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OIL INNOVATIONS TO REDUCE CLIMATE IMPACTS

DEBORAH GORDON AND JEFFREY FELDMAN | OCTOBER 20, 2016

Parties to the December 2015 Paris Agreement have an ambitious target for reductions in greenhouse gas (GHG) emissions: to avert global warming greater than 1.5 degrees Celsius by the end of the century and thus stave off the worst effects of climate change. To achieve this aim, GHG emissions from the oil sector must be fully accounted for and addressed. This is in part because oil is the world's largest source of energy, and there are few ready substitutes for it.[1] Additionally, petroleum-product combustion alone constitutes over one-third of carbon dioxide emissions associated with fuel combustion—a figure that is projected to grow under a business-as-usual scenario.[2] And this does not take into account all of the GHG emissions that go into a barrel of oil.

Most analyses of oils are underestimating the total GHG emissions associated with extracting, refining, and transporting these resources. Emissions can be large and vary significantly throughout the oil supply chain—in terms of upstream, midstream, and downstream contributors—and among diverse crude-oil resources. Estimates of the emissions resulting from the combustion of petroleum products also do not adequately account for this full range.

Reducing GHG emissions through innovation is technically feasible, and new technologies can be promoted by information, regulations, and pricing policies, including emissions tracking and carbon taxes, that are robustly designed for the oil sector. Despite a historic, concentrated regulatory focus on other fossil fuels and cars, the oil sector will increasingly present an opportunity to mitigate climate change.

FOCUSING ON EMISSIONS INTENSITIES

GHG emissions in the oil sector can be reduced in two ways. If the emissions associated with producing, refining, and consuming each barrel of oil—in other words, an oil's emissions intensity—are held constant, then reducing the total volume of oil supplied will diminish total emissions. Alternatively, holding supply volume constant while reducing the emissions intensities of oils will also reduce emissions.

Both strategies will be necessary to achieve the climate goals set in the Paris Agreement. But the focus here is on reducing emissions intensities for a number of reasons.

Volumes of oil produced and consumed are unlikely to decrease dramatically in the near future without disruptive market interventions. Quite the contrary—global oil consumption is projected to increase by approximately 20 percent over the next twenty years.[3] And though new fuel-efficient and electric vehicles that are recharged using renewables are slowly beginning to penetrate the market, auto fleet turnover takes many decades.[4] Moreover, oil is a key feedstock for plastics and other petrochemicals, it dominates air travel, and it fuels long-distance freight movements and other industry sectors. The oil industry

