LETTER

Climate-wise choices in a world of oil abundance

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Abstract

Constrained oil supply has given way to abundance at a time when strong action on climate change is wavering. Recent innovation has pushed US oil production to all-time heights and driven oil prices lower. At the same time, attention to climate policy is wavering due to geopolitical upheaval. Nevertheless, climate-wise choices in the oil sector remain a priority, given oil’s large role in modern economies. Here we use a set of open-source models along with a detailed dataset comprising 75 global crude oils (∼25% of global production) to estimate the effects of carbon intensity and oil demand on decadal scale oil-sector emissions. We find that oil resources are abundant relative to all projections of 21st century demand, due to large light-tight oil (LTO) and heavy oil/bitumen (HOB) resources. We then investigate the ‘barrel forward’ emissions from producing, refining, and consuming all products from a barrel of crude. These oil resources have diverse life-cycle-greenhouse gas (LC-GHG) emissions impacts, and median per-barrel emissions for unconventional resources vary significantly. Median HOB life cycle emissions are 1.5 times those of median LTO emissions, exceeding them by 200 kgCO$_2$ eq./bbl. We show that reducing oil LC-GHGs is a mitigation opportunity worth 10–50 gigatonnes CO$_2$ eq. cumulatively by 2050. We discuss means to reduce oil sector LC-GHGs. Results point to the need for policymakers to address both oil supply and oil demand when considering options to reduce LC-GHGs.

Introduction

The oil industry is in flux. A decade of high prices from 2004–2014 induced oil companies to invest hundreds of billions of dollars in technically challenging oil resources such as deep offshore, light-tight-oil (LTO), and heavy oil and bitumen (HOB). The resulting supply increases, combined with modest demand growth, eventually drove prices lower. Since 2014, lower prices have prompted renewed oil demand growth and supply-side investors to cut costs, especially in newer plays. Meanwhile, competition has increased as the cost of oil’s competitors—such as renewable electricity used in electric vehicles (EVs)—have been rapidly dropping [1].

At the same time, the threat of climate change looms. Warming targets from the 2015 Paris Climate Accord, if honored, would mean greenhouse gases (GHGs) from current reserves of oil, gas, and coal cannot be emitted [2–4]. To meet such targets, either some carbon will remain un-burned, renewable fuel inputs will be used, or the resulting CO$_2$ from oil will be captured [5]. For example, recent calculations argue that keeping climate change below 2 °C without large-scale carbon capture and storage would require leaving over one-third of current oil reserves unburned [6].

These intersecting trends present an opportunity to develop a climate-informed strategy for oil resource development in the 21st century. Wise choices can maximize the societal value of oil resources while minimizing their climate impacts. To aid such choices, we couple projections of oil demand to estimated resource endowments and GHG intensity estimates for each...
type of resource. This allows us to explore implications of future oil use. To accomplish this, we use a suite of open-source models to perform detailed life-cycle greenhouse gas (LC-GHG) analysis of 75 global crudes [7] representing ~25% of 2015 oil production. We then couple these GHG estimates to data on resource availability and future demand. This allows us to highlight for the first time the interplay between demand and cumulative emissions using detailed GHG intensities estimated for a diverse set of global crude oil resources.

Importantly, oil sector (especially upstream) emissions are not typically modeled or discussed in detail in overview assessments of transport emissions reduction potential [8–10]. For example, recent large-scale assessments of transport emissions, such as the Global Energy Assessment [9] or the Intergovernmental Panel on Climate Change (IPCC) Fifth Assessment Report [10], discuss fuel mitigation options generally (e.g. hydrogen or biofuels), they lack detailed treatment of the petroleum sector.

We first describe the methods to assess oil demand and oil resource availability. Next, we outline the methods to use our suite of open-source GHG assessment models to perform LC-GHG analysis of the global crudes in our study sample. Lastly, we describe methods to construct named oil resource scenarios with mixes of different resource types. Results are presented comparing demand projections to resource endowments, variation in LC-GHG intensity per resource type, and the impacts to 2050 and 2100 of different demand and LC-GHG intensity combinations.

