION	CRUDE NAME	2010 BASELINE CI (gCO_2e/MJ)[26]	LOOKUP TABLE CI (gCO_2e/MJ)[27]
	Ramona	3.45	3.74
	Richfield	3.65	3.86
	Rincon	3.4	3.73
	Rio Bravo	4.96	5.27
	Rio Viejo	2.52	2.61
	Riverdale	3.02	3.25
	Rose	2.12	2.57
	Rosecrans	5.24	5.6
	Rosecrans, South	3.14	3.03
	Rosedale	6.8	7.78
	Rosedale Ranch	8.66	8.15
	Round Mountain	29.18	28.56
	Russell Ranch	6.87	7.79
	Salt Lake	2.57	2.7
	Salt Lake, South	3.74	4.15
	San Ardo	27.39	26.02
	San Miguelito	4.51	5.44
	San Vicente	2.33	2.45
	Sansinena	2.74	2.6
	Santa Clara Avenue	3.34	3.39
	Santa Fe Springs	11.39	10.09
	Santa Maria Valley	4.93	5.54
	Santa Susana	3.19	3.47
	Sargent	4.81	4.49
	Saticoy	3.3	3.47
	Sawtelle	2.85	3.12
	Seal Beach	4.78	5.12
	Semitropic	3.7	3.42
	Sespe	2.99	3.35
	Shafter, North	2.56	2.76
	Shiells Canyon	3.39	3.64
	South Mountain	3.15	3.53
	Stockdale	1.85	1.91

REGION	CRUDE NAME	2010 BASELINE CI (gCO_2e/MJ)[28]	LOOKUP TABLE CI (gCO_2e/MJ)[27]
	Strand	2.31	2.97
	Tapia	5.2	16.11
	Tapo Canyon, South	2.78	3.01
	Tejon	5.5	6.48
	Tejon Hills	6.04	6.58
	Tejon, North	5.07	5.31
	Temescal	3.15	3.25
	Ten Section	6.19	6.12
	Timber Canyon	3.47	3.57
	Torrance	4.49	4.33
	Torrey Canyon	2.86	2.88
	Union Avenue	1.8	2.51
	Ventura	4.39	4.25
	Wayside Canyon		1.71
	Wheeler Ridge	4.09	4.36
	White Wolf	1.7	1.76
	Whittier	2.39	2.47
	Wilmington	6.43	6.71
	Yowlumne	11.15	10.02
	Zaca	7.46	8.2
US Federal OCS	Beta	1.75	1.81
	Carpinteria	2.65	2.71
	Dos Cuadras	3.9	3.96
	Hondo	4.24	4.3
	Hueneme	4.1	4.16
	Pescado	3.5	3.55
	Point Arguello	9.08	9.14
	Point Pedernales	4.81	4.87
	Sacate	2.35	2.41
	Santa Clara	2.43	2.48
	Sockeye	4.97	5.02
Default	**TEOR, Mining, Synthetic**		**20.59**
Default	**Conventional**		**10.36**

We note that while the results obtained by CARB and listed in Table 2.5 are based on analysis with the OPGEE tool, there are some differences in methodology between the March 2013 CARB analysis and the analysis presented later in this report (c.f. §8). Notably, the CARB analysis uses OPGEE v1.1, while our analysis is based on OPGEE v1.0. Also, while the approaches are very similar, there are some differences in the way that CARB has undertaken its MCON by MCON assessment compared to the representative fields methodology we have used, and thus there are cases where the contribution of individual fields to specific MCONs is different between the approaches. Finally, transport distances in our analysis reflect transport to European refineries, while CARB analysis reflects transport to Californian refineries.

2.2.3.c. Upstream emissions reductions

Under the California average carbon assessment methodology, there is an opportunity for fuel suppliers to claim LCFS credits for 'innovative' upstream emissions reductions projects. Under the legislation, the eligible project types are limited to solar generation of steam for thermally enhanced oil extraction, and the use of carbon capture and storage, both with a minimum threshold of 1 gCO_2e/MJ.[28]

2.2.4. Reporting requirements

The regulated parties are required to fulfill a number of obligations that include carbon intensity reduction requirements, physical pathway demonstration and reporting requirements. The CA-LCFS requires separate reduction schedules for gasoline and diesel fuel and their respective substitutes in order to meet a 10 percent reduction by 2020. To obtain credits for these different fuels/blendstocks, regulated parties must demonstrate (possibly through a third party) that there exists a physical pathway (railway, cargo tank truck route, pipeline, etc.) by which they intend to bring the fuel into California. The reporting requirements for the CA-LCFS are based on quarterly reports and annual compliance reports submitted through the online CA-LCFS reporting tool (LRT).[29]

The quarterly progress report is intended to show the credit balance of the regulated party. It reports how many CA-LCFS credits and deficits were generated during the quarter in question. The quarterly report includes information pertaining to the fuel name, application (e.g. light duty or medium duty vehicles), fuel pathway code and physical pathway. In addition to these entries, each transaction is recorded by type and amount, which in turn calculates the amount of credits and deficits, with the possibility to upload additional documents including invoices and the like. These reports are intended to be progress reports for the regulated party and CARB, so that regulated parties can take appropriate measures to adjust their position and avoid any possible shortfalls by the end of the compliance period. The quarterly reports are due within two months after the end of the quarter.

Starting with 2011, the annual compliance period is January 1st through December 31st of each year. Regulated parties must meet the carbon intensity reduction requirements for their fuel in each compliance period as recorded in their quarterly reports. Parties with shortfalls equivalent to less than 10 percent of their compliance obligation have one year to reconcile these, while those in excess are required to do so

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[28] In a public workshop held on June 20th (2013), CARB presented an amendment to the innovative crude methods provision. As part of this amendment, credits would be accrued by crude producers rather than refineries, be based on volumes of finished products sold in California and not be limited by the previous 1 gCO_2e/MJ threshold.

[29] http://www.arb.ca.gov/fuels/lcfs/reportingtool/reportingtool.htm

within the same timeframe before being subject to penalties. The annual report for each year is due by April 30th of the following year. The reported data in 2011 suggest that more credits than deficits were generated in California. To ensure that compliance with the program is indeed taking place, the executive officer of CARB or an approved third party can review the data and calculations submitted by the regulated party claiming credits and adherence.

2.2.5. Consultation and program monitoring

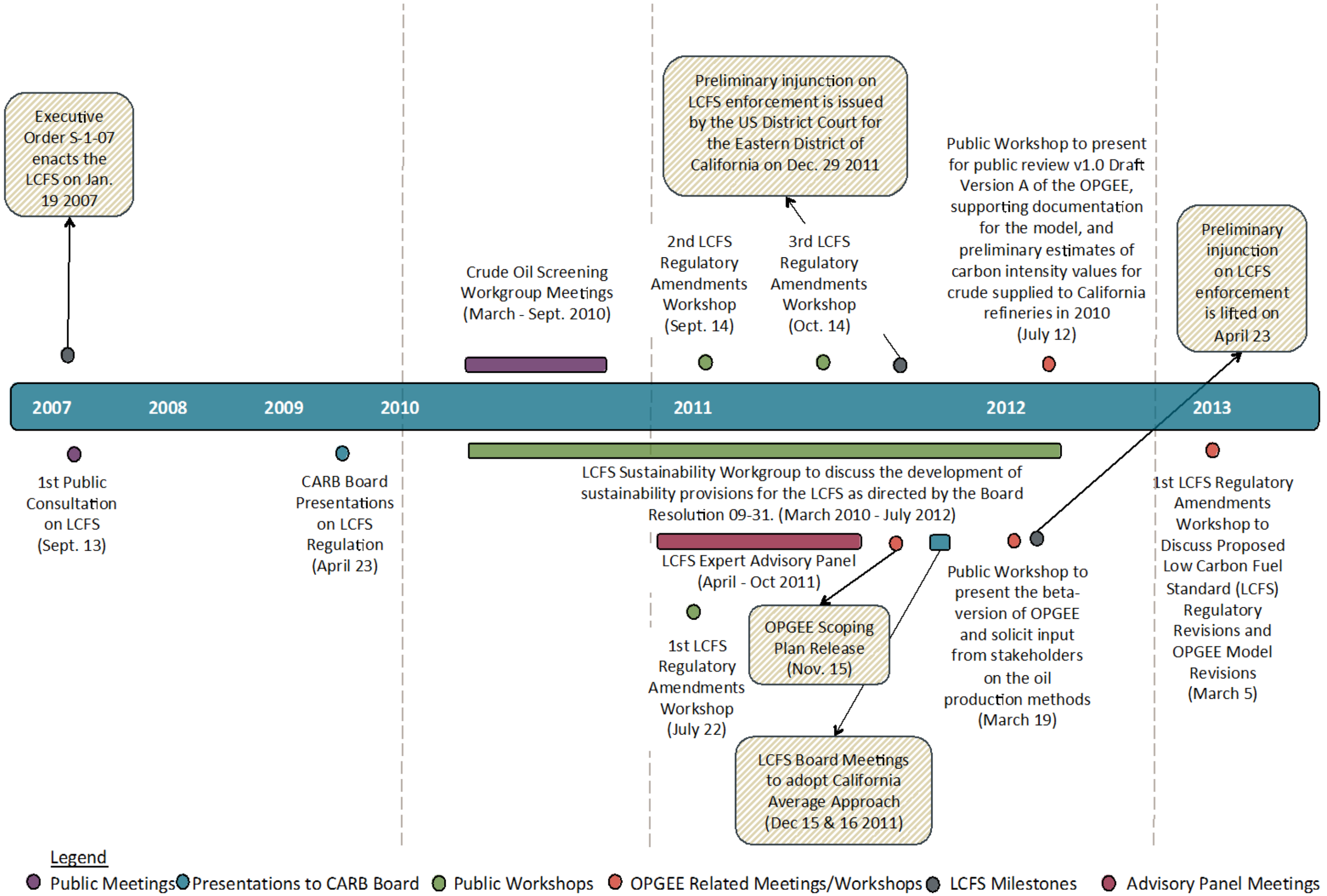
CARB has been holding CA-LCFS related public consultation meetings since 2007, in line with Executive Order S-1-07, which enacted the CA-LCFS on the 19th of January of the same year. The first public consultation meeting was held on September 13th of 2007. In this meeting, the groundwork was set out for a public workshop process with meetings every 4 to 6 weeks. In addition, four working groups – Lifecycle Analysis, Compliance and Enforcement, Policy and Regulatory Development and Environmental and Economic- each led by CARB staff, were established to concentrate on specific areas of the CA-LCFS with proposed meetings between workshops. Since that first meeting, over 40 public workshops, meetings and working group discussions have taken place.

In 2009, CARB commissioned a number of peer reviews to comment on the proposed CA-LCFS. These peer reviews were solicited to comply with Health and Safety Code section 57004 as well as to ensure that any rules be based upon sound scientific knowledge, methods and practices. In total, four peer reviews were submitted and made publically available. According to CARB, based on the content provided in the comments no significant modifications to either the proposed rule or the analysis used to support the proposal were necessary. In addition to these peer reviews, each public consultation has been followed by a 15 day comment period were interested parties were invited to submit comments relevant to the policies and procedures discussed in each meeting.

Between 2010 and 2012, CARB appointed a sustainability workgroup to discuss the development of sustainability provisions for the CA-LCFS and a High Carbon Intensity Crude Oil (HCICO) screening workgroup, as well as an expert advisory panel to advise CARB staff on the 2011 CA-LCFS program review. Following feedback from stakeholders and discussion by the HCICO screening workgroup and expert advisory panel, at the end of 2011 CARB proposed transitioning from the initial system of HCICO screening with fossil fuel LCA based on CA-GREET to the California average approach. As a result of this, on November 15th 2011, a scoping plan was released for the Oil Production Greenhouse Gas Emissions Estimator (OPGEE). On March 19th of the following year, the first beta version of the OPGEE model was presented at a public workshop where inputs were solicited from stakeholders on the oil production methods being modeled. The last set of revisions for the model was submitted on March 5th of 2013 with the release of OPGEE

1.0. Additional comment periods and review opportunities are expected, but as of June 2013, remain unscheduled.

Figure 2.1. CA-LCFS public engagement timeline



2.3. Oregon Clean Fuels Program (CFP)

2.3.1. Type of legislation, targets, and size of the affected market

In 2009, Oregon House Bill 2186 authorized the Oregon Environmental Quality Commission (EQC) to adopt an LCFS for Oregon (currently known as the Clean Fuels Program [CFP]), with the intent of reducing GHG emissions from the transportation sector by 10 percent (see Table 3.6). Toward this end, the state's Department of Environmental Quality (DEQ) developed a draft Clean Fuels program design with inputs from an advisory board consisting of diverse stakeholders in 2011. The draft rules for the CFP went through a public comment period in July/August 2012, and final rules for initial implementation were sent to the Environmental Quality Commission in November of the same year for approval and adoption. Based on stakeholder feedback, the CFP rules were separated into two Phases; a reporting phase (Phase I) and a compliance phase (Phase II). At this time, only Phase I of the program has been adopted. The EQC approved phase I of the CFP in December 2012. Under Phase-I fuel suppliers (fuel producers and importers) are required to monitor and report the volume and carbon intensities of the transportation fuels they supply for use in Oregon. This allows DEQ to gather better information on fuel types, volumes, and carbon intensities that will be used in refining the design of the compliance phase of the program (Phase II). DEQ has completed the initial Phase I registration of fuel importers and producers and will work with them on initial fuels reporting. Phase II of the program has not yet been proposed to the Environmental Quality Commission. Further action on Phase II is on hold pending further legislative action. There is a sunset date of December 31, 2015, which has to be removed through a legislative action to extend the program. If removed, the DEQ is expected to engage in additional stakeholder conversations and analysis regarding the availability of fuels, consumer safeguards, and the program's impact on Oregon's economy in order to finalize the Phase II program design. Based on this fresh assessment, DEQ would make a recommendation to the Environmental Quality Commission on whether to adopt Phase II of the program. The goal of phase II is to require fuel suppliers to reduce the carbon intensity of fuels by 10% below 2010 levels.

The proposed OR-CFP is a state-level initiative in Oregon and applies to fuel producers and suppliers in the state. Propane is excluded from the program. Also exempted are small producers with an output of less than 10,000 gasoline-equivalent gallons. As in the California LCFS, fuels used in certain applications such as farm machinery, oceangoing vessels, aircraft, and racing and military vehicles are exempted from the program. Suppliers of certain fuels may choose to opt in to generate credits. These include suppliers of electricity, hydrogen, propane, CNG from biogas and fossil fuel, and LNG from biomass. The CFP envisions deferrals in case of fuel shortages to protect consumers.

Table 2.6. Proposed compliance requirements for Oregon CFP

YEAR	% REDUCTION	CI (GASOLINE AND ITS SUBSTITUTES) (GCO_2E/MJ)	CI (DIESEL AND ITS SUBSTITUTES) (GCO_2E/MJ)
2012	Reporting only		
2013	0.25	90.15	89.78
2014	0.50	89.93	89.55
2015	1.00	89.48	89.10
2016	1.50	89.02	88.65
2017	2.50	88.12	87.75
2018	3.50	87.22	86.85
2019	5.00	85.86	85.50
2020	6.50	84.51	84.15
2021	8.00	83.15	82.80
2022	10.00	81.34	81.00

Source*: Oregon DEQ (2011)*

As part of assessing the benefits of the proposed CFP, an economic impact assessment was carried out using the VISION and REMI models. For this, eight compliance scenarios were considered using different combinations of fuels. Overall, the analysis found that the proposed regulation would increase the number of new jobs in a range from 863 to 29,290, personal income by $60 million to $2,630 million, and gross state product by $70 million to $2,140 million. Moreover, the program would result in fuel savings between $43 million and $1,607 million over a 10-year period (Wind, 2011).

Because Oregon is a small state by population, the market coverage of the proposed CFP is not extensive. For example, in 2009 Oregon accounted for 1.1 percent (37 million barrels) and 1.4 percent (18.6 million barrels) of U.S. motor gasoline and distillate fuel consumption, respectively. An economic impact analysis conducted by DEQ provides a glimpse of the likely impact of the proposed LCFS on the Oregon fuels market and vehicles. Of nine scenarios analyzed, most estimate an increase in in-state cellulosic biofuel, waste berry ethanol, and Midwestern ethanol in order to meet the required 10 percent reduction target. Scenarios D and E, on the other hand, predict a significant increase in the number of electric, PHEV, and CNG vehicles in addition to cellulosic biofuel (Oregon DEQ, 2010).

2.3.2. Methodology and data in petroleum GHG emissions calculations

Since there are no petroleum refineries in Oregon, the state brings in refined petroleum products from Washington and Utah. To calculate

WTW GHG emissions of gasoline and diesel, DEQ used a modified GREET model with some inputs and assumptions specific to Oregon. The reason for choosing the GREET methodology is that it is a transparent and publicly available source that is widely used as a tool to estimate fuel and vehicle lifecycle GHG emissions. It allows a user to modify input values to reflect Oregon-specific data for extraction, refining, and transport to calculate the CI of gasoline and diesel.

The crude mix used in Oregon's version of GREET is assumed to be the same as in 2007, with 90 percent refined in Washington and 10 percent in Utah. This mix consists of crude oil from Africa, Alaska, Canada, the Middle East, and South America. Supplies from Alaska accounted for about 65 percent of the 2007 crude mix, and oil sands from Canada accounted for about 9 percent (Oregon DEQ, 2011). The GREET model does not differentiate emissions among feedstocks that fall within the conventional crude category. However, it does differentiate emissions between oil sands by production method, i.e., in situ vs. surface mining. For regulatory purposes, emissions from tar sands are averaged with emissions from other crude sources to calculate the baseline carbon intensity of gasoline and diesel. Hence, there is no differentiation in CIs of gasoline and diesel by feedstock types. The CFP proposal mentions that the CI of gasoline and diesel will be updated every three years to account for changes in the crude mix but the intent is to update it as often as the data allows. As a result, any increases in GHG emissions due to use of heavier crudes such as tar sands from Canada can be quantified and regulated. With respect to data quality and availability, the comment made in the case of California's version of GREET (CA-GREET) also applies here.

For crude oil extraction and refining, DEQ uses GREET's default values for conventional crude oil and tar sands. For electricity use, however, DEQ adjusts the default values by using the actual electricity mix in 2007 in exporting countries for crude oil extraction and in Washington for refining. The electricity mix in Utah was used for electricity use in that state.

For crude oil and petroleum fuel transport, DEQ adjusted the values for distance traveled, payload, and mode of transport. It was assumed that 90 percent of petroleum fuels used in Oregon were transported from Washington refineries via the Olympic pipeline, followed by ocean tankers. The remaining petroleum fuels were transported from Utah via the Chevron pipeline. The cargo ship payload values for the Port of Portland and the Panama Canal were based on the deadweight limits of 125,000 tons and 80,000 tons, respectively (Oregon DEQ, 2011).

Finally NO_x and CH_4, and CO_2 emissions from fuel combustion in vehicles, were added to WTT GHG emissions to calculate WTW GHG emissions for gasoline and diesel. CO emissions were also added, as they eventually convert to CO_2.

2.3.3. Data aggregation, quality, and availability

GREET distinguishes the extraction emission profile of conventional oil from oil sands. For conventional oil production, GHG emissions represent the average extraction emissions for all conventional oil production in the United States and exporting countries. In the case of oil sands, GREET does distinguish emission profiles by production method, i.e., in situ vs. surface mining. GREET relies on secondary data, using industry aggregate information for oil sands.

The GREET model is limited by sparse data availability in crude oil extraction. Especially for conventional wells, no differentiation has been made by feedstock or country of origin. As in other models, venting and flaring data may not be reliable due to a high degree of uncertainty in measurement and estimation, especially because GREET uses average values.

2.4. Washington LCFS

2.4.1. Type of legislation, targets, and size of the affected market and fuels

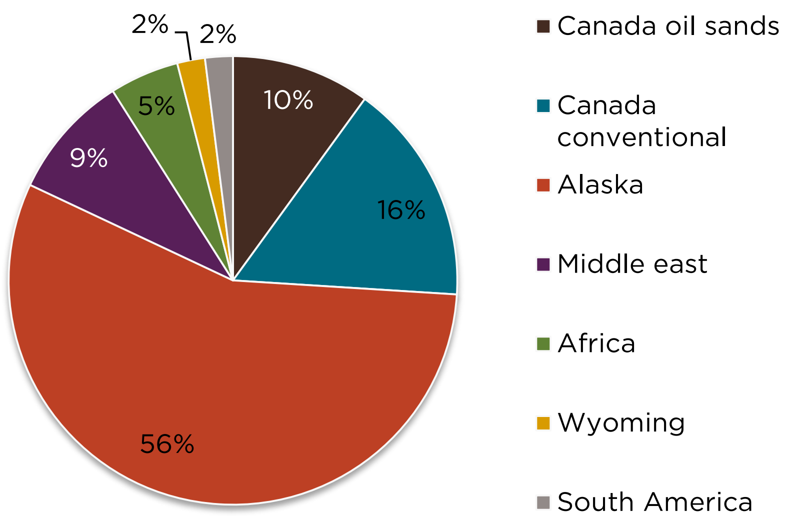
In response to the governor's executive order to determine if an LCFS similar to California's would help meet its GHG reduction commitments, the Washington state Department of Ecology conducted an exploratory study to assess the GHG reduction benefits and economic impact of an LCFS in Washington. It analyzed six compliance scenarios, which included contributions from cellulosic ethanol and electric vehicles. An economic impact analysis of an LCFS in Washington was carried out to evaluate the likely impact of the program. It found that the overall effects on employment, personal income, and gross state product would likely be positive but small. Corresponding to less than 0.5 percent when compared to the business-as-usual (BAU) scenario. It estimated that an LCFS may require additional investment in the range of $0.3 billion to 2.5 billion for electric vehicle infrastructure and E-85 (ethanol blend) stations and cellulosic ethanol production facilities (Rude, 2011). Based on this study, the Department of Ecology staff made a favorable recommendation for an LCFS program, but no decision has yet been made whether to adopt an LCFS.

If Washington decides to move ahead with an LCFS, it may affect gasoline and diesel markets that respectively account for about 2 percent and 1.9 percent of total U.S. total sales for motor gasoline and distillate fuel oil. According to the EPA MOVES model, about 2 percent of total automobiles in use in the United States are in Washington. Several compliance scenarios analyzed as part of the impact assessment in a TIAX study (Pont et al., 2011) show that an LCFS may increase the production and use of in-state and out-of-state cellulosic biofuel (ethanol and renewable diesel). In-state canola biodiesel may also help meet the diesel pool CI reduction requirement. In the high-electric-vehicle scenario for the gasoline pool (i.e., electric vehicles replace gasoline vehicles), it is assumed that the number of PHEVs and BEVs will increase four times as compared to the BAU scenario, while the number of CNG vehicles will increase by 1.2 times. For example, the estimated numbers of fully electric vehicles and PHEVs in 2023 are projected to be 48,028 and 282,912, respectively.

2.4.2. Methodology and data in petroleum GHG emissions calculations

The methodology used for calculating GHG emissions of petroleum fuel is similar to that used in the proposed CFP in Oregon. As in Oregon, the TIAX study (Pont et al., 2011) commissioned by the Department of Ecology used the GREET model with some modifications to reflect the Washington-specific inputs. The reason for choosing the GREET methodology is that it is a publicly available source and is transparent. It allows a user to modify input values to reflect Washington-specific data for extraction, refining, and transport to calculate the CI of gasoline and diesel. For the purpose of assessing the GHG reduction potential of an LCFS, the Department of Ecology estimated the carbon intensities of gasoline and diesel based on the weighted average of crude mix used in refineries in Washington and Montana in 2007. In other words, feedstock specific gasoline and diesel intensities were not calculated even though tar sands and other heavy crudes were in the crude mix in 2007. In that year, 89 percent of the gasoline and diesel Washington used was refined in-state. The remaining came from crude oil refined in Montana (9 percent) and Utah (< 2 percent); however, gasoline and diesel refined in Utah were not modeled (Pont et al., 2011).

Figure 2.2. Sources of crude oil refined in Washington



Source: *Pont et al (2011)*

2.4.2.b. Crude extraction

In 2007, more than 85 percent of crude refined in Montana came from Canada through the Terasen Express Pipeline. About 12 percent of Montana's crude oil was brought in from Wyoming, with the remaining volume coming from in-state production (Pont et al., 2011). Based on the composition of the 2009 Canadian crude oil supply to Washington and Montana, it was assumed that 23 percent and 45 percent of Canadian crude oil in Montana and Washington correspondingly, were oil sands. Figure 2.2 shows the breakdown of crude oil sources used in Washington.

The 2007 crude mix consisted of crude oil from Africa, Alaska, Canada, the Middle East, South America, and the continental United States. Supplies from Alaska accounted for about 65 percent of the 2007 crude mix. Tar sands from Canada accounted for about 9 percent of the 2007 crude mix.

For electricity used in crude extraction, the Department of Ecology modified the GREET default values for electricity use to reflect the actual electricity mix used in the countries and U.S. states sending crude oil that was then refined in Washington and Montana.

2.4.2.c. Crude transport

Crude oil is transported to Montana and Washington via pipeline and ocean tanker. The Department of Ecology used the miles transported proportionately to account for these two modes of transport and adjusted the GREET default value for tankers of 100,000 deadweight tons to reflect the payloads allowed into Washington ports.

2.4.2.d. Refining

For electricity use in refining, the 2007 electricity mixes in Washington and Montana were employed instead of the default GREET values by considering the 2007 electricity mix in exporting countries and supplying states for crude oil extraction and in Washington for refining in 2007. Table 2.7 shows the electricity resources mix for Washington and Montana.

Table 2.7. Electricity mix in Washington and Montana, 2007

	WASHINGTON	MONTANA
Residual oil	0%	1%
Natural gas	10%	0%
Coal	17%	64%
Biomass	1%	0%
Nuclear	5%	0%
Hydro	67%	34%

Source*: Pont et al., 2011*

2.4.2.e. Refined product transport

Gasoline and diesel are transported from Billings, Montana to Spokane, Washington via the Yellowstone pipeline (540 miles). They are also transported from Seattle to western Washington and to Pasco, Washington via pipeline and ocean barge, respectively. Trucks are used to carry refined products from terminals to refueling stations. The distance traveled by truck is assumed to be 75 miles.

2.4.2.f. End use

The methodology used for calculating combustion emissions is the same as that described for the Oregon CFP.

2.4.3. Data aggregation, quality, and availability

Since Washington uses GREET for lifecycle analysis of fuels, the same issues and comments relating to the Oregon CFP are applicable here.

2.5. Northeast and Mid-Atlantic States Clean Fuels Standard

In 2009, the governors from eleven Northeast and Mid-Atlantic (NE/MA) states signed a memorandum of understanding to evaluate and develop a program framework for a regional LCFS, similar to that adopted in

California, by 2011. However, there was no formal commitment to adopt the program. In response to this, the Northeast States for Coordinated Air Use Management (NESCAUM), a quasi-governmental organization, carried out an economic impact analysis of an LCFS in the region to explore the costs and benefits of the program. As part of this exercise, NESCAUM used the REMI model (NESCAUM, 2011) to analyze the economic impact of a regional LCFS, now known as the Clean Fuels Standard, for three scenarios: the biofuel future, the natural gas future, and the electricity future. In the biofuel future, six-tenths of the required 10 percent GHG reduction is met by low-cost biofuels, with the rest derived from high-cost natural gas (2 percent) and electricity (2 percent). In the natural gas future, low-cost natural gas provides a 6 percent reduction, and high-cost biofuel and electricity meet the remaining 4 percent reduction target. Similarly, in the electricity future, electricity achieves a 6 percent reduction, with the remaining reduction coming from high-cost biofuels and natural gas (2 percent each). The analysis found that the program could provide a net benefit of between $22 billion and $41 billion in 10 years, including job creation and health improvements.

As the next step, the NE/MA states are internally scoping out details on how a clean fuels program would work, with details on program elements, carbon intensity, credit trading, alternative policies, etc. There is no specific timeline for any of these decisions.

2.6. British Columbia Renewable and Low Carbon Fuel Requirements Regulation (RLCFRR)

2.6.1. Type of legislation, targets, and size of the affected market

The British Columbia (BC) Renewable and Low Carbon Fuel Requirements Regulation (RLCFRR) is a province-level regulation that is a subset of the Canadian province's Greenhouse Reduction Act.[30] It regulates both biofuels and fossil fuels imported to or produced in BC. The RLCFRR aims to increase the use of renewable fuels and reduce GHG emissions. In the fossil fuels category, the regulated fuels are diesel, gasoline, propane, CNG, LNG, electricity, and hydrogen. The RLCFRR consists of two parts: a renewable fuel requirement and a low carbon fuel requirement. The renewable fuel requirement sets the targets for renewable content in diesel and gasoline, whereas the low carbon fuel requirement is similar to California's LCFS and requires a 10 percent GHG reduction by 2020. The low carbon fuel requirement is a performance-based, fuel-neutral standard. It offers a flexible mechanism for compliance through emissions credit trading. One notable difference from California's LCFS is that deficits are not

[30] Greenhouse Gas Reduction (Renewable and Low Carbon Fuel Requirements) Act: Renewable and Low Carbon Fuel Requirements Regulation (2008). BC. Regulation 394/2008.

allowed to be carried over to the next year, although credits may be carried over.

Carbon credits and deficits are calculated by comparing the CI of the fuel in question with the baseline carbon intensity. The carbon intensities under the RCLFRR are given in terms of higher heating value of regulated fuels – this differs from the other programs considered here, all of which assess carbon intensities in lower heating value terms. For consistency with the underlying regulation, we quote the values in HHV terms for the remainder of this section. The RLCFRR treats the gasoline and diesel pools separately, with independent compliance targets. The average baseline WTW carbon intensities for 2010 were calculated by averaging the intensities of gasoline and ethanol for the gasoline pool, and biodiesel and diesel for the diesel pool. This is an update on the initial treatment introduced for the RLCFRR in 2010, under which there was a single baseline carbon intensity for all fuels, and brings the RLCFRR into line with California's LCFS, for which baseline carbon intensities of gasoline and diesel were also estimated separately. This change was made because in the initial 'reporting only' period, the single fuel pool approach created a potential problem in terms of the fuel supply. That is, it effectively disincentivized the supply of diesel. As a result the lieutenant governor approved an amendment to the regulation in November 2012, which designates gasoline and diesel classes as two separate pools with separate CIs effective from July 2013.

It is worth noting that the refinery and crude supply situation in British Columbia is somewhat distinct from that of California. The British Columbian refineries are highly dependent on Western Canadian oil, and do not have the same level of complexity as the refineries in California, meaning that they are more limited in the extent to which they could switch to heavier, sour crudes. British Columbia is also a smaller oil market than California, and there was a concern that under a mass balance system of crude oil tracking it might have been possible for refiners to nominally allocate lower-carbon oils to British Columbian operations without delivering real changes in the carbon intensity of the global oil supply, or having any impact on investments in high-carbon oils. These issues contextualize the decision of British Columbia to remove the option for differential reporting of crude carbon intensity.

Table 2.8. Compliance targets under the RLCFRR

COMPLIANCE PERIOD	CARBON INTENSITY LIMIT FOR GASOLINE CLASS FUEL	CARBON INTENSITY LIMIT FOR DIESEL CLASS FUEL
	(gCO_2e/MJ, HHV BASIS)	(gCO_2e/MJ, HHV BASIS)
July 1, 2013 to December 31, 2014	86.20	92.38
2015	85.11	91.21
2016	84.23	90.28
2017	82.93	88.87
2018	81.62	87.47
2019	80.31	86.07
2020 and subsequent compliance periods	78.56	84.20

The required CI of the average fuel used in BC for each compliance period was determined relative to the 2010 baseline, such that a 10 percent reduction is achieved by 2020.

CI values of all fuels in the mix were obtained using the GHGenius model (Table 2.9). To calculate a CI, GHG emissions from 12 components of a fuel lifecycle are considered:

(1) Removal of hydrogen and CO_2 from natural gas

(2) Carbon sequestration in fuel

(3) Direct land use

(4) Co-product production

(5) Feedstock production and harvest

(6) Feedstock transport

(7) Manufacturing of fertilizer and pesticide

(8) Fuel production

(9) Fuel transport and storage

(10) Fuel dispensing

(11) Venting and flaring

(12) Fuel combustion in vehicles

When calculating CI values for specific biofuels, GHG emissions from indirect land use changes, capital equipment, construction of facilities, vehicle manufacturing and operation, and corporate activities are not considered.

Table 2.9. CI of fuels obtained from GHGenius

FUEL	CARBON INTENSITY (gCO_2e/MJ, HHV BASIS)
Gasoline class	87.29
Propane	75.35
Diesel class	93.55
CNG	62.14
LNG	63.26
Electricity	11.00
Hydrogen	95.51

Source*: British Columbia Ministry of Energy and Mines (2013a)*

Ethanol and biodiesel are classified as gasoline class and diesel class fuels respectively, with default CI values of 87.29 gCO_2e/MJ and 93.55 gCO_2e/MJ, respectively, if fuel specific CI values are unavailable. The CI values for fuels such as electricity in the regulations are not adjusted for drivetrain efficiencies. However, when fuel suppliers undertake compliance reporting, credits are adjusted for these fuels to reflect more efficient drivetrains.

To allow the regulated parties to comply, British Columbia extended an initial 'reporting only' period to June 30, 2013. The low carbon fuel requirement is likely to increase biofuel blending and the number of advanced technology vehicles. There were 3.2 million motor vehicles registered in BC in 2009. However, no comprehensive study has been carried out to assess the market and environmental impacts of the RLCFRR.

2.6.2. Methodology and data in petroleum GHG emissions calculations

The carbon intensity analysis under the RLCFRR is undertaken using the lifecycle analysis tool GHGenius (c.f. §4.3). As of November 2013, the approved version of GHGenius for carbon intensity calculations under the RLCFRR was version 4.01 (British Columbia Ministry of Energy and Mines, 2013b). The reason for choosing GHGenius is that it is a publicly available model and has a transparent database. GHGenius is devised to estimate fuel and vehicle lifecycle GHG emissions in the Canadian context. This model also enables users to choose region-specific input values related to crude oil extraction, refining, and transport. For example, it has input values for western, central, and eastern Canada. While the initial implementation of the regulation provided scope for suppliers to report refinery specific crude oil carbon intensities, following amendment this option is no longer available and there are now single reportable carbon intensities for fossil gasoline and diesel fuel respectively.

It is worth noting that the refinery and crude supply situation in British Columbia is somewhat distinct from that of California. The British

Columbian refineries are highly dependent on Western Canadian oil, and do not have the same typical level of complexity as the refineries in California, meaning that they are more limited in the extent to which they could switch to heavier, sour crudes. British Columbia is also a smaller oil market than California, and there was a concern that under a mass balance system of crude oil tracking it might have been possible for refiners to nominally allocate lower-carbon oils to British Columbian operations without delivering real changes in the carbon intensity of the global oil supply, or having any impact on investments in high-carbon oils. These issues contextualize the decision of British Columbia to remove the option for differential reporting of crude carbon intensity.

Crude production and refining data as applicable to British Columbia were used to calculate CI values of gasoline and diesel.

2.6.2.a. Extraction

About half of the crude oil refined in Canada is imported. However, British Columbia only uses crude oil produced in western Canada. Table 2.10 shows the crude slates used in western Canada and their physical characteristics. The API gravity and sulfur content of the Canadian crude slate for BC is given below. The crude slate includes both bitumen and synthetic crude from bitumen upgrading, both derived from Canadian oil sands. Bitumen extracted using surface mining is then upgraded to synthetic crude via chemical processes, while bitumen extracted using thermal techniques such as Cyclic Steam Stimulation (CSS) and Steam Assisted Gravity Drainage (SAGD) can also be supplied directly to refineries without upgrading. In Alberta, about 20 percent of oil sands can be recovered via surface mining, with the rest using in situ technologies. GHGenius has default values for both of these two extraction pathways. Energy consumption data for conventional crude oil and conventional heavy oil come from Canada's Energy Outlook report (National Resources Canada, 2006). For synthetic crude, energy consumption data come from Suncor and Syncrude, which report GHG emissions of 0.78 metric tons/m^3 of crude oil. Energy consumption data for oil sands come from the Canadian Association of Petroleum Producers (CAPP). Additional data reported by Alberta Energy Resources Conservation Board (ERCB) for surface mining and tar sands are also used. In GHGenius, time series data on extraction are available. GHGenius provides values for the energy consumption (and associated emissions) used in the extraction of six broad categories of oil: condensate, offshore conventional, onshore conventional, heavy conventional, synthetic, and bitumen. However, when calculating lifecycle GHG emissions, the model does not differentiate between the CI of gasoline and diesel by feedstocks.

Table 2.10. Characteristics of crude oil slate used in BC

TYPE	API GRAVITY	SULFUR CONTENT (WT. CONTENT)	CRUDE SLATE IN BC
Condensate	63.6	0.00100	39%
Conventional	37.5	0.0055	
Conventional offshore	35.9	0.0040	
Heavy	28.6	0.0230	14%
Bitumen	8.0	0.0470	7%
Synthetic	31.0	0.0020	41%

Source: *Fuel characteristics from (S&T)² Consultants, Inc. (2008)*

Flaring and venting data were projected based on the CAPP flaring and venting rates for the year 2000, assuming that such emissions are declining. For example, the 2007 flaring and venting emissions for conventional oil were estimated to be 57 percent lower than in 2000 ([S&T]² Consultants, 2007). The 2000 CAPP flaring and venting emissions for light and medium oil were 3,488 gCO_2e/GJ. Conventional heavy oil has higher flaring and venting rates compared to bitumen extraction.

2.6.2.b. Refining

Refining data for 2002 were modified to reflect current industry practices and the production of ultra-low sulfur fuel. GHGenius uses the relationship between energy consumption, API gravity, and sulfur content to estimate energy consumption in refineries. Refining emissions for bitumen are higher than for synthetic crude oil and conventional oil owing to higher density and sulfur content. GHGenius has time series data to estimate changes in refining emissions over time.

2.6.3. Data aggregation, quality, and availability

GHGenius calculates the energy consumed in extraction differently for condensate, onshore, offshore, heavy oil, bitumen, and synthetic crude oil. Although it does not provide GHG extraction emissions for each of these feedstock/production types, it might be possible to calculate feedstock-specific extraction emissions. The BC RLCFRR does not differentiate petroleum fuels by crude type in calculating GHG emissions.

Since BC only uses crude extracted and refined in western Canada, data quality used in GHGenius for BC RLCFRR is good overall. This is helped by the narrow geographical range, which contributes to low data variability, while emissions and production information is available by crude oil type and even by operator. There have been several detailed studies on Canadian venting and flaring (see Johnson and Coderre, 2011, 2012; Johnson, Kostiuk, and Spangelo, 2001, among others), and operators have strict requirements to report venting and flaring emissions, which provides improved data for verifying any estimates. Time series data on crude oil extraction are also available.

2.6.4. Data quality for reporting

To ensure that CI calculations are accurate, the regulation has specified guidelines for choosing the best data available. Acceptable data for calculating CI using lifecycle analysis are: site-specific process data, secondary data that are not from specific processes in the product lifecycle data, activity data, emission factors, direct emission data (as measured with equipment), and financial data showing GHG emissions per unit of monetary activity. It is suggested that site-specific data should be used to the extent that it is available.

To ensure data quality, the regulation recommends meeting the data quality requirements set by the International Organization for Standardization's ISO 14044:2006 to assess the quality of data. Best practices to ensure data quality include:

- use the data from the latest period possible;
- use the data specific to the geographic region where the process occurs;
- use the data specific to a technology employed; in case of variance, a large set of data should be collected to calculate an average value;
- use the complete data collected over a year rather than for short period to the extent possible;
- use methodology and data consistent with the model;
- ensure that results are reproducible by a third party and minimize the uncertainty when appropriate.

2.6.5. Reporting requirements

For compliance purposes, fuel suppliers are required to complete a compliance report form designed for the regulated parties (British Columbia Ministry of Energy and Mines, 2013c). In addition they should provide a report explaining how CIs were calculated, how data were collected, and what types of assumptions were made. This allows the BC Ministry of Energy, Mines and Natural Gas to monitor and verify the calculations.

There are three ways the regulated party can report the CI intensity of fuels (Ministry of Energy, 2010).

- It can choose the default values provided in the regulation.
- It can calculate its own CI values using the approved version of GHGenius by modifying input data for a specific fuel pathway or production process. In such cases, it needs to provide the evidence for choosing the new input data.
- If fuel types, feedstocks, or production processes of interest are not included in GHGenius, fuel suppliers may request that the director approve a new CI by providing the methodology and input data used for calculating new values.

2.7. U.S. Renewable Fuel Standard 2 (RFS2)

2.7.1. Type of legislation, targets, and size of the affected market and fuels

The Renewable Fuel Standard RFS2 is a volumetric standard that aims to increase the production and use of renewable fuel in the United States. The RFS2 applies to producers and importers of gasoline and diesel in the United States; however, it does not regulate petroleum-based fuels. It mandates the use of 36 billion gallons of renewable fuel by 2022. The RFS2 classifies renewable fuel into four categories: cellulosic biofuel, biomass-based diesel, advanced biofuel, and renewable biofuel, and it has set the volumetric requirements for each biofuel category. It specifies a minimum GHG reduction threshold for each type of renewable fuel.

Cellulosic biofuel refers to biofuel derived from lignocellulosic feedstock, and it should achieve at least a 60 percent reduction in GHG emissions compared to gasoline/diesel. The RFS2 projects an availability of 16 billion gallons of cellulosic biofuel by 2022. Advanced biofuel is defined as any biofuel that achieves at least a 50 percent GHG reduction, with the exception of ethanol from corn starch which is explicitly excluded as an advanced biofuel feedstock[31]. It is expected that there will be 22 billion gallons of advanced biofuel by 2022. Renewable (biomass) diesel refers to methyl esters biodiesel or diesel-like fuel obtained from biomass using thermochemical processes; it should achieve at least a 50 percent reduction in GHG emissions. It is expected that there will be at least 1 billion gallons of biomass-based diesel by 2022. Renewable biofuel can be obtained from any renewable biomass including crops. It is assigned a threshold of 20 percent GHG reduction. Corn ethanol from plants built before 2007 or commissioned in 2007 is grandfathered. Each year the EPA is required to set the standards for cellulosic biofuel and biomass-based diesel based on the projections for their availability and other considerations for the following year.

[31] That said, we are not aware of any corn ethanol pathway that would currently achieve a 50% carbon reduction in the EPA lifecycle analysis framework.

To determine whether a biofuel can qualify as a renewable fuel and in what category, the carbon intensity of that biofuel is compared with the carbon intensity of baseline gasoline or diesel. The baseline reference is gasoline or diesel produced in the crude mix in the United States in 2005. Lifecycle analysis was used to estimate CI for various fuels. For biofuels, emissions from indirect land use changes are included. The EPA uses the FASOM model to estimate GHG emissions from domestic land use and the FAPRI model to estimate GHG emissions from international land use.

The regulatory impact analysis of the RFS2 shows that this policy can reduce GHG emissions by 138 million metric tons per year by 2022. It is expected to displace 13.6 billion gallons of diesel and gasoline by 2022 but is also likely to increase commodity prices. The RFS2 is also likely to have a significant impact on air and water quality: the analysis suggests that it will increase emissions of hydrocarbons, NO_x, acet-aldehyde, and ethanol but will reduce emissions of CO, benzene, and ammonia (EPA, 2010). These reductions come from decreases in exhaust CO emissions, gasoline use, and livestock population, respectively. The RFS2 is projected to increase annual nitrogen and fertilizer loading in the Mississippi River basin by 9 million kg and 0.5 million kg, respectively. Considering fuel costs, monetized health and GHG impacts, and energy security, the net benefit is expected to be in the range of $8.5 billion to $21.5 billion in 2022 (EPA, 2010). No social impact (e.g., labor rights, wages, working conditions, etc.) assessment was carried out for the RFS2.

The RFS2 affects gasoline and diesel consumption in the United States by increasing the volume of renewable fuel used in transport. In 2010, 9.0 MMbbl/d and 3.8 MMbbl/d of gasoline and diesel, respectively, were consumed in the United States (EIA, 2013a). This will affect the gasoline and diesel blending in motor vehicles. In 2009, there were 245 million automobiles[32] (cars and trucks) on road in the United States. Currently 10 percent ethanol and 20 percent biodiesel blending are common. In order to meet the RFS2 target, the volume of ethanol blended in gasoline must be increased. In this regard, the EPA has approved a 15 percent ethanol blend for vehicle model years 2001 or newer. Drop-in fuels such as renewable gasoline and diesel obtained from cellulosic feedstock could help meet part of the cellulosic biofuel requirement.

2.7.2. Methodology and data in petroleum GHG emissions calculations

To calculate carbon intensities of baseline gasoline and diesel, the EPA used the National Energy Technology Laboratory (NETL) analysis (2008). The Energy Independence and Security Act (EISA) of 2007 required that the GHG reductions of renewable fuels be measured

[32] U.S. Department of Energy. Transportation Energy Data Book. Available at: http://www-cta.ornl.gov/data/chapter3.shtml

against the baseline GHG emissions of gasoline and diesel. The reason for choosing the NETL study as opposed to the GREET model is that its goal and scope match with the EISA definition of baseline gasoline and diesel. The NETL analysis included all the crude oils refined in the United States as well as imported gasoline and diesel, taking into account three GHGs: CO_2, N_2O, and CH_4. The NETL analysis estimates GHG emissions by country of origin, but for the RFS2 only the weighted average value has been used.

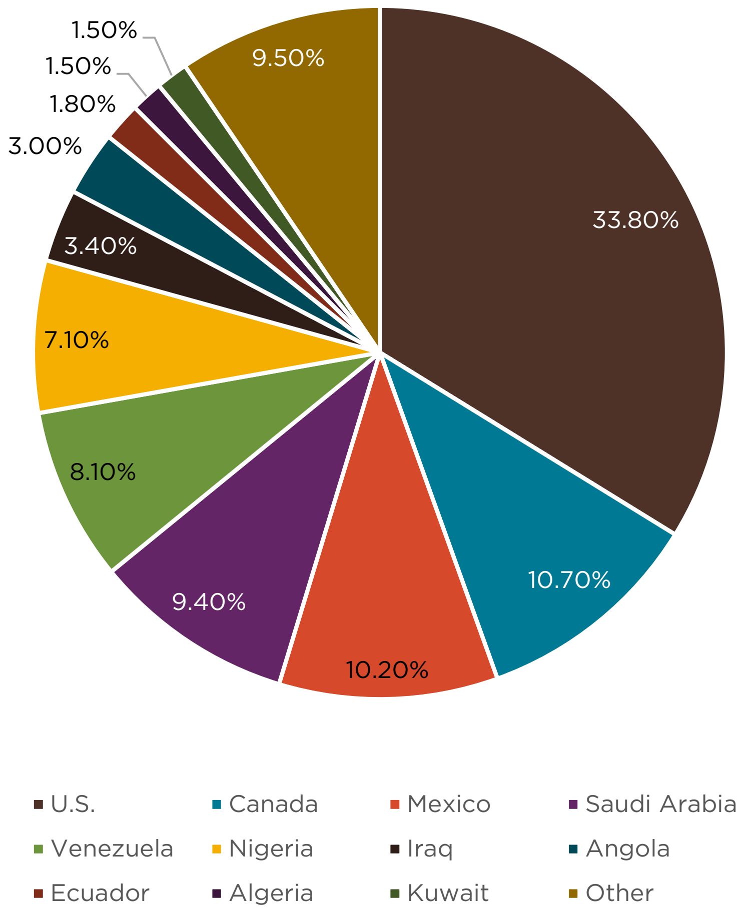
2.7.2.a. Extraction

To estimate the weighted average emissions from extraction in 2005, all crude types–domestic and imported–were analyzed, which included oil sands from Canada, heavy oil from Venezuela, and conventional crude oil. Conventional crude oil includes oil obtained from onshore and offshore extraction and enhanced oil recovery processes. The types and amounts of crude oil in the 2005 crude mix were determined based on EIA import data, CAPP, and other sources. U.S. domestic production accounted for 34 percent of the crude oil refined in the country, whereas imports from Canada, Mexico, Saudi Arabia, Venezuela, and Nigeria accounted for 11 percent, 10 percent, 9 percent, 8 percent, and 7 percent respectively (Figure 2.3).

The NETL analysis used the country-specific emission profiles obtained from PE International except for Canada (Table 2.11). For conventional oil production in Canada, the U.S. average value was used to estimate extraction emissions while adjusting for Canada-specific flaring and venting emissions. For oil sands, actual emissions reported by two major companies, Imperial Oil and Syncrude, were used to calculate extraction emissions per barrel and are close to the values estimated by Charpentier, Bergerson, and MacLean (2009). The estimated extraction emissions for conventional Canadian crude oil and oil sands are 32.4 $kgCO_2e/bbl$ and 111 $kgCO_2e/bbl$. The latter value was derived assuming that the fuel extracted from oil sands is composed of 43 percent crude bitumen and 57 percent synthetic crude oil. Except for Canada, in which emissions from oils sands are distinguished from conventional crude oil, extraction emissions are the aggregate values for each country.

The NETL study (2008) estimated country-specific flaring and venting emissions using the relationship between CO_2 emissions and the amounts of hydrocarbon vented or flared. Although it estimated extraction emissions of crude oil by country of origin, it did not calculate WTW emissions by gasoline and diesel differently by country of origin or feedstock type.

Figure 2.3. Sources of crude refined in U.S. refineries



Source*: U.S. EPA (2010)*

Table 2.11. Country-specific extraction emission profiles

COUNTRY	$kgCO_2e/BBL$
U.S.	24.5
Saudi Arabia	13.6
Mexico	38.4
Venezuela	24.2
Nigeria	128.6
Iraq	19.6
Angola	81.8
Ecuador	31.3
Algeria	35.1

Source*: NETL (2008)*

2.7.2.b. Foreign refineries

In 2005, the United States imported 12.7 percent and 5.2 percent of total gasoline and diesel consumed, respectively (NETL 2008). The two largest sources of refined products were Canada and the Virgin Islands. The imported gasoline and diesel from Canada accounted for 25 percent and 32 percent of total imports, respectively, while gasoline and diesel imported from the Virgin Islands accounted for 17 percent and 29 percent, respectively. For these two countries/territories, extraction emissions are modeled using the PE International extraction emission profiles. For other countries, extraction emissions are estimated using GaBi 4, a well-known lifecycle assessment application. For other countries for which extraction emissions profiles are not available, the EPA uses the surrogate emissions profiles.

2.7.2.c. Crude transport

For transport emissions, the EPA considers five modes of transport (ocean tanker, rail, water carrier, pipeline, truck) and miles traveled. For imported crude oil, transport by pipeline (100 miles) to the port or border within the exporting country followed by transport by ocean tanker to the U.S. border is assumed. The transport distance from the foreign country to the U.S. port comes from Portworld.com. For domestic production, crude is assumed transported to refiners by pipeline, ocean tankers, rail, and trucks. The estimated energy intensity for pipeline transport is 260 BTU/ton-mile.

In the case of imported refined products, transport by pipeline (100 miles) within the same country to refineries is assumed. If crude oil is imported from another country, GABi 4 software is used to estimate transport emissions.

2.7.2.d. Refining

The NETL analysis calculates refinery emissions based on four major contributors: (1) embodied emissions in energy inputs purchased from outside sources (power, steam, coal, natural gas) and used in the refinery; (2) hydrogen production; (3) fuel combustion; and (4) flaring and venting. These emissions are then allocated to gasoline and diesel based on capacity/throughput and contribution to refined products.

The impact of API gravity and sulfur content of crude on refinery unit processes such as coking, hydrocracking, and hydro-treating are used to estimate energy consumption and associated GHG emissions. For example, higher sulfur content in crude requires more hydro-treating and hence more hydrogen use. Likewise, API gravity affects catalytic cracking, hydrocracking, coking, and vacuum distillation. The NETL analysis uses regressions between API gravity and upgrading throughput, between API gravity and distillation capacity, and between volumetric throughput and energy consumption to estimate energy consumption.

For foreign refineries, a domestic refinery model was used as a surrogate to estimate refinery emissions.

2.7.2.e. Transport of refined products

For domestically produced refined products, the proportion of transport through each mode (pipeline, water carrier, trucks, and rail) and distance traveled are considered. The modal shares for transport of domestically refined products are 59.8 percent for pipeline, 29.9 percent for water carrier, 6.3 percent for trucking, and 4.0 percent for rail. The imported refined products are assumed transported to U.S. ports via ocean tanker or pipeline.

2.7.2.f. Combustion

CO_2 emissions from fuel combustion are based on the emission factors used in EPA's GHG emission standards for passenger vehicles. N_2O and CH_4 emissions are derived from the EPA's MOVES model.

2.7.3. Data aggregation, quality, and availability

For extraction emissions, the NETL study provides country-specific emissions profiles. Emissions are averaged for all crude types within a country that is part of the 2005 crude mix except for Canada. In the case of Canada, there is a differentiation between oil sands and conventional oil. Oil sands extraction emissions are based on project-level data reported by Syncrude and Imperial Oil for surface mining and in situ production methods. Venting and flaring emissions are the important contributors to GHG emissions, and the NETL study (2008) notes that the variability of extraction emissions among the countries analyzed is partly caused by venting and flaring rates. The other reasons for variability are the differences in extraction methods, field maturity, and crude characteristics, among others.

The NETL study uses surrogate emission profiles for countries for which extraction energy consumption and emission data are not available and thus may have contributed some uncertainty to the model. Also, emissions from heavy oil extraction in Venezuela are not included in the analysis because of lack of data. When the extraction emissions of heavy oil are assumed to be comparable to those of oil sands, NETL found that this would affect WTW GHG emissions by less than 3 percent. The NETL analysis (2008) notes that its WTW emission estimates are robust, with overall uncertainty of less than ±1 percent. Each variable analyzed did not contribute variance of more than ± 4 percent in WTW estimates. For a more in-depth analysis of the NETL study, please refer to §0.

2.7.4. Reporting requirements

Under the RFS2 there are no reporting requirements for petroleum-based fuels since they are not regulated fuels. Reporting requirements only pertain to biofuels. Regulated parties must comply with the biofuel requirements for a given year through Renewable Identification Number (RIN) transactions.

2.8. EU Fuel Quality Directive (FQD)

2.8.1. Type of legislation, targets, and size of the affected market

The Fuel Quality Directive (FQD) requires transport fuel suppliers in the EU to reduce GHG emissions by at least 6 percent by 2020.[33] This reduction can be achieved through the use of alternative fuels. As in other LCFSs, lifecycle analysis is the basis for calculating the carbon intensity of road transport fuels[34] and GHG savings. The FQD also outlines that an optional two percent GHG reduction can be achieved from the use of novel technologies such as CCS and the use of electric vehicles. Moreover, there is a mechanism for claiming a two percent reduction by using credits generated from Clean Development Mechanism (CDM) projects.

In addition, the FQD has sustainability criteria in place, aiming to ensure that biofuels meet a minimum standard of environmental sustainability and offer real GHG benefits. The FQD has set a minimum GHG savings threshold of 35 percent. This threshold will be increased to 50 percent, effective from January 2017, and 60 percent, effective from January 2018. Only biofuels produced in installations operated during or after 2017 will be subjected to the 60 percent GHG requirement. Biofuels from wastes and residues are subject to the GHG savings requirement but not the other sustainability rules. The methodology used for calculating the CI of biofuels is outlined in Annex IV of the FQD. The methodology does not include indirect land use change (ILUC) GHG emissions; however, the directive instructs the European Commission to evaluate ILUC and if necessary propose a measure to take ILUC into account. In this regard, the Commission has conducted several ILUC modeling studies and has carried out an impact assessment on how to incorporate ILUC into the FQD and the Renewable Energy Directive (RED). A proposal to limit the contribution of food based biofuels to the RED, and to introduce reporting of iLUC emissions based on default factors, is currently being considered by the European Union's institutions

Biofuel suppliers can either report the default values of fuels provided in the FQD or alternatively can demonstrate that their fuels achieve greater GHG savings. This may be necessary for some fuels to be eligible for support, where the default savings value is below 35/50/60 percent as appropriate. Using additional data to demonstrate better than default performance would also contribute to meeting suppliers' FQD targets and may deliver additional value for the biofuels dependent on member state implementation of the FQD. There are some restrictions on when suppliers are permitted to report default emissions values for biofuels, notably conditions around national

[33] Directive 2009/30/EC, OJL 140/88,5.6.2009
[34] The directive applies primarily to road transport fuel. A full discussion of the inclusion and exclusion of other fuel uses is beyond the scope of, and of limited relevance to, this paper.

NUTS[35] inventories for biofuels produced in Europe, but it is not yet clear how much effect these requirements will have once implemented in national legislation.

The FQD prohibits the use of biomass from land that (in January 2008) was forested, high-biodiversity grassland, peat land, or wetlands. The mass balance approach should be used to demonstrate compliance with sustainability criteria. In a mass balance approach, it is not required that the exact molecules of material with which a sustainability claim is associated should be tracked all the way from cradle to grave. However, at any intermediate facility in the chain-of custody it must be shown that an equal quantity of material with a given sustainability claim entered the facility as is reported to have left it. This contrasts to approaches such as book and claim, in which a sustainability claim can travel completely independently from the material. Fuel suppliers can use approved international and voluntary standards to show compliance with sustainability criteria.

The European Commission is required to report every two years to the European Parliament the measures taken to protect air, soil, and water by EU member countries and developing countries that supply biofuels. In addition, the Commission is required to report to the Parliament the impact of biofuel production on social sustainability issues such as land rights, labor rights, equal pay, and minimum employment age, among other issues.

As the use of biofuel and electricity in transport increases as a result of FQD implementation, this will affect the market for petroleum products and the share of different vehicle types in the EU. There are about 240 million vehicles in use in the EU, of which 87 percent are passenger vehicles.[36] At present, the number of electric vehicles in the EU is negligible to the RED/FQD targets but is expected to increase in response to FQD and RED implementation, as well as other long-term market and policy drivers. In the EU, more diesel is used in transport than gasoline (biodiesel has infrastructure compatibility advantages over ethanol and much greater existing production capacity), so it is expected that more biodiesel will be blended than ethanol. In the EU, refineries are configured to produce more diesel than gasoline, but there is still a shortage of domestically refined diesel, making diesel substitutes appealing. The amount of petroleum products consumed in the EU for all purposes was approximately 455 million metric tons of oil equivalent (toe) in 2010 (EUROSTAT, 2012). In 2006, 8.1 exajoules of diesel and 4.4 exajoules of gasoline were consumed in the EU (EUROSTAT, 2012).

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[35] NUTS stands for 'nomenclature of territorial units for statistics.'
[36] European Automobile Manufacturers' Association (ACEA). Available online at:
http://www.acea.be/news/news_detail/vehicles_in_use/

2.8.2. Methodology and data in fossil fuel GHG emissions calculations

Lifecycle GHG emissions are calculated using the following equation:

$E = e_{ec} + e_l + e_p + e_{td} + e_u - e_{sca} - e_{ccs} - e_{ccr} - e_{ee}$,

Where

E	Total emissions from the use of the fuel;
e_{ec}	Emissions from the extraction or cultivation of raw materials;
e_l	Annualized emissions from carbon stock changes caused by land-use change;
e_p	Emissions from processing;
e_{td}	Emissions from transport and distribution;
e_u	Emissions from the fuel in use;
e_{sca}	Emissions savings from soil carbon accumulation via improved agricultural management;
e_{ccs}	Emissions savings from carbon capture and geological storage;
e_{ccr}	Emissions savings from carbon capture and replacement; and
e_{ee}	Emissions savings from excess electricity from cogeneration.

Only CO_2, N_2O, and CH_4 emissions are taken into account. Embodied emissions in capital equipment are excluded.

To measure the GHG savings of biofuels, the CI of biofuels is compared to the CI of the fossil fuel comparator. The FQD requires the CI of the fossil fuel comparator to be based on the average lifecycle emissions of fossil fuels. The FQD states that the comparator should represent the carbon intensity of the European fossil fuel pool, as reported under the FQD, but that until such emissions data for gasoline and diesel are available, the value shall be taken to be 83.8 gCO_2e/MJ. To arrive at 83.8 gCO_2e/MJ, the EC used the CI of individual fossil fuels and their volumes. The data on volumes of fossil fuels used were obtained from sources such as the 2006 Fuel Quality Monitoring (FQM) report, the European Association of Liquefied Petroleum Gas (AEGPL), and EU fuel consumption data. In 2010, fossil fuels used in the EU were diesel, gas oil, petrol (gasoline), LPG, and CNG. The CIs of fossil fuel were obtained from Joint Research Centre–European Council for Automotive Research and Development and CONCAWE (JEC) WTW analysis (JEC, 2011).

The consultation document focused on the issue of balancing administrative burden with accuracy. The directive calls on the European Commission to develop a methodology for estimating GHG emissions of fossil fuels, and the Commission is considering the introduction of separate default values by feedstock type such as conventional oil, shale oil, oil sands, gas-to-liquid, and coal-to-liquid to provide market signals for GHG reduction.

2.9. EU Renewable Energy Directive (RED)

The RED is a volumetric mandate requiring 10 percent energy content in transportation to be from renewable sources including biofuels by 2020.[37] It is expected that at least 8 percent of transport energy will come from biofuels, with double counting of waste and cellulosic biofuels effectively reducing the overall energy target slightly (on the order of 1 percent), and the rest coming from renewable electricity such as solar and wind. Since the RED and FQD have been harmonized,[38] features in the RED relating to sustainability criteria, methodology for estimating GHG emissions, and indirect land use change are the same as in the FQD.

2.10. UK Renewable Transport Fuel Obligation (RTFO)

In 2008, the Renewable Transport Fuel Obligation (RTFO) was implemented, providing a volumetric mandate for renewable fuels in the United Kingdom. Under the RTFO, 5 percent (by volume) of road transport fuel[39] used in the United Kingdom should be biofuel by 2013. The RTFO was amended in 2011, and now biofuels sold in the United Kingdom are subjected to the same sustainability criteria as in the FQD/RED, as well as the other FQD/RED provisions. UK biofuels are required to achieve a 35 percent GHG savings (rising in due course as described above) and should not be produced from biomass derived from high carbon stock and biodiverse areas. When biofuels are independently verified (by the provision of a limited assurance opinion from a verifier qualified to do an International Standard on Assurance Engagements [ISAE] 3000 sustainability audit) for sustainability criteria, they accrue renewable transport fuel certificates (RTFCs), awarded to the owner of the fuel as it crosses the duty point. The RTFO counts the certificates accrued to biofuels produced from defined wastes and residues and from lignocellulosic feedstocks. Suppliers of fossil motor fuels are required to demonstrate compliance with the RTFO by earning or acquiring enough RTFCs to show that the required volume of biofuel has been supplied. The excess RTFCs can be traded among the participants. Alternatively, the obligated parties can pay a buyout price for the purpose of compliance. It is also possible for the obligated parties to carry over excess RTFCs for one year to the next to meet not more than 25 percent of the next year's obligation. The RTFO does not regulate fossil fuels and hence does not outline a methodology for estimating GHG emissions of fossil fuels.

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[37] Directive 2009/28/EC, OJL 140/16, 5.6.2009.

[38] In the sense of having the same lifecycle analysis requirements and sustainability criteria, and the fossil fuel comparator will be the same in both directives.

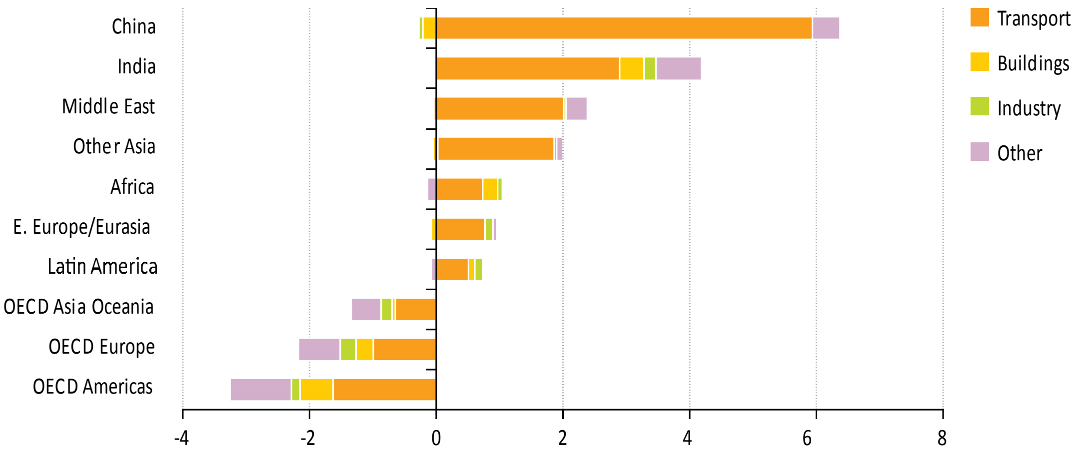
[39] The RED and FQD are not strictly limited to road transport fuel, and the RTFO takes its lead on fuel coverage from the directives, but because road transport is likely to be the dominant sector involved and non-road motorized machinery, canal boats, and so forth are tertiary to the goals of the current project, we have simplified for brevity.

3. European Union crude oil sourcing

3.1. Introduction

Over the past decade, the world economy has experienced a number of strong demand downturns that have reduced pressures on oil markets, despite a number of supply-side disruptions (e.g., from Iraqi and Libyan oil). Nonetheless, by 2010 global oil consumption was growing at a rate of 3.1 percent, reaching a record level of 87.4 million barrels per day (MMbbl/d) while outpacing supply that grew at a rate of 2.2 percent (British Petroleum [BP], 2011b). Despite supply reduction and price pressures, projections to 2035 show that oil demand (excluding biofuels) is expected to rise to 99 MMbbl/d (International Energy Agency [IEA], 2011). Most of this demand will be driven by a ballooning transport sector in non-OECD markets, accounting for 93 percent of global energy growth (BP, 2011a).

Figure 3.1. Projected change 2010-2035 in primary oil demand by sector and region in IEA 'New Policies Scenario' (IEA 2011f)



The transport sector is expected to remain the main source of global oil demand over the next quarter of a century (Figure 3.1), reaching almost 60 MMbbl/d in 2035, representing an increase of close to 14 MMbbl/d over 2010 levels (IEA, 2011f). Within the sector, road transport remains the primary driver of oil demand with projections holding it accountable for up to 75 percent of global transport oil demand by 2035, corresponding to more than 45 MMbbl/d (Ibid). With the global stock of road transport vehicles set to double between 2009 and 2035, driven largely by China, India, and other non- Organization for Economic Co-operation and Development (OECD) markets, passenger light-duty vehicles (PLDVs) will remain the single largest generator of emissions (Figure 3.2) and oil consumption (Figure 3.3). It is important to highlight the uncertainty related to some of these projections, given economic and political downturns that affected the world economy in the period following 2008. Nonetheless, vehicle ownership levels in non-OECD countries (125 per

1,000) are projected to remain well below the OECD levels of almost 550 per 1,000 people in 2035.

Figure 3.2. Total Well to Wheel (WTW) emissions by transportation mode and region (ICCT Roadmap, 2012)

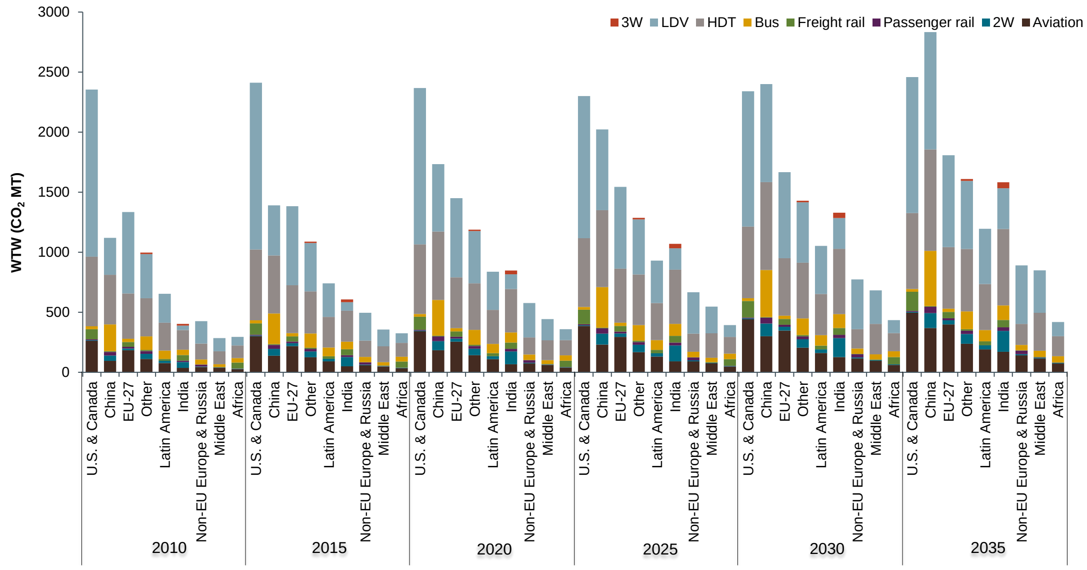
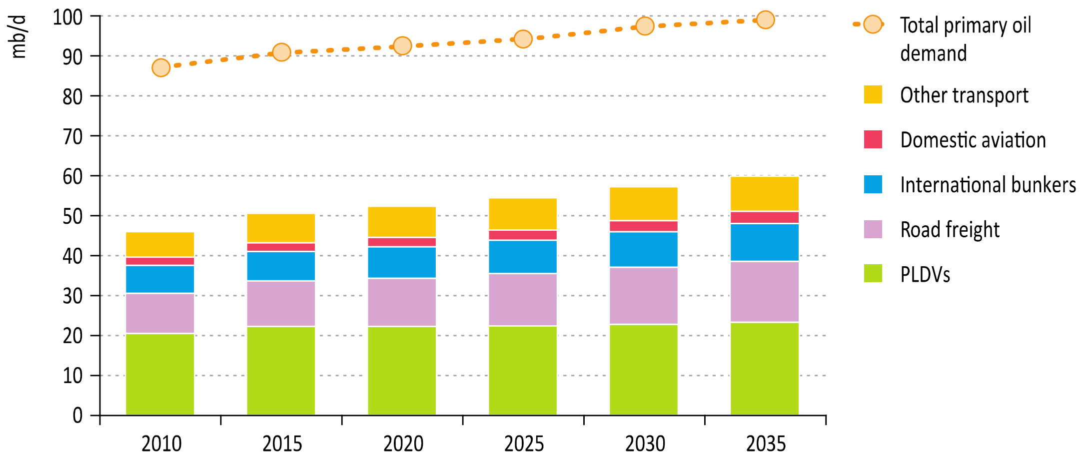


Figure 3.3. Projected world transportation oil demand by mode in New Policies Scenario (IEA 2011f)



Note: PLDVs are passenger light-duty vehicles comprising passenger cars, sports utility vehicles and pick-up trucks.

According to the International Energy Agency (IEA, 2011f), the market penetration of electric vehicles and hybrids is expected to remain relatively small at the global level through 2035. The role of policy, especially in some of the largest OECD markets, though, is expected to decrease further oil dependence with the adoption of policies incentivizing fuel efficiency improvements and fuel standards. However, it is important to consider different caveats in these projections. Not only can economic factors negatively affect these trends, but also the survival rates of passenger vehicles. For example, the U.S. National Highway Traffic Safety

Administration (2006) estimates that the survival rate at 15 years for passenger vehicles is around one-third.

Alternative fuels are also projected to grow but in these analyses remain far below some more ambitious expectations. Within this category, biofuels make the most important contributions, with the sector experiencing an annual average growth rate of 5 percent to 2035 (IEA, 2011f). Nonetheless, their share in total transport fuel demand would in this case grow to only 6 percent (IEA, 2011f) by then. Overall, oil remains the dominant energy source for the transport sector, representing 83 percent of all fuels up to 2035 (IEA, 2011f). The sourcing and carbon intensity of crude oil will hence continue to be of great importance to European energy and emissions. In the absence of countervailing pressures from emissions regulations, this crude sourcing is likely increasingly to include ‘unconventional’ sources such as thermally enhanced extraction of heavy, extra heavy, or bituminous reserves.

The following section explores the current sourcing of crude oil in the EU by detailing oil trading and distribution networks.

3.2. Crude oil sourcing for the European Union

From 2005 to 2011, the European Union (EU-27)[40] has averaged annual imports of crude oil of slightly more than 11.6 MMbbl/d at an average cost of insurance and freight (CIF) price of around $75/bbl (DG Energy, 2012a)[41]. The region remains a net importer of crude oil, with European Union crudes (which exclude those from Norway) representing only a fraction of all consumed crude in the region. For the time period 2005–2011 (see Figure 3.4), just below 38 percent of all crude was obtained from former Soviet Union (FSU) countries, followed by Africa (19 percent) and the Middle East (18 percent).[42] As shown in Figure 3.5, the Russian Federation has remained the main provider of crude to Europe, supplying on average more than 28 percent of all imports to the region. This is followed by Norway (14 percent). Iran, which was the fifth largest provider to Europe in 2007, has become less important in the intervening period, with Kazakhstan and Saudi Arabia absorbing much of its share. Presumably, given the current geopolitics of Iranian oil, this share is unlikely to increase again in the short term. Finally, Libya has remained the third largest supplier of crude to Europe since 2006.

[40] EU refers to the EU-27, i.e., Austria, Belgium, Bulgaria, Cyprus, the Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Ireland, Italy, Latvia, Lithuania, Luxembourg, Malta, the Netherlands, Poland, Portugal, Romania, Slovakia, Slovenia, Spain, Sweden, and the United Kingdom.

[41] The CIF price is defined as the cost, insurance, and freight price of a good delivered. According to the OECD, the price is set at the frontier of the importing country, including any insurance and freight charges incurred to that point, or the price of a service delivered to a resident. It does not include any payments of import duties or other taxes on imports or trade and transport margins within the country of delivery (OECD, 2012).

[42] Significantly, several of the European Union’s major suppliers–including Russia, Nigeria, Kazakhstan, and Iran-are associated with fields that have high levels of flaring on a unit production basis (ICCT/ER, 2010).

Figure 3.4. Crude oil imports into the EU-27 by region, 2006-2011 (DG Energy, 2012a)

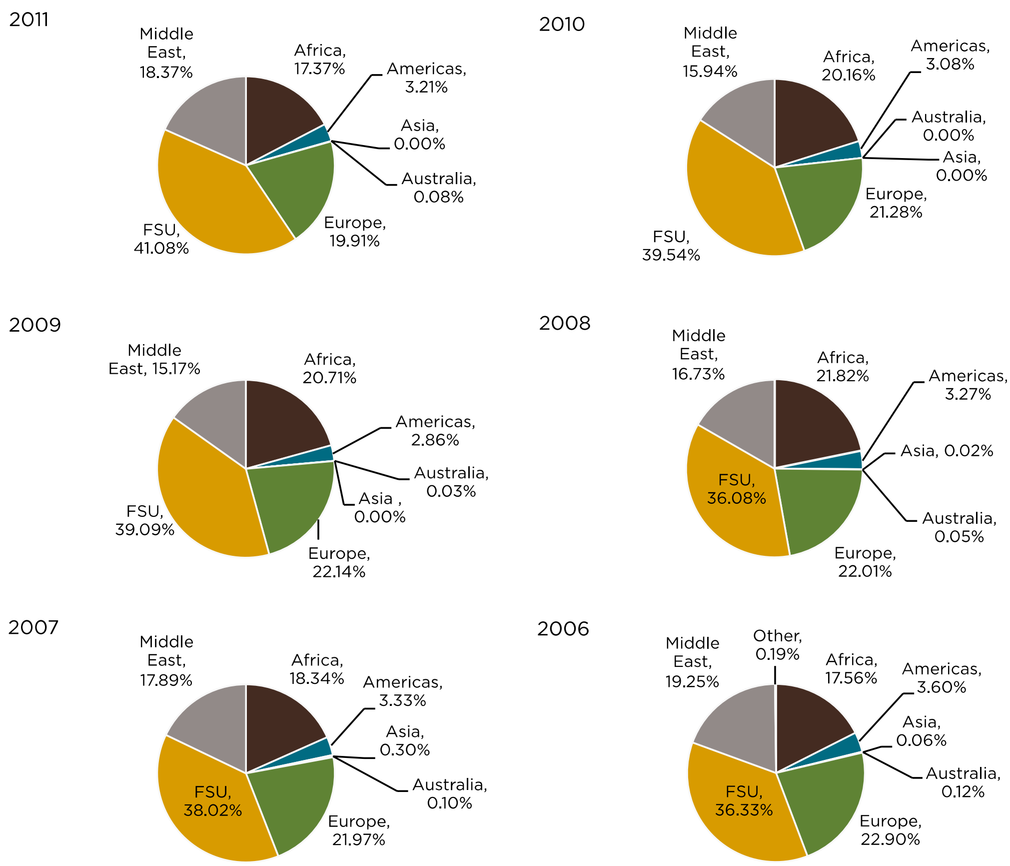
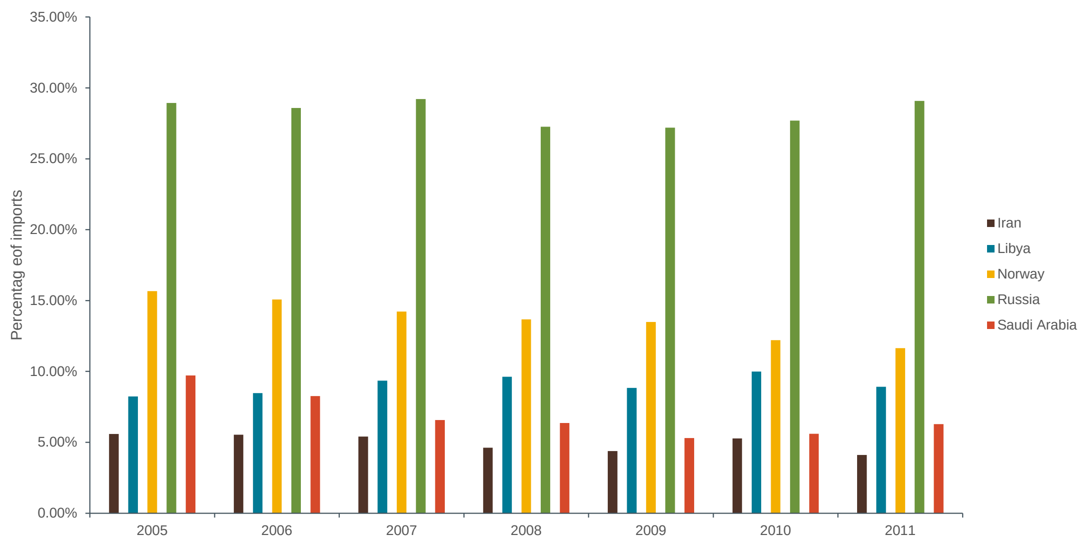


Figure 3.5. Major suppliers of EU crude oil (percentage of EU imports) (DG Energy, 2012a)



For that same six-year time period, the predominant import of crude oil blends (see Figure 3.4) has been Urals from Russia, averaging close to 16 percent of all crude oil imports into the EU. There is an additional 12.5

percent consisting of imports of other Russian crudes that are not specified in the European Commission data. Unspecified Norwegian crude (5.6 percent), Saudi Arabian Arab Light (5.5 percent), Kazakhstan crude (5.1 percent), and Libyan medium (30–40 API gravity) (4.4 percent) represent the remaining most commonly imported crudes.

Defining Crude Blends

The U.S. Energy Information Administration (EIA) defines crude oil as "a mixture of hydrocarbons that exists in liquid phase in natural underground reservoirs and remains liquid at atmospheric pressure after passing through surface separating facilities" (EIA, 2012). Depending on the characteristics of the crude stream, it may also include: (i) small amounts of hydrocarbons (in gaseous phase) in natural underground reservoirs that are liquid at atmospheric pressure; (ii) small amounts of non-hydrocarbons produced with the oil, such as sulfur and various metals; and, (iii) drip gases, liquid hydrocarbons produced from tar sands/oil sands, gilsonite, and oil shale (EIA, 2012). A crude blend denotes the commingling of two or more crudes. Crude blending provides an opportunity to create a new variety of crude for transportation needs, refining efficiency, or product value. This is accomplished through two methods: (i) on-line blending, where two or more components are injected and mixed in a single line, and (ii) tank blending, where components are added and mixed in a common tank based on a recipe approach (Husky Energy, 2012). The characteristics of a blended crude are determined by the relative flows of the commingled crudes, their physical properties, the size of the tank, the number of tank mixers, and mixing time, among other factors that make creating a homogenous blend a complex task. One of the most widely referenced blended crudes is Brent Crude, produced in the North Sea region from a mixture of light crudes, which serves as a reference for pricing a number of other crude streams. In this report, we talk about crude blends in the broad sense of being all of the blends that might be delivered to a refinery and will include any crudes that are delivered as a single stream from the well to refinery without actually being blended with other crudes.

3.2.2. Oil refineries

Currently, there are more than 6,000 individual oilfields in the world (ICCT/ER, 2010). Once these crudes are produced, they are typically mixed at a terminal and eventually sold onto the world crude market as approximately 300 distinct crude types or 'blends' (see box) for onward shipment to one of the world's roughly 650 refineries (ER, 2012). For example, Figure 3.6 shows how the production from certain Nigerian oilfields is collected and commingled before some minor processing at the ExxonMobil terminal of Qua Iboe. As can be seen, many fields supply the terminal (shown as a white square), via multiple pipeline routes (shown in green). Typically, blended crudes are transported by pipelines, tankers, and/or barges to their ultimate destination. The majority of these flows occur by oil tanker, transporting anywhere between 0.5 million and 2 million metric tons of oil, depending on their size. Given that each crude has different stated characteristics (notably the API gravity—light or heavy—and the sulfur content—sweet or sour) with specified conversion profiles for refining, refineries are supplied with information regarding a number of metrics necessary to enhance their refining process. The refinery, depending on how it is set up, will produce different quantities and types of oil derivatives, including gasoline and diesel among others. The yields of these products will vary with crude input and refinery processing configuration. Some offshore fields produce directly from the platform where crude is uploaded to a nearby marine terminal or a buoy and placed en route to a refinery. Examples of this include Hibernia in Canada but also the Chevron-operated Agbami field in Nigeria, which is the country's largest deepwater development of light, sweet crude (Chevron 2012). Fields produced from floating production storage offshore (FPSO) ships typically sell their own crudes without commingling.

Figure 3.6. Commingled field production for Qua Iboe blend (Nigeria) (ER, 2012a)

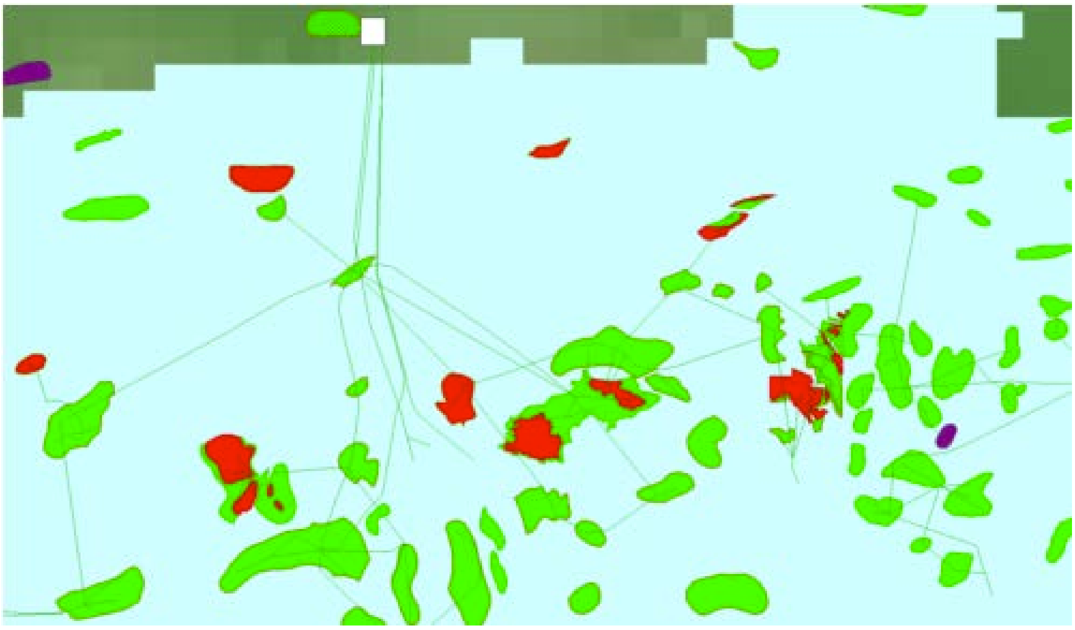
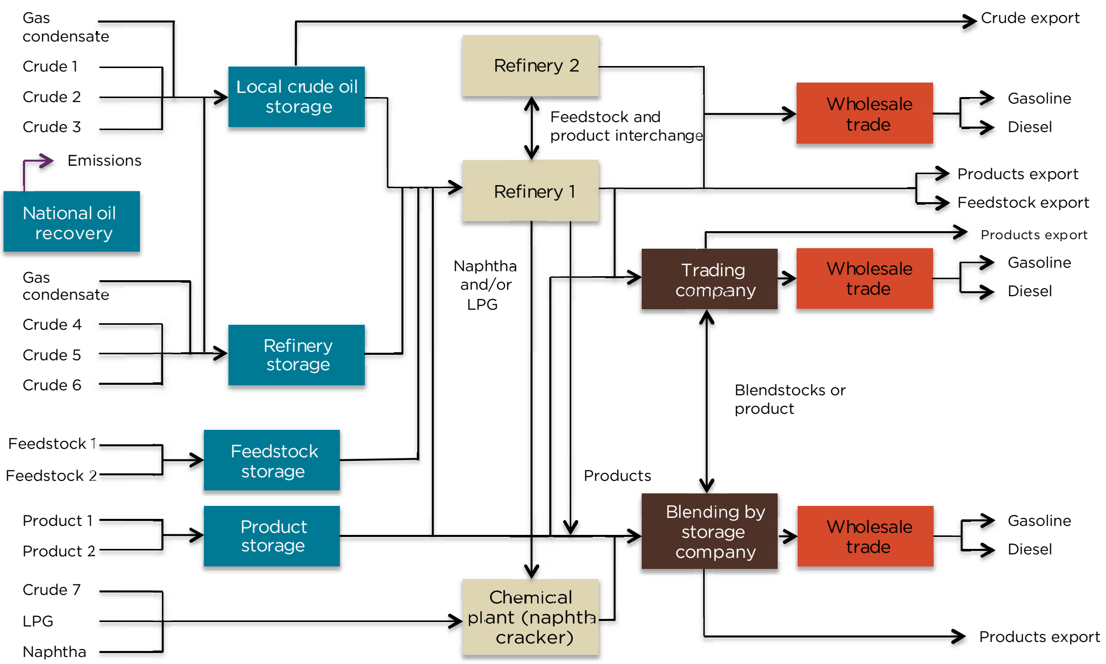


Figure 3.7 (Grinsven et al., 2012) shows the oil streams that might typically be imported into an EU country. Currently, there are 104 refineries located within the EU, with a crude refining capacity of 15.6 MMbbl/d (JRC, 2012). This is equivalent to 18 percent of total global capacity, making the region the second largest producer of petroleum products in the world after the United States.[43] Although the utilization

[43] There are refineries in 21 member states, with the exceptions of Cyprus, Estonia, Latvia, Luxembourg, Malta, and Slovenia.

rate of the refineries located in OECD Europe (the EU-27 minus a half-dozen smaller, primarily eastern countries, plus Iceland, Norway, Switzerland, and Turkey) has been as high as 90 percent, in recent years (due in large part to the economic downturn), utilization rates have fallen below the 80 percent mark (JRC, 2012b). The two primary refinery products in the EU are gasoline and gas oil/diesel. European refineries oversupply gasoline (measured against the domestic market), so gasoline is the main petroleum derivative export of the region, while they undersupply diesel, which is also imported as refined product in conjunction with jet fuel/kerosene.[44] Crude oil refinement can also be achieved at certain chemical plants, while storage and trading companies can construct their own blends from different oil streams or refining components.

Figure 3.7. Diagram of oil streams into refineries and their output (adapted from Grinsven et al., 2012)



3.2.3. Present locations of major trading and blending hubs supplying the EU

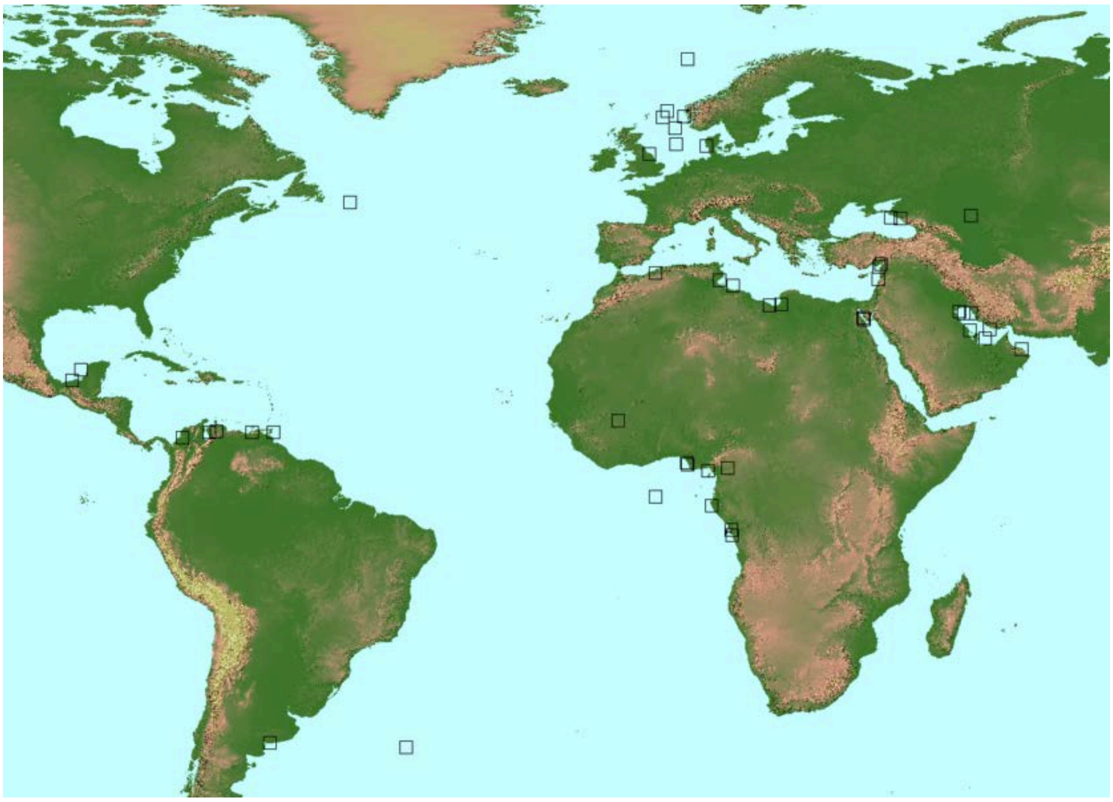
There are currently around 300 locations from which crude blends are sold in the world (ER, 2012)[45]. Although not all of these locations supply the EU market, around 50 to 70 crude blends from more than 35 countries are currently sold into the EU (ER, 2012). The current analysis has identified a total of 51 unique terminals supplying the EU market,

[44] Russia is the largest supplier of gas oil/diesel to the EU, followed by the United States, which is also the largest recipient of gasoline from the EU. Concerning kerosene/jet fuel imports, the EU mainly relies on a number of Middle Eastern countries.

[45] That includes single-field output sold from FPSO ships and offshore buoys.

including their geographical location (ER, 2012).[46] Given that the EU does not provide detailed description of all crude imports,[47] the analysis provides multiple terminal locations to reflect the fact that there are different crudes that might be sourced from each of these. The following paragraphs will provide a more in-depth inspection of three major suppliers of European crude oil: the FSU (including Russia) and Norway, because of the high volumes supplied from these regions, and Nigeria, because of its status as a source of high flaring emissions.

Figure 3.8. Location of major crude oil blending hubs supplying the EU market (ER, 2012a)



[46] Longitude and latitude of terminals may not be accurate and should be taken as approximate locations.

[47] It is likely that the EU might have the underlying details of these more generic descriptions.

Figure 3.9. Crude import volume to EU by blending hub of origin (ER, 2012a)

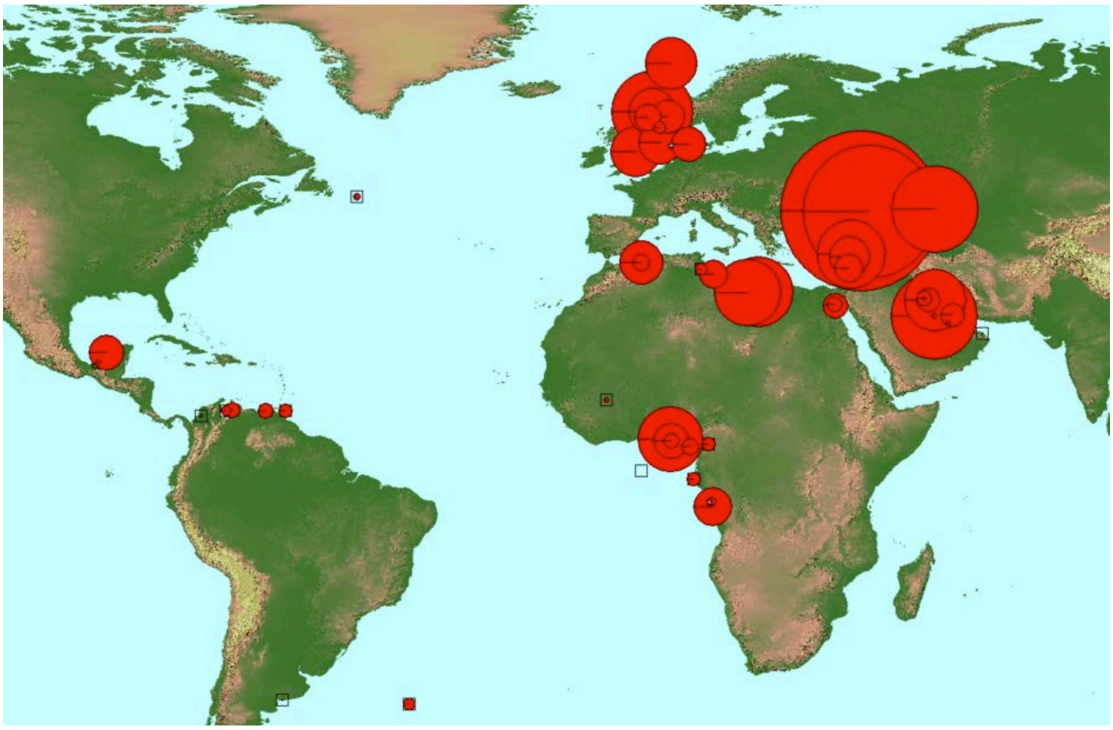


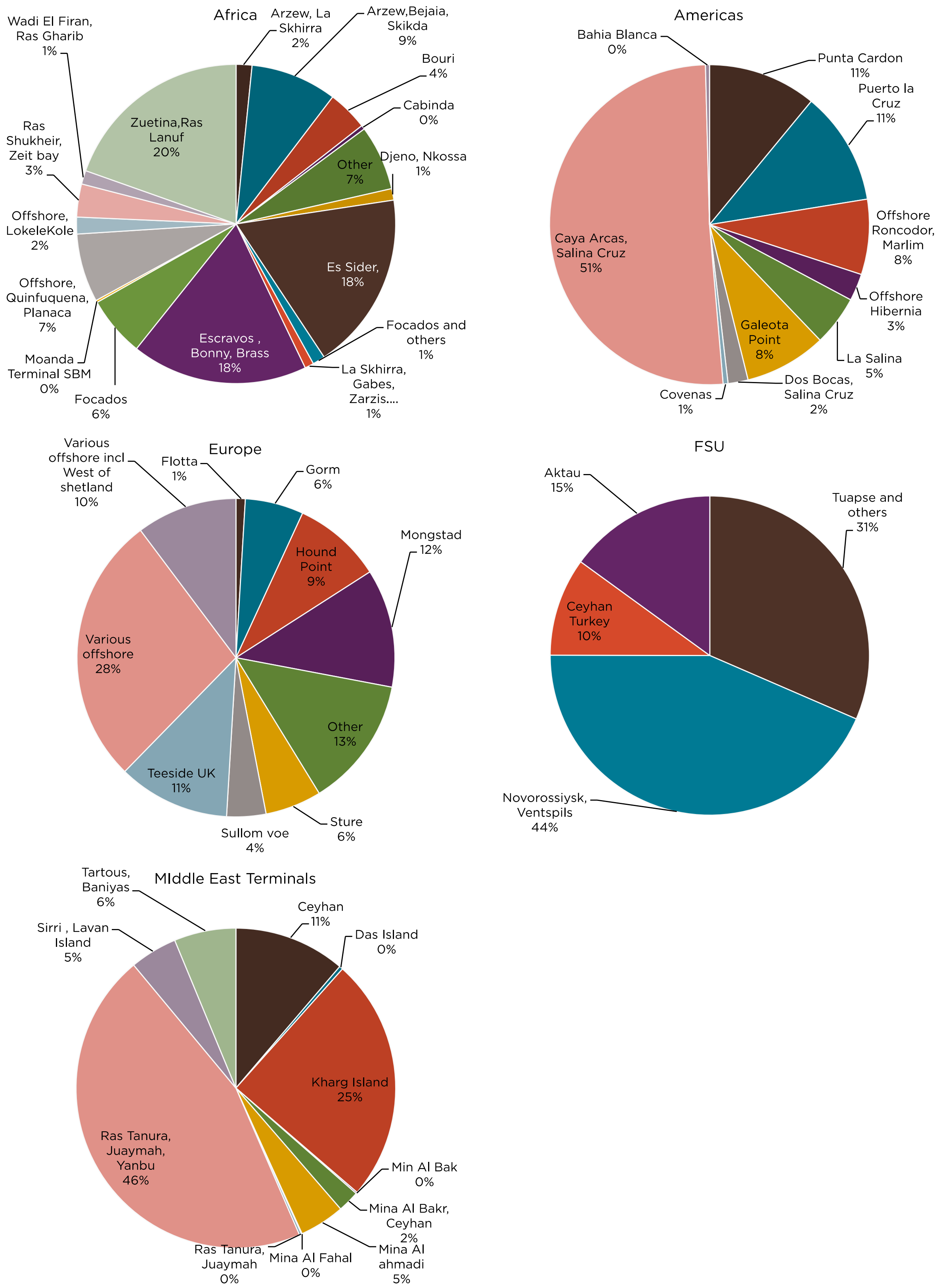
Table 3.1. 2011 crude oil imports into the EU, including terminal location (DG Energy, 2012a; ER 2012a)

COUNTRY OF ORIGIN	TYPE OF CRUDE OIL	% OF TOTAL IMPORTS	TERMINAL	LAT	LONG
Russian Federation	Other Russian Fed. Crude	12.7	Tuapse + others	44.09	39.07
	Urals	15.25	Novorossiysk; Ventspils, Latvia	44.34	37.47
Norway	Statfjord	1.6	Mongstad	69.49	5.02
	Ekofisk	2.48	Teesside, UK	54.39	-1.08
	Other Norway Crude	5.6	Various offshore	61.21	1.8
	Oseberg	1.03	Sture	60.37	4.51
	Gullfaks	0.89	Mongstad	69.49	5.02
Saudi Arabia	Arab Light	6.92	Ras Tanura, Juaymah, Yanbu	26.38	50.1
	Arab Medium	0.18	Ras Tanura, Juaymah, Yanbu	26.38	50.1
	Arab Heavy	0.14	Ras Tanura, Juaymah	26.38	50.1
Kazakhstan	Kazakhstan Crude	6.06	Aktau	44.56	50.26
Nigeria	Medium (<33°)	1.32	Focados	5.1	5.1
	Light (33-45°)	4.2	Escravos, Bonny, Brass	5.3	5
	Condensate (>45°)	0.31	Focados + others	5.1	5.1
Iran	Other Iran Crude	0.61	Sirri, Lavan Island	26.47	53.2
	Iranian Heavy	4	Kharg Island	29.14	50.19
	Iranian Light	1.03	Kharg Island	29.14	50.19

COUNTRY OF ORIGIN	TYPE OF CRUDE OIL	% OF TOTAL IMPORTS	TERMINAL	LAT	LONG
Azerbaijan	Azerbaijan Crude	4.44	Ceyhan, Turkey	36.86	35.94
United Kingdom	Flotta	0.13	Flotta	58.53	3.05
	Forties	1.82	Hound Point	56	3.22
	Brent Blend	0.7	Sullom Voe	60.27	1.17
	Other UK Crude	1.71	Various offshore incl. West of Shetland	61.21	1.8
Iraq	Basrah Light	0.9	Min al Bakr; Ceyhan, Turkey	29.41	48.48
	Kirkuk	2.02	Ceyhan, Turkey	36.53	35.56
	Other Iraq Crude	0.17	Min al Bakr	29.41	48.48
Libyan Arab Jamahiriya	Medium (30-40°)	1.37	Es Sider,	30.38	18.22
	Heavy (<30° API)	0.36	Bouri	33.54	12.39
	Light (>40°)	1.25	Zuetina, Ras Lanuf	30.51	20
Algeria	Saharan Blend	2.45	Arzew, Bejaia, Skikda	35.5	-0.08
	Other Algeria Crude	0.32	Arzew; La Skhirra, Tunisia	35.5	-0.08
Other FSU countries	Other FSU Crude	2.61	Novorossiysk, Russia; Ventspils, Latvia	44.34	37.47
Angola	Cabinda	0.05	Cabinda	-5.32	12.11
	Other Angola Crude	1.9	Offshore, Quinfuquena, Planaca	-6.2	12.14
Denmark	Denmark Crude	1.29	Gorm	55.63	8.11
Mexico	Isthmus	0.09	Dos Bocas, Salina Cruz	18.37	-93.1
	Maya	1.18	Caya Arcas, Salina Cruz	20.11	-91.59
Syria	Souedie	0.67	Tartous, Baniyas	34.53	35.45
	Syria Light	0.21	Tartous, Baniyas	34.53	35.45
Egypt	Heavy (<30° API)	0.36	Wadi El Firan, Ras Gharib	28.44	33.13
	Medium/Light (30-40°)	0.63	Ras Shukheir, Zeit Bay	28.08	33.17
Kuwait	Kuwait Blend	0.75	Mina al Ahmadi	29.04	49.09
Venezuela	Medium (22-30°)	0.16	Puerto la Cruz	10.14	-64.37
	Heavy (17-22°)	0.1	La Salina	10.22	-71.27
	Extra Heavy (<17°)	0.38	Punta Cardon	10.37	-70.13
Brazil	Brazil Crude	0.62	Offshore, e.g. Roncador, Marlim	-39.75	-39.75
Congo	Congo Crude	0.53	Djeno, Nkossa	4.56	11.54
Colombia	Other Colombia Crude	0.36	Covenas	9.31	-75.47
Cameroon	Cameroon Crude	0.34	Offshore, Lokele Kole	4.07	8.29
Tunisia	Tunisia Crude	0.23	La Skhirra, Gabes, Zarzis, Bizerte, Ashtart offshore terminal	34.31	10.16
Canada	Light Sweet (>30° API)	0.19	Offshore, including Hibernia	46.75	-48.77
Gabon	Other Gabon Crude	0.16	Depends on crude	-1.5	8.9
Abu Dhabi	Murban	0.12	Das Island	25.09	52.52

COUNTRY OF ORIGIN	TYPE OF CRUDE OIL	% OF TOTAL IMPORTS	TERMINAL	LAT	LONG
Congo (DR)	Congo (DR) Crude	0.1	Moanda Terminal SBM	12.1	-5.96
Other Latin America countries	Other Latin America Crude	0.06	Galeota Point, Trinidad and Tobago; Port of Spain, Trinidad and Tobago	10.13	-60.98

Figure 3.10. Crude oil imports into the EU by terminal for 2011 (DG Energy, 2012a; ER, 2012a)



3.2.4. Russia and FSU

As previously shown, more than 80 percent of the crude headed to the EU is derived from a small sample of oil-producing countries, led by former Soviet Union members, which represent on average 38 percent of all imports into the EU (DG Energy, 2012a). Of these, the most important supplier is Russia, which is currently estimated to produce just a bit more than 10 percent of the world's oil, making it the largest non-OPEC producer and the second largest global producer, behind only Saudi Arabia (IEA, 2011f). Recent data show that Russia exported a total of about 4.8 MMbbl/d of crude oil in 2011, with 78 percent of this going to European markets, particularly Germany, the Netherlands, and Poland (EIA, 2012). The country is also the main source of diesel to the European market, which as noted above is characterized by a structural shortage of diesel output. In terms of crude types, more than half of all Russian crude exports to Europe are the Urals Blend, with an API gravity between 31 and 33. The remaining crude exports to Europe are likely to be the Siberian Light blend that is exported via Tuapse, on the Black Sea.[48] Siberian light is another light, sweet stream, with an API gravity of around 35.

Close to 80 percent of Russia's oil is exported through the Transneft pipeline system (see Figure 3.11), with the remaining oil shipped via tankers from a number of Black Sea ports, although these seem to be in decline (EIA, 2012). The Transneft pipeline system spans more than 31,000 miles to the ports of Novorossiysk on the Black Sea and Primorsk on the Baltic (Transneft, 2012). In addition, the Caspian Pipeline Consortium (CPC)—a production association originally formed by the Russian and Kazakhstani governments in conjunction with a number of oil companies including Chevron, ExxonMobil, LUKoil, and Royal Dutch Shell, among others—currently controls the transport of Kazakhstani oil from the Tengiz, Kashagan, and Karachaganak fields to the Novorossiysk-2 marine terminal on Russia's Black Sea coast (CPC, 2012a)[49]. As a result, since 2005 the CPC has averaged in excess of 32 million metric tons of crude oil shipment volumes from its marine terminal (CPC, 2012b).

[48] EU data sources list the remaining crude imports from Russia as nonspecified.

[49] Ownership is currently as follows: Russian Federation (represented by Transneft–24%–and CPC Company–7%)–31%; Republic of Kazakhstan (represented by KMG–19%–and Kazakhstan Pipeline Ventures LLC–1.75%)–20.75%; Chevron Caspian Pipeline Consortium Company-15%; LUKARCO B.V.-12.5%; Mobil Caspian Pipeline Company–7.5%; Rosneft-Shell Caspian Ventures Limited–7.5%; BG Overseas Holding Limited-2%; Eni International N.A. N.V.-2%; and Oryx Caspian Pipeline LLC–1.75%.

Figure 3.11. Russian gas and oil pipeline network to Europe (EIA, 2012)

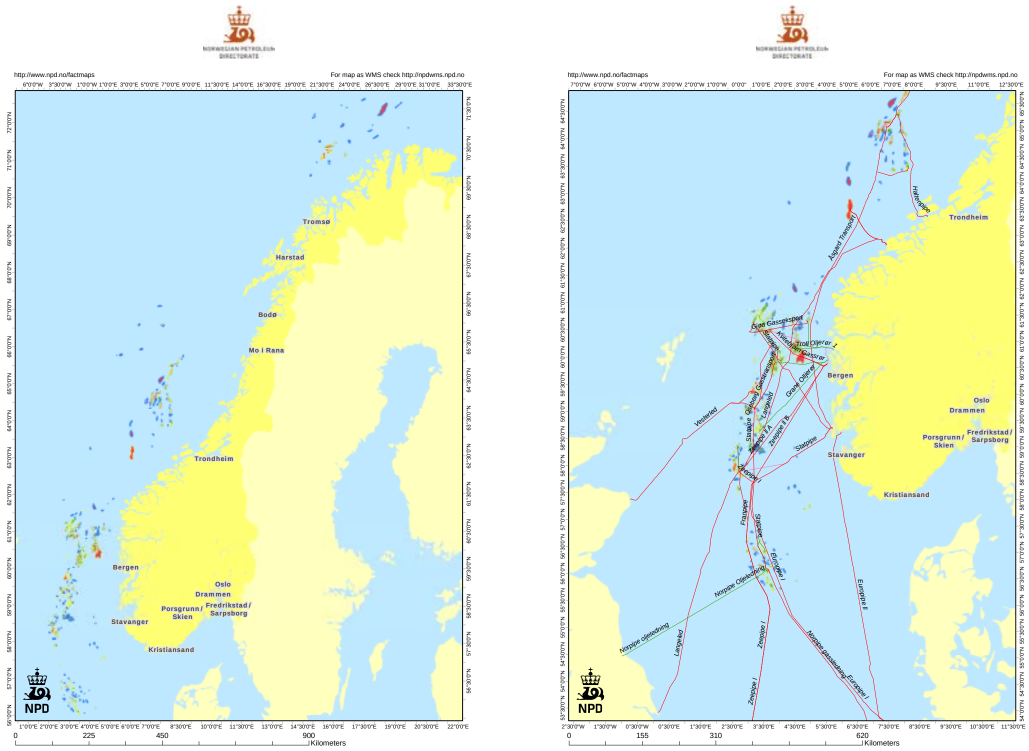
The Baku-Tbilisi-Ceyhan (BTC) pipeline is an important connection for other FSU exports, supplying Caspian oil to the Mediterranean Sea for shipment (see Figure 3.12). Currently, it is considered to be the second longest oil pipeline in the former Soviet Union after the Druzhba pipeline. As a result, the current pipeline system provides the principal route to market for more than half of non-Russian oil exports from the Caspian region. The region's largest producer, Kazakhstan, primarily supplies non-Russian crudes from the Caspian, destined for Europe. More than three-quarters of Kazakhstan's production is exported through Russia. There have also been a number of developments in Russia to reduce the amount of oil flows running through non-Russian ports. In 2001, the Baltic Pipeline System to the terminal at Primorsk, near St. Petersburg, was commissioned, making Primorsk the largest export outlet for Russian crude, overtaking the Druzhba pipeline to Central and Eastern Europe while diverting exports away from congested routes through the Black Sea port of Novorossiysk.

Figure 3.12. Caspian region pipelines (EIA, 2005)

3.2.5. Norway

The second largest national source of European crude imports is Norway, which remains one of the world's largest non-OPEC crude exporters and holds the largest oil reserves in Western Europe. The bulk of Norwegian oil production is located in the North Sea, although the government has recently pushed to increase exploration in the Norwegian and Barents Seas, resulting in a record 65 drilled wells and 28 discoveries made during 2009. According to the IEA, in 2009, Norway produced more than 122.5 million metric tons of fuel derivatives, of which 81 percent consisted of crude oil, followed by gas oil/diesel (4.9 percent) and gasoline (2.9 percent) (IEA, 2012). The large majority of this production is exported to Sweden (41 percent), Denmark (21 percent), the United Kingdom (12 percent), Ireland (9 percent), and the Netherlands (6 percent) (ETFDB, 2012). Although the EU does not specify the types of crudes imported from Norway, the country currently produces 18 varieties of light crude blends with an API gravity range of 25 to 62 and average sulfur content of 0.034 weight percent wt% (Statoil, 2012).

Figure 3.13. Location of major oil and gas fields (left) and pipelines (right) of Norway (Norwegian Petroleum Directorate, 2012)



The Norwegian oil sector is predominantly controlled by Statoil ASA—an international energy company that is 67 percent owned by the Norwegian government and controls 80 percent of the country's oil and gas production (Statoil, 2012). The government also provides a number of incentives for crude oil exploration that in practice refunds more than three-fourths of the costs associated with this process, as well as tax inducements for other oil activities. Norway has an extensive network of subsea oil pipelines (see Figure 3.13) connecting offshore fields with onshore processing terminals; however, the most extensive systems are those of the Oseberg Transport System and the Troll I and II (see Figure 3.14). In addition to these pipelines, ConocoPhillips operates the 900,000-bbl/d-capacity subsea Norpipe (see Figure 3.15), which connects Norwegian oilfields to the oil terminal and refinery at Teesside, England. Norway in itself has a refining capacity of 319,000 bbl/d of crude oil, at the Slagen plant (116,000 bbl/d) operated by ExxonMobil and the Mongstad plant (203,000 bbl/d) operated by Statoil. The latter is located in proximity of the port of Mongstad, the largest in Norway measured by tonnage and second only to Rotterdam for shipping crude oil and refined products in Europe.