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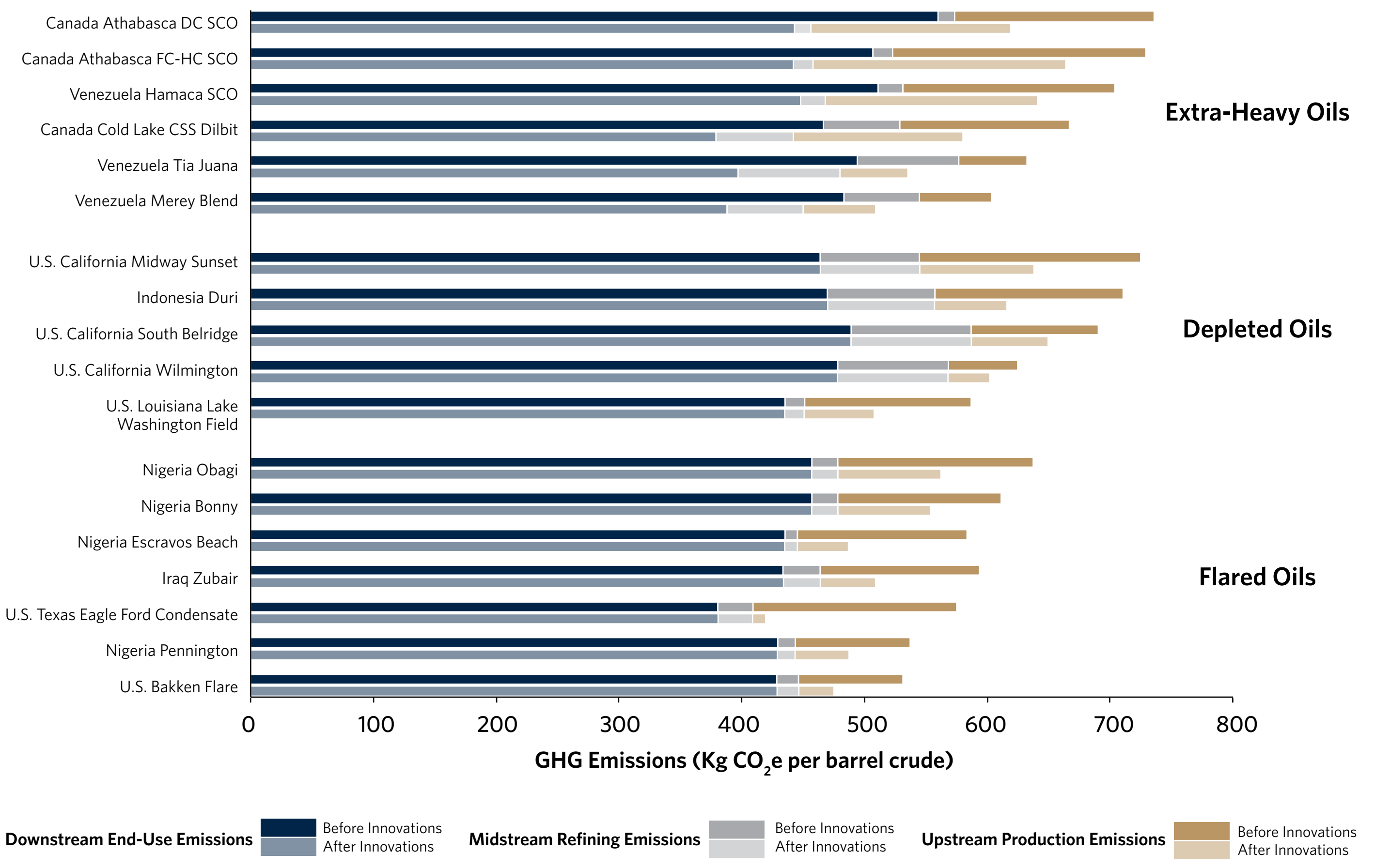
is deeply entrenched in the global economic and political system, as it continues to receive trillions of dollars in direct and indirect subsidies.[5] With the industry this insulated from the effects of the market and from current policies directed at disincentivizing oil production and consumption, it is unlikely that the industry will significantly reduce production in the absence of targeted policy reforms, such as a smart tax for oil.

Additionally, the emissions intensities of global oils are increasing. Producers are exploiting unconventional resources and employing unconventional techniques that, if poorly managed, can emit far more GHGs per barrel than conventional oil, as is made clear by the Carnegie Endowment for International Peace's Oil-Climate Index (OCI), which gauges GHG emissions throughout the oil supply chain.

Examples abound, particularly in three categories: tight oils and condensates, energy-intensive oils from depleted fields, and extra-heavy oils. Tight oils and condensates, like those found in the North American Bakken and Texas Eagle Ford plays, often have high volumes of natural gas sitting on top of or dissolved into the oil; producers can wastefully burn—or flare—this gas at the wellhead, contributing to the high emissions intensities of these resources. Oils from depleted fields require relatively more energy to extract due to low reservoir pressure and increasingly dense and often waterlogged crude. Extra-heavy oils and bitumen require large amounts of energy to extract, upgrade, or refine using existing pathways and techniques.

A number of innovations are poised to reduce the emissions intensities of extra-heavy, depleted, and flared tight oils, and these innovations in turn promise to cut aggregate emissions from the oil sector. This analysis focuses on a few of the most promising examples. Figure 1 estimates the potential per-barrel emissions savings for these high-GHG oils modeled in the OCI.

Figure 1. Reducing the Emissions of Energy-Intensive Oils Through Innovation



Source: Calculations based on the Carnegie Endowment for International Peace, "Oil-Climate Index," http://oci.carnegieendowment.org.

Note: This figure assumes a variety of emissions-reducing innovations. These include reducing the flare intensities of oils that contain associated gas, using solar steam technology and lowering the water intensities of oils from depleted plays, and foregoing the combustion of the petroleum coke (petcoke) produced during the refining of extra-heavy oils.