Methods

We briefly describe methods below, and refer the reader to supplemental information (SI) for more details available at stacks.iop.org/ERL/13/044027/mmedia. Our approach focuses primarily on the engineering and energy resource aspects of emissions from the petroleum sector, but where possible we highlight economic considerations and potential areas for improved analysis involving the economics of petroleum supply and demand.

Oil demand assessment

Oil demand projections were gathered from numerous sources, including international and national agencies, companies, and Integrated Assessment Modeling (IAM) efforts affiliated with the IPCC. See SI for additional detail on references and conversions and interpolation/extrapolation required to make demand projections comparable. Agency projections include: International Energy Agency (IEA, three projections); Energy Information Administration (EIA, three projections); and OPEC (one projection). Energy company scenarios include: Shell (four projections); ExxonMobil (one projection); British Petroleum (BP, one projection); Statoil (three projections). IPCC IAM scenarios from 2000 and 2016 are gathered, with year 2000 scenarios filtered to remove scenarios rendered infeasible due to observed historical evolution from 2000–2015 (40 projections). Year 2016 IAM scenarios are from the IIASA Shared Socioeconomic Pathways database, v1.1, (23 ‘Marker’ projections).

Oil resource assessment

All crude oil analyzed is categorized as belonging to one of three resource types: conventional crude, LTO and HOB. HOB is viscous, carbon-rich crude (e.g. Alberta oil sands); while LTO is light or ultra-light oil but is trapped in low-permeability rocks (e.g. Eagle Ford formation). LTO has been commercialized in the last decade using high-volume hydraulic fracturing of horizontal wells.

Cumulative total crude oil production from historical statistics is 1383 Gbbl from 1859 to the end of 2015 (see SI for methods and full references). From this, cumulative conventional oil consumption—1306 Gbbl—is computed by subtracting cumulative consumption of HOB and LTO (27 and 5 Gbbl, respectively, see SI). Uncertainty in cumulative historical consumption is likely at least +/- 5%, due to a combination of poor reporting in some regions, coupled with uncertain and inconsistent definitions of ‘crude oil’ in different times and regions. Reserves for conventional oil are generated from BP Statistical Review of World Energy, while remaining technically recoverable resources are from US Geological Survey Global Assessments (see SI).

Original oil in place (OOIP) of HOB is often estimated from 3000–5000 Gbbl each for both bitumen and heavy oil resources (see SI). Indicative recovery factors (RFs) of 15%, 25%, and 50% are studied. These are likely low, given high RFs seen for in situ HOB recovery.

Current estimates of global LTO resources are very uncertain. The largest challenge is that most of these resources have not been developed and can only be estimated by analogy [11–13]. These challenges noted, current US government estimates place technically recoverable LTO at 400 Gbbl, similar in scale to HOB reserves [11]. The above resource estimates use an average RF of 5% based on recent experience in US and Canada [11]. Thus, the global LTO OOIP exceeds 8000 Gbbl, of which 95% remains in the ground using current methods [10]. Dozens of recent papers have examined increasing recovery factors using enhanced oil recovery technologies in LTO formations (see SI for overview). Simulations suggest that LTO RFs could increase substantially, with RFs exceeding 50% in some studies [14]. A recent 16 well pilot project in Texas re-injected produced natural gas and increased LTO RFs by 40%–70% at an incremental cost of only $6/mtl [15]. Indicative LTO recovery factors of 5%, 15% and 30% are studied.
Oil resource GHG intensities

The Oil Climate Index (OCI) project [16, 17] combined three open-source engineering-based models to assess per-barrel LC-GHG impacts, or carbon intensity (CI) of oil supply [17–19]. These models include all supply-chain activities between exploration and consuming oil-based fuels in cars, airplanes and factories. Results for 75 crude oil streams from the OCI are compiled and aggregated into three emissions categories: upstream, refining, and fuel consumption. In the OCI, the upstream emissions are modeled using the OPGEE model of Stanford University [18, 20]. Refinery emissions are modeled using the PRELIM model of the University of Calgary [19, 21]. Both of these models have been previously peer reviewed. Fuel consumption emissions are modeled using the OPEM model developed by the Carnegie Endowment for International Peace.