Figure 3.14. Oseberg and Troll I and II pipeline networks (Norwegian Petroleum Directorate, 2012)

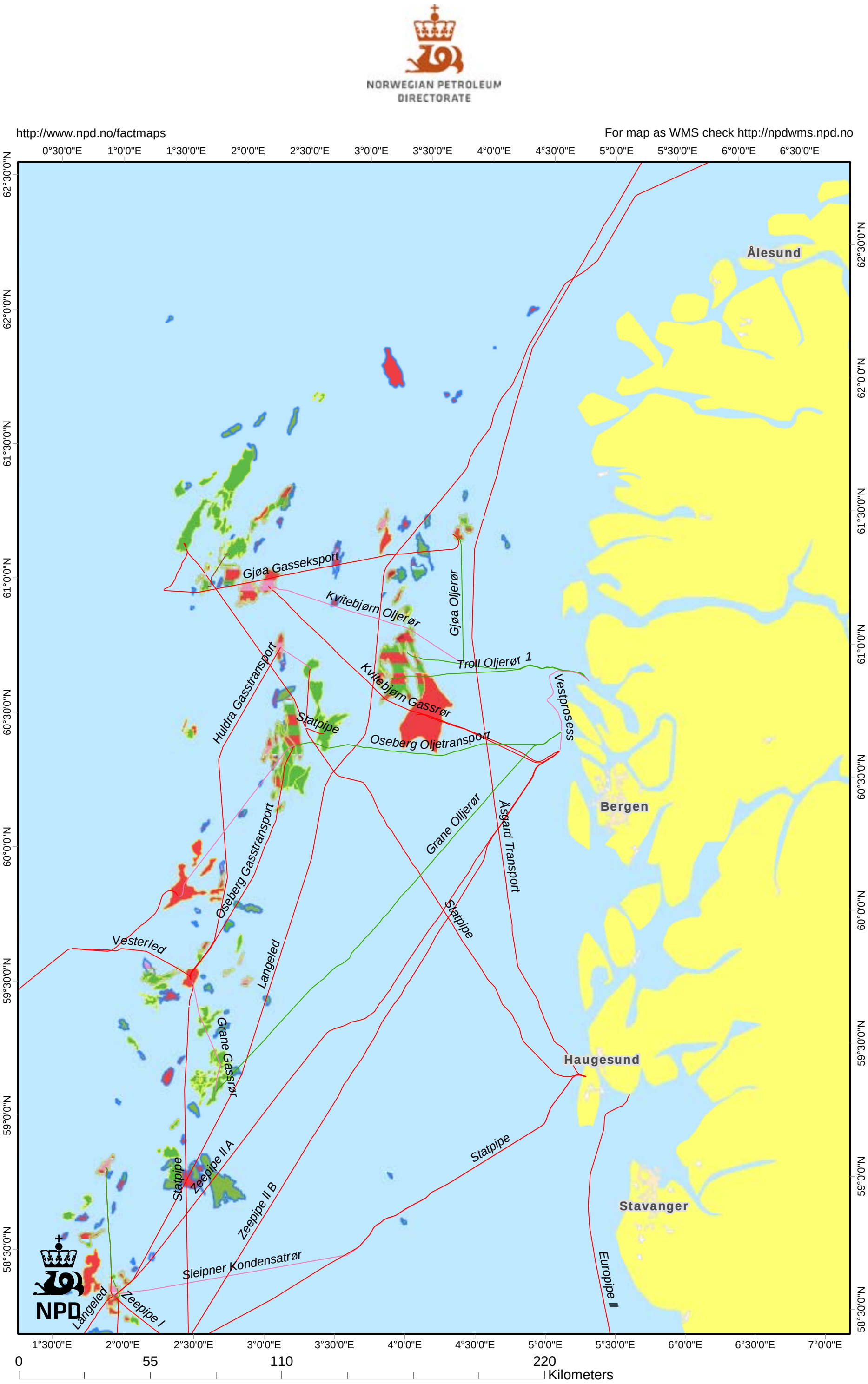
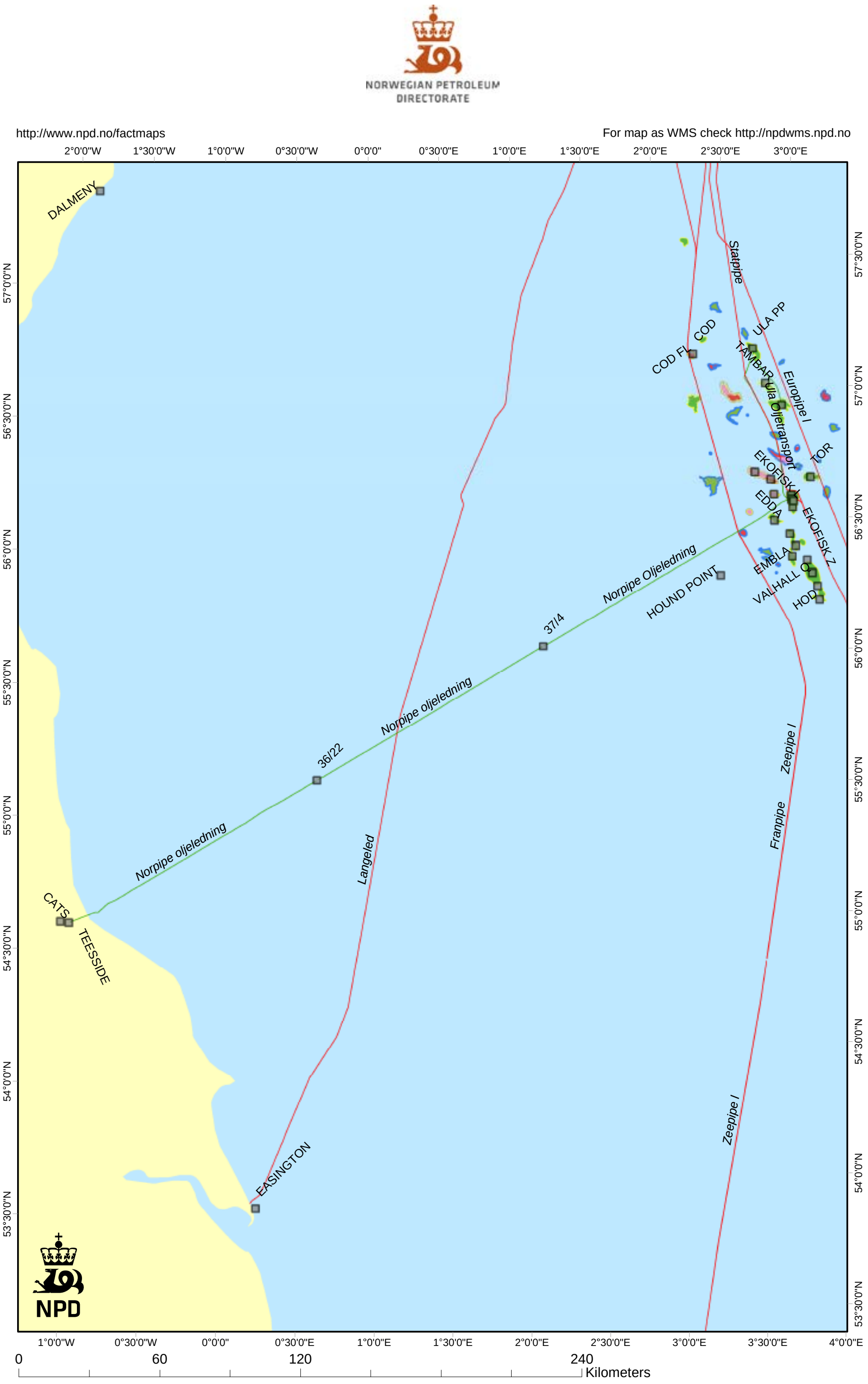


Figure 3.15. Subsea Norpipe Pipeline to Teesside refinery (UK) (Norwegian Petroleum Directorate, 2012)

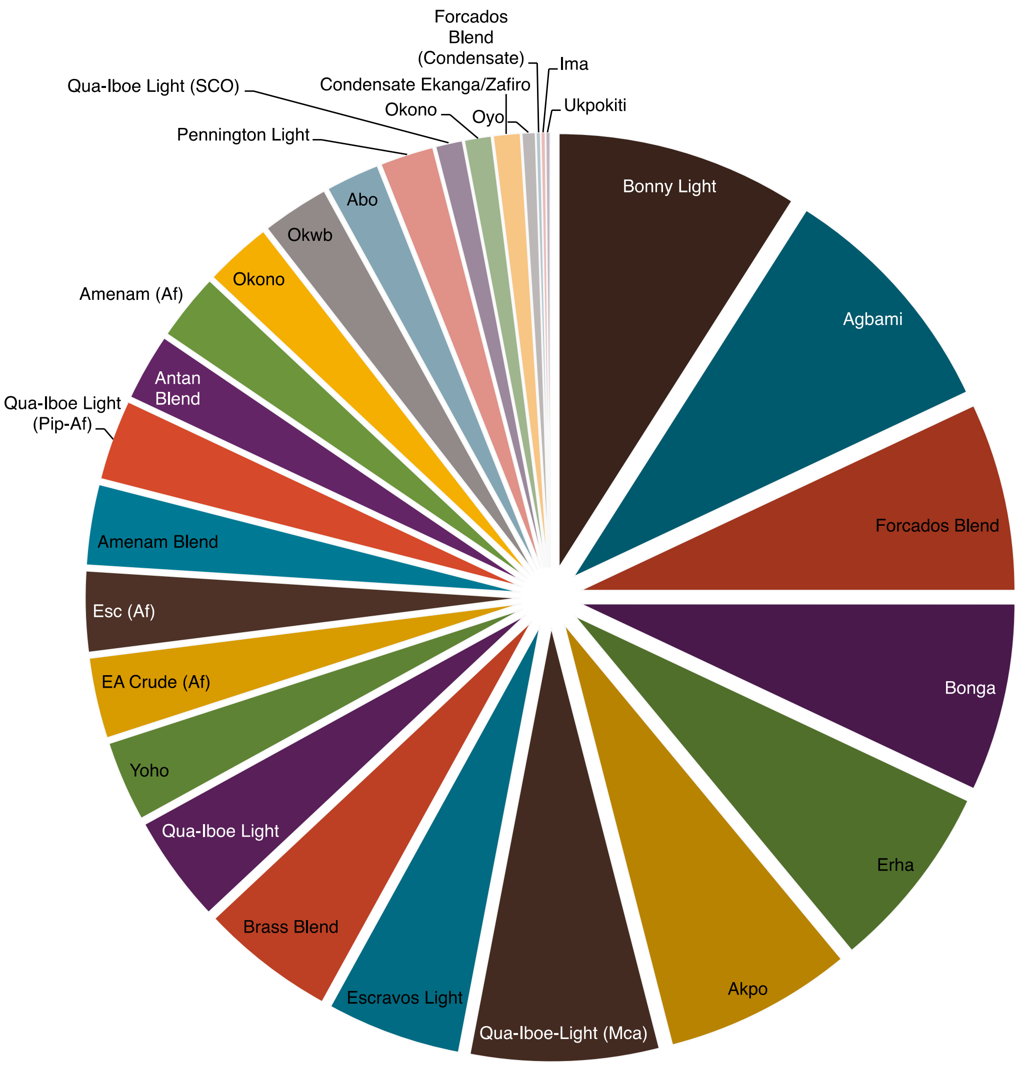


3.2.6. Nigeria

Nigeria currently has anywhere between 200 to 220 oil-producing fields that make up more than 25 different crude blend streams.[50] These crude streams vary in API gravity from 26.4 to 47.2, with an average of 35.9, situating them within the light crude specifications on average. These crudes have average sulfur content of 0.18 percent (Platts, 2012; Statoil, 2012). Nigerian crude oil is exported either as single-crude streams or commingled and exported via an oil marine terminal. In terms of production, Nigeria has supplied on average close to 5 percent of all EU crude imports, corresponding to some 22 percent of its total production, although the bulk of Nigerian output goes to the United States. The country is currently home to six oil export terminals owned and operated by different companies. Royal Dutch Shell owns the Forcados and Bonny terminals; ExxonMobil operates the Qua Iboe terminal in Akwa Ibom state; and Chevron owns the Escravos terminal located in the Delta state and operates the Pennington terminal; while ENI operates the Brass terminal. In addition to these terminals, around 10 percent of the country's oil-producing fields are offshore, making up close to half of crude production in Nigeria in 2011. An analysis of data provided by the Nigerian National Petroleum Corporation (NNPC) in its annual statistics (2010) allows us to investigate the split of the Nigerian crude categories in the EU data. We summarize these results in Figure 3.16 below.

[50] Field numbers can be expected to increase over time due to new discoveries.

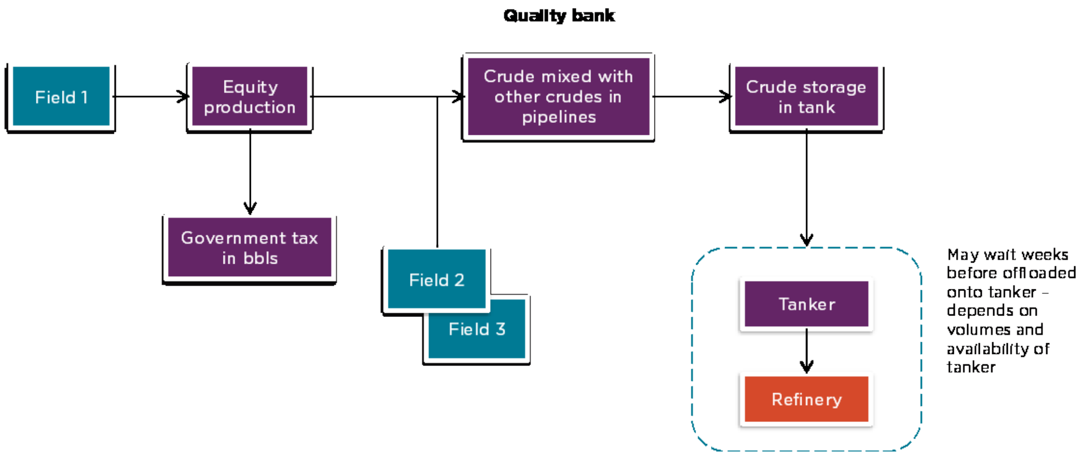
Figure 3.16. Nigerian crude blends by extraction volume (ER, 2012)



3.3. Crude trading and pricing

Trading of crudes does not occur at the physical hubs listed above but at financial exchanges like the ICE (Intercontinental Exchange) or NYMEX (New York Mercantile Exchange). In practice, equity stakeholders of particular oilfields own crude production, while entitlements to crude volumes by these owners depend on a number of factors. These include taxes taken by the government in the form of barrels of crude as well as any adjustments made for quality in commingled crude streams (see Figure 3.17 below). The latter occurs when producers use a crude quality bank. In practice, this is a system of credits and debits to adjust for market value differences in crude oil as measured by changes in certain specified crude characteristics. A quality bank allows producers of high-grade crude to be compensated when poorer-quality oil is mixed with theirs in a pipeline, with the lower-quality oil producers penalized. An allocation system is used to calculate the adjusted numbers of barrels, with producers of higher-graded crudes being allocated more barrels of the blend than they physically put into the system. Essentially, each crude is gauged so that the barrels received would equate to the value of the crude entered into the system. In addition, off-take by tankers is not a continuous process in the same way that crude is produced. A tanker may take a fixed volume of product from crude storage tanks. Hence, smaller owners may have to wait many months before they have enough volume to fill a tanker. Of course, they could sell their portion of the crude to larger traders/owners.

Figure 3.17. Crude allocation example (ER, 2012a)



3.3.2. Benchmark crudes

A crucial element in the development of the spot oil market in the late 1970s and early 1980s was the emergence of key benchmark grades. These grades served as the reference levels for crudes of similar quality and in similar locations, providing a focus for increased trading and a rise in market liquidity. Prices of other crudes were based on these key benchmarks. The first international spot market benchmark grades were Arabian Light in the Middle East and Forties in the North Sea. The emergence of UK Brent as a North Sea reference crude oil in place of Forties in the early 1980s was no accident; it resulted from the grade's mix of suitable characteristics. Benchmark grades are critical in defining the spot values of related crudes, and they have also become the key price variable in many term-contract price formulas. In addition, they are the basis for most hedging and risk management efforts and attract the bulk of speculative trading interest.

A full description of some fundamental benchmarks and their application is provided in the Oxford Institute for Energy Studies publication "An Anatomy of the Crude Oil Pricing System" (Fattouh, 2011). The essential point is that these future oil markets are tied to physical markets, allowing for producers, buyers, and speculators to trade and hedge on these volumes. These paper trades can be swapped for physical cargoes, for delivery at a later date. For example, a dated Brent deal is much like any other physical spot market transaction, with the buyer taking delivery of an actual cargo under set terms of time, price, and so forth. The main characteristics that distinguish the "wet" barrel market in Brent are its linkage to the forward and futures markets for "paper" barrels and the widespread use of its prices as a reference point for other crude oil trading. Virtually all of the trading in these physical cargoes occurs in the few weeks immediately before they are loaded. Trading further into the future is handled by the forward, futures, and swaps markets; trading at the time of loading or afterward is rare except for some cargoes in transit to more distant markets, such as the United States. The trading of cargoes during transit is further complicated by international regulations and guidelines and the need for the requisite paperwork.

Overall, prices and volumes reported on physical cargoes of oil are the result of an imperfect collection of a number of sources collated by price-reporting agencies such as Platts and Argus. These agencies decide which trades are included in their reports. Note that imports to refineries/terminals are a matter for customs of a particular country and are recorded in this system, hence the ability for the EU or country agencies to report such volumes. Fattouh (2011) provides data on the amount of trades on these various benchmarks. In terms of dated Brent contracts, the amount of trades on the primary benchmarks is actually quite low.

Table 3.2. Some basic features of benchmark crudes (Fattouh, 2011)

	ASCI	WTI CMA + WTI P-PLUS	FORTIES	BFOE	DUBAI	OMAN
Production (MMbbl/d)	736	300-400	562	1,220	70-80	710
Volume Spot Traded (MMbbl/d)	579	939	514	635	86	246
Number of Spot Trades per Calendar Month	260	330	18	98	3.5	10
Number of Spot Trades per Day	13	16	<1	5	<1	<1
Number of Different Spot Buyers per Calendar Month	26	27	7	10	3	5
Number of Different Spot Sellers per Calendar Month	24	36	6	9	3	6
Largest 3 Buyers % of Total Spot Volume	43%	38%	63%	72%	100%	50%
Largest 3 Sellers % of Total Spot Volume	38%	51%	76%	56%	100%	80%

3.3.3. Tracking crudes in transit

An analysis of ship movements requires detailed knowledge of ships' arrival and departure times at their ports of call. Such data have become available since 2001. Ships/ports have begun installing

Automatic Identification System (AIS) equipment.[51] AIS transmitters on board ships automatically report the arrival and departure times to the port authorities. This technology is primarily used to avoid collisions and increase port security; however, arrival and departure records are also available by Lloyd's Register-Fairplay for commercial purposes as part of its Sea-web database.[52] Significantly, AIS devices have not been installed in all ships and ports yet, and therefore there may be certain gaps in the data. Still, all major ports and the largest ships are included; thus, the database represents the majority of cargo transported on ships. There are also other companies like Drewry that will have access to similar data sets as well as recent compilations that are available at no cost.[53]

3.4. Future trends

3.4.1. Introduction

Several economic, political, and technological constraints interact to determine the quantity and flows of crude oil around the world. The EU remains one of the regions most heavily reliant on imports of crude to satisfy its current demand levels. For the period 2005–11, more than 60 percent of the EU's crude was sourced from former Soviet Union (FSU) countries (led by Russia) and non-EU-27 Europe (Norway), while the remaining crude came from the Middle East and Northern Africa. The dependence on non-EU oil is likely to increase in the foreseeable future, making crude sourcing an important strategic concern for the region. According to most projections, there will be limited room for maneuver in the sourcing strategies that the EU is employing today, with the biggest change coming from the decline of North Sea oil, compensated for by greater flows of West African and Caspian resources. However, these projections are sensitive to supply disruptions caused by political unrest as well as to the introduction of more restrictive sourcing policies in the EU and the potential to augment supplies from unconventional crudes.

3.4.2. Energy-Redefined projections

A 2010 Energy-Redefined (ER) study for the ICCT provided estimates for crude oil imports into Europe by source region until 2020 (ICCT/ER, 2010). These projections used data from the BP *Statistical Review of World Energy* (2009) and from a proprietary dataset managed by Energy-Redefined containing production data for approximately 3,100 oilfields in countries that supply to Europe. In addition, the U.S. Energy

[51] AIS technology is used on aircraft to track flights.
[52] www.sea-web.com. Note this is now owned by IHS. Analysis of these journey can be made from these data.
[53] See http://www.fleetmon.com and http://www.drewry.co.uk/publications/view_publication.php?id=324

Information Administration (EIA) *International Energy Outlook* reference case scenarios for 2015 to 2020 were used to estimate future global crude flows (EIA, 2009 and 2010). The study estimates the projected total imports into Europe from various countries and/or regions as well as additional volumes of crude that would be required over 2010 import demands. The study does not identify specific oilfields in each country that are more or less likely to export oil to Europe, and it excludes countries that are not currently exporting to Europe. It is also worth noting that, although the EU is a net importer of crude, it also exports crude, mainly from the United Kingdom (Norway, a European Economic Area [EEA] member, is also a significant crude producer). For the purpose of the Energy-Redefined analysis, only imports into Europe were considered.

Overall, the ICCT/ER study estimates that European imports are expected to increase by 10 percent, to about 1.4 MMbbl/d by 2020 (see Figure 3.18 and Figure 3.19). Imports to Europe are to be dominated by sourcing from FSU countries (including Russia), the Middle East, and North and West Africa, in that order. The study predicts that crude imports from West Africa and Canada in particular are likely to cover the increase in imports to Europe from 2010 levels. In the case of Canada, this is a major increase from its very low current exports to Europe and reflects expected increases in Canadian crude production as the tar sands are progressively exploited. The EIA's *International Energy Outlook* estimates that Canadian tar sands production will increase from around 1.0 MMbbl/d to around 4.0 MMbbl/d by 2020. In regard to West Africa, the expected increase of close to 40 percent reflects decreasing flows to the United States, given bullish forecasts for U.S. biofuels and crude production.

Figure 3.18. Projected crude oil imports into Europe (ICCT/ER, 2010)

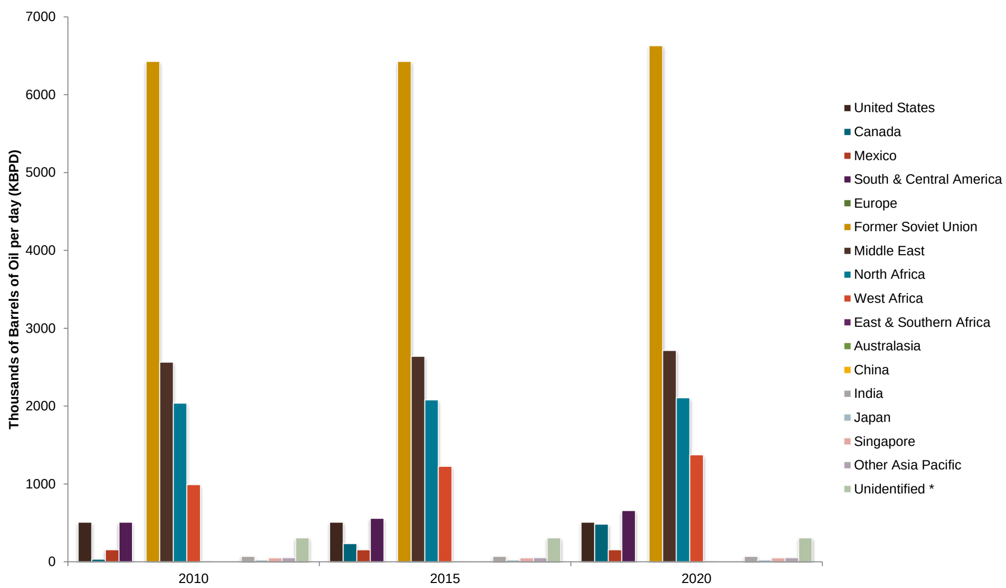
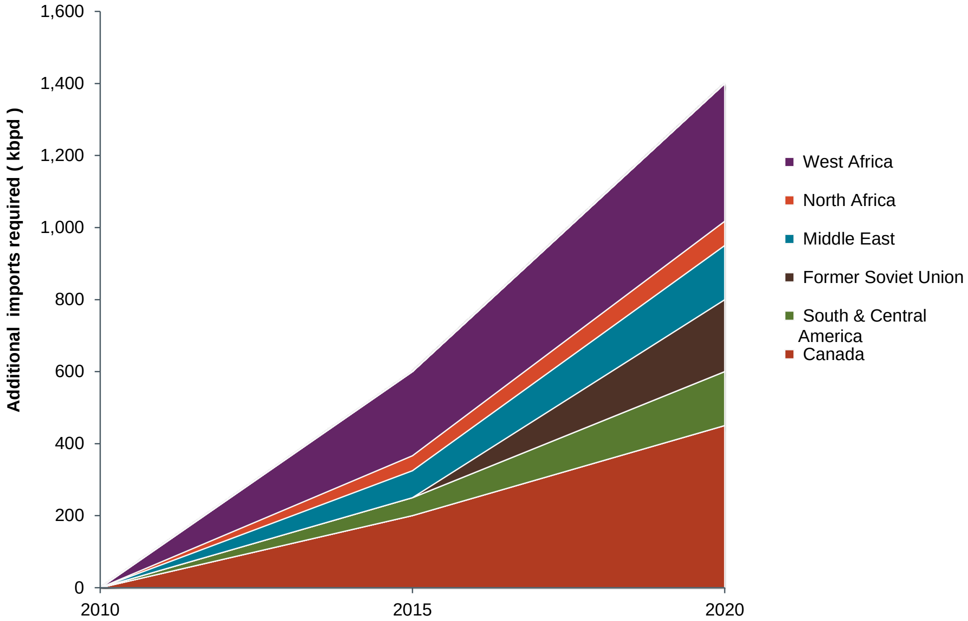


Figure 3.19. Additional crude imports into Europe over 2010 case (ICCT/ER, 2010)



In general, Europe will remain dependent on the Middle East, Russia, and Africa for its crude oil in the medium and long term. The relatively static nature of European crude sourcing offers the possibility to foster stronger trade relations with these partners but also creates a high level of dependency given the region's position as a net importer of fossil fuels. It should be noted that, with OPEC likely to maintain a strong position in world oil markets, with the relative lack of transparency inherent in the oil industry, and with potential political/institutional instability in oil-producing countries, these patterns might at any point be subject to changes that are difficult or impossible to predict. There is also a growing push toward unconventional crudes, with the EU's oil shale (see §3.4.3) and tight oil reserves[54] potentially taking a more significant role in supplying the region in the longer term. As previously mentioned, UK and Norwegian production are not explicitly characterized in the Energy-Redefined analysis, although the North Sea still represents a major source of oil for the EU. Production figures show that crude output peaked in Norway in 2001 and in the United Kingdom in 1999, and current downward trends are expected to continue (Höök and Aleklett, 2008), contributing to the need for increased imports. Nevertheless, while depletion of many of the giant fields in Norway and the United Kingdom are driving the overall decline in North Sea oil production, it remains to be seen how undiscovered and undeveloped fields may add to current production levels.

[54] Referring to light crude oil contained in shale

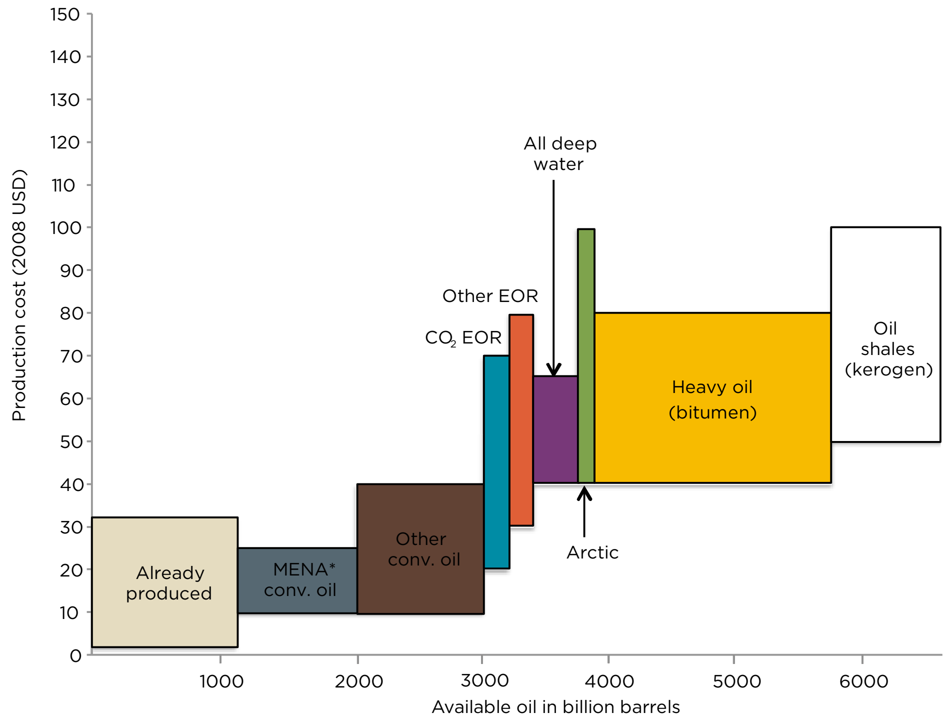
3.4.3. Oil shale in Europe

Oil shale is a broad classification for sedimentary rock that can contain up to 50 percent fossil organic matter called kerogen (Brandt, 2011). Oil shale can be exploited either by surface processing techniques or by in situ technologies. Once extracted, it can be used to obtain heat by direct combustion (e.g., in the generation of electricity), processed to produce oil, or exploited as a source of other valuable chemicals. According to conservative estimates from the World Energy Council (WEC), world oil shale resources in place were approximately 4.8 trillion barrels of oil in 2008 (WEC, 2010). Most of these are located in North America (approximately 78 percent), with Europe and Asia each accounting for around 8 percent of the inventoried resources. A little more than two-thirds of the listed European resources are located in Russia (67 percent), with the remainder mostly located in Italy (20 percent) and Estonia (4 percent) (WEC, 2010). Within the EU, oil shales are found in 14 member states (see Table 3.3). Historically, some areas of the EU (e.g., France and Scotland) have had experience of exploiting oil shales as early as the late 1600s; however, currently only Estonia is actively engaged in exploitation on a significant scale (350 metric kilotons per year) (EASAC, 2007). The Estonian oil shale deposit accounts for just 17 percent of all deposits in the EU, but Estonia generates in excess of 90 percent of its power from oil shale, and the oil shale energy sector accounts for 4 percent of Estonian GDP, while oil shale consumption represents close to 72 percent of its combustion-generated CO_2 emissions (EASAC, 2007 and Brandt, 2011). Given the experience of Estonia, there is much debate on whether to exploit further in other countries of the EU. While kerogen could be seen as a strategically useful domestic energy resource, it has a very large carbon footprint, with fuels refined from kerogen expected to be somewhat more carbon intensive than even the Canadian tar sands. Whether production happens will depend on a number of economic, political, and technological developments that are difficult to predict in the near future. The trajectory of oil prices is likely to be key (see Figure 3.20). Oil shale exploitation for transportation fuels seems unlikely to take off seriously if oil prices remain much below $100 per barrel, but it is likely to seem appealing for higher prices. Potentially more important than the oil price will be the environmental implications of kerogen exploitation and the political will to confront climate change. Legislation such as the Fuel Quality Directive, which assigns feedstock-based carbon intensity defaults to different types of oil, could act to discourage investment in shale oil. In terms of public opinion, the intense opposition of environmental campaigners to Canadian tar sands oil may well foreshadow similar opposition to kerogen development in Europe. The United States has more extensive oil shale reserves than Europe and probably also has more appetite to exploit them despite climate change concerns. It therefore seems likely that the experience of the United States will set a precedent for initiatives in the EU and could determine whether these resources are ever utilized significantly.

Table 3.3. Estimates of shale oil resources in place for Europe (in Gbbl and MMt) (DG Internal Policies, 2011)

COUNTRY	RESOURCES IN PLACE (WEC 2010) [Gbbl]	RESOURCES IN PLACE (WEC 2010) [MMt]
Austria	0.008	1
Bulgaria	0.125	18
Estonia	12.686	2494
France	7	1002
Germany	2	286
Hungary	0.056	8
Italy	73	10446
Luxembourg	0.675	97
Poland	0.048	7
Spain	0.28	40
Sweden	6.114	875
UK	3.5	501
EU	109.1	15775

Figure 3.20. Production cost curve (not including carbon pricing) (adapted from IEA, 2010d)



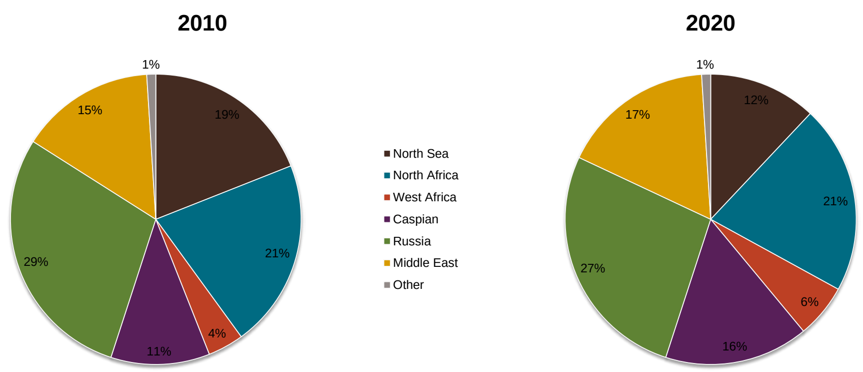
**Middle East and North Africa*

3.4.4. CONCAWE study

In 2008, the CONCAWE Refinery Technology Support Group (RTSG) published a research study aimed at assessing oil refining in the EU to 2020. In doing so, the report also provided perspective on the evolution of energy consumption and EU oil imports. Historical trends and projections of oil imports to the EU–which in this case refers to the "EU-27+2," i.e., the current 27 EU countries plus Norway and Switzerland–were obtained using an industry study by Wood Mackenzie (WM). WM uses a proprietary demand model integrated into its Macro Oils Service to provide long-term crude supply, demand, and price outlooks for the transportation sector. Furthermore, WM offers crude slate analysis by country or region that is integrated into its Global Oil Supply tool to yield long-term production and quality forecasts.

According to CONCAWE and WM, the EU-27+2 consumed about 715 MMt of crude oil and feedstocks in 2005, with consumption set to grow to 765 MMt by 2020. Crude oil supply is considered to be adequate within the time frame of the study, while the projected crude slate for EU imports shows shifts in future sourcing destinations (see Figure 3.21). Unlike the ICCT/ER analysis, which left out North Sea oil, CONCAWE includes it and expects North Sea production to be cut in half from its 2007 levels by 2020. In response to this drop, the crude supply to the EU is expected to be supplemented by Caspian oil, which will almost triple during the same time horizon, as well as by West African oil, increasing slightly from its 2007 levels. Overall, Russian, Middle Eastern, and North African oil dominate crude sourcing for the EU-27+2 through 2020. Any changes in the origins of the crude are not expected to affect significantly the average crude quality refined in Europe, thus maintaining the current proportion of around 45 percent of sweet (i.e., low sulfur) crudes over the next decade.

Figure 3.21. Projected EU crude oil by source (CONCAWE, 2008)



3.5. Case study: Russian oil industry

It is estimated that Russia currently holds around 13 percent of the world's ultimately recoverable resources of conventional oil, 26 percent of gas, and 18 percent of coal (IEA, 2011f). Despite this, the IEA (2011f) projects that oil exports (both crude and refined products) will decline slowly, from a peak of 7.7 MMbbl/d in 2012 to 6.4 MMbbl/d in 2035, as crude production falls and domestic demand for transport fuel continues to grow (see Figure 3.22).

Russia remains one of the major sources of oil and gas for Europe, with this trend expected by IEA to continue to 2035. Exports are likely to continue to exploit existing infrastructure with an expansion westward through the export terminals at Primorsk and Ust-Luga on the Baltic Sea. Nonetheless, these trends face important challenges in the near future. First, according to IEA estimates, Russian oil production is set to plateau around 10.5 MMbbl/d before starting a slight decline to 9.7 MMbbl/d by 2035 (see Figure 3.23). Second, the geography of oil exports is beginning to shift toward Asian markets, with the share of China in Russia's total fossil fuel export earnings rising from 2 percent in 2010 to 20 percent by 2035 and the EUs share falling from 61 percent to 48 percent in the same time period (IEA, 2011f). In addition to conventional oil resources, bitumen and extra-heavy oil resources are known to be extensive in Russia, with recent estimates at around 120 billion barrels located in Tatarstan, eastern Siberia, and around St. Petersburg. The IEA estimates that unconventional oil output is likely to be relatively low in the short to medium term, perhaps close to 0.1 MMbbl/d by 2035. Although there have been some pilot projects with steam-based thermal methods of recovery and other innovative mining methods, no large-scale developments have been commissioned.

Figure 3.22. Russian fossil fuel export earnings in 2010 and 2035 (in 2010 dollars) (adapted from IEA, 2011f)

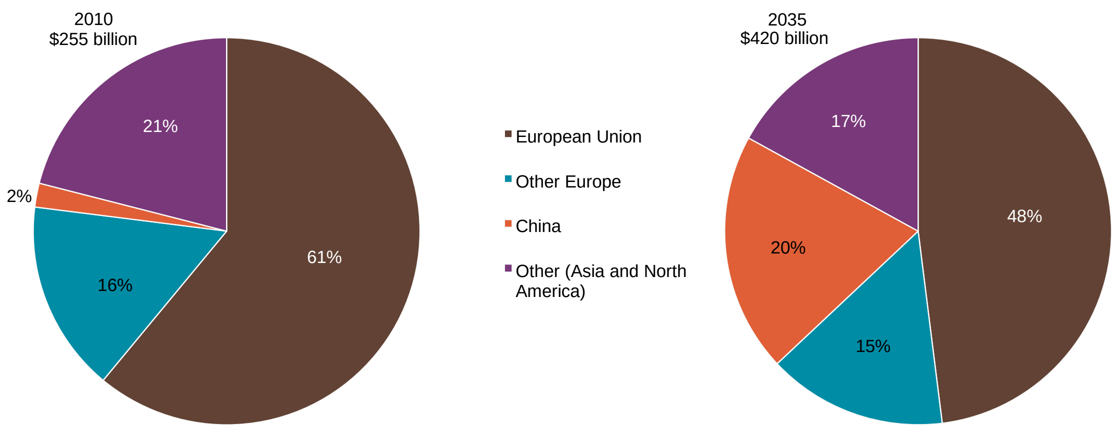
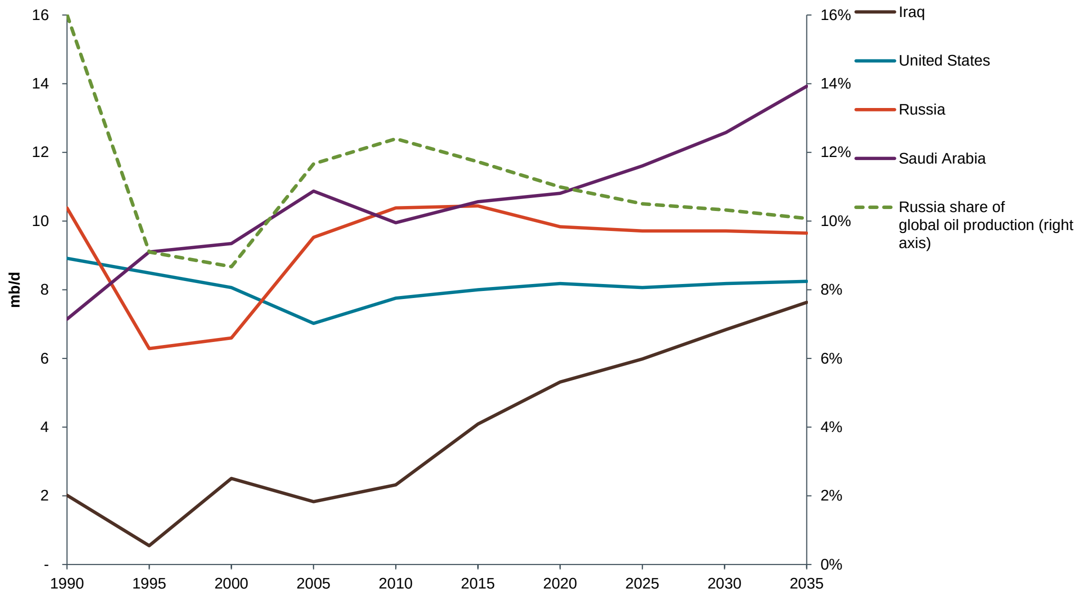


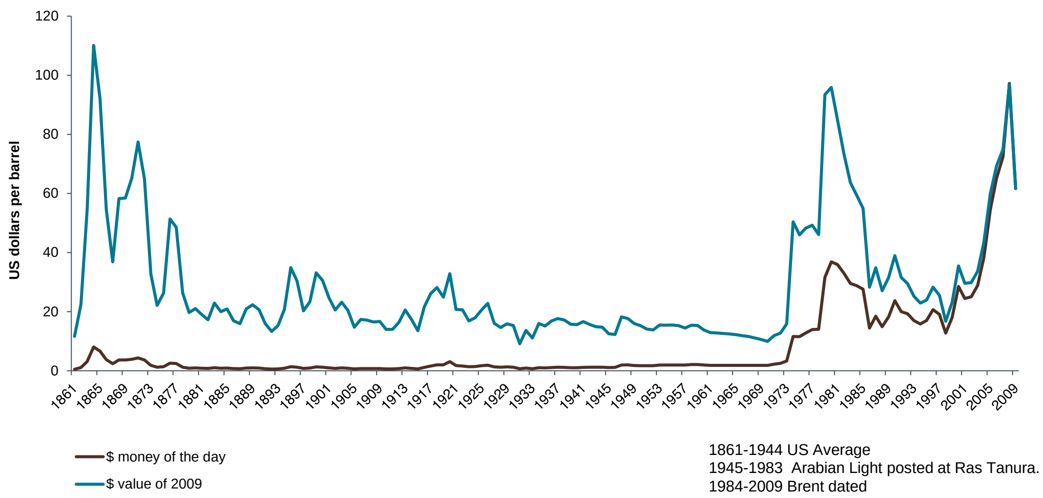
Figure 3.23. Oil production in Russia and selected countries (New Policy Scenario) (adapted from IEA, 2011f)



3.6. Benchmark crude oil price projections

Crude oil prices are determined by both supply restrictions and oil availability in the long term as well as current and future demand prospects. However, the dynamics of these markets are inherently complicated to predict. Most forecasts of oil prices in the medium and long term, project an upward trend stabilizing in due course at a higher level than has been normal in the past. Ultimately, higher oil prices may affect EU crude sourcing destinations as well as increased investment in unconventional oil developments.

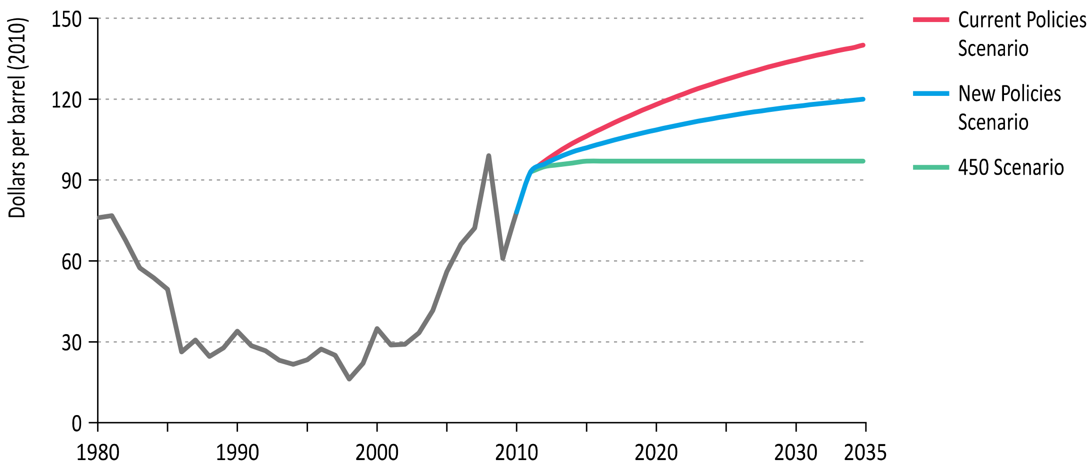
Figure 3.24. Crude oil prices 1861–2010 (BP, 2011b)



Historically, oil prices have been extremely volatile (see Figure 3.24), with episodes of volatility largely influenced by exogenous factors that have affected supply: obvious examples are the Arab oil embargo of 1973, the Iranian revolution, and the invasion of Iraq (after which a record $147 a barrel was set in 2008).[55] Over the past couple of years, the volatility of crude prices has continued, driven by instability in the Middle East and North Africa that drove Brent futures above $110 per barrel and West Texas Intermediate (WTI) above $87/bbl in December 2012. Currently, NYMEX crude futures, Brent spot, and WTI Cushing spot are all selling at more than $100/bbl (Bloomberg, 2012; accessed on April 13).

Estimates of future prices diverge substantially, depending on a number of assumptions (as well as the type of crude for which estimates are forecast, although we expect crude prices to continue to move in scale with each other). According to projections by the IEA (2011f) (Figure 3.25), crude oil prices (reflected in 2010 dollars) are expected to increase to somewhere within a range of $120 to $140 per barrel by 2035. In its Current Policy Scenario, crude oil prices are set to reach $118/bbl by 2020 and $140/bbl in 2035. In its New Policy Scenario, prices will reach $120/bbl by the latter date. In the 450 Scenario (in which relatively aggressive action on climate change reduces oil demand), prices stabilize at about $97/bbl in 2015. Similarly, a study by the EU Commission (DG Energy, 2010, Figure 3.26) looking at EU energy trends to 2030 has international fuel prices for the EU-27 projected to reach $90/bbl in 2020 and $108/bbl by 2030 (in 2010 dollars). More conservative estimates for the region are reflected in Purvin and Gertz (2008, Figure 3.27)–they have crude prices stabilizing in a range of $52-$57/bbl (in 2010 dollars) by 2020.

Figure 3.25. Average IEA crude oil prices and demand (IEA, 2011f)



At these projected price levels, it remains unclear how crude prices may affect EU sourcing decisions. As prices for conventional oil increase, the relative cost of investing in unconventional crudes decreases, raising the possibility of exploiting local resources such as oil shale. Note that domestic EU unconventional resources are much smaller than those

[55] In July 2008, light, sweet crude traded for an all-time high of $147.27, while Brent crude traded for $144.49 on London's ICE futures exchange (USA Today, 2008).

concentrated in Russia, which is already the major provider of fossil fuels to the region. It is less clear how price responsive the market for renewable fuels is–currently, European renewable fuel production is more responsive to regulations than prices. Still, in the event that advanced biofuel technologies could be commercialized at a production cost that made them competitive with fossil fuels, high oil prices could result in renewable fuel supply above mandated levels.

More generally, given transportation costs and the difficulties of rapidly adjusting refinery configuration to accommodate changing crude slates, it seems unlikely that generalized increases in benchmark prices for crudes currently on the market will substantially affect the mix of European imports. It will only be if the price spread significantly deviates, for instance, if light crudes become much more expensive compared to heavy crudes, that we might expect to see more profound shifts in refinery capacity and slates. Thus, while crude prices might well be an important determinant of the uptake of unconventional and renewable fuels, it seems likely that the European conventional crude slate will be somewhat stable relative to general crude price movements–i.e., it will be more important to the mix how big the gap is between any given crude prices over time than their absolute value.

Figure 3.26. World fossil fuel prices (constant $2008) (DG Energy, 2010)

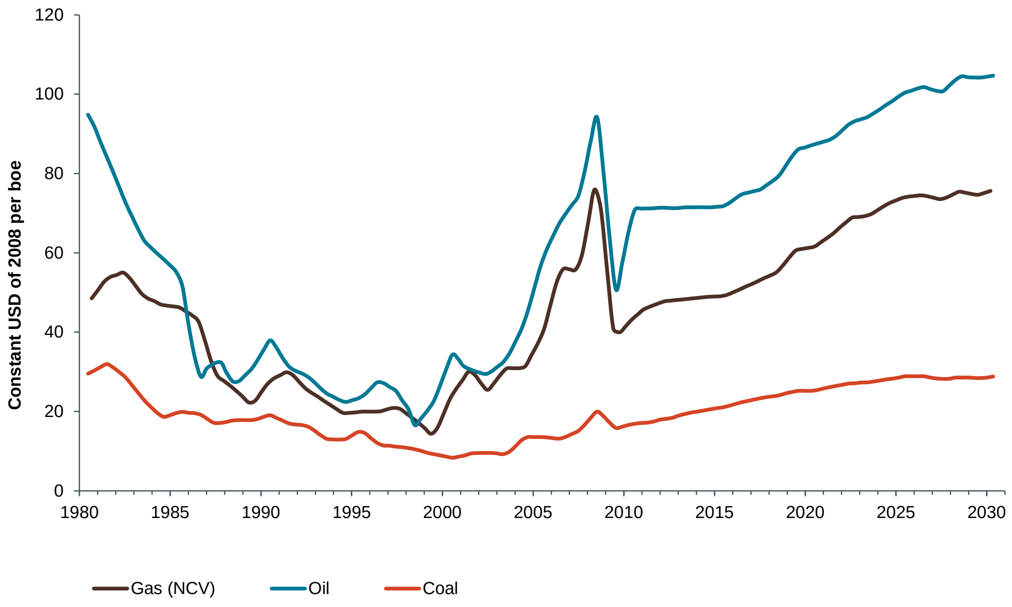
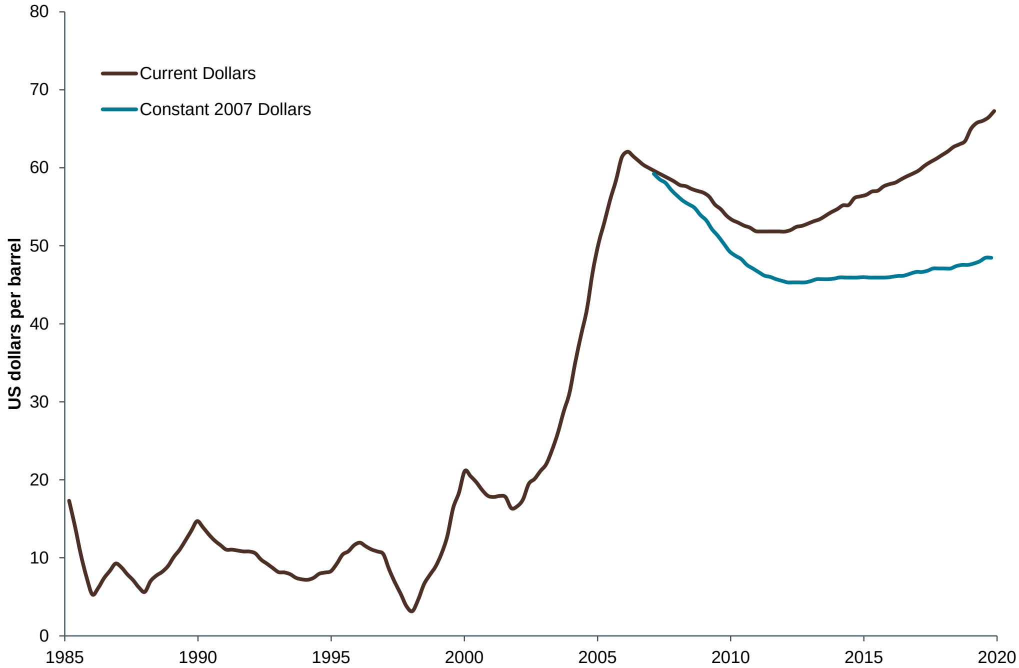


Figure 3.27. Brent crude oil price forecast (Purvin and Gertz, 2008)



3.7. Additional factors influencing EU crude sourcing

3.7.1. Global oil production and reserves

The latest *World Energy Outlook* published by the IEA (2011, Figure 3.28) estimated total world oil production at nearly 84 MMbbl/d in 2010 (excluding processing gains and biofuels). The BP *Statistical Review of World Energy* (BP, 2011b) has it slightly lower at 82 MMbbl/d, an increase of 2.2 percent since 2009. According to BP, this uptick was driven by gains in Nigeria, Qatar, Russia, the United States, and China, with the last of these experiencing its largest production increase ever (7.1 percent). On the other hand, Norway experienced the world's largest decline in absolute production, with the United Kingdom following close behind. Proven reserves of oil increased to 1.47 trillion barrels by 2010, according to the *Oil and Gas Journal* (2010)—equivalent to 48 years of production at existing levels. The *Statistical Review of World Energy* (BP, 2011b) has estimated proven reserves slightly higher–1.53 trillion barrels–an increase of 0.5 percent from 2009 to 2010. In either case, these estimates exclude recent upward revisions from Iraq and Iran that show 16 billion barrels discovered in 2010. Accounting for the probable remaining recoverable resources, it is estimated that total reserves could reach nearly 5.5 trillion barrels (IEA, 2011f).

Projections by the IEA (2011,Figure 3.28) show that global production is expected to increase by 15 percent from 2010 levels to reach 96 MMbbl/d by 2035, according to its New Policy Scenario,[56] at the same time as crude oil production from fields producing in 2010 will drop from 29 MMbbl/d to 22 MMbbl/d by 2035. As a result, global production will rely more heavily on the development of current and future oil discoveries as well as biofuels and unconventional oil sources. Each of these options will have carbon implications that are highly dependent on how projects are implemented. While the majority of current global production is by non-OPEC countries–accounting for 58.2 percent of global output in 2010–non-OPEC production is expected to peak at 51 MMbbl/d shortly after 2015 and then fall to less than 48 MMbbl/d by 2035, with Brazil, Canada, and Kazakhstan being the only suppliers not experiencing production declines.[57] (IEA, 2011f) Predicted increases in production for this period will be driven by OPEC oil output, which is expected to reach 49 MMbbl/d in 2035, corresponding to 51 percent of world output (IEA, 2011f, and BP, 2011b). Already, in 2010, non-OECD countries accounted for 85 percent of the increase in global crude runs (referring to refinery intakes of crude oil) and for the first time accounted for a majority of global output (BP, 2011b).

[56] IEA (2011f) provides three policy scenarios: (1) the Current Policy Scenario, which assumes no changes in current policies; (2) the New Policy Scenario, in which recent government policy commitments are assumed to be implemented, resulting in a level of emissions consistent with a long-term average temperature increase of more than 3.5°C; and (3) the 450 Scenario, which works back from the international goal of limiting the long-term increase in global mean temperature to 2.0°C Celsius above preindustrial levels.
[57] Recent expansion of fracking in the United States suggests that U.S. production might also expand.

Figure 3.28. Global oil production 2010–35 (New Policy Scenario) (IEA, 2011f)[58]

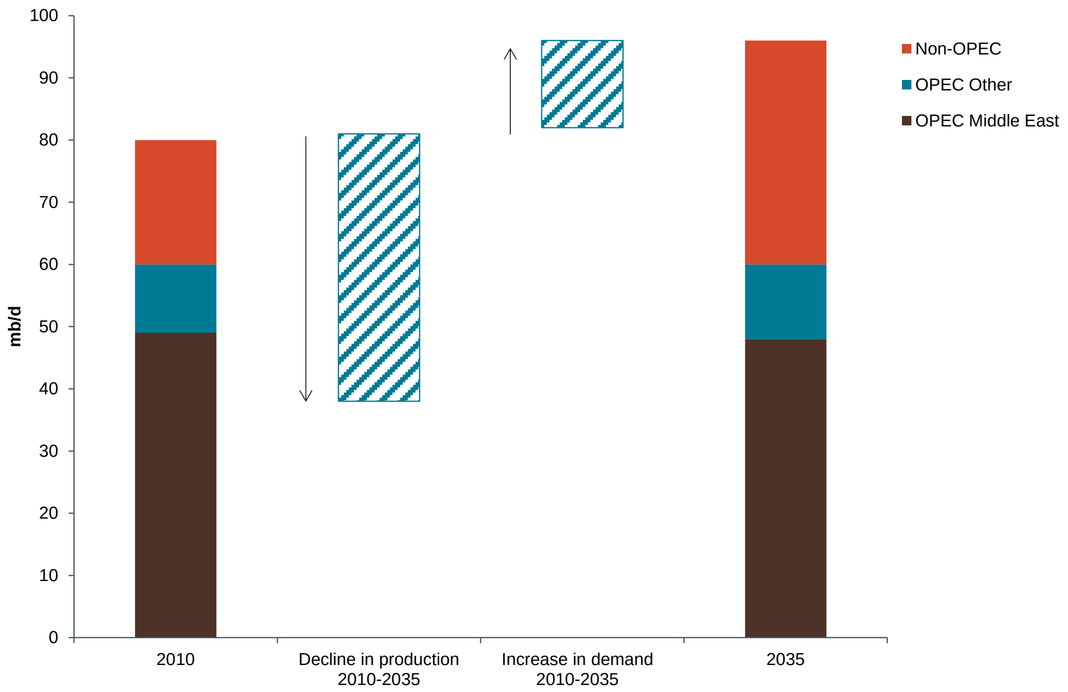
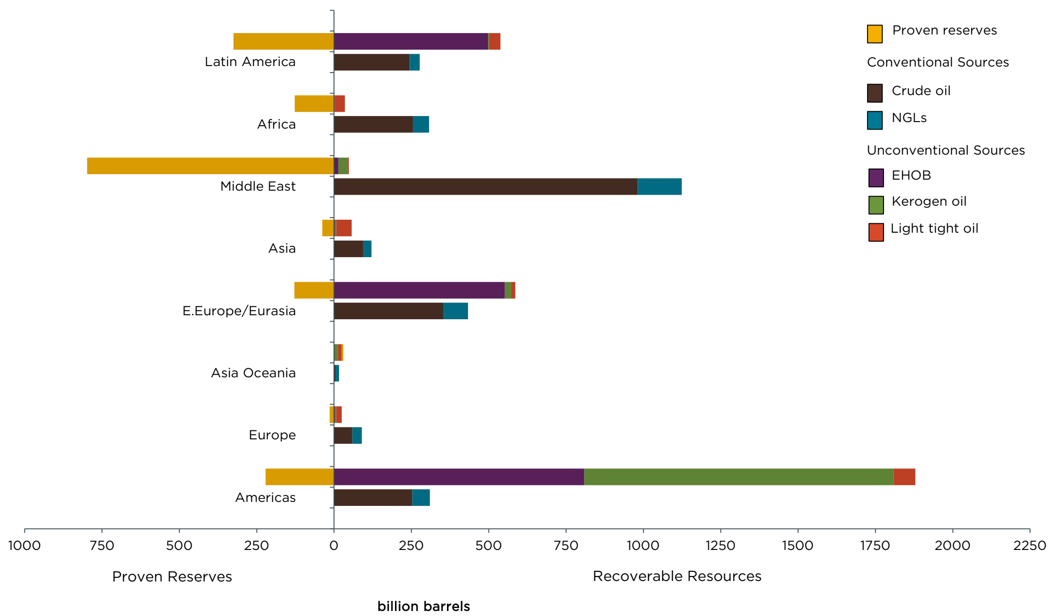


Figure 3.29. Recoverable oil resources and production by region 2010–35 (New Policy Scenario) (IEA, 2011f and BP, 2012)



According to projections by the *European Energy Pathways* report (Johnsson et al., 2011) the remaining oil resources appear to be sufficient to meet baseline demand up to 2030. This is driven by a number of factors including levels of discovered resources deemed to be substantially larger than proven reserves and a presumed large

[58] Decline in production estimates corresponds to oil fields producing in 2010.

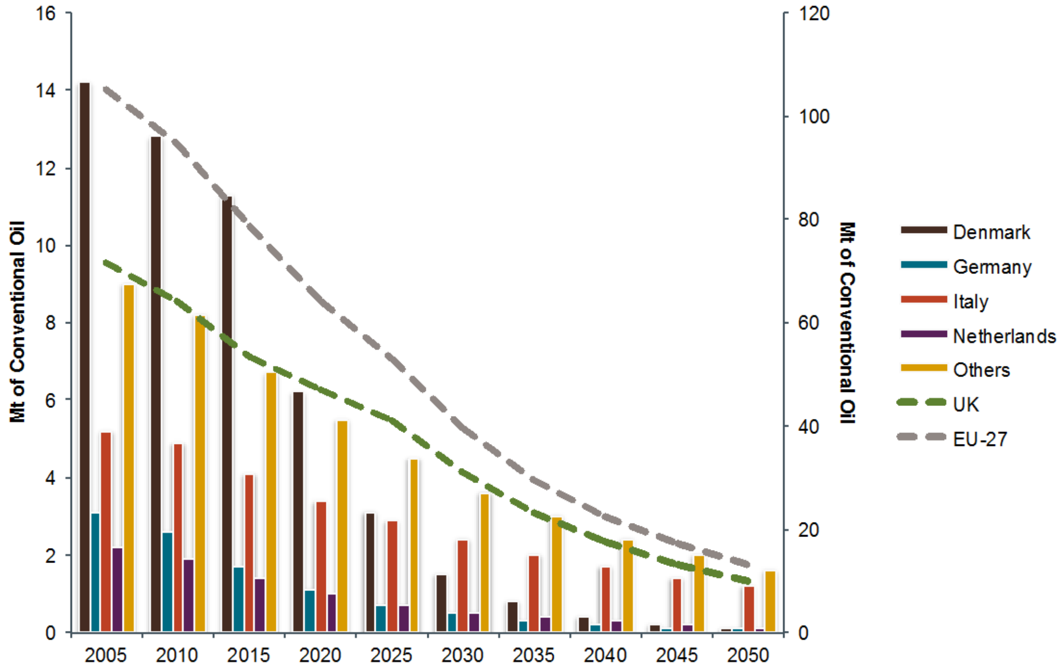
potential for resource growth in fields that have already been discovered. Nonetheless, it seems that global supply of oil will continue to be tight, driven by the rapid decline in production levels in Mexico and the North Sea as well as limited access to large resources in the Middle East, Russia, and Venezuela. These are further exacerbated by unfavorable institutional frameworks, which can lead to budgetary constraints for some large national oil companies, geopolitical tensions, and dwindling investments among producers to build up surplus production capacity.

In contrast to global production levels that are expected to continue to rise, production within the EU-27 is projected to experience a substantial decrease, from 105 MMt of conventional oil produced in 2008 to a mere 13.1 MMt in 2050, largely due to the depletion of UK resources (Johnsson et al., 2011,Table 3.4). As conventional production declines, it is possible that unconventional oil production, mainly in the form of oil shale located in Italy, Estonia, and the United Kingdom will begin to supplement rising demand. Given current production levels, these resources are expected to have an impact on oil markets only after 2020 (presuming there are no insurmountable political/environmental barriers to increased exploitation). Overall, given current demand forecasts, the EU will remain a net importer of crude and derivatives, and this trend will be further exacerbated by dwindling reserves in its member countries in the medium and long term.

Table 3.4. Conventional oil production and projections in the EU 2008–50 (Johnsson et al., 2011)

	2008	2010	2015	2020	2025	2030	2035	2040	2045	2050
Denmark	14.2	12.8	11.3	6.2	3.1	1.5	0.8	0.4	0.2	0.1
Germany	3.1	2.6	1.7	1.1	0.7	0.5	0.3	0.2	0.1	0.1
Italy	5.2	4.9	4.1	3.4	2.9	2.4	2	1.7	1.4	1.2
Netherlands	2.2	1.9	1.4	1	0.7	0.5	0.4	0.3	0.2	0.1
UK	71.5	64.3	53.5	46.9	41.1	31	23.3	17.6	13.3	10
Others	9	8.2	6.7	5.5	4.5	3.6	3	2.4.	2	1.6
EU-27	**105.1**	**94.7**	**78.7**	**64**	**52.9**	**39.5**	**29.7**	**22.5**	**17.1**	**13.1**

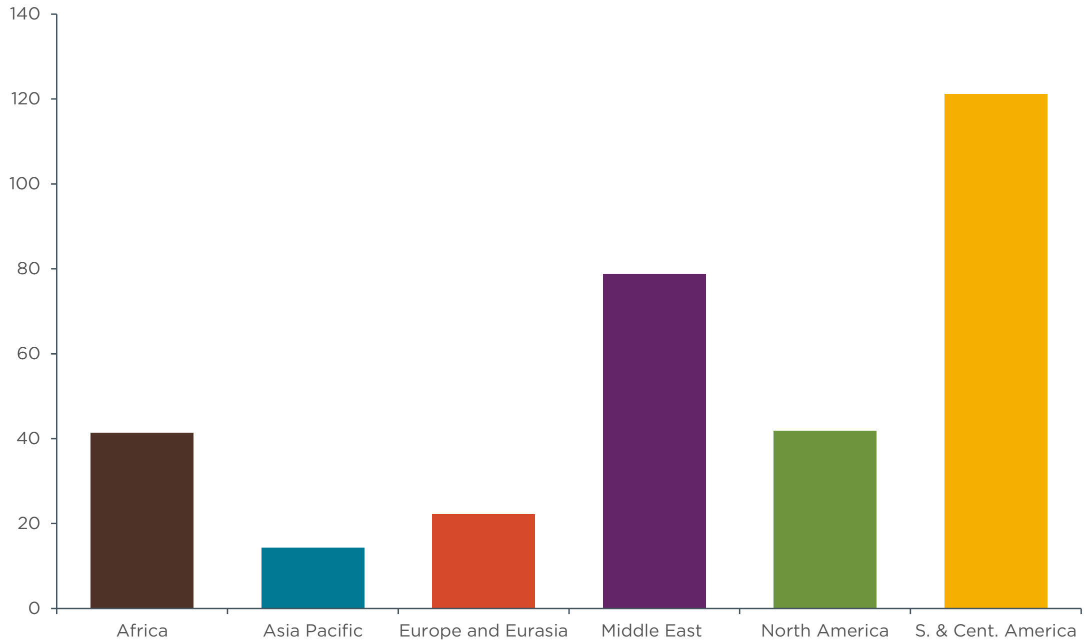
Figure 3.30. Projected oil production and demand levels to 2050 in the EU-27 (and Norway) (adapted from Johnsson et al., 2011)[59]



In general, it seems likely that reserves will be adequate to meet potential demand levels to 2050. The *Statistical Review of World Energy* (BP, 2012) suggests that Middle Eastern, North and South American, and African proven reserves should last to 2050 even with limited new finds. The lowest proven reserves relative to current production are in the Asia-Pacific, Europe and Eurasia (Figure 3.31).

[59] EE&TT refers to the European Energy and Transport - Trends to 2030 report (2008) by the European Commission Directorate-General for Energy in collaboration with Climate Action DG and Mobility and Transport DG.

Figure 3.31. Years of proven reserves at current production rates by region (BP, 2012)



While there is little question that North Sea oil production is dwindling, accurately estimating Russian and other FSU countries reserves is more challenging. Russia already accounts for more than 70 percent of current FSU imports to Europe and (according to BP) a similar percentage of proven FSU reserves. Table 3.5 summarizes findings from an Oil Drum (2006) literature review, which showed a range of reserve estimates for Russia between 60 and 200 Gbbl. In 2006, BP assessed less than half the reserves estimated by some other experts.[60] Nevertheless, we believe that restrictions on supply due to dwindling reserves in Russia are unlikely in the 2050 period. Russia also has extensive unconventional resources. For high-oil-price scenarios without preventative environmental regulation, it seems likely that these reserves will be exploited in the time frame to 2050. Still, given the increasing market for Russian oil in China and elsewhere in Asia, it is probable that Russian oil will represent a smaller fraction of EU imports moving forward.

[60] Note that some of this difference is to do with the probability threshold for counting reserves used for each estimate.

Table 3.5. Various estimates of Russian oil reserves (2006)

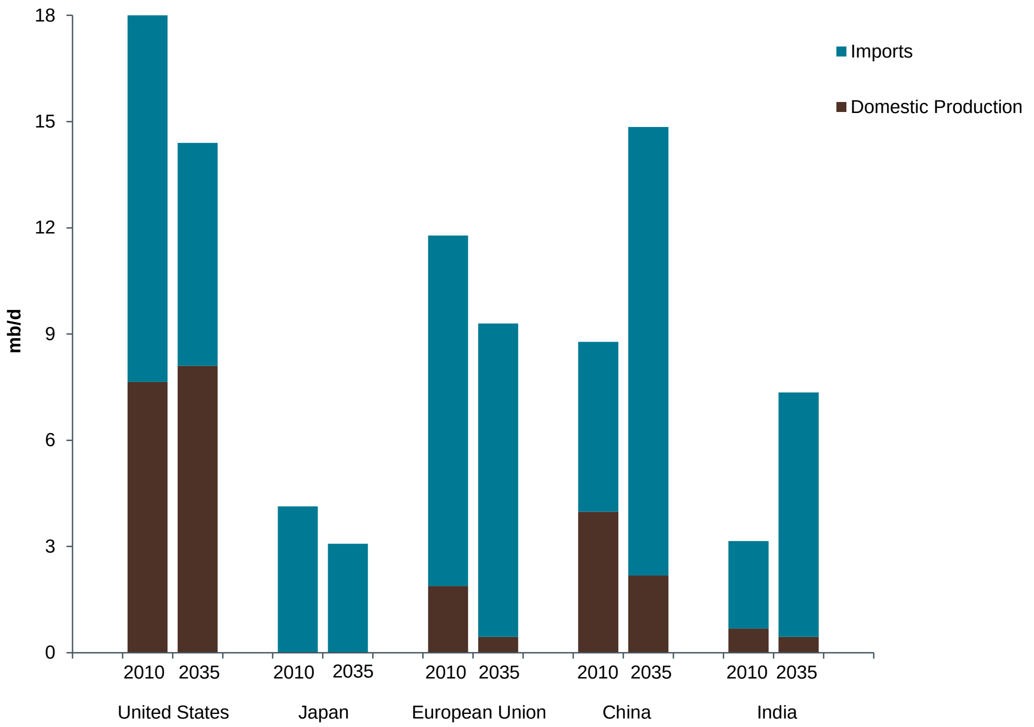
SOURCE	ESTIMATED RESERVES (THOUSAND MILLION BARRELS)
Oil & Gas Journal (OGJ)	60
John Grace*	68
World Oil	69
British Petroleum	72
10 largest Russian oil companies	82
Evgeni Khartukov (Russian oil expert)	110
United States Geological Survey	116
Ray Leonard (MOL Group)	119
Wood Mackenzie	120
IHS Energy	120
Mikhail Khodorkovsky (former Yukos head)	150
Brunswick UBS (consultants)	180
DeGolyer & MacNaughton (audit)	150 to 200

3.7.2. EU crude oil demand projections

According to the IEA (2011f), total primary energy demand in the European Union is set to increase by less than 5 percent from 2009 levels to 2035. The jump in energy demand occurs prior to 2020, with natural gas demand rising by 24 percent over the outlook period, corresponding to 30 percent of the region's energy mix by 2035 (IEA, 2011f). Similarly, the consumption of renewable energy is expected to increase annually by 3.5 percent, so that by 2035 its share of the energy mix grows to 23 percent (IEA, 2011f). Oil imports to the EU are expected to remain steady at around 9.8 MMbbl/d until around 2020 before declining to 8.8 MMbbl/d in 2035 (IEA, 2011f). The region will experience a more tempered demand schedule than that projected globally. The IEA (2011f, Figure 3.25), under its Current Policy Scenario, shows worldwide oil demand increasing by 24 percent over 2010 levels, or 0.8 percent annually, while under its New Policy Scenario the corresponding increase is reduced to 15 percent and 0.5 percent yearly.

Nonetheless, in the EU (as elsewhere), oil still will dominate energy consumption in the transport sector in 2035, accounting for 83 percent of the total; its total share of the EU's energy mix will be about one-fourth (IEA, 2011f). Overall, Europe remains the region most dependent on oil imports, accounting for 24.8 percent of global crude imports and 17.4 percent of petroleum product imports in 2010 (BP, 2011b). According to IEA projections, EU imports as a share of GDP are set to stabilize at around 3 percent until 2020 before dropping to approximately 2.5 percent by the end of 2035 (IEA, 2011f). The drop in import expenditures mirrors demand growth of alternative fuels and a more diversified energy mix. Nonetheless, over the long term the EU is likely to rely heavily on external trade to fulfill demand, as this presents a cheaper option than additional investments in unconventional crudes or refining capacity. Despite this, the product mix will become more diverse, enhancing energy security by diversifying crude sources and reducing exposure to supply shocks. Meanwhile, product quality requirements are not expected to act as a material barrier to trade as quality begins to converge internationally (see Purvin and Gertz, 2008).

Figure 3.32. Oil demand and its share of imports by region (New Policy Scenario) (IEA, 2011f)



3.7.3. Transportation sector fuel demand in Europe

Energy used for transport is likely to continue to be primarily oil in the coming decades, despite technological advances and increasing demand for renewable fuels. Currently, 97 percent of freight and transport activities rely on oil as a primary fuel, corresponding to 57 percent of all oil consumed in the EU-15[61] (Chen and Koppelaar, 2010). Furthermore, estimates show that the share of oil consumed by the transport sector for the EU is expected to rise to 59 percent by 2030 as overall oil consumption declines over time (Chen and Koppelaar, 2010). Similarly, Fiorello et al. (2008), using an integrated modeling framework to determine transport demand in a high-oil-price scenario, show that total passenger kilometers in the EU-27 are strongly affected by oil price changes through modal shifts, destination changes, and reduced distances traveled, as well as diminished economic activity. In

[61]Refers to Austria, Belgium, Denmark, Finland, France, Germany, Greece, Ireland, Italy, Luxembourg, the Netherlands, Portugal, Spain, Sweden and the United Kingdom

regard to freight performance, the authors conclude that high prices slow down the growth of tons per km but not total freight traffic.

Fiorello et al. note that transport demand is typically characterized as relatively price inelastic but argue that persistently high oil prices could lead to behavior changes. Renewal of the car fleet and adoption of alternative fuels, together with efficiency improvements, are likely to make the cost of traveling by car less sensitive to oil price toward 2050. Nonetheless, high fuel costs could encourage switching to rail (for which prices are much less sensitive to energy cost), not only from cars but also potentially from air travel and buses. Air travel demand is characterized as being particularly elastic with respect to energy prices.

3.8. EU crude sourcing trends - conclusions

The literature on the relationship of future European oil supply to cost is limited. Oil markets are notably volatile and subject to political instability; this pattern seems unlikely to change in the near future. The future of unconventional oil production is likely to be highly sensitive to oil prices and environmental legislation. Despite all this, we expect that, overall, European oil sources will be relatively stable over the coming decades. Russia, the FSU, the Middle East, and Africa look set to continue to dominate production; in general, we expect this production to be from conventional sources with a comparable emissions profile to the current EU crude slate. From an emissions modeling perspective most of the areas and processes of interest in 2050 are likely to be much the same as now. While increased oil prices would undoubtedly have some influence on the proportions extracted from different sources, the dynamics underlying these price increases would have a larger impact. So that high prices driven by Chinese demand might have a different effect on EU sourcing choices than high prices caused by a jump in U.S. demand. Regarding emissions, the impact of high prices is likely to be moderate–increased prices may make things like end-of-field-life enhanced recovery more viable, with associated emissions increases, but such enhanced recovery will not be a dominant means of extraction. In terms of upstream emissions modeling, of more interest is the trajectory of production from tar sands and oil shale reserves. It is possible that Canadian tar sands oil may become a growing source for the EU to 2020 and beyond. Similarly, with sustained high oil prices the pressure to expand oil shale exploitation (following the Estonian model) is likely to grow. Since both of these extraction approaches are likely to be profitable at oil prices in the range we expect moving forward, regulatory barriers (such as carbon pricing) may be more determinative of the importance of these fuel sources in Europe than the oil price alone.

It would be possible to use a linear programming approach to produce more detailed predictions for each oil price scenario, but we are cautious about the accuracy of such assessments. We have therefore restricted ourselves to more general conclusions and comments, focused on assessing any issues of particular interest as regards upstream oil emissions modeling. We summarize these in Table 3.6 below.

Table 3.6. EU Crude Sourcing

SOURCE	CURRENT IMPORTS	COMMENTS
FSU (Russia, Caspian)	41.7%	Russia's reserves may be slightly less certain in nature than those of other regions. There is also competition for Russian crudes from the Asian market. It is possible that in a low ($50) oil price scenario, Russian production could reduce and we might expect to see the importance of Russian crude to the European market diminish. For a persistent > $100 oil price, however, it seems probable that unconventional reserves will be exploited and will support continued exports to the EU (if with a different carbon profile). Even with unconventional production, given increasing oil demand from Asia, it seems unlikely that Russian crude will take a significantly larger place in EU imports to 2050 than it does now.
North Africa	12.3%	Given its proximity to the EU, and despite recent political changes, notably in Libya, North Africa is expected to continue being an important partner in oil sourcing. North African reserves are estimated at 69 billion barrels (dominated by Libyan reserves estimated at 47 billion barrels) by the EIA in 2012. This situates the region between Russia and the United Arab Emirates in terms of reserves. Aside from any new political upheavals, sourcing by the EU from the region as a whole is expected to remain broadly stable.
West Africa	7.8%	West African reserves are dominated by Nigeria, which makes up 98% of the region's 38 billion barrels according to the EIA in 2012. It seems likely that the EU will continue to be a key export market, not least given the European refining sector's substantial appetite for the light crudes characteristic of Nigerian production.
South & Central America	2.6%	Proven reserves in Latin America have risen dramatically in the last decade, and with extensive unconventional resources production increases seem likely, especially for a high-oil-price scenario ($150), which should allow the national oil companies scope to make serious investments. Energy-Redefined predicts a moderate increase in supply from now to 2020, and it seems reasonable to expect that new South and Central American sources will enter the EU fuel mix in the coming decades–perhaps more so for a high-oil-price scenario.

SOURCE	CURRENT IMPORTS	COMMENTS
Middle East	13.8%	Middle Eastern reserves are significant and should sustain production levels to 2050. There seems little reason to expect a major change in European imports, aside from political instability as exemplified by the recent Iranian oil embargo, from the Middle East–a high-oil-price scenario might drive more investment elsewhere, though, reducing the fractional importance of these supplies to Europe.
North Sea	20.6%	North Sea oil reserves are diminishing, and we see little reason to expect that to change. North Sea oil will be less important in Europe regardless of oil prices.
Canada	0.07%	Canada has extensive reserves of bituminous oil, which are highly profitable to exploit at $100 a barrel, and would still generate profits at $50. It seems likely that investment will move faster for a higher oil price, so higher prices are likely to make this source more significant for Europe. Given the relatively low gasoline yield from refining bitumen, and the structural shortage of diesel in Europe, one pathway might be for bitumen to be refined in the United States and the excess diesel to be exported as finished product.
Oil shales	0%	At $50 a barrel these will not be exploited, and at $100 other unconventional sources (e.g., fracking, tar sands) will probably take precedence in new development in the medium term, but in a $150 scenario these resources, extensive in many areas, will look appealing and, absent contrary price signals from climate legislation, could become an important source of EU crude.

4. Summary of Findings from LCA Studies

4.1. Introduction

In the fuels sector, one major policy response to the challenge of reducing carbon emissions has been the development of low carbon fuel standards (LCFS) and similar policies[62] (c.f. §2). Beginning with California in 2007, LCFS-type regulations have been seen as a useful tool to stimulate improvements in transportation fuel technologies with the aim of reducing the consumption carbon-intense fuels while incentivizing investments in new vehicles and low carbon fuels. The European Union's Fuel Quality Directive is one example of these policies. These regulatory frameworks require decreases in the carbon dioxide emissions associated with the entire lifecycle of fuels and thus rely on the application of lifecycle analysis (LCA). There is no single optimal LCA framework, or single agreed system boundary, but in general the aim of LCA is to account for the energy used and CO_2 emitted by processes related to the production, transport, storage, and use of fuel.

Given the complexity of fuel production processes and the lack of a single unified LCA framework, it is unsurprising that there have been diverging carbon intensity (CI) estimates published in the literature and that the accuracy of the modeling used to determine the CI of fuel sources has come under increased scrutiny. Added to this are complications regarding access to proprietary industrial data for product inputs and feedstock, to which many policy makers have limited access. In the regulatory context, the desire to minimize regulatory burdens conflicts with the desire to demand exhaustive data reporting to improve the accuracy of analytical results. Some regulatory frameworks have tried to manage this conflict by allowing the use of conservative default values while encouraging suppliers to "opt in" and report additional data to demonstrate a lower carbon intensity for their fuels (Sperling et al., 2007). Even outside of active regulatory frameworks, LCA results have become a key driver of discussions regarding climate policy–the debate around the exploitation of oil sands in particular has been characterized by the use of dueling CI estimates.

This chapter reviews the literature on the modeling of lifecycle GHG emissions from conventional crude oil production. We note that much of this literature has focused on the fuel mix available for consumption for the U.S. market, and as such, some degree of caution must be exercised in generalizing from the American to the European fuel markets. Still, there is

[62] Low Carbon Fuels Standard is the specific term for the policy in force in the state of California but is also commonly used as a generic term for that class of performance-based policies to regulate the carbon intensity of fuels.

much overlap of crude sources between the regions, and it is possible to infer conclusions about the CI of comparable processes even in different geographical locations. The sources we have reviewed include:

1. Joint Research Centre, EUCAR and CONCAWE (JEC) Well-To-Wheel Study (2011)
2. GREET 1 2011
3. GHGenius 4.00c
4. McCann and Associates (2001)
5. Energy-Redefined (ICCT/ER, 2010)
6. TIAX (2009)
7. Jacobs (2009) (plus overview of results from Jacobs, 2012)
8. National Energy Technology Laboratory (NETL) study (2009)
9. IHS CERA (2010a)

It is important to understand when comparing the results of different LCA studies that each set of results reflects a specific study methodology, system boundary, period of time analyzed and set of input data. Differences between results therefore can reflect both real differences between production systems analyzed and differences in the approach taken by the studies in question. While the outputs of these different studies can be usefully compared to some extent, caution is appropriate in interpreting what differences in results really mean. In this report, we focus on providing an overview of each individual study, rather than attempting a rigorous and comprehensive methodological comparison of different studies.

4.1. Joint Research Centre, EUCAR and CONCAWE (JEC) Well-To-Wheel study (2011)

4.1.1. Objective and data description

The primary objective of the JEC Well-To-Wheels (WTW) study is to establish the energy and greenhouse gas balance for various fuels suitable for road transport powertrains. The study notes that "the ultimate purpose … is to guide those who have to make a judgment on the potential benefits of substituting conventional fuels by alternatives"; i.e., it is intended to allow comparative judgments to be made about the greenhouse gas (GHG) reduction efficacy of various fuel pathways. The study aims to calculate the emissions, energy, and cost implications of replacing the conventional fossil fuel mix, as measured in 2010 and predicted in 2020, with increased use of the various alternative fuel possibilities.

4.1.2. Data quality and quantity

JEC uses International Association of Oil and Gas Producers (OGP) regional data as a key source. OGP publishes data annually–the year 2005 is chosen as the basis for the WTW study because, unlike later years, venting and flaring are reported explicitly (see Table 4.1). OGP membership covers about a third of global oil production–JEC notes that membership is skewed toward multinational oil operators and away from national oil firms.

Table 4.1. Energy and GHG emissions from crude oil production (OGP, 2005)

		TOTAL	AFRICA	ASIA	EUROPE	FSU	ME	NA	SA
OGP production MMt/a		2103	390	298	515	51	235	366	248
Total production MMt/a		6382	614	706	538	1262	1471	1318	473
Coverage %		33%	64%	42%	96%	4%	16%	28%	52%
ENERGY									
Total PJ/a		2688	325	441	476	59	142	820	425
Specific energy MJ/MJ		0.03	0.02	0.035	0.022	0.027	0.014	0.053	0.041
EMISSIONS									
CO_2	MMt/a	283.2	106.8	39.8	33.5	7.1	27.5	41.5	27
	t/kt	134.7	273.8	133.6	65	139.2	117	113.4	108.9
CH_4	kt/a	2361	674	566	122	49	139	389	422
	t/kt	1.12	1.73	1.9	0.24	0.96	0.59	1.06	1.7
CO_2e	MMt/a	342.2	123.7	53.9	36.6	8.3	31	51.2	37.5
	t/kt	162.7	317.1	181	71	163.2	131.8	140	151.4
% due to venting		21	16	36	9	17	13	23	39
% of C in crude		5.20							
Specific emissions g/MJ		3.87	7.55	4.31	1.69	3.89	3.14	3.33	3.6
FIGURES PRORATED TO TOTAL PRODUCTION									
CO_2e	MMt/a	1016.5	194.7	127.8	38.2	205.9	193.8	184.5	71.6
	t/kt	494	499	429	74	4038	825	504	289
Specific energy MJ/MJ		0.03							
% of C in crude		5.10	10.10	5.70	2.30	5.20	4.20	4.40	4.80
Specific emissions g/MJ		3.79							

The JEC study notes that the data coverage from OGP is variable–with the best coverage for Europe and reasonable coverage for Africa and South America but poor coverage elsewhere. This is illustrated in Table 4.2. It also notes that the aggregation implied in these regions could mask substantial variations. The coverage is nominally global, however, the coverage of EU crudes is complete, even if the data precision for those calculations is relatively poor.

Table 4.2. Coverage of OGP data ([S&T]², 2011)

REGION	2001	2002	2003	2004	2005	2006	2007	2008	2009
Africa		63%	63%	62%	66%	63%	61%	59%	59%
Asia/ Australasia		40%	43%	47%	46%	44%	43%	45%	42%
Europe	102%	104%	99%	94%	98%	100%	103%	98%	104%
Former Soviet Union	10%	10%	11%	4%	4%	5%	8%	8%	10%
Middle East	10%	9%	16%	15%	16%	17%	15%	20%	33%
North America		53%	51%	30%	29%	27%	25%	23%	25%
South America		47%	57%	58%	53%	42%	41%	40%	40%
Total		40%	41%	34%	34%	32%	32%	32%	36%

4.1.3. Methodological considerations

The JEC study is not a modeling study in the way that it approaches crude oil extraction emissions–rather, it uses estimates from the existing literature as a basis for its conclusions. This is somewhat similar to the NETL study (see §0). The JEC work predates the International Reference Lifecycle Data System (ILCD) guidelines and hence does not refer to them.

As in other studies, JEC does not include construction emissions or emissions involved with decommissioning plants and vehicles within the system boundary. It observes that the impact of these emissions on the overall pathway CIs is likely, in general, to be small compared to the uncertainty already in the estimates. The calculations for the WTW study are undertaken via proprietary software (the E3 database by L-B-Systemtechnik of Ottobrunn, Germany).

The study defines lifecycle stages similar to those defined in, for instance, the NETL study:

1. Production and conditioning at source
2. Transformation at source
3. Transportation to EU
4. Transformation in EU
5. Conditioning and distribution.

Stages one and two are of interest to us here. The stages are defined the same for all considered fuels, not only crude oil. The study aims to represent emissions for 2015–2020 and thus endeavors to account for technology that will be commercially available within that timeframe.

Carbon equivalency values for GHGs are based on the 100-year global warming potential (GWP) defined by the Intergovernmental Panel on

Climate Change (2007). As in other studies, lower heating values are used for the energy content of fuels.

The OGP report on which JEC bases its production emissions suggests that about 50 percent of the attributed GHG emissions are a result of venting and flaring–JEC cautions that it is unclear whether this includes or excludes the 35 percent of reported emissions that are ‘unspecified.’ It therefore concludes that flaring and venting account for 1.3–2 gCO_2e/MJ for the average EU crude, with extraction accounting for 2–2.6 gCO_2e/MJ. JEC cross-references the OGP flaring and venting values against National Oceanic and Atmospheric Administration (NOAA) values reported based on satellite mapping. The satellite mapping suggests a higher value for flaring and venting, potentially up to 3.2 gCO_2e/MJ—JEC settles on 2.5 gCO_2e/MJ ± 50 percent. This takes the average emissions for crude production to 4.8 gCO_2e/MJ.

For oil sands, JEC does not attempt modeling of extraction but instead takes a value of 20 gCO_2e/MJ for production based on the available literature. For Venezuela, JEC expects similar values but notes that Venezuelan extra-heavy oil is more liquid than Canadian bitumen, which might allow lower energy inputs. For both regions, JEC expects gas to supply power for steam generation.

Transport emissions by ship are calculated based on assumptions about type of oil tanker and distance transported. JEC is interested in marginal crude for comparative purposes with other alternative fuels. It believes the marginal crude to Europe would be a relatively light Middle Eastern crude, and thus it bases its transportation value on shipment from the Middle East, yielding 0.8 gCO_2e/MJ.

4.1.4. Parametric significance and temporal variations

JEC notes the importance of flaring estimates to oil extraction emissions. The JEC model is not based on modeling via extensive parameters, and so there is no parameter analysis to speak of. Similarly, there is no sensitivity analysis for individual parameters, as this is not intended as a potential reporting model. The JEC work aims to look five to ten years forward, but it has not made any assumptions about changing production emissions profiles over time–again, this is somewhat less relevant for the highly aggregated emissions values.

4.1.5. Summary findings

The JEC report finds average production emissions intensity of 4.8 gCO_2e/MJ of crude. The transport emissions (for Middle Eastern crude) are found to be 0.8 gCO_2e/MJ, giving a total of 5.7 gCO_2e/MJ for delivery of crude to a European refinery.

4.2. GREET 1 2011

4.2.1. Objective

The Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation (GREET) model has been widely used, especially in the United States, to calculate GHG intensity of fossil fuels. The carbon intensity calculated for the U.S. represents an aggregate average value. It is used for the upstream GHG intensity of fossil fuels for the EPA Rulemaking to Establish Light-Duty Vehicle Greenhouse Gas Emission Standards and Corporate Average Fuel Economy Standards and, in its modified California-GREET incarnation, for the California LCFS.

4.2.2. Methodological considerations

The GREET oil recovery calculations are based on an 'energy efficiency' rating for each fuel pathway. This expresses the percentage of total input fuel energy that is yielded as transport fuel—so if 9 MJ of energy (in the form of crude oil) were refined with 1 MJ of electricity into 9 MJ of petroleum, that process would have the following energy efficiency:

9 / (9 + 1) x 100 = 90 % efficiency.

This efficiency rating defines the energy inputs into the recovery process. This information is then cross-referenced with a breakdown of the type of process fuels (e.g., natural gas vs. coal vs. petroleum coke) used for oil recovery, and emissions factors for those fuels themselves, to determine total emissions from recovery for a range of pollutants–notably, methane, nitrous oxide, and of course carbon dioxide. In this way, GREET can calculate the total CO_2 equivalent emissions per megajoule of output fuel.

GREET currently calculates three fossil fuel recovery pathways–crude oil, oil sands mining, and oil sands in situ surface production. The recovery energy efficiencies and process fuel shares are detailed in Table 4.3.

Table 4.3. Efficiency and process energy use for oil recovery in GREET 2011

GREET	CRUDE RECOVERY	OIL SANDS MINING		OIL SANDS IN SITU	
		Bitumen Extraction	Bitumen Upgrading	Bitumen Extraction	Bitumen Upgrading
Energy efficiency	98.0%	94.8%	98.6%	84.3%	98.6%
Urban emission share	2.0%	2.0%	2.0%	2.0%	2.0%
Loss factor			1.000		1.000
Energy use (MJ/million MJ)					
Crude oil	204	0	0	0	0
Residual oil	204	0	0	0	0
Diesel fuel	3,057	329	0	0	0
Gasoline	408	0	0	0	0
Natural gas	12,635	45,132	13,787	181,011	13,787
Coal		0	0	0	0
Liquefied petroleum gas					
Electricity	3,872	9,377	397	5,214	397
Hydrogen			84,187		32,364
Petroleum coke		0	0	0	0
Feed loss	28	14	14	14	14
Refinery still gas		0	0	0	0
Natural gas flared	0*				

**GREET allows the user to input a flaring emissions value, but the default is zero*

As noted, the version of GREET used for the California Low Carbon Fuel Standard is slightly modified and referred to as California-GREET. California-GREET uses the same crude and bitumen recovery values as GREET 1 2011.

4.2.3. Data quality and quantity

The crude recovery efficiency value of 98 percent used in GREET is referenced in comparison to three other studies: NREL et al. (1991), Delucchi (1991), and Ecotraffic, (1992). The process fuel mix is based on Wang (1999). For oil sands, the process efficiencies and fuels are suggested by Larsen et al. (2004)–the efficiency of mining has been revised upwards between then and the current model version. There is no attempt in GREET to distinguish between crude recovery at different locations beyond these three pathways, and hence there is no coverage of specific crudes for import for Europe except the two Canadian pathways.

4.2.4. Summary findings

The carbon intensity of the pathways as detailed in GREET is given in Table 4.4.

Table 4.4. GREET oil production CIs

PATHWAY	CI (gCO_2e/MJ)
Crude oil	7.45
Mined bitumen	18.9
In situ bitumen	20.3

4.3. GHGenius 4.00c

4.3.1. Objectives

GHGenius has been developed by (S&T)[2] consultants since the year 2000 for Natural Resources Canada, based on Mark Delucchi's 1998 Lifecycle Emissions Model (LEM). It is similar to GREET in that it is essentially a spreadsheet-based model that can calculate emissions of both greenhouse gases and other pollutants. LEM initially modeled a steady Canadian crude slate (about 50 percent domestic, 50 percent imported). In 2011, the model was enhanced to provide a more time-sensitive encapsulation of changing crude flows and to have improved coverage of Canadian crudes exported for refining elsewhere.

The GHGenius model "is capable of analyzing the emissions from conventional and alternative fuelled internal combustion engines or fuel cells for light duty vehicles, for class 3–7 medium-duty trucks, for class 8 heavy-duty trucks, for urban buses and for a combination of buses and trucks, and for light duty battery powered electric vehicles. There are over 200 vehicle and fuel combinations possible with the model." ([S&T][2], 2011). GHGenius models past, present, and future years based on trends stored in the model.

4.3.2. Data quality and quantity

GHGenius has better coverage of areas importing oil to Europe than other North American models. Table 4.5 shows the regions that GHGenius includes data for, with the percentage of EU crude use they account for.

Table 4.5. Coverage by GHGenius of crudes from regions supplying Europe

REGION/COUNTRY	% OF CRUDE REFINED IN EUROPE (FIRST THREE MONTHS 2011)
United States	0 (Diesel imported as refined product)
Canada	0.07
Mexico	1.36
India	0
Northern Europe	20.59
OPEC	0
Venezuela	0.61
North Africa (Algeria, Libya)	11.12
Nigeria	5.38
Indonesia	0
Persian Gulf	12.95
Australia	0
Other South America	0.43
Other Middle East	0.86
Caribbean Basin	0
Other Africa	4.84
Asian Exporters	0
Other	0
Total coverage of EU crude	58

(S&T)[2] (2011) observes that there is no single comprehensive public source for the assays (properties) of the various crudes of interest for the Canadian marketplace. It uses the Oil Properties Database from Environment Canada, a poster from McQuilling[63] services LLP, company websites, and EIA country briefs. It further points out that because oilfield and oil properties can vary widely within regions or countries (see ICCT/ER, 2010), this introduces additional complications.

[63] www.meglobaloil.com/MARPOL/pdf

Energy consumption data for oil production is available for the United States and Canada, and in GHGenius the energy consumption of production in other countries is defined relative to the U.S. numbers. GHGenius has been calibrated to reflect energy consumption trends apparent in OGP data (see Table 4.6).

Table 4.6. Energy consumption for crude oil production (OGP regional values as compared to GHGenius U.S. value)

REGION	DATA COVERAGE	ENERGY CONSUMPTION, GJ/TONNE	RELATIVE TO U.S. GHGENIUS VALUE, 2009
Africa	59%	1.13	0.54
Asia/Australasia	42%	1.59	0.76
Europe	104%	1.12	0.54
FSU	10%	1.06	0.51
Middle East	33%	1.00	0.48
North America	25%	3.08	1.47
South America	40%	1.69	0.81
Average	**36%**	**1.53**	**0.73**

The values GHGenius uses are in Table 4.7. Data quality for the OPEC nations in particular is relatively poor, as indicated by the assignation of identical energy efficiency values to many country/product combinations. The GHGenius documentation explains that, for many regions, detailed data is unavailable. Hence, there is significant uncertainty in the GHGenius estimation of the regional energy intensity for each oil category.

Table 4.7. Energy efficiency of oil production in GHGenius 4.00c

CRUDE OIL PRODUCED IN:	RATIO OF ENERGY USE FOR GIVEN REGION/PETROLEUM PRODUCT TO ENERGY USE FOR U. S. ONSHORE CONVENTIONAL						
	condensate	onsh. con.	offsh. con.	heavy	bitumen	SCO	Weighted average across all petroleum products
United States	0.70	1.00	5.00	9.00	5.00	6.00	3.36
Canada	0.97	1.38	1.40	0.78	3.66	5.40	3.06
Mexico	0.70	1.00	1.50	2.90	5.00	6.00	2.17
India	0.45	0.64	0.42	0.58	5.00	6.00	0.50
Northern Europe	0.39	1.00	0.55	1.20	5.00	6.00	0.60
Venezuela	0.70	1.00	3.00	1.20	5.00	6.00	1.10
North Africa (Algeria, Libya)	0.39	0.55	0.65	1.20	5.00	6.00	0.55
Nigeria	0.46	0.55	0.65	1.20	5.00	6.00	0.60
Indonesia	0.46	0.65	2.00	1.20	5.00	6.00	0.92
Persian Gulf	1.19	1.70	2.00	1.20	5.00	6.00	1.58
Australia	0.53	0.76	2.00	1.20	5.00	6.00	1.69
Other South America	0.57	0.81	2.00	1.20	5.00	6.00	0.85
Other Middle East	1.05	1.50	2.00	1.20	5.00	6.00	1.50
Caribbean Basin	0.70	1.00	2.00	1.20	5.00	6.00	1.00
Other Africa	0.46	0.65	2.00	1.20	5.00	6.00	0.89
Asian Exporters	0.46	0.65	2.00	1.20	5.00	6.00	0.92
Other	0.70	1.00	2.00	1.20	5.00	6.00	1.00

For Canada, GHGenius uses more detailed data. For conventional oil, GHGenius uses data from *Canada's Energy Outlook: The Reference Case 2006.* For mining of oil sands, GHGenius uses a three-year average of energy consumption data from the Alberta Energy Resources Conservation Board (ERCB) 'ST-43' data. These data are based on actual reporting from the Albian Sands and Syncrude Aurora projects.

For in situ production from oil sands, data are again available from ERCB, the 'ST-53' data. GHGenius assigns steam:oil ratios (SOR, the key parameter for thermally enhanced production methods) based on these data. For cyclic steam stimulation (CSS) the SOR is taken to be 3.9, with 2.6 GJ of natural gas per metric ton of steam, while for steam-assisted gravity drainage (SAGD) the SOR is taken as 3.0, with 3.2 GJ/ton of steam. For primary in situ production, values have been based on Clearstone Engineering et al. (2009)–there is a lack of detailed data on the energy intensity of the primary production phase.

For bitumen upgrading, GHGenius bases its energy intensity calculation on 'ST-43' data for seven actual Alberta upgrader projects (stand-alone upgraders) and three actual Alberta projects (integrated upgraders).

Similarly, fugitive, flaring, and venting data for the mining and in situ projects are based on actual project data from ERCB.

For land use changes, GHGenius reviews the relevant literature and uses values in line with those papers–see (S&T)^2 (2012).

4.3.3. Methodological considerations

GHGenius 4.00c has a much more disaggregated set of crude oil production pathways than GREET, for instance. It includes pathways for production of condensate (API > 40), conventional onshore crude, conventional offshore crude, heavy crude, bitumen, and synthetic crude, for up to 16 regions—a total of 33 crude pathways.

GHGenius describes crudes with four characteristics: API gravity, sulfur content, carbon content,[64] and energy content.[65] The carbon and energy content are calculated values, making API and sulfur input parameters. For the carbon intensity of production, another fundamental input parameter is the energy efficiency (metric kilotons/ton of oil produced)–in GHGenius, these values are normalized to the energy intensity of U.S. onshore production (Table 4.7).

Finally, there is the rate of flaring and venting for each region. GHGenius uses data from the World Bank Gas Flaring Reduction Partnership (NOAA satellite imaging of flare intensity cross-referenced with production data from EIA to give flaring rates per ton of production) for flaring–this has replaced an earlier calculated flaring assessment in GHGenius 3.15 (see Table 4.8).

[64] Calculated from gravity and sulfur as
*% C = 76.99 + (10.19 * API gravity) + (-0.76 * Sulfur content)* (EIA, 2006)
[65] Also calculated from API
HHV = 42,860 + 93(API-10)* (Iowa State University)

Table 4.8. Flaring rates from GHGenius 3.15 and NOAA compared

REGION	GHGENIUS 3.15	NOAA
	Liters/tonne	Liters/tonne
U. S.	7,706	7,405
Canada	13,593	13,578
Mexico	9,383	11,230
India	30,604	18,370
N. Europe	5,455	3,177
Venezuela	28,214	17,472
North Africa (Algeria, Libya)	30,752	50,091
Nigeria	191,786	142,461
Indonesia	42,648	49,373
Persian Gulf	14,839	29,726
Australia	873	15,225
Other South America	25,442	20,240
Other Middle East	7,591	32,963
Caribbean Basin	15,158	28,996
Other Africa	148,851	60,054
Asian Exporters	1,865	29,973

The rates of flaring in liters per ton of production are combined with a flare efficiency rating to determine venting.[66] It is possible to estimate venting rates by assuming that gas that is produced and is not detected as flared by the World Bank is being vented, which gives overall flare efficiencies of 80–95 percent, i.e., between 5 percent and 20 percent of gas is being vented in each region. The World Bank uses an average flaring efficiency of 93 percent, which has been adopted by GHGenius. The OGP provides additional data on non-flaring methane emissions from production; see Table 4.9.

Table 4.9. Methane emissions excluding flaring and venting (OGP)

KG/TONNE	2005	2006	2007	2008	2009
Africa	1.73	1.45	1.6	1.37	1.38
Asia/Australasia	1.9	1.41	1.51	1.81	2.66
Europe	0.24	0.25	0.23	0.26	0.28
FSU	0.97	0.78	0.62	0.56	0.62
Middle East	0.47	0.41	0.33	0.17	0.13
North America	1.06	1.45	1.55	1.64	1.65
South America	1.7	1.42	1.41	1.36	1.66
Total	**1.11**	**1**	**1.03**	**1.02**	**1.14**

[66] This captures not only flare tip efficiency but also other expected venting losses.

4.3.4. Summary findings

The production emissions (including recovery, flaring, and upgrading) from GHGenius by region are listed in Table 4.10. The values are not based on single more or less representative oilfields but on a weighted average of national production emissions taking in relative volumes of condensate, onshore conventional, offshore conventional, heavy crude, bitumen, and synthetic crude oil (SCO).

Table 4.10.Production emissions in GHGenius, weighted average for each country/region across produced petroleum outputs*

COUNTRY/REGION	PRODUCTION EMISSIONS (gCO_2e/MJ)
U.S.	14.8
Canada	11.1
Canada oil sands	19.1
Canada conventional	8.8
Mexico	10.6
India	7.6
N. Europe	5.3
Venezuela	7.8
North Africa (Algeria, Libya)	9.1
Nigeria	14.8
Indonesia	12.0
Persian Gulf	12.1
Australia	11.9
Other South America	8.1
Other Middle East	11.0
Caribbean Basin	8.1
Other Africa	11.4
Asian Exporters	9.7
Other	6.3

**Emissions per MJ of refined product*

4.4. McCann and Associates (2001)

The consultancy McCann and Associates (McC&A) has published several crude oil LCAs since 1999[67]. The McC&A analysis is not extensively documented compared to the other examples listed here, and therefore we report only the results, without details of the methodology. We believe that the McC&A assessment of production emissions is based on energy consumption and flaring data rather than an engineering model. The results are shown in Table 4.11.

[67] http://www.ogj.com/articles/print/volume-97/issue-8/in-this-issue/general-interest/crude-oil-greenhouse-gas-life-cycle-analysis-helps-assign-values-for-co-2-emissions-trading.html

Table 4.11. McC&A 2001 LCA results (gCO_2e/MJ transport fuel)[68]

	CANADIAN LIGHT	BRENT BLEND	SAUDI LIGHT	NIGERIAN ESCRAVOS	CANADIAN SCO	VENEZUELAN PARTIAL UPGRADER
Production	3.8	3.4	5.5	12.6	17.8	19.1
Transport	1.3	2.1	4.9	1.8	1.2	1.6
Refining	5.7	6.0	6.0	5.5	5.9	6.2
Tailpipe	75.9	75.6	74.6	76.2	76.2	77.0
By-product combustion	4.1	4.3	4.6	3.9	3.8	3.6
WTW	90.7	91.5	95.6	100.1	104.9	107.6

4.5. Energy-Redefined

4.5.1. Objective and data description

In 2010, Energy-Redefined (ER), commissioned by the ICCT, published *Carbon Intensity of Crude Oil in Europe,* one of the few studies focusing its attention on the European market. The study aimed to quantify the upstream GHG emissions of crude oil supplied to the EU market from extraction to refining with the objective of highlighting the processes in which the greatest opportunities for significant reductions could be attained. In particular, emissions were quantified for five production processes: extraction; flaring and venting; fugitive emissions; crude oil transport; and refining. It is worth noting that the analysis does not delve beyond the refinery to include emissions associated with distribution or combustion of the end products.

4.5.2. Data quality and quantity

The ICCT/ER (2010) study is unique in terms of scope. The database used is extremely comprehensive, covering approximately 6,000 oilfields in total. ER believes that this database covers every major field in the world. The reported results cover about half of these fields, more than 4,000 locations that may be supplying the European market–the identification is done on the basis that any field in a country supplying Europe may itself be supplying Europe, and thus the coverage should be complete for all significant current flows to the continent. The database uses extensive public and proprietary data, as well as field level cross-correlation of relevant production parameters by ER[69]. It includes information on all crude characteristics required for the ER parametric model. It is significantly more comprehensive than would be possible using public data alone, having been developed with data obtained through ER's working relationships with the oil and gas sector. Similarly, the methodological considerations used to estimate the

[68] Converted from kg per 1000 liter based on an average 34 MJ/l of transport fuel
[69] Somewhere between 20 and 30 percent of the database was cross-correlated based on values for similar fields from a dataset containing over 30 production parameters for 12,000 oil and gas fields.

carbon intensity of these varying crudes draw from a wide collection of peer-reviewed literature compiled into a proprietary model. The ER study relied on public sources included the EIA, Canadian Association of Petroleum Producers (CAPP), the U.S. Geological Survey, the Ministry of Petroleum and Energy of Norway, and the UK Department of Energy and Climate Change, as well as the U.S. Minerals Management Service.[70] Many other public sources of information are likely to have been consulted during the compilation of the ER database, including a number of government organizations; however, ER does not specifically cite these. For flaring data, satellite data (obtained from the NOAA) was paired with country-level emissions factors from the Global Gas Flaring Reduction Unit (GGFR) at the World Bank. Fugitive emissions were determined on the basis of CAPP emission factors (CAPP, 2002) for equipment fittings such as seals, valves, and flanges.

Even given the extensive access of ER to proprietary data on top of publicly available resources, ER remarks that most fields (4,000-plus) are not described directly in the existing literature. In many cases, therefore, ER has cross-populated its database for specific fields based on data for comparable fields. The ER emissions model has been applied to this database and calibrated to the existing literature on emissions. Where possible, ER compared the GHG estimates provided by its engineering based model with the known data to establish acceptable levels of consistency. The precise details of the calibration procedure and the extent of cross-population are not documented in the ER report.

4.5.3. Methodological considerations

Methodologically, the study identified fourteen unique parameters that interact at five different stages of the extraction-to-refining process to estimate total GHG emissions of crudes supplied to the EU market. These parameters include both crude characteristics such as viscosity, API gravity, and feedstock as well as field characteristics including age of field, pressure, type of development, equipment components, and others (see Table 4.12 for parameters by crude process). Once identified, the parameters' interactions were modeled to estimate energy use, flaring, and venting at the field level. Rates of flaring and venting were modeled with a combination of oil characteristics, oilfield-specific information, and satellite mapping. Satellite mapping allows the identification of areas in which fields are flaring–however, because several oilfields may be indistinguishable in satellite flare imaging, this alone is not adequate to identify flaring rates. ER uses the gas-to-oil ratio (GOR) for fields to estimate gas production. ER models the variation of GOR over time–older fields are likely to have higher GOR than when they were initially tested, making for a substantial difference in expected per barrel flaring rates (Figure 4.1). ER parameterizes this

[70] On October 1, 2011, the Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE), formerly the Minerals Management Service (MMS), was replaced by the Bureau of Ocean Energy Management (BOEM) and the Bureau of Safety and Environmental Enforcement (BSEE) as part of a major reorganization.

time trend with the crude viscosity for the individual fields, which allows it to estimate the type of drive for each field (c.f. ER, p. 40). The time-varying GOR, coupled with the production rate for oil, allows ER to estimate production of gas at each field in the vicinity of which flaring is observed. It is assumed that the gas will be used to provide energy at the field. So that if more gas is produced than required and there is no gas-export infrastructure, it is assumed that the remaining gas is flared at an efficiency of 98 percent (see Figure 4.2). ER compared the bottom-up flaring estimates to World Bank national flaring data and found that there is a good correspondence between the two for most countries.

Figure 4.1. Variation of gas-to-oil ratio over time for a typical field, with weak, medium, or strong water drive, or a solution gas drive (ICCT/ER, 2010)

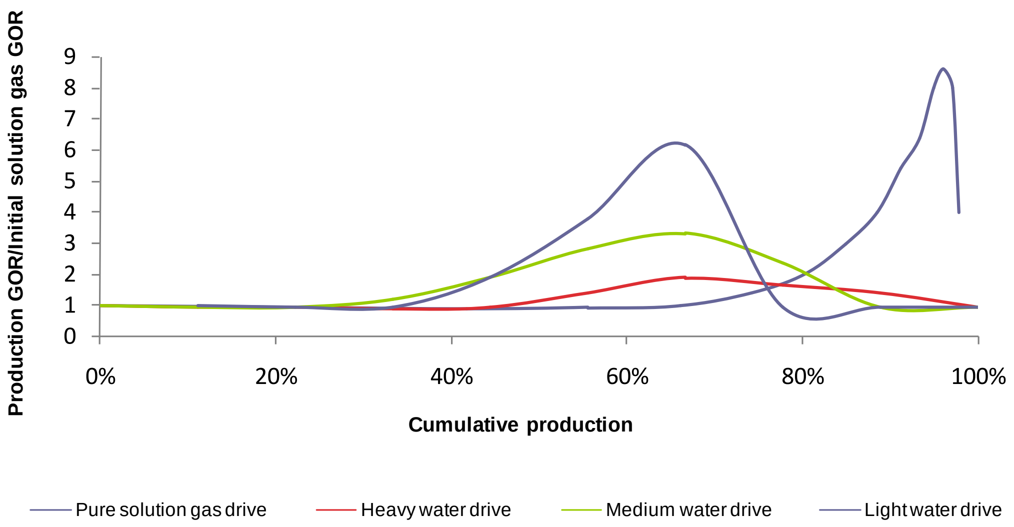
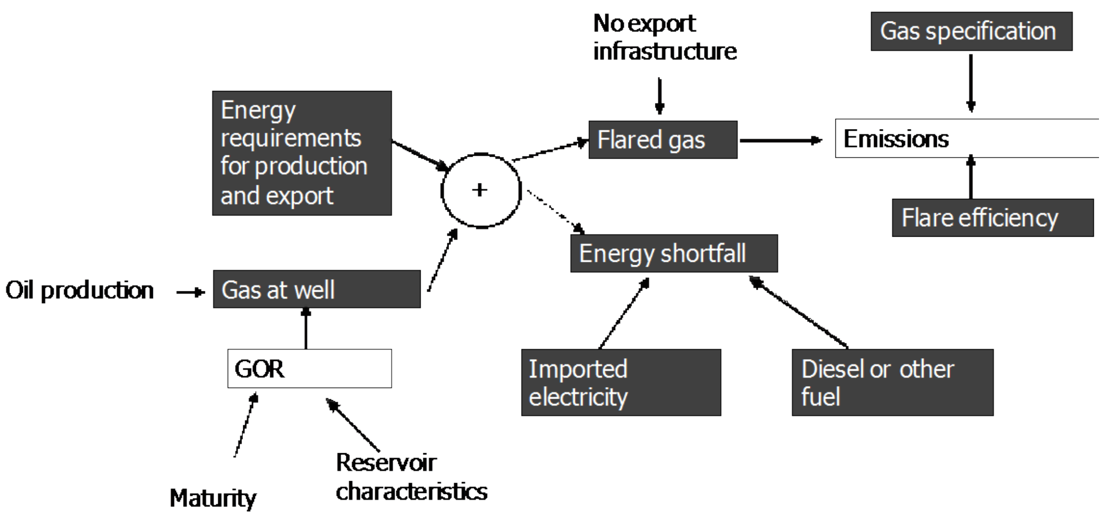


Figure 4.2. Schematic of the Energy-Redefined flaring rate estimation methodology (ICCT/ER 2010)



Adding to this, GHG emissions from crude oil transport were derived using emission factors for given modes of transport from GREET

(Wang, 2010). Similarly, to calculate emissions from crude refining, ER drew on parametric relationships devised by Keesom, Unnasch, and Moretta (2009), calibrating their findings to European refineries. The study assumes a notional refinery where GHG emissions are driven entirely by API gravity. This excludes the effect on refining energy intensity of other crude characteristics including sulfur content–it is not, however, expected to make a large difference to the results. The model excludes emissions associated with construction activities, freight or personal transportation, buildings, well work-overs and testing, exploration and seismic activity, and changes in land use.

Overall, the model arrived at an estimation of the marginal effect of each crude through the value chain, starting from the wellhead and ending with its impact at the refinery. The study is not based on the Joint Research Centre's ILCD handbook.

Table 4.12. Key parameters for different process stages in ICCT/ER report (2010)

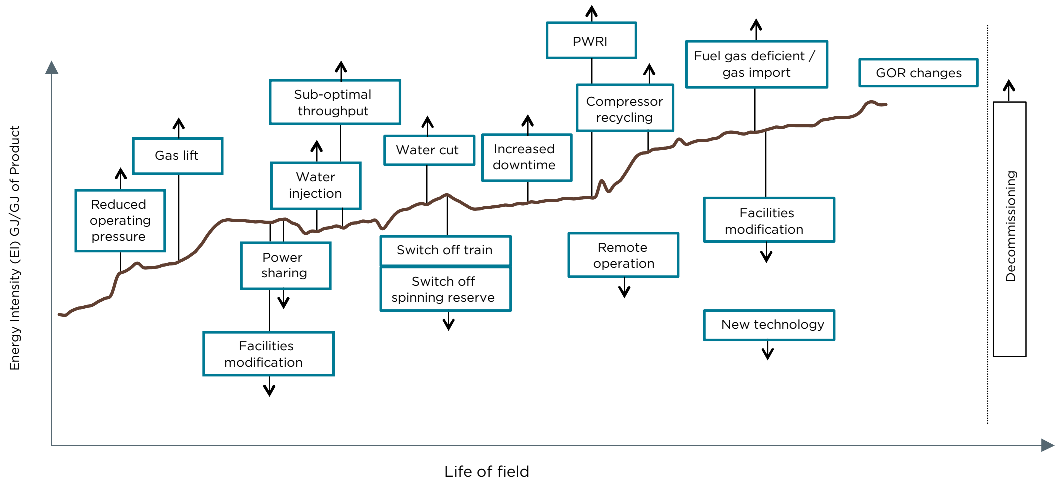
VALUE CHAIN ELEMENT	KEY PARAMETERS	DATA SOURCES	DATA CHALLENGES
Extraction	Age of field Depth Initial reservoir pressure Viscosity GOR API gravity Type of development/feedstock	Oil company reports, government reports, PennWell, Institute of Energy, Energy-Redefined LLC database for production energy	Confidential oil company data Not in one place Some data must be purchased for substantial fees, with restrictions Government ownership/secrecy Reporting of data on varied basis Frequent errors in data quality control
Flaring	Gas-to-oil ratio (GOR) Energy use at field Gas specifications Infrastructure for gas transport Age of field	GGFR country-average emission factors, Energy-Redefined LLC data, NOAA satellite data	No complete set of field-by-field data Inaccuracy in measurements (±20%) Not measured frequently
Fugitive emissions	Type of development Number of components	Oil company and government reports, CAPP/OGP/EPA emission factors, Energy-Redefined LLC field estimates from factors	No current detailed data for fugitive emissions by field Inaccuracy in measurements (±300%) Not measured frequently Confidential data
Transport	Distance API gravity	PennWell, portworld.com, GREET	Emissions not reported by tanker (but can be calculated)
Refining	API gravity Sulfur content Type of refinery	Oil company data, PennWell, publicly available literature	Confidential data Actual refinery setup and operation can vary Some data are estimates based on assumptions

Source*: Adapted from ER, 2010*

4.5.4. Parametric significance and temporal variations

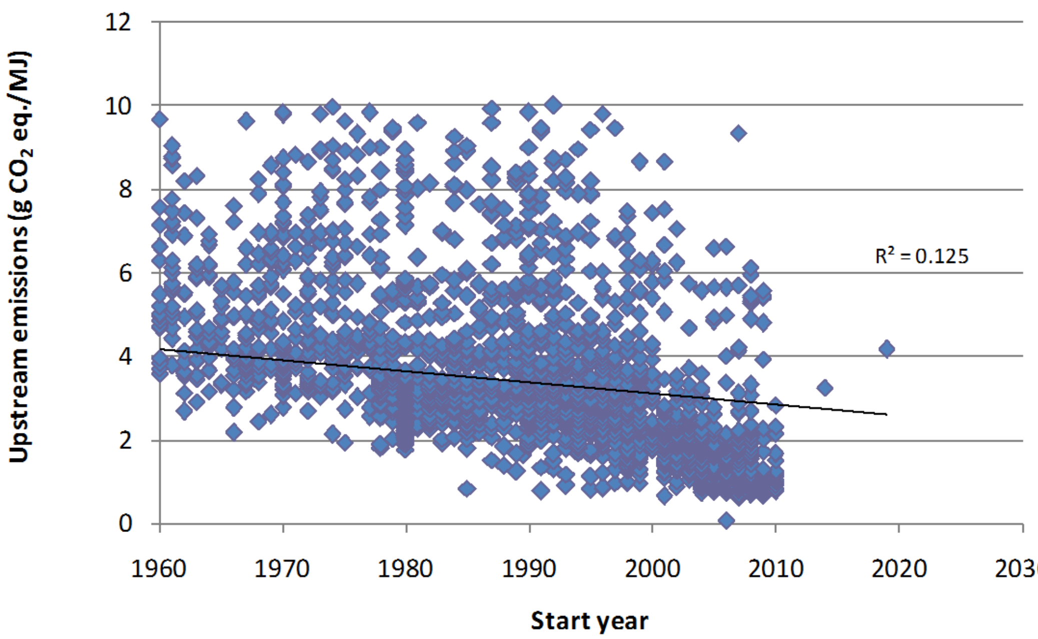
The ER parametric emissions model uses field age as a parameter in itself and also as a determinant variable for several oilfield characteristics—the ER database contains data of variable age and hence field-age-affected parameters such as the gas-to-oil ratio are moderated with reference to age of field. Energy intensity of oil processing will increase with age, and this is captured in the ER parametric model (see Figure 4.3, Figure 4.4). GOR is also expected to increase with age compared to the values measured at well exploration, and GOR is a key determinant of flaring rates (for fields that flare). ER has estimated the amount of flared gas produced at each field, using a field-by-field model that includes oil production, GOR, and the production profiles of fields displaying different characteristics over time (see ICCT/ER, 2010).

Figure 4.3. Example of events in life of oilfield and impact on energy intensity of production (from Vanner, 2005)



For medium to light crudes, ER shows that older fields tend to have higher emissions in its model (Figure 4.4).

Figure 4.4. Upstream emissions are lower for younger fields, considering in this case crudes with API > 30 (ICCT/ER, 2010)*

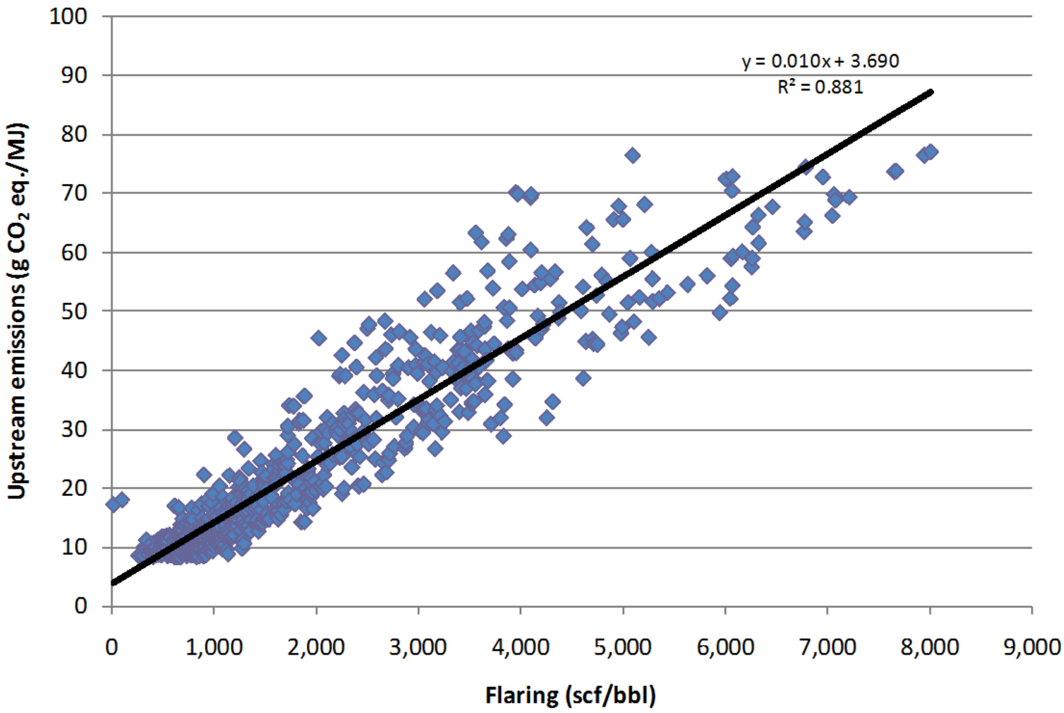


**Emissions in ICCT/ER (2010) are given per megajoule of gasoline produced*

The ER report notes that determination of emissions values is complex and that in general any single parameter is a poor indicator of emissions intensity. One exception to this rule is the flaring rate–

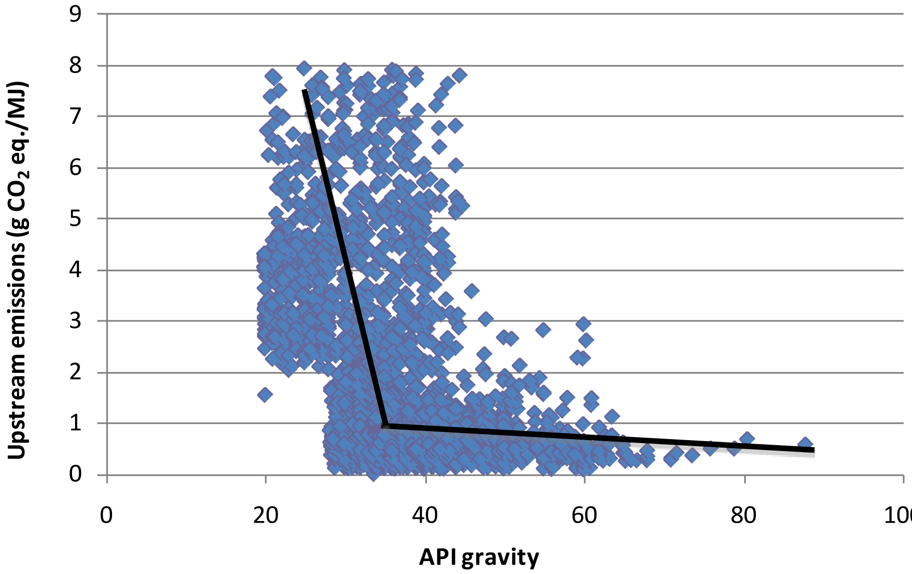
because flaring is such a significant proportion of the emissions for fields that flare, it is a relatively good indicator of overall emissions intensity for these fields (see Figure 4.5). Similarly, the steam injection rate for thermally enhanced fields is likely to be the primary driver of CI for those fields.