These three categories of oils have been selected for a number of reasons. They are climate intensive, and they constitute a major share of the world's remaining resources, estimated at 14 trillion barrels out of the roughly 24 trillion barrels of oil in place.[6] As demand for them increases, they can be better managed using innovative approaches.

ASSOCIATED GAS CAPTURE AND UTILIZATION

Gas flaring must be carefully managed and monitored because it can happen almost any time and point in the oil supply chain, especially for lighter oils and liquid condensates. The gas associated with oil is largely made up of methane, a potent GHG that drives climate change by a factor of 34 times greater than carbon dioxide and that therefore does significant damage when it is intentionally released or unintentionally escapes.[7]

While the associated gas in an oil reservoir has a monetary value that governments and oil companies can recoup, unfortunately technical, regulatory, economic, or geopolitical constraints too often result in its disposal through flaring or other methods. Each year, around 140 billion cubic meters of natural gas are wastefully burned worldwide when oil producers extract the gas alongside oil, releasing over 300 million metric tons of carbon dioxide annually,[8] approximately as much as the annual GHG emissions totals for individual countries like Egypt, the Netherlands, or Vietnam.[9]

Reducing the rate of gas that is flared by making use of better practices and new technologies can have a marked impact on emissions. For Texas Eagle Ford Condensate, for example, the OCI estimates that a 25 percent reduction in flaring can reduce upstream emissions by up to 26 percent.[10] Meanwhile, a 90 percent reduction can reduce upstream emissions by 93 percent (see figure 1).

There are many ways that oil producers can avoid flaring by making use of the associated gas that they extract from a reservoir along with oil: they can reinject the captured gas into the reservoir to improve oil recovery, use the gas as fuel on-site, or sell it on the market. Flaring associated gas is necessary on rare occasions when high volumes of gas surge out of a well. More routine flaring primarily occurs when it is not economically beneficial to capture gas and when gas-processing and transport infrastructure is insufficiently developed.

Durable reductions in flaring have proved elusive given the economic and other forces that influence day-to-day oil operation decisions. Countries in which oil operators flare natural gas have had mixed success in lowering volumes of gas flared. Global flaring data, derived from images taken between 2012 and 2014 by the Visible Infrared Imaging Radiometer Suite satellite instrument, show that some of the highest-flaring countries moderately reduced their flare volumes, such as Russia and Nigeria by 19 percent and 13 percent, respectively.[11] Meanwhile, Iraq, Venezuela, and the United States have increased their flare volumes (by 11 percent, 26 percent, and 23 percent, respectively).

Current policy efforts in a number of gas-producing jurisdictions appear to be helping diminish this wasteful practice. For example, many Russian oil and gas companies are projected to meet the 95 percent gas-capture rate in 2020 that the Ministry of Energy set after levying heavy fines for flaring.[12] In North Dakota, gas-capture rates have increased from around 71 percent in August 2013 to 89 percent in May 2016 with the institution of mandated gas-capture targets.[13]

There are important caveats to these successes, however. Remote fields in Russia remain difficult to address. The Russian government reports that a greater share of gas is flared in Siberia than what is gathered and utilized.[14] It is also unclear to what extent the increase in gas-capture rates achieved in North Dakota is attributable to the decline in production that has occurred since late 2014.[15] These reductions in North Dakota's flaring rates may not last if oil production volumes, along with volumes of associated gas, increase. Each unit of associated gas traveling through a pipeline diminishes the volume of gas that it can carry by more than one unit, due to the pipeline-clogging heavier natural gas liquids in Bakken associated gas. This leads to high rates of flaring even from wells connected to pipelines when high volumes of associated gas are produced.[16]

Using small-scale gas-capture and gas-processing technology at the site of oil extraction is one way to address these lingering gas-flaring challenges.[17] Modular, mobile technologies are more suited to twenty-first-century techniques of oil production, by which gas readily escapes during the process of fracturing light tight oils. Furthermore, because these kinds of operations tend to be quicker to develop, be more spread out geographically, and deplete more rapidly than conventionally drilled oil plays, pipeline infrastructure to transport the gas may take too long or be too costly to develop.