OCI results are point estimates for each of 75 crude streams. In addition to variability between these point estimates, there is uncertainty in each point estimate. While uncertainty has been studied for the OPGEE model (see SI), uncertainty is difficult to quantify due to challenges obtaining relevant comparative data for oil operations around the world. For this reason, we assign an approximate uncertainty range and draw crudes from the resulting distributions.

Each observation is drawn from a normal distribution with a mean value equal to the estimated OCI value for that crude. The standard deviation (SD) of each estimate is defined separately for each process stage:

- Upstream emissions from the OPGEE model are assigned a SD of 15% of the point value estimated in OCI (Approx. 95% CI is +/− 30%).
- Refining emissions from the PRELIM model are assigned a SD of 15% of the point value estimated in OCI (Approx. 95% CI is +/− 30%).
- Fuel transportation and fuel combustion emissions modeled in OPEM are assigned a SD of 5% of the point value estimated in the OCI (Approx. 95% CI is +/− 10%).

GHG intensity scenarios

The mix of conventional oil, HOB, and LTO consumed in coming decades is uncertain. Oil prices, technological change, geopolitics, and resource availability will all interact in complex ways to determine which resources will be used to meet demand. Instead of trying to predict such factors, we create three indicative scenarios for HOB and LTO supply (conventional oil provides the remainder in all cases):

- Scenario ‘BAU’ maintains current mixes until 2100: LTO and HOB supply 5% each.
- Scenario ‘Light world’ is a LTO-rich scenario: LTO provides 25% and 50% of demand by 2050 and 2100 respectively, while HOB supplies 5% over all time periods.
- Scenario ‘Heavy world’ is a HOB-rich scenario: HOB provides 25% and 50% by 2050 and 2100 respectively, while LTO share remains at 5%.

Results

Our collected projections suggest that oil will be used in large quantities for decades.

This is because significant inertia exists in the energy system: globalized product supply chains have increased freight fuel demand, and increasing wealth has historically induced more air travel. Vehicle substitution affects oil use slowly because of slow fleet turnover rates. New aircraft technologies, like distributed electric propulsion [22], will take time to deploy because of stringent engineering standards and long aircraft lifetimes [23].

These inertial factors should be somewhat tempered by recent events that are moving us in the direction of a low oil future. These include rising consumer interest in EVs, the rejection of diesel vehicles due to poorly controlled emissions, and possible bans on ICE engines in the 2030–2040 timeframe [24].

Taking these caveats into mind, figure 1(a) shows projected cumulative oil consumption, as estimated by governments, oil companies, non-governmental groups, international agencies, and integrated climate assessment models. From the start of the industrial revolution to 2015, humans have consumed ∼1330 billion barrels (Gbbl) of crude oil (see Methods for description, plotted in figures 1(a) as well as (b), pts. a, f, k). Projected consumption of oil from 2015–2100 exceeds cumulative historical consumption in 40 out of 40 included century-long scenarios. Given the above-mentioned trends toward less oil use, one can imagine scenarios with lower oil consumption, but future oil consumption is likely to reach levels similar to historical consumption in most scenarios.

Where will we get a century’s worth of oil? Figure 1(b) shows resource endowments of three resources: conventional oil, HOB, and LTO (see Methods for description and SI for figure key). Figure 1(b) shows that either HOB or LTO is likely sufficient to fill any shortfalls between supply and demand, even if conventional oil only reaches modest projections (see Methods for assessment details).

Note that the future price of oil is central to both panels of figure 1. If the oil price is high, then oil demand will more likely follow a comparatively low demand path in figure 1(a). However, if the oil price is high, producers will be incentivized to develop a larger fraction of the resource base in figure 1(b). Similarly, in low oil price scenarios, demand and supply also act in opposing directions (high demand, low supply). Each modeling team generating the scenarios used in
Figure 1. (a) Historical consumption and projections in billion barrels per year (Gbbl/y, inset) along with cumulative consumption (cumulative Gbbl, main). Grey segments are country-specific historical production rates. (b) Resources of conventional, heavy, and light-tight oil, including prior consumption, reserves, and varying estimates of additional technically recoverable resources. See SI for construction methods.