Figure 4.5. Upstream emissions for fields that flare are well correlated to flaring volumes (ICCT/ER, 2010)



For the lower-emissions crudes (i.e., crudes for which flaring is zero or lower) API may be a primary driver of emissions intensity, especially for heavier crudes. Figure 4.6 shows that for API below 35, API seems to be somewhat correlated to emissions intensity.

Figure 4.6. API is a more important parameter for lower-intensity crudes (< 8 gCO_2e/MJ upstream emissions) (ICCT/ER, 2010)



The ER report concludes that "many factors drive the level of crude emissions intensity" but suggests five of particular importance:

- Level of flaring (dependent on GOR and availability of nearby infrastructure)
- API gravity
- Reservoir depth
- Start year
- Development type (e.g., oil sands, floating platform, etc.)

ER does not report the emissions implications of enhanced oil recovery (EOR) techniques for non-bituminous oils explicitly, but some EOR projects are modeled. Deepwater fields are also specified in the Energy-Redefined database.[71]

4.5.5. Sensitivity analysis

ER presents a sensitivity analysis for three categories of fields (low, medium, and high emissions), subject to variation in the following parameters:

- Flaring default value: standard assumption used by Canadian regulators (2.3 $kgCO_2e/bbl$) versus the ER data based on gas specification, etc.

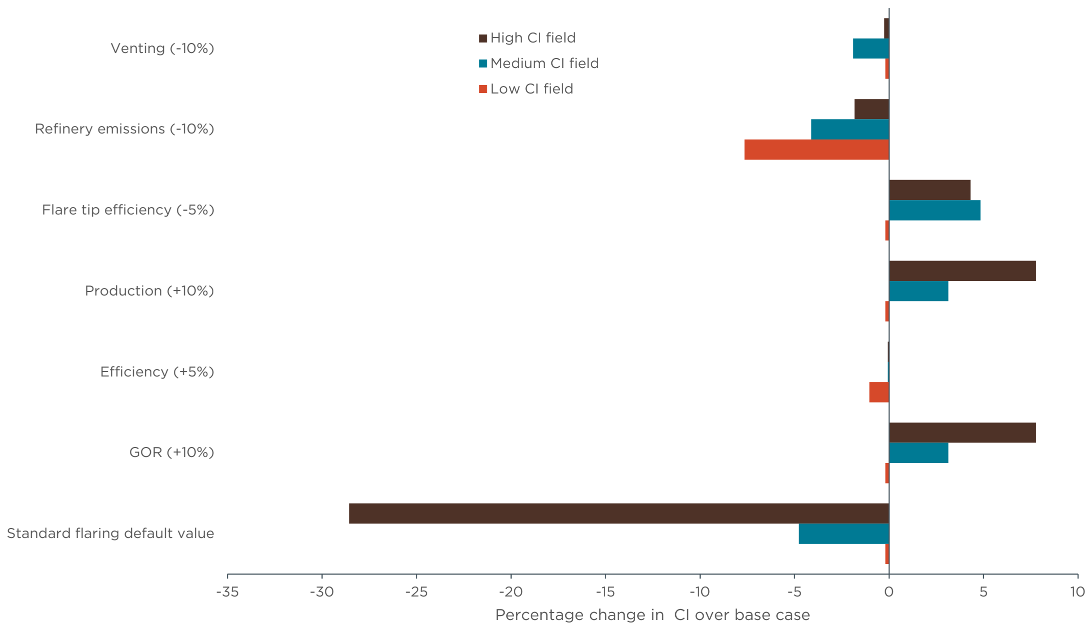
[71] It is the reservoir depth (and hence lifting energy) associated with deepwater fields that is likely to be the key determinant of emissions, rather than the depth of the water itself.

- GOR increased by 10 percent
- Efficiency increased by 5 percent
- Production increased by 10 percent
- Flare tip efficiency reduced by 5 percent, from 98 percent
- Refining allocation: straight run versus processing energy
- Refining emissions reduced by 10 percent
- Venting reduced by 10 percent

As with sensitivity analysis in some other studies (e.g., TIAX), these ranges are somewhat arbitrary, although informed by ER's expectations of uncertainty. Without a systematic uncertainty analysis, one should be cautious in treating the different parameter variations as comparable. In some cases, much larger variation from the base case may be plausible.

The results of the sensitivity analysis are presented in Figure 4.7. While this sensitivity analysis provides some indication of the importance of the principal parameters, ER does not follow this through to specific conclusions regarding the level of accuracy required of field level measurements for inputs to a modeling framework. In general, the tested sensitivities give less than a 5 percent change for the representative medium- and low-intensity cases. For the high-intensity representative case, the sensitivity is higher, in particular to flaring parameters (as flaring is the main driver of the high-intensity case). The flaring quantity sensitivity testing addresses not the accuracy of measurement but the difference between using a standardized allocation based on the Canadian default versus using the field-specific values calculated from satellite data by ER. It is recognized that flare measurements are challenging in the field and are likely to include substantial uncertainty (including flare tip efficiency uncertainty; see also Johnson and Kostiuk [2002]), and so ER also tests for sensitivity to flare tip efficiency. However, this report does not make recommendations about implementation of flaring monitoring systems, nor does it quantify the likely outcome uncertainty implied by uncertainty in flaring measurement.

Figure 4.7. Sensitivity results from ICCT/ER report (2010)



4.5.6. Summary findings

In summary, the findings of the analysis determine a carbon intensity of crudes ranging from 4 to 50 grams of CO_2 equivalent per megajoule of crude oil, with an average of 12 gCO_2e/MJ. Using 2009 as a baseline year, the analysis shows that roughly half (6.4 MMbbl/d) of all imported crude into the EU had an extraction-to-refining GHG emissions range of 4 to 9 gCO_2e /MJ, while the other half ranged from 9 to 19 gCO_2e/MJ. In addition, a small volume of imported crude (0.3 MMbbl/d) occupied the higher part of the emissions ranges with a carbon intensity between 19 to 50 gCO_2e/MJ. For the very high carbon intensity crudes, the determinants in GHG emissions are the presence of high levels of flaring, venting (related to very high GOR), and the extraction of unconventional crudes such as oil sands. Examples of oilfields with details of their signature characteristics and resultant carbon intensities are presented in Table 4.13.

The study estimates that the average emissions intensity for extraction projects and extraction-to-refinery output (tied to imports to the EU) will rise by about 18 percent and 7 percent, respectively, between 2010 and 2020. In addition it is worth noting that prior work relating to specific case studies showed that considering emissions derived from activities excluded by the current analyses, as previously mentioned, might add 5 to 10 percent to the lower numbers presented above–for the very high emissions estimates, this would be less as a percentage.

Emissions intensities for the full set of oilfields are detailed by oilfield cross-referenced to production volume (Figure 4.8), including division into oil sands projects, fields that flare, and fields that do not flare (Figure 4.9). The analysis gives a clear picture of a high-emissions tail to the European crude supply, for which substantial emissions savings should be possible.

Figure 4.8. Extraction-to-refining GHG emissions associated with imported crude oil (ICCT/ER, 2010)

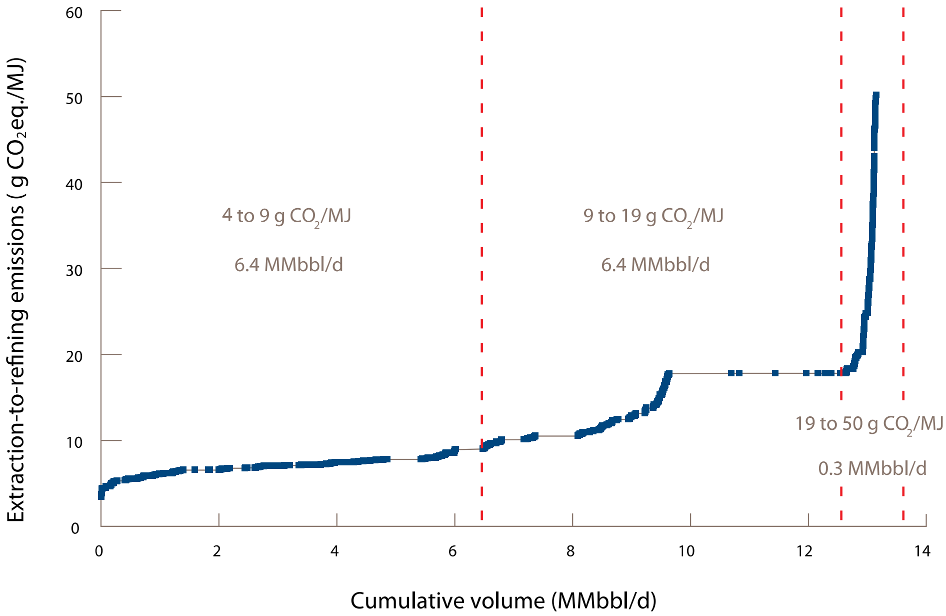
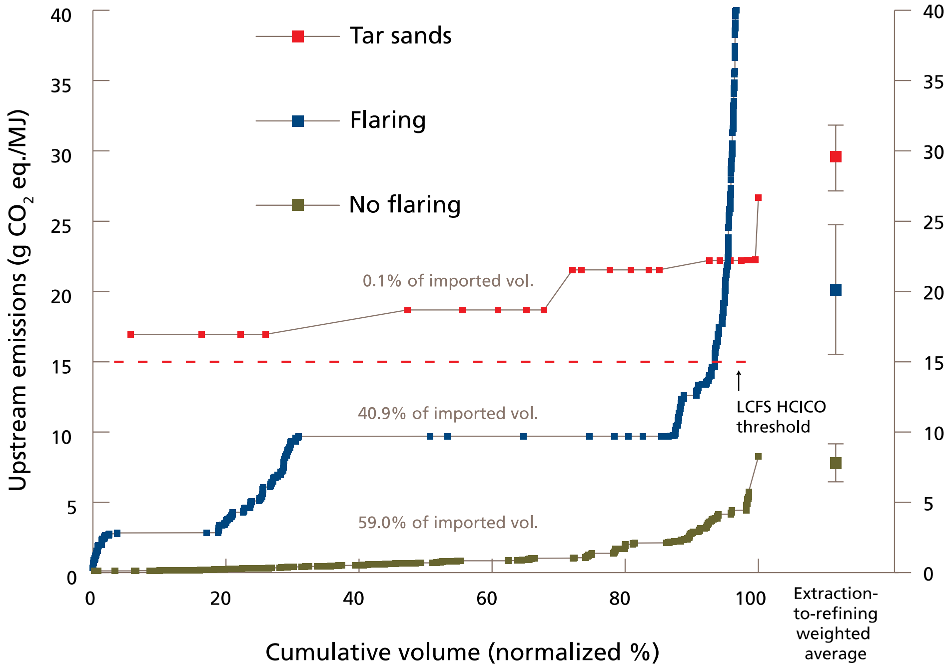


Figure 4.9. Upstream and well-to-refinery gate emissions from ICCT/ER (2010)



Left: Extraction GHG emissions for imported conventional crude oil (with and without flaring) and tar sands Right: Weighted average extraction-to-refining GHG emissions for imported conventional crude oil (with and without flaring) and tar sands, with uncertainty ranges for the average values

As well as the anonymous identification of emissions for all oilfields, ER presents characteristics and modeled emissions for a set of specified representative oilfields (Table 4.13). It observes an upstream emissions range in these representative crudes from 6.2 gCO_2e/MJ for the lightest crude with zero flaring (Mad Dog, in the USA) to 30.5 gCO_2e/MJ for Kupal in Iran, a field with extremely high levels of flaring. Oil sands production in Canada (mining) is represented by Steepbank/Millennium, with 26.6 gCO_2e/MJ.

ER discusses the applicability of various aggregation bases, concluding that a simple aggregation by characteristics (including country) will tend to leave substantial error margins in assessing any individual field. The emissions intensities are not aggregated by country/region in the report, but the report does detail emissions intensities from several representative named oilfields. As noted above, ER does not recommend that a single field should be considered representative of its region, but these individual field values would be appropriate data points for calibration of the Oil Production Greenhouse Gas Emissions Estimator (OPGEE) model. According to ER, it can be confidently asserted that oil sands projects are more carbon intensive than the average for conventional crude.

Table 4.13. Characteristics and upstream GHG intensity for representative fields (ICCT/ER, 2010)

FIELD AND COUNTRY	PRODUCTION VOLUME (KBPD)	API GRAVITY	SULFUR (%)	DEPTH (FT)	START YEAR	BTU/SCF OF ASSOCIATED GAS	INITIAL PRESSURE (PSIG)	DEAD CRUDE VISCOSITY (CP)	GOR (SCF/ BBL)	FUGITIVE EMISSIONS (G CO_2/MJ)	FLARING AND VENTING (G CO_2/MJ)	TYPE	WELLHEAD-TO-REFINERY EMISSIONS (G CO_2/MJ)
Cantarell, Mexico	772	22	3.7	8,528	1981	1,370	941	8	887	2.5	4.2	Integrated platform drilling	15.2
Mad Dog, USA	65	42	0.8	20,190	200 5	1,012	12,141	1.8	322	0.02	0.0	Deepwater integrated	6.2
Steepbank/ Millennium Mine, Canada	400	10	1	50	200 5	1,267	10	5000	—	0.1	—	Tar sands	26.6
Hibernia, Canada	139	35	0.2	12,500	1984	1,257	7,517	0.8	2,200	0.03	0.0	Integrated platform drilling	7.3
Kupal, Iran	55	32	2	10,500	1970	2,232	2,191	7.3	3,800	0.8	21.9	Onshore	30.5
Ghawar, Saudi Arabia	5,319	34	2.2	6,920	1951	1,255	3,957	1.6	570	0.03	0.2	Onshore	7.9
Dacion, Venezuela	42	20	1.3	6,000	1953	1,794	2,600	11	750	3.9	8.9	Onshore	22.0
Bu Attifel, Libya	340	41	0.04	14,000	1972	1,622	7,209	5.2	2,400	0.04	0.0	Onshore	6.9
Samotlor, Russia	600	34	1.1	5,800	1970	1,456	2,255	3.4	240	0.1	3.1	Onshore	11.8
Duri, Indonesia	233	22	0.2	770	1958	1,362	267	144.1	1,200	2.7	2.0	Onshore	14.3
Forties, UK	63	37	0.3	7,000	1975	2,851	3,128	2.2	400	0.1	1.4	Integrated platform drilling	8.0
Gullfaks, Norway	79	41	0.4	5,709	1987	1,557	2,551	2	700	0.04	0.2	Minimum facility	6.2

The study highlights that the greatest opportunities for emissions reductions are likely to lie in flaring and venting reduction, as well as through the reduction of emissions related to unconventional oil extraction. Flaring and venting reduction entails improvements to existing infrastructure, such as optimizing flare tip efficiency, moving to reinject associated gas, development of gas export infrastructure, or the capture and underground storage of CO_2. Unconventional oil extraction, on the other hand, is inherently characterized by energy-intensive technologies. Hence, while upgrading infrastructure might help reduce emissions somewhat, any efficiency-driven improvements in emissions performance, given current technologies, are unlikely to make these crudes competitive in carbon intensity terms with conventional crudes. It is worth noting once more that there are large uncertainties associated with flaring and fugitive emissions values. This as a result of the general lack of monitoring and measurement by producers and the lack of available data quantifying those that are measured–these issues have been explored in more detail by Matthew Johnson at Carleton University in Ottawa, Canada.[72]

4.6. TIAX

4.6.1. Objective

Motivated by the use of well-to-wheel (WTW) lifecycle measures of GHG emissions for transportation fuels in the recently adopted California LCFS as well as in the most recent discussions regarding the Renewable Fuels Standard 2 (RFS2) by the EPA, the TIAX study sought to provide estimates to add to the available literature. In addition, the authors recognized an opportunity to improve on the default values derived from the GREET model, currently used by both regulatory frameworks, for gasoline and diesel derived from conventional crude oil. That is, the current default values in the GREET model fail to account for the steady decline (decreases in API gravity and increases in sulfur content) in the quality of crude oil in the United States over the past 30 years. As such, the objective of the study was to estimate and compare well-to-tank (WTT) GHG emissions of Canadian crudes and other major crudes used in the United States. To do so, the study selected representative crudes to analyze before undertaking crude recovery and refining analysis to quantify the amount of energy consumed in each process and the division of this energy among process fuel types to determine their particular GHG emissions. Significantly, in an effort to maintain transparency, all the data used to develop emissions estimates were publicly available, while the calculations through which these estimates were obtained were clearly documented. This included a modified GREET model with new input values. Finally, it is worth remarking that the TIAX study is really a set

[72] For more information, including recent publications and journal articles, please refer to Johnson's webpage: http://faculty.mae.carleton.ca/Matthew_Johnson/publications.html.

of individual analyses rather than a single modeling effort that could be applied generally. This makes it different from several of the studies discussed including the ER, Jacobs, and OPGEE models.

4.6.2. Data quality and quantity

The data used by the TIAX study come from a variety of public, industry and government sources. The study assesses nine market crudes (as opposed to specific oilfields). Because the study is explicitly focused on important U.S. sources, the coverage of crudes entering the EU is relatively poor–even if one treats each studied crude as representative of all fields in its country of origin, TIAX covers less than 16 percent of EU imports (Table 4.14). In reality, the studied crudes are unlikely to be good emissions proxies for all oilfields in that region. However, unlike a more comprehensive study such as Energy-Redefined (2010), the data sources for each of the nine study crudes are well specified, public, and available; thus, the data quality is more readily ensured than in less transparent studies. Because it considers relatively well-documented crudes, the study does not rely on extensive cross-population of data.

Table 4.14. Countries for which crude GHG intensity is considered by TIAX, and percentage of EU imports coming from those countries

CRUDE SOURCE	% OF EU IMPORTS FROM THAT COUNTRY
Saudi Arabia	6.3
Iraq	1.9
Canada	0.1
Nigeria	5.4
Mexico	1.4
Venezuela	0.7
American crudes	Negligible imports of crude but may be represented in refined product (diesel) imports, particularly Gulf Coast crude

For each of these crudes, the data documenting recovery energy along with total production estimates as well as production gas and injection figures were obtained from national or state-level government organizations. For example, for the analysis of Alaskan crude, total production figures were obtained from EIA estimates, while production gas and injection ratios were derived from the Alaska Oil and Gas Conservation Commission. Similarly, data for Kern County Heavy Oil relied on the California Division of Oil, Gas, and Geothermal Resources' (DOGGR) annual report (2006). In addition, a 2008 NETL report regarding baseline data and analysis of lifecycle GHG emissions of petroleum-based fuels was used to establish the proportion of on-site electricity production to the grid. For foreign-sourced crude, production figures and crude characteristics were obtained from the EPA's Database of Petroleum Imports.

TIAX notes that flaring and venting data are only sparsely available, with venting data particularly sparse. Data on flaring were not available to TIAX at the reservoir level–the values are therefore based on reporting at regional levels, with the EIA and World Bank being the primary data sources (see Table 4.15). Because the data characterize only regional totals rather than field specifics, a potentially large error margin is introduced in predicting reservoir/crude/field-specific values (the same is true of the Jacobs report below)—the gap in flaring emissions between the highest or lowest flaring fields and the national average could be tens of gCO_2e/MJ. For assessment of the carbon intensity of Canadian oil sands projects, TIAX relies heavily on pre-project environmental impact assessments rather than operational data, which introduces a degree of uncertainty and may fail to reflect operational realities.

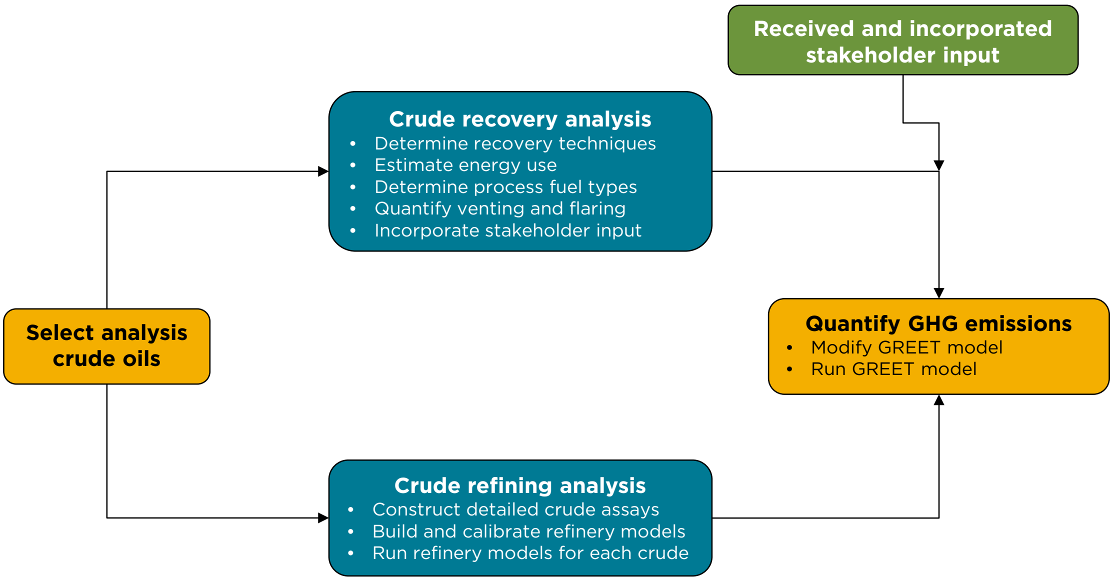
Table 4.15. Sources of venting and flaring emissions (TIAX Table 3-8)

ANAYLSIS CRUDE	BASIS FOR ANALYSIS VALUES
California Heavy	The venting and flaring values are based on actual data from the California Department of Conservation, the only data source found for California emissions.
Alaska - NS	The combined venting and flaring value is based on data from the State of Alaska Oil and Gas Conservation Commission. The total amount was split according to the U.S. average values for amount flared over total vented and flared (85%).
Gulf of Mexico	The combined venting and flaring values from the USEPA and EIA were averaged. The total amount was split according to the Gulf of Mexico values for amount flared over total vented and flared (26%).
Canada Heavy	The ERCB values for Alberta venting and flaring were used as they were the only Alberta specific values found
Mexico	For flaring, an average of the EIA and World Bank data is used. These values are consistent. For venting, an average of the NETL and EIA values is used.
Venezuela	For flaring, an average of the EIA and World Bank data is used. These values are consistent. For venting, an average of the NETL and EIA values is used.
Iraq	For flaring, an average of the EIA and World Bank data is used. These values are consistent. For venting, an average of the NETL and EIA values is used.
Saudi Arabia	For flaring, an average of the EIA and World Bank data is used. These values are consistent. For venting, an average of the NETL and EIA values is used.
Nigeria	For flaring, an average of the EIA, World Bank and HART data is used. These values are consistent. For venting, an average of the NETL and EIA values is used.

4.6.3. Methodological considerations

As previously mentioned, lifecycle emissions calculations for gasoline and diesel are highly sensitive to differences in crudes and recovery methods. As such, the TIAX study seeks to correct for deficiencies in current models through an approach that heavily favors the use of publicly available data and peer-reviewed methodologies. It does not use the ILCD handbook. The study is divided into three sections: (1) Crude Oil Recovery Data; (2) Refinery Modeling; and (3) GREET Integration. In order to launch these processes, a number of representative conventional crudes—nine in total—were identified by the steering committee for the recovery and refining analysis.[73]

Figure 4.10. TIAX technical approach (TIAX Figure 2-1)



The crude recovery analysis, for conventional crudes, consisted of the calculation of recovery energy consumed per barrel of crude, for each crude type and its dominant recovery technique. For unconventional crudes—Canadian oil sands—four bitumen recovery pathways were selected by the study's Steering Committee to characterize the range of recovery techniques used to deliver oil sands to refineries.[74] In parallel, six projects from the Athabasca and Cold Lake regions of Alberta were selected as being representative in order to determine energy balance data. This was done based on selection criteria that included making available public/releasable data, being currently engaged in production activities, and having a high production capacity relative to similar projects. Finally, for both conventional and unconventional crudes, flaring and venting quantities were derived based on published data.

[73] The following conventional crudes were included in the TIAX study: Alaska North Slope, Kern County Heavy Oil (Midway-Sunset), West Texas Intermediate (Permian Basin), Bow River Heavy Oil (Canada), Medium (Saudi Arabia), Basrah Medium (Iraq), Escravos (Nigeria), Maya Heavy (Mexico), Bachaquero 17 (Venezuela).
[74] The four bitumen recovery methods were: surface mining with upgrading, in situ steam-assisted gravity drainage (SAGD) with upgrading, in situ SAGD without upgrading, and in situ cycle steam stimulation (CSS) without upgrading.

Table 4.16. Conventional oil pathways by crude (TIAX Table 6-1)

LABEL	CRUDE NAME	RECOVERY METHODS
Alaska	Alaska North Slope	Water Alternating Gas (WAG) and Natural Drive
California Heavy	Kern County Heavy Oil	Steam Injection, Sucker Rod Pumps
Texas	West Texas Intermediate	Water Flooding, Natural Drive
Canada Heavy	Bow River Heavy Oil	Water Flooding, Progressive Cavity Pumps
Iraq	Basrah Medium	Water Flooding, Natural Drive
Mexico	Maya (Cantarell)	Nitrogen Flooding, Gas Lift
Nigeria	Escravos	Water Flooding, Gas Lift
Saudi	Saudi Medium	Water Flooding, Natural Drive
Venezuela	Bachaquero (Maracaibo)	Cyclic Steam Stimulation, Sucker Rod Pumps

Table 4.17. Oil sands pathways (TIAX Table 6-2)

LABEL	DESCRIPTION
SCO Mining, Sell Coke	Bitumen recovery through mining, onsite upgrading. Assume that the coke is ultimately utilized as a fuel (some of the recovery energy is allocated to the coke).
SCO Mining, Bury Coke	Bitumen recovery through mining, onsite upgrading. Assume that the coke is never utilized as a fuel (none of the recovery energy is allocated to the coke).
SCO SAGD, Use Coke	Bitumen recovery through SAGD, onsite upgrading. All coke is gasified with resulting syngas utilized as a process fuel.
SCO SAGD, Use NG	Bitumen recovery through SAGD, onsite upgrading. Assume that the carbon rich syngas is replaced with natural gas.
Bitumen, SAGD 1	Bitumen recovery through SAGD, SOR of 2.5, no electricity exports
Bitumen, SAGD 2	Bitumen recovery through SAGD, SOR of 2.5, with electricity exports
Bitumen, CSS 1	Bitumen recovery through CSS, SOR of 3.4, no electricity exports
Bitumen, CSS 2	Bitumen recovery through CSS, SOR of 4.8, with electricity exports

Refinery modeling was conducted with the objective of determining the amount of energy required to refine each crude oil into gasoline and diesel by process fuel types. In order to achieve this, MathPro Inc. used the ARMS refinery linear programming model to determine the impact of each crude oil on refinery energy consumption by fuel type. To do so, a regional approach, whereby the differences in refinery crude mixes, product slates, and refinery configuration are established regionally, was preferred. It used three regional models: PADD 2 (Midwest), PADD 3 (Gulf Coast), and California, as well as a national model, which is a composite of the three. Each model is a regional aggregate rather than attempting to represent a single refinery, and TIAX modeled 26 crude-refinery combinations in total. The refinery models were used to determine the total refinery energy consumption attributable to each crude type, and, by marginally reducing the output of each end product (e.g., gasoline, diesel) in turn, the refinery model was also used to determine energy allocations for these end products.

Once the energy balances were established for each pathway considered, these were converted to GREET terms in order to calculate the energy consumption and emissions associated with production of different transportation fuels. This was done for inputs to crude/bitumen recovery and refining. Emissions from by-product petroleum coke were attributed to the upgrading and refining process, as energy allocation to by-products was done using the substitution method.[75] The emissions attributable to crude and finished fuel transportation to the refinery and refueling stations, respectively, were estimated using GREET default values for energy intensity, transportation fuel types, and transport emissions factors. In addition, electricity as a process fuel was included using slightly modified GREET values to allow for different electricity mixes based upon field location and utilization of grid power with supplemental figures for certain countries obtained from IEA data.

4.6.4. Parametric significance, sensitivity analysis

TIAX[76] undertook sensitivity analysis for five upstream variables, plus refining efficiency, for all eight non-bituminous pathways plus the range of oil sands pathways it considered. The five upstream parameters were:

- Crude recovery efficiency, ± 2 percent
- Associated gas venting, minimum and maximum suggested values from literature review
- Associated gas flaring, minimum and maximum suggested values from literature review
- Gas oil ratio, ± 50 percent
- Fugitive volatile organic compounds (VOCs) (only for SCO mining).

For refinery efficiency, TIAX allowed ± 2 percent compared to the numbers defined in GREET and ± 50 percent on energy use for conventional crude production. The basis for using these ranges is not entirely clear.

Because the choices of upper and lower values for each test are at least somewhat arbitrary, the method for choosing them varies between parameters, and the report does not characterize any sense of the likely

[75] Whereby all the energy is allocated to the main product, with a subsequent credit given that is equal to the emissions associated with the processing of the product for which the by-product is substituting.
[76] Results of the sensitivity analysis are captured on pages 81–84.

distribution of these values, the comparability of the sensitivity by parameter is somewhat reduced. The comparison of sensitivity to variation in parameters would be more meaningful if the variations were more clearly comparable in their own right: the values in the TIAX analysis are relatively insensitive to gas flaring rate compared to refining, but this may tell us more about the ranges TIAX has chosen to consider than about the relative importance of refining and flaring to emissions intensity.

Sensitivity to different parameters varies by crude, in the way that one might expect. That is to say that oil with low upstream emissions is more sensitive to refining assumptions, while oil for which flaring and/or venting dominate emissions is more sensitive to flaring/venting assumptions, and oil sands are sensitive to extraction efficiency. Table 4.18 presents a matrix of the ranking of sensitivities for each pathway.

Table 4.18. Parameter sensitivity analysis by TIAX. Highlighting added, with more important parameters marked orange, less important green.

CRUDE	PARAMETERS (RANKED 1 FOR MOST SENSITIVE TO 5 FOR LEAST, N/A FOR NOT SENSITIVE AT ALL)					
	Crude recovery efficiency	Gas venting	Gas flaring	Gas-to-oil ratio[77]	Fugitive VOCs (SCO mining only)	Refining efficiency
Alaska	2	4	5	3	n/a	1
California Heavy	1	4	5	2	n/a	3
Gulf of Mexico	3	2	5	4	n/a	1
Alberta conventional	3	2	4	5	n/a	1
Saudi Arabia	3	4	2	5	n/a	1
Mexico	3	2	4	5	n/a	1
Iraq	4	2	3	5	n/a	1
Venezuela	1	4	3	5	n/a	2
Nigeria	4	1	3	5	n/a	2
SCO mining	2	5	4	n/a	3	1
SCO in situ	1	3	4	n/a	n/a	2
Synbit	2	3	4	n/a	n/a	1
Dilbit	2	3	4	n/a	n/a	1
Bitumen	2	3	4	n/a	n/a	1

We see in the sensitivity matrix that refining efficiency is consistently one of the most important determinants, while sensitivity to flaring assumptions and the gas-to-oil ratio seems to be less critical. As noted before, however, these results must be understood in terms of the parameter changes that TIAX used for its sensitivity analysis. For instance, the sensitivity of Nigerian results to venting is attributable to the large difference between minimum and maximum tested venting rates, more than ± 50 percent. Insensitivity to GOR is partly because the flaring rates are based on data rather than being parameterized by GOR, unlike the Energy-Redefined modeling, for instance.

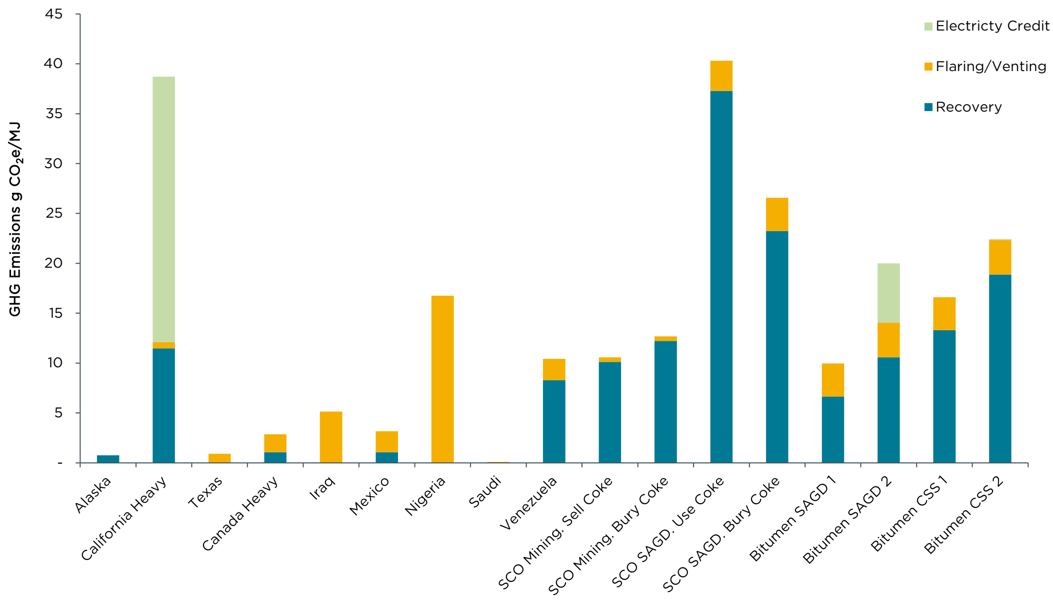
The TIAX study also pays particular attention to variation in assumptions about oil sands extraction processes. For oil sands

[77] Note that in the TIAX study, GOR is **not** an explanatory parameter for flaring, i.e., adjusting the GOR does not affect the amount of gas flared. This is because TIAX took flaring values from data about actual total flaring rates, not using a parametric equation. However, GOR is implicitly included in the flaring/venting estimates since in real life GOR is an explanatory variable for the flaring rate (e.g., the ICCT/ER [2010] report).

production, it compares upstream emissions for synthetic crude versus bitumen production (note that bitumen refining is likely to be more energy intensive than syncrude refining, so in that sense one might say that some of the refining emissions for bitumen that is upgraded to syncrude are shifted upstream in the TIAX report), different emissions allocations to petroleum coke (allocation to coke by energy content, no allocation to coke, and an assumption that coke would be used for extraction process energy), and different extraction technologies (mining, two versions of SAGD, two versions of CSS). It is clear that the disposition of petroleum coke (a higher carbon energy source than coal) is of significant importance to the analysis–a pathway assuming gasification of coke for process energy when SAGD bitumen is upgraded to syncrude has upstream emissions that are double those of most other pathways.

The variation in flaring emissions for each representative crude in Figure 4.11 is also indicative of the parametric importance of flaring assumptions.

Figure 4.11. Upstream emissions from TIAX split between flaring/venting, recovery and electricity co-production credits* (TIAX, based on Figure 6-1)

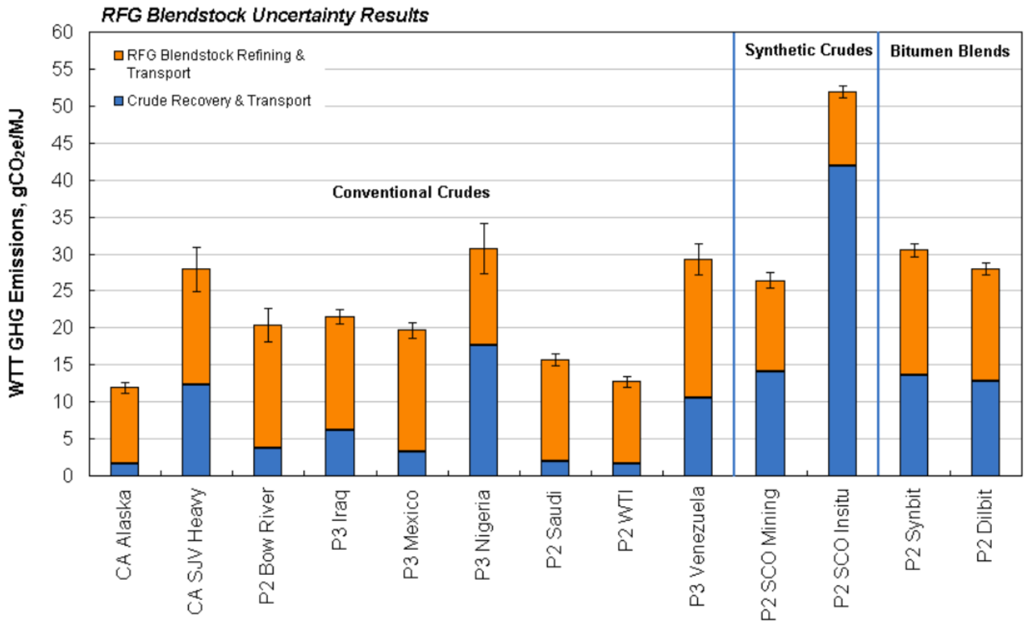


**Results in gCO2e/MJ of crude*

Because the TIAX study uses relatively up-to-date reported data, there is no consideration of the importance of temporal effects.

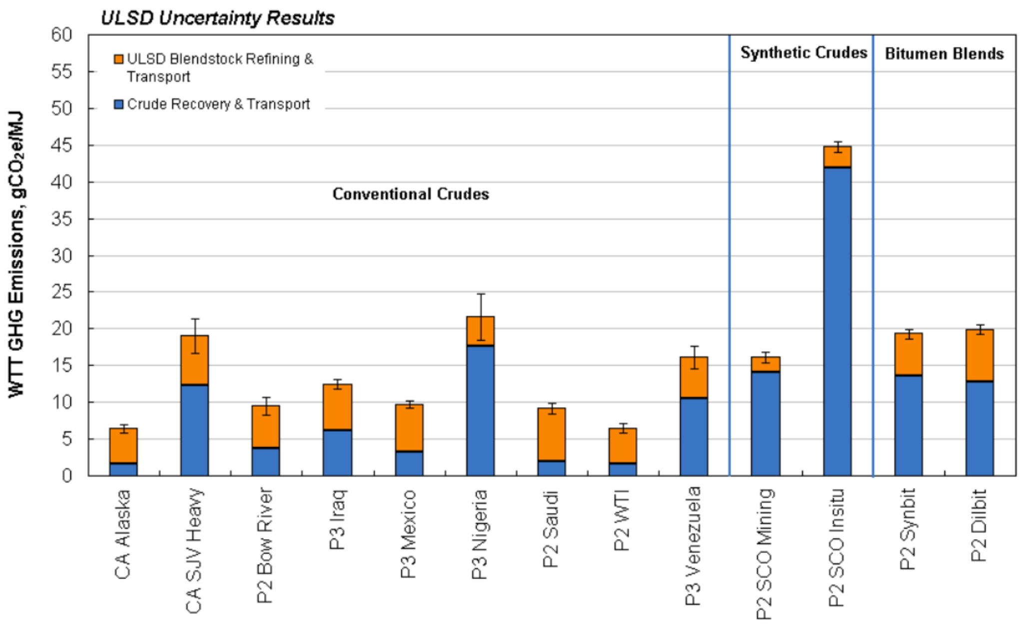
TIAX also performs uncertainty analysis using stochastic simulation with GREET. It notes that stochastic simulation does not in general change the crude rankings and that the error bars are adequately narrow to suggest that the results and rankings may be robust (Figure 4.12, Figure 4.13).

Figure 4.12. RFG uncertainty analysis (TIAX Figure 7-3)*



**Results in gCO_2e/MJ of RFG blendstock*

Figure 4.13. ULSD uncertainty analysis (TIAX Figure 7-4)



**Results in gCO_2e/MJ of ULSD*

4.6.5. Summary findings

There is substantial variation in the GHG emissions associated with crude/bitumen recovery, flaring, and venting, in particular for conventional crudes. The GREET default value for conventional crude extraction (5 gCO_2e/MJ) falls within the range presented by the analysis. The GREET default value for synthetic crude oil mining is 30 percent higher than that estimated by the TIAX model, mainly due to the omission of certain process fuel consumption activities by TIAX. On the other hand, the GREET default value for SCO-SAGD is less than half of the estimated result for the pathway in which coke is used for energy. The TIAX recovery and flaring emissions numbers are shown in Table 4.19.

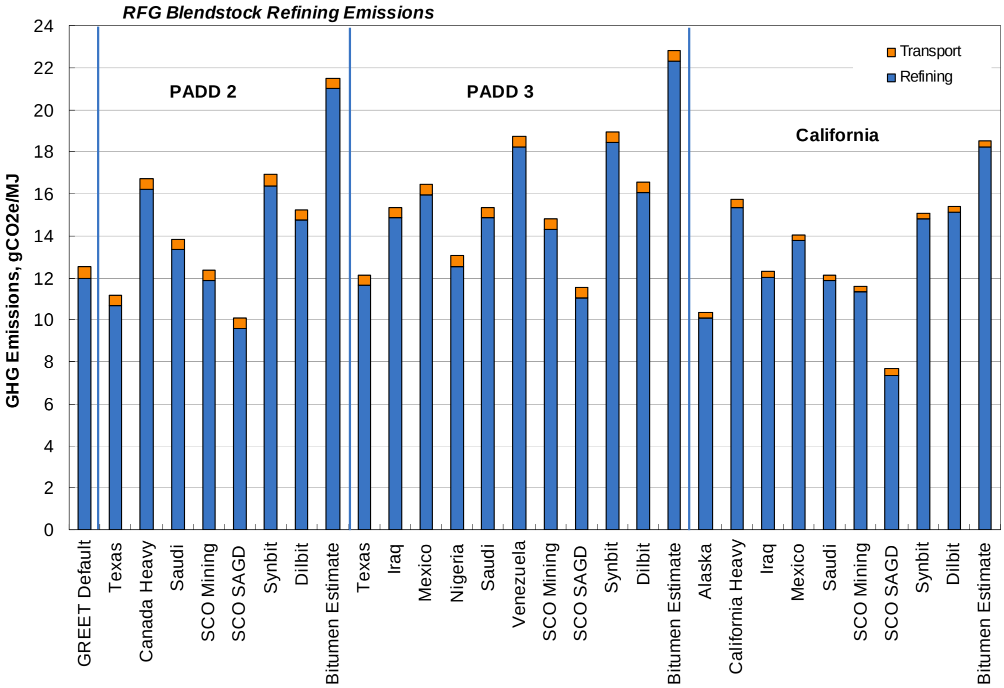
Table 4.19.Recovery, flaring, and venting emissions from TIAX

CRUDE	RECOVERY EMISSIONS (gCO_2e/MJ*)	VENTING/FLARING EMISSIONS (gCO_2e/MJ*)	RECOVERY TOTAL (gCO_2e /MJ*)
Alaska North Slope	0.7	0.1	0.9
California Heavy	11.6*	0.6	12.2
West Texas Intermediate	0.2	0.8	1
Canada Heavy	1.1	1.8	2.8
Iraq	0.2	4.9	5.1
Mexico	1.1	2	3.1
Nigeria	0.1	16.7	16.8
Saudi Arabia	0.1	0.2	0.3
Venezuela	8.5	1.8	10.3
SCO Mining, Sell coke	10.1	0.5	10.6
SCO Mining, Bury coke	12.4	0.5	12.8
SCO SAGD, Use all coke	37.3	3.3	40.6
SCO SAGD, Use no coke	23.4	3.3	26.7
Bitumen SAGD, no electricity export	6.7	3.3	10
Bitumen SAGD with electricity export	10.7*	3.3	14
Bitumen CSS, no electricity export	13.3	3.3	16.6
Bitumen CSS with electricity export	19.1*	3.3	22.4

**Results shown in gCO_2e/MJ of crude*

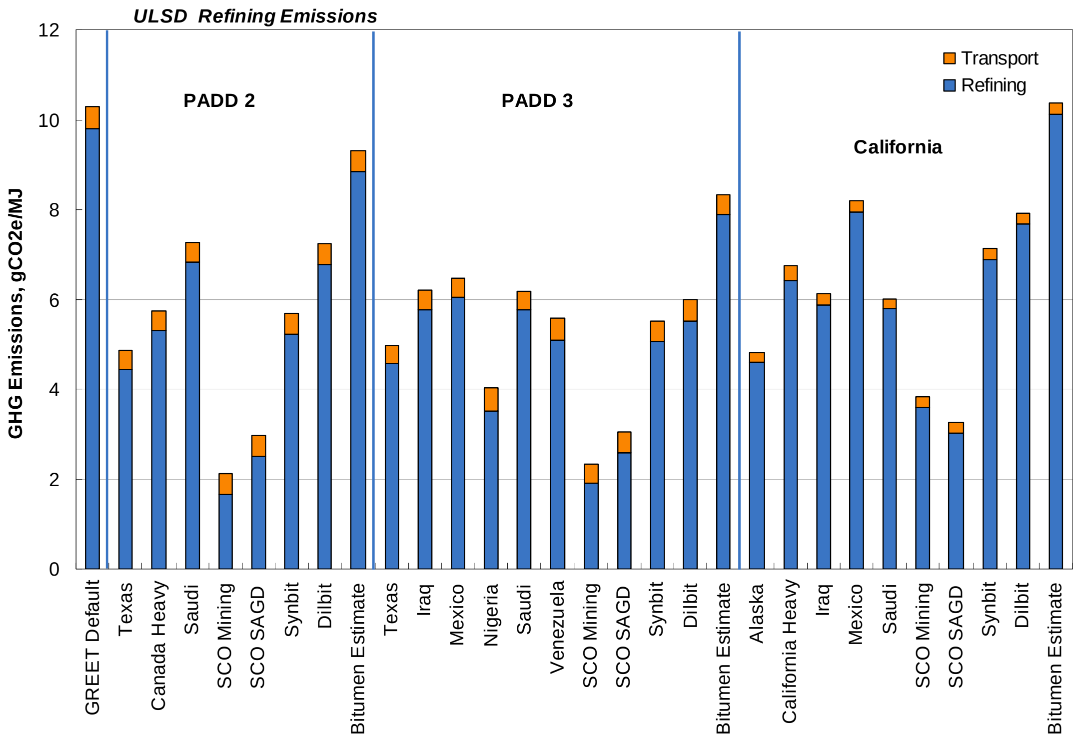
Refining emissions for given crude types vary by region, reflecting the impact of the crude slate, refinery configuration, local grid mix, and other characteristics. Overall, refining SCO has the lowest emissions of any crude oil over the entire sample (reflecting that the upgrading process means SCO is essentially somewhat pre-refined), while transport emissions are relatively small. The emissions associated with refining synbit (a blend of bitumen and SCO) and dilbit (a blend of bitumen and condensate) into reformulated gasoline (RFG) blendstock are comparable to conventional heavy crudes (see Figure 4.14), while emissions for refining synbit and dilbit into ultra-low-sulfur diesel (ULSD) are comparable to medium to heavy conventional crudes (see Figure 4.15). Note that this ignores emissions from initial syncrude upgrading. If one considers only the bitumen, ignoring the diluent, the refining emissions are somewhat higher than for any other crude.

Figure 4.14. RFG blendstock refining and transport emissions (TIAX Figure 6-3)*



**Results in gCO_2e/MJ of RFG blendstock*

Figure 4.15. ULSD blendstock refining and transport emissions (TIAX Figure 6-4)*



**Results in gCO_2e/MJ of ULSD*

The WTT emissions results show that the GREET default values (12.5 g/MJ) of RFG blendstock emissions for conventional crudes as well as oil sands mining and in situ are comparable to those obtained through the current analysis; that is, they fall within the same range (10 to 19 g/MJ). As for the GREET default values of ULSD emissions (10.3 g/MJ), the results are consistent with the higher-range values for conventional crudes but are much higher for oil sands mining and in situ (2 to 8 g/MJ). Overall, heavy conventional crudes tend to have comparable emissions to those of oil sands pathways, while SCO-Mining has the lowest emissions within this group.

The WTW emissions calculations show a wide range of results, from around 85 g/MJ to more than 125 g/MJ for RFG blendstock and from above 80 g/MJ to more than 120 g/MJ for ULSD (see Figure 4.16, Figure 4.17). As for the GREET default values, those for RFG blendstock and ULSD derived from conventional crude oil are within the calculated results, while those for oil sands mining are considerably higher. Similarly, GREET default values for RFG blendstock from in situ recovery of oil sands are consistent with those for synbit and dilbit, while those for ULSD are on the higher end of the spectrum.

Figure 4.16. Variation in WTT emissions for RFG (TIAX Figure 6-14)

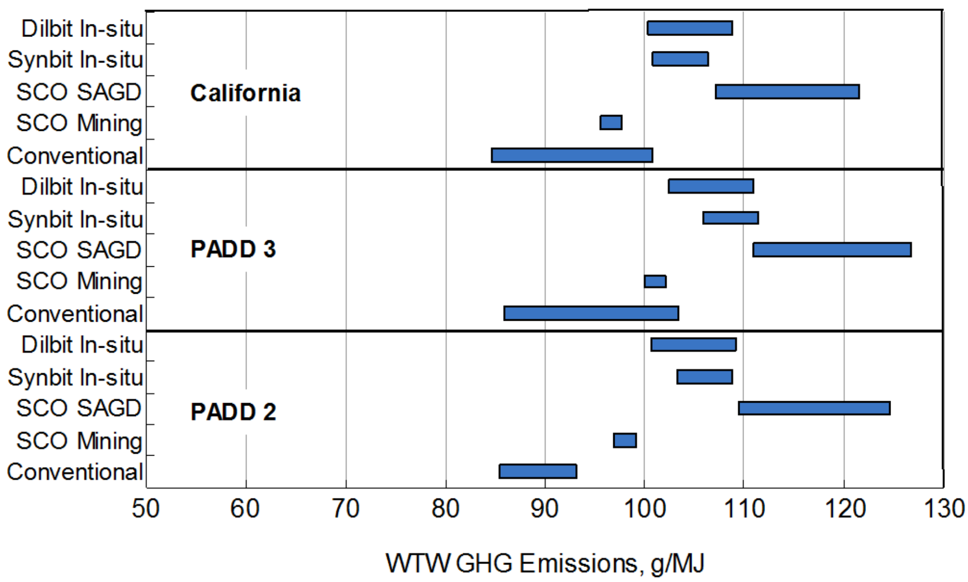
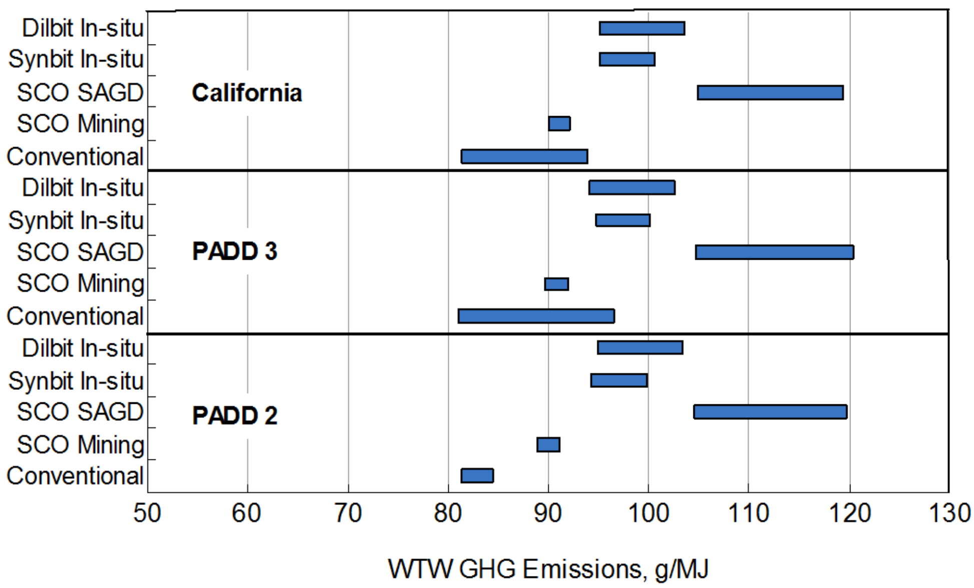


Figure 4.17. Variation in WTT emissions for ULSD (TIAX Figure 6-15)



In general, the analysis shows that a reasonable estimation of GHG emissions for distinct pathways is accessible with publicly available data and peer-reviewed methodologies. However, by considering only a small set of representative fields, the results ignore the variability in GHG emissions that would be demonstrated by using individual oilfields with a larger sample size.

4.7. Jacobs Consultancy (2009, 2012)

4.7.1. Objectives

The 2009 Jacobs study is motivated by the same policy environment and commissioned by the same sponsors (Alberta Energy Research Institute) as the TIAX study. In light of the California LCFS and the prospect of similar regulatory frameworks in other U.S. states and Canada, the Jacobs study sets out to calculate the lifecycle GHG emissions of petroleum fuels. In particular, emphasis is placed upon explaining the methodology to analyze different petroleum types as well as extraction technologies, reservoir locations, transport modes, and processing options. The study aims to fill the gap left by similar exercises by accounting for variations in GHG emissions from crude production in different regions that supply crude oil to the U.S. market as well as for differences in GHG emissions resulting from the conversion of different crudes and bitumen to transportation fuels. Overall, the primary objective of the study is to analyze the treatment of oil sands with respect to conventional crudes being processed in the United States by preparing a reasoned comparison of WTW GHG emissions for oil sands bitumen versus specific crudes–there is a keen interest in whether under some circumstances emissions from oil sands might fall within the same range as emissions from conventional oil.

Methodologically, the study specifies that it closely follows requirements and standards associated with ISO 14000 lifecycle assessment frameworks. The Jacobs study was not undertaken with reference to the JRC ILCD handbook. Overall, the model uses the GREET framework. However, as Jacobs notes, GREET provides limited resolution on crude and bitumen production emissions, and therefore Jacobs supplements it with its own model to calculate these based on a more detailed assessment of crude characteristics. This includes dealing with GHG emissions from co-products, flaring, and unconventional production methods such as nitrogen and steam injection. As an extension of these processes water-to-oil (WOR) ratios are also included in an effort to provide a more nuanced view of the differences between process energy requirements for extracting different crudes. The Jacobs study claims it aims to “ensure transparency of results, methodology and underlying data by using public and defendable data sources.” This statement is slightly ambiguous, but given the use among other things of proprietary models that are not generally available, we take it to mean that data should be public **or** defendable, rather than public **and** defendable.

4.7.2. Data quality and quantity

Jacobs models a set of ‘well-known’ market crudes–Bachaquero, Maya, ArabMed, Mars, Bonny Light, Kirkuk Blend, Canadian SAGD bitumen, California thermally enhanced oil recovery (TEOR), and Canadian mined bitumen. These are essentially the same crudes chosen in the

TIAX study (but excluding U.S. Gulf Coast and Alaskan), and hence, just as in the case of the TIAX study, the coverage of European crudes is poor–as noted above, even if we treated each crude as representative of its entire country (an optimistic assumption at best), we would have coverage of less than 16 percent of European crude imports. As with TIAX, however, the data quality is relatively good (an advantage of using major market crudes). The key reservoir parameters are generally referenced clearly, largely to trade publications. Jacobs note that data on Kirkuk are 'out of date and incomplete,' but it is unclear whether cross-population was necessary for the modeling in the report or on what basis that would have been carried out. Other than Kirkuk, it does not appear that Jacobs found it necessary to cross-populate data.

Crude production data were obtained from the EIA, as well as import data for crudes produced outside of the United States. The analysis uses the GREET model, supplemented with additional data, to define emissions from the transportation of fuels and refined products as well as vehicle fuel consumption. Estimates for electric power requirements and co-generation for different production technologies including TEOR, SAGD and mining were derived from the Electric Power Research Institute, DOGGR, and Jacobs Engineering (of which the consultancy is a subsidiary). In regard to gas flaring, estimates were obtained from a study sponsored by the World Bank based on analysis of satellite images by the NOAA. Certain well characteristics including reservoir depth ranges and pressure were obtained through proprietary datasets, notably the Oil and Gas Journal (PennWell Publishing) and the APS Review. It is unclear whether these characteristics were obtained through data purchases or through citations in publicly available literature. In any case, the transparency of these data is limited given that the stated sources are not publicly available for corroboration. Characteristics of the modeled crudes are presented in Table 4.20.

Table 4.20. Summary characteristics of documented crudes (Jacobs, 2009, Table E-1)

PETROLEUM RESERVOIR	AVG DEPTH	PRESSURE	THERMAL STEAM TO OIL	WATER TO OIL	PRODUCED GAS	FLARED GAS (WORLD BANK RPT)	N2 INJECTION
	ft	psi	bbl/bbl	bbl/bbl	scf/bbl	scf/bbl	scf/bbl
Bachaquero	5,100	500	0.5	0.25	90	70-80	-
Maya	9,500	1,600	-	3	340	20-50	1,200
Arab Medium	6,100	3,000	-	2.3	650	25-30	-
Mars	14,500	5,500	-	5.5	1,040	20-25	-
Bonny Light	8,700	4,300	-	2	840	650-840	-
Kirkuk	7,500	3,000	-	2	600	300-400	-
California Heavy		~5	-				
Bitumen - SAGD		~3	-				
Bitumen – Mining							

Gas flaring information is based on reporting by the World Bank and NOAA. Presumably, like TIAX, Jacobs found it necessary to make assumptions about the relationship between the regional flaring data from the Bank and NOAA and the rate of flaring at each field. This relationship is not documented, but we presume that Jacobs assumed regional average rates of flaring per barrel for all fields. For venting, Jacobs notes that data were not available; the same is true for fugitive emissions and for gas composition.

4.7.3. Methodological considerations

Overall, the WTW lifecycle approach covers the following core processes: crude/bitumen production and initial processing, transportation and storage, upgrading and refining, motor fuel distribution, and vehicle operation. Emissions for these processes, by fuel type, are summed over all of the steps from crude oil extraction to vehicle end use, including the impact of co-products. GHG emissions are then reported in grams of CO_2 equivalent per megajoule of transportation fuel produced. These emissions are based on the 100-year global warming potential (GWP) of the primary greenhouse pollutants from transportation fuels: carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O). The use of this approach seeks to provide an accurate estimate of GHG emissions for each crude oil or bitumen-based oil in each step of its specific lifecycle (Figure 4.18), instead of using average GHG emissions for crude oil production or for refining. These activities are undertaken with the objective of enhancing previous studies by aiming to reflect accurately differences between crude oil production, upgrading, and refining, for a basket of crudes that Jacobs argues is representative of crudes refined in the United States (Table 4.21).

Figure 4.18. Pathways for crude and bitumen extraction (Jacobs, 2009, Figure E-4)

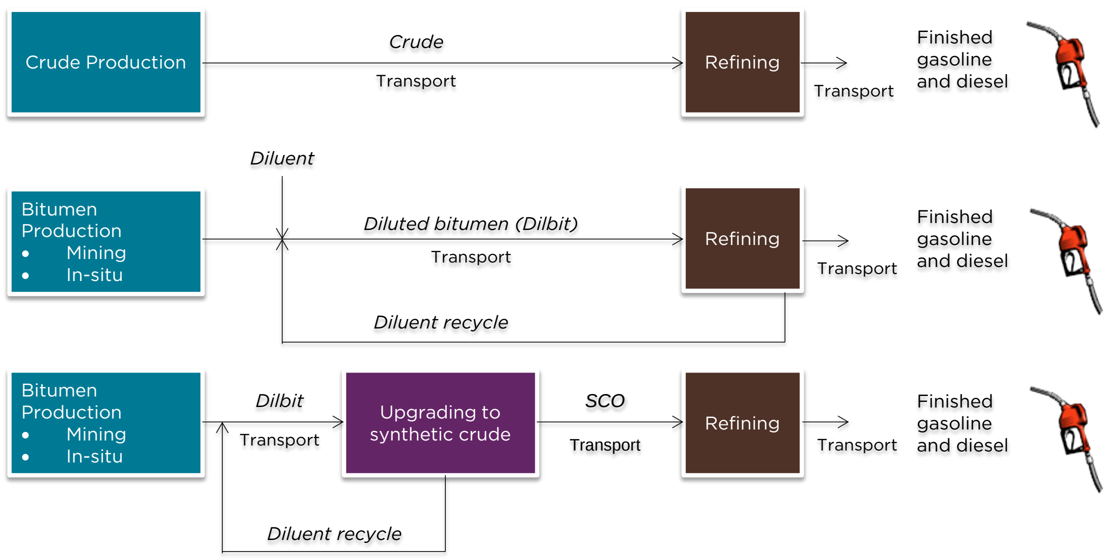


Table 4.21. Crudes modeled (Jacobs, 2009, Table 2-4)

FEEDSTOCK	EXTRACTION	UPGRADING	REFINING	FEEDSTOCK LOCATION	UPGRADER LOCATION	REFINERY LOCATION
Venezuela – Bachaquero	Conventional with steam assist	--	Base Refinery, FCC	Venezuela Lake Maracaibo	none	Chicago
Mexico – Maya	Conventional with N2 injection	--	Base Refinery, FCC	Cantarell field Gulf of Mexico	none	Chicago
Saudi Arabia – Arab Medium Crude Oil	Conventional with water flood	--	Base Refinery, FCC	Saudi Arabia	none	Chicago
Conventional crude oil from the U.S. Gulf Coast – Mars	Conventional off shore rig With water flood	--	Base Refinery, FCC	Mars Platform US Gulf Coast	none	Chicago
Nigerian – Bonny Light	Conventional – high flaring of gas	--	Base Refinery, FCC	Nigeria	none	Chicago
Iraqi Crude Oil – Kirkuk	Conventional with water flood	--	Base Refinery, FCC	Kirkuk Iraq	none	Chicago
California thermal heavy oil – Kern River, San Joaquin Heavy	Thermal enhanced oil recovery	--	Base Refinery, FCC	Bakersfield	none	Los Angeles
Canadian Oil Sands	SAGD	Delayed Coker, SCO	Base Refinery, FCC	Ft McMurray	Edmonton	Chicago
Canadian Oil Sands	Surface Mining	Delayed Coker, SCO	Base Refinery, FCC	Ft McMurray	Edmonton	Chicago
Canadian Oil Sands	SAGD	Ebulating Bed, SCO	Base Refinery, FCC	Ft McMurray	Edmonton	Chicago
Canadian Oil Sands	SAGD	Bitumen direct to refinery – diluent to refining	Base Refinery, FCC	Ft McMurray	none	Chicago
Canadian Oil Sands	SAGD	Bitumen direct to refinery – diluent returned to Canada	Base Refinery, FCC	Ft McMurray	none	Chicago
Canadian Oil Sands	Surface Mining	Bitumen direct to refinery – diluent returned to Canada	Base Refinery, FCC	Ft McMurray	none	Chicago

As previously mentioned, the methodology follows ISO standards 14000 on lifecycle analysis and uses the GREET model as a framework, supplemented with additional sub-models to differentiate GHG emissions from extraction and refining for specific crudes and bitumen, and upgrading for the bitumen-to-SCO pathway. The outputs from these extraction (plus upgrading) and refining models can then be expressed as process efficiencies and used to parameterize GREET to give a final result.

The extraction model was developed by Jacobs for the study and includes modeling of the major energy uses and emissions detailed in Table 4.22.

Table 4.22. Major sources of energy use and GHG emissions in crude production (Jacobs, 2009, Table 3-1)

EQUIPMENT	PURPOSE
Pumps	Downhole Pump, Water Re-injection Pump, Diluent Pump
Reciprocating Compressor	Gas Lift, Gas Re-injection
Heaters	Crude Stabilization, Reboiler @ 10% vaporization, Water Deaeration @ 5% vaporization
Glycol Dehydrator for Water Removal from Gas	Heater in Glycol Treater Pumps in Glycol Treater
Amine Treater for CO_2/H_2S Removal	Heater in Amine Treater Pumps in Amine Treater
Water Treatment	Reinjected Water, Water Discharge
Direct Venting	Vented Produced Gas, Fugitive Produced Gas
Gas Flaring	Flared Gas
CO_2 Venting	CO_2 Venting
Miscellaneous Energy	Lighting, offices, labs, maintenance, security, instrument air, storage, small pumps, etc.

Fuel consumption for extraction equipment was based on Caterpillar technical information, while power generation efficiency for on-site gas and diesel generators was assumed at 75 percent and pump efficiency, 65 percent (Natural Gas Processors Suppliers Association [NGPSA], 1998). Emissions for generators are based on GREET. The CO_2 emissions from gas generation are partly determined by the composition of the gas produced at the field (although, in practice, Jacobs reports that no data is available on gas composition, so this becomes irrelevant to the reported results).

Table 4.23 shows the parameters used to model extraction energy (and hence emissions), with the values for a ‘generic’ crude.

Table 4.23. Inputs to the Jacobs crude production model, for example, generic conventional crude (Jacobs, 2009, Table 3-4)

CRUDE DESCRIPTION		
Crude Name		Generic
API	wt%	30.0
Sulfur		2.0
Heating value		LHV
Crude Heating Value	GJ/Bbl	5.82
Reservoir characteristics		
Reservoir Pressure	psi	1,500
Reservoir Temperature	°F	200
Reservoir Depth	ft	5,000
Production characteristics		
Gas/Oil Ratio	scf/bbl	1,000
Water/Oil Ratio	bbl/bbl	10.0
Gas Lift		No
Gas Lift Rate	SCFB	0.0
Diluent Lift - Use if API below:		25.0
Produced gas composition (mol%)		
Source for Gas Composition		Default
Input Gas Composition		
H_2S	mol%	1.0%
CH_4	mol%	75.0%
C_2H_6	mol%	14.1%
C_3H_8	mol%	4.7%
CO_2	mol%	5.0%
H_2O	mol%	0.3%
Gas Heating Value - LHV Gas	BTU/SCF	1,018
Heating Value - LHV w/o CO_2	BTU/SCF	1,086
Venting of produced gas		
Vent Loss	%	0.5%
Fugitive Loss	%	0.5%
Reinjection of gas and water		
Gas Reinjection: % of Gas After Vent/Fugitive	%	50.0%
CO_2 Separation		Yes
CO_2 Reinjection: %	%	100.0%
Water Reinjection: % of Produced Water	%	100.0%
Treatment of Reinjected Water		Yes
Treatment of Discharged Water		Yes
Disposal of non-reinjected gas		
Amount of Non-Reinjected Gas	scf/bbl	500.0
Proportion of Gas to Flare	%	1.0%
Proportion of CO_2 to Flare/Vent	%	50.0%
Flaring of produced gas		
% Combusted	%	99%
% Non-Combusted	%	1%
Downhole Pump Driver		Natural Gas
Water Reinjection Pump Driver		Natural Gas
Compressor Driver		Natural Gas
Fired Heaters		Natural Gas
Water Treatment		Natural Gas
Amine Treater - Fired Heaters		Natural Gas
Amine Treater - Drivers for Motors		Natural Gas

Upgrading emissions modeling is based on the proprietary PetroPlan tool developed by AMI Consultants. Upgrading is broadly comparable to refining, and this model is much like a refining model, based on a modular construction in which product streams are allowed to flow from one process block to the next. Like the refining model, it uses a system of nonlinear equations to predict the outputs from which total process energy and emissions can be calculated. According to Jacobs, the PetroPlan model is customizable, and the consultancy used these features to model specific feedstocks, products, and technologies. The input data for this were "developed by Jacobs Consultancy" and "licensors and other parties where available and appropriate."

For refining, Jacobs assumes a high-conversion PADD 2 (Midwestern) refinery. The model is nonlinear and, as with the upgrader modeling, is run using PetroPlan. The parameters that determine energy use (other than refinery configuration) are API, sulfur content, nitrogen content, and microcarbon residue. Refinery output is partially determined by crude oil quality, so that lighter crudes yield more gasoline blendstock and middle distillate (diesel).

Jacobs acknowledged that the study is limited to extraction technologies that are currently being implemented, including both surface mining and thermal recovery methods. New or future processes may deliver improved efficiencies, as is normal in any industry. The analysis excludes emissions associated with labor, equipment production, and recycling, as well as those linked to tailing ponds used to store surface mining effluent or land clearing, which are both often included in the analysis of direct and indirect land use. The boundaries are drawn to encompass fully all major GHG emission contributors, vented and flared co-produced gas, fuel oil, coke, and other fuel by-products. In attributing emissions to fuel by-products, the study uses a system expansion approach, assigning process-level emissions to each refined product as well as a substitute value to by-product coke and light hydrocarbons. These emission levels are then examined for each oil-processing pathway.

4.7.3.a. Emissions allocation

For the upgrading phase of upgraded bitumen pathways, Jacobs (2009) make a methodological choice to assign emissions from by-product production at the upgrader to the main product. Therefore while Jacobs does attribute energy use to each of SCO, coke, sulfur and diluent return, giving respective emissions attributions of 7, 3, 35 and 1 gCO_2e/MJ, the by-product emissions are then returned into the SCO calculation to give an overall CI for SCO production from bitumen of 8.3 gCO_2e/MJ.

4.7.4. Parametric significance and sensitivity analysis

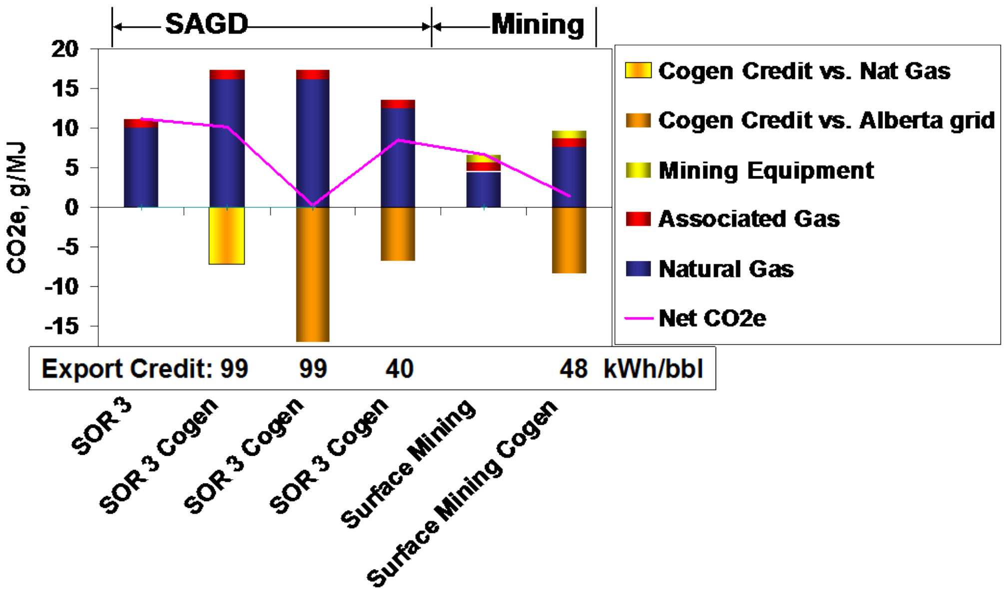
Jacobs introduces the analysis of parametric significance by varying the parameters for a 'generic' crude with three different reservoir depths–5,000 feet, 10,000 feet, and 20,000 feet. It varies six parameters across a wide range that seems to cover all or almost all likely values in real world oil production (0–100 percent flaring of gas not used for electric power, WOR of 0 to 25, GOR of 0 to 5,000 scf/bbl,[78] venting of 0–10 percent of gas produced, reservoir pressure of 100 to 10,000 pounds per square inch, CO_2 ratio in produced gas). Jacobs references sources for the real ranges of these parameters, which are comparable to the tested ranges in the report, though with some outliers (Jacobs, 2009, pp. 3–20).

Jacobs shows that the results are relatively insensitive to the CO_2 ratio in the produced gas but sensitive to all of the other parameters, though perhaps least to pressure. In particular, for deep wells pressure is essentially irrelevant, while WOR becomes the dominant variable at 20,000 ft. We have not at this time performed any analysis of the extent to which a combination of high WOR and deep reservoirs is prevalent in existing fields. Jacobs notes that there can be a substantial range in reservoir depth for some of these crudes–for Mars (Gulf of Mexico) and Bonny Light (Nigeria), the depth range accounts for an uncertainty of 2 or 3 gCO_2e/MJ either way. A similar result was found by El-Houjeiri et al. (2013) using OPGEE. The study found that increasing the depth of sample fields by 8,000 ft resulted in an increase in GHG emissions between 56 percent and 126 percent (with the difference attributed to other explanatory production and injection variables specific to the sample cases).

For thermally enhanced production, Jacobs shows the dependency of GHG intensity on the steam-to-oil ratio. Because such a large part of the emissions profile for these projects is energy to make steam, the results are extremely sensitive–varying from an SOR of 3 to 5 (SAGD Canadian) or 6 (TEOR California) roughly doubles the emissions profile. Brandt (2011) discusses the SOR for oil sands production in more detail. Jacobs also considers sensitivity to assumptions about heat and power co-generation–i.e., assumptions about whether thermally enhanced oil recovery projects (California, Canada) export excess electricity to the grid. In this modeling, it is assumed that heat and power for steam and electricity export comes from natural gas generation, and replaces 80 percent of coal-generated electricity. The consultancy does not consider electricity generation and export from coke combustion, and it does not attempt an assessment of real grid electricity CI for specific thermally enhanced oil projects nor of grid capacity to absorb co-generated electricity. Jacobs shows that the results are highly sensitive to co-generation assumptions–for instance, finding that co-generated natural gas replacing 80 percent of coal-powered grid electricity could fully offset extraction emissions for SAGD bitumen (Figure 4.19).

[78] Standard cubic feet per barrel. 1 cubic foot = 0.028 cubic meters.

Figure 4.19. Variation in extraction emissions for oil sands pathways (Jacobs, 2009, Figure 8-3)



Jacobs does not consider sensitivity in the context of reporting accuracy–it is unlikely that it sees the model as a potential reporting tool.

4.7.5. Summary findings

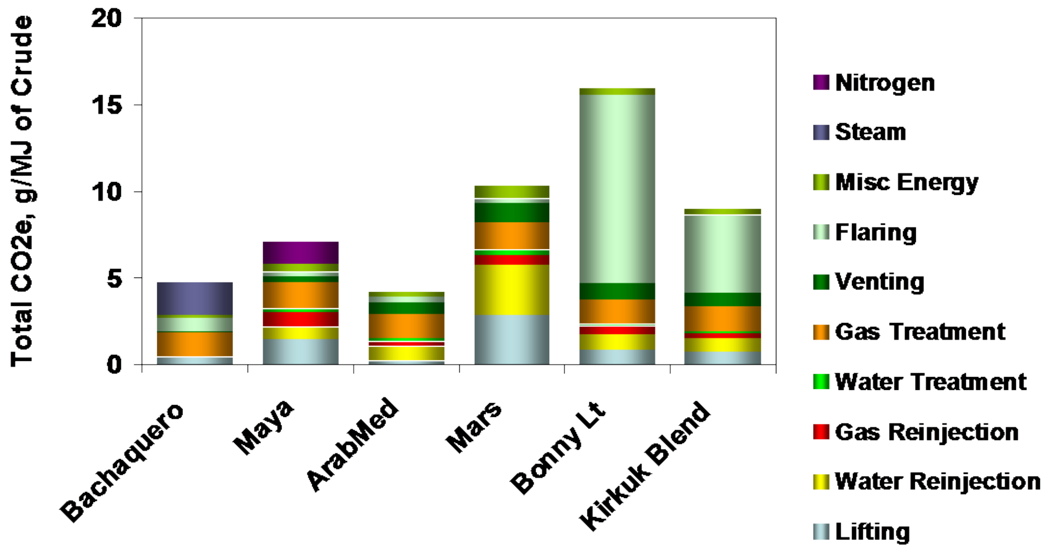
GHG emissions from crude oil production are highly dependent on the energy inputs used for the various processes as well as the venting and flaring of produced (associated) gas. There are a number of parameters correlated with energy use and GHG emissions, including water-to-oil ratios, gas-to-oil ratios, reservoir depth and API. These tend to vary by fuel type, reservoir location, and production technologies, and drive the energy intensity of production. In order to determine GHG emissions values, the study constructed a benchmark scenario for a generic crude (API density of 30) with reservoir depth of 5,000 ft, produced gas level of 1,000 SCFB, and GOR and WOR of 10:1. The GHG emissions breakdown from this generic crude production totaled 7.4 gCO_2e/MJ of crude, with more than 50 percent of emissions derived from water reinjection and gas treatment processes.[79] Using these base parameters, the study modeled a number of scenarios using different parameter ranges. The results show that the most significant parameters affecting emissions are WOR, which increases with reservoir depth, GOR, and flaring and venting of gas and CO_2 from associated gas.[80] The ranges at which these parameters are examined,

[79] The current analysis added 10 percent to the total energy emissions to account for miscellaneous energy from small users (i.e., lighting for the production site and offices, electricity for living quarters, security, etc.).

[80] The parameters included in the analysis and their ranges were: WOR (0 to 25), GOR (0 to 5,000 scf/bbl), reservoir pressure (100 to 10,000 psi), reservoir depth

although representative of a large subsection of crudes, are not based on actual observed ranges. For example, reservoir pressures can range to more than 15,000 psi, while WOR averages around 3:1 worldwide, but can vary from less than 1 to more than 50. The recovery emissions are shown in Figure 4.20, while the full WTW emissions broken down by lifecycle stage are shown in Table 4.24.

Figure 4.20. Recovery emissions (including flaring, venting) (Jacobs, 2009, Figure 3-11)



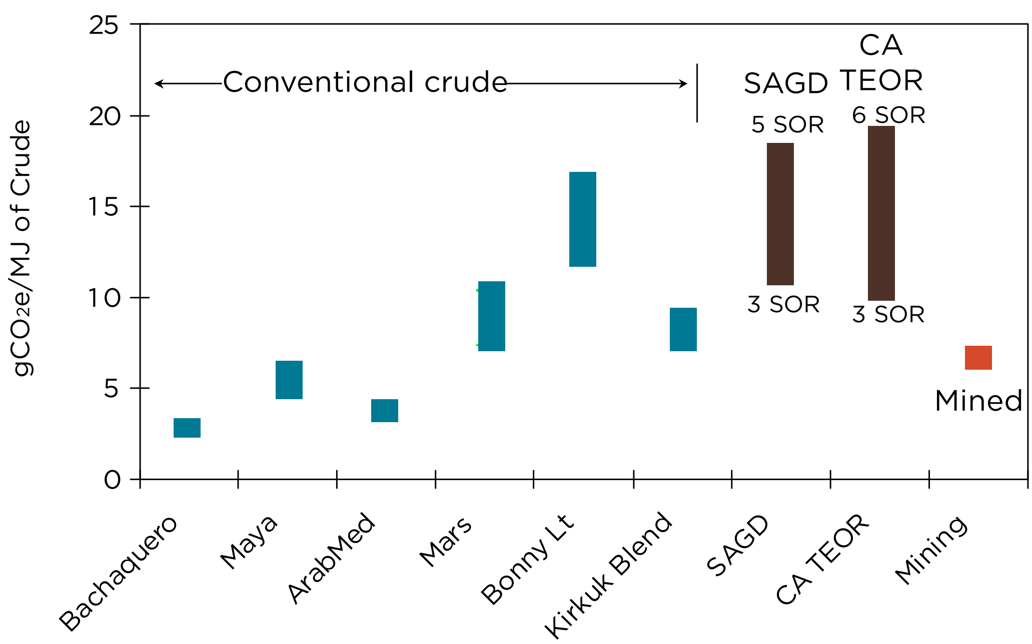
(5,000 to 20,000 ft), venting of produced gas (0 to 10 percent), flaring of produced gas (0 to 100 percent of net gas remaining after gas for electric power), CO_2 (0 to 10 percent in produced gas with venting of 100 percent of CO_2).

Table 4.24. Emissions from transport of crude to U.S. refineries (Jacobs, 2009)

	RATES				GHG INTENSITY			
	Crude	CBOB	RBOB	ULSD	Crude	CBOB	RBOB	ULSD
Rate BPSD	161,442	63,159	35,000	49,824				
Heating Value GJ/Bbl	6.3	5.1	5.19	5.88				
Emissions	GHG, MTD	GHG, MTD	GHG, MTD	GHG, MTD	g/MJ	g/MJ	g/MJ	g/MJ
Total WTTW Emissions						115.7	116.1	112.7
Vehicle CH_4, N_2O						0.8	0.8	0.8
Carbon in Fuel						72.8	72.9	74.1
Total GHG	32,307	13,547	7,705	11,064	31.7	42.1	42.5	37.8
Oil Production	11,313	4,573	2,579	4,161	11.1	14.2	14.2	14.2
Production GHG	11,313	4,573	2,579	4,161	11.1	14.2	14.2	14.2
Venting and Flaring GHG	0	0	0	0	0	0	0	0
Oil Transport	68	27	15	25	0.1	0.1	0.1	0.1
Upgrading	6,884	2,783	1,569	2,532	6.8	8.6	8.6	8.6
SCO	5,810	2,348	1,324	2,137	5.7	7.3	7.3	7.3
Coke - Upgrading GHG to Major Products	440	178	100	162	0.4	0.6	0.6	0.6
Sulfur - Upgrading GHG to Major Products	292	118	67	108	0.3	0.4	0.4	0.4
Diluent Return - Upgrading GHG to Major Products	342	138	78	126	0.3	0.4	0.4	0.4
SCO Transport	774	313	177	285	0.8	1	1	1
Refining - Major Products with Co-Products	8,890	3,998	2,294	2,598	8.7	12.4	12.6	8.9
GHG of Major Product	8,525	3,851	2,211	2,464	8.4	12	12.2	8.4
C3 - Refining GHG to Major Products	146	59	33	54	0.1	0.2	0.2	0.2
C4 - Refining GHG to Major Products	59	24	13	22	0.1	0.1	0.1	0.1
Coke - Refining GHG to Major Products	5	2	1	2	0	0	0	0
Sulfur - Refining GHG to Major Products	155	63	35	57	0.2	0.2	0.2	0.2
Delivery	336	136	77	124	0.3	0.4	0.4	0.4
Fuel Cycle	3,855	1,605	912	1,339	3.8	5	5	4.6
Natural Gas - Upstream GHG to Major Products	2,290	923	519	849	2.3	2.9	2.9	2.9
Electricity - Upstream GHG to Major Products	1,565	681	393	491	1.5	2.1	2.2	1.7
Other Feeds	186	113	82	0	0.2	0.3	0.5	0
Isobutane for Alkylation - Upstream GHG to Major Products	186	113	82	0	0.2	0.3	0.5	0
Impact of Replacing Coal with Refinery Pet Coke	1	0	0	0	0	0	0	0

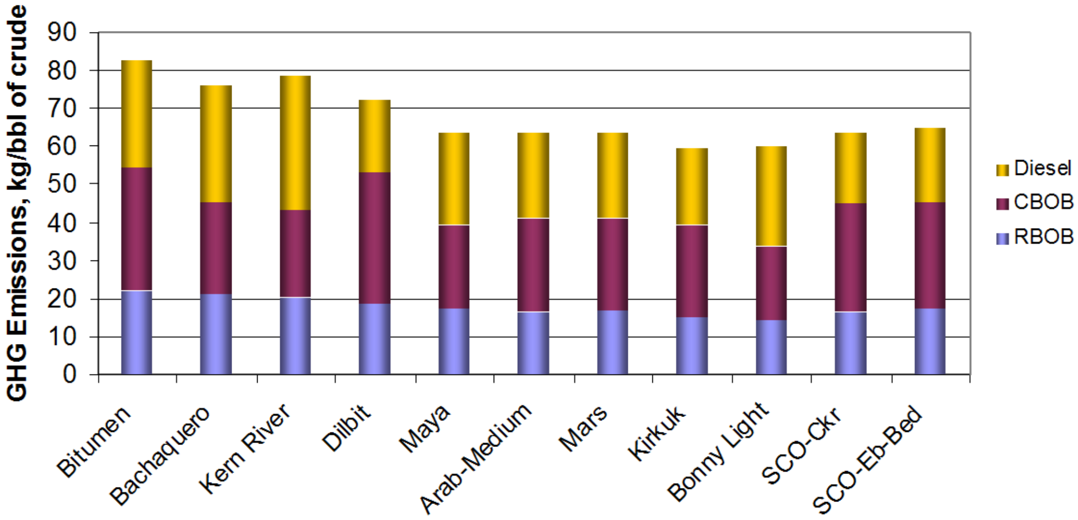
As a comparison to conventional technologies for crude oil production, thermally enhanced oil recovery (TEOR) processes (as used in California), in which steam is injected into the reservoir, are also examined. These include cyclic steam injection (CSS), steam-assisted gravity drainage (SAGD), steam-assisted oil recovery (used for Venezuelan heavy crude), and surface-mined bitumen with steam separation. The results for GHG emissions by crude type or process are presented below. Although it is generally assumed that TEOR results in higher emissions relative to conventional techniques, the study shows that GHG estimates for crude and bitumen production overlap those for crudes from deep reservoirs and with significant volumes of vented and flared associated gas. Overall, the evidence shows that there is a wide range in GHG emissions from producing crudes (Figure 4.21), and it is not sufficient to use an average to describe oil production. The inclusion of flaring and venting in particular results in a convergence between conventional and unconventional crude carbon intensities.

Figure 4.21. Variation in GHG emissions from crude production (Jacobs, 2009, based on Figure 3-12)



In addition to production processes, refining of crude oil and bitumen upgrading are included in the analysis. As previously mentioned, the study uses nonlinear upgrading and refining models to address differences in refining intensity for converting different crudes, bitumen, and SCOs into transportation fuels. Concerning bitumen technologies, two primary upgrading configurations were evaluated: delayed coking and ebulating bed (Eb-Bed) hydrocracking. Furthermore, the upgrading models were adapted for a representative refinery configuration: a high-conversion modern refinery located in PADD 2 of the United States, which uses a coker, fluid catalytic cracker (FCC), and other processing units to maximize gasoline and diesel production. The results show that emissions are generally higher per megajoule of SCO (between 8.3 and 11.64 g GHG/MJ of SCO) and for Eb-Bed configurations (11.6 g GHG/MJ of SCO or bitumen). Overall, the gap in GHG emissions between the two different upgrading configurations is 4.8 gCO_2e/MJ of bitumen but 3.3 gCO_2e/MJ of SCO. For crude oil refining, there is large variation depending on the type of product derived from refining, which ranges from 3.1 g GHG/MJ of coke produced to 12.5 g GHG/MJ of conventional blendstock for oxygenate blending CBOB gasoline produced (Figure 4.22).

Figure 4.22. GHG emissions from refining (Jacobs, 2009, Figure 5-16)



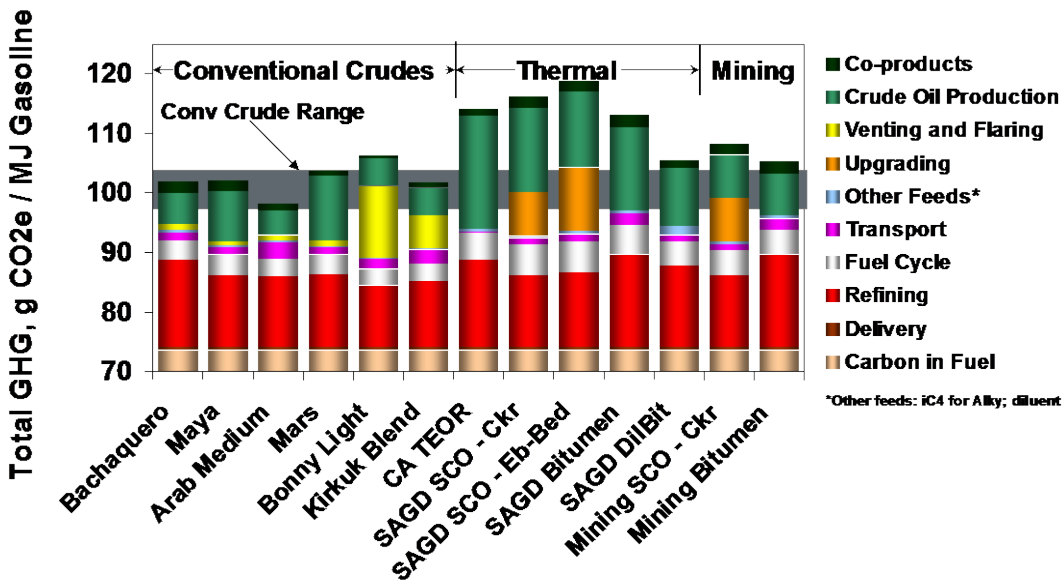
Also included in the analysis are crude transport, product distribution, and vehicle emissions. Transport emissions were calculated based on distance and transport mode. The study assumed that crude oil transport was from oilfield to marine terminal by pipeline, with marine tanker transport to the Gulf Coast and pipeline transport to PADD 2 refineries.[81]

WTW results derived from the study show that GHG emissions from oil sands bitumen are smaller than previously thought. For example, the difference in WTW GHG emissions between Arab-Medium and bitumen was found to be less than 18 percent for bitumen from SAGD and only 10 percent for bitumen from mining. Furthermore, if diluents derived from unconventional crude oils are converted to gasoline in the refinery, and the emissions from bitumen and diluent refining are averaged, total WTW GHG emissions are comparable to the conventional crudes. For example, SAGD dilbit lies almost within the conventional crude range—representing the 6 percent GHG emissions gap between Arab-Medium and Mars and 8 percent between Mars and Bonny Light (Figure 4.23). Overall, total GHG emissions are highest for crudes using thermal recovery processes, followed by those using mining and conventional crudes. The study shows that by including co-generation credits for thermal oil production, including SAGD, surface-

[81] The sole exception to this calculation was Kern County (California) crude oil. Here, the transport distance was calculated for an in-state refinery.

mined, and California TEOR, the GHG emissions fall to within the conventional range.

Figure 4.23. Variation in WTW GHG emissions for crude and bitumen (Jacobs, 2009, Figure E-6)



4.7.6. Jacobs 2012

In 2012, Jacobs released a similar study, "EU Pathway Study: Lifecycle Assessment of Crude Oils in a European Context", focused this time on the European market. The methodology is fundamentally similar to 2009, though with significant revisions and operating on a substantially different dataset. In this new study, Jacobs assessed 11 crudes, treated as representative of crude from 9 regions (three of the crudes were from a single region, the North Sea). The results for crude production CI are shown in Table 4.25.

Table 4.25. CI for crude oil production from Jacobs (2012)*

REGION	CRUDE	CI (gCO_2e/MJ OF CRUDE)
North Sea 1	Forties	3.4
North Sea 2	Ekofisk	3.6
North Sea 3	Mariner	3.8
Saudi Arabia	Arab Medium	3.8
Brazil	Tupi	4.8
Libya	Es Sider	5.2
Venezuela	Bachaquero	5.6
Iran	Sirri	5.9
Russia	Urals	6.8
Iraq	Kirkuk	7.8
Nigeria	Bonny Light	11.3
Canada	SAGD (bitumen)	12.8
Canada	SAGD (upgraded)	21.1
Canada	Mined (upgraded)	17.1
Canada	CHOPS (bitumen)	6.1
Canada	Polymer (bitumen)	10.1
Canada	Solvent Assist (bitumen)	10.8
Canada	Full solvent (bitumen)	6.5

**Jacobs present a number of variations of the SAGD and mined oil sands pathways – here we present arithmetic averages. Upgrading is included where indicated*

4.8. NETL study

4.8.1. Objective

The National Energy Technology Laboratory is part of the U.S. Department of Energy. The intention of the 2008 NETL study *'Development of Baseline Data and Analysis of Lifecycle Greenhouse Gas Emissions of Petroleum-Based Fuels'* is to provide a "comprehensive and transparent" baseline for comparison with lifecycle analyses of alternative transportation fuels, in response to the requirements of the Energy Independence and Security Act (2007), Title II, Subtitle A, sec. 201. This baseline is a necessary precondition for determining the eligibility of alternative fuel projects for U.S. government support. See also NETL (2009), '*An Evaluation of the Extraction, Transport and Refining of Imported Crude Oils and the Impact on Lifecycle Greenhouse Gas Emissions.*'

The study looks at conventional U.S. gasoline, diesel (< 500 ppm sulfur), and aviation kerosene and assesses the carbon intensity of these fuels as consumed in the United States in 2005.

Table 4.26. NETL LCA study design (NETL, 2008, Table ES-1)

LCA ISSUE	ANALYTICAL APPROACH
Lifecycle Boundary	Well-to-Wheels/Wake (Raw Material Extraction thru Fuel Use)
Temporal Representation	Year 2005
Technological Representation	Industry Average
Geographical Representation	Transportation Fuel Sold or Distributed in the United States
Transportation Fuel Lifecycles Modeled	Conventional Gasoline Conventional Diesel Fuel (≤500 ppm Sulfur) Kerosene-Based Jet Fuel
Impact Assessment Methodology	Global Warming Potential, IPCC 2007, 100-year time-frame
Reporting Metric	kg CO_2e/MMBtu LHV of Fuel Consumed
Data Quality Objectives	100% Publically Available Data
	Full Transparency of Modeling Approach and Data Sources
	Accounting for 99% of Mass and Energy Accounting for 99% of Environmental Relevance
	Process-based ("Bottoms-up") Modeling Approach

The study conforms to the ISO LCA standards 14040 and 14044 (Table 4.26). It does not use the JRC ILCD handbook.

4.8.2. Data quality and quantity

The primary refining data source for NETL is petroleum industry statistics from the Energy Information Administration, as relates to U.S. fossil fuels supplied in 2005. Refinery equipment operational on January 1, 2006, is assumed to be representative of 2005. The NETL study is based on data for 2005. As with several other studies discussed here, the focus of the NETL report is on the U.S. crude slate, and thus, coverage of crudes imported to Europe is comparatively poor. Table 4.27 shows the national provenance of the crudes assessed. They represent about 16 percent of EU crude imports.

Table 4.27. Sources of crude utilized at U.S. refineries in 2005 (NETL, 2008, Table 2-2)

U.S. CRUDE OIL SOURCES	PRODUCTION/IMPORT AS % OF REFINERY CRUDE INPUT
U.S. Crude Oil	33.80%
Canada Crude Oil	10.70%
Canada Oil Sands	
Mexico Crude Oil	10.20%
Saudi Arabia Crude Oil	9.40%
Venezuela Crude Oil	8.10%
Nigeria Crude Oil	7.10%
Iraq Crude Oil	3.40%
Angola Crude Oil	3.00%
Ecuador Crude Oil	1.80%
Algeria Crude Oil	1.50%
Kuwait Crude Oil	1.50%
Total	**90.50%**

NETL notes that data were not available to characterize the crude profiles in exporter nations in 2005; hence, 2002 data were relied upon in the analysis. No significant changes in extraction profile are believed to have occurred for any country except Canada, where oil sands extraction has been accelerating for several years. NETL used a 2005 mix of syncrude, dilbit, and conventional crude for Canada. On the refining side, data were not available in enough detail to disaggregate similar refinery outputs, such as low-sulfur road diesel versus higher-sulfur off-road diesel. It used a U.S. refinery configuration in its model for foreign crude refining–sensitivity analysis suggested that this introduced at most a ± 0.4 percent error in the overall result.

The crude extraction emissions data were based on purchased information from PE International. The data used in the extraction LCA by PE International are relatively well documented on a country-by-country basis. The PE International model includes country level information for:

1. Exploration
2. Onshore production
3. Offshore production

Emissions calculations take into account process energy inputs and emissions from flaring and venting. Energy use is based on data from the International Association of Oil and Gas Producers (OGP, 2005). Flaring and venting rates are assessed using data from the World Bank Global Gas Flaring Reduction initiative and the EIA. Canadian flaring data come from CAPP (2002). Additional sources are quoted country by country for exploration emissions, for additional data on flaring and venting, and as used by the authors. The energy inputs are determined using PE International's own calculations in addition to the referenced data. The PE International extraction profiles include some detail about the conditions of the oil industry in each producer country but do not scale down to the level of individual field characteristics.

The study required additional analysis for estimates of GHG emissions associated with natural gas and unfinished oil production, conventional crude oil, as well as blended and synthetic crudes from oil sands in Canada and Venezuelan extra heavy oil. While information for many of these products and by-products is readily available, either through public sources or the proprietary datasets acquired by the study team, data for Venezuelan extra heavy is particularly troublesome. As a result, the GHG emissions profile for extraction and preprocessing of Venezuela's extra-heavy oil was bounded using uncertainty analysis to determine a 90 percent confidence interval for related emissions.

The study notes that emissions related to infrequent high-impact events (the BP oil spill of 2010 would be an apt example) are excluded from the analysis. However, the use of 2005 data may imply that some impacts of abnormal events are implicitly internalized in the analysis– the shutdown of Gulf Coast refineries in the wake of hurricanes Katrina and Rita introduced abnormalities into the fuel usage profile of 2005– there is no attempt to 'correct' for such abnormalities.

The PE International data is in some cases based on cross-populating for one producer nation based on data from some or all exporter nations. In some cases, EIA data at a regional level are used in combination with authors' calculations to fill in national values for energy use. The appropriateness of cross-populating in the absence of specific data is not explicitly addressed in the report, though presumably it is implicit that PE International took that into consideration before undertaking cross-population.

4.8.3. Methodological considerations

In line with the ISO LCA standards, the NETL study clearly defines its goal and scope. It outlines a system boundary for the LCA and a functional unit, i.e., global warming potential expressed in $kgCO_2e/MMBtu$. The GHG emissions are limited to carbon dioxide, methane, and nitrous oxide, with carbon equivalency values based on 100-year GWP as defined by IPCC (2007). The system boundary includes all 'significant' material and energy inputs, with significance defined for input materials as having a mass of 1 percent or greater of the mass of the output, and defined for energy as being 1 percent or greater of the total energy use. Additionally, inputs may be deemed significant if they have a particularly high cost or environmental footprint–it is probably difficult and unhelpful to apply numerical cutoff criteria such as these completely rigorously. The assessment excludes construction-related emissions and any emissions from land use change. NETL aims to avoid the use of allocation methods wherever possible, instead favoring system expansion and unit process division.

The LCA is split into five stages: raw material acquisition, raw material transport, liquid fuels production, product transport and refueling, and vehicle/aircraft operation. Of most relevance to the current study is lifecycle stage 1, the acquisition of raw materials, which covers upstream emissions from crude oil extraction and post extraction processing before refining. NETL includes, in an attachment, notes from PE International on the analysis of upstream extraction emissions for each country individually. The LCA seems on the basis of the descriptions in the attachment to be a relatively simple model. It is certainly not documented in detail. In short, PE International provides a generic description of oil exploration and production, tailored to be relevant to the circumstances of each country. It characterizes production in each nation in terms of fractions of oil and gas, respectively, allocates energy use based on OGP regional data and some unspecified calculations. It also identifies flaring and venting using EIA data, and characterizes the waste and wastewater production and calorific properties of gas and crude for each country. Presumably, the CI calculation is based on energy inputs and flaring/venting volumes.

Note that the Canadian profile was calculated differently by NETL because of the importance of the mix of conventional and oil sands crude.

Countries exporting refined product to the United States were allocated emissions values based on GaBi 4 (2007), a lifecycle analysis database. This does not give an explicit breakdown of extraction, refining, etc., and so extraction emissions from crudes refined elsewhere and imported as refined product are inferred by assuming that the ratio between extraction-only and full WTW emissions for these crudes is the same for other countries as for the United States.

Emissions for pipeline transport are based on GREET. Shipping emissions are based on a measurement of port-to-port distances, and an average assumption for oil tanker fuel consumption is based on assessing various tanker models. The ton-distance travelled by crude oil with America is based on Association of Oil Pipe Lines (AOP) data, divided by transport mode. Transport CI is based on GREET or Oak Ridge National Laboratory (ORNL) data.

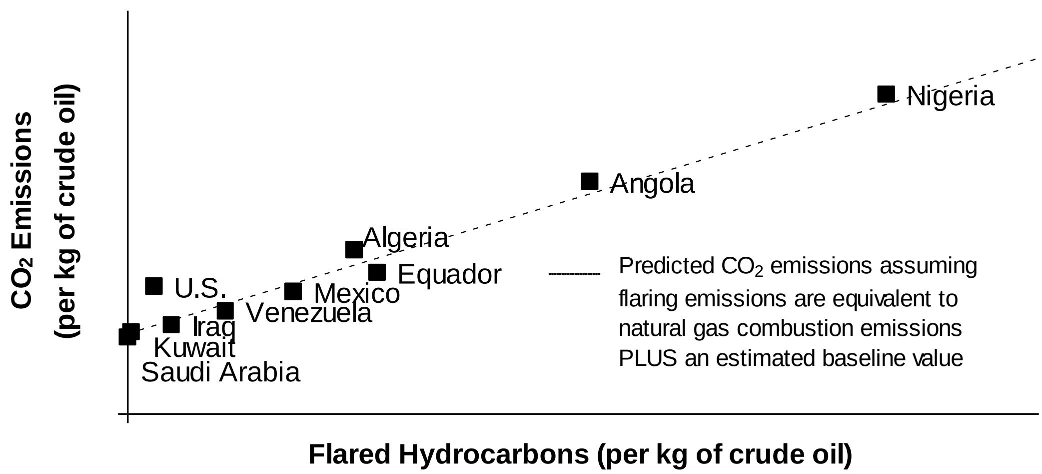
For refining, because NETL is interested in the average emissions of the U.S. refining sector rather than breaking out the emissions intensity of dealing with specific crudes, NETL bases its calculations on total sector data. It therefore does not calculate refinery intensities for the specific foreign crudes coming into the country but provides good-quality data for the overall emissions intensity of the U.S. refining sector.

4.8.4. Parametric significance, temporal variations, and sensitivity analysis

NETL aimed to capture carbon intensity in 2005, specifically, and aimed to use 2005 data. It found that while extraction profiles country by country may not have been available for 2005, they were nonetheless representative of 2005. The country-specific crude extraction profiles used were purchased from PE International. The industry average data used by NETL are likely to have included implicitly time-related emissions factors, insofar as they represented a cross-section of field ages at 2005. NETL does not, however, attempt a more detailed representation of the temporal variations in emissions intensity.

Flaring is highlighted as a key determinant of national average emissions intensities (see Figure 4.24). Because NETL represents the emissions intensities of average national crude exports rather than representative market crudes or individual oilfields, the use of aggregate flaring data is consistent with the results, unlike the studies that aim to use national average flaring rates to calculate emissions intensities for subsets of crudes.

Figure 4.24. Country-specific lifecycle stage 1 emissions vs. flaring (NETL, 2008)



NETL points out that the U.S. lifecycle stage 1 (extraction and upgrading) emissions are above the linear trend identified for flaring. It suggests that while U.S. extraction technologies may to some extent be more carbon intensive than systems in other regions, it is also likely that there is systematic underestimation for other regions, where data are generally of lower quality or less nationally specific. Given the sensitivity to flared volumes, and the use of 2002 data as a proxy for 2005, ongoing reductions in flaring would imply that emissions may have been overestimated for high-flaring countries.

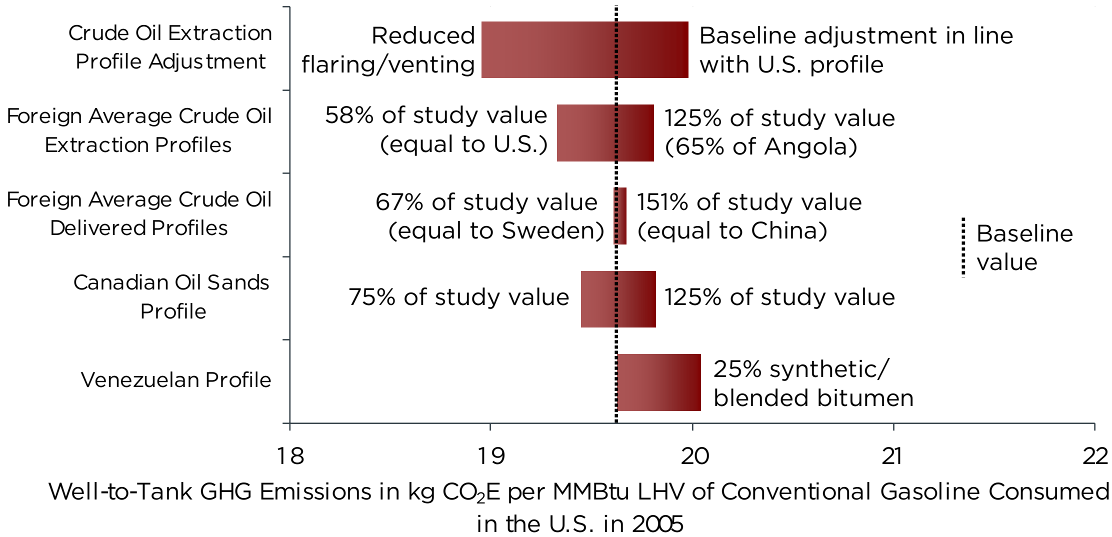
The sensitivity of the U.S. average emissions intensity to these factors (among others) is illustrated in Figure 4.25, in which the 'crude oil extraction profile adjustment' shows a range from a minimum in which a 25 percent reduction in flaring from 2002 to 2005 is assumed and a maximum that raises foreign crude source emissions by 3.4 $kgCO_2e/bbl$.

NETL also explores the variation in CI when changing (moving down Figure 4.25)

1. The ‘other’ foreign fuel sources that are not explicitly modeled
2. The profile of foreign countries with no explicitly modeled CI for material refined in the country and exported to the United States
3. The CI of Canadian oil sands extraction, down or up by 25 percent
4. The emissions intensity of Venezuelan crude, by assuming that 25 percent had the same emissions intensity as oil sands production in Canada.

The results of these five sensitivity tests are also shown for diesel and kerosene but are essentially comparable. There is no assessment of the significance of individual parameters, presumably because, based on the documentation of the PE International LCA, it represents only a simplified model rather than an engineering model of comparable complexity to the proposed OPGEE, for example.

Figure 4.25. Sensitivity analysis of lifecycle stage #1 activities on the well-to-tank GHG emissions profile for conventional gasoline consumed in the U.S. in 2005 (NETL, 2008)

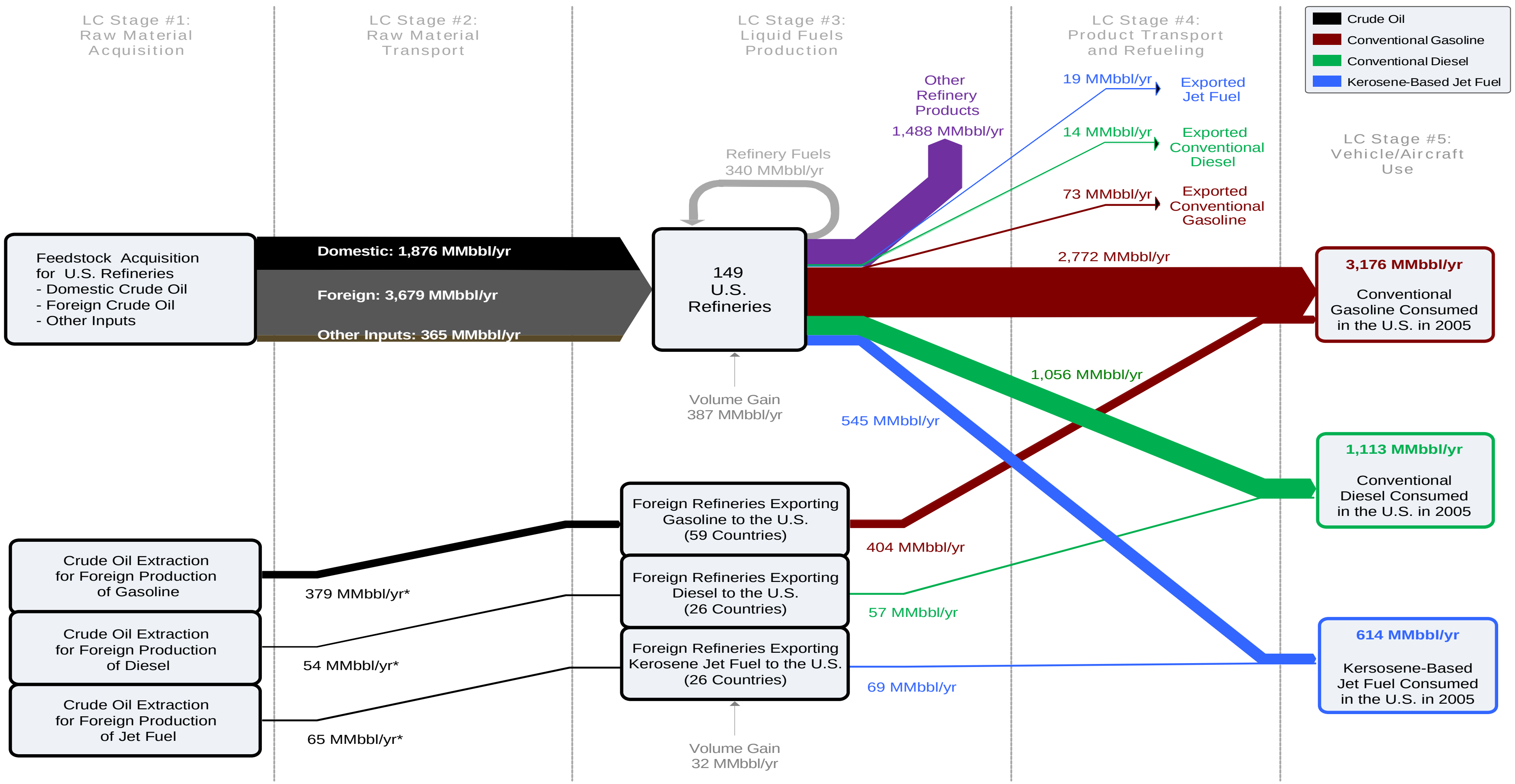


Because the NETL analysis is designed to be a baseline, with no intention of designing a scheme that would be appropriate for reporting and individual crude assessment, there is no consideration of the necessary level of data accuracy for field measurements as model inputs.

4.8.5. Summary findings

The NETL study aims to determine the average baseline CI of U.S. fossil fuels in 2005. It determines that the fuel flows that must be assessed to make this calculation are as depicted in Figure 4.26.

Figure 4.26. Feedstock and product volumetric flows for consumption of conventional gasoline, conventional diesel and kerosene-based jet fuel in the U.S. in 2005 (NETL, 2008)



Crude oil input to FOREIGN refineries include only the portion of crude oil considered to be contributing to gasoline, diesel and jet fuel production

NETL finds an average CI for 2005 U.S. gasoline of 91 gCO_2e/MJ,[82] for diesel of 90 gCO_2e/MJ, and for kerosene of 88 gCO_2e/MJ. Note again that these well-to-wheels values include a typical U.S. refinery configuration for all crude. The upstream part (lifecycle stage one 'raw material acquisition' + lifecycle stage two 'raw material transport') contributes 8.2, 7.5, and 7.7 gCO_2e/MJ for gasoline, diesel, and kerosene, respectively.

For individual nations, the raw material acquisition emissions are shown in Table 4.28 (for the case of diesel production). This includes the emissions for three categories of Canadian oil (bitumen, SCO, conventional). Note that this lifecycle stage includes upgrading for SCO, but does not consider the increased refining emissions required by bitumen that has not been upgraded. Note also that the Venezuelan emissions characterize only conventional crude production, not extra-heavy oil. The estimated upstream emissions of Venezuelan extra heavy oil production and upgrading are listed in parentheses.

Table 4.28. GHG emissions from lifecycle stage 1 (raw material acquisition) by country (NETL, 2008 & 2009)

NATION	EMISSIONS IN gCO_2e/MJ OF DIESEL PRODUCED
U.S.	4.0
Saudi Arabia	2.2
Mexico	6.3
Venezuela (conventional)	3.9
Venezuela (upgraded extra heavy)	15.5
Nigeria	20.9
Iraq	3.1
Angola	13.3
Ecuador	5.0
Algeria	5.7
Kuwait	2.7
Canada (oil sands)	18.0
Canada (conventional)	5.7

The results show, as in other studies, that the highest emissions intensities are driven by countries where average flaring rates are very high (Nigeria, Angola) or by extraction of bitumen (Canada).

82 Note that NETL presents results in $kgCO_2e/MMBtu$. These numbers are similar to the gCO_2e/MJ values, but must not be confused with the converted values.

4.9. IHS CERA

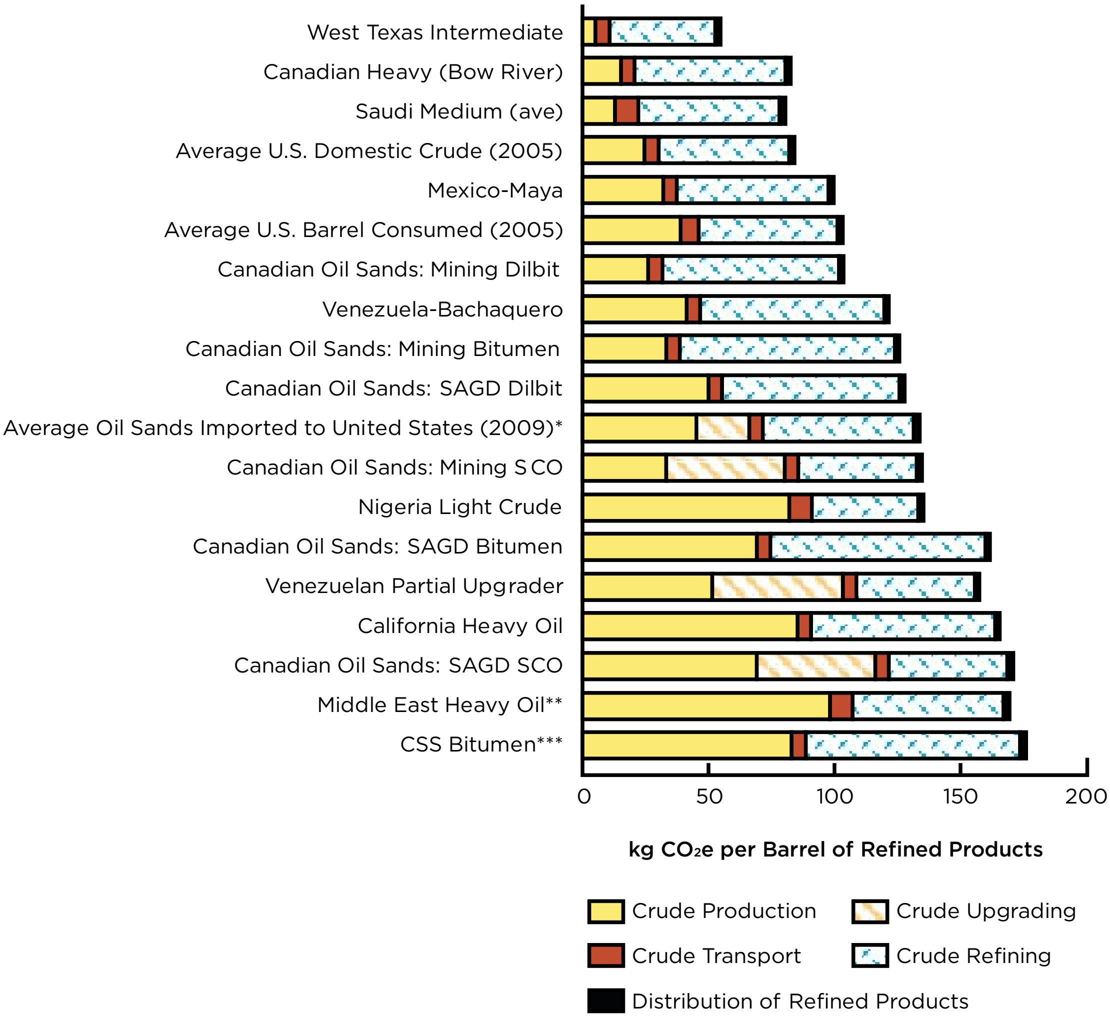
IHS CERA (2010a) presents results of a meta-analysis of studies of crude oil GHG intensity. The studies it considers include NETL, TIAX, Jacobs, GREET, GHGenius, and McCann. In addition, it considers *Unconventional Fossil-Based Fuels: Economic and Environmental Trade-Offs* (RAND Corporation, 2008); *Canadian Oil Sands: Opportunities and Challenges* (National Energy Board, Canada, 2006); *Environmental Challenges and Progress in Canada's Oil Sands* (Canadian Association of Petroleum Producers, 2008); *2009/10 Sustainability Report* (Syncrude Canada Ltd.); *The Shell Sustainability Report, 2006* (Shell); as well as IHS CERA's own data. We believe that the studies in this list not reviewed here do not contain additional analysis of emissions other than from Canadian oil sands. The results of the IHS CERA literature review are shown in Table 4.29 and Figure 4.27.

Table 4.29. Production emissions identified for various crudes by IHS CERA meta-analysis (2010)

CRUDE	PRODUCTION EMISSIONS, gCO_2e/MJ REFINED PRODUCT (INCL. UPGRADING)*
West Texas Intermediate	0.7
Canadian Heavy (Bow river)	2.4
Saudi Medium	2.0
U.S. average domestic crude	4.1
Mexico Maya	5.3
Average U.S. barrel consumed	6.7
Canadian mined dilbit**	4.4
Venezuela Bachaquero	6.8
Canadian mined bitumen	3.9
Canadian SAGD dilbit	8.5
Average oil sands imported to United States	11.1
Canadian mined SCO	13.5
Nigerian Light	14.0
Canadian SAGD bitumen	11.8
Venezuelan partial upgrader	17.7
California Heavy	14.5
Canadian SAGD SCO	20.0
Middle East Heavy^	16.7
CSS bitumen	14.0

**IHS values inferred from Figure 4.27, as they are not tabulated in the report*
***Note that to the best of our knowledge mined dilbit did not exist as a real pathway when IHS CERA wrote this report*
^Steam-assisted production

Figure 4.27. WTT emissions from IHS CERA meta-analysis (2010)



Source: IHS-CERA.
Results of a meta-analysis of 13 publicly available life-cycle studies.
Assumptions:
**Assumes 55 percent of exports to the U.S. are dilbit blends and 45 percent are SCO*
***Steam injection is used for production.*
****Assumes SOR of 3.35.*
12 percent loss of volume upgrading bitumen to SCO.
All SAGD crude production cases assume an SOR of 3.
All oil sands cases marked "Dilbit" assume that the diluent is consumed in the refinery with no recycle of diluents back to Alberta, and only 70 percent of the barrel is from oil sands.
All oil sands cases marked "Bitumen" assume that the diluent is recycled back to Alberta, and all of the barrel processed at the refinery is from oil sands.