There are a number of such technologies already available, and the University of North Dakota has developed an online clearinghouse to connect producers with these technologies, including on-site generators and sophisticated chemical conversion machinery.[18] Statoil and General Electric have developed a technology to capture associated gas and convert it into compressed natural gas (CNG), replacing diesel power in their oil rigs. This approach makes both economic and environmental sense. The fuel substitution generated savings of $2 million over a 2014 pilot period, more than covering the $1.6 million cost of implementation.[19] Substituting CNG for diesel is also expected to reduce GHG emissions intensities. However, it does not appear that a comprehensive life-cycle analysis of this technology has yet been performed.

Beyond this novel technique, more research is needed on the emissions-intensity impacts of what are known as virtual pipelines—the use of trucks and trains for transporting CNG to market. In conjunction with regulatory standards and economic incentives, these approaches could overcome current technical limits to associated gas capture.[20]

While these innovations are just a few examples of technologies that aim to reduce near-term emissions from flaring, it is widely agreed that the current flaring situation must be addressed. Many governments, oil companies, and development institutions have signed on to the World Bank's Zero Routine Flaring by 2030 initiative.

Still, associated gas can continue to present challenges when it is not flared and instead unintentionally seeps out or is intentionally discharged. Such fugitive emissions and venting, respectively, are growing problems that are currently underreported, making it hard to know whether flare-reduction innovations diminish methane leaks and venting.[21] Innovations will be needed, including ongoing monitoring that uses remote sensing technologies, like the European satellite-based SCIAMACHY sensor and the satellites now being developed in France, Germany, and Japan.[22] Detecting the methane released in oil operations will be important for verifying operators' reports of this colorless and odorless gas that is invisible to the naked eye. Better knowledge about the conditions under which methane is released in turn must result in new operating protocols to reduce GHG emissions to ensure change happens.

ENHANCED OIL RECOVERY

Conventional global oils are depleting due to mounting consumption of fixed stocks worldwide. Primary and secondary extraction techniques that are used when the oil flows entirely or relatively freely are being replaced by tertiary recovery methods. The latter methods work harder to coax the remaining conventional oil out of the ground by soaking reservoirs with steam, flooding them with water, injecting gas, applying heat, or introducing other substances such as carbon dioxide and polymers.

These methods generally require significant additional energy inputs, and these large energy inputs usually result in higher GHG emissions. Much of the energy that these enhanced oil recovery (EOR) processes require comes from the emissions-intensive burning of fossil fuels. Although marginal costs of EOR are high, the initial costs of many of these older, depleted wells have been amortized over long lifetimes, making EOR economically viable even in the face of such energy penalties.

EOR techniques are often deployed on a case-by-case basis and are continually evolving. An estimated 1,500 EOR projects occurred worldwide between 1981 and 2016 (the years for which records were voluntarily reported).[23] EOR was first spurred by high oil prices following the oil crises of the 1970s; since then, these techniques have been in various stages of use to enhance the recovery of an estimated 30 to 70 percent of the remaining oil in place in mature reservoirs.[24] EOR deployment is expected to increase in the future if consumption continues to rise and oil prices remain relatively high.

A consequence of depleting oil resources and proliferating EOR projects is that the energy return on investment (EROI)—the ratio of the energy extracted to the energy required to extract the oil—has diminished over time. A 2009 research study estimated that the EROI for oil and gas projects peaked globally in 1999.[25] As more energy is required to extract depleting oil resources, these oils' emissions intensities tend to skyrocket. EOR techniques that involve injecting steam into reservoirs to improve the oil's flow have to date been the most common in active EOR projects worldwide, but oils extracted using this method were found to have the lowest EROI of a sample of forty global oils.[26] Accordingly, the OCI estimates that steam-intensive EOR oils have average upstream emissions that are 80 percent higher than the upstream emissions of the average OCI oil. The high energy inputs required for steam may be one reason why EOR techniques, such as injecting carbon dioxide gas into depleted reservoirs, are increasingly being used. That said, such injection technologies raise new GHG issues that extend beyond the emissions directly related to their EROI. The source of carbon dioxide and whether this potent GHG is permanently sequestered in the oil reservoir must be considered when determining whether these EOR projects reduce, or actually increase, emissions over their lifetimes.