Figure 1 (a) will have an oil price path (either specified or solved endogenously as part of the modeling effort). Also, different resources can have different production cost trajectories (i.e. cost of tight oil has declined much more quickly than HOB). It is beyond the scope of this paper to delve deeply into the supply and demand modeling assumptions of each scenario modeling team (see below for more discussion).

What of this oil abundance for the climate? Figure 2 shows probabilistic results for 75 global oils, comprising approximately 25% of 2015 global oil production. Figure 2 compares the emissions distributions for the same three resource categories used in figure 1 (b). Numerous prior studies, including many by these authors [25–28], found emissions increases of around 15%–30% for HOB resources. These studies took a ‘product-centric’ approach, analyzing the life cycle impacts from a unit of final product like gasoline or diesel. In contrast, the Oil Climate Index uses a ‘crude-centric’ approach, tracking total emissions associated with producing, refining, and consuming a barrel of crude in the ground. The crude-centric approach leads to a larger percentage divergence between the lowest- and highest-emitting crudes due to the synergistic interaction of crude quality, crude processing energy, and final product mix [7].

Another result from figure 2 is that mitigation options exist in each resource (see blue mitigation outlines). For both conventional and LTO, flaring of associated gas can have a material impact on emissions. Blue mitigation curves in figure 2 show the effects of flaring reduction (to 20 scf/bbl) for these two resource classes. The distribution of LTO emissions in figure 2 is based on 2014 production methods, which result in significant flaring in two key LTO regions of North Dakota and Texas (see SI). If flaring is regulated to realistically-achievable values (see SI), LTO LC-GHGs become even more favorable. Some regions are already making significant progress on this front: in the Bakken LTO formation the fraction of gas flared declined from 37% to as low as 8% between 2012 and 2016 [29].

Other technological options exist. A recent study [30] of potential solar deployment in the 2013 global oil and gas sector suggested that PV power could supply from 0.2 to 0.7 EJ_e−/y, while solar thermal could supply 0.4–1.2 EJ_ th/y. This potential is large, but is a small fraction (<10%) of current global oil and gas sector energy use. Challenges found in using solar in oil and gas include: (1) offshore oil contributes one-third of production; (2) low-insolation or highly seasonable resources in Northern Europe, Russia, and Canada, make solar economics challenging in some key oil and gas regions; and (3) solar without storage does not provide round-the-clock offset required for 24 hour operations. Solar results in potential emissions reductions of order 5 kg CO_2/bbl averaged over all bbl. Larger reduction fractions exist for HOB in sunny regions. For example, Oman is building the world’s largest solar thermal plant (~1 GW) to replace natural-gas-based steam for HOB recovery [31].

A last key result from figure 2 is that median emissions from HOB are ~200 kg CO_2 eq. higher than median emissions from conventional and LTO. HOB requires more energy to extract, more energy to process, and results in a more carbon-rich slate of products, using conventional techniques. First, HOB has high viscosity, which requires heating or dilution to reduce the viscosity of the oil so that it will flow to producing
Figure 2. Life cycle emissions distributions for conventional crude, HOB and light-tight oil. Pie charts represent fractional share of production (P), refining (R), and refined fuel combustion (F) emissions. n is the number of crudes of each resource type modeled in OCI.

wells. Next, HOB has a high fraction of heteroatoms (mainly sulfur and metals), coupled with a carbon-rich molecular structure that requires significant refining to produce light fuels. Both of these factors necessitate intensive refining. These problems are solved through addition of H\textsubscript{2} (with concomitant emissions from H\textsubscript{2} production) or production of high-carbon residuals such as petroleum coke (‘petcoke’). These factors lead to HOB having higher fractions of emissions from production (label P) and refining (label R) compared to conventional or LTO (see pie charts, figure 2).

In terms of future climate impact, how important are above crude oil GHG intensities compared to demand reduction measures? Such demand measures—widely studied as methods to reduce oil-associated climate impacts—include fuel economy improvements, alternative fuels (e.g. biofuels), or alternative vehicles (e.g. EVs).

Figure 3 examines the effects of demand reductions and GHG intensity reductions by plotting cumulative post-2015 emissions from the oil sector, with color scale representing GtCO\textsubscript{2}eq. with white isolines of constant emissions. Cumulative emissions are computed over the period 2015–2050 (figure 3(a)) and 2015–2100 (figure 3(b)). In each plot, the x-axis represents crude GHG intensity, while the y-axis represents the percentile of projected cumulative demand reached for that year, relative to all studied demand projections. The ranges of y- and x-axes are informed by figures 1 and 2 respectively.