4.10. Overview of modeled LCA emissions

Table 4.30. Comparison of oil production emissions in gCO_2e/MJ[83] from the reviewed LCA studies, by region

REGION		JEC (OGP)	GREET	GHGENIUS	MCC&A	ER**	TIAX	JACOBS 2009	JACOBS 2012	NETL	IHS CERA (META-STUDY)	% OF EU CRUDE
EU		1.7		5.3								9.0%
	UK				3.4	3.0			3.6α			5.0%
Norway						2.5			3.6			11.6%
North America		3.3										0.1%
	U.S.		7.45	14.8^^		2.8				4.0	4.1	Imports of refined diesel
	Alaska						0.9					
	Texas						1				0.7	
	Gulf Coast							11.8				
	California						12.2	18.9			14.5	
	Canada (conventional)			8.8	3.8	1.6	2.8			5.7	2.4	0.07%
	Canada (oil sands)	20.0	19.6ª	19.1^	17.8	13.0	19.2ª	15.6ª	14.6 (6.1-21.1)ª	18.0	11.9ª	Believed to be negligible
Africa		7.6										21.3%
	Nigeria			14.8	12.6		16.8	16.8	11.3	20.9	14.0	5.4%
	Angola									13.3		1.6%
	North Africa			9.1								12.3%

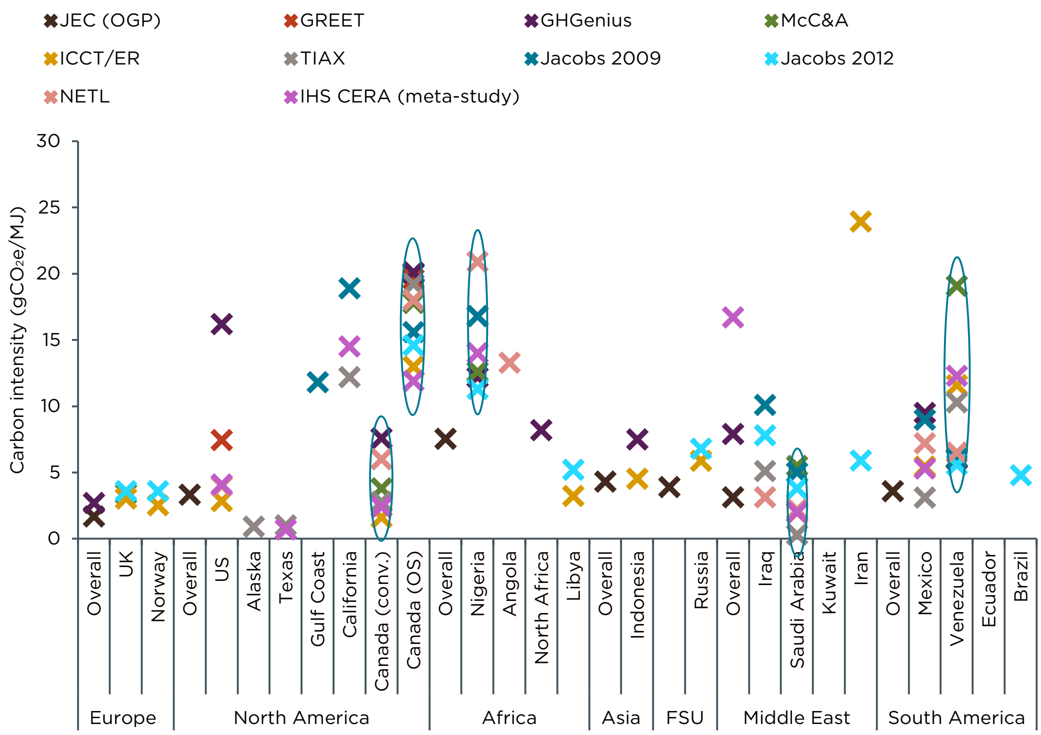
[83] The emissions in this table are quoted variously per MJ of crude, average refined product, gasoline or diesel, as given in the studies.

REGION \ STUDY		JEC (OGP)	GREET	GHGENIUS	MCC&A	ER**	TIAX	JACOBS 2009	JACOBS 2012	NETL	IHS CERA (META-STUDY)	% OF EU CRUDE
	Libya					3.2			5.2			8.9%
	Algeria									5.7		2.2%
Asia		4.3										0%
	Indonesia			12.0		4.5						0%
FSU		3.9										41.7%
	Russia					5.9			6.8			29.1%
Middle East		3.1		11.0							16.7	13.8%
	Iraq						5.1	10.1	7.8	3.1		1.9%
	Saudi Arabia				5.5	2.0	0.3	5.0	3.8	2.2	2.0	6.3%
	Kuwait									2.7		0.6%
	Iran					23.9			5.9			4.1%
South America		3.6										2.5%
	Mexico			9.5		5.4	3.1	9		6.3	5.3	1.4%
	Venezuela			6.0	19.1	11.6	10.3	6.1	5.6	3.9 (15.5)[β]	12.3^	0.7%
	Ecuador									5.0		< 0.2%
	Brazil								4.8	20.8		0.62%

*JEC revise the OGP emissions upwards based on higher flaring estimates from satellites. This is only captured for the global average.
**Energy Redefined give example crudes, not national averages, and only well to refinery gate values. We have used their approximately linear scaling of refinery emissions to API to back refining out, but transport to refinery is still included.
[a]This model covers a number of oil sands pathways - this is a simple arithmetic average, including upgrading where appropriate.
^GHGenius includes both bitumen and SCO pathways. This is the average for the production GHGenius models in 2011.
^^GHGenius reports relatively high U.S. emissions because U.S. heavy and offshore production are modeled as being very energy intensive.
[α]Jacobs (2012) have two UK crudes – Forties and Mariner. This is an arithmetic average.
[β]NETL (2009) report a separate value for Venezuelan extra heavy, shown in parentheses

The production emissions from the models are shown by region above in Table 4.30 (including transport to refinery in the case of Energy-Redefined). There are certain obvious trends in the data from various studies, for instance thermally enhanced recovery consistently results in very high emissions, as do high levels of flaring. While we have grouped results by region for ease of reference, note that national origin is not in general a good indicator of carbon intensity, as noted by ICCT/ER (2010). Indeed, as shown in Figure 4.28 national origin can be a very poor indicator for countries such as the U.S, Canada or Venezuela where production ranges from conventional light crude to thermally enhance extraction of heavy crude or bitumen.

Figure 4.28. Upstream crude oil CI from studies in the literature



Both Jacobs (Jacobs, 2009; 2012) and Energy Redefined (ICCT/ER, 2010) undertake parametric modeling of extraction emissions, and there is some consistency on the primary parameters for modeling between these studies. The following list includes the most important variables as identified in those papers:

- API gravity
- Reservoir pressure
- Reservoir depth
- Reservoir temperature
- Viscosity
- GOR

- WOR
- Age of field
- Flaring rate[84]
- Venting rate
- Fugitive emissions
- Type of lift
- Development type

84 Most analyses lack a model of flaring. Energy-Redefined is an exception in this regard, having a parameterized model based on engineering considerations plus satellite data.

5. Best practices in the development of GHG estimation tools for the oil and gas industry

Building a tool that estimates greenhouse gas (GHG) emissions from oil and gas operations can be done at a variety of levels of detail and using an assortment of approaches, tools, and modeling frameworks. An important consideration is that some of these goals or desirable qualities are in tension, i.e., a more complete and rigorous model is generally more complex and less easy to use. Hence, certain models place stronger emphasis on transparency than rigor and vice versa. The particular objectives of the currently available models estimating GHG emissions from oil and gas operations will be discussed in detail in subsequent sections.

The purpose of the current analysis is to highlight the properties that are most desirable and that may enter in conflict when designing such a tool. These include (i) rigor, complexity, and calculation detail; (ii) transparency of data sources and modeling equations; (iii) completeness in coverage of sources and types of emissions; (iv) usability of model and controls by outside parties; (v) choice and quality assessment of data, defaults, and model parameterization; and (vi) consistency in the presentation of model output and results.

In addition to these considerations, there are a number of benchmark guidelines and handbooks outlining methods and procedures that should be followed when estimating lifecycle GHG emissions from different sources, including crude oil and natural gas. These include the International Organization for Standardization (ISO) 14040 lifecycle assessment (LCA) framework, the International Reference Lifecycle Data System (ILCD) Handbook (European Commission, 2010), and the American Petroleum Institute (API) compendium of GHG emissions estimation methodologies for the oil and gas industry (API, 2009), among other relevant publications.

The following section will explore both established guidelines and the desired properties of GHG emissions estimators.

5.1. Guidelines for GHG estimation

5.1.1. API compendium of GHG emissions estimation methodologies for the oil and natural gas industry

The API compendium came about as a result of the growing need to harmonize the efforts of local, regional, and international organizations developing or revising guidelines on estimating, reporting, and verifying GHG emissions.[85] Consequently, an effort was made to compile the most currently recognized methods used to estimate emissions from the oil and natural gas industry, with the objective of enhancing the consistency of emissions estimation. As such, it aims to accomplish four main goals (API, 2009):

- To assemble an extensive collection of relevant emission factors and methodologies for estimating GHG emissions, based on available and recently published public documents;
- To summarize detailed procedures for conversions between different measurement unit systems, with emphasis on oil and natural gas industry standards;
- To describe the multitude of oil and natural gas industry operations and the associated GHG emissions sources; and
- To develop emission inventory examples to demonstrate the broad applicability of the methodologies.

In terms of scope, the compendium sets out to recognize the full range of industry operations from exploration and production through refining and the marketing and distribution of end products. In regard to emissions, estimation methods include those for carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6) for all common sources, including combustion, vented and fugitive emissions. In addition, an effort is made to include estimation techniques from indirect emissions, characterized mainly by those associated with purchased and imported energy as well as from the allocation of emissions among energy streams.

5.1.2. Comparison of international guidelines for estimating GHG emissions in the oil and gas industry

Recognizing the inherent difficulty in providing a systemic, consistent, reliable, and credible methodology to derive GHG emissions for the oil and gas industry, Ritter et al. (2003) conducted a literature review to analyze the consistency in GHG emission estimations for oil and gas industry operations across a number of commonly cited protocols. Their efforts were primarily motivated by the API compendium, which was then in a pilot phase of distribution. Their analysis focused on the root sources of the emission factors used for estimating GHG emissions in an effort to provide transparency and relevance in the emissions factors' development and application. Overall, the authors' results have provided important feedback for future revisions and lessons learned for the API compendium as well as other initiatives.

The authors compared the API compendium to five other international guidelines. These were: (i) the Australian Greenhouse Office (AGO)

[85] Since 2003, the API GHG emissions methodology working group is coordinating internally with the API benchmarking workgroup to support aggregating industry emissions and to develop a compendium software tool.

Workbook for Fuel Combustion Activities, (ii) the Canadian Industrial Energy End-Use Data and Analysis Centre (CIEEDAC) memorandum on "Guide for the Consumption of Energy Survey," (iii) the Intergovernmental Panel on Climate Change (IPCC) Guidelines for National Greenhouse Gas Inventories, (iv) the UK emissions trading scheme, and (v) the World Resources Institute/World Business Council for Sustainable Development (WRI/WBCSD), Greenhouse Gas Protocol. To compare these guidelines with those proposed by the API compendium, the authors used emissions derived from combustion devices, given that these represent the major sources of emissions for oil and gas industry operations, as well as many other industries. The results of this exercise are provided in Table 5.1, demonstrating numerical differences resulting from the various guidelines.

Table 5.1. Comparison of CO_2 emissions factors for fuel combustion (Ritter et al., 2003)*

VARIABILITY (%)	FUEL TYPES	METRIC TONS OF CO_2 / MMBTU (LHV*)					
		API CO_2 Emission Factor	AGO Workbook 1.1 (Table 4)	IPCC Volume 3 (Table 1-1)	DEFRA, Protocol	WRI/ WBCSD	CIEEDAC
3.6	Aviation Gas	0.074	0.0767		0.0752	0.0741	
14.4	Bitumen	0.0864	0.0908	0.0862	0.0938	0.0993	
35.2	Coke (Coke Oven/Gas Coke)	0.1212	0.1407	0.1209	0.0982	0.1209	0.0997
5.4	Crude Oil	0.0793		0.0783	0.075		
6.4	Distillate Fuel	0.0777	0.0762		0.0746	0.0777	0.0796
11.9	Electric Utility Coal	0.1063	0.1033		0.094		
-	Ethanol	0.0775					
-	Flexi-Coker/Low Btu Gas	0.1262					
1.4	Gas/Diesel Oil	0.0794	0.0786	0.0794	0.0783	0.0783	
2.8	Jet Fuel	0.0773	0.0767		0.0752	0.0758	
4.4	Kerosene/Aviation Kerosene	0.0773	0.0786	0.0766	0.0752	0.0774	
3.8	Lignite	0.1174		0.1218		0.1175	
2.7	LPG	0.0677	0.0674	0.068	0.0662	0.0679	
2.9	Butane	0.0726					0.0705
5.3	Ethane	0.0653		0.0675	0.0641		
11.6	Propane	0.0764				0.0685	0.0686
2.8	Misc. Petroleum Products and Crude	0.0771	0.0773		0.0752		
2.5	Motor Gasoline	0.0763		0.0743	0.0753	0.076	
9.7	Naphtha (< 104°F)	0.0711	0.0744	0.0785	0.0814		
0.0	Natural Gas Liquids	0.068		0.068			
6.8	Natural Gas	0.0588	0.06	0.0589	0.0616	0.0588	0.0576
7.3	Other Bituminous Coal	0.0972		0.0989	0.0918	0.0972	
0.3	Other Oil (> 104°F)	0.0783		0.0785			
-	Pentanes Plus	0.0724					
37.3	Petroleum Coke	0.1082	0.1337	0.1072	0.0933	0.1083	0.1047
26.4	Refinery Fuel Gas	0.0619	0.078		0.0637		0.0615
11.0	Residual Fuel	0.0843	0.0768	0.0829	0.0752	0.0844	
-	Special Naphtha	0.0779					
-	Still Gas	0.0697					
8.9	Sub-bituminous Coal	0.1045		0.1044	0.0954	0.1047	
-	Unfinished Oil	0.0794					

**The values in this table are originally given by Ritter in higher heating value (HHV) terms. They have been converted using LHV:HHV ratios taken from the Engineering Toolbox (www.EngineeringToolbox.com) for coke, pentane and ethane, and GREET for all other fuels.*

5.2. Desirable properties of GHG estimation tools for the oil and gas industry

5.2.1. Lifecycle assessment practices

Any lifecycle emissions model should use best practices in bottom-up lifecycle assessment calculations to provide rigorous estimates of emissions:

- The model should clearly define system boundaries and make clear distinctions between included and excluded emissions sources.
- The model should follow accepted standards for LCA in areas where methodology is flexible (e.g., co-product allocation or system boundary expansion). Commonly accepted standards include ISO standards for LCA (Series 14040) as well as the International Reference Lifecycle Data System (ILCD) Handbook developed by the European Commission (2010).
- The model should apply formal significance criteria when setting system boundaries. This allows a comprehensive approach to analysis while preventing the model scope from expanding beyond feasible levels. These significance criteria should recognize the uncertainty in initial assessments and apply cutoffs in a conservative manner. For example, if an emissions source is nearly large enough for inclusion within the significance boundary, caution should err on the side of inclusion.
- The model should clearly define the rules concerning data cross applicability i.e. how data for one field, MCON, country or region could be utilized for estimating emissions from another field, MCON, country or region.

5.2.2. International Organization for Standardization (ISO) 14040 Series

The ISO 14040 series describes the preparation, conduct, and critical review of lifecycle assessment (LCA) studies as well as lifecycle inventories (LCIs). These have become a benchmark across industries, including the oil and gas sector. In general, these processes encompass the definition of the goal and scope of the LCA, the lifecycle impact assessment (LCIA) phase, the lifecycle interpretation phase, reporting and critical review of the LCA, limitations of the LCA, the relationship between the LCA phases, and conditions for use of value choices and optional elements. In regard to ISO 14040 for LCA, four interrelated phases are described. These are: (i) definition of scope and goal (ISO 14041), (ii) inventory analysis (ISO 14041), (iii) impact assessment (ISO 14042), and (iv) lifecycle interpretation and results (ISO 14043). These are generally constructed as part of an iterative process whereby feedback is consistently communicated from and incorporated into different LCA phases. In addition, the standards provide guidance on the nature and quality of data collected for the LCA study.

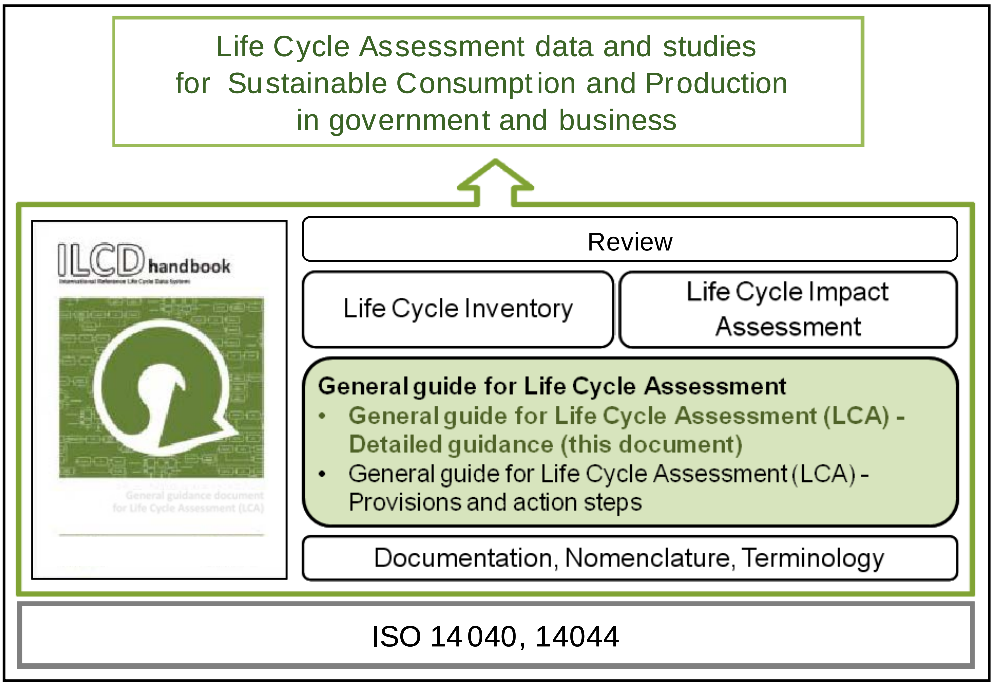
The ISO standard 14040 provides an overview of the practice, applications, and limitations of LCA. It does not provide a detailed review of the techniques or methodologies for individual phases of the assessment, given that the purpose of the standard is cross-applicability between diverse sectors. ISO 14040 provides the methodological requirements with which any LCA should comply. The standard cannot lay out specific recommendations on practice because the significance of different characteristics and processes vary so much from one LCA to another. Therefore, there are several ways in which an LCA can be ISO compliant.

5.2.3. International Reference Lifecycle Data System (ILCD) handbook (European Commission, 2010)

In 2010, the European Commission, together with the Joint Research Centre (JRC) and the Institute for Environment and Sustainability published the first edition of the International Reference Lifecycle Data System (ILCD) Handbook. The goal of the ILCD Handbook is to provide technical guidance for detailed LCA studies as well as the technical basis to derive product-specific criteria, guides, and simplified tools. It is based on and conforms to the ISO 14040 standards but extends beyond these, providing additional details for lifecycle assessments (Figure 5.1). Specifically, the ILCD Handbook further details the ISO provisions for the three main areas of support: (i) micro-level decisions, (ii) meso-/macro-level decisions, and (iii) accounting. Micro-level decisions are assumed to have limited structural consequences outside the decision context, so that decisions have no direct impact on production capacity. Meso-/macro-level decisions are assumed to have structural consequences outside the decision context, directly affecting production capacity. Finally, accounting provisions are purely descriptive documentation of the system's life.

The objective of the handbook is to achieve more sustainable production and consumption patterns, by providing producers and consumers with a framework to consider the environmental implications of the whole supply chain of products (both goods and services), their use, and waste management.

Figure 5.1. The role of the ILDC Handbook in LCA guidance (European Commission, 2010)



5.2.4. Rigor, complexity, and calculation detail

Modeling efforts should take an appropriate approach to determine a balance of rigor and detail, given the associated trade-offs and data limitations:

- Where possible, the model should use fundamentals of petroleum engineering and earth sciences to define functional relationships and parameter values. Sources with appropriate rigor include peer-reviewed literature, industry texts, and reference handbooks used in industry. Web sources and other informal sources should be minimized where possible.
- The model should not be more complex than necessary, given uncertainties and accuracy of data inputs. In general, the level of detail in an LCA model is not expected to approach that used in calculations for industry production and operations purposes. Not only is such detail unneeded, but the additional data inputs required in such a model would make an LCA tool difficult to use.
- The model should aim to include rigorous default values or include default relationships in the absence of reasonable single values of input data (see §6.4.3.c).

5.2.5. Transparency

Lifecycle modeling should be performed in as transparent a fashion as possible. Some models, due to dependence on proprietary data or methods, cannot be made public. In that case, use of such proprietary models should be minimized. Transparency is especially important in an LCA tool that will be used in the public domain. This transparency has a number of dimensions:

- Documentation should be complete and thorough and should explain in sufficient detail all major aspects of the model.
- All sources should be cited clearly in both model structure and documentation.
- Publicly available sources should be used wherever possible. While exceptions may need to be made for accurate model functioning, these should be minimized.
- All model calculations should be accessible to the user, to the extent that they do not excessively reveal any proprietary data sources used.
- The model should be built using a widely used and accessible program (e.g., Microsoft Excel).
- The model should be freely downloadable over an open and accessible website.

5.2.6. Completeness

Model development should be as complete as practicable. Attention should be paid to the importance of various sources. More specifically:

- The modeling should address all lifecycle stages of oil and gas production, including exploration and drilling, production and extraction, surface processing, maintenance, waste disposal, and crude transportation.
- The modeling should take in (as needed) all possible types of emissions sources from oil and gas operations, including combustion emissions, flaring emissions, fugitive and vented emissions, land use emissions, and emissions embodied in purchased electricity or other consumed materials used on-site.

5.2.7. Usability and controls

Ease of use, as well as internal controls to prevent misuse, is an essential feature of a modeling framework intended for general use. The usability and safety features to ensure ease of use include the following:

- The user should access the model, in nearly all cases, through a front-user control and results sheet. This will allow a user to input a set of data into the model and to generate results without modifying the numerous background aspects of the model.
- The model should present graphic results in easy-to-read and easily exportable format.
- The model should alert the user when data are entered incorrectly. Such data entry errors could include fractional percentages that do not sum to 100 percent, or nonphysical assumptions.

- The model should alert the user when an improbable combination of data is entered into the model. For example, if a user supplies a pressure that is far below the expected pressure at a given field depth, the model should alert the user that this is a possible data error. The model should continue to run but should simply alert the user that this is an area that might need more attention.
- The model should collect all error statements and caution statements in an easy-to-read summary sheet to check for model running capability.

5.2.8. Data, defaults, and model parameterization

Any modeling framework should give significant attention to concerns about data availability and quality:

- The LCA modeling effort should include a data quality assessment as a fundamental part of the analysis.
- Effort should be applied to find accurate data inputs for default parameters and relationships.
- The model should be parameterized with a variety of default values or default relationships so that it can be run to estimate emissions in the absence of complete information[86].
- The model should strive to include realistic default values for parameters of secondary importance or for constants needed in computations.
- Where input parameters have important variation over the life of the field or in proportion with other known parameters, default relationships should be specified in preference to default values. For example, if the water-to-oil ratio is not known, a default relationship that relates the age of the field to the expected water-to-oil ratio should be used in preference to a single default value for all fields.

5.2.9. Model output and results presentation

Model outputs should be specified in forms that are usable and fully comparable to other studies (e.g., gCO_2e/MJ). The model should allow flexible outputs in forms that are readily usable in other fuel lifecycle models (e.g., GREET, GHGenius).

[86] For additional information regarding OPGEE defaults, please refer to §7.3.3.

6. OPGEE

6.1. Introduction

At the core of this project is the oil production greenhouse gas emissions estimator (OPGEE), an engineering-based lifecycle assessment tool for the measurement of greenhouse gas emissions from the production, processing, and transport of crude petroleum. It is a project of Stanford University, with contributions from the California Air Resources Board (CARB) and the International Council on Clean Transportation (ICCT), administered by Dr. Adam Brandt. OPGEE is an upstream model - the system boundary extends from initial exploration to the refinery gate -, and emissions are reported in terms of grams of carbon dioxide equivalent per megajoule (gCO_2e/MJ) of crude oil delivered to the refinery (using lower heating values). OPGEE has been developed to fill a gap in the set of currently available tools for GHG analysis of oil production. Tools like GREET and GHGenius have broad scope, are publicly available and transparent but do not include process-level details. Models such as those used by Jacobs and Energy-Redefined examine processes but are proprietary, and results from these models cannot be reproduced by the public or interested parties.

The OPGEE model is built in the spreadsheet application Microsoft Excel. Excel is a widely owned and familiar software, and its use makes the workings of the model (including all calculations) accessible to most potential users. It also enables the model to be modified by users. A full explanation of OPGEE is available in the OPGEE documentation, attached as Annex C of this report. Alongside this report, the ICCT has included a modified version of OPGEE used to calculate the EU baseline, OPGEE 1.0.ICCT.

6.2. OPGEE development

OPGEE was developed with funding from the California Air Resources Board in support of the California Low Carbon Fuel Standard (LCFS). The CA-LCFS seeks to reduce the carbon intensity (CI) of transportation fuels by 10 percent from the baseline value by 2020. A significant need for CA-LCFS implementation is that the baseline CI of current fuels be constructed using an accurate and robust methodology. Since baseline fuels are almost entirely petroleum-based, a predictive model was required to estimates GHG emissions from oil and gas operations.

The goals of OPGEE development were to:

1. Build a rigorous, engineering-based model of GHG emissions from oil production operations.
2. Use detailed data, where available, to provide maximum accuracy and flexibility.

3. Use public data wherever possible.
4. Document sources for all equations, parameters, and input assumptions.
5. Provide a model that is free to access, use, and modify by any interested party.
6. Build a model that easily integrates with existing fuel cycle models and could readily be extended to include additional functionality (e.g., refining)

In the summer and autumn of 2011, a model-scoping plan was created and circulated to interested regulators, industry observers, and other interested parties. This scoping plan was not released for general comment. Based on comments received, the scope and planning of the model was revised somewhat. At that stage, a large variety of data sources were accessed and compiled. Industry-specific reference texts were purchased (see OPGEE documentation for the full list of technical references). Peer-reviewed oil industry literature databases were gathered. More than 125 sources were accessed in model development.

In early 2012, a beta version of OPGEE was created. This was an initial "scoping" version that was created to solicit feedback from industry observers and other experts. This beta version was introduced in a public workshop on March 19 at the California Air Resources Board. Verbal and written comments from this process were incorporated into the revisions to the model.

After the beta version of OPGEE was released and revisions were made, the OPGEE documentation was created. This model documentation aimed to:

1. Explain the use of the model, the required data, and the method of gathering results.
2. Give advice for effective use of the model with limited data availability.
3. Document all major equations in the model, with easy access to model pointers so that the documentation serves as effective reference for the model.
4. Document data inputs for all model parameters, ranges of parameters, and any "smart defaults" that were developed to aid in predictions with limited data.
5. Document assumptions and simplifications made in model development.

The model documentation and draft version of OPGEE v1.0 (called OPGEE v1.0 draft a) were released in a workshop on July 12, 2012, at the California Air Resources Board offices. Verbal and written feedback was solicited from workshop participants. No official comments were taken at this meeting, although extensive feedback was received and incorporated (where possible) into the model.

The proposed CARB regulatory version of OPGEE v1.0 was released to official public comment on September 17, 2012.[87] On November 26, the regulation became effective. Most recently, a March 5th 2013 CARB public

[87] http://www.arb.ca.gov/regact/2011/lcfs2011/lcfs2011.htm

workshop presented a revised OPGEE version 1.1 draft a, with stakeholder comments due by April 5th of 2013. This latest version of OPGEE includes a number of improvements, including:

1. An enhanced user inputs worksheet for the implementation of new macro for the bulk assessment.
2. More flexible modeling features allowing for the removal of gas processing units, addition of ocean tanker size and volume fraction of diluent.
3. Modified accounting of emissions that removed the allocation of off-site GHG emissions (credits/debts), added a separate emissions category for total off-site GHG emissions and a separate emissions category for diluent lifecycle emissions.
4. An enhanced graphing interface
5. Modified land use change emissions factors to account for 30 year analysis period
6. Added petroleum coke lifecycle energy consumption and GHG emissions based on GREET
7. A new model functionality for flaring efficiency calculations that incorporates the choice of including flare tip diameters as well as including a wind impacts.
8. An improved water-oil ratio smart default with extended geographical coverage, inclusion of fields larger than 630 M bbl and the elimination of long tail effects.
9. A more detailed demethanizer model that includes energy consumed by demethanizer
10. The option of diluent blending after production that accounts for indirect GHG emissions associated with importing NGL for use as diluent
11. A non-integrated upgrader option for heavy oil (non-bitumen pathways)
12. Allowed processing configuration flexibility to be able to switch dehydrator, AGR unit and/or demethanizer on and off.
13. Changed heater/treater calculations so that default oil emulsion (14% emulsified water) gives fraction of emulsified water irrespective of WOR
14. Improved compressor model so that it varies between 1 and 5 stages
15. As well as a number of minor error correction and model clarifications

6.3. Modeling considerations

6.3.1. Co-produced natural gas and electricity

Many oilfields not only produce crude oil, but also export natural gas and/or excess electricity. As detailed in Annex D, §4.7, OPGEE handles these co-products through system expansion, rather than by allocation. System expansion is recommended as the preferred methodology to handle co-product emissions by the ISO LCA standards. Where co-products are exported, an emissions credit is calculated and attributed to the oilfield based on the emissions avoided by displacing natural gas production or electricity production from the rest of the system. The default electricity generation in OPGEE is natural gas based, and hence excess electricity exports are assigned a credit assuming displacement of natural gas based electricity. A larger credit would be assigned if displacement of coal based electricity was assumed, or a smaller credit for displacement of renewable electricity. In principle, it would be possible to implement regionally specific characterization of the carbon intensity of displaced electricity, but such an inventory has not been implemented at this stage. The carbon intensity value for natural gas production is based on the lifecycle inventory used in CA-GREET.

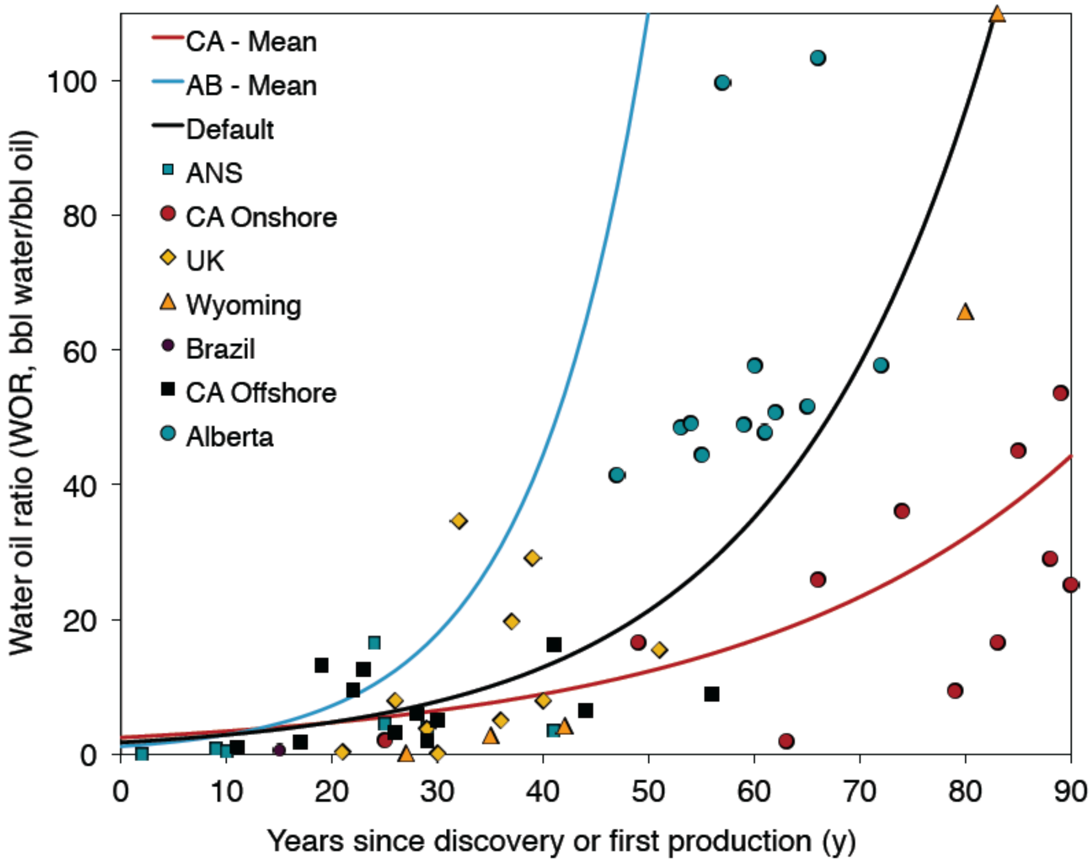
6.3.2. Dynamic emissions estimates

Emissions from an oilfield will tend to *increase* over time rather than decrease. This results from a variety of conditions that change as an oilfield ages. Operating improvements may offset some of these, but the likely net effect of field age is to increase emissions.

As an oilfield ages, a variety of developments will cause emissions to rise: increased water production per unit of oil production, increased gas production per unit of oil production, increased wear on devices, and increased likelihood of need for maintenance operations such as well work-overs and equipment blowdowns (gas evacuations) that require venting of emissions.

Age increases water production significantly in an oilfield (see Figure 6.1). Because of the effects of multiphase flow in the subsurface, as the oil saturation decreases in a reservoir, the water production increases, sometimes rapidly. This increased water production is generally difficult to reverse due to the preferential flow of low-viscosity water compared to high-viscosity oil (e.g., once water flow is established, the reservoir will resist efforts to force the flow of more viscous oil). As water flow per unit of oil increases, the amount of effort required per unit of oil produced greatly increases. This increases the work of production and increases emissions while also increasing costs, which is why wells and fields are generally shut in after they “water out”.

Figure 6.1. Exponential WOR model using mean results for Alberta and California cases. Default case is a moderate case that is between the Alberta and California cases.



As oilfield pressure drops, increasing amounts of gas are evolved from the oil in the reservoir. This results in a generally increasing gas-to-oil ratio (GOR) as a function of field age. Thanks to the potential for fugitive emissions, higher-GOR fields will likely have a higher GHG burden than low-GOR fields.

Also, over time, oilfield equipment wears and reduces in efficiency. This wear can occur, for example, in pump strings, which can rub on production tubing and increase the work of lifting (Takacs, 2003). Also, as gaskets, seals, and other equipment age, the possibility of fugitive emissions increases. Because maintenance is expensive and labor intensive, oilfield fugitive emissions are likely to increase in older fields compared to younger fields.

Finally, oilfield maintenance operations and process upsets are likely to increase as an oilfield ages. For example, older wells must be worked over to improve flow properties and prolong production. This can involve fugitive emissions when opening the wellbore to the environment. Also, maintenance operations often require that equipment be “blown down” (evacuated of hydrocarbons) for safety prior to operations. Since one can expect maintenance operations to increase in frequency with age, servicing-related emissions are likely to increase.

OPGEE includes the effect of some of these changes over time. The "smart default" for the water-to-oil ratio (WOR) includes a correlation that automatically increases the default WOR as the field ages. OPGEE additionally has the ability to model oilfield changes with age if data are available. For example, if it is known that aging of the oilfield has resulted in reduced lifting efficiency (due to pump wear) and increased fugitive emissions, these changes can be included in the model as changes to inputs in the detailed model calculations.

6.3.3. Modeling highly gaseous oil fields

Highly gaseous oil fields may be associated with higher emissions for several reasons. First, as gas production increases, the possibility of fugitive emissions increases because of the need for more gas handling equipment and higher throughput rates. Second, if flaring is practiced to dispose of gas in remote or uneconomic ("stranded") locations, a highly gaseous field will have higher flaring per unit of oil produced. These effects are seen in the high levels of emissions from flaring in countries such as Nigeria and Russia.

OPGEE can model fields with high rates of gas production, although as the GOR gets very high the results can become quite uncertain without full data coverage (see §8.2.5). As the model GOR is increased, OPGEE automatically increases gas throughputs via the gas balance sheet. This increases the fugitive emissions from gas processing units such as the AGR (acid gas removal) unit.

OPGEE does not have the ability to predict the gas production rate from other parameters such as oil gravity and reservoir pressure. With additional modeling, a coarse estimate could be made of GOR based on oilfield characteristics, but additional data are likely required as well (oil bubble point pressure, etc.). Accurate field-characteristic based estimates of producing GOR are unlikely to be developed due to the uncertainty associated with this variable and lack of required input data, and so GOR is likely to remain a model input rather than a predicted quantity.

6.4. Areas for development in OPGEE

Like any lifecycle analysis tool, OPGEE has limitations that prevent it from being 100 percent accurate 100 percent of the time. These limitations do not prevent OPGEE from generating valuable results. Indeed, OPGEE has been subject to public consultation in California where the Air Resources Board has concluded that OPGEE v1.0 produces results of sufficient accuracy to be used within a regulatory framework. Nevertheless, it is important to acknowledge these limitations and to recognize where there is room for future development.

6.4.1. System boundary

OPGEE includes within its system boundaries more than 100 emissions sources from oil and gas production. The system boundaries of the current version of the model (OPGEE v1.0) encompass emissions sources from all major process stages (e.g., drilling and development, production and extraction, surface processing). However, emissions are subject to significance cutoffs, wherein very small emissions sources are neglected as (likely) insignificant in magnitude. Therefore, some emissions sources from exploration, maintenance, and waste disposal are not explicitly modeled. These cutoffs are applied because it would be infeasible (and counterproductive) for regulators or producers to model the magnitude of every emissions source. It is unlikely that excluding these sources results in any significant inaccuracy in OPGEE. Indeed, OPGEE's system boundaries include a broader coverage of upstream emissions sources than any of the models discussed in §6.4.1.

6.4.2. Technical questions

6.4.2.a. Production modeling

The production technologies included in OPGEE are: primary production, secondary production (water flooding), and major tertiary recovery technologies (steam injection). Innovative production technologies such as solar thermal steam generation and CO_2 flooding are not included in OPGEE v1.0.

OPGEE assumes single-phase liquid flow in the calculation of the pressure drop between the well-reservoir interface and the wellhead. In reality, there is a simultaneous flow of both liquid (oil and water) and vapor (associated gas). Results show that pressure drop calculated using a two-phase flow model can be significantly lower than that calculated using a single-phase flow linear model (Clegg, 2007). The deviation of the single-phase flow assumption from reality is expected to grow with increasing GOR. Adding a two-phase flow model should therefore improve the accuracy of OPGEE for fields with very high GOR.

In the modeling of thermal enhanced oil recovery (TEOR), OPGEE does not currently recognize that the viscosity of the oil in lifting is sensitive to steam injection (Green & Willhite, 1998). The concept of TEOR is based on reducing the viscosity of the oil, and this should decrease the lifting energy requirement. This effect is likely to be small compared to overall emissions for TEOR projects, because the bulk of the energy consumption in TEOR is from steam generation and not from lifting, but still modeling the viscosity reduction would improve the results.

6.4.2.b. Surface processing modeling

In OPGEE it is not possible to account for the wide variations in surface processing. The goal is to include the most frequently applied processes in the industry while still retaining some flexibility to model varying operating modes.

For example, the placement of a heater/treater in water-oil separation significantly affects the result. Also, the associated gas-processing scheme has a default configuration that includes gas dehydration and acid gas removal (AGR) units, which are not used in all oilfields.

6.4.3. Data availability

6.4.3.a. Flaring

Default flaring rates (millions of standard cubic feet per barrel of oil) used in OPGEE to model GHG emissions from gas flaring are calculated using country-level data, which cannot account for variations in field characteristics and practices. These country-level estimates are calculated using data from the National Oceanic and Atmospheric Administration and the Energy Information Administration (Elvidge et al., 2007; Elvidge et al., 2009; EIA, 2010). While data is available for reported flaring emissions in some jurisdictions (e.g. Nigeria), in general it is difficult to obtain field specific flaring data. Ongoing work with UC Davis is attempting to achieve a much better resolution for the satellite data, enabling flares to be connected to specific fields and field specific flaring rates to be calculated.

6.4.3.b. Fugitives and venting

Most fugitive and venting emissions in OPGEE are calculated using emissions factors derived from CARB industry survey data (Lee, 2011).[88] The completeness and quality of data collected in the survey is challenging to verify (as is common with survey data). Also, the data are specific to California, where environmental regulations and practices are different from other regions. Further investigation would be appropriate to determine whether it would be appropriate to adjust these California based defaults to better characterize practices in other regions.

6.4.3.c. Default specifications

All inputs to OPGEE are assigned default values that can be kept as is or changed to match the characteristics of a given oilfield or marketable crude oil name (MCON). If only a limited amount of information is available for a given field, most of the input values will be set to defaults. In contrast, if detailed data are available, a more accurate emissions estimate can be generated.

Some defaults require more flexible (“smart”) default specifications. The water-to-oil ratio (WOR) is an important parameter influencing GHG emissions. OPGEE includes a statistical relationship for water production as a function of reservoir age. The default exponential relationship is a moderate case parameterized with a variety of industry data. Nevertheless, this relationship does not work well in all cases – for

[88] California emissions factors are used except for CO_2 venting from the AGR unit, venting from storage tanks, and fugitive emissions from production equipment (valves, connectors, seals, etc.)

instance, it can give misleading results for giant fields with a very high productivity index (e.g., those in Saudi Arabia[89]).

The GOR varies over the life of the field. As the reservoir pressure drops, increasing amounts of gas evolve from oil (beginning at the bubble point pressure if the oil is initially undersaturated). This tends to result in increasing GOR over time. Also, lighter crude oils tend to have a higher GOR. Because of this complexity, a static single value for GOR is not desirable. OPGEE uses California producing GORs to generate GORs for three crude oil bins based on API gravity. All the data required to generate empirical correlations for GOR are not likely to be readily available.

6.4.3.d. General lack of data availability

As noted in several places in this report, in general, many input parameters are not available in the public domain for any given oilfield. There are exceptions where better data is available, and these relatively well-documented fields have been used as representative fields to build the EU Baseline in this report (§8). Still, even for these fields many parameters must still be based on defaults, and this restriction on data availability is the greatest challenge to the use of OPGEE to assess oilfield emissions globally.

6.4.4. Uncertainty

OPGEE estimates GHG emissions based on data about oilfield operations. OPGEE can function using limited data for a given field by relying on default values and smart defaults. If only a small subset of the required data inputs is available for a given field, then most OPGEE parameters will be set to default values. Because OPGEE was designed for "typical" oilfields with moderate conditions, it works well to estimate energy demand in these cases. However, if OPGEE is applied to a field with extreme characteristics (very high WOR, high GOR, significant amounts of gas reinjection), then OPGEE defaults may be less representative of how that field may actually operate. An example of this is given by El-Houjeiri et al. (2013) for the Alaska North Slope region, where there are unusual surface processing arrangements owing to the very high GOR and remote location with no gas infrastructure.

When using OPGEE to model fields with regulatory and other public datasets,[90] it is common that production data will be available in some detail, while little public data will be available on the oilfield configuration and production design. Associated gas production will often be reported, which allows computation of the field GOR. However, generally, it will not be reported whether the same field uses an AGR unit to treat the associated gas, and sometimes it is not reported whether the field reinjects the gas, flares it, or sells it to the

[89] The WOR for Saudi Arabian fields is referenced to literature sources in the EU Baseline.
[90] For instance, when using the data published by the UK Department of Energy and Climate Change for the country's North Sea fields.

market. For high-GOR fields, there could be substantial emissions uncertainty associated with this question (see Annex D, Table C.3).

For a given field, it is impossible to know, a priori, how large the distortion from reliance on defaults will be. Only by accessing more data and customizing OPGEE inputs to match field conditions can one definitively quantify any distortion. In most cases, we believe it is likely to be small. For example, El-Houjeiri et al. (2013) observe that for the OPGEE "generic" case (moderate WOR, moderate GOR), OPGEE default assumptions about pump efficiencies, electricity use, pump driver type, and other "secondary" assumptions were responsible for only very small (< 0.5 g/MJ) deviations in model results when varied over reasonable observed values. That is, OPGEE was not sensitive to modeler assumptions about field parameters and equipment. In cases with more extreme production patterns, however, this result may not always hold (see §8.2.7.b).

6.4.5. LCI consistency

The lifecycle inventory (LCI) data (such as the carbon intensity of diesel fuel, electricity and natural gas) used in OPGEE are chosen to be congruent with the CA-GREET model. This reflects the focus on the California fuel market in the original development of OPGEE. GREET is a well-established and respected LCA system, but using CA-GREET data as OPGEE inputs means that there is less regional specificity to input data than would be ideal. There is also an issue of consistency of the input LCI data with the model results. To give an example, because OPGEE predicts high carbon intensity for most Nigerian crudes, we might expect diesel fuel used in Nigerian crude oil production to have a higher carbon intensity than the average diesel fuel used in California. However, because CA-GREET LCI data are used, this linkage would be missed. Ideally, the model would capture such regional variation in process fuel carbon intensity, but turning OPGEE into a fully integrated modeling system would represent a major modeling challenge, and was beyond the scope of the exercise presented in this report.

6.5. Future work on OPGEE

Potential future work and model improvements focus on the following areas:

- Calibrating the model to oil field emissions inventory data. If detailed data about oil field production parameters can be combined with emissions inventory data, it would allow the estimates from OPGEE to be directly tested, and calibrated as necessary. This would likely require cooperation from oil industry stakeholders.
- Developing a two-phase flow-lifting model. This adds complexity to model calculations but does not increase the number of input parameters.

- Building modules for innovative production technologies such as solar steam generation and CO_2 flooding.
- Making the lifting model sensitive to the viscosity change induced by steam injection. Adding emissions associated with the demethanizer (refrigeration system and fractionation column). Implemented in OPGEE v1.1.
- Adding flexibility to the gas-processing scheme: allow the options of removing the gas dehydrator, AGR unit and/or demethanizer. Collecting more data and improving the correlations of WOR and GOR defaults. Implemented in OPGEE v1.1
- Calculating field-level flaring rates using ongoing work by Elvidge (NOAA) and Hart (University of California, Davis).
- Using technical reports and workbooks to update fugitive and venting emissions factors.
- Building an engineering-based model for the calculation of GHG emissions from oil sands production (the current module is derived from GHGenius [see http://www.ghgenius.ca/]).
- Many OPGEE defaults, including default processes, are currently not sensitive to region or development type. Additional consultation with industry and examination of the petroleum engineering literature may allow default typical local production practices (for example for North Sea offshore production) to be more accurately identified, and used in place of global defaults.
- The OPGEE model has been released and made available for stakeholder comment in California, but not to date in Europe. Actively seeking input from European stakeholders with petroleum engineering expertise and access to industry data would provide an opportunity for further calibration of OPGEE and expansion of the EU Baseline database.
- El-Houjeiri et al. (2013) have done some initial sensitivity analysis with OPGEE, but a more systematic and extensive analysis would be very valuable in identifying regulatory strategies and reconfirming that OPGEE estimates are robust enough for regulatory use.

7. Data availability and collection

This chapter provides an overview of the data that have been identified as potential sources of supplementary inputs for the oil production greenhouse gas emissions estimator (OPGEE) model. The objective of this analysis is to determine the quantity, quality, and (in certain cases) cost of available data as it pertains to the calculation of greenhouse gas (GHG) emissions from conventional and unconventional crude oil sources. Given limitations of data access and transparency within the oil industry, many oilfields have scarce information in the public domain. Whereas publicly available data sources have been prioritized, the study has also identified proprietary datasets.

The current analysis is focused on populating OPGEE with data relevant to the EU, however, some of the sources reviewed refer to North American production that is not currently exported in any quantity to Europe. In some cases, data from North America have been used to calibrate and/or populate the OPGEE model–this takes as an assumption that these relatively data-rich operations can be considered representative of crude extraction operations elsewhere. The subsequent section first highlights the main data requirements of the OPGEE tool, followed by a description of a number of available data sources.

7.1. Data requirements of OPGEE model

As previously described, the OPGEE model is an open-source, fully public, engineering-based model of GHG emissions from oil production operations that is currently being developed for the California Air Resources Board (CARB) and the European Commission by Hassan M. El-Houjeiri and Adam R. Brandt at Stanford University, with the collaboration of the International Council on Clean Transportation (ICCT) (see Annex D for additional information). The model employs an engineering framework based on bottom-up modeling of production, processing, storage, and transport of oil to refineries using field characteristics as input data. The tool aims to develop a standardized methodology for assessing GHG emissions from fuel production (Brandt and Houjeiri, 2011). For data inputs, the model relies primarily on publicly available, disaggregated data for all input equations and parameter defaults. The focus on publicly available data in the development of OPGEE reflects the desire to maximize the credibility of the model by way of transparency and clarity of assumptions. Having said this, the challenge of obtaining information that is both accessible and of solid quality may hinder the intention to rely solely on public datasets.

In its current design, OPGEE describes well-to-refinery gate operations in six stages: (i) exploration and drilling, (ii) production and extraction, (iii) surface processing, (iv) maintenance, (v) waste disposal, and (vi) crude transport. Web sources and public domain data, journal articles, textbooks, and industry references currently provide the basis for the lifecycle modeling of these processes. Table 7.1 provides a summary of the currently cited literature and standards organized by different lifecycle processes for conventional crudes.

Table 7.1. OPGEE references cited by lifecycle process (El-Houjeiri and Brandt, 2012)

LIFECYCLE PROCESS	REFERENCES
Drilling	Mitchell, R., Miska, S. *Fundamentals of Drilling Engineering*
	Gidley, J., Holdtich, S., Nierode, D. *Recent Advances in Hydraulic Fracturing*
	Lake, L. *Petroleum Engineering Handbook: Volume I-VI*
	Devereux, S. *Practical Well Planning and Drilling Manual*
	Azar, J., Samuel, G. *Drilling Engineering*
Production	Raymond, M., Leffler, W. *Oil and Gas Production in Nontechnical Language*
	Allen, T., Roberts, A. *Production Operations 1: Well Completions, Workover, and Simulations*
	Lake, L. *Petroleum Engineering Handbook: Volume I-VI*
	Cholet, H. *Well Production: Practical Handbook*
Lifting and Pumping	Takacs, G. *Modern Sucker-Rod Pumping*
	Takacs, G. *Sucker-Rod Pumping Manual*
	Takacs, G. *Gas lift manual*
General Environmental Issues	Wilson, M., Frederick, J. *Environmental Engineering for Exploration and Production Activities*
	Reed, M., Johnsen, S. *Produced Water 2: Environmental Issues and Mitigation Technologies*
Secondary Recovery (Waterflooding)	*Waterflooding.* SPE reprint series no. 56
	Craig, F. *The Reservoir Engineering Aspects of Waterflooding*
	Rose, S., Buckwalter, J., Woodhall, R. *The Design Engineering Aspects of Waterflooding*
Enhanced Oil Recovery	Green, D., Willhite, G. *Enhanced Oil Recovery*
	Prats, M. *Thermal Recovery*
	Jarrell, P., Fox, C., Stein, M., Webb, S. *Practical Aspects of CO_2 flooding*
Enhanced Oil Recovery System Details	American Petroleum Institute standards:
	RP 534 - Heat Recovery Steam Generators
Surface operations, Separations and Processing	Chilingarian, G., Robertson, J., Kumar, S. *Surface operation in petroleum production, I & II*
	Manning, F., Thompson, R. *Oilfield Processing of Petroleum. Volume 1: Natural Gas*
	Manning, F., Thompson, R. *Oilfield Processing of Petroleum. Volume 2: Crude Oil*

LIFECYCLE PROCESS	REFERENCES
Crude Transport	Szilas, A. *Production and transport of oil and gas. Part B: Gathering and transport*
	McAllister, E.W., *Pipeline Rules of Thumb: Handbook*
	Miesner, T., Leffler, W. *Oil and Gas Pipelines in Nontechnical Language*
Surface Operations	American Petroleum Institute standards:
	Spec 12J - Specification for Oil and Gas Separators
	Spec 12K - Specification for Indirect Type Oilfield Heaters
	Spec 12L - Specification for Vertical and Horizontal Emulsion Treaters
	RP 50 - Natural Gas Processing Plant Practices for Protection of the Environment
	RP 51R - Environmental Protection for Onshore Oil and Gas Production Operations and Leases
Venting, Flaring, and Fugitive Emissions	American Petroleum Institute standards:
	RP 1127 - Marine Vapor Control Training Guidelines
	RP 1124 - Ship, Barge and Terminal Hydrocarbon Vapor Collection Manifolds
	Publ 1673 - Compilation of Air Emission for Petroleum Distribution Dispensing Facilities
	Std 521/ISO 23251:2006 - Guide for Pressure-relieving and Depressuring Systems
	Std 2000/ISO 28300 - Venting Atmospheric and Low-pressure Storage Tanks
	Std 537/ ISO 25457:2008 - Flare Details for General Refinery and Petrochemical Service
	Publ 306 - An Engineering Assessment of Volumetric Methods of Leak Detection in Aboveground Storage Tanks
	Publ 334 - A Guide to Leak Detection for Aboveground Storage Tanks
Other	American Petroleum Institute standards:
	DR 141- Global Emissions of Carbon Dioxide from Petroleum Sources
	Schmidt. *Fuel Oil Manual*

In addition to the above-cited references, the study relies on various publicly available data regarding emissions factors and specifications for engineering components used in the production of conventional fuels. These include emissions factors from GREET (the Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation Model), oil and gas engine specifications from Caterpillar, Inc., and electric motor attributes from General Electric. The study also relies on country-specific crude oil production data from the Energy Information Agency (EIA) and regional flaring volumes from the National Oceanic and Atmospheric Administration (NOAA) (to determine average regional flaring rates).

Table 7.2. Public data sources currently referenced in OPGEE Model (El-Houjeiri and Brandt, 2012)

SOURCE	REFERENCED INFORMATION
GREET	Emissions Factors: Boilers/Heaters, Turbines, Reciprocating Engines, and Flaring with 0.2% Non-combustion
	Fuel Cycles and Displaced Systems for Natural Gas
	Ocean Tanker/Pipeline Transport
	Fuel Specifications (Liquid Fuel Heating Values)
Caterpillar, Inc.	Technical Sheets for Oil and Gas Engines
General Electric (GE)	Technical Sheets for Electric Motors
EIA	Country-Specific Crude Oil Production
NOAA	Country-Specific Flaring Volumes

The OPGEE model is designed so that users can estimate GHG emissions from specific crude feedstocks and production processes by providing a number of input parameters. These can be divided into four groups: (i) general field properties, (ii) fluid properties, (iii) production practices, and (iv) processing practices (see Table 7.3). In addition to these parameters, the model includes a number of inputs related to land use impacts, crude oil transport, unit efficiencies, and small-source emissions. As described in the model documentation, in many instances these parameters use default values (given the lack of field-level data). In the case of California, many of the model's input requirements were available through the California state Division of Oil, Gas, and Geothermal Resources (DOGGR) report (2007) and the CARB survey (2011), as well as through national authorities like the EIA. In the cases of the EU and Africa, only Britain, Denmark, and Nigeria publish extensive national oil production statistics at the field level, to the best of our knowledge. These datasets are made available via the British and Danish energy agencies and the Nigerian National Petroleum Corporation (NNPC) and contain detailed (monthly) time series data at the field level across a number of parameters included in the OPGEE model. Even so, many parameters are absent from these datasets and have had to be supplemented from other sources or based on defaults.

Table 7.3. OPGEE required data inputs (El-Houjeiri and Brandt, 2012)

GENERAL FIELD PROPERTIES	PRODUCTION PRACTICES
Field Location Field Depth Field Age Reservoir Pressure Oil Production Volume Number of Producing Wells	Gas-Oil Ratio (GOR) Water-to-Oil Ratio (WOR) Steam-to-Oil Ratio (SOR) Water Injection (Y/N, Quantity) Gas Injection (Y/N, Quantity) N2 Injection (Y/N, Quantity) Steam Injection (Y/N, Quantity) On-site Electricity Generation
PROCESSING PRACTICES	**FLUID PROPERTIES**
Heater-Treater (Y/N) Stabilizer Column (Y/N) Flaring Volume Venting Volume	API Gravity of Produced Fluid Associated Gas Composition

7.2. Public dataset overview

7.2.1. CARB Survey Data for California

As one of a number of measures under the California Global Warming Solutions Act of 2006 (commonly referred to as AB 32), requiring reductions of greenhouse gas emissions to 1990 levels by 2020, CARB has surveyed relevant parties in the oil and gas sectors of California. In 2009 the survey was mailed out to crude oil and natural gas production, processing, and storage facilities in California. The purpose of this survey was to create a comprehensive tool that could be used to create a robust GHG emissions inventory for the oil and gas production sector. In previous years, CARB had already identified a list of discrete early action measures, assembling an inventory of historic emissions, establishing GHG reporting requirements, and setting the 2020 emissions limit that would serve as the basis for future refinements.[91] As a result of this work, CARB recognized the oil and gas production sector as well as transmission and distribution pipeline systems as important contributors to GHG emissions. In order to further investigate the sources of these emissions, the 2007 survey was sent out to a total of 1,429 companies operating within the state. Of these, 960 were removed from the list after they were identified as being out of business, having merged or been bought by other companies, or not operating within the crude oil and gas industry. Consequently, a total of 325 companies, representing approximately 97 percent of the 2007

91 As part of this project, in November 2007, CARB published the 1990–2004 California GHG inventory.

crude oil and natural gas production in California, completed the survey.[92]

Table 7.4. Referenced sources of emissions factors and calculation methodologies (CARB, 2011)

SOURCES
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HARC (2006). Houston Advanced Research Center. VOC Emissions From Oil and Condensate Storage Tanks. October, 2006.
INGAA (2005). Interstate Natural Gas Association of America. Greenhouse Gas Emission Estimation Guidelines for Natural Gas Transmission and Storage, Volume 1.
Kern County APCD (1990). Corrections to CARB's AB2588 Air Toxics "Hot Spots" Technical Guidance Document Table D-1, Page 118. April 25, 1990.

The survey collected data from equipment information to serve as inputs for commonly used and publicly available equations and emissions factors.[93] These were primarily derived from EPA guidelines and the American Petroleum Institute (API) compendium of GHG

92 The response rate of the survey was 83 percent after excluding companies that had gone out of business, had merged or been bought by another company, or were mistakenly thought of as being in the crude oil or natural gas business.
93 In order to reduce the complexity of assigning emissions to a particular company, CARB allowed the company to list a company name, a facility location, and a facility identification number (ID). The facility location and facility ID were defined by contiguous property boundaries. As a result, 325 companies representing 1,379 facility locations and 1,632 facility IDs in 17 air districts across California completed the survey.

emissions methodologies for the oil and gas industry. The reporting unit for the survey was at the level of the operator or in some cases the financial jurisdiction. Overall, the survey collected information from the following categories: (i) facility type, (ii) facility production, (iii) facility electrification, (iv) vapor recovery and flares, (v) combustion equipment, (vi) component counts, (vii) automated control devices, (viii) inspection and maintenance program, (ix) natural gas dehydration, (x) natural gas sweetening or acid gas removal, (xi) other natural gas processing, (xii) natural gas compressors, (xiii) pipelines, (xiv) crude oil or natural gas separation units, (xv) crude oil separation sumps or pits, and (xvi) crude oil storage tanks.[94] The results for both the oil and the gas sectors' total California emissions were reported by type: combustion, vented, and fugitive. The total estimated emissions derived from the equipment covered by the survey were 18.8 million metric tons of CO_2 equivalent, with combustion sources (equipment burning fuel for energy) accounting for 87 percent of the total CO_2e emissions.[95]

One of the major challenges presented by these data was the difference in reporting units with the DOGGR survey (see below). While CARB reported at the level of the operator, the latter reported information by field. Therefore, if there is a field with more than one operator (as is the case in many instances), it will be difficult to ensure alignment between these datasets. Nonetheless, the data obtained from the mandatory CARB survey serve as one of the few sources of observed public data on GHG emissions from the oil and gas industry.

We are not aware that a similar survey has been carried out or is being planned for the public domain in any of the countries sourcing the EU. Despite certain caveats, particularly in the reporting unit, the CARB survey is a valuable source of comprehensive public data on crude production. Insofar as these processes are comparable across regions and crude characteristics, the data can be used to cross-populate the model default values for the EU scenario.

94 For additional details regarding the survey distributed by CARB, refer to Annex A of the Oil and Gas Industry Survey Results Final Report (CARB, 2011).

95 The remaining 13 percent (2.4 million metric tons of CO_2e) were derived from vented (3 percent) and fugitive (10 percent) sources. The crude oil industry proved to be the largest emitter, with 58 percent of all California CO_2e emissions derived from onshore crude producing facilities and steam generators contributing to 41 percent of all California CO_2e combustion emissions.

Table 7.5. Total CO_2 emissions for California by crude production range (CARB, 2011)

RANGE (BARRELS CRUDE OIL PRODUCED PER YEAR)	NUMBER OF FACILITIES	TOTAL BARRELS OF CRUDE OIL PRODUCED	% OF TOTAL CO_2 EMISSIONS		
			Combustion	Vented	Fugitive
Not Reported	88	Not Reported	50%	4%	46%
< 1,000	87	42,720	37%	3%	60%
1,000 to 10,000	238	961,326	69%	5%	26%
10,000 to 25,000	84	1,267,662	95%	0%	5%
25,000 to 50,000	57	2,093,042	54%	3%	43%
50,000 to 75,000	21	1,344,532	91%	2%	7%
75,000 to 100,000	11	896,802	29%	2%	69%
> 100,000	99	227,371,062	92%	1%	7%
Totals	684	233,977,146	90%	1%	7%
Averages	86	33,425,307	65%	3%	33%

7.2.2. State of California Division of Oil, Gas, and Geothermal Resources California dataset

The State of California's Department of Conservation Division of Oil, Gas, and Geothermal Resources (DOGGR) publishes an annual report containing production and injection data on all California oil and gas operations. These reports have been produced annually since 1915, although the reporting parameters and methodologies have changed through the years. The most recent available report is from 2010.[96] The publicly available dataset contains detailed descriptions of all operations in California, with production and injection variables by field and operator. The dataset also provides information on reserve revisions, pressure maintenance projects, gas storage projects, carbon dioxide injection projects, enhanced oil recovery projects, oilfield co-generation projects, discoveries, and prospect wells. Currently, the study team is looking to establish 2007 as a baseline year for comparisons of GHG emissions derived from the OPGEE model with observable data collected on GHG emissions by the 2007 CARB Oil and Gas Industry Survey. For this task, the OPGEE model will be adjusted using input values obtained from the DOGGR 2007 annual report.

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96 See DOGGR: http://www.conservation.ca.gov/dog/pubs_stats/annual_reports/Pages/annual_reports.aspx

Table 7.6. Sample aggregated data categories from the 2009 DOGGR annual report

OIL AND GAS OPERATIONS
California District No.1
California District No.2
California District No.3
California District No.4
California District No.5
California District No.6
Offshore
Oil and Gas Statistics
California Oil and Gas Facts
Largest California Fields (2009)
Ten Oil Fields with Largest Production Increases
Ten Oil Fields with Largest Production Decreases
Thirty Largest Oil Producers in California (2009)
Twenty Largest Gas Producers in California (2009)
Production by District
Notices Filed and Inspections
Reports Issued by the Division
Producing Wells and Production of Oil, Gas, and Water by County
Unconventional Petroleum Production in California
Offshore Oil and Gas Fields (2009)
Operations - Oil and Gas Fields
Production and Reserves
Oil and Gas Produced by Operator
Injection
Injection, by Operator
Reserve Revisions
Gas Storage Projects
Carbon Dioxide Injection Projects
Incremental Oil Production from Enhanced Oil Recovery Projects
Oilfield Co-generation Projects
Oil and Gas Discoveries
Oil Sand Discoveries prior to 2009
Prospect Wells Drilled to Total Depth in 2009
Prospect Wells Drilled to Total Depth prior to 2009
Geothermal Operations
Summary of Geothermal Operations
Geothermal Statistics
Geothermal Operations and Feet Drilled
California's Steam-dominated Geothermal Fields
California's Water-dominated Geothermal Fields
Geothermal Exploratory Wells Drilled to Total Depth in 2009
Geothermal CEGA Applications and Site Visits
Fluid Produced and Injected and Power Plant Capacity
Financial Report
Financial Statement (2008–2009 Fiscal Year)
Collection of Funds by Assessment
List of Delinquent Assessments and Penalties

7.2.3. Energy Resources Conservation Board (ERCB) dataset on Albertan crude production

This comprehensive data has been used to investigate well characteristics, develop smart defaults and relationships based on historical relations, and provide insights into unconventional crude production processes. The dataset ST-16 contains monthly pool/deposit-level production and injection records from 1962 to 2011. Data from 2011 were discarded, as observations were available only for the first four months. Overall, 26 injection and 11 production variables are included in the dataset (see Table 7.7). Four out of 975 fields included in the dataset were classified as unconventional, meaning that their primary output was crude bitumen and not crude oil. The WOR was provided within the dataset and was also calculated on a monthly basis for each pool.

The dataset was transferred from a pdf file into a Stata data file so that a longitudinal (panel) dataset could be created. A longitudinal dataset contains observations on multiple production and injection variables over multiple time periods for the same unit of observation. In this case, the unit of observation is the unique identifier (ID) that was created for each possible pool and field combination (51,272), which interacts with a time variable that corresponds to the number of months (588) included in the analysis. Not all combinations have been in production uninterruptedly since 1962, so the dataset is referred to as an unbalanced panel.

Only pool and field combinations for which WOR data are available for at least 6 non-consecutive months and for which the value differed from zero are included in the analysis. A total of 17,082 pool and field combinations satisfied these conditions. A preliminary analysis suggested that many of these pools are extremely small producers and exhibited erratic or sporadic production behavior. We therefore limited the analysis to the top 100 pool/fields. Overall, these pools contributed over 65 percent of Alberta crude production over the dataset time period. The OPGEE documentation (Annex D of this report) provides further details on the results of this analysis in its own Annex D.

Table 7.7. ERCB variables by production process and measurement unit

ABBREVIATION	DEFINITION	PROCESS		MEASUREMENT UNITS	
		Injection	Production	m^3	1,000 m^3
ACID-G	Acid Gas Injection	✓		✓	
AIR	Idem	✓		✓	
AMMNIT	Ammonium Nitrate	✓			✓
AN AMN	Unknown	✓			✓
$BRKH_2O$	Brackish Water	✓			✓
BUTANE	Idem	✓			✓
CO_2	Idem	✓		✓	
COND	Condensate	✓	✓		✓
CR BIT	Crude Bitumen		✓		✓
CR OIL	Crude Oil		✓		✓
CR-OIL	Crude Oil	✓			✓
ENTGAS	Entrained Gas	✓		✓	
ETHANE	Idem	✓			✓
GAS	Idem	✓	✓	✓	
GAS/CDR	Gas/Carbon Dioxide Recovery		✓	✓	
GOR	Gas to Oil Ratio		✓	N/A	N/A
LPG	Liquefied Petroleum Gas	✓			✓
MICLAR	Micellar flooding technology	✓			✓
N2	Nitrogen Gas	✓		✓	
NAPHTH	Naphtha	✓			✓
OIL	Oil	✓			✓
OIL SRCE	Oil Source		✓		✓
OIL/CDR	Oil/Carbon Dioxide Recovery		✓	✓	
OXYGEN	Idem	✓		✓	
PENT+	Pentanes plus (molecules larger than C5)	✓			✓
POLYM	Polymer flood	✓			✓
PROPNE	Propane	✓			✓
SOLV	Solvent	✓		✓	
SRCWTE	Source of Water	✓			✓
STEAM	Idem	✓			✓
WASTE	Idem	✓			✓
WATER	Idem	✓	✓		✓
WGR	Water to Gas Ratio		✓	N/A	N/A
WOR	Water to Oil Ratio		✓	N/A	N/A

7.2.4. Publically available datasets for crudes sources to the EU

The OPGEE project aims to "use public data wherever possible", in order to maximize transparency. Notwithstanding this preference, extensive public datasets for crudes consumed in the EU market were obtained only for British, Danish and Nigerian fields. These datasets are made available via each jurisdiction's energy agency, or in the case of Nigeria from the National Petroleum Corporation (NNPC). The Norwegian Petroleum Directorate (NPD) was also used to supplement information from additional sources, however supplementary information from their public data portal (operated by Halliburton) was unable to be retrieved/purchased. Overall, the above-cited datasets, with the exception of Norway, contain detailed (monthly) time series data at the field level across a number of parameters included in the OPGEE model (see Annex D). Even so, several important parameters are not included in these datasets and have had to be supplemented from a number of different sources. In particular, because the reports are focused on production data, they do not address the physical characteristics of the fields, including parameters such as field depth and reservoir pressure.

Table 7.8. Publically available datasets for crudes sourced to the EU

COUNTRY	SOURCE	YEARS	NUMBER OF DISTINCT FIELDS	PARAMETERS INCLUDED
United Kingdom	Department of Energy and Climate Change (DECC)	1975 – 2011	390	Field Name, Current Operator, Offshore Indicator, Oil Production, Condensate Production, Gas Production, Associate Gas, Gas Flared, Gas Injected, Gas Vented, Produced Water, Produced Water to Sea, Injected Water, Reinjected Produced Water[97]
Denmark	Danish Energy Agency (DEA)	1972 – 2010	19	Field Name, Produced Oil (stb), Produced Water (stb), Produced Gas (scf)
Nigeria	Nigeria National Petroleum Corporation (NNPC)	1997 - 2010	250+	Field Name, Current Operator, Oil Production, Gas Production, Water Production, Number of Wells, API Gravity, Gas Oil Ratio, Gas Used as Fuel, Gas Sold, Gas Reinjected, Gas for LNG, Gas Lift, Total Gas Utilized, Gas Flared.

In addition to the national data reporting for these three countries, we have conducted extensive data searching of online sources, journal articles, textbooks and industry references. These sources are listed in Table 7.9.

[97] All UK volume parameters measured in m^3 except for gas parameters measured in Ksm^3.

Table 7.9. Literature references for the EU Baseline

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SPE 102026	Muqeem, M.A. et al (2006) Underbalanced Drilling in Saurdi Arabia-Start Up Experience. Prepared for ADC/SPE Asia Pacific Drilling Technology Conference 2006, 3–15 November, Bangkok, Thailand. Conference paper SPE 102026-MS.
SPE 105131	Kabir, C.S., Al-Khayat, N.I., and Choudhary, M.K (2008) Lessons Learned From Energy Models: Iraq's South Rumaila Case Study. SPE Res Eval & Eng11 (4): 759-767. SPE-105131-PA.
SPE 107305	Ben Amor, B. et al (2007) Successful Application of Underbalanced Coiled-Tubing Drilling in Horizontal Short-Radius Re-Entry Well to Enhance Oil Production in Hassi Messaoud Field, Algeria. Prepared for SPE/IADC Middle East Drilling and Technology Conference, 22-24 October 2007, Cairo, Egypt. Conference paper SPE 107305-MS.
SPE 111512	Andersson, G. et al. (2008) Innovative Water-Shutoff Solution Enhances Oil Recovery From a West Venezuela Sandstone Reservoir. Prepared for SPE International Symposium and Exhibition on Formation Damage Control, 13-15 February 2008, Lafayette, Louisiana, USA. Conference paper SPE 111512-MS.
SPE 112638	Fipke, S. and Celli, A. (2008) The Use of Multilateral Well Designs for Improved Recovery in Heavy-Oil Reservoirs. Prepared for IADC/SPE Drilling Conference, 4-6 March 2008, Orlando, Florida, USA. Conference paper SPE 112638-MS.
SPE 112904	Qiu, K. et al. (2008) Case Study: The Application of Sand Management Solution for Sarir Field in Libya. Prepared for SPE North Africa Technical Conference & Exhibition, 12-14 March 2008, Marrakech, Morocco. Conference paper SPE 112904-MS.
SPE 112940	Neidhardt, J. et al. (2008) The Omar Field (NE Syria) is Overcoming Its Mid-Life Crisis. Prepared for SPE North Africa Technical Conference & Exhibition, 12-14 March 2008, Marrakech, Morocco. Conference paper SPE 112940-MS.
SPE 11691	Herbas, J. et al. (2007) Evaluating Connected Reservoir Volume for Optimizing Reservoir Management in Farragon Field a North Sea New Development. Prepared for International Petroleum Technology Conference, 4-6 December 2007, Dubai, U.A.E. Conference paper SPE 11691-MS.
SPE 128440	Shatwan, M. Ben (2010) Horizontal Underbalanced Drilling Technology Successfully Applied In Sarir C- Main Field - Libya: Case Study. Prepared for North Africa Technical Conference and Exhibition, 14-17 February 2010, Cairo, Egypt. Conference paper SPE 128440-MS.
SPE 143336-MS	Addoun, et al. (2011) Initial Deployment of a New Design One-Trip Straddle System Resolves High Pressure Cross-Flow Problem in Water Injection Well in Algeria. Prepared for SPE ICoTA Conference, April 5-6 2011, The Woodlands Texas. Conference paper SPE 143336-MS.

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SPE 15334-MS	Chetri, H.B. et al. (2011) Doubling the Production from a Mature Reservoir in North Kuwait-Challenges, Achievements & Lessons Learnt. Prepared for International Petroleum Technology Conference, 7-9 February 2012, Bangkok, Thailand. Conference paper SPE 15334-MS.
SPE 18044-MS	Longo, C.E.C.V. et al (2006) Albacora Leste Field - Subsea Production System Development. Prepared for Offshore Technology 2006, 1-4 May, Houston, Texas. Conference paper SPE 18044-MS.
SPE 20528	Atakan, Z. et al. (2010) Design and Operability Considerations of the Gas Flowline at Parque das Conchas (BC-10) Ostra Field. Prepared for Offshore Technology Conference, 3-6 May 2010, Houston, Texas, USA. Conference paper SPE 20528-MS.
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SPE 38534	MacFarlane, J.S. (1997) Gannet E: The World's Longest Subsea ESP Tie-Back. Prepared for Offshore Europe, 9-12 September 1997, Aberdeen, United Kingdom. Conference paper SPE 38534-MS.
SPE 57065	Tetlow, J. and Wingate, P. (1999) The Britannia Field Development. Prepared for the 1999 Offshore Technology Conference held in Houston, 3–6 May. Conference paper SPE 57065.
SPE 65186	Marquardt, M.B. (2000) Production Gains from Re-Fracturing Treatments in Hassi Messaoud, Algeria. Prepared for SPE European Petroleum Conference, 24-25 October 2000, Paris, France. Conference paper SPE 65186-MS.
SPE 69848	Robles, J. (2001) Application of Advanced Heavy-Oil-Production Technologies in the Orinoco Heavy-Oil-Belt, Venezuela. Conference paper SPE 69848-MS.
SPE 86947	Ramirez, R. et al. (2004) Multilateral Field Experience in Developing an Extra Heavy Crude-Oil Reservoir. Prepared for SPE International Thermal Operations and Heavy Oil Symposium and Western Regional Meeting, 16-18 March 2004, Bakersfield, California. Conference paper SPE 86947-MS.
SPE 87092	Longis, G. et al. (2004) An LWD Formation Pressure Test Tool (DFT) Refined the Otter Field Development Strategy. Prepared for IADC/SPE Drilling Conference, 2-4 March 2004, Dallas, Texas. Conference paper SPE 87092-MS.
SPE 98655-MS	Lilien, J.P. et al. (2006) Development of a Biodiversity Action Plan for the Boscan Field (Western Venezuela). Prepared for the SPE International Health, Safety & Environment Conference, 2-4 April 2006, Abu Dhabi, UAE. Conference paper SPE 98655-MS.
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SubSealQ (10/26/2012)	SubSealQ (10/26/2012) Offshore Field Development Projects - Dalia. Last accessed on 10/31/2012: <http://www.subseaiq.com/data/Project.aspx?project_id=248>.
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Total (2003a)	Total (2003b) Total in Venezuela. Last accessed on 10/31/2012: <http://www.total.com/MEDIAS/MEDIAS_INFOS/661/FR/Total-2003-FieldTrip-Venezuela.pdf>.
Total (2003b)	Total (2003b) Girassol: A stepping stone for the industry. Last accessed on 10/31/2012: <http://www.total.com/MEDIAS/MEDIAS_INFOS/2151/FR/girassol-VA.pdf>.
Total (2007)	Total (2007) Dalia: The conquest of the deep offshore. Last accessed on 10/31/2012: <http://www.total.com/MEDIAS/MEDIAS_INFOS/2139/EN/dalia-conquest-deep-offshore-VA.pdf?PHPSESSID=e41839e02e5e9c7c9cbfb71317d9f9a3>.
Wethington, W.B. et al. (2002)	Wethington, W.B. et al. (2002) Development of a Super Giant, ACG Field, Offshore Azerbaijan: An Overview. AAPG Search and Discovery Article #90007. Presented at AAPG Annual Meeting, March 10-13 2002. Houston, Texas.

7.3. Proprietary dataset overview

7.3.1. Information Handling Services (IHS) dataset

IHS Inc. is a global information company employing over 5,500 people in more than 30 countries around the world. It offers products for all aspects of oil and gas asset management including information covering 425 oil and gas basins worldwide and more than 4 million wells, integrated with more than 15 engineering, economics and interpretation software suites. Although much of their information is concentrated on the U.S. and Canadian markets, the company owns proprietary data and software suites tailored to the global oil and gas industry. In this sense, it is likely to be one of the prime sources of comprehensive proprietary industry information.

We understand that the IHS data includes parameters on: (i) field-level production of oil, (ii) field-level production of gas, (iii) field depth, (iv) field location, (v) API gravity of liquids produced, (vi) field-level injection of water and/or steam, (vii) field level injection of gas, (viii) flaring volumes, (ix) well-head pressure/temperature, (x) reservoir pressure/temperature, (xi) associated gas composition, (xii) field production (water), (xiii) number of producing wells, (xiv) production technology (lifting or separation technology), and (xv) on-site electricity generation. The California Air Resources Board (CARB) have been in contact with IHS but have not, to date, been able to negotiate access to this data for use with OPGEE, nor to obtain a price quote, or confirm data availability. It is estimated that the dataset would fall within a six-figure price range, certainly outside the cost boundaries for purchase for this project. It is also likely that this information would be limited for many of the crude sourced by the EU, particularly field level data in Former Soviet Union (FSU) and Russia.

We believe that Deloitte and Wood Mackenzie own datasets with somewhat comparable scope, but as with IHS, it is unclear at what price or whether these data might be made available to regulators.

7.3.2. Energy-Redefined (ER) dataset

ER owns a dataset including over 6,000 oilfields, which is understood to cover every major field in the world.[98] Although the dataset is proprietary, it is based on an extensive cross-population of both public and proprietary data. These included the EIA, Canadian Association of Petroleum Producers (CAPP), U.S. Geological Service (USGS), the Ministry of Petroleum and Energy of Norway and the UK Department of Energy and Climate Change as well as the U.S. Minerals Management Service.[99] Many other public sources of information are likely to have

[98] Of these, about 4,000 are in countries supplying oil to Europe (ICCT/ER, 2010 and OGJ 2010).
99 On October 1, 2011, the Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE), formerly the Minerals Management Service (MMS), was replaced by

been consulted, including a number of government organizations; however we do not have access to an exhaustive list. For flaring, satellite data (obtained from NOAA) was paired with country-level emissions factors from the Global Gas Flaring Reduction Unit (GGFR) at the World Bank. Similarly, fugitive emissions were determined on the basis of CAPP emission factors (CAPP, 2002) for equipment fittings such as seals, valves, and flanges.

Following a request for price indications for data parameters for the OPGEE model, ER has defined a number of parameter and price ranges that are summarized in Table 7.10. The prices are meant to be indicative and discounts may be given for multiple dataset acquisitions. As a whole, the entire dataset could be bought for somewhere between $300,000 and $400,000 U.S. dollars. These prices apply to purchase of the data set for confidential use by the European Commission, not for purchase to put the dataset in the public domain, which would be a different and more expensive question.

the Bureau of Ocean Energy Management (BOEM) and the Bureau of Safety and Environmental Enforcement (BSEE) as part of a major reorganization.

Table 7.10. Data inputs available from ER (ER 2012)

DATA INPUTS	COMMENTS FROM ER
Field-level production of oil	Available for all 6000 fields Plus new ones. Currently does not include for yet to find or developments, but this can be added. Very important for longer term forecasts. Else after about year 5 large "planners droop" will occur.
Field-level production of gas at field - wellhead	Available for all 6000 fields Plus new ones. Currently does not include for yet to find or developments but this can be added. Very important for longer term forecasts. Else after about year 5 large "planners droop" will occur.
Field-level production of gas exported from field	Volumes exported
Field depth	Available for all 6000 fields
Field location Latitudes Longitudes Central position	Will provide a single point will be at the center of the field. Field name and long latitudes provided
Field Location Outlines shape files	This (point field locations) may not be what you might need to identify flare locations, because fields can extend over many square miles. In one instance I just looked at 2700 sq. miles. The flare is in the bottom right hand corner of the field. You might actually want shape files e.g. the shapes of the fields in areal extent.
API gravity of liquids produced	Assumed constant but will change through time as reservoir pressure drops. Could estimate what this might be.
Field-level injection of water	Have some numbers and details on water injection capacities. Could estimate for others based on reservoir characteristics.
Field-level injection of water of steam	Have some and can estimate others.
Field level injection of gas	Have some data but estimate others.
Flaring volumes	Some actual - many estimated by field
Well-head pressure/temperature	Point estimates at certain times. Could estimate going forward based on reservoir characteristics location and reservoir type. Note based somewhat on reservoir - This price is assuming Reservoir data is purchased
Reservoir pressure/temperature	Have lots of data - some can be estimated from detailed reservoir. Will need to estimate future pressure of reservoir
Associated gas composition	Assumed same throughout period - could estimate what changes might look like. Especially important over longer term. This is data that has been collected by ER, over many years. We believe that this essentially complete data set is a one of a kind. It may be possible to collect some values here and there. E.g. methane contents for specific fields. Our gas contents includes a breakdown of CO_2, N2, H_2s and C1-c6
Field production - Water	Have some numbers can estimate others based on reservoir characteristics
Number of producing wells	Current numbers. Would need to estimate future
Production technology (lifting or separation technology)	
Electricity generation on-site	Note sure if this is import or export. Estimate based on power imported and data on generation units at the fields
Blend Characteristic	To estimate refinery emissions you will need to have API and other characteristics of the blends. Will change through time. Can estimate the effect

7.3.3. Other

Data has been obtained from the Oil and Gas Journal (OGJ) and Petro Tech Intel (PTI), providing key input parameters or confirming the data quality from public sources for a range of fields. The Petroleum Economist World Energy Atlas has also been used to inform our assessment on issues such as access to gas pipeline infrastructure. These datasets, although of global scope and containing some information at the field level, cover only a limited subset of the key input parameters, with data on many fields aggregated at the state/province or even country level.

Two final potential sources of data have been identified. The first is the PennWell Oil and Gas Journal dataset, which is currently being investigated by CARB. This contains information on international fields with Enhanced Oil Recovery techniques and mining, field depths and production start dates. However, we have not included any fields that are included in this dataset. The second source is PE International, as referenced in the National Energy Technology Laboratory (NETL) Lifecycle Assessment (LCA) study.

7.4. Summary of available data

We have been able to obtain adequate data to perform an initial analysis of about 300 oil fields – many more than covered in any previous crude oil CI analysis of which we are aware, except ICCT/ER (2010). The only extensive dataset with information on international fields and crude characteristics for which data licensing terms have been offered is the Energy Redefined dataset. We note that even this dataset depends heavily on informed cross-population of data values.

As described in preceding sections, the EU sources a significant portion of its crude from Russia and FSU countries. Crude production data for these countries is notoriously difficult to obtain, and the extent to which these countries are accurately covered in proprietary datasets is unclear. Another major contributor of EU crude is the North Sea. Publically available data has been obtained for a number of parameters for the UK and Denmark. It is possible that further conversations with Norway and Statoil could deliver additional sources of Norwegian information. To the extent that this data is available, it can be compiled at a lower cost than many of the proprietary alternatives. The data sources are summarized in Table 7.11.

Overall, there are a number of variables for which there is a reasonable likelihood of finding publically available data (see Table 7.12). Still, many important parameters remain difficult to source. While in many cases OPGEE's defaults will provide reasonable answers, reliance on defaults necessarily introduces an additional degree of uncertainty to the model. As discussed in §8.2.5, we have excluded several fields from our initial EU baseline analysis where lack of process data injects too great a level of uncertainty into the analysis.

Table 7.11. Summary of available input parameters by data source

INPUT PARAMETER	EIA	DG ENER	DOGGR	CARB	ERCB	NOAA/ WORLD BANK	ER	OGJ	DECC (UK)	DEA (DK)	NNPC (NG)	CIMS	WORLD ENERGY ATLAS
API Gravity	✓						✓	✓			✓	✓	
Reservoir Pressure			✓				✓						
Reservoir Depth	✓		✓	✓			✓						
Reservoir Temperature			✓				✓						
Viscosity							✓					✓	
GOR			✓	✓	✓		✓		✓	✓	✓		
WOR			✓	✓	✓		✓		✓	✓	✓		
Age of Field			✓		✓		✓	✓					
Flaring Rate				✓		✓	✓		✓		✓		
Venting Rate				✓		✓	✓		✓		✓		
Fugitive Emissions				✓		✓	✓				✓		
Type of Lift				✓			✓						
Development Type				✓			✓						
Field Location			✓	✓	✓		✓	✓	✓	✓	✓	✓	✓
Field Depth			✓	✓			✓	✓					
Number of Wells							✓	✓			✓		
Associated Gas Composition	✓		✓	✓	✓		✓		✓		✓		
Production Volumes	✓	✓	✓	✓	✓		✓	✓	✓	✓	✓	✓	
Water Injection			✓	✓	✓		✓		✓		✓		
Gas Injection			✓	✓	✓		✓		✓		✓		
Nitrogen Gas Injection			✓	✓	✓		✓						
Steam Injection			✓	✓	✓		✓						
Onsite Electricity Gen.			✓	✓			✓						
MCON/Blend												✓	

Table 7.12. Likelihood of obtaining data for OPGEE input variables

VARIABLE	HIGH LIKELIHOOD	LOW LIKELIHOOD	USE DEFAULT VALUE
Field Location	✓		
Field Depth	✓		
Field Age	✓		
Reservoir Pressure	✓		
API Gravity	✓		
Oil production Volume	✓		
Number of Wells	✓		
Gas to Oil Ratio		✓	
Water to Oil Ratio		✓	
Steam to Oil Ratio		✓	
Water Injection Quantity		✓	✓
Gas Injection Quantity		✓	✓
N2 Injection Quantity		✓	✓
Steam Injection Quantity		✓	✓
Onsite Electricity Generation		✓	✓
Heater – Treater Use		✓	✓
Stabilizer Column Use		✓	✓
Flaring Volume		✓	✓
Venting Volume		✓	✓
Associated Gas Composition		✓	✓

7.5. Data for the EU Baseline

This section provides an overview of the process used to determine the quantity, quality and availability of data on crude oils entering the European Union market, and to collect that data. The objective of this analysis is to collect data on key parameters in order to construct an estimated baseline of lifecycle greenhouse gas emissions from EU sourced crudes using the OPGEE model. For this purpose, a methodology for data collection was established taking into account the project requirements set forth by DG Clima and the specifications of the OPGEE model.

In the subsequent section, we first detail the main data requirements of OPGEE and the specific questions highlighted in the project requirements. Secondly, we detail the data collection methodology used. Thirdly, we present an overview of data availability issues, including the potential use of purchased proprietary data as well as the uncertainty surrounding both public and private sources. Finally, we present the results of the data collection exercise as well as a description of limitations in data access and transparency.

7.5.1. Field level characteristics and modeling parameters

The data collection process has focused on the input parameters required by the OPGEE model. These are described in detail in the accompanying documentation and are divided into four main groupings: (1) general field properties, (2) production practices, (3) processing practices and (4) fluid properties (see Table 7.3). In addition to these parameters, the model also includes a number of additional inputs relating to land use impacts, crude oil transport, unit efficiencies and small source emissions. As described in the model documentation, in many instances these parameters use default values (given the lack of field level data).

7.5.2. Public versus private datasets

As noted above (c.f. §7.2.4) the British and Danish Energy Agencies and Nigerian National Petroleum Corporation make available monthly and annual time series data at the field level across a number of parameters included in the OPGEE model.

In addition, several potential private data sources have been identified, but their cost, uncertainty regarding the quality of information and/or the lack of cooperation from the data owners has limited acquisition of much of this data to date. Notwithstanding these limitations, data has been obtained from the Oil and Gas Journal (OGJ) as well as Petro Tech Intel (PTI), and has served to provide key input parameters for a range of fields (see Table 7.13). These datasets, although of global scope and containing some information at the field level, cover only a limited subset of the key input parameters, with data on many fields aggregated at the state/province or even country level. We believe Deloitte, IHS and Wood Mackenzie have databases with substantially more comprehensive coverage of key parameters, however, it has not been possible to negotiate access to this data for this study, nor negotiate a price for that access. Additional data comes from the sources identified in Table 7.9.

Table 7.13. Proprietary datasets for crudes sourced to the EU

SOURCE	PARAMETERS INCLUDED	NUMBER OF DISTINCT FIELDS	YEARS
Oil and Gas Journal	Country of Origin, Company, Date of Discovery, Depth, API Gravity, Number of Producing Wells, Total Production (b/d)	6000+	2008 - 2011
Petro Tech Intel's Crude Information Management System	Crude Location, Estimated Probable and Recoverable Reserves, Crude Properties, Production Rates, Export Data, Operator,	3500+ Crude Grades	Latest Available Monthly Data
Petroleum Economist Ltd World Energy Atlas	Field Location, Field Name, Country, Distinction between Gas and Oil Fields	6000+	2007

In addition to the sources identified in Table 7.13, the study relies on a number of publically available data sources for information including emissions factors and the specifications of various process equipment used in the production of conventional fuels. These include emissions factors from GREET (Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation Model), country specific crude oil production data from the Energy Information Agency (EIA) and the International Energy Agency (IEA) as well as flaring volumes from the National Oceanic Atmospheric Administration (NOAA). Quinn Hart at the University of California Davis has also been collaborating to obtain field level flaring estimates using satellite imagery (using the World Energy Atlas to correlate flares to fields). The hope is to replace the national/regional average NOAA estimates with this field level data wherever possible. In addition to these, extensive data searches of online sources, journal articles, textbooks and industry references have been conducted and these data are used to complements the sources above.

8. The European Crude CI Baseline

The availability of OPGEE makes it possible to analyze the carbon intensity of crude oil supplied to the European Union (EU) at a level of detail not previously possible without access to proprietary models. In this chapter, we outline our methodology for estimating the carbon intensity (CI) of crude sourced in Europe, and present results from our assessment. As we have noted, there are many gaps in the data that was available to undertake this analysis – with additional data research and/or reporting by companies it will be possible to refine these estimates to deliver an increasingly accurate view of the carbon intensity of the transport fuels consumed in the EU.

8.1. Baseline construction methodology

The following section provides a detailed outline of the steps followed in the data collection process as well as in the selection of the baseline crudes included in the forthcoming analysis. In addition, a discussion of the data aggregation tool used to estimate the baseline will also be included.

8.1.1. Field selection process

As described above, the analysis concentrated on a set of crudes, based on reporting by DG Energy, being imported into the EU. However, the characterization of most of these crudes in the DG Energy reporting is limited to their country of origin, with in certain cases an associated API gravity range or MCON. Given that the OPGEE model relies on field level characteristics, a methodology was developed to determine the carbon intensity of a given crude based on analysis of the most representative available fields (see Figure 8.1). For the cases where an MCON was available, the process consisted in determining the fields supplying that particular MCON. Where the DG Energy reporting does not specify an MCON, but only a region or a region and API gravity (e.g. 'Nigeria Light (33-45°)'), we identified fields in that region with the appropriate gravity[100].

Without additional reporting information to link specific fields to European crude consumption, it is likely that in some case the fields that have been modeled may not actually be supplying oil to Europe. The use of representative fields may, in some cases, result in significant errors in the identification of the average carbon intensity for particular crudes – either because the chosen representative field is not in reality one of the fields sending oil to Europe, or because the representative fields identified have systematically higher or lower carbon intensities than the real average for that crude (see ICCT/ER 2010). Nevertheless, we believe that given the data available the representative field system

[100] DG Energy specifies gravity either by explicit range (e.g. 30-40) or qualitatively (e.g. 'heavy')

is the best available methodology to estimate the European crude CI baseline.

Figure 8.1. Field selection process

8.1.1.b. CARB process for MCON analysis under CA-LCFS

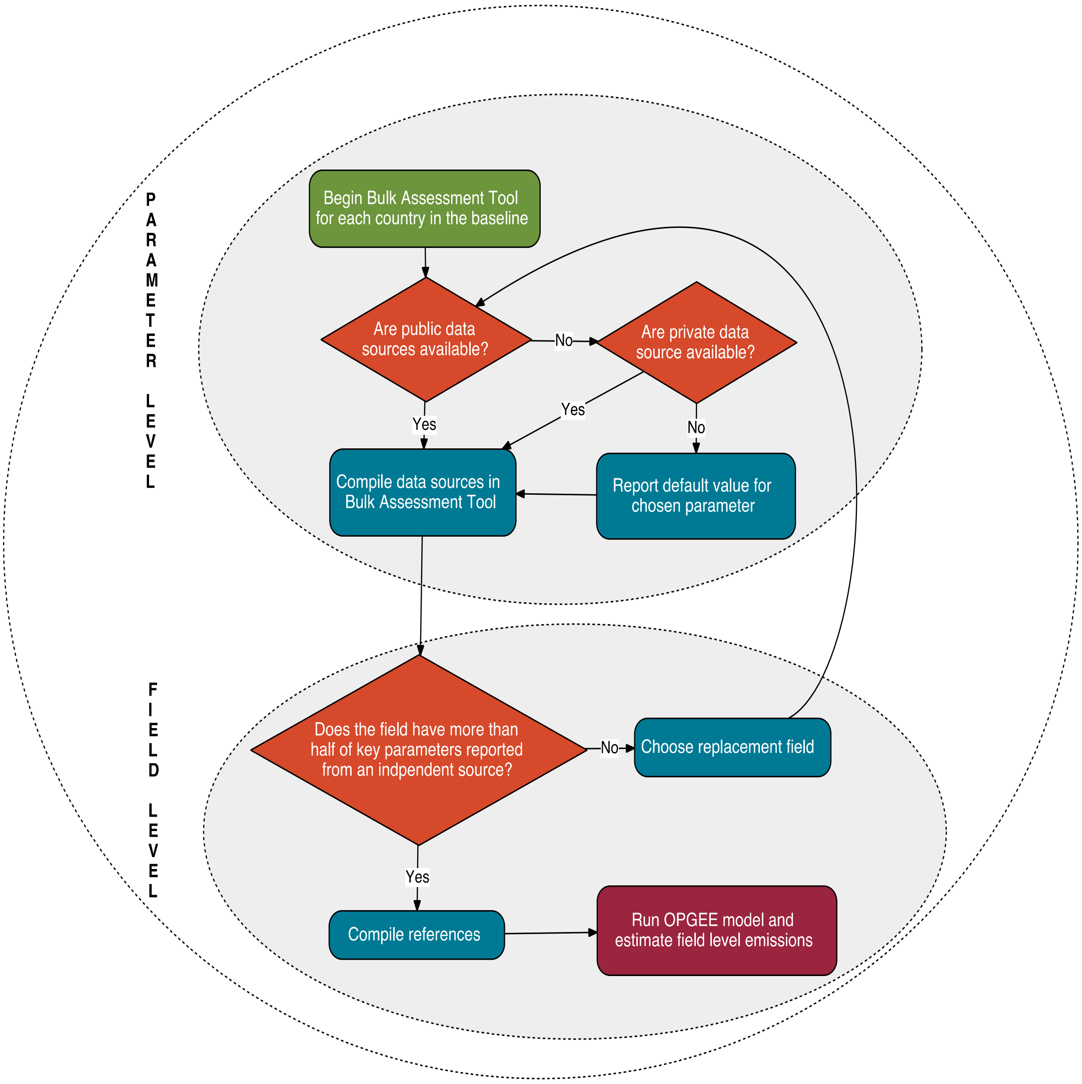
The California Air Resources Board goes through a similar process to assess the carbon intensity of given MCONs for the crude oil carbon intensity lookup tables under the CA-LCFS. For the March 2013 preliminary draft carbon intensity lookup values, CARB analyzed 275 MCONs, including all 152 California oilfields producing more than 10 kbbl/d, 18 other U.S. crudes, 14 Canadian crudes and 91 from the rest of the world (see Table 2.5). While many of the MCONs, such as the Californian ones, are explicitly modeled on individual oilfields, in other cases such as Saudi Arabian Arab Extra Light, CARB has used a similar process to that outlined in this report. In this case, using a combination of average Saudi Arabian data for inputs including volume per well, field age and field depth among others. For another example, in the case of Russian Sokol crude, CARB has identified three source fields (Chayvo, Odoptu, Arkutin-Dagi) but has used data as available – so depth is modeled on Chayvo only, and age is based on Chayvo and Odoptu only. For the non-North American crudes in particular, CARB has relied extensively on default values to complete the input data.

8.1.2. Data collection process

Once a set of representative fields was identified for each country or MCON, the next step was engaging in the data collection process for field level characteristics. As previously mentioned, public data sources were favored over private ones. For a given field level parameter (e.g. water-oil-ratio, reservoir pressure, etc.), the data collection process stipulates that public data sources be exhausted before moving to private data sources. If none of these are available, the OPGEE default value is imputed into the bulk assessment tool[101]. The process is repeated for all the parameters included in the OPGEE model. Once this is completed, an assessment of the parameters included for each field is carried out. In doing so, a set of key parameters was identified as crucial to the robust emissions estimation for each field. These are: age, depth, oil production volume, number of producing wells, reservoir pressure, API gravity, gas-oil-ratio, and water-oil-ratio. If a given field has less than half of these parameters from verified independent sources, the field is discarded and a replacement field from the country is assigned to the bulk assessment tool. If not, a list of references for each of the used parameters is compiled into the bulk assessment tool and the OPGEE model is run to estimate field level emissions. Figure 8.2 summarizes the data collection process.

[101] For an expanded discussion on default values, please refer to Appendix C. In addition, Appendix D describes additional adjustments made to OPGEE default values in an iterative basis.

Figure 8.2. Data collection process



8.2. Findings

This section provides an overview of the scope of our baseline analysis as well as descriptive statistics of our main findings. The objective of this analysis is to provide an empirical description of the fields and geographic areas that are sourcing crude to the European Union (EU) and will be used to construct the baseline of lifecycle greenhouse gas (GHG) emissions with OPGEE for this report. We first detail the scope of our analysis for including crude sources supplying the EU by geographic location. The remaining section provides findings of the fields chosen for our baseline in terms of production statistics as well as crude and field characteristics. Finally, the section includes the GHG baseline for crude sourced to the EU in 2010.

8.2.1. Scope of analysis

The project scope requires the contractor to, “use the predictive model to estimate the GHG intensity of each oil field feeding in aggregate at least 95 percent of crude oil consumption in the EU”. We have focused our analysis on the most voluminous crude streams entering the EU market in 2010. These crudes make up a total of about 93 percent of all EU crude. We determined which crudes are being imported to Europe based on reporting by DG Energy (2012a). We excluded from the baseline analysis crude streams that accounted for less than 0.25 percent of all imports as well as generic crudes that were not associated to a given country (e.g. ‘other European crudes’). The exception to this second rule was ‘Other FSU crude’, which we believe comes from Uzbekistan and Turkmenistan, a well enough defined region to model through representative fields. The identification of crudes is based on data from DG Energy (2012a). In some cases crudes are identified in the data by MCONs, but in other cases crudes are generic and attributed to some combination of country/region and oil characteristics (e.g. ‘Nigerian light, 33-45°’). In all cases, we have tried to determine the most representative available data.

As well as crude listed in the import statistics from DG Energy, some EU produced crude is refined in its country of origin, most importantly in the UK and Denmark. DECC (2013) report that over 400 kbbl/d of UK produced oil was sent to UK refineries in 2010. We are not aware of published data detailing the fraction of the four UK blends considered (Brent, Forties, Flotta, Other UK crude) that is refined in the UK, and therefore we assume that each blend is used in UK refineries in proportion to its total production (DECC, 2013). For Denmark, EIA (2013b) reports that about 90 kbbl/d of domestic crude went to Danish refineries in 2010. As we only consider one crude stream from Denmark (‘Denmark Crude’) we assume that all of this oil was from the Denmark Crude stream. Based on EIA statistics, a further 260 kbbl/d is refined domestically in other EU countries, but we have not assessed any representative fields from these countries. These volumes of domestically refined crude (Table 8.1) are added to the import statistics to give a full characterization of the oil consumed in the EU (see Table 8.2).

Table 8.1. Volumes of domestically produced crude refined in the UK and Denmark

CRUDE STREAM	ANNUAL VOLUME ASSUMED REFINED DOMESTICALLY (THOUSAND BBL)
Brent Blend	27,416
Forties	68,032
Flotta	7,632
Other UK crude	53,249
Denmark Crude	33,582

After determining the geographic sources of crudes supplying the EU, through the data collection process that has been previously described, we have been able to compile field level characteristics for a total of 265 distinct oil fields that may be supplying the EU market (i.e. the fields produce crudes consistent with one of the crude designations in the DG Energy data). These fields are across 22 countries in seven different regions across the world. Table 8.3 lists all the fields as well as an illustrative set of field characteristics.

8.2.2. Production statistics

In 2010, the EU imported an average of about 11,000,000 bbl/d of crude oil (DG Energy, 2012a), including intra-EU trade in oil (primarily imports from the UK). Approximately a further 750,000 bbl/d of EU produced oil is refined domestically. The 265 fields included in the analysis are considered representative of approximately 93 percent of all EU oil consumption, about 11,000,000 bbl/d in 2010. These fields ranged in production levels from North Sea fields producing less than 100 bbl/d to mega-fields like Ghawar reaching over 5.3 MMbbl/d. The average field production volume from our sample is 73,589 bbl/d with a median value of 9,630 bbl/d.

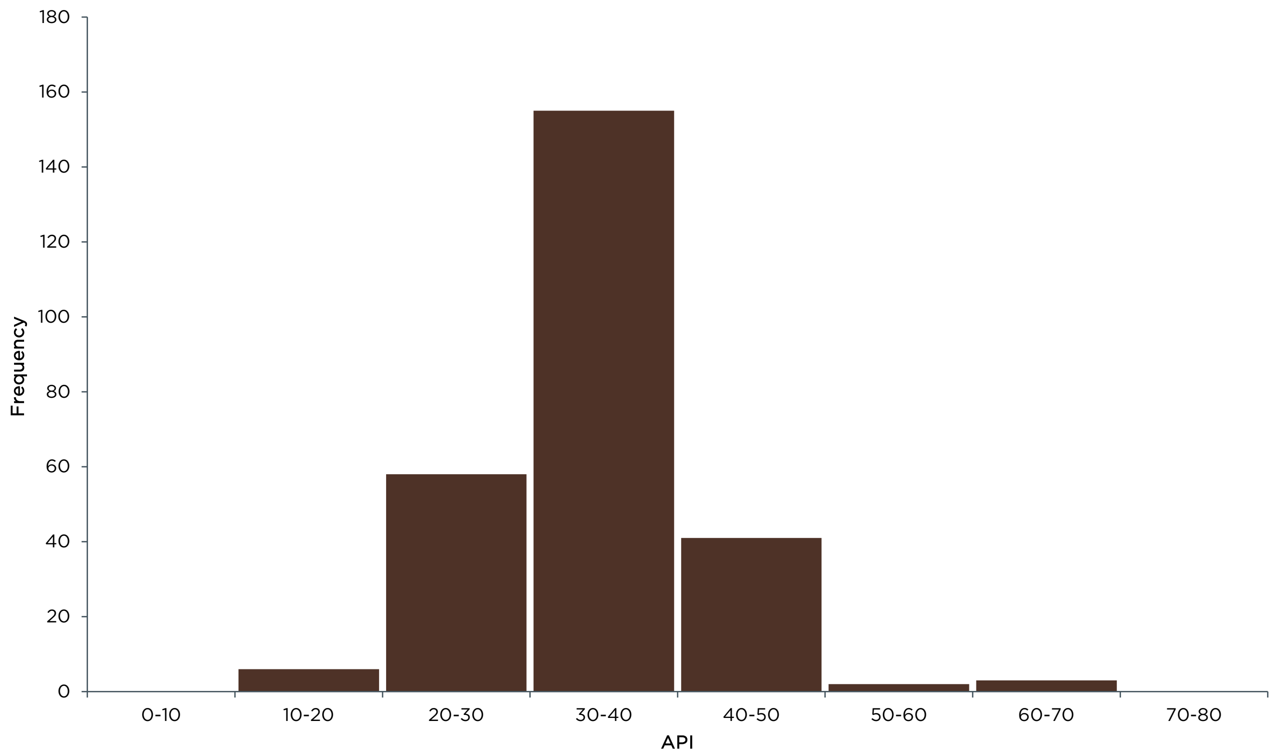
Table 8.2. Crudes included in emissions baseline analysis of EU crude sourcing (DG Energy, 2012a)

REGION	COUNTRY OF ORIGIN	DG ENERGY CRUDE	% OF EU CRUDE	REGION	COUNTRY OF ORIGIN	DG ENERGY CRUDE	% OF EU CRUDE
Africa	Algeria	Other Algerian Crude	0.4%	Europe	United Kingdom	Brent Blend	1.3%
Africa	Algeria	Saharan Blend	0.9%	Europe	United Kingdom	Flotta	0.4%
Africa	Angola	Other Angolan Crude	1.3%	Europe	United Kingdom	Forties	3.5%
Africa	Cameroon	Cameroon Crude	0.3%	Europe	United Kingdom	Other UK Crude	3.4%
Africa	Congo	Congo Crude	0.4%	FSU	Azerbaijan	Azerbaijan Crude	3.4%
Africa	Egypt	Egyptian Medium/ Light (30-40°)	0.4%	FSU	Kazakhstan	Kazakhstan Crude	5.2%
Africa	Libyan Arab Jamahiriya	Libyan Heavy (<30° API)	0.3%	FSU	Other FSU countries	Other FSU Crude	2.5%
Africa	Libyan Arab Jamahiriya	Libyan Light (>40°)	4.6%	FSU	Russian Federation	Other Russian Fed. Crude	11.1%
Africa	Libyan Arab Jamahiriya	Libyan Medium (30-40°)	4.4%	FSU	Russian Federation	Urals	14.7%
Africa	Nigeria	Nigerian Light (33-45°)	2.8%	Middle East	Iran	Iranian Heavy	2.6%
Africa	Nigeria	Nigerian Medium (<33°)	0.8%	Middle East	Iran	Iranian Light	1.4%
America	Brazil	Brazil Crude	0.8%	Middle East	Iran	Other Iran Crude	0.9%
America	Mexico	Maya	0.9%	Middle East	Iraq	Basrah Light	0.5%
America	Venezuela	Venezuelan Extra Heavy (<17°)	0.4%	Middle East	Iraq	Kirkuk	2.0%
Europe	Denmark	Denmark Crude	2.1%	Middle East	Iraq	Other Iraq Crude	0.2%
Europe	Norway	Ekofisk	2.0%	Middle East	Kuwait	Kuwait Blend	0.6%
Europe	Norway	Gullfaks	1.0%	Middle East	Saudi Arabia	Arab Light	5.1%
Europe	Norway	Oseberg	1.3%	Middle East	Syria	Souedie	0.9%
Europe	Norway	Other Norwegian Crude	5.8%	Middle East	Syria	Syria Light	0.3%
Europe	Norway	Statfjord	1.3%	**Total**			**92.6%**

8.2.3. Crude characteristics

Of the 64 different crude types listed by DG Energy (2012a), data was ultimately collected for fields corresponding to 39. The crudes from these fields covered a range of densities, stretching from extra heavy crudes with API gravities as low as ten (Venezuelan Extra Heavy from Boscan) to fields producing ultra-light crudes with APIs as high as 68 (feeding the Gullfaks and Statfjord blends). Overall, the API gravity of our sample fields averaged 34 with a median value of 35.

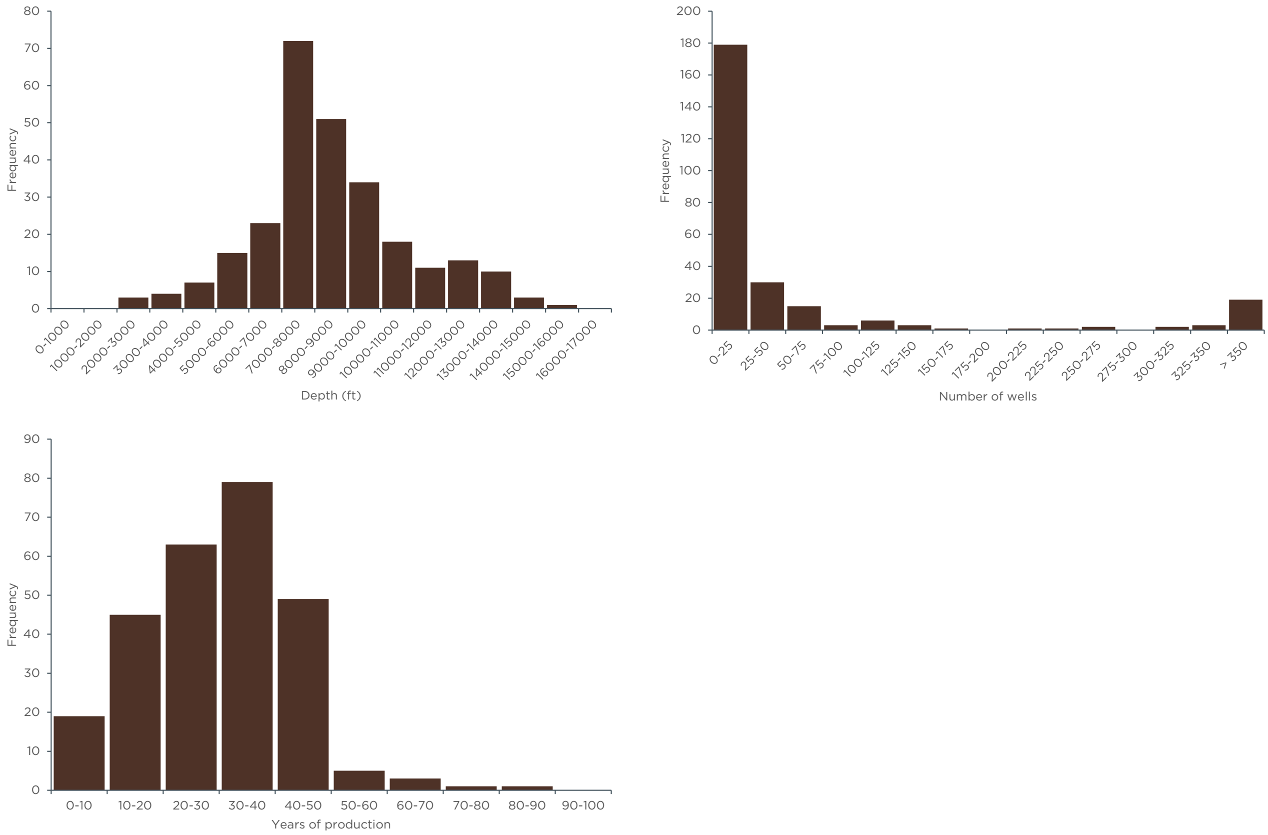
Figure 8.3. API gravity frequency distribution



8.2.4. Field characteristics

As previously mentioned, 265 fields of varying characteristics were included in the EU Baseline. Fields as old as Kirkuk (Iraq), discovered in 1927, to recent discoveries as late as 2009 (Frade in Brazil) are included. The range of field depths included is from 2,000 feet for Zatchi in Congo to 16,000 feet for Asgard in Norway. Finally, the number of wells for the average field is 85 wells with a median value of 10. This includes a number of fields with more than 1,000 wells. On average, fields included in the EU Baseline were 33 years old with a median age of 34.

Figure 8.4. Frequency distribution plots for reservoir depth, number of wells (per field) and age



8.2.5. Handling uncertainty and outliers

As mentioned in §6.4.4, for fields with more extreme characteristics such as high water-oil-ratio (WOR) and/or gas-oil-ratio (GOR), the uncertainty related to process characterization can become increasingly large. We have put maximum limits on GOR and WOR for inclusion of fields in the EU Baseline analysis in order to exclude fields where the uncertainty in emissions estimates would be the highest. The GOR and WOR cut-offs we have used to define fields as 'outliers' for this purpose are based on the following criteria. For GOR, the threshold is set as the level at which, *for a generic field otherwise based on the OPGEE defaults*, the sensitivity of the results to activation or deactivation of the acid gas removal (AGR) unit or to assuming gas reinjection rather than export is greater than 5 gCO_2e/MJ. We have therefore excluded fields with GOR greater than 5,000 scf/bbl from the baseline. Similarly to GOR, for WOR the threshold is set as the level at which, *for a generic field otherwise based on the OPGEE defaults*, the sensitivity to activation or deactivation of the heater treater or doubling the number of injection wells is greater than 5 gCO_2e/MJ. We have therefore excluded fields with WOR greater than 45 from the baseline. Including such fields without a more accurate characterization of processing practices would not add value to the EU Baseline assessment. We also excluded three further North Sea fields (Iona, Kittiwake and Chanter) due to very high reported water or gas injection to oil production ratios. Further investigation and additional process data would be warranted before including these fields in the analysis.

8.2.6. GHG baseline estimation

Having removed outliers, 265 fields were analyzed with OPGEE. The resulting carbon intensity results are show in Table 8.3 below.