Another way to reduce the energy and emissions impacts of today's steam-intensive EOR projects is by using renewable resources to power them—technological developments have made this approach possible. Solar thermal EOR is currently the most promising renewable EOR technology. It uses concentrated solar power (CSP) to turn water into steam, which is then pumped into a reservoir. The OCI estimates for the depleted California Midway Sunset oil field, for example, indicate that reducing the energy input used to generate steam by 50 percent can reduce upstream emissions by up to 47 percent (see figure 1). The largest investments in solar thermal EOR as of 2016 have been made by Petroleum Development Oman,[27] the country's majority-state-owned oil company; these investments aim to boost its oil recovery rates without consuming large volumes of valuable natural gas.

Investments in renewable steam EOR may even reduce emissions beyond the oil sector. Heat accounts for two-thirds of industrial energy needs,[28] and thus solar steam has the potential to reduce emissions not only upstream but also midstream at refineries, as well as in other industrial processes outside the oil sector.[29] By investing oil-sector capital in renewables, developing economies of scale that lower the cost of CSP, and cross-training workers in the field, solar thermal EOR providers may build a wider bridge from fossil fuels to a lower-carbon economy.

EXTRA-HEAVY OIL TECHNOLOGIES

Among the most emissions-intensive oils modeled in the OCI is a broad and evolving category of extra-heavy oils, including solid bitumen from Canada's oil sands and the semisolid resources in Venezuela's Orinoco oil belt. Extra-heavy oils also include oil shales—such as kerogen, a mixture of chemical compounds found in organic matter in sedimentary rocks—that are being produced today in limited amounts in Estonia. Moreover, as oils deplete, their character can change markedly, making them heavier—or lighter. For example, California's Midway Sunset depleted oil field now contains a heavy to extra-heavy oil, whereas the UK's long-producing Brent oil field is turning into a gas field as it ages. This can make extraction more emissions intensive, depending on the techniques used.

It is useful to focus on the state of research in the Canadian oil sands because research is active and more or less transparent in this area. Still, energy technology innovations will have an impact on extra-heavy oil extraction around the globe. The average extra-heavy oil modeled in the OCI is 23-percent more emissions intensive than the index's average oil, and these excess emissions arise at nearly every stage in the supply chain, from extraction to refining to the combustion of by-products. Huge stores of emissions-intensive, extra-heavy oil resources make it imperative that innovations be developed and widely introduced in Canada, in Venezuela, and ultimately worldwide.

Bitumen that is locked up in sandstone (oil sands) is one type of an expanding array of extra-heavy oil resources. For bitumen from Canadian oil sands, there are two predominant modes of extraction. Shallow bitumen resources can be dug out at the surface through open pits or strip mines. This is a resource-intensive process that requires clearing forests, heating the extracted oil sands with water and diluents to obtain solid bitumen, and then transporting the bitumen by truck to upgrading plants where it can be processed into a synthetic crude. Trucks contribute significantly to the GHG footprints of surface mining.

Yet, it is estimated that 80 percent of Canada's bitumen resources are located deeper underground (or in situ),[30] and most future bitumen extraction will require what are known as in-situ production techniques to mobilize the practically solid substance. The most widely used technique today, steam-assisted gravity drainage, involves generating steam and pumping it underground through a well to liquefy the bitumen, which is collected in a separate lower well. This technique is the most energy-intensive process associated with bitumen production,[31] and it is the process most likely to present opportunities to reduce emissions intensities. In-situ techniques also include cyclic steam stimulation, which uses high-pressure steam to fracture the oil sands and melt the bitumen, so it flows to the surface. Advanced in-situ pathways can use solvents, microbes, and other mechanisms under development.

Once the bitumen is extracted, there are a number of pathways by which it can flow to the refinery and be converted into petroleum products. It can be upgraded into synthetic crude oil to be sent to a refinery, a process that requires significant amounts of fossil-fuel energy and creates petroleum coke (petcoke) as a by-product. Or bitumen can instead be sent to refineries in a mixture of diluent, known as dilbit, which flows as a liquid. At the refinery, an energy-intensive and petcoke-producing process similar to upgrading must be used to refine the dilbit. If combusted, the petcoke by-products greatly increase the emissions associated with oil-sands crudes.