The x-axis supplemental keys show variation in LC-GHG for three pre-defined scenarios of crude oil GHG intensity: ‘Business as usual (BAU)’, ‘Light world’, and ‘Heavy world’ (see Methods). The y-axis supplemental keys plot each demand scenario from figure 1 at its percentile of cumulative demand across all demand scenarios for that year. Note that figure 3(b) only includes IPCC scenarios because no company or government projections extend to 2100. Per-bbl GHG distributions for these scenarios are computed by sampling from figure 2 distributions at noted mixes. Ranges for each scenario are presented below x-axis as 10/50/90 percentiles.

The red star in figure 3(a) is an illustrative scenario with GHG intensity at the 50th percentile of the Heavy world scenario and demand near the 50th percentile of all 2050 demand projections (a Statoil scenario, their central ‘Reform’ case, see SI). Cumulative oil emissions to 2050 are 675 GtCO\textsubscript{2}eq in this case. The dashed arrows represent three mitigation opportunities. First, we can reduce oil GHG intensity from the median Heavy world scenario to the median Light world scenario (leftward arrow), reducing cumulative emissions by ∼55 Gt CO\textsubscript{2}eq. Alternatively, we can reduce demand from the 50th percentile to a low demand scenario IEA ‘450 scenario’, at ∼20th percentile of 2050 cumulative demand projections (downward arrow); this change reduces cumulative emissions by ∼110 Gt CO\textsubscript{2}eq. Lastly, the above demand reduction and CI mitigation options can be pursued simultaneously (diagonal arrow), which reduces emissions by ∼160 Gt CO\textsubscript{2}eq.

For a broad region of moderate 2050 cumulative demand percentiles, an interesting trend emerges:
the isolines of cumulative emissions decline relatively steeply, suggesting that reducing oil emissions intensity is a mitigation measure of importance similar to demand reductions (about half the magnitude). While most attention to date has been focused on reducing demand, the above-described LC-GHG-reduction strategies should clearly be pursued along with demand reductions. For the 2015–2100 case (3b) the isolines slope more gently, suggesting greater importance in reducing demand percentiles because variation in cumulated demand over the century is larger than LC-GHG variation between different oil scenarios.

Note that figure 3 does not make claims about causal relationships between any particular demand reduction effort and movement along the cumulative demand (vertical) axis. It simply traces the impact of movement (by any set of means) up or down the projected demand percentiles. Also, figure 3 does not
illustrate the cost of moving a certain distance in the x-axis or y-axis direction. Importantly, moving in one direction could be substantially cheaper than the other. It is likely that the cost of moving along either axis is a complex function of the starting position on each axis (i.e. the marginal cost of reductions changes as a function of location in demand-CI space), as well as a function of hard-to-predict features such as cumulative technological change or breakthroughs in competing industries (i.e. cost trends in batteries for EVs).

Discussion

One overarching result is the challenge of data availability. While the underlying OCI models utilize ‘smart’ default values, more data would allow less reliance on defaults and assumptions. Required data for OPGEE upstream modeling are sparsely spread throughout 100s of technical documents and regulatory reports. Additionally, reliable, comprehensive crude properties data (i.e. crude oil assays) needed for the PRELIM model are largely private or unpublished. This points to a first result: the absence of detailed, comprehensive, and transparent information about possible GHG impacts for particular oil resources leads to a material risk for governments, investors, and companies alike. These data gaps expose decision makers to risk that their resource becomes ‘stranded’ oil that may never be produced. Gross resource categories like HOB and LTO are only partly predictive of LC-GHG impacts due to large variability between different oil fields in similar resource categories (figure 2). Efforts toward reducing these knowledge gaps are underway: at least one investment firm is using OCI-like methods to assess GHG risk of investments in energy projects [32].