Table 8.3. EU Baseline fields and carbon intensity estimations

REGION	COUNTRY	FIELD NAME	DG ENERGY CRUDE†	API GRAVITY	CARBON INTENSITY (gCO_2e/MJ)			FLARING DATA SOURCE
					VFF††	OTHER	TOTAL	
Africa	Algeria	Ourhoud	Other Algerian Crude	40	6.2	9.2	**15.4**	NOAA
Africa	Algeria	Hassi Messaoud	Saharan Blend	46	3.4	9.4	**12.8**	NOAA
Africa	Angola	Dalia FPSO	Other Angolan Crude	23	5.0	4.4	**9.4**	NOAA
Africa	Angola	Girassol FPSO	Other Angolan Crude	30	5.3	4.9	**10.3**	NOAA
Africa	Angola	Greater Plutonia FPSO	Other Angolan Crude	33	4.2	3.8	**8.0**	NOAA
Africa	Cameroon*	Ebome (KF)	Cameroon Crude	34	20.0	3.2	**23.3**	NOAA
Africa	Cameroon*	Kole	Cameroon Crude	31	19.8	4.2	**24.0**	NOAA
Africa	Cameroon*	Makoko NE plus Abana	Cameroon Crude	29	19.6	3.9	**23.5**	NOAA
Africa	Cameroon*	Moudi D.	Cameroon Crude	21	18.9	3.2	**22.1**	NOAA
Africa	Congo	Kitina	Congo Crude	38	9.9	3.7	**13.6**	NOAA
Africa	Congo	Loango	Congo Crude	27	9.1	3.5	**12.6**	NOAA
Africa	Congo	M'Boundi	Congo Crude	40	10.0	3.6	**13.6**	NOAA
Africa	Congo	Zatchi	Congo Crude	27	9.1	2.9	**12.0**	NOAA
Africa	Egypt	Ashrafi	Egyptian Medium/ Light (30-40°)	39	4.9	3.7	**8.6**	NOAA
Africa	Egypt	Meleiha	Egyptian Medium/ Light (30-40°)	42	5.0	4.4	**9.4**	NOAA
Africa	Egypt	Ras Qattara	Egyptian Medium/ Light (30-40°)	28	4.3	3.8	**8.1**	NOAA
Africa	Libya	Bouri	Libyan Heavy (<30° API)	26	3.9	5.0	**8.9**	NOAA
Africa	Libya	Bu Attifel	Libyan Light (>40°)	41	4.6	3.8	**8.3**	NOAA
Africa	Libya	Sarir	Libyan Medium (30-40°)	38	4.5	9.0	**13.6**	NOAA
Africa	Nigeria	Abiteye	Nigerian Light (33-45°)	40	34.5	3.3	**37.8**	Reported
Africa	Nigeria	Abura	Nigerian Light (33-45°)	45	17.8	8.0	**25.8**	Reported
Africa	Nigeria	Adua	Nigerian Light (33-45°)	35	13.0	2.7	**15.8**	Reported
Africa	Nigeria	Afremo	Nigerian Light (33-45°)	37	10.0	2.8	**12.8**	Reported
Africa	Nigeria	Agbara	Nigerian Light (33-45°)	38	54.8	3.9	**58.7**	Reported
Africa	Nigeria	Ahia	Nigerian Light (33-45°)	38	32.0	3.2	**35.2**	Reported
Africa	Nigeria	Akaso	Nigerian Light (33-45°)	37	9.7	4.1	**13.8**	Reported
Africa	Nigeria	Amukpe	Nigerian Light (33-45°)	42	50.6	5.6	**56.1**	Reported
Africa	Nigeria	Asabo	Nigerian Light (33-45°)	35	6.4	3.2	**9.7**	Reported
Africa	Nigeria	Asasa	Nigerian Light (33-45°)	40	18.0	4.6	**22.6**	Reported
Africa	Nigeria	Benin River	Nigerian Light (33-45°)	42	6.7	2.3	**9.0**	Reported
Africa	Nigeria	Cawthorne Chan	Nigerian Light (33-45°)	37	11.4	3.9	**15.3**	Reported
Africa	Nigeria	Delta	Nigerian Light (33-45°)	37	22.6	2.5	**25.0**	Reported
Africa	Nigeria	Delta South	Nigerian Light (33-45°)	38	30.0	3.4	**33.4**	Reported
Africa	Nigeria	Diebu Creek	Nigerian Light (33-45°)	40	24.3	3.0	**27.3**	Reported
Africa	Nigeria	Edop	Nigerian Light (33-45°)	37	14.9	6.3	**21.2**	Reported
Africa	Nigeria	Egbema	Nigerian Light (33-45°)	33	26.0	2.9	**28.9**	Reported

REGION	COUNTRY	FIELD NAME	DG ENERGY CRUDE†	API GRAVITY	CARBON INTENSITY (gCO_2e/MJ)			FLARING DATA SOURCE
					VFF††	OTHER	TOTAL	
Africa	Nigeria	Egbema West	Nigerian Light (33-45°)	41	27.0	2.8	**29.8**	Reported
Africa	Nigeria	Ekpe	Nigerian Light (33-45°)	35	13.4	3.2	**16.6**	Reported
Africa	Nigeria	Elelenwa	Nigerian Light (33-45°)	36	10.5	3.7	**14.2**	Reported
Africa	Nigeria	Enang	Nigerian Light (33-45°)	37	16.3	2.2	**18.6**	Reported
Africa	Nigeria	Etim	Nigerian Light (33-45°)	37	9.5	2.8	**12.3**	NOAA
Africa	Nigeria	Idama	Nigerian Light (33-45°)	33	25.6	2.3	**27.9**	Reported
Africa	Nigeria	Inanga	Nigerian Light (33-45°)	38	13.0	3.0	**16.0**	Reported
Africa	Nigeria	Inda	Nigerian Light (33-45°)	45	17.5	2.9	**20.4**	Reported
Africa	Nigeria	Inim	Nigerian Light (33-45°)	38	18.6	2.4	**21.0**	Reported
Africa	Nigeria	Iyak	Nigerian Light (33-45°)	38	14.8	2.9	**17.7**	Reported
Africa	Nigeria	Jisike	Nigerian Light (33-45°)	41	31.2	2.7	**33.9**	Reported
Africa	Nigeria	Malu	Nigerian Light (33-45°)	40	30.8	2.4	**33.1**	Reported
Africa	Nigeria	Mfem	Nigerian Light (33-45°)	36	30.7	2.2	**32.9**	Reported
Africa	Nigeria	Mina	Nigerian Light (33-45°)	40	49.9	2.3	**52.2**	Reported
Africa	Nigeria	Okan	Nigerian Light (33-45°)	38	9.2	3.0	**12.2**	Reported
Africa	Nigeria	Olo	Nigerian Light (33-45°)	37	12.0	3.6	**15.7**	Reported
Africa	Nigeria	Robertkiri	Nigerian Light (33-45°)	40	5.7	2.6	**8.3**	Reported
Africa	Nigeria	Tapa	Nigerian Light (33-45°)	40	69.7	2.6	**72.4**	Reported
Africa	Nigeria	Ubit	Nigerian Light (33-45°)	36	10.5	5.4	**15.8**	Reported
Africa	Nigeria	Unam	Nigerian Light (33-45°)	33	14.5	4.1	**18.6**	Reported
Africa	Nigeria	Utue	Nigerian Light (33-45°)	37	12.7	6.6	**19.3**	Reported
Africa	Nigeria	W. Isan	Nigerian Light (33-45°)	40	7.1	2.1	**9.2**	Reported
Africa	Nigeria	Adanga	Nigerian Medium (<33°)	32	38.8	3.8	**42.6**	Reported
Africa	Nigeria	Adibawa	Nigerian Medium (<33°)	26	7.6	3.0	**10.6**	Reported
Africa	Nigeria	Adibawa NE	Nigerian Medium (<33°)	25	15.2	2.8	**18.0**	Reported
Africa	Nigeria	Afia	Nigerian Medium (<33°)	26	5.7	1.9	**7.6**	Reported
Africa	Nigeria	Agbada	Nigerian Medium (<33°)	24	6.6	4.5	**11.1**	Reported
Africa	Nigeria	Ata	Nigerian Medium (<33°)	26	15.1	2.3	**17.4**	Reported
Africa	Nigeria	Benisede	Nigerian Medium (<33°)	22	8.3	2.8	**11.1**	Reported
Africa	Nigeria	Edikan	Nigerian Medium (<33°)	29	8.5	2.2	**10.7**	Reported
Africa	Nigeria	Ekulama	Nigerian Medium (<33°)	32	11.6	2.8	**14.4**	Reported
Africa	Nigeria	Eriemu	Nigerian Medium (<33°)	21	10.8	5.1	**15.8**	Reported
Africa	Nigeria	Escravos Beach	Nigerian Medium (<33°)	31	9.3	3.0	**12.2**	Reported
Africa	Nigeria	Etelebou	Nigerian Medium (<33°)	31	15.5	3.0	**18.5**	Reported
Africa	Nigeria	Evrweni	Nigerian Medium (<33°)	26	10.4	3.1	**13.5**	Reported
Africa	Nigeria	Idoho	Nigerian Medium (<33°)	31	34.7	4.3	**39.0**	Reported
Africa	Nigeria	Ime	Nigerian Medium (<33°)	28	3.4	2.3	**5.7**	Reported
Africa	Nigeria	Isobo	Nigerian Medium (<33°)	30	31.6	2.2	**33.8**	Reported
Africa	Nigeria	Jokka	Nigerian Medium (<33°)	23	11.0	2.7	**13.7**	Reported
Africa	Nigeria	Kito	Nigerian Medium (<33°)	31	12.1	2.6	**14.7**	Reported
Africa	Nigeria	Makaraba	Nigerian Medium (<33°)	28	19.2	4.3	**23.5**	Reported
Africa	Nigeria	Meji	Nigerian Medium (<33°)	32	14.5	4.4	**18.9**	Reported
Africa	Nigeria	Meren	Nigerian Medium (<33°)	32	38.7	4.1	**42.7**	Reported

REGION	COUNTRY	FIELD NAME	DG ENERGY CRUDE†	API GRAVITY	CARBON INTENSITY (gCO_2e/MJ)			FLARING DATA SOURCE
					VFF††	OTHER	TOTAL	
Africa	Nigeria	Nembe Creek	Nigerian Medium (<33°)	31	10.4	3.0	**13.4**	Reported
Africa	Nigeria	Obagi	Nigerian Medium (<33°)	23	9.7	4.4	**14.1**	NOAA
Africa	Nigeria	Obigbo North	Nigerian Medium (<33°)	23	9.4	4.1	**13.6**	Reported
Africa	Nigeria	Ogini	Nigerian Medium (<33°)	18	6.2	3.1	**9.3**	Reported
Africa	Nigeria	Olomoro	Nigerian Medium (<33°)	22	5.9	3.8	**9.7**	Reported
Africa	Nigeria	Opukushi	Nigerian Medium (<33°)	28	9.5	2.6	**12.1**	Reported
Africa	Nigeria	Oroni	Nigerian Medium (<33°)	23	5.7	2.6	**8.3**	Reported
Africa	Nigeria	Otamini	Nigerian Medium (<33°)	21	12.6	3.1	**15.7**	Reported
Africa	Nigeria	Otumara	Nigerian Medium (<33°)	25	6.7	3.6	**10.3**	Reported
Africa	Nigeria	Oweh	Nigerian Medium (<33°)	26	2.9	2.7	**5.6**	Reported
Africa	Nigeria	Saghara	Nigerian Medium (<33°)	32	7.9	2.7	**10.6**	Reported
Africa	Nigeria	Ubie	Nigerian Medium (<33°)	28	16.5	3.7	**20.3**	Reported
Africa	Nigeria	Ughelli West	Nigerian Medium (<33°)	21	12.9	4.2	**17.0**	Reported
Africa	Nigeria	Usari	Nigerian Medium (<33°)	23	8.9	4.4	**13.3**	Reported
Africa	Nigeria	Utonana	Nigerian Medium (<33°)	20	10.5	2.8	**13.3**	Reported
Africa	Nigeria	Uzere East	Nigerian Medium (<33°)	29	17.5	4.8	**22.3**	Reported
Africa	Nigeria	Uzere West	Nigerian Medium (<33°)	25	10.7	2.9	**13.6**	Reported
Americas	Brazil	Albacora Leste	Brazil Crude	20	3.0	3.8	**6.8**	NOAA
Americas	Brazil	Frade	Brazil Crude	21	2.8	4.0	**6.7**	NOAA
Americas	Brazil	Marlim	Brazil Crude	20	1.7	3.7	**5.4**	NOAA
Americas	Brazil	Marlim Sul	Brazil Crude	26	3.7	5.5	**9.2**	NOAA
Americas	Brazil	Ostra	Brazil Crude	24	1.3	3.0	**4.3**	NOAA
Americas	Brazil	Polvo	Brazil Crude	20	1.7	4.1	**5.8**	NOAA
Americas	Mexico	Cantarell	Maya	22	2.2	6.0	**8.2**	NOAA
Americas	Venezuela	Boscan	Venezuelan Extra Heavy (<17°)	10	2.2	6.2	**8.4**	NOAA
Europe	Norway	Ekofisk	Ekofisk	41	1.0	1.8	**2.8**	NOAA
Europe	Norway	Eldfisk	Ekofisk	41	1.0	1.4	**2.5**	NOAA
Europe	Norway	Embla	Ekofisk	42	1.1	1.6	**2.6**	NOAA
Europe	Norway	Gyda	Ekofisk	48	1.1	1.4	**2.5**	NOAA
Europe	Norway	Tor	Ekofisk	38	1.0	1.1	**2.2**	NOAA
Europe	Norway	Ula	Ekofisk	35	1.0	1.3	**2.3**	NOAA
Europe	Norway	Valhall	Ekofisk	42	1.1	2.2	**3.2**	NOAA
Europe	Norway	Gullfaks	Gullfaks	38	1.8	4.2	**5.9**	NOAA
Europe	Norway	Tordis	Gullfaks	68	1.8	2.3	**4.1**	NOAA
Europe	Norway	Vigdis	Gullfaks	68	1.8	3.7	**5.5**	NOAA
Europe	Norway	Visund	Gullfaks	34	1.7	22.1	**23.8**	NOAA
Europe	Norway	Brage	Oseberg	37	1.8	3.8	**5.5**	NOAA
Europe	Norway	Huldra	Oseberg	30	1.3	3.3	**4.5**	NOAA
Europe	Norway	Oseberg	Oseberg	37	1.8	5.8	**7.5**	NOAA
Europe	Norway	Oseberg Ost	Oseberg	37	1.8	4.1	**5.8**	NOAA
Europe	Norway	Oseberg Sor and Nord	Oseberg	37	1.8	3.7	**5.4**	NOAA
Europe	Norway	Veslefrikk	Oseberg	37	1.8	4.3	**6.1**	NOAA
Europe	Norway	Asgard	Other Norwegian Crude	41	1.8	7.7	**9.5**	NOAA

REGION	COUNTRY	FIELD NAME	DG ENERGY CRUDE†	API GRAVITY	CARBON INTENSITY (gCO_2e/MJ)			FLARING DATA SOURCE
					VFF††	OTHER	TOTAL	
Europe	Norway	Gungne	Other Norwegian Crude	34	1.7	3.1	**4.8**	NOAA
Europe	Norway	Heidrun	Other Norwegian Crude	27	1.3	3.5	**4.8**	NOAA
Europe	Norway	Hod	Other Norwegian Crude	34	1.7	4.4	**6.1**	NOAA
Europe	Norway	Njord	Other Norwegian Crude	35	1.7	3.5	**5.3**	NOAA
Europe	Norway	Norne	Other Norwegian Crude	33	1.7	2.8	**4.5**	NOAA
Europe	Norway	Sleipner East	Other Norwegian Crude	58	1.8	2.9	**4.7**	NOAA
Europe	Norway	Sleipner West	Other Norwegian Crude	58	1.8	5.3	**7.2**	NOAA
Europe	Norway	Tambar	Other Norwegian Crude	45	1.1	1.6	**2.7**	NOAA
Europe	Norway	Troll	Other Norwegian Crude	28	1.3	4.1	**5.4**	NOAA
Europe	Norway	Snorre	Statfjord	68	1.8	4.6	**6.4**	NOAA
Europe	Norway	Statfjord	Statfjord	38	1.8	4.8	**6.5**	NOAA
Europe	Norway	Sygna	Statfjord	30	1.3	2.2	**3.5**	NOAA
Europe	United Kingdom	Columba E	Brent Blend	38	0.9	3.7	**4.6**	Reported
Europe	United Kingdom	Dunlin	Brent Blend	35	2.7	7.8	**10.5**	Reported
Europe	United Kingdom	Eider	Brent Blend	34	3.5	8.8	**12.4**	Reported
Europe	United Kingdom	Lyell	Brent Blend	36	6.8	2.0	**8.8**	Reported
Europe	United Kingdom	Magnus	Brent Blend	39	2.9	8.0	**10.9**	Reported
Europe	United Kingdom	Merlin	Brent Blend	31	1.4	7.7	**9.2**	Reported
Europe	United Kingdom	Murchison	Brent Blend	36	5.8	24.0	**29.8**	Reported
Europe	United Kingdom	Osprey	Brent Blend	31	1.3	5.9	**7.3**	Reported
Europe	United Kingdom	Pelican	Brent Blend	35	2.0	0.9	**3.0**	Reported
Europe	United Kingdom	Strathspey	Brent Blend	43	7.2	4.1	**11.3**	Reported
Europe	United Kingdom	Tern	Brent Blend	39	2.2	5.8	**8.0**	Reported
Europe	United Kingdom	Thistle	Brent Blend	38	8.1	23.8	**31.9**	Reported
Europe	United Kingdom	Claymore	Flotta	30	1.2	7.3	**8.5**	Reported
Europe	United Kingdom	Duart	Flotta	30	0.8	1.5	**2.3**	Reported
Europe	United Kingdom	Galley	Flotta	44	4.7	5.7	**10.4**	Reported
Europe	United Kingdom	Highlander	Flotta	35	1.0	1.9	**2.9**	Reported
Europe	United Kingdom	Petronella	Flotta	35	4.0	1.1	**5.1**	Reported
Europe	United Kingdom	Piper	Flotta	37	2.4	15.3	**17.7**	Reported
Europe	United Kingdom	Saltire	Flotta	42	7.7	16.4	**24.1**	Reported
Europe	United Kingdom	Scapa	Flotta	33	1.5	7.4	**8.9**	Reported
Europe	United Kingdom	Tartan	Flotta	39	9.1	2.9	**12.0**	Reported
Europe	United Kingdom	Arbroath	Forties	38	0.8	0.9	**1.7**	Reported
Europe	United Kingdom	Arkwright	Forties	40	0.9	1.2	**2.1**	Reported
Europe	United Kingdom	Balmoral	Forties	39	2.3	1.8	**4.2**	Reported
Europe	United Kingdom	Buchan	Forties	34	2.1	1.1	**3.3**	Reported
Europe	United Kingdom	Buzzard	Forties	33	0.7	1.6	**2.3**	Reported
Europe	United Kingdom	Forties	Forties	37	1.1	3.0	**4.1**	Reported
Europe	United Kingdom	Larch	Forties	35	1.0	1.4	**2.5**	Reported
Europe	United Kingdom	Nelson	Forties	40	1.5	2.7	**4.1**	Reported
Europe	United Kingdom	Scott	Forties	36	2.3	12.3	**14.6**	Reported
Europe	United Kingdom	Stirling	Forties	42	2.3	1.5	**3.8**	Reported

REGION	COUNTRY	FIELD NAME	DG ENERGY CRUDE†	API GRAVITY	CARBON INTENSITY (gCO$_2$e/MJ)			FLARING DATA SOURCE
					VFF††	OTHER	TOTAL	
Europe	United Kingdom	Thelma	Forties	38	5.0	0.7	**5.7**	Reported
Europe	United Kingdom	Tiffany	Forties	34	3.2	1.4	**4.6**	Reported
Europe	United Kingdom	Toni	Forties	35	4.4	2.1	**6.5**	Reported
Europe	United Kingdom	Alba	Other UK Crude	20	1.6	14.6	**16.2**	Reported
Europe	United Kingdom	Auk	Other UK Crude	38	3.0	1.4	**4.4**	Reported
Europe	United Kingdom	Blane	Other UK Crude	42	0.7	1.2	**1.8**	Reported
Europe	United Kingdom	Captain	Other UK Crude	19	1.1	3.7	**4.8**	Reported
Europe	United Kingdom	Carnoustie	Other UK Crude	39	1.0	1.2	**2.2**	Reported
Europe	United Kingdom	Clair	Other UK Crude	23	0.9	1.3	**2.2**	Reported
Europe	United Kingdom	Clapham	Other UK Crude	30	0.5	1.9	**2.4**	Reported
Europe	United Kingdom	Clyde	Other UK Crude	38	2.5	3.5	**6.0**	Reported
Europe	United Kingdom	Cyrus	Other UK Crude	36	0.6	2.6	**3.3**	Reported
Europe	United Kingdom	Deveron	Other UK Crude	38	4.4	4.9	**9.4**	Reported
Europe	United Kingdom	Douglas	Other UK Crude	44	0.5	5.9	**6.4**	Reported
Europe	United Kingdom	Farragon	Other UK Crude	35	0.6	1.6	**2.2**	Reported
Europe	United Kingdom	Foinaven	Other UK Crude	25	1.8	2.9	**4.7**	Reported
Europe	United Kingdom	Fulmar	Other UK Crude	40	10.1	12.6	**22.7**	Reported
Europe	United Kingdom	Gannet D	Other UK Crude	43	1.5	1.1	**2.6**	Reported
Europe	United Kingdom	Gannet E	Other UK Crude	20	0.4	1.1	**1.5**	Reported
Europe	United Kingdom	Gannet F	Other UK Crude	35	1.4	1.2	**2.7**	Reported
Europe	United Kingdom	Gannet G	Other UK Crude	39	1.0	1.2	**2.3**	Reported
Europe	United Kingdom	Gryphon	Other UK Crude	21	2.7	2.2	**4.9**	Reported
Europe	United Kingdom	Guillemot A	Other UK Crude	37	1.5	1.4	**2.9**	Reported
Europe	United Kingdom	Hannay	Other UK Crude	32	6.4	1.3	**7.8**	Reported
Europe	United Kingdom	Harding	Other UK Crude	21	1.9	3.7	**5.6**	Reported
Europe	United Kingdom	Hudson	Other UK Crude	33	0.5	2.3	**2.8**	Reported
Europe	United Kingdom	Janice	Other UK Crude	36	4.6	4.0	**8.6**	Reported
Europe	United Kingdom	Keith	Other UK Crude	38	4.3	-0.9	**3.4**	Reported
Europe	United Kingdom	Leven	Other UK Crude	39	3.3	12.1	**15.4**	Reported
Europe	United Kingdom	Machar	Other UK Crude	40	1.0	1.6	**2.6**	Reported
Europe	United Kingdom	Mallard	Other UK Crude	38	2.8	3.0	**5.9**	Reported
Europe	United Kingdom	Medwin	Other UK Crude	39	2.8	1.2	**4.0**	Reported
Europe	United Kingdom	Ness	Other UK Crude	37	2.2	0.9	**3.1**	Reported
Europe	United Kingdom	Ninian	Other UK Crude	37	3.8	24.0	**27.9**	Reported
Europe	United Kingdom	Orion	Other UK Crude	44	6.5	1.1	**7.6**	Reported
Europe	United Kingdom	Otter	Other UK Crude	37	3.6	1.7	**5.2**	Reported
Europe	United Kingdom	Ross	Other UK Crude	41	3.2	11.2	**14.4**	Reported
Europe	United Kingdom	Saxon	Other UK Crude	30	1.0	1.2	**2.2**	Reported
Europe	United Kingdom	Schiehallion	Other UK Crude	26	2.6	1.1	**3.7**	Reported
Europe	United Kingdom	Teal	Other UK Crude	37	2.1	7.1	**9.2**	Reported
Europe	United Kingdom	Telford	Other UK Crude	38	5.4	0.1	**5.5**	Reported
Europe	United Kingdom	Tullich	Other UK Crude	38	3.2	1.5	**4.7**	Reported
Europe	Denmark	Cecilie	Denmark Crude	35	1.2	2.2	**3.4**	NOAA
Europe	Denmark	Dan	Denmark Crude	31	2.1	0.9	**3.0**	NOAA

REGION	COUNTRY	FIELD NAME	DG ENERGY CRUDE†	API GRAVITY	CARBON INTENSITY (gCO_2e/MJ)			FLARING DATA SOURCE
					VFF††	OTHER	TOTAL	
Europe	Denmark	Gorm	Denmark Crude	34	2.1	1.0	**3.1**	NOAA
Europe	Denmark	Halfdan	Denmark Crude	31	2.5	0.6	**3.1**	NOAA
Europe	Denmark	Kraka	Denmark Crude	33	2.1	0.7	**2.8**	NOAA
Europe	Denmark	Lulita	Denmark Crude	32	3.0	0.7	**3.7**	NOAA
Europe	Denmark	Nini	Denmark Crude	39	1.3	1.1	**2.4**	NOAA
Europe	Denmark	Rolf	Denmark Crude	31	1.0	1.3	**2.4**	NOAA
Europe	Denmark	Siri	Denmark Crude	37	1.4	4.4	**5.8**	NOAA
Europe	Denmark	Skjold	Denmark Crude	29	1.2	1.7	**2.9**	NOAA
Europe	Denmark	Svend	Denmark Crude	36	1.4	2.6	**4.0**	NOAA
Europe	Denmark	Syd Arne	Denmark Crude	37	2.0	1.5	**3.5**	NOAA
Europe	Denmark	Valdemar	Denmark Crude	42	3.1	1.1	**4.2**	NOAA
FSU	Azerbaijan	Azeri Central	Azerbaijan Crude	34	1.7	3.7	**5.4**	NOAA
FSU	Azerbaijan	Azeri East	Azerbaijan Crude	34	1.7	3.7	**5.3**	NOAA
FSU	Azerbaijan	Azeri West	Azerbaijan Crude	34	1.7	3.7	**5.4**	NOAA
FSU	Azerbaijan	Chirag	Azerbaijan Crude	35	1.7	3.7	**5.4**	NOAA
FSU	Azerbaijan	Gunashli	Azerbaijan Crude	34	1.7	3.6	**5.3**	NOAA
FSU	Kazakhstan	Tengiz	Kazakhstan Crude	44	4.9	12.8	**17.7**	NOAA
FSU	Russia	Druzhnoye	Other Russian Fed. Crude	33	6.2	5.2	**11.4**	NOAA
FSU	Russia	Kharyaginskoye	Other Russian Fed. Crude	38	6.3	3.3	**9.6**	NOAA
FSU	Russia	Kogalymskoye	Other Russian Fed. Crude	38	6.3	3.8	**10.1**	NOAA
FSU	Russia	Kravtsovskoye	Other Russian Fed. Crude	39	6.3	2.7	**9.0**	NOAA
FSU	Russia	Nivagalskoye	Other Russian Fed. Crude	34	6.2	4.6	**10.8**	NOAA
FSU	Russia	Nong-Yeganskoye	Other Russian Fed. Crude	35	6.3	4.8	**11.1**	NOAA
FSU	Russia	Pokachevskoye	Other Russian Fed. Crude	35	6.3	3.6	**9.9**	NOAA
FSU	Russia	Povkhovskoye	Other Russian Fed. Crude	37	6.3	6.7	**13.0**	NOAA
FSU	Russia	Samotlor	Other Russian Fed. Crude	34	3.8	4.9	**8.7**	NOAA
FSU	Russia	Tedinskoye	Other Russian Fed. Crude	25	5.6	3.2	**8.8**	NOAA
FSU	Russia	Tevlinsko-Russkinskoye	Other Russian Fed. Crude	34	6.2	4.3	**10.6**	NOAA
FSU	Russia	Uryevskoye	Other Russian Fed. Crude	34	6.2	4.3	**10.5**	NOAA
FSU	Russia	Usinskoye	Other Russian Fed. Crude	25	5.6	2.7	**8.3**	NOAA
FSU	Russia	Vat-Yeganskoye	Other Russian Fed. Crude	34	6.2	4.8	**11.1**	NOAA
FSU	Russia	Vozeiskoye	Other Russian Fed. Crude	38	6.4	3.9	**10.3**	NOAA
FSU	Russia	Pamyatno-Sasovskoye	Urals	40	6.3	6.6	**12.9**	NOAA
FSU	Russia	Unvinskoye	Urals	40	6.4	5.4	**11.8**	NOAA
FSU	Turkmenistan**	Dzheitune (Lam)	Other FSU Crude	40	9.8	10.7	**20.5**	NOAA
FSU	Turkmenistan**	Dzhygalybeg (Zhdanor)	Other FSU Crude	40	9.8	10.3	**20.1**	NOAA
Middle East	Iran	Nowruz	Iranian Heavy	21	4.4	7.4	**11.8**	NOAA

REGION	COUNTRY	FIELD NAME	DG ENERGY CRUDE†	API GRAVITY	CARBON INTENSITY (gCO_2e/MJ)			FLARING DATA SOURCE
					VFF††	OTHER	TOTAL	
Middle East	Iran	Soroosh	Iranian Heavy	19	4.0	7.1	**11.2**	NOAA
Middle East	Iran	Aghajari	Iranian Light	34	5.1	10.8	**15.8**	NOAA
Middle East	Iran	Kupal	Iranian Light	32	6.6	11.0	**17.6**	NOAA
Middle East	Iran	Ahwaz-Asmari	Other Iran Crude	32	5.0	6.9	**11.9**	NOAA
Middle East	Iran	Bibi Hakimeh	Other Iran Crude	30	4.6	5.7	**10.3**	NOAA
Middle East	Iran	Faroozan	Other Iran Crude	29	4.6	6.7	**11.3**	NOAA
Middle East	Iraq	Rumaila (South)	Basrah Light	34	6.4	4.0	**10.4**	NOAA
Middle East	Iraq	Kirkuk	Kirkuk	33	6.0	3.0	**9.0**	NOAA
Middle East	Iraq	East Baghdad	Other Iraq Crude	23	5.8	3.9	**9.7**	NOAA
Middle East	Iraq	Zubair	Other Iraq Crude	35	6.5	5.1	**11.6**	NOAA
Middle East	Kuwait	Burgan	Kuwait Blend	31	2.3	3.7	**6.0**	NOAA
Middle East	Saudi Arabia	Berri	Arab Light	33	1.5	3.6	**5.0**	NOAA
Middle East	Saudi Arabia	Ghawar	Arab Light	34	1.3	4.3	**5.6**	NOAA
Middle East	Saudi Arabia	Khurais	Arab Light	35	1.1	2.9	**4.0**	NOAA
Middle East	Saudi Arabia	Qatif	Arab Light	34	1.4	3.5	**5.0**	NOAA
Middle East	Syria	Jebisseh	Souedie	18	3.9	3.8	**7.8**	NOAA
Middle East	Syria	Khurbet East	Souedie	25	4.4	3.5	**7.9**	NOAA
Middle East	Syria	Yousefieh	Souedie	24	4.4	3.3	**7.7**	NOAA
Middle East	Syria	Omar	Syria Light	42	5.2	4.9	**10.1**	NOAA

** Total field production for Cameroonian fields was aggregated. In order to report field level production, a weighted average using the number of wells as weight was constructed.*
*** Total field production for Turkmen fields was aggregated. In order to report field level production, a weighted average using the number of wells as weight was constructed.*
† 'DG Energy Crude' means crude categorizations based on reporting by DG Energy on the European crude supply.
†† VFF is emissions from venting, flaring and fugitives.

The average carbon intensity of the EU baseline is calculated from the field specific carbon intensities in Table 8.3 as follows. Firstly, each oilfield in the Baseline is associated with a particular crude from the DG Energy reporting. Then in any case where there is more than one field associated with a given crude, an average carbon intensity for that crude is calculated as the production weighted average of the CIs of the associated oilfields. In any case where there is only one field associated with a given crude stream, then the estimated CI of that crude stream will be based directly on that oilfield.

Having assigned CIs to each individual crude, these are used to estimate the average carbon intensity of crude supplied in Europe in 2010 overall. This is done by taking the average CI across all DG Energy identified crudes, weighted by their contribution to the EU crude slate.

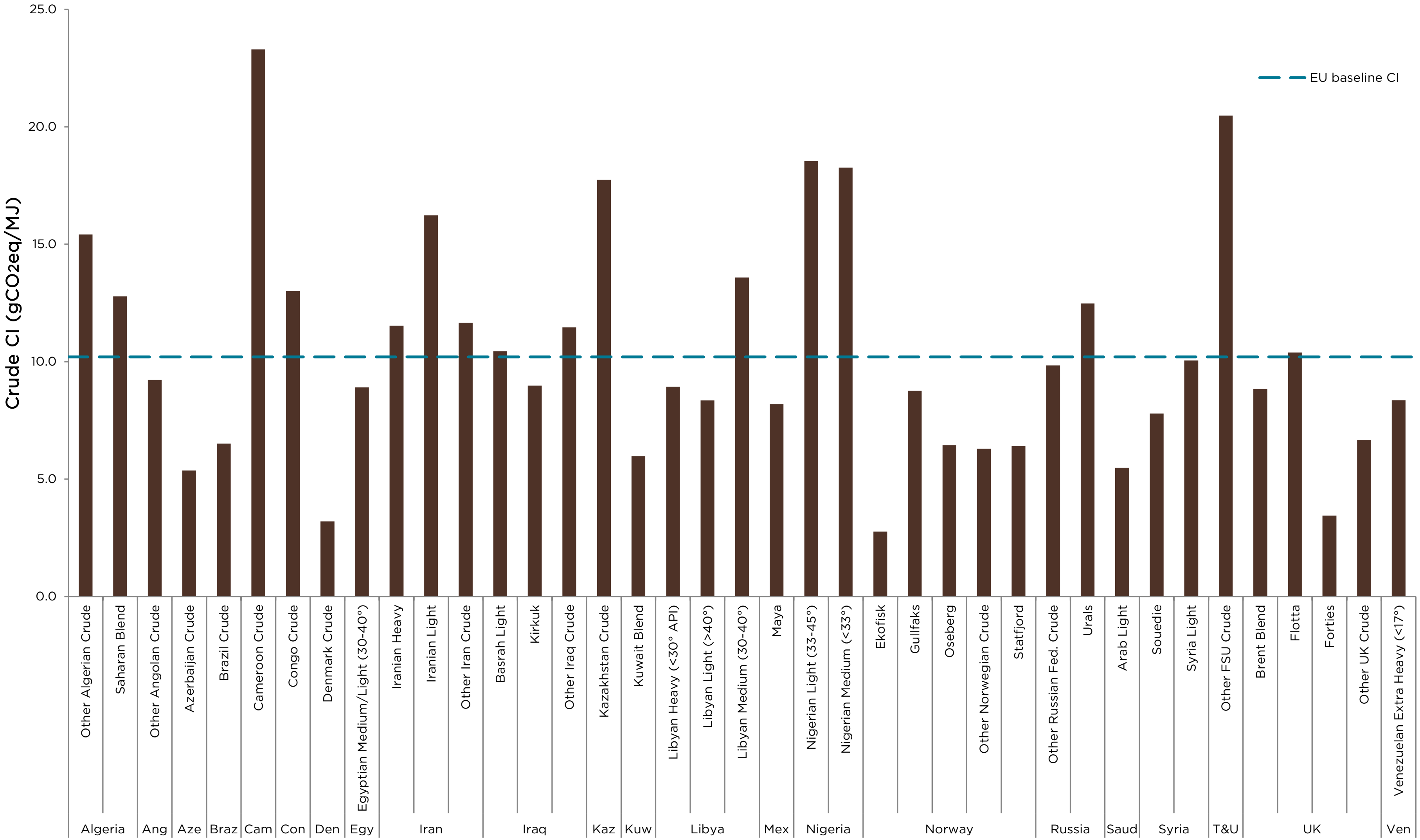
The carbon intensity and associated volume of consumption in the EU for each of the crudes reported by DG Energy is shown in Table 8.4, and illustrated graphically in Figure 8.5. The estimated average CI of the EU crude slate is 10.2 gCO_2e/MJ.

Table 8.4. EU 2010 Crude Baseline Carbon Intensity

REGION	COUNTRY	CRUDE	CRUDE CI (gCO_2e/MJ)	NUMBER OF FIELDS ASSESSED FOR EACH CRUDE STREAM	2010 CONSUMPTION IN EU (1,000 BBL)	% OF EU CRUDE
Africa	Algeria	Other Algerian Crude	15.4	1	19,076	0.4%
Africa	Algeria	Saharan Blend	12.8	1	40,738	0.9%
Africa	Angola	Other Angolan Crude	9.2	3	58,089	1.3%
Africa	Cameroon	Cameroon Crude	23.3	4	14,838	0.3%
Africa	Congo	Congo Crude	13.0	4	19,223	0.4%
Africa	Egypt	Egyptian Medium/ Light (30-40°)	8.9	3	19,429	0.4%
Africa	Libyan Arab Jamahiriya	Libyan Heavy (<30° API)	8.9	1	14,992	0.3%
Africa	Libyan Arab Jamahiriya	Libyan Light (>40°)	8.3	1	196,971	4.6%
Africa	Libyan Arab Jamahiriya	Libyan Medium (30-40°)	13.6	1	191,018	4.4%
Africa	Nigeria	Nigerian Light (33-45°)	18.5	39	120,680	2.8%
Africa	Nigeria	Nigerian Medium (<33°)	18.3	38	32,989	0.8%
America	Brazil	Brazil Crude	6.5	6	34,648	0.8%
America	Mexico	Maya	8.2	1	39,729	0.9%
America	Venezuela	Venezuelan Extra Heavy (<17°)	8.4	1	16,036	0.4%
Europe	Denmark	Denmark Crude	3.2	13	89,133	2.1%
Europe	Norway	Ekofisk	2.8	7	86,989	2.0%
Europe	Norway	Gullfaks	8.8	4	44,408	1.0%
Europe	Norway	Oseberg	6.4	6	57,310	1.3%
Europe	Norway	Other Norwegian Crude	6.3	10	249,212	5.8%
Europe	Norway	Statfjord	6.4	3	54,439	1.3%
Europe	United Kingdom	Brent Blend	8.8	18	57,589	1.3%
Europe	United Kingdom	Flotta	10.4	9	17,907	0.4%
Europe	United Kingdom	Forties	3.4	20	152,792	3.5%
Europe	United Kingdom	Other UK Crude	6.7	26	144,748	3.4%
FSU	Azerbaijan	Azerbaijan Crude	5.4	5	146,742	3.4%
FSU	Kazakhstan	Kazakhstan Crude	17.7	1	224,638	5.2%
FSU	Other FSU countries	Other FSU Crude	20.5	2	105,827	2.5%
FSU	Russian Federation	Other Russian Fed. Crude	9.8	15	480,350	11.1%
FSU	Russian Federation	Urals	12.5	2	637,003	14.7%
Middle East	Iran	Iranian Heavy	11.5	2	110,759	2.6%

REGION	COUNTRY	CRUDE	CRUDE CI (gCO_2e/MJ)	NUMBER OF FIELDS ASSESSED FOR EACH CRUDE STREAM	2010 CONSUMPTION IN EU (1,000 BBL)	% OF EU CRUDE
Middle East	Iran	Iranian Light	16.2	2	61,179	1.4%
Middle East	Iran	Other Iran Crude	11.7	3	40,811	0.9%
Middle East	Iraq	Basrah Light	10.4	1	22,885	0.5%
Middle East	Iraq	Kirkuk	9.0	1	85,192	2.0%
Middle East	Iraq	Other Iraq Crude	11.5	2	10,483	0.2%
Middle East	Kuwait	Kuwait Blend	6.0	1	24,753	0.6%
Middle East	Saudi Arabia	Arab Light	5.5	4	219,859	5.1%
Middle East	Syria	Souedie	7.8	3	40,661	0.9%
Middle East	Syria	Syria Light	10.1	1	13,802	0.3%
EU baseline average CI:			**10.2**	**Total crude modeled:**		**3,997,924**

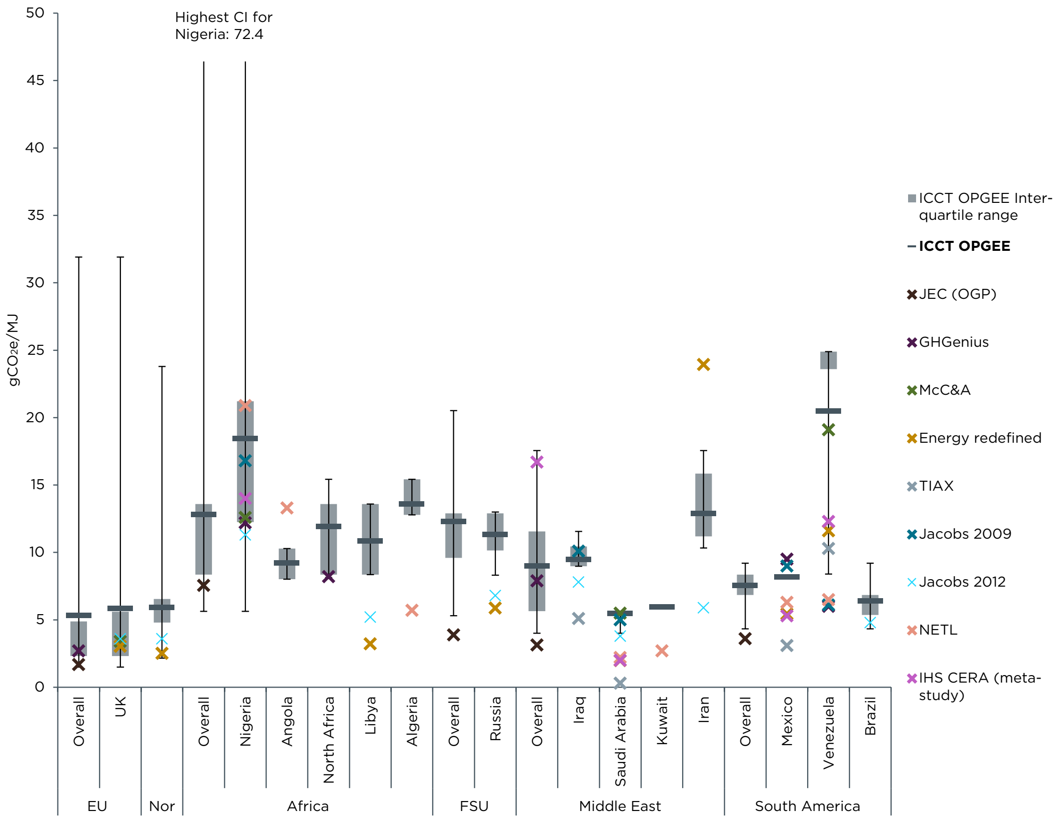
Figure 8.5. Crude carbon intensities grouped by country, compared to EU baseline



8.2.7. Comparing the EU Baseline to previous LCA studies

In §4 we discussed the results of past lifecycle assessment studies. Figure 8.6 compares (at the regional/national level) the results in these studies to our results using OPGEE. For the OPGEE results, the dark grey bars mark the average for each country/region, and the box-whisker overlays show the full range of results for individual fields, and the interquartile range by field production volume. The results identified from other studies are results reported for crudes from the country in question, and do not generally represent an average for that country. The results are presented by country to allow comparison between the new results in this report and the results of previous studies. It should be noted however that national grouping is not generally an adequate approach to disaggregating crude oil carbon intensity, and it has been used here purely for illustrative purposes. As discussed in §9.1.8, a system of grouping crude oil by national origin would have several regulatory drawbacks.

Figure 8.6. Emissions from previous LCA studies compared to the average, inter-quartile range and full range from the OPGEE EU Baseline analysis*,,*****



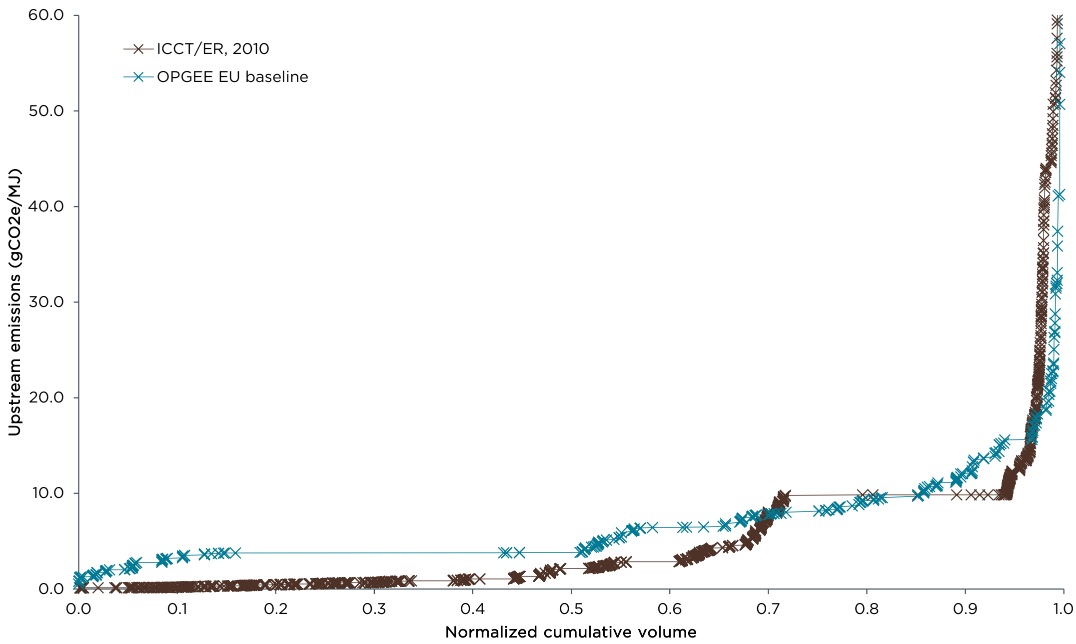
The CI range for Nigerian fields goes up to 72 gCO_2e/MJ for Tapa, which reports nearly 5000 scf/bbl of gas flaring.
***Note that where literature estimates have been associated with an overall region, this is because that is how they were reported in the relevant report – whereas the 'overall' values and ranges reported for OPGEE represent the full range of fields within that region.*
****The box of the box-whisker is inclusive, so if for instance there were three fields modeled for a country with CIs of 5, 10 and 15 gCO_2e/MJ, each supplying 33% of fuel, the box would span the whole CI range. On the other hand, if the fields supplied 20, 50 and 30% of fuel respectively, the inter-quartile range would span only 10 – 15 gCO_2e/MJ.*
***** Venezuelan synthetic crudes were excluded from the EU baseline as the volumes of Venezuelan heavy/medium/light crude reported by DG Energy are below the cut-off for inclusion, but we include them here for comparison, as several previous studies model upgraded Venezuelan crudes.*

The OPGEE results from the baseline analysis are broadly consistent with the range of results reported in the literature. In general national averages from OPGEE are towards the high end of previously reported values, (e.g. UK, Saudi Arabia, Nigeria) but not by an enormous amount.

The studies we have referenced generally aimed to assess either regional average CIs or find single crudes to use as representative of regional production. It is therefore not surprising that the European Union baseline results, capturing the carbon intensities of hundreds of individual fields, show more variation than in many of the past studies. For the United Kingdom and Nigeria in particular we see a very wide range of results. We believe that these ranges are representative of real variation in field level emissions – in Nigeria driven largely by flaring, while in the United Kingdom the highest emissions rates correspond to fields that are reporting high water-oil-ratio and high rates of gas and/or water injection. However, it is important to recognize that the apparent lack of variation in other areas does not necessarily imply a relative homogeneity of emissions profile – rather, we have been able to estimate such a range of carbon intensities for United Kingdom and Nigerian fields because of our access to published data on production for these fields. It is almost certain that if we had similar reporting for fields in Russia, or any other major producing country that we find much expanded emissions ranges for those countries as well.

The only study with a broader coverage of crudes than the EU Baseline in this report is ICCT/ER (2010), where over 3000 fields were assessed. That study had different system boundaries than OGPEE (it included refining, and excluded sources such as drilling and exploration). For purposes of a fair comparison, in Figure 8.7 the carbon emissions from production only are compared for ICCT/ER against the OPGEE EU baseline. ICCT/ER find an average production CI of 5.3 gCO_2e/MJ, while OPGEE gives an average using the representative fields methodology of 8.5 gCO_2e/MJ. Both studies show a similar pattern of CI values – the first half of production is at relatively low CIs, followed by another 40-45% that are higher and a final 5-10% of fields with very high emissions, due to high flaring, high WOR (OPGEE), upgrading, thermally enhanced production (ICCT/ER) and so on. The similarities in results between the two modeling efforts suggest that the EU Baseline from OPGEE is delivering a good characterization of the CI of crude entering Europe.

Figure 8.7. Comparing the ICCT/ER (2010) and OPGEE carbon intensity values – production emissions only*, by normalized cumulative volume of oil



**OPGEE normally includes transport, drilling and exploration in the system boundary. ICCT/ER included transport and refining. The values charted here are for production only for purposes of comparison.*

8.2.7.b. Very high CI fields

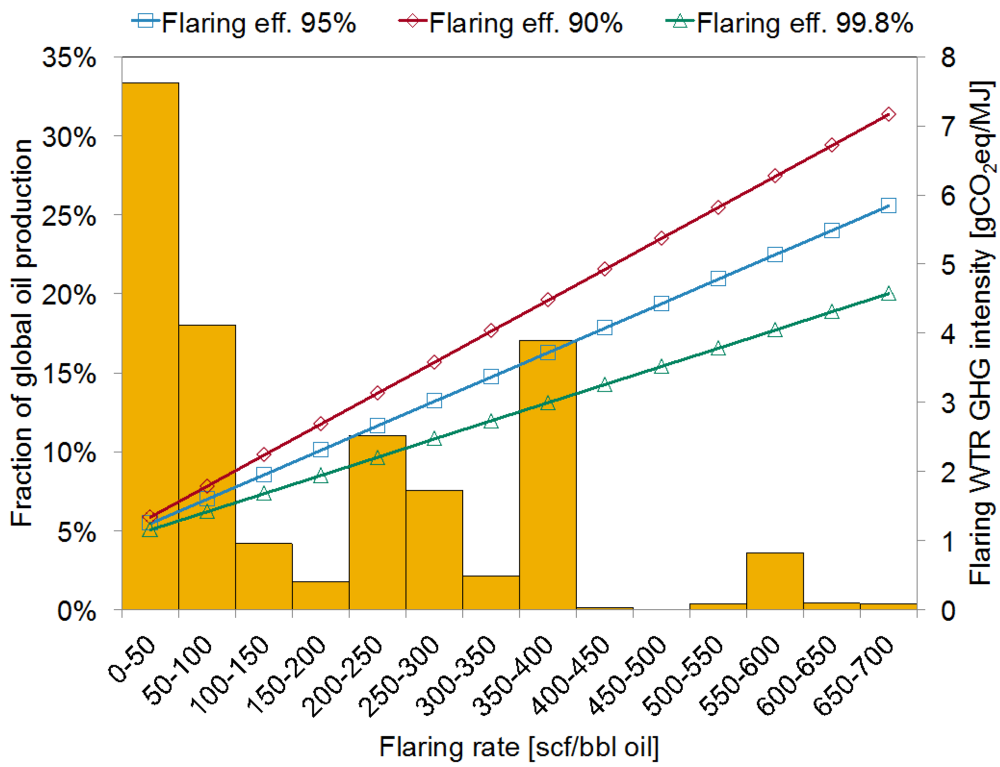
Several of the fields modeled for the EU baseline, even after excluding outliers as described in §8.2.5, have been estimated to have relatively high carbon intensities – approaching or even exceeding the upstream carbon intensities associated with processes such as thermally enhanced production and oil sands extraction. The fields estimated to have emissions over 15 gCO_2e/MJ (the former high carbon intensity crude oil cutoff under the California LCFS) are listed in Table 8.5. In most cases, these very high intensity fields have either a high level of flaring[102], a high water-oil-ratio (WOR).[103] For comparison, in this section we have included two Venezuelan extra heavy fields (Petrozuata and Zuata Principle) that include the emissions from upgrading to synthetic crude oil. In the cases where fields do not feed upgraders or exceed one of the two thresholds defined, they either have a combination of above average flaring and relatively high WOR, or for some United Kingdom fields inject large volumes of gas or water.

High levels of flaring cause CO_2 emissions directly, as a product of combustion of flared gas. In the case of inefficient flare burn, the greenhouse gas impact is even higher, as methane has a higher global warming potential (GWP) than CO_2. The correlation between flare

[102] Defining 'high' flaring as over 500 standard cubic feet of gas flared per barrel of oil produced
[103] Over 10

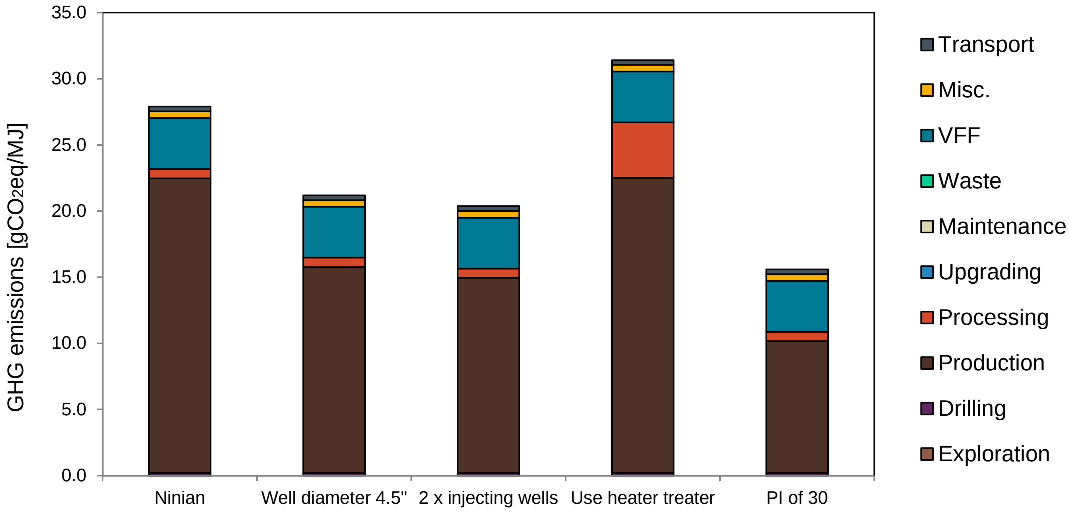
rates, flare efficiency and carbon intensity is shown in Figure 8.8 from El-Houjeiri et al (2012, in review).

Figure 8.8. A reduction in flare efficiency by 10 percentage points increases the carbon intensity of flaring by over 50 percent



High WOR can be a driver of high emissions because of the energy required to pump large volumes of fluid from the reservoir to the surface – and/or to reinject large volumes of produced water. Whereas we can have high certainty that high-flaring fields have high carbon intensities, for fields with high WOR the results from OPGEE can become quite sensitive to other parameters that may not be known, and where the model hence must rely on defaults. For instance, the United Kingdom's North Sea Ninian field is relatively well characterized with detailed production data released by DECC (2012), and has been estimated to have emissions of nearly 30 gCO_2e/MJ, largely due to a high WOR. However, if we change various model assumptions from the defaults for which we do not yet have data, the estimated emissions could change substantially. For instance, if the field's productivity index is much higher than the OPGEE default, the estimated emissions would drop by nearly 50 percent. Our assessment of Ninian's emissions and four variations based on changing single defaults are shown in Figure 8.9. While the emissions are still relatively high in all cases, there is substantial uncertainty about the precise value. This serves to emphasize that while the model gives the best results possible given data limitations, for fields with relatively extreme production characteristics in particular it would greatly increase the certainty of the results to collect additional process data. Within a regulatory framework, a hybrid reporting system (or other system allowing data reporting) would enable producers to provide data and ensure that they would not be unduly penalized because the OPGEE defaults did not reflect their fields.

Figure 8.9. The OPGEE modeled emissions for Ninian are sensitive to process choices because of the high WOR



Note: Default well diameter assumption is 2.8". Default assumption on injecting wells is one for every two producing wells. PI stands for productivity index.

The third factor that has caused oils to be characterized as very high carbon intensity is upgrading. Upgrading is a process of increasing the value of very heavy crude oils through techniques such as coking, in which the heavy ends of the crude are removed, to allow a higher value, higher API synthetic crude to be sold on. It is used for mined bitumen in Alberta, and also by Venezuelan extra heavy oil producers. The process is energy intensive, and therefore it is possible to be confident that oils going through the upgrader will have a high associated lifecycle carbon intensity.

It's important to note that in the EU baseline, we have only considered fields that we believe may currently be supplying crudes coming to the EU in significant volumes. This section additionally considers two examples of Venezuelan fields feeding upgraders, but the report does not consider some other high carbon intensity pathways, such as thermally enhanced oil production. These are common in regions including California and Canada, and likely to be used more in other parts of the world in future. Because steam generation is very energy intensive these processes tend to have very high carbon intensities.

Table 8.5. High carbon intensity crude oils

COUNTRY	FIELD	CI	FLARING	WOR	UPGRADER
Algeria	Ourhoud	15.4			
Cameroon	Ebome (KF)	23.3	High flaring		

COUNTRY	FIELD	CI	FLARING	WOR	UPGRADER
Cameroon	Kole	24.0	High flaring		
Cameroon	Makoko NE plus Abana	23.5	High flaring		
Cameroon	Moudi D.	22.1	High flaring		
Nigeria	Abiteye	37.8	High flaring		
Nigeria	Abura	24.2	High flaring		
Nigeria	Adua	15.0	High flaring		
Nigeria	Agbara	58.7	High flaring		
Nigeria	Ahia	35.2	High flaring		
Nigeria	Amukpe	56.1	High flaring	High WOR	
Nigeria	Asasa	22.6	High flaring		
Nigeria	Cawthorne Chan	15.3	High flaring		
Nigeria	Delta	25.0	High flaring		
Nigeria	Delta South	33.4	High flaring		
Nigeria	Diebu Creek	27.3	High flaring		
Nigeria	Edop	21.2	High flaring		
Nigeria	Egbema	28.9	High flaring		
Nigeria	Egbema West	29.8	High flaring		
Nigeria	Ekpe	16.6	High flaring		
Nigeria	Enang	18.6	High flaring		
Nigeria	Idama	27.9	High flaring		
Nigeria	Inanga	16.0	High flaring		
Nigeria	Inda	20.4	High flaring		
Nigeria	Inim	21.0	High flaring		
Nigeria	Iyak	17.7	High flaring		
Nigeria	Jisike	33.9	High flaring		
Nigeria	Malu	33.1	High flaring		
Nigeria	Mfem	32.9	High flaring		
Nigeria	Mina	52.2	High flaring		
Nigeria	Olo	15.7	High flaring		
Nigeria	Tapa	72.4	High flaring		
Nigeria	Ubit	15.8			
Nigeria	Unam	18.6	High flaring		
Nigeria	Utue	19.3	High flaring		
Nigeria	Adanga	42.6	High flaring		
Nigeria	Adibawa NE	18.0	High flaring		
Nigeria	Ata	17.4	High flaring		
Nigeria	Etelebou	18.5	High flaring		
Nigeria	Idoho	39.0	High flaring		
Nigeria	Isobo	33.8	High flaring		
Nigeria	Makaraba	22.4	High flaring		
Nigeria	Meji	18.9	High flaring		
Nigeria	Meren	42.7	High flaring		
Nigeria	Otamini	15.7	High flaring		
Nigeria	Ubie	20.3	High flaring		
Nigeria	Ughelli West	16.2	High flaring		
Nigeria	Uzere East	21.3	High flaring		
Nigeria	Ogharefe	52.0	High flaring		
Venezuela	Petrozuata	23.6			Upgrading

COUNTRY	FIELD	CI	FLARING	WOR	UPGRADER
Venezuela	Zuata Principal	24.9			Upgrading
Norway	Visund	23.8			
United Kingdom	Saltire	24.1			
United Kingdom	Alba	16.2			
United Kingdom	Fulmar	22.7	High flaring		
United Kingdom	Leven	15.4		High WOR	
United Kingdom	Murchison	29.8		High WOR	
United Kingdom	Ninian	27.9		High WOR	
United Kingdom	Piper	17.7			
United Kingdom	Thistle	31.9		High WOR	
Kazakhstan	Tengiz	17.7			
Turkmenistan	Dzhygalybeg (Zhdanor)	20.1	High flaring	High WOR	
Turkmenistan	Dzheitune (Lam)	20.5	High flaring	High WOR	
Iran	Aghajari	15.8		High WOR	
Iran	Kupal	17.6		High WOR	

9. Comparative analysis of policy options

In the preceding chapters of this report, we have: discussed existing legislative frameworks for regulating fuel greenhouse gas (GHG) emissions; reviewed the literature on crude oil carbon intensities (CIs); discussed the crudes entering the European Union (EU) and the availability of data to describe those crudes; outlined a new, open sourced, spreadsheet model that can be used to assess crude oil CI; and used that model to estimate the carbon intensity of the European fuel baseline.

In this chapter, we discuss possible ways to use this information to implement reporting and/or regulation of transport fuel lifecycle CI in the EU, in particular in the context of the Fuel Quality Directive (FQD). If a reporting and/or accounting framework were to be introduced by the European Commission through an Implementing Measure, it would need to be consistent with the requirements of Council Decision (199/468/EC)) "Laying down the procedures for the exercise of implementing powers conferred on the Commission". Article 5a, paragraph 3(b), lays out the conditions in which the European Parliament or Council may oppose the adoption of an Implementing Measure proposed by the Commission. These are where:

(1) The draft measures exceed the implementing powers provided for in the basic instrument,

(2) The draft is not compatible with the aim or the content of the basic instrument,

(3) The draft does not respect the principles of subsidiarity or proportionality.

Any reporting or accounting framework that could not be implemented on this basis would require amendment to the underlying legislation.

9.1. Potential methods/procedures for comparing greenhouse gas emissions

Before proposing a legislative approach under FQD, it is worth reviewing again the potential options. Several approaches have been implemented or proposed in various jurisdictions for comparing greenhouse gas emissions. In this section, we detail several of these existing initiatives as well as outlining some variations that would warrant consideration. The approaches we consider are:

- Reporting and accounting based on actual calculations;
- Hybrid approach analogous to biofuel reporting under Renewable Energy Directive/Fuel Quality Directive (RED/FQD) and the United Kingdom Renewable Transport Fuel Obligation (RTFO);

- Feedstock defaults approach outlined in European Commission implementing proposal for FQD;
- High carbon intensity crude oil (HCICO) approach adopted by the California Air Resources Board (CARB) in 2011 for the Low Carbon Fuel Standard (LCFS);
- California average approach adopted in 2012 by CARB to replace HCICO approach;
- Other approaches proposed for discussion by CARB;
- British Columbian treatment under the Renewable Low Carbon Fuel Requirements Regulation (RLCFRR);
- Country/region specific default values approach (RTFO 2008/10);
- Emissions reduction credits approach modeled on Clean Development Mechanism (CDM).

For each approach, we describe what it entails, indicate how it might be integrated into the overall framework of the FQD and discuss pros and cons. In Section 9.3 we provide a discussion of legality of the various different frameworks under World Trade Organization (WTO) rules.

9.1.1. Full reporting and accounting

The simplest (conceptually) but most burdensome (administratively) approach would be to require detailed reporting by companies bringing transport fuels into the European market (henceforth ‘fuel suppliers’) that would allow assessment of the carbon intensity of each fuel individually using the OPGEE (or some comparable tool). This approach could be structured to require reporting by well, field or marketable crude oil name (MCON). The level of reporting burden would be proportionately higher for well or field level reporting than MCON level reporting, but if such a system were implemented, the results would also be more accurate with a higher resolution. Given the challenges of data collection from the oil industry and sensitivity around commercial information, we focus here on MCON level reporting – however, well or field level reporting would work in much the same way.

Under a full reporting system, each fuel supplier would be required to report the MCONs from which the supplied fuels were derived, and the relative fraction of each MCON. A mass-balance data tracking approach would likely be appropriate for tracking the MCON data. In order to ensure compliance, it would be necessary to apply penalties for any failure by fuel suppliers to report the appropriate data. For each MCON, the supplier would be required to report a minimum set of information. It would be appropriate to consult with stakeholders on the precise data points required, but we would suggest that the minimum dataset would be something like the set outlined in Table 9.1.

Table 9.1. Data reporting minimum requirement illustration

OPGEE INPUT PARAMETERS	UNIT	BASIS OF REPORTING
MCON name	n/a	Name of crude as traded
Field properties		
Field age	years	Representative value or weighted average for fields supplying MCON
Field depth	feet	Representative value or weighted average for fields supplying MCON
Oil production volume	bbl/d	Total production of MCON
Average reservoir pressure	psi	Representative value or weighted average for fields supplying MCON
Fluid properties		
API gravity of produced crude	deg. API	Value for MCON
Water-to-oil ratio (WOR)	bbl water/bbl crude	Representative value or weighted average for fields supplying MCON
Gas-to-oil ratio (GOR)	scf/bbl crude	Representative value or weighted average for fields supplying MCON
Production methods		
Downhole pump	Yes/No	Summary of practices in place for fields supplying MCON.
Water reinjection/flooding	Yes/No	Summary of practices in place for fields supplying MCON.
Gas reinjection/flooding	Yes/No	Summary of practices in place for fields supplying MCON.
Gas lifting	Yes/No	Summary of practices in place for fields supplying MCON.
Steam flooding	Yes/No	Summary of practices in place for fields supplying MCON.
Other	Describe	
Production practices		
Water injection ratio	bbl water/bbl crude	Representative value or weighted average for fields supplying MCON
Gas injection ratio	scf/bbl crude	Representative value or weighted average for fields supplying MCON
Gas lifting injection ratio	scf/bbl crude	Representative value or weighted average for fields supplying MCON
Steam-to-oil ratio (SOR)	bbl cwe/bbl crude	Representative value or weighted average for fields supplying MCON
Percentage electricity generated onsite	%	Representative value or weighted average for fields supplying MCON
Volume of associated gas flared	scf/bbl crude	Representative value or weighted average for fields supplying MCON
Volume of associated gas directly vented	scf/bbl crude	Representative value or weighted average for fields supplying MCON

Using these parameters alongside OPGEE default values, each MCON would be assigned an average upstream fuel carbon intensity. It should be noted that, as discussed above, OPGEE relies on an extensive set of default data such as equipment efficiencies, and that in some cases actual performance could differ substantially from model defaults. It is also important to recognize that OPGEE does not model every possible upstream process variant, limiting the potential accuracy in some cases. This could be coupled either to a single default refining emissions value, a value determined based on API or other fuel parameters, or potentially a more sophisticated evaluation of refining emissions, to give a total fuel carbon footprint for each regulated party.

One question that must be answered in implementing a full-reporting system (or any of the hybrid reporting systems discussed here) would be whether the fuel suppliers or the regulators would be given the responsibility of undertaking the OPGEE assessment. In California under LCFS, and under the United States federal Renewable Fuel Standard (RFS), the regulator retains the prerogative of undertaking any new pathway analysis. In contrast, in the United Kingdom under RTFO the responsibility of undertaking the revised analysis is placed on the company, which also has a requirement to provide an independent verifier's confirmation that the reported data and value are legitimate. In Germany under the Biofuel Sustainability Ordinance (BSO), the responsibility for the pathway assessment is outsourced to defined third party certification bodies and verifiers.

Within the legal framework of the Fuel Quality Directive (FQD), it is unlikely that the European Commission (EC) could or would take responsibility for the full administration of a fossil fuel reporting system. The legal responsibility for verifying data reported under the FQD lies with the Member States, and hence we must anticipate potentially divergent implementations of any reporting system in the Member States. It would be important to the credibility of the system that there was a degree of consistency in treatment across the Member States, both in terms of reporting and in terms of verification. It would also be important to consider what the appropriate level of data reporting from the Member States to the Commission would be under such a system – for instance, if the Member State took the responsibility for undertaking the revised calculations, would the submitted data also be required by the Commission? We would suggest that any implementing measure to introduce a full reporting and accounting framework should provide detailed guidelines to ensure pan-Union consistency and to reduce the burden on businesses operating in multiple Member States. Developing detailed data reporting guidelines and Identifying appropriate measures to verify data reporting is a substantial task – we have not attempted to fully outline a data reporting system here.

A full reporting system might be opposed by some stakeholders, as elements of the data required may be considered commercially sensitive, and as in some cases data on the full set of parameters for a given MCON might not be easily available. One scenario in which data transfer through the chain of custody might be difficult would be in cases where National Oil Companies control production. If the government of a non-EU fuel-producing nation took a position against data reporting, this could limit the capacity of purchasers to insist on information transfer in those cases.

Another important question would be how to deal with potentially divergent reporting by different companies on the same MCON (or field etc.). It would be necessarily to either allow an inconsistency to stand, even while recognizing that the crude potentially had the same carbon intensity in both cases, or else to implement a data assessment system across the EU to adjudicate diverging data. Once an MCON carbon value had once been defined, it would be necessary to decide whether to set this as a reportable default in future, or insist that companies continue reporting the full set of data in each reporting period (and going through the appropriate verification process to assure the chain of custody). At the point that the system came into effect, it would be vital to have the fuel supply prepared for the data reporting requirements, as otherwise a data reporting rule could have the effect of blocking entry into the EU market for volumes of crude that did not have proper data tracking associated with them. This could be partly facilitated with clearly defined Member State transposition deadlines.

Given full reporting under the framework of the FQD, it would need to be decided whether suppliers would be required to deliver a 6 percent greenhouse gas reduction compared to an EU average 2010 baseline, or compared to a baseline based on assessment of supplier specific fossil fuel carbon intensities. In either case, a supplier with a higher-carbon initial fuel slate would have to achieve larger compensating carbon reductions through supplying alternative fuel or other eligible offsets, or else transition to a lower carbon fossil fuel slate. A fuel supplier with a lower carbon fuel slate would need to invest less in credits from alternative fuels and other eligible offsets. A full accounting and reporting system would base the assessment of fuel carbon intensity on a well-defined and scientifically rigorous assessment system (e.g. OPGEE), and would not treat any one region unfairly compared to another, and hence should be robust under trade rules.

Some advantages and disadvantages of the reporting and accounting system are outlined in Table 9.2.

Table 9.2. Pros and cons of accounting and reporting system

PROS	CONS
Full accounting gives relatively accurate emissions assessment	Relatively high administrative burden
Companies assessed based on actual performance	Refineries set up to process heavy oil likely to be disadvantaged
Poor performers cannot hide behind defaults	Relatively high verification burden
Forces the development of chain of information custody	Potential for product and/or crude shuffling to meet carbon reduction obligations
Provide direct rewards for measures taken to improve field-level carbon performance	Challenge of dealing with divergent reported data
Could drive real carbon emissions reductions	In the case that it was not practically possible to trace the minimum data for some crudes, could have the effect of blocking them from the EU market

9.1.2. Feedstock specific defaults

The draft implementing measure[104] on article 7(a) of the FQD proposes a system of default emissions values by feedstock for fossil fuels (see Table 9.1).

[104] February 2012, see http://ec.europa.eu/transparency/regcomitology/index.cfm?do=search.documentdetail&XOvfOQKYHt67nl0gDR9EQ0pDU4MfDGIJHglKuEmrBsRhxbx1TISJ2Mfg5DtxY23N

Table 9.3. Proposed default fossil fuel carbon intensity values by feedstock (largely based on JEC well-to-wheels study [2011])

FEEDSTOCK SOURCE AND PROCESS	FUEL OR ENERGY PLACED ON THE MARKET	UPSTREAM UNIT GHG INTENSITY (gCO_2e/MJ)	LIFECYCLE UNIT GHG INTENSITY (gCO_2e/MJ)
Conventional crude	Petrol	5.2	87.5
	Diesel or gasoil	5.3	89.1
Natural bitumen	Petrol	24.7	107
	Diesel or gasoil	24.7	108.5
Oil shale	Petrol	49	131.3
	Diesel or gasoil	49	133.7
Any fossil sources	Liquefied Petroleum Gas	3.5	73.6
Any fossil sources	Liquid or compressed natural gas	3.5	76.7
Coal converted to liquid fuel	CTL petrol, diesel or gasoil	100	172
Coal converted to liquid with Carbon Capture and Storage of process emissions	CTL petrol, diesel or gasoil	100	81
Natural gas converted to liquid fuel	GTL petrol, diesel or gasoil	25	97
Natural gas using steam reforming	Hydrogen	3,5	82
Coal	Hydrogen	100	190
Coal with Carbon Capture and Storage of process emissions	Hydrogen	100	6
Waste plastic	Petrol, diesel or gasoil	0	86

A system of defaults by feedstock would minimize the reporting burden to fuel suppliers from the regulation. In general, crude supplied to European refineries is neither bituminous nor kerogenous, and most regions do not produce such crudes. CE Delft (2012) note that for crude oil imported to Europe, the necessary chain of custody already exists for customs reporting etc., so any additional reporting burden for imported crude should be minimal. This is not the case for final product imports (diesel) or for intermediate product imports or petroleum feedstock from the chemicals industry. In the near term, it might be expected that unconventional bituminous crude in particular is more likely to enter Europe as finished product than for refining.[105] Delft estimate a chain of custody burden of the order of 0.01 € per barrel for the oil industry overall, a relatively negligible cost burden.

Reporting by feedstocks makes sense if emissions are reasonably well described by feedstock. An analogous system is used under the FQD for biofuels, under which default emissions values are allocated by feedstock crop. Stratton et al. (2011) investigate variability in lifecycle analysis (LCA) greenhouse gas inventories of mid-distillate fuels, and report variation in the lifecycle emissions of kerogen, bitumen and conventional crude based diesels. However, the variation within fossil feedstock categories is less than within biodiesel feedstocks.

[105] Expanded refining of bituminous material in the United States is likely to generate excess bituminous-distillate capacity in the United States refinery sector, for which there will be a market in more heavily dieselified European Union.

One way to investigate the legitimacy of the feedstock-based approach is to try to estimate the probability that the relative emissions intensity of two batches of fuel from different feedstocks could be miscategorized.[106] Using Stratton et al. (2011) we allocated distributions for the emissions for several fuel feedstocks (kerogen, coal-to-liquid [CtL], bitumen, gas-to-liquid [GtL]) defined as beta-pert distributions with the minimum, baseline and maximum values from Stratton et al. (2011). For conventional oil, we fitted a beta distribution to the conventional oil emissions profile from ICCT/ER (2010), to give the most detailed available distribution of the carbon intensities of conventional crude oil supplying EU transport fuels. The Stratton et al. (2011) and ICCT/ER (2010) crude intensity baseline values are not identical to the values proposed for the FQD, but the hierarchy is the same (CI of conventional crude < GtL < bitumen < kerogen < CtL).

Using Monte-Carlo analysis, we investigate the probability that two batches of fuel may be incorrectly categorized compared to each other, giving the results shown in Table 9.4.

Table 9.4. Probability that the hierarchy of emissions could be misstated for various fuel pairs (based on Stratton et al., 2011)

FUELS COMPARED	PROBABILITY OF MISCHARACTERISATION
Probability that conventional is actually worse than GtL	4%
Probability that conventional is actually worse than Bitumen	2%
Probability that conventional is actually worse than Kerogen	1%
Probability that conventional is actually worse than CtL	0%
Probability that GtL is actually worse than Bitumen	14%
Probability that GtL is actually worse than CtL	0%
Probability that GtL is actually worse than Kerogen	7%
Probability that Bitumen is actually worse than CtL	0%
Probability that Bitumen is actually worse than Kerogen	22%
Probability that Kerogen is actually worse than CtL	0%

Based on the level of variability reported by Stratton et al. (2011), there is a 4 percent chance that a given batch of conventional crude based diesel might actually be worse than a given batch of GtL fuel, despite being given a lower default under a feedstock based approach. For tar sands (bitumen), there is only a 2 percent chance that a given batch of

[106] I.e. the probability that the two batches would be given the wrong comparative carbon intensity ranking.

diesel from conventional crude would have higher emissions than a given batch of bituminous diesel. The highest likelihood of miscategorization is that tar sands oil might be incorrectly labeled as better than oil from shale (22 percent).

For comparison, if the same calculation is undertaken using the LCA variability for soy, palm and oilseed rape (OSR) based diesel identified by Stratton et al. (2011), the highest likelihood of miscategorization is 31 percent (the chance of soy oil being having lower emissions than palm oil but being labeled as worse). The miscategorization likelihood for the other pairs was 3 percent. We conclude from this that while the real carbon intensity of any given batch of fuel may deviate from the default, the use of feedstock based defaults will generally give the correct ordering between different fuel batches. Feedstock based fossil fuel defaults give a high likelihood of correctly ordering fuels, and are probably less likely to incorrectly order any two fuel-batches than the defaults assigned by feedstock for biofuels.

Under the general FQD framework, the use of feedstock specific emissions values would ensure that emissions savings target of 6 percent would not be undermined by unaccounted increases in the use of very high carbon feedstocks. However, such a feedstock specific scheme provides no resolution within feedstock categories – so, for instance, it would be impossible to reward low flaring crude oil compared to high flaring crude oil, or mined oil sands bitumen compared to in situ produced. It would also be possible, in principle, that there could be a significant shift in the average intensity of conventional crude (on the order of 1 gCO_2e/MJ or so) that would not be captured by a feedstock-based methodology.

The feedstock specific scheme has already reportedly been threatened with WTO action by Canada[107], which has been vocal in opposition to it. Canadian officials have argued that the feedstock approach is discriminatory against the oil sands because bituminous sources of oil are singled out, while other extra heavy oil and otherwise very high carbon intensity oil would not be distinguished from lighter crudes. Canadian representatives in Europe have claimed that while Canada is in agreement in principle with the legitimacy of disaggregating fossil fuel carbon intensities, it is against a treatment in which bitumen is the 'only' case singled out for a distinct default.

A feedstock-based approach can be based on the premise that the feedstocks identified are indeed chemically distinct, with differing chemical and physical properties. This, combined with the expectation that a feedstock carbon intensity hierarchy will be largely accurate and the benefits in terms of reduced administrative burden, might be considered to make feedstock reporting an appropriate simplification. There is legal precedent from the United States for considering bitumen as a distinct product from crude oil – bitumen is tax exempt under U.S. law from contribution to the Oil Spill Liability Trust Fund.[108]

[107] E.g. http://www.guardian.co.uk/environment/2012/feb/20/canada-eu-tar-sands
[108] http://priceofoil.org/2012/07/31/tar-sands-tax-loophole-highlighted-in-two-more-reports/

Defense Terre (2011) provide an opinion that carbon intensity assessment by feedstock is likely to be acceptable under WTO rules. They argue that while the end use products from bitumen and conventional crude are alike, in the context of the lifecycle carbon intensity reduction requirement of the FQD this question of comparable end use is not the determinative question, and that the real distinctions in physical properties and lifecycle environmental footprint between the feedstocks are legitimate bases for classification of unlike status. Defense Terre also noted that bituminous and kerogenous oils are given different tariff classification to conventional oil, further suggesting the legitimacy of distinguishing products on this basis.

Some advantages and disadvantages of feedstock defaults are outlined in Table 9.5.

Table 9.5. Pros and cons of feedstock based default values

PROS	CONS
Feedstock defaults provide reasonable proxy to account for the highest carbon fuels	Does not capture variation within feedstock categories
Low administrative burden for companies and regulators	No incentive for field level emissions reductions
Incentives to develop low carbon fuels and/or conventional oil resources rather than expanding high carbon unconventional production	May drive shuffling rather than real production shifts
Does not penalize refineries handling heavy conventional crudes	Less incentive for chain of information custody development
Distinctions reflect existing categorization in tariff classification and the U.S. Oil Spill Liability Trust Fund	Risk (small in most cases) of miscategorizing the hierarchy of emissions intensities between two fuel batches

9.1.3. Hybrid reporting system (c.f. RED/FQD, RTFO biofuel reporting)

In biofuel accounting regulations in the RED/FQD, the option is left open to report better-than-default carbon performance, as a way to allow suppliers to avoid having their fuels unduly penalized. A comparable option is proposed in the 2011 proposed Implementing Measure for the FQD, allowing suppliers to submit a reduced value for high carbon intensity fuels if they can "demonstrate to the Member State that this value is derived using an ISO 14064 compatible methodology". This option would further reduce the likelihood that a batch of fuel would be unduly penalized due to being from a high carbon category, despite having relatively good performance within that category.

A variation on the ISO 14064 based own-value reporting scheme outlined in the 2011 proposed Implementing Measure could be based on the biofuel reporting system implemented in the UK under the RTFO from 2008. Under this biofuel reporting scheme, the Renewable Fuels Agency (RFA) set conservative default emissions values for various fuel pathways, but also provided a clear methodology for suppliers to report revised values based on additional data. Under the RTFO scheme, rather than allowing any given ISO 14064 LCA to be eligible, it was required that all revised emissions estimates should be calculated using a single LCA framework, defined in the RFA's reporting guidance and made available as a calculation tool. Specifying a calculation tool and/or detailed calculation methodology, has the advantage that it reduces any opportunity to tweak the lifecycle analysis methodology to optimize the emissions results. For instance, under ISO 14064 more than one co-product emissions credit assessment might be possible. In that case, an allocative or substitutive methodology might be chosen by a supplier based not on appropriateness, but on which delivers the most favorable outcome. If a tool such as OPGEE were specified by a revised Implementing Measure, then the treatment of methodological questions of this sort would be consistent for all pathways.

The RTFO system also allowed for emissions estimates to be adjusted based on subsets of data – for instance allowing the reporting of facility specific process characteristics, without updating farm level information. A similar 'modular' data reporting approach is permitted under RED/FQD for biofuels. A hybrid reporting system based on OPGEE could offer feedstock level emissions values, but give the option to adjust these based, for instance, on reporting of key characteristics like water cut, or on full field specific data reporting. In the RTFO system, certain values were linked – so, for instance, changing fertilizer application was only permissible with specific data on yields. Similarly, it might be appropriate to enforce links between some OPGEE parameters in a hybrid reporting system – such as insisting on linking production volume, well number and productivity number. Under the RTFO system, suppliers were also under a legal obligation to report more accurate emissions data if known. In principle, this should drive increased reporting and in some cases could result in actual reporting of emissions values higher than the feedstock defaults – however, in practice such a requirement is difficult to enforce, and it is difficult to determine whether it would deliver significant benefits. Nevertheless, a requirement to report data if known could be a useful deterrent to selective reporting, and compliance minded oil companies might well prefer to respect the rule even given limited expectation of enforcement than take even a small risk of prosecution. Such a requirement is not included when considering the pros and cons in Table 9.6 below.

Within the FQD, a hybrid reporting system would require Member States to put in place reporting and verification rules for fossil fuels in parallel to the rules for biofuels – it may be appropriate to give the same regulatory authority responsibility for handling both of the parallel systems. It would also require a set of default reference carbon intensity values to be made available – options for setting these default values are suggested later. One key question if implementing a hybrid reporting system and GHG calculation methodology under FQD would be how the EU average and/or supplier specific baseline fossil fuel emissions comparator should be set (defining the size of the 6 percent required carbon intensity reduction). This issue is discussed in further detail below, as the answer is not trivial.

Several systems similar to this hybrid reporting suggestion already exist in the case of biofuels (RTFO, German BSO, RLCFRR, CA-LCFS), and thus it seems likely that such a system would be compliant in principle with WTO rules. We note however that there is no precedent for these biofuel systems being challenged at the WTO, and thus a definitive answer from case law is not available. The key characteristics of a WTO robust hybrid reporting system are:

- Clear reference to good technical analysis in setting values/methodology;
- Similar treatment accorded to fuels from all regions including Europe;
- Measures not designed to be unduly burdensome;
- Underlying methodology not unduly discriminating against fuels from any given single region.

Table 9.6. Pros and cons of hybrid reporting scheme

PROS	CONS
Feedstock defaults provide reasonable proxy to actual fuel carbon values	No incentive to report poor performance
Incentives to develop conventional oil rather than expanding high carbon unconventional production	No incentive for projects unless they would reduce emissions below the feedstock default (i.e. ineffective for controlling high carbon conventional crudes)
Opportunity for good performance to be rewarded if reported	Use of conservative defaults might systematically over-report emissions (making FQD target artificially challenging)
Low administrative burden for companies not opting in to specific reporting	Use of average values would reduce incentive to report, and might systematically under-report emissions (as the only non-average projects reported would be those with low emissions)
Supports longer term development of chain of information custody	Baselining becomes vexatious in the context of a carbon reduction % target
Could accommodate different levels of data precision (MCON, field, well)	

9.1.3.a. Hybrid reporting and Conservatism

One potential drawback of a hybrid reporting system is that there is no incentive for poor performers[109] to report (reporting poor performance would subject a supplier to disincentives). If best-estimate average

[109] I.e. suppliers of crudes with worse-than-default CIs.

values were used as defaults in a hybrid-reporting scheme, it would therefore remove the value incentive to improve much of overall oil production. A standard method to manage this is to adopt conservative default values – emissions estimates that represent worse-than-typical practice. In the biofuel segment of the FQD, this is done by applying a multiplier to the process emissions in the fuel production chain, so that the default carbon intensity values are generally higher (in some cases quite substantially) than typical estimates. In the pre-RED/FQD RTFO, a system was used in which the default emissions represented 'worst common practice' – the highest emissions intensity that was deemed likely for a given pathway. With OPGEE, conservatism could either be applied by making the default parameters conservative when calculating default CI values, or by continuing to use typical default parameters, but then adopting some RED/FQD like conservatism factor when calculating the reportable default CIs.

Using conservative defaults in the FQD context is complicated by the fact that, as a percentage intensity-reduction target, the baseline emissions are as important to determining compliance needs as the reportable emissions. Conservative defaults, especially if reporting was sparse, could result in systematic over-estimation of the total emissions intensity of the fuel pool. If the conservatism was not reflected in the baseline, then there would be an emissions penalty to most suppliers unless they reported fully on all their oil. This would certainly encourage reporting, but would also potentially have the effect of increasing the quantities of alternative fuels required to meet the 6 percent carbon saving target, which might be undesirable as it could increase compliance costs, as well as increasing any other impacts from alternative fuel production, such as food security impacts. On the other hand, if the conservatism *was* reflected in the baseline, then large paper reductions would be possible by reporting actual performance rather than by delivering real changes. This would have the potentially undesired side effect of reducing the ambition of the carbon saving requirement (as some significant fraction of the 6 percent 'savings' could represent better reporting without a real change in performance).

In California under the CA-LCFS, the baseline is subject to revision whenever the LCA in general is revised, which has advantages but can introduce a perception of uncertainty into the marketplace. To fully support the operation of a dynamic baseline without creating opportunities for paper credits, it would be necessary to require that for any field/MCON being reported based on real data, a supplier would report not only data for the year in question but also for the baseline year. A requirement to report past data would clearly introduce additional challenges, and could limit the opportunity to use actual data in the regulation, as past data may in some cases not be readily available to suppliers even when current data is.

In Table 9.7 we compare some of the features of systems in which: the default GHG values are conservative but the baseline is best-estimate; the default GHG values are conservative *and* the baseline is conservative; and in which the baseline is dynamic.

Table 9.7. Issues with different treatments of conservatism

ISSUES	BOTH DEFAULT AND BASELINE BEST ESTIMATE	DEFAULT CONSERVATIVE; BASELINE BEST ESTIMATE	BOTH DEFAULT AND BASELINE CONSERVATIVE	CONSERVATIVE DEFAULTS; DYNAMIC BASELINE
Are carbon savings 'real' or do they only reflect better data?	Carbon savings could reflect data reporting for cherry picked fields, but could also reflect real savings.	Any overall emissions reductions should be real, and will tend to be underestimated. For individual suppliers, cherry-picking of data reporting may be possible.	Emissions reductions compared to baseline likely to reflect reporting rather than real savings.	Towards 2020 as baseline accuracy progressively improves reductions are more likely to reflect real savings.
Impact on alternative fuels market	Likely to be limited. Expect crude slate CI to rise rather than fall overall, hence making target more challenging.	Likely to create additional alternative fuels demand. Add uncertainty to overall market size.	Likely to reduce total alternative fuel demand. Add uncertainty to overall market size.	Effect on alternative fuel market size will depend on crude slate evolution. Add complexity and uncertainty to determining overall market size.
Value signal for carbon reductions	No price signal for higher-than-average CI MCONs. Relatively high value for savings projects for low CI MCONS.	Best value carbon savings for companies will be achieved by better reporting, not better performance. Relatively high value to real savings projects.	Best value carbon savings for companies will be achieved by better reporting, not better performance. Relatively low value to real savings projects.	Improved reporting should not deliver long-term carbon benefits to companies. Relatively high value to real savings projects.
Market certainty	Limited impact on market certainty	By effectively increasing stringency of target, although it introduces uncertainty on total market size minimum strength of price signal should be clear.	By potentially reducing effective stringency of target, introduce substantial uncertainty about minimum value of carbon savings.	Dynamic baseline introduces uncertainty and complexity. Perception of uncertainty (and risk) may be higher than rational expectation of uncertainty and risk.
Is the 6% target guaranteed?	Program may deliver below 6% real carbon savings	Program should deliver minimum 6% real carbon savings.	Program likely to deliver below 6% real carbon savings.	Program should deliver minimum 6% real carbon savings.

9.1.3.b. Decoupling fossil and alternative fuels

One way to deal with elements of the conservatism problem would be to more substantially revise the FQD framework so as to decouple requirements on alternative fuels from requirements on fossil fuels. This would, however, depart from the principle of technology neutrality that is currently reflected in the FQD, and would probably require a more substantial regulatory revision than would be possible through an Implementing Measure. Fossil fuel emissions performance would then not add variability to the alternative fuel market size. One outcome of regulation of fossil fuel carbon intensity would be to value carbon so as to introduce a price spread between high carbon crude oils and lower carbon crude oils. A cost spread would incentivize increased investment in emissions reduction measures and low carbon extraction processes, while disincentivizing investment in higher carbon crudes, and could still be put in place without requiring a link to alternative fuel prices. It would be possible, for instance, to decouple fossil from alternative fuels targets by imposing a 'no-increase' requirement on the average carbon intensity of fossil fuels to run in parallel to the overall 6 percent emissions reduction requirement.

In that case, credits could be earned if a supplier's fossil fuel carbon intensity was below the baseline, while deficits would be accrued if the carbon intensity were above the baseline. Alternatively, as in the 'California average' system such a system could be set up so that deficits would be accrued for supplying higher carbon intensity crudes, but without offering credits for the use of lower carbon intensity crudes. This would create financial incentives to favor lower carbon crudes. With a conservative baseline, most suppliers would be able in principle to report more accurate data in order to earn credits – this improvement in data quality would not in itself deliver 'real' carbon reductions, but insofar as it made better data available and did not impact the ambition of alternative fuels targets this could be an appropriate compromise. Only suppliers whose actual performance was worse than a conservative baseline would then have to accrue deficits. An alternative compliance mechanism (such as the UK RTFO 'buy-out price') could be imposed on the market as a whole so that the cost of a generalized shift to higher carbon intensity crude oils would be controlled, limited and predictable. Adjustments to the baseline comparator could be considered over time if the Commission felt that there were legitimate reasons for a systematic drift to either higher or lower carbon intensity crudes, or if improved data collection made it clear that the baseline had been over- or under-estimated. As in any other hybrid system, the degree of conservatism could be tuned to increase or reduce the pressure to report.

9.1.3.c. Clean Development Mechanism-like credits for emissions reductions

A hybrid reporting system such as outlined above should give value to some fossil fuel emissions reduction projects, in particular projects on fields that already have lower-than-default emissions. It may be a poor driver for emissions savings on the highest carbon intensity projects, as for these reporting defaults would remain financially preferable.

As an alternative or complementary measure to crediting emissions reduction projects through hybrid reporting, value could be given to specific emissions reduction projects by allowing Upstream Emissions Reduction credits to be generated for emissions reductions without reference to the baseline carbon intensity of the field in question.

To give an example, for a field in the United States with particularly high flaring (e.g. many of the new North Dakota fracking plays), there would be no incentive under a hybrid reporting system to report data for a project to reduce flared emissions unless it reduced overall field emissions below the default value. However, if CDM credits or CDM-like credits (for a more detailed discussion see §9.1.9) could be allocated to such a project for a given tonnage of carbon savings, and these credits be accepted towards FQD compliance, it would give such specific projects additional value. For lower-than-default emissions oilfields, this could allow some degree of double counting. For instance, for a field in Nigeria with flaring below the national average but still high, running a flare reduction project could allow reporting of reduced MCON emissions intensity via OPGEE and *also* allow Upstream Emissions Reduction credits to be earned. As such a project would be guaranteed to deliver real savings rather than 'paper savings', it might be considered acceptable to allow it to accrue this additional value (as in many cases savings reported under a hybrid system compared to the default will not reflect real reductions, but simply reporting of existing practice). Alternatively, measures would have to be taken to ensure that emissions reduction projects could only be accounted through one of the two routes, which might be administratively challenging.

9.1.4. California LCFS high carbon intensity crude oil treatment

The California LCFS has had two treatments of fossil fuel carbon intensity since it was introduced in 2009. The original regulatory treatment was based on a 'California basket' of crudes, and screening for high carbon intensity crude oils (HCICOs) outside of the basket – we will describe this treatment first.

In this treatment, henceforth referred to as the 'HCICO treatment', the baseline carbon intensity of crude oil supplied to California was determined based on the crude types refined in California whose volumes in 2006 were greater than 2 percent of the total crude volume in California. This basket included most Californian produced crude and many imported crudes, but excluded sources such as Venezuelan heavy and Canadian bitumen from the baseline carbon intensity estimation. The second part of the HCICO treatment was a screening methodology for HCICOs, with HCICOs defined as any crude oil with an upstream carbon intensity more than 15 gCO_2e/MJ above the carbon intensity of the baseline. The screening process was to be based on factors like use of thermal recovery, origin in regions with high levels of flaring and so on. A fuel deemed to be at risk of being an HCICO must then have a full lifecycle analysis undertaken – if it was determined after such analysis to be an HCICO, then its actual carbon intensity would have to be accounted under the CA-LCFS. The supplier bringing that fuel into California would then have to obtain additional CA-LCFS credits to offset those emissions 'deficits'.

The determination of the set of fuels in the 'California basket' was important in the HCICO treatment, because fuels already in the basket were to be excluded from HCICO screening, on the basis that the carbon intensity of these fuels was already accounted within the baseline. This measure had the practical effect that, for instance, thermally enhanced recovery of Californian heavy oils *already in operation in 2006* would be allocated the baseline carbon intensity, even though those specific projects may have been more than 15 gCO_2e/MJ more carbon intensive than the average. Thermal production of Venezuelan extra heavy oil, in contrast, would have been subject to screening and a carbon penalty if appropriate. It seems possible that if challenged under international trade rules, this treatment might have been found to be unfairly favorable to Californian product, and to illegitimately restrict trade in 'like' oil products. The case against the California basket approach at the WTO would likely have been somewhat stronger than the potential case against a feedstock specific approach. Even if the adjudicators accepted the appropriateness of considering carbon intensity as a key characteristic of oil, high carbon Californian and high carbon Venezuelan oils would have been treated differently despite having similar chemical as well as carbon characteristics[110]. The California basket provision could therefore have been perceived was a way of extending favorable treatment to local produce against imports.

A HCICO approach could, of course, be implemented without the use of a baseline basket – in that case, we believe it would be likely to be WTO compliant. The advantage in principle of the HCICO approach, or a similar approach, over a feedstock specific approach would be that it would leave open the possibility of assigning a higher carbon intensity to high carbon conventional oils, such as thermal enhanced oil recovery (TEOR) or oils with very high levels of flaring. The disadvantage would be that the screening process would introduce a level of uncertainty not present in the feedstock approach, as a supplier would not know whether a given MCON was a HCICO until after the screening and analysis. The requirement for lifecycle analysis would place a relatively high administrative burden on oils deemed at high risk of being HCICOs compared to a low administrative burden on other oils. In the context of the FQD, we doubt that a European basket provision would be deemed appropriate, so it is more constructive to consider a variation on the California HCICO system in which all oils would be screened. In practice, this would mean building a database of non-HCICOs and possible-HCICOs that would cover most MCONs delivered to Europe. Over time as the possible HCICOs were analyzed, the list would become increasingly well defined. Only new MCONs, or MCONs where there was reason to believe the emissions profile could have changed, would actually need to be subject to additional analysis. A fuller assessment of pros and cons is outlined in Table 9.8.

[110] There would be less physical difference between a given Venezuelan heavy oil and its California counterpart than between either and a Canadian (or Venezuelan) bitumen.

Table 9.8. Pros and cons of HCICO reporting system

PROS	CONS
Accounts for high carbon conventional oils as well as bitumen, kerogen etc.	Does not capture variation among non-HCICOs
Incentives to improve performance to bring production below the HCICO screening intensity	No incentive to reduce emissions further beyond the screening intensity
Incentives to develop non-HCICO oil rather than expanding HCICO production	No incentive to reduce emissions unless it would bring emissions below the screening intensity
Minimal administrative burden for supply of known non-HCICOs	Limited driver of development of chain of information custody
Minimal ongoing administrative burden once HCICOs have been categorized	May drive shuffling rather than real production shifts
	Relatively high initial administrative burden on suppliers of possible HCICOs

9.1.5. California average approach

From 2010-11 CARB convened a subgroup on the screening of HCICOs. In 2011, it also convened an Expert Advisory Panel to advise the staff review of the CA-LCFS program as a whole. In the staff report on the CA-LCFS informed by this advisory panel, the CARB staff commented that[111],

> *"Petroleum refiners in California assert that the current HCICO provisions are overly burdensome to their industry, discriminatory toward sources of crude oil, will increase the potential for global crude-shuffling, which they contend would increase GHG emissions, and would put California refiners at an economic disadvantage to out-of-state refiners."*

On the other hand, they also noted that,

> *"Other stakeholders are equally as adamant that the LCFS should continue to account for increases in lifecycle carbon emissions that could occur if higher-intensity crudes are used to replace existing supplies."*

As a result of the concerns expressed about the HCICO screening system, particularly by the oil industry, the staff presented five potential alternatives for the future of the treatment of fossil fuel carbon emissions in the CA-LCFS. These were:

- The 'California average' approach;

[111] CARB (2011)

- The ‘hybrid California average/company specific’ approach;
- The ‘company specific’ approach;
- The ‘worldwide average’ approach;
- The ‘California baseline’ approach.

Following discussion, the staff recommended to the CARB Board of Directors the adoption of the California average approach, and this was duly adopted by the Board. We will now outline the California average approach and discuss an analogous treatment under FQD. We will then discuss the other four proposed approaches in the following section, for comparative purposes.

In the California average approach, the average emissions intensity of the California crude slate is to be calculated based on a full assessment with OPGEE of the carbon intensities of all crudes supplied to California in a given year. If the average intensity of the California crude mix were higher than the intensity of the California baseline, then there would be an additional ‘California average incremental deficit’ in carbon emissions that must be made up for by all companies by obtaining additional CA-LCFS credits to offset the deficit. Imagine that in a given year the carbon reduction target under CA-LCFS was 5 percent, but the California average crude slate was 1 percent more carbon intensive than the baseline. In that case, each fuel supplier in California would have to generate enough CA-LCFS credits to meet not only the 5 percent reduction target, but also to offset the 1 percent increase in fossil fuel carbon intensity. There would be no comparable credit to fuel suppliers if the California crude slate evolved to a lower average carbon intensity than in the baseline year (i.e. this approach would only be permitted to make the compliance schedule more challenging, not less challenging). In this approach and several of the other approaches, there is a proposal for an innovative emissions reduction credit for being early adopters of technology such as carbon capture and sequestration (CCS). We shall discuss such credit options separately below.

A primary difference between the California average approach and most of the other approaches we discuss here is that it largely decouples any additional compliance burden (additional LCFS deficits generated) from the specific fuel supplier making the choice to bring higher carbon intensity oils in to California. It therefore would be unlikely to generate a significant carbon price on upstream fuel extraction emissions. The system can be demonstrated with the following example. Consider a simplified market with two suppliers, A and B, both refining the same amount of oil. Suppose oil company A made an effort to improve extraction efficiency and reduced the intensity of its slate by 0.5 gCO_2e/MJ, while oil company B invested in tar sands bitumen and increased the intensity of its slate by 2.5 gCO_2e/MJ. Under the average approach, both companies would have to obtain additional CA-LCFS credits to offset a 1 gCO_2e/MJ increase in the California average fossil fuel carbon intensity. Rather than giving B an incentive to develop lower carbon sources, this system would not prevent B potentially achieving a competitive advantage compared to A (for importing cheaper feedstock while not investing in emissions savings). Given that the increased costs of ‘poor’ performance would be spread across the industry, we see little reason to expect that the California average treatment would be strongly effective in preventing increases in fossil fuel carbon intensity. It does, however, force such increases to be offset by increased supply of other low carbon fuels, so that in principle there would be no increase in carbon intensity across the fuel pool as a whole due to adopting the average approach.

Under FQD, a European Union average approach could be adopted to guarantee that the 6 percent target greenhouse gas saving would not be undermined by increases in fossil fuel carbon intensity. It would not effectively incentivize reductions in fossil fuel carbon intensity, but it would protect the wider program target. Whether it is actually desirable to necessitate the use of alternative fuels to offset changes in crude intensity is a more complicated question.

The initial and subsequent annual determination of a European Union average would require the collection and analysis of substantial data by the European Commission through the Member States. The stringency of information reporting requirements would to some extent determine the accuracy of this approach. The Californian example has already shown that while a relatively high accuracy may be possible for oil extracted in regimes with strong regulation and transparency, oilfield level emissions estimation is challenging without additional data for other jurisdictions. A hybrid reporting framework is expected to be implemented by California, but the effectiveness of data acquisition by this system is likely to be influenced by the nature (if any) of penalties or disadvantage due to non-reporting. With no financial benefit from reporting, and given the general reluctance of the oil industry to disclose proprietary data, disclosure may be limited.

Because the California average type of approach would only place a limited barrier on imports of high carbon intensity crude oil to Europe (being more likely to drive an expanded alternative fuels market than crude shuffling) it seems unlikely that it would be, or could be, attacked via the WTO. Given that the approach is even handed towards all regions and would aim to assess each oil on its merits, it also seems unlikely that this approach would suffer a setback if a case was brought.

Table 9.9. Pros and cons of 'California average' approach

PROS	CONS
Accounts for all fuel sources with reasonable accuracy	Does not provide significant incentive for individual fuel suppliers to choose lower carbon crudes
Prevents increases in average oil CI from undermining policy goals	No incentive to achieve marginal emissions reductions
Depending on reporting regime, could drive chain of information custody development	Changes in oil slate would cause variation in effective stringency of compliance targets for biofuels
Minimal administrative burden for supply of known non-HCICOs	Limited driver of development of chain of information custody
Minimal ongoing administrative burden once HCICOs have been categorised	
Allows 'innovative' emissions reductions to be credited	

9.1.6. Other proposed California Approaches

For reference, below is a brief discussion of the other proposed approaches from the CA-LCFS.

9.1.6.a. The 'hybrid California average/company specific' approach

In this approach, companies would incur additional 'deficits' if their crude slate increased in carbon intensity over time. Each company would be assessed a carbon intensity for its baseline crude slate, and would be required to offset using low carbon fuels any increase compared to the baseline. In the proposal, there would in general be no additional credits for reducing the carbon intensity of the crude slate (except for 'innovative' emissions savings). Under this approach, it could be argued that a company with a high carbon intensity baseline is rewarded by being given more freedom to revise its crude slate than a company with a relatively low baseline carbon intensity – as a company starting with a low carbon intensity crude slate would be locked into that slate, or face deficits.

There would be an incentive for a supplier to reduce the carbon intensity of specific crudes, but only if other changes to its crude slate would otherwise cause a deficit. Assuming that the company baseline carbon intensity would be revised if additional data were collected about specific oilfields, there would be limited if any advantage to individual companies from reporting additional data. Indeed, as noted above, a high carbon intensity starting crude slate would give more freedom to shuffle crudes in the future, so there could be a perverse incentive to have the initial crude slate over-assessed for carbon intensity.

9.1.6.b. The 'Company Specific' approach

In this approach, the company's basic compliance targets would be based on its own baseline fuel slate carbon intensity, rather than a California average compliance target. That is, the company would have a 2020 target of delivering fuel 10 percent less carbon intensive than its own baseline, rather than 10 percent below the California baseline. Each year the company's performance would be measured against the compliance target based on its actual fuel slate, and deficits would be accrued dependent upon the difference between the compliance path and the actual slate. In this variant, a switch to higher carbon intensity crudes would result in more deficits (i.e. the requirement to obtain more credits) while a switch to low carbon intensity crudes (or the reduction of the carbon intensity of existing crudes) would reduce the number of credits required to comply. This is comparable to a full hybrid reporting approach for FQD (as we assume that some crudes would be assigned default carbon intensities under this approach).

9.1.6.c. The 'Worldwide Average' approach

This approach is analogous to the California average approach, but would consider world average oil carbon intensity rather than looking specifically at California. The price signal in such a system would be even more diluted, and so the net effect would be to slightly increase the stringency of the compliance schedule for supply of CA-LCFS credits from alternative fuels if the worldwide average carbon intensity of oil went up over time. It seems unlikely that there would be any appetite to move to such a system under the FQD, as it creates a substantial analysis burden for the regulatory agency without delivering significant advantages over a constant baseline approach in which fossil fuel carbon intensity is not accounted at all.

9.1.6.d. The 'California Baseline' approach

In this approach, there are no additional deficits regardless of what individual companies or the market as a whole do. This would be comparable to allocating a single constant fuel comparator under the FQD for all diesel and for all gasoline for the duration of the policy.

9.1.7. The British Columbia (RLCFFRR) approach

The British Columbia RLCFRR fills the regulatory space covered in California by the combination of the RFS and CA-LCFS, and covered in Europe by the combination of RED and the carbon intensity reduction requirements of FQD. It includes both a minimum requirement for renewable content in gasoline and diesel class fuels (4 percent in diesel from 2011 onwards and 5 percent in gasoline) and a carbon reduction requirement for these fuels (targeting a 10 percent reduction by 2020). Credits for both renewable fuel supply and low carbon fuel supply may be transferred between suppliers providing this is notified to the appropriate regulatory authority.

The RLCFRR allows fuel carbon intensities to be calculated in one of three ways. Firstly, it is permitted to report a default carbon intensity for a given fuel. The default carbon intensities for fossil fuels are shown in Table 9.10. Note that biofuel suppliers are allowed to report the default value *for their fuel class* rather than having feedstock specific defaults – so ethanol by default would be allocated the same CI as gasoline.

Table 9.10. RLCFRR fossil fuel default carbon intensities

FUEL	CARBON INTENSITY (gCO_2e/MJ)
Gasoline class	90.21
Propane	78.29
Diesel class	93.33
CNG	59.74
LNG	66.54
Electricity	11.94
Hydrogen	92.06

Secondly, it is permitted to use the approved version of the Canadian LCA tool GHGenius to calculate a specific carbon intensity value for a given fuel. Thirdly, the appointed regulatory authority may permit an alternative calculation to be used at their discretion.

The combination of default values and the option to report an alternative assessment makes this a good example of a hybrid reporting system. Because it is permitted to report default values for diesel and gasoline, there is no incentive for a supplier of higher CI fuel to calculate a fuel specific carbon intensity value. We would therefore not expect in the BC system that fuels such as diesel from tar sands would be reported at their actual carbon intensities, but rather at lower carbon intensities. On the other hand, for fossil fuels of carbon intensity below the defaults, there is an incentive to report a more accurate carbon intensity, as this would ease compliance with the low carbon part of the standard. There is also an incentive to reduce carbon emissions for a given refinery or production process so long as the fuel is already better than default, or the improvement would move the fuel carbon intensity below the default. The RLCFRR can therefore be understood as a hybrid reporting system with only a single carbon default for each fuel class.

For companies operating in several jurisdictions using various crudes, a system such as RLCFRR does open the possibility of fuel shuffling being used rather than real carbon intensity improvements. In 2010, several fossil fuel suppliers did report lower than default carbon intensities for their fuels (in a voluntary reporting year), but we understand that the BC fuel industry has argued that by changing bookkeeping practices they would have been able to allocate on paper all of their lower carbon intensity fuel to BC while allocating all their higher carbon intensities fuel to other markets. In some instances such shuffling could in principle be limited by the imposition of specific restrictions on chain of custody, but the Government of British Columbia has agreed in the light of fuel supplier concerns to revise the RLCFRR to have single reportable gasoline and diesel CIs in future – this is expected to take effect from mid-2013.

Under FQD, the equivalent of such a system would be to impose single fuel-class defaults and to allow credits for fossil fuels with lower carbon intensity. With single fuel-class defaults, this would have in some ways the opposite effect to the proposed FQD implementation by feedstock default, or a system like the California HCICO screening, in that it would allow crediting of good performance but provide no regulatory driver to reduce the use of very high carbon fuels. An obvious question with regard to the FQD is whether, given that the British Columbia Government moved away from this approach die to the risk/likelihood of fuel shuffling, the same risk would be there for FQD. The first observation to make is that Europe is a much larger fuel market than British Columbia. It would be much more difficult to 'data-shuffle' to cover such a large market than a smaller one. There is also a particular risk of shuffling in Canada because of the split between the very high carbon bituminous crudes and the conventional crudes. Directing the conventional product to BC and allowing the bituminous product to go elsewhere in Canada may be relatively simple in the context of Western Canada's status as a net oil exporter. For Europe oil flows are much more complex, with many more potential oil sources (as discussed elsewhere for this project). Thus, the level of shuffling risk for BC is potentially uniquely high (in the absence of comparable oil carbon intensity regulation in other Western Canadian provinces.

As regards the WTO, the RLCFRR treatment is likely to be no more at risk of challenge than any other basic hybrid frameworks discussed here. Indeed, a single default with a reporting option is probably one of the more WTO robust arrangements, as there can be no accusation that the system of allocating defaults was skewed in favor of one region over another.

Some pros and cons of the BC system are shown in Table 9.11.

Table 9.11. Pros and cons of the RLCFRR approach

PROS	CONS
Allowing defaults reduces reporting burden	Limited incentive to avoid very high carbon fuels
Provides incentive to shift from using higher-than-default or equal to default fuels to using lower-than-default fuels	No incentive to achieve marginal emissions reductions on fuels substantially above default
For lower-than-default fuels, could drive chain of information custody development	Poor driver of development of chain of information custody for high carbon fuels
Incentive to improve refinery/extraction performance for fuels at or below default CI	Could drive shuffling of lower-than-default fuels into BC and higher-than default fuels elsewhere (this has been considered critical in BC, and the reporting system is therefore being simplified to single fuel values).
Likely to be robust against WTO challenge	

9.1.8. Country/region specific default values

Under the UK's pre-RED RTFO, biofuel emissions defaults were distinguished by country. This allowed the pre-RED RTFO to draw distinctions between regions with distinctly different production practices, e.g. between (typically) bagasse powered Brazilian ethanol mills and (typically) coal powered Pakistani ones. These defaults were sub-categories under feedstock defaults – so there was not, for instance, a generic 'Brazilian ethanol' value, but rather the option to report sugarcane ethanol as Brazilian.

A country-default (or region-default) approach could also be implemented in principal under the FQD for fossil fuels, either at the sub-feedstock level (like the RTFO) or by using countries as the key determinant for fossil fuel emissions and removing feedstock distinctions.

9.1.8.a. Country as a sub-feedstock distinction

Introducing national origin as a sub-feedstock distinction would be a relatively simple way of providing increased discrimination among conventional crudes. While bitumen mining is only undertaken at large scale in Canada, conventional oil extraction practices like enhanced recovery and flaring and field characteristics like pressure and water cut vary substantially between regions. For conventional oil production, countries like Nigeria with high levels of flaring, or Venezuela with large amounts of heavy crude production, are likely to have substantially higher average emissions than the global average. Country of origin is likely to be one of the most simple fuel characteristics to track, as it is already of interest for customs reporting. Such national defaults would also add resolution to the conventional oil reporting under FQD, which would answer some of the concerns raised by parties with a financial interest in Canada's oil sands that the feedstock defaults could be considered to be singling them out while neglecting to deal with other high- carbon intensity oil sources.

While country level defaults would add resolution to the FQD in some cases, national discrimination is not necessarily a good indicator of the performance of a given oilfield. ICCT/ER (2010) comment that in their analysis of over 300 different crudes the carbon intensities "do not cluster according to country or along other obvious lines." While some countries may have relatively homogeneous oilfields and production practices, others could cover a very wide range – for instance the U.S. has very large differences between Texan nodding donkeys, Alaskan North Slope, Californian thermally enhanced heavy and North Dakotan fracking.

A country-based defaults system (whether sub-feedstock level or used as the major distinction) would risk being challenged under the Most Favored Nation and National Treatment rules of the General Agreement on Tariffs and Trade (GATT). The United States, for instance, could argue that there was discrimination against its own low carbon intensity crudes compared to those from a country with a lower average carbon intensity, because the United States crudes would be 'penalized' for geographical proximity to California heavy oil. In such a case, two like products (in chemistry and carbon intensity) could be treated differently due to national origin. A system based on regions chosen because of having some degree of similarity in terms of oil carbon intensities would be much more defensible.

9.1.8.b. Country as the major distinction

If feedstock based reporting and defaults were replaced entirely by country defaults, countries like Canada and Nigeria would tend to have higher emissions defaults (because of bitumen extraction and flaring respectively) while countries like Norway and Saudi Arabia would likely have lower defaults. A country level system might be seen as diluting the price signal against very high carbon intensity crudes (compared to hybrid reporting or feedstock defaults) in sending disincentives for the highest carbon processes. For any country where high carbon intensity crude oil were a minority of the production, the national defaults would send only a diluted signal. As noted above, a country level reporting scheme would likely be particularly vulnerable to attack via the WTO. Making national origin the major criterion for defaults value seems likely to increase the risk of action compared to a system based on two or more characteristics including national origin. A regional treatment informed by oil characteristics rather than political boundaries would be likely to be considered more acceptable.

Table 9.12. Pros and cons of drawing national defaults

PROS	CONS
National origin is already known for crude oil entering the EU	For countries with heterogeneous oil geology, national defaults are likely to miss a great deal of resolution regarding carbon emissions
In some cases, national origin is likely to be a good indicator of crude intensity	As with other hybrid approaches, poor driver of data reporting and actual value use by higher-than-average CI operations
For lower-than-default fuels, could drive chain of information custody development	At relatively high risk of WTO challenge
Incentive to improve refinery/extraction performance for fuels at or below default CI	

9.1.9. Clean Development Mechanism-like credits (combinable with other accounting schemes)

As noted above, the Californian treatment of fossil fuel now offers specific credits for innovative carbon intensity reductions such as carbon capture and storage. The European FQD identifies reductions in venting and flaring as a specific area in which credits could be awarded. Because such credit awards for reducing the carbon intensity of specific projects could be made available in combination with various systems of defaults, we have separated them here for further discussion.

Under the FQD, it is suggested that reductions in flaring and venting at fuel production sites should be eligible for credits. In contrast, the California average accounting system under CA-LCFS allows ‘innovative’ carbon intensity reductions to be credited but specifically does not include standard measures to reduce venting and flaring (the logic being that these technologies are already available, legally mandated in some jurisdictions and should be rolled out by companies without additional demand-end regulatory drivers). The choice about which types of reduction scheme should be covered could reflect:

1. Verifiability of reductions achieved;
2. Overall ambition for level of reductions to target;
3. Ambition for impact of individual schemes (e.g. CARB require a minimum carbon intensity impact of 5 percent for eligibility);
4. Desire to support innovation;
5. Desire to target ‘low hanging fruit’;
6. Regulatory burden (for either of fuel suppliers or Governments);

7. Existence of other schemes targeting the same projects.

Flare reduction could be seen as low hanging fruit where projects are relatively well understood and where there is a high total reduction potential. Because flare reduction projects are already covered by CDM and other similar mechanisms, there should be a proportionately lower burden to design new systems to demonstrate savings than for a newer technology. On the other hand, flare reduction is already a national objective for several key countries (e.g. Nigeria) and a stated objective of several oil majors. One could therefore argue that adding additional incentives would invite the risk of providing windfalls for projects already planned and funded.

A known barrier to involvement in existing frameworks for emissions reduction crediting is the additionality criterion – the requirement that it must be demonstrated that emissions savings would not have been achieved otherwise. Such requirements can reduce the risk of providing windfalls, but in the case of CDM have been identified as a major barrier to project registration. The problem is that in can be difficult to provide clear evidence that a project would not have happened without a regulatory driver – this is particularly hard to argue if the project will actually be cost negative overall. Under the FQD, the underlying emissions reporting framework is one that aims to reward low emissions in general, rather than only emissions driven by the policy. That is to say that the FQD gives carbon value to fuels, with no reference to whether a company would have supplied those fuels in the absence of the policy. Under the feedstock defaults system, conventional oil is credited compared to bitumen. Under the biofuel defaults, sugarcane ethanol is credited compared to corn ethanol. One could therefore argue that for flaring reduction projects it would be consistent to give credit proportional to the carbon intensity reduction regardless of additionality. On the other hand, especially if a CDM style book-and-claim system operating beyond the set of crudes imported into Europe were to be implemented, it could be argued that the benefit came from driving additional projects (as it would not necessarily affect the CI of fuels actually imported to Europe).

We note that a full accounting or hybrid reporting system would effectively give credit to all emissions reductions schemes within the chain of custody of European fuel supply (provided the scheme is based on an LCA adequately sophisticated to measure their impacts), with no additionality requirement. One way that an emissions reduction crediting system could fruitfully operate in parallel to a hybrid reporting system would be if the chain of custody requirements were distinct between the two parts of the accounting. For instance, it might be considered worthwhile to provide a price signal for all flaring reduction projects regardless of whether the oil from that field was actually coming to Europe. In that case, like CDM a credit could be generated for a scheme and ‘cashed in’ in Europe without reference to whether the fuel from that field actually came to Europe. It might be considered acceptable to allow effective double counting (and hence double incentivization) for the project by allowing the actual emissions for the field to also be reported under hybrid reporting. If this type of double counting were not considered acceptable, it would be necessary for the credits to be associated with information about the field where the project was undertaken so that this could be cross-referenced against fields for which actual carbon intensities were calculated. There is unlikely to be any WTO concern with crediting emissions reduction projects – such projects are already eligible for implied subsidy under EU Emissions Trading System (ETS) and so forth.

Some pros and cons of a CDM-like emissions-reduction crediting scheme are detailed in Table 9.13.

Table 9.13. Pros and cons with CDM-like crediting system

PROS	CONS
Incentives for defined emissions reduction activities	Project verification can be challenging/burdensome
Focus interest on defined area (e.g. flaring or innovative technologies)	Challenge of demonstrating/achieving additionality
Provide alternative compliance route (to biofuels/electric vehicles) under legislation	Relies on fuel supplier engagement
No administrative burden unless suppliers opt-in	Could result in double crediting of individual projects with other schemes
Adding additional driver to existing mechanisms (like CDM) could amplify impact	Allowing reductions across the fuel system on a book and claim basis might be seen as inconsistent with the rest of the FQD
Allowing reductions across the fuel system on a book and claim basis could increase scope for reductions	

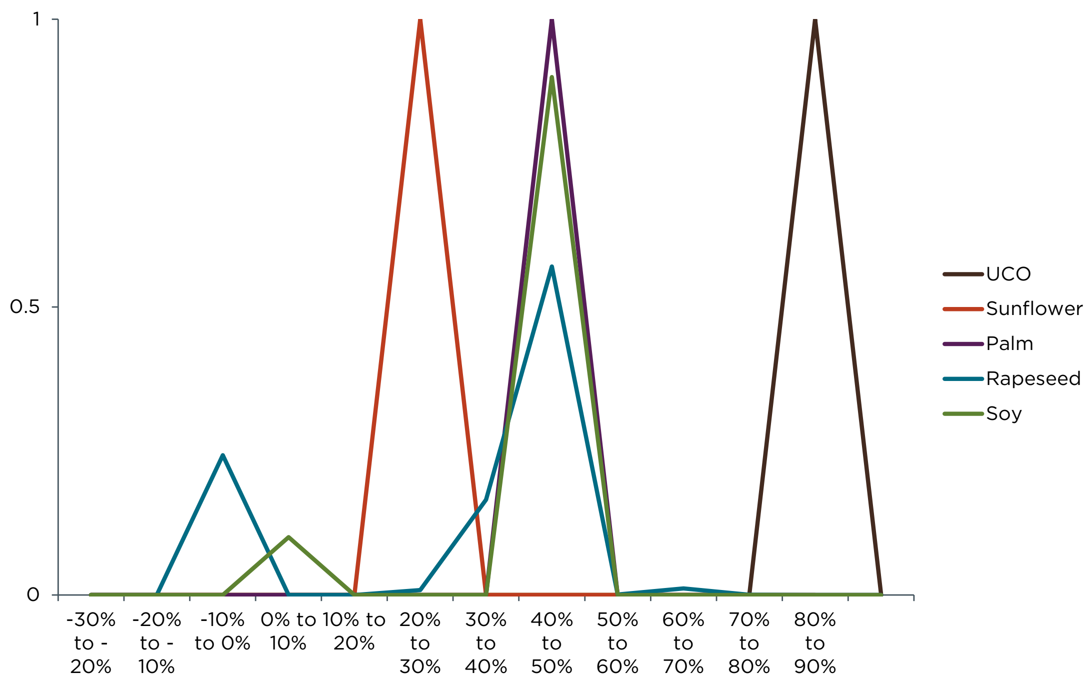
9.2. Legal precedent for disaggregating GHG emissions in legislation

9.2.1. Precedent from biofuel policies (RFS, RTFO, RED, CA-LCFS)

Several existing biofuel policies include characterization of the emissions from different biofuel pathways based on the use of lifecycle analysis. This includes the RED and FQD themselves, in which the emissions of various biofuels are characterized by defaults based on feedstocks and (in some cases) technology pathway and region of origin. The emissions defaults are based on well to wheels analysis by the Joint Research Centre. While the feedstock values are based on a characterization of 'typical' practices, the reality is that within a given pathway emissions could vary substantially depending on local practices, grid electricity carbon intensity, climatic conditions, soil quality and so forth – Stratton et al. as discussed above provides one characterization of the variability in emissions for biodiesel from vegetable oil. In the biofuel part of the FQD it is implicitly accepted that the defaults may well mischaracterize the carbon intensity of any given batch of fuel. Indeed, by introducing a conservatism factor it is actually intended that the emissions of a typical fuel batch will be mischaracterized.

Data from the UK's RTFO 2009/10 (RFA, 2011) shows that the variation in reported emissions for one feedstock can alter its characterization compared to other fuels. In particular, in Figure 9.1 we see that the reported emissions savings of rapeseed oil biodiesel were generally similar to the emissions savings for soy biodiesel, but that a small fraction was reported with very poor emissions performance, while some batches were reported with a better saving of up to 70 percent. Similarly, some soy biodiesel was reported with worse performance than the norm for rapeseed biodiesel, i.e. the possible ranges for each feedstock overlap substantially. The implicit expectation that the 'real' carbon intensity of each batch of fuel will vary along a continuum, and that the range of intensity of different feedstocks will overlap, is common to all of these LCA based biofuel regimes.