Opportunities for technological innovation to reduce GHG emissions are available at each step in the supply chain for extra-heavy oils. A relatively simple way to reduce climate impacts from these oils is to develop noncombustible uses for the solid residual carbon that remains when they are upgraded or refined. The OCI estimates for Canada Athabasca Delayed Coker Synthetic Crude Oil, for example, indicate that a 50 percent reduction in petcoke combustion can reduce downstream emissions by 10 percent. Meanwhile, eliminating petcoke combustion altogether for this candidate oil sand can reduce downstream emissions by 21 percent (see figure 1).

A range of other extra-heavy oil innovations are in various stages of development. Using solvent-assisted or solvent-based processes, producers can reduce or eliminate steam requirements, in turn reducing energy requirements and GHG emissions. One solvent-assisted project demonstrated a reduction in GHG emissions of 25 percent relative to conventional in-situ techniques, while improving recovery rates; solvent-based projects still in early development may reduce emissions by up to 90 percent. Electromagnetic heating—using microwaves—could shorten the time needed to heat bitumen, help avoid heat losses to the environment by directly transmitting energy to the bitumen, and diminish GHG emissions relative to steam-based processes.[32]

The use of renewable resources to power extraction and upgrading could also greatly reduce the emissions associated with these energy-intensive processes. In addition, the use of nanoscale technologies and microbes to liberate energy from oil sands while keeping their associated carbon in the ground is being researched.[33] Ultimately, since extra-heavy oils are all naturally deficient in hydrogen, the needed addition of zero-GHG hydrogen derived from renewable resources instead of hydrogen derived from fossil fuels could significantly reduce the GHG footprint of these oils. Moreover, technological breakthroughs on renewable hydrogen could act as a firm bridge between the oil sector and non-fossil-fuel energy production and storage.[34]

REDUCING EMISSIONS THROUGH OIL INNOVATION

As reported in the *Oil and Gas Journal*, International Energy Agency Executive Director Fatih Birol has said that it is “extremely crucial” that Canada employ advanced technology even if this increases the cost of oil-sands production, since it is a “key asset-protection strategy.”[35] This opportunity extends beyond Canada to the array of other global oils with their own climate challenges. To ensure that oil production, refining, transport, and end use proceeds in a way that is consistent with climate change goals, these oil resources must be safely managed worldwide.

These and other future emissions-reducing technologies may greatly affect the oil sector’s climate impacts, but their mere existence does not ensure their uptake and durability. One example is solar steam for depleted oils. Although a Chevron pilot project performed well in California’s depleted Coalinga oil field, it has since ceased to operate due to weak economic signals from low-priced natural gas and volatile regulatory signals.[36] Another example is the petcoke used for reclaiming oil sands from open pits in Canada. Although this residual by-product is not being combusted, it may take changes to Canadian law to guarantee that this resource remains permanently buried.

Innovations that reduce the oil sector’s GHG emissions must be spurred through smart policies. This begins with data transparency, as well as expanding and using tools such as the OCI that can inform regulations and investments in research and development. But such transformative technologies are not expected to be economically competitive without the application of a carbon tax that sends a direct and long-lasting market signal to oil sector stakeholders.

The widespread implementation of these emissions-reducing technologies is contingent on outcomes associated with the complex and uncertain workings of markets, public policies, and scientific research, a web of interactions that scholars have called the energy technology innovation system (ETIS). The literature on the ETIS emphasizes the roles of actors, institutions, policy regimes, and investments in the successful deployment of new energy technologies. The relationships, planning, and feedback among these ETIS elements at each stage of technological development ultimately influence what is achievable in terms of emissions reductions. Given the high-risk and high-reward fundamentals of the oil sector's business model and the odds that it will remain profitable for at least another generation, it will take more than the prospect of innovation to change course.[37]

Oil's emissions footprint, though it certainly will change as unconventional oil resources and techniques transform the sector, does not have to continue to grow. Reducing the climate impacts of the most emissions-intensive oils is possible with technologies that already exist. Even greater reductions are possible with innovations undergoing development. Technology-focused policies can kick-start the low-carbon future that the climate, and the Paris Agreement, demands.

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