Improved data are important to good decision-making because they would allow: prioritization of mitigation efforts; setting of appropriate or attainable targets; estimation of mitigation opportunity magnitude by technology type and resource class; and, not least, estimation of the marginal costs of different mitigation options. A good amount of such data are likely collected by private firms, but are not publically available in most jurisdictions. This makes it challenging for policymakers, regulators, and investors to incorporate GHGs into their decisions in any granular or detailed fashion.

In addition, improved data in this sector can and should be used to inform large-scale climate futures modeling efforts, such as the Integrated Assessment Models used as part of the IPCC modeling and mitigation efforts. While such models are necessarily (by virtue of their breadth) limited in how much resolution they can apply to any particular sector, we believe that upstream and midstream oil sector emissions are important enough—in both potential impacts and potential for mitigation—to warrant more attention in future modeling efforts.

The above analysis points to numerous approaches to reducing oil sector emissions. The leakage of GHGs throughout the oil and gas supply chain is one strategic target. For example, while not costless, flaring reduction is an obvious first step as it generates useful product to offset costs. So too are verifiable ways to eliminate the release of methane gas. Global estimates of 2016 flaring in recent estimates amount to 150 Gm$^2$ per year [33, 34], which with reasonable gas composition assumptions causes approximately 8–10 kg CO$_2$/bbl in 2016.

Flaring is an operational decision, so reductions will require ongoing monitoring and verification. Monitoring is always challenging in the diverse global oil sector. Thankfully, new satellites [33] offer the potential for independent checks on reported improvements, and additional support of such remote-sensing methods could play a large role in future emissions reductions. For example: methane-sensing satellites for high-frequency observations of fugitive emissions and venting.

International efforts to eliminate gas flaring do exist [34], but progress is slow. If producing regions will not mandate flaring reductions, responsible companies and importing nations can lead the way to eliminate these unneeded emissions. Current fuel standards efforts underway in California, Canada, and the EU to reduce oil sector emissions can be restructured to incentivize responsible behavior in exporting regions [35, 36]. In a world where abundant oil supplies reduce the market power of producers, action by consuming areas is a possible way forward.

In current practice, the GHG disadvantage of HOB is much larger in per-barrel magnitude. This is manifest in divergence between median emissions in figure 2, as well as the 50 kg bbl$^{-1}$ divergence between median ‘Heavy world’ emissions compared to median ‘Light world’ emissions in figure 3. This GHG disadvantage become a monetary disadvantage even at moderate carbon taxes. Every 100 kg CO$_2$ eq per bbl becomes a value penalty of 5 $/bbl for HOB at emissions cost of 50 $/tCO$_2$. In the highest-emitting HOB projects, the resulting penalty could exceed 15 $/bbl compared to a light crude with low flaring. Such a disadvantage must be added to an existing challenge for HOB due to its higher transport and refining costs.

An obvious first step for HOB emissions reduction is to mandate disposal (rather than burning) of petcoke (figure 2 middle, blue curve). Some Canadian producers already dispose of petcoke as part of mine reclamation projects. Because petcoke has a low market value, this foregoes revenues of a few USD per bbl, but can avoid up to 100 kg CO$_2$-eq per bbl. Canadian federal and provincial agencies are leading global efforts to reduce HOB emissions. Their carbon taxes and incentives for capturing and storing CO$_2$ from HOB upgrading are promising steps in the right direction [37]. Other novel decarbonization options for HOB are being studied, including use of advanced
microbial engineering to extract energy from oil sands without carbon release [38–40]. It remains unclear whether such efforts will be sufficient for the HOB resource to remain cost competitive in a low-emissions, oil-abundant world.

Much more scientific work is needed to explore these issues. In particular, improved interdisciplinary collaboration between engineers, resource geologists, environmental scientists, and economists would aid the understanding of the interactions between long-term supply and long-term demand. Such work can incorporate technological learning on both supply side and demand side, as well as improved understanding of granular GHG intensities and resource base estimates.

It is increasingly likely that the world has more oil than it will reasonably need for the 21st century. Leaders should make decisions about oil use with consideration of the climate impacts of different oil options. Currently, incomplete data from global oil operations renders this type of analysis challenging and labor intensive. A rational approach to 21st century oil resource development must include detailed, data-driven GHG assessment to make wise choices that maximize societal value, support the vital transport sector, and minimize climate impacts.

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