Figure 9.1. Variation in reported emissions for biodiesel feedstocks under RTFO 2009/10 (graph shows fraction of total supplied feedstock in 10% carbon saving bins).



Under the U.S. Renewable Fuel Standard, fuel is only eligible if it is produced in accordance with one of several EPA defined pathways.

9.3. Legal implications of regulating fossil fuel carbon intensity in the European Union

This section identifies potential legal barriers to adopting reporting and accounting measures for conventional crudes under the Fuel Quality Directive (FQD). It briefly addresses issues presented by Member State and European Union law before focusing significant attention on international trade law due to its relevant importance to their legality, the process of adoption, and ultimate design.

9.3.1. Legal barriers and issues at the member state and European Union level

Few consequential barriers, if any, exist for the regulatory approaches under Member State and European Union law. Member States and the European Union share competency on environmental matters and a procedure exists for instances in which Member-State elect to derogate from harmonization measures adopted at the European Union level.[112] The European Union enjoys broad competence to adopt measures for the approximation of laws in Member States to ensure the functioning of the internal market. The European Union is empowered to adopt reporting and accounting measures for conventional crudes. The primary barriers presented by European law are those that apply to legislative acts adopted by the European Union in general, namely the subsidiarity and proportionality principles. The subsidiarity principle requires that the Union only acts "if and insofar as the objectives of the proposed action cannot be sufficiently achieved by Member States… but can rather, by reason of the scale and effects of the propose action, be better achieved at the Union level."[113] The proportionality principle requires that "the content and form of Union action shall not exceed what is necessary to achieve the objectives of the Treaties."[114] There are no foreseeable issues presented under these principles, especially since the FQD was already adopted under the treaties and these measures would further implement the obligations therein. Indeed, several precedents exist for nearly identical measures and no challenges have been successful to date.

9.3.2. Legal barriers and issues at the international level

The primary barrier to the adoption of reporting and accounting measures for conventional crudes is international trade law, namely the World Trade Organization (WTO). The WTO is an international organization regulating trade between nations of which the European Union and its Member States are members. It consists of rules designed to reduce obstacles to international trade and contains an adjudicatory branch—the Panel and the Appellate Body, jointly referred to as the

[112] *See* Treaty on the Functioning of the European Union, Articles 191-192.
[113] Treaty on the European Union, Article 5(3).
[114] Treaty on the European Union, Article 5(4).

Dispute Settlement Body (DSB)—charged with settling disputes regarding the application of its rules. All measures impacting trade from member countries, including the European Union, must comply with these rules. The WTO specifies several trade-related obligations on member countries, including those found in the Global Agreement on Tariffs and Trade (GATT). For example, advantages granted to one country must be extended to all.[115] Foreign products must be accorded no less favorable treatment than those accorded to like products of national origin.[116] Member countries must generally refrain from adopting measures prohibiting or restricting imports of products from another member country.[117] The objective is to eliminate discrimination among "like products" regardless whether foreign or domestic. But WTO rules also contain several exceptions to the general rule against trade restrictions. In particular, under Article XX(g) of GATT, member countries may discriminate between like products to achieve environmental objectives subject to certain conditions.[118] At issue here is how to construct reporting and accounting measures for lifecycle GHG emissions from conventional crudes within the Fuel Quality Directive (FQD) so as to ensure that WTO compliance. No WTO precedent exists for such measures.

9.3.2.a. Likeness determination

The WTO prohibits discrimination against "like products" under Articles I, III and X of GATT.[119] The DSB uses four criteria as the basis for the likeness determination: end use, physical properties, tariff classification, and consumer tastes and habits.[120] These criteria do not represent "a closed list of criteria" and others may be relevant.[121] Nor do they "dissolve the duty or need to examine, in each case, all of the pertinent evidence."[122] The issue of likeness receives its most significant attention in *EC – Asbestos*, a case brought by the Canadian government against a French ban on asbestos and asbestos-containing products, with other cases provide additional context.[123] In *EC – Asbestos*, the DSB declares that the criteria "provide a framework for analyzing the 'likeness' of particular products on a case-by-case basis," serving as "tools to assist in the task of sorting and examining the relevant evidence."[124] Indeed,

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[115] General Agreement on Tariffs and Trade 1994, Apr. 15, 1994, Marrakesh Agreement Establishing the World Trade Organization, 1867 U.N.T.S. 187, 33 I.L.M. 1153 (1994) [hereinafter "GATT 1994"] at Article I.
[116] GATT 1994, Articles III:4 and XI:1.`
[117] GATT 1994, Articles III:4 and XI:1.
[118] GATT 1994, Article XX.
[119] GATT 1994 at Article I and III:4.
[120] Appellate Body Report, *EC – Asbestos*, WT/DS135/AB/R, adopted 12 March 2001 [hereinafter "*EC – Asbestos*"], , paras. 101- 103; *see also* Appellate Body Report, Japan — Taxes on Alcoholic Beverages, WT/DS8/AB/R, WT/DS10/AB/R, WT/DS11/AB/R, adopted 1 November 1996, DSR 1996:I, 97 [hereinafter "*Japan – Alcoholic Beverages*"], fns. 46 and 58; *see also* Panel Report, *United States – Gasoline*, footnote 15, para. 6.8 (approach set forth in the *Border Tax Adjustment* case was adopted in a dispute concerning Article III:4 of the GATT 1994 by the panel).
[121] *EC – Asbestos*, para. 102.
[122] *EC – Asbestos*, para. 102.
[123] *See* Appellate Body Report, *EC – Asbestos*, para. 102; *see generally* Appellate Body Report, *EC — Computer Equipment*.
[124] *EC – Asbestos*, para. 102.

the kinds of evidence to be examined in assessing the likeness of the products "will, necessarily, depend upon the particular products and legal provision at issue."[125] Once all the evidence is examined, the inquiry turns to "whether that evidence, as a whole, indicates that the products in question are 'like' in terms of the legal provision at issue."[126] The term "like products" "is concerned with competitive relationships between and among products" and therefore "it is important... to take account of evidence which indicates whether, and to what extent, the products involved are—or could be—in a competitive relationship in the marketplace."[127] According to the DSB, an approach based on the four criteria should "examine[] the evidence relating to each of [the] four criteria and, then, weigh[] *all* of that evidence, along with any other relevant evidence, in making an *overall* determination of whether the products at issues could be characterized as 'like.'"[128] In other words, "a determination on the 'likeness' of products cannot be made on the basis of a partial analysis of the evidence."[129] The burden is on the party alleging the products are like.[130] To date, these criteria have not been applied to measures to account for lifecycle GHG emissions. This would be a case of first impression and, as a result, a preliminary determination of WTO compliance can only be guided by the principles found in precedent.

The first question to be asked is whether the products are "like." The four criteria have been described and applied as follows:

> *Physical Properties. The DSB requires panels to "examine fully the physical properties of products."[131] In particular, it is important to "examine those physical properties that are likely to influence the competitive relationship between products in the marketplace."[132] Although this analysis sometimes focuses on the final product as it crosses the border—and as subject to tariff classification, discussed below—whether the legal provision at issue focuses process and production methods (PPMs) is also an important factor in the analysis. EC – Asbestos reaffirms that the physical-properties criterion should scrutinize the properties of the products at the point of regulation where the alleged trade restriction occurs, and not conflate physical properties with end uses: "[w]e believe that physical properties deserve a separate examination that should not be confused with the examination of end-uses."[133]*

> *End Use. The DSB requires panels to apply the end-use criterion, and determine its relevance, in consideration of the particular product in question within the context of the legal provision at issue.[134] Again, this is particularly relevant in the case of non-product-related PPMs*

[125] *EC – Asbestos*, para. 103.
[126] *EC – Asbestos*, para. 103.
[127] *EC – Asbestos*, para. 103.
[128] *EC – Asbestos*, para. 109.
[129] *EC – Asbestos*, para. 109.
[130] *EC – Asbestos*, para. 141.
[131] *EC – Asbestos*, para. 14.
[132] *EC – Asbestos*, para. 114.
[133] *EC – Asbestos*, paras. 111 and 117.
[134] *EC – Asbestos*, para. 103.

targeting lifecycle GHG reductions at stages coming before placement of the product on the market, i.e. before the eventual end use. The analysis of the competitive relationship here must take into account the objectives of the Fuel Quality Directive and its reporting measures, in particular the achievement of lifecycle GHG reductions, but must also reflect the fact that only transportation fuels fall under their purview.

Tariff Classification. The DSB considers the tariff classification highly relevant to the likeness determination, especially in the context of the other criteria.[135] *EC – Computer Equipment stands for the proposition that conformity of tariff classifications to the Harmonized System for nomenclature in the World Customs Organization (WCO) must be considered.*[136] *In the European Union, Council Regulation (EEC) No 2658/87 provides tariff classifications for imported goods according to the Combined Nomenclature (CN).*[137] *Each year, the European Commission publishes an updated version of Annex I setting out tariff classifications—called CN codes—for all imported and exported products.*[138] *The annual updates account for changes agreed to at the international level, specifically the Harmonized System for nomenclature in the WCO.*[139]

Consumer Tastes and Habits. The DSB declares that "evidence about the extent to which products can serve the same end-uses, and the extent to which consumers are or would be willing to choose one product instead of another to perform those end-uses, is highly relevant evidence in assessing the 'likeness' of those products." In particular, "where the physical properties… are very different, an examination of the evidence relating to consumers' tastes and habits is an indispensable—although not, on its own, sufficient—aspect of any determination that products are 'like.'"[140] *The nature of the competitive relationship, not just end use but also regulatory function, are relevant considerations.*[141]

The likeness determination is nuanced and, within the regulatory approaches outlined here, spans a broad spectrum of possibilities. It will depend on how expansive a view the DSB perceives any challenge, which is influenced by the approach taken in the adopted measures (i.e. full reporting and accounting, a hybrid reporting approach, feedstock defaults approach, etc.) and how the challenge is framed.[142] For example, a WTO challenge brought by Canada or Venezuela against

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[135] *EC – Asbestos*, paras. 124-125.
[136] EC — Computer Equipment, paras. 89-93.
[137] *See* Council Regulation (EEC) No 2658/87 of 23 July 1987 on the tariff and statistical nomenclature and on the Common Customs Tariff.
[138] Council Regulation (EEC) No 2658/87 of 23 July 1987 on the tariff and statistical nomenclature and on the Common Customs Tariff, Article 12.
[139] European Commission, *The Combined Nomenclature*, *available at* http://ec.europa.eu/taxation_customs/customs/customs_duties/tariff_aspects/combined_nomenclature/index_en.htm (last visited 27 June 2011).
[140] *EC – Asbestos*, para. 139.
[141] *EC – Asbestos*, para. 139.
[142] *See* Appellate Body Report, United States — Standards for Reformulated and Conventional Gasoline, WT/DS2/AB/R, adopted 20 May 1996, DSR 1996:I, 3 [hereinafter "*U.S. – Gasoline*"].

measures setting out default values for fuels that differentiate *among* feedstocks (i.e. conventional crude, natural bitumen, oil shale, coal, gas and waste plastic) are more likely not to be found discriminatory against "like products" than measures that differentiate *within* any given feedstock (i.e. conventional crude). This is because the criteria for physical properties, tariff classification, and consumer tastes and habits are not so clear and the overall competitive relationship is much closer.

The draft comparative analysis outlines several different approaches for reporting and accounting within conventional crudes. It should also be assumed that likeness is more likely to be found—hence discrimination—for reporting and accounting measures that differentiate *within* feedstocks than for reporting and accounting measures that differentiate *among* feedstocks.[143] In other words, the hurdle is higher here. This is not to say that such measures will violate the WTO and should be reconsidered or abandoned. Even if likeness is found, the measures could still be justified under the exceptions in Article XX of GATT. It simply means that the likeness determination is less clear and placing too much emphasis on it is misguided. When contemplating measures to account for lifecycle GHG emissions from conventional crudes, the better approach is to proceed along two paths: first (i) allocate the upstream emissions as closely as possible to the feedstock or process that produced the final product to provide the best shot at overcoming a likeness determination but (ii) otherwise adhere strictly to the requirements of Article XX, in particular those found in the *chapeau*, which will provide the surest path toward WTO compliance.

9.3.2.b. Article XX General Exceptions

Once found to be "like products," the measures will still be WTO compliant if they comply with Article XX of GATT. In particular, a country may adopt discriminatory measures for the conservation of exhaustible natural resources regardless whether the products are "like," subject to certain conditions:

Article XX
General Exceptions

> *Subject to the requirement that such measures are not applied in a manner which would constitute a means of arbitrary or unjustifiable discrimination between countries where the same conditions prevail, or a disguised restriction on international trade, nothing in this Agreement shall be construed to prevent the adoption or enforcement by any contracting party of measures:*

*** *** ***

[143] See Défense Terre, Legal Analysis: WTO Implications of Reporting Measures for Tar Sands under the Fuel Quality Directive (June 2011).

> *(g) relating to the conservation of exhaustible natural resources if such measures are made effective in conjunction with restrictions on domestic production or consumption;*

Article XX can be divided into two separate parts: the exception that is being claimed, i.e. the *manteau*, and the introductory paragraph that precedes it, i.e. the *chapeau*. The measures must first comply with the *manteau* requirements, namely under Article XX(g) that they "relat[e] to the conservation of exhaustible natural resources" and be "made effective in conjunction with restrictions on domestic production and consumption."[144] Once this requirement is met, the measures must then comply with the *chapeau* requirements, namely that they "are not applied in a manner which would constitute arbitrary or unjustifiable discrimination or a disguised restriction on international trade."[145] As discussed below, there is little reason to believe that the *manteau* requirements cannot be met under any approach adopted. Rather it is the *chapeau* requirements, both substantive and procedural, that merit close observation and strict adherence.

9.3.2.c. Application of the *Manteau* Requirements

In order to fall under Article XX(g), the measures must comply with the careful wording of the exception. In *U.S. - Shrimp*, the DSB provides extensive discussion of the relevant considerations:

> *"Natural Resource" – The concept of natural resource is "evolutionary" and responsive to modern concerns.[146] It embraces both living and non-living resources.[147]*
>
> *"Exhaustible" – A natural resource is exhaustible when it is capable of being depleted.[148] International recognition further substantiates the claim to exhaustibility.[149]*
>
> *"Relating to the Conservation of…" – The measure must, as a whole, be "primarily aimed at" the conservation of the identified exhaustible natural resource.[150] It "cannot be regarded as merely incidentally or inadvertently aimed at [its] conservation."[151] The general design and structure must have a "genuine relationship of ends and means."[152]*

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[144] GATT 1994, Article XX(g).
[145] GATT 1994, Article XX.
[146] Appellate Body Report, United States — Import Prohibition of Certain Shrimp and Shrimp Products, WT/DS58/AB/R, adopted 6 November 1998, DSR 1998:VII, 2755 [hereinafter "*U.S. – Shrimp*"], para. 130; *see also* Appellate Body Report, United States — Import Prohibition of Certain Shrimp and Shrimp Products — Recourse to *Article 21.5* of the DSU by Malaysia, WT/DS58/AB/RW, adopted 21 November 2001 [hereinafter "*U.S. – Shrimp Recourse*"].
[147] *U.S. – Shrimp*, para. 130.
[148] *U.S. – Gasoline* at p. 19; *see also U.S. – Shrimp* at Paragraph 129; Panel Report, *U.S. – Canadian Tuna* at Paragraph 4.9; Panel Report, *U.S. – Tuna (EEC),* unadopted, at Paragraph 5.13; Panel Report, *U.S. – Gasoline* at Paragraph 6.37.
[149] *U.S. – Shrimp*, para. 132.
[150] *U.S. – Shrimp*, paras. 135-136.
[151] *U.S. – Shrimp*, para. 136 *citing U.S. – Gasoline*, p. 19.
[152] *U.S. – Shrimp*, para. 136 *citing U.S. – Gasoline*, p. 19.

> *"Made Effective in Conjunction Restrictions..." – The measure must restrict domestic production or consumption in some way, which does not require "identical treatment of domestic and imported products"*[153] *but rather "even-handedness" is essential.*[154]

The DSB has not yet examined whether there is an implied jurisdictional limitation in Article XX(g) that would prevent one country from enacting measures to conserve exhaustible natural resources that only occur abroad.[155] It has stated, however, that even if an implied jurisdictional limitation exists a "sufficient nexus" between the exhaustible natural resource and the territoriality of the country adopting the measure would suffice to overcome it.[156] When a measure falls within the *manteau* requirements, it is "provisionally justified" subject to the more exacting *chapeau* requirements.[157]

The main objective of the measures here will be a climate one. The climate system, like clean air in *U.S. – Gasoline*, is an exhaustible natural resource. There is also a sufficient nexus between reducing lifecycle GHG emissions and protecting the climate system, a global commons that encompasses European Union territory.[158] The measures must also "relate to the conservation of" the climate system and are "made effective in conjunction with restrictions on domestic production and consumption" to ensure some level of even-handedness that will be subject to further examination under the *chapeau* requirements, which is the case for all approaches under consideration here.

9.3.2.d. Application of the *Chapeau* requirements

Measures provisionally justified under the *manteau* must also comply with the *chapeau* requirements. In particular, measures must not "constitute a means of arbitrary or unjustifiable discrimination between countries where the same conditions prevail, or a disguised restriction on international trade."[159] Several WTO cases set out the analytical contours, including *U.S. – Gasoline*, *U.S. – Shrimp*, *EC – Asbestos* and *Brazil – Tires*. Those cases, described in 0, and in particular *U.S. – Gasoline* and *U.S. – Shrimp*, provide a framework for ensuring compliance with the procedural and substantive requirements embodied in the *chapeau*.

In general, the task of applying the *chapeau* is "the delicate one of locating and marking out a line of equilibrium between the right of a [country] to invoke an exception under Article XX and the rights of the other [country] under the varying substantive provisions" of GATT.[160] The location of this line of equilibrium may move "as the kind and the

153 U.S. – Gasoline, p. 21.
154 U.S. – Shrimp, para. 54.
155 U.S. – Shrimp, para. 133.
156 U.S. – Shrimp, para. 133.
157 Appellate Body Report, Brazil – Measures Affecting Imports of Retreaded Tyres, adopted 3 December 2007, WT/DS332/AB/R [hereinafter "Brazil – Tyres"], para. 227.
158 United Nations Framework Convention on Climate Change, 1771 UNTS 107, 31 ILM 849 (1992) at Preamble 1 (climate and its adverse effects are a "common concern of humankind").
159 GATT 1994, Article XX; see also U.S. – Shrimp at Paragraph 150.
160 Brazil – Tyres, para. 224 citing U.S. – Shrimp, para. 158.

shape of the measures at stake vary and as the facts making up specific cases differ."[161] Its overriding purpose is to prevent abuse of the exceptions.[162] The burden would be on the party invoking the exception, in this instance the European Union.[163] The DSB has said that the *chapeau* requirements are "but one expression of the principle of good faith."[164]

9.3.2.e. Arbitrary or unjustifiable discrimination

Arbitrary or unjustifiable discrimination "relates primarily to the cause or the rationale of the discrimination."[165] It focuses on "whether the discrimination that might result from the application of those measures [has] a legitimate cause or rationale in light of the objectives listed" in the *manteau*.[166] In every instance, the Commission must scrutinize the measure and its constituent parts – asking itself whether they are related to the conservation of the climate system.

This will entail a two-part inquiry. The first part of the inquiry will examine whether the measure *as a whole* has a legitimate cause or rationale. In the instance of accounting for lifecycle GHG emissions within FQD, the case is again straight-forward: a well-known consequence of conventional-crude extraction and processing is the release of GHG emissions into the atmosphere that, depending on the characteristics of crudes and methods used for its processing, can be more or less carbon intense. As a result, when extraction and processing are properly taken into account, certain crudes are less effective and others more effective at reducing upstream GHG emissions. FQD seeks to reduce lifecycle GHG emissions from transportation fuels so measures accounting for upstream GHG emissions are legitimately related to protecting the climate system, which for its part is a matter of significant public interest, a "common concern of humankind."[167] The second part of the inquiry will examine whether the measure's constituent parts all advance this legitimate cause or rationale. This means that the *chapeau* requirements also apply to any subparts of the measure, such as the use of default values or exemptions. In other words, any shortcuts causing discrimination must also relate to the pursuit of the "objective that was provisionally found to justify a measure under a paragraph of Article XX" or, at least, not undermine it.[168] This is intended to prevent the very politicking that often occurs during negotiations on any legislative or regulatory matter that causes components of the adopted measures from having a no "rational connection to the objective."[169]

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[161] *Brazil – Tyres*, para. 224.
[162] *Brazil – Tyres*, para. 224; *U.S. – Gasoline*, p. 21.
[163] *See e.g. U.S. – Shrimp*, para. 34.
[164] *U.S. – Shrimp* at Paragraph 158.
[165] *Brazil – Tyres*, para. 225.
[166] *Brazil – Tyres*, para. 225; *U.S. – Shrimp Recourse*, para. 144-147.
[167] United Nations Framework Convention on Climate Change (New York, 9 May 1992), Recital 1.
[168] *Brazil – Tyres*, para. 227.
[169] *See Brazil – Tyres*, para. 227.

There are three elements to find arbitrary or unjustifiable discrimination.[170] *First*, the application of the measure must result in discrimination, the nature and quality of which is different from the discrimination that resulted in the initial WTO violation.[171] This discrimination may be on its face or as applied.[172] *Second*, and most importantly, that discrimination must not be arbitrary or unjustifiable in character, an inquiry that focuses on both the actual provisions in the measure and how it is applied in practice.[173] Arbitrary discrimination examines whether the measure is overly inflexible or rigid, providing no space for means of compliance that are comparable in effectiveness.[174] To the extent subsequent decision-making occurs, the procedures must embody due-process values that ensure fundamental fairness such as transparency, predictability, opportunities to be heard, reasoned decisions, and appeal procedures.[175] Unjustifiable discrimination focuses on "the cause of discrimination, or the rationale put forward to explain its existence."[176] It must make sense. And it must also take into account the different conditions in different countries during the design of the measure.[177] Unjustifiable discrimination also contains a duty to negotiate with all interested and impacted parties, not just select ones, where the problem requires a multilateral solution.[178] *Third*, the discrimination must occur between countries where the same conditions prevail.[179] Such discrimination can occur not only between different exporting countries, but also between the exporting country and the importing country.[180]

Here, full reporting and accounting is the most-sound approach from a WTO perspective. It meets all the requirements above: justifiable, universal, fair. Once additional elements lead us to depart from full reporting and accounting, such as the use of default values or baselines, careful attention must be paid to avoid discrimination. It is necessary for each departure from full reporting and accounting to be analyzed using the three elements above so to ensure WTO compliance is not compromised. This may mean, for example, that if a default value is adopted to reduce administrative burden, a non-climate rationale, it be structured so as not to undermine the climate objective, for example by selecting a conservative value that is periodically reviewed through a transparent process to account for the best available scientific evidence, and also to ensure fairness, for example by allowing suppliers to show actual values where appropriate. This is the path to WTO compliance.

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170 *See e.g. U.S. – Shrimp* at Paragraph 150-160.
171 *U.S. – Shrimp*, para. 150; *see also U.S. – Gasoline*, p. 23.
172 U.S. – Shrimp, para. 160.
173 *U.S. – Shrimp* at Paragraph 160.
174 *U.S. – Shrimp*, paras. 177-179.
175 *U.S. – Shrimp*, paras. 180-183.
176 *Brazil – Tyres*, paras. 226, 229-230.
177 *U.S. – Shrimp*, para. 164.
178 *U.S. – Shrimp*, paras. 166-175.
179 *U.S. – Shrimp*, para. 150; *see also U.S. – Gasoline*, pp. 23-24.
180 *U.S. – Shrimp*, para. 150; *see also U.S. – Gasoline*, pp. 23-24.

9.3.2.f. Disguised restriction on trade

A disguised restriction on trade relates primarily to protectionism.[181] The DSB has found that "the kinds of considerations pertinent in deciding whether the application of a particular measure amounts to 'arbitrary and unjustifiable discrimination,' may also be taken into account in determining the presence of a 'disguised restriction' on international trade."[182] "The fundamental theme is to be found in the purpose and object of avoiding abuse or illegitimate use of the exceptions to the substantive rules available in Article XX."[183] Even though "a law has been narrowly tailored to achieve a *bona fide* conservation [goal] does not mean that, when applied, it does not constitute a disguised restriction on trade."[184] The DSB recognizes that "[a]lthough it is true that the aim of a measure may not be easily ascertained, nevertheless its protective application can most often be discerned from the design, the architecture, and the revealing structure of a measure."[185]

9.3.3. Safeguards for proposed approaches

This report considers nine different approaches. With respect to the likeness determination, for all approaches, the case will no longer be as clear as it was when simply differentiating *among* feedstocks.[186] Now that the differentiation is occurring *within* feedstocks, where the physical properties, tariff classifications and consumer tastes and habits are not as distinct or pronounced, the case is harder to make. Thus strict adherence to the *chapeau* requirements is important for all approaches, and that is the primary thrust of the analysis below.

9.3.3.a. Full reporting and accounting approach

Full reporting and accounting is the soundest approach from a WTO perspective. It differentiates among conventional crudes based on actual physical properties and production methods related to that fuel. With respect to Article XX, there is a very strong likelihood that it would comply with the *chapeau* requirements if uniform methodologies were adopted for all fuels. Any discrimination that could be claimed would have a rational explanation based upon on the actual conditions on the ground, and therefore be justifiable. Arbitrariness poses the greatest risk. But this can be diminished with appropriate safeguards. In particular, with respect to the assessment of carbon intensity, a clear and uniform methodology and reliance on a scientifically rigorous assessment system is needed. If regulators undertake the assessment,

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[181] World Trade Organization, *WTO Rules and Environmental Policies: GATT Exceptions*, *available at* http://www.wto.org/english/tratop_e/envir_e/envt_rules_exceptions_e.htm (last visited 6 June 2012).
[182] *U.S. – Gasoline*, p. 25.
[183] *U.S. – Gasoline*, p. 25.
[184] U.S. – Shrimp, para. 149
[185] Appellate Body Report on *Japan – Taxes on Alcoholic Beverages*, adopted on 1 November 1996, WT/DS8; DS10; DS11/AB/R, p. 29.
[186] *See* Défense Terre, *Legal Analysis: WTO Implications of Reporting Measures for Tar Sands under the Fuel Quality Directive* (June 2011).

due process should be provided to impacted parties, i.e. transparency, predictability, opportunities to be heard, reasoned decisions, and appeal procedures. *U.S. – Gasoline*, described in 0, shows how this can be achieved. If companies undertake the assessment, due process is less of a concern although it would be advisable to include measures to ensure system credibility and prevent abuse.

9.3.3.b. Feedstock defaults, hybrid reporting, and British Columbia approaches

All three approaches can be crafted to ensure WTO compliance. Like full accounting and reporting, all three approaches differentiate *within* the conventional-crude feedstock based on the physical properties and processing methods related to the crude. The primary difference is that the approaches do not require actual values in every instance, instead providing default values that may be replaced by actual values, sometimes only in certain circumstances, at the election of the supplier. With respect to Article XX, safeguards are therefore advised to make sure all the constituent parts are WTO compliant. On one hand, for actual values, the recommendations made above for the full reporting and accounting approach will also be applicable here. On the other hand, for default values, the key characteristics of a WTO compliant reporting and accounting system are that: (i) it is based on the best available scientific and technical evidence gathered through an open and participatory process; (ii) it applies a uniform and unbiased methodology for establishment of default values to all fuels; and (iii) it is subject to periodic review and revision of default values to account for changing conditions or new information, which could also be initiated upon petition by interested parties. In addition, when selecting a default value, it is recommended to adopt conservative default values over ones based on averages. Conservative default values do not reward more carbon-intense fuels by allowing them to claim default values based on averages. This would prevent objections from countries that have invested in cleaning up their extraction and processing operations. To reinforce this point, for example, one can imagine Canada in the context of tar sands default values alleging that the selection of the default value for tar sands based on average emissions rewards Venezuelan tar sands since Venezuela has not invested in reducing emissions associated with tar-sands extraction but can nevertheless claim the default. So the risk is that not only a country producing more carbon-intense fuels raises a WTO challenge, but that a country producing less carbon-intense fuels that is penalized under the default value raises one too. This is one reason to select conservative values, as was done with biofuels. An additional mechanism to protect against WTO noncompliance is to allow actual values to be reported when under the default value in all instances, not just certain ones.

9.3.3.c. HCICO approach

The HCICO approach suffers from shortcomings that call into question its ability to be WTO compliant. With respect to Article XX, the fuels in the California basket are provided preferential treatment for reasons that have no clear legitimate climate rationale. It can easily be understood as a protectionist measure, and therefore unjustifiable and possibly a disguised restriction on trade. Adopting a similar approach in the European Union and relying on a European basket would suffer from similar issues. Any measures that include *de facto* or *de jure* grandfathering preferential to domestic suppliers and production will raise similar concerns and should therefore be avoided.

9.3.3.d. California Average approach

The California average approach does not raise any new WTO issues. It creates softer obligations on individual fuel suppliers that raise serious implementation and compliance issues but not any clear WTO ones. With respect to Article XX, the assessment of the carbon intensity for any given fuel should conform to the recommendations outlined above.

9.3.3.e. Country- or Region-Specific Default Values approach

The country- or region-specific default values approach raises immediate WTO concerns, namely by characterizing all fuels based on national origin regardless of their actual carbon intensity. This would penalize less carbon-intense fuels due to their proximity to more carbon-intense fuels. While it would lessen the administrative burden that justification alone would be inadequate since there is no clear rationale for discriminating against a product of national origin when lifecycle GHG emissions vary from product to product and region to region. There is a stronger justification for taking a region-specific approach, especially if the regions are delineated to reflect the lifecycle GHG emissions of types of conventional crudes coming from the area. In addition, a region-specific approach would presumably not be limited to regions within a country but also include ones that span two or more countries. This approach, if done with a degree of specificity to capture of the lifecycle GHG emissions specific to the fuels from that region, could be WTO compliant. It would be important to provide a scientific basis and rationale for it. In addition, creating some mechanism for fuels that come from a region to show that their emissions are less than the default value would be important safeguard. For example, the Commission could undertake an analysis to subdivide the region based on submitted information or could allow for actual values below the default.

> *Note: it may also be that a national or regional approach is adopted for only one or some of the factors that form the basis for the lifecycle GHG analysis, such as only for emissions from flaring or processing but not for emissions from extraction. This would raise similar issues but, as described above, the region-specific approach would be less likely to violate the WTO than the country-specific approach and allowing the option of showing actual values could provide a safeguard.*

9.3.3.f. Emission Reduction Credits approach

There are no WTO concerns arising from the use of emission reduction credits.

10. Conclusions

The experience of biofuel regulation through policies such as the European Union's Renewable Energy Directive (RED), the United Kingdom's Renewable Transport Fuel Obligation (RTFO), California Low Carbon Fuel Standard (CA-LCFS) and the United States federal Renewable Fuels Standard (RFS) has demonstrated that effective regulation of the climate impact of transportation fuels requires a solid basis in lifecycle analysis. Where the relative lifecycle implications of a process are well characterized (for instance the comparative emissions intensities of different corn pathways analyzed under California's 2A/2B process), this creates the basis to reward good performance. Wherever key lifecycle emissions are excluded (for instance indirect land use change under the RED) this leaves a risk of perverse outcomes. Until now, while there have been many studies of the lifecycle emissions of fossil fuel extraction, there has been no transparent analytical framework available to regulators that is able to accommodate detailed, process based analysis of different oil extraction pathways. In instances where the CI of fossil fuels has been primarily of interest in setting a baseline against which to compare alternative fuels (such as the U.S. NETL [2008] study or the JEC [2011] well-to-wheels study) a full process-based modeling framework has not been necessary – the task is to provide a reasonable characterization of the average (or marginal) emissions of fossil fuel, to allow thresholds to be set for alternative fuels, rather than for the purpose of comparing different crudes to each other. A certain amount of disaggregation of fossil fuels can be achieved without full process modeling by focusing on clearly defined categories with distinctly different carbon footprints, such as the different feedstock pathways in the FQD draft implementing measure. However, when the objective is to disaggregate the emissions intensity of prima facie similar crude oils, with the purpose of providing additional value to lower carbon crudes and reduced value to higher carbon crudes, a rigorous and detailed basis for comparisons becomes vital.

In this report we have presented the Oil Production Greenhouse gas Emissions Estimator (OPGEE), a spreadsheet model that uses engineering principles to assess the carbon intensity of oil production. Like Biograce, the RTFO Carbon Calculator and CA-GREET for biofuels, OPGEE is able to distinguish crude oil pathways by carbon intensity given an adequate set of inputs. With these inputs, it could even be used to compare the energy intensity of different crude oil extraction processes, to provide information that could be factored into commercial decision-making. We have outlined in the report priority areas to expand OPGEE further, such as two-phase flow and process modeling of bitumen extraction, but the more significant limitation on calculating accurate emissions estimates is data availability. In general, it is difficult to find field-specific data especially for oil fields in countries like Russia with limited transparency. As an alternative to inputting data, the OPGEE model has default assumptions available for all parameters, allowing estimates to be made even where data is limited. Inevitably, however, a greater reliance on default data implies added uncertainty.

While the ideal is that all parameters would be reported based on real data, not all parameters are equally important in the calculation of greenhouse gas emissions. The key drivers of energy use are: gas-oil-ratio and gas processing decisions; water-oil-ratio; use of thermally enhanced recovery techniques; depth and pressure of reservoir. In addition to energy use, the key driver of carbon intensity is the rate of gas flaring – for fields with very high flared volumes, the flare rate is the primary driver of the carbon intensity. In general, if these parameters can be well-characterized for a given field, a good characterization of the carbon intensity of that field should be possible.

In this report, we have used a substantial, but still limited, database of oilfield characteristics to estimate the baseline carbon intensity of European crude oil. We find an average upstream carbon intensity for the EU crude baseline of 10.2 gCO_2e/MJ, lower than the baseline calculated by CARB using OPGEE for crude oils coming into California, but somewhat higher than previous JEC (2011) estimates. This assessment is a substantial advance in terms of data coverage and transparency on any previous published work, but is still significantly limited by data availability. While we have targeted acquiring data on the most important input parameters, in some cases we have still had to rely on defaults and 'smart defaults', for instance for water-oil-ratio and gas-oil-ratio. We have also had to rely on regional averages for flaring in many fields.

The situation for European regulators is particularly challenging – while California and British Columbia are heavily reliant on crude from North America where data is relatively rich, Europe is highly import dependent and imports crude from all over the world. Indeed, the largest single exporter of crude to Europe is Russia, where data is sparse especially in the public domain, and where there are few lifecycle analyses in the existing literature. Improving the accuracy of the results for these data-sparse regions will require working with the oil and gas industry to improve the European Commission's understanding of typical processes and field characteristics in these regions. Even in areas for which production data is available (e.g. the United Kingdom North Sea fields) there is substantial space for industry to improve the accuracy of the analysis by supplying additional field specific process data. In the first instance, this engagement with industry could be undertaken through formal and informal consultation. In a regulatory context, a hybrid-reporting scheme with conservative defaults would provide the mechanism and incentive for industry to assist the Commission in developing its database.

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Annex A Crudes Excluded in Emissions Baseline Analysis

REGION	COUNTRY OF ORIGIN	TYPE OF CRUDE OIL	% OF TOTAL IMPORTS
Middle East	Abu Dhabi	Murban	0.02%
Middle East	Abu Dhabi	Upper Zakum	0.06%
Middle East	Oman	Oman	0.03%
Middle East	Other Middle East Countries	Other Middle East Crude	0.00%
Middle East	Saudi Arabia	Arab Medium	0.00%
Middle East	Saudi Arabia	Arab Heavy	0.00%
Middle East	Saudi Arabia	Berri (Extra Light)	0.16%
Middle East	Yemen	Masila Blend	0.04%
Africa	Congo (DR)	Congo (DR) Crude	0.05%
Africa	Egypt	Heavy (<30° API)	0.21%
Africa	Gabon	Rabi/Rabi Kounga	0.02%
Africa	Gabon	Other Gabon Crude	0.19%
Africa	Nigeria	Nigerian condensate (>45°)	0.26%
Africa	Other African Countries	Other Africa Crude	1.18%
Africa	Tunisia	Tunisia Crude	0.22%
Europe	Ukraine	Ukraine Crude	0.01%
Europe	Other European countries	Other Europe Crude	2.33%
Americas	Argentina	Argentina Crude	0.11%
Americas	Canada	Light Sweet (>30° API)	0.10%
Americas	Colombia	Other Colombia Crude	0.11%
Americas	Ecuador	Other Ecuador Crude	0.01%
Americas	Mexico	Olmeca	0.01%
Americas	Mexico	Isthmus	0.15%
Americas	Venezuela	Medium (22-30°)	0.17%
Americas	Venezuela	Heavy (17-22°)	0.13%
Americas	Venezuela	Light (>30°)	0.04%

Based on DG Energy, 2012a

Annex B WTO Cases Applying the *Chapeau* Requirements

Several high-profile cases have developed a body of jurisprudence to understand how the *chapeau* requirements and associated elements are applied under real-world scenarios. Four environmental disputes are particularly relevant: *U.S. – Gasoline*, U.S. – *Shrimp*, EC – *Asbestos*, and *Brazil – Retreaded Tires*. These cases delineate the contours of permissible and impermissible trade restrictions.[187]

B.1 U.S. – Gasoline (1996)

The dispute arose when the United States (U.S.) applied stricter rules on the chemical characteristics of imported gasoline than it did for domestically refined gasoline. To achieve clean air, the U.S. instituted a program that required the dirtiest air basins, those in "nonattainment" of air quality standards, to use cleaner reformulated gasoline. Air basins in "attainment" were permitted to use dirtier conventional gasoline. To prevent refiners from dumping the pollutants extracted from reformulated gasoline into conventional gasoline—an inexpensive way to dispose of them—the U.S. required conventional gasoline to meet a certain baseline for gasoline quality. For domestic refiners, the baseline was calculated as the quality of their gasoline in 1990, the so-called "individual baseline." For foreign refiners, the baseline was fixed in the U.S. Clean Air Act, the so-called "statutory baseline." Venezuela and Brazil challenged the measure as violating the *chapeau* requirements, arguing that allowing domestic refiners to use individual baselines and requiring foreign refiners to use statutory baselines was unjustifiable discrimination.[188]

The Appellate Body found that the claim to exception under Article XX(g) was proper, but that the U.S. unjustifiably discriminated in violation of the *chapeau*. It found unpersuasive the justifications proffered for barring foreign refiners from using individual baselines and allowing domestic refiners to avoid statutory baselines:

- *Barring foreign refiners from using individual baselines*. The U.S. argued that it would prove too administratively burdensome to verify and enforce on foreign soil. But the Appellate Body noted that this categorical statement did not apply to all foreign refiners, and that the U.S. had failed to seek cooperative arrangements with foreign refiners and the foreign governments to make that determination, including with Venezuela and Brazil.[189] In other words,

[187] These summaries are extracted, with some slight modifications, from a legal analysis provided by the same author. *See* Grabiel, T., Défense Terre, *Legal Analysis: WTO Implications of Reporting Measures for Tar Sands under the Fuel Quality Directive* (June 2011), pp. 10-12; *See* Grabiel, T., *Legal Analysis: WTO Implications of European Union Tar Sands Policies* (June 2010), pp. 4-6.
[188] *See U.S. – Gasoline.*
[189] *U.S. – Gasoline*, pp. 23-24.

the U.S. could not justify the across-the-board application of the statutory baseline on foreign refiners.

- *Allowing domestic refiners to avoid statutory baselines*. The U.S. argued that applying the statutory baseline to domestic refiners would have been physically and financially impossible because of the magnitude of the changes required in almost all U.S. refineries, causing substantial delay in the program. But the Appellate Body noted that although "this may very well have constituted sound domestic policy," the U.S. "disregard[ed] that kind of consideration when it came to foreign refiners."[190]

The Appellate Body concluded that these two omissions—to explore adequately means of mitigating the administrative problems and counting the costs for foreign refiners of statutory baselines—constituted unjustifiable discrimination and a disguised restriction on international trade.[191] It therefore struck down the measures. This case makes clear that countries implementing trade-restrictive measures must be able to justify them, and the WTO judiciary will scrutinize any justification to ensure it conforms to the stated objective.

B.2 U.S. – Shrimp (1998)

The dispute arose when the U.S. prohibited imports of certain shrimp and shrimp products. The import ban resulted from the listing of five species of migratory sea turtles under the U.S. Endangered Species Act. As a result of the listing, the U.S. government was required to prohibit any harassment, hunting, capture or killing of sea turtles. The U.S. government therefore required its shrimp trawlers to use "turtle-excluder devices" in their nets when fishing in areas frequented by sea turtles. The U.S. government also prohibited imports of shrimp harvested with technology that adversely affected sea turtles unless the harvesting country had a certified regulatory program similar to that of the U.S. or it was found that its particular fishing environment did not pose a threat to sea turtles.

The practical effect of the ban was to require shrimp-harvesting countries with any of the listed sea turtles in their waters to impose on their shrimp trawlers essentially the same requirements as those borne by U.S. shrimp trawlers if they wanted to be certified to export shrimp products to the U.S. In essence, it required the use turtle-excluder devices. India, Malaysia, Pakistan and Thailand challenged the U.S. ban on the grounds that it unjustifiably and arbitrarily discriminated against their shrimp and shrimp products.

The Appellate Body found both unjustifiable and arbitrary discrimination. Although the ban was proper under Article XX(g) since the protection of sea turtles was at its heart, the Appellate Body found several facets

[190] *U.S. – Gasoline*, pp. 25-26.
[191] *U.S. – Gasoline*, pp. 26.

violated the *chapeau*, detailing in the clearest terms to date the *chapeau*'s procedural and substantive requirements:

- *Essentially the Same Program*. The implementing regulations required foreign governments to adopt certified regulatory program that essentially dictated what a comparable regulatory program would entail.[192] The Appellate Body found that the U.S. established "a single rigid and unbending requirement"[193] that required adoption of "*essentially the same* policies and enforcement practices as those applied to, and enforced on, domestic shrimp trawlers," namely the use of turtle-excluder devices.[194] The certification process provided "little or no flexibility in how officials make the determination for certification pursuant to these provisions."[195] In addition, the measure implied that, in certain circumstances, shrimp caught abroad using methods identical to those employed in the U.S. would be excluded from the U.S. market.[196] The Appellate Body found this was "difficult to reconcile with the declared objective of protecting and conserving sea turtles."[197]

- *Unequal Treatment*. The U.S. provided certain countries—mainly in the Caribbean—technical and financial assistance and longer transition periods for their fishermen to start using turtle-excluder devices. The Appellate Body found that the U.S. impermissibly discriminated between countries by affording these countries preferential treatment.[198]

- *Duty to Negotiate*. The U.S. made serious efforts to negotiate a pact with only certain countries, including those countries that received technical and financial assistance. The Appellate Body found that the U.S. failed to engage all shrimp-exporting countries "in serious, across-the-board negotiations with the objective of concluding bilateral and multilateral agreements for the conservation and protection of sea turtles before enforcing the import prohibition."[199] This duty to negotiate—and the failure thereof—was heightened by the unilateral nature of the prohibition.[200]

- *Due Process*. The certification process was not subject to formal procedural protections that allowed for review and appeal. The Appellate Body found that the certification process "to be singularly informal and casual" with no written opinion or formal appeal procedure, failing to meet "certain minimum standards for transparency and procedural fairness in the administration of trade regulations."[201]

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192 *U.S. – Shrimp*, paras. 161-162.
193 *U.S. – Shrimp*, para. 177, fn. 24.
194 *U.S. – Shrimp Recourse*. Para. 140.
195 *U.S. – Shrimp*, paras. 178-186.
196 *U.S. – Shrimp*, para. 165.
197 *U.S. – Shrimp*, para. 165.
198 *U.S. – Shrimp*, paras. 173-175.
199 *U.S. – Shrimp*, paras. 166-171.
200 *U.S. – Shrimp*, para. 172.
201 *U.S. – Shrimp*, paras. 178-186.

In the wake of the Appellate Body decision, the U.S. undertook a series of actions to address the issues outlined above. It engaged in across-the-board negotiations with shrimp-exporting countries.[202] It revised its regulations to require a regulatory program that was "comparable in effectiveness" rather than "essentially the same."[203] On that point, the Appellate Body found "there is an important difference between conditioning market access on the adoption of essentially the same program, and conditioning market access on the adoption of a program *comparable in effectiveness*."[204] The U.S. also revised its regulations to permit sufficient flexibility for officials certifying programs, allowing them to take into account the unique circumstances in any given country. And it addressed the procedural fairness concerns, ensuring due process through transparent decision-making and the right to challenge an adverse determination.[205] Despite these actions, Malaysia nevertheless challenged the ban again through the "recourse" procedure. This time, however, the Appellate Body upheld the prohibition, finding that it no longer resulted in unjustifiable or arbitrary discrimination.[206]

B.3 EC – Asbestos (2001)

The dispute arose when France prohibited the import of asbestos and asbestos-containing products.[207] Asbestos is a highly toxic material, exposure to which poses significant threats to human health, including asbestosis, lung cancer and mesothelioma. But due to resistance to very high temperatures, certain asbestos are widely used in various industrial sectors. To control the health risks associated with their release, France imposed a general ban on asbestos as well as on products that contained it. Canada, a major producer of asbestos-containing products, challenged the French law.

The Appellate Body upheld the ban. The objective of the French government to protect human health legitimately allowed it to halt the proliferation of asbestos within its borders under Article XX(b).[208] With regard to the *chapeau* requirements, the Appellate Body upheld the Panel findings that, in the text of the French law, "[o]nly the product in question is mentioned, without any reference to its origin" and, therefore, no discrimination based on national origin was readily apparent.[209] It was also important that, within the administrative aspects of the law, there was no "expressly discriminatory provision."[210] The Canadian government's failure to show discrimination beyond a general import ban was insufficient to

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[202] *U.S. – Shrimp Recourse*, paras. 119-134.
[203] *U.S. – Shrimp Recourse*, paras. 135-144.
[204] *U.S. – Shrimp Recourse*, para. 144.
[205] *U.S. – Shrimp Recourse*, paras. 145-150.
[206] *U.S. – Shrimp Recourse*, paras. 153-54.
[207] *See EC – Asbestos Panel*; *EC – Asbestos*.
[208] *EC – Asbestos*, para. 168.
[209] *EC Asbestos Panel*, para. 8.228.
[210] *EC Asbestos Panel*, para. 8.228.

meet its burden to establish unjustifiable and arbitrary discrimination under the *chapeau*.[211]

B.4 Brazil – Retreaded Tires (2007)

The dispute arose when Brazil instituted an import ban on retreaded tires. The goal of the ban was to reduce "the risks of waste tyre accumulation to the maximum extent possible."[212] Brazil had concluded that waste tires were breeding grounds for vectors and rodents, and their decomposition or destruction by fire released toxins that were harmful to humans and the environment. As originally drafted, the ban did not include an exemption for members of the *Mercado Común del Sur* (*Mercosur*) – Spanish for Southern Common Market. But a ruling by a *Mercosur* tribunal amended the import ban on retreaded tires, requiring an exemption be established for *Mercosur* members.[213] The European Community challenged both the import ban on retreaded tires and the *Mercosur* exemption as violating the *chapeau* requirements.[214]

The Appellate Body found that Brazil unjustifiably discriminated against foreign exporters of retreaded tires. The import ban as originally drafted and justified was proper under Article XX(b). But the *Mercosur* exemption violated the *chapeau* requirements. According to the Appellate Body, "whether the application of a measure results in arbitrary or unjustifiable discrimination should focus on the cause of the discrimination, or the rationale put forward to explain its existence."[215] As a result, the Appellate Body analyzed the ruling issued by the *Mercosur* tribunal and found an unjustifiable rationale for discrimination because it bore "no relationship to the legitimate objective pursued by the Import Ban."[216] The case makes clear that subsequent modifications to a trade-restrictive measure are reviewable as are their justifications.

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211 *EC Asbestos Panel*, para. 8.229.
212 *Brazil – Retreaded Tyres* at Paragraph 134.
213 *Id*. at Paragraphs 122-123.
214 *Id*. at Paragraph 123.
215 *Id*. at Paragraphs 225-226; *see also US –Shrimp*; *US – Shrimp Recourse*; *US –Gasoline*.
216 *Brazil – Retreaded Tyres* at Paragraph 228.

Annex C Documentation of modifications to OPGEE 1.0 in OPGEE 1.0.ICCT

C.1 Modified inputs

The following minor amendments have been made to OPGEE v1.0.ICCT as compared to OPGEE 1.0 (see Annex D):

- A switch has been added to distinguish onshore from offshore production. For offshore fields, the defaults are amended as follows: production per well is greater (1,500 bbl/d); electricity is generated onsite; land use impacts are set to 'low'.
- A switch has been added to allow upgrading emissions to be added automatically for Venezuelan upgraders.
- Field age has been replaced by field year, allowing the model to be run for different years without amending the input data.
- Modeled year has been added at the top of the sheet as an input.
- A new input row has been added to distinguish cases where the year is the discovery year vs. cases where it is the first year of production. Where the data is for discovery year, it is assumed that 3 years passed between discovery and first production (i.e. the field age is 3 less).
- The downhole pump is set off by default for any field with gas lift.
- Data on tanker size has been added on the input sheet to allow it to be entered via the bulk assessment more easily.

C.2 Iterative solvers

Firstly, in the case that gas lift is turned on, the gas composition from the field will be modified by the composition of the lift gas. When the bulk assessment is run, we invoke an iterative solver that adjusts gas composition until the composition of the gas used for gas lift is consistent with the produced gas being a combination of untreated reservoir gas and treated lift gas.

Secondly, OPGEE 1.0 does not support setting a default to have all gas not accounted for at a field reinjected. We have added a default switch (-1 in the input data) that causes OPGEE to calculate the appropriate proportion of produced gas reinjected that is consistent with zero gas export.

C.3 Bulk assessment

We have implemented a revised bulk assessment tool, which is able to handle an unlimited number of input fields, and which makes a set of corrections systematically for fields with physically inconsistent data. In addition to running through all fields from the bulk assessment sheet and invoking the iterative solver for gas lift composition, the bulk assessment:

- Fills in any blanks in the data based on the OPGEE defaults.
- Requests user correction if the number of wells for a given field is set to zero.
- Where the flaring rate is known from user data but the gas-oil-ratio (GOR) is based on the default and is inadequate to sustain that level of flaring, it increase the GOR so that more gas is produced than flared.
- Where GOR is known but flare rate is based on regional defaults, and the GOR is below the amount of gas flared, the flare rate is reduced so that only as much gas can be flared as is produced.
- Where GOR is reported as very low and is inadequate to cover the fugitive emissions programed into OPGEE (based on Californian data), the GOR is raised to ensure a positive gas balance.
- Where the default productivity index is too low given the volumes of liquid produced, it is raised to be consistent with production levels.
- Where the default pipe diameter is low compared to the production volume, such that friction accounts for an implausible proportion of the pressure traverse in the well, we increase the pipe diameter to a maximum of 4.5 inches. If the friction is still dominant, we adjust the number of wells upwards, assuming that no oil producer would allow frictional losses to become disproportionately high.
- If the GOR is inadequate to support the requirements of gas lift, we increase the GOR to accommodate gas lift.

Annex D OPGEE documentation

Oil Production Greenhouse Gas Emissions Estimator

OPGEE v1.0

User guide & Technical documentation

DRAFT VERSION A

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Part I

Introduction and user guide

1 Introduction

The Oil Production Greenhouse gas Emissions Estimator (OPGEE) is an engineering based life cycle assessment (LCA) tool for the measurement of greenhouse gas (GHG) emissions from the production, processing, and transport of crude petroleum. The system boundary of OPGEE extends from initial exploration to the refinery gate (see Figure 1.1).

The aim of this technical documentation is to introduce OPGEE and explain the calculations and data sources in the model. First, the overall goals and motivation for OPGEE are described. Then, the general structure of OPGEE is introduced with a brief explanation of the worksheets contained in the model. Next, each production stage is explained in detail, outlining the methods and assumptions used to generate estimates of energy use and emissions for that stage. Following, supplemental calculation sheets are outlined. After this, the gathering sheets which collect and aggregate intermediate results are described. Lastly, we describe the sheets that contain fundamental data inputs.

1.1 Model motivation

Current research suggests that GHG emissions from petroleum production can be quite variable [4–11]. Facilities that do not rely on energy intensive production methods and use effective controls on fugitive emissions sources will have low GHG emissions per unit of energy produced. In contrast, some crude oil sources can have higher GHG emissions if they rely on energy-intensive production methods.

The variability in crude oil production emissions is partly due to the use of energy-intensive secondary and tertiary recovery technologies [9, 12, 13]. Another major factor is significant variation in the control of venting, flaring and fugitive (VFF) emissions [14–16]. Other emissions arise from increased pumping and separation work associated with increased fluid handling in depleted oil fields (i.e., fields with a high water-oil ratio).

The existing set of general fuel cycle emissions models, exemplified by GREET and GHGenius [13, 17], cover a wide range of transport fuels, from biofuels to electric vehicles. These broad models have the advantage of being publicly available and transparent. Unfortunately, they lack process-level detail for any particular fuel cycle and only represent pathway averages. For example, all conventional crude oil production in GREET is modeled using a common default production pathway, fuel mix, and energy efficiency. While these LCA tools have been useful to date, future regulatory approaches will require a more specific method of assessing the

Box 1.1. Goals of OPGEE

1. Build a rigorous, engineering-based model of GHG emissions from oil production operations.
2. Use detailed data, where available, to provide maximum accuracy and flexibility.
3. Use public data wherever possible.
4. Document sources for all equations, parameters, and input assumptions.
5. Provide a model that is free to access, use, and modify by any interested party.
6. Build a model that easily integrates with existing fuel cycle models and could readily be extended to include additional functionality (e.g. refining)

differences between crude oil sources.

1.2 OPGEE model goals

The goals of OPGEE development are listed in Box 1.1.

First, OPGEE is built using engineering fundamentals of petroleum production and processing. This allows more flexible and accurate emissions estimations from a variety of oil production emissions sources.

OPGEE is constructed using *Microsoft Excel* to ensure transparency and maximum accessibility by stakeholders, including industry, governments, and members of the public. OPGEE will be available for download from Stanford University servers, and servers of future institutions in which Adam Brandt is employed. This will ensure its future availability. Regular updates of the model are expected in intervals of 1-2 years.

Another goal of OPGEE is the generation of comprehensive documentation. Model functions and input data are documented within the *Excel* sheet to allow effective use and modification of the tool by users. This long-form model documentation serves to explain model calculations and assumptions and provides information on model data sources.

1.3 OPGEE model construction

1.3.1 Model functional unit

The functional unit of OPGEE is 1 MJ of crude petroleum delivered to the refinery entrance (a well-to-refinery, or WTR process boundary). This functional unit is held constant across different production and processing pathways included in OPGEE. This functional unit allows integration with other fuel cycle models that calculate refinery emissions per unit of crude oil processed, and will allow easy integration with future work on refinery

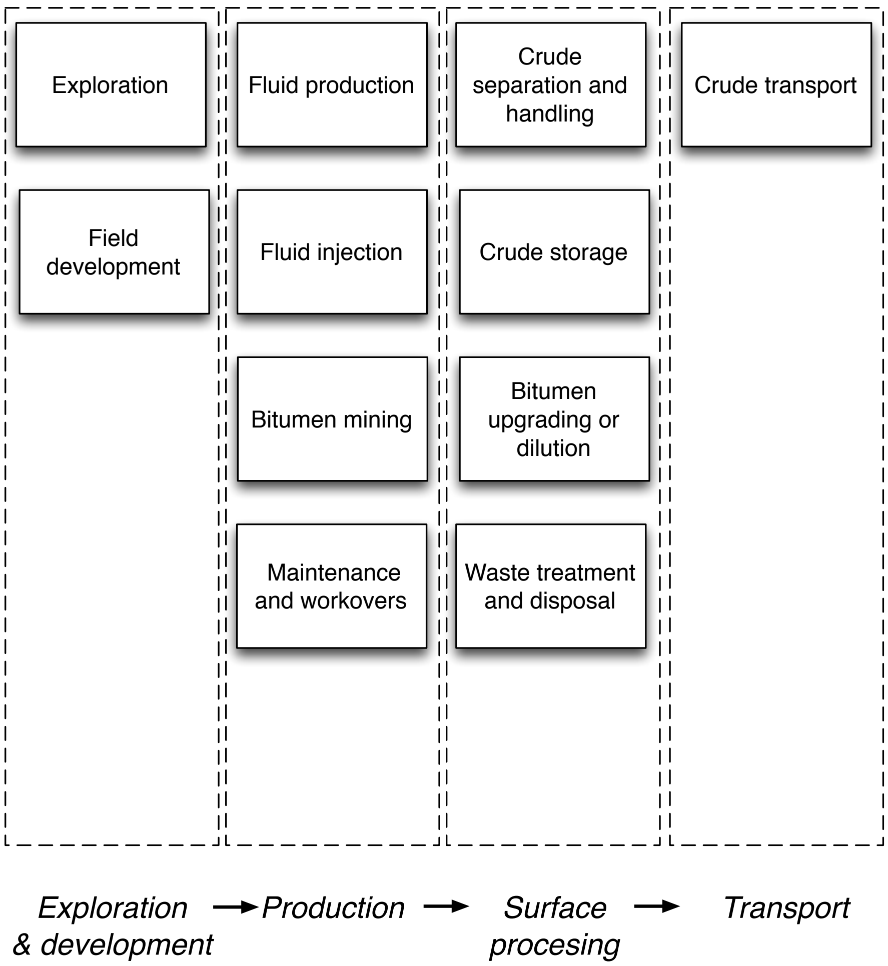


Figure 1.1: Schematic chart showing included stages within OPGEE.

models. The heating value basis can be chosen as lower or higher heating value (LHV or HHV), depending on the desired basis for the emissions intensity. The model defaults to LHV for best interface with GREET.

1.3.2 Model scope and focus

OPGEE includes emissions from all production operations required to produce and transport crude hydrocarbons to the refinery gate (see Figure 1.1 for model system boundaries). Included production technologies are: primary production, secondary production (water flooding), and major tertiary recovery technologies (also called enhanced oil recovery or EOR). In addition, bitumen mining and upgrading is included in a simplified fashion.

1.3.3 Spreadsheet structure

OPGEE is modular in structure, with interlinked sheets representing each production stage. Within each major production stage, a number of activities and processes occur, such as fluid production or fluid injection. The number of processes and sub-processes varies depending on the process stage. The calculations take place sequentially and are numbered in a hierarchical fashion (see Box 1.1 for explanation of documentation pointers to the model).

1.3.4 Modeling detail and default specifications

OPGEE models oil production emissions in more detail than previous LCA models. For example, the energy consumed in lifting produced fluids (oil, water, and associated gas) to the surface is computed using the fundamental physics of fluid lifting, accounting for lifting efficiencies and pump efficiencies.

Increased modeling detail results in an increase in the number of model parameters. All required inputs to OPGEE are assigned default values that can be kept as is or changed to match the characteristics of a given oil field or marketable crude oil blend. If only a limited amount of information is available for a given facility, most of the input values will remain equal to defaults. In contrast, if detailed field-level data are available, a more accurate emissions estimate can be generated.

For some processes and sub-processes, correlations or relationships are developed for defaults, which we call "smart defaults". For example, the amount of water produced with oil (water-oil-ratio, or WOR) affects the energy consumed in lifting, handling, and separating fluids. If the WOR is known, it can be inputed directly. However, in some regions, water production is not reported, so OPGEE includes a statistical relationship for water production as a function of reservoir age (see Appendix D for a description of the analysis underlying this smart default).

A workflow for updating and improving the data basis and accuracy of an emissions estimate using OPGEE is given in Figure 1.2. This workflow represents one possible way that OPGEE could be used.

1.3.5 Emissions sources classification

Each process stage or sub-process in OPGEE could be associated with a variety of emissions sources. For example, the *'Drilling & Development'* process stage includes the terrestrial drilling sub-process. Terrestrial drilling includes the following emissions sources:

- Combustion emissions from drilling rig prime mover;
- Flaring emissions from drilling rig (for reservoirs with significant gas production);
- Vents and other upset emissions from drilling rig;
- Combustion emissions from work performed in land clearing and site preparation;
- Biogenic emissions from ecosystem disturbance during development;
- Embodied emissions in cement and casing;

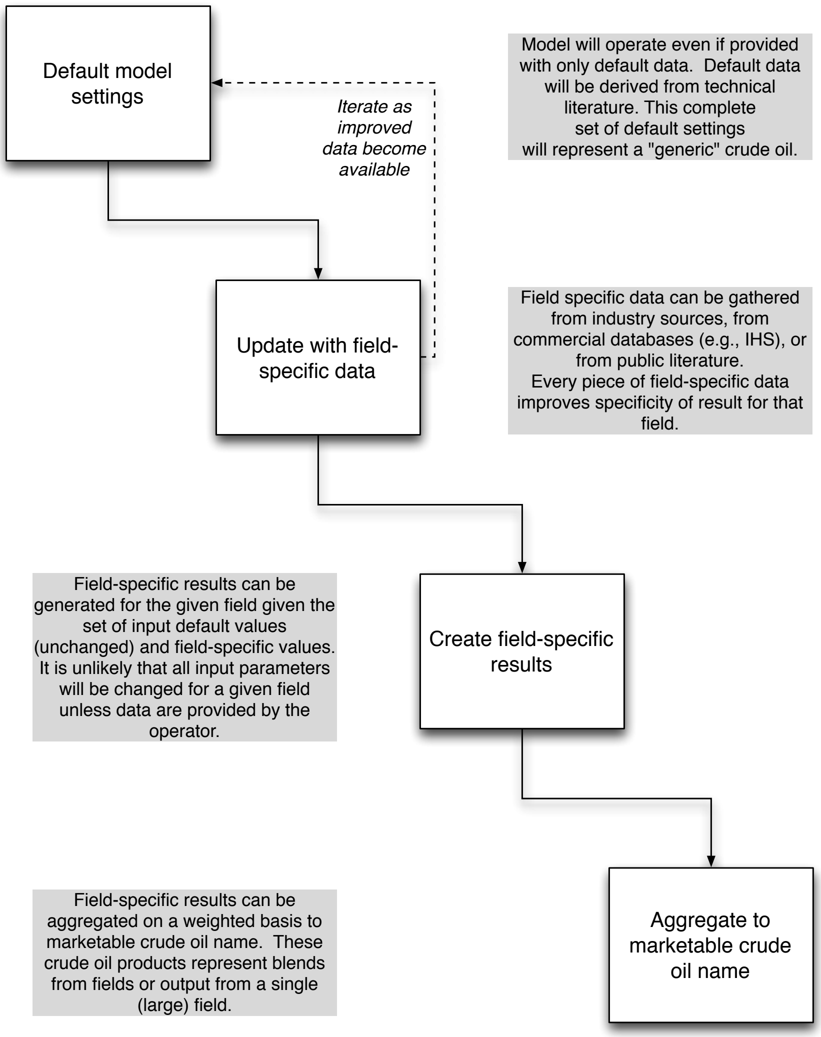


Figure 1.2: Proposed workflow for improving emissions estimates using OPGEE.

- Embodied emissions in other consumable materials (e.g., fracturing sand)

Note that these emissions sources are of significantly different magnitude and have different causation and potential methods of mitigation. In total, over 100 emissions sources are classified in OPGEE v1.0 across all process stages (e.g., all included processes and sub-processes). See Appendix C for a complete tabulation and classification of emissions sources.

1.3.6 Emissions source significance cutoffs

OPGEE includes within its system boundaries over 100 possible emissions sources in oil and gas production (see Appendix C). It would be infeasible (and counter-productive) for regulators or producers to attempt to estimate or model the magnitude of every emissions source. Fortunately, a much smaller number of emissions sources will result in most of the emissions from petroleum production operations.

For this reason, emissions sources included in the OPGEE system bound-

Table 1.1: Emissions classification, order of magnitude emissions, and significance description.

Class	Est. mag. [gCO_2/MJ]	Description
*	0.01	Minor emissions sources unworthy of further study or estimation. Numerous sources result in this being the most common classification. One-star emissions are accounted for by adding a value for miscellaneous minor emissions.
**	0.1	Minor emissions sources that are often neglected but may be included for physical completeness.
***	1	Sources that can have material impacts on the final GHG estimate, and therefore are explicitly modeled in OPGEE.
****	10	Sources that are large in magnitude (though uncommon). Examples include steam production for thermal oil recovery and associated gas flaring. These sources are significant enough to require their own dedicated OPGEE modules.

ary are classified by estimated emissions magnitude. These emissions magnitudes are meant to represent *possible* emissions magnitudes from a source, not the actual emissions that would result from that source for any particular field. An order-of-magnitude estimation approach is used, with each source assigned a rating in "stars" from one-star (*) to four-star (****) corresponding to 0.01 to 10 g CO_2 eq. per MJ of crude oil delivered to the refinery gate. These classifications are explained in more detail in Table 1.1.

Emissions estimated to be one-star emissions (*) are not modeled in OPGEE due to insignificant magnitude. These are included in the overall emissions estimate by including a small sources term. Two-star (**) sources are included simply or are included in the small sources term. Often, two-star sources are minor in magnitude, but are modeled due to the need to model the physics and chemistry of crude oil production and processing.[1] Three-star (***) sources are explicitly modeled in OPGEE. Four-star sources (****) are modeled in detail with stand-alone modules to allow variation and uncertainty analysis.

User Inputs & Results 3.6

1.3.7 Data sources

Because of the need for transparent data basis, OPGEE uses data from a variety of technical reference works. For example, emissions factors are derived from standard engineering references from the American Petroleum Institute (API) and EPA [18, 19]. A large number of technical references, journal articles, and fundamental data sources have been consulted during the construction of OPGEE, including:

- Exploration and drilling [19–26]
- Production and surface separations [2, 18, 19, 27–55]
- Secondary and tertiary recovery [56–61]

[1] No strict criteria exist to determine the inclusion or exclusion of two-star sources. Modeler judgement is applied to determine the need for modeling these sources.

- Water treatment and waste disposal [26, 50, 53, 62–65]
- Venting, flaring, and fugitive emissions [27–29, 29–36, 66–70]
- Petroleum transport and storage [33, 36, 46, 69, 71–75]

2 User guide

OPGEE is divided into three types of worksheets: (i) process stage sheets, (ii) supplementary sheets, and (iii) output sheets.

2.1 Process stage worksheets

Process stage worksheets form the core of OPGEE, and are where most model calculations occur. These sheets have red-colored tabs.

2.1.1 *'Exploration'* worksheet

The *'Exploration'* worksheet contains pre-production emissions that occur during primary exploration for petroleum. These emissions are generally very small in magnitude when amortized over the productive life of an oil field, as they occur only at the outset of production. For this reason, these sources are classified as below the significance cutoff in OPGEE v1.0. Exploration emissions are described in more detail in Section 3.1, and emissions sources from exploration are listed and classified in Table C.1.

2.1.2 *'Drilling & Development'* worksheet

The *'Drilling & Development'* sheet includes emissions that occur during development of crude oil production facilities. Key sources include drilling and land use impacts from land clearing and conversion. Drilling and development emissions tend to be relatively small because they only occur at the outset of production or sporadically during field life. Drilling and development emissions are described in more detail in Section 3.2, and emissions sources from drilling and development are listed and classified in Table C.2.

2.1.3 *'Production & Extraction'* worksheet

The *'Production & Extraction'* sheet models the work required to lift fluids from the subsurface and to inject fluids into the subsurface. A variety of fluid lifting and production technologies are included in OPGEE, including the two most common lifting technologies: sucker-rod pumps and gas lift. Also included are the energy requirements of water flooding, gas flooding, and steam flooding. The lifting model used for calculating lifting energy is a single phase flow model which neglects gas slippage. Injection horsepower calculations are based on operating pressures and temperatures using fundamental physics. Production emissions are described in more detail in Section 3.3, and emissions sources from production are listed and classified in Table C.3.

2.1.4 *'Surface Processing'* worksheet

The *'Surface Processing'* sheet models handling of crude, water, and associated gas with a set of common industry technologies. By defining default configurations and parameter values, the amount of data required is reduced. For example, in gas processing, default processes are assumed such as the amine-based acid gas removal (AGR) and glycol-based gas dehydration units. Process flow diagrams are included in the surface processing sheet for improved readability. Surface processing emissions are described in more detail in Section 3.4, and emissions sources from surface processing are listed and classified in Table C.4.

2.1.5 *'Maintenance'* worksheet

The *'Maintenance'* sheet includes venting and fugitive emissions associated with maintenance. These emissions occur during compressor blowdowns, well workovers and cleanups, and gathering pipeline maintenance. Maintenance emissions are described in more detail in Section 3.5, and emissions sources from maintenance are listed and classified in Table C.5.

2.1.6 *'Waste Disposal'* worksheet

The *'Waste Disposal'* sheet includes emissions associated with waste disposal are within the system boundary of OPGEE. However, these sources are believed to be below the significance cutoff, so they are not explicitly modeled in OPGEE. Waste disposal emissions are described in more detail in Section 3.6, and emissions sources from waste disposal are listed and classified in Table C.6.

2.1.7 *'Crude Transport'* worksheet

The *'Crude Transport'* sheet calculations allow variation in transport modes and in the distance travelled. Transport emissions are modeled using the method established in CA-GREET [76]. Transport emissions are described in more detail in Section 3.7, and emissions sources from transport are listed and classified in Table C.7.

2.1.8 *'Bitumen Extraction & Upgrading'* worksheet

The *'Bitumen Extraction & Upgrading'* sheet models extraction of crude bitumen separately from the production of conventional crude oil, due to the differences in technologies applied (e.g., mining and upgrading equipment have no analogues in conventional crude oil operations). Instead of detailed process models, data from the GHGenius model are included in OPGEE [13]. Bitumen extraction and upgrading emissions are described in more detail in Section 3.8.

2.2 Supplementary sheets

Supplementary sheets support calculations throughout OPGEE, including: calculating intermediate outputs in the process stage sheets, compiling output in the gathering sheets, and calculating final results in the *'User Inputs & Results'* sheet. Supplementary sheets have blue-colored tabs.

'Gas Balance' worksheet This sheet tracks produced gas composition from production to final user or sale to ensure that all produced gas is accounted for in the gas processing equipment, VFF emissions, and final gas sales. The *'Gas Balance'* worksheet is described in Section 4.1

'Steam Injection' worksheet This sheet is supplementary to the production and extraction sheet and calculates in detail the natural gas consumed and electricity cogenerated (if applicable) during steam generation. The *'Steam Injection'* worksheet is described in Section 4.2

'Electricity' worksheet This sheet determines the offsite electricity mix and calculates the energy consumption in onsite electricity generation (other than electricity co-generated with steam). The *'Electricity'* worksheet is described in Section 4.5.

'Drivers' worksheet This sheet provides a database of energy consumption for different types and sizes of prime movers (gas and diesel engines, gas turbines and electric motors). The *'Drivers'* worksheet is described in Section 4.4

'Fuel Cycle' worksheet This sheet retrieves and calculates the fuel cycle energy consumption and GHG emissions for the calculation of credits/debits from fuel exports/imports. The *'Fuel Cycle'* worksheet is described in Section 4.7.

'Emission Factors' worksheet This sheet retrieves and builds emissions factors for the calculation of combustion and non-combustion GHG emissions from energy use and losses. The *'Emissions Factors'* worksheet is described in Section 4.6

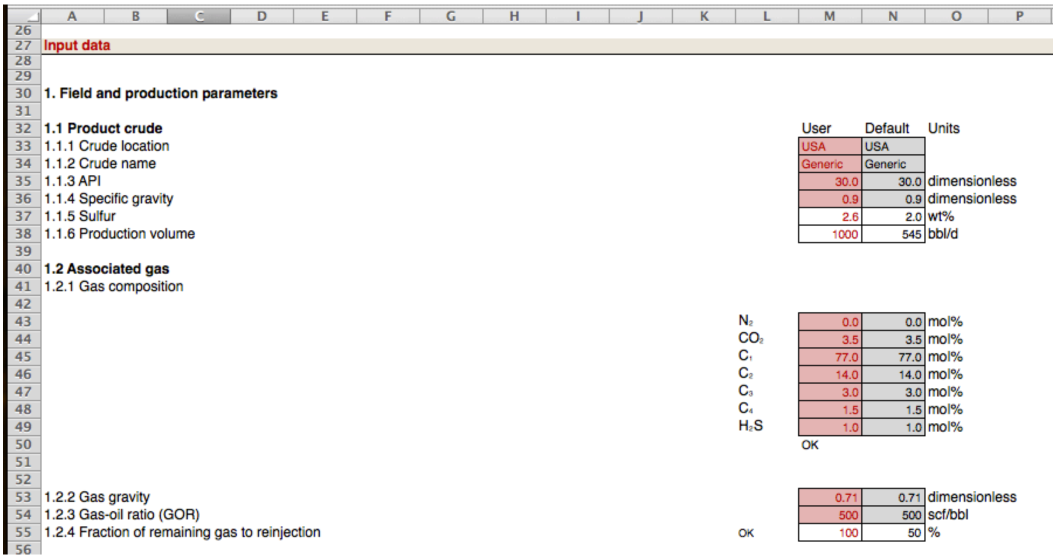
'VFF' worksheet This sheet calculates in detail the GHG emissions associated with venting, flaring and fugitives. The *'VFF'* worksheet is described in Section 4.3.

'Fuel Specs' worksheet This sheet provides fuel specifications required for OPGEE calculations. The *'Fuel Specs'* worksheet is described in Section 6.

'Input Data' worksheet This sheet provides other needed data inputs such as conversion factors and steam enthalpies. The *'Input Data'* worksheet is described in Section 6.

2.3 Output gathering sheets

Output sheets gather the information from the process stage calculations and compile them into summed energy consumption (including energy co-production credits) and summed GHG emissions (including any offsets from co-produced energy). Also included in the output sheets is the sheet



			User	Default	Units
27	Input data				
30	1. Field and production parameters				
32	1.1 Product crude		User	Default	Units
33	1.1.1 Crude location		USA	USA	
34	1.1.2 Crude name		Generic	Generic	
35	1.1.3 API		30.0	30.0	dimensionless
36	1.1.4 Specific gravity		0.9	0.9	dimensionless
37	1.1.5 Sulfur		2.6	2.0	wt%
38	1.1.6 Production volume		1000	545	bbl/d
40	1.2 Associated gas				
41	1.2.1 Gas composition				
43		N_2	0.0	0.0	mol%
44		CO_2	3.5	3.5	mol%
45		C_1	77.0	77.0	mol%
46		C_2	14.0	14.0	mol%
47		C_3	3.0	3.0	mol%
48		C_4	1.5	1.5	mol%
49		H_2S	1.0	1.0	mol%
50			OK		
53	1.2.2 Gas gravity		0.71	0.71	dimensionless
54	1.2.3 Gas-oil ratio (GOR)		500	500	scf/bbl
55	1.2.4 Fraction of remaining gas to reinjection	OK	100	50	%

Figure 2.1: Input data section of *'Production & Extraction'* sheet. User inputs are in column M, while defaults are kept as reference in column N.

where users input key parameters and display summary results. Output sheets have green-colored tabs.

'Energy Consumption' worksheet The *'Energy Consumption'* sheet gathers data on energy consumption for sub-processes from all process sheets. Each main process sheet is included in the gathering table. All energy consumed is summed by type across all stages. This gross consumption is used to compute net consumption and energy imports and exports. The *'Energy Consumption'* worksheet is described in Section 5.1

'GHG Emissions' worksheet The *'GHG Emissions'* sheet takes the energy quantities consumed in each stage and converts them to emissions using emissions factors. It also gathers any emissions associated with land use change and VFF emissions. Emissions are computed as gCO_2eq./d. The *'GHG Emissions'* worksheet is described in Section 5.2.

'User Inputs & Results' worksheet The *'User Inputs & Results'* sheet serves two functions. First, it serves as the place for primary model interaction (see below). Also, this sheet presents summary results in tabular and graphical form. The *'User Inputs & Results'* worksheet is described in Section 5.3.

2.3.1 Structure of each worksheet

Each process stage sheet is divided into two main sections: (i) input data and (ii) calculations. The input data section (see Figure 2.1) is where the user enters the input parameters (e.g., API gravity, production volume). The input section of each sheet has two data columns: *User* and *Default*, in columns M and N, respectively. The cells within the *User* column are the active cells, and are used to generate results. The cells within the *Default* column are used for reference, bookkeeping of default values, and generating defaults using correlations based on field data.

Below the input data section is the calculations section of a sheet, where

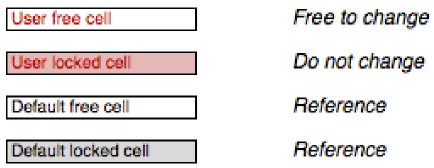


Figure 2.2: Types of cells. *User Free* and *Default Free* cells can be changed, while *Locked* cells should not be changed due to possibility of compromising model functionality.

intermediate model outputs are calculated. These intermediate outputs are summarized and compiled by the gathering sheets to provide the overall energy and emissions measures compiled in the *'User Inputs & Results'* sheet.

2.3.2 Types of model cells

Four main types of cells exist in the calculation columns M and N: *User Free*, *User Locked*, *Default Free*, *Default Locked* (See Figure 2.2). As might be expected, locked cells should not be changed.[1] This is typically because locked cells contain formulas that draw on other cells and therefore should not be changed. "User Free" cells are cells that allow entry of user data.

2.4 Working with OPGEE

This section explains how to work with OPGEE. Box 2.1 shows how to best use this documentation in concert with the OPGEE model itself.

2.4.1 Primary interaction

The first level of interaction with OPGEE (which this document calls "primary" interaction) consists of changing a small number of key parameters to determine the energy consumption and emissions from an oil production facility. These key parameters have the following characteristics:

- They have a significant effect on the GHG emissions from an oil and gas operation;
- They vary significantly across different operations and therefore could cause variability between different fields or projects;
- They are likely to be measured or are well-understood by operators.

The list of key inputs is a relatively small list of important factors. Other factors excluded from this list are left to process sheets.

[1]Note: 'locked' cells are not locked via *Excel* password-protected locking mechanism, so they can be changed if desired by the user. However, this should be done with care, as the model can easily be rendered inoperable.

Box 2.1: Using OPGEE documentation and model together

OPGEE model documentation aligns with the model itself. Pointers to the model are contained in the right-hand margin of the model documentation in red, italic text. For example, a reference to the Production & Extraction sheet calculation of water specific gravity, which is calculation number 2.1.3.3 on that sheet (see Figure 2.4, Row 54), would be referred to in the right-hand margin as *Production & Extraction 2.1.3.3*

2.4.1.1 Controls on the 'User inputs & Results' sheet

The "User Inputs" section of the *'User Inputs & Results'* sheet is where key field parameters can be easily changed (see Figure 2.3). These key parameters are explained below. *User Inputs & Results 3.1 - 3.8*

Production methods Controls to turn on or off production methods including downhole pump, water reinjection, gas reinjection, water flooding, gas lifting, gas flooding, and steam flooding. *User Inputs & Results 3.1*

- Downhole pump: This option is used when the natural energy of the reservoir is not enough to lift the fluids from the subsurface to the surface at the desired wellhead pressure.

- Water reinjection: This option is used when injecting a fraction of the produced water. This option does not apply if the amount of water injected is more than the amount of water produced after treatment.

- Gas reinjection: This option is used when injecting a percentage of the amount of gas produced. This option does not apply if the amount of gas injected is more than the amount of gas remaining after processing and VFF losses. The remaining gas is shown in the *'Gas Balance'* worksheet.

- Water flooding: This option is used when injecting an amount of water which is more than the amount of water produced. The amount of water injected is determined by the injection ratio (given in bbl water/bbl oil) and the fraction of water produced to reinjection/flooding must be set to 1.0. **The option of water reinjection must be turned OFF when the option of water flooding is turned ON.**

- Gas lifting: This option is used when gas is not injected into the reservoir, but injected into production tubular to reduce the pressure at the reservoir interface and induce production from the reservoir.

- Gas flooding: This option is used when injecting an amount of gas which is more than the amount of gas remaining. The amount of gas injected is determined by the injection ratio (given in scf/bbl oil) and the fraction of remaining gas to reinjection must be set to 1.0. This option can also be used when flooding nitrogen gas. **The option of gas reinjection must be turned OFF when the option of gas flooding is turned ON.**

Field properties Field properties, including field location, field name, field age, field depth, oil production volume, number of producing wells, well diameter, productivity index, and average reservoir pressure. *User Inputs & Results 3.2*

Fluid properties A variety of fluid properties, including API gravity of crude oil and composition of produced associated gas. *User Inputs & Results 3.3*

Production practices A variety of production practices or operating ratios. These include gas-to-oil ratio (GOR), water-to-oil ratio (WOR), water-injection ratio, gas lifting injection ratio, gas flooding injection ratio, steam-to-oil ratio (SOR), fraction of required electricity generated on site, fraction of remaining gas reinjected, fraction of water produced reinjected, and fraction of steam generation via co-generation. WOR, GOR, and SOR are common parameters and self explanatory. Other less common parameters are explained below. *User Inputs & Results 3.4*

- Water injection ratio: The ratio of the amount of water injected in water flooding to the amount of oil produced. This is required only when the option of water flooding is turned ON.
- Gas lifting injection ratio: The ratio of the amount of gas injected for lifting to the amount of liquid (water + oil) produced. The amount of gas injected for gas lifting **does not** include gas injected into the reservoir. This is required only when the option of gas lifting is turned ON.
- Gas flooding injection ratio: The ratio of the amount of gas injected in gas flooding to the amount of oil produced. This is required only when the option of gas flooding is turned ON.
- Fraction of required electricity generated onsite: This parameter determines the fraction of the electricity required that is generated onsite not including electricity co-generation with steam generation. The fraction entered can be greater than 1.0, designating electricity export into the grid.
- Fraction of remaining gas reinjected: This parameter determines the fraction of gas remaining that is reinjected into the reservoir. In the case of methane gas flooding this fraction must be equal to 1.0 (the amount of gas injected is more than the amount of gas remaining).
- Fraction of water produced reinjected: This parameter determines the fraction of water produced after treatment that is reinjected into the reservoir. In the case of water flooding this fraction must be equal to 1.0 (the amount of water injected is more than the amount of water produced).
- Fraction of steam generation via co-generation: OPGEE allows the modeling of steam generation for thermal enhanced oil recovery with or without electricity co-generation. This parameter determines the share of steam generation via co-generation of electricity.

Processing practices Binary variables which represent the use of heater/treaters and stabilizer columns, the ratio of gas flared to oil produced, and the ratio of gas vented to oil produced. Some parameters are explained below. *User Inputs & Results 3.5*

- Heater/treater: Binary variables (0 or 1) are used to determine the use of a heater/treater in the oil-water separation process. 1 is used to turn ON the heater/treater and 0 is used to turn OFF the heater/treater. More detailed choices for heater/treaters are made in the *'Surface Processing'* worksheet.

- Stabilizer column: Binary variables (0 or 1) are used to determine the use of a stabilizer column in the oil-gas separation process. 1 is used to turn ON the stabilizer column and 0 is used to turn OFF the stabilizer column. The stabilizer/column is defined in section 3.4.2.2.

- Ratio of flaring to oil production: This is the ratio of gas flared to oil produced.

- Ratio of venting to oil production: This is the ratio of gas vented (not including operational venting or default leaks) to oil produced. **This ratio only includes venting used for gas disposal, as an alternative to flaring. It does not address normal operational vents and leaks**. Other default leaks are accounted in the *'VFF'* worksheet.

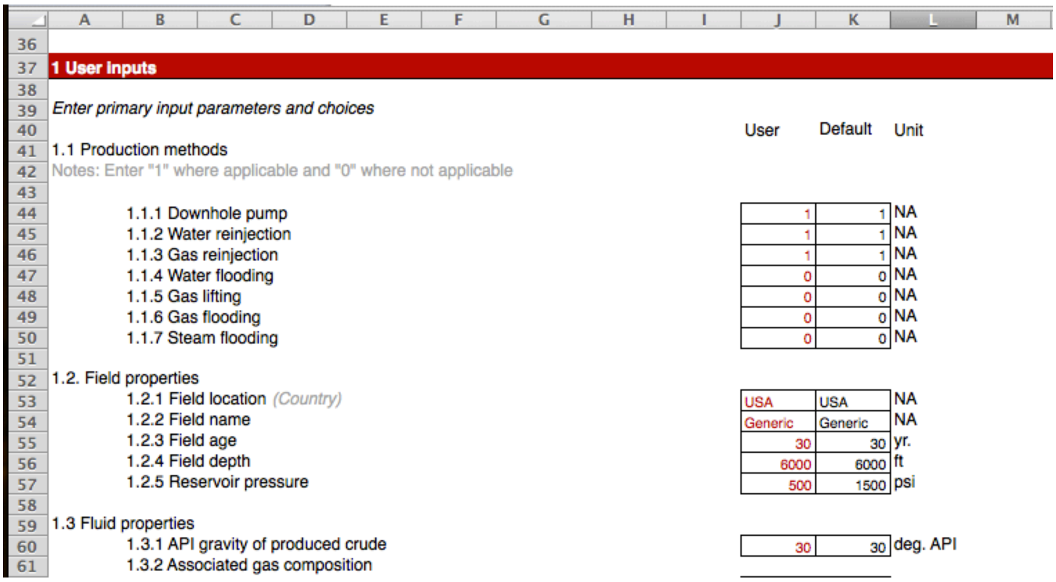
Land use impacts Parameters that determine the GHG emissions from land use change, including ecosystem carbon richness and relative disturbance intensity. *User Inputs & Results 3.6*

- Ecosystem carbon richness: Ecosystem carbon richness controls the amount of carbon emissions per unit of disturbed land, and varies from semi-arid grasslands (low potential carbon emissions) to forested (high potential carbon emissions).

- Field development intensity: The intensity of development can be chosen to be low, medium, or high. High intensity development resembles California thermal EOR operations, well production and injection wells are drilled on tight spacing. Low intensity development resembles conventional natural gas development or directional drilling from centralized drill pads, where the land disturbed per well is small.

Crude oil transport Parameters which determine transport modes and distances. This includes the fraction of crude oil transported by each mode of transport and the transport distance (one way) of each mode. The total fraction of all modes may exceed 1.0 because more than one transportation legs may be involved for transporting the crude oil from field to refinery. *User Inputs & Results 3.7*

Small emissions sources An added term to account for all emissions sources that are not explicitly included in OPGEE through calculations. Tables C.1 through C.7, as well as the *'Model Organization'* tab in OPGEE, describe which sources are explicitly included in the model. All sources that are not *User Inputs & Results 3.8*



			User	Default	Unit
36					
37	**1 User Inputs**				
38					
39	*Enter primary input parameters and choices*				
40			User	Default	Unit
41	1.1 Production methods				
42	Notes: Enter "1" where applicable and "0" where not applicable				
43					
44		1.1.1 Downhole pump	1	1	NA
45		1.1.2 Water reinjection	1	1	NA
46		1.1.3 Gas reinjection	1	1	NA
47		1.1.4 Water flooding	0	0	NA
48		1.1.5 Gas lifting	0	0	NA
49		1.1.6 Gas flooding	0	0	NA
50		1.1.7 Steam flooding	0	0	NA
51					
52	1.2. Field properties				
53		1.2.1 Field location *(Country)*	USA	USA	NA
54		1.2.2 Field name	Generic	Generic	NA
55		1.2.3 Field age	30	30	yr.
56		1.2.4 Field depth	6000	6000	ft
57		1.2.5 Reservoir pressure	500	1500	psi
58					
59	1.3 Fluid properties				
60		1.3.1 API gravity of produced crude	30	30	deg. API
61		1.3.2 Associated gas composition			

Figure 2.3: User inputs section of the *'User Inputs & Results'* sheet.

explicitly included are deemed to small to model, and are included in the small emissions sources term.

After entry into *'User Inputs & Results'*, values for key parameters are propagated to other sheets as needed for calculations. Therefore, if a key parameter (such as API gravity) is to be changed, it **must** be changed on the front *'User Inputs & Results'* sheet so that it is changed identically in all calculations.

OPGEE provides fixed defaults for required input parameters; these can be replaced with user inputs where data are available. In some cases, OPGEE calculates 'smart default' values dynamically based on user inputs for other parameters. For instance, the default flaring volume is determined from NOAA data based on the specified field location [16]. These smart defaults can also be overruled by user inputs if available.

2.4.2 Secondary interaction

If more detailed data are available for a given oil production operation, and more specific estimates are desired, secondary interaction can be pursued by changing parameters on process-stage specific sheets and supplementary sheets.

It should not be necessary to change these secondary input parameters in general use of OPGEE. This is because these secondary parameters include parameters with less effect on the resulting emissions, that are not highly variable across operations, or that are less likely to be known by model users. Examples include compressor suction pressure and temperature, type of prime mover, or pump efficiency. Note that some of these parameters (e.g., pump efficiency) have significant effects on model results, but are not believed to be highly variable across fields (except in cases of especially old or poorly maintained equipment).

All secondary input parameters are free for the user to change in the input data sections of the process stage sheets. Parameters that are classified as *User Locked* (see Figure 2.2 above) should not be changed because they are either calculated from other primary inputs or derived from the *'User Inputs & Results'* sheet.

Figure 2.4 shows the input data section of the *'Production & Extraction'* sheet. Moving left to right across the screen, features of interest include:

Parameters and sub-parameters In columns A through K, the names and descriptions of parameters and calculation results are numbered in a hierarchical fashion. Each parameter or calculation result has a unique number to allow ease of reference to the model. For example, in the Produced Water group of parameters and calculations (2.1.3), the water specific gravity is calculated using the concentration of dissolved solids (2.1.3.2).

User and default columns Columns M and N include the user and default inputs for the production calculations. Column M is always used in the final calculations. Column N is included for reference, and includes default values. Before any user input is changed, all user values are equal to default values.

Free and locked cells As shown in Figure 2.2, *User Free* and *Default Free* cells are included with light tones, while *User Locked* and *Default Locked* cells are included with dark tones. For example, in Figure 2.4 the highlighted cell M40 represents the mol% of methane (C_1) in the associated gas. Because this quantity is a key input parameter and is defined on the *'User Inputs & Results'* sheet, it is marked here as *User Locked*. Therefore, if the user wishes to change the gas composition, this should be done on the *'User Inputs & Results'* sheet where gas composition is listed as *User Free*.

Units In column O, units are listed for all input parameters, variables, and calculation results (where applicable).

User and default reference Columns Q and S are spaces to record the data sources of input parameters. Where applicable, the source of the default value is listed in the *Default reference* column. If a user changes a parameter to a non-default value, they can place any desired information about the source (such as author, page, dataset, vintage, data quality, expected uncertainty, etc.) in the *User reference* column.

Notes To the right of the default reference column is the notes column (not shown, column Y). The *Notes* column contains explanatory notes or other information that may be useful to the user.

2.4.3 Checking for errors

It is possible to mistakenly enter data that are invalid, contradictory, or otherwise result in errors. In OPGEE, errors are checked at the bottom of the *'User Inputs & Results'* sheet. Before reporting results from an OPGEE calculation, the user should check that no errors appear in the error check section. *User Inputs & Results 3.9 & 7.1*

A summary indicator for model errors is *'User Inputs & Results'* reported as the 'Overall error check.' An error found in the overall error check here *User Inputs & Results 3.9*

Box 2.2: Hints for using OPGEE without errors

1. Do not change formulas in *User locked* or *Default locked* cells, as these can result in mis-calculation;
2. Always check error reports in *'User Inputs & Results'* section 7.1 and 7.2 for errors before considering results final;
3. Use care to collect physically realistic and consistent data where default values will be overwritten (e.g., if depth of field is greatly increased, operating pressure will often increase as well);
4. To ensure reproducibility of results, document any sources for user inputs in the 'User Reference' column;
5. Save individual field assessments as separate sheets to prevent incorrect propagation of changed cells.

can be traced to a particular sheet and cell by examining the 'Specific error checks.' Specific error checks can be debugged by moving to the sheet and cell in question and tracing any logical or inputs errors that have flagged that error check. Common sources of errors include logical errors in pathway selection (e.g., more than one mutually exclusive technology selected) and input errors (e.g., gas composition sums to more than 100 mol%).

User Inputs & Results 7.1.1 - 7.1.26

Hints for using OPGEE without errors are given in Box 2.2.

2.4.4 Results

After the user enters data, OPGEE computes the resulting GHG emissions from that project. Emissions results are presented in tabular form in gCO_2 equivalent GHG emissions per MJ LHV crude oil delivered to the refinery gate.[2] Emissions are broken down by stage (generally) or by type, with fugitive emissions for all process stages summed together for convenient interpretation as 'VFF' emissions. Emissions are plotted in graphical form as well, with space for up to 5 comparative assessments. Total energy consumed per unit of energy delivered to the refinery gate is also presented in tabular and graphical form. These tabular and graphical results are illustrated in Figures 2.5 and 2.6.

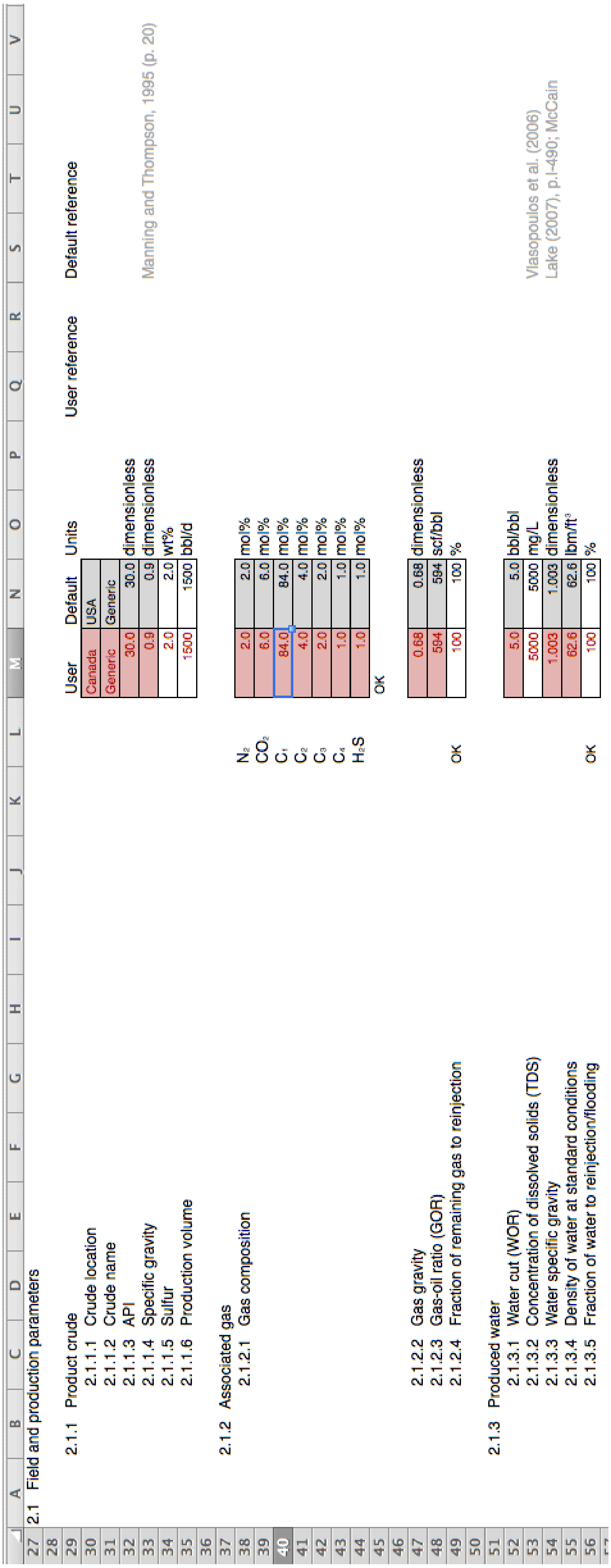
User Inputs & Results Table 1.1

User Inputs & Results Figure 1.1

User Inputs & Results Table 1.2, Figure 1.2

Results from multiple runs can be copied and pasted to the cells to the right of the current active column. This allows multiple results to be compared.

[2]The heating value basis of the denominator crude oil can be changed so that emissions are calculated per MJ HHV of refinery input. This can be changed on the *'Fuel Specs'* sheet. See discussion below in Section 6.4.



Row	Parameter		User	Default	Units	User reference	Default reference
27	2.1 Field and production parameters						
28							
29	2.1.1 Product crude		User	Default	Units	User reference	Default reference
30	2.1.1.1 Crude location		Canada	USA			
31	2.1.1.2 Crude name		Generic	Generic			
32	2.1.1.3 API		30.0	30.0	dimensionless		
33	2.1.1.4 Specific gravity		0.9	0.9	dimensionless		Manning and Thompson, 1995 (p. 20)
34	2.1.1.5 Sulfur		2.0	2.0	wt%		
35	2.1.1.6 Production volume		1500	1500	bbl/d		
36							
37	2.1.2 Associated gas						
38	2.1.2.1 Gas composition	N_2	2.0	2.0	mol%		
39		CO_2	6.0	6.0	mol%		
40		C_1	84.0	84.0	mol%		
41		C_2	4.0	4.0	mol%		
42		C_3	2.0	2.0	mol%		
43		C_4	1.0	1.0	mol%		
44		H_2S	1.0	1.0	mol%		
45			OK				
46							
47	2.1.2.2 Gas gravity		0.68	0.68	dimensionless		
48	2.1.2.3 Gas-oil ratio (GOR)		594	594	scf/bbl		
49	2.1.2.4 Fraction of remaining gas to reinjection	OK	100	100	%		
50							
51	2.1.3 Produced water						
52	2.1.3.1 Water cut (WOR)		5.0	5.0	bbl/bbl		
53	2.1.3.2 Concentration of dissolved solids (TDS)		5000	5000	mg/L		Vlasopoulos et al. (2006)
54	2.1.3.3 Water specific gravity		1.003	1.003	dimensionless		Lake (2007), p.I-490; McCain
55	2.1.3.4 Density of water at standard conditions		62.6	62.6	lbm/ft^3		
56	2.1.3.5 Fraction of water to reinjection/flooding	OK	100	100	%		

Figure 2.4: Input data section of *'Production & Extraction'* sheet.

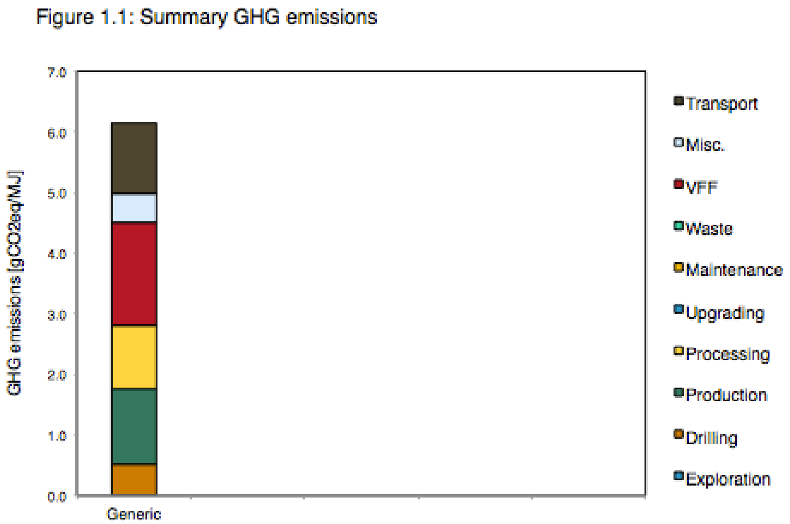


Figure 2.5: Graphical results for a 'Generic' crude oil. *'User Inputs & Results'* Figure 1.1.

Table 1.1: Summary GHG emissions

GHG emissions [gCO2eq/MJ]					
	Generic				
Exploration	0.0				
Drilling	0.5				
Production	1.3				
Processing	1.1				
Upgrading	0.0				
Maintenance	0.0				
Waste	0.0				
VFF	1.7				
Misc.	0.5				
Transport	1.2				

Notes: Copy highlighted column and paste 'as numbers' to generate a record

Figure 2.6: Tabular results for a 'Generic' crude oil. *'User Inputs & Results'* Table 1.1.

Part II

Technical documentation

3 Process stage sheets

This section explains the main assumptions and calculations for each process stage sheet. Items discussed include user assumptions and choices, process calculation assumptions, calculations of input parameters, and calculations of intermediate outputs.

3.1 Exploration emissions

3.1.1 Introduction to petroleum exploration

Emissions from petroleum exploration occur during clearing of land for seismic surveys, operation of seismic survey equipment, drilling of exploratory wells, and from fugitive emissions during drilling operations. Emissions also occur offsite due to other ancillary services consumed during drilling (e.g., computing energy consumed during seismic data processing). A complete list of emissions sources, along with their categorization and estimated magnitude, is shown in Table C.1.

3.1.2 Calculations for petroleum exploration

Because petroleum exploration emissions only occur at the outset of production, they are likely to be very small when amortized over the producing life of an oil field. For this reason, emissions from exploration are considered below the significance cutoff in the OPGEE v1.0.

3.1.3 Defaults for petroleum exploration

Because exploration activities are believed to be below the significance cutoff, modeled exploration emissions default to 0 gCO_2/MJ. Therefore, any exploration emissions are assumed to be part of the small emissions sources term.

User Inputs & Results 3.6

3.2 Drilling & development

3.2.1 Introduction to drilling & development

Drilling and development operations result in a variety of emissions. Well drilling and installation of production equipment results in on-site energy use (e.g., for rigs and other construction equipment) as well as indirect offsite energy use (e.g., embodied energy consumed to manufacture well casing). Drilling and development also results in land use impacts, which can release biogenic carbon from disturbed ecosystems [77]. In addition, fugitive emissions can occur during the drilling process. A list of emissions sources, along with their categorization and estimated magnitude, is shown in Table C.2.

3.2.2 Calculations for drilling & development

Two aspects of field drilling and development are modeled in OPGEE v1.0: drilling energy consumption and land use impacts. Any other emissions from drilling and development are not explicitly modeled and therefore would be accounted for in the small sources term. The parameters and variables used in the drilling and development model equations are listed in Table 3.1.

User Inputs & Results 3.6

3.2.2.1 Emissions from drilling

Drilling oil wells consumes fuel. This fuel is consumed on site in prime movers (generally diesel engines) for a variety of purposes: to power mud pumps; apply torque to drill string; pull drill string; raise, lower and retrieve subsurface monitoring equipment; and pump cement. The amount of fuel consumed per unit of depth drilled increases as a well gets deeper, due to slower drilling progress with depth.

Relationships for these functions are from Brandt [78]. Data from Canadian drilling operations are collected for the years 2000, 2001, 2002, and 2005 [79–81]. True drilling depth (not vertical depth) is related to amount of fuel consumed per well. An exponential relationship is found between drilling depth and fuel use (see Figure 3.1). High and low energy consumption curves are fit to these data:

Drilling & Development 1.2.2

$$e_{DR} = a_{DR} \exp\left(b_{DR} h_W\right) \qquad \text{[mmBtu/1000 ft]} \tag{3.1}$$

where e_{DR} = depth-specific drill rig energy intensity [mmBtu/1000 ft]; a_{DR} = drill rig energy intensity scaling constant [mmBtu/1000 ft]; b_{DR} =drill rig energy intensity growth constant [1/1000 ft]; and h_W = true well depth (not vertical depth) [1000 ft]. When fitting this equation to high and low-intensity drilling data, fits are of moderate predictive ability (R^2 = 0.708 for low intensity, 0.589 for high intensity).

Drilling energy consumption must be amortized over the producing life of a well. Also, drilling and development energy must account for drilling of water injection wells. The lifetime productivity of wells varies by orders of magnitude, depending on the quality of the oil reservoir and its size.

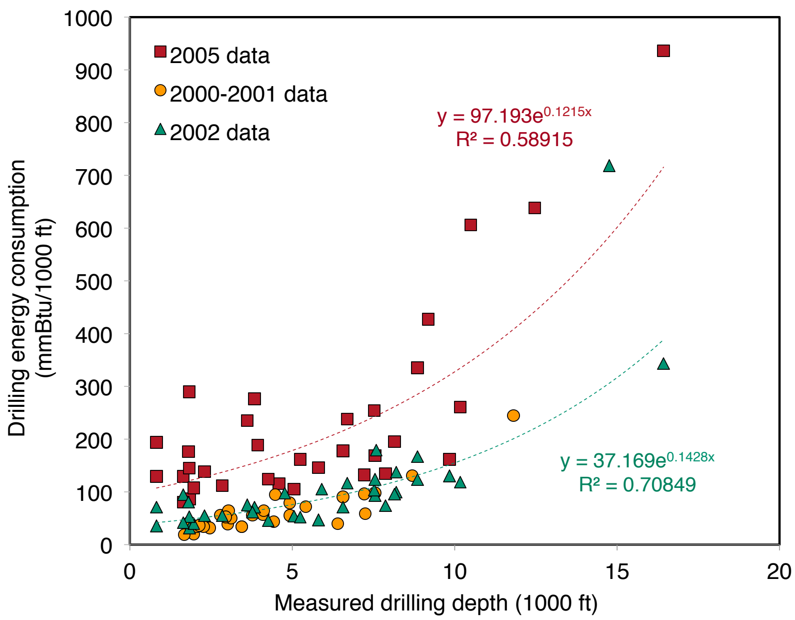


Figure 3.1: Drilling energy intensity as a function of well depth as measured for Canadian drilling operations.

In order to obtain a central estimate for the productivity of a well, we use historical data from California.

California reports the number of producing and shut-in wells, with ≈ 100,000 wells counted in recent years [77]. However, these datasets do not include:

- Wells that are fully abandoned and therefore not classed as "shut-in",
- Wells that were drilled and plugged in abandoned fields,
- Wells that were drilled before 1915, when reporting began.

To address these shortcomings, wells drilled on a yearly basis were compiled from the California Department of Oil, Gas, and Geothermal Resources (DOGGR) annual reports [82]. Production and injection wells drilled per year are compiled from 1919-2005, while exploration wells drilled per year are compiled from 1926 to 2005 (exploratory wells were not reported before 1926). Total exploratory and production/injection drilling activity over these years was equal to 188,508 wells. Due to missing wells (early exploratory wells, all wells prior to 1919, other missing wells) we assume total wells drilled = 200,000. Cumulative production in the entire state of California was ≈ 25.99 Gbbl at the end of 2005. Therefore, average oil produced per well drilled was ≈ 130,000 bbl/well. *Drilling & Development 1.3.1*

The energy intensity of drilling per unit of energy produced is therefore calculated as follows: *Drilling & Development 1.4*

$$ei_{DR} = \frac{e_{DR} h_W}{Q_{o,tot} LHV_o} \qquad \text{[mmBtu/mmBtu]} \qquad (3.2)$$

where ei_{DR} = energy intensity of drilling [mmBtu/1000 ft]; h_W = average well depth [1000 ft]; $Q_{o,tot}$ = total lifetime productivity per well drilled [bbl oil/well]; and LHV_o = lower heating value of the crude produced [mmBtu LHV/bbl].

The energy intensity of drilling tends to be small when amortized over total well productivity, with default values on order 10^{-4} to 10^{-3} mmBtu/mmBtu.

3.2.2.2 *Emissions from land use impacts*

Land use impacts during drilling and field development are included in OPGEE for three categories: soil carbon that is oxidized upon disturbance of land, biomass carbon that is oxidized biomass disturbance, and emissions from foregone sequestration, due to the fact that biomass carbon sequestration is slowed on cleared land. For each of these impacts, emissions estimates from Yeh et al. [77] are included.

Drilling & Development 2.1 - 2.4

In order to estimate land use GHG emissions, three settings are required. First, the crude production method must be chosen. The options for crude production method include conventional production via wellbore (primary, secondary, and tertiary recovery of conventional and heavy hydrocarbons, including in situ recovery of bitumen) and mining-based production of bitumen.

Drilling & Development 2.1.3

Next, the carbon richness of the ecosystem must be specified. The options include low, moderate, and high carbon richness. The low carbon richness estimates are derived from California production in the semi-arid to arid central valley of California [77]. The high carbon richness estimates are derived from forested regions in Alberta (e.g., rocky mountain foothills) [77]. Moderate carbon richness is considered a mixed ecosystem with carbon richness between these two types of ecosystems.

Drilling & Development 2.1.4

Lastly, the intensity of field development must be specified. High intensity field development corresponds to high fractional disturbance, such as in a field drilled on tight spacing. Low intensity field development corresponds to a sparsely developed field with little fractional disturbance. Moderate field development occurs between these two extremes. Work by Yeh et al. [77] can be consulted for satellite images of low and high field development intensity.

Drilling & Development 2.1.5

The emissions associated with each choice are shown in Table 3.2 in units of gCO_2eq GHGs per MJ of crude oil produced. Land use emissions from oil sands operations are tracked separately on the *'Bitumen Extraction & Upgrading'* sheet (see Section 3.8).

Emissions Factors Table 1.4

3.2.3 Defaults for drilling & development

Default values for drilling & development calculations are shown in Tables 3.1 and 3.2.

Table 3.2: Default land use GHG emissions from field drilling and development in OPGEE for conventional oil operations [g CO_2 eq./MJ of crude oil produced]. Data from Yeh et al. (2010).

	Low carbon stock (semi-arid grasslands)			Moderate carbon stock (mixed)			High carbon stock (forested)		
	Low int.	Med. int.	High int.	Low int.	Med. int.	High int.	Low int.	Med. int.	High int.
Soil carbon	0.03	0.13	0.35	0.10	0.35	1.50	0.16	0.57	2.65
Biomass	0.00	0.00	0.00	0.01	0.09	0.33	0.02	0.17	0.65
Foregone seq.	0.00	0.00	0.00	0.02	0.03	0.05	0.03	0.05	0.09

Table 3.1: Default inputs for drilling calculations.

Param.	Description	Eq. no.	Default	Literature range	Unit	Sources	Notes
a_{DR}	Drill rig energy consumption constant	-	37.169	37.169 - 97.193	[mmBtu/1000 ft]	[78]	a
b_{DR}	Drill rig energy consumption increase rate	-	0.1428	0.1215 - 0.1428	[1/1000 ft]	[78]	b
h_W	Well depth (true drilling depth)	-	$=h$	0.5 - 25	[1000 ft]	-	c
Q_{ot}	Total cumulative production per well over life of well	-	130,000	Unknown	[bbl/well]	[82, 83]	d
LHV	Lower heating value of crude oil	-	5.51	5.15 - 6.18	[mmBtu/bbl]	[84]	e

[a] Low and high drilling efficiency constants found from fitting data. Default set to low intensity.
[b] Exponential increase with drilling depth. Low intensity drilling actually has slightly higher growth rate.
[c] Default well depth chosen to be depth of field h. Range of field depths is large in practice.
[d] Cumulative production per well in California equals 130,000 bbl/well to the end of 2005.
[e] Higher heating value of crude depends on density and composition.

3.3 Production & extraction

3.3.1 Introduction to production & extraction

The production and extraction process transports reservoir fluids from the subsurface reservoir to the surface. Emissions from crude oil production and extraction mainly occur from fuel combustion for lifting and injection drivers, with other smaller sources such as fugitive emissions from wellbores.

The reservoir is the source of fluids for the production system. It can also furnish energy for production. In many cases, the reservoir is unable to furnish sufficient energy to produce fluids to the surface at economic rates throughout the life of the reservoir. When this occurs, artificial lift equipment is used to enhance production rates by adding energy to the fluids. Energy can be supplied to the fluids through a subsurface pump (e.g., downhole pump). Or, producers can reduce the back pressure on the reservoir with surface compression equipment that allows lower wellhead pressure. Also, producers can inject gas into the production string to reduce the flowing gradient of the fluid (i.e., gas lift) [44, p. 1].

In addition to artificial lifting, water can be injected into the reservoir to support reservoir pressure and increase oil recovery. Recovery is increased by maintaining reservoir pressure and by physically displacing oil with water from near injection wellbores to production wellbores [59, p. 1]. Tertiary recovery technologies (also known as enhanced oil recovery [EOR]) include gas flooding and steam injection.

Most common artificial lifting and improved oil recovery techniques are included in OPGEE. These include: downhole pump, gas lift, water flooding, gas flooding, and steam injection. In the *'User Inputs & Results'* sheet the user is prompted to choose a combination of techniques applicable to the modeled operation. Some techniques are not built in the current version of OPGEE, including CO_2 flooding and hydraulic fracturing (also known as "fracking"). These modules will be added in the future.

A complete list of emissions sources from production, along with their estimated magnitude, is shown in Table C.3. A list of all of the equation parameters and their default values (if applicable) and sources is included in Table 3.4.

3.3.2 Calculations for production and extraction

Energy for lifting is required to overcome the pressure traverse, i.e., the pressure drop between the subsurface reservoir and the surface wellhead. The pressure traverse arises due to two factors: (i) flow against gravity, and (ii) frictional losses. The pressure required for lifting is calculated by adding the wellhead pressure to the pressure traverse and subtracting the wellbore pressure. The artificial lifting methods that can be chosen in OPGEE are: (i) downhole pump, and (ii) gas lift. The pressure required for lifting is equal to the discharge pressure of the downhole pump. The power required to generate the required discharge pressure depends on the discharge flow rate and pump efficiency. Finally the energy required to drive the pump is calculated based on the power requirement (expressed as brake horsepower).

The calculation of the energy required in water injection- and gas injection-based enhanced oil recovery uses the user inputs for injection volume and discharge pressure. Smart defaults are in place to help assign the discharge pressure taking into account the well depth and frictional losses.

The energy required for steam flooding requires rigorous modeling of steam generation. An additional complexity is caused by the modeling of electricity co-generation. This is explained in Section 4.2.

In the case of gas lift, if the user enters the volume of gas injected and the discharge pressure, OPGEE will compute the compression energy. However, OPGEE is not sensitive to changes in the gas lift, i.e. the dynamics between the volume of gas lift and the lifting head are not considered. The calculation of these dynamics is beyond the scope of a linear GHG estimator. This requires a two phase flow model, which is not included in OPGEE v1.0.

Default values for production and extraction calculations are shown in Table 3.4.

3.3.2.1 Oil specific gravity

The specific gravity of crude oil is usually reported as API gravity, measured at 60 °F. The API gravity is related to the specific gravity γ_o by:

Production & Extraction 2.1.1.4

$$^{\circ}\mathrm{API} = \frac{141.5}{\gamma_o} - 131.5 \qquad [-] \tag{3.3}$$

where API gravity and γ_o are dimensionless measures. The specific gravity is the ratio of the density of the liquid to the density of water at 60 °F [73, p. 478].

3.3.2.2 Gas specific gravity

The specific gravity of associated gas is calculated using air density at standard conditions with [85, p. 10]:

Production & Extraction 2.1.2.2

$$\gamma_g = \frac{\rho_{gsc}}{\rho_{asc}} \qquad [-] \tag{3.4}$$

where ρ_{gsc} = gas density at standard conditions [lbm/ft^3]; and ρ_{asc} = air density at standard conditions [lbm/ft^3]. Standard conditions refers to the temperature and pressure required to specify 1.0 scf (60 °F and 14.7 psia) [2, p. 35]. Accordingly, the gas density at standard conditions is calculated using:

$$\rho_{gsc} = \frac{p_b \mathrm{MW}_g}{\mathrm{R}T_b} \qquad \left[\frac{\mathrm{lbm}}{\mathrm{ft}^3}\right] \tag{3.5}$$

where MW_g = molecular weight of the associated gas mixture [lbm/lbmol]; p_b = base pressure [psia]; and T_b = base temperature [°R]; R = gas constant [ft^3-psia/lbmol-°R]. The molecular weight is calculated from the molecular weights and molar fractions of the gas constituents.

3.3.2.3 Water specific gravity

The specific gravity of produced water at standard conditions can be estimated with [45, p. I-481]:

Production & Extraction 2.1.3.3

$$\gamma_w = 1 + C_{sd} 0.695 \times 10^{-6} \qquad \text{[-]} \tag{3.6}$$

where C_{sd} = concentration of dissolved solids (also known as TDS) [mg/L]. The constant 0.695×10^{-6} has units of [L/mg].

3.3.2.4 Gas compression ratio

The total gas compression ratio is calculated using:

$$R_C = \frac{p_d}{p_s} \qquad \text{[-]} \tag{3.7}$$

where P_d = discharge pressure [psia]; and P_s = suction pressure [psia].

If ratio R_C is more than 5 to 1, two or more compressor stages will be required [73, p. 295]. The compression of gas generates significant amount of heat, but compressors can only handle a limited temperature change. Multiple stage compressors allow cooling between stages making compression less adiabatic and more isothermal. The same compression ratio is ideally used for each stage. Each stage has the same ratio if the compression ratio per stage is the N^{th} root of the total compression ratio, when N = number of stages:

Production & Extraction 2.4.1.3

$$\text{If } \frac{p_d}{p_s} < 5, \text{ then } R_C = \frac{p_d}{p_s}, \text{ otherwise if } \left(\frac{p_d}{p_s}\right)^{\frac{1}{2}} < 5, \text{ then } R_C = \left(\frac{p_d}{p_s}\right)^{\frac{1}{2}}, \ldots \tag{3.8}$$

where p_d = discharge pressure [psia]; and p_s = suction pressure [psia].

The number of stages is determined from the calculation of the compression ratio, as shown in eq. (3.8). OPGEE allows a maximum of 3 stages of compression.

3.3.2.5 Gas compressor suction temperature

When multiple stage compressors are used the gas must be cooled between stages to reduce the adiabatic work of compression. The discharge temperature of the compressor is calculated as [57, p. 105]:

$$\frac{T_d}{T_s} = \left(\frac{p_d}{p_s}\right)^{\left[\frac{(C_{p/v}-1)}{C_{p/v}}\right]} \qquad \text{[-]} \tag{3.9}$$

where T_d = discharge temperature [°R]; T_s = suction temperature [°R]; and $C_{p/v}$ = ratio of specific heats at suction conditions. Ideal gas behavior (i.e., gas compressibility factor (Z)= 1) is assumed.

The suction temperature of the subsequent compressor is estimated assuming 80% interstage cooling (imperfect cooling) so that:

Production & Extraction 2.4.1.6

$$T_{s2} = \lambda_{\Delta T} (T_d - T_s) + T_s \qquad [°R] \tag{3.10}$$

where T_{s2} = suction temperature of stage 2 compressor [°R]; and $\lambda_{\Delta T}$ = fraction of temperature increase remaining after cooling, 0.2 [fraction]. The default of ≈80% interstage cooling is taken from an example of imperfect cooling in [86, Table 7].

3.3.2.6 *Well pressure traverse*

The pressure traverse is the total pressure required to lift the crude oil mixture against gravity and overcome friction and kinetic losses. This is equal to the pressure drop along the well tubing from the wellbore to the wellhead which has two main components: (i) the elevation component, which is the pressure drop due to gravity; and (ii) the friction component, which is the pressure drop due to liquid contact with the inner walls of the well tubing.

The first step in the estimation of the pressure traverse is the calculation of the total head as:

Production & Extraction 3.1.1

$$h_{tot} = h_{el} + h_f \qquad [\text{ft}] \tag{3.11}$$

where h_{tot} = total head [ft]; h_{el} = well depth [ft]; and h_f = friction head [ft]. The friction head is calculated using the Darcy formula [73, p. 447]:

Production & Extraction 3.1.1.2

$$h_f = \frac{f h_{el} v_{l,W}^2}{2 D_P g_c} \qquad [\text{ft}] \tag{3.12}$$

where f = Moody friction factor [-]; h_{el} = well depth [ft]; $v_{l,W}$ = pipeline flow velocity [ft/s]; D_P = pipeline diameter [ft]; and g_c = gravitational constant, 32.2 [lbm-ft/lbf-s^2].

A Moody friction factor chart is shown in Figure 3.2 [1]. In laminar flow f varies with Reynold's Number (NRe). In turbulent flow f varies with NRe and the roughness of the pipeline [73, p. 481]. Table 3.3 shows the NRe ranges of different flow patterns.

The Moody friction factor is estimated using simplifications for the default case as follows. Water and oil are assigned viscosities of 1 and 10 cP, respectively. The viscosity of the oil-water mixture is assigned the volume-weighted viscosity of the two fluids.[1]

Reynolds number Nre is calculated as follows [87, p. 46]:

$$\text{Nre} = \frac{1.48 Q_l \rho_l}{D_P \mu_l} \tag{3.13}$$

where Q_l is the total liquid production rate [bbl/d]; ρ_l is the liquid density (oil-water mixture) [lbm/ft^3]; D_P is the wellbore production diameter [in], and μ_l is the fluid viscosity [cP]. Roughness of commercial steel of

[1] This simplification does not account for the complexity of oil-water mixture viscosity, but is used as a first-order approximation. Heavy oil can have very high viscosities as well.

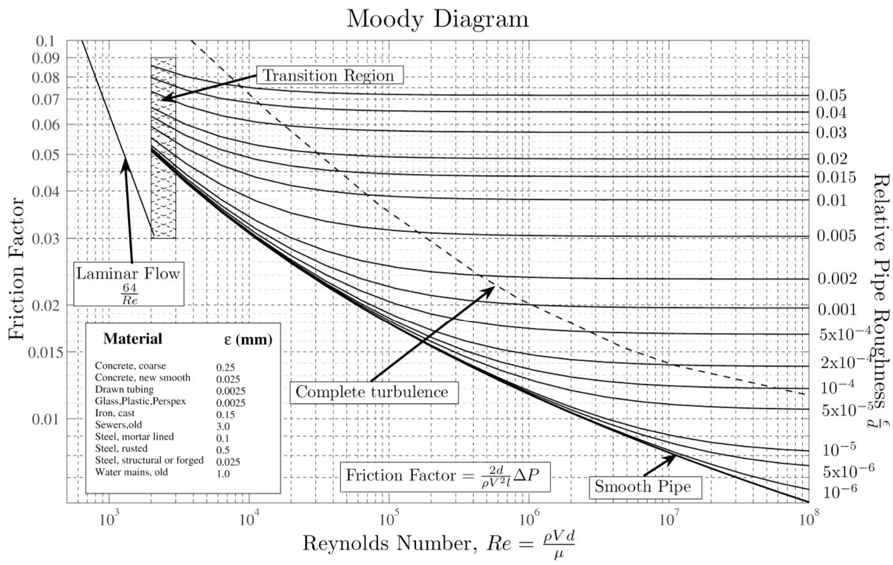


Figure 3.2: Moody friction factor chart [1].

Table 3.3: Reynold's Number ranges of different flow patterns. Data from McAllister (2009).

Flow pattern	NRe [-]
Laminar flow	NRe<2000
Transition flow	2000≤NRe≤4000
Turbulent flow	NRe> 4000

0.0018 in is assumed [88], for a relative roughness r of 0.0006. The approximate friction factor can be calculated as [88, p. 625]:

$$f = \left(\frac{-1}{1.8 \log \left(\left[\frac{6.9}{\text{Nre}} \right] + \left[\frac{r}{3.7} \right]^{1.11} \right)} \right)^2 \tag{3.14}$$

This equation gives a friction factor f of 0.02 for default conditions. The friction factor is a user input on the *'Production & Extraction'* worksheet and can be adjusted based on the flowing fluids velocity.

The pipeline flow velocity is calculated as:

$$v_{l,W} = \frac{Q_{l,W}}{A_P} \quad [\text{ft/s}] \tag{3.15}$$

where $Q_{l,W}$ = wellbore flow rate or liquid production per well [ft^3/s]; and A_P = the cross sectional area of the pipe [ft^2]. The wellbore flow rate is calculated as:

Production & Extraction 3.1.1.2

$$Q_{l,W} = \frac{Q_l}{N_W} \quad [\text{ft}^3/\text{s}] \tag{3.16}$$

where Q_l = total rate of liquid production [ft^3/s]; and N_W = number of producing wells. The total rate of liquid production is calculated as:

$$Q_l = Q_o(1 + \text{WOR}) \qquad [\text{ft}^3/\text{s}] \tag{3.17}$$

where Q_o = total rate of oil production [bbl/d]; WOR= water-to-oil ratio [bbl/bbl]. The total rate of liquid production is converted from [bbl/d] to [ft^3/s].

A column of fresh water at 60 °F exerts a gradient of ≈0.43 psi/ft [59, p. 25]. For brackish water, or to account for temperature, this gradient is multiplied by the specific gravity of the mixture at a given temperature. Accordingly the pressure traverse is estimated using the total head as [73, Table 1, p. 455]:

Production & Extraction 3.1.1.1

$$p_{trav,tot} = 0.43 h_{tot} \gamma_l \qquad [\text{psi}] \tag{3.18}$$

where $p_{trav,tot}$ = total pressure traverse [psi]; 0.43 = fresh water gradient at 60 °F [psi/ft]; $h_{tav,tot}$ = total head [ft]; and γ_l = the specific gravity of the crude oil mixture [-], calculated as:

$$\gamma_l = \gamma_o \lambda_o + \gamma_w \lambda_w \qquad [\text{-}] \tag{3.19}$$

where γ_o = the specific gravity of oil [-]; γ_w = the specific gravity of water [-]; λ_o = fraction of oil [fraction]; and λ_w = fraction of water [fraction]. The fraction of oil is calculated as:

$$\lambda_o = \frac{Q_o}{Q_o(1 + \text{WOR})} \qquad [\text{-}] \tag{3.20}$$

The elevation component of the pressure traverse is estimated using a linear one phase flow model where the gas-to-liquid ratio is equal to zero (GLR= 0) and the temperature and pressure effects are ignored. Figure 3.3 shows an example of a linear pressure-traverse curve for a particular production rate and fluid properties. The slope of the curve is the relative density of the flowing oil-water mixture. For GLR>0 the relationship becomes non-linear and the pressure traverse becomes less sensitive to changes in the well depth with increasing GLR [44, Fig 1.12]. However, the generation of a non-linear relationship requires the application of the multi-phase flow correlations which requires an iterative, trial-and-error solution to account for the changes in flow parameters as a function of pressure. Due to the complexity of this approach, this is not implemented in the OPGEE v1.0.

3.3.2.7 *Pressure for lifting*

The second step after estimating pressure traverse is the calculation of the pressure for lifting which is the pressure required by artificial means (e.g., pump) to lift the oil-water mixture to the surface at the desired wellhead pressure. The pressure for lifting is calculated as:

Production & Extraction 3.1.2

$$p_{lift} = (p_{trav,tot} + p_{wh}) - p_{wf} \qquad [\text{psi}] \tag{3.21}$$

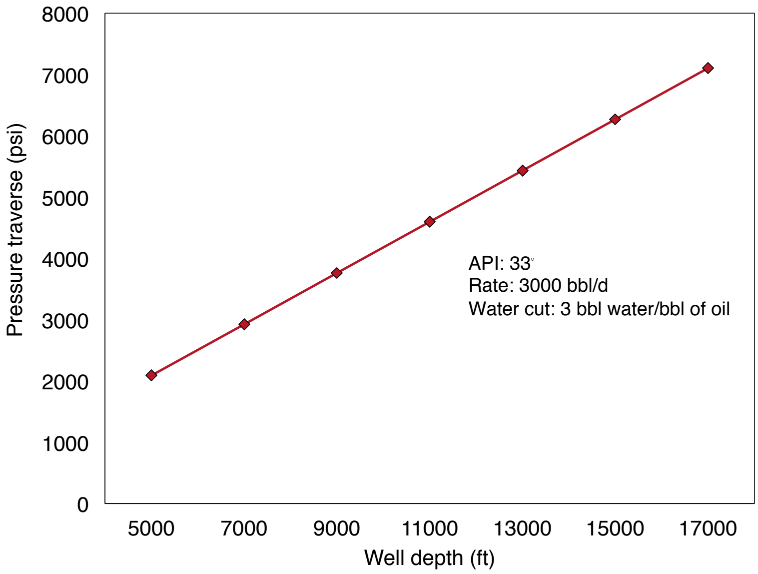


Figure 3.3: An example of a linear pressure traverse curve (GLR= 0).

where p_{lift} = pressure for lifting [psi]; $p_{tav,tot}$ = total pressure traverse [psi]; p_{wh} = wellhead pressure [psi]; and p_{wf} = bottomhole pressure [psi]. The wellbore pressure is calculated from the average reservoir pressure by subtracting the pressure drawdown. The pressure drawdown is the difference between the reservior pressure and the bottomhole pressure. This pressure drawdown causes the flow of reservoir fluids into the well and has the greatest impact on the production rate of a given well [85, p. 23].

$$\mathrm{PI} = \frac{Q_{l_W}}{(p_{res} - p_{wf})} \qquad \left[\frac{\text{bbl liquid}}{\text{psi-d}}\right] \tag{3.22}$$

where PI = well productivity index [bbl liquid/psi-d]; Q_{l_W} = liquid production per well [bbl liquid/d]; p_{res} = average reservior pressure [psi]; and p_{wf} = wellbore pressure [psi]. The increase in production requires an increase in pressure drawdown at a constant productivity index. In OPGEE a default productivity index of 3.0 [bbl liquid/psi-d] is assumed to calculate the pressure drawdown. The user has to control the inputs to satisfy the condition of $p_{wf} \geq 0$.

The pressure for lifting can either be applied by a downhole pump or by gas injection into the production string. The latter technique is known as gas lift. In some wells both a downhole pump and gas lift is used where the injected gas reduces the flowing gradient of the fluid.

3.3.2.8 Pump brake horsepower

The input horsepower to a pump is stated in terms of brake horsepower (BHP). The input is greater than the output because of pump efficiency. The brake horsepower is calculated using the pump discharge flow rate and the pumping pressure as [59, p. 27]:

Production & Extraction 3.1.3

$$\text{BHP}_P = \frac{1.701 \times 10^{-5} Q_d \Delta p}{\eta_P} \qquad \text{[hp]}$$

This is broken down to:

$$\text{BHP}_P\,[\text{hp}] = \frac{\frac{1[\text{hp}]}{1714[\text{gpm-psi}]} \frac{42\left[\frac{\text{gal}}{\text{bbl}}\right]}{24\left[\frac{\text{hr}}{\text{d}}\right]60\left[\frac{\text{min}}{\text{hr}}\right]} Q_d \left[\frac{\text{bbl}}{\text{d}}\right] \Delta p[\text{psi}]}{\eta_P} \tag{3.23}$$

where BHP_P = brake horsepower [hp]; Q_d = pump discharge rate [bbl/d]; Δp = pumping pressure [psi]; and η_P = pump efficiency [%]. The term 1714 is a dimensionless factor that converts between [hp] and [gpm-psi]. The pumping pressure is the difference between pump discharge and suction pressures. The default suction pressure is 0 [psi]. In the case of a downhole pump the pumping pressure is equal to the pressure for lifting as calculated in eq. (3.21).

3.3.2.9 *Compressor brake horsepower*

In determining compressor horsepower, the conventional compressor equation apply. For multi-stage compressors, horsepower calculations are made for each stage and summed to determine the required driver size. For assumed reciprocating compressors, the ideal isentropic horsepower is calculated using [57, p. 105]: *Production & Extraction 3.3.1-3.3.3*

$$-W_N = \left\{\frac{C_{p/v}}{(C_{p/v}-1)}\right\}\left(3.027 \cdot \frac{14.7}{520}\right) T_s \left\{\left(\frac{p_d}{p_s}\right)^{\frac{(C_{p/v}-1)}{C_{p/v}}} - 1\right\} \qquad \left[\frac{\text{hp-d}}{\text{MMscf}}\right] \tag{3.24}$$

where W_N = adiabatic work of compression of N^{th} stage [hp-d/MMscf] (-W denotes work output); $C_{p/v}$ = ratio of specific heats [-]; T_s = suction temperature [°R]; p_s = suction pressure [psia]; and p_d = discharge pressure [psia]. The constant 3.027 has a unit of [hp-d/MMscf-psia]. The base temperature and pressure is 14.7 [psia] and 520 [°R], respectively. Ideal gas behavior is assumed (i.e., Z = 1).

The total work of compression of the multiple stage compressor is multiplied by the compressor discharge rate and divided by the compressor efficiency to calculate the brake horsepower requirement as: *Production & Extraction 3.3.6*

$$\text{BHP}_C = \sum_{N=1}^{3} \frac{W_N Q_d}{\eta_C} \qquad \text{[hp]} \tag{3.25}$$

where Q_d = compressor discharge rate [MMscf/d]; and η_C = compressor efficiency [fraction].

3.3.2.10 *Driver fuel consumption*

The total brake horsepower requirement (BHP) is used to determine the driver size. A database of drivers of different types and sizes (natural gas engine, diesel engine, electric motor, etc.) is built in the *'Drivers'* supplementary sheet using technical sheets of engine and motor manufacturers such as Caterpillar and General Electric [89, 90]. Natural gas fueled drivers, for example, range from 95 hp engine to 20,500 hp turbine. The appropriate driver is retrieved from a database based on the chosen driver type and the required driver size. Finally the fuel consumption of the component (pump, compressor, etc.) is calculated as:

Production & Extraction 3.3.7

$$E_j = \mathrm{BHP}_j \cdot E_D \cdot \frac{24}{10^6} \qquad \left[\frac{\mathrm{MMBtu}}{\mathrm{d}}\right] \tag{3.26}$$

where E_j = component fuel consumption [MMBtu/d]; and E_D = driver fuel consumption [Btu/hp-hr]. The type of fuel consumed (i.e. natural gas, diesel, etc.) is determined by the chosen type of driver.

The driver fuel consumption is required for the calculation of energy consumption of various production components. This includes sucker-rod pumps, electric submersible pumps, water injection pumps, and gas compressors.

3.3.3 Production and extraction defaults

Default values for production and extraction equations are shown in Table 3.4. The data basis for smart defaults for production and extraction modeling are described below.

Table 3.4: Default inputs for production and extraction.

Param.	Description	Eq. no.	Default	Literature range	Unit	Sources	Notes
°API	API gravity	(3.3)	-	-	[-]	[50, p. 47]	
A_P	Pipeline cross sectional area	-	$\pi\left(\frac{D_P}{2}\right)^2$	-	[ft^2]		
BHP$_P$	Pump brakehorse power	(3.23)	-	-	[hp]	[59, p. 27]	
BHP$_C$	Compressor brakehorse power	(3.25)	-	-	[hp]		
BHP$_j$	Component j brakehorse power	-	-	-	[hp]		
C_{sd}	Concentration of dissolved solids	-	5000	-	[mg/L]	[91]	
$C_{p/v}$	Ratio of specific heats	-	1.28	1.16-1.40	[-]	[73, p. 320]	a
D_P	Well diameter	-	2.78	1.04-4.50	[in]	[44, p. 121]	
η_P	Pump efficiency	-	65%	70%	[-]	[59, p. 27]	b
η_C	Compressor efficiency	-	70%	75-85%	[-]	[57, p. 105]	c
E_j	Fuel consumption of component j	(3.26)	-	-	[MMBtu/d]		
E_D	Driver fuel consumption	-	var.	Section 4.4	[Btu/hp-hr]		
f	Friction factor	(3.14)	0.02	$\leq$0.1	[-]		d
γ_o	Oil specific gravity	-	0.84	0.8-1.05	[-]	[84]	e
γ_g	Gas specific gravity	(3.4)	-	-	[-]	[85, p. 10]	
γ_w	Water specific gravity	(3.6)	-	-	[-]	[45, p. I-481]	
γ_l	Liquid mixture specific gravity	(3.19)	-	-	[-]	[85]	
g_c	Gravitational constant	-	32.2	-	[lbm-ft/lbf-s^2]		
h	Well depth	-	7240	-	[ft]	Figure 3.6	
h_{tot}	Total head	(3.11)	-	-	[ft]		
h_{el}	Elevation head	-	h	-	[ft]		
h_f	Frictional head	(3.12)	-	-	[ft]	[73, p. 447]	
λ_o	Volume fraction of oil	(3.20)	-	-	[-]		

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Param.	Description	Eq. no.	Default	Literature range	Unit	Sources	Notes
λ_w	Volume fraction of water	-	$1 - \lambda_o$	-	[-]		
MW_g	Gas molecular weight	-	var.	-	[lbm/lbmol]	[2, p. 35]	f
μ_l	Fluid viscosity	-	var.	-	[cP]		
Nre	Reynolds number	(3.13)	-	-	[unitless]	[87]	
N_W	Number of producing wells	-	$\frac{Q_o[\text{bbl/d}]}{183[\text{bbl/well-d}]}$	-	[-]	Section 3.3.3.3	
p_b	Base pressure	-	14.7	-	[psi]	[2, p. 35]	
p_d	Flow discharge pressure	-	var.	-	[psi] or [psia]		
p_s	Compressor suction pressure	-	125	-	[psia]		
$p_{trav,tot}$	Total pressure traverse	(3.18)	-	-	[psi]	[73, p. 455]	g
p_{lift}	Pressure for lifting	(3.21)	-	-	[psi]		
p_{wh}	Wellhead pressure	-	1000	-	[psi]	[2, p. 80]	
p_{res}	Reservoir pressure	-	$0.5\left(\frac{h[\text{ft}]}{2.31[\text{ft/psi}]}\right)$	-	[psi]		
p_{wf}	Bottomhole pressure	-	-	-	[psi]		
PI	Well performance index	(3.22)	3	-	[bbl liquid/psi-d]		
$Q_{l,W}$	Wellbore flow rate	(3.16)	-	-	[ft^3/s]		
Q_d	Discharge flow rate	-	var.	-	[bbl/d] or [MMscf/d]		
Q_l	Total rate of liquid production	(3.17)	-	-	[ft^3/s]		
Q_o	Total rate of oil production	-	1500	-	[bbl/d]		
r	Relative pipe roughness	-	0.0006	-	[unitless]	[88]	
R_C	Compression ratio	(3.7)	-	-	[-]		
ρ_{gsc}	Gas density at standard conditions	(3.5)	-	-	[lbm/ft^3]	[2, p. 35]	
ρ_{asc}	Air density at standard conditions	-	0.0764	-	[lbm/ft^3]	[85, p. 10]	
T_b	Base temperature	-	520	-	[°R]	[2, p. 35]	
T_d	Compressor discharge temperature	(3.9)	-	-	[°R]	[57, p. 105]	
T_s	Compressor 1 suction temperature	-	656.7	-	[°R]		
T_{s2}	Compressor 2 suction temperature	(3.10)	-	-	[°R]		h

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Param.	Description	Eq. no.	Default	Literature range	Unit	Sources	Notes
$v_{l,W}$	Pipeline flow velocity	(3.15)	-	-	[ft/s]	[85]	
WOR	Water-to-oil ratio	-	Section D	-	[bbl water/bbl oil]		
Z	Compressibility factor	-	1.0	-	[-]		

a - The default of the ratio of specific heats for methane (not pure) is 1.28. In the case of nitrogen gas the default is 1.40.
b - A typical centrifugal pump efficiency is 70% [59, p. 23]. OPGEE default is slightly more conservative to account for wear, tear, older equipments, etc.
c - Compression efficiency accounts for losses of energy stemming from thermodynamics and mechanical causes. A typical range for compression efficiency is 75-85% [57, p.05]. OPGEE default is more conservative to account for wear, tear, older equipments, etc.
d - For the calculation of the friction head a Moody friction factor of 0.02 is assumed.
e - See *'Fuel specs'*. Crude oil specific gravity varies between 0.8 and 1.05 in most cases.
f - Calculated based on the molecular weights and molar fractions of gas constituents.
g - Pressure traverse is calculated from the total head using the pressure gradient of fresh water.
h - Assume compressibility factor Z of 1.0 in the calculation of the compression energy.

3.3.3.1 Default field age

Field age data were collected for global oil fields. A total of 6502 global oil fields were collected from the Oil & Gas Journal *2010 Worldwide Oil Field Production Survey* [92]. A total of 4837 of these fields had reported discovery dates. No data are available on date of first production, although this commonly occurs less than 5 years after discovery.

The histogram of field discovery dates is shown in Figure 3.4. Because of a lack of field-specific production data in the same dataset, a production-weighted average age figure was not thought to provide an accurate representation of the true production-weighted age distribution, so this was not calculated. The mean date of discovery in the dataset was 1972.1. If a conservative 3 year development timeline is assumed, an average of 35 years has elapsed between 1975 and 2010. *User Inputs & Results 3.2.3*

However, many of these fields are likely small fields that do not supply large quantities of oil to the global export markets. It is known that giant oilfields are somewhat older on average than the general field population [93–96]. A database of 116 giant oilfields was collected (defined as all producing over 100 kbbl/d in the year 2000) [94, Appendix A]. In total, these 116 fields produced ≈32,000 kbbl/d, or some 43% of global oil production in 2000.

These giant fields have a count distribution and produciton-weighted average age distribution that are somewhat older than the complete set of global fields. Figure 3.5 shows these distributions. The production-weighted average discovery year of the sample was 1960.2, for an average age of 40 years since discovery at the time of production data collection (weighted by year 2000 production data). Data on giant oilfield production in 2010 are not available. Due to the general global slowdown in the discovery of giant fields since the 1970s, it is likely that the age distribution of giant oilfields has not shifted in step with advancing years. Therefore, the production-weighted average age for large fields is likely now greater than 40 years.

3.3.3.2 Default field depth

Field depth data were collected for a large number of global oil fields [92]. A total of 6502 global oil fields were collected from the Oil & Gas Journal *2010 Worldwide Oil Field Production Survey*. Of these fields, 4489 fields had depth data presented. For fields where a range of depths was presented, the deeper depth is used.

The distribution of depths by number of fields per depth range is presented in Figure 3.6. Because of sporadic reporting of production data in the same dataset, a production-weighted depth figure was not thought to provide an accurate representation. The mean depth for these 4489 fields is 7238, or ≈ 7240 ft. The standard deviation is 3591 ft. The depth distribution has a longer right (deep) tail than left (shallow) tail, so the mean is somewhat larger than the median (median = 6807 ft). *User Inputs & Results 3.2.4*

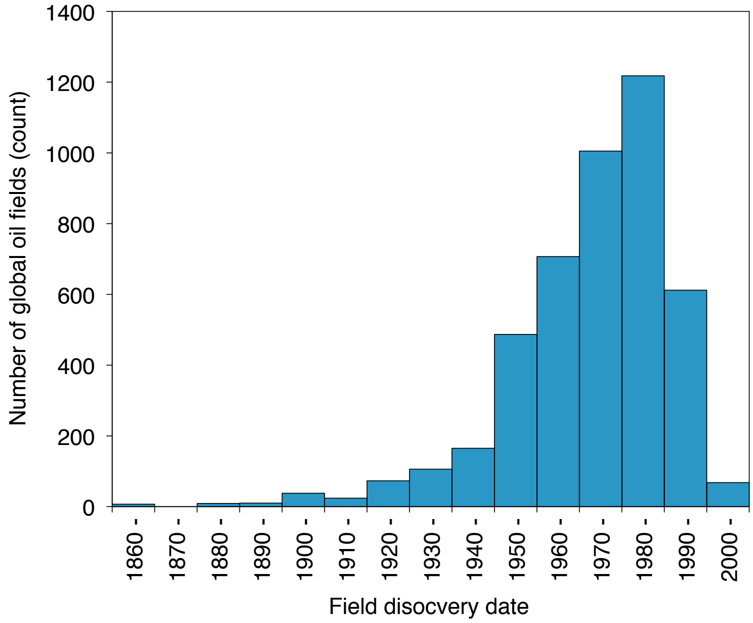

Figure 3.4: Distributions of global oilfield ages. Mean date of discovery (by count not by production-weighted average) is 1978.4.

3.3.3.3 *Default production per well*

Country-level oil production data and numbers of producing wells were collected for a large number of oil producing countries. Data from a total of 107 oil producing countries were collected from the Oil & Gas Journal *2010 Worldwide Oil Field Production Survey* [97]. Production data and operating well counts for 2008 were collected from 92 of these 107 countries.

The distribution of per-well productivities for all countries is shown in Figure 3.7. A majority of oil producing countries produced less than 500 bbl/well-d. Weighting these well productivities by country-level share of global production, we see a very similar distribution.

Because of the large number of countries producing less than 500 bbl/well-d, we plot the distribution for countries under 500 bbl/well-d (see Figure 3.8). For the 55 countries with per-well productivity less than 500 bbl/well-d, the most common productivity by number of countries was the 0-25 bbl/well-d. However, when weighted by total production, the most common productivity bin is 75-100 bbl/well-d.

In 2008, the world produced 72822 kbbl/d from 883691 wells, for an average per-well productivity of 82 bbl/well. However, the very low productivity of the US oil industry (representing ≈512000 wells) pulls down this average significantly. Non-US producers averaged a per-well productivity of 183 bbl/well-d, which is used as default well productivity in OPGEE.

User Inputs & Results 3.2.6

3.3.3.4 *Default gas composition*

The default gas composition for associated gas from oil production is derived from reported gas composition data from 135 California oil fields [3].

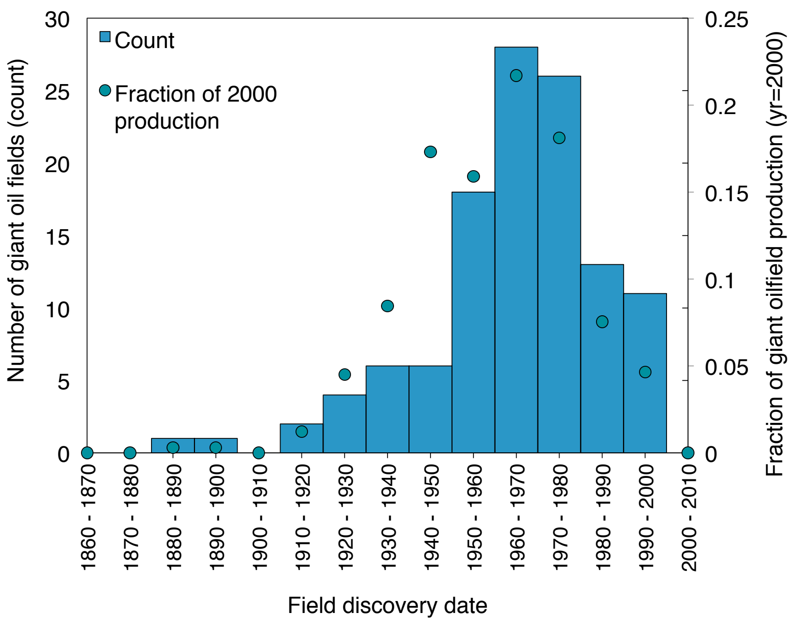

Figure 3.5: Distributions of giant oilfield ages. Mean date of discovery (by production-weighted average) is 1960.2.

Species concentration distributions for major gas species is shown in Figure 3.9. In order to remove outliers, all compositions with methane concentration less than 50% were removed from the dataset (17 data points removed out of 135). The resulting mean compositions were rounded and used in OPGEE for default gas composition. *User Inputs & Results 3.3.2*

3.3.3.5 Smart default for GOR

The gas-oil ratio (GOR) varies over the life of the field. The amount of gas able to be evolved from crude oil depends on its API gravity, the gas gravity, and the temperature and pressure of the crude oil [98, p. 297]. As the reservoir pressure drops, increasing amounts of gas evolve from the liquid hydrocarbons (beginning at the bubble point pressure if the oil is initially undersaturated) [98]. This tends to result in increasing producing GOR over time. Also, lighter crude oils tend to have a higher GOR.

Because of this complexity, a static single value for GOR is not desirable. However, all data required to use empirical correlations for GOR is not likely to be available for all crude oils modeled. Therefore we use California producing GORs to generate average GORs for three crude oil bins. *User Inputs & Results 3.4.1*

Crude oils are binned by API gravity into heavy (<20 °API), medium ($\geq 20, < 30$ °API), and light crude (≥ 30 °API). Each California oil field is assigned an average API gravity using the following procedure:

1. API gravity by pool is collected from DOGGR datasets [99–101] and digitized.

2. If a range of API gravities is given for a single pool, the high and low value are averaged to obtain a single value per pool.

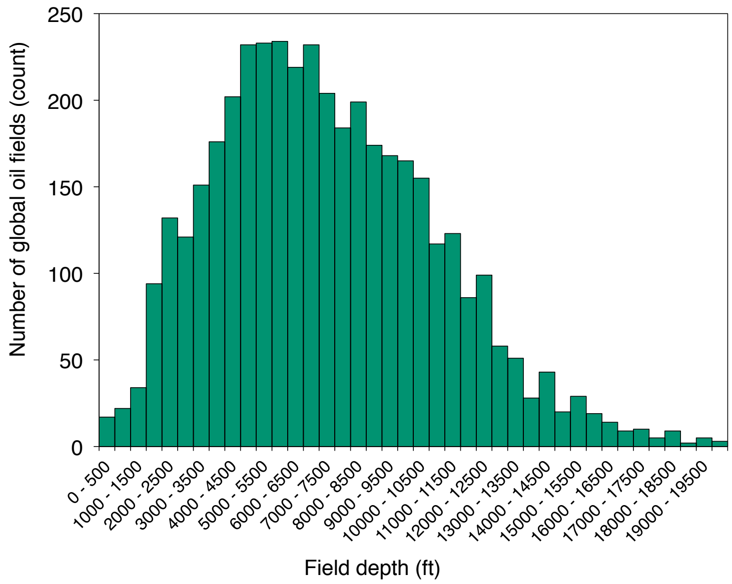

Figure 3.6: Distributions of global oilfield depths in bins of 500 ft depth. $N = 4489$ fields, mean = 7238 ft, SD = 3591 ft, median = 6807 ft.

3. The above steps give a set of single API values by pool. Each field has between 1 and 17 pools that have data in DOGGR field properties datasets.

4. Each field is assigned an average API gravity using the following method: a) if a single pool API value is given for the field, that is used; b) if multiple pool API gravities are given, and production data are available by pool, the pools are weighted by production level; c) if multiple pool API gravities are given but no relative production data exist to weight the pools, the API gravities are averaged.

5. The above procedure results in a single average API gravity for each field in California.

The associated gas GOR for 174 California oil fields was compiled for January to December 2010 [102, 103]. Five of these fields had very high GORs of above 10,000 scf/bbl and were removed as outliers, leaving 169 fields with data. These data are binned as above based on their average API gravity value. The distributions, mean, and median values for each crude bin were generated (see Figure 3.10 for plot of distributions and Table 3.5 for listing of mean and median GORs by bin).

The mean GORs are used to assign a smart default for each bin.

3.3.3.6 Default water oil ratio (WOR)

A smart default for the water oil ratio as a function of field age was generated using data from hundreds of oil pools/fields in Alberta and California. Appendix D gives a thorough methodological explanation of the analysis underlying the WOR smart default.

User Inputs & Results 3.4.2

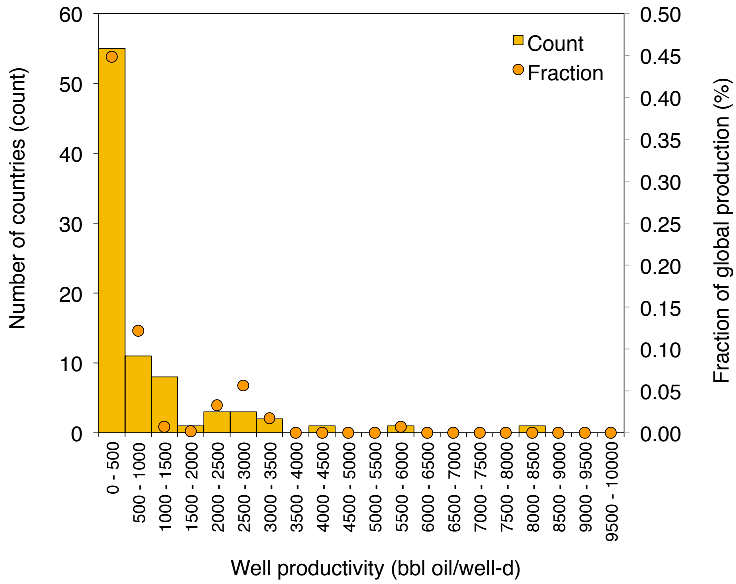

Figure 3.7: Distributions of oilfield per-well productivity (bbl oil/well-d) for bins of 500 bbl/d, counted by numbers of countries (bar) and by fraction of production (dot) N = 92 countries.

Table 3.5: GOR values by crude oil API gravity bin.

Crude bin	Num. fields [#]	Gravity range [°API]	Avg. gravity [°API]	Mean GOR [scf/bbl]	Median GOR [scf/bbl]
Heavy	53	< 20	15.6	361	105
Medium	65	$\geq 20, < 30$	25.0	843	594
Light	51	≥ 30	35.4	1431	959

The default WOR is represented by an exponential function:

$$WOR(t) = a_{WOR} \exp[b_{WOR}(t - t_0)] \qquad \left[\frac{\text{bbl water}}{\text{bbl oil}}\right] \tag{3.27}$$

where a_{WOR} = fitting constant for the initial WOR in time = t_0 [bbl water/bbl oil]; b_{WOR} = exponential growth rate [1/y]; t_0 = initial year of analysis [y]; and t = year being modeled (independent variable) [y].

The results of fitting this model to the smart default fit values, compared to oil fields from a variety of world regions, is show in figure 3.11. The tabular results for a_{WOR} and b_{WOR} for the California, Alberta, and default OPGEE cases are shown in Table 3.6.

3.3.3.7 Default waterflooding volume

The volume of water injected in a waterflooding project is meant to maintain reservoir pressure. As a default value, OPGEE assumes that the surface volume is replaced, such that the total oil produced plus the water produced is reinjected, or the injection per bbl = 1 + WOR.

User Inputs & Results 3.4.3

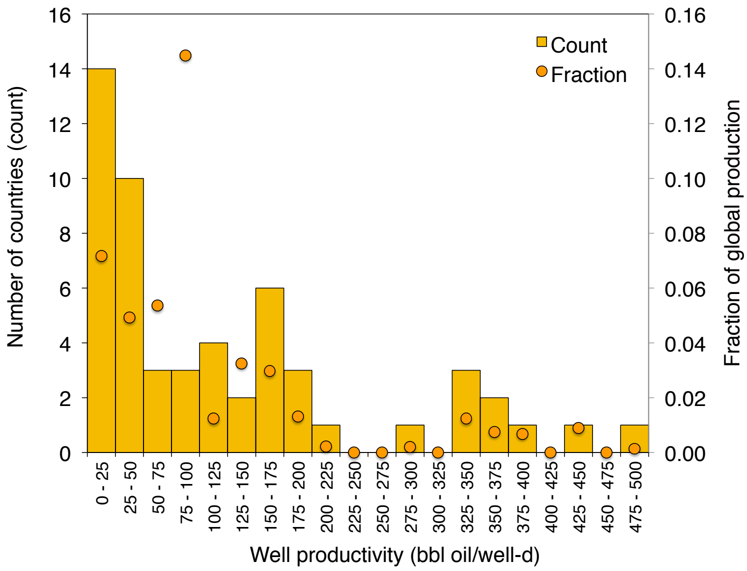

Figure 3.8: Distributions of oilfield per-well productivity (bbl oil/well-d) for all countries with per-well productivities lower than 500 bbl/well-d, counted by numbers of countries (bar) and by fraction of production (dot) $N = 55$ countries.

Table 3.6: OPGEE WOR relationships.

Case	a_{WOR}	b_{WOR}	Source
Low	2.486	0.032	CA Mean
OPGEE Default	2.5	0.035	User spec.
High	1.168	0.091	AB mean

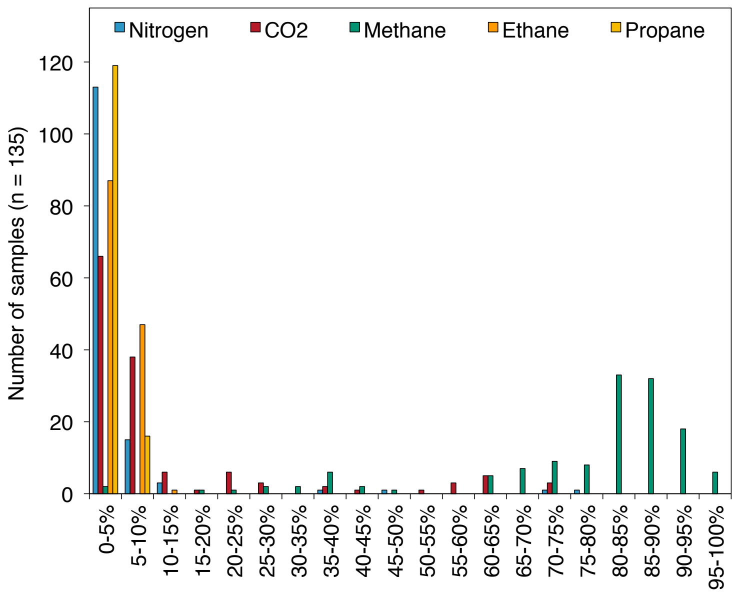

Figure 3.9: Distributions of major gas species across 135 samples from California associated gas producers.

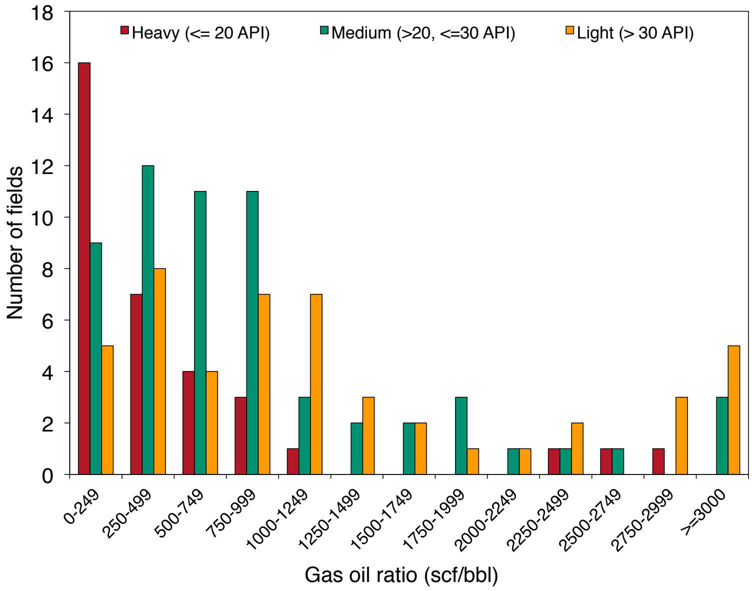

Figure 3.10: Distributions of California GORs, binned by crude density.

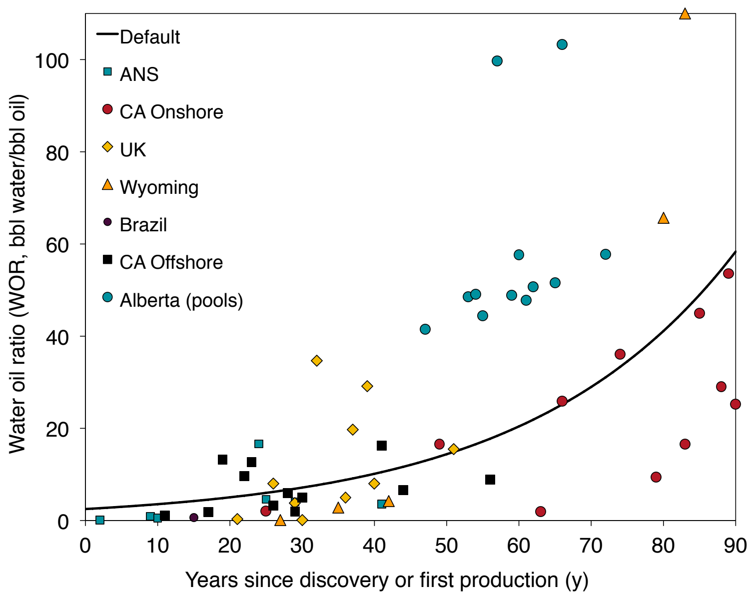

Figure 3.11: Exponential WOR model fit with smart default parameters [$a_{WOR} = 2.5$, $b_{WOR} = 0.035$].

3.4 Surface processing

3.4.1 Introduction to surface processing

Surface processing of crude oil includes all production steps required after lifting the crude oil from the subsurface and before it is transported to the refinery. Activities undertaken in surface processing include oil-water-gas separation, treatment and stabilization of crude oil, and treatment and cleanup of produced gas.

The first step in the processing of crude oil is the separation of individual phases (gas, liquid hydrocarbon, liquid water and solids). This is performed as early as is practical. Field processing schemes can vary considerably depending on the nature of produced fluids (water cut, gas-to-oil ratio and the nature of crude oil, e.g., API gravity), the location and size of the field, availability of gas and electricity, the relative value of gas and crude oil [50, p. 65].

In OPGEE it is not possible to account for the wide variations in surface processing. The goal is to include the most frequently applied processes in the industry, while still retaining some flexibility to model varying operating modes.

A complete list of emissions sources from surface processing, along with their estimated magnitude, is shown in Table C.4. A list of all equation parameters and their default values (if applicable) and data sources is included in Table 3.9.

3.4.2 Calculations for surface processing

3.4.2.1 Crude oil dehydration

The production separator can be a gas-liquid separator or a gas-water-oil separator. The type of production separator determines whether free water is removed at an early stage in the processing scheme. After free water removal, produced oil often contains excessive emulsified water. Treating via crude oil dehydration is required to reduce the water content to a level acceptable for transportation and sale.

Crude oil dehydration can be accomplished by gravitational / chemical means without heat. If this separation is not sufficient, heat can be applied to aid the separation of crude oil and water. The application of heat in the dehydration of crude oil is a significant source of fuel consumption in surface processing.

Gravity separation occurs in large holding vessels called wash tanks, settlers, or gun barrels, and in free-water knockouts (FWKO). FWKOs remove only free water. Emulsion breaking chemicals can be added upstream from the FWKO to improve separation. Better gravitational/chemical separation can be achieved in holding vessels. Holding vessels generate a "washing" action with mild agitation that causes contact between the entrained water drops and the retained water volume, thus coalescing and removing water droplets from the oil stream [50, p. 118]. The advantage of wash tanks is that they use coalescence and retention time instead of heat (no fuel use) [104] [50, p. 119]. Because no fuel is used in these gravitational separation techniques, no significant GHG emissions occur from gravity separation units.

Depending on the nature of the well stream, the above gravity separation techniques may not be sufficient to produce crude oil with the desired water content. Additional treatment may be provided by a heater/treater.

Heater/treater placement in the processing scheme affects the total heater treater duty. If the full well stream is the feed stream, then the section of the heater/treater below the firetube is sized to allow for significant retention time to drop out more than half of the free water. Heaters/treaters, however, are not suitable for removing large amounts of free water, and this limitation becomes more acute in older fields as WOR increases [50, p. 120]. Removing free water before flowing the crude oil mixture into a fired heater saves considerable fuel. It takes 350 Btu to heat 1 bbl of water 1 °F but only 150 Btu to raise 1 bbl of oil 1 °F [50, p. 188]. The removal of free water upstream from the heater/treater is therefore desirable from a cost and emissions perspective.

OPGEE allows the user to switch on and off the heater/treater. If the heater/treater applies, the user choses whether the total well stream is the feed stream or whether free water is removed upstream from the heater/treater unit. For upstream removal of free water, the user choses between a production separator at the well head or an FWKO/tank. In either case, the user can change the amount of water removed as a percentage of water cut.

The first step in the calculation of the heat duty of the heater/treater is the calculation of the volume of heated water. If the total well stream is the feed stream then the volume of heated water is calculated using the fraction of water entrained in oil as:

Surface Processing 2.1.1

$$Q_{w,heat} = Q_{w,ent} + \lambda_{w,rem}(Q_w - Q_{w,ent}) \qquad \left[\frac{\text{bbl}}{\text{d}}\right] \tag{3.28}$$

where $Q_{w,heat}$ = volume of heated water [bbl/d]; $Q_{w,ent}$ = volume of entrained water, [bbl/d]; $\lambda_{w,rem}$ = the fraction of non-entrained water removed prior to heater/treater firetube [-]; and Q_w = volume of produced water [bbl/d]. The volume of entrained water $Q_{w,ent}$ is calculated from the fraction of water entrained in oil as:

Surface Processing 2.1.1.1

$$\lambda_{w,ent} = \frac{Q_{w,ent}}{Q_{w,ent} + Q_o}, \quad \text{therefore} \quad Q_{w,ent} = \lambda_{w,ent}\frac{Q_o}{1 - \lambda_{w,ent}} \qquad \left[\frac{\text{bbl}}{\text{d}}\right] \tag{3.29}$$

where $\lambda_{w,ent}$ = fraction of water entrained in oil [-]; and Q_o = rate of oil production [bbl/d]. The volume of produced water Q_w is calculated from the water-to-oil ratio as:

Surface Processing 2.1 Figure

$$Q_w = \text{WOR} \cdot Q_o \qquad \left[\frac{\text{bbl water}}{\text{d}}\right] \tag{3.30}$$

where WOR = water-to-oil ratio [bbl of water/bbl of oil]. The produced water is the sum of free and entrained waters.

In the calculation of the volume of heated water in eq. (3.28) it is assumed that the heater/treater is designed to drop out 60% of the free water below the fire tube, so $\lambda_{w,rem}$ = 0.4 by default. The fraction of water entrained in oil is a user input with a default value of 14% [50, p. 136].

Surface Processing 2.1.1.1

If free water is removed upstream of the heater/treater, the volume of heated water is calculated from the volume of water remaining in the well stream after initial separation. The fraction of water removed as a percentage of produced water is variable. For example, crude oil leaving the FWKO may still contain emulsified water content ranging from 1% to as much as 30 or 40 % [50, p. 118]. The default values for the production separator and gravitational treatment are 60% and 70% of produced water, respectively.[2]

Surface Processing 1.1.1.1.2, 1.1.1.2.2

Once the volume of heated water is calculated, the heat duty is calculated using:

Surface Processing 2.1.1.4

$$\Delta H_{CD} = \Delta T_{CD} \left(Q_o C_{p_o} + Q_{w,heat} C_{p_w}\right) (1 + \epsilon_{CD}) \left(\frac{1}{10^6}\right) \qquad \left[\frac{\text{MMBtu}}{\text{d}}\right] \tag{3.31}$$

where ΔH_{CD} = heat duty [MMBtu/d]; C_{p_o} = specific heat of oil [Btu/bbl-°F]; C_{p_w} = specific heat of water [Btu/bbl-°F]; ΔT_{CD} = difference between treating and feed temperatures [°F]; and ϵ_{CD} = heat loss [fraction]. Default values are 90 and 165 °F for feed and treating temperatures, respectively; 150 and 350 Btu/bbl-°F for specific heats of oil and water, respectively; and 0.02 for heat loss [50, p. 136].

3.4.2.2 *Crude oil stabilization*

Dissolved gas in the wellhead crude oil must be removed to meet pipeline, storage, or tanker Reid vapor pressure (RVP) specifications. Removal of the most volatile organic hydrocarbons decreases the RVP dramatically and is called crude oil stabilization. Crude oil can be stabilized by passing it through a series of flash drums or separator vessels at successively lower pressures. Tray tower with reboilers, alternatively or in conjunction with separators, are also used, though less often [50, p. 159].

The use of a reboiled stabilizer column is the most important user assumption in the oil-gas separation scheme. Stabilizer columns are tray columns usually provided with sieve trays for vapor-liquid contacting. Vapor, which is produced in the reboiler, flows up the column, stripping out methane, ethane, propane, and sufficient butane to produce a stabilized crude oil [50, p. 160]. The separation achieved is better than in a simple flash drum. Higher pressures correlate with higher separation efficiency. The default type of stabilizer in OPGEE is a high-pressure stabilizer (100 psi) which requires a higher reboiler temperature compared to a low-pressure stabilizer.

[2] As mentioned earlier the efficiency of the initial water-oil separation is significantly variable. For gravitational treatment 70% was assumed given the literature range of 1-40% of water remaining with crude oil from FWKO. The three-phase production separator has a lower assumed efficiency of 60% because gravitational treatment generally has the advantage of adding demulsifiers and/or generating a "washing' action.

The use of a stabilizer column is an important assumption because a heat source is required to provide the neccessary temperature. OPGEE assumes a direct-fired heater. The use of a stabilizer column and the overall complexity of crude oil processing depends on the nature of the well fluids. For instance, when the gas-to-oil ratio (GOR) is between 25-100 scf/bbl, onshore locations are likely to use one stage of flash separation followed by wash tanks. Offshore, two stages of separation might be attractive [50, p. 172]. The comparisons between a series of flash drums and/or reboiled stabilization are of real economic benefit only for high volume, high GOR streams (>150 scf/bbl) [50, p. 163].

The heat duty of the stabilizer column is calculated as:

Surface Processing 2.1.2.2

$$\Delta H_S = \Delta T_S Q_o C_{p_o} \left(1 + \epsilon_S\right) \left(\frac{1}{10^6}\right) \qquad \left[\frac{\text{MMBtu}}{\text{d}}\right] \tag{3.32}$$

where ΔH_S = heat duty [MMBtu/d]; C_{p_o} = specific heat of oil [Btu/bbl-°F]; ΔT_S = difference between reboiler and feed temperatures [°F]; and ϵ_S = heat loss [fraction]. All of these parameters are user inputs. The default values are 120 and 344 °F for feed and reboiler temperatures, respectively; 150 Btu/bbl-°F for the specific heat of oil; and 0.02 for heat loss [50, p. 161, 163, tables 9-1, 9-3].

3.4.2.3 Acid gas removal

The second step after the separation of individual phases is the treatment of associated gas. Treatment of associated gas starts with acid gas removal (gas sweetening). There are more than 30 natural gas sweetening processes. OPGEE assumes that the amine process is used. The batch and amine processes are used for over 90% of all onshore wellhead applications with amines being preferred when lower operating costs justifies the higher equipment cost. The chemical cost of batch processes may be prohibitive [2, p. 99].

In the amine process an aqueous *alkanolamine* solution is regenerated and used to remove large amounts of sulfur and CO_2 when needed. The model scheme allows the user to choose between the commonly used amine solutions (MEA, DEA, DGA, etc.). Each amine solution is characterized by a K value which is inversely proportional to both the acid gas removal rate (pick up) and amine concentration [2, p. 115]. When choosing an "other" amine solution, the user must enter a K value. The default contactor operating pressure is the median value of the pressures reported in the calculation of the contact tower diameter [105] [2, p. 117]. A schematic of the amine process is shown in Figure 3.12.

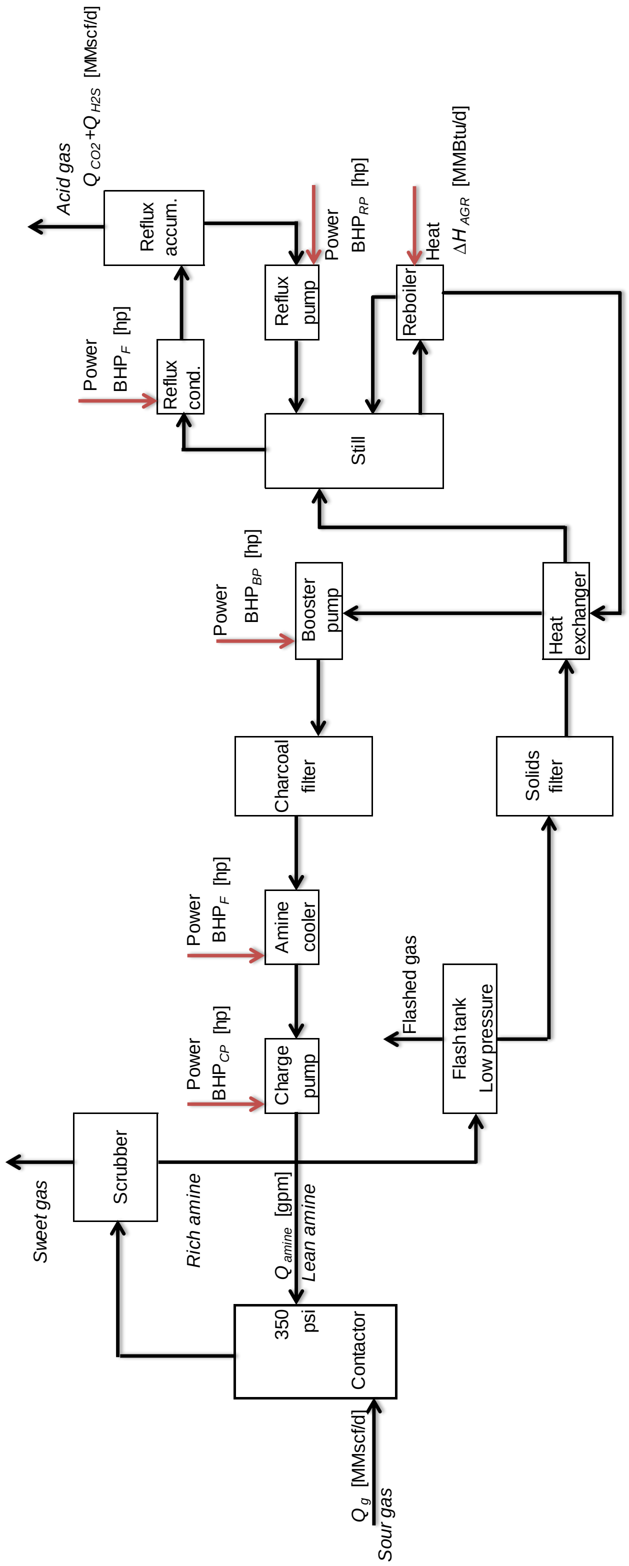

Figure 3.12: Amine simple process flow diagram [2, p. 112].

The inlet gas flow rate of the gas processing stage in the gas balance (see '*Gas Balance*' sheet) is calculated as:

Surface Processing 2.2.1 Figure

$$Q_g = Q_o \cdot \mathrm{GOR}\left(\frac{1}{10^6}\right) - Q_F \qquad \left[\frac{\mathrm{MMscf}}{\mathrm{d}}\right] \tag{3.33}$$

where Q_g = inlet gas flow rate [MMscf/d]; Q_o = rate of oil production [bbl/d]; Q_F = flaring rate [MMscf/d]; and GOR = gas-to-oil ratio [scf/bbl]. The inlet gas flow rate is used in the calculation of the amine circulation rate in eq. (3.35). Although the accumulation of gases to flare likely occurs at various points throughout the process, OPGEE assumes that the gas flared is removed before gas processing occurs. This allows for OPGEE to account for "early field production" or production in locations without a gas market. For these situations, no surface processing exists and all produced gas is flared.

The amine reboiler in OPGEE is a direct fired heater that uses natural gas. The reboiler duty is: (i) the heat to bring the acid amine solution to the boiling point, (ii) the heat to break the chemical bonds between the amine and acid gases, (iii) the heat to vaporize the reflux, (iv) the heat load for the makeup water, and (v) the heat losses from the reboiler and still [2, p. 117].

The heat duty of the amine reboiler can be estimated from the circulation rate of the amine solution as [2, p. 119—originally Jones and Perry, 1973]:

Surface Processing 2.2.1.4

$$\Delta H_{AGR} = \frac{24 \cdot 72000 \cdot Q_{amine}}{10^6} 1.15 \qquad \left[\frac{\mathrm{MMBtu}}{\mathrm{d}}\right] \tag{3.34}$$

where ΔH_{AGR} = heat duty [MMBtu/d]; and Q_{amine} = amine flow rate [gpm]. A gallon of amine solution requires approximately 72000 Btu for regeneration [106]. A safety factor of 15% is added for start up heat losses and other inefficiencies. The flow rate of the amine solution can be estimated using the following equation [2, p. 115]:

Surface Processing 2.2.1.1.1

$$Q_{amine} = 100\,K(Q_{H_2S} + Q_{CO2}) \qquad [\mathrm{gpm}] \tag{3.35}$$

where Q_{amine} = amine flow rate [gpm]; K = amine solution K value [gpm-d/100MMscf]; Q_{H_2S} = H_2S removal [MMscf/d]; and Q_{CO2} = CO_2 venting from AGR unit [MMscf/d]. The venting of CO_2 from the AGR unit is calculated in the '*Gas Balance*' sheet. The rate of H_2S removal is calculated as:

$$Q_{H_2S} = x_{H_2S} \cdot Q_g \qquad \left[\frac{\mathrm{MMscf}}{\mathrm{d}}\right] \tag{3.36}$$

where x_{H_2S} = molar fraction of H_2S [-]; and Q_g = inlet gas flow rate [MMscf/d]. The calculation of the inlet gas flow rate is shown in eq. (3.33). The molar fraction of H_2S is determined from the composition of associated gas.

In OPGEE all H_2S remaining in the associated gas is removed in the AGR unit. Removed H_2S is calculated in eq. (3.36) by multiplying the inlet gas flow rate with the molar percent of H_2S. Also all the CO_2 removed is vented and that is calculated in the '*Gas Balance*' sheet.

Other equipment in the amine regeneration system that consume power and energy include the reflux condenser and the amine cooler. There also are reflux, booster, and circulation pumps. The reflux condenser and the amine cooler are air-cooled, forced-draft heat exchangers. In OPGEE both services are combined into one structure with a common fan.

The motor size of the amine cooler fan can be estimated from the amine circulation rate as [2, p. 118]:

Surface Processing 2.2.1.3.1

$$\mathrm{BHP}_F = 0.36 \cdot Q_{amine} \qquad \text{[hp]} \tag{3.37}$$

where BHP_F = fan brake horsepower [hp]; and Q_{amine} = amine circulation rate [gpm].

The heat duty of the reflux condenser is approximately twice the heat duty of the amine cooler [2, p. 117]. Therefore the motor size of the 'common' fan is estimated by multiplying the brake horsepower of the amine cooler by 3.

Similarly motor sizes of pumps can also be estimated from the amine circulation rate as [2, p. 118]:

Surface Processing 2.2.1.2

$$\mathrm{BHP}_{RP} = 0.06 \cdot Q_{amine} \qquad \text{[hp]} \tag{3.38}$$

$$\mathrm{BHP}_{BP} = 0.06 \cdot Q_{amine} \qquad \text{[hp]} \tag{3.39}$$

$$\mathrm{BHP}_{CP} = 0.00065 \cdot Q_{amine} \cdot p_d \qquad \text{[hp]} \tag{3.40}$$

where BHP_{RP} = reflux pump brake horsepower [hp]; BHP_{BP} = booster pump brake horsepower [hp]; BHP_{CP} = circulation pump brake horsepower [hp]; and p_d = pump discharge pressure [psi]. The circulation pump discharge pressure = 50 psi over contactor operating pressure [2, p. 121]. The default contactor operating pressure as mentioned earlier is 350 psi.

3.4.2.4 Gas dehydration

Fluids at the wellhead almost invariably contain water. Except for a few shallow wells, natural gas is produced saturated with water. There are many reasons for the dehydration of natural gas, including avoiding: (i) solid hydrates formation which can plug valves, fittings or even pipelines; (ii) corrosivity in case the acid gases are still present; (iii) condensation of water which creates a slug flow and increases pressure losses in the pipeline due to slippage; and (iv) decreases in heating value [2, p. 139]. There are several methods for the dehydration of natural gas including liquid (glycols) and solid (e.g., alumina) desiccants. The method assumed in OPGEE as default is triethylene glycol (TEG) desiccant. For more than 40 years sweet and sour gases have been dehydrated using TEG which has general acceptance as the most cost effective choice [2, p. 140].

The wet or "rich" glycol that leaves the absorber is preheated in the glycol-glycol heat exchanger before it enters the stripping column and flows down the packed bed section into the reboiler. The steam generated in the reboiler strips water from the liquid glycol as it rises up the packed bed. The water vapor and desorbed gas are vented from the top of the stripper [2, p. 140]. The venting from glycol dehydrator is discussed in the VFF section of this document (see Section 4.3). A schematic of the glycol dehydrator is shown in Figure 3.13.

The first step in the estimation of the reboiler duty is the calculation of the rate of water removed using the assumed weight of water vapor in the inlet and exit gases as:

Surface Processing 2.2.2.1.3

$$\Delta M_{w,rem} = M_{w,in} - M_{w,out} \qquad \left[\frac{\text{lb H}_2\text{O}}{\text{MMscf}}\right] \tag{3.41}$$

where $\Delta M_{w,rem}$ = water removed [lb H_2O/MMscf]; $M_{w,in}$ = water in inlet gas [lb H_2O/MMscf]; $M_{w,out}$ = water in outlet gas [lb H_2O/MMscf]. The weights of water vapor in the inlet and exist gases are user inputs. The default values are 52 and 7 lb H_2O/MMscf, respectively [2, p. 160]. The weight of water removed is converted to rate of water removal ($\Delta Q_{w,rem}$) in lb H_2O/d by multiplying with the gas flow rate, MMscf/d.

The regenerator duty is estimated using the rule of thumb [2, p. 158]:

Surface Processing 2.2.2.2.1

$$\Delta H_{GD} = 900 + 966\, q_{TEG} \left(\frac{1}{10^6}\right) \qquad \left[\frac{\text{MMBtu}}{\text{lb H}_2\text{O}}\right] \tag{3.42}$$

where ΔH_{GD} = reboiler heat duty [MMBtu/lb H_2O] removed; and q_{TEG} = TEG circulation rate [gal TEG/lb H_2O] removed. The heat duty is converted to MMBtu/d by multiplying with the rate of water removed, lb H_2O/d, as calculated in eq. (3.41).

The main parameter in eq. (3.42) is the TEG circulation rate. The water picked up by glycol increases with increasing inlet-glycol concentration and higher circulation rates. The concentration of TEG used typically ranges from 98.5 to 99.9 wt% [2, p. 155]. The default concentration assumed is 99 wt%. In the past a conservative TEG circulation rate of 3 gal TEG/lb H_2O removed was common. However, energy conservation practices have lowered the circulation to 2 gal TEG/lb H_2O removed and this is used as default in OPGEE [2, p. 147].

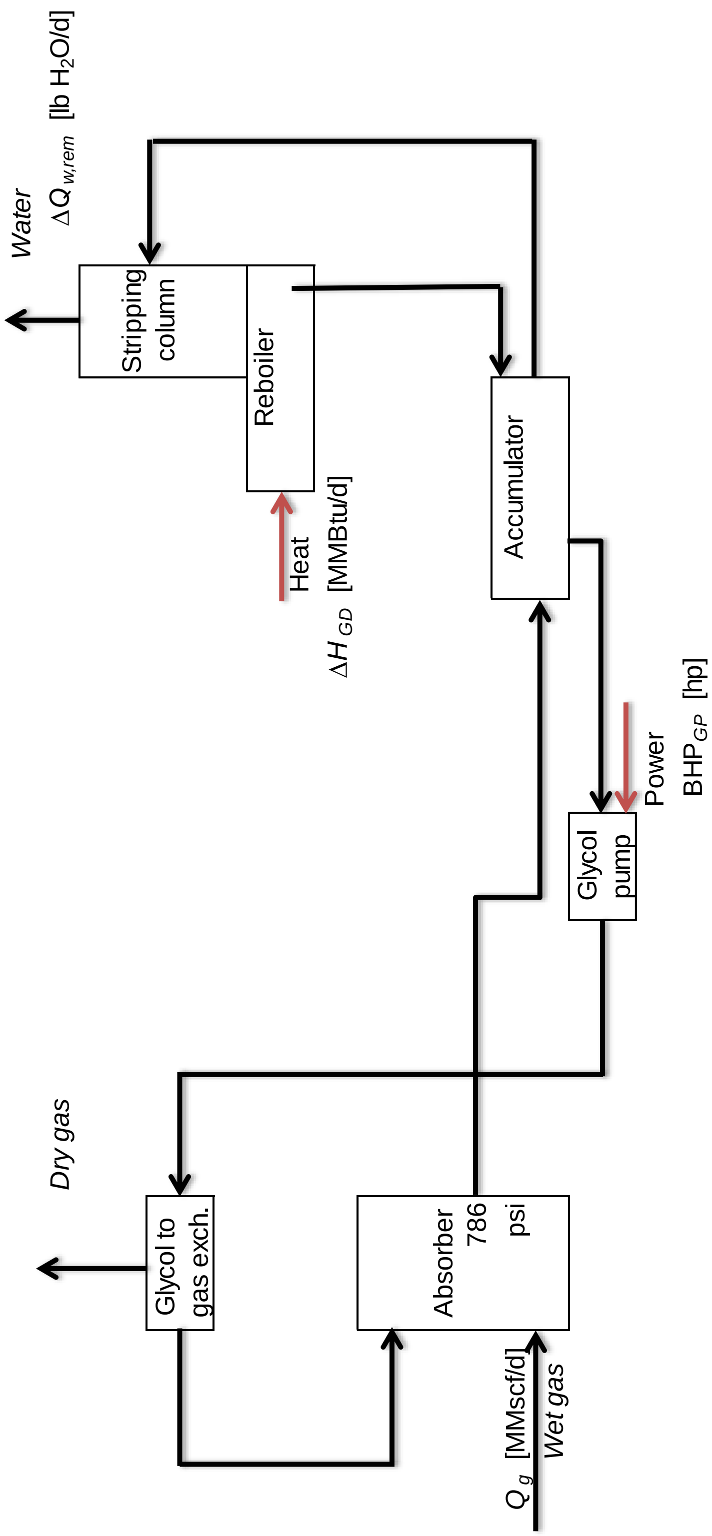

Figure 3.13: Glycol dehydrator simple process flow diagram [2, p. 141].

Table 3.7: Typical concentration of process water pollutants.

Pollutants	Concentration (mg/l)
Oil and grease	200
Boron	5
Total dissolved solids (TDS)	5000
Sodium	2100

The glycol pump in the gas dehydration process is assumed to be electric by default. The horsepower is calculated using the conventional brake horsepower equation:

Surface Processing 2.2.2.3

$$\text{BHP}_{GP} = \frac{Q_{TEG} \cdot \Delta p}{1714\eta_{GP}} \qquad \text{[hp]} \tag{3.43}$$

where BHP_{GP} = glycol pump brake horsepower [hp]; Q_{TEG} = TEG circulation rate [gpm]; Δp = pumping pressure [psi]; and η_{GP} = glycol pump efficiency [-]. The pumping pressure is the difference between pump discharge and suction pressures. The default pump suction pressure is 0 [psi]. The glycol pump discharge pressure is equal to contactor operating pressure. The default contactor operating pressure is 786 psi [2, p. 160]. The TEG circulation rate in gpm is calculated as:

Surface Processing 2.2.2.1.5

$$Q_{TEG} = q_{TEG} \Delta Q_{w,rem} \left(\frac{1}{24 \cdot 60} \right) \qquad \text{[gpm]} \tag{3.44}$$

where q_{TEG} = TEG circulation rate [gal TEG/lb H_2O removed]; and $\Delta Q_{w,rem}$ = rate of water removal [lb H_2O/d]. The calculation of the rate of water removal is shown in eq. (3.41).

3.4.2.5 *Gas demethanizer*

In the demethanizer 50% of ethane and 100% of propane and butane are assumed to condense. These fractions can be changed on the '*Surface Processing*' worksheet. Although associated gas fractionation is included in the surface processing gas balance but no emissions (process or fugitive) are assigned to the demethanizer.

Surface Processing 1.2.3

3.4.2.6 *Water treatment*

Oil production generates a significant amount of produced water, which can be contaminated with hydrocarbons, salts, and other undesirable constituents. The fraction of water produced is determined by the WOR. After cleaning, produced water is reinjected, discharged to the local environment, or injected into aquifers. Produced water can contain a variety of pollutants at varying concentrations. The pollutant nature and concentration are largely source dependent including location, geology and age of the oil field [91]. A typical concentration of pollutants found in oil extraction process waters is shown in Table 3.7 [91, p. 59].

Table 3.8: Categorization of water treatment technologies.

Name	Signifier
Stage 1	
Dissolved air flotation	DAF
Hydrocyclones	HYDRO
Stage 2	
Rotating biological contactors	RBC
Absorbents	ABS
Activated sludge	AS
Trickling filters	TF
Air stripping	AIR
Aerated lagoons	AL
Wetlands	CWL
Microfiltration	MF
Stage 3	
Dual media filtration	DMF
Granular activated carbon	GAC
Slow sand filtration	SSF
Ozone	OZO
Organoclay	ORG
Ultrafiltration	UF
Nanofiltration	NF
Stage 4	
Reverse osmosis	RO
Electrodialysis reversal	EDR

Process water from oil production can be treated in a variety of different ways. The technologies in OPGEE are grouped into 4 different treatment stages according to the categorization of water treatment technologies as shown in Table 3.8 [107]. This categorization and the energy consumption of each technology in kWh per m^3 of water *input* (converted to kWh per bbl of water) was adopted from Vlasopoulos et al. [91].

The user can set up a water treatment system or treatment train composed of 1-4 stages of treatment with one option from each treatment stage as shown in Table 3.8. Stage 1 to 3 technologies are used to reduce the oil and grease to levels that can be either discharged or reused. The fourth stage of treatment is used to reduce the sodium, TDS, and boron levels to produce high quality water required by some end uses [91, p. 60]. The technology combinations are selected according to the target water qualities that need to be achieved.

The model scheme has two treatment trains: (i) one for the treatment of process water generated from oil production and (ii) another for the treatment of imported water, e.g., sea water, if applicable.

The user can set up a treatment train by switching on/off the treatment technologies listed under each treatment stage. One option is allowed for each treatment stage. Based on the user selections, OPGEE retrieves the corresponding electricity consumption and calculates the total electricity consumption:

Surface Processing 2.3.1

$$E_{tot} = e_{s1}Q_{w1} + e_{s2}Q_{w2} + e_{s3}Q_{w3} + e_{s4}Q_{w4} \qquad \left[\frac{\text{kWh}}{\text{d}}\right] \tag{3.45}$$

where E_{tot} = total electricity consumption [kWh/d]; $e_{s,N}$ = electricity consumption of stage N [kWh/ bbl of water input]; and $Q_{w,N}$ = water feed into stage N [bbl of water/d].

For the produced water treatment train the water feed of stage 1 is equal to the water flow in the well stream as calculated in eq. (3.30). The default volume losses are assumed 0% for all treatment technologies except for wetlands which is assumed 26% [91]. The water feed of stages 2-4 is calculated as:

Surface Processing 2.3.1 Figure

$$Q_{w,N} = Q_{w,(N-1)}[1 - \epsilon_{V,(N-1)}] \qquad \left[\frac{\text{bbl of water}}{\text{d}}\right] \tag{3.46}$$

where $\epsilon_{V,(N-1)}$ = volume loss in stage $N-1$ [fraction].

For the imported water treatment train, if applicable, the same calculations apply but the water feed is calculated backwards starting from stage 4 where the output is equal to the amount of water supplied to the process in excess of the output from the produced water train. The volume losses are set to be direct user inputs in the mass balance to avoid circular references.

3.4.3 Defaults for surface processing

Defaults for surface operations are shown in Table 3.9.

Table 3.9: Default inputs for surface processing.

Param.	Description	Eq. no.	Default	Literature range	Unit	Sources	Notes
BHP_F	Fan brakehorse power	(3.37)	-	-	[hp]	[2, p. 118]	
BHP_{RP}	Reflux pump brakehorse power	(3.38)	-	-	[hp]	[2, p. 118]	
BHP_{BP}	Booster pump brakehorse power	(3.39)	-	-	[hp]	[2, p. 118]	
BHP_{CP}	Circulation pump brakehorse power	(3.40)	-	-	[hp]	[2, p. 118]	
BHP_{GP}	Glycol pump brakehorse power	(3.43)	-	-	[hp]	[73, p. 455]	
C_{p_o}	Specific heat of oil	-	150	-	[Btu/bbl-°F]	[50, p. 136]	
C_{p_w}	Specific heat of water	-	350	-	[Btu/bbl-°F]	[50, p. 136]	
E_{tot}	Total electricity consumption	(3.45)	-	-	[Kwh/d]		
$e_{s1} \ldots e_{s4}$	Electricity consumption by stage	-	-	-	[Kwh/d]		
ϵ_j	Fraction of heat loss in unit j	-	0.02	-	[-]	[50, p. 136]	
$\epsilon_{V,(N-1)}$	Fraction of volume loss in stage $N-1$	-	var.	-	[-]	[91]	a
η_P	Pump efficiency	-	0.65	-	[-]		
$\lambda_{w,rem}$	Fraction of water removed below fire tube	-	0.4	-	[-]	[50, p.136]	
GOR	Gas-to-oil ratio	-	Section 3.3.3.5	-	[scf/bbl]		
ΔH_{AGR}	Amine process reboiler heat duty	(3.34)	-	-	[MMBtu/d]	[2, p. 119]	
ΔH_{GD}	Glycol dehydrator reboiler heat duty	(3.42)	-	-	[MMBtu/d]	[2, p. 158]	
K	Amine solution K value	-	2.05	0.95-2.05	[gpm-d/100MMscf]	[2, p. 115]	b
$\lambda_{w,ent}$	Fraction of water entrained in oil	-	0.14	-	[-]	[50, p. 136]	
q_{TEG}	TEG circulation rate	-	2	-	[gal TEG/lb H_2O]	[2, p. 147]	
p_d	Pump discharge pressure	-	786	-	[psi]	[2, p. 160]	
$\Delta Q_{w,rem}$	Rate of water removal	-	$Q_g \, \Delta M_{w,rem}$	-	[lb H_2O/d]		
Q_{amine}	Amine flow rate	(3.35)	-	-	[gpm]	[2, p. 115]	
Q_{CO_2}	Volume of CO_2 removed	-	var.	-	[MMscf/d]	*'Gas Balance'*	

Continued on next page...

Continued from previous page

Param.	Description	Eq. no.	Default	Literature range	Unit	Sources	Notes
$Q_{w,ent}$	Volume of entrained water	(3.29)	-	-	[bbl/d]	[50, p. 136]	
Q_F	Flaring volume	-	Section 4.3.2	-	[MMscf/d]		
Q_g	Inlet gas flow rate	(3.33)	-	-	[MMscf/d]	*'Gas Balance'*	
Q_{H_2S}	Volume of H_2S removed	-	var.	-	[MMscf/d]	*'Gas Balance'*	
$Q_{w,heat}$	Volume of heated water	(3.28)	-	-	[bbl/d]	[50, p. 136]	
Q_o	Volume of oil production	-	1500	-	[bbl/d]		
Q_{TEG}	TEG circulation rate in gpm	(3.44)	-	-	[gpm]		
Q_w	Volume of produced water	(3.30)	-	-	[bbl/d]		
$Q_{w1} \cdots Q_{w4}$	Water feed by stage	(3.46)	-	-	[bbl water/d]		
ΔT_{CD}	Crude dehyd. temp. difference	-	75	-	[°F]	[50, p. 136]	
ΔT_S	Crude stabilizer temp. difference	-	224	-	[°F]	[50, p. 161, 163]	
$\Delta M_{w,rem}$	Weight of water removed	(3.41)	-	-	[lb H_2O/MMscf]		
$M_{w,in}$	Weight of water in inlet gas	-	52	-	[lb H_2O/MMscf]	[2, p. 160]	
$M_{w,out}$	Weight of water in outlet gas	-	7	-	[lb H_2O/MMscf]	[2, p. 160]	
WOR	Water-to-oil ratio	(3.27)	-	-	[bbl water/bbl oil]]		

a - This is a user input. No defaults are available for most of the treatment technologies. The default for wetlands (CWL) where volume losses are significant is 26% [91].
b - The default is monoethanolamine (MEA).

3.5 Maintenance operations

3.5.1 Introduction to maintenance operations

Emissions from maintenance include venting and fugitives associated with compressor blowdowns, well workovers and cleanups, separator cleaning and repair, and gathering pipeline maintenance and pigging. Other maintenance emissions are believed to be below the significance cut-off and are not included.

3.5.2 Calculations for maintenance operations

Emissions from maintenance operations are classified in Table C.5. Emissions from maintenance operations are either very small (e.g., embodied energy consumed in maintenance parts) or are tracked in the VFF modeling page (see Section 4.3). For this reason, OPGEE does not perform specific maintenance emissions calculations in the separate *'Maintenance'* sheet.

3.5.3 Defaults for maintenance operations

Defaults used in the calculation of emissions from maintenance operations are discussed in Section 4.3.

3.6 Waste treatment and disposal

3.6.1 Introduction to waste treatment and disposal

Emissions from waste disposal occur during routine oilfield maintenance operations (e.g., disposal of residual hazardous waste products) due to clean up operations, or due to one-time events such as decommissioning of oilfield equipment. Emissions occur offsite due to the energy demands of waste disposal and the transport requirements for moving waste to waste treatment or disposal sites. A complete list of emissions sources, along with their categorization and estimated magnitude, is shown in Table C.6.

3.6.2 Calculations for waste treatment and disposal

Because waste treatment emissions only occur sporadically, they are likely to be small when amortized over the producing life of an oil field. For this reason, emissions from waste treatment are considered below the significance cutoff in OPGEE v1.0.

Possible exceptions could be the treatment and disposal of fracturing fluids and fracturing flow-back water, due to the large volumes produced. Future versions of the model may include these factors.

3.6.3 Defaults for waste treatment

Waste treatment emissions default to 0 gCO_2/MJ. Any waste treatment emissions are assumed to be captured in the small sources emissions default parameter.

User Inputs & Results 3.6

3.7 Crude oil transport

3.7.1 Introduction to crude oil transport

Crude oil transport includes all activities associated with moving crude oil from a production facility to a refinery. In the case of land transport, this generally involves transport via pipeline to the refinery. Pipelines are powered by natural gas, oil, or electric-powered drivers. In some instances, rail transport is used for overland transport. In the case of inter-continental trade, crude oil is transported to a loading dock, loaded onto a tanker or barge, transported via ship over water, unloaded at the destination, and finally transported to a refinery.

Transport emissions occur due to energy consumption by transport equipment and due to fugitive emissions from loading and unloading operations. In OPGEE, transport emissions are modeled using methods and data from CA-GREET [76]. Transport emissions calculations allow for variations in transport modes, distance travelled, and fuel mix in each mode.

3.7.2 Calculations for crude oil transport

OPGEE crude oil transport calculations use sets of transport modes, transport propulsion technologies in each mode (most commonly one technology per mode), and transport fuels. Emissions are tracked per species of GHG. Transport modes include tanker (T), barge (B), pipeline (P), and rail (R). Pipelines include two propulsion technologies: turbines (GT) and reciprocating engines (RE). Fuels used in transport include diesel fuel (di), residual oil (ro), natural gas (ng), and electricity (el).

The effectiveness crude oil transport [Btu/ton-mi] is calculated for a variety of modes using a similar general form. Each mode has an effectiveness U. For example, tanker transport effectiveness is calculated as:

Crude Transport Table 2.7

$$U_T = \frac{\eta_T l_T P_T}{v_T C_T} \qquad \left[\frac{\text{Btu}}{\text{ton-mi}}\right] = \frac{\left[\frac{\text{Btu}}{\text{hp-hr}}\right][-][\text{hp}]}{\left[\frac{\text{mi}}{\text{hr}}\right][\text{ton}]}, \tag{3.47}$$

where U_T = specific energy intensity of crude oil transport via tanker [Btu/ton-mi]; η_T = efficiency of tanker transport [Btu/hp-hr]; l_T = load factor of tanker (different on outbound and return trip) [-]; P_T = tanker power requirements [hp]; v_T = tanker velocity [mi/hr]; and C_T is tanker capacity [ton/tanker]. Barge transport is calculated in an analogous fashion.

For the case of pipeline and rail transport, the calculation is simpler. For pipeline transport the effectiveness is calculated as follows:

Crude Transport Table 2.7

$$U_P = \sum_{j \in GT,RE} \lambda_{Pj} U_{Pj} \qquad \left[\frac{\text{Btu}}{\text{ton-mi}}\right] = [-]\left[\frac{\text{Btu}}{\text{ton-mi}}\right] \tag{3.48}$$

where λ_{Pj} = fraction of each pipeline pumping technology j [-]; and U_{Pj} = effectiveness of pipeline transport for technology j [Btu/ton-mi]. For rail transport, only one technology exists, so no summation is required.

Back haul trips are calculated using GREET factors for the energy intensity of return trips [17]

The energy-specific transport energy intensity is calculated from the transport effectiveness using the energy density of crude oil. For example, in the case of tanker transport:

Crude Transport Table 2.7

$$e_T = U_T \frac{1}{LHV_o} \rho_w \gamma_o \frac{1}{2000} \tag{3.49}$$

$$\left[\frac{\text{Btu}}{\text{MMBtu-mi}}\right] = \left[\frac{\text{Btu}}{\text{ton-mi}}\right]\left[\frac{\text{bbl}}{\text{MMBtu}}\right]\left[\frac{\text{lb}}{\text{bbl water}}\right]\left[\frac{\text{lb/bbl oil}}{\text{lb/bbl water}}\right]\left[\frac{\text{lb}}{\text{ton}}\right] \tag{3.50}$$

where UE_T = crude oil transport intensity per unit of energy transported [Btu/MMBtu-mi], LHV_o = crude lower heating value [MMBtu/bbl]; ρ_w = density of water [lb/bbl]; γ_o = crude specific gravity [-]; and 1/2000 = conversion factor between lb and ton.

Calculating emissions of GHG species associated with the consumption of a given energy type in a given device is performed via multiplication with the appropriate emissions factor. For example, in the case of tanker emissions:

Crude Transport Table 2.7

$$\begin{gathered} EM_{Ti} = e_T \sum_k \lambda_{Tk} EF_{Tki}, \qquad (k \in di, ro, ng) \\ \left[\frac{\text{g}}{\text{MMBtu-mi}}\right] = \left[\frac{\text{Btu}}{\text{MMBtu-mi}}\right][-]\left[\frac{\text{g}}{\text{Btu}}\right] \end{gathered} \tag{3.51}$$

where EM_{Ti} = emissions of species i from tankers [g/MMBtu-mi]; λ_{Tk} = fraction of fuel k used in tankers [-]; and EF_{Tki} = emissions factor for fuel k, species i consumed in tankers [g/Btu]. Other modes are calculated similarly.

The total CO_2 equivalent emissions are then computed by weighting by gas global warming potential (GWP). Again, for the case of tanker transport:

Crude Transport Table 2.7

$$EM_T = \sum_i EM_{Ti} GWP_i, \qquad \left[\frac{\text{g CO}_2\text{ eq.}}{\text{MMBtu-mi}}\right] = \left[\frac{\text{g}}{\text{MMBtu-mi}}\right]\left[\frac{\text{g CO}_2\text{ eq.}}{\text{g}}\right] \tag{3.52}$$

where GWP_i = GWP of species i.

The total energy consumption from transport is computed using the distances and fractions of transport, along with the mode-specific energy intensity of transport:

Crude Transport 3.1

$$\begin{gathered} E_{TR} = \sum_j \lambda_j D_j UE_j \qquad (j \in T, B, P, R) \\ \left[\frac{\text{Btu}}{\text{MMBtu}}\right] = [\text{mi}]\left[\frac{\text{Btu}}{\text{MMBtu-mi}}\right][-] \end{gathered} \tag{3.53}$$

where D_j = distance of crude oil transport in mode j [mi]; UE_j = energy-specific transport effectiveness for mode j [Btu/MMBtu-mi]; and λ_j = fraction of crude oil transported in mode j. The sum of fractional transport

λ can be greater than 1, because some crude may be transported via both pipeline and tanker, for example.

The total emissions are calculated identically:

Crude Transport 3.2

$$EM_{TR} = \sum_j \lambda_j D_j EM_j \qquad (j \in T, B, P, R)$$
$$\left[\frac{\text{g CO}_2\text{ eq.}}{\text{MMBtu}}\right] = [\text{mi}] \left[\frac{\text{g CO}_2\text{ eq.}}{\text{MMBtu-mi}}\right] [-] \tag{3.54}$$

where EM_j are the emissions from mode j on a CO_2 equivalent basis.

3.7.3 Defaults for crude oil transport

Defaults for crude oil transport are generally taken from the CA-GREET model, with some modifications and simplifications applied. Defaults for surface operations are given below in Table 3.10.

Table 3.10: Default inputs for crude transport.

Param.	Description	Eq. no.	Default	Literature range	Unit	Sources	Notes
C_j	Transport capacity of mode j	-	*'Crude Transport'* Table 2.1		[ton]	[17]	
e_m	Energy intensity of transport in mode j by energy unit transported	(3.49)	-	-	[Btu/MMBtu-mi]		
EF_{jki}	Emissions factor for fuel k, species i, mode j	-	*'Emissions Factors'* Table 1.5		[g/MMBtu]		a
EM_{ji}	Emissions of species i by mode j	(3.51)	-	-	[g/MMBtu-mi]		
EM_j	Emissions of all GHGs in CO_2 eq. units by mode j	(3.52)	-	-	[g CO_2 eq./MMBtu-mi]		
E_{TR}	Total energy use in transport	(3.53)	-	-	[Btu/MMBtu]		a
EM_{TR}	Total emissions from in transport	(3.54)	-	-	[g/MMBtu]		a
η_j	Efficiency of transport mode j	-	*'Crude Transport'* Table 2.3		[Btu/hp-hr]	[17]	
GWP_i	Global warming potential for species i	-	*'Input data'* Table 2.1		[gCO_2eq./g]		
γ_o	Specific gravity of crude oil	-	0.876	0.8-1.05	[-]	[84]	
l_j	Load factor of mode j	-	*'Crude Transport'* Table 2.3		[%]	[17]	
$\lambda_{j_1 j_2}$	Fraction of technology j_2 used in mode j_1	-	*'Crude Transport'* Table 2.6		[%]	[17], Est.	
λ_{jk}	Fraction of fuel k used in mode j	-	*'Crude Transport'* Table 2.7		[-]	Est.	a
P_j	Power consumption of mode j	-	*'Crude Transport'* Table 2.2		[hp]	[17]	
ρ_w	Density of fresh water	-	350.4	-	[lb/bbl]	[108]	
U_j	Transport effectiveness in mode m	(3.48); (3.47)	-	-	[Btu/ton-mi]		
$U_{j_1 j_2}$	Transport effectiveness of propulsion tech j_2 used in mode j_1	-	*'Crude Transport'* Table 2.5		[Btu/ton-mi]	[17]	
v_j	Velocity of mode j	-	*'Crude Transport'* Table 2.3		[mi-hr]	[17]	

[a] Default crude oil shipment distance in CA-GREET is 750 mi for a one-way trip [17].

3.8 Bitumen extraction & upgrading

3.8.1 Introduction to bitumen extraction & upgrading

Bitumen extraction and upgrading is modeled separately from conventional oil extraction because the technologies applied differ. OPGEE v1.0 does not include process models as for bitumen extraction. Instead, OPGEE uses energy consumption and fugitive emissions data from GHGenius [13].

3.8.2 Calculations for bitumen extraction & upgrading

The OPGEE bitumen module tracks three hydrocarbon products: raw bitumen, synthetic crude oil, and hydrocarbon diluent. For each product, the API gravity, specific gravity (γ), and lower heating value (LHV) are generated. Blends of SCO and raw bitumen (synbit) or diluent-SCO-bitumen (dil-synbit) are not included in OPGEE. For bitumen and SCO, γ and LHV are derived from API gravity via formula or lookup [84]. The table of heating values as a function of API gravity does not account for composition differences between SCO of a given density and conventional crude of the same density. This introduces uncertainty of an unknown (though likely small) magnitude.

Fuel Specs Table 1.1

Diluent composition, density, and heating value are derived from tabulated diluent compositions [109]. Three diluent streams were selected from literature sources [109]. Hydrocarbon species are combined into bins (see notes in model) and the composition of diluent samples is plotted in Figure 3.14. Element fractions of C and H are calculated and the resulting heating value is calculated using the Dulong formula [108].

Bitumen Extraction & Upgrading Table 4.7

After specifying the properties of the hydrocarbon streams, production pathways are defined. First, the product is chosen as upgraded SCO or diluted bitumen:

Bitumen Extraction & Upgrading 2.6.1

$$y_{sco} \text{ or } y_{db} = 1 \tag{3.55}$$

where y is a binary variable representing a SCO product y_{sco} or a diluted bitumen product y_{db}.

Next, the primary extraction and (if applicable) upgrading technology pathway is defined:

Bitumen Extraction & Upgrading 2.6.2

- Bitumen mining with integrated upgrading, $y_{MI} = (0 \text{ or } 1)$
- Bitumen mining with non-integrated upgrading, $y_{MN} = (0 \text{ or } 1)$
- In situ production via non-thermal methods (e.g., production via cold heavy oil production with sand (CHOPS) or polymer flood), $y_{IP} = (0 \text{ or } 1)$
- In situ production via steam assisted gravity drainage (SAGD), $y_{IS} = (0 \text{ or } 1)$
- In situ production via cyclic steam stimulation (CSS), $y_{IC} = (0 \text{ or } 1)$

In this case, only one path can be chosen so the sum of binary pathway variables y_j must equal 1:

$$\sum_j y_j = 1 \qquad (j \in MI, MN, IP, IS, IC) \tag{3.56}$$

An important parameter is the fraction diluent blending rate λ_{db}. Dilbit blending rates depend on the input bitumen density, the quality of product being produced, and the relative market value of diluent and bitumen (i.e., heavy-light refining value differential).

Bitumen Extraction & Upgrading 2.8

The calculation of emissions from bitumen extraction and upgrading operations is based on energy intensities from GHGenius [13]. OPGEE estimates diesel, natural gas, electricity, coke, and still gas use. Values are derived from GHGenius as energy consumed, to avoid divergence due to varying energy densities.[3] GHGenius energy intensities are derived from industry-reported energy use [110].

Bitumen Extraction & Upgrading Table 4.1 - 4.4

The energy consumed of a given fuel type k per unit of energy produced is given by e_k:

$$e_k = e_{EX,k} + e_{UP,k} \qquad [\text{mmBtu/bbl SCO}] \tag{3.57}$$

where the primary resource extraction energy use $e_{EX,k}$ for fuel type k is equal to:

Bitumen Extraction & Upgrading 3.1.1

$$e_{EX,k} = y_{sco}\left(\sum_j y_j e_{EX,jk}\right)\frac{1}{\Delta V_{UP}} + y_{db}\left(\sum_{\forall j \neq MI} y_j e_{EX,kj}\right)(1-\lambda_{db})$$

$$(j \in MI, MN, IP, IS, IC) \quad (k \in di, ng, el, ck, sg) \qquad [\text{mmBtu/bbl SCO}] \tag{3.58}$$

where in this equation $e_{EX,jk}$ = specific energy use in extraction pathway j of fuel type k [mmBtu/bbl bitumen]; ΔV_{UP} = volumetric gain upon upgrading [bbl SCO/bbl bitumen]; and λ_{db} = fraction of diluent blended into the dilbit product. Depending on whether y_{sco} or y_{db} is equal to 1, only one of these sums is performed. If the bitumen is upgraded, the energy consumed per bbl of bitumen mined is reduced by the factor $1/\Delta V_{UP}$ because 1 bbl of bitumen results in the production of more than 1 bbl of SCO. In the case of blended dilbit, the energy consumed per bbl of bitumen is reduced by the factor (1-λ_{db}) because the dilbit contains diluent in addition to bitumen.

For modeling natural gas consumption, a special consideration is made for the steam oil ratio. In this case:

Bitumen Extraction & Upgrading 3.1.1.2

$$e_{EX,ng} = y_{sco}\left(\sum_j y_j e_{EX,jk}\frac{SOR_j}{SOR_{j0}}\right)\frac{1}{\Delta V_{UP}} + y_{db}\left(\sum_{\forall j \neq MI} y_j e_{EX,kj}\frac{SOR_j}{SOR_{j0}}\right)(1-\lambda_{db})$$

$$(j \in MI, MN, IP, IS, IC)$$

[3] For example, natural gas heating values are quite variable between GHGenius and GREET per scf of gas

(3.59)

where SOR_j = steam oil ratio observed in pathway j and SOR_{j0} = default SOR in that pathway. In pathways without steam injection,the SOR term is equal to 1. Energy demand in thermal extraction will scale nearly linearly with steam injection rates because of the increase in steam energy consumption and increase in fluid handling energy requirements with increasing SOR [4, 12].

Energy of type k consumed in upgrading is modeled using the following function:

Bitumen Extraction & Upgrading 3.1.2

$$e_{UP,k} = y_{sco}\left(\sum_{\forall j \neq MI} y_j e_{UP,jk} + y_{MI}\left(e_{UP,MI,k} - \frac{e_{EX,MN,k}}{\Delta V_{UP}}\right)\right)$$

$$(j \in MI, MN, IP, IS, IC) \quad (k \in di, ng, el, ck, sg) \qquad [\text{mmBtu/bbl SCO}] \tag{3.60}$$

Where $e_{UP,k}$ is energy consumption of fuel type k for stand alone upgrading, and $e_{UP,MI,k}$ and $e_{EX,MN,k}$ are energy use of type k for integrated mining and upgrading and non-integrated mining. Therefore, the upgrading energy consumption for an integrated operation is modeled as the difference between an integrated mining and upgrading operation and the volumetric gain adjusted energy consumption for a stand-alone mining operation.

Venting, flaring and fugitive emissions are calculated using volumetric dilbit and SCO adjustments as above. As with conventional pathways in OPGEE, country-level average satellite flaring rates for Canada are applied to oil sands operations. This is done because of preference for the verifiable nature of satellite-derived data. For fugitive emissions, tabulated fugitive emissions factors from GHGenius are used as reported in GHGenius documentation [110].

Bitumen Extraction & Upgrading 3.2

External energy requirements are tabulated from total net energy inputs by making the following default assumptions about internal vs. external fueling of oil sands projects :

Bitumen Extraction & Upgrading 2.9

- Diesel, coke, and still gas consumed are generated onsite in upgraders or purchased from other local oil sands operations. This is generally the case due to the remote location of the oil sands operations;
- Natural gas and net electricity demand (on site consumption less on site generation) are purchased from external operations.

Using these assumptions, net energy requirements from the external energy system are computed. These net inputs are used to generate off-site emissions credits or debits from oil sands operations. Because diluent is typically a natural gas condensate, diluent consumed is counted as external natural gas production. In order to maintain congruence with other OPGEE pathways, upstream fuel cycle emissions are used from GREET.

Bitumen Extraction & Upgrading 3.3

Bitumen Extraction & Upgrading 3.3.1.6

Total net energy consumed and fugitive emissions, per bbl of output hydrocarbon product produced (e.g., diluted bitumen or SCO), are integrated with the overarching OPGEE emissions calculation framework.

Fuel Cycle Tables 1.2, 1.4

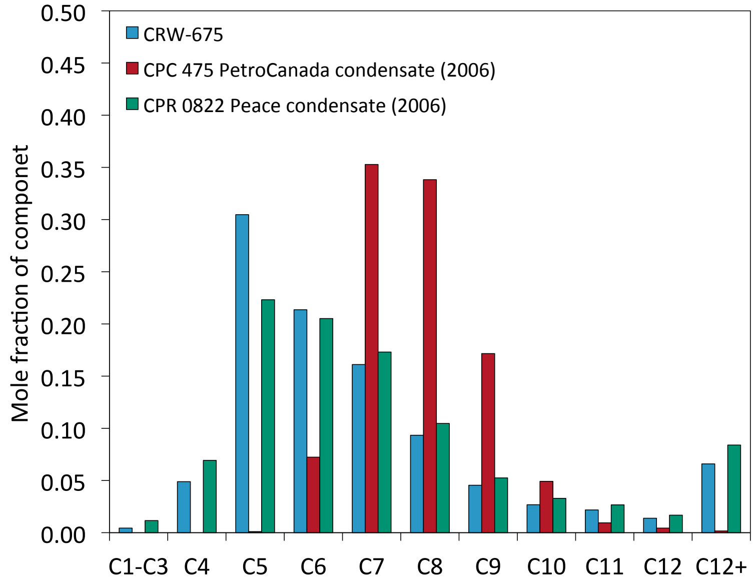

Figure 3.14: Composition of three diluent products from C1 to C12+ hydrocarbons.

Land use emissions from bitumen extraction operations are calculated similarly to those from conventional oil operations [77]. See Section 3.2 for a detailed description.

Bitumen Extraction & Upgrading 3.5

3.8.3 Defaults for bitumen extraction

The complete list of model terms, along with default values (if applicable) are included for all parameters in Table 3.11.

Table 3.11: Default inputs for bitumen extraction & upgrading calculations.

Param.	Description	Eq. no.	Default	Literature range	Unit	Sources	Notes
$^\circ API_{db}$	API gravity of bitumen	-	8	4 - 12	[-]	[13]	
$^\circ API_{sco}$	API gravity of SCO	-	32	20 - 34	[-]	[13]	
$^\circ API_{dl}$	API gravity of diluent	-	59.4	55 - 63	[-]	[109]	
$e_{EX,k}$	Cons. of fuel k in extraction	(3.58)	-	-	[mmBtu/bbl]	-	
$e_{EX,j,k}$	Cons. of fuel k pathway j in extraction	-	var.	-	[mmBtu/bbl]	[13]	a
$e_{UP,k}$	Cons. of fuel k in upgrading	(3.60)	-	-	[mmBtu/bbl]	-	
$e_{UP,j,k}$	Cons. of fuel k for pathway j in upgrading	-	var.	-	[mmBtu/bbl]	[13]	a
e_k	Total cons. of fuel k in bitumen extraction & upgrading	(3.57)	-	-	[mmBtu/bbl]	-	
λ_{db}	Diluent blending fraction in dilbit	-	0.33	0.15 - 0.5	[%]	[109, 111]	
SOR_{IS}	Steam oil ratio, SAGD	-	3.0	2.5 - 5	[bbl steam/bbl bit]	[112]	
SOR_{IC}	Steam oil ratio, CSS	-	3.9	3.5 - 6	[bbl steam/bbl bit]	[112]	
SOR_{IS0}	Default steam oil ratio, SAGD	-	3.0		[bbl steam/bbl bit]	[112]	
SOR_{IC0}	Default steam oil ratio, CSS	-	3.9		[bbl steam/bbl bit]	[112]	
ΔV_{UP}	Volumetric gain upon upgrading	-	1.17	Unknown	[bbl SCO/bbl bitumen]	[13]	b
y_{sco}	Binary var. for producing SCO	-	1	0 or 1	[y/n]		c
y_{db}	Binary var. for producing diluted bitumen	-	0	0 or 1	[y/n]		c
y_{MI}	Binary var. for integrated mine & upgrade	-	1	0 or 1	[y/n]		d
y_{MN}	Binary var. for non-integrated mine & upgrade	-	0	0 or 1	[y/n]		d
y_{IP}	Binary var. for in situ, primary	-	0	0 or 1	[y/n]		d
y_{IS}	Binary var. for in situ, SAGD	-	0	0 or 1	[y/n]		d
y_{IC}	Binary var. for in situ, CSS	-	0	0 or 1	[y/n]		d

[a] Data are presented in OPGEE tables 'Bitumen Extraction & Upgrading' sheet.
[b] Volumetric gain upon upgrading is based on 1:1 mass throughput rate for bitumen to SCO [13] and reduction in density from 8 to 32 °API.
[c] The most common pathway for bitumen production is mining and upgrading to synthetic crude oil, so upgrading is selected by default.
[d] The most common pathway for bitumen production is integrated mining and upgrading to synthetic crude oil, so y_{mi} is chosen by default.

4 Supplemental calculations sheets

4.1 Gas balance

This sheet tracks the gas balance across the process stages and ensures that gas is conserved in the system. Due to the complexity of allocating VFF emissions some simplifications were made to the overall structure of the system.

The gas-to-oil ratio (GOR) is defined as the total gas evolved while reducing the oil to atmospheric pressure divided by the volume of the remaining crude oil [2]. The GOR is used to calculate the volume of the produced gas stream. The total GOR depends on the crude oil, on the number of stages used in the oil-gas separation sequence, as well as the operating pressure of each stage [2]. The GOR and the associated gas composition is calculated after three or more separation stages when the GOR approaches a limiting value. Fugitives from active wells, well cellars, and well maintenance events (such as well workovers and cleanups) are assumed to occur upstream from surface separation. Therefore these emissions sources do not affect the volume and composition of the initial produced gas stream in the gas balance. *Gas Balance Table 1.1*

The flaring of associated gas is assumed to occur upstream of the gas processing stage. Although the accumulation of gases to flare likely occurs at various points throughout the process, the flared gas is modeled as being flared before gas processing in OPGEE. This allows for an added flexibility in OPGEE to account for early field production or production in locations without a gas market. For these situations, no surface processing occurs and all produced gas is flared. *Gas Balance Table 1.2*

Gas processing is presented in the gas balance as one process stage which includes gas treatment and dehydration as well as all the fugitives and venting of associated gas in these two processes system. These fugitive emissions do not include the venting from crude oil storage tanks. The associated gas GOR is computed at the last stage in the surface oil-gas separator. In reality the gas dehydrator can process both sweet and sour gases. The simplification of gas processing into one stage eliminates the need to determine which gas processing unit comes first (AGR unit or gas dehydrator). Accordingly, no differentiation is made between the inlet gas volumes of the gas treatment and gas dehydration units. *Gas Balance Table 1.4*

A user control is placed at the composition of the inlet gas to the gas processing stage to make sure that the total fugitives and venting of associated gas components (i.e., CO_2, CH_4, and C2+) are conserved in the gas stream. In the event of "ERROR" the user has to increase either the molar fraction of the gas component or the GOR.

The last stage in the gas balance before the generation of the product gas is the demethanizer where heavy gas components (C3+) are condensed and produced as natural gas liquid (NGL). The product NGL left after the use of NGL as a process fuel is either added to the crude oil output to increase its market value or exported. The export of NGL incurs a GHG emissions credit. The user determines the proportion of each gas component that is condensed in the demethanizer in the *'Surface Processing'* sheet. The default assumption is 50% ethane, 100% propane, and 100% butane.

Gas Balance Table 1.7

The volume of lifting gas, if applicable, is subtracted from the volume of product gas stream to calculate the volume of gas remaining for use as a process fuel and/or re-injection into the reservoir for pressure maintenance. Any product gas left after supplying the process fuel requirements and gas re-injection is exported.

4.2 Steam injection for thermal oil recovery

4.2.1 Introduction to steam injection

Steam injection for thermal enhanced oil recovery (TEOR) is practiced globally, with significant operations in California, Alberta, Indonesia, and Venezuela [113]. Steam injection reduces the viscosity of heavy crude oils by multiple orders of magnitude, even with relatively small temperature increases [12, 58, 61, 114, 115]. This viscosity reduction results in improved flow characteristics and improved reservoir sweep [61]. Many fields that would not produce economic volumes of hydrocarbons without steam injection become large producers after steam injection.

4.2.2 Calculations for steam injection

Steam generation for thermal oil recovery is modeled using two technologies: steam generation via once-through steam generators (OTSG) (Figure 4.1) and steam and electricity co-production via gas turbine and heat recovery steam generator (HRSG) combination (4.3). *Steam Injection 1.1.6*

4.2.2.1 Steam system properties

The quantity of steam required is given by the oil production rate and the steam oil ratio: *Steam Injection 1.2.4*

$$Q_{ws} = SOR\rho_w Q_o \qquad \left[\frac{\text{lbm water}}{\text{d}}\right] \tag{4.1}$$

Where Q_{ws} = steam required to be generated per day [lbm water/d]; SOR = steam oil ratio [bbl steam as cold water equivalent/bbl water]; ρ_w = density of water [lbm/bbl]; and Q_o = quantity of oil produced [bbl/d]. Steam quantities are measured as volume of cold water equivalent.

The enthalpy of steam generated ($h_{ws} = h_{ws}(p_{ws}, T_{ws})$) at steam quality X_{ws}, steam pressure p_{ws}, saturated steam temperature T_{ws} is given by: *Steam Injection 1.2.13*

$$h_{ws} = h_{ws,g}X_{ws} + h_{ws,f}(1 - X_{ws}) \quad \text{where} \quad h_{ws} = h_{ws}(p_{ws}, T_{ws}) \qquad \left[\frac{\text{Btu}}{\text{lbm}}\right] \tag{4.2}$$

Steam temperature T_{ws} [°F] is tabulated for saturated steam as a function of saturation pressure p_{ws} [psia] (assuming that pressure is the controlled variable) [116]. Because we are using steam tables rather than direct computation, steam pressure is rounded before lookup. $h_{ws,g}$ = enthalpy of vapor phase water at p_{ws} [Btu/lbm] while $h_{ws,f}$ = enthalpy of saturated water at p_{ws} [Btu/lbm]. *Input Data Table 5.3*

Steam is generated at sufficient pressure to ensure that it will flow into the subsurface (eliminating the need for wellhead compressors). Due to friction and thermal losses in piping and wellbore, the steam pressure drops before reaching the reservoir: *Steam Injection 1.2.8*

$$p_{ws} = p_{res}\epsilon_{ws} \qquad [\text{psia}] \tag{4.3}$$

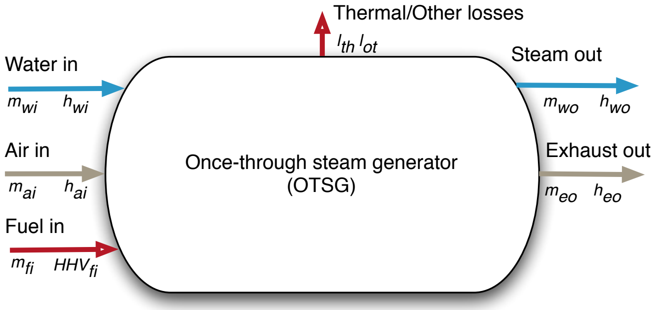

Figure 4.1: Once-through steam generator with mass and energy balance terms. Lower case terms are defined per lbmol of input fuel.

where ϵ_p = pressure loss factor which is $\geq$ 1 [psia generator/psia reservoir]. Chilingarian et al. [41, p. 228] note that 10-50% of the pressure in the steam at steam generator outlet can be lost by the time the steam reaches the reservoir.

Steam quality X_{ws} [lbm vapor/lbm steam] is governed by the needs of the project. Higher steam qualities impart more energy into the formation, but steam quality is limited by the steam generator configuration. Once-through steam generators cannot generate 100% quality steam because of deposition of solids in boiler tubes. In practice, ≈20% of water mass is left in fluid state to carry solutes ($X_{ws} \approx 0.8$) [117].

The enthalpy increase of water is given by the difference between water inlet enthalpy and exit enthalpy:

Steam Injection 1.2.14

$$\Delta h_{ws} = h_{ws} - h_{w,in} \qquad \left[\frac{\text{Btu}}{\text{lbm water}}\right] \tag{4.4}$$

Where $h_{w,in}$ is water inlet enthalpy [Btu/lbm] for compressed water enthalpy at inlet water pressure $p_{w,in}$ and inlet water temperature $T_{w,in}$ [116]. Inlet pressure is assumed equal to required steam outlet pressure (e.g., no pressure gradient in boiler).

Input Data Table 5.4

4.2.2.2 Once-through steam generator modeling (OTSG)

Once-through steam generators are modeled [12, 117], as shown in Figure 4.1. Fuel inputs include pipeline quality natural gas, produced gas, or produced crude oil. A binary choice is required for gaseous or liquid fuels. For gaseous fuels, a mixture of produced gas and purchased gas is allowed.

Steam Injection 2.1.1, 2.1.2

The operating conditions of combustion must be specified. These include the inlet air temperature $T_{a,in}$ [°F], the outlet exhaust temperature $T_{e,out}$ [°F] and the excess air in combustion $R_{a,comb}$ [mol O_2/ mol stoichiometric O_2].

Gaseous fuel combustion for steam generation The gas species tracked in the OTSG are described below in Section 6.4. For an arbitrary fuel makeup, the composition, average molar mass, and lower heating value (LHV) are calculated.

Steam Injection 2.3.1

OTSG inlet air composition, combustion stoichiometry, and excess air ratio are used to compute the mass of air required per lbmol of fuel consumed. For each reactive species, the reactants needed per mol of input fuel are computed:

Fuel Specs Table 2.3

$$N_i = \frac{x_{a,i}}{x_{a,O2}}\left(x_{f,C} + \frac{x_{f,H}}{4}\right) \qquad \left[\frac{\text{lbmol}}{\text{lbmol fuel}}\right] \tag{4.5}$$

where N_i = number of moles of air species i [mol]; x_a, i = mole fraction of species i in air [mol/mol]; $x_{f,C}$ = mol of carbon per mol of fuel (e.g., 2 for C_2H_6) [mol/mol]; and $x_{f,H}$ = mol of hydrogen per mol of fuel [mol/mol]. The sum over all species i gives air required for stoichiometric combustion, which is multiplied by the excess air ratio $R_{a,comb}$ to get real air requirements:

Steam Injection 2.4.3.1

$$N_a = R_{a,comb}\sum_{i=1}^{n} N_i \qquad \left[\frac{\text{lbmol air}}{\text{lbmol fuel}}\right] \tag{4.6}$$

Where $R_{a,comb}$ = ratio of combustion air to stoichiometric air [lbmol air / min lbmol air for combustion]. In this case there are n species present in air.

At constant pressure the change in enthalpy with temperature is given as:

$$\delta h = C_p \delta T \qquad \left[\frac{\text{Btu}}{\text{lbmol}}\right] \tag{4.7}$$

Specific heat capacity C_p as a function of T can be defined for gas species i as [118, Table A-2E]:

$$C_{p,i} = a_i + b_i T + c_i T^2 + d_i T^3 \qquad \left[\frac{\text{Btu}}{\text{bmol-°R}}\right] \tag{4.8}$$

Which can be integrated between outlet and inlet temperatures

$$h_i = \int_{T_{in}}^{T_{out}} C_{p,i}dT = a_i + \frac{b_i}{2}T^2 + \frac{c_i}{3}T^3 + \frac{d_i}{4}T^4 + e_i \qquad \left[\frac{\text{Btu}}{\text{lbmol}}\right] \tag{4.9}$$

where e_i is a constant of integration. OPGEE sets h = 0 at T = 300 K to solve for e_i. Terms a through d are given in OPGEE for N_2, O_2, CO_2, SO_2, air, $H_2O_{(v)}$ and fuel inputs (approximated as CH_4) [118].

Input Data Table 4.1

For example, inlet air enthalpy is computed using the inlet air temperature:

Input Data Table 4.1 - 4.6

$$h_{a,in} = \sum_{i=1}^{n}\left(a_i T_{a,in} + \frac{b_i}{2}T_{a,in}^2 + \frac{c_i}{3}T_{a,in}^3 + \frac{d_i}{4}T_{a,in}^4 + e_i\right) \qquad \left[\frac{\text{Btu}}{\text{lbmol air}}\right] \tag{4.10}$$

where again we have $i \in 1 \ldots n$ components in air.

The outlet lbmol of all gases per lbmol of fuel consumed are computed assuming complete combustion (e.g., no unburned hydrocarbons, no CO produced), and no reactions with nitrogen.

Steam Injection 2.5.1.1

The enthalpy of OTSG outlet exhaust $h_{e,out}$ is computed with eq. (4.10), using user input OTSG exhaust outlet temperature $T_{e,out}$. In practice, efficient steam generation is achieved by reducing $T_{e,out}$ to as low as practicable, thus removing as much heat as possible from OTSG combustion products. $T_{e,out}$ has a lower limit due to the need to avoid condensing corrosive flue gas moisture onto heat transfer tubes [117]. *Steam Injection 2.5.1.4*

A wide range of exhaust gas temperatures is cited. Buchanan et al. cite ideal (minimum) exhaust gas temperatures of 266 °F [130 °C] or higher [119, p. 78]. Other sources cite temperatures of 350 °F [115, p. 36], 400 °F [41, p. 227] and even greater than 550 °F for older Russian units [114, p. 181]

In some cases, the exhaust gas temperature is limited by the approach to the inlet water temperature. In SAGD operations hot produced water is used as inlet water, and $T_{e,out}$ comes to within 15 °C of the inlet water temperature. An air preheater would allow utilization of this excess energy if hot produced fluids are used for water source [119].

In addition to losses from flue gas exhaust, other losses occur in an OTSG. We lump all thermal losses into a thermal shell loss term. For simplicity, it is assumed that 4% of fuel enthalpy is lost as thermal shell loss ϵ_{th} [Btu/lbmol fuel consumed]. Other losses (start up inefficiencies, fouling, etc.) ϵ_{ot} are assumed ≈1% of the fuel LHV [Btu/lbmol fuel consumed]. These total losses are supported by references, which cite losses of approximately 4% [117]. *Steam Injection 2.6.2, 2.6.3*

The enthalpy available for transfer to the incoming water is given by the difference between incoming enthalpy sources (incoming combustion air, fuel inputs) and outgoing enthalpy sources (hot exhaust, shell losses, other losses): *Steam Injection 2.6.4*

$$\Delta h_{comb} = LHV + h_{a,in} - h_{e,out} - \epsilon_{th} - \epsilon_{ot} \qquad \left[\frac{\text{Btu to water}}{\text{lbmol fuel}}\right] \tag{4.11}$$

The efficiency of steam generation η_{OTSG} (LHV basis) can be computed by comparing the enthalpy imparted on steam to the higher heating value of the fuel inputs: *Steam Injection 2.6.5*

$$\eta_{OTSG} = \frac{\Delta h_{comb}}{LHV} \qquad \left[\frac{\text{Btu to steam}}{\text{Btu fuel}}\right] \tag{4.12}$$

Using the enthalpy provided to steam and ΔH_{comb}, the total fuel consumption rate required per day can be computed. *Steam Injection 2.7.2*

$$m_f = \frac{Q_{ws}\Delta h_{ws}}{\Delta h_{comb}} \qquad \left[\frac{\text{lbmol fuel}}{\text{d}}\right] \tag{4.13}$$

Liquid fuels for steam generation Liquid fuels can be used for steam generation. In general, these are produced heavy crude oils that are consumed on site for steam generation. This was common practice in California TEOR developments until the 1980s, when air quality impacts stopped the practice.

Table 4.1: Hydrogen constant a_H as a function of API gravity.

API gravity	a_H
0 - 9	24.50
10 - 20	25.00
21 - 30	25.20
31 - 45	25.45

Because liquid fuels do not have consistent molar compositons, computations generate lbm of fuel consumed. The heating value of crude oil as a function of API gravity is tabulated [84]. The bulk chemical composition of crude oil is calculated [84, p. 41]. The mass fraction hydrogen w_H as a function of crude specific gravity sg is given as:

Fuel Specs Table 1.1

Fuel Specs Table 1.2

$$w_H = a_H - 15\gamma_o \qquad [\text{mass frac. H}] \tag{4.14}$$

Where a_H is a constant that varies with crude API gravity (and therefore specific gravity) as show in Table 4.1.

The mass fraction of sulfur and other contaminants decreases with increasing API gravity, as seen in Figure 4.2 [120, Ch. 8, tables 3, 4] [120, Ch. 7, tables 2, 3, and 19] [121]. We therefore include default values of w_S that vary with API gravity from 5 wt.% (API gravity 4-5) to 0.5 wt.% (API gravity greater than 35). Nitrogen and oxygen content $w_N + w_O$ is assumed constant at 0.2 wt.% and in element balance it is assumed to be entirely made up of N. Mass fraction carbon w_C is calculated by difference using above mass fractions. Using the relative molar proportions of C, H, S, and N, the stoichiometric oxygen demand per carbon atom is computed assuming complete combustion.

Fuel Specs Table 1.2

Using the oxygen requirement for combustion and the excess air ratio $R_{a,comb}$, the lbmol of air required is computed similarly to eq. (4.6) above. The inlet air enthalpy for combustion is computed using eq. (4.10) above. The outlet exhaust composition is computed via element balance assuming complete oxidation (including S to SO_2). The outlet exhaust enthalpy is computed as in eq. (4.10) for gaseous fuels combustion. The energy balance for combustion of liquid fuels is computed as in eq. (4.11).

Steam Injection 2.4.4

4.2.2.3 *Gas turbine with heat recovery steam generator*

Cogeneration is used to co-produce electricity and steam for thermal oil recovery. These systems combine a gas turbine (GT) with a heat recovery steam generator (HRSG) to produce steam from the exhaust gas of the gas turbine (see Figure 4.3).

Gas turbine modeling The chemical kinetics software tool Cantera [122] is used with MATLAB to compute the efficiency, losses, and turbine exit temperature for four hypothetical gas turbines labeled A, B, C, and D. The general method is as follows:

- Fuel and air compositions are specified in OPGEE for purchased natural gas (95% CH_4, 3% C_2H_6, 1.5% C_3H_8, and 0.5% inert) and air (dry

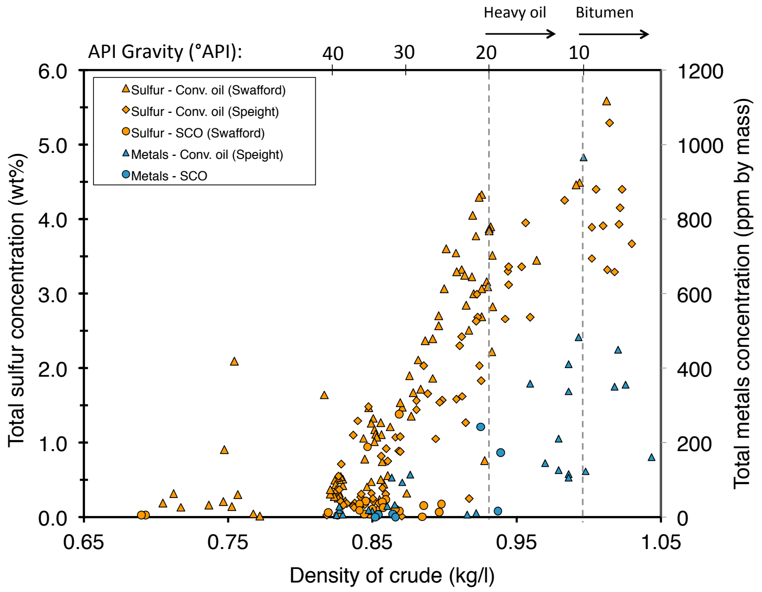

Figure 4.2: Increase of crude contaminant load with increase in crude specific gravity (decrease in API gravity). Data from: Speight (1994) and Swafford (2009).

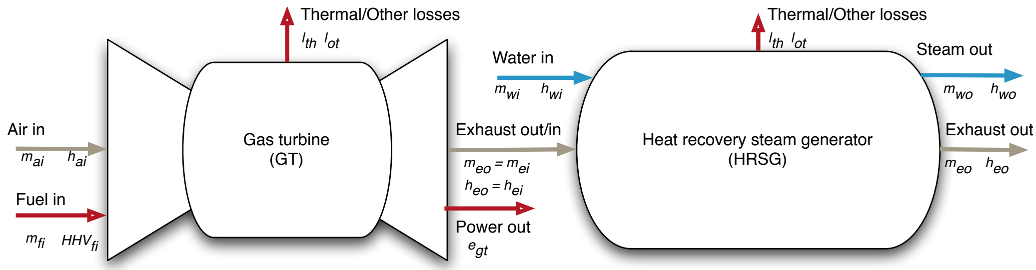

Figure 4.3: Gas turbine plus heat recovery steam generator model. Mass flows represented by m and energy flows represented by fuel lower heating value (LHV), electric power out (e) and enthalpy of gases (h).

air with 2% moisture).

- The LHV of the fuel is computed assuming complete combustion.
- Using the excess air fraction for a given turbine, the amount of O_2 (and therefore air) required relative to stoichiometric air requirements is used to compute relative air and fuel inputs into a mixture. The masses of fuel inputs $m_{f,in}$ and air inputs $m_{a,in}$ are normalized to a 1 kg mixture, as is default in Cantera.
- The fuel and air mixture is equilibrated using the assumption of adiabatic combustion.
- The enthalpy of products of adiabatic combustion is recorded as h_e, or the mass-specific enthalpy after combustion.

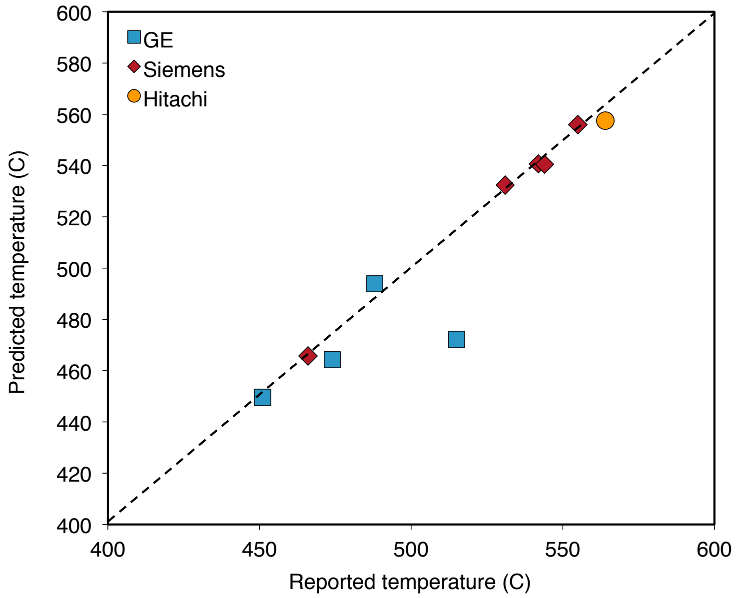

Figure 4.4: Predicted turbine exit temperatures for variety of turbines from literature (*y-axis*) as compared to reported value from the literature (*x-axis*).

- The enthalpy of products of combustion is computed when returned to initial conditions (300 K, 101.325 kPa) to compute the reference enthalpy $h_{e,atm}$.
- The difference between the enthalpy of hot combustion products and the reference enthalpy of completely cool exhaust is partitioned into losses (pressure and temperature losses due to real machine imperfections), work provided by turbine (W_{GT}), and enthalpy of hot exhaust ($h_{e,out}$).
- The resulting temperature of hot exhaust gases is computed.

The gas turbine model was tested against reported gas turbine data. Data for turbine heat rate, power output, turbine exhaust mass flow rate, and turbine exhaust temperature were collected for commercial turbines from Siemens, GE, and Hitachi [123–125]. The code assumes consistent 4% thermal and other losses ($\epsilon_{th} + \epsilon_{ot}$) for each turbine. Results show excellent agreement between predicted turbine exhaust temperature and manufacturer-reported turbine exhaust temperatures (Figure 4.4).

The GT model is used to model four hypothetical turbines A - D, using characteristics similar to those specified by Kim [126]. The results from our code are used to generate required inputs for turbines A-D including turbine exhaust temperature [F], turbine efficiency [Btu e- per Btu LHV fuel input], turbine specific power [Btu e-/lb exhaust], turbine excess air [lbmol O_2 / lbmol stoichiometric O_2], and turbine loss factor [Btu/Btu LHV fuel input]. These results are shown in Table 4.2.

Input data Table 3.1

Using turbine efficiency and turbine loss from Table 4.2, energy balances for each turbine are computed. Using turbine excess air ratios from Table

Steam Injection 4.3.1

Table 4.2: Gas turbine model results for hypothetical turbines A-D. These results serve as input data to OPGEE GT model.

Parameter	Unit	Turb. A	Turb. B	Turb. C	Turb. D
Turbine exhaust temp.	[°F]	932.0	947.9	950.0	1074.1
Turbine efficiency	$\left[\frac{\text{Btu e-}}{\text{Btu LHV}}\right]$	0.205	0.237	0.280	0.324
Turbine specific power	$\left[\frac{\text{Btu e-}}{\text{lb exhaust}}\right]$	69.5	85.4	108.0	155.7
Turbine excess air	$\left[\frac{\text{Mol } O_2 \text{ real}}{\text{Mol } O_2 \text{ stoich.}}\right]$	4.00	3.75	3.50	2.80
Turbine loss	$\left[\frac{\text{Btu loss}}{\text{Btu LHV}}\right]$	0.041	0.036	0.032	0.027

4.2, total air requirements per lbmol of fuel input to gas turbine are computed. Inlet air enthalpy is computed as shown in eq. (4.10). Moles of combustion products are computed via stoichiometric relationships. Using turbine exhaust temperature, turbine exhaust composition, and relationships from eq. (4.10), the enthalpy of gas turbine exhaust is computed.

Steam Injection 4.3.4.4

Steam Injection 4.3.5.2

The enthalpy of the gas turbine exhaust is the useful energy input to the HRSG. Steam production via the HRSG is modeled analogously to that of the OTSG.

Steam Injection 4.3.5.7

4.2.3 Defaults for steam injection

4.2.3.1 General default parameters

Parameters and variables in the steam injection model are listed below in Table 4.3.

Table 4.3: Default inputs for steam injection calculations.

Param.	Description	Eq. no.	Default	Lit. range	Unit	Sources	Notes
a_H	Crude hydrogen fraction constant	-	Table 4.1	-	[lbm H / lbm crude oil]	[84]	
$a_i \ldots e_i$	Species-specific heat capacity constants	-	var.	-	[various]	[118]	
C_p	Heat capacity at constant pressure	(4.8)	-	-	[Btu/lbmol-°R]		
η_{OTSG}	OTSG efficiency	(4.12)	-	-	[Btu steam / Btu LHV fuel]		
ϵ_{th}	Thermal losses from OTSG	-	0.04	-	[Btu/Btul fuel]	[117]	
$\epsilon_{ot,ng}$	Other losses from OTSG fueled with natural gas	-	5000	-	[Btu/lbmol fuel]	[117]	c
$\epsilon_{ot,co}$	Other losses from OTSG fueled with crude oil	-	250	-	[Btu/lbml fuel]	[117]	c
ϵ_{ws}	Steam pressure loss factor	-	1.25	0.1 - 0.5	[frac.]	[41]	d
λ_{ng}	Fraction natural gas	-	1	0 - 1	[frac]	-	b
λ_{pg}	Fraction processed associated gas	-	0	0 - 1	[frac]	-	b
$h_{a,in}$	Inlet air enthalpy	(4.10)	-	-	[Btu/lbmol]		
$h_{e,out}$	Enthalpy of OTSG exhaust	(4.10)	-	-	[Btu/lbmol]		
$h_{ws,f}$	Enthalpy of liquid phase water in steam	-	var.	180 - 730	[Btu/lbm]		
$h_{ws,g}$	Enthalpy of vapor phase water in steam	-	var.	1090 - 1205	[Btu/lbm]		
h_{ws}	Enthalpy of injected steam (< 100% quality)	(4.2)	-	-	[Btu/lbm]		
$h_{w,in}$	Inlet water enthalpy	-	9.8	-	[Btu/lbm]		
Δh_{ws}	Change in water enthalpy upon boiling	(4.4)	-	-	[Btu/lbm]		
Δh_{comb}	Heat available from combustion to water	(4.11)	-	-	[Btu / lbmol fuel]		
h_i	Enthalpy of species i	(4.9)	-	-	[Btu/lbmol]		
LHV	Lower heating value of fuel	-	var.	-	[Btu LHV / lbmol fuel]		
N_i	Number of moles of air species i	(4.5)	-	-	[lbmol]		
N_a	Number of moles of air for real (non-stoichiometric) combustion	(4.6)	-	-	[lbmol]		

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Param.	Description	Eq. no.	Default	Lit. range	Unit	Sources	Notes
$p_{w,in}$	Inlet water pressure	-	$= p_s$	-	[psia]		
p_{ws}	Steam pressure	(4.3)	-	-	[psia]		
Q_o	Quantity of oil produced	-	1000	-	[bbl oil/d]		
Q_{ws}	Steam required	(4.1)	-	-	[lbm water/d]	-	
$R_{a,comb}$	Excess air combustion ratio	-	1.2	1.075 - 1.25	[lbmol air/lbmol air stoich.]		e
ρ_w	Density of water	-	350.4	-	[lbm/ft^3]	[108]	f
γ_o	Crude specific gravity	(3.3)	-	-	[-]		
SOR	Ratio of steam injected to oil produced	-	3.0	2.5 - 6	[bbl water/bbl oil]	[112, 127]	g
$T_{a,in}$	Inlet air temperature	-	540	500 - 560	[°R]		h
$T_{e,out}$	Temperature of OTSG exhaust	-	810	725 - 910	[°R]	[various]	i
$T_{w,in}$	Inlet water temperature	-	40	-	[°F]		j
T_{ws}	Steam temperature	-	var.	-	[°F]		
w_H	Mass fraction hydrogen in crude	(4.14)	-	-	[lbm H / lbm oil]		
$x_{a,i}$	Mole fraction of species i in air	-	var.	-	[lbmol/lbmol]		m
x_C	Moles of carbon per mole of fuel	-	var.	-	[lbmol/lbmol]		a
x_H	Moles of hydrogen per mole of fuel	-	var.	-	[lbmol/lbmol]		a
X_s	Steam quality	-	0.8	-	[lbm vap./lbm steam]	[61]	k
y_{ng}	Binary variable: gaseous fuel in OTSG?	-	1	0 or 1	[y/n]	-	l
y_{co}	Binary variable: crude oil in OTSG?	-	0	0 or 1	[y/n]	-	l

a - See *'Fuel specs'* Table 2.3 for combustion factors for gas inputs.
b - Assumption: Gas is purchased due to typical low GORs for heavy crudes.
c - Assumption to account for incomplete combustion, fouling, warm up and cool-down, and other real-world inefficiencies.
d - Piping friction losses can represent 10-50% of the steam pressure developed at the outlet of the steam generator." [41, p. 228]
e - Conservative assumption for input excess air. Can be lower with special combustion equipment.
f - Fresh water input
g - Common SOR for efficient TEOR project. Range is quite variable, especially in early years of steam injection.
h - Equal to 300 K. Chosen for ease of gas turbine modeling.

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Param.	Description	Eq. no.	Default	Lit. range	Unit	Sources	Notes

i - Equal to 350 °F. Reported range is wide in literature. See [41, 114, 115, 119].
j - Assumption for cool water inlet.
k - Most commonly cited steam quality. Other qualities cited include 75%.
l - Assumption: Most steam generation in California and Alberta is natural gas fired.
m - See *'Input Data'* Table 2.4 for air composition.

Table 4.4: Indicators of SOR distributions for California and Alberta thermal EOR production.

	Mean - SOR_t	Mean - SOR_i
California - 2009	3.32	4.29
California - 2010	3.41	Unk.
Alberta - 2009	3.58	NA
Alberta - 2010	3.32	NA

4.2.3.2 *Default for steam-oil-ratio (SOR)*

Because the SOR is a key parameter driving GHG emissions from thermal oil production operations, we examine default values for SOR in more detail.

SOR data are collected for California and Alberta thermal oil recovery operations for 2010 and 2011 [103, 112, 127–129].

For California operations, incremental SOR is calculated for 2009 using volumes of steam injected and reported incremental production due to steam injection. 'Total' SOR is also calculated for 2009 using total production by field and total steam injection. For 2010, only monthly data are available, so incremental production data are not available. Therefore, only total SOR is reported.

For Alberta operations, data on bitumen produced and steam injected were collected for 24 thermal recovery projects (SAGD and CSS). No data were available on incremental rather than total production, and it is not clear what incremental production figures would represent bitumen operations where non-enhanced production would be very small.

Production volumes are binned by SOR for both regions and reported in Figure 4.5. Averages for SOR are presented in Table 4.4.

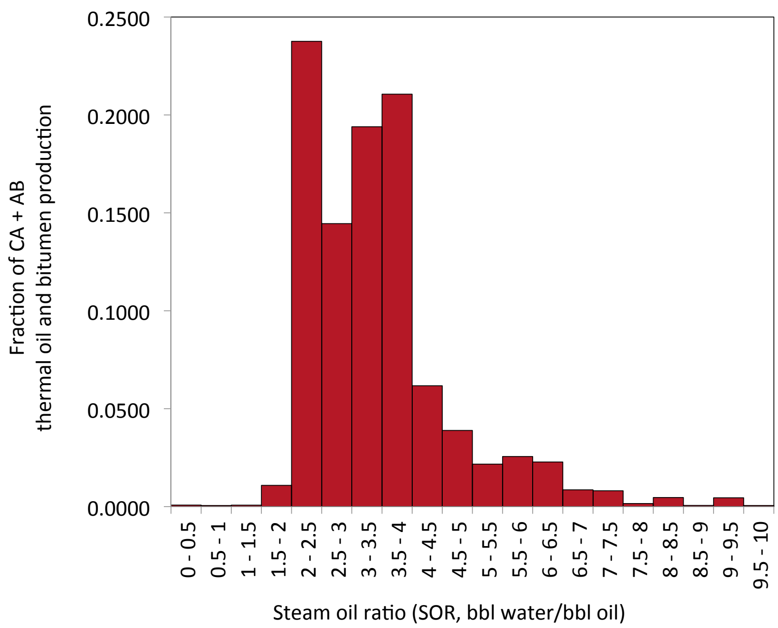

Figure 4.5: Distribution of SOR values for California and Alberta thermal EOR projects (steamflood, cyclic steam stimulation, steam-assisted gravity drainage).

4.3 Venting, flaring and fugitives (VFF)

4.3.1 Introduction to venting, flaring, and fugitive emissions

Venting, flaring and fugitive emissions can be a significant source of GHG emissions from oil production operations. We use these definitions here:

Venting emissions Purposeful release of non-combusted hydrocarbon gases to the atmosphere. Venting emissions generally occur during maintenance operations and other intermittent, infrequent activities.

Flaring emissions Purposeful combustion of hydrocarbon gases for disposal purposes. Results in CO_2 emissions rather than hydrocarbon species, with the exception of unoxidized hydrocarbon gases released due to flare inefficiency.

Fugitive emissions Non-purposeful or non-planned emissions of non-combusted hydrocarbon gases to the atmosphere. Fugitive emissions commonly result from leaking equipment and tanks.

Flaring is used to dispose of associated natural gas where there is no economic use for the gas. Associated gas evolves from crude oil as it is brought to surface temperatures and pressures, and is separated from oil before transport (see Section 3.4). Gas flaring resulted in emissions of 0.28 Gt CO_2 eq. in 2008, or about 1% of global GHG emissions [16]. Because gas flaring is used to dispose of gas (typically at remote locations), the volume of flared gas is uncertain.

Venting and fugitive emissions arise from oil field operations and devices. Sources include well workovers and cleanups, compressor startups and blowdowns, pipeline maintenance, gas dehydrators, AGR units, well cellars, separators (wash tanks, free knock outs, etc.), sumps and pits, and components (valves, connectors, pump seals, flanges, etc.). The heterogenous nature of these sources makes venting and fugitive sources difficult to monitor and track.

4.3.2 Calculation of flaring emissions

The NOAA National Geophysical Data Center have used earth observation satellite data for the estimation of gas flaring volumes since 1994 [16]. Gas flaring volumes are estimated for individual countries. Results show that gas flaring is concentrated in a small number of countries: in 2008, Russia and Nigeria together accounted for 40% of global gas flaring [16].

For the calculation of flaring emissions, the key input parameter is the flaring-to-oil ratio, or FOR [scf/bbl]. The FOR is converted into flaring volume using the volume of oil produced: VFF 2.1.1

$$Q_F = \frac{FOR \cdot Q_o}{10^6} \quad \text{[MMscf/d]} \tag{4.15}$$

where Q_F = flaring volume [MMscf/d]; FOR = flaring-to-oil ratio [scf/bbl of oil]; and Q_o = volume of oil produced [bbl/d].

Table 4.5: Stoichiometric relationships for complete combustion.

Fuel	Stoichiometric factor Π
CO_2	1
CH_4	44/16
C_2H_6	88/30
C_3H_8	132/44
C_4H_{10}	176/58

The OPGEE default FOR is given by country-level flaring data [130] and production volume [131] for 2010. The default flaring rate is retrieved from *'VFF'* sheet based on the field location specified in the *'User Inputs & Results'* sheet. The flaring rate in a specific oil field could be significantly higher or lower than the country-average. In the case no default is available for the specified field location, the world wide average is taken as the default value.

VFF Table 1.1

Carbon-dioxide-equivalent flaring emissions are calculated from the flaring volume using the flare efficiency η_F. The flare efficiency is the fraction of flared gas that is combusted. The remaining gas undergoes fuel stripping and is emitted as unburned hydrocarbons.

Flare efficiency varies with flare exit velocities and diameters, cross wind speed, and gas composition [14, 15]. For example, flare efficiencies in Alberta were estimated to range from 55% to $\geq$ 99%, with a median value of 95%, adjusted for wind speed distributions [14].

Emissions from non-combusted gas are calculated using the composition of associated gas from the *'Gas Balance'* sheet:

VFF 3.1.2

$$EM_{F,str} = Q_F(1-\eta_F)\sum_i x_i \rho_i GWP_i \qquad [\text{tCO}_2\text{eq/d}] \tag{4.16}$$

where $EM_{F,str}$ = flaring emissions from stripped, non-combusted gas [tCO_2eq/d]; η_F = flaring efficiency [%]; Q_F = flaring volume [MMscf/d]; i = index of gas species CO_2, CH_4, and volatile organic compounds C_2H_6, C_3H_8 and C_4H_{10}; x_i = molar fraction of gas component i [mol/mol]; ρ_i = density of gas component i [g/ft^3]; and GWP_i = GWP of gas component i [g CO_2 eq. /g gas].

Emissions from flare combustion products assume complete combustion:

VFF 3.1.1

$$EM_{F,comb} = Q_F \eta_F \sum_i x_i \rho_i \Pi_i \qquad [\text{tCO}_2\text{eq/d}] \tag{4.17}$$

where $EM_{F,comb}$ = flaring emissions from combusted gas [$tCO_2eq./d$]; Π_i = stoichiometric relationship between component i and product CO_2 for complete combustion [g CO_2/g gas]. Combustion factors are listed in Table 4.5.

Total flaring emissions are the sum of stripped and combustion emissiosn:

VFF 3.1

$$EM_{F,tot} = EM_{F,str} + EM_{F,comb} \qquad [\text{tCO}_2\text{eq/d}] \tag{4.18}$$

4.3.3 Calculation of venting emissions

Two types of venting occur in production and processing facilities: (i) operational venting, and (ii) venting to dispose of associated gas where there is no infrastructure for the use of gas. Operational venting is associated with production, processing and maintenance operations such as well workovers and cleanups, compressor blowdowns, and gas processing units (AGR and glycol dehydrator). These operations necessitate the venting of some gas. For instance, in a glycol dehydrator, steam generated in the reboiler strips water from the liquid glycol as it rises up the packed bed and the water vapor and desorbed natural gas are vented from the top of the stripper [2, p. 140].

Disposal venting is not common, due to safety concerns and environmental impacts, but may be practiced in some fields as an alternative to flaring. Venting as an alternative to flaring is not environmentally acceptable because methane and volatile organic compounds (VOCs) have higher GWPs compared to carbon dioxide. The venting of produced gas is a user input and is presented by the venting-to-oil ratio or VOR in the *'User Inputs & Results'* sheet. The calculation of emissions from vented gas is as shown in eq. (4.16).

Venting associated with production and surface operations is estimated using data collected in the 2007 oil & gas GHG emissions survey in California, performed by California Air Resources Board (ARB) [3], and the API manual of petroleum measurement standards [68].

4.3.3.1 Venting from general sources

Operational venting may be associated with units (e.g., compressors), events (e.g., well workovers), or distance of product transport (e.g., gathering pipelines). The amount of gas vented from various sources is calculated using the number of unit-years, mile-years, or events associated with the volume of oil produced. A unit-year (abbreviated unit-yr), for example, is one unit operating over a time period of one year.

The sources for general venting are listed in Table 4.6. The first step in calculating venting emissions from general sources is to estimate the number of unit-years, mile-years, or events associated with one barrel of oil, as shown in Table 4.6. The venting emissions from general sources are calculated as: *VFF 3.2.2*

$$EM_{V_G} = \sum_s c_{V_G,s} Q_o EF_{V_s} \qquad [\mathrm{g/d}] \tag{4.19}$$

where EM_{V_G} = venting emissions from general sources as listed in Table 4.6 [g/d]; $c_{V_G,s}$ = activity factor per unit of oil produced [unit-years/bbl, event/bbl or mile-years/bbl]; Q_o = total rate of oil production [bbl/d]; and EF_{V_s} = vent emissions factors for source s [g/unit-yr, g/mile-yr, or g/event]. $c_{V_G,s}$ is calculated as shown in Table 4.6 by multiplying $a_{V_G,s}$ which is the total number of units, events or miles surveyed [mile, unit, or event/yr] with $b_{V_G,s}$ which is the reported oil production volumes [bbl/yr].

Table 4.6: Emissions data used in the estimation of operational venting. Data from California oil fields, 2007 [3].

Source	Activity a_{V_G}	Unit	Oil Prod. (bbl/yr) b_{V_G}	Activity factor c_{V_G}	Unit [event/bbl]
Well workovers					
- Ultra-heavy	0	[event/yr]	614,683	0	[event/bbl]
- Heavy	12,889	[event/yr]	156,304,520	8.25×10^{-5}	[event/bbl]
- Light	5,424	[event/yr]	61,524,698	8.82×10^{-5}	[event/bbl]
- Ultra-light	599	[event/yr]	15,649,398	3.83×10^{-5}	[event/bbl]
Well cleanups					
- Ultra-heavy	0	[event/yr]	614,683	0	[event/bbl]
- Heavy	956	[event/yr]	156,304,520	6.12×10^{-6}	[event/bbl]
- Light	1977	[event/yr]	61,524,698	3.21×10^{-5}	[event/bbl]
- Ultra-light	187	[event/yr]	15,649,398	1.19×10^{-5}	[event/bbl]
Compressors	$\simeq$643[a]	[unit]	234,093,299	2.75×10^{-6}	[unit-yr/bbl]
Gathering pipelines	1218[b]	[mile]	234,093,299	5.20×10^{-6}	[mile-yr/bbl]
Pigging launcher openings	$\simeq$850[a]	[event/yr]	234,093,299	3.63×10^{-6}	[event/bbl]

a - Estimated from the total number of compressors which is shared by both the crude oil and dry gas businesses in California. The number of crude oil wells surveyed makes ≈60% of the total number of wells [3]. Accordingly the crude oil business is roughly allocated 60% of the total number of compressors reported in the survey.
b - Estimated by summing the number of miles associated with the crude oil business. Miles associated with dry gas production and gas storage facilities are not counted. For central gas processing facilities 75% of the miles are allocated to the crude oil business. This assumption is based on the split between the types of gases produced in California where ≈75% of the produced gas is associated gas [3].

The emissions factors and therefore the emissions estimates are specific to gas components (e.g., CO_2). The emissions factors for the venting of CO_2 and CH_4 are also estimated using data from the ARB survey [3]. Calculations of emissions factors are explained in Section 4.6.

4.3.3.2 *Venting from gas processing units*

Other than the general venting emissions sources that are listed in Table 4.6 there are major venting sources which include venting from gas processing units like glycol dehydrator unit and amine acid gas removal (AGR) unit. The methods for calculating venting from glycol dehydration and amine AGR units are volume based. For the glycol dehydrator unit the venting emissions of both CO_2 and CH_4 are calculated based on the gas unit volume as: *VFF 3.2.2*

$$EM_{V_{GD}} = Q_{GD} EF_{V_{GD}} \qquad [\mathrm{g/d}] \tag{4.20}$$

where $\mathrm{EM}_{V_{GD}}$ = venting emissions from the glycol dehydrator unit [g/d]; Q_{GD} = volume throughput of the glycol dehydrator unit [MMscf/d]; and $EF_{V_{GD}}$ = vent emissions factors for glycol dehydrator [g/MMscf]. The emissions factors as noted above are calculated from the ARB survey data [3] as explained above. The approximate volume throughput of the glycol dehydrator is determined by the gas balance and is calculated as shown in eq. (3.33). A description of the gas balance is found in Section 4.1.

The calculation of CH_4 venting from the AGR unit is performed as outlined above for the glycol dehydrator: *VFF 3.2.2*

$$EM_{V_{AGR}} = Q_{AGR} EF_{V_{AGR}} \qquad [\mathrm{g/d}] \tag{4.21}$$

where $EM_{V_{AGR}}$ = CH_4 venting emissions from the amine AGR unit [g/d]; Q_{AGR} = volume of the amine AGR unit [MMscf/d]; and $EF_{V_{AGR}}$ = vent emissions factor for AGR unit [gCH_4/MMscf]. On the other hand, the calculation of the CO_2 emissions from the amine AGR unit is determined by the gas balance where all the CO_2 left in the gas after flaring, fugitives and other venting is assumed to be absorbed and stripped in the amine treater.

4.3.3.3 *Venting from crude oil storage tanks*

The estimation of venting emissions from storage tanks is based on an emissions factor generated using data from the ARB survey. The emissions factor for CH_4 emissions was calculated as 49.2 gCH_4/bbl oil [3]. From the CH_4 emissions factor an emissions factor for VOCs was calculated given the average speciation profile of storage tank losses as shown in Table 4.7 [66, p. ES-2]. VOCs are mainly composed of C_2 to C_4 species which on average constitute 66.24% of the total storage tank losses. Accordingly the VOCs emissions factor was calculated as 145.75 gVOC/bbl oil. *VFF 3.2.3*

4.3.3.4 *Venting emissions gathering*

All the methods that have been discussed for the estimation of emissions from venting generate weight of gas species lost into the atmosphere. The

Table 4.7: Average W&S gas speciation profile.

Species	Mol%
CH_4	22.36
C_2H_6	20.49
C_3H_8	28.00
i-C_4H_{10}	6.84
n-C_4H_{10}	10.92
C5+	11.40

Table 4.8: Categorization of venting emissions sources by process stage.

Process stage	Venting emissions sources
Exploration	None
Drilling & development	None
Production & extraction	None
Oil field processing	Flaring substitute
	Gas dehydrator
	AGR unit
	Storage standing losses
	Storage working losses
Maintenance	Well workovers and cleanups
	Gathering pipelines maintenance and pigging
	Compressor blowdowns and startups
Waste disposal	None

balancing of the gas as is discussed in Section 4.1. Therefore weight is converted to volume using the densities of gas species (e.g., CH_4) [108]. The estimated weight of the gas species emissions is converted to [g/d] and divided by the species density [g/ft^3]. *VFF 3.2.2, 3.2.3.5*

After the weight and volume of emissions from each source is calculated, categorization of the emissions sources is required to allocate venting emissions to the different stages in OPGEE (e.g., *'Production & Extraction'*). Table 4.8 lists the sources of venting emissions under each process stage. Crude oil transport is not included because it is a separate process.

The emissions volumes from each process stage are converted into CO_2 equivalent GHG emissions using the IPCC GWPs of the gas constituents [132].

4.3.4 Calculation of fugitive emissions

The estimation of fugitive emissions from various components is difficult due to the non-planned nature of the losses and the number of sources. This includes fugitive emissions from active wells, well cellars, gas processing units, gathering pipelines, sumps and pits, storage tanks (e.g., free knock out vessel) and various equipment (valves, connectors, flanges, etc). Fugitives associated with production and surface operations are estimated using data collected by ARB [3], and emissions factors from the API workbook for oil and gas production equipment fugitive emissions [30].

The approach used to estimate fugitive emissions is similar to the ap-

Table 4.9: ARB data used in the estimation of fugitives. Data from ARB (2011).

Source	Activity a_{FG}	Unit	Oil prod. (bbl/yr) b_{FG}	Activity factor c_{FG}	Unit
Gathering pipelines[a]	1218	[mile]	234,093,299	5.20×10^{-6}	[mile-yr/bbl]
Separators	≃3557[b]	[unit]	234,093,299	1.52×10^{-5}	[unit-yr/bbl]
Sumps & pits	250	[unit]	234,093,299	1.07×10^{-6}	[unit-yr/bbl]
Valves (without open-ends)	≃2,647,951[c]	[unit]	234,093,299	1.13×10^{-2}	[unit-yr/bbl]
Pump seals	≃48,444[c]	[unit]	234,093,299	2.07×10^{-4}	[unit-yr/bbl]

a - Miles of pipeline. Same as Table 4.6.
b - Estimated by summing the number of separators associated with the crude oil business. Separators associated with dry gas production and gas storage facilities are not counted. For gas processing facilities 75% of the separators are allocated to the crude oil business. This assumption is based on the split between the types of gases produced in California where ≈75% of the produced gas is associated gas [3].
c - Estimated by summing the number of valves associated with crude oil service. Valves associated with natural gas service are shared by both the crude oil and dry gas businesses in California. The number of crude oil wells surveyed makes ≈60% of the total number of wells [3]. Accordingly the crude oil business is roughly allocated 60% of the valves associated with natural gas service.

proach used in the calculation of venting emissions. Fugitive losses are linked to various units (e.g., equipment and active wells), gathering pipeline miles, and volumes of gas processing units (e.g., AGR unit). Most fugitive losses are linked to units and equipment. The number of unit-years or mile-years associated with the total volume of oil produced is estimated using the ARB survey data [3]. *VFF 3.3.1*

4.3.4.1 Fugitives from general sources

Fugitive emissions from general sources are listed in Table 4.9. This table does not include all equipment fugitives. API research suggests that a good approximation of the number of components can be obtained by estimating the number of valves and pumps and then calculating the probable number of flanges, connectors, open-ended lines, and other components from the number of valves [30, p. 14]. During a field study of petroleum production operations, API found that the number of flanges is usually about the same as the number of valves, while the number of connectors (threaded pipes and tubing fittings) is about three times the number of valves. API also found that about 10% of all valves have one side that can be opened to the atmosphere (open-ended lines) and that the number of other components is approximately 5% of the number of valves. No correlation was found between the number of valves and the number of pumps [30, p. 14]. The number of valves and pump seals are estimated from the ARB survey

Table 4.10: Estimating the number of remaining components.

Component	Number
Valves (with open ends)	N
Pumps	No correlation
Flanges	N
Connectors	$3N$
Open-ends	$0.1N$
Others[a]	$0.05N$

a - Includes compressor seals, diaphragms, drains, etc.

data as shown in Table 4.9 and the number of remaining components is estimated from the number of valves using the API method.

As shown in Table 4.9 the number of unit-years or mile-years associated with one barrel of oil production is estimated using data from the ARB survey [3]. The number of remaining sources of fugitive emissions is estimated from the number of valves as outlined in Table 4.10. Therefore the total number of unit-years or mile-years associated with the amount of oil produced in OPGEE and the fugitive emissions from the various sources listed in Tables 4.9 and 4.10 is calculated as:

VFF 2.3 3.3.1

$$EM_{F_G} = \sum_s c_{F_G,s} Q_o EF_{F_s} \qquad [\mathrm{g/d}] \tag{4.22}$$

where EM_{F_G} = fugitive emissions [g/d]; $c_{F_G,s}$ = number of unit-years or mile-years per barrel of oil and is calculated as shown in Table 4.9; Q_o = total rate of oil production entered by the user [bbl/d]; and EF_{F_s} = fugitive emissions factors for source s [g/unit-yr, g/mile-yr]. $c_{F_G,s}$ is calculated by multiplying $a_{F_G,s}$ which is the total number of units or miles surveyed [mile, unit] with $b_{F_G,s}$ which is the reported oil production volumes [bbl/yr]. For the estimation of fugitives from active wells and well cellars the number of active wells or producing wells is given in the *'User Inputs & Results'* sheet and the number of well cellars is assumed equal to the number of active wells.

The emissions factors generated from the ARB survey, and therefore the calculated emissions, are specific to gas components (e.g., CO_2). The calculation of the emissions factors is explained in Section 4.6. Emissions factors for equipment fugitives that are listed in Table 4.10 are taken from the API documentation [30, p. 20]. The emissions factors from API are not speciated. The speciation in Table 4.11 is used to allocate the total hydrocarbon (THC) emissions calculated using the API emissions factors to the main gas components, i.e. methane and VOC [30, p. 15].

As shown in Table 4.11 the fractions are different for fugitives from different streams. For the division of THC emissions, 75% of the components are assumed in oil service, and 25% in gas service. This assumption is based on an example from the API methods on the calculation of fugitive emissions from a crude oil production operations which co-produce natural gas [30, p. 16]. For oil service components the fraction is determined by the API gravity of the oil. For the calculation of the volume of VOC emissions the

Table 4.11: Speciation fractions for total hydrocarbon (THC) emissions calculated using API emissions factors [-].

Emissions component	Gas	Heavy oil	Light oil
Methane	0.687	0.942	0.612
VOC	0.171	0.030	0.296

VOC is broken down into 31% C_2, 42% C_3, and 27% C_4. The fraction of C_5+ VOC components is negligible. This breakdown is based on average THC emissions speciation profiles [66, p. ES-2].

4.3.4.2 *Fugitives from gas processing units*

Other than the general fugitive emissions sources that are listed in Tables 4.9 and 4.10, fugitives sources include gas processing units like glycol dehydrator units and amine acid gas removal (AGR) units. The methods for calculating fugitives from glycol dehydration and amine AGR units are volume based. The fugitive emissions of both CO_2 and CH_4 are calculated based on the gas unit throughput volume as: *VFF 2.3 3.3.1*

$$EM_{F_{GP}} = Q_{GP} EF_{F_{GP}} \qquad [\text{g/d}] \tag{4.23}$$

where $EM_{F_{GP}}$ = fugitive emissions from the gas processing unit [g/d]; Q_{GP} = volume throughput of the gas processing unit [MMscf/d]; and $EF_{F_{GP}}$ = fugitive emissions factors for gas processing unit [g/MMscf]. The emissions factors are calculated from the ARB survey data [3] as explained in Section 4.6.2. The emissions factor for fugitive CH_4 emissions from AGR unit is taken from [133, p. 23]. The approximate volume of the gas processing unit is determined by the gas balance and is calculated as shown in eq. (3.33). A description of the gas balance is found in Section 4.1.

4.3.4.3 *Fugitive emissions gathering*

All the methods that have been discussed for the estimation of fugitives end up generating mass of gas species lost into the atmosphere. The balancing of the gas is discussed in Section 4.1. Therefore mass is converted to volume using the densities of gas species [108]. After the mass and volume of emissions from each source is calculated, categorization of the emissions sources is required to allocate fugitive emissions to the different stages in OPGEE (e.g., '*Production & Extraction*'). Table 4.12 lists the sources of fugitive emissions under each process stage. Fugitive emissions from crude oil transport are not included because it forms a separate process. *VFF 3.3.1*

The emissions volumes of each process stage are converted into CO_2 equivalent GHG emissions using the IPCC GWPs [132].

4.3.5 Default values for VFF emissions

The default emissions factors and the number of associated unit-years, mile-years or events/yr are generated from the ARB survey data [3]. The estima-

Table 4.12: Categorization of fugitive emissions sources by process stage.

Process stage	Fugitive emissions sources
Exploration	None
Drilling and development	None
Production and extraction	Active wells
	Well cellars
Oil field processing	Separators
	Gas dehydrator
	AGR unit
	Gathering pipelines
	Sumps and pits
	Components (valves, connectors, flanges, etc)
Maintenance	None
Waste disposal	None

tion of the number of unit-years, mile-years or events/yr was previously discussed. The user is allowed to overwrite these defaults. As these defaults represent the average case in California, in some cases they might not be a good representation of the level of venting and fugitives in other areas of the world. This is particularly true where practices and environmental regulations are significantly different than California regulations. The average EPA emissions factors for fugitives from the various components listed in Table 4.10 are used as default [30, p. 20]. These defaults represent the average US case and can also be overwritten by the user to represent changes in equipment condition, practices, and environmental regulations.

Table 4.13: Default inputs for venting, flaring, and fugitive emissions.

Param.	Description	Eq. no.	Default	Literature range	Unit	Sources	Notes
$c_{F_G,s}$	Number of fugitive source per oil barrel	-	Table 4.9	-	[unit-yr/bbl]	[3]	a
$c_{V_G,s}$	Number of vent source per oil barrel	-	Table 4.6	-	[event/bbl]	[3]	b
$EF_{F_{GP}}$	Fugitive em. factors for gas proc. unit	-	Section 4.6	-	[g/MMscf]	[3, 133]	
EF_{F_s}	Fugitive emissions factors for source s	-	Tables 4.18 & 4.19	-	[g/unit-yr]	[3, 30]	c
$EF_{V_{AGR}}$	Vent emissions factors for AGR	-	0	-	[gCH_4/MMscf]	[3]	d
$EF_{V_{GD}}$	Vent emissions factors for gas dehydrator	-	Section 4.6	-	[g/MMscf]	[3]	
EF_{V_s}	Vent emissions factors for source s	-	Table 4.17		[g/event]	[3]	e
$EM_{F,comb}$	Flare combustion emissions	(4.17)	-		[tCO_2eq/d]		
EM_{F_G}	Fugitive emissions general	(4.22)	-	-	[g/d]		
$EM_{F_{GP}}$	Fugitive emissions from gas proc. unit	(4.23)	-	-	[g/d]		
$EM_{F,str}$	Flare stripping emissions	(4.16)	-	-	[tCO_2eq/d]		
$EM_{V_{AGR}}$	Vent emissions from AGR	(4.21)	-	-	[g/d]		
$EM_{V_{GD}}$	Vent emissions from gas dehydrator	(4.20)	-	-	[g/d]		
EM_{V_G}	Vent emissions general	(4.19)	-	-	[g/d]		
η_F	Flaring efficiency	-	0.95	0.54 - $\geq$ 0.99	[-]	[14, 15, 134]	f
FOR	Flaring-to-oil ratio	-	177	11-3010	[scf/bbl]		
GWP_i	Global warming potential for species i	-	*'Input data'* Table 2.1	-	[$gCO_2eq.$/g]	[132]	g
Π_i	Stoichiometric combustion ratios	-	Table 4.5	-	[gCO_2/g]	-	h
Q_{AGR}	Volume of amine treater	-	*'Gas Balance'*	-	[MMscf/d]		
Q_{GD}	Volume of gas dehydrator	-	*'Gas Balance'*	-	[MMscf/d]		
Q_F	Flaring volume	(4.15)	-	-	[MMscf/d]		
Q_o	Volume of oil production	-	1500	-	[bbl/d]		
Q_{GP}	Volume of gas processing unit	-	*'Gas Balance'*	-	[MMscf/d]		
ρ_i	Gas density for species i	-	*'Input Data'* Table 2.2	-	[g/ft^3]	-	i

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Param.	Description	Eq. no.	Default	Literature range	Unit	Sources	Notes
x_i	Mole fraction of gas composition	-	*'Gas Balance'* Table 1.1	-	[-]	[3]	j

a - Most of the fugitives are associated with units. Therefore the most common unit for the number of sources per oil barrel is [unit-yr/bbl]. Other units include [mile-yr/bbl] for fugitives associated with pipeline miles.
b - Most venting is associated with events. Therefore the most common unit for number of sources per oil barrel is [event/bbl]. Other units include [unit-yr/bbl] and [mile-yr/bbl] for venting associated with units and pipeline miles, respectively.
c - Most of the fugitives are associated with units. Therefore the most common unit for fugitive emissions factors is [q/unit-yr]. Other units include [g/mile-yr] for fugitives associated with pipeline miles.
d - Venting of CO_2 from the AGR unit is calculated from the gas balance.
e - Most of the venting is associated with events. Therefore the most common unit for vent emissions factors is [g/event]. Other units include [q/unit-yr] and [g/mile-yr] for venting associated with units and pipeline miles, respectively.
f - Average efficiency for Alberta found to be ≈0.95 across 4 years of data using known wind distributions and flaring volumes [14]. Very low efficiencies are seen in high cross winds and with high fractions of non-combustible gas components (e.g., CO_2, N_2).
g - 100-year GWPs from the IPCC Fourth Assessment Report [132].
h - Standard combustion stoichiometry assuming complete combustion.
i - Standard gas densities [108]
j - Gas composition can vary. Default gas composition given from [3].

Table 4.14: Types and size ranges of the drivers embedded in OPGEE.

Type	Fuel	Size range [bhp]
Internal combustion engine	Natural gas	95 - 2,744
Internal combustion engine	Diesel	1590 - 20,500
Simple turbine	Natural gas	384 - 2,792
Motor	Electricity	1.47 - 804

4.4 Drivers

Drivers (also known as prime movers) of pumps, compressors, and on-site electricity generators come in different types and sizes. Drivers in OPGEE include natural gas driven engines, natural gas turbines, diesel engines, and electric motors. The size and energy consumption of the driver is required to convert power requirements (e.g., downhole pump brake horsepower) into energy consumption as explained in Section 3.3.2.10. A database of drivers specifications of different types and sizes is included in OPGEE. Table 4.14 shows the types and size ranges of the drivers included in OPGEE.

The specifications of natural gas driven engines and diesel driven engines are taken from Caterpillar technical sheets [89]. The specifications of natural gas turbines are taken from Solar Turbines technical sheets, a subsidiary of Caterpillar [135]. The specifications of electric motors are taken from General Electric technical sheets [90]. Data were reported in different forms and with different levels of completeness.

The data for each driver model was converted into [bhp] for power and [Btu/bhp-hr] for energy consumption. In some cases the data on engine power was given in [bhp] and energy consumption is given in [Btu/bhp-hr], so no conversion is required. In other cases only data on the electricity generator set is given. The generator set includes an engine and an electricity generator. The brake horsepower of the engine is calculated from the electric power of the generator set as:

$$P_D = \frac{P_{GS}}{\eta_G} \cdot 1.34 \qquad [\text{bhp}] = \frac{[\text{ekW}]}{[\text{-}]}\left[\frac{\text{bhp}}{\text{bkW}}\right] \tag{4.24}$$

where P_D = driver brake horsepower [bhp]; P_{GS} = electric power of the electricity generator set [ekW]; and η_G = efficiency of the electricity generator (not including engine) [-]. For the calculation of the electric power [ekW] of the electricity generator sets Caterpillar assume an electricity generator (without engine) of efficiency 96% [136, p. 4]. Accordingly η_G in eq. (4.24) is equal to 0.96 [-].

In the case where the overall efficiency of the electricity generator set is given, but the energy consumption of the engine component is not, the latter is calculated as:

$$
\begin{aligned}
e_D &= \frac{3.6}{\eta_{GS}}\eta_G \qquad \left[\frac{\text{MJ}}{\text{bkW-hr}}\right] = \frac{\left[\frac{\text{MJ}}{\text{bkW-hr}}\right]}{[\text{-}]}[\text{-}] \\
e_D &= \frac{E_D \cdot 947.8}{1.34} \qquad \left[\frac{\text{Btu}}{\text{bhp-hr}}\right] = \frac{\left[\frac{\text{MJ}}{\text{bkW-hr}}\right]\left[\frac{\text{Btu}}{\text{MJ}}\right]}{\left[\frac{\text{bhp}}{\text{bkW}}\right]}
\end{aligned}
\tag{4.25}
$$

where e_D = driver energy consumption [Btu/bhp-hr]; η_{GS} = efficiency of generator set (engine + generator) [-]; η_G = efficiency of generator (without engine) [-].

The diesel engines energy consumption is reported in the technical sheets in the form of gallons per hour [gal/hr]. This is converted into [Btu/bhp-hr] by:

$$
e_D = \frac{e_D 137,380}{P_D} \qquad \left[\frac{\text{Btu}}{\text{bhp-hr}}\right] = \frac{\left[\frac{\text{gal}}{\text{hr}}\right]\left[\frac{\text{Btu}}{\text{gal}}\right]}{[\text{bhp}]}
\tag{4.26}
$$

where e_D = driver energy consumption [Btu/bhp-hr]; P_D = driver brake horsepower [bhp]. The driver brake horsepower, P_D , is calculated from the electric power [ekW] of the given generator set as shown in eq. (4.24).

The calculation used to convert the efficiency of electric motors from the General Motors technical sheets into energy consumption in [Btu/bhp-hr] is very similar to the calculation of the energy consumption of the engine component from the overall efficiency of the generator set in eq. (4.25):

$$
e_D = \frac{3.6}{\eta_M} \qquad \left[\frac{\text{MJ}}{\text{kWh}}\right] = \frac{\left[\frac{\text{MJ}}{\text{kWh}}\right]}{[\text{-}]}
\tag{4.27}
$$

where e_D = driver energy consumption [Btu/bhp-hr]; η_M = electric motor efficiency [-]. The energy consumption is converted to [Btu/bhp-hr] as shown in eq. (4.25).

As mentioned before in Section 3.3.2.10 OPGEE retrieves the energy consumption of the appropriate driver based on the user input and the required size.

Table 4.15: Default inputs for drivers calculations.

Param.	Description	Eq. no.	Default	Literature range	Unit	Sources	Notes
e_D	Driver energy consumption	(4.25)	-	-	[Btu/bhp-hr]		a
η_M	Electric motor efficiency	-	var.	0.84-0.96	[-]	[90]	b
$\eta_G S$	Efficiency of electricity generator set	-	var.	0.36-0.40	[-]	[89]	c
η_G	Efficiency of electricity generator (no engine)	-	0.96	-	[-]	[136, p. 4]	d
P_D	Driver brakehorse power	(4.24)	-	-	[bhp]		
P_{GS}	Electric power of elect. gen. set	-	var.	275-2000	[ekWh]	[89]	e

[a] The cited equation is for gas drivers. Energy consumption of diesel and electricity drivers is calculated in eq. (4.26) and (4.27), respectively.
[b] Motor efficiency ranges from 0.84 to 0.96 for commonly applied motor size ranges [90].
[c] Literature range cited only for gas generator sets with gas engine sizes ranging from 1535-2744 [bhp].
[d] Standard electicity generator efficiency [136, p. 4].
[e] Literature range cited for diesel generator sets [89].

4.5 Electricity

The *'Electricity'* sheet calculates the energy consumption of onsite electricity generation. The *'Electricity'* sheet does not include electricity co-generation in steam generation system. Available generation technologies include natural gas generator set, natural gas turbine, and diesel generator set. The user enters the capacity of onsite electricity generation as a fraction of the electricity required. The fraction of electricity above 1.0 is exported. In the *'Electricity'* sheet the amount of electricity generated onsite is calculated as:

$$E_{el,gen} = \lambda_{el} \cdot E_{el,req} \qquad \left[\frac{\text{MMBtu}}{\text{d}}\right] \tag{4.28}$$

where $E_{el,gen}$ = onsite electricity generation [MMBtu/d]; λ_{el} = fraction of required electricity generated onsite; and $E_{el,req}$ = electricity required. The electricity required is calculated in the *'Energy Consumption'* sheet.

The energy consumption of the generator is calculated from the appropriate driver in the *'Drivers'* sheet as:

$$e_{GS} = \frac{e_D}{0.75\eta_G} \qquad \left[\frac{\text{Btu}}{\text{kWh}}\right] = \frac{\left[\frac{\text{Btu}}{\text{bhp-hr}}\right]}{\left[\frac{\text{bkW}}{\text{bhp}}\right] \text{[-]}} \tag{4.29}$$

where e_{GS} = energy consumption of generator set [Btu/kWh]; η_G = efficiency of the electricity generator (not including driver) [-]; and e_D = driver energy consumption [Btu/bhp-hr]. The appropriate driver is determined by the required size based on the electricity generation capacity as calculated in eq. (4.28).

Once the onsite electricity generation, $E_{el,gen}$, and the energy consumption of the electricity generator, e_{GS}, are calculated the total energy consumption of onsite electricity generation is calculated as:

$$E_{EG} = E_{el,gen} \cdot 0.000293 \cdot e_{GS} \qquad \left[\frac{\text{MMBtu}}{\text{d}}\right] = \left[\frac{\text{MMBtu}}{\text{d}}\right]\left[\frac{\text{kWh}}{\text{Btu}}\right]\left[\frac{\text{Btu}}{\text{kWh}}\right] \tag{4.30}$$

where E_{EG} = energy consumption of onsite electricity generation [MMBtu/d].

In addition to calculating the energy consumption of onsite electricity generation, this sheet determines the grid electricity mix and the allocation method of credits from electricity export (see Section 4.7 on the *'Fuel Cycle'* sheet). The user is allowed to choose between two allocation methods for credit from electricity export: (i) allocation by substitution of grid electricity, and (ii) allocation by substitution of natural-gas-based electricity. The default allocation method is the substitution of natural-gas-based electricity. This method prevents achieving unreasonably large credits from operations with significant power generation.

Table 4.16: Combustion technologies and fuels included in OPGEE.

	Natural gas	Diesel	Crude	Residual oil	Pet. coke	Coal
Industrial boiler	✓	✓	✓	✓	✓	✓
Turbine	✓	✓				
CC gas turbine	✓					
Reciprocating engine	✓	✓				

4.6 Emissions factors

Emissions factors are required for the calculation of GHG emissions from combustion (fuel combustion) and non-combustion (venting and fugitives) sources.

4.6.1 Combustion emissions factors

The emissions factors for fuel combustion are from CA-GREET [76]. Table 4.16 shows the technologies and fuels included. Gas species tracked include VOC, CO, CH_4, N_2O, and CO_2. Emissions are converted into carbon dioxide equivalent using IPCC GWPs [132] as shown in eq. (4.31).

$$EM_{CO_2eq,i} = EM_i \cdot \mathrm{GWP}_i \qquad [\mathrm{gCO_2eq}] \tag{4.31}$$

where $EM_{CO_2eq,i}$ = emissions of species i in carbon dioxide equivalent [$\mathrm{gCO_2eq}$]; EM_i = emissions of species i [g]; and GWP_i = GWP of species i [$\mathrm{gCO_2eq./g}$]. GWPs are discussed in Section 6.1.

4.6.2 Non-combustion emissions factors

Section 4.3 describes how emissions factors for venting and some fugitives sources are generated from the ARB survey data [3]. Emissions factors from ARB are specified by gas component. The ARB survey data used to generate emissions factors for venting are shown in Table 4.17.

The emissions factors for venting by gas component were calculated using ARB survey data as:

$$\begin{aligned} EF_{CO_2Vent} &= \frac{a_{EF_V}}{c_{EF_V}} 10^6 \qquad \left[\frac{\mathrm{g}}{\mathrm{event}}\right], \text{ etc.} \\ EF_{CH_4Vent} &= \frac{b_{EF_V}}{c_{EF_V}} 10^6 \qquad \left[\frac{\mathrm{g}}{\mathrm{event}}\right], \text{ etc.} \end{aligned} \tag{4.32}$$

where EF_{CO_2Vent} = emissions factor of CO_2 venting [g/event; g/mile-yr; g/MMscf]. For a description of a_{EF_V}, b_{EF_V}, and c_{EF_V} parameters see Table 4.17.

Similar calculations were performed for emissions factors for fugitives from the sources listed in Table 4.18. Emissions factors for fugitives from other sources (valves, flanges, etc) are taken from API [30, p. 20].

Table 4.17: ARB data used in the calculation of venting emissions factors (unit specified below) [3].

Source	Total CO_2 emissions (tonne/yr) a_{EF_V}	Total CH_4 emissions (tonne/yr) b_{EF_V}	# units (event/yr, otherwise noted) c_{EF_V}
Well workovers			
- Ultra-heavy	0	0	–
- Heavy	405	1,428	12,889
- Light	225	575	5,424
- Ultra-light	9	65	599
Well cleanups			
- Ultra-heavy	0	0	–
- Heavy	103	90	956
- Light	113	201	1977
- Ultra-light	3	21	187
Compressor startups	4	69	1071
Compressor blowdowns	172	3,238	1071
Gathering pipelines maintenance	2659	2490	2295 (mile)
Gathering pipelines pigging	104	5	1417
Gas dehydrator[a]	308	10829	701123.3 (MMscf/yr)

[a] Emissions factors of venting from gas dehydrator are calculated on volume throughput basis.

Table 4.18: ARB data used in the calculation of fugitives emissions factors (unit specified below).

Source	Total CO_2 emissions (tonne/yr) a_{EF_F}	Total CH_4 emissions (tonne/yr) b_{EF_F}	# units (event/yr, otherwise noted) c_{EF_F}
Active wells			
- Ultra-heavy	0	0	–
- Heavy	66	155	36,619
- Light	459	1,415	14,261
- Ultra-light	19	139	1,323
Well cellars			
- Ultra-heavy	–	3	22
- Heavy	–	933	7,461
- Light	–	850	4,998
- Ultra-light	–	369	2,168
Gathering pipelines	327	867	2,295 (mile)
Separators	11	170	4,618
Sumps and pits	–	264	250
Gas dehydrator[a]	16,682	10,802	701123.3 (MMscf/yr)

[a] Emissions factors of fugitives from gas dehydrator are calculated on volume basis.

Table 4.19: An example of EPA emissions factors for oil and gas production components (g/unit-yr).

Source	CH_4	VOC emissions
Non-leaking components (< 10,000 ppmv)		
Valves		
Gas service	148	37
Heavy oil service	69	2
Light oil service	101	49
Connectors		
Gas service	60	15
Heavy oil service	62	2
Light oil service	52	25
Leaking components (> 10,000 ppmv)		
Valves		
Gas service	590,678	147,025
Heavy oil service	–	–
Light oil service	465,479	225,134
Connectors		
Gas service	159,029	39,584
Heavy oil service	–	–
Light oil service	141,668	68,519

Emissions factors for gas dehydrators and AGR units are calculated on volume basis (i.e., in grams per MMscf processed gas). The emissions factors for venting and fugitives from the gas dehydrator are calculated as shown in Tables 4.17 and 4.18. As mentioned in Section 3.4.2.3, venting from the AGR unit is calculated from the gas balance of OPGEE by assuming that all CO_2 left in the gas stream after flaring, fugitives, and other venting is vented. The emissions factor for CH_4 fugitives from the AGR unit is 965 scf CH_4/MMscf of gas throughput [133, p. 23].

EPA emissions factors for fugitives from the components listed in Table 4.10 are reported by API as total hydrocarbons (THC) by service type, i.e. gas service, heavy oil service [30, p. 20]. As explained in Section 4.3.4.1 the THC emissions factors are calculated assuming that 25% of the components are associated with gas service and the remaining 75% are associated with oil service. An example of EPA emissions factors for oil and gas production components after speciation is shown in Table 4.19 for valves and connectors [30, p. 20]. Fugitives from non-leaking components are negligible. The user determines the percentage of leaking components in the '*VFF*' sheet.

Emissions factors for land use change are discussed in Section 3.2. Table 3.2 shows the emissions factors per unit of crude oil produced for low, medium, and high intensity development in low, medium, and high ecosystem productivity environments [77].

4.7 Fuel cycle

For fuels consumed in OPGEE, the upstream or "fuel cycle" energy consumption and GHG emissions are required to calculate the indirect energy consumption and GHG emissions of imported fuel. For example, if purchased electricity is used on site, the emissions associated with generating and transporting that purchased electricity must be accounted for and added to the direct emissions burden. Similarly, any co-products that are sold separately from the produced oil (e.g., natural gas, electricity, NGL) must be assigned a co-production credit for emissions avoided from the system that they displace. The approach here can therefore be described as a co-product emissions assessment via system boundary expansion rather than via allocation between products [137, 138]. In all cases, the energy consumption and GHG emissions of the displaced production system is calculated from CA-GREET [76].

For the calculation of credit from the export of natural gas or natural gas liquid (NGL), the natural gas production system is displaced. For NGL export, the natural gas production system is displaced because NGL is a byproduct of gas production and does not have an independent fuel cycle. Credit is not given for avoided gas transport emissions, because it is assumed that the gas will be transported to a remote consumer.

For the calculation of credit from electricity exports, the boundary of the system is extended to the user "plug": the displaced system includes electricity generation and transport to the end user. This choice was made because exported electricity will naturally flow to the nearest consuming entity and not require long-distance transport. OPGEE calculates the energy consumption and GHG emissions of electricity generation based on the grid electricity mix (entered in the '*Electricity*' sheet) using CA-GREET data of different electricity sources (natural gas, biomass, etc).

5 Gathering sheets

This section explains three sheets in OPGEE which are used to collect output from intermediate calculations in process stage and supplemental sheets. This collected output is used to calculate the overall WTR energy consumption and GHG emissions of the study crude. These gathering sheets are the *'Energy Consumption'*, *'GHG Emissions'*, and *'User Inputs & Results'* sheets.

5.1 *'Energy Consumption'* gathering sheet

In the *'Energy Consumption'* gathering sheet, energy use is summed in order of process stages, from Exploration to Waste disposal. For consistency, all energy inputs are summed on a daily basis, either as thermal energy (MMBtu/d) or as electrical energy (kWh/d). All energy types are classified using a fuel code. The primary energy types included are: 1A) Natural gas; 1B) Natural gas liquids; 2) Diesel fuel; 3) Electricity; 4) Crude oil.

First, the amount and type of fuel consumed by each component of the model (e.g., downhole pump, gas compressor, etc) is collected using nested if then statements. Second, the fuel consumption is summed by fuel type (e.g., natural gas, diesel) to calculate the gross energy consumption.

Energy Consumption Table 2

Energy Consumption Table 3

The gross energy consumption can include double counted energy. For example, the electricity consumed to drive a pump may be generated onsite and the energy consumed to generate that electricity would also be counted as natural gas or diesel, resulting in double counting.

The net energy consumption is calculated by fuel type. The net energy consumption is equal to the gross energy consumption for all fuels except for electricity. The net energy consumption of electricity is calculated as:

Energy Consumption Table 5

$$E_{el,net} = E_{el,gr} - E_{el,gen} \qquad \text{[MMBtu]} \tag{5.1}$$

where $E_{el,net}$ = net electricity consumption [MMBtu/d]; $E_{el,gr}$ = gross electricity consumption [MMBtu/d]; and $E_{el,gen}$ = total electricity generated onsite [MMBtu/d]. The total electricity generated onsite includes electricity generated using an onsite generator or simple turbine and electricity co-generated in the steam generation system, if applicable. In other words, the net electricity consumption is equal to the electricity imported from the grid, if any.

Once the net energy consumption is calculated by fuel type the energy exports/imports are calculated by fuel type. Energy exports/imports are used to calculate indirect (offsite) energy consumption and GHG emissions by fuel type. Indirect energy consumption and GHG emissions are associated with the production and transport (production only in case of exports)

Energy Consumption Table 4

of the fuel consumed directly. The exports/imports of natural gas are calculated as:

$$E_{ng,exp} = E_{ng,gr} - E_{ng,fuel} + E_{ng,mu} - E_{ng,rec} \qquad \left[\frac{\text{MMBtu}}{\text{d}}\right] \tag{5.2}$$

where $E_{ng,exp}$ = natural gas export/import [MMBtu/d]; $E_{ng,gr}$ = gross natural gas consumption [MMBtu/d]; $E_{ng,fuel}$ = natural gas produced as fuel after gas lifting/re-injection [MMBtu]; $E_{ng,mu}$ = make up natural gas for gas flooding [MMBtu/d], if applicable; and $E_{ng,rec}$ = natural gas recovered from venting and fugitives. The produced gas remaining to be used as a process fuel is equal to 0 MMBtu/d in the case of gas flooding where 100% of produced gas is re-injected. Negative $E_{ng,exp}$ represents gas exports. Positive $E_{ng,exp}$ represents gas imports.

The exports/imports of natural gas liquid (NGL) is calculated as:

$$E_{ngl,exp} = E_{ngl,gr} - E_{ngl,fuel} \qquad \left[\frac{\text{MMBtu}}{\text{d}}\right] \tag{5.3}$$

where $E_{ngl,exp}$ = NGL export/import [MMBtu/d]; $E_{ngl,gr}$ = gross NGL consumption [MMBtu/d]; and $E_{ngl,fuel}$ = amount of NGL produced as fuel [MMBtu/d].

The import of diesel is equal to gross diesel consumption. The export of diesel does not apply because diesel is not produced in upstream operations. The export/import of electricity is equal to electricity net consumption as calculated in eq. (5.1). Positive net electricity consumption is equal to electricity imported from the grid and negative net electricity consumption is equal to electricity exported to the grid. Crude oil export/import does not apply because crude oil is the main product. Any crude oil used as a process fuel on site is subtracted from the amount produced and shipped (see Section 5.3).

Finally, the indirect energy consumption by fuel type is calculated. The indirect energy consumption is calculated as:

Energy Consumption Table 6

$$\begin{aligned} &E_{k,ind} = E_{k,exp}\, E_{k,FC} && \text{for } E_{k,exp} > 0 \\ &E_{k,ind} = E_{k,exp}\, E_{k,DS} && \text{for } E_{k,exp} < 0 \text{ and displacement} \\ &E_{k,ind} = 0 && \text{for } E_{k,exp} < 0 \text{ and allocation by energy value} \end{aligned} \tag{5.4}$$

where k refers to the fuel type; $E_{k,ind}$ = indirect energy consumption [MMBtu/d]; $E_{k,exp}$ = fuel export/import [MMBtu/d]; $E_{k,FC}$ = fuel cycle energy consumption [MMBtu/MMBtu]; and $E_{k,DS}$ = energy consumption of displaced system in case of fuel export [MMBtu/MMBtu]. For details on the energy consumption of fuel cycles and displaced systems, see Section 4.7.

5.2 *'GHG Emissions'* gathering sheet

The GHG emissions gathering sheet compiles and computes emissions of all emissions types across all process stages. The first step is the calcula-

GHG Emissions Table 1

tion of direct GHG emissions from the different components of the model. Direct GHG emissions are calculated as:

$$EM_{s,k} = E_{s,k,gr}\, EF_{s,k} \qquad \left[\frac{\text{gCO}_2\text{eq}}{\text{d}}\right] \tag{5.5}$$

where s = emissions source (e.g., downhole pump driver); k = fuel type; $EM_{s,k}$ = direct GHG emissions from the consumption of fuel k in source s [gCO_2eq/d]; and $E_{s,k,gr}$ = gross energy consumption of fuel k in source s [MMBtu/d]; and $EF_{s,k}$ = emissions factor of source s using fuel k [g CO_2 eq./MMBtu]. This equation does not apply to electricity, where direct GHG emissions are equal to 0 gCO_2eq./d.

Next, the GHG emissions from land use VFF are calculated by process stage. This includes gathering emissions calculated in each process stage and supplemental sheets. *GHG Emissions Table 1*

The next step is the calculation of indirect GHG emissions by fuel import type. The indirect GHG emissions are calculated as: *GHG Emissions Table 2*

$$\begin{aligned} EM_{k,ind} &= E_{k,exp}\, EM_{k,FC} && \text{for } E_{k,exp} > 0 \\ EM_{k,ind} &= E_{k,exp}\, EM_{k,DS} && \text{for } E_{k,exp} < 0 \text{ and displacement} \\ EM_{k,ind} &= 0 && \text{for } E_{k,exp} < 0 \text{ and allocation by energy value} \end{aligned} \tag{5.6}$$

where k refers to the fuel type; $EM_{k,ind}$ = indirect GHG emissions from fuel consumption [gCO_2eq/d]; $E_{k,exp}$ = fuel export/import [MMBtu/d]; $EM_{k,FC}$ = fuel cycle GHG emissions [gCO_2eq/MMBtu]; and $EM_{k,DS}$ = GHG emissions from displaced system in case of fuel export [gCO_2eq/MMBtu]. For details on the GHG emissions of fuel cycles and displaced systems, see section 4.7.

5.3 *'User Inputs & Results'* gathering sheet

In this sheet the total energy consumption and GHG emissions are calculated and displayed in graphical form. Both the total energy consumption and total GHG emissions are calculated by process stage (e.g., Production & Extraction). First the total energy consumption is calculated as: *User Inputs & Results 5.1.1. - 5.7.1*

$$E_{tot} = \frac{E_{tot,dir} + E_{tot,ind} + EL_{VFF}}{E_{tot,out}} \qquad [\text{MJ/MJ}_{out}] \tag{5.7}$$

where E_{tot} = total energy consumption of the process [MJ/MJ$_{out}$]; $E_{tot,dir}$ = total direct energy consumption (calculated in the *'Energy Consumption'* sheet as net energy consumption) [MMBtu/d]; $E_{tot,ind}$ = total indirect energy consumption (calculated in the *'Energy Consumption'* sheet) [MMBtu/d]; EL_{VFF} = total energy loss from VFF emissions [MMBtu/d]; and $E_{tot,out}$ = total process energy output [MMBtu/d]. The total process energy output is calculated as: *User Inputs & Results 5.1.1. - 5.7.1*

$$E_{tot,out} = Q_o\, \text{HV}_o + E_{ngl,blend} - E_{co,net} \qquad [\text{MMBtu/d}] \tag{5.8}$$

where $E_{tot,out}$ = total process energy output [MMBtu/d]; Q_o = volume of oil production [bbl/d]; HV_o = heating value of crude oil [MMBtu/bbl]; $E_{ngl,blend}$ = amount of produced NGL that is added to crude oil [MMBtu/d]; and $E_{co,net}$ = net crude oil consumption, if applicable [MMBtu/d]. The heating value HV for the denominator crude oil can be selected as LHV or HHV.

Fuel Specs 1.1

If the allocation of co-products is done by energy value and not displacement then eq. (5.8) becomes:

$$E_{tot,out} = Q_o \, \mathrm{HV}_o + E_{ngl,blend} - E_{co,net} + |\sum_k E_{k,exp}| \quad \text{and } E_{k,exp} < 0 \tag{5.9}$$

where $|\sum_k E_{k,exp}|$ = absolute sum of all energy exports [MMBtu/d].

Total energy consumption is allocated by process stage using the fraction of direct energy consumed in a stage (not including the energy consumption of electricity generation). The allocation of energy consumption to different process stages has no effect on the total energy consumption.

For each process stage, GHG emissions are broken down into three categories: (i) combustion/land use, (ii) VFF, and (iii) credit/debt. For combustion/land use emissions, the direct GHG emissions and land use GHG emissions associated with the process stage are summed in the *'GHG emissions'* sheet. The direct GHG emissions from electricity generation, if any, are divided between the production & extraction and surface processing stages based on the shares of total direct energy consumption between these stages.

GHG Emissions Table 1

VFF emissions associated with a process stage are summed from the *'GHG emissions'* sheet. Indirect GHG emissions calculated in the *'GHG emissions'* sheet represent the total net credit/debt, which is allocated by process stage using the same allocation method used for allocating the total energy consumption.

GHG Emissions Table 1

GHG Emissions Table 2

Finally, the total energy consumption and GHG emissions from the process stages of crude oil extraction and surface processing of associated fluids are integrated with the total energy consumption and GHG emissions of crude oil transport to the refinery to calculate the life cycle energy consumption and GHG emissions on a well-to-refinery basis. The life cycle GHG emissions, for example, are calculated as:

$$EM_{LC} = EM_{PP,tot}\,\epsilon_{CT} + EM_{CT,tot} \qquad \left[\frac{\mathrm{gCO_2eq}}{\mathrm{MJ}_{ref}}\right] \tag{5.10}$$

where EM_{LC} = life cycle GHG emissions [gCO_2eq/MJ_F]; $EM_{PP,tot}$ = total GHG emissions from the process stages of crude oil production and processing [gCO_2eq/MJ_{out}]; ϵ_{CT} = crude oil transport loss factor (calculated based on the amount of crude oil lost in transportation) [-]; and $EM_{CT,tot}$ = total GHG emissions from crude transport [gCO_2eq/MJ_{ref}]. 1 MJ_{out} is one MJ of energy output from crude oil production and processing; and 1 MJ_{ref} is one MJ at refinery gate.

The life cycle energy consumption and GHG emissions are shown in tabular and graphical formats with full GHG emissions breakdown. The total GHG emissions has a separate category for VFF emissions. The energy

User Inputs & Results Tables 1.1 - 1.2 Figures 1.1 - 1.2 content of fuels lost to VFF emissions is not tracked as a separate category of energy consumption.

6 Fundamental data inputs

A variety of fundamental data inputs and conversions are required in OPGEE. These data inputs are included in the sheets *'Input data'* and *'Fuel Specs'*. These inputs are described below, organized by broad class of property.

6.1 Global warming potentials

Global warming potentials (GWPs) for gases with radiative forcing are taken from the IPCC Fourth Assessment Report [132]. The GWPs used are the 100-year GWPs. *Input data Table 2.1*

6.2 Properties of water and steam

The density of fresh water at 32 °F is used as the base density of water for lifting, boiling and other calculations in OPGEE. Thermodynamic properties of water and steam are required for steam generation calculations. The following data tables are required for use in steam generation calculations in OPGEE: *Input data Table 5.1*

- Saturation properties as a function of temperature;
- Saturation properties as a function of pressure;
- Properties of compressed water and superheated steam.

6.2.1 Saturation properties as a function of temperature

Saturation properties of saturated water and steam as a function of saturation temperature are produced using Knovel steam tables [116, Table 1b]. Properties are derived for temperatures starting at 32 °F and in increments of 20 °F from 40 °F to the critical temperature of 705.1 °F. Properties included are liquid and vapor specific volume v [ft^3/lb], specific enthalpy h [Btu/lbm], specific internal energy u (Btu/lbm), and specific entropy s [Btu/lbm °R] *Input Data Table 5.2*

6.2.2 Saturation properties as a function of pressure

Saturation properties of saturated water and steam as a function of saturation pressure are produced using Knovel steam tables [116, Table 1d]. Properties are derived for pressures starting at 15 psia in increments of 5 psia from 15 to 2500 psia. Identical properties are included as above. *Input Data Table 5.3*

6.2.3 Properties of compressed water and superheated steam

Properties of compressed water and superheated steam are compiled from Knovel steam tables [116, Table 2b]. Pressures are included from 100 to 1500 psia in increments of 100. The following temperatures are included: 32°F and in increments of 20 °F from 40 °F to 1500 °F. Identical properties are included as above.

Input Data Table 5.4

6.3 Properties of air and exhaust gas components

The composition of dry air and densities of gases required in OPGEE are derived from online tabulations [108]. Moisture in atmospheric air varies as a function of temperature and relative humidity. Assumed moisture content is 2 mol%.

Input Data Table 2.2

6.3.1 Enthalpies of air and exhaust gas components

The enthalpy of air and exhaust gas at various temperatures and atmospheric pressure is modeled as described above in the Steam Injection methods description (see Section 4.2). Coefficients for the specific heats of gases as a function of temperature are taken from literature tabulations [118, Table A2-E]. Specific heats are integrated to derive the enthalpy change between two temperatures for combustion products (exhaust gases) and inlet air/fuel mixtures.

Input Data Tables 4.1 - 4.7

6.4 Compositions and properties of fuels

6.4.1 Heating value of crude oil as a function of density

Crude oil heating values are a function of the chemical composition of the crude oil. Crude oil density can be used to determine the approximate heating value (gross and net heating value, or HHV and LHV) of crude oils. Gross and net crude oil heating values (in Btu per lb and Btu per gallon) are presented as a function of API gravity and are given for API gravities from 0 to 46 °API [84, Table 11]. These heating values are converted to SI units and specific gravity for broader applicability.

Fuel Specs Table 1.1

6.4.2 Crude oil chemical composition as a function of density

Crude oil chemical compositions (C, H, S, (O+N)) are given as a function of the density of crude oil [84, Table 9]. Values are interpolated between those given in the table using a relationship for fraction H as a function of API gravity. O + N contents are assumed to sum to 0.2 wt.%. Sulfur content ranges from 5 wt% to 0.5 wt.%, with approximate concentrations derived from Figure 4.2. Carbon mass fraction is computed by difference.

Fuel Specs Table 1.2

6.4.3 Heat of combustion of gaseous fuel components

A variety of properties were collected for gaseous fuel components, including

Fuel Specs Table 1.3

N_2, Ar, O_2, CO_2, H_2O, CH_4, C_2H_6, C_3H_8, n-C_4H_{10}, CO, H_2, H_2S, and SO_2 [139, Chapter 17] [117]. For simplicity, N_2, Ar and all other inert species are lumped and given properties of N_2. The following properties were collected for each species:

- Molar mass [g/mol, mol/kg];
- Moles of C and H per mole of each species (for stoichiometric combustion calculations);
- Higher and lower heating value (HHV, LHV) on a volumetric [Btu/scf], gravimetric [Btu/lbm] and molar basis [Btu/mol, Btu/lbmol]. For completeness, gravimetric energy densities in SI units [MJ/kg] are also included.

6.4.4 Refined and processed fuels heating values

The heating values and densities of refined and processed fuels are taken from the CA-GREET model [76] for a variety of fuels.

Fuel Specs Table 4.1

A Terminology: Acronyms and abbreviations

Table A.1: Acronyms and abbreviations.

Acronym or abbreviation	Description
ABS	Absorbents
AGR	Acid gas removal
AIR	Air stripping
AL	Aerated lagoons
ANS	Alaska North Slope
API	American Petroleum Institute
ARB	California Air Resources Board
AS	Activated sludge
BHP	Brake horsepower
CHOPS	Cold heavy oil production with sand
CSS	Cyclic steam stimulation
CWL	Wetlands
DAF	Dissolved air flotation
DEA	Di-ethanol amine
DGA	Diglycolamine
DMF	Dual media filtration
DOGGR	State of California Department of Conservations Division of Oil, Gas and Geothermal Resources
EDR	Electrodialysis reversal
EGOR	Onsite electricity generation to oil ratio
EOR	Enhanced oil recovery
EPA	Environmental Protection Agency
ERCB	Alberta Energy Resources Conservation Board
FOR	Flaring to oil ratio
FWKO	Free-water knockouts
GAC	Granular activated carbon
GGFR	Global Gas Flaring Reduction Partnership at the World Bank
GHG	Greenhouse gases
GLR	Gas to liquid ratio
GOR	Gas to oil ratio
GREET	Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation Model
GT	Gas turbine
GWP	Global warming potential
HHV	Higher heating value
HRSG	Heat recovery steam generator
HYDRO	Hydrocyclones

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Acronym or abbreviation	Description
IPCC	Intergovernmental Panel on Climate Change
LCA	Life cycle assessment
LHV	Lower heating value
MEA	Monoethanolamine
MF	Microfiltration
NF	Nanofiltration
NGL	Natural gas liquid
NOAA	National Oceanic and Atmospheric Administration
OPGEE	Oil Production Greenhouse Gas Emissions Estimator
ORG	Organoclay
OTSG	Once-through steam generators
OZO	Ozone
RBC	Rotating biological contactors
RO	Reverse osmosis
RVP	Reid vapor pressure
SAGD	Steam assisted gravity drainage
SCO	Synthetic crude oil
SOR	Steam to oil ratio
SSF	Slow sand filtration
TDS	Total dissolved solids
TEG	Triethylene glycol
TEOR	Thermal enhanced oil recovery
TF	Trickling filters
THC	Total hydrocarbon
UF	Ultrafiltration
VFF	Venting, flaring and fugitives
VOC	Volatile organic compounds
VOR	Venting to oil ratio
W&S	Standing and working losses
WOR	Water to oil ratio
WTR	Well to refinery

B Mathematical terms and definitions

Mathematical terms and subscripts are defined in Table B.1. Parameters and variables serve as the key signifiers in the formulae. A variety of subscripts are used in the mathematics, and can be divided into:

1. Process stages, represented by a a two- or three-letter capitalized symbol (e.g., DD = Drilling & Development)
2. Sub-processes, represented by two- or three-letter capitalized symbol (e.g. GP = Gas processing)
3. Process flows or environments, represented by lower-case symbols (e.g., a = air)
4. Technologies or technology components, represented by capitalized symbols (e.g., GD = glycol dehydrator)
5. Primary fuels and energy carriers, represented by one- to three-letter lower-case symbols (e.g., di = Diesel fuel)
6. Modifiers, represented by lower-case symbols or word fragments (e.g., avg = averge)
7. Gas species, represented by capitalized species formulae (e.g., $O2$ = oxygen)

In general, a term in the equation will follow the above order as in:

$$[Param]_{[PROCESS][SUB-PROCESS][flow][TECHNOLOGY][fuel][modifier(s)][SPECIES]} \tag{B.1}$$

if an element is not needed, it is simply excluded. To create a (relatively extreme) example, one might have: $p_{OTSG,ng,avg,in}$, which represents average inlet natural gas pressure to the once-through steam generator. Most equation elements will not require this many elements.

Table B.1: Mathematical symbols and subscripts.

Symbol	Description
Parameters and variables	
α	Solar absorbance
δ	Change
ϵ	Loss
η	Efficiency
γ	Specific gravity
λ	Fraction or share
ρ	Density
$a, b, c, d \ldots$	Constants in fitting equations or from data
C	Capacity
C	Concentration
D	Diameter
API	Degrees API
e	Energy (per unit of something)
E	Energy quantity
EF	Emissions factor
EL	Energy loss
EM	Emissions
f	Friction factor
FOR	Flaring oil ratio
GOR	Gas oil ratio
GWP	Global warming potential
h	Height
h	Enthalpy
H	Head
I	Solar insolation
l	Load factor
m	Mass
MW	Molecular weight
N	Number of something
p	Pressure
P	Power
Q	Flow rate
R	Ratio
r	Radius
RVP	Reid vapor pressure
T	Temperature
U	Effectiveness
v	Velocity
V	Volume
W	Work
w	Mass fraction
WOR	Water oil ratio
x	Mole fraction
y	Binary variable
Process stages (Index = j)	
EX	Exploration

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Symbol	Description
DD	Drilling & Development
PE	Production & Extraction
SP	Surface Processing
MA	Maintenance
CT	Crude Transport
BE	Bitumen Extraction & Upgrading
SI	Steam Injection
EL	Electricity
FC	Fuel cycle
VFF	Venting, flaring and fugitives
LC	Life cycle
DS	Displaced system
PP	Process stages of curde oil production and processing
Sub-processes (Index = *j*)	
EX	Extraction
GP	Gas processing
IC	In situ production via CSS
IP	In situ productio via primary prod.
IS	In situ production via SAGD
MI	Integrated mining & upgrading
MN	Non-integrated mining & upgrading
UP	Upgrading
Process flows & Environment (Index = *i*)	
a	Air
atm	Atmosphere
e	Exhaust
f	Fuel
g	Gas
l	Liquid
o	Oil
w	Water
ws	Water as steam
Technologies (Index = *j*)	
AGR	AGR unit
B	Barge
BP	Booster pump
C	Compressor
CD	Crude dehydrator
CP	Circulation pump
D	Driver
DR	Drill rig
EG	Electricity generator
F	Flaring
F	Fan
F	Fugitives
G	Generator
GD	Gas dehydrator (glycol dehydrator)
GP	Glycol pump

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Symbol	Description
GS	Generator set
GT	Gas turbine
$HRSG$	Heat recovery steam generator
M	Motor
$OTSG$	Once-through steam generator
P	Pipeline
R	Rail
R	Roof
RE	Reciprocating engine
RP	Reflux pump
S	Stabilizer
T	Tanker
T	Tank
V	Vent
W	Well
Fuels and energy carriers (Index = k)	
ag	Associated gas
c	Coal
ck	Coke
co	Crude oil
db	Diluted bitumen
di	Diesel
dl	Diluent
el	Electricity
ng	Natural gas
ngl	Natural gas liquids
pg	Processed gas (processed associated gas)
ro	Residual oil
sco	Synthetic crude oil
sg	Still gas
Modifiers	
avg	Average
atm	Atmospheric
b	Base
wf	Bottomhole (well-formation)
$comb$	Combusted
dir	Direct
d	Discharge
ent	Entrained
exp	Exported
gen	Generated
gr	Gross
$heat$	Heated
im	Imported
ind	Indirect
in	Input
l	Lost
mu	Make-up
max	Maximum

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Symbol	Description
min	Minimum
net	Net
ot	Other
out	Output
rem	Removed
req	Required
res	Reservoir
rec	recovered
ref	refinery
s	Stages
sc	Standard conditions
str	Stripped
s	Suction
th	Thermal
tot	Total
to	Turn over
wh	Wellhead
$trav$	traverse
$lift$	lifting
Gas species (Index = i)	
C	Carbon
$CO2$	Carbon dioxide
H	Hydrogen
$H2O$	Water
$H2S$	Hydrogen sulfide
$N2$	Nitrogen
$O2$	Oxygen

C Tabulated sources for each production stage

The full classification of emissions sources for each production stage is given below in Tables C.1 to C.7.

Each emissions source is classified according to process, sub-process, and specific emissions source. Any variants of that emissions source are listed (if they have material effects on emissions or energy consumption). A sensitivity code is given from 1 to 4 stars (* to ****) based on judgement of the likely magnitude of the source. Lastly, the table indicates whether or not an emissions source is included (incl. = 1 means that the source is included).

Table C.1: Emissions sources from exploratory operations. For inclusion: 0 = not included, 1 = included.

Main stage	Process	Sub-process	Emissions source	Variants	Sensitivity code	Estimated magnitude	Incl.
Exploration	Seismic exploration	Terrestrial seismic	Vehicular emissions	-	*	$\leq$ 0.01 g	0
			Data processing	-	*	$\leq$ 0.01 g	0
			Consumed materials (charges etc.)	-	*	$\leq$ 0.01 g	0
			Land use impacts	-	*	$\leq$ 0.01 g	0
		Oceanic seismic	Ship emissions	-	*	$\leq$ 0.01 g	0
			Data processing	-	*	$\leq$ 0.01 g	0
			Consumed materials	-	*	$\leq$ 0.01 g	0
	Exploratory drilling	Terrestrial drilling	Prime mover emissions	-	*	$\leq$ 0.01 g	0
			Land clearing and construction	-	*	$\leq$ 0.01 g	0
			Vents and upset emissions	-	*	$\leq$ 0.01 g	0
			Drilling flares	-	*	$\leq$ 0.01 g	0
			Casing and cement	-	*	$\leq$ 0.01 g	0
			Other material consumption (e.g., frac sand)	-	*	$\leq$ 0.01 g	0
			Land use impacts	-	*	$\leq$ 0.01 g	0
			Indirect land use impacts (opening of inaccessible land)	-	*	$\leq$ 0.01 g	0
		Offshore drilling	Prime mover emissions	-	*	$\leq$ 0.01 g	0
			Drilling flares	-	*	$\leq$ 0.01 g	0
			Vents and upset emissions	-	*	$\leq$ 0.01 g	0
			Casing and cement	-	*	$\leq$ 0.01 g	0
	Waste handling and disposal	Mud and fluid handling	Energy consumption (other than prime mover)	-	*	$\leq$ 0.01 g	0
			Fugitives from mud	-	*	$\leq$ 0.01 g	0
			Disposal of mud	-	*	$\leq$ 0.01 g	0
		Fracturing fluid disposal	Processing and disposal of fracturing fluid	-	*	$\leq$ 0.01 g	0
		Produced water disposal	Processing of produced water	-	*	$\leq$ 0.01 g	0
			Disposal of produced water (remote or on-site reinjection)	-	*	$\leq$ 0.01 g	0

Table C.2: Emissions sources from drilling operations.

Main stage	Process	Sub-process	Emissions source	Variants	Sensitivity code	Estimated magnitude	Incl.
Drilling and development	Developmental drilling	Terrestrial drilling	Prime mover emissions	-	**	0.1 g	1
			Drilling flares	-	*	$\leq$ 0.01 g	0
			Vents and upset emissions	-	**	0.1 g	0
			Land use impacts	-	**	0.1 g	1
			Clearing and construction	-	*	$\leq$ 0.01 g	0
			Casing and cement embodied emissions	-	*	$\leq$ 0.01 g	0
			Other materials consumption (e.g., frac sand)	-	*	$\leq$ 0.01 g	0
		Oceanic drilling	Prime mover emissions	-	**	0.1 g	1
			Drilling flares	-	*	$\leq$ 0.01 g	0
			Vents and upset emissions	-	**	0.1 g	0
			Casing and cement embodied emissions	-	*	$\leq$ 0.01 g	0
	Processing capital investment	Oil/gas/water separators	Separator assembly	-	*	$\leq$ 0.01 g	0
			Separator fabrication	-	*	$\leq$ 0.01 g	0
			Separator transport	-	*	$\leq$ 0.01 g	0
			Raw materials manufacture	-	*	$\leq$ 0.01 g	0
		Water reinjection wells	Various drilling emissions from reinjection wells (see above)	-	*	$\leq$ 0.01 g	0
		Pumps	Pump assembly	-	*	$\leq$ 0.01 g	0
			Pump fabrication and raw materials manufacture	-	*	$\leq$ 0.01 g	0
			Pump transport	-	*	$\leq$ 0.01 g	0
	Storage capital investment	Storage capital investment	Tank assembly	-	*	$\leq$ 0.01 g	0
			Tank fabrication	-	*	$\leq$ 0.01 g	0
			Tank transport	-	*	$\leq$ 0.01 g	0
			Raw materials manufacture	-	*	$\leq$ 0.01 g	0
			Land use impacts	-	*	$\leq$ 0.01 g	0
	Transport capital investment	Pipeline capital investment	Pipeline assembly	-	*	$\leq$ 0.01 g	0
			Pipe fabrication	-	*	$\leq$ 0.01 g	0
			Pipe transport	-	*	$\leq$ 0.01 g	0
			Raw materials manufacture	-	*	$\leq$ 0.01 g	0
			Land use impacts	-	*	$\leq$ 0.01 g	0
		Other transport capital investment	Other infrastructure fabrication and assembly	-	*	$\leq$ 0.01 g	0

Table C.3: Emissions sources from production and extraction operations.

Main stage	Process	Sub-process	Emissions source	Variants	Sensitivity code	Estimated magnitude	Incl.
Production and extraction	Lifting	Pumping	Combustion for pump driver	-	***	1 g	1.0
			Electricity for pump driver	-	***	1 g	1.0
			Casing and wellhead fugitive emissions	-	***	1 g	1.0
		Gas lift	Compressor prime mover emissions	-	***	1 g	1.0
			Compression electricity emissions	-	***	1 g	1.0
			Casing and wellhead fugitive emissions	-	***	1 g	1.0
	Injection	Gas injection	External gas processing (e.g., N2 production)				1.0
			Gas compression energy		***	1 g	1.0
			[-] Gas sequestration credit (CO2 flood)	-	***	1 g	0.0
		Water injection	Water pumping energy	-	***	1 g	1.0
		Steam injection	Water pre-treatment	-	*	¡= 0.01 g	0.0
			OTSG fuel combustion	NG, produced oil	****	10 g	1.0
			Turbine gas consumption (combined cycle)	Low, med, high efficiency	****	10 g	1.0
			HRSG duct firing (combined cycle)	-	***	1 g	1.0
			[-] Electricity co-production offsets (combined cycle)	Grid mix variation	****	10 g	1.0
			Steam pumping energy (if any)	-	*	¡= 0.01 g	0.0
		Polymer flood	Polymer embodied energy	-	*	¡= 0.01 g	0.0
			Polymer mixing	-	*	¡= 0.01 g	0.0
			Polymer/water mixture pumping energy	-	*	¡= 0.01 g	0.0
		Surfactant/other injection	Surfactant/other embodied energy	-	*	¡= 0.01 g	0.0
			Surfactant/other mixing	-	*	¡= 0.01 g	0.0
			Surfactant/other mixture pumping energy	-	*	¡= 0.01 g	0.0

Table C.4: Emissions sources from surface processing operations.

Main stage	Process	Sub-process	Emissions source	Variants	Sensitivity code	Estimated magnitude	Incl.
Separation and surface processing	Fluid separation	Oil-water-gas separation	Oil-water-gas separation	-	**	0.1 g	1
			Oil-water-gas separation with heater-treaters	-	**	0.1 g	1
			Associated gas venting	Variations in flare efficiency	****	10 g	1
			Associated gas flaring	Variations in flare efficiency	****	10 g	1
	Solid/fluid separation	Solid separation from fluids	Solids removal from separation	-	*	$\leq$ 0.01 g	0
	Gas processing	Gas processing	Produced gas dehydration	-	*	$\leq$ 0.01 g	1
			Produced gas venting and flaring	-	***	1 g	1
	Water treatment and disposal	Water treatment	Produced water cleanup	-	**	0.1 g	1
			Produced water handling and pumping	-	**	0.1 g	1
		Water reinjection and disposal	Produced water reinjection	-	***	1 g	1
			Produced water disposal	-	**	0.1 g	1
	Storage (as part of separation)	Storage	Storage pumping energy	-	*	$\leq$ 0.01 g	0
			Tank assembly and installation	-	*	$\leq$ 0.01 g	0
			Evaporative and fugitive emissions	-	**	0.1 g	1
			Tank materials manufacture	-	*	$\leq$ 0.01 g	0
			Land use impacts	-	*	$\leq$ 0.01 g	0

Table C.5: Emissions sources from maintenance operations.

Main stage	Process	Sub-process	Emissions source	Variants	Sensitivity code	Estimated magnitude	Incl.
Maintenance and workovers	Well workover	Terrestrial well workover	Workover rig energy use	-	*	$\leq$ 0.01 g	0
			Fugitive emissions during workover	-	**	0.1 g	1
			Embodied energy in consumed replacement parts	-	*	$\leq$ 0.01 g	0
		Offshore well workover	Workover rig energy use	-	*	$\leq$ 0.01 g	0
			Fugitive emissions during workover	-	**	0.1 g	1
			Embodied energy in consumed replacement parts		*	$\leq$ 0.01 g	0
	Other maintenance	Other maintenance	Solids removal from separation	-	*	$\leq$ 0.01 g	0

Table C.6: Emissions sources from waste treatment and disposal operations.

Main stage	Process	Sub-process	Emissions source	Variants	Sensitivity code	Estimated magnitude	Incl.
Waste treatment and disposal	Water processing waste	Water treatment waste disposal	Subsurface disposal of concentrated WW residuals	-	*	$\leq$ 0.01 g	0
			Surface disposal of separated solids	-	*	$\leq$ 0.01 g	0
			Surface disposal of concentrated WW residuals	-	*	$\leq$ 0.01 g	0
	Other waste separation and disposal	Other waste separation and processing	Other waste separation and processing	-	*	$\leq$ 0.01 g	0
			Other waste storage	-	*	$\leq$ 0.01 g	0
			Spills and other upsets	-	*	$\leq$ 0.01 g	0
		Other waste disposal	Other waste transport	-	*	$\leq$ 0.01 g	0
			Other waste disposal (non-hazardous)	-	*	$\leq$ 0.01 g	0
			Other waste disposal (hazardous)	-	*	$\leq$ 0.01 g	0
	Solid waste disposal and project decommissioning	Solid waste disposal	Solid waste separation and processing	-	*	$\leq$ 0.01 g	0
			Solid waste transport and disposal	-	*	$\leq$ 0.01 g	0
		End of life and decommissioning	Demolition and decommissioning	-	*	$\leq$ 0.01 g	0
			Scrap and waste disposal	-	*	$\leq$ 0.01 g	0
			[-] Credit for waste recycling (embodied energy)	-	*	$\leq$ 0.01 g	0

Table C.7: Emissions sources from crude transport.

Main stage	Process	Sub-process	Emissions source	Variants	Sensitivity code	Estimated magnitude	Incl.
Crude product transport	Pipeline transport	Pipeline transport	Combustion for pump prime mover	-	***	1 g	1
			Electricity for pump use	-	***	1 g	1
			Process upsets (one-time events)	-	*	$\leq$ 0.01 g	1
			Leaks (pipeline losses)	-	***	1 g	1
		Pipeline construction	Construction equipment energy use	-	*	$\leq$ 0.01 g	0
			Embodied energy in pipeline materials (cement and steel)	-	*	$\leq$ 0.01 g	0
			Land use impacts	-	*	$\leq$ 0.01 g	0
	Tanker transport	Tanker transport	Combustion in tanker prime mover (bunker fuels)	-	***	1 g	1
			Loading and unloading pumping	-	*	$\leq$ 0.01 g	1
			Flares	-	*	$\leq$ 0.01 g	1
			Vents, leaks and upsets	-	*	$\leq$ 0.01 g	1
		Tanker construction	Embodied energy in tanker materials (steel)	-	*	$\leq$ 0.01 g	0
			Construction energy	-	*	$\leq$ 0.01 g	0
	Storage (as part of transport)	Storage	Storage pumping energy	-	*	$\leq$ 0.01 g	0
			Tank assembly and installation	-	*	$\leq$ 0.01 g	0
			Evaporative and fugitive emissions	-	**	0.1 g	1
			Tank materials manufacture	-	*	$\leq$ 0.01 g	0
			Land use impacts	-	*	$\leq$ 0.01 g	0

D Statistical analysis of water oil ratios

This appendix outlines the analysis underlying the smart default for the water oil ratio (WOR) as a function of field age. The WOR is a determining factor influencing the energy consumed in lifting, handling and separating fluids.

A default value for WOR as a function of time is generated by performing statistical analysis of historical oil production data in Alberta and California. A variety of fields in other regions also have data collected for cross comparison with the Alberta and California data.

First, the data sources used in the analysis are described. Second, a review of the theoretical and practical drivers of WOR is presented. Third, a description of the methodology used to find the best model fit for WOR in Alberta and California is conducted. Finally, the results and default values to be used in OPGEE are presented.

D.1 Methods of Analysis

D.1.1 Data sources

Data on oil and water production are collected from the Alberta Energy Resources Conservation Board (ERCB) and DOGGR.

From ERCB, the data set ST-16 [140] was obtained, containing monthly pool/deposit-level production and injection records from 1962 to 2011. Data from 2011 were discarded, as observations were available only for the first four months. Overall, 26 injection and 11 production variables are included in the data set. Four out of 975 fields included in the data set were classified as unconventional, meaning that their primary output was crude bitumen and not crude oil. The WOR was provided within the dataset and was also calculated on a monthly basis for each pool.

The data set was transferred from pdf into a *Stata* data file so that a longitudinal/panel data set could be created. A longitudinal/panel data set contains observations on multiple production and injection variables over multiple time periods for the same unit of observation. In this case, the unit of observation is the unique identifier (ID) which was created for each possible pool and field combination (51,272) which interacts with a time variable that corresponds to the number of months (588) included in the analysis. Reservoir age was calculated relative to the first year for which production was recorded for each unique pool and field combination. Not all combinations have produced uninterruptedly since 1962, so the data set is referred to as an unbalanced panel.

Table D.1: Characteristics of collected Alberta production and injection dataset.

Data element	Number
Fields	975
Pools	8,043
Months	588
Years	49
Unique field + pool combinations (IDs)	55,104[a]
IDs with 6 months of WOR values	17,082
Production variables	11
Injection variables	26
Total observations	5,579,496

[a] As can be seen, most of these field/pool combinations do not have significant data available, and likely represent failed production projects or non-commercial discoveries.

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Table D.2: Characteristics of collected California production and injection dataset.

Data element	Number
Fields	306[a]
Years	6
Production variables	3
Field characteristic variables	6
Total observations	1836

[a] Most of these fields are rejected in an initial screen that removes all fields that do not contribute more than 0.1% of total California cumulative production over the years of the dataset (see text for explanation).

Only pool and field combinations for which WOR data are available for at least 6 non-consecutive months and for which the value differed from zero are included in the analysis.[1] A total of 17,082 pool and field combinations satisfied these conditions.

A preliminary analysis suggested that many of these pools are extremely small producers and exhibited erratic or sporadic production behavior. We therefore limited the analysis to the top 100 pool/fields. These pools contributed over 65% of Alberta crude production over the dataset time period.

For California, crude production and water injection data was obtained from the State of California Department of Conservation, Division of Oil, Gas and Geothermal Resources (DOGGR). DOGGR data was available on a ten-year interval from 1955 to 2005 for a total of 306 California oil fields [78, 82]. Because of data quality concerns, small fields were excluded. Cumulative production over all sampled years was summed, and all fields contributing less than 0.1% of California production were excluded from the dataset. This resulted in a sample of 80 fields.

[1] This data cleaning was performed because one must have a minimum number of observations with variance to compute a regression. At a minimum, the number of observations should double the number of parameters used in the estimation of the model and be different from zero so as to have variance within the set of observations.

D.1.2 Determining the best fitting model

The producing WOR in a field is generally a function of the oil and water viscosities, total and relative reservoir permeabilities, geologic heterogenaity, and field age. The WOR tends to increase over the producing life of a field [141]. A common method used to plot WOR over time is to plot cumulative production on the x-axis and WOR on a logarithmic scale on the y-axis [141, Fig. 7.5]. The trend in WOR is often nearly linear in this semi-log space, but is often interspersed with periods of more or less rapid increase as layers in a field or pool breakthrough with water at different times. This trend implies exponential behavior of WOR. Because cumulative production data are not likely to be available in general, we develop an alternative model with time as the independent variable rather than cumulative production.

Three models were tested to fit the relationship between WOR and field age. The parametric models tested included an exponential function, a logistic function and a Gompertz function. To determine the best fitting model, nonlinear regression functions by least squares were fitted to the data and their relative coefficients of determination (R^2) compared to determine which model had the greatest predictive power.

Although there is no precise rule for the number of observations required in nonlinear regressions, observations should substantially exceed the number of predictor variables in a model. For the case of Alberta, given the extensive data set the ratio of observations to variables was 68:1 whereas for California the ratio was 3:1 (exponential model).

D.1.2.1 Exponential Function

The exponential function is fitted to the available pool level data as seen in Figure D.1. This function is defined as follows:

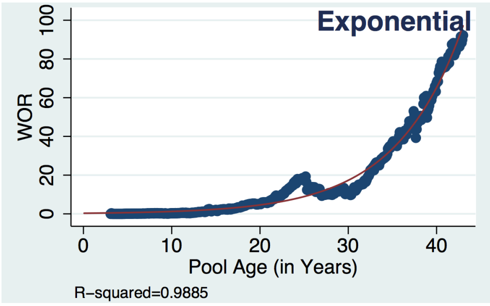
$$WOR(t) = a_{WOR} \exp[b_{WOR}(t - t_0)] \tag{D.1}$$

where a_{WOR} = initial WOR in time = t_0 [bbl water/bbl oil]; b_{WOR} = exponential growth rate [1/y]; t_0 = initial year of analysis [y]; and t = year being modeled (independent variable) [y].

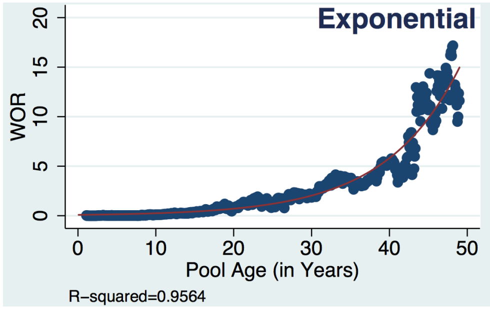
The exponential function shows WOR consistently increasing over time with the age of the reservoir (see Figure D.1). In the cases shown in the figure, the model is an excellent predictor of WOR, as demonstrated by the R^2 coefficients (here, the model captures over 95% of the variation due to the independent variable).

D.1.2.2 Logistic and Gompertz models

In addition to the exponential model, two other models were tested: a logistic function and a Gompertz function. Both are sigmoidal in shape, increasing initially and then leveling off (symmetrically in the case of the logistic function, asymmetrically in the case of the Gompertz function). These models were not chosen for the analysis because they did not fit significantly better than the exponential model (increase in mean R^2 of 0.014 and 0.015



(a) Grand Forks, Upper Mannville K



(b) Snipe Lake, Beaverhill Lake

Figure D.1: Example exponential fits to Alberta pool-level WOR dataset. Pool age is calculated relative to discovery date of pool (not initial year in dataset).

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Table D.3: Results for exponential fit to Alberta oil fields.

Var.	Obs.	Mean	Median	Std. dev.	Min	Max
R^2	100	0.866	0.82	0.184	0.034	0.994
b_0	100	1.168	0.279	3.295	2×10^{-9}	29.43
b_1	100	0.091	0.082	0.061	-0.061	0.512

for logistic and Gompertz models respectively) and they constitute a significant increase in model complexity (3 parameters rather than 2). Increased model complexity should not be favored if it does not result in meaningful improvement to model fit [142].

D.2 Results

Results for the exponential fits are included below in tabular and graphical form.

D.2.1 Alberta WOR analysis

Table D.3 summarizes the results for the exponential fit to Alberta oil pools and fields. The model results in a strong fit with a mean R^2 of 0.866 and a standard deviation of 0.184. Figure D.2 shows a histogram of R^2 values. There are some model fits with R^2 below 0.6, but most have high predictive value, suggesting that the exponential model is generally useful.

The WOR growth rate (b_1) has a mean value of 0.091 across 100 fits, with a standard deviation of 0.061 and a median value of 0.082. Hence, WOR values in Alberta tend to grow at a rate of 9.1% per year. Figure D.3 shows the distribution of WOR growth rates with relation to initial WOR values. As can be seen, most fields have initial WOR below 2 bbl/bbl.

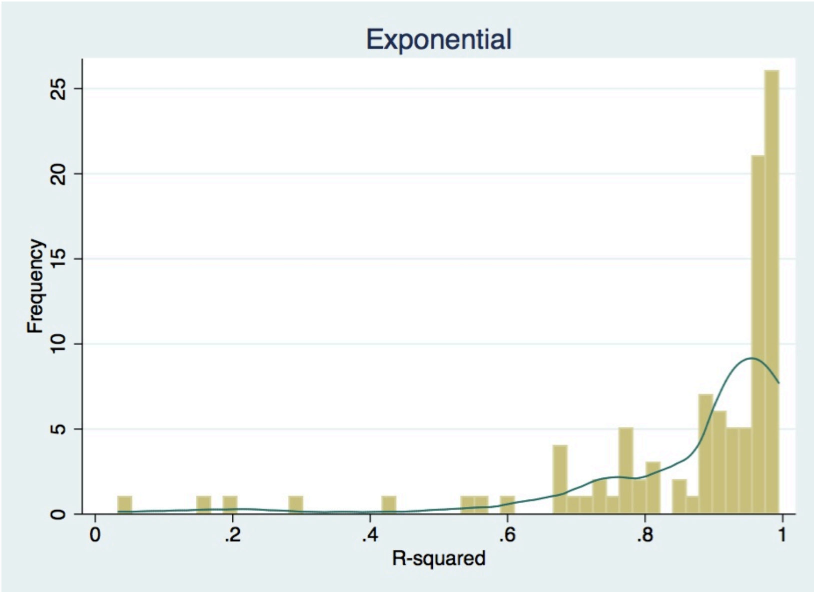

Figure D.2: Histogram of R^2 for Albertan Crude Production (Exponential Fit).

Table D.4: Results for exponential fit to California oil fields.

Var.	Obs.	Mean	Median	Std. dev.	Min	Max
R^2	80	0.893	0.950	0.152	0.317	0.999
b_0	80	2.486	0.905	4.399	0.000	30.9
b_1	80	0.030	0.031	0.029	-0.019	0.182

D.2.2 Californian WOR analysis

Table D.4 summarizes the results for the exponential fit for the Californian oil fields. The model results in a stronger fit relative to Albertan production with a mean R^2 of 0.893 and a standard deviation of 0.152. As can be seen in the histogram of R^2 values (see Figure D.4), the fit of the model is very good overall.

California WOR trends are different than Alberta trends. In California, b_1 shows a mean value of 0.032 with a standard deviation of 0.029. Hence, WOR increases at a slower rate of 3.2% per year. Figure D.5 shows the distribution of WOR growth rates with relation to initial WOR values. As can be seen, much of the growth is clustered in pool/fields with initial WOR values below 2 but there is a significant amount of fields with initial WOR above 2.

D.2.3 Generating the smart default value

In addition to the above detailed analysis of multiple California and Alberta fields, WOR values are collected for a variety of oil fields in diverse geographic locations. These fields are collected as available, and do not represent comprehensive assessments of these regional emissions. These WOR values, along with field age, are included in the analysis to provide more

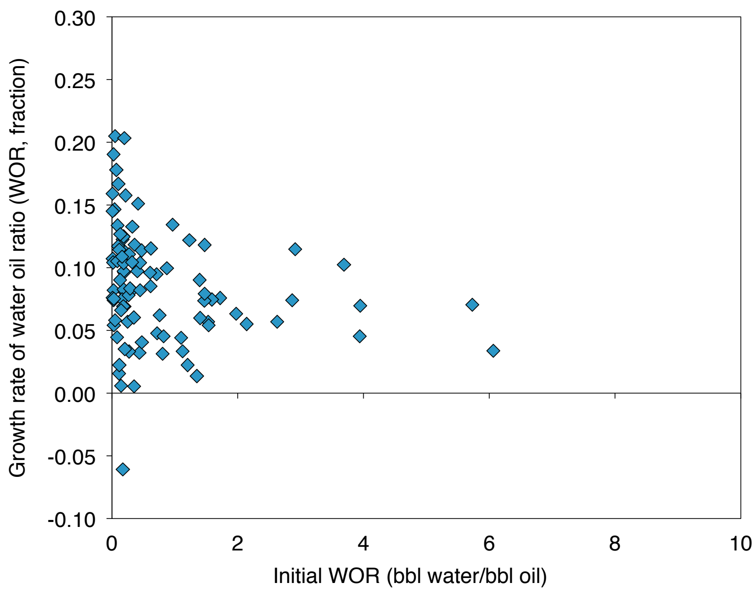

Figure D.3: Plot of values of b_0 and b_1 for exponential fits to Alberta producing WORs.

Table D.5: OPGEE WOR relationships.

Case	b_0	b_1	Source
Low	2.486	0.032	CA Mean
Default	1.75	0.05	User spec.
High	1.168	0.091	AB mean

comparative information. The sources and field names for the comparative cases are included in Table D.6.

These varied regional WORs are plotted along with important California and Alberta WORs (see Figure D.6). Because of the sporadic data availability, a visual fit is performed, resulting in the following smart default WOR relationship:

$$WOR_{sd}(t) = a_{sd}\exp[b_{sd}(t - t_0)] \tag{D.2}$$

where a_{sd} = 2.5 and b_{sd} = 0.035. This results in the smart default curve seen in Figure D.6.

Table D.6: Sources of WOR data for global oil fields.

Location	Fields	Sources	Notes
Alaska North Slope (ANS)	Colville River, Kupuruk Rover, Milne Point, Prudhoe Bay, Northstar, Endicott, Oooguruk	[143]	
Brazil	Marlim	[144]	
CA onshore	Huntington Beach, Inglewood, La Cienegas, Montalvo West, San Miguelito, Santa Fe Springs, Seal Beach, Shafter North, Tejon	[127]	
CA offshore	Beta, Carpenteria, Dos Cuadras, Hondo, Hueneme, Pescado, Point Arguello, Point Pedernales, Sacate, Santa Clara, Sockeye, Ellwood South Offshore, Belmont Offshore	[128, 145]	a
UK	Humbly Grove, Singleton, Welton, Magnus, Stockbridge, Forties, Wytch Farm, Piper, Brent, Ninian	[146]	b
Alberta	Provost, Wimborne, Hayter, Bantry, Bellshill Lake, Judy Creek, Leduc-Woodbend, Sturgeon Lake South, Virginia Hills, Carson Creek North, Fenn-Big Valley, Nipsi, Swan Hills South, Redwater	[140]	
Wyoming	Salt Creek, Houise Creek, Hartzog Draw, Hornbuckle, Finn-Shurley, Oregon Basin, Spring Creek South, Elk Basin, Hamilton Dome, Garland	[147]	c

[a] In addition to data from the Bureau of Ocean Energy Management, Regulation and Enforcement data, a variety of other web data sources were use to generate first production dates for California offshore fields.
[b] In addition to data from the UK Department of Energy and Climate Change, a variety of other sources were consulted to obtain field age.
[c] Wyoming fields were taken from the top five producing fields in the Powder River Basin and Bighorn Basin. Not all fields had available start dates.

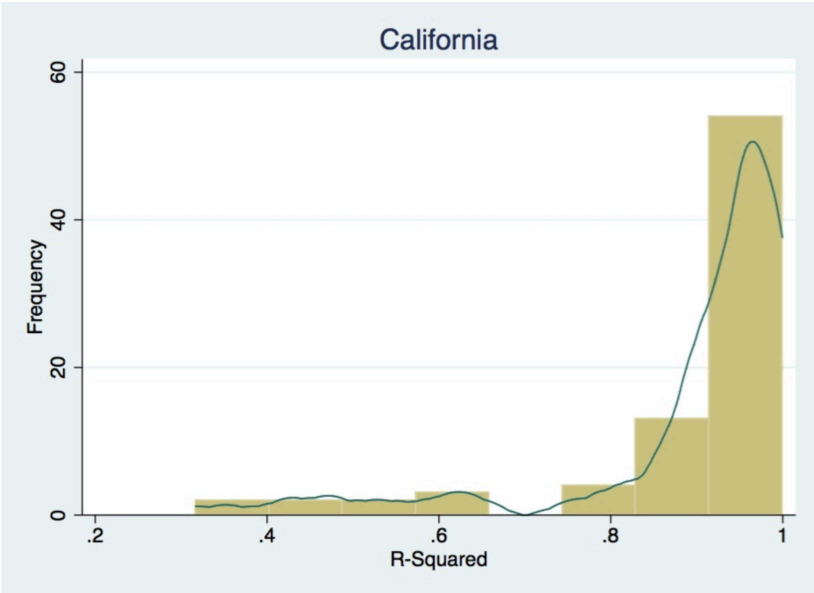

Figure D.4: Histogram of R^2 for Californian Crude Production (Exponential Fit).

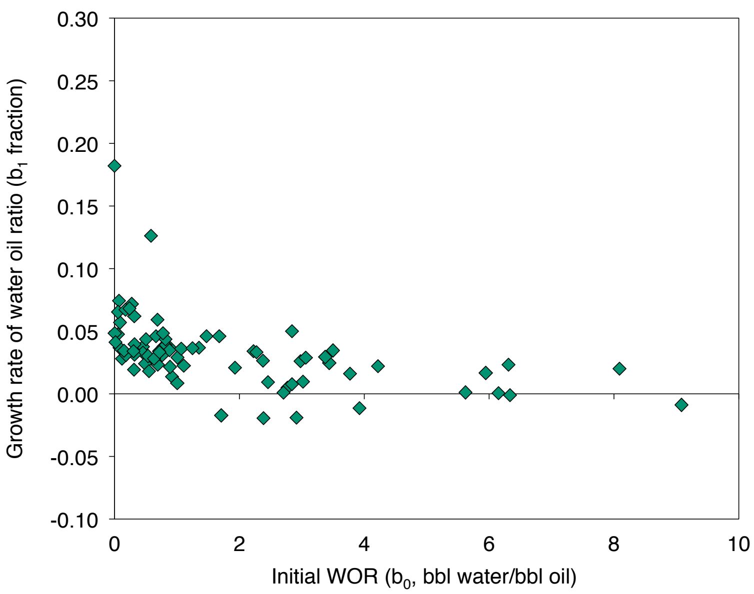

Figure D.5: Plot of values of b_0 and b_1 for exponential fits to California producing WORs.

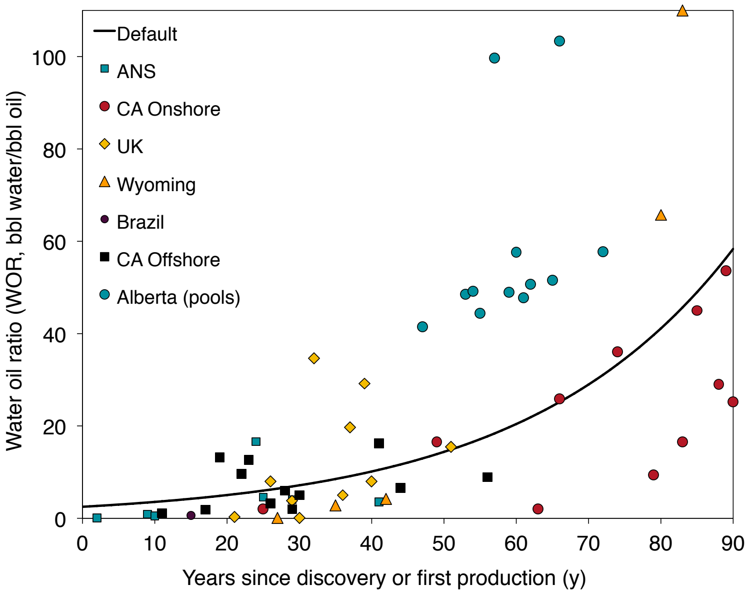

Figure D.6: Smart default WOR in comparison to fields from California, pools from Alberta, and a collection of global fields with available data.

E Changes and updates from previous versions of OPGEE

E.1 Changes from OPGEE v1.0 Draft A to OPGEE v1.0 Draft B

Draft version A of the model was released on June 22nd, 2012 for public review and commenting. A public workshop which was held on the July 12th, 2012 at California Air Resources Board, Sacramento. In this appendix the comments received at this meeting and at other times are addressed as described below.

E.2 Major changes

- The version released to the public is now the same as the "pro" version of the model. The public version of the model now contains the macro to run up to 50 fields at one time. See sheet *'Bulk Assessment Tool'*, which allows the user to run multiple cases at once.

- Complex storage tank emissions calculations were removed from OPGEE v1.0 Draft A and replaced with a single parameter. At this time, it was judged that the scale of tank emissions (relatively small) and the complexity with which they were addressed (high complexity) were incommensurate. This is especially the case given the large numbers of parameters needed for the storage tank emissions model, many of which would not likely be available to users of the model. In place of the complex tank calculations, an average tank emissions factor from California data is included.

- The *'User Inputs & Results'* sheet was significantly expanded to allow easier running of the model with less need to access the detailed calculation sheets. Parameters added to the *'User Inputs & Results'* sheet include: fraction of steam generated via cogeneration for thermal enhanced oil recovery projects; field productivity index; and well production tubing diameter.

- An option is now added to deal with the co-production of oil and other products (NGLs, gas, etc.): OPGEE v1.0 Draft A only treated co-production with system boundary expansion, while in OPGEE v1.0 Draft B, allocation of emissions by energy content is allowed. In system boundary expansion (also known as co-product displacement or co-product credit method), an alternative production method for the co-produced product is assessed and the resulting emissions are credited to the main product as if the co-product directly displaces material produced elsewhere. In allocation, the emissions are divided between products and co-products in proportion to some measure of output (often energy, mass, or monetary value). The user can now choose the co-product treatment method on the *'Fuel Cycle'* sheet.

- OPGEE was updated with data from the CA-GREET variant of the GREET model. This update allows better congruence with other California LCFS calculations, which rely on the CA-GREET model. The data inputs changed include fuel properties and upstream (fuel cycle) emissions for use in co-product displacement calculations.
- All calculations were updated to use lower heating values instead of higher heating values. The user can still choose the heating value metric for the denominator energy content of the final result (e.g., g/MJ LHV or g/MJ HHV crude oil delivered to refinery).
- Water injection pressure is now calculated using reservoir pressure and an injectivity index (bbl/psi-well). This is more in line with the calculation of work to lift fluids.

E.3 Minor changes

- The user guide is expanded with additional descriptions of the input parameters on the *'User Inputs & Results'* sheet to reduce uncertainty about the definitions of parameters. These descriptions are included in Section 2.4.1.
- More explanation is given in tables regarding parameters that are outside of literature ranges (e.g., pump and compressor efficiency).
- More attention is drawn to the overall model error check indicator to alert the user to possible errors in model inputs.
- An error is reported when a user puts in an incorrectly spelled country name. This prevents spurious default to average flaring emissions rates that might occur due to simple input errors.
- To address transmission losses between pumps and prime movers, pump efficiency is slightly reduced. This is believed to be a minor factor, and data are not currently available to separate transmission losses from other losses.
- The value for flaring emissions on the *'User Inputs & Results'* sheet (J99 in OPGEE v1.0 Draft A) is now used to compute flaring emissions.
- The friction factor is now included as a 'User Free' cell instead of a fixed default. This will allow the user to reduce the friction factor in cases of very high well flow rates (flow character in turbulent regime).

- Water reinjection pump suction pressure is added as a parameter to allow for high pressure oil-water separation and resulting reduced pump work.
- Conversion factor from grams to pounds changed to 453.59 g/lb from 453.
- The units that accompanied cell *'Bitumen Extraction & Upgrading'* M164 in OPGEE v1.0 Draft A, are corrected from g/bbl to g/MJ.
- GWP values are allowed to vary for examining differences using 20 and 100 year GWPs.

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